EXHIBIT 12

Top 10 Stationary Sources of Greenhouse Gas Emissions in Washington

- 2022 -

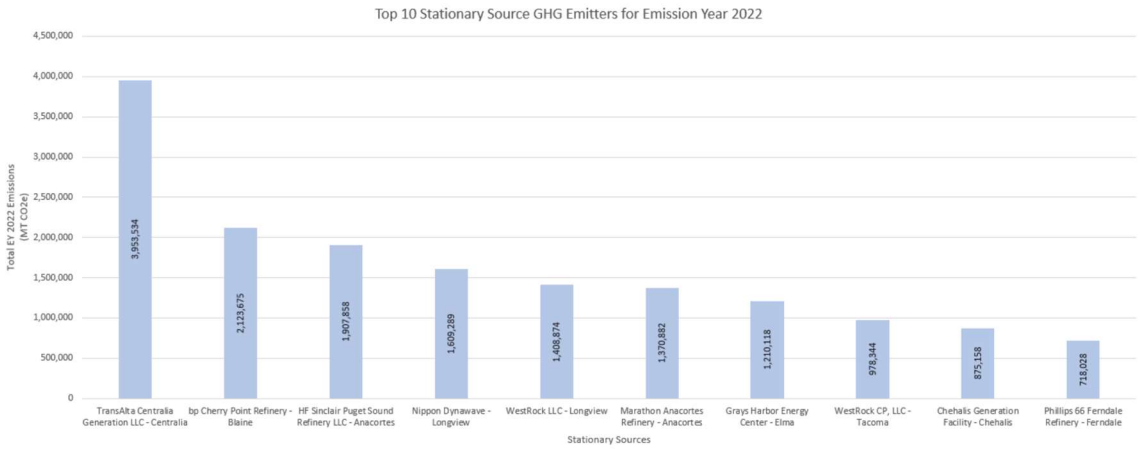


Figure 1 - Bar graph displaying the reported emissions for 2022 of the ten largest stationary sources of greenhouse gas emissions in Washington based on the data reported to Ecology pursuant to the mandatory greenhouse gas reporting program, all of which is available on Ecology's public data page. *See* https://data.wa.gov/Natural-Resources-Environment/GHG-Reporting-Program-Reporter-Emissions/84ua-fhbx. Note: the bar graph does not include fuel suppliers or electric power entities, as they are not stationary sources. Fuel suppliers report emissions associated with the end use of their product, while electric power entities report emissions based on the imported and exported electricity in Washington.

EXHIBIT 13

Facility	GHGRP ID	City	State	ZIP Code	Address	Latitude, Longitude	Reported Subsectors	Subparts	NAICS Code	2023 Total Reported Direct Emissions (Metric Tons CO2e)
AGRIUM US INC - KFO	1004236	KENNEWICK	Washington	99337	227515 E BOWLES ROAD	[-119.017218,46.165957]	Nitric Acid Production	C,U,V	325311	13,399.79
Air Liquide Hydrogen Plant	1007253	Anacortes	Washington	98221	8581 South Texas Road	[-122.553982,48.467675]	Hydrogen Production	P	325120	72,276.60
ALCOA INTALCO WORKS	1003562	FERNDALE	Washington	98248	4050 MOUNTAIN VIEW RD.	[-122.7055,48.8455]	Aluminum Production, Industrial Landfills	C,F,TT	331313	8,533.45
ANALOG DEVICES	1004746	CAMAS	Washington	98607	4200 NW PACIFIC RIM BLVD	[-122.45204,45.59995]	Electronics Manufacturing	C,I	334413	18,420.96
Ardagh Glass Inc. (Seattle)	1000024	SEATTLE	Washington	98134	5801 EAST MARGINAL WAY SOUTH	[-122.337152,47.551767]	Glass Production	C,N	327213	44,364.37
ASH GROVE CEMENT COMPANY-SEATTLE	1002537	SEATTLE	Washington	98134	3801 EAST MARGINAL WAY SOUTH	[-122.34255,47.56799]	Cement Production	C,H	327310	367,650.90
Asotin County Regional Landfill	1014475	Clarkston	Washington	99403	2901 6th Ave	[-117.111887,46.383767]	Municipal Landfills	C,HH	562212	60,392.91
Avista Corporation-WA	1003050	Spokane	Washington	99220	1411 E. Mission	[-117.39,47.66]	Natural Gas Distribution, Natural Gas Local Distribution Companies	NN,W	221210	16,268.35
Avista Landfill	1014921	Kettle Falls	Washington	99141		[-118.0893892,48.6001297]	Industrial Landfills	TT	562212	6,485.50
Basic American Foods	1010722	Moses Lake	Washington	98837	538 Potato Frontage Road	[-119.222474,47.075778]	Food Processing	C	311423	24,109.86
Boeing Commercial Airplanes - Everett	1000640	Everett	Washington	98204	3003 West Casino Rd	[-122.273197,47.923302]	Other Manufacturing	C	336411	66,124.50
BOISE PAPER	1002893	WALLULA	Washington	99363	31831 WEST HIGHWAY 12	[-118.911147,46.097264]	Industrial Landfills, Pulp and Paper Manufacturing	AA,C,TT	322130	99,158.25
Boulder Park Generating Station	1010860	Spokane Valley	Washington	99027	4424 N. Barker Road	[-117.154729,47.696823]	Power Plants	C	221112	31,456.23
BP CHERRY POINT REFINERY	1006468	BLAINE	Washington	98230	4519 GRANDVIEW ROAD	[-122.735,48.884]	CO2 Capture, Hydrogen Production, Petroleum Refineries	C,MM,P,PP,Y	324110	2,179,352.24
Cardinal FG Company	1004225	Winlock	Washington	98596	545 Avery Road West	[-122.9259,46.5439]	Glass Production	C,N	327211	107,117.58
Cascade Natural Gas Coporation - Washington	1006497	Kennewick	Washington	99336	8113 W Grandridge Blvd	[-119.22946,46.21929]	Natural Gas Distribution, Natural Gas Local Distribution Companies	NN,W	221210	27,197.99
Cathcart Landfill	1006550	SNOHOMISH	Washington	98296	8915 Cathcart Way	[-122.123604,47.872482]	Municipal Landfills	C,HH	562111	22,301.33
Centralia	1007310	CENTRALIA	Washington	98531	913 BIG HANAFORD RD	[-122.8578,46.7559]	Power Plants	C,D	221112	4,536,949.43
CenTrio	1002677	SEATTLE	Washington	98101	1319 WESTERN AVE	[-122.340619,47.605772]	Power Plants	C	221330	68,650.52
CERTAINTEED GYPSUM SEATTLE	1006572	SEATTLE	Washington	98134	5931 E MARGINAL WY S	[-122.337341,47.547909]	Other Minerals	C	327420	55,644.54
Chehalis Generation Facility	1000144	CHEHALIS	Washington	98532	1813 BISHOP ROAD	[-122.9145,46.6226]	Power Plants	C,D	221112	914,725.61
City of Spokane Waste-to-Energy	1004053	SPOKANE	Washington	99224	2900 S GEIGER BLVD	[-117.49944,47.62846]	Solid Waste Combustion	C	562213	100,598.63
Cosmopolis Pulp Mill	1008999	Cosmopolis	Washington	98537	1701 First St	[-123.761737,46.953543]	Industrial Landfills, Pulp and Paper Manufacturing	AA,C,TT	322110	2,864.00
Cowlitz County Headquarters Landfill	1008180	Castle Rock	Washington	98611	3434 South Silver Lake Road	[-122.778109,46.248725]	Municipal Landfills	C,HH	562212	317,648.03
COWLITZ COUNTY LANDFILL	1005412	LONGVIEW	Washington	98632	85 TENNANT WAY	[-122.905601,46.107229]	Municipal Landfills	C,HH	562212	26,798.49
Darigold Inc	1010891	Sunnyside	Washington	98944	400 Alexander Road	[-120.015979,46.300368]	Food Processing	C	311513	36,711.16
Encogen Generating Station	1006502	Bellingham	Washington	98225	915 Cornwall Ave	[-122.486,48.746]	Power Plants	D	221112	427,032.47
Frederickson Power LP	1000301	Tacoma	Washington	98446	18610 50Th Ave East	[-122.3644,47.0864]	Power Plants	D	221112	708,700.82
Frederickson PSE	1004175	TACOMA	Washington	98446	4714 192ND STREET EAST	[-122.3649,47.08187]	Power Plants	C	221112	118,684.19
Fredonia Generating Station	1004066	Mount Vernon	Washington	98273	13085 Ball Road	[-122.435,48.4553]	Power Plants	C,D	221112	641,257.23

Facility	GHGRP ID	City	State	ZIP Code	Address	Latitude, Longitude	Reported Subsectors	Subparts	NAICS Code	2023 Total Reported Direct Emissions (Metric Tons CO2e)
Gas Transmission Northwest Pipeline Rosalia CS#6	1004773	ROSALIA	Washington	99170	EAST 315 BABB ROAD	[-117.406708,47.277262]	Natural Gas Transmission/Compression	C,W	486210	113,466.93
Gas Transmission Northwest Pipeline Wallula CS#8	1004775	WALLULA	Washington	99363	638 LAMBDIN RD	[-118.843934,46.053153]	Natural Gas Transmission/Compression	C,W	486210	133,439.56
Gas Transmission Northwest Starbuck Sta.#7 (Starbuck, WA)	1012641	Starbuck	Washington	99359	Lyons Ferry Road	[-118.1273778,46.5185845]	Natural Gas Transmission/Compression	C,W	486210	133,777.70
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1005998	CAMAS	Washington	98607	401 NE ADAMS STREET	[-122.407758,45.582929]	Industrial Landfills, Other Paper Producers	C,TT	322120	53,793.62
GEORGIA-PACIFIC GYPSUM LLC	1005059	TACOMA	Washington	98421	1240 ALEXANDER AVENUE	[-122.394869,47.269558]	Other Minerals	C	327420	49,843.24
GOLDENDALE GENERATING STATION	1001436	GOLDENDALE	Washington	98620	600 INDUSTRIAL WAY	[-120.833,45.8114]	Power Plants	D	221112	826,171.79
GOODRICH SPOKANE LANDING SYSTEMS, CARBON PRODUCTS	1000363	SPOKANE	Washington	99224	11135 W WESTBOW BLVD	[-117.568511,47.583604]	Other Manufacturing	C	336413	18,147.03
GRANT CNTY EPHRATA LANDFILL 1	1007160	EPHRATA	Washington	98823	3803 Neva Lake Rd. NW	[-119.55494,47.26597]	Municipal Landfills	HH	562212	41,759.00
Grays Harbor Energy Center	1000207	Elma	Washington	98541	401 Keys Rd	[-123.48,46.9688]	Power Plants	C,D	221112	1,397,812.07
HF Sinclair Puget Sound Refining LLC	1004211	ANACORTES	Washington	98221	8505 SOUTH TEXAS ROAD	[-122.560194,48.472836]	Petroleum Refineries	C,MM,Y	324110	1,900,998.90
Hidden Valley Landfill	1004384	Puyallup	Washington	98375	17925 Meridian Street East	[-122.2878,47.095]	Municipal Landfills	HH	562212	5,313.00
Horn Rapids Landfill	1007090	Richland	Washington	99352	3102 Twin Bridges Road	[-119.346,46.3432]	Municipal Landfills	HH	562212	29,884.75
J R SIMPLOT CO	1002804	OTHELLO	Washington	99344	1201 N BROADWAY AVE	[-119.176389,46.837778]	Food Processing, Wastewater Treatment	C,II	311411	107,816.90
J. R. Simplot Co.	1002832	Moses Lake	Washington	98837	14124 Wheeler Road NE	[-119.18926,47.131732]	Food Processing, Wastewater Treatment	C,II	311411	26,271.28
Jackson Prairie Natural Gas Storage	1012347	Chehalis	Washington	98532	239 Zandecki Rd	[-122.835181,46.53254]	Underground Natural Gas Storage	C,W	486210	14,652.05
Kaiser Aluminum Washington	1002056	Spokane Valley	Washington	99216	15000 E Euclid Ave	[-117.212673,47.687074]	Other Metals	C	331315	124,834.28
Kettle Falls Generating Station	1010858	Kettle Falls	Washington	99141	1151 Hwy. 395 North	[-118.10147,48.614625]	Power Plants	C	221117	22,132.00
KING CNTY SOLID WST CEDAR HILLS LANDFILL	1007822	MAPLE VALLEY	Washington	98038	16645 228TH AVENUE SE	[-122.046025,47.462625]	Municipal Landfills	C,HH	562212	249,403.18
LAMB WESTON	1000607	CONNELL	Washington	99326	811 GUM STREET	[-118.872717,46.651744]	Food Processing	C	311411	26,956.45
Lamb Weston Holdings Inc	1000613	Quincy	Washington	98848	1005 E Street SW	[-119.869914,47.234413]	Food Processing	C	311411	29,971.19
Lamb Weston Inc.	1000614	RICHLAND	Washington	99352	2013 SAINT STREET	[-119.297683,46.309388]	Food Processing, Wastewater Treatment	C,II	311411	74,726.36
LAMB WESTON INC. PASCO	1000611	PASCO	Washington	99301	960 GLADE ROAD NORTH	[-119.115336,46.288137]	Food Processing	C	311411	35,749.92
LAND RECOVERY LANDFILL INDUST	1004679	GRAHAM	Washington	98338	30919 MERIDIAN STREET EAST	[-122.292929,47.127923]	Municipal Landfills	HH	562212	119,144.50
LANXESS Corporation Kalama Site	1003518	KALAMA	Washington	98625	1296 NORTHWEST 3RD STREET	[-122.85698,46.02191]	Other Chemicals	C	325199	60,119.92
Matheson - Anacortes Hydrogen Plant	1010969	Anacortes	Washington	98221	8529 South Texas Road	[-122.565397,48.465891]	Hydrogen Production	P	325120	53,407.10
MCCAIN FOODS USA INC	1002287	OTHELLO	Washington	99344	100 LEE STREET	[-119.174622,46.836659]	Food Processing, Wastewater Treatment	C,II	311411	59,352.13
Milne Fruit Products	1014644	Prosser	Washington	99350	804 Bennett Ave	[-119.776211,46.202338]	Food Processing	C	311411	7,387.07
Mint Farm Generation Station	1001435	Longview	Washington	98632	1200 Prudential Blvd	[-122.9842,46.1403]	Power Plants	D	221112	798,750.44

Facility	GHGRP ID	City	State	ZIP Code	Address	Latitude, Longitude	Reported Subsectors	Subparts	NAICS Code	2023 Total Reported Direct Emissions (Metric Tons CO2e)
Mutual Materials	1014553	Mica	Washington	99023	10627 Sr 27	-	Other Minerals	C	327120	8,595.67
Naval Base Kitsap Bremerton	1001816	Bremerton	Washington	98314	120 South Dewey Street	[-122.646324,47.562807]	Military	C	928110	41,809.04
NIPPON DYNAWAVE PACKAGING	1006360	LONGVIEW	Washington	98632	3401 INDUSTRIAL WAY	[-122.974048,46.122749]	Pulp and Paper Manufacturing	AA,C	322130	376,731.57
North Pacific Paper Company LLC	1012181	Longview	Washington	98632	3001 Industrial Way	[-122.968082,46.118735]	Other Paper Producers	C	322120	36,394.81
Northwest Pipeline GP - Pipeline	1013340	Tulsa	Washington	74172	One Williams Center	[-95.67245,36.08256]	Natural Gas Transmission Pipelines	W	486210	2,592.50
NORTHWEST PIPELINE GP - SNOHOMISH C/S	1007092	Snohomish	Washington	98390	22902 Echo Lake Road	[-122.05728,47.78943]	Natural Gas Transmission/Compression	C,W	486210	69,638.45
NORTHWEST PIPELINE GP GOLDENDALE C/S	1009017	Goldendale	Washington	99322	120 Hoctor Road	[-120.799267,45.771216]	Natural Gas Transmission/Compression	C,W	486210	20,981.93
NORTHWEST PIPELINE GP MT. VERNON	1009161	Mt. Vernon	Washington	98295	1539 Lange Road	[-122.20969,48.41248]	Natural Gas Transmission/Compression	C,W	486210	74,319.23
NORTHWEST PIPELINE GP ROOSEVELT C/S	1009019	Bickleton	Washington	99322	652 Sixprong Road	[-120.213925,45.9034459]	Natural Gas Transmission/Compression	C,W	486210	11,254.76
NORTHWEST PIPELINE GP SUMAS C/S	1007513	SUMAS	Washington	98295	4738 JONES RD	[-122.2214,49.001]	Natural Gas Transmission/Compression	C,W	486210	105,263.46
NORTHWEST PIPELINE GP SUMNER C/S	1009163	Sumner	Washington	98390	3104 166th Ave. E	[-122.209551,47.228986]	Natural Gas Transmission/Compression	C,W	486210	51,136.26
NORTHWEST PIPELINE GP WASHOUGAL C/S	1009215	Washougal	Washington	98671	1309 NE Brown Road	[-122.36516,45.63236]	Natural Gas Transmission/Compression	C,W	486210	10,942.27
NORTHWEST PIPELINE GP WILLARD C/S	1009016	Cook	Washington	98605	Willard Rd. Milepost 1	[-121.626,45.7769]	Natural Gas Transmission/Compression	C,W	486210	9,153.27
NUCOR STEEL SEATTLE INC	1000029	SEATTLE	Washington	98106	2424 SOUTHWEST ANDOVER STREET	[-122.367332,47.569331]	Iron and Steel Production	C,Q	331110	82,395.85
NW Natural - Washington	1011405	Portland	Washington	97204	250 SW Taylor Street	[-122.588485,45.370186]	Natural Gas Distribution, Natural Gas Local Distribution Companies	NN,W	221210	9,114.25
OLYMPIC VIEW SANITARY LANDFILL INC	1003586	PORT ORCHARD	Washington	98367	10015 SOUTHWEST BARNEY WHITE ROAD	[-122.78081,47.50473]	Municipal Landfills	HH	562212	497.00
PHILLIPS 66 FERNDALE REFINERY	1008018	FERNDALE	Washington	98248	3901 UNICK ROAD	[-122.692114,48.830142]	Petroleum Refineries	C,MM,Y	324110	902,436.38
PORT TOWNSEND PAPER CORP	1005732	PORT TOWNSEND	Washington	98368	100 MILL ROAD	[-122.796806,48.093793]	Industrial Landfills, Pulp and Paper Manufacturing	AA,C,TT	322120	62,519.29
PSE Ferndale Generating Station	1000001	FERNDALE	Washington	98248	5105 LAKE TERRELL ROAD	[-122.685533,48.828707]	Power Plants	D	221112	715,257.16
PUGET POWER ENERGY-WHITEHORN GEN.STATION	1004176	BLAINE	Washington	98230	4930 BROWN RD.	[-122.753527,48.886533]	Power Plants	C	221112	308,591.29

Facility	GHGRP ID	City	State	ZIP Code	Address	Latitude, Longitude	Reported Subsectors	Subparts	NAICS Code	2023 Total Reported Direct Emissions (Metric Tons CO2e)
PUGET SOUND ENERGY - SUMAS	1004367	SUMAS	Washington	98295	1340 THOMPSON LANE	[-122.2733,48.9905]	Power Plants	D	221112	389,614.16
Puget Sound Energy LDC	1005387	Bellevue	Washington	98004	10885 NE 4th St	[-122.19453,47.61373]	Natural Gas Distribution, Natural Gas Local Distribution Companies	NN,W	221210	67,478.70
REC SOLAR GRADE SILICON	1007200	MOSES LAKE	Washington	98837	3322 ROAD N NE	[-119.1942,47.040595]	Other Metals	C	331410	5,955.63
Resers Fine Foods Inc	1014653	Pasco	Washington	99301	5526 N Capitol Ave	[-119.08574,46.278579]	Food Processing	C	311991	6,717.72
River Road	1001133	VANCOUVER	Washington	98660	5201 N W LOWER RIVER ROAD	[-122.7231,45.65]	Power Plants	D	221112	700,249.80
ROOSEVELT REGIONAL LANDFILL	1003676	ROOSEVELT	Washington	99356	500 ROOSEVELT GRADE ROAD	[-120.182,45.802]	Municipal Landfills	C,HH	562212	235,650.15
SOLVAY CHEMICALS INC	1005156	LONGVIEW	Washington	98632	3500 INDUSTRIAL WAY	[-122.982513,46.136952]	Hydrogen Production	P	325180	50,067.50
TACOMA CITY SOLID WASTE FAC	1005619	TACOMA	Washington	98409	3510 SOUTH MULLEN	[-122.502724,47.231735]	Municipal Landfills	C,HH	562212	6,948.22
Tacoma LNG	1014541	Tacoma	Washington	98421	1001 East Alexander Avenue	-	Liquefied Natural Gas Storage, Other Combustion	C,W	221210	15,536.95
TESORO CORPORATION-ANACORTES REFINERY	1003904	ANACORTES	Washington	98221	10200 WEST MARCH POINT ROAD	[-122.564292,48.489534]	Petroleum Refineries	C,MM,Y	324110	1,202,266.94
THE BOEING COMPANY	1000639	AUBURN	Washington	98001	700 15TH ST SW	[-122.24277,47.283625]	Other Manufacturing	C	336413	33,303.22
TYSON FRESH MEATS	1000038	WALLULA	Washington	99363	13983 DODD ROAD	[-118.91564,46.13672]	Food Processing, Wastewater Treatment	C,II	311611	100,445.24
U.S. Department of Energy Hanford Site	1010830	Richland	Washington	99354	2420 Stevens Center Place	[-119.28001,46.32095]	Municipal Landfills, Use of Electrical Equipment	C,DD,HH	924110	30,898.61
University of Washington Seattle Campus	1002682	Seattle	Washington	98195		[-122.3041,47.6562]	Universities	C	611310	80,935.84
US ARMY JOINT BASE LEWIS-MCCHORD	1001561	Joint Base Lewis-McChord	Washington	98433	2012 Liggett Ave	[-122.609857,47.090196]	Municipal Landfills	C,HH	928110	71,410.53
US OIL & REFINING TACOMA	1007658	TACOMA	Washington	98421	3001 MARSHALL AVENUE	[-122.395259,47.257694]	Petroleum Refineries	C,MM,Y	324110	148,011.92
WaferTech LLC	1009361	Camas	Washington	98607	5509 NW Parker St.	[-122.456295,45.619591]	Electronics Manufacturing	C,I	334413	73,391.15
Washington Potato Company	1014463	Warden	Washington	98857	1900 W. 1st Street	[-119.064353,46.970696]	Food Processing	C	311991	31,872.28
WASHINGTON STATE UNIVERSITY	1005091	PULLMAN	Washington	99164	2660 GRIMES WAY	[-117.154274,46.728721]	Universities	C	611310	59,448.04
WASTE MANAGEMENT GREATER WENATCHEE LANDF	1007818	EAST WENATCHEE	Washington	98802	191 E WEBB RD	[-120.1704,47.4042]	Municipal Landfills	HH	562212	42,821.25
WESTROCK LONGVIEW LLC	1006454	LONGVIEW	Washington	98632	300 FIBRE WAY	[-122.926617,46.107527]	Pulp and Paper Manufacturing	AA,C	322130	182,361.23
WestRock Tacoma Mill	1000624	TACOMA	Washington	98421	801 PORTLAND AVE.	[-122.425332,47.26384]	Pulp and Paper Manufacturing	AA,C	322130	118,773.75
Weyerhaeuser Raymond Lumbermill	1010843	Raymond	Washington	98577	51 Ellis Street	[-123.736804,46.687926]	Other Manufacturing	C	321113	438.28
YAKIMA CNTY CHEYNE LANDFILL	1004918	ZILLAH	Washington	98953	4970 CHEYNE ROAD	[-120.2688,46.4785]	Municipal Landfills	HH	562212	47,466.25
YAKIMA COUNTY TERRACE HTS LANDFILL	1004916	YAKIMA	Washington	98901	7151 ROZA HILL DRIVE	[-120.393883,46.610587]	Municipal Landfills	C,HH	562212	130,876.25

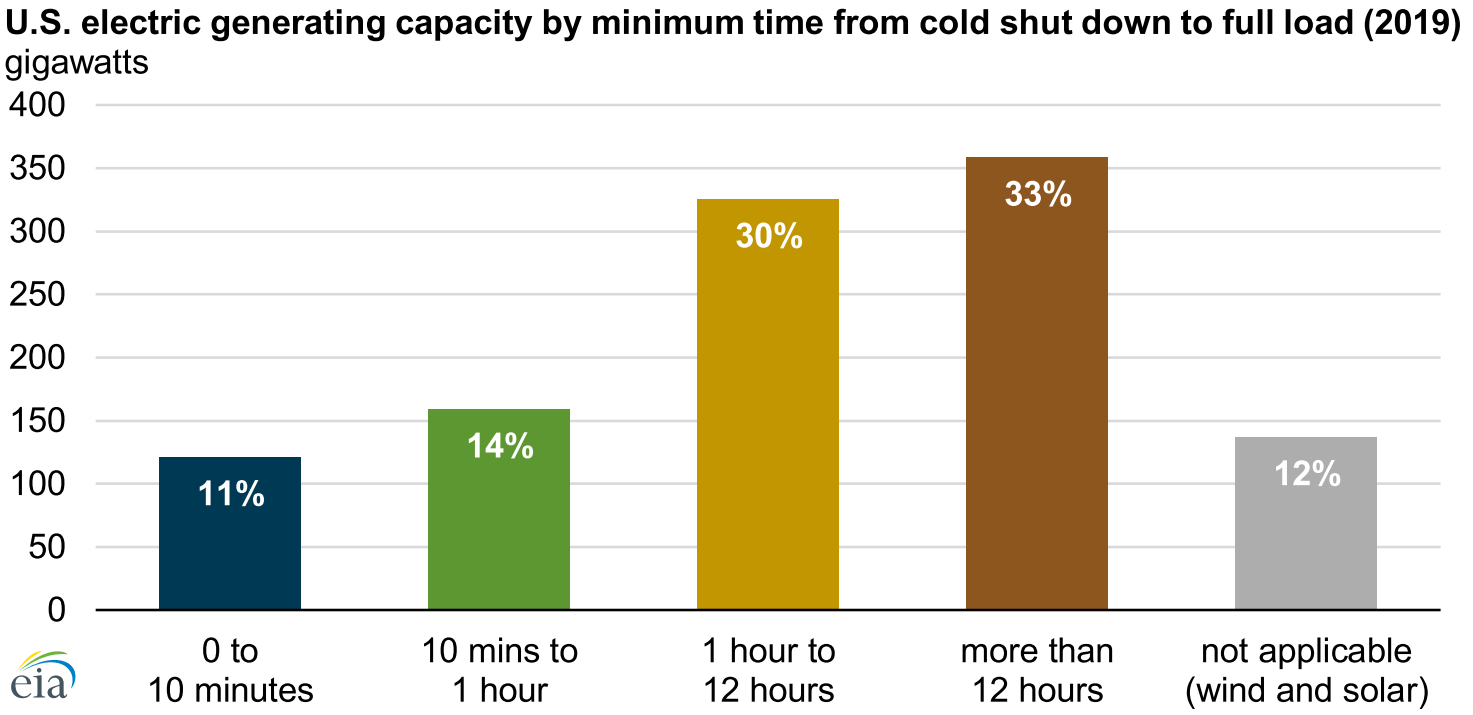
EXHIBIT 14

U.S. Energy Information Administration

Today in Energy

November 19, 2020

About 25% of U.S. power plants can start up within an hour



Source: U.S. Energy Information Administration, *Annual Electric Generator Inventory*

About 25% of U.S. power plants can start up—going from being shut down to fully operating—within one hour, based on data collected in EIA's annual survey of electric generators. Some power plants, especially those powered by coal and nuclear fuel, require more than half a day to reach full operations. The time it takes a power plant to reach full operations can affect the reliability and operations of the electric grid.

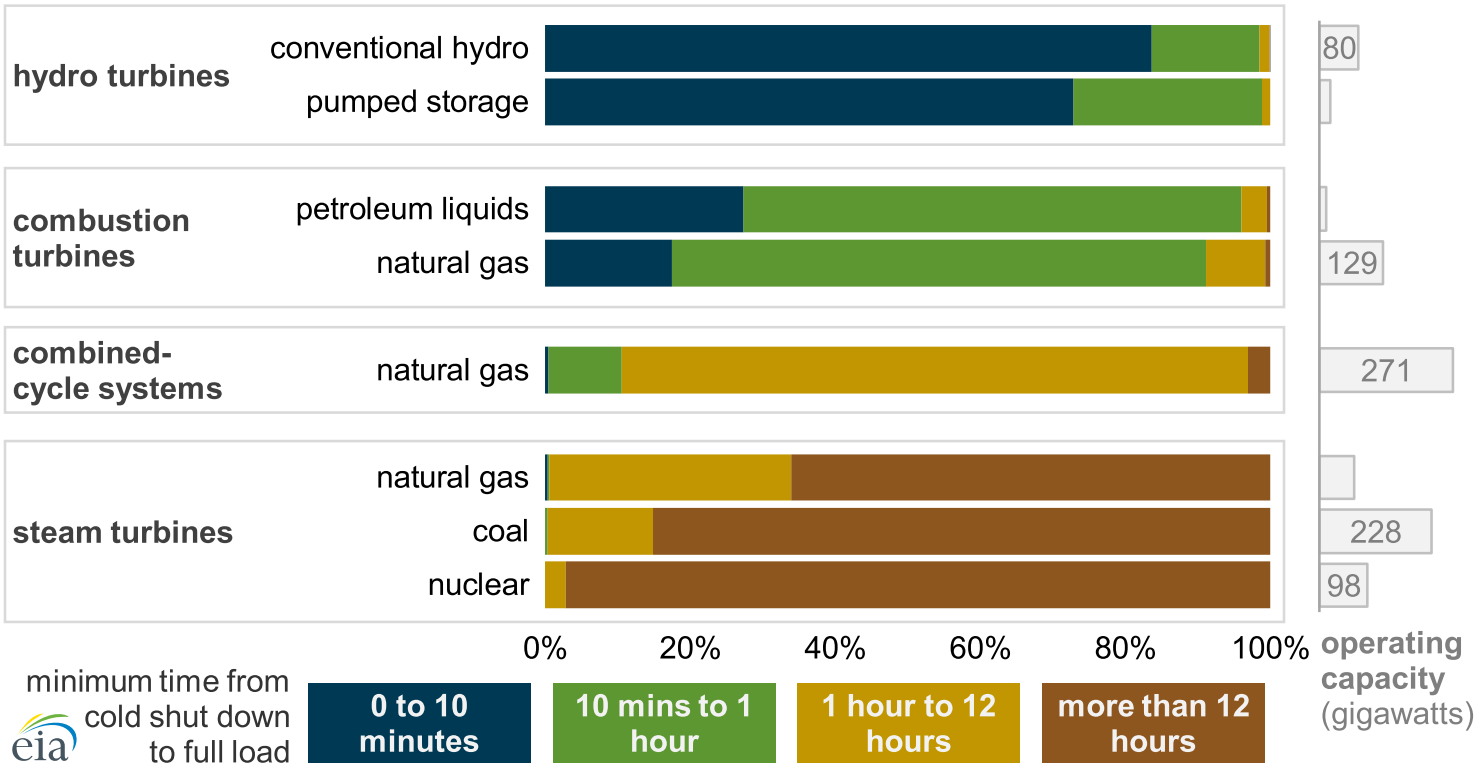
Generator startup time differs across electricity-generating technologies because of the differences in the complexity of electricity generating processes, especially when starting again after all processes have been stopped (cold shut down). A generator's startup time is different from a generator's ramp rate, which reflects how quickly that generator can modify its power output once it's operating.

Most hydroelectric turbines, which use flowing water to spin a turbine, can go from cold start to full operations in less than 10 minutes. Combustion turbines, which use a combusted fuel-air mixture to spin a turbine, are also relatively fast to start up.

Steam turbines often require more time. A fuel heats up water to form steam, and that steam needs to reach certain temperature, pressure, and moisture content thresholds before it can be directed to a turbine that can spin the electricity generator.

Nuclear power plants use steam turbines, but these plants have additional time-intensive processes that involve managing their nuclear fuel. Almost all nuclear power plants require more than 12 hours to reach full operations. Power plants that require more than 12 hours to start up are increasingly rare. Only 4% of the generating capacity that came online from 2010 to 2019 requires more than half a day to reach full load.

U.S. electric generating capacity by minimum time from cold shut down to full load (2019)



Source: U.S. Energy Information Administration, *Annual Electric Generator Inventory*
Note: Only technology/fuel combinations with at least 10 gigawatts of operating capacity are shown.

Natural gas combined-cycle systems, which involve both a steam turbine and a combustion turbine, account for more capacity than any other generating technology in the United States. Most of those systems can reach full operations in between 1 hour to 12 hours, although some can start up within an hour.

The percentage of the generator fleet that does not respond to this question in EIA's survey has doubled—from 6% in 2013, when EIA first collected this data, to 12% in 2019—as a result of the number of utility-scale solar and wind power plants added in recent years. This question is not relevant for these types of plants.

Principal contributor: Owen Comstock

EXHIBIT 15

Plant Job Under Way

Site preparation — the first step in construction of the $206 million Centralia steam - electric generation plant — started in the Hanaford Valley Thursday.

A spokesman for Pacific Power and Light Co., one of two sponsoring firms of the project, said Friday clearing of the site is under way.

Bulldozers of Morrison - Knudson Co., Inc., Seattle, were working on a hillside Friday to clear trees and brush.

The plant site is to be at an excavated hillside location to the south of the existing Hanaford Valley Road about five miles northeast of Centralia.

The existing road will be relocated to run south of the plant.

Site preparation will account for a major share of approximately $1 million worth of work scheduled this summer. M-K is expected to have about 50 men employed in the initial grading and the road work.

Bechtel Corp., construction managers and engineers for the project, have established an office in the former Charles Benz home PP and L also has an office there. M-K has established quarters in a trailer near the site, and large earth - movers are in readiness in a field north of the road.

Major boiler and turbine components have been ordered for the first 700,000 - kilowatt generating unit, scheduled to begin producing power from coal in September, 1971. The second unit will be built when power is required. Second major sponsor of the project is Washington Water Power Co.

NewspaperArchive by Storied

Centralia Daily Chronicle, June 14, 1968 Pg. 1, Centralia, Washington, US
https://newspaperarchive.com/centralia-daily-chronicle-jun-14-1968-p-1/

EXHIBIT 16

SWCAA
Southwest Clean Air Agency

11815 NE 99th Street, Suite 1294
Vancouver, WA 98682
(360) 574-3058
www.swcleanair.org

September 22, 2021

Mr. Mickey Dreher
TransAlta Centralia Generation, LLC
913 Big Hanaford Road
Centralia, WA 98531

Subject: Issuance of FINAL Title V Permit for TransAlta Centralia Generation

Dear Mr. Dreher:

The comment period for your draft Air Operating Permit (SW98-8-R5-A) ended on July 25, 2021. The proposed permit dated July 30, 2021 was submitted to Region 10 of the Environmental Protection Agency for the mandatory 45 day review period. The EPA's 45-day review period has passed without comment from EPA; therefore, the Southwest Clean Air Agency is issuing the final Air Operating Permit as proposed.

Copies of the Final Air Operating Permit and Title V Basis Statement accompany this letter. In addition, copies of these documents will be available on SWCAA's website at http://www.swcleanair.org/permits/title5final.asp.

If you have any questions or comments, please contact me at (360) 574-3058 extension 131.

Sincerely,

Clint Lamoreaux
Air Quality Engineer

TransAlta Centralia Generation, LLC
Centralia Plant

Air Operating Permit
SW-98-8-R5-A

September 22, 2021

Southwest Clean Air Agency
11815 NE 99th Street, Suite 1294
Vancouver, WA 98682-2322
Telephone: (360) 574-3058

AIR OPERATING PERMIT NUMBER: SW98-8-R5-A

ISSUED TO: TransAlta Centralia Generation, LLC
913 Big Hanaford Road
Centralia, WA 98531

PLANT SITE: TransAlta Centralia Generation, LLC
913 Big Hanaford Road
Centralia, WA 98531

NATURE OF BUSINESS: Coal-Fired Electric Energy Generation

STANDARD INDUSTRIAL CLASSIFICATION CODE (SIC): 4911

NORTH AMERICAN INDUSTRY CLASSIFICATION SYSTEM CODE (NAICS): 221112

AEROMETRIC INFORMATION RETRIEVAL SYSTEM NUMBER: 53-041-10010

ACID RAIN PROGRAM
PLANT NAME: Centralia Plant
ORIS CODE: 03845

EFFECTIVE DATE: September 22, 2021

EXPIRATION DATE: October 14, 2024

RENEWAL APPLICATION DUE DATE: October 14, 2023

PERMIT ENGINEER:

Clint Lamoreaux, P.E., Air Quality Engineer — Date 9/22/2021

REVIEWED BY:

Paul T. Mairose, P.E., Chief Engineer — Date 9/22/2021



Uri Papish, Executive Director — Date 9/22/2021

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I. ABBREVIATIONS

List of Common Abbreviations

Administrator	EPA Administrator
AOP	Air Operating Permit
BAAQMD	Bay Area Air Quality Management District (California)
BACT	Best Available Control Technology
CAM	Compliance Assurance Monitoring (40 CFR 64)
CEM / CEMS	Continuous emission monitor / Continuous emission monitoring system
CFR	Code of Federal Regulations
CO	Carbon monoxide
DAHS	Data Acquisition and Handling System
EGU	Electric Utility Steam Generating Unit
EPA	U.S. Environmental Protection Agency
EU	Emissions unit
EU-"X"	Refers to a specific emissions unit numbered "X"
°F	Fahrenheit temperature, degrees
FCAA	Federal Clean Air Act
G"X"	Refers to a specific general term and condition numbered "X"
FGD	Flue gas desulfurization
gr/dscf	Grains per dry standard cubic foot
HAP	Hazardous air pollutant
IEU	Insignificant emissions unit
IEU"X"	Insignificant emissions unit numbered "X"
K"X"	Refers to a specific recordkeeping term or condition (requirement) numbered "X"
lb/hr	Pounds per hour
lb/MMBtu	Pounds per million British thermal units
M"X"	Refers to a specific monitoring term or condition (requirement) numbered "X"
MW	Megawatts
MW_{ge}	Megawatts, gross electric
NO_X	Oxides of nitrogen
NSR	New source review
O_2	Oxygen
PM	Particulate matter
PM_{10}	Particulate matter with an aerodynamic diameter less than or equal to 10 micrometers
$PM_{2.5}$	Particulate matter with an aerodynamic diameter less than or equal to 2.5 micrometers
ppm	Parts per million
ppmvd	Parts per million, dry volume basis
@ X% O_2	Corrected to X% oxygen content
PTE	Potential to emit
R"X"	Refers to a specific reporting requirement numbered "X"
RACT	Reasonably Available Control Technology
RCW	Revised Code of Washington
Region 10	Region 10 of the U.S. Environmental Protection Agency
Req-X	Applicable operating term or condition (requirement) numbered "X"
SO_2	Sulfur dioxide
SIP	State implementation plan
SWCAA	Southwest Clean Air Agency
TAP	Toxic air pollutant
VOC	Volatile organic compound
WAC	Washington Administrative Code
WDOE	Washington Department of Ecology

Terms not otherwise defined in this permit have the meaning assigned to them in the referenced regulations.

II. REGULATORY BASIS

This Air Operating Permit, hereafter referred to as the "Permit," is authorized under the procedures established in Washington Administrative Code (WAC) 173-401 and Title V (US Code §7661 *et seq.*) of the Federal Clean Air Act (FCAA). As used in this Permit, "term," "condition," "standard," and "requirement" have the same meaning as "applicable requirement" specified under 40 CFR 70.2 and WAC 173-401-200.

The Permit is intended to contain a comprehensive list of the local, state, and federal air pollution regulations and standards applicable to the Permittee's facility and to assure and provide for certification of compliance with those requirements. As listed in Sections V through VIII the requirements describe the emissions limitations, operating requirements, ambient monitoring, recordkeeping requirements, and reporting frequencies for the facility and cite the originating local, state, or federal regulation or requirement. Federal requirements may be direct (e.g. FCAA or CFR citation) or established under the Washington State Implementation Plan (SIP). Each citation in the table also includes one or two effective dates of the cited regulation. Where there are two dates for the same regulatory citation, the underlying requirement is substantially the same, but the date of the regulation used for enforcement purposes would be different (e.g. federally enforceable versus SWCAA enforceable).

SWCAA is the primary authority that can enforce *all* requirements – federal, state, and local requirements – listed in the Permit. However, the EPA and private citizens may also take enforcement actions under the Permit for those requirements that are federally enforceable; federal regulations, regulations that have a SIP date, and terms of ADPs are federally enforceable. Rules, regulations, and permits that are not SIP approved or federally promulgated are not federally enforceable and are denoted as "*Local*" to indicate they are only enforceable by SWCAA.

For specific subparts of 40 CFR 60, 40 CFR 61, or 40 CFR 63 for which SWCAA has not been delegated implementation and enforcement authority by the EPA, all monitoring, reporting, or recordkeeping that is required to be sent to the EPA Administrator must be sent to both SWCAA and the EPA Administrator. Unless otherwise specified in the delegation agreement or regulation, once specific subparts of 40 CFR 60, 40 CFR 61, or 40 CFR 63 have been delegated to SWCAA by EPA, all monitoring, reporting, or recordkeeping that is required to be sent to the EPA Administrator only needs to be sent to SWCAA.

Federal Regulations	Regulation Version Effective Date	SWCAA Delegation Effective Date
40 CFR 51	June 22, 2021	Not Delegated
40 CFR 52	June 22, 2021	Not Delegated
40 CFR 60 Subpart A	June 22, 2021	July 1, 2019
40 CFR 60 Subpart IIII	June 22, 2021	July 1, 2019
40 CFR 61 Subpart A	June 22, 2021	July 1, 2019
40 CFR 61 Subpart M	June 22, 2021	July 1, 2019
40 CFR 63 Subpart A	June 22, 2021	July 1, 2019
40 CFR 63 Subpart ZZZZ	June 22, 2021	July 1, 2019
40 CFR 63 Subpart DDDDD	June 22, 2021	July 1, 2019
40 CFR 63 Subpart UUUUU	June 22, 2021	July 1, 2019
40 CFR 64	7/1/2000 (this is found in WAC 173-401-615(4))	Not Delegated

Federal Regulations	Regulation Version Effective Date	SWCAA Delegation Effective Date
40 CFR 68	June 22, 2021	Not Delegated
40 CFR 72	June 22, 2021	Not Delegated
40 CFR 75	June 22, 2021	Not Delegated
40 CFR 82, Subparts B and F	June 22, 2021	Not Delegated
40 CFR 98	June 22, 2021	Not Delegated

State Regulations	SIP Regulation Version Effective Date	State Regulation Version Effective Date
WAC 173-400-105(1)	November 25, 2018	November 25, 2018
WAC 173-400-117	December 29, 2012	November 25, 2018
WAC 173-400-720	July 1, 2016	November 25, 2018
WAC 173-406-106(3)(a)(i)	—	12/24/1994
WAC 173-406-106(4)	—	12/24/1994
WAC 173-401	—	9/16/2018
WAC 173-441	—	10/16/2016
WAC 173-460	—	8/21/1998*
* Note that a newer version of WAC 173-460 has been published, however it has not been adopted by SWCAA. The version being enforced by SWCAA was effective August 21, 1998.		

SWCAA Regulations	SIP Regulation Version Effective Date	SWCAA Regulation Version Effective Date
SWCAA 400-036	October 9, 2016	March 21, 2020
SWCAA 400-040	October 9, 2016 (excludes (1)(a), (1)(c), (1)(d), (2), and (4))	March 21, 2020
SWCAA 400-050	October 9, 2016 (excludes (3), (5), and (6))	March 21, 2020
SWCAA 400-060	October 9, 2016	March 21, 2020
SWCAA 400-070	October 9, 2016 (excludes (2)(a), (3)(b), (5), (6), (7), (8)(c), (9), (10), (11), (12), (14); and (15)(c))	March 21, 2020
SWCAA 400-072	October 9, 2016 (except (5)(a)(ii)(B), (5)(d)(ii)(B), (5)(d)(iii)(A), (5)(d)(iii)(B), and all reporting requirements related to TAPs)	March 21, 2020
SWCAA 400-075	—	March 21, 2020
SWCAA 400-076	—	March 21, 2020
SWCAA 400-081	October 9, 2016	March 21, 2020
SWCAA 400-091	October 9, 2016	March 21, 2020
SWCAA 400-100	—	March 21, 2020
SWCAA 400-103	—	March 21, 2020
SWCAA 400-105	October 9, 2016 (excludes reporting requirements related to TAPs)	March 21, 2020

SWCAA Regulations	SIP Regulation Version Effective Date	SWCAA Regulation Version Effective Date
SWCAA 400-106(1)(a)	October 9, 2016	March 21, 2020
SWCAA 400-107	September 21, 1995	March 21, 2020
SWCAA 400-109	October 9, 2016 (except TAP emissions thresholds (3)(d), (3)(e)(ii), and (4))	March 21, 2020
SWCAA 400-110	October 9, 2016 (except (1)(d))	March 21, 2020
SWCAA 400-111	October 9, 2016 (except (7))	March 21, 2020
SWCAA 400-112	October 9, 2016 (except (6))	March 21, 2020
SWCAA 400-114	November 9, 2003	March 21, 2020
SWCAA 400-115	—	March 21, 2020
SWCAA 400-116	November 9, 2003	March 21, 2020
SWCAA 400-120	—	March 21, 2020
SWCAA 400-130	October 9, 2016	March 21, 2020
SWCAA 400-141	—	March 21, 2020
SWCAA 400-151	November 9, 2003	March 21, 2020
SWCAA 400-171	October 9, 2016 (except (2)(a)(xii))	March 21, 2020
SWCAA 400-205	March 18, 2001	March 21, 2020
SWCAA 400-270	—	March 21, 2020
SWCAA 400 Appendix A	10/9/2016	March 21, 2020
SWCAA 425	—	June 18, 2017
SWCAA 476	—	March 22, 2020

Regulatory Orders and Permits	SIP Approval Date	State / Local Effective Date
ADP 97-2057R1	June 11, 2003	2/26/1998
ADP 01-2403	—	2/27/2002
PSD-01-01 Amendment 2	—	6/11/2004
ADP 05-2636	—	11/23/2005
ADP 08-2779	—	3/12/2008
ADP 11-2972	—	4/14/2011
ADP 11-2984	—	6/14/2011
ADP 12-3016	—	4/30/2012
ADP 14-3093	—	4/30/2014
ADP 16-3188	—	6/1/2016
ADP 16-3202	—	12/13/2016
Second Revision of BART Order No. 6426	May 7, 2021	7/29/2020

III. EMISSION UNIT IDENTIFICATION

EU NO.	Generating Equipment	Emission Control	CAM Applicable
EU-1	Unit 1 Boiler (BW21) – 670 MW (net), coal fired (Retired)	N/A (Retired)	N/A (Retired)
EU-2	Unit 2 Boiler (BW22) – 670 MW (net), coal fired	CO: Combustion controls NO_X: Combustion controls, SNCR VOC: Combustion controls PM: Dual ESPs, wet scrubber SO_2: Wet scrubber Hg: Sorbent enhancement additive in boiler, carbon injection between ESPs	Yes for PM
EU-3	Auxiliary Boiler – 170 MMBtu/hr, oil-fired	Fuel consumption limit	No
EU-4	Material Handling (Coal Handling, Ash Handling, FGD Bleed Treatment Lime Storage Silo, Limestone Ball Mill)	Coal Handling – minimal emissions, no controls necessary except use of wet suppression at Coal Unloading Facility Ash Handling – baghouse, wet suppression, and enclosure as appropriate FGD Bleed Treatment Lime Storage Silo – Baghouse Limestone Ball Mill – Wet process, full enclosure	No
EU-5	Turbine Lube Oil Mist Vent 1	N/A (Retired)	N/A (Retired)
EU-6	Turbine Lube Oil Mist Vent 2	Turbine Lube Oil Mist Eliminator 2	No
EU-7	Black Stop Diesel Generator Engine – 1,445 hp diesel engine (Retired)	N/A (Retired)	N/A (Retired)
EU-8	Journal Shop Welding	Journal Shop Baghouse	No
EU-9	Emergency Diesel Generator 1	Ultra-low sulfur fuel	No
EU-10	Emergency Diesel Generator 2	Ultra-low sulfur fuel, EPA Tier 3 design, operating hours limit	No
EU-11	Fire Pump Engine (205 hp diesel engine)	Ultra low sulfur fuel, EPA Tier 3 design, operating hours limit	No
EU-12	Coal Unloading Facility Emergency Diesel Sump Pump Engine (115 hp diesel engine)	Ultra low sulfur fuel, EPA Tier 2 design, operating hours limit	No
EU-13	SEA System 1	Cartridge-style Fabric Filter	No

EU NO.	Generating Equipment	Emission Control	CAM Applicable
EU-14	SEA System 2	Cartridge-style Fabric Filter	No
EU-15	Sorbent Silo 1	Cartridge-style Fabric Filter	No
EU-16	Sorbent Silo 2	Cartridge-style Fabric Filter	No
EU-17	Fly Ash Bin 11	Baghouse	Yes for PM
EU-18	Fly Ash Bin 12	Baghouse	Yes for PM
EU-19	Fly Ash Bin 14	Baghouse	Yes for PM
EU-20	Fly Ash Bin 14 Air Slide to Bin 11 Air Slide	Cartridge-style Fabric Filter	No
EU-21	Fly Ash Bin 14 to 6050 Air Slide	Cartridge-style Fabric Filter	No
EU-22	Fine Coal Handling	Wet suppression	No

IV. PERMIT PROVISIONS

P1. Credible Evidence — 40 CFR 60.11, 40 CFR 61.12

For the purposes of submitting compliance certifications or establishing whether a violation of any term or condition of this Permit has occurred or is occurring, nothing precludes the use, including the exclusive use, of any credible evidence or information, relevant to whether the Permittee would have been in compliance with a specific term or condition if the appropriate performance or compliance test or procedure would have been performed.

P2. Confidentiality of Records and Information — WAC 173-401-500(5), WAC 173-401-620(2)(e), SWCAA 400-270 (*Local*)

The Permittee is responsible for clearly identifying information that is considered proprietary and confidential prior to submittal to SWCAA. Information considered to be proprietary and confidential may be released only after legal opinion by SWCAA's legal counsel, and notice to the Permittee of the intent to release or deny the release of information. [SWCAA 400-270]

In the case where the Permittee has submitted information to SWCAA under a claim of confidentiality, SWCAA may also require the source to submit a copy of such information directly to the EPA. [WAC 173-401-500(5)]

Upon request, the Permittee must also furnish to SWCAA copies of records required to be kept by the Permittee or, for information claimed to be confidential, the Permittee may furnish such records directly to the EPA along with a claim of confidentiality. SWCAA must maintain confidentiality of such information in accordance with RCW 70.94.205. [WAC 173-401-620(2)(e)]

P3. Insignificant Emission Unit - Permit Revision — WAC 173-401-530(6)

Any emission unit or activity that qualifies as insignificant solely on the basis of provisions in WAC 173-401-530(1)(a) must not exceed the emissions thresholds specified in WAC 173-401-530(4) until this Permit is modified pursuant to WAC 173-401-725.

(a) *Duty to comply.* The Permittee must comply with all conditions of this Permit. Any Permit noncompliance constitutes a violation of RCW 70.94 and, for federally enforceable provisions, a violation of the FCAA. Such violations are grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

(b) *Need to halt or reduce activity not a defense.* It must not be a defense for a Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Permit.

(c) *Permit actions.* This Permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of a request by the Permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

(d) *Property rights.* This Permit does not convey any property rights of any sort, or any exclusive privilege.

(e) *Duty to provide information.* The Permittee must furnish to SWCAA, within a reasonable time, any information that the SWCAA may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the Permit, or to determine compliance with the Permit. Upon request, the Permittee must also furnish to SWCAA copies of records required to be kept by the Permittee or, for information claimed to be confidential, the Permittee may furnish such records directly to the EPA along with a claim of confidentiality. SWCAA must maintain confidentiality of such information in accordance with RCW 70.94.205.

(f) *Permit fees.* The Permittee must pay fees in accordance with RCW 70.94.162 and SWCAA's fee schedule. Failure to pay fees in a timely fashion subjects the Permittee to civil and criminal penalties as prescribed in RCW 70.94.430, RCW 70.94.431, and SWCAA 400-103(9).

(g) *Emissions trading.* No permit revision is required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in this Permit.

(h) *Severability.* If any provision of this Permit is held to be invalid, all unaffected provisions of the Permit will remain in effect and will be enforceable.

(i) *Permit appeals.* This Permit or any conditions in it may be appealed only by filing an appeal with the Pollution Control Hearings Board and serving it on SWCAA within thirty days of receipt of the Permit pursuant to RCW 43.21B.310. This provision for appeal in this section is separate from and additional to any federal rights to petition and review under FCAA Section 505(b).

(j) *Permit continuation.* This Permit and all terms and conditions contained herein do not expire until the renewal Permit has been issued or denied if a timely and complete application has been submitted. An application shield granted pursuant to WAC 173-401-

705(2) remains in effect until the renewal Permit has been issued or denied if a timely and complete application has been submitted.

P5. Federally Enforceable Requirements — WAC 173-401-625

All terms and conditions in a Permit, including any provisions designed to limit a source's potential to emit, are enforceable by the EPA and citizens under the FCAA;

Notwithstanding the above, any terms and conditions included in this Permit that are not required under the FCAA or under any of its applicable requirements are specifically designated as "*Local*" and are not federally enforceable under the FCAA. Terms and conditions so designated are not subject to the EPA and affected states review requirements of WAC 173-401-700 through WAC 173-401-820.

P6. Permit Shield — WAC 173-401-640

Compliance with the conditions of this Permit is deemed compliance with all applicable requirements that are specifically identified in this Permit as of the date of Permit issuance. Nothing in this Permit alters or affect the following:

(a) The provisions of section 303 of the FCAA (emergency orders), including the authority of the EPA under that section;

(b) The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of Permit issuance;

(c) The applicable requirements of the acid rain program, consistent with section 408(a) of the FCAA;

(d) The ability of the EPA to obtain information from a source pursuant to section 114 of the FCAA; and

(e) The ability of SWCAA to establish or revise requirements for the use of reasonably available control technology (RACT) as defined in RCW 70.94.

P7. Emergency Provision — WAC 173-401-645

An "emergency" as defined in WAC 173-401-645(1) constitutes an affirmative defense to an action brought for noncompliance with technology based emission limitations. The affirmative defense of emergency must be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

(a) An emergency occurred and that the Permittee can identify the causes(s) of the emergency;

(b) The permitted facility was at the time being properly operated;

(c) During the period of the emergency the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the Permit; and

(d) The Permittee submitted notice of the emergency to SWCAA within two working days of the time when emission limitations were exceeded due to the emergency or shorter periods of time specified in an applicable requirement. This notice fulfills the requirement of WAC 173-401-615(3)(b) unless the excess emissions represent a potential threat to human health and safety. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

Burden of proof lies with the Permittee.

P8. Permit Expiration – Application Shield **WAC 173-401-705(2) WAC 173-401-710(3)**

Permit expiration terminates the source's right to operate unless a timely and complete renewal application has been submitted consistent with WAC 173-401-710(1) and WAC 173-401-500. All terms and conditions of the Permit will remain in effect after the Permit expires if a timely and complete permit application has been submitted. Operation under the terms and conditions of the expired Permit will be allowed until SWCAA takes final action on the renewal application.

P9. Permit Revocation **WAC 173-401-710(4)**

SWCAA may revoke a Permit only upon the request of the Permittee or for cause. SWCAA must provide at least thirty days written notice to the Permittee prior to revocation of the Permit or denial of a permit renewal application. Such notice must include an explanation of the basis for the proposed action and afford the Permittee/applicant an opportunity to meet with SWCAA prior to the authority's final decision. A revocation issued under WAC 173-401-710(4) may be issued conditionally with a future effective date and may specify that the revocation will not take effect if the Permittee satisfies the specified conditions before the effective date.

P10. Changes not Requiring Permit Revision/Off Permit Changes **WAC 173-401-722 WAC 173-401-724**

The Permittee may make changes described in WAC 173-401-722 and WAC 173-401-724 without revising this Permit, provided that the changes satisfy the criteria set forth in those sections, including the requirements to notify SWCAA and EPA.

P11. Reopenings for Cause **WAC 173-401-730**

This Permit must be reopened and revised under any of the following circumstances:

(a) Additional applicable requirements become applicable to a source with a remaining permit term of 3 or more years. Such a reopening must be completed not later than 18 months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the Permit is due to expire, unless the original Permit or any of its terms and conditions have been extended pursuant to WAC 173-401-620(2)(j);

(b) Additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program. Upon approval by the EPA, excess emissions offset plans will be deemed to be incorporated into the Permit;

(c) SWCAA or the EPA determines that the Permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the Permit; or

(d) SWCAA or the EPA determines that the Permit must be revised or revoked to assure compliance with the applicable requirements.

Proceedings to reopen and issue this Permit must follow the same procedures as apply to initial permit issuance and affect only those parts of the Permit for which cause to reopen exists. Reopenings under this section must not be initiated before a notice of such intent is provided to the source by SWCAA. Such notice must be made at least 30 days in advance of the date that the Permit is to be reopened, except that SWCAA may provide a shorter time period in the case of an emergency.

P12. Unavoidable Excess Emissions — SWCAA 400-107(2)

The provisions of SWCAA 400-107 do not apply to federal standards, emission limits or standards contained in a PSD permit issued solely by EPA, or any event that causes a monitored exceedance of any relevant ambient air quality standard.

Excess emissions which the owner or operator wishes to be considered as unavoidable, must he reported to SWCAA as soon as possible, but no later than forty-eight (48) hours after discovery. The owner or operator of a "source" has the burden of proving to SWCAA or decision-making authority in an enforcement action that excess emissions were unavoidable.

(a) *Startup or shutdown.* Excess emissions due to startup or shutdown conditions will be considered unavoidable provided the Permittee reports as required under SWCAA 400-107(1) and adequately demonstrates that:
  (1) Excess emissions could not have been prevented through careful planning and design;
  (2) Startup or shutdown was done as expeditiously as practicable;
  (3) All emission monitoring systems were kept in operation unless their shutdown was necessary to prevent loss of life, personal injury, or severe property damage;
  (4) The emissions were minimized consistent with safety and good air pollution control practice during the startup or shutdown period;
  (5) If a hypass of control equipment occurs, that such bypass was necessary to prevent loss of life, personal injury, or severe property damage; and
  (6) Excess emissions that occur due to upsets or malfunctions during routine startup or shutdown are treated as upsets or malfunctions under section (c) below.

(b) *Maintenance.* Excess emissions due to scheduled maintenance will be considered unavoidable if the "source" reports as required under section (1) of SWCAA 400-107 and adequately demonstrates that the excess emissions could not have been avoided through reasonable design, hetter scheduling for maintenance or through better operation and maintenance practices.

(c) *Upsets or malfunctions.* Excess emissions due to upsets or equipment malfunctions will be considered unavoidable provided the Permittee reports as required under of SWCAA 400-107(1) and adequately demonstrates that:
  (1) The event was not caused by poor or inadequate design, operation, maintenance, or any other reasonably preventable condition;
  (2) The event was not of a recurring pattern indicative of inadequate design, operation, or maintenance;

(3) The operator took immediate and appropriate corrective action in a manner consistent with safety and good air pollution control practice for minimizing emissions during the event, taking into account the total emissions impact of the corrective action, including slowing or shutting down the emission unit as necessary to minimize emissions, when the operator knew or should have known that an emission standard or permit condition was being exceeded;
(4) All emission monitoring systems and pollution control systems were kept operating to the extent possible unless their shutdown was necessary to prevent loss of life, personal injury, or severe property damage; and
(5) The amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent possible.

P13 Right to Appeal Permit/Petition the EPA **42 USC 7661d(b)(1)**

If the Administrator does not object in writing to the issuance of a Title V Permit pursuant to 42 USC 7661d(b)(1), any person may petition the EPA within 60 days after the expiration of the 45-day review period specified in 42 USC 7661d(b)(1) to take such action. A copy of such petition must be provided to the permitting authority and the applicant by the petitioner. The petition must be based only on objections to the permit that were raised with reasonable specificity during the public comment period provided by the permitting agency (unless the petitioner demonstrates in the petition to the Administrator that it was impracticable to raise such objections within such period or unless the grounds for such objection arose after such period). The petition must identify all such objections. If the permit has been issued by the permitting agency, such petition will not postpone the effectiveness of the permit.

V. GENERAL TERMS AND CONDITIONS

G1. Asbestos **40 CFR 61 Subpart M (§61.140)**
SWCAA 400-075 (*Local*)
SWCAA 476 (*Local*)

The Permittee must comply with the provisions of SWCAA 476 "Standards for Asbestos Control, Demolition and Renovation" when conducting any renovation, demolition, or asbestos storage activities at the facility.

G2. Chemical Accident Prevention **40 CFR 68**

The Permittee must comply with the requirements of the Chemical Accident Prevention Provisions of 40 CFR 68 no later than the following dates:

(a) Three years after the date on which a regulated substance, present above the threshold quantity, is first listed under 40 CFR 68.130; or

(b) The date on which a regulated substance is first present above a threshold quantity in a process. [40 CFR 68.10]

G3. Protection of Stratospheric Ozone — **40 CFR 82 Subpart B (§82.30); 40 CFR 82 Subpart F (§82.150)**

The Permittee must comply with the standards for recycling and emissions reduction as provided in 40 CFR Part 82, Subparts B and F.

G4. Duty to Supplement or Correct Application — **WAC 173-401-500(6)**

The Permittee, upon becoming aware that relevant facts were omitted or incorrect information was submitted in a Permit application, must promptly submit such supplementary facts or corrected information. In addition, an applicant must provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application but prior to release of a draft Permit.

G5. Certification — **WAC 173-401-520**

All application forms, reports, and compliance certifications must be certified by a responsible official. Certification must state that, based on information and belief formed after reasonable inquiry, the statements and information contained in the submittal are true, accurate, and complete.

G6. Inspection and Entry — **WAC 173-401-630(2); SWCAA 400-105(2) and (3)**

The Permittee must allow inspection and entry, upon presentation of credentials and other documents as may be required by law, by SWCAA or an authorized representative to perform the following:

(a) Enter upon the Permittee's premises where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the Permit;

(b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of the Permit;

(c) Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the Permit; and

(d) Sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the Permit or applicable requirements.

G7. Schedule of Compliance — **WAC 173-401-630(3)**

The Permittee must continue to comply with all applicable requirements with which the source is currently in compliance. The Permittee must meet on a timely basis any applicable requirements that become effective during the permit term. The Permittee must comply with any approved schedule of compliance in accordance with WAC 173-401-510(2)(h)(iii).

G8. Permit Renewal Application — **WAC 173-401-710(1); WAC 173-401-610**

The Permittee must submit a complete permit renewal application to SWCAA no later than the date established in the Permit. Permit expiration terminates the Permittee's right to operate

unless a timely and complete renewal application has been submitted consistent with WAC 173-401-710(1) and WAC 173-401-500. All terms and conditions of the Permit must remain in effect after the Permit expires if a timely and complete Permit application has been submitted. Operation under the terms and conditions of the expired Permit will be allowed until SWCAA takes final action on the renewal application.

This Permit expires on October 10, 2023. A renewal application is due on October 10, 2022 and a complete renewal application is due no later than April 10, 2023.

G9. Transfer of Ownership or Operational Control — WAC 173-401-720(1)(d)

A change in Permittee due to transfer of ownership or operational control of an affected source requires a request for administrative permit amendment as governed by WAC 173-401-720(1)(d).

G10. Reporting of Emissions of Greenhouse Gases — WAC 173-441 (*Local*)

WAC 173-441 requires owners and operators of affected facilities to quantify and report emissions of greenhouse gases from applicable source categories listed in WAC 173-441-120. This regulation applies to any facility located in Washington State with total greenhouse gas emissions of ten thousand metric tons of carbon dioxide equivalent (CO_2e) or more per calendar year. The Permittee must prepare and submit greenhouse gas reports to Ecology for each affected facility. All requests, notifications, and communications to Ecology pursuant to chapter 173-441 WAC, other than submittal of the annual GHG report, must be submitted to the following address:

Greenhouse Gas Report
Air Quality Program, Department of Ecology
PO Box 47600
Olympia, WA 98504-7600

G11. Misrepresentation and Tampering — SWCAA 400-105(5) and (6)

The Permittee must not make any false material statement, representation or certification in any form, notice, or report required under RCW 70.94, or any ordinance, resolution, regulation, permit or order in force pursuant thereto.

The Permittee must not render inaccurate any monitoring device or method required under RCW 70.94, or any ordinance, resolution, regulation, permit, or order in force pursuant thereto.

G12. Emission Testing and Monitoring — SWCAA 400-106

SWCAA may conduct or require that emission testing be conducted of any "source" or emission unit within the jurisdiction of SWCAA to determine compliance, evaluate control equipment performance, evaluate RACT, or quantify emissions.

The Permittee must provide the necessary platform and sampling ports for SWCAA personnel or others to perform a test of an emission unit. SWCAA must be allowed to obtain a sample from any emission unit. The Permittee must be given an opportunity to observe the sampling and to obtain a sample at the same time.

Portable sources which locate temporarily at the site a source are allowed to operate at the temporary location without filing an ADP application provided that:

(a) The source/emissions units are registered with SWCAA;

(b) The source/emissions units have an ADP to operate as a portable source;

(c) The owner(s) or operator(s) notifies SWCAA of the intent to operate at the new location at least ten business days prior to starting the operation;

(d) The owner(s) or operator(s) supplies sufficient information including production quantities and hours of operation, to enable SWCAA to determine that the operation will comply with the emission standards for a new source, and will not cause a violation of applicable ambient air quality standards and, if in a nonattainment area, will not interfere with scheduled attainment of ambient standards; and

(e) Portable sources that do not have a valid ADP issued by SWCAA, but do have a valid approval issued by a Washington air pollution control authority after July 1, 2010, may operate within SWCAA jurisdiction without filing an ADP application pursuant to SWCAA 400-109 or obtaining an ADP pursuant to SWCAA 400-110 provided the requirements of SWCAA 400-036 are met.

G14. New Source Review **WAC 173-400-117**
WAC 173-400-720
WAC 173-460-040 (*Local*)
SWCAA 400-072
SWCAA 400-076
SWCAA 400-109
SWCAA 400-110
SWCAA 400-820

The Permittee must submit an application and approval must be issued or written confirmation of exempt status must be received before commencing construction of the proposed installations, modifications, changes, or alternations. Portable sources may be exempt from this requirement if they fulfill the criteria described in **G13.**

G15. Replacement or Substantial Alteration of Emission Control Technology at an Existing Stationary Source **SWCAA 400-114**

Prior to replacing or substantially altering emission control technology installed at an existing stationary source or emission unit, the Permittee must file an ADP application with SWCAA. Construction must not commence on a project subject to review until SWCAA issues a final ADP or other regulatory order. However, any ADP application filed under this section is deemed to be approved without conditions if SWCAA takes no action within thirty (30) days of receipt of a complete application.

G16. Process Equipment — SWCAA 400-116(1)

Any process equipment, including features, machines, and devices constituting parts of or called for by plans, specifications, or other information submitted for approval or required as part of an approval, such as an ADP, must be maintained and operate in good working order. SWCAA reserves the right to take any and all appropriate action to maintain compliance with approval conditions, including directing the facility to cease operations of defective or malfunctioning equipment until corrective action can be completed.

G17. Pollution Control Equipment — SWCAA 400-116(2)

Any equipment that serves as air contaminant control or capture equipment must be maintained and operate in good working order at all times in accordance with good operations and maintenance practices and in accordance with SWCAA's approval conditions. SWCAA reserves the right to take any and all appropriate action to maintain compliance with approval conditions, including directing the facility to cease operations of defective or malfunctioning equipment until corrective action can be completed.

G18. Adjustment for Atmospheric Conditions — SWCAA 400-205

Varying the rate of emission of a pollutant according to atmospheric conditions or ambient concentrations of that pollutant is prohibited, except as directed according to air pollution episode regulations as specified at SWCAA 400-230(5).

G19. Outdoor Burning — SWCAA 425 (*Local*)

The Permittee is prohibited from conducting outdoor burning except as allowed by SWCAA 425.

VI. OPERATING TERMS AND CONDITIONS

The following table lists all federal, state, and locally enforceable requirements applicable to the Permittee. The effective date for each applicable requirement is listed in Section II, which also describes the enforceability of the term. Those specific requirements that are enforceable only by SWCAA are denoted with "*Local.*" Any requirement with "Plantwide" listed in the Emission Unit column, applies universally to all emission units or activities, regardless of whether identified as an EU or an IEU. Monitoring requirements are used to provide a reasonable assurance of compliance with the applicable requirements and may or may not involve the use of a reference test method.

Req. No.	Requirement	Emission Point	Monitoring
Req-1	Permittee must not cause or permit any emission that exceeds 20% opacity for more than three minutes in any one hour. Reference Method: SWCAA Method 9 SWCAA 400-040(1)	Plantwide	M2

Req. No.	Requirement	Emission Point	Monitoring
Req-2	Permittee must not cause or permit fallout of particulate matter beyond the source's property boundary in sufficient quantity to interfere unreasonably with the use and enjoyment of the property on which the fallout occurs. SWCAA 400-040(2)	Plantwide	M3, M5
Req-3	Permittee must take reasonable precautions to prevent the release of fugitive emissions from any emission unit which is a source of fugitive emissions. SWCAA 400-040(3)	Plantwide	M4, M6
Req-4	Permittee must use recognized good practice and procedures to reduce odors to a reasonable minimum. SWCAA 400-040(4) Local Only	Plantwide	M5
Req-5	The Permittee must not cause or permit the emission of any air contaminant if it is detrimental to the health, safety, or welfare of any person, or causes damage to property or business. SWCAA 400-040(5)	Plantwide	M5
Req-6	Permittee must not cause or permit any emission unit to emit a gas containing sulfur dioxide in excess of 1,000 ppm of sulfur dioxide on a dry basis, corrected to 7% O_2 for combustion sources, and based on an average of 60 minutes. Reference Method: 40 CFR 60 Appendix A Methods 3A, 6C SWCAA 400-040(6) ADP 97-2057R1, Sections 22 and 28(a)	EU-2, EU-3, EU-9, EU-10, EU-11, EU-12	M7, M8, M9
Req-7	Permittee must not cause or permit the installation or use of any means which conceals or masks an emission which would otherwise violate any provisions of SWCAA 400-040. SWCAA 400-040(7)	Plantwide	N/A
Req-8	Permittee must take reasonable precautions to prevent emissions of fugitive dust and operate the source to minimize emissions. SWCAA 400-040(8)(a)	Plantwide	M4, M5
Req-9	Permittee must not cause or permit emissions of particulate matter from a combustion or incineration emission unit in excess of 0.1 gr/dscf of exhaust gas corrected to 7% oxygen. Reference Method: 40 CFR 60 Appendix A Method 5 SWCAA 400-050(1 and 4)	EU-2, EU-3, EU-9, EU-10, EU-11, EU-12	M3, M6, M8, M9, M20

Req. No.	Requirement	Emission Point	Monitoring
Req-10	The Permittee must not burn fuel oil with a sulfur content greater than 15 ppm by weight (ppmw). SWCAA 400-050(2)	EU-2, EU-3, EU-9, EU-10, EU-11, EU-12	M7, M17, M26, M27, M28
Req-11	Permittee must not cause or allow emissions of particulate matter from a general process unit (excludes combustion) in excess of 0.1 gr/dscf of exhaust gas. Reference Method: 40 CFR 60 Appendix A Method 5 SWCAA 400-060	Plantwide	M3, M6
Req-12	Permittee must conduct all abrasive blasting inside a structure designed to capture blast grit and overspray except for items too large to be reasonably handled indoors. SWCAA 400-070(8)	Plantwide	N/A

Req. No.	Requirement	Emission Point	Monitoring
Req-13	Permittee must install, calibrate, maintain, and operate continuous monitoring equipment for opacity for the bypass stack of Unit 2 in accordance with the requirements found in 40 CFR 51, App. P Section 3, 4, and 5 and 40 CFR 60 App. B – F as appropriate. SWCAA 400-105(4)(a)(i) and (4)(e)	EU-2	M9
Req-14	Permittee must not cause or allow emissions of filterable particulate matter from the stack of Unit 2 in excess of 0.010 gr/dscf of exhaust gas corrected to 7% O_2. Reference Method: 40 CFR 60 Appendix A Method 5 ADP 97-2057R1 Section 34	EU-2	M8, M9, M11, M20
Req-15	Permittee must not cause or permit any emission which exceeds 20% opacity based on a 6-minute average, except for one 6-minute period/hour not to exceed 27% opacity. Permittee must not allow visible emissions to exceed 20% opacity for more than three minutes, in any one hour. Reference Method: EPA Method 9 and SWCAA Method 9 ADP 97-2057R1 Section 36	EU-2	M2, M9, M11

Req. No.	Requirement	Emission Point	Monitoring
Req-16	The Permittee must not cause or allow emissions of filterable particulate matter from the stack of Unit 2 in excess of either 0.030 lb/MMBtu or 0.30 lb/MWh gross output, 30-boiler operating day rolling average. These limits do not apply to periods of startup or shutdown as defined in 40 CFR 63.10042. Reference Method: 40 CFR 60 Appendix A Method 5 with increased filter temperature (320 ± 25°F filter temperature) and minimum 1 dry standard cubic meter sample volume per run or PM CEMS 40 CFR 63.9991(a)(1) – Reference to Table 2 40 CFR 63.10000(a) – Startup and shutdown exception 40 CFR 63.10005(a) – Explanation that either limit applies 40 CFR 63 Subpart UUUUU Table 2 Section 1(a) - Limits 40 CFR 63 Subpart UUUU Table 5 – Reference Methods	EU-2	M8, M9
Req-17	Permittee must not cause or allow total SO_2 emissions from the stack of Unit 2, the auxiliary boiler, and other emission points throughout the facility, combined, in excess of 10,000 tons per year in any rolling 12-month period. Reference Method: 40 CFR 75, Appendix A; 40 CFR 60 Appendix B Performance Specification 2 and 3: 40 CFR 60 Appendix F ADP 97-2057R1 Section 18	EU-2, EU-3	M9, M12, M14
Req-18	Permittee must not cause or allow any unit to emit SO_2 in excess of 250 ppm on a dry basis, corrected to 7% O_2, 1-hour average except during startups, shutdowns and forced or planned outages of the SO_2 control system. Reference Method: 40 CFR 60 Appendix A Methods 3A, 6C ADP 97-2057R1 Sections 21(a) and 28(a)	EU-2	M8, M9, M11
Req-19	During startups, shutdowns, and forced or planned outages of the SO_2 control system, Permittee must not allow 1-hour average SO_2 emissions from the affected unit(s) in excess of 1,000 ppm. Reference Method: 40 CFR 60 Appendix A Method 6C ADP 97-2057R1 Section 21(b) and 21(c)	EU-2	M9, M11
Req-20	The Permittee must schedule SO_2 emission control system outages to the maximum extent possible during daily or weekly load reduction periods. No planned SO_2 system outage is allowed from June 15 through September 15 of any year except when the unit burns no fuel. ADP 97-2057R1 Section 23	EU-2	M11

Req. No.	Requirement	Emission Point	Monitoring
Req-21	The Permittee must not cause or allow emissions of sulfur dioxide from the stack of Unit 2 in excess of either 0.20 lbMMBtu or 1.5 lb/MWh gross output, 30-boiler operating day rolling average. These limits do not apply to periods of startup or shutdown as defined in 40 CFR 63.10042. Reference Method: SO_2 CEMS 40 CFR 63.9991(a)(1) – Reference to Table 2 40 CFR 63.10000(a) – Startup and shutdown exception 40 CFR 63.10005(a) – Explanation that either limit applies 40 CFR 63 Subpart UUUUU Table 2 Section 1(b) - Limits 40 CFR 63 Subpart UUUUU Table 5 – Reference methods, averaging period	EU-2	M8, M9
Req-22	Permittee must: (1) hold SO_2 Acid Rain allowances, as of the allowance transfer deadline, in the source's account (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of SO_2 for the previous calendar year from the affected units at the source; and (2) comply with the applicable Acid Rain emissions limitation for SO_2. (See Appendix B Acid Rain Permit). Reference Method: 40 CFR 75 40 CFR 72.9(c)(1) WAC 173-406-106(3)(a)(i)	EU-2	M9
Req-23	The Permittee must forfeit ownership of SO_2 Acid Rain allowances to SWCAA equal to 1.5 times the quantity of emissions in excess of the 10,000 ton annual limit calculated on a calendar year basis. Reference Method: 40 CFR 75 ADP 97-2057R1 Section 28(f)	EU-2	M9, M12
Req-24	The original stack may remain for bypass provided certified CEMS are maintained to monitor SO_2 emissions from the bypass stack. If SO_2 emissions from the original stack are not monitored by certified functioning CEMS, the Permittee must only use the original stack during extreme emergency conditions. ADP 97-2057R1 Section 29	EU-2	M13

Req. No.	Requirement	Emission Point	Monitoring
Req-25	SO_2 emissions from Unit 2 must not exceed 1,350 pounds per hour (1-hour average). Compliance with the SO_2 emission limit must be based on using SO_2 emissions data from a Continuous Emissions Monitoring System (CEMS) operated in accordance with 40 CFR 75. Only unadjusted, quality-assured SO_2 concentration values and flow rate data must be used in the emissions calculations. Bias adjustment factors and 40 CFR 75 substitute data values must not be used. The CEMS must provide valid hourly SO_2 emissions for at least 95% of the hours that the boiler is operated during each calendar month except for periods of monitoring system downtime, provided that the owner or operator demonstrated that the downtime was not a result of inadequate design, operation, or maintenance, or any other reasonable preventable conditions, and any necessary repairs to the monitoring system are conducted in a timely manner. ADP 16-3202 Paragraphs 13 and 14	EU-2	M9
Req-26	The Permittee must not cause or allow emissions of mercury from the stack of Unit 2 in excess of either 1.2 lb/TBtu or 0.013 lb/GWh gross output, 30-boiler operating day rolling average. These limits do not apply to periods of startup or shutdown as defined in 40 CFR 63.10042. Reference Method: Hg CEMS or sorbent trap monitoring system 40 CFR 63.9991(a)(1) – Reference to Table 2 40 CFR 63.10000(a) – Startup and shutdown exception 40 CFR 63.10005(a) – Explanation that either limit applies 40 CFR 63 Subpart UUUUU Table 2 Section 1(c) - Limits 40 CFR 63 Subpart UUUUU Table 5 – Reference methods, averaging period	EU-2	M8, M9
Req-27	Emissions of nitrogen oxides must not exceed 0.30 lb/MMBtu for those hours when the unit's generating load is 360 MW gross or greater. This annual average is calculated as the combined arithmetic sum of hourly emission rates when generating load is 360 MW gross, or greater, during the calendar year. Reference Method: 40 CFR 75 ADP 97-2057R1 Section 30	EU-2	M9

Req. No.	Requirement	Emission Point	Monitoring
Req-27b	Emissions of nitrogen oxides from Unit 2 are limited to 0.18 lb/MMBtu (30-boiler operating day rolling average). The Permittee may use a variety of means as necessary to control emissions of nitrogen oxides to meet the prescribed NO_X limit including the Combustion Optimization System with Neural Network, the SNCR, Low NOx Burners, boiler control, variety (source) of coal, or any combination thereof. Compliance with the nitrogen oxides emission limitation will be determined by use of a continuous emission monitoring system meeting the requirements of 40 CFR Part 75. For any hour in which coal is combusted in a unit, the owner/operator of each unit must calculate the hourly nitrogen oxides concentration in lb/MMBtu at the CEMS installed in accordance with the requirements of 40 CFR Part 75. The 30-day average lb/MMBtu rate is calculated by summing the hourly emissions in pounds (unit lb/MMBtu times unit heat input) and dividing that by the sum of the hourly heat inputs in million Btu. At the end of that boiler's operating day, the owner/operator must calculate and record a new 30-day rolling average emission rate in lb/MMBtu from all valid hourly data for that boiler's operating day and for that boiler's previous 29 successive boiler operating days. An hourly average nitrogen oxides emission rate is valid only if the minimum number of data points, as specified in 40 CFR 75, is acquired as necessary to calculate nitrogen oxides emissions and heat rate. Data reported to meet these requirements must not include data substituted using the missing data substitution procedures of subpart D of 40 CFR part 75, and the data must not have been bias adjusted according to the procedures of 40 CFR part 75. A boiler operating day is a 24-hour period between 12 midnight and the following midnight during which coal is combusted at any time in the boiler. It is not necessary for coal to be combusted for the entire 24-hour period. Second Revision of BART Order No. 6426 Conditions 1.1, 1.2, 3.3, and 5	EU-2	M9
Req-28	Reserved		
Req-29	Reserved		
Req-30	Emissions of ammonia from the coal-fired utility steam generating unit is limited to a maximum of 10 ppmvd, 30 operating day rolling average. The ammonia concentration measured during the periodic emissions testing required by M8 is the 30 operating day rolling average value used for compliance starting on the date of the completion of the test until the completion of the next required periodic emission test. Second Revision of BART Order No. 6426 Conditions 2.1 and 4.1.4	EU-2	M8, M25

Req. No.	Requirement	Emission Point	Monitoring
Req-31	Unit 1 and Unit 2 must permanently cease coal-fired power generation operations as follows: (a) One of the units must cease no later than December 31, 2020. (b) The other unit must cease no later than December 31, 2025. These conditions do not apply in the event the Washington Department of Ecology determines as a requirement of state or federal law or regulation that the selective catalytic reduction technology must be installed on either coal fired unit. Second Revision of BART Order No. 6426 Condition 3	EU-1, EU-2	M9, R9
Req-32	Reserved		
Req-33	Reserved		
Req-34	Reserved		
Req-35	NO_X emissions must not exceed 0.40 lb/million Btu annual average for Unit 2 (see Appendix B Acid Rain Permit). Reference Method: 40 CFR 75 40 CFR 76.7(a)(1) WAC 173-406-106(4)	EU-2	M9
Req-36	Permittee must not cause or allow carbon monoxide emissions in excess of 200 ppm, on a dry basis, corrected to 7% O_2, annual (calendar year) average. Reference Method: Averaging of plant CO CEMS data as provided in M8 ADP 97-2057R1 Section 39	EU-2	M8
Req-37	Permittee must certify, operate, and maintain continuous emissions monitoring systems (CEMS) and a continuous opacity monitoring system (COMS) with an automated data acquisition and handling system for determining and recording all SO_2, NO_X, and CO_2 emissions from the scrubber stack and all SO_2, NO_X, and CO_2 emissions and opacity from the bypass stack as required by 40 CFR 75. 40 CFR 75.10(a)	EU-2	M9
Req-38	The Permittee must conduct a tune-up of Unit 2 initially and every 48 months thereafter in accordance with the requirements of 40 CFR 63.10021(e) and Table 3 of 40 CFR 63 Subpart UUUUU. 40 CFR 63.10000(e) – Requirement for periodic tune-ups 40 CFR 63.10006(i)(2) – Frequency of periodic tune-ups 40 CFR 63.10021(e) – Procedures and frequency 40 CFR 63 Subpart UUUUU Table 3 Section 1 40 CFR 63 Subpart UUUUU Table 7 Section 5	EU-2	M33

Req. No.	Requirement	Emission Point	Monitoring
Req-39	For startup of Unit 2, the Permittee must comply with one of the options provided in Table 3 of 40 CFR 63 Subpart UUUUU. If Option 2 is chosen, the Permittee must use clean fuels to the maximum extent possible during the startup period and engage both sets of electrostatic precipitators within 1 hour of firing coal. All other control devices must be engaged as expeditiously as possible, considering safety and manufacturer/supplier recommendations. Applicable emission limits from 40 CFR 63 Subpart UUUUU apply within 4 hours of the start of electricity generation. Startup ends when all applicable emission control devices are engaged (ESPs, mercury control system and flue gas desulfurization system) or 4 hours after the electrical generating unit generates electricity or useful thermal energy, whichever is earlier. While firing coal or residual oil during shutdown, the Permittee must operate all applicable control technologies, and continue to operate those control devices after the cessation of coal or residual oil being fed into the boiler and for as long as possible thereafter considering operational and safety concerns. Shutdown ends when the electrical generating unit no longer generates electricity or makes useful thermal energy and no fuel is being fired in the electrical generating unit. The Permittee must comply with all applicable emissions limits at all times except for periods that meet the definitions of startup and shutdown in 40 CFR 63 Subpart UUUUU. 40 CFR 63.10000(a) for startup and shutdown work practice requirements 40 CFR 63.10042 "startup" and "shutdown" definitions 40 CFR 63 Subpart UUUUU Table 3 Sections 3 and 4	EU-2	M33
Req-40	At all times, including periods of startup, shutdown, and malfunction, the Permittee must, to the extent practicable, maintain and operate air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to SWCAA, which may include, but is not limited to, monitoring results, review of operating and maintenance procedures and records, and inspection of the source. [40 CFR 63.10000(b), ADP 97-2057R1 Section 48] The flue gas desulfurization system must be operated at all times consistent with 40 CFR 63.10000(b) except as allowed during startup by Table 3 of Subpart UUUUU of Part 63. [40 CFR 63.9991(c)(2), 40 CFR 63 Subpart UUUUU Table 3, Section 3] 40 CFR 63.9991(c)(2) 40 CFR 63.10000(b) ADP 97-2057R1 Section 48	EU-2	M8, M9

Req. No.	Requirement	Emission Point	Monitoring
Req-41	Permittee must not cause or allow total annual fuel oil combusted in the auxiliary boiler in excess of 600,000 gallons per year. ADP 97-2057R1 Section 45	EU-3	M14
Req-42	Effective January 31, 2016, the Permittee must operate and maintain the Auxiliary Boiler in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to SWCAA, which may include, but is not limited to, monitoring results, review of operating and maintenance procedures and records, and inspection of the source. 40 CFR 63.7500(a)(3)	EU-3	N/A
Req-43	A tune-up of the Auxiliary Boiler must be conducted initially and every 5 years thereafter, no later than 61 months after the previous tune-up. The initial tune-up must be conducted no later than January 31, 2016. Each tune-up must be conducted in accordance with 40 CFR 63.7540(a)(10)(i) through (vi). The burner inspection specified in 40 CFR 63.7540(a)(10)(i) may be delayed until the next scheduled or unscheduled unit shutdown; however the burner must be inspected at least once every 72 months. 40 CFR 63.7500(c) 40 CFR 7505(a) 40 CFR 63.7510(e) 40 CFR 63.7515(d) 40 CFR 63.7540(a)(12) 40 CFR 63 Subpart DDDDD Table 3	EU-3	M34
Req-44	The opacity of emissions from the loading of fly ash trucks from the 6050 unloaders must not exceed twenty percent for more than 3 minutes in any one-hour period as determined in accordance with SWCAA 400, Appendix A, Method 9. ADP 01-2403 Section 11(a)	EU-4	M4
Req-45	The opacity of emissions from the Unit 2 turbine lube oil mist eliminator stack must not exceed five percent for more than 3 minutes in any one-hour period as determined in accordance with SWCAA 400, Appendix A, Method 9. ADP 01-2403 Section 11(b)	EU-6	M2
Req-46	Emissions of PM_{10} from the Coal Unloading Facility must not exceed 2,411 pounds per year. Annual emissions must be calculated using the methodology identified in Section V of the Title V Basis Statement. ADP 11-2972 Condition 2	EU-4	M3, M21

Req. No.	Requirement	Emission Point	Monitoring
Req-47	The opacity of emissions from all emission points within the Coal Unloading Facility must not exceed zero percent for more than three minutes in any one hour period as determined in accordance with SWCAA 400, Appendix A, Method 9. ADP 11-2972 Condition 3	EU-4	M3
Req-48	Coal drop (transfer) points associated with the Coal Unloading Facility must utilize a high pressure water spray system to control fugitive dust during coal unloading and transfer operations. Water pressure at the spray/fog nozzles must be maintained at 80 psig or greater during coal unloading and coal transfer operations. A functional pressure gauge must be maintained onsite and a connection point provided for the gage for the purpose of demonstrating compliance with this pressure limit. ADP 11-2972 Condition 8	EU-4	M3
Req-49	Emissions of PM_{10} from the FGD Bleed Treatment Lime Storage Silo must not exceed 0.005 grains per dry standard cubic foot (1-hour average). Reference Method: 40 CFR 60 Appendix A Method 5 or 201A ADP 05-2636 Condition 1	EU-4	M3, M22
Req-50	The opacity of emissions from the FGD Bleed Treatment Lime Storage Silo must not exceed zero percent for more than three minutes in any one hour period as determined in accordance with SWCAA 400, Appendix A, Method 9. ADP 05-2636 Condition 2	EU-4	M3
Req-51	The opacity of emissions from the Journal Shop Baghouse must not exceed zero percent for more than three minutes in any one hour period as determined in accordance with SWCAA 400, Appendix A, Method 9. ADP 08-2779 Condition 1	EU-8	M3, M6
Req-52	The Journal Shop Baghouse must be operated to collect welding fume whenever welding activities are taking place in the Journal Shop. The Journal Shop baghouse must be maintained in good repair and must utilize afterfilters meeting a HEPA or better particulate matter collection efficiency (99.97% or better on particles measuring 0.3 microns or greater in diameter). ADP 08-2779 Condition 2	EU-8	M3, M6

Req. No.	Requirement	Emission Point	Monitoring
Req-53	The Permittee must conduct the following maintenance for Emergency Diesel Generator 1. (a) Change oil and filter every 500 hours of operation or annually, whichever comes first except as provided in 40 CFR 63.6625(i); (b) Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; and (c) Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. 40 CFR 63.6640(a) 40 CFR 63.6602 and Table 2c SWCAA 400-075	EU-9	M26
Req-54	The Permittee must minimize the time Emergency Diesel Generator 1 spends at idle and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes. 40 CFR 63.6602 40 CFR 63.6625(h) and Table 2c SWCAA 400-075	EU-9	N/A
Req-55	The Permittee must operate and maintain Emergency Diesel Generator 1 according with the Small Engine Maintenance Plan detailed in Appendix C. 40 CFR 63.6625(e) 40 CFR 63.6640(a) and Table 6 SWCAA 400-075	EU-9	M26
Req-56	The Permittee must maintain a non-resettable hour meter on Emergency Diesel Generator 1 and Emergency Diesel Generator 2. 40 CFR 60.4209(a) – Emergency Diesel Generator 2 40 CFR 63.6625(f) – Emergency Diesel Generator 1 SWCAA 400-075	EU-9, EU-10	M26
Req-57	At all times Emergency Diesel Generator 1 must be operated and maintained in a manner consistent with safety and good air pollution control practices for minimizing emissions. 40 CFR 63.6605(b), SWCAA 400-075	EU-9	M26

Req. No.	Requirement	Emission Point	Monitoring
Req-58	Operation of Emergency Diesel Generator 1 and Emergency Diesel Generator 2 for maintenance checks and readiness testing must not exceed 100 hours per year each. Emergency operation of the emergency generator engines is not limited. A nonresettable time totalizer must be installed on each engine and used to measure hours of operation. Emergency Diesel Generator 1 and Emergency Diesel Generator 2 may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. 40 CFR 63.6640(f) - Em. Diesel Generator 1 40 CFR 60.4211(f)(2) – Em. Diesel Generator 2 SWCAA 400-075 ADP 16-3188 Condition 5	EU-9, EU-10	M26
Req-59	Operation of Emergency Diesel Generator 1 and Emergency Diesel Generator 2 must be limited to maintenance checks, readiness testing, and as necessary for emergency service. 40 CFR 63.6640(f)(2) -Em. Diesel Generator 1 40 CFR 60.4211(f)(2) – Em. Diesel Generator 2 SWCAA 400-075 ADP 16-3188 Condition 6	EU-9, EU-10	M26
Req-60	Emissions from the Coal Unloading Facility Emergency Diesel Sump Pump Engine must not exceed: Pollutant — Emission Limit Nitrogen Oxides — 0.25 tons per year Carbon Monoxide — 0.044 tons per year PM — 0.0055 tons per year PM_{10} — 0.0055 tons per year $PM_{2.5}$ — 0.0055 tons per year Reference Methods: EPA Methods 1-5, 7E, 10, 201A Annual emissions must be calculated using the methodology identified in Section V of the Title V Basis Statement. ADP 11-2972 Condition 5	EU-12	M28

Req. No.	Requirement	Emission Point	Monitoring
Req-61	Visible emissions from the Coal Unloading Facility Emergency Diesel Sump Pump Engine must not exceed five percent opacity for more than 3 minutes in any one hour period as determined in accordance with SWCAA Method 9 (See Appendix A of SWCAA 400) except during startup. For the purposes of this requirement, the startup period ends when the earlier of the following operating events occurs: (a) The engine has reached normal operating temperature; or (b) The engine has been operating for 15 minutes. Reference Method: SWCAA Method 9 ADP 11-2972 Condition 6	EU-12	M5
Req-62	The Coal Unloading Facility Emergency Diesel Sump Pump Engine must only be fired on No. 2 diesel or better. The sulfur content of the fuel fired in the diesel engine must not exceed 0.0015% by weight (15 ppm). A fuel certification from the fuel supplier may be used to demonstrate compliance with this requirement. 40 CFR 60.4207(b) SWCAA 400-050(2) ADP 11-2972 Condition 9	EU-12	M28
Req-63	Operation of the Coal Unloading Facility Emergency Diesel Sump Pump Engine must be limited to maintenance checks, readiness testing, and as necessary to provide emergency or backup pumping. The engine may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Operation for maintenance checks and readiness testing must not exceed 100 hours per year. 40 CFR 60.4211(f)(2) ADP 11-2972 Condition 10	EU-12	N/A
Req-64	The Coal Unloading Facility Emergency Diesel Sump Pump Engine must be operated no more than 200 hours per year. A nonresettable time totalizer must be installed and used to measure hours of operation. ADP 11-2972 Condition 11	EU-12	M28
Req-65	The exhaust from the Coal Unloading Facility Emergency Diesel Sump Pump Engine must be discharged vertically. Any device that obstructs or prevents vertical discharge is prohibited. ADP 11-2972 Condition 12	EU-12	N/A

Req. No.	Requirement	Emission Point	Monitoring
Req-66	Except as provided in 40 CFR 60.4211(g), the Coal Unloading Facility Emergency Diesel Sump Pump Engine must be operated and maintained according to the manufacturer's emissions-related written instructions and the Permittee may only change those emissions-related settings that are permitted by the manufacturer. The manufacturer's written instructions have been summarized in Appendix C of this Permit. 40 CFR 60.4211(g) contains alternative requirements, including a source test requirement, if the Permittee chooses to deviate from the manufacturer's written instructions. 40 CFR 60.4211(a) SWCAA 400-115 ADP 11-2972 Condition 13	EU-12	M28
Req-67	Emissions from the Fire Pump Engine must not exceed: Pollutant — Emission Limit Nitrogen Oxides — 0.28 tons per year Carbon Monoxide — 0.14 tons per year PM — 0.013 tons per year PM_{10} — 0.013 tons per year $PM_{2.5}$ — 0.013 tons per year Annual emissions must be calculated using the methodology identified in Section V of the Title V Basis Statement. Reference Methods: EPA Methods 1-5, 7E, 10, 201A ADP 16-3188 Condition 1	EU-11	M27
Req-68	Visible emissions from the Fire Pump Engine and Emergency Diesel Generator 2 must not exceed five percent opacity for more than 3 minutes in any one hour period as determined in accordance with SWCAA Method 9 (See Appendix A of SWCAA 400) except during startup. For the purposes of this requirement, the startup period ends when the earlier of the following operating events occurs: (a) The engine has reached normal operating temperature; or (b) The engine has been operating for 15 minutes. ADP 16-3188 Condition 2	EU-10, EU-11	M2, M5

Req. No.	Requirement	Emission Point	Monitoring
Req-69	Except as provided in 40 CFR 60.4211(g), the Fire Pump Engine and Emergency Diesel Generator 2 must be operated and maintained according to the manufacturer's emissions-related written instructions and the Permittee may only change those emissions-related settings that are permitted by the manufacturer. The manufacturer's written instructions have been summarized in Appendix C of this Permit for the Fire Pump Engine. 40 CFR 60.4211(g) contains alternative requirements, including a source test requirement, if the Permittee chooses to deviate from the manufacturer's written instructions. 40 CFR 60.4211(a) SWCAA 400-115	EU-10, EU-11	M26, M27
Req-70	The Fire Pump Engine and Emergency Diesel Generator 2 must only be fired on No. 2 diesel or better. The sulfur content of the fuel fired in the diesel engines must not exceed 0.0015% by weight (15 ppm). A fuel certification or receipt from the fuel supplier, or test results using an appropriate method listed in 40 CFR 60.17, may be used to demonstrate compliance with this requirement. 40 CFR 60.4207(b) SWCAA 400-050(2) ADP 16-3188 Condition 3	EU-10, EU-11	M27
Req-71	The Fire Pump Engine must be operated no more than 504 hours per year. A nonresettable time totalizer must be installed on the engine and used to measure hours of operation. ADP 16-3188 Condition 4	EU-11	M27
Req-72	The exhaust from the Fire Pump Engine and Emergency Diesel Generator 2 must be discharged vertically. Any device that obstructs or prevents vertical discharge is prohibited. ADP 16-3188 Condition 7	EU-10, EU-11	N/A

<table>
<tr><th>Req. No.</th><th>Requirement</th><th>Emission Point</th><th>Monitoring</th></tr>
<tr><td>Req-73</td><td>Emissions of filterable particulate matter (PM, PM_{10}, and $PM_{2.5}$) from each of the mercury control project material handling exhaust stacks must not exceed 0.005 gr/dscf (1-hour average) and the quantities identified below:

<table>
<tr><th>Generating Equipment</th><th>Short-Term Limit (1-hour average)</th><th>Annual Limit</th></tr>
<tr><td>SEA System 1</td><td>0.048 lb/hr</td><td>0.21 tons per year</td></tr>
<tr><td>SEA System 2</td><td>0.048 lb/hr</td><td>0.21 tons per year</td></tr>
<tr><td>Sorbent Silo 1</td><td>0.015 lb/hr</td><td>0.07 tons per year</td></tr>
<tr><td>Sorbent Silo 2</td><td>0.015 lb/hr</td><td>0.07 tons per year</td></tr>
<tr><td>Fly Ash Bin 11</td><td>0.63 lb/hr</td><td>2.77 tons per year</td></tr>
<tr><td>Fly Ash Bin 12</td><td>0.63 lb/hr</td><td>2.77 tons per year</td></tr>
<tr><td>Fly Ash Bin 14</td><td>0.63 lb/hr</td><td>2.77 tons per year</td></tr>
<tr><td>Fly Ash Bin 14 Air Slide to Bin 11 Air Slide</td><td>0.039 lb/hr</td><td>0.17 tons per year</td></tr>
<tr><td>Fly Ash Bin 14 to 6050 Air Slide</td><td>0.026 lb/hr</td><td>0.11 tons per year</td></tr>
</table>
Annual emissions must be calculated using the methodology identified in Section V of the Title V Basis Statement.

Reference Method: EPA Method 5 or 17

ADP 11-2984 Condition 1</td><td>EU-13, EU-14, EU-15, EU-16, EU-17, EU-18, EU-19, EU-20, EU-21</td><td>M29, M30, M31</td></tr>
<tr><td>Req-74</td><td>Visible emissions from each emission unit installed as part of the mercury control project must not exceed zero percent opacity for more than 3 minutes in any one hour period as determined in accordance with SWCAA Method 9 (See Appendix A of SWCAA 400). This limit applies to stack exhausts as well as fugitive leaks from equipment.

ADP 11-2984 Condition 2</td><td>EU-13, EU-14, EU-15, EU-16, EU-17, EU-18, EU-19, EU-20, EU-21</td><td>M2, M29, M30, M31</td></tr>
<tr><td>Req-75</td><td>Each pollution control device must be operated whenever the processing equipment served by that control device is in operation. Each control device must be maintained in good working order. Furthermore, control devices must be operated in a manner that minimizes emissions.

ADP 11-2984 Condition 3</td><td>EU-13, EU-14, EU-15, EU-16, EU-17, EU-18, EU-19, EU-20, EU-21</td><td>M29, M31</td></tr>
</table>

Req. No.	Requirement	Emission Point	Monitoring
Req-76	Exhaust from each of the mercury control project material handling filters must be discharged vertically. Any device that obstructs or prevents vertical discharge is prohibited. ADP 11-2984 Condition 4	EU-13, EU-14, EU-15, EU-16, EU-17, EU-18, EU-19, EU-20, EU-21	N/A
Req-77	Each fly ash bin baghouse and dust collector must be equipped with a differential pressure gauge capable of continuously measuring the pressure drop across filtration media in the unit. ADP 11-2984 Condition 5	EU-17, EU-18, EU-19	N/A
Req-78	Emissions of filterable particulate matter (PM, PM_{10}, and $PM_{2.5}$) from the Fly Ash Weigh Bin Baghouse must not exceed 0.002 gr/dscf (1-hour average) and the quantities identified below: Generating Equipment — Short-Term Limit (1-hour average) — Annual Limit Fly Ash Weigh Bin — 0.046 lb/hr — 0.20 tons per year Reference Method: EPA Method 5 or 17 ADP 12-3016 Condition 1	EU-4	M3, M5
Req-79	Visible emissions from the Fly Ash Weigh Bin must not exceed zero percent opacity for more than 3 minutes in any one hour period as determined in accordance with SWCAA Method 9 (See Appendix A of SWCAA 400). This limit applies to stack exhausts as well as fugitive leaks from equipment. Reference Method: SWCAA Method 9 ADP 12-3016 Condition 2	EU-4	M3, M5
Req-80	The Weigh Bin Baghouse must be used to control emissions whenever the equipment served by that baghouse is in operation. ADP 12-3016 Condition 3	EU-4	M5
Req-81	Exhaust from the Fly Ash Weigh Bin Baghouse must be discharged vertically. Any device that obstructs or prevents vertical discharge is prohibited. ADP 12-3016 Condition 4	EU-4	N/A
Req-82	The Fly Ash Weigh Bin Baghouse must be equipped with a differential pressure gauge capable of continuously measuring the pressure drop across filtration media in the unit. ADP 12-3016 Condition 5	EU-4	N/A

Req. No.	Requirement	Emission Point	Monitoring
Req-83	Emissions from fine coal recovery must not exceed: Pollutant — Emission Limit PM — 0.009 tons per year PM_{10} — 0.003 tons per year $PM_{2.5}$ — 0.0005 tons per year Annual emissions must be calculated using the methodology identified in Section V of the Title V Basis Statement. ADP 14-3093 Condition 1	EU-22	M3, M35
Req-84	Visible emissions from fine coal handling and conveying equipment must not exceed 0% opacity for more than 3 minutes in any one hour period as determined in accordance with SWCAA Method 9 (See Appendix A of SWCAA 400). Reference Method: SWCAA Method 9 ADP 14-3093 Condition 2	EU-22	M3, M35
Req-85	Visible emissions from fine coal handling and conveying equipment must be less than 10% opacity (1-hour average) as determined in accordance with EPA Method 9. Reference Method: EPA Method 9 40 CFR 60.254(b)(1) ADP 14-3093 Condition 3	EU-22	M3, M35
Req-86	The transfer of fine coal from the stacker to the fine coal stockpile (TP-05) must be controlled as necessary using a high pressure water spray system or other wet suppression system reviewed and approved by SWCAA to provide equivalent or superior control of particulate matter emissions. Each high pressure spray system must maintain 80 psig or greater during operation. A functional pressure gauge must be maintained onsite and a connection point provided for the gage for the purpose of demonstrating compliance with this pressure limit. ADP 14-3093 Condition 4	EU-22	M3
Req-87	The fine coal stockpile must be watered as necessary to control fugitive dust emissions. ADP 14-3093 Condition 5	EU-22	M3
Req-88	Additional wet suppression must be provided as necessary to control fugitive dust from material handling equipment in the event that process controls or enclosures are insufficient to meet the visible emission limits. ADP 14-3093 Condition 7	EU-22	M3, M35

Req. No.	Requirement	Emission Point	Monitoring
Req-89	The Permittee must develop and operate in accordance with a fugitive coal dust emissions control plan for any clean coal stockpile subject to 40 CFR 60 Subpart Y. 40 CFR 60.254(c) ADP 14-3093 Condition 8	EU-22	N/A

VII. MONITORING AND RECORDKEEPING TERMS AND CONDITIONS

The Permittee must conduct each of the monitoring and recordkeeping activities listed below. All monitoring information required by this permit must be recorded and readily available on-site for inspection. [WAC 173-401-615(2)]

All records and supporting information required by this Permit must be kept for a minimum period of no less than five years and must be maintained in a form readily available for inspection by SWCAA representatives. [WAC 173-401-615(2)(c), 40 CFR 63.10(b)(1), 40 CFR 63.6660]

Pursuant to WAC 173-401-530(2)(c), the following monitoring or recordkeeping requirements do not apply to IEUs unless specified.

M1. General Recordkeeping

WAC 173-401-615(2)
ADP 97-2057R1 Sections 26, 29, and 42
ADP 05-2636 Condition 4
ADP 08-2779 Condition 4(b)
ADP 11-2972 Condition 15
ADP 14-3093 Condition 11(c)

Except for data recorded by an automated system, each record required by this Permit must include, at a minimum, the date and the name of the person making the record entry. For those records required for a control device or process, if the control device or process is not operating during a specific time period, a record must be made to that effect.

Permittee is required to keep the following records as applicable:

(a) Inspections and Certifications
  (1) Date and time of the inspection or certification;
  (2) Name and title of the person who conducted the inspection or certification;
  (3) Identification of the unit or activity being inspected or certified;
  (4) Operating conditions of the unit or the type of activity occurring at the time of the inspection or certification;
  (5) Compliance status of each monitored requirement as described in Sections VI and VII of this Permit; and
  (6) Description of corrective action (if any) taken in response to a discovered permit deviation, excess emission, upset condition, or malfunction, as applicable.

(b) Complaints
  (1) Date and time of complaint;
  (2) Name of the complainant;

(3) Description of the complaint;
(4) Date and time of follow-up inspection;
(5) The name and title of the person who conducted the follow-up inspection; and
(6) Description of corrective action (if any) taken in response to complaint.

(c) Sampling and Emissions Testing
(1) Date sampling was performed;
(2) Entity that performed the sampling;
(3) Name and title of the person or the entity that performed the sampling or testing to include, as a minimum for source emissions testing;
(i) Heat input into boiler (million Btu/hr) (EU-2);
(ii) Fuel consumption rate (lb/hr);
(iii) Air discharge flowrate (dry standard cubic feet);
(iv) Exhaust temperature of emissions out the stack; and
(v) Unit load on an hourly basis (megawatts);
(4) Analytical techniques used to take the sample;
(5) Operating conditions existing at the time of sampling or measurement;
(6) Date analytical analyses (if any) were performed;
(7) Entity that performed the analyses;
(8) Analytical techniques or methods used;
(9) Results of such analyses;
(10) Compliance status of each monitored requirement as described in Section VI and VII of this Permit; and
(11) Description of corrective action taken in response to permit deviations and when action was initiated.

(d) Periodic Monitoring and Emissions Records
(1) Date and time of parameter observation or emission calculation;
(2) Name of parameter observed or emission calculated;
(3) Observed parameter value or calculated emission value with appropriate units; and
(4) Periods that data was unavailable.

(e) Excess Emissions and Permit Deviations
(1) Date and time of excess emission or permit deviation occurred;
(2) Description of the excess emission or permit deviation and an identification of the affected unit, process, or activity; and
(3) Description of corrective action taken in response to a discovered permit deviation, excess emission, upset condition, or malfunction, as applicable.

(f) Maintenance Activities
(1) Date and time of the maintenance activity;
(2) Name of the person/company who performed the maintenance;
(3) Identification of the unit or activity being maintained; and
(4) Description of the maintenance being conducted.

(g) Changes at Source
(1) Date changes were made to the source that resulted in emissions of a regulated air pollutant but not otherwise regulated under the Permit;
(2) Description of the changes made to the source; and
(3) Quantity of emissions resulting from the changes.

(h) Upset Conditions

Coal Plant [ADP 97-2057R1 Sections 26 and 29]
(1) Equipment out of service and upset conditions that impact SO_2 emissions; and
(2) Any emissions bypass that is not monitored by a certified functional CEMS.

Coal Unloading Facility [ADP 11-2972 Condition 15(d)]

(3) Upset conditions that cause excess emissions from the coal unloading facility must be recorded for each occurrence.

FGD Bleed Treatment Lime Storage Silo [ADP 05-2636 Condition 4(c)]

(4) Upset conditions that cause excess emissions from the FGD Bleed Treatment Lime Storage Silo must be recorded for each occurrence.

Journal Shop [ADP 08-2779 Condition 4(b)]

(5) Upset conditions that cause excess emissions from the Journal Shop must be recorded for each occurrence.

Fine Coal Handling [ADP 14-3093 Condition 11(c)]

(6) Upset conditions that cause excess emissions from fine coal handling must be recorded for each occurrence.

M2. Visible Emission Monitoring **WAC 173-401-615(1) - (for EU-3)**
ADP 97-2057R1 Section 36
ADP 01-2403 Section 11(c)
ADP 11-2984 Condition 7
ADP 14-3093 Condition 10

EU-1, EU2, and EU-3: At least 6 minutes of opacity observations must be conducted each calendar quarter for EU-2 and EU-3 by a Certified Observer using the visible emissions evaluation method in Appendix A of this permit. [ADP 97-2057R1 Section 36, and WAC 173-401-615(1)]

EU-4 and EU-6: The Permittee must perform monthly inspections of fly ash loading from the 6050 unloaders and Unit 2 turbine lube oil mist eliminator during daylight hours to identify any evidence of visible emissions violations. The inspections must be conducted by an EPA Method 9 certified individual or someone educated in the procedures of visible emission evaluation. Inspection of the fly ash unloading must consist of a survey to determine the presence or absence of excessive opacity, excessive fugitive dust, or evidence of excess emissions. Inspection of the turbine lube oil mist eliminator stack must consist of at least six minutes of opacity observations taken in accordance with SWCAA 400, Appendix A, Method 9. If conditions do not permit opacity readings, an opacity log sheet must be filled out with the weather and operating conditions noted. A reasonable attempt must be made to schedule opacity readings while weather conditions are favorable for the method (i.e. in a warm afternoon vs. a cool morning). For every reading in excess of the opacity standard, opacity must be read for an additional 6 minutes to a maximum total of 60 minutes or 13 readings in excess of the opacity standard, whichever is shorter. Whenever visible emissions in excess of the standard or excessive fugitive dust are observed during the monthly inspection, or any other time, the Permittee must initiate corrective action within 2 hours of observing excess visible emissions. Whenever excess emissions are observed or evidenced, the Permittee must identify the pertinent equipment and verify whether the equipment is or is not experiencing a malfunction and that all relevant air pollution control equipment is operating properly. [ADP 01-2403 Condition 11(c)]

EU-11, EU-13, EU-14, EU-15, EU-16, EU-17, EU-18, EU-19, EU-20, EU-21, and EU-22 and plantwide sources of fugitive dust: The Permittee must perform monthly inspections of EU-11, EU-13, EU-14, EU-15, EU-16, EU-17, EU-18, EU-19, EU-20, EU-21, and EU-22 during daylight hours to identify and prevent potential emissions violations. Whenever visible emissions are observed, at least six minutes of opacity observations must be conducted of that source using SWCAA Method 9. For every reading in excess of the opacity standard, opacity must be read for an additional 6 minutes to a maximum total of 60 minutes or 13 readings in excess of the opacity standard, whichever is shorter. Whenever fallout of particulate matter beyond the

Permittee's property boundary, visible emissions in excess of the standard, or any other potential excess emissions are observed during the monthly inspection or any other time, the Permittee must determine the source of the emissions. The Permittee must initiate corrective action within 2 hours of observing the excess emissions. The Permittee must determine whether the pertinent equipment is or is not experiencing a malfunction and whether all relevant air pollution control equipment is operating properly. Within 24 hours of initial discovery, the Permittee must resolve the operational problem, or notify SWCAA by the next working day of progress made in resolving the operational problem. [ADP 14-3094 Condition 10 for EU-22, ADP 11-2984 Condition 7 for EU-19 through EU-27]

Implementation of corrective action does not relieve the Permittee from the obligation of reporting permit deviations as specified in WAC 173-401-615(3).

M2. Particulate Matter Emissions Monitoring **SWCAA 05-2636 Condition 3**
SWCAA 11-2972 Condition 14
SWCAA 12-3016 Condition 7
SWCAA 14-3093 Condition 6
WAC 173-401-615(1)

The Permittee must perform monthly inspections of emission units EU-2 through EU-6, and EU-8 during daylight hours to identify potential particulate matter emissions violations. All other emission units (EUs and IEUs) must be inspected if the specific unit is implicated by a complaint or if otherwise unusual emissions are observed. Whenever fallout of particulate matter beyond the Permittee's property boundary or visible emissions in excess of the standard are observed during the periodic inspection as required in M1, or any other time, the Permittee must determine the source of the emissions. The Permittee must initiate corrective action within 2 hours of observing particulate matter fallout or excess visible emissions. The Permittee must confirm whether the pertinent equipment is or is not experiencing a malfunction and whether all relevant air pollution control equipment is operating properly. Within 24 hours of initial discovery, the Permittee must resolve the particulate matter fallout or excess emissions or notify SWCAA by the next working day of progress made in resolving the operational problem.

Spray/fog nozzles in high pressure water spray systems at the Coal Unloading Facility must be visually inspected once per month when in operation to ensure proper function. Clogged or defective nozzles must be replaced or repaired prior to subsequent operation. The operating pressure of the water spray system must be measured during the monthly inspection.

Spray/fog nozzles in the wet suppression system(s) for the fine coal handling system must be visually inspected once per week when in operation to ensure proper function. Clogged or defective nozzles must be replaced or repaired prior to subsequent operation.

M4. Fugitive Emissions Monitoring **WAC 173-401-615(1)**
SWCAA 01-2403 Section 11(c)

The Permittee must perform monthly inspections of emission units EU-2 through EU-8 during daylight hours to identify any excess fugitive emissions including fugitive dust. All other emission units (EUs and IEUs) must be inspected if the specific unit is implicated by a complaint or if otherwise unusual emissions are observed. Inspection of the fly ash unloading must consist of a survey to determine the presence or absence of excessive opacity, excessive fugitive dust, or evidence of excess emissions. Whenever fugitive emissions including excessive fugitive dust are observed during the monthly inspection or any other time, the Permittee must determine the source

of the emissions. The Permittee must within 2 hours of discovery initiate investigation of the equipment involved to confirm whether the equipment is or is not experiencing a malfunction, and whether reasonable precautions and good work practices are being employed to minimize emissions. For this requirement, reasonable precautions and good work practices include, but are not limited to, the following:

(a) Apply water and/or chemical dust suppressants to coal when received at the plant site and to coal entering conveyors or other process or transfer points daily when fugitive dust from coal handling operations is routinely observed to be 20% or higher opacity, or more frequently as necessary to minimize fugitive coal dust consistent with Req-8;
(b) Operate baghouse dust collectors at any shop where significant welding is conducted (e.g. Journal Shop); and
(c) Use a water truck to apply water to paved and unpaved traffic areas on a daily basis during periods when fugitive dust from these areas is routinely observed to be 20% opacity, or more frequently as necessary, to minimize fugitive road dust.

M5. Complaint Monitoring **WAC 173-401-615(1)**
SWCAA 11-2984 Condition 9
SWCAA 12-3016 Condition 9

The Permittee must record, and maintain record of, any air quality related complaints received by either the Permittee or SWCAA. All complaints must be investigated no later than one workday after the Permittee has been notified, and those complaints subject to requirement M2 must be addressed in a timely manner consistent with M2. The Permittee must determine the validity of each complaint and the cause of any emissions that may have prompted the complaint, and initiate corrective action, if needed, in response to the complaint. Within 24 hours of notification and investigation, the Permittee must resolve the subject of the complaint, or notify SWCAA by the next working day of progress made in resolving the complaint.

M6. Operations Monitoring **WAC 173-401-615(1)**

The Permittee must perform monthly inspections of emission units EU-2 through EU-8 during daylight hours to confirm that pollution control equipment is operating according to manufacturer specifications and/or consistent with good engineering and maintenance practices. All other emission units (EUs and IEUs) must be inspected if the specific unit is implicated by a complaint or if otherwise unusual emissions are observed. Whenever nonstandard conditions are observed during the monthly inspection or any other time, the Permittee must initiate corrective action within 2 hours of observing an equipment problem. The Permittee must determine whether the pertinent equipment is or is not experiencing a malfunction and whether all relevant air pollution control equipment is operating properly. The Permittee must review maintenance records as necessary to monitor the operations of air pollution control equipment. Within 24 hours of initial discovery, Permittee must resolve the operational deficiency, or notify SWCAA by the next working day of progress made in resolving the operating problem. Implementation of corrective action does not relieve the Permittee from the obligation of reporting permit deviations as specified in WAC 173-401-615(3).

M7. Coal Plant SO_2 General Standard Monitoring

SWCAA 97-2057R1 Section 27(c) and 43(a)

This monitoring requirement applies to EU-2 and EU-3 only.

Monitoring to ensure compliance with Req-6 on a 60-minute average is described in M8. The Permittee must monitor, record, and maintain record of the sulfur content of coal combusted in the boiler of emission unit EU-2. This monitoring must include, at a minimum, the sulfur content determined on a monthly basis from analysis of composite coal samples. A linear relationship exists between coal sulfur content and unscrubbed SO_2 concentration with a sulfur content of approximately 1% by weight corresponding to an unscrubbed emission concentration of 1,000 ppm. Coal sulfur content must be used, as necessary, to verify SO_2 monitoring results required by M8. The Permittee must determine the sulfur content of the fuel oil used to fuel the auxiliary boiler (EU-3) and for startup of EU-2 at a sufficient frequency that allows the sulfur content to be certified in each quarterly report.

M8. Coal Plant Stack Sampling Monitoring Requirements

SWCAA 97-2057R1 Sections 35, 40, and 42
Second Revision of BART Order No. 6426 Condition 4.1 except 4.1.4
40 CFR 63 Subpart UUUUU Sections 63.10007 and 63.10030

CO, PM Monitoring [SWCAA 97-2057R1]

This monitoring requirement applies to EU-2 only.

The Permittee must conduct emissions testing of EU-2 at least once every year to quantify emissions of particulate matter and to validate the CO CEMS. A minimum of three test runs must be performed at a minimum of 500 MW gross to establish that collected data are representative of normal operation. The use of continuous monitors is acceptable as an alternative emissions sampling schedule. The following reference test methods from 40 CFR 60 Appendix A, or equivalent methods if approved in writing by SWCAA in advance, must be used for these emissions tests:

Pollutant:	CO	PM
EPA Test Method:	10	5 and 202

The carbon monoxide annual emission concentration must be determined by the arithmetic average of hourly plant operating CO data corrected to 7% O_2 as follows:

CO, dry @ 7% O_2 = [(20.9 - 7) / (20.9 - O_2%, dry)] * CO, dry @ actual O_2%

The CO concentrations must be validated once per year, for each stack (flue), by source testing and the plant CO data adjusted for bias based on the Method 10 results. A formal relative accuracy test audit is not required.

The particulate matter test method must be consistent with the SO_2 control technology selected and must be appropriate for the stack conditions (i.e., wet or dry stack). Only the filterable fraction (as measured by EPA Method 5) must be used for comparison with the permitted limit, however, the condensable portion must continue to be measured and reported for emission inventory purposes. The PM result must be corrected to 7% O_2.

Ammonia Monitoring [Second Revision of BART Order No. 6426 Condition 4.1 except 4.1.4]

The ammonia monitoring and recordkeeping requirements below apply in any calendar year in which urea is injected using the SNCR system.

Ammonia emissions for compliance must be monitored by means of periodic emissions testing utilizing Bay Area Air Quality Management District (BAAQMD) Method ST1B or Environmental Protection Agency Conditional Test Method 027 (CTM-027). The sampling point will be in the stack following the wet scrubber. Stack testing must occur on the following frequency:

(a) Testing must occur once each calendar year if the ammonia feed-rate exceeds 1.5 gallons per minute during that calendar year. Testing must be performed while the SNCR is in operation and the feed-rate is above 1.5 gallons per minute during testing, with no consecutive tests less than 80 or more than 110 calendar days apart.

(b) If two consecutive tests are each more than the ammonia limitation, then the testing frequency decreases to once every six calendar months, provided the nitrogen oxides emission limit is complied with during the test.

(c) If, after there are three consecutive tests less than the ammonia limitation, the next two consecutive tests are less than 50% of the ammonia emission limitation, then the testing frequency reduces to once annually, provided the nitrogen oxides emission limit is complied with during the tests.

Performance Testing for 40 CFR 63 Subpart UUUUU

Performance testing for PM must be conducted quarterly in accordance with M9 if the Permittee choses the quarterly testing option over the PM CEMS option.

The Permittee must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin. [40 CFR 63.9(e) as modified by 40 CFR 63 Subpart UUUUU Table 9, 40 CFR 63.10030(a), 40 CFR 63.10030(d)]

Upon request, the Permittee must make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of 40 CFR 63.10007. [40 CFR 63.10007(g)]

M9. Coal Plant Continuous Monitoring Provisions

40 CFR 63 Subpart UUUUU Sections 63.10000(c)(1)(iv), 63,10000(d), 63.10006, 63.10007, 63.10010, 63.10020, 63.10021, Table 3 and Table 5
40 CFR 75
WAC 173-401-615
SWCAA 400-105(4)(a) and (4)(e)
SWCAA 97-2057R1 Sections 21, 24, 26, 27a, 27b, 27c, 30, and 36
SWCAA 16-3202 Section 14
Second Revision of BART Order No.6426 Condition 5

This monitoring requirement applies to EU-2 only.

The Permittee must monitor opacity, SO_2, NO_X, Hg, filterable PM, diluent (CO_2 and/or O_2), moisture, and stack flow for EU-2 in accordance with the requirements listed below.

The Permittee must monitor and collect data to demonstrate continuous compliance with the 30-boiler operating day Hg, SO_2, and PM emission limits from 40 CFR 63 Subpart UUUUU according to the requirements in 40 CFR 63.10020 and 40 CFR 63 Subpart UUUUU Table 3. 40 CFR

63.10020 requires that monitoring be conducted at all times with certain exceptions (e.g. calibration checks), that data from all time periods except certain excepted periods listed in 63.10020(c) be used to report emissions, and specifies that any failure to collect required data is a deviation from the monitoring requirements of 40 CFR 63 Subpart UUUUU. 40 CFR 63.10020, 63.10021(h), and Table 3 require that monitoring be conducted during startup and shutdown. [40 CFR 63.10020, 40 CFR 63.10021(h)(2), 40 CFR 63 Subpart UUUUU Table 3]

Opacity

(a) Opacity of emissions from EU-2 must be monitored in accordance with the requirements of 40 CFR 75.

(b) If moisture is present in the gas stream to the extent that it interferes with the COMS providing accurate opacity data, then visual observations using Method 9, as described in Appendix A to this permit, must be performed a minimum of once per quarter to demonstrate compliance. [SWCAA 97-2057R1 Section 36]

(c) The Permittee must reduce all opacity data to 6-minute averages calculated from 36 or more data points equally spaced over each 6-minute period. Opacity data recorded as 1-minute averages calculated from 6 or more data points equally spaced over each 1-minute period must also meet this monitoring requirement. [40 CFR 75.10(d)(2); 40 CFR 51 Appendix P; SWCAA 97-2057R1 Section 36; WAC 173-401-615(1)]

SO_2

(d) SO_2 emissions from EU-2 must be monitored in accordance with the requirements of 40 CFR 75. [40 CFR 75, 40 CFR 63.10010(f), SWCAA 97-2057R1 Section 27, SWCAA 16-3202 Section 14]

(e) For the purposes of demonstrating compliance with the SO_2 limits found in SWCAA 97-2057R1 and SWCAA 400 the following additional requirements apply:

(1) In addition to 40 CFR Part 75 requirements, the SO_2 CEMS with automated DAHS must also record the SO_2 concentration (ppm) corrected to 7% O_2, dry, consistent with SWCAA 400-050(4) with the use of an O_2 CEMS (consisting of an O_2 concentration monitor) with automated DAHS. The O_2 system measures and records O_2 concentration (%) in the stack gas discharged to the atmosphere in accordance with 40 CFR 75.13(c) and 40 CFR 75 Appendix F. The correction for SO_2 must use the following method:

SO_2, dry @ 7% O_2 = [(20.9 - 7) / (20.9 - O_2%, dry)] * SO_2, dry @ actual O_2%; [SWCAA 97-2057R1 Sections 21 and 27a, and SWCAA 400-040(6) and 400-050(4)]

(2) 40 CFR Part 75 provisions also apply to each CEMS and component thereof for measuring and recording fixed clock 1-hour averages of O_2 concentrations and SO_2 standard concentrations (dry, corrected to 7% O_2). [SWCAA 97-2057R1 Section 27a]

(3) Except for the purposes of 40 CFR 63 Subpart UUUUU, whenever a valid hour of SO_2 concentration and flow rate data have not been measured and recorded, the Permittee must provide substitute data in accordance with 40 CFR 75 Subpart D. When determining compliance with the SO_2 concentration standard of SWCAA 97-2057R1 Sections 21 and 22, and SWCAA 400-040(6) (dry @ 7% O_2) and the SO_2 annual emission standard of SWCAA 97-2057R1 Sections 18 and 20, alternative data may be used for missing data periods. For monitor out-of-service periods of four hours or less in duration, the average of the hour before and the hour following a monitor out-of-service period, in accordance with 40 CFR 75.33(b)(1)(i) must be used. For monitor out-of-service periods greater than four hours, data from an on-line coal analyzer, any as-burned coal analyses conducted by the Permittee, and plant emission control system operating data must be evaluated. The data or combination of data that best represents actual emissions must be used to determine compliance with the SO_2 limitations. Stack source test data may be used, if available and

the source test is conducted according to methods approved by SWCAA. [SWCAA 97-2057R1 Section 27c]

(4) The Permittee must maintain records of SO_2 rolling 12-month mass emissions (not recorded hourly), as measured and reported from the certified primary monitoring system(s), certified redundant or non-redundant back-up monitoring system(s), or other approved method(s) of emissions determination: [SWCAA 97-2057R1 Sections 24, 26, and 27b]

(i) Tons of SO_2 emitted from all relevant stacks (including any emergency bypasses) for each rolling 12-month period; and

(ii) All SO_2 emissions during startup, shut down, equipment out of service, and upset conditions must be recorded separately from normal operations.

(f) For the purposes of demonstrating compliance with the SO_2 emission limits from 40 CFR 63 Subpart UUUUU, the following additional requirements apply:

(1) Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO_2 data and do not use part 75 substitute data values. For startup or shutdown hours the default electrical load and the diluent cap are available for use in the hourly SO_2 emission rate calculations, as described in 40 CFR 63.10007(f). Use a flag to identify each startup or shutdown hour and report a special code if the diluent cap or default electrical load is used to calculate the SO_2 emission rate for any of these hours. [40 CFR 63.10010(f)(4), 40 CFR 63.10021(h)(1)]

(2) Calculate and record a 30-boiler operating day rolling average SO_2 emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid SO_2 emission rates in the preceding 30-boiler operating days. [40 CFR 63.10010(f)(3)]

NO_X

(g) NO_X emissions from each EU-2 be monitored in accordance with the requirements of 40 CFR 75.

(h) For the purposes of demonstrating compliance with the NO_X limits found in SWCAA 97-2057R1, the following additional requirements apply:

(1) Whenever a valid hour of NO_X concentration and flow rate data have not been measured and recorded, the Permittee must provide substitute data in accordance with 40 CFR 75 Subpart D. Stack source test data may be used, if available and the source test is conducted according to methods approved by SWCAA. [SWCAA 97-2057R1 Section 27c]

(2) The Permittee must maintain records of the hourly average NO_X emission rate (lb/million Btu, rounded to nearest hundredth) adjusted for bias if necessary as provided for in 40 CFR 75.24(d), for those hours when a unit's generating load is 360 MW gross or greater, both units averaged together. [SWCAA 97-2057R1 Section 30, WAC 173-401-615]

(i) Reserved

Mercury (Hg) – Note that TransAlta is also subject to off-permit Hg control and monitoring requirements from a settlement agreement with Washington State signed in May 2010.

(j) For the purposes of demonstrating compliance with the Hg emission limits from 40 CFR 63 Subpart UUUUU, the Permittee must install, certify, operate, maintain and quality assure the data from the Hg CEMS or Hg sorbent trap monitoring system in accordance with Appendix A of 40 CFR 63 Subpart UUUUU. The Permittee must calculate and record a 30-boiler operating day rolling average Hg emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is

the average of all of the valid Hg emission rates in the preceding 30-boiler operating days. [40 CFR 63.10000(d), 40 CFR 63.10010(g), 40 CFR 63 Appendix A]

Filterable PM

(k) For the purposes of demonstrating compliance with the PM emission limits from 40 CFR 63 Subpart UUUUU, the Permittee must either install, certify, operate, maintain and quality assure the data from a PM CEMS or perform quarter testing as described below [40 CFR 63.1000(c)(1)(iv)]:

(1) PM CEMS Option

The CEMS must be operated in accordance with 40 CFR 63.10010(i) and 40 CFR 63 Subpart UUUUU Table 5. The Permittee must calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler operating hours. [40 CFR 63.10010(i) and 40 CFR 63 Subpart UUUUU Table 5]

(2) Quarterly Testing Option

Testing for filterable PM must be conducted in accordance with 40 CFR 63.10007 and Section 1 of 40 CFR 63 Subpart UUUUU Table 5. Tests must be conducted each calendar quarter except as provided by 40 CFR 63.10021(d)(1). 40 CFR 63.10021(d)(1) allows a performance test to be skipped in a quarter with less than 168 operating hours, except that a performance test must be conducted at least once every calendar year. [40 CFR 63.1000(c)(1)(iv), 40 CFR 63.10021(d)(1)]

At least 45 calendar days, measured from the test's end date, must separate performance tests conducted every quarter. [40 CFR 63.10006(f)(1)(i)]

A performance test must be conducted in the 4th quarter of a calendar year if the unit has skipped performance tests in the first 3 quarters of the calendar year. [40 CFR 63.10006(f)(2)]

If a unit misses a performance test deadline due to being inoperative and if 168 or more boiler operating hours occur in the next quarter, an additional performance test must be conducted in that quarter. At least 15 calendar days must separate two performance tests conducted in the same quarter. [40 CFR 63.10006(f)(3)]

A minimum of 1 dry standard cubic meter of stack gas must be collected for each run. The unit must be operated at maximum normal operating load during each performance test run. [40 CFR 63.10006(c), 63.10007(a)(2), 63.10007(b), 63.10021(d) and Section 1 of Table 2 and Section 1 of Table 5 of 40 CFR 63 Subpart UUUUU]

Diluent (O_2 and/or CO_2)

(l) CO_2 and/or O_2 in the exhaust from EU-2 must be monitored in accordance with the requirements of 40 CFR 75. [40 CFR 75, 40 CFR 63.10010(b) SWCAA 97-2057R1 Sections 27]

(m) For the purposes of demonstrating compliance with the SO_2, PM, and Hg emission limits from 40 CFR 63 Subpart UUUUU, the following additional requirements apply:

(1) Only quality-assured diluent (O_2 or CO_2) data may be used in emission calculations. The data substitution procedures of 40 CFR 75 must not be used. [40 CFR 63.10010(b)]

Stack Gas Moisture Content

(n) The moisture content of the exhaust from EU-2 must be monitored in accordance with the requirements of 40 CFR 75 as necessary to convert pollutant concentrations or stack flow measurements from the measured basis (wet or dry) to the necessary basis (wet or dry) for emission rate calculations or comparison with applicable emission limits. [40 CFR 75]

(o) For the purposes of demonstrating compliance with the SO_2, PM, and Hg emission limits from 40 CFR 63 Subpart UUUUU, the following additional requirements apply:

(1) If the Permittee is required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 2 of Subpart UUUUU, the Permittee must install, certify, operate, and maintain a moisture monitoring system in accordance with part 75 of this chapter. Alternatively, the Permittee may use appropriate fuel-specific default moisture values from 40 CFR 75.11(b) to estimate the moisture content of the stack gas. If a moisture monitoring system is utilized, the Permittee must not use substitute moisture data in the emissions calculations. [40 CFR 63.10010(d)]

Stack Flow

(p) Stack flow rate from EU-2 must be monitored in accordance with the requirements of 40 CFR 75. [40 CFR 75, 63.10010(c), SWCAA 97-2057R1 Section 27, SWCAA 16-3202 Section 14]

(q) For the purposes of demonstrating compliance with the SO_2, PM, and Hg emission limits from 40 CFR 63 Subpart UUUUU, the following additional requirements apply:

(1) If stack flow is used to convert pollutant concentrations to units of an electrical output-based emission standard from Subpart UUUUU, only unadjusted, quality-assured flow rate data may be used. Bias adjustment factors must not be applied to the flow rate data and substituted flow rate data must not be used in the calculations. [40 CFR 63.10010(c)]

General Monitoring Provisions Specific to 40 CFR 63 Subpart UUUUU

(r) CEMS for SO_2 and CEMS or sorbent trap monitoring systems for Hg must be installed in accordance with location requirements of 40 CFR 63.10010(a). [40 CFR 63.10010(a)]

(s) If a CEMS for SO_2 or Hg is not installed on the bypass stack of Unit 2, any operation through the affected bypass stack other than during startup or shutdown is a deviation from the monitoring requirements of 40 CFR 63 Subpart UUUUU. If a PM CEMS is not installed, or quarterly testing for PM is not conducted on the bypass stack of Unit 2, any operation through the affected bypass stack other than during startup or shutdown is a deviation from the monitoring requirements of 40 CFR 63 Subpart UUUUU. [40 CFR 63.10006(c), 40 CFR 63.10010(a)(4)] (All deviations must be reported in the semiannual report).

(t) Except as otherwise provided in 40 CFR 63.10020(c), all quality-assured hourly data recorded by the SO_2, PM, and Hg CEMS and tbe other required monitoring systems (e.g. flow rate, CO_2, O_2, or moisture systems) must be used to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day rolling average basis, updated at the end of each new boiler operating day. The following equation must be used to determine the 30-boiler operating day rolling average: [40 CFR 63.10021(b), Section 1 of 40 CFR 63 Subpart UUUUU Table 7]

$$\text{Boiler operating day average} = \frac{\sum_{i=1}^{n} Her_i}{n}$$

Where:

Her_i is the hourly emissions rate for hour i and n is the number of hourly emissions rate values collected over 30-boiler operating days.

(u) The Permittee must operate, maintain, and quality assure the SO_2, PM, and Hg CEMS in accordance with 40 CFR 63.8 except that the general duty clause to minimize emissions referenced to 40 CFR 63.6(e)(1) and requirements related to a written startup, shutdown, and malfunction plan do not apply. [40 CFR 63.8 and 40 CFR 63 Subpart UUUUU Table 9]

(v) The electrical output from Unit 2 must be recorded for each hour of operation. [WAC 173-401-615(1)]

(w) Submit notification to SWCAA of the date required SO_2 and Hg RATAs are scheduled to begin at least 60 calendar days before the RATA is scheduled to begin. [40 CFR 63.9(g)(1), 40 CFR 63.10030(a), 40 CFR 63 Subpart UUUUU Table 9]

M10. 40 CFR 63 Subpart UUUUU Recordkeeping and Startup Monitoring

40 CFR 63.8
40 CFR 63.10
40 CFR 63 Subpart UUUUU Sections 63.10000(m), 63.10020(e), 63.10032, 63.10033, and Table 9
WAC 173-401-615(2)

(a) The Permittee must generate and maintain the following records for Unit 2 (EU-2): [40 CFR 63.10032]

(1) A copy of each notification and report submitted to comply with 40 CFR 63 Subpart UUUUU, including all documentation supporting any Initial Notification or Notification of Compliance Status or compliance report submitted according to the requirements of 40 CFR 63.10(b)(2)(xiv). [40 CFR 63.10032(a)]

(2) Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required by 40 CFR 63.10(b)(2)(viii). The applicable reports referenced in 40 CFR 63.10(b)(2)(viii) are performance tests and continuous monitoring system evaluations (e.g. RATAs).

(3) The following records regarding PM, Hg, and SO_2 CEMS: [40 CFR 63.10032(b)]
  (i) Each period during which a continuous monitoring system was malfunctioning or inoperative (including out-of-control periods).
  (ii) All required measurements needed to demonstrate compliance with the requirements of 40 CFR 63 Subpart UUUUU as described in 40 CFR 63.10(b)(2)(vii).
  (iii) All measurements as may be necessary to determine the conditions of performance tests and performance evaluations.
  (iv) All CEMS calibration check results.
  (v) All adjustments and maintenance performed on the CEMS.

(4) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period. [40 CFR 63.10032(b)(4)]

(5) Previous (*i.e.*, superseded) versions of the performance evaluation plan as required in 40 CFR 63.8(d)(3). [40 CFR 63.10032(b)(2)]

(6) Records of PM performance test reports, tune-up reports, startup and shutdown work practice standard monitoring, and all monitoring data and calculated averages for the SO_2 CEMS and Hg sorbent trap monitoring system. [40 CFR 63.10032(c)]

(7) Identification of the type and amount of each fuel combusted. [40 CFR 63.10032(d)(1)]

(8) Regarding startup periods or shutdown periods: [40 CFR 63.10000(m), 40 CFR 63.10032(f)]

(i) Records of occurrence and duration of each startup and/or shutdown.
(ii) Records of the determination of the maximum clean fuel capacity;
(iii) Records of the determination of the maximum hourly clean fuel heat input and of the hourly clean fuel heat input; and
(iv) Records of the information required in 40 CFR 63.10020(e). 40 CFR 63.10020(e) requires that the following information be recorded for each startup and shutdown period: [40 CFR 63.10020(e)]
   a. The date and time that clean fuels being combusted for the purposes of startup and shutdown begins. [40 CFR 63.10020(e)(1)(i). 63.10020(e)(2)(i)]
   b. The quantity and heat input of clean fuel for each hour of startup and shutdown. [40 CFR 63.10020(e)(1)(ii), 63.10020(e)(2)(ii)]
   c. The gross output for each hour of startup and shutdown. [40 CFR 63.10020(e)(1)(iii), 63.10020(e)(2)(iii)]
   d. The date and time that non-clean fuel combustion begins for each startup and ends for each shutdown. [40 CFR 63.10020(e)(1)(iv), 63.10020(e)(2)(iv)]
   e. The date and time that clean fuels being combusted for the purpose of startup and shutdown ends for each startup and shutdown. [40 CFR 63.10020(e)(1)(v), 63.10020(e)(2)(v)]
   f. The temperature and combustion air flow or calculated flow as determined from combustion equations of post-combustion (exhaust) gas, as well as amperage of forced draft fan(s) upstream of the filterable PM control devices during each hour of startup. [40 CFR 63.10020(e)(3)(i)(A)]
   g. The temperature and flow rate of exhaust gas and amperage of induced draft fan(s) downstream of each filterable control device during each hour of startup. [40 CFR 63.10020(e)(3)(i)(B)]
   h. The number of ESP fields in service, as well as each field's secondary voltage and secondary current during each hour of startup. [40 CFR 63.10020(e)(3)(i)(C)]

      For the monitoring systems used to provide the data listed above, the Permittee must install, verify, operate, maintain, and quality assure each monitoring system and develop a site-specific monitoring plan for work practice monitoring during startup periods. The site-specific monitoring plan must be developed in accordance with the requirements listed in 40 CFR 63.10010(l). The Permittee must submit the site-specific monitoring plan upon request by SWCAA. [40 CFR 63.10010(l)]

      During startup periods, the Permittee must monitor and collect data according to this section and the site-specific monitoring plan required by 40 CFR 63.10010(l). [40 CFR 63.10020(e)(3)]

(9) Records of the occurrence and duration of each malfunction of an operation (*i.e.*, process equipment) or the air pollution control and monitoring equipment. [40 CFR 63.10032(g)]
(10) Records of actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. [40 CFR 63.10032(h)]
(11) Records of the type(s) and amount(s) of fuel used during each startup or shutdown. [40 CFR 63.10032(i)]

(b) The Permittee must generate and maintain the records required by the sections of 40 CFR 63.10 listed in 40 CFR 63 Subpart UUUUU Table 9 for Unit 2 (EU-2). These records include, but are not limited to: [40 CFR 63 Subpart UUUUU Table 9]

(1) All required maintenance of CEMS and pollution control equipment.
(2) All CEMS data.
(3) Identification of all time periods when a CEMS was inoperative except for zero and span checks.
(4) Identification of all time periods when a CEMS was out of control.
(5) Identification of each period of excess emissions.
(6) The nature and cause of any malfunction.
(7) The corrective action taken or preventive measures adopted.
(8) The nature of the repairs or adjustments to CEMS that were inoperative or out of control.
(9) All procedures that are part of a quality control program developed and implemented for the CEMS under 40 CFR 63.8(d).

The records must be in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1). The records must be maintained for five years following the date of each occurrence, measurement, maintenance, corrective action, report or record. Each record must be kept on site, or they must be accessible from on site, for at least five years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. [40 CFR 63.10033]

M11. Coal Plant Startup, Shut Down, and Outage Operation Procedures for RACT Order SWCAA 97-2057R1 Sections 21b, 23, 25, 26, 28e, 37, and 38

This monitoring requirement applies to EU-2 only.

During startup and shutdown of EU-2, emissions control equipment must be operated to minimize overall emissions, except to the extent equipment operation will cause degradation of its long-term performance. Opacity exceedances during manual ESP rapping and boiler chemical cleaning are excused under SWCAA 400-107(2)(d). Exceedances of the PM and opacity limitations are excused under SWCAA 400-107 during unit startup and shutdown when the ESPs are out of service. Exceedances of the normal operation hourly SO_2 limitation (250 ppmvd @ 7% O_2), are excused under SWCAA 400-107 during startup and shutdown when the ESPs and SO_2 emission control technology are out of service, provided the alternative SO_2 emission limits of Req-19 are met. The shutdown period begins when the ESP temperature drops to 220°F, when the SO_2 emission control technology and then the ESPs are taken out of service. The startup period begins when fuel is introduced into a boiler to raise its temperature to operating conditions. The startup period ends when the earlier of the two operating events below occurs:

(a) Opacity in the gas path downstream of both ESPs has stabilized below 10% for 30 minutes; or
(b) 8 hours have elapsed after the startup unit is synchronized electrically on-line.

During SO_2 emission control technology outages and upsets, emissions in excess of the hourly SO_2 limitation are excused provided they satisfy the alternative SO_2 emission limits of Req-19 or they meet the burden of proof regarding unavoidable emissions in accordance with SWCAA 400-107. The Permittee must demonstrate that a forced outage of the SO_2 emission control technology while the unit operates is managed to minimize emissions. Implementation of corrective action does not relieve the Permittee from the obligation of reporting permit deviations as specified in WAC 173-401-615(3).

M12. Coal Plant SO_2 12-Month Period Emission Evaluation
SWCAA 97-2057R1 Sections 26, 28c, and 28d

This monitoring requirement applies to EU-2, and EU-3 only.

All hourly SO_2 emission data for startup, shutdown, upset and forced or planned emission control system outage periods must be included in the calculations of the annual tons of SO_2 emitted. For periods when all fuel is out of a boiler, SO_2 emissions for that unit must be assumed to be zero. An exceedance of the annual limitation is one 12-month period exceeding the tons/year SO_2 limitation as defined in Req-17. Each exceedance of the rolling 12-month emission limitation, except as excused under SWCAA 400-107, will constitute a continuing violation for the days in the last month of the 12-month period. Each day of violation must be treated equally and be subject to penalty as allowed by law at the time of the non-compliance. The Permittee may calculate 365-day emission summations ending on each day in the last month of the 12-month period to reduce the number of violation days subject to penalty. If adequately demonstrated, the number of violation days must not include the number of 365-day periods ending within the last month of the exceedance period for which the emissions summation did not exceed the annual limit.

M13. Coal Plant SO_2 Monitoring of Bypass Stack **SWCAA 97-2057R1 Section 29**

This monitoring requirement applies to EU-2 only.

Any bypass through the bypass stack that is not monitored by a certified functional CEMS for SO_2 is considered an upset condition and must be reported consistent with requirement R1. All SO_2 emissions discharged from the bypass stack must be included in the calculation of emissions for determining compliance with the annual limit.

M14. Coal Plant Fuel Oil Usage Evaluation **40 CFR 63.7525(k)**
SWCAA 97-2057R1 Sections 43 and 45

The Permittee must monitor fuel oil usage in the boilers at the Coal Plant (EU-2, and EU-3). The Auxiliary Boiler (EU-3) must have a separate fuel meter to monitor the total amount of fuel consumed in that boiler. Emissions of SO_2 from the Auxiliary Boiler must be included when evaluating the 10,000 tons per year emission limit in Req-17. Emissions must be calculated based on fuel consumption and fuel sulfur content. [SWCAA 97-2057R1 Sections 43 and 45]

The amount of fuel oil used in the Auxiliary Boiler must be recorded for each day of operation. [40 CFR 63.7525(k)]

M15. Reserved

M16. Reserved

M17. Reserved

M18. Reserved

M19. Maintenance Activities Monitoring **40 CFR 63.6655(e)**
SWCAA 01-2403 Section 11(c)

This monitoring requirement applies to EU-4 and EU-6 only.

The Permittee must document each occurrence of maintenance and repairs to the fly ash unloading pugmill and turbine lube oil mist eliminator that may affect emissions.

M20. Particulate Matter Compliance Assurance Monitoring for BW22

40 CFR 64
WAC 173-401-615(4)

This monitoring requirement applies to EU-2 only.

This monitoring requirement applies unless a particulate matter continuous emissions monitoring system is installed and certified in accordance with the requirements of 40 CFR 63 Subpart UUUUU.

In addition to the opacity monitoring requirements of Requirement 13 and M8, the Permittee must continuously monitor opacity in the ductwork upstream of the bypass stack in accordance with the quality assurance and quality control requirements of 40 CFR 75 except that the existing monitoring locations immediately upstream of the bypass stack are acceptable. The COMS must provide for at least 90% data availability (annual average rolled monthly).

Opacity less than the following is indicative of proper operation of the ESPs and provides a reasonable assurance of compliance with the particulate matter emission limits:

Exhaust Point	Maximum Opacity[1]
EU-2 Bypass Stack	20% (1-hour average)
EU-2 FGD Stack	30% (1-hour average)

[1] This range does not apply during the defined startup and shutdown periods, during planned maintenance or outage periods, load changes, and during manual rapping of the ESP. The 1-hour average applies to the clock hour recorded by the COMS. An hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour) if data are unavailable as a result of the performance of calibration, quality assurance, or preventive maintenance activities.

If opacity is measured in two ducts for the same emission unit, the arithmetic average of the opacity measurements from each duct must be used to compare with the maximum opacity listed above.

An excursion is defined as any exceedance of the maximum opacity levels identified in the table above. For each excursion:

(a) Inspect electrostatic precipitators within four hours. Report ESP field settings and a list of fields out of service.
(b) If the exceedance occurs during FGD operation, inspect FGD system for proper operation (excess inlet particulate loading can affect FGD performance) within four hours. Report the numbers of spray headers in service.
(c) Make necessary repairs as soon as practical.

(d) Restore opacity levels to less than the maximum levels indicated above as expeditiously as practical in accordance with good air pollution control practices for minimizing emissions.
(e) Notify SWCAA no later than the end of the next business day in accordance with R1.

M21. Coal Unloading Facility **SWCAA 11-2972 Condition 15(a)**

This monitoring requirement applies to EU-4 only.

The Permittee must develop and maintain the following information for the Coal Unloading Facility:

(a) The total amount of coal unloaded each calendar year.

M22. FGD Bleed Treatment Lime Storage Silo
SWCAA 05-2636 Condition 4(a) and 4(b)

This monitoring requirement applies to EU-4 only.

The Permittee must develop and maintain the following information for the FGD Bleed Treatment Lime Storage Silo:

(a) The total number of hours the FGD Bleed Treatment Lime Storage Silo dust collector is actively vented must be recorded for each calendar year; and
(b) The differential pressure across the FGD Bleed Treatment Lime Storage Silo dust collector must be recorded once per calendar month during loading.

M23. Journal Shop **SWCAA 08-2779 Condition 4(a)**

This monitoring requirement applies to EU-8 only.

The Permittee must develop and maintain the following information for the Journal Shop:

(a) The total amount of each welding rod type used in the Journal Shop must be recorded for each calendar year.

M24. Reserved

M25. SNCR System Monitoring **WAC 173-401-615(1)**

This monitoring requirement applies to EU-2 only.

The Permittee must continuously monitor and record the following parameters related to operation of the SNCR system for each hour of operation:

(a) The urea concentration and flow rate.

M26. Coal Plant Emergency Engine Monitoring

40 CFR 63.6655
40 CFR 60.4214(b)
WAC 173-615(1)
SWCAA 400-075
SWCAA 400-115
SWCAA 16-3188 Condition 8

This monitoring requirement applies to EU-9 and EU-10 only.

The Permittee must conduct the following monitoring for EU-9 and EU-10:

(a) The Permittee must document and record each incidence of maintenance, maintenance checks, and repairs conducted to demonstrate compliance with the emissions-related maintenance requirements. Required maintenance activities are identified in Appendix C – Small Engine Maintenance Plan for Emergency Diesel Generator 1 (EU-9). [40 CFR 63.6655(e)]
(b) The number of hours Emergency Diesel Generator 1 and Emergency Diesel Generator 2 are operated each calendar year must be recorded from the non-resettable hour meter. The Permittee must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours were spent for non-emergency operation. [40 CFR 63.6655(f), 40 CFR 60.4214(b), SWCAA 16-3188 Condition 8(b)]
(c) The sulfur content of the diesel burned in Emergency Diesel Generator 1 and Emergency Diesel Generator 2 must be determined and recorded for each fuel delivery. A fuel supplier certification or receipt may be used in lieu of new fuel testing. [SWCAA 16-3188 Condition 8(a)]
(d) For the Emergency Diesel Generator 2 (EU-10), the Permittee must document and record each incidence of maintenance and repairs conducted to demonstrate compliance with the emissions-related maintenance requirements of 40 CFR 60.4211(a). The documentation must include a description of the maintenance and/or repair conducted and the hour meter reading on the engine at the time of the maintenance. [WAC 173-401-615(1)]

M27. Fire Pump Engine Monitoring

WAC 173-401-615(1)
SWCAA 16-3188 Conditions 8(a) and 8(b)

This monitoring requirement applies to EU-11 only.

The Permittee must conduct the following monitoring for the Fire Pump Engine:

(a) The fuel sulfur content of the diesel burned in the Fire Pump Engine must be determined and recorded for each fuel delivery. A fuel supplier certification or receipt may be used in lieu of new fuel testing. [SWCAA 16-3188 Condition 8(a)]
(b) The Permittee must document the total number of hours the Fire Pump Engine operates each year. [SWCAA 16-3188 Condition 8(b)]
(c) For the Fire Pump Engine (EU-11), the Permittee must document and record each incidence of maintenance and repairs conducted to demonstrate compliance with the emissions-related maintenance requirements of 40 CFR 60.4211(a). The documentation must include a description of the maintenance and/or repair conducted and the hour meter reading on the engine at the time of the maintenance. [WAC 173-401-615(1)]

M28. Coal Unloading Facility Emergency Diesel Sump Pump Engine Monitoring
40 CFR 60.4211(a)
WAC 173-401-615(1)
SWCAA 11-2972 Conditions 15(b and c)

This monitoring requirement applies to EU-12 only.

(a) The fuel sulfur content of the diesel burned in the Coal Unloading Facility Emergency Diesel Sump Pump Engine must be determined and recorded for each fuel delivery. A fuel supplier certification may be used in lieu of actual fuel testing. [SWCAA 11-2972 Condition 15(b)]
(b) The Permittee must document the total number of hours the Coal Unloading Facility Emergency Diesel Sump Pump Engine operates each year using the non-resettable hour meter. [SWCAA 11-2972 Condition 15(c)]
(c) The Permittee must document and record each incidence of maintenance and repairs conducted to demonstrate compliance with the emissions-related maintenance requirements of 40 CFR 60.4211(a). The documentation must include a description of the maintenance and/or repair conducted and the hour meter reading on the engine. [WAC 173-401-615(1)]

M29. Mercury Control System and Fly Ash Material Handling
SWCAA 11-2984 Condition 8
SWCAA 12-3016 Condition 8

This monitoring requirement applies to EU-4, EU-13, EU-14, EU-15, EU-16, EU-17, EU-18, EU-19, EU-20, and EU-21 only.

The Permittee must conduct the monitoring indicated below for EU-13 through EU-21:

(a) The total number of hours each emission unit associated with the mercury control project (SEA System 1, SEA System 2, Sorbent Silo 1, Sorbent Silo 2, Fly Ash Bin 11, Fly Ash Bin 12, Fly Ash Bin 14, Fly Ash Bin 14 Air Slide to Bin 11 Air Slide, Fly Ash Bin 14 to 6050 Air Slide) and the Fly Ash Weigh Bin is vented must be determined and logged for each calendar year.
(b) The output of each baghouse leak detection system installed on the exhausts of Fly Ash Bin 11, Fly Ash Bin 12, and Fly Ash Bin 14 must be logged continuously.
(c) Copies of operating and maintenance manuals for the pollution control equipment on SEA System 1, SEA System 2, Sorbent Silo 1, Sorbent Silo 2, Fly Ash Bin 11, Fly Ash Bin 12, Fly Ash Bin 14, Fly Ash Bin 14 Air Slide to Bin 11 Air Slide, Fly Ash Bin 14 to 6050 Air Slide, and the Fly Ash Weigh Bin must be maintained for reference purposes.
(d) Maintenance activities (including filter replacements) that may affect emissions from SEA System 1, SEA System 2, Sorbent Silo 1, Sorbent Silo 2, Fly Ash Bin 11, Fly Ash Bin 12, Fly Ash Bin 14, Fly Ash Bin 14 Air Slide to Bin 11 Air Slide, Fly Ash Bin 14 to 6050 Air Slide, and Fly Ash Weigh Bin must be logged for each occurrence.

M30. Fly Ash Baghouses - Source Emission Testing Requirements
SWCAA 11-2984 Conditions 12, 13, and Appendix A

This monitoring requirement applies to EU-17, EU-18, and EU-19 only.

Source emissions testing of the Fly Ash Bin 11 Baghouse, Fly Ash Bin 12 Baghouse, and Fly Ash Bin 14 Baghouse must be conducted as described below. Initial source emissions testing of each baghouse was conducted in October 2011. Subsequent source emissions testing must be conducted

no later than the end of October every 5 years following the initial source emissions test. Source emissions tests conducted more than three months before the required due date will not satisfy the periodic source emission testing requirement without prior approval from SWCAA.

Testing for each constituent must consist of a minimum of three sampling runs of the duration specified below.

Constituent	Test Method or Equivalent[1]	Minimum Test Duration
Stack gas velocity, flow rate	EPA Methods 1 and 2	N/A
Stack gas dry molecular weight	EPA Method 3A (may assume ambient O_2 and CO_2 concentrations)	60 minutes
Stack gas moisture content	EPA Method 4	60 minutes
Particulate matter	EPA Method 5 or 17	60 minutes
Visible emissions	SWCAA Method 9	6 minutes

[1] The use of an alternate or equivalent test method must be pre-approved by SWCAA in writing.

A comprehensive test plan must be submitted to SWCAA for review and approval at least 10 business days prior to testing.

SWCAA personnel must be notified of the test date at least 5 days prior to the testing campaign so that they may be present during testing.

A complete record of operational parameters applicable to the testing, including but not limited to the operating status of the units being vented to the baghouse, leak detection system output, startups, and shutdowns must be kept during emissions testing to correlate operations with emissions and must be recorded in the final report of the test results.

Source operations during emissions testing must be representative of maximum intended operating conditions.

M31. Fly Ash Bin Baghouses – Compliance Assurance Monitoring **40 CFR 64**
WAC 173-401-615(4)

This monitoring requirement applies to EU-17, EU-18 and EU-19 only.

In addition to the source emissions testing requirements of M33, the Permittee must utilize an Electrostatic Particle Detection (EPD) system to continuously monitor relative particulate matter concentration in the exhaust from the Fly Ash Bin 11 Baghouse, Fly Ash Bin 12 Baghouse, and Fly Ash Bin 14 baghouse.

The EPD system must provide for at least 90% data availability (annual average rolled monthly).

An EPD system output of less than the following alarm setpoints is indicative of proper operation of the baghouses and provides a reasonable assurance of compliance with the particulate matter emission limits:

Exhaust Point	Alarm Setpoint
Fly Ash Bin 11 Baghouse (EU-17)	100 pA (5-minute average)
Fly Ash Bin 12 Baghouse (EU-18)	100 pA (5-minute average)

Fly Ash Bin 14 Baghouse (EU-19)	100 pA (5-minute average)

An excursion is defined as any exceedance of the maximum output levels identified in the table above. For each excursion:

(a) Cease operation of the affected baghouse as soon as practicable and operate only as necessary to effectuate trouble-shooting and repairs.
(b) Make necessary repairs as soon as practical.
(c) Notify SWCAA no later than the end of the next business day in accordance with R1.

Alarm setpoints may be modified based on the results of additional source emissions testing when the Permittee can demonstrate that the new alarm setpoint provides a reasonable margin of compliance with the particulate matter emission limit.

M32. Reserved

M33. Coal-Fired Boiler Tune-up and Startup/Shutdown Monitoring **40 CFR 63.10000(l, m)**
40 CFR 63.10032(a)(1)
40 CFR 63.10032(f)

This monitoring requirement applies to EU-2 only.

(a) To demonstrate compliance with the tune-up requirements in 40 CFR 63 Subpart UUUUU, the Permittee must document and keep records of each tune-up of EU-2. The records must document the date of each tune-up, all activities performed as part of the tune-up, and the results of NO_X, CO, and O_2 monitoring conducted as part of the tune-up. [40 CFR 63.10032(a)(1)]
(b) To demonstrate compliance with the provisions related to startup and shutdown in 40 CFR 63 Subpart UUUUU, the Permittee must continuously monitor and record the following for EU-2) beginning April 16, 2015: [40 CFR 63.10000(l)]
    (1) Distillate oil consumption;
    (2) Coal consumption;
    (3) Electricity generation;
    (4) When steam generated by the boiler is in use for any purpose; and
    (5) Operational status of each electrostatic precipitator, mercury emission control system, and flue gas desulfurization system.

    The equipment used to monitor these parameters must be verified, operated, maintained, and quality assured. Monitoring system specifications or instruction or manufacturer's specifications may be relied upon to meet these requirements. [40 CFR 63.10000(m)]

M34. Auxiliary Boiler Tune-up Monitoring **40 CFR 63.7555, 63.7560**
WAC 173-401-615(b)(2)

The Permittee must conduct the following monitoring and recordkeeping for the Auxiliary Boiler (EU-3):

(a) The Permittee must document and keep records of each tune-up of EU-3. The records must document the date of each tune-up, all activities performed as part of the tune-up, and the results of NO_X, CO, and O_2 monitoring conducted as part of the tune-up. [40 CFR 63.7555(a)(1) (initial tune-up), WAC 173-615(b)(2) – (subsequent tune-ups)]

(b) The Permittee must maintain a copy of each notification and report submitted to comply with 40 CFR 63 Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status or compliance report submitted according to the requirements of 40 CFR 63.10(b)(2)(xiv); [40 CFR 63.7555(a)(1)] and
(c) The Permittee must maintain a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the Auxiliary Boiler was operating. [40 CFR 63.7555(a)(3)]

The records must be in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1). The records must be maintained for five years following the date of each occurrence, measurement, maintenance, corrective action, report or record. Each record must be kept on site, or they must be accessible from on site, for at least two years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. The Permittee may keep the records off site for the remaining three years. [40 CFR 63.7560]

M35. Fine Coal Handling **40 CFR 60 Subpart Y Sections 60.255, 60.257, and 60.258(a) SWCAA 14-3039 Condition 11(b)**

This monitoring requirement applies to EU-22 only.

The Permittee must perform initial performance testing of the coal processing and conveying equipment to demonstrate compliance with the opacity standard from 40 CFR 60.254. Testing must be conducted in accordance to the requirements in 40 CFR 60.8 and the methods identified in 40 CFR 60.257. [40 CFR 60.255(b)] Subsequent monitoring and performance testing must be conducted in accordance with either the schedule provided in 40 CFR 60.255(b)(2) or 40 CFR 60.255(f). All performance testing consists of monitoring emissions from each point using EPA Method 9 for 30 to 60 minutes. [40 CFR 60.257(a)]

40 CFR 60.255(b)(2) requires subsequent testing within 90 operating days of the date the previous performance test was required to be completed if any 6-minute average opacity reading in the previous performance test exceeds 5% opacity. If all 6-minute average opacity readings in the most recent performance test are less than 5%, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed. [40 CFR 60.255(b)(2)]

40 CFR 60.255(f), as a compliance alternative to 40 CFR 60.255(b)(2), requires that the Permittee either follow the steps listed in (a) – (c) below or utilize an approved site specific monitoring plan for a digital opacity compliance system as described in 40 CFR 60.255(f)(2). [40 CFR 60.255(f)]
(a) Conduct a 15-second observation for each affected facility each operating day. If visible emissions are observed during any 15-second observation, the owner or operator must adjust the operation of the affected facility and demonstrate within 24 hours that no visible emissions are observed from the affected facility. If visible emissions are observed, a Method 9, of appendix A-4 of 40 CFR Part 60, performance test must be conducted within 45 operating days. [40 CFR 60.255(f)(1)(i)]
(b) Conduct a monthly visible observation of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible. [40 CFR 60.255(f)(1)(ii)]
(c) Conduct a performance test using EPA Method 9 at least once every 5 calendar years. [40 CFR 60.255(f)(1)(iii)]

The Permittee must develop and maintain the following information:

(d) The total amount of fine coal conveyed across Big Hanaford Road must be recorded for each calendar month. [40 CFR 60.258(a)(3)]
(e) The manufacturer's recommended maintenance procedures and the date and time of any maintenance and inspection activities and the results of those activities. Any variance from manufacturer recommendation, if any, must be noted. [40 CFR 60.258(a)(1)]
(f) The date and time of periodic coal preparation and processing plant visual observations, noting those sources with visible emissions along with corrective actions taken to reduce visible emissions. Results from the actions must be noted. [40 CFR 60.258(a)(2)]
(g) The date and time of periodic coal preparation and processing plant visual observations, noting those sources with visible emissions along with corrective actions taken to reduce visible emissions. Results from the actions must be noted. [40 CFR 60.258(a)(2)]

M36. Acid Rain, RACT, and NSR CEMS Data Recordkeeping Requirements
40 CFR 75.57, 75.58, and 75.59
WAC 173-401-615(2)
SWCAA 97-2057R1 Sections 24, 26, 27 and 30

The Permittee must record and maintain for EU-2, a file of all measurements, data, reports, and other information required by this permit at the source in a readily accessible form suitable for inspection for at least five (5) years from the date of each record. This file must include all information required in 40 CFR Part 75.57 through 75.59 with the following:
(a) SO_2 standard concentrations (dry @ 7% O_2) required by condition M8 of this permit. [SWCAA 97-2057R1 Section 27]
(b) For SO_2 rolling 12-month mass emissions (not recorded hourly), as measured and reported from the certified primary monitoring system(s), certified redundant or non-redundant back-up monitoring system(s), or other approved method(s) of emissions determination: [SWCAA 97-2057R1 Sections 24, 26, and 27b]
    (1) Tons of SO_2 emitted from all relevant stacks (including any emergency bypasses) for each rolling 12-month period; and
    (2) All SO_2 emissions during startup, shut down, equipment out of service, and upset conditions must be recorded separately from normal operations.
(c) Hourly average NO_X emission rate (lb/million Btu, rounded to nearest hundredth) adjusted for bias if necessary as provided for in 40 CFR 75.24(d), for those hours when the unit's generating load is 360 MW gross or greater. [SWCAA 97-2057R1 Section 30, WAC 173-401-615]

M37. 40 CFR 63 Subpart DDDDD Recordkeeping **40 CFR 63.7555**
40 CFR 63.7560

The Permittee must record and maintain the following records for the Auxiliary Boiler (EU-3): [40 CFR 63.7555]

(a) A copy of each notification and report submitted to comply with 40 CFR 63 Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status or compliance report submitted according to the requirements of 40 CFR 63.10(b)(2)(xiv); [40 CFR 63.7555(a)(1)] and
(b) A copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the Auxiliary Boiler was operating. [40 CFR 63.7555(a)(3)]

The records must be in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1). The records must be maintained for five years following the date of each occurrence, measurement, maintenance, corrective action, report or record. Each record must be kept on site, or they must be accessible from on site, for at least two years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. The Permittee may keep the records off site for the remaining three years. [40 CFR 63.7560]

M38. 40 CFR 60 Subpart Y Recordkeeping **40 CFR 60.258**
SWCAA 14-3093 Conditions 12 and 13

The Permittee must record and maintain the following records for the Fine Coal Recovery equipment north of Big Hanaford Road:

(a) The manufacturer's recommended maintenance procedures and the date and time of any maintenance and inspection activities and the results of those activities. Any variance from manufacturer recommendation, if any, must be noted. [40 CFR 60.258(a)(1)]
(b) The date and time of periodic coal preparation and processing plant visual observations, noting those sources with visible emissions along with corrective actions taken to reduce visible emissions. Results from the actions must be noted. [40 CFR 60.258(a)(2)]
(c) The amount and type of coal processed each calendar month. [40 CFR 60.258(a)(3)]
(d) Monthly certification that the dust suppressant systems were operational when any coal was processed and that manufacturer's recommendations were followed for all control systems. Any variance from the manufacturer's recommendations, if any, must be noted. [40 CFR 60.258(a)(5)]

With the exception of data recorded by an automated data acquisition system, all records must include the date and name of the person making each entry.

IX. REPORTING TERMS AND CONDITIONS

All required reports must be certified by a responsible official consistent with WAC 173-401-520. Where an applicable requirement requires reporting more frequently than once every six months, the responsible official's certification need only be submitted once every six months, covering all required reporting since the date of the last certification. Pursuant to WAC 173-401-530(2)(c), reporting requirements are not applicable to IEUs unless specified.

Where a reporting schedule is specified (e.g. quarterly, semiannual, or annual), compliance with the reporting frequency is met when reports are submitted more frequently than required.

Each report that is required to be submitted to the Department of Ecology or the EPA must also be submitted to SWCAA by the deadline specified in the applicable requirement for that report. For submissions made electronically to EPA electronically, the copy to SWCAA must be in a format approved by SWCAA. [WAC 173-401-615(3)]

Addresses of regulatory agencies are the following, unless otherwise instructed:

Southwest Clean Air Agency
11815 NE 99th Street, Suite 1294
Vancouver, WA 98682-2322

Clean Air Act Compliance Manager
US EPA Region 10, Mail Stop: 20-C04
1200 Sixth Avenue, Suite 155
Seattle, WA 98101

Department of Ecology
Air Quality Program
PO Box 47600
Olympia, WA 98504-7600

Acid Rain Program address, unless otherwise instructed:

U.S. Environmental Protection Agency
Clean Air Markets Division
1200 Pennsylvania Avenue, NW
Mail Code 6204J
Washington, DC 20460

R1. Deviations from Permit Conditions and CAM Excursions

40 CFR 60.7(b) - where applicable
40 CFR 64.9(a)(2)(i)
WAC 173-401-615(3)(b)
SWCAA 400-107
SWCAA 400-115 – where applicable
PSD-01-01 Amendment 2 Condition 22(d)(1)
Second Revision of BART Order No. 6426 Condition 8
SWCAA 97-2057R1 Sections 23, 28, 29, and 37
SWCAA 01-2403 Section 11(e)(1)
SWCAA 11-2984 Conditions 15 and 16
SWCAA 14-3093 Conditions 17 and 18
SWCAA 16-3188 Condition 12 and 13

Excess emissions must be reported to SWCAA as soon as possible but no later than 48 hours after discovery in accordance with SWCAA 400-107. Deviations from permit requirements must be reported no later than thirty days after the end of the month during which the deviation is discovered. Deviations which represent a potential threat to human health or safety must be reported as soon as possible but no later than twelve hours after the deviation is discovered.

Excess emission reports must contain the following information: [SWCAA 400-107]

(a) Identification of the emission unit(s) involved;
(b) A brief description of the event including identification of known causes;

(c) Date, time and duration of the event;
(d) For exceedances of non-opacity emission limitations, an estimate of the quantity of excess emissions;
(e) Corrective action taken in response to the event; and
(f) Preventive measures taken or planned to minimize future recurrence.

Reports of deviations from permit requirements must include: [WAC 173-401-615(3)(b)]

(g) Whether or not the deviation is or was due to upset conditions;
(h) The probable cause of the deviation; and
(i) The corrective action taken, and when the corrective action was initiated.

Excess emissions, including opacity exceedances for startups, shut downs, upsets, and maintenance as described in M10, and any bypass upset (M12), must be reported to SWCAA during the current business day or next business morning and must be noted in the quarterly report. Permittee must submit a written report to SWCAA of any SO_2 emission control technology forced outage longer than 72 hours. Any bypass upset must be reported to SWCAA during the current business day or by the next business morning and must be documented to SWCAA within 5 days of the occurrence. An exceedance of the annual limitation is one 12-month period exceeding the tons per year SO_2 limitation of Requirement 16.

Excursions from CAM indicator ranges must be reported to SWCAA no later than the next business day. The report must include the duration and cause of the excursion (if known), and the corrective actions taken in response to the excursion.

In addition to the above requirements, excess NO_X or ammonia emissions due to malfunctions must be documented in writing and submitted to SWCAA and Ecology with the quarterly emission report. [Second Revision of BART Order No. 6426 Condition 8]

All reports must be submitted in writing (e.g. e-mail, facsimile or letter).

R2. Complaint Reports **WAC 173-401-615(3)**

The Permittee must report all complaints to SWCAA within three business days of receipt. Complaint reports must include the date and time of the complaint, the name of the complainant, and the nature of the complaint.

R3. Quarterly Reports

40 CFR 75.64 and 75.65
SWCAA 400-105(7) (Local Only)
WAC 173-401-615(3)
SWCAA 97-2057R1 Sections 27d, 43, and 45
SWCAA 01-2403 Section 11(c)
PSD-01-01 Amendment 2 Conditions 22(b and c)
Second Revision of BART Order No. 6426 Condition 8, 9.1.1, 9.1.2, and 9.2

The Permittee must submit to SWCAA by April 30th, July 31th, October 31th, and January 31th for the calendar quarter periods of January through March, April through June, July through September, and October through December, respectively, all of the information listed below. Information listed in paragraph (f) below must also be submitted to Ecology. All NO_X data must be submitted in an electronic format acceptable to SWCAA. [Second Revision of BART Order No. 6426 Condition 9.2] In addition, all NO_X and ammonia emission data, urea injection data, and excess NO_X or

ammonia emissions resulting from malfunctions must also be reported to the Washington Department of Ecology no later than 30 days after the end of each calendar quarter [Second Revision of BART Order No. 6426 Condition 8].

(a) Records of monthly plant inspections as described in conditions M2 through M4;
(b) Sulfur content of the fuel oil used to fuel the auxiliary boiler (EU-3) and for startup of EU-2 as described in condition M7;
(c) Hourly SO_2 concentration corrected to 7% O_2 (dry volume basis) as described in M9(e);
(d) Tons of SO_2 emitted from all relevant stacks for each 12-month period, ending with the last day of each month in the quarter as described in M12;
(e) The following information with respect to NO_X emissions:
    (1) For each hour of operation for the coal-fired boiler, the average NO_X emission rate (lb/MMBtu to at least two significant figures);
    (2) For each hour of operation for the coal-fired boiler, the average gross unit load (MW); and
    (3) Average NO_X emission rate during the quarter and cumulative NO_X emission rate for the calendar year, (lb/MMBtu to at least two significant figures), for those hours when generating load is 360 MW gross or greater as described in M9(h)(2);
(f) 30 day rolling average NO_X emission rate in lb/MMBtu for each operating day, and the tons of NO_X emitted per unit and combined during the current calendar year calculated in accordance with the Second Revision of BART Order No. 6426. NO_X emission rates must be reported with at least two significant figures. Cumulative tons of NO_X must be rounded to the nearest ton. [Second Revision of BART Order No. 6426 Conditions 9.1.1 and 9.1.2]
(h) Estimated monthly average heating values (Btu/lb) for coal burned in EU-2;
(i) Fuel oil consumption in each boiler (Unit 2 and auxiliary boiler) as described in M14;
(j) Quarterly average CO concentration for EU-2 as described in M8;
(k) Excess opacity based on 6 minute averaging periods must be reported with the time period clearly identified and a brief explanation as to the cause of the exceedance, or quarterly Method 9 test results must be reported if continuous opacity monitoring is not possible under stack conditions; and
(l) All instances of deviation from permit requirements to be reported as described in condition R1 must be clearly identified.

Acid Rain. The Permittee's designated representative must electronically report the data and information required in accordance with 40 CFR 75.64 and must report excess emissions of opacity to SWCAA in accordance with 75.65.

R4. Semiannual Reports

40 CFR 63.10(e)(3)(vi) as referenced by 40 CFR 63 Subpart UUUUUU
40 CFR 63 Subpart ZZZZ Sections 63.6640(b), 63.6650
40 CFR 63 Subpart UUUUU Sections 63.10031(e)
40 CFR 64.9(a)(2)(ii)
SWCAA 400-075
WAC 173-401-615(3)

Consistent with WAC 173-401-615(3) the Permittee must submit to SWCAA by September 15th and March 15th for the six month periods January through June and July through December respectively, a report on the status of all monitoring requirements. All instances of deviation from permit requirements must be clearly identified. The number, duration and cause of opacity monitor downtime incidents must be summarized in the semiannual report. For all EPA Method 9 or SWCAA Method 9 monitoring conducted during the semiannual period, a copy of the relevant opacity certification(s) must be submitted with the semiannual report. The semiannual report must contain a certification of any reports submitted during the semiannual period that have not already been certified. The certification must be consistent with WAC 173-401-520. In addition, a Responsible Official must certify that continuous emissions monitoring equipment, if used to quantify emissions of any non-Acid Rain pollutant, is capable of monitoring the emissions of that pollutant.

A separate semiannual report is not necessary if the Permittee elects to provide the above information and certification with each quarterly report.

R5. Annual Reports and Compliance Certification

WAC 173-401-615(1)(b)
WAC 173-401-630(5)
SWCAA 11-2972 Conditions 19(a - c)
SWCAA 05-2636 Condition 8
SWCAA 08-2779 Condition 8(a)
SWCAA 11-2985 Condition 17(a)
SWCAA 16-3188 Condition 14(a)
SWCAA 14-3093 Condition 20(a – c)

(a) Annual Compliance Certification: The Permittee must submit to SWCAA and EPA a certification of compliance with all terms and conditions of this permit in accordance with WAC 173-401-630(5)(d). The Permittee must submit by March 15th of the following year the following information for the period of January through December:

(1) Identification of each term or condition of the permit that is the basis of the certification;
(2) Statement of compliance status;
(3) Whether compliance was continuous or intermittent;
(4) Method(s) used for determining the compliance status of the source, currently and over the reporting period consistent with WAC 173-401-615;
(5) Such other facts as SWCAA may require to determine the compliance status of the source;
(6) The certification must also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR 64 (CAM) occurred; and
(7) Such additional requirements as may be specified pursuant to Sections 114(a)(3) and 504(b) of the FCAA.

(b) Coal Unloading Facility: The Permittee must submit by March 15th of the following year the following information for the period of January through December:

(1) The total amount of coal unloaded;
(2) The average moisture content of the coal unloaded (if this information is not provided, a conservative value of 2.7% must be assumed); and
(3) The total number of hours the Coal Unloading Facility Emergency Diesel Sump Pump Engine operated.

(c) FGD Bleed Treatment Lime Storage Silo: The Permittee must report to SWCAA annually by March 15th for the previous calendar year the total number of hours the FGD Bleed Treatment Lime Storage Silo was actively vented.

(d) Journal Shop: The Permittee must report to SWCAA annually by March 15th for the previous calendar year the total amount of each welding rod type used in the Journal Shop.

(a) Filter Systems on Mercury Control System and Fly Ash Bins: The Permittee must report to SWCAA annually by March 15th for the previous calendar year the total number of hours each of the following units operated: SEA System 1, SEA System 2, Sorbent Silo 2, Fly Ash Bin 11, Fly Ash Bin 12, Fly Ash Bin 14, Fly Ash Bin 14 Air Slide to Bin 11 Air Slide, and Fly Ash Bin 14 to 6050 Air Slide.

(b) Coal Plant Engines: The Permittee must report to SWCAA annually by March 15th for the previous calendar year the total number of hours the Fire Pump Engine, Emergency Diesel Generator 1 and Emergency Diesel Generator 2 operated.

(c) Fine Coal Recovery Equipment: The following emission-related information must be reported to SWCAA by March 15th for the previous calendar year:
(1) The total amount of fine coal produced for each month of the calendar year;
(2) The total amount of fine coal transferred to the power plant stockpile; and
(3) If available, the average moisture content of the fine coal produced (if this information is not provided, a conservative value of 8% must be assumed).

R6. Emission Inventory Reports

WAC 173-400-105(1)
SWCAA 400-105
SWCAA 97-2057R1 Section 50
SWCAA 01-2403 Section 11(e)(3)
SWCAA 05-2636 Condition 8(b)
SWCAA 11-2972 Condition 19(d)
SWCAA 08-2779 Condition 8(b)
SWCAA 11-2985 Condition 17(b)
SWCAA 16-3188 Condition 14(b)
SWCAA 14-3093 Condition 20(d)

The Permittee must submit an inventory of annual emissions each year to SWCAA by March 15th of the following year in accordance with SWCAA 400-105 unless an alternate date is approved by SWCAA. The inventory must include stack and fugitive emissions of NO_X, SO_2, CO, VOC, PM, PM_{10}, $PM_{2.5}$, hazardous air pollutants, and toxic air pollutants identified in WAC 173-460.

Permittee must meet the following requirements for source test reports:

(a) Submit a comprehensive test plan to SWCAA for review and approval at least five business days prior to any periodic testing beyond CEMS monitoring required in condition M9 of this permit.

(b) Notify SWCAA at least three days in advance of any testing of Boiler 2 (EU-2), and five days in advance of any testing of any other emission unit so that SWCAA personnel may be present during testing.

(c) Provide test results from required emissions testing to SWCAA within 45 days following completion of testing. All gaseous emissions must, as a minimum, be reported in parts per million by volume, pounds per hour, and pounds per million Btu of heat input. Emissions data must be corrected to units of the applicable standard. Results of ammonia emission testing of the coal-fired boiler required by Second Revision of BART Order No. 6426 must also be submitted to Ecology.

(d) For EU-2, include in the test report a summary of operating conditions for each test run to include, as a minimum:
   (1) Estimated boiler heat input (million Btu/hr);
   (2) Estimated fuel consumption rate (lb/hr);
   (3) Air discharge flowrate in dry standard cubic feet;
   (4) Exhaust temperature of emissions out the stack;
   (5) Estimated sulfur content of coal;
   (6) Estimated SO_2 reduction in percent, as a result of controls; and
   (7) Unit load in megawatts on an hourly basis.

(e) Each required source test report must include:
   (1) A description of the source including manufacturer, model number and design capacity of the equipment, and the location of the sample ports or test locations;
   (2) Time and date of the test and identification and qualifications of the personnel involved;
   (3) A summary of results, reported in units and averaging periods consistent with the applicable emission standard or limit;
   (4) A summary of control system or equipment operating conditions;
   (5) A summary of production related parameters;
   (6) A description of the test methods or procedures used including all field data, quality assurance/quality control procedures and documentation;
   (7) A description of the analytical procedures used including all laboratory data, quality assurance/quality control procedures and documentation;
   (8) Copies of field data and example calculations;
   (9) Chain of custody information;
   (10) Calibration documentation;
   (11) Discussion of any abnormalities associated with the results; and
   (12) A statement signed by the senior management official of the testing firm certifying the validity of the source test report.

All test reports must be submitted in electronic format.

R8. Acid Rain Notification of Certification and Recertification Test Dates and Applications and Other General Reporting Provisions **40 CFR 75.60, 75.61, and 75.63**

The Permittee or designated representative must submit written notification to EPA Region X and SWCAA of certification tests, recertification tests, and revised test dates as specified in 40 CFR 75.20 for CEMS in accordance with 40 CFR 75.61. The designated representative must submit applications and reports in accordance with 40 CFR 75.63.

The designated representative must comply with all Acid Rain Program reporting requirements in accordance with 40 CFR 75.60 and with the signatory requirements of 40 CFR 72.21.

R9. BART Order Milestone and Urea Injection Reports
Second Revision of BART Order No. 6426 Conditions 6 and 7

The Permittee must submit a letter to the Washington State Governor, Ecology, and SWCAA reporting achievement of each of the following milestones:

(a) Compliance with the requirement to permanently cease burning coal in one coal fired boiler no later than December 31, 2020.
(b) Compliance with the requirement to permanently cease burning coal in the second coal fired boiler no later than December 31, 2025.

Each letter must be submitted within 30 days of achieving each of the above milestones.

(c) A letter reporting TransAlta used urea injection must be sent to Ecology and SWCAA within 30 days of the first urea injection occurring during each calendar year. The letter must contain, at a minimum, the dates of urea injection, urea concentration, and the urea injection rate. No letter is required for any calendar year in which no urea injection occurred.

R10. 40 CFR 63 Subpart DDDDD Reports for Auxiliary Boiler
40 CFR 63.7550(b) and (c), Table 9

Compliance Reports

The Permittee must submit the first compliance report to SWCAA covering the period from January 31, 2016 (the initial compliance date) through January 31, 2021. The first compliance report must be submitted by January 31, 2022. [40 CFR 63.7550(b)(1) and (2)]

Subsequent reports must be submitted every 5 years covering the subsequent 5-year periods from January 1 to December 31 and must be submitted by January 31st of the following year. [40 CFR 63.7550(b)(3) and (4)]

The compliance report must include the following for the Auxiliary Boiler: [40 CFR 63.7550(c)]

(a) The company and facility name and address.
(b) Identification of the boiler and the process it is used in and the fact that the unit is not subject to any emission limitations or process parameter limitations from 40 CFR 63 Subpart DDDDD.
(c) The date of the report and the beginning and ending dates of the reporting period.
(d) The total operating time during the reporting period.

(e) The date of the most recent tune-up for EU-2. The date of the most recent burner inspection if it was delayed until the next scheduled or unscheduled shutdown.
(f) A statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

R11. 40 CFR 63 Subpart UUUUU Reports and Notification **40 CFR 63.9**
40 CFR 63.10
40 CFR 63 Subpart UUUUU Sections 63.10006(j), 63.10021, 63.10030, 63.10031 and Table 8

The Permittee must submit the reports required under 40 CFR 63.10031 for Unit 2 (EU-2) to the Administrator electronically, using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool as provided in 40 CFR 63.10021(f) in accordance with the submission requirements of 40 CFR 63.10031(f)(6). [40 CFR 63.10021(f), 40 CFR 63.10031(f)(6)]

A copy of each report required to be submitted to the EPA must also be submitted to SWCAA. A copy of each report submitted in electronic format to an EPA database (e.g. quarterly reports) must be submitted to SWCAA in an approved format. Each report must be submitted to SWCAA no later than the date the report must be submitted to the EPA. [40 CFR 63.13, WAC 173-401-615]

Hg Monitoring System
For the mercury continuous monitoring system, the Permittee must meet the electronic reporting requirements of Appendix A to 40 CFR 63 Subpart UUUUU. [40 CFR 63.10031(a)(1), Section 1 of 40 CFR 63 Subpart UUUUU Table 8, Appendix A to 40 CFR 63 Subpart UUUUU]

SO_2 Monitoring System
For the SO_2 CEMS, the Permittee must submit reports in accordance with 40 CFR 63.10031(a)(5). [40 CFR 63.10031(a)(5), Section 5 of 40 CFR 63 Subpart UUUUU Table 8]

Semiannual Compliance Reports
The Permittee must submit semiannual compliance reports in accordance with 40 CFR 63.10031(b). Each semiannual report must be submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. The semiannual report must contain the information required in 40 CFR 63.10031(c)(1) through (10). All semiannual reports must be submitted as PDF files. The final semiannual compliance report must cover the reporting period from July 1, 2023, through December 31, 2023. [40 CFR 63.10031(b), 40 CFR 63.10031(c), 40 CFR 63.10031(d), 40 CFR 63.10031(f)(4), 40 CFR 63.10031(i), Section 9 of 40 CFR 63 Subpart UUUUU Table 8]

Quarterly Compliance Reports
Quarterly compliance reports must be submitted in accordance with 40 CFR 63.10031(g), starting with a report covering the first calendar quarter of 2024. Each quarterly report and the associated Appendix E information must be submitted no later than 60 days after the end of each calendar quarter. Quarterly reports must be submitted in XML format. For startup and shutdown event(s) that occur on or after January 1, 2024, the Permittee must use the ECMPS Client Tool to submit the information in 40 CFR 63.10031(c)(5) and 40 CFR 63.10020(e) along with each quarterly compliance report, in a PDF file, starting with a report for the first calendar quarter of 2024 (this information is part of the PDF format semiannual report prior to 2024). The startup and shutdown reports are due when the quarterly report is due (no later than 60 days after the end of each calendar quarter). The applicable data elements in 40 CFR 63.10031(f)(6)(i) through (xii) must be entered into ECMPS with each startup and shutdown report. [40 CFR 63.10031(d), 40

CFR 63.10031(f)(4), 40 CFRF 63.10031(g), 40 CFR 63.10031(i), Sections 11 and 12 of 40 CFR 63 Subpart UUUUU Table 8]

PM Source Test Reports

For each filterable particulate matter source test conducted to satisfy the testing requirements of 40 CFR 63 Subpart UUUUU completed prior to January 1, 2024, the Permittee must submit a PDF test report in accordance with 40 CFR 63.10031(f)(6). Each report must be submitted to EPA no later than 60 days after the date on which the testing is completed. For each test completed on or after January 1, 2024, in accordance with 40 CFR 63.10031(g), the Permittee must submit the applicable reference method information in sections 17 through 31 of appendix E to 40 CFR 63 Subpart UUUUU along with the quarterly compliance report for the calendar quarter in which the test was completed. [40 CFR 63.10031(f), Section 6 of 40 CFR 63 Subpart UUUUU Table 8]

RATA Reports

For each RATA of an Hg or SO_2 monitoring system completed prior to January 1, 2024, the Permittee must submit a PDF test report in accordance with 40 CFR 63.10031(f)(6), no later than 60 days after the date on which the test is completed. For each SO_2 or Hg RATA completed on or after January 1, 2024, the Permittee must submit the applicable reference method information in sections 17 through 31 of appendix E to this subpart prior to or concurrent with the relevant quarterly emissions report. [40 CFR 63.10031(f)(1), Section 7 of 40 CFR 63 Subpart UUUUU Table 8]

Tune-Up Reports

Prior to January 1, 2024, the Permittee must report the tune-up date electronically, in a PDF file, in the semiannual compliance report, as specified in 40 CFR 63.10031(f)(4) and (6) and, if requested by the Administrator, in hard copy, as specified in 40 CFR 63.10031(f)(5). On and after January 1, 2024, the Permittee must report the tune-up date electronically in the quarterly compliance report, in accordance with 40 CFR 63.10031(g) and section 10.2 of appendix E to 40 CFR 63 Subpart UUUUU. The tune-up report date is the date when tune-up requirements in paragraphs (e)(6) and (7) of 40 CFR 63.20021 are completed. [40 CFR 63.10021(e)(9), 40 CFR 63.10031(c)(4)]

Notifications

The Permittee must submit notifications for Unit 2 as required by 40 CFR 63.10030. [40 CFR 63.10030, Section 7.2.2 of Appendix A to 40 CFR 63 Subpart UUUUU]

The Permittee must submit notification to SWCAA of the date required SO_2 and Hg RATAs are scheduled to begin at least 60 calendar days before the RATA is scheduled to begin. [40 CFR 63.8(e), 40 CFR 63.9(g)(1), 40 CFR 63.10030(a), 40 CFR 63 Subpart UUUUU Table 9]

The Permittee must submit a Notification of Intent to conduct each filterable particulate matter performance test to SWCAA at least 30 days before the performance test is scheduled to begin. [40 CFR 63.9(e) as modified by 40 CFR 63 Subpart UUUUU Table 9, 40 CFR 63.10030(a), 40 CFR 63.10030(d)]

R12. 40 CFR 60 Subpart Y Performance Monitoring Reports **40 CFR 60.258(d)**
SWCAA 14-3093 Condition 19

Within 60 days of completing each Subpart Y EPA Method 9 performance evaluation, owners or operators must submit the results to the following address: United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; mail code: D243-01; RTP, NC 27711. In addition, all EPA Method 9 performance results must be submitted to SWCAA within 45 days of test completion.

X. NON-APPLICABLE REQUIREMENTS

WAC 173-401-640(2)

The following table lists all federal, state, and/or local requirements that might reasonably apply to the Permittee, but are deemed nonapplicable after review by SWCAA. In accordance with WAC 173-401-640, the Permittee is provided a permit shield for not complying with the requirements described below where they have been identified to be non-applicable to specific emission units. Certain subsections describe requirements that may apply to the Permittee but are not "applicable requirements" for the purposes of the Air Operating Permit program and therefore will not be included in an Air Operating Permit.

N1. Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971 (Subpart D)

40 CFR 60.40 et seq.
SWCAA 400-115

Subpart D applies to all fossil-fuel-fired steam generating units for which construction, modification, or reconstruction is commenced after August 17, 1971, and that have a maximum design heat input rate of greater than 250 million Btu per hour. The coal fired boiler at this source has a design heat input greater than 250 million Btu per hour, but commenced construction with signing of a construction contract on December 23, 1968 prior to August 17, 1971, and has not undergone modification that would trigger the requirement since. Therefore, this regulation is not applicable.

N2. Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978 (Subpart Da)

40 CFR 60.40a et seq.
SWCAA 400-115

Subpart Da applies to all electric utility steam generating units for which construction, modification, or reconstruction is commenced after September 18, 1978, and that have a maximum design heat input from fossil fuel greater than 250 million Btu per hour. The coal-fired boiler at this source has a design heat input greater than 250 million Btu per hour, but commenced construction with signing of a construction contract on December 23, 1968 (prior to September 18, 1978) and has not undergone modification that would trigger the requirement since. Therefore, this regulation is not applicable.

N3. Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (Subpart Db)

40 CFR 60.40b et seq.
SWCAA 400-115

Subpart Db applies to all steam generating units that commence construction, modification, or reconstruction after June 19, 1984, and that have a heat input capacity from fuels combusted in the steam generating unit of greater than 100 million Btu per hour. The auxiliary boiler in the coal plant has a heat input capacity greater than 100 million Btu per hour, but commenced construction with signing of a construction contract on December 23, 1968 (prior to June 19, 1984), and has not undergone modification that would trigger the requirement since. Therefore, this regulation is not applicable to EU-3.

N4. Standards of Performance for Nonmetallic Mineral Processing Plants (Subpart OOO) **40 CFR 60.670 et seq.**
SWCAA 400-115

Subpart OOO establishes particulate matter and opacity limitations and initial testing requirements for applicable units. The limestone ball mill is an applicable unit because it was built after August 31, 1983 (installed new ~2001), is a fixed unit with a capacity of greater than 25 tons per hour (the unit is rated at 40 tons per hour), and is used to reduce the size of limestone (a listed non-metallic mineral). The Limestone Ball Mill is fully enclosed (the process equipment is sealed and located within a building) and water is injected at the upstream end of the ball mill, therefore the ball mill is not a potential source of particulate matter emissions. Even though this emission unit is not a potential source of emissions, the initial compliance tests were conducted on October 24, 2007, therefore the initial testing requirements are no longer applicable.

N5. Prevention of Significant Deterioration, Review of Major Stationary Sources and Major Modifications - Source Applicability and Exemptions **40 CFR 52.21(i)**

This section applies to all major stationary sources and major modifications with respect to each regulated pollutant, except as otherwise provided in this section. Requirements of this section do not apply to a particular major stationary source or major modification if construction commenced on the source or modification before August 7, 1977. The coal-fired boiler at this source commenced construction with signing of a construction contract on December 23, 1968 (prior to August 7, 1977) and, except for construction of the combustion turbine facility in 2001-2002, this facility has not since undergone modification that would trigger the requirement. Therefore, this regulation is not applicable to EU-2 or EU-3.

N6. Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers **40 CFR 63.400 et seq.**
SWCAA 400-075

Subpart Q applies to all new and existing industrial process cooling towers that are operated with chromium-based water treatment chemicals on or after September 8, 1994. The cooling towers at this facility do not use chromium-based water treatment chemicals; therefore this requirement is not applicable.

N7. Emission Standards for Combustion and Incineration Units **SWCAA 400-050(3)**

SWCAA 400-050(3) prohibits emissions of carbonyls from any incinerator in excess of 100 ppm total carbonyls as measured by applicable sampling methods. Pursuant to SWCAA 400-030(58), an incinerator is defined as "...a furnace used primarily for the thermal destruction of waste." The primary purpose of the coal-fired boiler at this source is the production of steam for

generation of electric energy and not the destruction of waste; therefore, this regulation is not applicable.

N8. Registration Program **SWCAA 400-100**

The Permittee is an air operating permit source. Pursuant to SWCAA 400-100(1)(b) air operating permit sources are exempt from the registration requirements of SWCAA 400-100.

N9. Requirements for Sources in a Maintenance Plan Area **SWCAA 400-111**

The Permittee is not located in a maintenance plan area for any criteria pollutant. Therefore, this regulation is not applicable.

N10. Requirements for New Sources in Nonattainment Areas **SWCAA 400-112**

The Permittee is not located in a nonattainment area for any criteria pollutant. Therefore, this regulation is not applicable.

N11. Bubble Rules **SWCAA 400-120**

The Permittee has not requested an emission bubble for any regulated pollutant. Therefore, this regulation is not applicable.

N12. Acquisition and Use of Emission Reduction Credits **SWCAA 400-130**

The Permittee has neither sought nor been issued emission reduction credits (ERCs). Therefore, this regulation is not applicable.

N13. State-Only Greenhouse Gas Requirements – Applicable if Triggered
RCW 80.80 and WAC 173-407

WAC 173-407 (Part II) (effective July 20, 2008) establishes a greenhouse gas emission standard and attendant monitoring, recordkeeping, reporting and, if necessary, sequestration requirements. The requirements of WAC 173-407 (Part II) are based on RCW 80.80 which was modified by Senate Bill 5769 (effective July 22, 2011). In accordance with the modified requirements, this facility must meet specific greenhouse gas emission limits by December 31, 2020 for one boiler and December 31, 2025 for the second boiler unless the Washington Department of Ecology determines that a requirement of state or federal law or regulation requires the installation of selective catalytic reduction (SCR) technology on one or both of the boilers. It is assumed that the boilers will comply with the greenhouse gas standards by being retired. If SCR is not required, then no further requirements of the rule apply. If SCR must be installed then the greenhouse gas requirements of the rule would apply to the Permittee's facility if:

(a) The facility or a unit is upgraded; or
(b) The existing facility or a unit is subject to a new long-term financial commitment.

An "upgrade" means any modification made for the primary purpose of increasing the electric generation capacity of a baseload electric generation facility or unit.

A "long-term financial commitment means:

(a) Either a new ownership interest in baseload electric generation or an upgrade to a baseload electric generation facility; or
(b) A new or renewed contract for baseload electric generation with a term of five or more years for the provision of retail power or wholesale power to end-use customers in this state.

"New ownership interest" means a change in the ownership structure of a baseload power plant or a cogeneration facility or the electrical generation portion of a cogeneration facility affecting at least:

(a) Five percent of the market value of the power plant or cogeneration facility; or
(b) Five percent of the electrical output of the power plant or cogeneration facility.
The above thresholds apply to each unit within a multi-unit generation facility.

The greenhouse gas emission standard in WAC 173-407 Part II is based only on the authority of RCW 80.80. Requirements originating only from RCW 80.80 are not "applicable requirements" as defined in WAC 173-401; therefore these requirements would not be included in the Permittee's Air Operating Permit. These requirements would be enforced by the Washington Department of Ecology outside of the Air Operating Permit Program.

N14. Federal Greenhouse Gas Reporting Requirements **40 CFR 98**

The EPA GHG reporting rule was finalized September 22, 2009. In the preamble EPA responds to a question regarding whether it is an applicable requirement for the purposes of Title V:

"As currently written, the definition of "applicable requirement" in 40 CFR 70.2 and 71.2 does not include a monitoring rule such as today's action, which is promulgated under CAA sections 114(a)(1) and 208.

These requirements will be enforced directly by the USEPA outside of the Air Operating Permit Program."

N15. State Only Mercury Emission Limits for EU-1 and EU-2
May 25, 2010 Settlement Agreement Between Ecology and TransAlta

A Settlement Agreement between the Washington Department of Ecology and TransAlta signed on May 25, 2010 by the Washington Department of Ecology provides for agreed actions to limit mercury emissions from EU-1 and EU-2. These provisions do not implement RCW 70.94 or any other regulation that is an "applicable requirement" for the purposes of WAC 173-401. Although the Permittee is bound by the conditions of the Agreed Order while it is in effect, those conditions cannot be included in the Air Operating Permit.

N16. National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities

40 CFR Part 63.11110 et seq.
Subpart CCCCCC, SWCAA 400-075

The Permittee operates a gasoline storage tank that is used to fuel vehicles at the facility. Subpart CCCCCC would apply to this unit if it was located at an area source of HAP emissions. This regulation is not applicable in this instance because the Permittee's facility is a major source of HAPs and Subpart CCCCCC only applies to equipment located at an area source of HAPs.

N17. Standards of Performance for Coal Preparation Plants

40 CFR Part 60.250 et seq.
Subpart Y, SWCAA 400-115

Subpart Y establishes emission limits and operating requirements for coal preparation and processing plants with a capacity of more than 200 tons per day of coal. The definition of coal includes coal refuse for facilities constructed after May 27, 2009. This regulation is applicable to the fine coal processing activities that span the TransAlta Centralia Mining and TransAlta Centralia Generation facilities.

SWCAA has determined that the existing coal storage piles at TransAlta Generation are not subject to 40 CFR 60 Subpart Y because TransAlta Generation is a separate source that is not included in the coal preparation plant for the purposes of Subpart Y. 40 CFR 60.250(a) states that Subpart Y applies to affected facilities in coal preparation and processing plants. In the preamble of the October 10, 2009 Federal Register Notice for the final Subpart Y standards, EPA writes that they have distinguished the "coal preparation plant" from other operating areas with the following definition from EPA's Office of Water: "The term "coal preparation plant" means a facility where coal is subjected to cleaning, concentrating, or other processing or preparation in order to separate coal from its impurities and then is loaded for transit to a consuming facility."

In addition, the coal storage pile will not be "new," "reconstructed," or "modified" as defined in 40 CFR 60.

APPENDIX A

VISIBLE EMISSIONS EVALUATION METHOD

1. Principle

The opacity of emissions from stationary sources is determined visually by a qualified observer.

2. Procedure

The observer must be certified in accordance with the provisions of Section 3 of 40 CFR Part 60, Appendix A, Method 9, as in effect on July 1, 2002.

2.1 Position

The observer shall stand at a distance sufficient to provide a clear view of the emissions with the sun oriented in the 140° sector to his/her back. Consistent with maintaining the above requirement, the observer shall, as much as possible, make his/her observations from a position such that his/her line of vision is approximately perpendicular to the plume direction, and when observing opacity of emissions from rectangular outlets (e.g., roof monitors, open baghouses, noncircular stacks), approximately perpendicular to the longer axis of the outlet. The observer's line of sight should not include more than one plume at a time when multiple stacks are involved, and in any case, the observer should make his/her observations with his/her line of sight perpendicular to the longer axis of such a set of multiple stacks (e.g., stub stacks on baghouses).

2.2 Field Records

The observer shall record the name of the plant, emission location, type of facility, observer's name and affiliation, a sketch of the observer's position relative to the source, and the date on a field data sheet. The time, estimated distance to the emission location, approximate wind direction, estimated wind speed, description of the sky condition (presence and color of clouds), and plume background are recorded on a field data sheet at the time opacity readings are initiated and completed.

2.3 Observations

Opacity observations shall be made at the point of greatest opacity in that portion of the plume where condensed water vapor is not present. The observer shall not look continuously at the plume, but instead shall observe the plume momentarily at 15 second intervals.

2.3.1 Attached Steam Plumes

When condensed water vapor is present within the plume as it emerges from the emission outlet, opacity observations shall be made beyond the point in the plume at which condensed water vapor is no longer visible. The observer shall record the

approximate distance from the emission outlet to the point in the plume at which the observations are made.

2.3.2 Detached Steam Plumes

When water vapor in the plume condenses and becomes visible at a distinct distance from the emission outlet, the opacity of emissions should be evaluated at the emission outlet prior to the condensation of water vapor and the formation of the steam plume.

2.4 Recording Observations

Opacity observations shall be recorded to the nearest 5 percent at 15 second intervals on a field data sheet. A minimum of 24 observations shall be recorded. Each momentary observation recorded shall be deemed to represent the average opacity of emissions for a 15 second period.

2.5 Data Reduction

The number of observation at each opacity level shall be determined and recorded on the field data sheet. Opacity shall be determined by the highest 13 observations in any consecutive 60-minute period. The opacity standard or emissions limit is exceeded if there are more than 12 observations during any consecutive 60 minute period for which an opacity greater than the standard or emission limit is recorded. The opacity standard is a 1 hour standard (rolling 60 minutes). Only one violation of the standard per hour may be recorded meaning that a violation for any given consecutive 60 minute period may be recorded in substantially fewer than 60 minutes. No one hour time sets shall overlap for purpose of determining a violation or violations. Data used to establish a violation in one consecutive 60 minute period can not be used to establish a violation in a second consecutive 60 minute period. The opacity determination shall be recorded on the observational record sheet.

3. References

Federal Register, Vol. 36, No. 247, page 24895, December 23, 1971.

"Criteria for Smoke and Opacity Training School 1970 - 1971" Oregon-Washington Air quality Committee."

"Guidelines for Evaluation of Visible Emissions" EPA 340/1-75-007.

APPENDIX B

ACID RAIN PERMIT

Acid Rain Permit No. SW-ARP-1-R3

Issued to:	Centralia Plant
Operated by:	TransAlta Centralia Generation, LLC
Address:	913 Big Hanaford Road Centralia, WA 98531
ORIS code:	03845
Affected units at source:	BW21 (Unit 1) BW22 (Unit 2)
Effective:	This Acid Rain permit, as part of the Centralia Plant Title V permit, will become effective upon the effective date of the Title V permit (SW-98-8-R5). The Acid Rain Permit has a permit term ending on October 14, 2024. Acid Rain Permit SW-ARP-1-R2-A is superseded in its entirety by this Acid Rain Permit.

Acid Rain Permit Contents

1) Statement of Basis

2) SO_2 allowances allocated under this permit and NO_X requirements for each affected unit.

3) Comments, notes and justifications regarding permit decisions and changes made to the permit application forms during the review process, and any additional requirements or conditions as per WAC 173-406-501, Acid Rain Permit Contents.

4) The permit applications submitted for this source. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the application and in WAC 173-406-106 "Standard Requirements."

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1) Statement of Basis

Statutory and Regulatory Authorities: In accordance with Washington Administrative Code (WAC) 173-406 "Acid Rain Regulation" and WAC 173-401 "Operating Permit Regulation," the Southwest Clean Air Agency issues this permit pursuant to WAC 173-406 and WAC 173-401. WAC 173-406 is based on the provisions of Title 40 Code of Federal Regulations (CFR) parts 72-76, which is part of the requirements established pursuant to Title IV of the Clean Air Act, 40 U.S.C. 7401, et seq., as amended by Public Law 101-549 (November 15, 1990).

2) SO_2 Allowance Allocations and NO_X Requirements for Each Affected Unit

		pre 2019[a]	2019	2020	2021	2022	2023	2024
BW21 (Unit 1)	Acid Rain NO_X limit (lb/MMBtu) annual average		0.40	0.40	0.40	0.40	0.40	0.40
BW22 (Unit 2)	Acid Rain NO_X limit (lb/MMBtu) annual average		0.40	0.40	0.40	0.40	0.40	0.40
Facilitywide	SO_2 allowances held	268,395[a]	32,981[b]	34,981[b]	39,481[b]	39,481[b]	39,481[b]	39,481[b]

This Acid Rain Permit must not be construed to exempt or exclude an affected unit from compliance with any other provisions of the Clean Air Act consistent with 40 CFR 72.9(h) and WAC 173-406-106(8).

Table Footnotes

[a] This column lists the number of allowances from prior years that have not been utilized.

[b] The number of allowances actually held by an affected source in a unit account may differ from the number allocated by the U.S. EPA. Pursuant to 40 CFR 72.9(c)(i) and WAC 173-406-106(3)(a)(i), this unit is required to hold SO_2 allowances, as of the allowance transfer deadline, in the unit's compliance subaccount not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit. All allowances for this facility are held in the "facility" account.

3) Comments, Notes and Justifications

This Acid Rain Permit is deemed to incorporate the definition of terms under WAC 173-406-101 unless otherwise expressly defined in this permit.

4) Permit Application

The permit renewal application is attached.

Standard Requirements

Permit Requirements

(1) The designated representative of the Centralia Plant and each affected unit at the Centralia Plant must:

(i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30 and WAC 173-406-301; and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit.

(2) The owners or operators of the Centralia Plant and each affected unit at the Centralia Plant must:

(i) Operate the units in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and

(ii) Have an Acid Rain permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of the Centralia Plant and each affected unit at the Centralia Plant must comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 must be used to determine compliance by the source or units, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain program.

(3) The requirements of 40 CFR part 75 do not affect the responsibility of the owners and operator to monitor emissions of other pollutants or other emissions characteristics at the units under other applicable requirements of the Act, applicable requirements of Title 173 WAC and other provisions of the operating permit for the Centralia Plant.

Sulfur Dioxide Requirements

(1) The owners and operator of the Centralia Plant and each affected unit at the Centralia plant must:

(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the Centralia Plant; and

(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide constitutes a separate violation of the Act.

(3) An affected unit will be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:

(i) Starting January 1, 2000, an affected unit under WAC 173-406-103(1)(b); or

(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under WAC 173-406-103(1)(c).

(4) Allowances must be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

(5) An allowance must not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain

permit, or an exemption under 40 CFR 72.7, 40 CFR 72.8, WAC 174-406-104, or WAC 173-406-105 and no provision of law limits the authority of the United States to terminate or limit such an authorization.

(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the Centralia Plant and each affected unit at the Centralia Plant must comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year must submit a proposed offset plan, as required under 40 CFR part 77.

(2) The owners and operators of an affected source that has excess emissions in any calendar year must:

(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and

(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the Centralia Plant and each affected unit at the Centralia Plant must keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:

(i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certification of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents must be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;

(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period applies;

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and

(iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of the Centralia Plant and each affected unit at the Centralia Plant must submit the reports required under the Acid Rain Program, including those under 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7, 40 CFR 72.8, WAC 173-406-104, or WAC 173-406-105, including

any requirement for the payment of any penalty owed to the United States, will be subject to enforcement pursuant to section 113(c) of the Act and by the permitting authority pursuant to Revised Code of Washington (RCW) 70.94.431 and RCW 70.94.435.

(2) Any person who knowingly makes any false, material statement in any record, submission, or report under the Acid Rain Program is subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001 and by the permitting authority pursuant to RCW 70.94.430.

(3) No permit revision excuses any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.

(4) The Centralia Plant and each affected unit at the Centralia Plant must meet the requirements of the Acid Rain Program.

(5) Any provision of the Acid Rain Program that applies to the Centralia Plant (including a provision applicable to the designated representative of an affected source) also applies to the owners and operators of the Centralia Plant and to the affected units at the Centralia Plant.

(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) also applies to the owners and operators of such unit.

(7) Each violation of a provision of WAC 173-406-100 through 173-406-950 and 40 CFR 72, 73, 75, 76, 77, and 78, and regulations implementing section 410 of the Act by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, is a separate violation of the Act.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 40 CFR 72.8 may be interpreted as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

(2) Limiting the number of allowances a source can hold; provided, that the number of allowances held by the source do not affect the source's obligation to comply with any other provisions of the Act;

(3) Requiring a change of any kind in any state law regulating electric utility rates and charges, affecting any state law regarding such state regulation, or limiting such state regulation, including any prudence review requirements under such state law;

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or

(5) Interfering with or impairing any program for competitive bidding for power supply in a state in which such program is established.

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2018

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☐ new ☐ revised ☒ for ARP permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

TransAlta Centralia Generation LLC	Washington	3845
Facility (Source) Name	State	Plant Code

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
00384500BW21	Yes
00384500BW22	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

EPA Form 7610-16 (Revised 12-2016)

TransAlta Centralia Generation LLC
Facility (Source) Name (from STEP 1)

STEP 3

Read the standard requirements.

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:
  (i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
  (ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:
  (i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
  (ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
  (i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
  (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
  (i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
  (ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

EPA Form 7610-16 (Revised 12-2016)

TransAlta Centralia Generation LLC
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
  (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
  (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
  (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
  (ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
  (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
  (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

EPA Form 7610-16 (Revised 12-2016)

TransAlta Centralia Generation LLC
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

(2) Limiting the number of allowances a source can hold; provided, that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;

(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4

Read the certification statement, sign, and date.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Mickey Dreher	
Signature	Date August 30, 2018

EPA Form 7610-16 (Revised 12-2016)

APPENDIX C

SMALL ENGINE MAINTENANCE PLAN

The maintenance program described below has been developed to cover maintenance instructions for Stationary Small (less than 500 HP) Reciprocating Internal Combustion Engines on the TransAlta Centralia Generation site. The current engines that fit into this category are: PMP-06 at ECUF (EU-12), Unit 1 Emergency diesel Gen-01 (EU-9), Unit 2 Emergency diesel Gen-02 (EU-10), and the Fire Pump Engine (EU-11). This maintenance program is required to meet the federal standard requirements of 40 CFR 63 and Title 5.

For units in regular or continuous operation the following checks will be conducted daily when operating:

1. Check engine oil level
2. Check coolant level
3. Check fuel filter water separator bowl-drain as needed
4. Check air cleaner dust unloader if equipped
5. Check air cleaner restriction indicator gage
6. Conduct walk around inspection
7. Check lamps if equipped
8. Check and note grease and oil accumulations

At a maximum two week interval, perform (see note below) and document this inspection on the Small Stationary Engine Inspection Form developed for this purpose. Assure that all information is complete including: the date of inspection; name and employee number of inspector; run time hours at time of inspection; indication of completion of each inspection point; identification of each item needing attention found during inspection; additional comments as necessary.

For units in standby mode, at a maximum two week interval, a prestart up inspection will be done for the above mentioned units and will consist of the following inspection points:

1. Check engine oil level
2. Check coolant level
3. Check fuel filter water separator bowl-drain as needed
4. Check air cleaner dust unloader if equipped
5. Check air cleaner restriction indicator gage
6. Conduct walk around inspection
7. Check lamps if equipped
8. Check and note grease and oil accumulations

After completing the prestart up inspection perform an engine startup. Operate engine for greater than 15 but no more than 30 minutes (see note below). Upon startup and again upon completion of operation perform a visual inspection of engine to identify leaks from pressurized systems. Document this inspection on the Small Stationary Engine Inspection Form developed for this purpose (still in development). Assure that all information is complete including: the date of inspection; name and employee number of inspector; run time hours at time of inspection; indication of completion of each inspection point; identification of each item needing attention found during inspection; additional comments as necessary. This form will be completed, submitted for review and sent to the Environmental Department for filing. Copies of these documents will be retained for 5 years.

Operating Maintenance Note: In accordance with manufacturers recommendations, whenever possible units that are running, or idle and started for maintenance testing, should be loaded to a minimum of 50% of rated load for the maintenance checks. Because this is not possible without exceptional effort and exceptional risk to plant operations, these requirements have been removed from the requirements of engines which power emergency equipment at TransAlta Centralia Generation.

At 500 operating hours or every 12 months a PM and inspection will be performed that will include the following items:

1. Check manual belt tensioner and belt wear;
2. Change engine oil and replace oil filter;
3. Check crankcase ventilation system;
4. Check air intake hoses, connections, and system;
5. Replace fuel filter elements;
6. Check automatic belt tensioner and belt wear;
7. Check engine electrical ground connection;
8. Check cooling system – add coolant as needed;
9. Conduct cooling solution analysis – add SCAs as required;
10. Pressure test cooling system;
11. Check engine speeds;

Completion of this maintenance will be documented in the PM database. A copy of the completed PM will be submitted to the Environmental Department for filing.

At 2,000 operating hours or every 24 months a PM and inspection will be performed that will include the following items:

1. Check crankshaft vibration damper;
2. Flush and refill cooling system;
3. Test thermostats;
4. Check and adjust engine valve clearances;
5. Test glow plugs;
6. Check fuses;
7. Bleed fuel system; and
8. Replace fan and alternator belts;

Completion of this maintenance will be documented in the PM database. A copy of the completed PM will be submitted to the Environmental Department for filing.

Note the above maintenance schedule has been developed to provide the minimum operational maintenance tests required for the engine side of machines driven by Stationary Small (less than 500 HP) Reciprocating Internal Combustion Engines per 40 CFR 63. Additional testing for the load portion of these machines may be required by other federal, state, regional or local requirements. In these cases, operating time limits of 40 CFR 63 (a maximum of 100 hours for maintenance testing of emergency machines) still apply.

EXHIBIT 17

TransAlta Centralia Generation, LLC
Centralia Plant

Title V Basis Statement

September 22, 2021

Southwest Clean Air Agency
11815 NE 99th Street, Suite 1294
Vancouver, WA 98682-2322
Telephone: (360) 574-3058

PERMIT No.:	SW98-8-R5-A
PREPARED FOR:	TransAlta Centralia Generation, LLC Centralia Plant 913 Big Hanaford Road Centralia, WA 98531
PLANT SITE:	Centralia Plant 913 Big Hanaford Road Centralia, WA 98531
PERMIT ENGINEER:	Clinton H. Lamoreaux, Air Quality Engineer
REVIEWED BY:	Paul T. Mairose, Chief Engineer

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I. GENERAL INFORMATION AND CERTIFICATION

1. Company Name: TransAlta Centralia Generation, LLC
2. Facility Name: Centralia Plant
3. Contact Person: Mickey Dreher, Plant Manger
4. Inspection Contact Person: David Raastad, Manager EH&S
5. Unified Business Identification Number: 601-985-591
6. SIC Number: 4911
7. Basis for Title V Applicability:

The Centralia Steam Electric Generating Plant has the potential to emit more than 100 tons per year of sulfur dioxide, nitrogen oxides, particulate matter with an aerodynamic diameter less than 10 microns, particulate matter with an aerodynamic diameter less than 2.5 microns, and carbon monoxide which are criteria air pollutants listed under section 302 of the Federal Clean Air Act, more than 100 tons per year of volatile organic compounds (VOCs), and the potential to emit more than 25 tons per year of all hazardous air pollutant (HAP) emissions combined, which are listed under Section 112 of the Clean Air Act.

Facilitywide Potential To Emit Summary (not including nonroad engines)

Pollutant	Potential Emissions (tons per year
Nitrogen oxides	6,760
Carbon monoxide	8,044
Volatile organic compounds	87
Sulfur dioxide	5,917
Particulate Matter	1,929
PM_{10}	1,467
$PM_{2.5}$	1,386
Combined HAPs	53
Individual HAP	28 (HF)
CO_2 equivalent	8,081,792

8. Current Permitting Action:

This Title V Air Operating Permit is being re-issued to incorporate revisions to 40 CFR 63 Subpart UUUUU "National Emission Standards for Hazardous Air Pollutants: Coal and Oil-fired Electric Utility Steam Generating Units" and the latest revision to BART Order 6426. In addition, units that were removed from service with the shutdown of Unit 1 have been removed, regulatory date citations have been updated, the permit format has been modified, minor typographical errors have been corrected and the word "shall" has been removed or replaced in each instance to improve clarity.

9. Attainment Area:

The Centralia Plant is located in an area that is in attainment or unclassifiable for all criteria pollutants.

10. Facility Description:

Coal Plant

The Centralia Coal Plant generates electric energy from a steam driven turbine. Pulverized coal is combusted in a single boiler to create heat that generates pressurized steam used in the turbine. Until December 31, 2020 when "Unit 1" retired, the facility utilized two coal-fired boilers, therefore permits and historical references will frequently refer to two boilers (Unit 1 and Unit 2). Combustion of coal produces emissions of sulfur dioxide (SO_2), oxides of nitrogen (NO_X), particulate matter (PM), carbon monoxide (CO), volatile organic compounds (VOCs), and certain hazardous air pollutants (HAPs) in sufficient quantities to designate the facility as a Title V source of air pollutants.

Until May 4, 2000, PacifiCorp owned the largest share of the Centralia Plant and operated the facility on behalf of all eight utility owners. As of May 4, 2000, TransAlta Centralia Generation, LLC took over ownership of the plant. The plant consists of one 670 net MW unit identified as Unit 2 (Acid Rain Program designation BW22) which is the source of nearly all emissions released from the facility. An auxiliary boiler is used to provide steam for starting the main coal-fired boiler when it is off line. Historically, coal was supplied primarily from the adjacent TransAlta Centralia Mining, LLC (a subsidiary of TransAlta) mine and stacked and reclaimed in the Centralia Plant's coal handling yard. A smaller portion of coal from the Powder River Basin in Wyoming was blended with Centralia coal to meet Btu requirements in the boilers and, potentially, to ensure that the hourly SO_2 emission limit continued to be met. The coal mine ceased active mining operations in November 2006 and currently almost all coal is supplied from the Powder River Basin. Since 2015 a small percentage of coal is supplied coal fines recovered during the reclamation process of the fine coal refuse impoundments formed during the Centralia Mine's coal washing process. The coal mine could conceivably re-open and once again supply coal to the power plant in the future.

Particulate matter from coal combustion is controlled by dual electrostatic precipitators (ESPs) in series. Sulfur dioxide emissions are managed by coal blending and scrubbing of the flue gas. Mercury emissions are controlled by an activated carbon injection system upstream of the second set of ESPs coupled with a sorbent enhancement additive injected into the boiler. The mercury control systems were completed November 24, 2011. NO_X emissions are controlled with low-NO_X burners with coupled over-fire air systems (LNC3) and a selective non-catalytic reduction system (SNCR). The LNC3 controls were installed on Unit 2 in 2001. The SNCR systems were installed on both units in 2012. Emissions of other gaseous pollutants are minimized through good combustion practices. A portion of the fly ash captured in the ESPs is sold and shipped off site while the balance is stockpiled or trucked to the Centralia Mine landfill site. Bottom ash is also sold, stockpiled, or returned to the Centralia Mine landfill site. Additional emission points include the cooling towers, coal storage and handling yard, emergency diesel generators, mist eliminators for turbine lube oil ventilation exhaust, and maintenance activities.

The Centralia Coal Plant's two units can operate continuously 24 hours per day, 7 days per week. One or the other, and occasionally both, of the units are taken off line for maintenance purposes as conditions dictate, for economy, or reserve shut down. The auxiliary boiler operates only as needed, which is typically less than 120 hours per year.

Combustion Turbine Facility

Construction of the combustion turbine project commenced in 2001 and was completed during the summer of 2002. The project was permitted as a major modification to an existing major source. The Combustion Turbine Facility, with the exception of the Black Stop Diesel Generator Engine, was retired effective January 1, 2015. The Black Stop Diesel Generator Engine was retired at the end of 2020.

11. SWCAA Air Discharge Permits and Consent Order(s):

The following table lists each Air Discharge Permit and Consent Order(s) issued for this facility. Permits or Orders in bold contain no active requirements. The requirements may have been superseded, may have been of limited duration, or the equipment may have been removed.

Order/Permit Number	App. No.	Date Issued	Description
69-1107LET	L-1	11-7-69	Approval to construct Units 1 and 2
72-0804LET	N/A	8-4-72	Approval to restart after outage – output not to exceed 300 MW unless approved after PM compliance indicated by testing
72-0914LET	N/A	9-14-72	Approval given for operation at 400 MW
72-1006LET	N/A	10-6-72	Approval given for operation at 500 MW
72-1017LET	N/A	10-17-72	Approval to operate Unit 2 at full load for 48 hour demonstration
72-1102LET	N/A	11-2-72	Approval to operate Unit 1 at same load as Unit 2
72-1211LET2	N/A	12-11-72	Approval given for operation of each unit up to 500 MW, PM not to exceed 0.06 gr/dscf
73-0329LET	L-49	3-29-73	Approval to install SO_3 conditioning system to aid PM removal in Koppers ESPs
73-0413LET	L-50	4-13-73	Approval to install second set of ESPs as pilot test
73-0426LET	N/A	4-26-73	Regulatory Order requiring testing to provide additional information on SO_3 conditioning system
73-0504LET	N/A	5-4-73	Required testing and reporting for ESP pilot test program
73-0522LET	N/A	5-22-73	Modified dates and operating conditions specified in 4-4-73 letter
73-0611LET	N/A	6-11-73	Approval to operate Unit 1 at up to 700 MW w/ PM ≤ 0.06 gr/dscf
74-0702LET	L-50R	2-7-74	Approved design and installation of second set of ESPs

Order/Permit Number	App. No.	Date Issued	Description
74-0222LET	N/A	2-22-74	Revision to clarify language in 2-7-74 letter
74-38	N/A	3-25-74	Specifies testing on Unit 2
74-38A	N/A	5-2-74	Extends high load testing days to 30
87-934	N/A	8-26-87	Order of Violation – Exceedance of 1,000 ppm SO_2 limit, inconsistent with 1969 application, penalties levied, required to sample coal, stack SO_2.
87-934-STAY	N/A	9-21-87	Order staying for 18 months requirements for SO_2 sampling, coal S sampling, and withdrawing Order of Violation 87-934 if compliance with ambient SO_X limits met despite being above 1,000 ppm limits.
88-934	N/A	2-24-88	Order, Withdrawal of Stay, and Modification of Order of Violation - Required to study lime injection, blend and wash coal install continuous SO_2 and O_2 emissions monitors, install ambient air quality monitors at three sites near the facility.
88-934B	N/A	7-14-98	Variance and Modification of Order – Modified SO_2 averaging period, required ambient modeling and collection of meteorological data.
88-934C	N/A	10-24-99	934C Variance Renewal and Modification of Order - extended the variance for weekly instead of hourly averaging of SO_2 emissions until November 25, 1990, extended the collection of ambient monitoring data through September 30, 1990, and modified the ambient air monitoring provision to require two rather than three sites
90-934D	N/A	11-9-90	Variance Renewal and Modification of Order - extended the variance for weekly instead of hourly averaging of SO_2 emissions until the earlier of November 25, 1991 or the date on which practicable means for the adequate abatement or control of SO_2 emissions from the Centralia Plant become known, available, and implementable. The Order required that collection of ambient meteorological monitoring data extend through September 30, 1991, and that the permittee report to SWCAA the results of its dispersion modeling by December 31, 1991.

Order/Permit Number	App. No.	Date Issued	Description
90-934E	N/A	4-5-91	Withdrawal of Petition, Surrender of Variance, and Order - terminated the variance, meteorological monitoring, ambient monitoring, dispersion modeling, and modeling report provisions of SWCAA 90-934D and 88-934.
95-1787	N/A	8-25-95	RACT order limiting SO_2 emissions to 1.1 lb/MMBtu
96-1872	N/A	3-20-96	Withdraws RACT Order 95-1787. Replaced with a Letter of Agreement between SWCAA and PacifiCorp.
97-2057	N/A	12-8-97	Determination of SO_2, NO_x, CO and PM RACT, SO_2 and NO_x controls
97-2057R1	N/A	2-26-98	Revision of RACT determination
99-2187	N/A	2-1-99	Stay Order extending the date when procurement contract for Unit 1 control technology must be signed by 60 days (new date May 31, 1999)
01-2350	L-480	5-30-01	Minor source permit for combustion turbine project. Does not address PM or NO_x emissions
PSD-01-01	N/A	2-22-02	PSD permit for combustion turbine project – addresses PM and NO_x emissions
01-2403	L-490	2-27-02	Replacement of the Unit 1 and Unit 2 Turbine Lube Oil Mist Eliminators and Replacement of Two Rotary Fly Ash Unloaders With a Single Pug Mill
01-2350R1	L-496	5-6-02	Modification of 01-2350 primarily to increase SO_2 limit to account for higher sulfur content in natural gas
PSD-01-01 Amendment 1	N/A	1-30-03	Modification of PSD-01-01 to accommodate a larger than originally permitted BHP auxiliary boiler
01-2350R2	L-505	10-15-03	Modification of 01-2350R1 to accommodate a larger than originally permitted BHP auxiliary boiler.
PSD-01-01 Amendment 2	N/A	6-11-04	Modification of PSD-01-01 Amendment 1 to allow use of 40 CFR 75 RATA schedule where 40 CFR 60 schedules had been required
01-2350R3	L-552	5-12-05	Modification of source testing and RATA frequencies for Combustion Turbine Facility
05-2612	L-556	7-15-05	Expansion of West Coal Unloading Facility with addition of 1 hopper

Order/Permit Number	App. No.	Date Issued	Description
05-2636	L-565	11-23-05	Installation of FGD Bleed Treatment Lime Storage Silo
07-2712	L-590	2-7-07	Modification of West Coal Unloading Facility with surge capacity addition
07-2749	L-603	9-26-07	Installation of East Coal Unloading Facility and modification of requirements for West Coal Unloading Facility. After removal of the West Coal Unloading Facility in 2011, East Coal Unloading Facility simply referred to as the Coal Unloading Facility.
01-2350R4	L-608	1-18-08	Elimination of 1.5 ppmvd @ 15% O_2 (8-hour average) CO emission limit for BHP Project combustion turbines. The 3.0 ppmvd @ 15% O_2 (1-hour average) limit was retained.
08-2779	L-613	3-12-08	Replacement of the existing 1,800 cfm cartridge-style Torit baghouse with a larger Donaldson Torit cartridge style baghouse rated at 4,000 cfm in the Journal Shop
09-2876	L-634	6-16-09	Installation and operation of a 251 horsepower nonroad engine that will drive a Jetstream pressure washer. The engine and pressure washer package will be mounted on a mobile trailer for use throughput the power plant and associated facilities. Because this is a non-road engine, it is not part of the facility's Title V permit.
Order No. 6426	N/A	6-18-10	BART Order from Washington Department of Ecology establishing NO_x emission limit of 0.24 lb/MMBtu for the coal fired boilers and coal quality requirements. EPA approved the SIP submission containing this BART submission in a Federal Register notice dated December 6, 2012.
11-2972	L-647	4-14-11	Installation and operation of an emergency water pump at the (East) CUF powered by a diesel engine. Superseded 07-2749.
11-2984	L-650	6-14-11	Installation of equipment associated with activated carbon injection mercury emission control system.
11-2996	L-654	11-3-11	Installation and operation of the Pump 8 Engine. This permit also addressed the grandfathered engine on Barge 5429. Note that Pump 8 was subsequently referred to as the Pump-05 engine.
First Revision of Order No. 6426	N/A	12-13-11	Revision of BART Order 6426 with new requirements for SNCR.

Order/Permit Number	App. No.	Date Issued	Description
12-3016	L-657	4-30-12	Installation of a baghouse to replace the existing baghouse on the fly ash weigh bin (operated by Lafarge North America), and the relatively new "Fly Ash Bin 11 to Weight Hopper Air Slide Filter" (operated by TransAlta). The new baghouse filters dust from air collected from the fly ash loading spout and air vented to the fly ash bin from the No. 11 Air Slide and the No. 12 Air Slide
12-3035	L-659	10-18-12	Installation of a new fire pump engine that may also be used to supply water to other systems at the plant during a maintenance event. Superseded 11-2996.
14-3093	L-668	4-30-14	Approval of coal mine waste reprocessing activities and fine coal recovery at TransAlta Centralia Mining and delivery by conveyor to TransAlta Centralia Generation.
16-3188	L-683	6-1-16	Approval of one trailer-mounted water pump driven by a 99 horsepower diesel engine and one Caterpillar emergency generator set powered by a 480 horsepower diesel engine to replace the Unit 2 emergency generator set. Superseded 12-3035.
16-3202	N/A	12-13-16	Regulatory order to limit SO_2 emissions to protect 1-hour SO_2 NAAQS.
Second Revision of Order No. 6426	N/A	7-29-20	Revision of BART Order 6426 with lower NO_x limit for one unit and removal of prescriptive SNCR operating requirements.

D. EMISSIONS UNIT DESCRIPTIONS

Summary Table

EU No.	Generating Equipment	Emission Control
EU-1	Unit 1 Boiler (BW21) – 670 MW (net), coal fired (Retired)	N/A (Retired)
EU-2	Unit 2 Boiler (BW22) 670 MW (net), coal fired	CO: Combustion controls NO_X: Combustion controls, SNCR VOC: Combustion controls PM: Dual ESPs, wet scrubber SO_2: Wet scrubber Hg: Sorbent enhancement additive in boiler, carbon injection between ESPs
EU-3	Auxiliary Boiler - 170 MMBtu/hr, oil-fired	Fuel consumption limit
EU-4	Material Handling (Coal Handling, Ash Handling, FGD Bleed Treatment Lime Storage Silo, Limestone Ball Mill)	Coal Handling – minimal emissions, no controls necessary except use of wet suppression at Coal Unloading Facility Ash Handling – baghouse, wet suppression, and enclosure as appropriate FGD Bleed Treatment Lime Storage Silo – Baghouse Limestone Ball Mill – Wet process, full enclosure
EU-5	Turbine Lube Oil Mist Vent 1 (Retired)	N/A (Retired)
EU-6	Turbine Lube Oil Mist Vent 2	Turbine Lube Oil Mist Eliminator 2
EU-7	Black Stop Diesel Generator Engine 1,445 hp diesel engine (Retired)	N/A (Retired)
EU-8	Journal Shop Welding	Journal Shop Welding Filter
EU-9	Emergency Diesel Generator 1	None
EU-10	Emergency Diesel Generator 2	Ultra-low sulfur fuel, EPA Tier 3 design, operating hours limit
EU-11	Fire Pump Engine (205 hp diesel engine)	Ultra low sulfur fuel, EPA Tier 3 design, operating hours limit
EU-12	Coal Unloading Facility Emergency Diesel Sump Pump Engine (115 hp diesel engine)	Ultra low sulfur fuel, EPA Tier 2 design, operating hours limit
EU-13	SEA System 1	Cartridge-style Fabric Filter
EU-14	SEA System 2	Cartridge-style Fabric Filter
EU-15	Sorbent Silo 1	Cartridge-style Fabric Filter
EU-16	Sorbent Silo 2	Cartridge-style Fabric Filter
EU-17	Fly Ash Bin 11	Baghouse

EU No.	Generating Equipment	Emission Control
EU-18	Fly Ash Bin 12	Baghouse
EU-19	Fly Ash Bin 14	Baghouse
EU-20	Fly Ash Bin 14 Air Slide to Bin 11 Air Slide	Cartridge-style Fabric Filter
EU-21	Fly Ash Bin 14 to 6050 Air Slide	Cartridge-style Fabric Filter
EU-22	Fine Coal Handling	Wet suppression

Detailed Descriptions

EU-1 Unit 1 Boiler (Retired)

EU-1 retired at the end of 2020.

EU-2 Unit 2 Boiler

EU-2 consists of the Unit 2 boiler and its exhaust gas flow path including the 470 ft tall stacks (bypass and scrubber) through which the flue gases are discharged to the ambient air. The Unit 2 boiler is a Combustion Engineering coal-fired steam generator equipped with superheat and reheat that combusts pulverized coal in a divided furnace with tangential injection of pulverized coal and combustion air. The eight corners (four in each half of the split furnace configuration) of the boiler are supplied with fuel and air by eight levels of burners, with each level supplied by one of the eight coal pulverizers. A maximum design capacity of 490 tons per hour of coal can be combusted in the boiler. Typically, full load is attained burning 420 tons per hour of average heat content coal by operating seven of the eight pulverizers at rated capacity. Incidental quantities of on-site generated dangerous waste, used oil and grease may also be burned in the boiler. Combustion produces emissions of SO_2, NO_X, CO, PM, VOCs, and HAPs. Flue gases exit the boiler through heat exchangers and pass first through a Koppers electrostatic precipitator (ESP) with a specific collection area of 333 ft^2/1,000 acfm, and then through a Lodge-Cottrell ESP with a specific collection area of 384 ft^2/1,000 acfm for removal of particulate matter. The dual ESP system achieves a collection efficiency of 99.7% or better for particulate matter. Final flue gas treatment occurs in a forced oxidation limestone flue gas desulfurization system (wet scrubber) installed in 2001. The original stack has been retained for bypass operations during emergencies, startup, shutdown, and outages of the flue gas desulfurization system.

Mercury emissions are controlled by an activated carbon injection system upstream of the second set of ESPs coupled with a sorbent enhancement additive injected into the boiler. The mercury control system was completed November 24, 2011. NO_X emissions are controlled with "Low-NO_X Combustion, Level 3" (LNC3) controls consisting of Alstom concentric firing, low NO_X burners with close coupled and separated over-fire air. The LNC3 controls were installed in 2001.

The SNCR system was installed in 2012 and consists of Nalco Mobotec's Rotamix SNCR system. The system consists of concentrated urea storage, urea dilution, and three levels of diluted urea injection near the top of the boiler. Each urea injection point utilizes an air atomizing nozzle with annular air to allow the urea to be dispersed into the boiler before

reacting. Each nozzle can be angled approximately 30 degrees upward or downward. The lowest level of injectors is approximately at the 10.5 floor level. Each of the three horizontal levels consists of six injectors spread across the front of the boiler, with four more injectors slightly above the row of six, for a total of 30 injectors. A single air header with a blower supplies ambient air to all of the annular air supplies on the boiler. The air intake for these blowers is inside the top of the boiler building.

Each SNCR blower or pump has a redundant backup to minimize the possibility of a system outage. As the temperature regime changes with changing boiler load, the levels at which the urea is injected is modified accordingly to ensure the proper injection location.

The following individual pieces of equipment are associated with EU-2:

Equipment	Facility Designation
One Boiler for Unit 2	Unit 2 or BW22
Two ESP units in series	Koppers 21 & 22; Lodge-Cottrell 21A & 22A
Unit 2 wet scrubber	FGD 2

Construction of EU-2 officially commenced (for the purposes of 40 CFR 60) with signing of a construction contract on December 23, 1968. EU-2 commenced commercial operation in September 1972.

Applicable NSPS/NESHAP/MACT: 40 CFR 63 Subpart UUUUU

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
NO_x	6,744	Yes/No[1]	Yes	No. Permit requires CEMS.
CO	8,042	No	Yes	No. No emission control equipment and the permit requires CEMS
VOC	86	No	No	No
SO_2	5,913	Yes	Yes	No. Permit requires CEMS.
PM_{10}	1,277	Yes	Yes	Yes. See M20 of Permit
NH_3	220	No	Yes	No
HF	28	Yes	No	No

[1] SNCR is available but there is no requirement to use the system and there is little likelihood the system will be used in the future.

EU-3 Auxiliary Boiler

EU-3 consists of the auxiliary boiler which is used to provide auxiliary steam throughout the plant when sufficient auxiliary steam is not available from Unit 2, such as during cold startup. The auxiliary boiler is a Babcock & Wilcox watertube steam boiler (National Board number 23173, Washington State ID number 26415-71W) with a rated capacity of 115,000 lb/hr of steam and 170 MMBtu/hr. It combusts No. 2 fuel oil, also known as distillate grade diesel fuel, to produce steam at 150 psig and 500°F and discharges flue gases through a 5 ft diameter

steel stack 250 ft in height. EU-3 emits NO_X, SO_2, CO, PM, and VOCs from combustion of No. 2 fuel oil.

Construction of EU-3 officially commenced (for the purposes of 40 CFR 60) with signing of a construction contract on December 23, 1968.

Applicable NSPS/NESHAP/MACT: 40 CFR 63 Subpart DDDDD

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
NO_X	6.00	No	No	No
CO	1.50	No	No	No
VOC	0.08	No	No	No
SO_2	4.26	No	No	No
PM_{10}	0.99	No	No	No

EU-4 Material Handling

EU-4 consists of all coal handling equipment and operations on the Centralia Plant site, the ash collection and load-out facilities, the FGD Bleed Treatment Lime Storage Silo, and the Limestone Ball Mill. The coal handling equipment receives and stores the coal, reclaims coal from storage piles, and distributes the coal throughout the plant. Historically, coal has been received from the adjacent coal mine and delivered from the Powder River Basin. Most of the coal combusted in the Centralia Plant has been obtained from the adjacent TransAlta Centralia Mining (TCM) mine, which processed coal at its preparation plant and transferred the coal by conveyor to the Centralia Plant. This mine is currently closed. Coal is received by rail car at the Coal Unloading Facility from which it is transferred by conveyor and mobile machinery to storage piles. Note that prior to 2011 there were two Coal Unloading facilities. One located at the West end of the plant site and one located the East end of the plant site. The West Coal Unloading Facility was removed from service in 2011. Except for descriptions in historical context all coal is unloaded at a single point: the Coal Unloading Facility formerly the known as the East Coal Unloading Facility. In 2007 the permittee received an Air Discharge Permit to construct the Coal Unloading Facility. A traveling bucket-wheel stacker-reclaimer transfers yard conveyor transported coal to or from ready storage piles. In addition, a coal blending system installed in 2001 supplies coal to the plant from the ready storage pile. Dust suppression is provided to minimize generation of fugitive dust as coal is transported to the silos and pulverizers.

Fly ash is collected in storage silos and sent off-site via one of two load-out facilities. A portion of the fly ash is sold and loaded into trucks by an off-site contractor who is contractually responsible to the permittee for operation and air quality compliance of these truck-loading facilities at the Plant. Permittee is ultimately responsible for compliance under the Clean Air Act at this facility. The other load out operated by the Plant is used to dispose of fly ash in the TCM mine. Bottom ash is dewatered in settling tanks and loaded while damp into trucks for transport to the TCM mine as backfill or sold for off site use.

The following individual pieces of equipment are associated with EU-4:

Equipment	Facility Designation
Coal Unloading Facility	CUF
Twelve coal conveyors	Conveyors 1-5, 6A, 6B, 7, 11, 12, 21, & 22
One bucket-wheel stacker-reclaimer	Stacker-reclaimer
Coal blending system	
Chemical stabilizing dust suppression systems at CUF and No. 5 reclaim	(N/A)
Four coal silos	Silos 21-28 (Unit 2)
Coal surge bin	(N/A)
Four bottom ash dewatering bins	Bins 11, 12, 21, 22
Various mobile machinery	(N/A)
Four fly ash bins	Bins 11, 12, 13, 14

- Bin 11 – Unclassified ash with single UCC model 6050 pin paddle mixer/unloader – 330 tph capacity, installed in 2009
- Bin 12 – Classified ash with single UCC model 6050 pin paddle mixer/unloader – 330 tph capacity, installed in 2009
- Bin 13 – Repurposed as a boron removal clarifier in the FGD Bleed Treatment system
- Bin 14 - Replaced into service in 2011 to handle fly ash from the Lodge-Cottrell that contains carbon sorbent from the mercury control system.

Fly Ash Weigh Bin Baghouse	Same
FGD Bleed Treatment Lime Storage Silo	Same
Limestone Ball Mill	Same

Coal Unloading Facility Details

The Coal Unloading Facility consists of two below-grade hoppers, each associated with a drag flight conveyor that transfers coal to an interim conveyor that feeds the new radial stacker or feeds directly into the coal blending system. The radial stacker transfers coal to the plant stockpiles. Coal in the coal stockpiles is dozed to the coal blending/plant feed conveyors. The following transfer points are associated with the Coal Unloading Facility:

1. Rail car to below-grade hoppers (2)
2. Below-grade hoppers to apron feeders
3. Apron feeders to Conveyor 8A
4. Conveyor 8A to Conveyor 8B (stacker)
5. Conveyor 8B (stacker) to coal stockpile or Conveyor 8C
6. Conveyor 8C to ground level reclaims 3, 3A
7. Reclaims 3, 3A to Conveyor 4 or 4A (which feed the plant)

The maximum coal unloading rate is 4,000 tons per hour with 5,000 ton per hour surge capacity. The Coal Unloading Facility began operation on February 1, 2008.

FGD Bleed Treatment Lime Storage Silo Details

The FGD Bleed Treatment Lime Storage Silo stores hydrated lime ($Ca(OH)_2$). The lime is used to treat a bleed stream of scrubber liquid from the flue gas desulfurization system. The scrubber liquid treatment system is designed to reduce boron and zinc levels in the wastewater. The silo is located immediately southeast of the Unit 1 scrubber vessel. The silo is pneumatically loaded from trucks at a rate of approximately 16.7 tons per hour. Specific silo and associated dust collector information is listed below.

Silo Make/Model:	USFilter Lime Silo; WHM® Bulk Chemical Storage; Model T-1
Silo Capacity:	5,600 cubic feet
Silo Height:	53'1" without dust collector, 58' with dust collector
Dust Collector Make/Model:	C.P. Environmental Filters, Inc. / model 36-CTBFD-009-CM-30
Number of Bags:	9 cartridge style pleated "bags" measuring 6" in diameter by 36" long
Cleaning Method:	Reverse Pulse-Jet
Cloth Area:	270 ft²
Filter Media:	8.5 oz. pleated spun bonded polyester felt with PTFE membrane laminated to the exterior surface of the fabric
Design Exhaust Flow:	600 acfm
Installed:	2006

The manufacturer warrants that the particulate matter concentration in the effluent gas will not exceed an average of 0.005 gr/acf based on an inlet loading of 10 gr/acf.

Limestone Ball Mill Details

The Limestone Ball Mill is located in the ground floor of the FGD Building. The Limestone Ball Mill crushes limestone transferred from the limestone storage silo with water to form a limestone slurry for use in the Flue Gas Desulfurization systems. The Limestone Ball Mill is fully enclosed and is not a potential source of particulate matter emissions (the process is fully enclosed and water is injected at the upstream end of the ball mill), however it is an "affected facility" for the purposes of Title 40 Code of Federal Regulations (CFR) Part 60 Subpart OOO "Standards of Performance for Nonmetallic Mineral Processing Plants."

Ball mill processing capacity:	41 tons per hour
Manufacturer:	Svedala Industries (now known as Metso Minerals)
Serial number:	49663
Manufacture date:	May 2000
Installation date.	September 2001

Fly Ash Weigh Bin Baghouse Details

The Fly Ash Weigh Bin receives fly ash from the No. 11 Air Slide and the No. 12 Air Slide. The Fly Ash Weigh Bin was manufactured by Halliburton and has a capacity of up to 30,000 pounds. During normal operation, approximately 900 cfm of fluidizing air from one of the air slides is vented out of the Fly Ash Weigh Bin Baghouse. The Fly Ash Weigh Bin Baghouse draws approximately 900 cfm of air from the fly ash loading spout to control fugitive dust while loading, for a total air flow of 1,800 cfm. At times total airflow could range up to 2,700

cfm if fly ash were being loaded into the Fly Ash Weigh Bin from both air slides (i.e. more than one Fly Ash Bin) simultaneously. The Fly Ash Weigh Bin Baghouse is turned on/off by the contractor in charge of loading fly ash (currently Lafarge North America), however TransAlta will retain responsibility for maintenance of, and the emissions from, the Fly Ash Weigh Bin Baghouse. The following details of the cartridge collector were provided:

Baghouse Make / Model:	Donaldson Torit / Powercore CPV-4
Installed:	Installation completed July 30, 2012
Design Flow Rate:	2,700 cfm (rated at 1,400 cfm to 2,700 cfm)
Filter Description:	4 cartridges (7" wide x 22" long x 7.5" tall), total of 252 ft² filter area
Filter Description:	Ultra-web nanofiber material
Cleaning Method:	Pulsed jet – collected fly ash will drop down into the fly ash weigh bin
Stack Description:	16" inside diameter stack exhausting vertically approximately 8' above the top of the fly ash weigh bin and 49.50' above ground level. An 18" diameter shroud (stack within a stack design) may be used to prevent rain intrusion into the stack.

Applicable NSPS/NESHAP/MACT: None

CAM Applicability Review

Particulate matter is the only regulated pollutant of interest for units that comprise EU-4. Equipment that utilizes a control device and has a particulate matter emission limit is reviewed below.

Equipment	Uncontrolled PTE (tons)	Subject to CAM?
FGD Bleed Treatment Lime Storage Silo	12[1]	No
Fly Ash Bin 11 Fly Ash Bin 12 Fly Ash Bin 14	0[2]	No. CAM plan is included in the Permit as M31 for the exhausts (treated as separated EUs from the piping, storage, and transfer equipment listed here).
Fly Ash Weigh Bin	68[3]	No

[1] Assumes an inlet loading of 10 gr/dscf (likely a gross overestimate) for a potential operating time of 467 hours per year based on 6 25-ton loads per week at an off-loading rate of 16.7 tons per hour. Note that the bin vent may be "inherent process equipment".

[2] This does not include the baghouses which are treated as separate EUs. This equipment consists only of sealed piping and transfer equipment which does not have emissions unless a pipe fails or leaks

[3] Assumes 1,800 cfm of operation for 8,760 hours per year at an "uncontrolled" rate of 1 gr/dscf. Due to the nature of fly ash, filtration of some time is required, therefore at least some level of control is "inherent process equipment". Unit operates with 900 cfm of bin fluidizing air at all times, only exceeding this rate when actual loading is occurring and when the weigh bin is receiving ash from more than one storage bin at a time.

EU-5 Turbine Lube Oil Mist Vent 1 (Retired)

Retired at the end of 2020.

EU-6 Turbine Lube Oil Mist Vent 2

The Unit 2 turbine is equipped with an oil storage tank, lube oil reservoir, and other components of the lube oil system that supplies clean oil to the turbine-generator bearings and other equipment. The turbine lube oil mist eliminator controls oil droplet emissions from the vapor extractor, which removes moisture from the oil.

Turbine Lube Oil Mist Eliminator 2 is an Advanced Environmental Systems Air-Clear™ Mist Collection System sized to handle up to 1,000 cubic feet per minute (cfm) of oil mist at a concentration of 1,500 mg/m^3 and a temperature of 120°F. The mist eliminator utilizes 67 ft^2 (based on the inside diameter of cylindrical filters) of fiberbed diffusion coalescing filters to collect up to 99.5% of the liquid mists on a particle count basis. Manufacturer literature suggests that the collection efficiency can be as high as 99.99% on a mass basis. This unit is designed to maintain the exit opacity at 5% or below. The blower system is designed to supply an average exhaust flowrate of 5 cfm (maximum of 600 cfm for short periods). This is substantially lower than the 1,000 cfm design of the mist eliminator. The mist eliminator is designed so that the filter elements are replaced when the gas flow becomes overly restricted due to high differential pressure across the filters. The differential pressure across the filters is less important to emission control than the average flow velocity through the filters. The manufacturer estimates that a velocity of 40 feet per minute or less is required for adequate opacity control. The permittee's blower has the capacity to produce a velocity of approximately 9 feet per minute (600 cfm/67 ft^2).

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
VOC	0.01	Yes	Yes	No

EU-7 Black Stop Diesel Generator Engine (Retired)

The Black Stop Diesel Generator Engine retired at the end of 2020.

EU-8 Journal Shop Welding

Coal journals used in the coal pulverizers are repaired in the Journal Shop. Repairs consist primarily of welding replacement metal onto the journals to replace metal worn off during normal use. TransAlta submitted Air Discharge Permit Application 1-613 on February 4, 2008 for replacement of the existing 1,800 cfm cartridge-style Torit baghouse with a larger Donald Torit cartridge style baghouse rated at 4,000 cfm. The purpose of the replacement

was to improve worker hygiene in the Journal Shop, especially to reduce potential worker exposure to chromium welding fumes.

Journal Shop – Baghouse. Journal Shop welding electrode use is less than 12,000 pounds per year. The baghouse pickups are positioned in such a way to minimize exposure of welders to welding fumes. Most welding is expected to be shielded metal arc welding. The following baghouse details were available:

Make / Model:	Donaldson Torit / DFO 2-8
Filter Area:	1,520 square feet of cartridge style filters
Primary Filter Media:	Ultra-Web FR with a MERV rating of 13
No. of Filters:	8
Secondary Filters:	Contains two 24" x 24" x 12" HEPA filters downstream of cartridge filters
Design Capacity:	4,000 cubic feet per minute @ 10" w.c., 70 °F
Installed:	September 10, 2008
Stack Description:	Exhausts horizontally through two 24" x 24" x 12" ducts at ambient temperature ~12' above grade.

Applicable NSPS/NESHAP/MACT: None

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	0.49	Yes	Yes – opacity as a surrogate for PM	No

EU-9 Emergency Diesel Generator 1

Engine Rating:	440 horsepower
Engine Make / Model:	Caterpillar / D343
Engine Serial Number:	6287637
Stack Description:	~ 8" diameter exhausted above the 8th floor roof

Diesel fuel oil is burned by this generator to supply back-up power to critical electrical systems in Unit 1. The generator is operated for about ½ hour each week for testing, and consumes less than 500 gallons of fuel annually producing emissions below the thresholds of WAC 173-401-530(4) for an insignificant emission unit. This unit is not an insignificant emission unit because it is subject to applicable requirements found in 40 CFR 63 Subpart *ZZZZ*. The applicable requirements became effective May 3, 2010 (Federal Register notice dated March 3, 2010) with a compliance date of May 3, 2013.

Applicable NSPS/NESHAP/MACT: 40 CFR 63 Subpart ZZZZ

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
NO_X	1.36	No	No	No
CO	0.29	No	No	No
VOC	0.11	No	No	No
SO_2	0.00048	No	No	No
PM_{10}	0.01	No	No	No

EU-10 Emergency Diesel Generator 2

Generator Set Make / Model:	Caterpillar / C9
Generator Output:	300 kW
Engine Make / Model:	Caterpillar / C9
Engine Serial Number:	CASP01214
Fuel:	Diesel, 22.7 gallons per hour at full load
Engine Power:	480 hp
Engine Built:	2016
Engine Certification:	EPA Tier 3 Emergency
Stack Description:	~ 7" diameter, exhausting vertically, ~8' above the 8th floor roof, stack flow 2,460.9 acfm at 927.2°F
Location:	46°45'19.19"N, 122°51'36.24"W
NSPS/NESHAP/MACT:	40 CFR 60 Subpart IIII, 40 CFR 63 Subpart ZZZZ

Applicable NSPS/NESHAP/MACT: 40 CFR 60 Subpart IIII, 40 CFR 63 Subpart ZZZZ

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
NO_X	0.42	No	No	No
CO	0.02	No	No	No
VOC	0.01	No	No	No
SO_2	0.00049	No	No	No
PM_{10}	0.0024	No	No	No

EU-11 Fire Pump Engine

The Fire Pump Engine drives a backup fire water pump. This unit will operate for testing and maintenance of the engine, as necessary during an emergency, and for limited time periods for non-emergency operation (e.g. during maintenance events when the electrical pump system is unavailable). Total annual operation is expected to be no more than 504 hours per year (3 weeks). Engine details are provided below.

Engine Make / Model:	Cummins / CFP7E-F50 Fire Pump Driver
Engine Serial Number:	73467344
Fuel:	Diesel, 10.6 gallons per hour at full load

Engine Power:	205 hp
Engine Built:	2012
Engine Installed:	Installation completed December 27, 2012
Engine Certification:	EPA Tier 3
Stack Description:	~ 4" diameter, exhausting vertically ~18' above grade, 1' 10" above roof level, stack flow 1,174 acfm @ 879°F
Location:	46°45'22.44"N, 122°51'44.23"W

Applicable NSPS/NESHAP/MACT: 40 CFR 60 Subpart IIII, 40 CFR 63 Subpart *ZZZZ*

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
NO_X	0.28	No	Yes	No
CO	0.14	No	Yes	No
VOC	0.01	No	No	No
SO_2	0.0006	No	No	No
PM_{10}	0.013	No	Yes	No

EU-12 Coal Unloading Facility Emergency Diesel Sump Pump Engine

The CUF Emergency Diesel Sump Pump consists of a Godwin water pump driven by a diesel engine. The engine is operated for testing, maintenance, and as an emergency backup to the existing electric water pump. Engine details are provided below:

Engine Make / Model:	John Deere / 4045TF275
Engine Serial Number:	PE 4045TF593425
Engine Family:	6JDXL06.8082
Fuel:	Diesel, 42.7 pounds per hour @ full load
Horsepower Rating:	115
Engine Built:	July 9, 2006
Engine Certification:	EPA Tier 2
Stack Description:	~ 4" diameter, exhausting vertically ~6.5' above grade, stack flow 713 acfm @ 860 °F

Applicable NSPS/NESHAP/MACT: 40 CFR 63 Subpart *ZZZZ*, 40 CFR 60 Subpart IIII

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
NO_X	0.25	No	Yes	No
CO	0.04	No	Yes	No
VOC	0.0077	No	No	No
SO_2	0.00013	No	No	No
PM_{10}	0.0055	No	Yes	No

EU-13 SEA System 1

Based on a review of the potential Sorbent Enhancement Additive (SEA) materials, no significant increase in pollutant emission rates is expected as a result of injecting SEA into the boiler. Emissions are associated with venting of SEA laden air from the SEA hopper and the hammermill crusher through the SEA System 1 Cartridge Collector. The system feed capacity is 5-100 lb/hr, therefore the hammermill crusher is not subject to 40 CFR 60 Subpart OOO. The following details of the cartridge collector were provided:

Make / Model:	Grünergy Technologies / PV-2-160 AR III
Design Flow Rate:	1,130 cfm
Design Exhaust Concentration:	0.005 gr/dscf
No. of Cartridges:	2
Filter Description:	160 ft^2 of 8 oz/yd^2 thermally fused polyester with PTFE membrane
Cleaning Method:	Pulsed jet
Stack Description:	6" diameter stack exhausting vertically on east wall of the boiler building.

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	42.42[1]	Yes	Yes	No

[1] Assumes conservative (high) inlet concentration loading of 1.0 gr/dscf.

EU-14 SEA System 2

Based on a review of the potential SEA materials, no significant increase in pollutant emission rates is expected as a result of injecting SEA into the boiler. Emissions are associated with venting of SEA laden air from the SEA hopper and the hammermill crusher through the SEA System 2 Cartridge Collector. The system feed capacity is 5-100 lb/hr, therefore the hammermill crusher is not subject to 40 CFR 60 Subpart OOO. The following details of the cartridge collector were provided:

Make / Model:	Grünergy Technologies / PV-2-160 AR III
Design Flow Rate:	1,130 cfm
Design Exhaust Concentration:	0.005 gr/dscf
No. of Cartridges:	2
	Filter Description: 160 ft^2 of 8 oz/yd^2 thermally fused polyester with PTFE membrane
Cleaning Method:	Pulsed jet
Stack Description:	6" diameter stack exhausting vertically on east wall of the boiler building.

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	42.42[1]	Yes	Yes	No

[1] Assumes conservative (high) inlet concentration loading of 1.0 gr/dscf.

EU-15 Sorbent Silo 1

Sorbent Silo 1 is located directly north of the ductwork between the Koppers ESPs and the Lodge-Cottrell ESPs. The following details of the vent filter system were provided:

Make / Model:	Torit Technologies / TBV-4 Insertable
Design Flow Rate:	350 cfm, passively vented
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	4 Ultra-Web II NL cartridges, each containing a filter area of 170 ft^2 of 8 oz/yd^2 nanofiber on cellulose material
Cleaning Method:	Reverse air jet
Stack Description:	Circular exhaust measuring approximately 12" diameter exhausting vertically on the top of the silo, approximately 95' above grade

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	13.14[1]	Yes	Yes	No

[1] Assumes conservative (high) inlet concentration loading of 1.0 gr/dscf.

EU-16 Sorbent Silo 2

Sorbent Silo 2 is located directly south of the ductwork between the Koppers ESPs and the Lodge-Cottrell ESPs. The following equipment details were provided:

Make / Model:	Torit Technologies / TBV-4 Insertable
Design Flow Rate:	350 cfm, passively vented
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	4 Ultra-Web II NL cartridges, each containing a filter area of 170 ft^2 of 8 oz/yd^2 nanofiber on cellulose material
Cleaning Method:	Reverse air jet
Stack Description:	Circular exhaust measuring approximately 12" diameter exhausting vertically on the top of the silo, approximately 95' above grade

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	13.14[1]	Yes	Yes	No

[1] Assumes conservative (high) inlet concentration loading of 1.0 gr/dscf.

EU-17 Fly Ash Bin 11 Baghouse

The Fly Ash Bin 11 Baghouse is located on top of the fly ash bins. A baghouse leak detector has been installed. The following equipment details were provided.

Make / Model:	Industrial Accessories Company (IAC) / 144TB-BVWT-256-S6
Design Flow Rate:	14,730 cfm
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	256 bags, 114 inches long with a total filter area of 4,997 ft^2, top load, DuPont Type 54 or equal, polyester material.
Cleaning Method:	Reverse air jet
Stack Description:	Rectangular exhaust measuring approximately 18" x 50" exhausting vertically – 5' above the top of the baghouse, approximately 30' above the top of the fly ash bin.
Leak Detector:	Tribo-Flow model 4001-1111-01-154N with 12" long probe

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	553[1]	Yes	Yes	Yes – CAM plan is included in the Permit as M31.

[1] Assumes inlet concentration loading of 1.0 gr/dscf.

EU-18 Fly Ash Bin 12 Baghouse

The Fly Ash Bin 12 Baghouse is located on top of the fly ash bins. A baghouse leak detector has been installed. The following equipment details were provided:

Make / Model:	Industrial Accessories Company (IAC) / 144TB-BVWT-256-S6
Design Flow Rate:	14,730 cfm
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	256 bags, 114 inches long with a total filter area of 4,997 ft^2, top load, DuPont Type 54 or equal, polyester material.
Cleaning Method:	Reverse air jet

Stack Description:	Rectangular exhaust measuring approximately 18" x 50" exhausting vertically ~ 5' above the top of the baghouse, approximately 30' above the top of the fly ash bin.
Leak Detector:	Tribo-Flow model 4001-111-1-154N with 12" long probe

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	553[1]	Yes	Yes	Yes – CAM plan is included in the Permit as M31.

EU-19 Fly Ash Bin 14 Baghouse

The Fly Ash Bin 14 Baghouse is located on top of the fly ash bins. A baghouse leak detector has been installed. The following equipment details were provided.

Make / Model:	Industrial Accessories Company (IAC) / 144TB-BVWT-256-S6
Design Flow Rate:	14,730 cfm
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	256 bags, 114 inches long with a total filter area of 4,997 ft^2, top load, DuPont Type 54 or equal, polyester material.
Cleaning Method:	Reverse air jet
Stack Description:	Rectangular exhaust measuring approximately 18" x 50" exhausting vertically ~ 5' above the top of the baghouse, approximately 30' above the top of the fly ash bin.
Leak Detector:	Tribo-Flow model 4001-111-1-154N with 12" long probe

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	553[1]	Yes	Yes	Yes – CAM plan is included in the Permit as M31.

EU-20 Fly Ash Bin 14 Air Slide to Bin 11 Air Slide

The air slide utilizes approximately 900 cfm of air to help move fly ash from Fly Ash Bin 14 to the Bin 11 Air Slide which in turn moves fly ash to the weigh hopper. The air is exhausted through a cartridge-style air filter system. The blower is located downstream of the air filter. The following equipment details were provided:

Make / Model:	DCL / VML185

Design Flow Rate:	900 cfm
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	4 polyester cartridges, each measuring approximately 8" outside diameter by 22 inches long, combined filter area of 185 ft^2
Cleaning Method:	Reverse air jet
Stack Description:	Exhausts approximately 35 feet above ground on the south side of the Bin 11 building - discharged vertically through ~ 6" diameter exhaust

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	33.8	Yes	Yes	No

EU-21 Fly Ash Bin 14 to 6050 Air Slide

The air slide utilizes approximately 600 cfm of air to help move fly ash from Fly Ash Bin 14 to the 6050 unloader. The air is exhausted through a cartridge-style air filter system. The blower is located downstream of the air filter. The following equipment details were provided:

Make / Model:	DCL / VML140
Design Flow Rate:	600 cfm
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	3 polyester cartridges, each measuring approximately 8" outside diameter by 22 inches long, combined filter area of 140 ft^2
Cleaning Method:	Reverse air jet
Stack Description:	Exhausts approximately 35 feet above ground inbetween the Bin 11 and Bin 14 buildings discharged vertically through ~ 6" diameter exhaust.

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	33.8	Yes	Yes	No

EU-22 Fine Coal Handling

Coal mine waste reprocessing and fine coal recovery activities at the Centralia Mine were approved in April 2014 and production began in December 2014. The activities involve dredging waste coal fines from ponds, processing those materials to separate fine coal from waste material, transferring waste slurry to a pit in the North Hanaford area, and transferring fine coal to the coal stockpile at TransAlta Generation. Fugitive dust may be generated at unenclosed material transfer points.

The fine coal handling equipment spans both the TransAlta Centralia Generation and TransAlta Centralia Mining facilities. Each facility maintains separate Air Operating Permits. TransAlta has indicated that after construction is complete, all equipment from Transfer Point 04 (TP-04) and downstream (including the fine coal stockpile) are the responsibility of TransAlta Centralia Generation. An enclosed conveyor will transfer fine coal over Big Hanaford Road from TransAlta Centralia Mining to TransAlta Centralia Generation. TP-04 is the first transfer point north of Big Hanaford Road. Responsibility for the equipment upstream of TP-04 has been retained by TransAlta Centralia Mining.

Transfer Point (TP)	Emission Control Notes
TP-01 (screen bowl centrifuge to clean coal collection conveyor)	Fully enclosed and in the process building
TP-02 (clean coal collection conveyor to 48" conveyor)	Fully enclosed
TP-03 (48" conveyor to conveyor over Big Hanaford Road)	Fully enclosed
TP-04 (transfer either to existing conveyor to directly feed power plant or transfer to fixed stacker for periods when the power plant is not running. A flop gate will direct the flow.)	Fully enclosed
TP-05 (discharge from the stacking conveyor to clean coal stockpile – estimated to be 15% of total throughput)	High pressure suppression as necessary at stacker discharge.

Conveyor Descriptions

Conveyor from TP-01 to TP-02 (Clean Coal Collection Conveyor): This 24" conveyor passes through the process building wall and is covered, but not fully enclosed, where it exits the building.

Conveyor from TP-02 to TP-03: 48" conveyor running along the south side of Parking Lot No. 2. This conveyor is covered but not fully enclosed.

Conveyor from TP-03 to TP-04 (conveyor over Big Hanaford Road): This conveyer is fully enclosed with the exception of some portal sized openings and open sides for a short distance near the head and tail pulleys.

Conveyor from TP-04 to Power Plant: This is an existing conveyor that runs along the south side of the coal plant stockpile and feeds the power plant.

Conveyor to TP-04 to Stockpile: This is an existing stacker that has been re-located to this fixed location. This is a 250' long open conveyor.

Applicable NSPS: 40 CFR 60 Subpart Y "Standards of Performance for Coal Preparation and Processing Plants."

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	0.09	Yes (water spray)	Yes	No

III. EXPLANATION OF INSIGNIFICANT EMISSIONS UNIT DETERMINATIONS

Each emission unit listed as insignificant in the permit has been reviewed by SWCAA to confirm its status. The numbering system used to identify these emission units is consistent with internal Centralia Plant designations and does not necessarily use consecutive numbers. Emission units were determined to be insignificant as follows:

IEU-55B Maintenance Shops Welding Emissions

Maintenance welding is exempt from registration according to SWCAA 400-101(10) and did not require an approval. Emissions from this discharge point are less than 0.1 ton/yr, well below the 0.75 ton PM_{10}/yr threshold of WAC 173-401-530(4)(e) so this unit is considered insignificant. Based on a conservative estimate that no more than 2,000 lb of electrode is used annually in any one shop and the highest value emission factor of 82 lb/1,000 lb from EPA AP-42 Table 12.19-1, the annual emissions are calculated to be:

2,000 lb * (82 lb/1,000 lb) * (1 ton/2,000 lb) = 0.1 ton/yr

IEU-57 Cooling Towers

Primary cooling of the process steam takes place at the cooling towers for the Coal Plant. The cooling towers are categorically exempt insignificant emissions units under WAC 173-401-532(121) because of processing exclusively non-contact cooling water. Furthermore, the cooling towers do not use chromium-based water treatment chemicals. Sodium hypochlorite is used to treat circulating cooling water and does not escape to the ambient air.

IEU-61 Cold Solvent Parts Washers

Eight parts washing solvent tanks are used at the Centralia Plant site for only non-chlorinated solvent, each tank ranging in size from 30 to 40 gallons. The tanks are covered by lids when parts are not actively loaded or unloaded into or out of the tanks. The parts washers emit minimal VOC emissions and are considered insignificant because only fugitive emissions are released consistent with the definition of insignificant emission units in WAC 173-401-530(1)(d) and because their emissions are below the 2.0 tons per year VOC threshold of WAC 173-401-530(4)(d). Based on solvent use of 12,000 lb/yr and a recycle rate of 92% estimated by the solvent recycle vendor, VOC emissions are calculated to be:

12,000 lb/yr * (1 - 0.92) * (1 ton/2,000 lb) = 0.48 tons per year VOC

IEU-71 Fuel Oil Storage Tank 1

This storage tank supplies fuel oil to the boiler for startups and has a capacity of 100,000 gallons. Its VOC emissions are well below the insignificant emission thresholds of WAC 173-401-530(4)(d) (2.0 tons per year of VOC) so the emission unit is considered insignificant. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.079 lb/1,000 gal was derived for this tank. For annual throughput of 220,000 gallons, VOC emissions are calculated to be:

220,000 gal * 0.079 lb/1,000 gal * (1 ton/2,000 lb) = 0.009 tons per year VOC

IEU-72 Fuel Oil Storage Tank 2

This storage tank supplies fuel oil to the boiler for startups and has a capacity of 100,000 gallons. Its VOC emissions are well below the insignificant emission thresholds of WAC 173-401-530(4)(d) (2.0 tons per year of VOC) so the emission unit is considered insignificant. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.079 lb/1,000 gal was derived for this tank. For an annual throughput of 220,000 gallons, VOC emissions are calculated to be:

220,000 gal * 0.079 lb/1,000 gal * (1 ton/2,000 lb) = 0.009 tons per year VOC

IEU-73 Gasoline Storage Tank

The tank is a 5,200 gallon above ground tank with a white concrete shell used to fuel vehicles and equipment on site. The tank utilizes submerged fill and is not equipped with Stage I or II vapor recovery. No pressure/vacuum valve is utilized. Annual emissions from the storage tank are reported by the permittee to be less than 0.5 ton/yr, well below the 2.0 tons VOC/yr insignificant emission threshold of WAC 173-401-530(4)(d)

Gasoline vapors are emitted primarily from the following:

1. Storage Tank Loading Losses
2. Storage Tank Breathing Losses

Storage tank loading and breathing losses were estimated using EPA's Tanks 4.09D emission estimation software.

The parameters were used in Tanks 4.09D:

Nearest City:	Olympia, WA
Type of Tank:	Horizontal Tank
Shell Length:	12.5'
Shell Diameter:	9'
Tank Volume:	5,200 gallons
Shell Color:	White
Shell Condition:	Poor
Vacuum Setting:	0.0 psi
Pressure Setting:	0.0 psi
Liquid:	Gasoline (RVP=10)

Based on EPA Speciate 3.2 profile number 2455, approximately 50.85% of the total VOC emissions are toxic air pollutants (TAPs) as defined by WAC 173-460, and approximately 12.91% of the total VOC emissions are federally listed hazardous air pollutants (HAPs). For a throughput of 930,000 gallons per year, TAP and HAP emission rates are estimated to be:

IEU-73 Gasoline Storage Tank Emissions

Throughput =	15,000 gallons per year
Control Efficiency =	0% (Assume no vapor balance fittings)
Emission Factors	
Storage Tank Working Losses =	7.099 lb/1,000 gallons
Storage Tank Breathing Losses =	770 lbs/year

Emissions Summary	lbs	tons
Volatile Organic Compounds	876	0.44
Toxic Air Pollutants	446	0.22
Hazardous Air Pollutants	113	0.06

IEU-74 Diesel Storage Tank

The storage tank has a capacity of 5,200 gallons and is used to fuel vehicles and equipment on site. VOC storage tanks not greater than 10,000 gallons capacity with appropriate closure and vapor pressure not greater than 80 mmHg are defined in WAC 173-401-533(2)(c) to be insignificant emission units. Annual emissions from the storage tank are reported by the permittee to be less than 0.001 ton/yr, below the 2.0 tons VOC/yr insignificant emission threshold of WAC 173-401-530(4)(d). Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.020 lb/1000 gal was derived for this tank. For an annual throughput of 16,000 gallons, VOC emissions are calculated to be:

16,000 gal * 0.020 lb/1000 gal * (1 ton/2,000 lb) = 0.0002 tons per year VOC

IEU-75 U1 Emergency Diesel Generator Fuel Storage Tank

This fuel storage tank has a capacity of 350 gallons and supplies the U1 emergency diesel generator. Storage tanks not greater than 1,100 gallons capacity with maximum vapor pressure of 550 mmHg are defined in WAC 173-401-533(2)(b) to be insignificant emission units. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.034 lb/1,000 gal was derived for this tank. For an annual throughput of 300 gallons, VOC emissions are calculated to be:

300 gal * 0.034 lb/1,000 gal * (1 ton/2,000 lb) = 0.00001 tons per year VOC

IEU-76 U2 Emergency Diesel Generator Fuel Storage Tank

This fuel storage tank has a capacity of 350 gallons and supplies the U2 emergency diesel generator. Storage tanks not greater than 1,100 gallons capacity with maximum vapor pressure of 550 mmHg are defined in WAC 173-401-533(2)(b) to be insignificant emission units. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an

effective emission factor of 0.034 lb/1,000 gal was derived for this tank. For annual throughput of 300 gallons, VOC emissions are calculated to be:

300 gal * 0.034 lb/1,000 gal * (1 ton/2,000 lb) = 0.00001 tons per year VOC

IEU-77 Emergency Diesel Fire Pump Fuel Storage Tank

This fuel storage tank has a capacity of 350 gallons and supplies the emergency diesel fire pump. Storage tanks not greater than 1,100 gallons capacity with maximum vapor pressure of 550 mmHg are defined in WAC 173-401-533(2)(b) to be insignificant emission units. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.47 lb/1,000 gal was derived for this tank. For an annual throughput of 150 gallons, VOC emissions are calculated to be:

150 gal * 0.47 lb/1,000 gal * (1 ton/2,000 lb) = 0.00004 tons per year VOC

IEU-78 Limestone Silo

The limestone silo receives limestone shipments from trucks and feeds the ball mill for the FGD system. Particulate matter emissions are controlled by a Flex-Kleen model 30/36-PVBL-9-11 G vent filter (serial number 100770) located on top of the limestone silo. The vent filter has a rated efficiency of 99.9%. The conveyor to the silo has a capacity of 200 tons per hour and the ball mill has a capacity of 41 tons per hour, therefore the unit can operate up to 8,760*(41/200) = 1,796 hours per year. The vent filter fan is rated at 900 cfm. At a maximum emission concentration of 0.005 gr/dscf (typical maximum for material handling silo filters), potential emissions are:

$$\frac{1{,}796\ \text{hours per year}}{\text{year}} * \frac{900\ \text{cubic feet}}{\text{minute}} * \frac{60\ \text{minutes}}{\text{hour}} * \frac{0.005\ \text{grains}}{\text{standard cu ft}} * \frac{1\ \text{pound}}{7{,}000\ \text{grains}} = \frac{69\ \text{pounds}}{\text{year}}$$

Emissions from this discharge point are well below the 0.75 ton PM_{10}/yr threshold of WAC 173-401-530(4)(e) so this unit is considered insignificant.

IEU-79 Lime Silo

The lime silo receives lime shipments from trucks and feeds the FGD system when necessary (e.g. ball mill is inoperable). Particulate matter emissions are controlled by a Flex-Kleen model 30-PVBL-9-11 G vent filter located on top of the limestone silo. The vent filter has a rated efficiency of 99.9%. This unit can receive approximately 25 tons per hour of material from a truck (1 truckload per hour). The vent filter fan is rated at 900 cfm. At a maximum emission concentration of 0.005 gr/dscf (typical maximum for material handling silo filters), potential emissions are:

$$\frac{8{,}760\ \text{hours per year}}{\text{year}} * \frac{900\ \text{cubic feet}}{\text{minute}} * \frac{60\ \text{minutes}}{\text{hour}} * \frac{0.005\ \text{grains}}{\text{standard cu ft}} * \frac{1\ \text{pound}}{7{,}000\ \text{grains}} = \frac{338\ \text{pounds}}{\text{year}}$$

This unit typically operates one hour per day, so typical emissions are far less than 338 pounds per year. Emissions from this discharge point are well below the 0.75 ton PM_{10}/yr threshold of WAC 173-401-530(4)(e) so this unit is considered insignificant.

IV. EXPLANATION OF SELECTED PERMIT PROVISIONS AND GENERAL TERMS AND CONDITIONS

P11. Unavoidable Excess Emissions
[SWCAA 400-107]

SWCAA 400-107 establishes criteria and procedures for determining when excess emissions are considered unavoidable. Emissions that meet the requirements to be classified as unavoidable are still considered excess emissions and are reportable but are excused and not subject to penalty. Notification of excess emissions is required as soon as possible and must occur by the next business day following the excess emissions event. Excess emissions due to startup or shutdown conditions are considered unavoidable if the permittee adequately demonstrates the excess emissions could not have been prevented through careful planning and design. Upset excess emissions are considered unavoidable if the permittee adequately demonstrates the upset event was not caused by poor or inadequate design, operation, maintenance, or other reasonably preventable condition, and the permittee takes appropriate corrective action that minimizes emissions during the event, taking into account the total emissions impact of that corrective action. Additional descriptions of potential excess emissions and how the permittee is expected to respond to those events are provided in requirements M9 and M15 - Startup, Shut Down, and Outage Operation Procedures.

The Utility MACT (Subpart UUUUU) and the Boiler MACT (Subpart DDDDD) are federally standards that can be delegated to state and local agencies and contain specific, and more restrictive, affirmative defense provisions that apply only to malfunctions. For these reasons, SWCAA has concluded that the state and local excess emission provisions cannot apply to these standards.

G2. Chemical Accident Prevention
[40 CFR 68]

Part 68 requires risk management plans be developed for the substances and thresholds listed in 40 CFR 68.130. Chlorine and ammonia are listed substances. The permittee no longer uses chlorine or ammonia on site. The SNCR system utilizes urea rather than ammonia. The permittee uses no other substance listed in 40 CFR 68.130, therefore this standard currently does not apply to this facility.

G11. Portable Sources
[SWCAA 400-036, SWCAA 400-110(6)]

SWCAA 400-110(6) establishes procedures for approving the operation of portable sources of air emissions that locate temporarily at project sites. These requirements are general statewide standards and apply to all portable sources of air contaminants. Common equipment subject to these conditions include emergency generators, engine-powered pumps, rock crushers, concrete batch plants, and hot mix asphalt plants that operate for a short time period at a site to fulfill the needs of a specific contract. Portable sources exempt from registration under SWCAA 400-101 are exempt from SWCAA 400-110 and not subject to

the portable source requirements. Among those categories listed in SWCAA 400-101 that are exempt are operations with potential to emit less than 1 ton per year of all criteria pollutants other than $PM_{2.5}$ and less than 0.5 tons per year of $PM_{2.5}$.

V. EXPLANATION OF OPERATING TERMS AND CONDITIONS

Req. 1-8 General Standards for Maximum Emissions
[SWCAA 400-040, SWCAA 01-2350R4]

SWCAA 400-040 establishes maximum emission standards for various air contaminants. These requirements are general statewide standards and apply to all sources of air contaminants. Therefore, these requirements apply to all emission units at the source, both EU and IEU. Pursuant to WAC 401-530(2)(c), the permit does not contain any testing, monitoring, recordkeeping, or reporting requirements for IEUs except those specifically identified by the underlying requirements. The averaging time for the SO_2 standard of Req-6 is satisfied by 60-minute average values averaged over each clock hour consistent with the monitoring provisions of M8.

No specific monitoring was specified for Req-7 because there are no specific monitoring requirements that can be used to encompass the whole range of potential concealment and masking scenarios. The permittee is required to certify compliance with all terms and conditions of the permit, including these prohibited items, at least annually. The permittee must make a reasonable inquiry to determine if concealment or masking has occurred during the reporting period in order to certify compliance.

Req. 9-10 Emission Standards for Combustion and Incineration Units
[SWCAA 400-050]

SWCAA 400-050 establishes maximum emission standards for selected emissions from combustion and incineration units. These requirements apply to all combustion and incineration units at the source, both EUs and IEUs. Pursuant to WAC 401-530(2)(c), the permit does not contain any testing, monitoring, recordkeeping, or reporting requirements for IEUs except those specifically identified by the requirements as applying to IEUs.

Req. 11 Emission Standards for General Process Units
[SWCAA 400-060]

SWCAA 400-060 establishes maximum particulate matter emission standards for general process units. These requirements apply to all general process units at the source, both EUs and IEUs. Pursuant to WAC 401-530(2)(c), the permit does not contain any testing, monitoring, recordkeeping, or reporting requirements for IEUs except those specifically identified by the requirements as applying to IEUs.

Req. 12 Emission Standards for Certain Source Categories - Abrasive Blasting
[SWCAA 400-070(8)]

SWCAA 400-070 establishes emission standards for seven specific source categories. The requirements of SWCAA 400-070(8) apply due to the potential for infrequent abrasive blasting operations at the plant site. Abrasive blasting is required to be conducted inside a booth or structure designed to capture the blast grit, overspray, and removed material, except for blasting of outdoor structures and items too large to be handled inside an enclosure. Outdoor blasting is to be performed with either steel shot or an abrasive material containing less than 1 percent by mass material that would pass through a No. 200 sieve. Precautions to minimize emissions, such as enclosure of the area being blasted with tarps, are to be used for outdoor blasting.

No specific monitoring was specified for this requirement because there are no specific monitoring requirements that can be used to encompass the whole range of potential blasting scenarios. The permittee is required to certify compliance with all terms and conditions of the permit, including this requirement, at least annually. The permittee must make a reasonable inquiry to determine if prohibited activities have occurred during the reporting period in order to certify compliance.

Req. 13 Opacity Monitoring, and Reporting
[SWCAA 400-105(4)(a)(i) & (4)(c)]

SWCAA 400-105(5)(a) & (5)(c) requires that fossil fuel-fired steam generators of 250 million Btu/hr or greater heat input without sulfur dioxide control equipment install a continuous monitor for opacity, and operate it in accordance with the requirements found in 40 CFR 51, Appendix P and 40 CFR 60, Appendices B - F, as appropriate. This requirement applies to emission units EU-1 and EU-2 only during a scheduled outage of the flue gas desulfurization system and anticipated startups. Anticipated startups exclude startups immediately (less than 12 hours) following a forced outage. This requirement does not establish a visible emission standard with a specified opacity value; Reqs-1 and 15 are the applicable requirements that set a visible emission standard expressed as an opacity value to be achieved. The evaluation method is presented in Appendix A of the Air Operating Permit.

Req. 6, 14, 15, 17 - 20, 23, 24, 27, 35, 39, 40 Regulatory Order to Establish RACT
[SWCAA 97-2057R1]

The Regulatory Order to Establish Reasonably Available Control Technology (RACT) superseded all previous Orders applicable to EU-1 and EU-2.

Following extensive analysis of what constitutes RACT for this source, SWCAA issued Regulatory Order to Establish RACT SWCAA 97-2057 to the Centralia Plant on December 8, 1997 to establish Reasonably Available Control Technology (RACT) emission limits for SO_2, NO_x, PM, and CO emissions from the plant. The Centralia Plant petitioned SWCAA for a modification of the NO_x emission limit, and SWCAA revised the RACT Order as SWCAA 97-2057R1 on February 26, 1998. This Order establishes RACT emission limits for SO_2, NO_x, PM, and CO emissions, restricts the annual consumption of fuel oil by the

auxiliary boiler (EU-3), and supersedes all Orders previously issued to the Centralia Plant (see VI. Explanation of Obsolete and Future Requirements).

Section 3b of SWCAA 97-2057R1 (Requirement 15) establishes opacity limitations for the boiler (EU-2). The permittee operates opacity monitors in the ductwork upstream of the bypass stack. No correlation has been developed to describe the relationship between the opacity indicated by these monitors and the opacity of the FGD exhaust; therefore these monitors cannot be used to determine compliance with this requirement for the FGD exhaust.

Requirement 18 applies during normal operation. Emissions during startups, shutdowns, and outages of the FGD system are addressed by Requirement 19.

Req. 16, 21, 26 Utility MACT Emission Limits
[40 CFR 63 Subpart UUUUU]

The Utility MACT established emission limitations for hazardous air pollutants or their surrogates from coal and oil fired electric utility steam generating units.

For non-Hg HAP metals, sources may comply with an alternative particulate matter (PM) emissions limit as a surrogate. Past source emissions testing at this facility has consistently demonstrated compliance with the Utility MACT PM emission limit by a wide margin and the Utility MACT emission limit is far less stringent than the PM emission limit in RACT Order 97-2057R1, therefore TransAlta has chosen not to utilize the "emissions averaging" provisions and therefore does not need to develop an "emissions averaging plan". The Utility MACT PM emission limit and the PM emission limit in RACT Order 97-2057R1 were listed separately for informational purposes and because of the significant monitoring and recordkeeping requirements tied directly to the Utility MACT.

For HCl and HF emissions, sources may comply with an alternative SO_2 emissions limit as a surrogate. This is the choice TransAlta has chosen for the obvious reason that TransAlta must already operate an SO_2 CEMS to comply with the Acid Rain Program, and SWCAA 97-2051R1. CEMS data for this facility indicates that this facility consistently demonstrates compliance with the Utility MACT SO_2 emission limit by a wide margin, therefore TransAlta has chosen not to utilize the "emissions averaging" provisions and therefore does not need to develop an "emissions averaging plan".

The Hg emission limit in the Utility MACT is more stringent than the Hg emission limit TransAlta complies with under an off-permit agreement with Washington State signed May 2010. To comply with this off-permit agreement, TransAlta installed a Hg CEMS system that was certified to the Clean Air Mercury Rule standards in December 2009. In 2017 TransAlta replaced the CEMS with a sorbent trap monitoring system to demonstrate compliance with the Hg emission limit. A Hg process monitor provides the real-time feedback necessary to allow TranAlta to adjust operation of the Hg control system to assure compliance with the standard. Using the sorbent trap monitoring system, a single concentration value is assigned to each hour in the operating period (40 CFR 60 Subpart UUUUU Appendix A, Section 6.1.2). Concentration data is then converted to units of the emission standard (e.g. lb/TBtu) for each hour in the monitoring period using other CEMS data (e.g. diluent).

TransAlta has chosen not to utilize the "emissions averaging" provisions and therefore does not need to develop an "emissions averaging plan". For the Hg standard, sources must meet a more stringent Hg emission limit under the emissions averaging provisions.

Req. 22 Acid Rain Compliance Plan
[WAC 173-406-400, 40 CFR 72.40(a)]

40 CFR 72.9 and WAC 173-406-106 require that the Centralia Plant hold SO_2 allowances not less than the total annual emissions in tons of SO_2 from the affected units (EU-1, EU-2) at the Centralia Plant. The Centralia Plant received an initial allocation of allowances only for BW21 (EU-1) and BW22 (EU-2). The EPA may reallocate the number of allowances assigned to individual units and between units; therefore, annual allowance allocations may change in the future. The number of allowances actually held by a source in an Acid Rain affected unit account may differ from the number initially allocated by U.S. EPA as allowances are bought and sold on the open market to cover actual emissions.

Req. 27b - 31 Washington Department of Ecology BART Order
[Second Revision of BART Order No. 6426]

The BART Order established NO_X and NH_3 emission limits and associated operating, monitoring, recordkeeping, and reporting requirements for the coal fired boiler. The BART NO_X emission limit of 0.18 lb/MMBtu (30-day rolling average) is expected to be more stringent in all aspects than the previously established RACT permit limit of 0.30 lb/MMBtu (annual average for operation >360 MWt; however the RACT limit in Req-27 was retained for the extremely unlikely scenario where overall NO_X emissions are less than 0.18 lb/MMBtu but NO_X emissions at operations above 360 MW were much higher.

Req. 34 Acid Rain NOx Reduction Early Election for Group 1, Phase II Boilers
[WAC 173-406-106, 40 CFR 76.7(a)(1)]

The Phase II emission limit of 0.40 lb/million Btu was effective January 1, 2008.

Req. 36 Acid Rain Primary Monitoring Provisions
[40 CFR 75.10(a)]

40 CFR 75.10(a)(1) through (3) requires that an Acid Rain affected unit be equipped with continuous emissions monitoring systems with an automated data acquisition and handling system for measuring and recording SO_2, NO_X, and CO_2 emissions, respectively, discharged to the atmosphere. 40 CFR 75.10(a)(4) requires such units to be equipped with a continuous opacity monitoring system with an automated data acquisition and handling system for measuring and recording the opacity of discharged emissions.

Opacity

40 CFR 75.14(b) exempts units utilizing a wet flue gas pollution control system from the opacity monitoring requirements if the owner or operator can demonstrate that condensed water vapor is present in the exhaust stream and would impede the accuracy of opacity measurements. The Centralia Plant has provided ample demonstration that condensed water vapor is present in sufficient quantities to interfere with an opacity monitor and is therefore exempt from the requirement to continuously monitor opacity from the scrubber flues.

The gas stream leaving the scrubbers is saturated with water. As the flue gas inevitably cools, water condenses out of the gas stream forming steam and water droplets. The results of testing conducted during November 2001 (6 runs during scrubber performance test) and December 2001 (9 runs during initial RATA) indicated that the flue gas was supersaturated. Condensed water vapor is clearly visible through the sample ports at the test platform. All subsequent testing has supported this determination.

Gaseous Pollutant Monitoring at Bypass Stack

SWCAA 97-2051R1 requires monitoring of SO_2 emissions from both the bypass and scrubber flues. Acid Rain rules do not require direct monitoring at the bypass stack. This policy was detailed in question "17.6 Revised" from the Acid Rain Policy Manual (December 2000) in addition to the Acid Rain rules promulgated May 1, 2002. Note that "Question 17.6 Revised" is also found as "Question 16.47" in the 2013 version of the Part 75 Emissions Monitoring Policy Manual. The CEMS may be located upstream. When a certified monitoring system is not maintained on the bypass stack, the maximum potential emissions must be reported for bypass hours.

Req. 37 Utility MACT Tune-up Requirements

[40 CFR 63 Subpart UUUUU]

Subpart UUUUU requires initial and periodic tune-ups of the coal-fired boiler. The tune-up requirements are detailed in 40 CFR 63.10021(e) and Table 3 of 40 CFR 63 Subpart UUUUU. At the time this permit is being issued, TransAlta does not utilize neural network combustion optimization software; therefore the tune-up must be conducted every 36 months. In accordance with 40 CFR 63.10021(e) the initial inspection of the burners may be delayed beyond the October 13, 2015 compliance date and until the next "scheduled outage" if an outage is not scheduled before the compliance date. EPA describes this "scheduled outage" as a "major outage" in comment responses during rule development where there were comment regarding the long period of time necessary to erect scaffolding in the boiler. It is SWCAA's understanding that a short-term economic outage or an outage planned with little lead-time (for example to effect repairs) is not the type of "scheduled outage" discussed by this section of the rule. For the purposes of this requirement, SWCAA believes that a "scheduled outage" is a boiler outage where the boiler will be offline for a significant amount of time (e.g. weeks or months), and would usually be associated with planned inspections, major maintenance and/or repairs of the boiler interior.

Req. 38 Utility MACT Startup and Shutdown Provisions
[40 CFR 63 Subpart UUUUU]

Subpart UUUUU requires that all startups be conducted on "clean fuels". During startup and shutdown the facility typically uses ultra-low sulfur diesel, which is included in the definition of "clean fuels". In accordance with 40 CFR 63.10011(f) the facility must determine the "cleanest fuel" available on-site or accessible nearby for use during periods of startup or shutdown. However, the facility is required to utilize a "clean fuel", but not necessarily the "cleanest fuel" identified in 40 CFR 63.10011(f). See Response to Comment 67 in EPA's November 2014 Summary of Public Comments and Responses to the startup and shutdown reconsideration of 40 CFR 63 Subpart UUUUU.

The permittee is not precluded from considering a capital project to add natural gas firing capability. However New Source Review would be required before installing natural gas firing capability.

In the interests of streamlining the permit, the portions of the cited regulations that reference recordkeeping and reporting requirements were considered informational and not included in the permit requirement. All applicable recordkeeping and reporting requirements are included elsewhere in the permit.

Table 3 of Subpart UUUUU provides compliance options for two different definitions of "startup". The permittee is not committed to use either one. In option one, the ESPs and flue gas desulfurization (FGD) system must be engaged once coal is fired.

In option two, additional records must be generated and kept, clean fuels must be fired to the maximum extent possible during the startup period, the particulate control devices must be engaged within 1 hour of firing coal, and the Subpart UUUUU emission limits apply within 4 hours of producing electricity for any purpose. The FGD systems are not designed as PM control devices and are not necessary to meet PM emission limits; therefore, only the ESPs must be engaged within 1 hour of firing coal. SWCAA understands that operation of the FGD systems too early in the startup process when oil is being fired, and when PM levels have not been sufficiently reduced, is detrimental to both the short-term and long-term performance of the FGD system and would likely cause an increase in overall acid gas emissions. The US EPA provided some clarification of the startup requirements in an e-mail message dated August 13, 2015.

For Option 2, the end of "startup" was defined as ending when the EGU generates electricity that is sold or used for any other purpose (including on site use), or 4 hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (16 U.S.C. 796(18)(A) and 18 CFR 292.202(c)), whichever is earlier. The end of the startup period must be known to determine when "clean fuels" (ultra-low sulfur diesel in this case) no longer need to be fired to the "maximum extent possible". Based on the intent of the section and SWCAA's conversations with EPA staff, SWCAA believes that the end of startup could be much earlier (i.e. when all of the applicable pollution control devices have been engaged). At that point there is no need to continue firing "clean fuels" for the purpose of minimizing emissions and the facility should be able to achieve compliance with all applicable emission limits.

With respect to firing clean fuel to the "maximum extent possible", SWCAA understands this requirement to impose a duty to fire as much clean fuel as necessary to enable the applicable emission control equipment to be engaged as soon as possible, but no later than 1 hour after, coal is fired.

Req. 39 Good Air Pollution Control Practices
[40 CFR 63.9991(c)(2), 63.1000(b), SWCAA 97-2057R1]

This requirement as it originates from SWCAA 97-2057R1 is meant to require reasonable practices to reduce emissions below the short-term emission limits provided in SWCAA 97-2057R1 when possible, and optimize use of the emission control equipment. The following paragraphs describe good air pollution control practices for minimization of SO_2, NO_x, and PM emissions from the coal-fired boiler for compliance with the requirements from SWCAA 97-2057R1.

Sulfur Dioxide
The SO_2 emission control equipment is the Flue Gas Desulfurization (FGD) system or scrubber. Good air pollution control practice is to utilize recycle pumps as necessary to maintain SO_2 as low as practicable without allowing the SO_2 CEMS indication to drop to or below zero (below zero indications are possible due to minor instrument drift). A small amount of SO_2 must be maintained in the flue gas to assure that the gypsum that is produced is of marketable quality for manufacturing, and to prevent degradation or damage to the desulfurization system from scaling. If all SO_2 in the flue gas is reacted, the residual limestone can, in a short time period, cause scaling in the reaction vessel leading to reduced scrubbing efficiency and mechanical failure.

The original design specifications for the scrubber specify that three of the four recycle pumps would be in operation at any one time. The fourth recycle pump would be maintained as a maintenance spare and backup. The specification was based on the use of high sulfur coal from the Centralia Mine. When the plant is using low sulfur coal from the Powder River Basin, SO_2 can be maintained at a minimum level with the use of less than three recycle pumps.

In addition to maintaining minimum SO_2 levels, at times it may not be possible to operate the design number of recycle pumps and spray levels due to operational problems including when:

1. Equipment problems require two pumps off-line for maintenance or repair activities; and
2. Equipment problems downstream of the scrubber (e.g. vacuum belt filter malfunctions, problems with reaction tank oxidation blowers) or upstream of the scrubber (e.g. reagent pump or ball mill failures) limit reagent addition or gypsum removal.

Such events should be reported as an upset condition and will be reviewed on an individual basis.

Nitrogen Oxides

The NO_X emissions control system is good boiler combustion practices, low NO_X burner modifications on the boiler, and the SNCR system. NO_X control through good combustion practices is significantly different than add-on SO_2 control. This form of NO_X control is an integral part of the combustion process. If the boiler is operated to minimize NO_X emissions, combustion efficiency decreases to the point of limiting electrical power output, increases coal combustion/megawatt which increases emissions of other pollutants (SO_2, PM, CO and VOCs) and increases slagging, sootblowing and maintenance costs from increased boiler tube repairs. Based on current information, good air pollution control practice for NO_X is balancing the varied factors and maintaining emissions below the RACT and BART limitations.

Particulate Matter

The particulate matter (PM) emissions control systems are the two tandem electrostatic precipitators in series. In addition, the FGD system removes additional PM through the scrubbing process. Maintaining good precipitator performance is important in order to maintain the quality of the gypsum by-product necessary for sale for use in wallboard.

Req. 41, 42 Boiler MACT Requirements for Auxiliary Boiler

[40 CFR 63 Subpart DDDDD]

Boilers in the "limited use" subcategory are those boilers with a federally enforceable annual average capacity factor of no more than 10 percent. The Auxiliary Boiler (EU-3) is a startup boiler; therefore, a low capacity utilization would be expected. Section 45 of SWCAA 97-2057R1 expressly limited the total amount of fuel this boiler can fire to 600,000 gallons per year. The boiler has a rated heat input capacity of 170 MMBtu/hr. Assuming a fuel oil heat input capacity of 138,000 Btu/gallon (from 40 CFR 98), the 600,000 gallon per year limitation is equivalent to a capacity factor of approximately 5.6%. Both the 600,000 gallon per year limitation and the 10 percent capacity factor threshold are on a calendar year basis. Boilers in the "limited use" subcategory are subject to the general requirement to operate consistent with good air pollution control practices and the requirement to conduct initial and periodic tune-ups rather than specific emission limits.

Req. 43 Pug Mill Opacity

[SWCAA 01-2403]

This requirement represents BACT for control of fugitive particulate matter from this source at the time of permitting (2001). The only potential point of emissions from this source is fugitive during the transfer to trucks. The pug mill mixing function is conducted through the use of the two UCC Model 6050 Pin Paddle Mixers installed in 2009.

Req. 44 Turbine Lube Oil Mist Eliminators Opacity

[SWCAA 01-2403]

This requirement represents BACT for control of visible emissions/lube oil mist from this source at the time of permitting (2001). The manufacturer literature for the Advanced Environmental Systems mist eliminator guarantees opacity levels of 5% or less. On-site observations have demonstrated that visible emissions from this source do not exceed 5%. Using the conservative assumption of a 99.5% control efficiency (provided by Advanced

Environmental Systems on a particle count basis), and 8,760 hours of operation per year, each turbine lube oil mist eliminator will emit up to 0.1 pounds of lube oil mist per year.

Req. 45 - 47 Control of Particulate Matter from Coal Unloading
[SWCAA 11-2972]

The requirements in Air Discharge Permit SWCAA 11-2972 represent BACT for control of particulate matter (coal dust) from the unloading of coal from rail cars at this facility.

Annual emissions of PM_{10} from the Coal Unloading Facility are to be calculated using the following equation (found in Section 6 of the Technical Support Document for Air Discharge Permit 11-2972) for each transfer point:

$$E = k(0.0032)\frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}$$

Where: E = emission factor (lbs PM per ton coal unloaded)
k = particle size multiplier (dimensionless). k = 1.0 for PM, 0.35 for PM_{10}, 0.11 for $PM_{2.5}$
U = mean wind speed (miles per hour)
M = coal moisture content (%)

A control factor of 90% is applied to transfer points utilizing high pressure wet suppression to control fugitive dust (some pre-existing transfer points may be uncontrolled).

Req. 48, 49 Control of Particulate Matter from FGD Bleed Treatment Lime Storage Silo
[SWCAA 05-2636]

Air Discharge Permit SWCAA 05-2636 was written in response to an Air Discharge Permit (ADP) application for installation of a new hydrated lime storage silo. This silo was installed as part of a project to remove boron and zinc from the flue gas desulfurization (FGD) system scrubbing liquor. These requirements represent BACT for control of particulate matter (hydrated lime) from the pneumatic loading of hydrated lime into the silo.

Req. 50, 51 Control of Particulate Matter from Journal Shop
[SWCAA 08-2779]

Air Discharge Permit SWCAA 08-2779 was written in response to an Air Discharge Permit (ADP) application for installation of a larger capacity cartridge filtration system to control welding fumes exhausted from the Journal Shop. The purpose of the project was to reduce worker exposure to welding fumes. The requirements in Air Discharge Permit were written to implement BACT and protect ambient air quality.

Req. 52 - 58 Engine Requirements Originating from 40 CFR 63 Subpart ZZZZ
[40 CFR 63 Subpart ZZZZ]

40 CFR 63 Subpart *ZZZZ* established emission limitations and operating requirements for various categories of reciprocating engines. The engines at the coal plant fall into two categories of engines regulated by Subpart *ZZZZ*. All of the applicable requirements for these engines have been included in the Air Operating Permit.

One requirement requires that engines be maintained "according to the manufacturer's emission-related written instructions or develop a maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions." The permittee submitted a maintenance plan for their "existing" stationary diesel engines to SWCAA on August 8, 2011. The portions of the maintenance plan relevant to engine emissions are included in Appendix C and are applicable requirements as described in Req-54.

For the purposes of this requirement, emergency operation of the fire pump is any operation necessary in response to a fire.

Req. 55, 57, 58, 61, 62, 65 Engine Requirements Originating from 40 CFR 60 Subpart IIII
[40 CFR 63 Subpart IIII]

40 CFR 63 Subpart IIII established emission limitations and operating requirements for various categories of "new" reciprocating engines. Where the requirements under Subpart IIII are the same as for 40 CFR 63 Subpart *ZZZZ*, the terms have been streamlined and applied to groups of engines. All of the applicable requirements for these engines have been included in the Air Operating Permit.

Req. 59 - 65 Requirements for the Coal Unloading Facility Emergency Diesel Sump Pump Engine
[40 CFR 63 Subpart *ZZZZ*, 40 CFR 60 Subpart IIII, and SWCAA 11-2972]

The Coal Unloading Facility Emergency Diesel Sump Pump Engine was installed as a "new" engine for the purposes of 40 CFR Subpart *ZZZZ*, therefore the engine is required to comply with Subpart *ZZZZ* by meeting the requirements of 40 CFR 60 Subpart IIII. The engine underwent New Source Review, resulting in the issuance of Air Discharge Permit 11-2972. Air Discharge Permit 11-2972 contained all of the applicable requirements from 40 CFR 60 Subpart IIII and additional requirements originating from SWCAA's general regulations and the minor New Source Review process.

In a June 28, 2011 amendment to 40 CFR 60 Subpart IIII, EPA changed section 60.4211(a) to allow owners/operators of stationary engines to deviate from manufacturer's written emissions-related instructions if they complied with additional recordkeeping and conducted an initial source test to demonstrate compliance with the applicable emission standards. These alternative requirements are included in section 60.4211(g). This compliance option is not detailed in the permit because the permittee has indicated that they will follow the manufacturer's written instructions.

For the purposes of this requirement, emergency operation is any operation necessary because the electrical water pump at the Coal Unloading Facility has unexpectedly failed. If the electrical water pump fails, it must be repaired as soon as practical. Operation of the Coal Unloading Facility Diesel Sump Pump Engine because the electrical water pump was not repaired as soon as practicable, would not be considered emergency operation.

Compliance with the annual emission limits for the Engine in Condition 5 of SWCAA 11-2972 is to be determined by multiplying the hours of operation by the emission factors presented in the Technical Support Document for SWCAA 11-2972 unless new emission factors are provided by the manufacturer or developed through source testing.

Req. 66 - 71 Requirements for Fire Pump Engine and Emergency Diesel Generator 2
[SWCAA 16-3188]

The requirements for these two engines appear together in many places because they are both subject to 40 CFR 60 Subpart IIII and are regulated by Air Discharge Permit 16-3188. Compliance with the annual emission limits for the Fire Pump Engine must be determined by multiplying the hours of operation by the emission factors presented in the Technical Support Document for SWCAA 16-3188 unless new emission factors are provided by the manufacturer or developed through source testing. These emission factors are listed in the explanation of M27

Req. 72 – 76 Requirements for the Material Handling Systems Associated with the Mercury Control System and Fly Ash Bins
[SWCAA 11-2984]

Air Discharge Permit 11-2984 was written to approve material handling modifications necessary to implement an activated carbon injection (ACI) mercury control system on the two coal-fired boilers (one of which retired at the end of 2020). The fly ash bin baghouse exhausts are subject to the Compliance Assurance Monitoring (CAM) requirements of 40 CFR 64, and each utilize a baghouse leak detection monitor. This monitoring (along with periodic source emissions testing) is expected to provide an adequate assurance of compliance with the permitted emission limits.

Compliance with the annual emission limits in Condition 1 of SWCAA 11-2984 is to be determined by multiplying the hours of operation by the design flow rate and an emission concentration of 0.005 gr/dscf unless new emission factors are developed through source testing

Filter	Rated Flow
SEA System 1	1,130
SEA System 2	1,130
Sorbent Silo 1	350
Sorbent Silo 2	350
Fly Ash Bin 11	14,730
Fly Ash Bin 12	14,730
Fly Ash Bin 14	14,730
Fly Ash Bin 14 Air Slide to Bin 11 Air Slide	900

Filter	Rated Flow
Fly Ash Bin 11 to Weigh Hopper Air Slide	900
Fly Ash Bin 14 to 6050 Air Slide	600

Condition 3 of SWCAA 11-2984 requires that each emission unit be operated properly. It will be presumed that the equipment is being operated properly unless otherwise indicated by an inspection or excess emissions. In that case, equipment operating manuals and maintenance records may be reviewed to determine if the equipment is being improperly operated or maintained.

Req. 77 – 81 Requirements for the Fly Ash Weigh Bin
[SWCAA 12-3016]

Air Discharge Permit 12-3016 was written to approve a new baghouse for the Fly Ash Weigh Bin to replace the existing baghouse on the fly ash weigh bin (operated by Lafarge North America at the time of permitting), and the relatively new "Fly Ash Bin 11 to Weight Hopper Air Slide Filter" (operated by TransAlta). The replacement baghouse filters dust from air collected from the fly ash loading spout and air vented to the fly ash bin from the No. 11 Air Slide and the No. 12 Air Slide.

Compliance with the annual emission limits in Condition 1 of SWCAA 12-3016 is to be determined by multiplying the hours of operation by the design flow rate and an emission concentration of 0.002 gr/dscf until or unless new emission factors are developed through source testing.

Req. 82 – 88 Requirements for Fine Coal Handling
[SWCAA 14-3093]

Air Discharge Permit 14-3093 was written to approve coal mine waste reprocessing activities and fine coal recovery. Only fine coal handling will occur at TransAlta Centralia Generation.

Annual emissions of particulate matter from the transfer of fine coal onto the coal stockpile are to be calculated using the following equation (found in Section 6 of the Technical Support Document for Air Discharge Permit 14-3093) for each transfer point:

$$E = k(0.0032)\frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}$$

Where: E = emission factor (lbs PM per ton coal unloaded)
k = particle size multiplier (dimensionless). k=1.0 for PM, 0.35 for PM_{10}, 0.11 for $PM_{2.5}$
U = mean wind speed (miles per hour)
M = coal moisture content (%)

Meteorological data indicates that the mean wind speed at this site is 4 miles per hour. It was assumed that wet suppression will provide for 90% control of fugitive dust emissions. There is only one transfer point that is not fully enclosed (transfer to the TransAlta Generation stockpile). The transfer to the TransAlta Generation stockpile will be equipped with high-pressure wet suppression that will be used if visible emissions are observed. It is expected that the fine coal moisture will be too high to generate significant dust.

Req. 88 – 92, 95, 96 Minor New Source Review Permit and Subpart *ZZZZ* Requirements for Black Stop Generator Operation

Requirements removed – the Black Stop Generator Engine was permanently retired at the end of 2020.

Req. 93, 94 PSD Permit for Combustion Turbine Facility (Black Stop Diesel Generator Engine)

Requirements removed – the Black Stop Generator Engine was permanently retired at the end of 2020.

VI. EXPLANATION OF OBSOLETE AND FUTURE REQUIREMENTS

1. Obsolete Regulatory Orders/Permits

SWCAA issued eight Orders and Air Discharge Permits to the permittee between 1972 and 1974 in response to a particulate matter control equipment testing program and Air Discharge Permit applications submitted for installation or modification of such equipment and for operations at the source. Seven Orders were issued to the permittee between 1987 and 1991 regarding the averaging period for the SWCAA SO_2 emission standard and a variance request by the source. These seven Orders are no longer applicable as described below. From 1995 through early 1998, three Regulatory Orders concerning Reasonably Available Control Technology (RACT) requirements were issued to the permittee, two of which are no longer applicable as described below.

A SWCAA Order dated December 11, 1972 required the PM emission level of 0.06 gr/dscf not to be exceeded at any time, and also established maximum operating levels during compliance testing of both units. An Order dated April 13, 1973 approved installation of additional ESP collection area and required that additional sections be designed and installed to control emissions to 0.06 gr/dscf. A SWCAA Order dated April 26, 1973 specified objectives of a particulate matter emission testing program, allowed operation at maximum output during a specified test schedule for Unit 1, and reiterated the 0.06 gr/dscf emission limit in the December 11, 1972 Order. An Order dated May 4, 1973 approved operation of Unit 2 at maximum output during a scheduled particulate matter emissions test and listed the objectives of the test program. A May 22, 1973 Order extended the test schedule for Unit 2. A SWCAA Order dated June 11, 1973 approved full output operation of Unit 1, and, not to be exceeded at any time, the particulate matter emission level of 0.06 gr/dscf.

These Orders were effectively replaced by a subsequent SWCAA Order (dated February 7, 1974 and revised on February 22, 1974) that approved installation of the Lodge-Cottrell ESPs in series following the original ESPs on both Units 1 and 2. This February 1974 Order approved continued operation at an emission level not to exceed 0.06 gr/dscf and required

demonstration of satisfactory equipment performance within three months after startup of the new ESPs. Administrative Order 74-38 established a high-load testing schedule for Unit 2 not to exceed ten days commencing May 6, 1974. Although these Orders were not explicitly superseded until SWCAA 97-2057R1 was issued, the Orders dealing only with the testing program to improve and evaluate particulate matter collection became moot with the approval and subsequent performance demonstration of the Lodge-Cottrell ESPs.

The Centralia Plant disagreed with SWCAA's authority to establish via the February 1974 Order an emission limit more stringent than the state standard for particulate matter, 0.1 gr/dscf. SWCAA established the 0.06 gr/dscf emission limit consistent with "advances in the art" (the term that predates BACT) to not allow degradation of the control equipment and ensure meaningful emission reductions as intended under the Clean Air Act. Although all previous Orders have been superseded by Section 49 of SWCAA 97-2057R1, the 0.06 gr/dscf emission limit based on "advances in the art" was effective until the RACT limit of 0.010 gr/dscf become the applicable requirement for particulate matter emissions after December 31, 2001.

Order of Violation SWCAA 87-934 was issued for violations of the 1,000 ppm SO_2 emission limit based on average daily coal sulfur analyses, and required the permittee to implement coal analysis at twenty minute intervals, perform sampling of SO_2 emissions, and correlate the sampling results with the coal analyses. The Order suspended a civil penalty provided that no additional violations of the SO_2 emission standard occurred for one year. Stay of Order of Violation SWCAA 87-934-STAY stayed for up to 18 months from September 21, 1987 the requirements in SWCAA 87-934 for coal analysis and SO_2 emission sampling, and the civil penalty.

Order, Withdrawal of Stay, and Modification of Order of Violation SWCAA 88-934 required the Centralia Plant to install continuous SO_2 and O_2 emissions monitors, install ambient air quality monitors at three sites near the facility, blend and wash the coal supplied to its boilers, conduct a feasibility study of lime injection multiple burner technology to reduce SO_2 emissions, and comply with the SO_2 emission limit of 1,000 ppm averaged over a one week period. This Order, issued on February 24, 1988, withdrew the coal analysis and SO_2 emission sampling provisions and the civil penalty assessed by SWCAA 87-934. SWCAA 88-934 was amended by Variance and Modification of Order SWCAA 88-934B which granted a variance from the 1-hour averaging period of the SO_2 emission standard and established a weekly averaging period effective May 25, 1988 through November 25, 1989. SWCAA 88-934B required measured SO_2 emissions to be corrected to a dry basis, installation of meteorological monitoring equipment to be operated from October 1, 1988 through September 30, 1989, modeling of SO_2 emissions by an EPA approved dispersion model, and other minor modifications to 88-934.

SWCAA 88-934C Variance Renewal and Modification of Order extended the variance for weekly instead of hourly averaging of SO_2 emissions until November 25, 1990, extended the collection of ambient monitoring data through September 30, 1990, and modified the ambient air monitoring provision to require two rather than three sites. SWCAA 90-934D Variance Renewal and Modification of Order extended the variance for weekly instead of hourly averaging of SO_2 emissions until the earlier of November 25, 1991 or the date on which practicable means for the adequate abatement or control of SO_2 emissions from the Centralia

Plant become known, available, and implementable. The Order required that collection of ambient meteorological monitoring data extend through September 30, 1991, and that the permittee report to SWCAA the results of its dispersion modeling by December 31, 1991. Effective on April 5, 1991, SWCAA 90-934E Withdrawal of Petition, Surrender of Variance, and Order terminated the variance, meteorological monitoring, ambient monitoring, dispersion modeling, and modeling report provisions of SWCAA 90-934D and 88-934.

SWCAA 90-934E Withdrawal of Petition, Surrender of Variance, and Order (issued on April 5, 1991) revoked an earlier Variance and restored compliance with the SO_2 standard over a 1-hour averaging period. It also established a procedure for determining compliance with the hourly SO_2 standard which defined an "excess SO_2 emission day" as 3 or more unique excess SO_2 emission hours during any continuous 24-hour period in the month, and an "SO_2 emission violation" as 3 or more unique excess SO_2 emission days occurring in a calendar month. SWCAA 97-2057R1 supersedes Order No. SWCAA 90-934E along with its SO_2 compliance procedure.

Regulatory Order to Establish RACT SWCAA 95-1787 established a plant-wide annual average emission rate limit and total tonnage limit for SO_2 and specified compliance dates for achieving these emission limits. This Order was appealed by a third party to the Pollution Control Hearings Board (PCHB). SWCAA issued Order of Withdrawal SWCAA 96-1872 to withdraw SWCAA 95-1787 while pursuing additional SO_2 emission reductions through a collaborative process. However, the PCHB ruled SWCAA 96-1872 was an amendment to the original RACT Order, and therefore the RACT Order (95-1787) was still in effect. The SWCAA Board then approved Resolution 1996-8 on September 18, 1996 which withdrew both SWCAA 95-1787 and 96-1872, a decision later upheld by the PCHB.

An EPA Order on Consent was issued on May 18, 2001 to allow the permittee to commence construction of the Combustion Turbine Facility prior to issuance of a PSD permit. This order became obsolete upon issuance of PSD permit No. PSD-01-01.

PSD-01-01 was issued on February 22, 2002 for construction of the Combustion Turbine Facility. This PSD permit dealt only with those PSD pollutants with emissions at or above the PSD significance threshold (PM and NO_X). SWCAA Air Discharge Permit 01-2350 was issued on May 30, 2001 to address emissions of all other pollutants. Air Discharge Permit 01-2350 was superseded by Air Discharge Permit SWCAA 01-2350R1, issued on May 6, 2002. Air Discharge Permit SWCAA 01-2350R1 was written in response to an Air Discharge Permit application requesting an increase in the combustion turbine facility's sulfur oxides emission limits.

The permittee became aware on July 12, 2002 that the auxiliary boiler that was ultimately installed at the Combustion Turbine Facility was not the one approved by PSD-01-01 or Air Discharge Permit SWCAA 01-2350R1. PSD-01-01 and Air Discharge Permit SWCAA 01-2350R1 approved the 4.18 MMBtu/hr Cleaver-Brooks boiler specified in the Notice of Construction (NOC) applications for those permits. The permittee notified SWCAA of this fact on the next business day (July 15, 2002).

On July 22, 2002 SWCAA issued Consent Order SWCAA 02-2422 to address the issue. The consent order was signed by Ms. Linda Chambers for TransAlta Centralia Generation,

LLC on July 24, 2002. This consent Order became obsolete with the submittal of a Notice of Construction L-505 on August 15, 2002 (submittal of this notice satisfied the last requirement in the consent order).

PSD-01-01 was superseded by PSD-01-01 Amendment 1 on January 30, 2003. The permit amendment was made to approve the existing BHP Auxiliary Boiler.

Air Discharge Permit 01-2350R1 was superseded by Air Discharge Permit 01-2350R2 on October 15, 2003. Air Discharge Permit 01-2350R2 was written in response to Air Discharge Permit application L-505 for approval of the existing BHP Auxiliary Boiler.

PSD-01-01 Amendment 1 was superseded by PSD-01-01 Amendment 2 on June 11, 2004. The permit amendment was made to clarify the RATA frequency requirements.

Air Discharge Permit 01-2350R2 was superseded by Air Discharge Permit 01-2350R3 on May 12, 2005. Air Discharge Permit 01-2350R3 was written to make the source testing and RATA frequencies in the minor source permit consistent with the RATA frequencies in PSD-01-01 and the Acid Rain Program rules.

Air Discharge Permit 05-2612 was issued on July 15, 2005 for the addition of a coal unloading hopper to the West Coal Unloading Facility. Air Discharge Permit 05-2612 was superseded by Air Discharge Permit 07-2712 on February 7, 2007. Air Discharge Permit 07-2712 was written in response to a request for installation of surge capacity to the West Coal Unloading Facility. Air Discharge Permit 07-2712 was superseded by Air Discharge Permit 07-2749 on September 26, 2007. Air Discharge Permit 07-2749 was written in response to a request for modification of the West Coal Unloading Facility operating limitations and installation of the Coal Unloading Facility. Air Discharge Permit 07-2749 was superseded by Air Discharge Permit 11-2972 on April 14, 2011. Air Discharge Permit 11-2972 was written in response to a request to install a diesel-fired emergency water pump at the Coal Unloading Facility.

Air Discharge Permit 01-2350R3 was superseded by Air Discharge Permit 01-2350R4 on January 18, 2008. Air Discharge Permit SWCAA 01-2350R4 was written in response to an ADP application submitted by the permittee to eliminate the 1.5 ppmvd @ 15% O_2 (8-hour average) CO emission limit (BACT was re-evaluated) for the combustion turbines. The 3.0 ppmvd @ 15% O_2 (1-hour average) was retained.

Best Available Retrofit Technology (BART) Order No. 6426 was issued June 18, 2010 by the Washington Department of Ecology as implementation of Washington's visibility program (WAC 173-400-151) which is implemented consistent with the federal visibility protection program (40 CFR Part 51, Subpart P). Order No. 6426 established a NO_X emission limit of 0.24 lb/MMBtu for the coal fired boilers and a minimum coal quality requirements. EPA approved the SIP submission containing this BART submission in a Federal Register notice dated December 6, 2012.

BART Order No. 6426 was superseded by the First Revision of BART Order No. 6426 issued December 13, 2011. The First Revision of BART Order No. 6426 was issued to implement new requirements from a 2011 law (Washington Engrossed Second Substitute Senate Bill 5769). Under this law the Governor is required to enter in a "memorandum of agreement" with the plant owner on behalf of Washington State to install and operate selective non-catalytic reduction (SNCR) to provide additional control of NO_x emissions no later than January 1, 2013. The Memorandum of Agreement was finalized December 23, 2011. The law also requires one boiler to comply with the greenhouse gas emission performance standard in RCW 80.80 by December 31, 2020 and the second boiler by December 31, 2025. These requirements were included in the First Revision of BART Order No. 6426. Approval of this revision into the Washington SIP was published in the Federal Register on December 6, 2012.

The First Revision of BART Order No. 6426 was superseded by the Second Revision of BART Order No. 6426 issued July 29, 2020. This revision was made to address problems with, and caused by, the SNCR system. The revision reduced the NO_x limit for the longer-lived unit from 0.21 lb/MMBtu to 0.18 lb/MMBtu while removing the prescriptive SNCR operating requirements. Approval of this revision into the Washington SIP was published in the Federal Register on May 7, 2021.

Air Discharge Permit 11-2996 was issued November 11, 2011 for installation and operation of the Pump-05 Engine. Air Discharge Permit 11-2996 was superseded on October 18, 2012 by Air Discharge Permit 12-3035. Air Discharge Permit 12-3035 was issued for installation of a new fire pump engine that may also be used to supply non-emergency water pumping during plant maintenance events. The permit conditions related to the engines addressed in Air Discharge Permit 11-2996 were carried forward in Air Discharge Permit 12-3035.

Air Discharge Permit 12-3035 was superseded by Air Discharge Permit 16-3188 on June 1, 2016. Air Discharge Permit 16-3188 was written for approval of a nonroad engine and an emergency generator engine to replace the Emergency Diesel Generator 2 engine.

2. Initial Testing Requirements for Limestone Ball Mill

The initial testing requirements of 40 CFR 60.18 for the Limestone Ball Mill (consisting of opacity observations as specified in 40 CFR 60 Subpart OOO) were completed on October 24, 2007.

3. Acid Rain Requirements

The general Acid Rain recordkeeping provisions of 40 CFR 75.50 are no longer valid as of January 1, 1996, and are replaced by the general recordkeeping provisions of 40 CFR 75.54. The Acid Rain Program provided an optional set of recordkeeping requirements with only slightly different provisions prior to January 1, 1996, but disallows their use from January 1996 onward.

4. Future NSPS/MACT/NESHAP Standards

None

5. Future Coal-Fired Boiler Shutdown Requirements

Condition 3 of the Second Revision of Bart Order No. 6426 requires that one coal-fired unit permanently cease burning coal no later than December 31, 2020, and the second permanently cease burning coal no later than December 31, 2025. These requirements would not apply if the Department of Ecology determines as a requirement of state or federal law or regulation that selective catalytic reduction (SCR) technology must be installed on either coal fired boiler. This requirement implements requirements in RCW 80.80 as amended in 2011. RCW 80.80 requires that the coal fired boilers meet a greenhouse gas performance standard that is the lower of 1,100 lbs/MW-hr or the average available greenhouse gas emissions output as determined under RCW 80.80.050. The output determined under RCW 80.80.050 is published by the Washington Department of Commerce in WAC 194-26 and was 925 lbs/MW-hr effective April 6, 2013. These standards cannot be met by these boilers without the addition of CO_2 capture equipment or shutdown.

VII. EXPLANATION OF MONITORING AND RECORDKEEEPING TERMS AND CONDITIONS

M1. General Recordkeeping

This recordkeeping section is taken directly from SWCAA 97-2057R2 Sections 26 and 29, SWCAA 05-2636, SWCAA 08-2779, SWCAA 11-2072, SWCAA 14-3093, and WAC 173-401-615(2). Sections (a) through (d) were added to clarify specific requirements. Under K1(c)(i) of the permit "equipment out of service" is limited to SO_2 emission control equipment, and "upset conditions" are limited to pollution control equipment or equipment that would directly impact SO_2 emissions.

M2. Visible Emission Monitoring

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the general requirements drawn from SWCAA 400 and the specific requirements drawn from SWCAA 97-2057R1, SWCAA 01-2403, and SWCAA 14-3093. The general requirements in SWCAA 400 do not directly establish any specific regime of monitoring or recordkeeping. Consequently, SWCAA has implemented monitoring and recordkeeping requirements under the "gap filling" provisions of WAC 173-401-615 where no other monitoring is required by an applicable requirement. M1 is designed to provide periodic assurance of compliance and record any necessary corrective action. This requirement pertains to the visual technique for evaluating visible emissions, not the continuous monitor method. Demonstration of compliance is required in some cases via visible emissions evaluation. An individual educated in the procedures of visible emission observation and evaluation is to perform the periodic compliance assurance monitoring. A Certified Observer, certified in accordance with EPA Method 9, is to perform the visible emission observations based on the method in Appendix A of the Air Operating Permit

M13. Particulate Matter Emissions Monitoring

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the general requirements drawn from SWCAA 400 and specific requirements drawn from SWCAA 05-2636, SWCAA 11-2972, SWCAA 12-3016, and SWCAA 14-3093. A particulate matter exhaust standard of 0.1 gr/dscf applies to both combustion and non-combustion emission units. These requirements do not directly establish any specific regime of monitoring or recordkeeping. Consequently, SWCAA has implemented monitoring and recordkeeping requirements under the "gap filling" provisions of WAC 173-401-615 where no other monitoring is required by an applicable requirement. M2 is designed to assure compliance through periodic facility inspections and prompt corrective action within 2 hours of observing particulate matter fallout or excess visible emissions whenever necessary. The permittee is required to resolve the particulate matter fallout or excess emissions problem within 24 hours of initial discovery, or notify SWCAA by the next working day of progress made towards resolution. Excess emissions are emissions above the state standard or permit limit. The site inspection and visual observation are surrogate methods for assessing the relative emissions from non-combustion emission units EU-4, EU-5, and EU-6 that have demonstrated emissions well below the general standards.

Both Coal Plant units (EU-1 and EU-2) are equipped with electrostatic precipitators that remove over 99.5% of the particulate matter from coal combustion leaving emission concentrations less than one-tenth of the standard in Req-9. Combustion of fuel oil in the auxiliary boiler (EU-3) does not produce emission concentrations near this standard either. Monitoring for the standards in Reqs-9 and 11 makes use of observations that will readily indicate if control equipment or material handling management practices are seriously deficient. The site inspection and visual observation are surrogate methods for assessing the relative emissions from emission units EU-1, EU-2, and EU-3 that have demonstrated emissions well below the general standards.

Condition 8 of Air Discharge Permit SWCAA 11-2972 requires that the water pressure of the spray/fog nozzles be maintained at 80 psig or greater during operation of the coal unloading facility, however no monitoring of the water pressure was required (although a visual inspection is required monthly). Consequently, SWCAA has implemented monitoring and recordkeeping requirements under the "gap filling" provisions of WAC 173-401-615 that require the spray pressure to be measured during the monthly inspection and recorded in accordance with Section VIII K.1(a).

M14. Fugitive Emissions Monitoring

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the general requirements drawn from SWCAA 400 and the specific requirement from SWCAA 01-2403 to control fugitive dust from operation of the fly ash pugmill. SWCAA 400 does not directly establish any specific regime of monitoring or recordkeeping for these standards. Consequently, SWCAA has implemented monitoring and recordkeeping requirements under the "gap filling" provisions of WAC 173-401-615 for those general requirements. M3 is designed to assure compliance through a combination of periodic facility inspections, use of

reasonable precautions and good work practices, and prompt corrective action whenever necessary.

M5. Complaint Monitoring

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the general requirements drawn from SWCAA 400 and specific requirements in SWCAA 01-2350R4, SWCAA 11-2972, SWCAA 12-3016, and SWCAA 16-3188. SWCAA 400, SWCAA 01-2350R4, Condition 3 of SWCAA 12-3016, and SWCAA 16-3188 do not directly establish any specific regime of monitoring or recordkeeping for these requirements. Consequently, for these rules SWCAA has implemented monitoring and recordkeeping requirements under the "gap filling" provisions of WAC 173-401-615. M4 is designed to assure compliance through prompt complaint response and corrective action whenever necessary.

M6. Operations Monitoring

The requirements cited in this monitoring section are "gap-filling" monitoring under the authority of WAC 173-401-615(1). No requirements rely solely on this monitoring condition to assure compliance. These requirements ensure sufficient monitoring where the applicable rule or permit does not provide an adequate assurance of compliance with the applicable requirement. M5 is designed to assure compliance through operation of pollution control equipment according to manufacturer specifications and/or consistent with good engineering and maintenance practices, and by taking corrective action whenever necessary. Emissions control equipment is operated to minimize overall long-term emissions. Manufacturer specifications should be followed except in instances where alternative practices are equivalent or better. The goal is to maintain performance rather than follow exact manufacturer specifications.

M7. Coal Plant SO_2 General Standard Monitoring

This monitoring requirement in combination with M8 is used to provide a reasonable assurance of compliance with the general SO_2 emission concentration limit contained in SWCAA 400. SWCAA 400-040(6) limits the emission of sulfur dioxide from combustion sources to a maximum of 1,000 ppmv corrected to a specified oxygen percentage as noted in SWCAA 400-050(3). The combustion sources at this facility combust pulverized coal and fuel oil (No. 2 distillate diesel oil). EU-3 is fueled exclusively with fuel oil, and its monitoring requirement consists only of quarterly certification of fuel sulfur content. A CEM mandated by the Acid Rain Program continuously measures the SO_2 concentrations of the flue gasses emitted by EU-1 and EU-2 and determines 60-minute averages (see M9).

SWCAA 97-2057R1 requires the use of coal sulfur content sampling to fill in missing CEM data periods, and certification of fuel oil burned in the auxiliary boiler and BW21 and BW22 but does not detail the frequency of such monitoring. This requirement provides the explanation of the minimum monitoring necessary to comply with these requirements. Monitoring of coal sulfur content by monthly composite sampling is required for comparison and potential backup purposes in the event of missing CEMS data. The conversion between fuel sulfur content and SO_2 concentration relies upon an approximate linear relationship based

on operational experience with a coal sulfur content of 1% by weight corresponding to an SO_2 bypass stack concentration of 1,000 ppm. Quarterly certification of fuel oil sulfur content is required to demonstrate compliance with the 1,000 ppm requirement, but the frequency of each sulfur content determination depends on the fuel suppliers' shipments and is not a continuous monitoring requirement. The maximum level of sulfur in the fuel oil consumed is 0.5% by weight. The following calculation demonstrates how the 1,000 ppmvd sulfur dioxide limit cannot be exceeded when burning fuel oil with a sulfur content of 0.5% or less:

$$ppm SO_2 @ 7\% O_2 = \frac{7.206 lb oil}{gallon} * \frac{1 gallon}{0.141 MMBtu} * \frac{0.005 lb S}{lb oil} * \frac{lb\text{-}mole}{32 lb S} * \frac{385 scf}{lb\text{-}mole} * \frac{MMBtu}{9,190 dscf} * \frac{(20.9 - 7\% O_2)}{20.9} * 10^6$$

$$ppm SO_2 @ 7\% O_2 = 22.2$$

M8. Coal Plant Stack Sampling Monitoring Requirements

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the general requirements drawn from SWCAA 400, the specific emission limits contained in SWCAA 97-2057R1, Second Revision of BART Order No. 6426 and 40 CFR 63 Subpart UUUUU. SWCAA 400-052 specifies a frequency for source testing of all applicable combustion units, which are those which emit 100 tons per year or more of NO_X, CO, particulate matter, SO_2, or VOC. Emissions tests are required every two calendar years for those pollutants for which the source emits 100 tons per year or more. The use of continuous emissions monitors is an acceptable alternative to the specified sampling schedule. The permittee operates CEMS at each stack for NO_X and SO_2 that meet Acid Rain requirements. In addition, CO is continuously monitored from both scrubbed flues. Requirement M9 is designed to elaborate on the SWCAA-only regulation, integrate its requirements with those from the RACT Order, and provide periodic assurance of compliance with the particulate matter exhaust concentration standards.

Past source testing at the bypass stacks has indicated compliance with the particulate matter emission limits by a wide margin. With one exception during a scrubber upset, source tests on scrubbed flues have demonstrated compliance with the PM emission limits by an adequate margin. Because continuous methods are used to quantify emissions of SO_2, NO_X, and CO, compliance with the PM emission limits has been repeatedly demonstrated by a wide margin, and because opacity monitor data utilized as part of a CAM plan, and equipment maintenance review provides additional assurance that PM emission limits are met, periodic source testing is adequate to provide a reasonable assurance of continuous compliance with the PM emission limit.

Ammonia slip monitoring must be conducted at least annually, and as frequently as semiannually in accordance with the requirements of the Second Revision of BART Order No. 6426. Between source emission tests, urea usage is monitored in accordance with M25. Large increases in urea usage without corresponding decreases in NO_X emissions would indicate the possibility of increased ammonia slip.

M9. Coal Plant Continuous Monitoring Provisions

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the general requirements drawn from SWCAA 400, the specific emission limits contained in SWCAA 97-2057R1, Second Revision of BART Order No. 6426, 40 CFR 63 Subpart UUUUU, and to provide compliance with the Acid Rain requirements.

CEMS for SO_2, NO_x, CO, CO_2, Hg, and moisture monitor exhaust concentrations and allow for the calculation of mass emission rates of these pollutants from the coal-fired boiler. A COMS for measuring the opacity of emissions has been retained at each bypass stack but will not be installed on the scrubber flues because condensed water vapor makes opacity monitoring at these flues impossible. Note that TransAlta received an official exemption from the Acid Rain Program COMS requirements for the scrubbed stacks in accordance with 40 CFR 75.14(b) [see letter from Sam Napolitano (EPA) to Lou Florence (TransAlta) dated July 28, 2011]. SWCAA 97-2057R1 requires the use of an SO_2/O_2 CEMS on the bypass stacks. NO_x and CO_2 CEMS are not required on the bypass stacks by SWCAA 97-2057R1, local, state, or federal (40 CFR 75) regulations. The CEMS and/or COMS are calibrated daily in the active stack to ensure accurate measurements. An O_2 monitor measures and records O_2 concentration in the stack gas discharged to the atmosphere consistent with the Acid Rain monitoring provisions, although the requirement for operating an O_2 monitor is based on SWCAA 97-2057R1, Sections 21 and 27a, and SWCAA 400-040(6) and 400-050(3) which specify that the 1-hour average SO_2 concentration data be on a dry basis corrected to 7% O_2. The correction method uses the as-measured SO_2 concentration for each clock hour and the corresponding actual O_2 concentration to standardize the SO_2 data to 7% O_2, as shown:

$$SO_2, \text{dry } @ 7\% O_2 = [(20.9 - 7) / (20.9 - O_2\%, \text{dry})] * SO_2, \text{dry } @ \text{ actual } O_2\%$$

This monitoring is to be used for demonstrating compliance with the specific pollutant emissions limits and standards in the permit. The monitors are to be installed, operated, maintained, and calibrated in accordance with the Acid Rain Program monitoring requirements and Subpart UUUUU as applicable. SWCAA 400-040 does not directly establish any specific regime of continuous monitoring or recordkeeping for the COMS. Consequently, SWCAA has used the monitoring requirements from SWCAA 97-2057R1 Section 36 and recordkeeping requirements under the "gap filling" provisions of WAC 173-401-615. Requirement M9(e) is designed to assure compliance with the state visible emissions standard using the COMS 6-minute average opacity data. Monitoring of 1-minute average opacity also meets this monitoring requirement because 6-minute averages may be calculated from 1-minute average data. This method of evaluation is deemed adequate to demonstrate compliance with the visible emissions standard of SWCAA 400-040(1), which is primarily a visual observation method. SWCAA 97-2057R1 Section 36 specifies that evaluation of the visible emission standard occur by both COMS and visual observation using Method 9 as prescribed in Appendix A to the permit.

Missing data procedures for the Acid Rain Program are specified for those hours when the CEMS does not measure or record valid data for the applicable monitors. The requirements specify methods for substituting data depending on factors such as the length of the missing data period and monitor system data availability rate. For compliance with the SO_2 concentration standard of SWCAA 400-040(6), the missing data procedures are identical to

those of 40 CFR 75.30 - 75.33 when the length of the missing data period is four hours or less. However, when monitor out-of-service periods are greater than four hours, data from an on-line coal analyzer, any as-burned coal analyses conducted by the permittee, and plant operating data is evaluated. For state and local rules and permits, the purpose of missing data substitution is to represent true and actual emissions as closely as possible. Therefore, the data or combination of data that best represents actual emissions is used to determine the SO_2 concentrations.

Missing data substitution procedures of 40 CFR 75 are not utilized to demonstrate compliance with the NO_X emission limit from the Second Revision of BART Order No. 6426 or the SO_2, PM, or Hg emission limits from 40 CFR 63 Subpart UUUUU. Reported emissions for comparison with these limits are intended to be more representative of actual emissions than the more conservative reporting required by 40 CFR 75 (Acid Rain Program Monitoring).

Electric output monitoring was added under the "gap filling" provisions of WAC 173-401-615 in order to allow the calculation of SO_2, PM, and Hg emission rates in units of lb/MWh or lb/GWh for comparison with the emission limits in 40 CFR 63 Subpart UUUUU.

Section M9(s) describes the requirements to monitor the bypass stack for SO_2, Hg, and PM in accordance with 40 CFR 63.10006(c) and 40 CFR 63.10010(a)(4). 40 CFR 63.10010(a)(4) indicates that if a relevant CEMS is not installed on the bypass stack, bypass hours are counted as deviations from the monitoring requirements. Based on a review of EPA's December 2011 Response to Public Comments, it appears that EPA intends to count a failure to monitor the bypass stack for either Hg or PM as a deviation from Subpart UUUUU requirements only if the bypass stack is used outside of startup or shutdown. Otherwise is appears that EPA would simply count unmonitored bypass hours as monitor downtime. In EPA's response to Commenter 17675, EPA writes.

" *The EPA has modified the bypass stack monitoring requirements. Under 40 CFR Part 75, the EPA allows the use of a maximum potential concentration value on a bypass stack. That approach works within the broad context of an emissions trading program but does not work when evaluating compliance with a specific emission limit over a shorter period. Thus, the final rule provides two other options for a source. One is to monitor the bypass stack consistent with the proposed rule. The other is to treat any hours of bypass stack emissions as periods of monitor downtime. In general, this is consistent with the EPA's approach to startup and shutdown periods, in that we treat those periods as subject to a work practice standard. That generally obviates the need to monitor the bypass stack as the emission limit does not apply during the periods when the source is most likely to operate a bypass stack...*"

In the past many facilities, although not this facility, have operated certain pollution control equipment only seasonally, therefore the bypass stack was routinely used during normal operation. The requirement in Subpart UUUUU to monitor the bypass stack addresses this possibility.

M10. 40 CFR 63 Subpart UUUUU Recordkeeping and Startup Monitoring

This recordkeeping requirement is taken directly from 40 CFR 63 Subpart UUUUU and the general requirements of 40 CFR 63.8 and 40 CFR 63.10 that apply to Subpart UUUUU.

M11. Coal Plant Startup, Shut Down, and Outage Operation Procedures for RACT Order

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the specific requirements contained in SWCAA 97-2057R1. Pursuant to SWCAA 400-081 "Start-up and Shutdown," technology based emission standards and control technology determinations must take into consideration the physical and operational ability of a source to comply with the applicable standards during start-up or shutdown. Where it is determined that a source is not capable of achieving continuous compliance with an emission standard during start-up or shutdown, SWCAA must include appropriate emission limitations, operating parameters, or other criteria to regulate performance of the source during start-up or shutdown.

M9 ensures sufficient monitoring to excuse unavoidable excess emissions or demonstrate compliance with the permit. The use of terms, test methods, units, averaging periods, and other conventions will be consistent with the applicable requirements. Emissions control equipment is operated to minimize overall emissions, except to the extent equipment operation will cause degradation of its long-term performance.

Exceedances of the PM and opacity limitations are excused under SWCAA 97-2057R1 based on SWCAA 400-107 during on-line preventive maintenance and manual ESP rapping which may cause short duration emissions increases, and during startup and shutdown when the ESPs are out of service. Excess emissions due to scheduled maintenance are considered unavoidable if the permittee adequately demonstrates the excess emissions could not have been avoided through reasonable design, better scheduling for maintenance, or through better operation and maintenance practices. ESP component maintenance and manual rapping of ESP plates are among the maintenance activities that often result in short duration excess emissions, however these excess emissions are considered unavoidable and necessary to enhance long-term equipment performance and, as such, are excused from penalty.

Shutdown of one FGD system requires opening of the damper to the associated bypass stack. This operation has been known to cause excess opacity. The cause of the excess opacity is believed to be re-entrainment of ash deposited in the duct near the damper. Excess opacity due to opening of the bypass damper and re-entrainment of ash deposits is unavoidable, and therefore will be excused from penalty providing:

(a) The permittee reports the excess emission as soon as possible but no later than 48 hours after discovery;

(b) The permittee adequately demonstrates that the cause of the excess opacity was opening of the bypass duct (e.g. the excess opacity was contemporaneous with bypass duct opening); and

(c) The permittee adequately demonstrates that directing flue gas to the bypass stack was unavoidable (e.g. the FGD shutdown was not reasonably preventable).

Hourly SO_2 emissions during shutdown, startup, and maintenance of the SO_2 emission control technology in excess of 250 ppm are excused under SWCAA 400-107 provided the alternative hourly SO_2 limits of Req-20 are not exceeded. Shutdown and startup periods are defined based on an ESP temperature of 220°F or below, and the startup period begins when fuel is

introduced into a boiler to raise its temperature to operating conditions. ESP operation during startup and shutdown of EU-1 or EU-2 will degrade the overall ESP performance. When ESP temperature is below about 220°F, and especially when the boiler is combusting fuel oil, continued operation can result in fouling of the precipitator plates, which decreases long-term PM collection efficiency. Operation of the SO_2 emission control technology when the ESPs are off line and not removing PM is expected to foul or possibly plug key components, so the SO_2 emission control technology is not required to be placed in operation until the upstream ESPs are functioning. The end of the startup period is defined based on identifiable operating events.

Emissions in excess of both the 250 ppm hourly SO_2 limit and the alternative shutdown, startup, and SO_2 emission control technology outage limits of Req-20 may be excused provided the permittee meets the burden of proof regarding unavoidable emissions under SWCAA 400-107, especially subsections (4), (5), and (6). For unit startups, shutdowns, and on-line maintenance when the SO_2 emission control technology is out of service, the permittee is expected to blend lower sulfur coal into the boiler fuel supply prior to a planned outage of the SO_2 control system. The permittee submitted a scrubber startup, shutdown, and maintenance procedure in correspondence dated September 19, 2002. The document outlines the procedures implemented by the permittee to maintain compliance with the emission limits and operational requirements imposed by applicable air regulations and permits.

If burning high sulfur coal, sulfur dioxide emissions in excess of the 1,000 ppm limit in Req-19 are unavoidable during the first 6 – 8 hours (the length of time required to burn through coal stored in the silos) of a forced outage of the flue gas desulfurization (FGD) system if the cause of the forced outage is itself unavoidable. Good air pollution control practice for minimizing emissions during a forced outage of the FGD system include changing the coal blend so that emissions will be reduced below the 1,000 ppm limit after the high-sulfur coal blend is burned out of the silos. The permittee has indicated that the coal blend will be changed within approximately 15 minutes of notification of a scrubber problem.

M12. Coal Plant SO_2 12-Month Period Emission Evaluation

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the specific requirements contained in SWCAA 97-2057R1. Calculation of the annual tons of SO_2 emitted for comparison with the limitations must include all hourly SO_2 emission data, including startups, shutdowns, upsets, and forced or planned emission control system outages. An exceedance of the annual limitation is defined as any consecutive 12 calendar months in which SO_2 emissions exceed the tons per year SO_2 limitations applicable at the time. Although each day in the last month of the 12-month exceedance period can be treated as a separate day of violation, an alternative day-by-day evaluation method can be used by the permittee to more specifically identify the violation period. According to the alternative evaluation method, the number of violation days is equal to the number of 365-day emission summations, ending within the last month of the exceedance period, in which the SO_2 emissions exceed the annual limitation. This alternative evaluation method is the same as a 365-day rolling total, rolled each calendar day.

M13. Coal Plant SO_2 Monitoring of Bypass Stacks

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the specific requirements contained in SWCAA 97-2057R1. The owners of the Centralia Plant had sole discretion to select the SO_2 and NO_X emission control technologies provided they met the applicable emission limits. The control technology configuration could include the maintenance of the original stacks for bypass provided a CEMS was maintained to monitor SO_2 emissions from the bypass stacks.

If the bypass stacks do not contain certified functional CEMS for SO_2, any emergency bypass emissions released through these stacks will be considered an upset condition reportable to SWCAA as a deviation from permit conditions. All SO_2 emissions released from the facility, regardless of where, how, or under what operating condition, is included in the plant SO_2 total for comparison with the annual limitation.

M14. Coal Plant Fuel Oil Usage Evaluation

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the specific requirements contained in SWCAA 97-2057R1 and the fuel usage monitoring requirement of 40 CFR 63.7525(k). The permittee is required to monitor fuel oil usage in all of the boilers. The permittee accepted a voluntary limit on the amount of fuel oil consumed by the auxiliary boiler (EU-3) so it would not be necessary to evaluate RACT for this unit. RACT may have otherwise been applicable because the auxiliary boiler's potential-to-emit was sufficient to qualify it as a major source on its own, even though emissions calculated from actual fuel usage resulted in emissions substantially below the major source threshold. To evaluate fuel usage compared to the consumption limit, the auxiliary boiler must be equipped with a separate fuel meter or be supplied by its own unique fuel tank to identify fuel consumed in the auxiliary boiler. If the auxiliary boiler consumes fuel oil containing the maximum allowed 0.5% sulfur by weight, the SO_2 emissions from EU-3 will be larger than emissions of other criteria pollutants from EU-3. Emissions are calculated based on emission factors from U.S. EPA AP-42 §1.3. An example of this SO_2 emission calculation using the maximum allowed annual fuel consumption is shown below:

$$\frac{600{,}000\ \text{gallons}}{\text{year}} \cdot \frac{7.206\ \text{lb oil}}{\text{gallon}} \cdot \frac{0.005\ \text{lb S}}{\text{lb oil}} \cdot \frac{1\ \text{lb-mole S}}{32\ \text{lb S}} \cdot \frac{64\ \text{lbs SO}_2}{\text{lb-mole SO}_2} \cdot \frac{1\ \text{ton}}{2{,}000\ \text{lbs}} = 21.6\ \text{tons per year}$$

The daily fuel monitoring requirement of 40 CFR 63.7525(k) is used to demonstrate that the boiler remains in the "limited use" subcategory and is exempt from many of the requirements of 40 CFR 63 Subpart DDDDD.

M15. Black Stop Diesel Generator Engine Source Testing Requirements

Requirements removed – the Black Stop Generator Engine was permanently retired at the end of 2020

M16. Black Stop Diesel Generator Engine Startup and Shutdown

Requirements removal – the Black Stop Generator Engine was permanently retired at the end of 2020.

M17. Black Stop Diesel Generator Engine Fuel Certification

Requirements removed – the Black Stop Generator Engine was permanently retired at the end of 2020.

M18. Black Stop Diesel Generator Engine Hours Monitoring

Requirements removed – the Black Stop Generator Engine was permanently retired at the end of 2020.

M19. Maintenance Activities Monitoring

The data provided by this monitoring requirement, in conjunction with source testing, provides a reasonable assurance that emissions that are not monitored continuously are within permitted limits. Each occurrence of maintenance and repairs to the fly ash unloading pugmill or turbine lube oil mist eliminators that may affect emissions is recorded. This data is available to plant personnel and SWCAA upon inspection. This data can be periodically reviewed by SWCAA and plant personnel to determine if emission factors used to calculate emissions remain valid.

For example, the replacement of filters in the lube oil mist eliminators could affect emissions if a slightly different filter were installed, therefore filter replacements for the turbine lube oil mist eliminators must be documented.

his monitoring term was included in SWCAA 01-2403 because it can be a valuable inspection tool that requires minimal effort on the part of the permittee.

M20. Particulate Matter Compliance Assurance Monitoring for BW22

The permittee was required to submit a Compliance Assurance Monitoring (CAM) plan for particulate matter emissions from EU-2 in accordance with 40 CFR 64 for the permit renewal in 2004. CAM is applicable to emissions from both the bypass and FGD stacks of EU-2. The permittee's CAM plan was approved as incorporated into the Air Operating Permit. The CAM plan utilizes opacity as a surrogate indicator of particulate matter control device operation and particulate matter emissions.

The CAM plan for the bypass stacks was required because the permittee is allowed to use the bypass stack for limited periods of time outside of startup, shutdown, and extreme emergency conditions. To date, the bypass stacks have not been used except during startup, shutdown, and upsets. Because facilitywide SO_2 emissions are limited to 10,000 tons per year, use of the unscrubbed bypass stack rapidly utilizes the allowable annual emissions (at a rate of ~5 tons per hour), therefore use of these stacks outside of startup, shutdown, and extreme emergencies is unlikely. Any significant use of the bypass stack can result in

restrictions on plant operation to maintain compliance with the 10,000 ton per year SO_2 limit.

For the FGD stack, opacity in the ductwork upstream of the scrubber of less than 30% provides an adequate assurance that particulate matter emissions from the applicable FGD stack will be less than the permit limit. Source testing at this facility has demonstrated that the scrubber is highly efficient at removing particulate matter from the flue gas. Particulate matter emission levels well below the indicator range will adversely affect scrubbing liquor chemistry and gypsum quality and potentially result in damage to the scrubber, therefore the permittee is highly motivated to maintain opacity levels well below the 30% level.

When an excursion occurs, the Permittee is required to submit a report that includes the "ESP field settings" along with the fields out of service. The ESP field settings are the secondary voltage and secondary current, consistent with 40 CFR 63 Subpart UUUUU.

M21. Coal Unloading Facility

The data provided by this monitoring requirement is used to calculate annual emissions of particulate matter from the coal unloading facility.

M22. FGD Bleed Treatment Lime Storage Silo

Differential pressure across the dust collector must be recorded at least monthly to assist in evaluating whether the dust collector is operating properly. Large changes in differential pressure can indicate operational problems. The number of hours the silo is actively vented must be recorded annually to allow the calculation of emissions from the silo. In conjunction with the monthly inspections required by M3, this data will provide a reasonable assurance of ongoing compliance with the particulate matter emission limits.

M23. Journal Shop

The amount of each type of welding rod that is used in the Journal Shop must be monitored and recorded to calculate annual emissions. The Journal Shop baghouse is designed to provide a high level of control and utilizes both primary filters and secondary HEPA filters. SWCAA believes that unless there is an obvious upset condition (for which monitoring is required), the unit will comply with particulate matter emission limits.

M24. Reserved

M25. SNCR System Monitoring

In accordance with Condition 4 of the Second Revision of BART Order No. 6426, ammonia monitoring is required only when urea injection exceeding 1.5 gallons per minute is used for NO_x control. Condition 7 requires reporting of the urea concentration and injection rate within 30 days of first injecting urea in a calendar year, but does not include monitoring, or any reporting after those 30 days. Urea flow rate monitoring is necessary for SWCAA and Ecology to know when ammonia testing is required; therefore, this

provision was added under the "gap filling" monitoring provisions of WAC 173-401-615(1).

M26. Coal Plant Emergency Engine Monitoring

These requirements come directly from 40 CFR 60 Subpart IIII (for Emergency Diesel Generator 2), 40 CFR 63 Subpart *ZZZZ* (for Emergency Diesel Generator 1), and SWCAA 16-3188. For the purposes of Subparts IIII and ZZZZ, the engines are classified as emergency compression ignition engines with a site rating of less than 500 horsepower. For this classification of engine in each rule, the applicable requirements are all operating or maintenance requirements. The permittee must document how many hours each engine is operated, and for what purpose it was operated, to demonstrate that the engines are indeed being operated as emergency engines. Because all operating and maintenance activities must be documented, and all operating hours accounted for, these monitoring provisions provide a reasonable assurance of compliance with the applicable requirements. A review of the documentation for a specific engine will conclusively determine the compliance status of the unit with respect to the operating and maintenance requirements.

M27. Fire Pump Engine Monitoring

M27(a) comes directly from SWCAA 16-3188 and provides a reasonable assurance of compliance with the fuel sulfur limitations and allows for the calculation of annual sulfur dioxide emissions.

M27(b) comes directly from SWCAA 16-3188 and provides a reasonable assurance of compliance with the hours limitation and allows for a calculation of annual emissions.

Unless new testing is conducted after the issuance date of SWCAA 16-3188 (June 1, 2016), the following emission factors are to be used.

Pollutant	Fire Pump Engine Emission Factors (lb/hr)
NO_X	1.12
CO	0.54
PM	0.050
PM_{10}	0.050
$PM_{2.5}$	0.050

M27(c) provides a reasonable assurance of compliance with the maintenance requirements of 40 CFR 63 Subpart IIII. Subpart IIII requires that certain maintenance activities be undertaken as specified frequencies (measured in the number of hours an engine has operated) but does not include any provision for monitoring how many hours an engine has operated. SWCAA has required the permittee to document the hour meter reading at each incident of maintenance and repairs under the "gap filling" provisions of WAC 173-401-615. Since maintenance activities must occur at least once per year, this means that at least once per year there will be written documentation of the number of hours of operation between maintenance events. Also, at any time after the first maintenance event, the

permittee or the inspector can compare the hour meter reading for an engine to the hour meter reading during the last maintenance event to determine whether the maintenance schedule is being met.

M28. Coal Unloading Facility Emergency Diesel Sump Pump Engine Monitoring

M28(a) comes directly from SWCAA 11-2972 and provides a reasonable assurance of compliance with the fuel sulfur limitations and allows for the calculation of annual sulfur dioxide emissions.

M28(b) comes directly from SWCAA 11-2972 and provides a reasonable assurance of compliance with the hours limitation and allows for a calculation of annual emissions.

Unless new testing is conducted after the issuance date of SWCAA 11-2972 (April 14, 2011), the following emission factors are to be used:

Pollutant	Emission Factors (lb/hr)
NO_x	2.54
CO	0.44
PM	0.055
PM_{10}	0.055
$PM_{2.5}$	0.055

M28(c) provides a reasonable assurance of compliance with the maintenance requirements of 40 CFR 60 Subpart IIII. Subpart IIII requires that certain maintenance activities be undertaken as specified frequencies (measured in the number of hours an engine has operated) but does not include any provision for monitoring how many hours an engine has operated. SWCAA has required the permittee to document the hour meter reading at each incident of maintenance and repairs under the "gap filling" provisions of WAC 173-401-615. Since maintenance activities must occur at least once per year, this means that at least once per year there will be written documentation of the number of hours of operation between maintenance events. Also, at any time after the first maintenance event, the permittee or the inspector can compare the hour meter reading for an engine to the hour meter reading during the last maintenance event to determine whether the maintenance schedule is being met.

This documentation can be compared with the written maintenance instructions provided or approved by the manufacturer to determine the status of compliance with this requirement.

M29. Mercury Control System and Fly Ash Material Handling

The number of hours each unit is operated must be logged to allow for the calculation of annual emissions. Annual emissions must be calculated using the emission factors shown below unless new emission factors are developed through source testing.

Filter	(lb/hr)
SEA System 1	0.048
SEA System 2	0.048
Sorbent Silo 1	0.015
Sorbent Silo 2	0.015
Fly Ash Bin 11	0.63
Fly Ash Bin 12	0.63
Fly Ash Bin 14	0.63
Fly Ash Bin 14 Air Slide to Bin 11 Air Slide	0.039
Fly Ash Bin 11 to Weigh Hopper Air Slide	0.039
Fly Ash Bin 14 to 6050 Air Slide	0.026

The above emission rates listed in the table above are based on the design flow rate for each unit and the permitted emission concentration (0.005 gr/dscf).

M30. Fly Ash Baghouses - Source Emission Testing Requirements

Initially, periodic source emissions testing was coupled with the use of a baghouse leak detection system to provide a reasonable assurance with the permitted emission limits. This was the same approach taken by EPA in NSPS and MACT standards (e.g. NSPS Subpart Y) issued after November 15, 1990 to assure compliance with numeric particulate matter limits; therefore, this approach was presumed to be equivalent to CAM. A CAM Plan was later developed for these baghouses in accordance with 40 CFR 64 and is included as M34. The CAM Plan replaced the previous requirement to operate the baghouse leak detectors in accordance with the requirements in 40 CFR 62.256(c).

The initial alarm setpoints of 100 pA were established based on the results of source emissions testing conducted October 2011 during which the following results were obtained:

Baghouse	Bin 11	Bin 12	Bin 14
Filterable PM	0.0001 gr/dscf	0.0002 gr/dscf	0.0001 gr/dscf
Leak Detector Output	23 pA	18 pA	42 pA

The system utilizes a Triboflow model 4001-1111-01-154N detector. Manufacturer literature indicates that the equipment is designed for a detection limit on the order of 0.0005 gr/dscf; therefore, the instrument response during the initial testing appears to be a low baseline. The 100 pA alarm setpoint is significantly less than 10 times this baseline for all stacks and well below the response expected at a concentration of 0.005 gr/dscf (the permit limit)

M31. Fly Ash Bin Baghouses – Compliance Assurance Monitoring

The permittee was required to submit a Compliance Assurance Monitoring (CAM) plan for particulate matter emissions from EU-17, EU-18, and EU-19 in accordance with 40 CFR 64 for the permit renewal in 2014. CAM is applicable to these units because

uncontrolled PM emissions would be expected to exceed 100 tons per year each. The permittee's CAM plan was approved as incorporated into the Air Operating Permit. The CAM plan utilizes an electrostatic particle detection system (also known as a baghouse leak detection system) as a surrogate indicator of particulate matter control device operation and particulate matter emissions. This is the same approach taken by EPA in NSPS and MACT standards (e.g. NSPS Subpart Y) issued after November 15, 1990 to assure compliance with numeric particulate matter limits; therefore, this approach is presumed to satisfy CAM requirements.

During initial source emissions testing in October 2011, emissions from the baghouses were measured at 0.0001 – 0.0002 gr/dscf. This level is generally at the method detection limit and 25-50 times lower than the applicable emission limit of 0.005 gr/dscf. During the testing the electrostatic particle detector readings were 18 – 42 pA. Based on this testing, TransAlta's initial alarm setpoint of 100 pA was sufficiently protective of the permit limit that no additional testing was necessary to establish an appropriate upper limit to the indicator range.

Alarm setpoints for these types of detectors may need to be adjusted from time to time due to changes in stack conditions, ambient conditions, or detector replacements. Where such detectors are referenced in NSPS/MACT regulations (e.g. 40 CFR 60 Subpart Y, 40 CFR 63 Subpart SSSSSS), sources are allowed to change the alarm setpoints quarterly in accordance with their site-specific monitoring plan. TransAlta's CAM plan (analogous to a site specific monitoring plan under NSPS/MACT regulations) indicates that changes to the alarm setpoint would be based upon the results of source emissions testing. SWCAA incorporated this provision into the Permit.

M32. Reserved

M33. Coal-Fired Boiler Tune-up and Startup/Shutdown Monitoring

40 CFR 63 Subpart UUUUU requires periodic tune-ups in accordance with specific requirements. In addition, all "applicable control technologies" must be engaged when firing anything other than "clean fuels". In this case, the only other fuel is coal.

A semiannual compliance report must be submitted that includes the date of the most recent tune-up and a report if there were any deviations from the work practice standards (consisting of the tune-up and the startup and shutdown provision). 40 CFR 63.10032(a)(1) requires sources to maintain all documentation supporting each semiannual report. This requirement describes this documentation as it pertains to the work practice standards (tune-ups and startup/shutdown provisions).

Full documentation of each tune-up as required by section (a) provides all of the records necessary to determine if all the tune-up requirements are being met.

The information in section (b) is necessary to determine:
a. That "clean fuels" are being burned during startup;
b. When the unit is in startup or shutdown, because the emission limits from Subpart UUUUU do not apply during startup or shutdown; and

c. That the relevant emission control equipment is being engaged when required.

M34. Auxiliary Boiler Tune-up Monitoring

40 CFR 63 Subpart DDDDD requires periodic tune-ups in accordance with specific requirements. The initial tune-up must be fully documented in to comply with 40 CFR 63.7555(a)(1), but there is no specific requirement to fully document subsequent tune-ups. Consequently, SWCAA has implemented this documentation requirement for subsequent tune-ups under the "gap filling" provisions of WAC 173-401-615.

Full documentation of each tune-up as required by this requirement provides all of the records necessary to determine if all the tune-up requirements are being met.

M35. Fine Coal Handling

The requirements listed this monitoring condition are all included in both 40 CFR 60 Subpart Y and SWCAA 14-3093. Because the permittee has not committed to a single monitoring strategy, both of the allowable strategies were included. The total amount of coal transferred is required by Subpart Y and necessary to calculate annual emissions.

M36. Acid Rain, RACT, and NSR CEMS Data Recordkeeping Requirements

This recordkeeping section is taken from 40 CFR 75.57, 75.58, and 75.59 and supplemented by specific requirements from SWCAA 97-2057R1, and the "gap filling" provisions of WAC 173-401-615(2)

The Acid Rain Program requires that pertinent records be maintained for at least three years from the date of the record. However, the recordkeeping provisions of the Air Operating Permit regulations, WAC 173-401-615(2)(c), require retention of records for a period of five years.

The basis for recordkeeping requirements for 1-hour SO_2 standard concentrations (dry @ 7% O_2) is the "gap filling" provisions of WAC 173-401-615(2). Data from the plant computer system not required by the Acid Rain Program is not saved for archiving in the same way that data consistent with 40 CFR 75.57 - 75.59 is recorded.

The Acid Rain regulation specifies the type and format of data to be recorded for flow and SO_2 emissions from Acid Rain affected units. The data recordkeeping requirements pursuant to SWCAA 97-2057R1 for 1-hour SO_2 standard concentration (dry @ 7% O_2) are parallel to those of the Acid Rain Program, but for a smaller quantity of required data. The data recordkeeping requirements for rolling 12-month SO_2 emissions (tons per year) are specified, and the additional data to be included in this summation stated for recordkeeping purposes.

The data recordkeeping requirements for hourly NO_x corresponding to unit generating load of 360 MW gross or greater are parallel to those of the Acid Rain Program, but for a smaller quantity of required data pursuant to SWCAA 97-2057R1 Section 30.

M37. 40 CFR 63 Subpart DDDDD Recordkeeping

This recordkeeping requirement is taken directly from 40 CFR 63.7555 and 40 CFR 62.7560.

M38. 40 CFR 60 Subpart Y Recordkeeping

This recordkeeping requirement is taken directly from 40 CFR 60 Subpart Y. The amount of coal processed will be the amount of coal conveyed to the permittee's facility and used to calculate annual emissions.

VIII. EXPLANATION OF SELECTED REPORTING TERMS AND CONDITIONS

R1. Deviations from Permit Conditions and CAM Excursions

The permittee is required to report all permit deviations promptly. This reporting requirement is taken directly from WAC 173-401-615(3) and is included in some form in PSD-01-01 Amendment 2 Condition 22(d)(1), Second Revision of BART Order No. 6426 Section 11,SWCAA 97-2057R1 Sections 23, 28, 29, and 37, SWCAA 01-2403 Section 11(e)(1), SWCAA 01-2350R4 Conditions 28(a & b), SWCAA 11-2984 Conditions 15 and 16, SWCAA 14-3093 Conditions 17 and 18, and SWCAA 16-3188 Conditions 12 and 13. SWCAA defines "prompt" in the permit in relation to the degree and type of deviation likely to occur and the applicable requirement. Excess emissions of SO_2, particulate matter, or opacity are to be reported to SWCAA during the current business day or next business morning. A written report may be requested by SWCAA and is required for any SO_2 emission control technology forced outage longer than 72 hours. Any emissions released through a bypass duct without a certified functioning CEMS are defined as an upset condition which must be reported to SWCAA during the current business day or by the next business morning and must be documented to SWCAA within 5 days of occurrence. All other deviations must be reported no later than 30 days following the end of the month during which the deviation was discovered. This reporting frequency is taken from WAC 173-401-615(3).

R2. Complaint Reports

The permittee is required to report all complaints to SWCAA within three business days of receipt to ensure prompt complaint response. This reporting section is based on WAC 173-401-615(3), and SWCAA's definition of "prompt" for reporting of complaints.

R3. Quarterly Reports

The permittee is required to report specific monitoring records and provide a certification of monitoring records on a quarterly basis for the Acid Rain Program. Although a semiannual report on the status of, and certification of monitoring records is required by WAC 173-401-615(3), quarterly reporting of specified monitoring records is required under 40 CFR 75.64, with compliance certification according to 40 CFR 75.64(c). Non-Acid Rain reporting requirements for the coal plant are derived from 40 CFR 63 Subpart UUUUU, the Second Revision of BART Order No. 6426, SWCAA 97-2057R1 Sections 27d, 43, and 45, and WAC 173-401-615(3). Non-Acid Rain reporting requirement for the combustion turbine facility

are specified in SWCAA 01-2350R4 and PSD-01-01 Amendment 2. Although records are reported quarterly, certification of non-Acid Rain monitoring records is only required every six months consistent with WAC 173-401-615(3).

No specific NO_X reporting requirements were included in the SWCAA 97-2057R1 to demonstrate compliance with the NO_X emission limits that apply at 360 MW or greater, therefore section R3(e) was added using the "gap-filling" provisions of WAC 173-401-615.

For Subpart UUUUU reports, no special SO_2 CEMS data reporting are listed because reporting of SO_2 data (and supporting diluent and/or moisture monitors) is covered by the Acid Rain Program reporting requirements (see the Acid Rain Permit and 40 CFR 75). EPA guidance indicates that Acid Rain Program requirements must not be detailed in Title V permits. The Acid Rain Permit incorporates the appropriate requirements by reference. The Hg CEMS reporting requirements mirror the Acid Rain Program reporting requirements for SO_2 and require utilization of the same data reporting system. SWCAA will have access to the data through EPA's system upon submission.

R4. Semiannual Reports

The permittee is required to provide a report of all monitoring records and provide a certification of all reports on a semi-annual basis. Semiannual reporting and certification of monitoring records is required by WAC 173-401-615(3). A Responsible Official must certify all reports required by the Title V permit.

In addition, specific reporting elements required by 40 CFR 63 Subpart UUUUU have been listed.

R5. Annual Reports and Compliance Certification

The permittee is required to report and certify compliance with all permit terms and conditions on an annual basis. Annual compliance certification is required by WAC 173-401-630(5) for all requirements, including Acid Rain Program requirements. Since 2005, a separate Acid Rain Program certification has not been required.

All of the items other than the compliance certification are used to calculate annual emissions from individual emission units.

R6. Emission Inventory Reports

The permittee is required to report an inventory of emissions from the source on an annual basis. Annual reporting of emissions inventory is required under SWCAA 400-105 to be submitted to SWCAA by March 15th for the previous calendar year unless an extension is approved by SWCAA. SWCAA's Executive Director may extend the submittal date to April 15th (the deadline in WAC 173-400-105).

R7. Source Test Plans and Reports

The permittee is required to notify SWCAA in advance of all required source testing so that SWCAA personnel may be present during testing. The permittee must also report test results within 45 days of test completion to allow timely review by SWCAA. Operating conditions are also to be included in all test reports to relate emissions to the method of operation. Source testing described in monitoring requirements M8 and M15 are examples of source test results subject to this reporting requirement.

R8. Acid Rain Notification of Certification and Recertification Test Dates and Applications and Other General Reporting Provisions

This reporting section is taken from 40 CFR 75.60, 75.61 and 75.63 to indicate that the reporting requirements in these Acid Rain sections apply. Advance notification within specified time periods is required for the date each unit commences commercial operation, CEMS certification and recertification tests, relative accuracy test audits, and COMS certification and recertification tests at Acid Rain affected units. An application for certification or recertification is required for Acid Rain affected units. Each certification application is to be submitted in electronic or paper format as specified by the EPA Administrator. The permittee must comply with All Acid Rain reporting requirements in 40 CFR 75.60.

R9. BART Order Milestone and Urea Injection Reports

This reporting section is taken directly from the Second Revision of BART Order No. 6426

R10. 40 CFR 63 Subpart DDDDD Reports for Auxiliary Boiler

This reporting section is taken from 40 CFR 63.7545(e) and 40 CFR 63.9. The Notification of Compliance Status must include an identification of which category each boiler is in for the purposes of 40 CFR 63 Subpart DDDDD. The Auxiliary Boiler (EU-3) is in the "Limited Use Boiler" subcategory.

R11. 40 CFR 63 Subpart UUUUU Reports

This reporting section is taken from 40 CFR 63 Subpart UUUUU and includes all reports not required to be submitted each quarter or semiannually.

R12. 40 CFR 60 Subpart Y Performance Monitoring Reports

This reporting section is taken from 40 CFR 63 Subpart Y and applies to the periodic visible emission evaluation reports required by Subpart Y.

IX. COMPLIANCE HISTORY

The following Notices of Violation (NOV) were issued for the time period beginning 5 years before the current permit term.

NOC/ NOV No.	Violation Date	Notes
5881	7/12/2015	Bypass of the Unit 2 scrubber during normal operation. The bypass occurred because maintenance personnel accidentally locked out the pH probe signals, rather than the level probe signals, when performing a monthly preventative maintenance flush on the level probes
5882	7/23/2015	Failure to complete SNCR optimization testing by the end of calendar year 2014.
6111	6/18/2016	Partial bypass of Unit 1 scrubber and associated opacity exceedance. The Unit 1 scrubber was partially bypassed between 11:20 and 11:48 on Saturday June 18, 2016. The partial bypass occurred when the connection between a damper actuator and control motor broke during a startup of Unit 1.
6121	8/22/2017	Unit 2 selective non-catalytic reduction (SNCR) system was offline between 05:52 and 11:28 when the urea tank ran empty. TransAlta's report of the incident indicated that they were maintaining a low level in the tank after some foundation concern following an earlier subsurface water leak. Subsequently the urea need increased due to increased operations and urea deliveries were not increased to compensate.
6123	7/28/2017, 8/3/2017, 10/9/2017	Exceedances of voluntary SO_2 emission limit established to protect NAAQS. Primary cause may have been that increasing emissions were not noticed in time by control room operators.
6125	8/5/2017 – 9/14/2017 U1 7/21/2017 – 9/13/2017 U2	Exceedances of the 30-boiler operating day rolling average mercury emission limit. Caused in part by under-feeding carbon adsorbent.
6426	2017	Improper operation of SNCR systems for Units 1 and 2 for calendar year 2017. Included under-injection of urea, use of incorrect injection devices, and use of incorrect urea concentrations.
6427	12/27/2017 – 1/23/2018	The mercury emissions from Unit 2 exceeded 1.2 lb/TBtu (30-boiler operating day rolling average) from December 27, 2017 through January 23, 2018.
10101	8/3/2018 – 8/10/2018	The mercury emissions from Unit 1 exceeded 1.2 lb/TBtu (30-boiler operating day rolling average) from August 3, 2018 through August 10, 2018
10102	9/1/2018	Unit 1 scrubber bypass between approximately 05:25 and 06:01. The bypass was initiated by an inadvertent mouse click that resulted in one of the two ducts (duct 11) being placed in bypass mode.

NOC/ NOV No.	Violation Date	Notes
10103	11/8/2018	During the startup of Unit 1 on November 8, 2018 the selective non-catalytic reduction (SNCR) system was not engaged as early as it should have been to control NO_x emissions. During this startup a set of fans on the boiler tripped, which also tripped the SNCR system offline. The fact that the SNCR system had been tripped offline was not noticed by the operators until the shift change at 7:00 a.m. TransAlta reported that based on the steam flow the SNCR system should have been operational between 05:00 and 06:00. Operators noticed the issue and started the SNCR system between 07:00 and 08:00.
10106	1/1/2018 – 4/13/2019	Improper operation of the SNCR systems on both Units 1 and 2.

X. APPENDICES

Appendix A of the Air Operating Permit contains the methods by which visible emissions from the permittee's operations are to be evaluated when performing required monitoring. SWCAA has exercised its latitude under SWCAA 400-105(4) "Source Testing" to approve an alternative test method in advance for visible emissions. Approval has been granted via signature of SWCAA's Control Officer in this permit. The federal requirements still require that EPA Method 9 be performed. The difference between the Appendix A visible emission method and EPA Method 9 is the data reduction method used.

Appendix B of the Air Operating Permit contains the Acid Rain Permit for the Centralia Plant. The Acid Rain permit is effective beginning on the same date as this Air Operating Permit through the expiration date of this Air Operating Permit. Nearly all requirements in the Acid Rain permit are incorporated by reference to the applicable regulation; therefore changes in the applicable regulation are automatically incorporated into the permit.

Appendix C of the Air Operating Permit contains TransAlta's Small Engine Maintenance Plan used to meet the maintenance requirements of 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ for specific engines.

XI. PERMIT ACTIONS

Air Operating Permit SW98-8 (original Title 5 permit)

1. Final Permit Issued: August 6, 1999

Air Operating Permit SW98-8-R1 (administrative permit amendment)

1. Final Permit Issued: July 12, 2000

Air Operating Permit SW98-8-R2 (first renewal)

1. Final Permit Issued: August 6, 2004

Air Operating Permit SW98-8-R2-A (modification)

1.	Final Permit Issued:	May 12, 2005

Air Operating Permit SW98-8-R2-B (modification)

1.	Final Permit Issued:	March 25, 2008

Air Operating Permit SW98-8-R3 (second renewal)

1.	Renewal Permit Application Submitted:	February 3, 2009
2.	Permit Application Deemed Complete:	March 17, 2009
3.	Permit Application Sent to EPA:	May 15, 2009
4.	Draft Permit Issued:	May 15, 2009
5.	Proposed Permit Issued:	July 21, 2009
6.	Final Permit Issued:	September 16, 2009

Air Operating Permit SW98-8-R3-A (modification)

1.	"Reopening for Cause" Letter to Permittee:	July 12, 2011
2.	Draft Permit Issued:	September 14, 2011
3.	Proposed Permit Issued:	October 26, 2011
4.	Final Permit Issued:	December 21, 2011

Air Operating Permit SW98-8-R4 (third renewal)

1.	Renewal Permit Application Submitted:	September 16, 2013
2.	Permit Application Deemed Complete:	January 8, 2014
3	Permit Application Sent to EPA:	January 8, 2014
4.	Draft Permit Issued:	June 6, 2014
5.	Proposed Permit Issued:	July 16, 2014
6.	Final Permit Issued:	September 16, 2014

Air Operating Permit SW98-8-R4-A (modification)

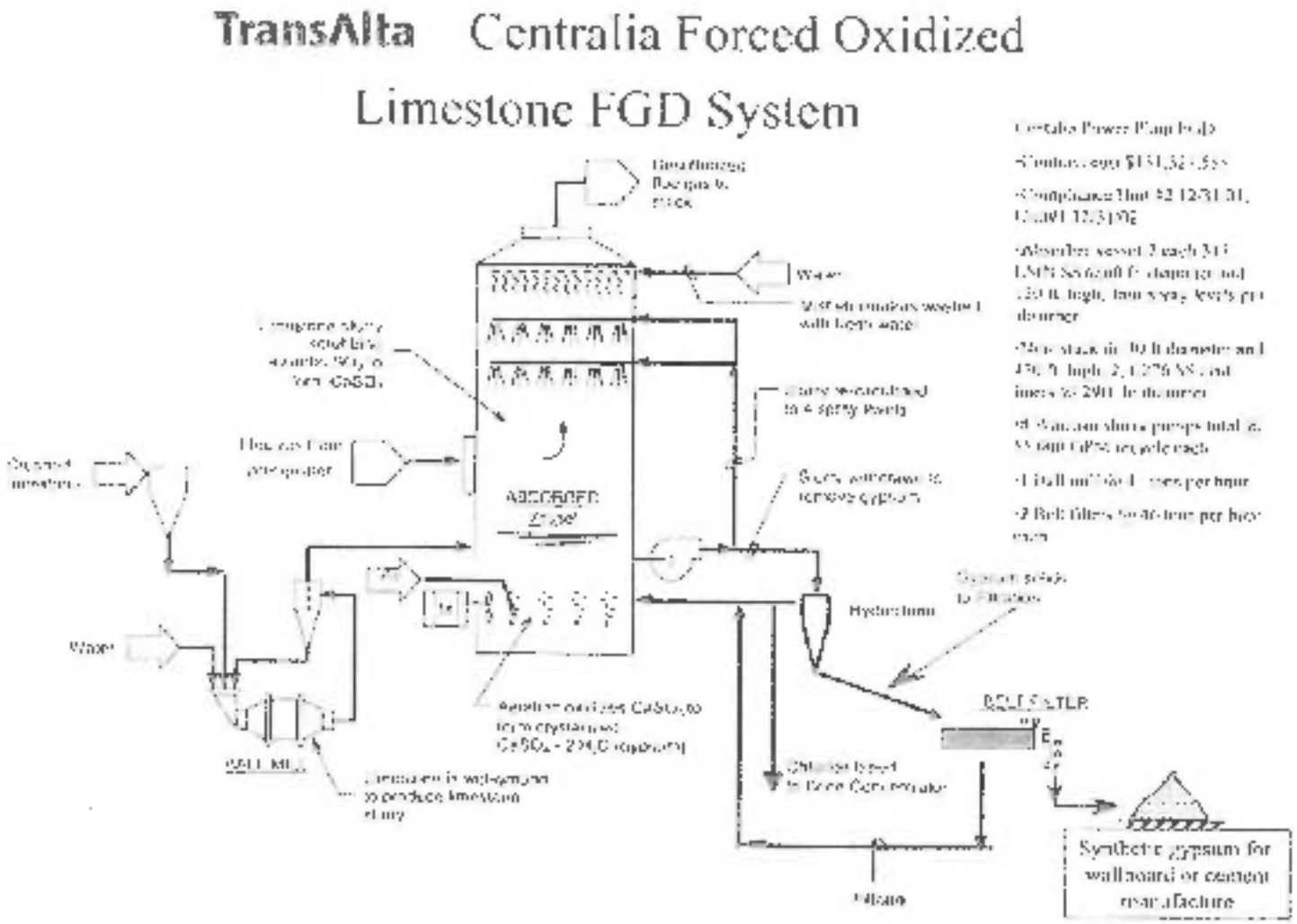
1.	Reopening for Cause" Letter to Permittee:	April 24, 2015
2.	Draft Permit Issued:	November 20, 2015
3.	Proposed Permit Issued:	January 7, 2016
4.	Final Permit Issued:	March 14, 2016

Air Operating Permit SW98-8-R5 (fourth renewal)

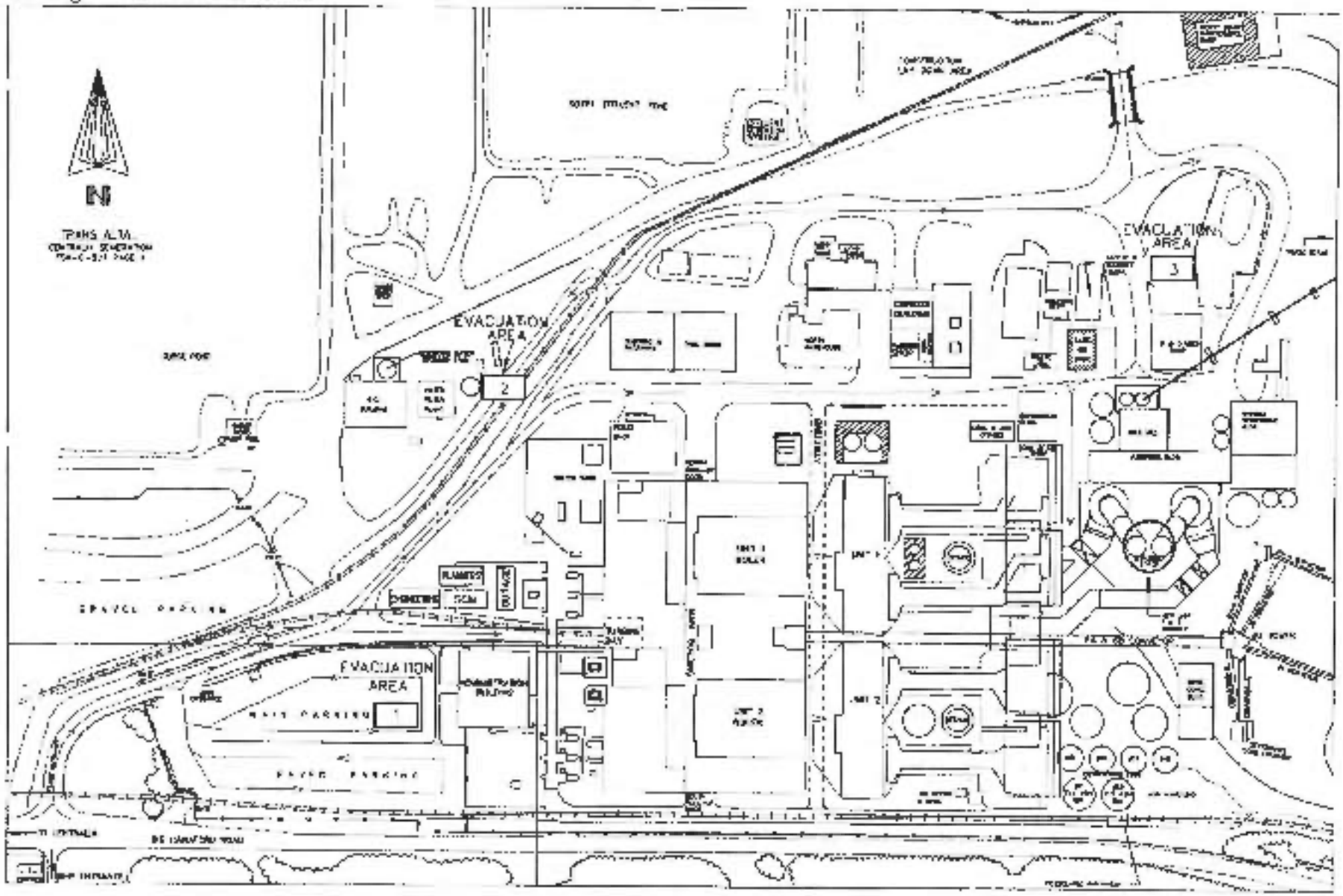
1.	Renewal Permit Application Submitted:	September 13, 2018
2.	Permit Application Deemed Complete:	April 19, 2019
3.	Permit Application Sent to EPA:	July 18, 2019
4.	Draft Permit Issued:	July 18, 2019
5.	Proposed Permit Issued:	August 27, 2019
6.	Final Permit Issued:	October 14, 2019

XII. PLANT DRAWINGS

Drawing 1 – Forced Oxidized Limestone FGD System



Drawing 2 - Coal Plant Schematic



Appendix A
Applicable Requirement Review

CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
60.4200	—	"Am I subject to this subpart?" Informational. This subpart applies to the Coal Unloading Facility Emergency Diesel Sump Pump Engine, Emergency Diesel Generator 2, and the Fire Pump Engine.
60.4201	—	"What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?"
60.4202	—	"What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?"
60.4203	-	"How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?"
60.4204	—	"What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?" Section (b) states that 2007 model year and later non-emergency engines must comply with 40 CFR 60.4201 as applicable. This applies to the Fire Pump Engine. Compliance is met through engine certification and proper operation and maintenance. This engine is Tier 3 EPA certified which meets this requirement. No active requirement.
60.4205	—	"What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?" Section (a) states that the pre-2007 model year engines must meet the requirements in Table 1. This applies to the Coal Unloading Facility Emergency Diesel Sump Pump. Compliance is met through engine certification and proper operation and maintenance. This engine is Tier 2 EPA certified which meets the Table 1 requirement. Section (b) states that 2007 model year and later emergency engines must comply with 40 CFR 60.4202 as applicable. This applies to Emergency Diesel Generator 2. Compliance is met through engine certification and proper operation and maintenance. This engine is Tier 3 EPA certified which meets this requirement. No active requirements in this section.
60.4206	—	"How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?" Informational. No exemption or modification of any other requirement in this section.
60.4207	Req-60, Req-68	"What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?"
60.4208	—	"What is the deadline for importing or installing stationary CI ICE produced in previous model years?"
60.4209	—	"What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?" Requires compliance with monitoring requirements of 40 CFR 60.4211.

CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
60.4209(a)	Req-54	Requires emergency engines that do not meet the requirements for non-emergency engines to install a non-resettable hour meter. This applies to Emergency Diesel Generator 2 which is a 2016 model year certified to EPA Tier 3 for emergency use only.
60.4209(b)		Requirements for engines using particulate filters to comply with standards. The engines as this facility do not utilize particulate filters.
60.4210	—	"What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?"
60.4211	"What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?"	
60.4211(a)	Req-64, Req-67	Operation and maintenance requirements.
60.4211(b)	—	For applicable pre-2007 model year engines, requires demonstration of compliance by one of several methods. This is applicable to the Coal Unloading Facility Emergency Diesel Sump Pump Engine and compliance was demonstrated by purchasing a certified engine (option 1). There are no ongoing requirements.
60.4211(c)	—	For 2007 and later model year engines, requires compliance by purchasing an engine certified to the appropriate standards. This is applicable to the Fire Pump Engine and Emergency Diesel Generator 2. Both units were certified to the appropriate standards. There are no ongoing requirements.
60.4211(d)	—	This section applies to engines with a displacement ≥ 30 liters per cylinder. The engines at this facility are all smaller than this.
60.4211(e)	—	Requirements for modified or reconstructed engines. There are no modified or reconstructed engines at this facility.
60.4211(f)	Req-56, Req-57, Req-61	Operating limits for emergency engines.
60.4211(g)	Req-64, Req-67	Alternatives for engines not installed, configured, operated or maintained in accordance with manufacturer's instructions.
60.4211(f)	--	Requirements applicable to engines with auxiliary emission control devices. None of the engines at this facility utilize such units.
60.4212	—	"What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?" Testing is not required for any of the engines at this facility.
60.4213	—	"What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?" The engines at this facility are all smaller than this.

CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
60.4214	M26	"What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?" The only remaining applicable requirement is a requirement for Emergency Diesel Generator 2 to keep records of operation in emergency and non-emergency service
60.4215	—	"What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?"
60.4216	—	"What requirements must I meet for engines used in Alaska?"
60.4217	—	"What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?" This facility does not have approval to utilize special fuels.
60.4218	—	"What parts of the General Provisions apply to me?" Refers to Table 8.
60.4219	—	"What definitions apply to this subpart?" Informational.
Table 1	—	"Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007-2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder" Informational listing of the emission standards. This section is applicable to the Coal Unloading Facility Emergency Diesel Sump Pump Engine. Compliance was demonstrated by purchasing a EPA Tier certified engine that exceeds the standards in Table 1.
Table 2	—	"Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder." No engine in this category at the facility.
Table 3	—	"Certification Requirements for Stationary Fire Pump Engines." No engine in this category at the facility. The Fire Pump Engine at this facility is used for non-emergency use as well as fire protection and therefore is not a "fire pump engine" for the purposes of this subpart.
Table 4	—	"Emission Standards for Stationary Fire Pump Engines." The Fire Pump Engine at this facility is used for non-emergency use as well as fire protection and therefore is not a "fire pump engine" for the purposes of this subpart.
Table 5	—	"Labeling and Recordkeeping Requirements for New Stationary Emergency Engines." Not a requirement for the owner/operator.
Table 6	—	"Optional 3-Mode Test Cycle for Stationary Fire Pump Engines." Not a requirement for the owner/operator.
Table 7	—	"Requirements for Performance Tests for Stationary CI ICE With a Displacement of >30 Liters per Cylinder." No engine in this category at the facility.
Table 8	—	"Applicability of General Provisions to Subpart IIII." Table 8 was not listed directly in the permit, rather the individual General Provisions were independently identified.

CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
Applicable General Requirements Identified by Table 8		
60.1	—	General applicability of the General Provisions
60.2	—	Definitions
60.3	—	Units and abbreviations
60.4	—	Address. Informational.
60.5	—	Determination of construction or modification
60.6	—	Review of plans
60.7	—	Notification and Recordkeeping. There are no notification requirements applicable to this engine.
60.8	—	Performance tests. No performance tests are required.
60.9	—	Availability of information. Informational
60.10	—	State Authority. Informational.
60.11	P1	Compliance with standards and maintenance requirements. No active requirements, however, the credible evidence provision was included in P1.
60.12	—	Circumvention (masking or concealing emissions that would violate an applicable standard). The only applicable emission standards apply to initial certification.
60.13	—	Monitoring requirements. Only applies to stationary CI ICE with a displacement of ≥30 liters per cylinder.
60.14	—	Modification. Modification is subject to New Source Review.
60.15	—	Reconstruction. Reconstruction is subject to New Source Review.
60.16	—	Priority list
60.17	—	Incorporations by reference
60.18	—	General control device requirements. No control devices.
60.19	—	General notification and reporting requirements. There are no notification requirements applicable to the engines at this facility.

63 Subpart DDDDD – National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters		
Requirement	**Title V Permit Location**	**Comments**
63.7480	—	"What is the purpose of this subpart?"
63.7485	—	"Am I subject to this subpart?"
63.7485		"Am I subject to this subpart?" This subpart is applicable to the Auxiliary Boiler.
63.7490	—	"What is the affected source of this subpart?"
63.7491	—	"Are any boilers or process heaters not subject to this subpart?"
63.7495		"When to I have to comply with this subpart?" All applicable compliance dates are past.

63 Subpart DDDDD – National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters		
Requirement	**Title V Permit Location**	**Comments**
63.7499	—	"What are the subcategories of boilers and process heaters?" Informational. The Auxiliary Boiler is in the "limited-use" subcategory.
63.7500	"What emission limitations, work practice standards, and operating limits must I meet?"	
63.7500(a)	Req-40	Requirements to comply with applicable elements in tables, and general duty clause. Only the general duty clause applies to the Auxiliary Boiler because it is in the "limited-use" subcategory (see 75.DDDDD(c)).
63.7500(c)	Req-41	Tune-up requirements and exemption from specific requirements.
63.7500(d)	—	Tune-ups for small boilers.
63.7500(e)	—	Requirements for specific subcategories
63.7500(f)	—	Statement that standards apply to all normal operation. No operating standards applicable to the Auxiliary Boiler.
63.7505	Req-41	"What are my general requirements for complying with this subpart?"
63.7510	Req-41	"What are my initial compliance requirements and by what date must I conduct them?" Applies to the initial tune-up.
63.7515	Req-41	"When must I conduct subsequent performance tests, fuel analyses, or tune-ups?" Only the tune-up requirements apply to the Auxiliary Boiler.
63.7520	—	"What stack tests and procedures must I use?" No stack test is required.
63.7521	—	"What fuel analysis, fuel specification, and procedures must I use?" No requirements for the Auxiliary Boiler.
63.7522	—	"Can I use emissions averaging to comply with this subpart?" Only 1 affected unit at this facility, and no applicable emission limits apply.
63.7525	M14	"What are my monitoring, installation, operation, and maintenance requirements?"
63.7530	—	"How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?" No requirements in this section for units subject only to the work practice standards.
63.7533	—	"Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart?" Applies to emission limits. There are no applicable emission limits for the Auxiliary Boiler.
63.7535	—	"Is there a minimum amount of monitoring data I must obtain?" No continuous monitoring requirements for the Auxiliary Boiler.
63.7540	Req-41	"How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?" Section (12) requires a tune-up every 5 years.
63.7541	—	"How do I demonstrate continuous compliance under the emissions averaging provision?" Emissions averaging does not apply.
63.7545	—	"What notifications must I submit and when?" The only applicable requirements was the initial notification of compliance status, which has been completed.
63.7550	R10	"What reports must I submit and when?" Compliance reports must be submitted every 5 years.

63 Subpart DDDDD – National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters		
Requirement	**Title V Permit Location**	**Comments**
63.7555	M34	"What records must I keep?"
63.7560	M34, M41	"63.7560 In what form and how long must I keep my records?"
63.7565		"What parts of the General Provisions apply to me?" Informational
63.7570		"Who implements and enforces this subpart?" Informational
63.7575	—	Definitions
Table 1	—	"Emission Limits for New or Reconstructed Boilers and Process Heaters"
Table 2	—	"Emission Limits for Existing Boilers and Process Heaters"
Table 3	Req-41	"Work Practice Standards"
Table 4	—	"Operating Limits for Boilers and Process Heaters"
Table 5	—	"Performance Testing Requirements"
Table 6		"Fuel Analysis Requirements"
Table 7	—	"Establishing Operating Limits"
Table 8	—	"Demonstrating Continuous Compliance"
Table 9	—	"Reporting Requirements"
Table 10	—	"Applicability of General Provisions to Subpart DDDDD". Informational.
Table 11	—	"Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After June 4, 2010, and Before May 20, 2011"
Table 12	—	"Table 12 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After May 20, 2011, and Before December 23, 2011"
Table 13	—	"Table 13 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After December 23, 2011, and Before April 1, 2013"

63 Subpart *ZZZZ* – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
63.6580	—	"What is the purpose of subpart *ZZZZ*?"
63.6585	—	"Am I subject to this subpart." All of the stationary engines are subject, however no requirements from subpart *ZZZZ* apply to the units that are also subject to Subpart IIII.

63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
63.6590	—	"What parts of my plant does this subpart cover?" The Black Stop Diesel Generator Engine and Emergency Diesel Generator 1 are subject to requirements from subpart ZZZZ. The Black Stop Diesel Generator Engine is an existing emergency engine > 500 bhp at a major HAP source. Emergency Diesel Generator 1 is an existing emergency engine < 500 hp at a major HAP source.
63.6595	—	"When do I have to comply with this subpart?"
63.6600	—	"What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?" This section exempts emergency stationary RICE from compliance with the emission limits in Tables 1a, 2a, 2c, and 2d, and the operating limits in Tables 1b and 2b. This section provides exemptions but no direct requirements.
63.6601		"What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?" No engines in this category at the facility.
63.6602	Req-51, Req-52	"What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?" References the applicable emission limits in Table 2c. The only applicable emission limit category in Table 2c is "Non-emergency, non-black start CI stationary RICE 100<HP≤300 HP" with a CO emission limit of 230 ppmvd @ 15% O_2.
63.6603	—	"What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?" This facility is a major source.
63.6604	—	"What fuel requirements must I meet if I own or operate a stationary CI RICE?" None of the engines at this facility fall into one of the specific categories listed in this section.
63.6605	Req-55, M42	"What are my general requirements for complying with this subpart?" This section is a general duty clause.
63.6610	—	"By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?" There are no applicable testing requirements for engines at this facility.

63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
63.6611	—	"By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?" No engines in this category at the facility.
63.6612	M4	"By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?" There are no applicable testing requirements for engines at this facility.
63.6615	—	"When must I conduct subsequent performance tests?" Requires subsequent testing as per Table 3. This facility does not have any engines subject to performance testing requirements.
63.6620	—	"What performance tests and other procedures must I use?" This facility does not have any engines subject to performance testing requirements.
63.6625	Req-52, Req-53, Req-54, Req-94	"What are my monitoring, installation, collection, operation, and maintenance requirements?" Only sections (e), (f), and (h), and optionally (i) apply to any engines at this facility. Section (e)(2) and (f) apply to Emergency Diesel Generator 1 only.
63.6630	—	"How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?" The engines at this facility are not subject to any of the limitations or requirements for which a compliance demonstration is required.
63.6635	—	"How do I monitor and collect data to demonstrate continuous compliance?" Continuous compliance monitoring is not required for any of the engines at this facility.
63.6640	"How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?"	
63.6640(a)	Req-51, Req-53	Section (a) requires compliance with applicable requirements in Tables 1a, 1b, 2a, 2b, 2c, and 2d in accordance with Table 6.
63.6640(b)	R4	Deviation reporting requirements. Included as part of routine semiannual reporting.
63.6640(c)	—	Requirements for specific 4SLB and 4SRB. This facility does not have any engines in this category.
63.6640(d)	—	Exemptions for "engine burn-in". No engines at this facility are this new
63.6640(e)	—	Section (e) requires reporting of deviations from Part 63 "General Provisions" for non-exempted engines. Emergency engines are exempt.
63.6640(f)	Req-56, Req-90	Operating limitations for emergency engines.

63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
63.6645	—	"What notifications must I submit and when?" In accordance with 40 CFR 63.6645(a)(5) the general notification requirements in (a) do not apply to existing emergency engines.
63.6650	R4	"What reports must I submit and when?" The general requirement to report deviations in the semiannual Title V report is found in 63.6650(f).
63.6655	M19, M26	"What records must I keep?" Maintenance and operating records must be kept.
63.6660	VII	"In what form and how long must I keep my records?" This section and 63.10(b) are included in the introductory paragraphs of Section VII.
63.6665	—	"What parts of the General Provisions apply to me?" References Table 8. This section itself is informational and not included in the permit. This section exempts existing emergency engines > 500 bhp at major HAP sources (Black Stop Diesel Generator Engine) from the general provisions. While Emergency Diesel Generator 1 is not specifically exempted, there are no active general requirements for this unit.
63.6670	—	"Who implements and enforces this subpart?" This section is informational.
63.6675	—	"What definitions apply to this subpart?" This section is a reference for other sections and does not contain any directly applicable requirements.
Table 1a	—	"Table 1a to Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions" No engines in this category at this facility.
Table 1b	—	"Table 1b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions" No engines in this category at this facility.
Table 2a	—	"Table 2a to Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE >250 HP Located at a Major Source of HAP Emissions". No engines in this category at this facility.
Table 2b	—	"Table 2b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and CI Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing CI Stationary RICE >500 HP" No engines in this category at this facility.

63 Subpart *ZZZZ* – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
Table 2c	Req-51, Req-52, Req-94, Req-95	"Table 2c to Subpart *ZZZZ* of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions".
Table 2d	—	"Table 2d to Subpart ZZZZ of Part 63—Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions" This facility is a major source of HAP.
Table 3	—	"Table 3 to Subpart *ZZZZ* of Part 63—Subsequent Performance Tests" There are no engines in the categories listed in Table 3 at this facility.
Table 4	—	"Table 4 to Subpart *ZZZZ* of Part 63—Requirements for Performance Tests". No engines at this facility are required to conduct performance tests.
Table 5	—	"Table 5 to Subpart *ZZZZ* of Part 63—Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements". None of the engines at this facility are subject to initial compliance demonstrations.
Table 6	Req-53	"Table 6 to Subpart *ZZZZ* of Part 63—Continuous Compliance With Emission Limitations, and Other Requirements". The work practice standard requirements addressed here do not apply to engines > 500 bhp such as the Black Stop Diesel Generator Engine.
Table 7	—	"Table 7 to Subpart *ZZZZ* of Part 63—Requirements for Reports". The only applicable engines at this facility are existing emergency engines. There are no reporting requirements for existing emergency engines.
Table 8	—	"Table 8 to Subpart *ZZZZ* of Part 63—Applicability of General Provisions to Subpart *ZZZZ*." Table 8 was not listed directly in the permit, rather the individual General Provisions were independently identified as applicable.
Applicable General Requirements Identified by Table 8		
63.1	—	General applicability of the General Provisions
63.2	—	Definitions
63.3	—	Units and abbreviations
63.4	—	Prohibited activities and circumvention
63.5	—	Construction and reconstruction notification. Construction or reconstruction would require NSR.
63.6(a)	—	Applicability. Informational
63.6(b)(1)-(4)	—	Compliance dates for new and reconstructed sources. Informational
63.6(b)(5)	—	Notification for new or reconstructed sources. Construction or reconstruction would require NSR.
63.6(b)(7)	—	Compliance dates for new and reconstructed area sources that become major sources. Informational. This facility is already a major source.
63.6(c)(1)-(2)	—	Compliance dates for existing sources. Compliance dates have passed.

63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
63.6(e)(5)	—	Compliance dates for existing area sources that become major sources. Informational. This facility is already a major source.
63.6(f)(2)	—	Methods for determining compliance. Informational.
63.6(f)(3)	—	Finding of compliance. Informational
63.6(g)(1)-(3)	—	Use of alternate standard. Informational.
63.6(i)	—	Compliance extension procedures and criteria
63.6(j)	—	Presidential compliance exemption
63.7(a)(1)-(2)	—	Performance test dates. All initial testing has been completed.
63.7(a)(3)	—	CAA section 114 authority
63.7(b)(1)	—	Notification of performance test
63.7(b)(2)	—	Notification of rescheduling
63.7(c)	—	Quality assurance/test plan
63.7(d)	—	Testing facilities
63.7(e)(2)	—	Conduct of performance tests and reduction of data. Informational
63.7(e)(3)	—	Test run duration. Run duration already specified in rule.
63.7(e)(4)	—	Administrator may require other testing under section 114 of the CAA. Informational
63.7(f)	—	Alternative test method provisions. Informational. No reasonable reason to utilize an alternative test method.
63.7(g)	—	Performance test data analysis, recordkeeping, and reporting. Source test report requirements are detailed in R6, however Subpart ZZZZ testing requirements in the permit are primarily informational because all initial testing has been completed.
63.7(h)	—	Waiver of tests. Informational.
63.8(a)(1)	—	Applicability of monitoring requirements.
63.8(a)(2)	—	Performance specifications
63.8(b)(1)	—	Alternative Monitoring.
63.8(b)(2)-(3)	—	Multiple effluents and multiple monitoring systems
63.8(c)(1)	—	Continuous monitoring system (CMS) operation and maintenance. No CMS at this facility.
63.8(c)(1)(i)	—	Continuous monitoring system parts
63.8(c)(2)-(3)	—	Monitoring system installation
63.8(c)(4)	—	Continuous monitoring system requirements
63.8(c)(6)-(8)	—	CMS requirements
63.8(d)	—	CMS quality control
63.8(e)	—	CMS performance evaluation. Except that §63.8(e) only applies as specified in §63.6645.
63.8(f)(1)-(5)	—	Alternative monitoring method
63.8(f)(6)	—	Alternative to relative accuracy test
63.8(g)	—	Data reduction for CMS

63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
63.9(a)	—	Applicability and State delegation of notification requirements
63.9(b)(1)-(5)		Initial notifications. Except that §63.9(b) only applies as specified in §63.6645.
63.9(c)	—	Request for compliance extension
63.9(d)		Notification of special compliance requirements for new sources
63.9(e)	—	Notification of performance test
63.9(g)(1)	—	Notification of performance evaluation
63.9(g)(3)	—	Notification that criterion for alternative to RATA is exceeded. Except that §63.9(g) only applies as specified in §63.6645.
63.9(h)(1)-(6)		Notification of compliance status
63.9(i)	—	Adjustment of submittal deadlines
63.9(j)		Change in previous information submitted. Due to the nature of the equipment at this facility and SWCAA's review, no such notice will be necessary.
63.10(a)	—	Administrative provisions for recordkeeping/reporting
63.10(b)(1)	VII	Record retention
63.10(b)(2)(vi)-(xi)		Records
63.10(b)(2)(xii)		Record when under waiver
63.10(b)(2)(xiii)	—	Records when using alternative to RATA
63.10(b)(2)(xiv)	—	Records of supporting documentation
63.10(b)(3)	—	Records of applicability determination
63.10(c)	—	Additional records for sources using CEMS
63.10(d)(1)	—	General reporting requirements. Reporting specified as per the applicable standard.
63.10(d)(2)	—	Report of performance test results
63.10(d)(4)		Progress reports. No progress reports required.
63.10(e)(1) and (2)(i)	—	Additional CMS Reports
63.10(e)(3)	—	Excess emission and parameter exceedances reports (CEMS)
63.10(f)	—	Waiver for recordkeeping/reporting. Informational.
63.12		State authority and delegations
63.13	—	Addresses. Informational
63.14	—	Incorporation by reference
63.15	—	Availability of information

40 CFR 60 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units		
Requirement	**Title V Permit Location**	**Comments**
63.9980	—	"What is the purpose of this subpart"
63.9981	—	"Am I subject to this subpart" This facility is subject to this regulation.
63.9982		"What is the affected source for this subpart" Defines the affected source. For this facility the Unit 1 and Unit 2 EGU's are classified as "existing".
63.9983	—	"Are any EGUs not subject to this subpart?" None of the exemptions apply to this facility.
63.9984	—	"When do I have to comply with this subpart?" All of the compliance dates have passed
63.9985	—	"What is a new EGU?" TransAlta's EGU's are not new.
63.9990	—	"What are the subcategories of EGUs?" TransAlta's coal may exceed 8,300 Btu/lb, therefore these units fall into the category of "designed for coal greater than or equal to 8,300 Btu/lb" subcategory – listed elsewhere as "Coal-fired unit not low rank virgin coal."
63.9991	Req-15, Req-20, Req-25, Req-38	"What emission limitations, work practice standards, and operating limits must I meet?" This section refers to the requirements in Tables 1 – 4. Where those requirements are cited, this section that points to those requirements is cited as well.
63.10000	"What are my general requirements for complying with this subpart?"	
63.10000(a)	Req-15, Req-20, Req-25, Req-37	States that must comply with the requirements of this subpart and includes the startup and shutdown exceptions where work-practice standards apply in lieu of emission limits.
63.10000(b)	Req-38	Requirements to operate consistent with good air pollution control practices for minimizing emissions.
63.10000(c)	—	Initial performance testing requirements. All initial performance testing has been completed; therefore, these requirements are not included in the Air Operating Permit.
63.10000(d)	M9	Requires the generation of a site-specific monitoring plan for any CMS or CEMS used to demonstration compliance with an applicable emission limit. This requirement does not apply to affected sources with existing monitoring plans prepared in accordance with 40 CFR 60 Appendix B, or 40 CFR 75. This facility utilizes a CEMS with a monitoring plan in accordance with 40 CFR 75 for SO_2 to demonstrate compliance with acid gas limitations and therefore this CEMS is exempt from this requirement. The plan elements are considered to be met for Hg sorbent trap monitoring systems installed, operated, and quality-assured in accordance with Appendix A of Subpart UUUUU. This facility utilizes a sorbent trap monitoring system to monitor Hg emissions in accordance with Appendix A of Subpart UUUUU, therefore the plan elements are met. The only remaining requirements are to operate the Hg monitoring system in accordance with the site-specific monitoring plan (i.e. Appendix A).

40 CFR 60 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units		
Requirement	**Title V Permit Location**	**Comments**
63.10000(e)	Req-36	Requirement to conduct periodic tune-ups according to 40 CFR 63.10021(e).
63.10000(f)	—	Requires that EGUs remain subject to this subpart at least 6 months after the EGU met definition of a subject EGU. This section is information and does not contain additional applicable requirements.
63.10000(g)	—	States that EGUs no longer meeting the definition of an EGU subject to this part must comply with any new requirements on the date no longer subject to this subpart. This section is information and does not contain additional applicable requirements.
63.10000(h)	—	Requirements related to EGUs that become subject after April 16, 2015. The only EGU's at this facility were already subject to this subpart as of April 16, 2015 therefore this does not apply to the EGUs at this facility.
63.10000(i)	—	Requirements for EGU's that cease to operate in a manner that causes the EGU to meet the definition of an EGU subject to this subpart. This section is not currently applicable. No change in applicability is anticipated in the permit term.
63.10000(j)	—	Requirement to have operational pollution control equipment as required for the EGU classification (subject or not subject to this subpart) as of the date the relevant standard is applicable. This section is not currently applicable. No change in applicability is anticipated in the permit term.
63.10000(k)	—	Requirement to have operational pollution monitoring equipment as required for the EGU classification (subject or not subject to this subpart) as of the date the relevant standard is applicable. This section is not currently applicable. No change in applicability is anticipated in the permit term.
63.10000(l)	M33, M10	No later than the date an EGU is subject, must have all necessary monitoring in place for PM or non-Hg HAP metals during startup and shutdown. Must collect, record, report, and maintain data for startup and shutdown periods to demonstrate compliance with work practice standards.
63.10000(m)	M33, M10	If using paragraph (2) of startup definition, must have all necessary monitoring in place for PM or non-Hg HAP metals on or before applicability date. Must collect, record, report and maintain applicable data.
63.10000(n)	—	If permanently convert to natural gas or biomass firing, the EGU is no longer subject to this subpart. This section is information and does not contain additional applicable requirements.
63.10005	Req 15, Req-20, Req-25	What are my initial compliance requirements and by what date must I conduct them? Although all initial compliance requirements have been completed, the reference in 63.10005(a) that clarifies that where two emission limits are specified compliance may be demonstrated with either limit, was listed for reference where two limits were specified.

40 CFR 60 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units		
Requirement	**Title V Permit Location**	**Comments**
63.10006	When must I conduct subsequent performance tests or tune-ups?	
63.10006(a)		Requirements for units using PM CPMS. This facility conducts quarterly testing in lieu of PM CPMS.
63.10006(b)		Requirements for LEE units. The EGUs at this facility do not meet LEE requirements, therefore this section is not applicable.
63.10006(c)	M9	Requirement to conduct periodic filterable PM testing or total HAP metals in accordance with Table 5, 63.10007, 63.10000(c) except as provided in 63.10021(d)(1).
63.10006(d)	—	HCl testing requirements for units that do not use CEMS to demonstrate compliance with acid gas limitations. This facility uses a SO_2 CEMS to demonstrate compliance therefore this section is not applicable.
63.10006(e)	—	Requirements for acid gas monitoring for liquid oil-fired EGUs.
63.10006(f)	M9	Time between performance tests. This applies to the quarterly PM testing.
63.10006(g)		Emissions averaging provisions. This facility does not conduct emissions averaging and starting in 2021 will only operate one unit.
63.10006(h)	—	LEE test provisions. The EGUs at this facility do not meet LEE requirements, therefore this section is not applicable.
63.10007	What methods and other procedures must I use for the performance test?	
63.10007(a)	M8, M9, R7	Requirements to comply with general test requirements of 63.7 and develop a site-specific test plan. Permanent testing facilities have been installed in accordance with 63.7(d).
63.10007(b)	M8, M9	Requirement to conduct performance tests in accordance with Table 5.
63.10007(c)	—	Requirements for tests for facilities with PM CEMS. This facility utilizes quarterly PM testing option in lieu of PM CEMS, therefore this section is not applicable.
63.10007(d)	M8, M9	Requirement to conduct 3 separate runs and meet the time and volume requirements of Table 1 or 2.
63.10007(e)	M9	This section explains how to use the performance test results to determine compliance with applicable emission limits. M8 contains a general reference to conduct the testing in accordance with 63.10007.
63.10007(f)	M9	Default values for startup and shutdown period CEMS calculations. This would apply to the SO_2 CEMS.
63.10007(i)	M8	Requirement to provide documentation of performance tests to the EPA Administrator upon request.
63.10009		May I use emissions averaging to comply with this subpart. This facility has not utilized the option to use emissions averaging.
63.10010	What are my monitoring, installation, operation, and maintenance requirements?	
63.10010(a)	M8	Allowable locations for CEMS and sorbent trap monitoring systems based on the stack configuration. The applicable equipment at this facility are the SO_2 CEMS and the Hg sorbent trap monitoring systems.
63.10010(b)	M9	O_2/CO_2 monitoring requirements.

40 CFR 60 Subpart UUUUC – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units		
Requirement	**Title V Permit Location**	**Comments**
63.10010(c)	M9	Requirement to monitor flow in accordance with 40 CFR 75. (required for Hg monitoring).
63.10010(d)	M9	Requirement to monitoring moisture in accordance with 40 CFR 75. Moisture data is necessary to correlate wet flow measurements with dry Hg measurements.
63.10010(e)	—	Requirements for sources utilizing HCl and/or HF CEMS. This facility utilizes the SO_2 CEMS option, therefore this requirement does not apply.
63.10010(f)	M9	Requirement to monitor SO_2 in accordance with 40 CFR 75 if utilizing the SO_2 CEMS option for acid gas monitoring. This option is used by this facility. This additional requirements in section (2) do not apply because this facility does not utilize a span of 30 ppm or less.
63.10010(g)	M9	Hg monitoring and data reduction requirements.
63.10010(h)	—	Requirements for source utilizing PM CPMS to demonstrate compliance with an operating limit. This facilaty does not utilize the PM CPMS option.
63.10010(i)	M9	Requirements for PM CEMS for sources complying with filterable PM limit in lieu of metal HAP limit. This facility utilizes the alternative quarterly PM testing option; however, the PM CEMS option was included in M8 as an alternative.
63.10010(j)	—	Requirements applicable to the use of a metal HAP CEMS. This facility utilizes the alternative quarterly PM testing option.
63.10010(k)	—	Requirements applicable to quarterly HCl and HF testing of liquid oil-fired EGUs.
63.10010(l)	M33	Quality assurance and site-specific monitoring plan requirements for startup monitoring systems.
63.10011	—	Initial compliance demonstration requirements. The references to 63.10011 were removed from Air Operating Permit because all initial demonstrations have been completed.
63.10020	"How do I monitor and collect data to demonstrate compliance?"	
63.10020(a)	—	General requirement to monitor in accordance with the requirements in 63.10020 and the site-specific monitoring plan. These referenced requirements are contained in other sections.
63.10020(b)	M9	Monitoring requirements and exceptions.
63.10020(c)	M9	Lists what data must be excluded from compliance calculations.
63.10020(d)	M9	Requires monitoring at all times with specific exceptions.
63.10020(e)	M10	Startup and shutdown work practice monitoring requirements
63.10021	"How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?"	
63.10021(a)	—	General requirement to demonstrate compliance with applicable requirements. These referenced requirements are contained in other sections.
63.10021(b)	M9	Describes how to use CEMS data to demonstrate compliance.

40 CFR 60 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units		
Requirement	**Title V Permit Location**	**Comments**
63.10021(c)	—	Requirements for use of a PM CPMS. This facility does not utilize a PM CPMS.
63.10021(d)	M9	Contains details related to performance monitoring.
63.10021(e)	Req-36, R11	Tune-up requirements.
63.10021(f)	R11	Repeats the requirements to use ECMPS Client Tool for submittal of a variety of reports, specifies implications of weekend, holiday, and ECMPS outages. Although it does contain some exceptions for holidays, ECMPS system outages, etc. this section is primarily informational in nature, the specific reporting requirements are detailed elsewhere.
63.10021(g)	R4	Requirement to report deviations from emission limits, operating limits, or failed to conduct a tune-up.
63.10021(h)	M9	Requirement to following the startup or shutdown requirements in Table 3 and conduct all required monitoring during startup and shutdown. General requirements in this section that repeat the requirement to comply with another section are not reproduced in the permit.
63.10021(i)	R4	General requirement to report activities during startup and shutdown in accordance with 63.10031.
63.10022	—	"How do I demonstrate continuous compliance under the emissions averaging provision?" This facility has not utilized the option to use emissions averaging.
63.10023	—	"How do I establish my PM CPMS operating limit and determine compliance with it?" This facility does not utilize a PM CPMS.
63.10030	What notifications must I submit and when?	
63.10030(a)	M8, M9, R11	General requirement to submit the notifications required by 40 CFR 63.7, 63.8, and 63.9 as applicable except that only certain provision of 63.9 apply (see 40 CFR 63.10040 and Table 9). The only remaining notifications are for performance tests and RATAs (30-days prenotification required for each in accordance with Table 9)
63.10030(b)	—	Initial notification deadline for existing units. Initial notifications have been submitted.
63.10030(c)	—	Initial notification deadline for "new" units. Initial notifications have been submitted.
63.10030(d)	M8	Performance test notification.
63.10030(e)	—	Initial Notice of Compliance Status report requirements. All initial notifications have been submitted.
63.10030(f)	—	Requirement to submit the notification in 40 CFR 63.10000(h)(2) and (i)(2) that apply. This is applicable to newly applicable EGUs and EGUs that modify their operation such that they are no longer subject to this subpart. Both units at this facility are "existing" and no change in applicability is anticipated in the permit term.
63.10031	What reports must I submit and when?	

40 CFR 60 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units		
Requirement	**Title V Permit Location**	**Comments**
63.10031(a)(1)	R11	Hg CMS reporting requirements found in Appendix A are referenced here.
63.10031(a)(2)	—	Not applicable because this facility does not elect to monitor HCl and/or HF continuously. Instead, this facility continuously monitors SO_2 as a surrogate for HCl.
63.10031(a)(3)	—	Not applicable because this facility conducts quarterly PM stack tests instead of operating a PM CEMS.
63.10031(a)(4)	—	Not applicable because this facility conducts quarterly PM stack tests instead of operating a PM CEMS.
63.10031(a)(5)	R11	SO_2 CEMS reporting requirements.
63.10031(b)	R11	Semiannual reporting requirements.
63.10031(c)	R11	Semiannual report contents.
63.10031(d)	R11	Excess emissions and deviation reporting. Re-states the requirement in 40 CFR 63.10031(c)(1) to include the CMS summary report from 63.10(e)(3)(vi) in the semiannual report, and re-states the requirement from 40 CFR 63.10031(g) to report the applicable data elements from Section 13 of Appendix E in the quarterly reports that replace the semiannual reports in 2024.
63.10031(e)	R4	Requirement to report deviations in the semiannual Title V report unless the deviation has been reported in the semiannual or quarterly Subpart UUUUU reports and these reports are submitted with, or as part of, the semiannual Title V report.
63.10031(f)	R4	Compliance test reporting. The only applicable test is the filterable PM testing.
63.10031(f)(1)	R4	RATA test reporting. This facility does not have, and is not likely to install, PM, HCl, or HF CEMS, therefore references to these systems were removed.
63.10031(f)(2)	—	Provisions for commons stacks. This facility does not have any common stacks.
63.10031(f)(3)	—	Reserved
63.10031(f)(4)	R4	Semiannual compliance reports. This section re-states the requirement to submit semiannual reports in accordance with 63.10031(b) – (d) and the initial Notice of Compliance Status (NCS) reports required by 63.10030(e) and adds that they must be submitted as PDF files. All applicable NCS have been submitted

40 CFR 60 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units		
Requirement	**Title V Permit Location**	**Comments**
63.10031(f)(5)	—	Requires all reports not in 63.10031(f), (f)(1), (f)(2) and (f)(4) to be submitted to the Administrator at the applicable address listed in 63.13. This requirement is at odds with 63.10021(f) which states that all reports must be submitted electronically using the ECMPS Client Tool, and the specific reporting requirements listed in the applicable reporting sections and Table 8. Because this section appears to be at odds with the intent of the revisions meant to simply report submission published in the Federal Register September 9, 2020, and is directly at odds with other submission requirements, it was not included in the Title V permit.
63.10031(f)(6)	R11	This section contains details of how to submit reports to ECMPS. Since it appears that all reports must be submitted to ECMPS, this requirement was included in the first paragraph of R11 as applicable to all reports.
63.10031(g)	R11	Details for quarterly report submissions that begin in 2024.
63.10031(h)	—	Initial Notice of Compliance Status reports submitted on or after January 1, 2024. All initial reports have been completed.
63.10031(i)	R11	This section is applicable to this facility because this facility uses the "paragraph (2)" definition of startup.
63.10031(j)	—	Applicable if use PM CEMS. This facility does not use PM CEMS.
63.10031(k)	—	Applicable if use PM or HAP metals CEMS. This facility does not use PM or HAP metal CEMS.
63.10032	What records must I keep?	
63.10032(a)	M10, M37	Records of notifications and reports.
63.10032(b)	M10	CEMS and CPMS recordkeeping.
63.10032(c)	M10	Requires maintaining records of the information listed in Table 7.
63.10032(d)	M10	Of the 3 requirements listed, only the requirement to keep records of monthly fuel use applies to this facility.
63.10032(e)		Recordkeeping for emissions averaging. This facility does not utilize emissions averaging.
63.10032(f)	M10	Startup and shutdown period records.
63.10032(g)	M10	Malfunction records
63.10032(h)	M10	Records of responses to malfunctions.
63.10032(i)	M10	Records of fuel use during startup and shutdown.
63.10032(j)		Recordkeeping to prove EGU qualifies as limited-use liquid oil-fired.
63.10033	M10	Record form and retention requirements
63.10040	—	Informational. Indicates that Table 9 shows which general provisions from part 63 apply.
63.10041	—	Who implements and enforces this subpart? This section does not contain applicable requirements
63.10042	Req-15, Req-20, Req-25, Req-37	Definitions. The definition of "startup" contains two options and is relevant to several requirements.

40 CFR 60 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units		
Requirement	**Title V Permit Location**	**Comments**
Table 1	—	Emission Limits for New or Reconstructed EGUs.
Table 2	Req-15, Req-20, Req-25, M9	Emission Limits for Existing EGUs
Table 3	Req-36, Req-37, Req-38, Req-41, M9	Work Practice Standards
Table 4	—	Operating Limits for EGUs – applies only to PM CPMS. This facility does not use PM CPMS.
Table 5	Req-15, Req-20, Req-25, M9	Performance Testing Requirements
Table 6	—	Establishing PM CPMS Operating Limits. This facility does not use PM CPMS.
Table 7	Req-36, M9	Demonstrating Continuous Compliance.
Table 8	R4, R11	Reporting Requirements.
Table 9	M8, M9, M10	Applicability of General Provisions to Subpart UUUUU.
Appendix A	M9	Hg Monitoring Provisions.
Appendix B	--	HCl and HF Monitoring Provisions. This facility has elected to continuously monitor SO_2 in lieu of HCl and HF.

Second Revision of BART Order No. 6426		
Condition	**Title V Permit Location**	**Comments**
1.1	Req-27b	NO_X limits.
1.2	Req-27b	Requirement to calculate the 30-day rolling average in accordance with Condition 5.
1.3	—	Informational. Explains that the Permittee is not limited in how to achieve compliance with the NO_X limits.
2.1	Req-30	Ammonia emission limit
2.2	—	Informational. Explains that the injection of urea to meet the NO_X emissions limit is at the Permittee's discretion.
3.1	Req-31	End of coal burning by first unit.
3.2	Req-31	End of coal burning by second unit
3.3	Req-27b	References the requirement to comply with Condition 1.1.3.
3.4	Req-21	Describes when Conditions 3.1 and 3.2 would not apply.
4.1 except 4.1.4	M8	Ammonia testing requirements

Second Revision of BART Order No. 6426		
Condition	**Title V Permit Location**	**Comments**
4.1.4	Req-30	Describes how compliance with the 30-day rolling average ammonia limit is determined.
5	Req-27b, M9	Describes how NO_X emissions are monitored and averaged for compliance with the BART NOx limit.
6	R9	Reporting the end of coal firing in each boiler.
7	R9	Urea usage letter
8	R1	BART Order malfunction emission exceedance reports
9.1.1 & 9.1.2	R3	BART Order quarterly reports
9.1.3	R7	Ammonia test reports must be submitted with 45 days of test completion.
9.2	R3	Emission monitoring report requirements.

EXHIBIT 18

(Native Format)

EXHIBIT 19



State Implementation Plan Revision

Second Regional Haze Plan (2018 – 2028)

By

Air Quality Program

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Contact Information

Air Quality Program

P.O. Box 47600
Olympia, WA 98504-7600
Phone: 360-407-7600
Website: www.ecology.wa.gov/contact

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Map of Counties Served



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Northwest	Island, King, Kitsap, San Juan, Skagit, Snohomish, Whatcom	15700 Dayton Avenue N. Shoreline, WA 98133	206-594-0000
Central	Benton, Chelan, Douglas, Kittitas, Klickitat, Okanogan, Yakima	1250 West Alder Street Union Gap, WA 98903	509-575-2490
Eastern	Adams, Asotin, Columbia, Ferry, Franklin, Garfield, Grant, Lincoln, Pend Oreille, Spokane, Stevens, Walla Walla, Whitman	4601 North Monroe Spokane, WA 99205	509-329-3400
Headquarters	Statewide	P.O. Box 46700 Olympia, WA 98504	360-407-6000

State Implementation Plan Revision

Second Regional Haze Plan (2018 – 2028)

Air Quality Program
Washington State Department of Ecology
Headquarters

Olympia, WA



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Appendices

Due to document size constraints, all appendices are available as separate documents. Note that some of the content was not drafted by Ecology and cannot meet Ecology's document accessibility requirements.

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The principal contributors from Ecology:

Anya Caudill
Philip Gent
Gary Huitsing
Jean-Paul Huys
Scott Inloes
Margaret Plummer
Colleen Stinson
Farren Thorpe

The managers from Ecology who provided review and oversight:

Jason Alberich
Martha Hankins
Chris Hanlon-Meyer

Acronyms, Abbreviations, and Terms

Anthropogenic	Caused or produced by humans
ARS	Air Resource Specialist, Inc.
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
Btu	British thermal unit
CAA	Clean Air Act
CAMx	Comprehensive Air Quality Model with Extensions
CD	Clearest days
CFR	Code of Federal Regulations
CIRA	Cooperative Institute for Research in the Atmosphere
CISWI	Commercial and Industrial Solid Waste Incineration Units
CM	Coarse Matter
CMAQ	Community Multi-Scale Air Quality Model
CO	Carbon Monoxide
CO_2	Carbon Dioxide
DNR	Washington Department of Natural Resources
dv	Deciview; a measure of light extinction
EC	Elemental Carbon
Ecology	Washington State Department of Ecology
EGU	Electric Generating Unit
EI	Emission Inventory
EPA	US Environmental Protection Agency
FCCU	Fluid Catalytic Cracking Unit
FIP	Federal Implementation Plan
FLM	Federal Land Manager
GCVTC	Grand Canyon Visibility Transport Commission
GHG	Greenhouse Gas
Glidepath	The rate of improvement sufficient to attain natural conditions by 2064
HI	Haze Index
IMPROVE	Interagency Monitoring of Protected Visual Environments
LTS	Long Term Strategy
MARPOL VI	Maritime Pollution Annex VI
MID	Most Impaired Days
Mm^{-1}	Inverse megameter; a measure of light extinction
MM	Million
MM5	Meteorological Mesoscale 5
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	Ammonia
$(NH_4)2SO_4$	Ammonium Sulfate
NO_2	Nitrogen Dioxide
NO_3	Ammonium Nitrate or NH4NO3
NOx	Nitrogen Oxides

NPCA	National Parks Conservation Association
NPDES	National Pollutant Discharge Elimination System
NPS	National Park Service
NSPS	New Source Performance Standards
NSR	New Source Review
NTEC	National Tribal Environmental Council
NWPPA	Northwest Pulp and Paper Association
O_3	Ozone
OC	Organic Carbon
ODEQ	Oregon Department of Environmental Quality
OM	Organic Mass
OMC	Organic Mass of Carbon
PM	Particulate Matter
$PM_{2.5}$	Fine Particles or Particulate Matter with an aerodynamic diameter of 2.5 microns or less
PM_{10}	Coarse Particles or Particulate Matter with an aerodynamic diameter of 10 microns or less
POA	Primary Organic Aerosol
ppm	parts per million
PSAT	Particulate Matter Source Apportionment Technology
PSD	Prevention of Significant Deterioration
RACT	Reasonably Available Control Technology
RAVI	Reasonably Attributable Visibility Impairment
RH	Regional Haze
RHR	Regional Haze Rule
RPG	Reasonable Progress Goal
RPO	Regional Planning Organization
RRF	Relative Response Factors
SIP	State Implementation Plan
SMOKE	Sparse Matrix Operator Kernel Emissions
SMP	Smoke Management Plan
SOIL	Fine Soil
SO_2	Sulfur Dioxide
SO_4	Ammonium Sulfate or $(NH_4)_2SO_4$
SOx	Sulfur Oxides
TIP	Tribal Implementation Plan
TSS2	Technical Support System
URP	Uniform Rate of Progress
USDA FS	U.S. Department of Agriculture – Forest Service
USDI FWS	U.S Department of the Interior – Fish and Wildlife Service
USDI NPS	U.S. Department of the Interior – National Park Service
USGS	U.S. Geological Survey
VOC	Volatile Organic Compound
WAC	Washington Administrative Code

WEP	Weighted Emissions Potential
WESTAR	Western States Air Resources Council
WRAP	Western Regional Air Partnership

Executive Summary

This report is Washington's second Regional Haze State Implementation Plan covering 2018 through 2028 and the progress report for 2014 through 2018. The Regional Haze Rule requires Washington to meet natural visibility conditions (no human-caused haze) in our eight mandatory Class 1 federal Areas by 2064.

The plan must:

- Establish goals to improve visibility in Washington's three national parks and five wilderness areas (mandatory Class 1 federal Areas).
- Develop long-term strategies to reduce air pollution that causes poor visibility:
  - Improve visibility on the 20 percent most polluted days;
  - Protect current visibility on the 20 percent clearest days;
  - Identify and reduce Washington's air impacts to mandatory Class 1 federal Areas outside Washington.

Ecology identified that:

- Two mandatory Class 1 federal Areas (Goat Rocks Wilderness and Mount Adams Wilderness) are forecast to meet natural conditions (EPA's visibility goals) by 2028.
- Emissions from transportation are the largest source of air pollution that causes poor visibility. We have started rulemaking to reduce transportation emissions:
  - Chapter 173-423 WAC, Clean Vehicles Program, which adopts California's more protective vehicle emission standards;
  - Chapter 173-424 WAC, Clean Fuels Program Rule, which reduces pollution from vehicle fuels.
- Emissions from petroleum refineries contribute to poor visibility. We plan to identify emission controls, if any, to reduce emissions from refineries. After we have identified and scheduled installation of controls, we will amend this plan.

Washington's second Regional Haze State Implementation Plan:

- Establishes 2028 visibility goals for Washington's mandatory Class 1 federal Areas.
- Develops a long-term strategy to improve visibility.
- Provides inventories of emissions causing a visibility problem.
- Analyzes sources of haze in Washington's mandatory Class 1 federal Areas.
- Selects and evaluates the largest emitting stationary sources for potential emission controls.
  - Determines reasonable controls using a reasonability analysis.
  - Determines the emission controls that sources must install to improve visibility.

Chapter 1. Regional Haze Program Overview and Plan Development

1.1 Background

In 1977, Congress amended the Clean Air Act (CAA), 42 U.S.C. 7401 et seq., to include provisions to protect scenic vistas in certain Class 1 Areas. In these amendments, Congress declared a national visibility goal:

> *"The prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution." (CAA Section 169A)*

In 1979, EPA, in consultation with the Secretary of the Interior, established 156 mandatory class 1 federal Areas (Class 1 Areas) in which they determined visibility was an important factor. EPA designated eight Class 1 Areas in Washington.

EPA promulgated reasonably attributable visibility impairment (RAVI) regulations in 1980 to address the national visibility goal. RAVI regulations address distinct plumes (called "plume blight") caused by large stationary sources. RAVI regulations represented the first phase in addressing visibility impairment. Each state must develop visibility plans as part of the larger air quality State Implementation Plan (SIP). The SIP is a large body of federally-enforceable state regulations, programs, and permits that implement, maintain, and enforce federal ambient air quality standards and the Regional Haze Program.

The Washington State Department of Ecology (Ecology) revised the SIP for the purpose of visibility protection (Visibility SIP) and submitted it to EPA in March 1985. EPA formally approved the Visibility SIP on May 4, 1987. Ecology reviewed and revised the Visibility SIP several times since then.

Washington's Visibility SIP addressed the distinct plumes from large stationary sources and silvicultural smoke. Although we do not consider prescribed burning from forestry activities a stationary source, prescribed burning has a significant impact on visibility. Because of this, Washington addressed this source in its Visibility SIP. Specifically, Ecology coordinated with the Washington Department of Natural Resources (DNR) to include visibility protections in the 1998 Smoke Management Plan (SMP). Ecology submitted a RAVI SIP — including the 1998 SMP —that focused on silvicultural (forest) smoke management in addition other sources that affect haze. Ecology submitted the 1999 RAVI SIP to EPA on November 5, 1999; EPA approved it June 11, 2003.[1]

EPA adopted the Regional Haze Rule (RHR) in 1999. The RHR addressed visibility impairment from widespread haze caused by emissions from multiple sources. These emissions often mix and

[1] Final Federal Register Notice: 68 FR 34821, June 11, 2003. https://www.govinfo.gov/content/pkg/FR-2003-06-11/pdf/03-14573.pdf#page=1; Proposal Federal Register Notice: 67 FR 65077, October 23, 2002. https://www.govinfo.gov/content/pkg/FR-2002-10-23/pdf/02-26992.pdf

disperse over long distances. The RHR established a comprehensive visibility protection program for the 156 Class 1 Areas.

In 2010, Ecology developed its first Regional Haze SIP (Ecology, 2010, revised 2012). It identified key sources of air pollution and defined a strategy to improve visibility in Washington's Class 1 Areas during the first planning period from 2005 through 2018. Ecology submitted the required Regional Haze Five Year Progress Report for the state (Ecology, 2017) in 2017. This document is the second Regional Haze SIP and covers the 10-year period from 2018 through 2028. It also serves as the progress report for 2014 through 2018.

For information on Washington's Regional Haze program, visit Ecology's Regional Haze website (Ecology, 2021).[2]

1.2 Regional Haze Rule

The objectives of the RHR are:

- Improve existing visibility in all 156 Class 1 Areas;
- Prevent future impairment of visibility by anthropogenic sources; and
- Meet the national goal of natural visibility conditions by 2064.

The RHR requires each state to adopt a RH SIP that focuses on improving visibility in the 20 percent most impaired days (MID), and protecting visibility in the 20 percent clearest days. A state's RH SIP must provide a comprehensive analysis of natural and anthropogenic sources of haze in each Class 1 Area within the state and contain strategies to control and reduce emissions that contribute to haze. For each Class 1 Area, the state must establish reasonable progress goals (RPGs) for each implementation period towards achieving natural visibility conditions. The RPGs must provide an improvement in visibility for the most impaired days over the period of the implementation plan and maintain the visibility for the clearest days over the same period. The SIP must also address Class 1 Areas outside of the state that we anticipate emissions from within the state might affect.

The RHR breaks the regional haze program into several planning periods from 2005 to 2064. The first RH SIP covered the initial planning period from 2005 - 2018. That SIP established the basis for future RH SIP revisions and initiated the process of making reasonable progress toward the 2064 goal. This second RH SIP covers the planning periods from 2018 - 2028.

In 2017, EPA revised the RHR. EPA clarified the relationship between long-term strategies and RPGs in state plans and the long-term strategy obligations of all states. EPA reiterated that the CAA requires states to consider four statutory factors in each implementation period to determine the rate of progress towards natural visibility conditions that is reasonable for each Class 1 Area. Those four factors are:

- Costs of compliance;
- Time necessary for compliance;
- Energy and non-air quality environmental impacts; and

[2] https://ecology.wa.gov/Air-Climate/Air-quality/Air-quality-targets/Regional-haze

- Remaining useful life of the facility.

The 2017 RHR revisions also addressed other issues, including:

- Described the way in which we select a set of days during each year for purposes of tracking progress towards natural visibility conditions;
- Revised some requirements for the content of progress reports;
- Updated, simplified, and extended to all states the provisions for reasonably attributable visibility impairment;
- Revoked federal implementation plans adopted in the 1980s that require EPA to assess and address any existing RAVI situations in some states;
- Revised the requirement for states to consult with the federal land managers (FLMs);
- Adjusted the due date for the next SIP from 2018 to 2021;
- Revised the due dates for progress reports; and
- Changed the requirement that states submit progress reports as formal SIP revisions to documents that need not comply with the procedural requirements of 40 CFR 51.102, 40 CFR 51.103, and Appendix V to Part 51.

Changes to FLM consultation requirements will bring the expertise and perspective of these officials into the state plan development process early enough that they can meaningfully contribute to the state's deliberations.

1.3 Progress report requirements

This RH SIP revision also serves as a progress report that demonstrates Washington's progress towards the 2018 Reasonable Progress Goals (RPGs) during the period since the previous progress report. To serve as a progress report, the 2021 Regional Haze Plan revision must address the *Requirements for periodic comprehensive revisions of implementation plans for regional haze in* 40 CFR 51.308(f) and (g). Each state must analyze the following elements in evaluating progress towards intermediate visibility goals. These elements include:

- A status update of all controls that were implemented and relied on to achieve the RPGs;
- A summary of the emissions reductions;
- A current conditions analysis including the clearest and most impaired days;
- Any changes to the speciated analysis at each Class 1 Area to identify if there are changes to which pollutants impact visibility in each Class 1 Area;
- Updated emissions inventory and any changes in emissions and sources;

EPA also specifies that the evaluation period should only cover the period since the last progress report, and include the most recent five years of available data.

In October 2017, Ecology submitted to EPA the progress report (Ecology, 2017). The report was originally due to EPA in 2015, using the data from 2009 – 2013. However, due to the delay in submitting the report, we reviewed intermediate progress based on the data collected during the 2009 - 2013 period as well as 2010 – 2014. The 2017 Progress Report addressed the following:

- Status of RH Plan state strategy
- Emissions reductions from RH Plan control strategies

- Visibility progress and emission inventory trends
- Assessment of changes impeding visibility progress
- Review of visibility monitoring strategy
- RH Plan adequacy determination
- FLM comments

We concluded in our 2017 Progress Report that visibility in Washington's Class 1 Areas improved since the 2000 – 2004 baseline period, and the visibility measured in the 2010–2014 period met or exceeded the 2018 visibility goals.

In the current 2021 RH SIP revision, however, EPA recalculated visibility metrics. At the time of the preparation of this RH SIP revision, the most recent data available for the analysis was for the 2014 – 2018 five-year period.

Preliminary raw Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring data for 2019 was presented via the FLMs Environmental Database website to the public in February 2021.[3] However, we did not use this raw data for this progress report because it could be incomplete and any missing data substitutions would influence progress report analysis.

Table 1-1 describes each of the progress report elements required by EPA and references relevant chapters in this RH SIP revision where it addresses each element.

Table 1-1: EPA required elements of the Progress Report and the corresponding references in relevant chapters.

Progress Report Element	Chapter where Addressed
40 CFR 51.308(g)(1) A description of the status of implementation of all measures included in the implementation plan for achieving reasonable progress goals for mandatory Class 1 Federal areas both within and outside the State	Chapter 9. Reasonable Progress Goals.
40 CFR 51.308(g)(2) A summary of the emissions reductions achieved throughout the State through implementation of the measures described in paragraph (g)(1) of this section.	Chapter 4. Emissions Inventory.
40 CFR 51.308(g)(3) For each mandatory Class 1 Federal area within the State, the State must assess the following visibility conditions and changes, with values for most impaired, least impaired and/or clearest days as applicable expressed in terms of 5-year averages of these annual values. The period for calculating current visibility conditions is the most recent 5-year period preceding the required date of the progress report for which data are available as of a date 6 months preceding the required date of the progress report.	Chapter 3. Current Visibility Conditions in Washington's Class 1 Areas.

[3] http://vista.cira.colostate.edu/Improve/aqrv-summaries/

Progress Report Element	Chapter where Addressed
40 CFR 51.308(g)(4) An analysis tracking the change over the period since the period addressed in the most recent plan required under paragraph (f) of this section in emissions of pollutants contributing to visibility impairment from all sources and activities within the State. Emissions changes should be identified by type of source or activity. With respect to all sources and activities, the analysis must extend at least through the most recent year for which the state has submitted emission inventory information to the Administrator in compliance with the triennial reporting requirements of subpart A of this part as of a date 6 months preceding the required date of the progress report. With respect to sources that report directly to a centralized emissions data system operated by the Administrator, the analysis must extend through the most recent year for which the Administrator has provided a State-level summary of such reported data or an internet-based tool by which the State may obtain such a summary as of a date 6 months preceding the required date of the progress report. The State is not required to backcast previously reported emissions to be consistent with more recent emissions estimation procedures, and may draw attention to actual or possible inconsistencies created by changes in estimation procedures.	Chapter 3. Current Visibility Conditions in Washington's Class 1 Areas. Chapter 4. Emissions Inventory. Chapter 5. Western Regional Air Partnership Modeling. Chapter 7. Source Apportionment and Impacted Class 1 Areas. Chapter 9. Reasonable Progress Goals.
40 CFR 51.308(g)(5) An assessment of any significant changes in anthropogenic emissions within or outside the State that have occurred since the period addressed in the most recent plan required under paragraph (f) of this section including whether or not these changes in anthropogenic emissions were anticipated in that most recent plan and whether they have limited or impeded progress in reducing pollutant emissions and improving visibility.	Chapter 4. Emissions Inventory.

The current implementation plan elements and strategies are sufficient to enable Washington or other states with Class 1 Areas affected by emissions from Washington, to meet all established RPGs for the period covered by the first implementation plan. All Washington Class 1 Area 2018 RPGs were below the uniform rate of progress and Washington remains on track to meet the long-term goal of natural conditions by 2064.

1.4 Regional haze state implementation plan development

Regional haze planning requires a regional approach to visibility impairment. This section provides background on:

- Regional planning to address regional haze.
- The role of the Western Regional Air Partnership (WRAP) in the development of this second regional haze State Implementation Plan (RH SIP).

Regional planning

Haze-causing pollutants originate from numerous sources located in different geographic areas and can transport over long distances. In recognition of this, EPA encouraged states to create regional planning organizations (RPOs) to coordinate regional activities related to the Regional Haze Rule (RHR). States formed—and EPA funded—five RPOs, which collectively cover the 48 contiguous states, Alaska, and Hawaii (Figure 1–1).



Figure 1–1: Regional Planning Organizations

Western Regional Air Partnership

The Western Regional Air Partnership (WRAP) is a voluntary organization of western states, tribes, and federal agencies that work collaboratively to address visibility impairment in Class 1 Areas. WRAP formed in 1997 as the successor to the Grand Canyon Visibility Transport Commission (GCVTC). The 1990 Amendments to the CAA authorized the formation of visibility transport commissions and required EPA to establish the GCVTC.

WRAP promoted, supported, and monitored the implementation of the GCVTC's June 1996 recommendations for improving visibility in the 16 national parks and wilderness areas on the Colorado Plateau. The recommendations developed by the GCVTC represented a significant milestone in the study of regional haze. The GCVTC's technical analysis found the customary focus on mitigating visibility impairment from stack plumes associated with stationary point sources insufficient to address the wide range of pollutants and sources that caused or contributed to visibility impairment across the Colorado Plateau. The GCVTC's air quality monitoring and modeling showed that the long-range transport (more than 100 miles) of emissions from numerous and widespread sources contributed to regional haze.

The RHR expanded the focus of regional visibility planning processes in the West from the Colorado Plateau to all western Class 1 Areas. WRAP embraced this geographic expansion by expanding its role to address regional haze in all 13 contiguous western states, Alaska, and Hawaii.

The focus of WRAP for this second RH SIP is technical analysis. WRAP has engaged in compilation of ambient monitoring, emission inventories, air quality modeling, and data analysis. The result is a regionally consistent body of technical data and analysis to address regional haze in the west. WRAP also provides a forum for coordination and consultation between states, tribes, and FLMs.

WRAP staff work through committees, and workgroups composed of states, tribes, FLMs, and EPA. Various state and federal agencies provide additional staff time. WRAP also contracts with environmental consulting firms for analysis of air pollution data, compilation and preparation of emissions inventory data, photochemical modeling, and analyses of natural and/or uncontrollable air pollution sources.

Washington's consultation with other states, tribes, and FLMs.

Addressing regional haze requires communication between states, tribes, EPA, and FLMs. Communications can be both informal and formal. The RHR has requirements for a state to consult with the FLMs administering Class 1 Areas within a state. This section discusses the role of consultation between the state of Washington and other states, tribes, and FLMs in the development of the second RH SIP.

Consultation with other states

The RHR requires consultation between states on the development of coordinated emission management strategies. This requirement applies both to Class 1 Areas within Washington, and to Class 1 Areas outside Washington, where we anticipate emissions from Washington contribute to visibility impairment.

Coordination facilitates completion of technical tasks and policy decisions in areas such as:

- Monitoring
- Emissions
- Source attribution
- Modeling
- Control measures

This extensive coordination results in an RH SIP that reflects Washington's implementation of a regionally consistent approach to addressing visibility impairment in the west.

Washington held several conference calls with neighboring states (Alaska, Idaho and Oregon) from 2019 through 2021 to discuss the progress of regional haze plan development, including discussions on the RACT/four factor analysis and control strategies (Appendix R). Our participation in WRAP also fostered a regionally consistent approach to regional haze planning in the western states and provided a sound mechanism for consultation (Appendix K). Consultation among the fifteen western states within WRAP continues through conference calls and WRAP sponsored working group updates and results meetings.

Tribal notification

Although the RHR does not have a requirement for formal consultation with the tribes, Washington notified tribes in Washington, and federally recognized tribes in Oregon, and Idaho closest to Washington, of the development of the RH SIP. This was an informative letter to the chairpersons of the tribes in Washington. We followed up with invitations to chairpersons, natural resource managers, and tribal historic preservation officers to public meetings held in December of 2020 and January 2021 and several participated in those meetings.

Consultation with federal land managers

The RHR requires consultation between Washington and FLMs on development and implementation of the RH SIP. The RHR specifies that the consultation must provide an opportunity for affected FLMs to comment on the state's assessment of visibility impairment in each Class 1 Area and provide recommendations on the reasonable progress goals and the development and implementation of visibility control strategies to address visibility impairment. Ecology provided FLMs with an opportunity to comment on the long-term strategy, reasonable progress goals, source selection, and four-factor analysis to identify reasonable controls of haze causing emissions more than 120 days prior to the start of a public hearing or other public comment opportunity.

Formal consultation requirements do not preclude informal consultation. Ecology had informal consultation opportunities and other public comment opportunities during SIP development. These were conference calls with representatives of the U.S. Forest Service, the National Park Service, and the U.S. Fish and Wildlife Service. The major focus of these meetings was Ecology's source selection. Ecology used the EPA recommended Q/d (emissions over distance to the nearest Class 1 Area) method to determine the sources we analyzed, the four-factor analyses, and suggested control strategies. These discussions were helpful for both Ecology and the FLMs. Ecology used the discussions and informal written comments from FLMs to review the Q/d determinations.

Appendix A contains information on Ecology's early and formal consultation with the FLMs for this RH SIP. It includes the written comments submitted to Ecology along with a synopsis of FLM comments accompanied by Ecology's responses, as well as a summary of our meetings.

1.5 Environmental justice considerations

Introduction

Ecology incorporates environmental justice (EJ) into their planning process. EJ envisions and captures the need for change and defines actions the agencies may take to remove disparities. In general, EJ includes two main components:

- Fair treatment means that no group of people should bear a disproportionate share of the negative environmental consequences resulting from industrial, governmental, and commercial operations or policies
- Meaningful involvement means that the public has a fair opportunity to participate in decisions about activities that may affect their environment and/or health; can influence the regulatory agency's decision; and the decision-makers seek out and facilitate the involvement of those potentially affected early and throughout the process.

Ecology EJ actions

Ecology consulted with our EJ coordinator to determine how best to address EJ concerns within the constraints of the Regional Haze Rule and guidance. Based upon her guidance and the use of EJSCREEN, we took the following actions:

- Identify the population characteristics of the people affected by the action (such as minority populations, low-income populations, non-English speaking populations, and tribes).
- Assess and address disproportionately high and adverse human health or environmental effects on minority populations and low-income populations.
- Plan for and facilitate the meaningful involvement of affected communities in the processes.
- Ensure that potentially affected populations have appropriate opportunity to learn about, participate in, and influence Ecology's decisions and actions.

To ensure that all people, regardless of their social, racial, geographical, or able-bodied status could participate in the review and decision making about the second Regional Haze SIP, we:

- Provided public notices that meet online accessibility requirements and notified interested public via emails and newspaper publications.
- Translated the notices into the priority minority languages in Washington:
    - Spanish
    - Korean
    - Vietnamese
    - Chinese
- Notified the leaders of the tribal communities in Washington and offered Government-to-Government consultation in addition to inviting the tribal members to attend public meetings.

- Held accessible online webinars to discuss various aspects of the program.
- Provided 45 days for the public to submit comments.
- Held a virtual public hearing.
- Simplified and formatted the Public Review Draft (text and graphics) to ensure it is compatible with available text-to-speech readers.

The long-term strategy in this regional haze SIP revision includes emission reductions from permits and state rules. The visibility benefits of these controls provide co-benefits to the communities that are in the vicinity where emission reductions occur. An example of such controls would be federal fuel and engine rules that have resulted in large reductions in mobile source air pollution and improvements in visibility.

Grant programs to reduce mobile source emissions and diesel pollution in disproportionately impacted communities

There are several emission control grant programs in Washington that take into account EJ concerns in awarding grants or have co-benefits for nearby disadvantaged communities. These include the woodstove buy-back and exchange program (Chapter 173-433 WAC), the low emission vehicles 2021 rulemaking to reduce emissions around ports, distribution centers, and freight corridors (which tend to be located within disadvantaged communities), and the Volkswagen enforcement action grants that prioritizes projects in or near communities disproportionately impacted by diesel fumes.

1.6 Meaningful public participation

Summary of changes to the public review draft

Ecology made the following changes to the public review draft SIP:

- In Chapter 7, changed all occurrences of “All controls identified as reasonable in the reasonability analysis will be installed and operated as an enforceable requirement consistent with the RHR” to “All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR.”
- In Chapter 7, in the conclusion to the Marathon Petroleum Company changed the following sentence “To allow for scheduling flexibility needed to maintain cost-effectiveness, installation of controls will likely occur in the next implementation period” to “To allow for scheduling flexibility needed to maintain cost-effectiveness, installation of controls may occur in the next implementation period.”
- In Table 7-19, a footnote was added to the BART 2008 $/ton column that stipulates: “FCCU is SNCR, others LNB.”
- In the Executive summary, “Emissions from petroleum refineries cause poor visibility” was changed to “Emissions from petroleum refineries contribute to poor visibility.”
- Added the following paragraphs to Section 6.8:

The PSAT identified sulfate contributions from non-EGU point sources in Washington, originating from the 12,053 tons of non-EGU SO2 emissions included in the model (see Chapter 6). However, 64 percent of those modeled SO2 emissions (7,729 tons) are from the two aluminum facilities in Washington (Alcoa Wenatchee and Alcoa Intalco). WRAP modeled these facilities using historical emissions data and with no assumed emissions reductions. The Alcoa Wenatchee facility curtailed in 2015, going to zero emissions, and announced on December 13, 2021, that it will permanently close. The Alcoa Intalco facility curtailed in 2020 and went to zero emissions. Ecology and Intalco entered into an Agreed Order in January 2021 requiring Intalco to conduct a four-factor analysis before restarting (see Chapter 7 and appendix Q for more details).

As a result of the above analysis, we have determined that sources in Washington do not have significant impacts in other States' mandatory Class 1 Areas beyond the measures already addressed in this SIP submittal. Ecology did not receive any request for additional reductions from neighboring states during our consultations with them.

- Ecology received a comment noting that we did not include a facility with a Q/d greater than 10 in the four-factor analysis. The McKinley Paper Plant is a recycled paper mill and is not a chemical pulping facility, which is why it was not included with the other chemical pulp and paper facilities for whom we requested a four-factor analysis. Our original intent was to have the McKinley facility included with other non-chemical paper mills in future implementation periods. However, the McKinley facility does have a Q/d of 83.1, which exceeds the selection criteria of 10. Ecology will start the four-factor analysis process with McKinley and include the results in an update to the SIP.

Ecology's response to comments on the public review draft

Please see Appendix U and V for the individual comments and Appendix W for Ecology's responses.

1.7 Organization of the second regional haze plan (2018 -2028)

The RH SIP is organized as follows:

Chapter 1

- Overview of the RHR and the development of the RH SIP.
- This includes the role of regional planning, the Western Regional Air Partnership (WRAP), and consultation with FLMs, tribes, and other states.
- It also includes a description of where the progress report elements are found in the document.

Chapter 2

- Primer on visibility
- Describes Washington's eight Class 1 Areas
- Describes visibility monitoring for these area at the Interagency Monitoring of Protected Visual Environments (IMPROVE) sites.

Chapter 3

- Describes current conditions in the Class 1 Areas.
- Describes the uniform rate of progress (URP) in visibility improvement needed to achieve the 2064 natural conditions.

Chapter 4

- Discusses the visibility baseline and 2018 statewide emissions inventories that Ecology developed and used to prepare this plan.

Chapter 5

- Describes the modeling used by the WRAP that Washington relied upon for this plan.

Chapter 6

- Discusses the significant in-state and regional sources of haze that affect Washington's Class 1 Areas and will likely affect visibility conditions in 2028.
- Discusses the Class 1 Areas in adjacent states that Washington emissions significantly affect.

Chapter 7

- Describes the source selection process and the four-factor analysis to determine the reasonableness of additional emission controls for inclusion in the long-term strategy.

Chapter 8

- Describes the long-term strategy to address regional haze visibility impairment in Washington's Class 1 Areas.
- Identify and reduce Washington's air impacts to mandatory Class 1 federal Areas outside of Washington.

Chapter 9

- Defines the reasonable progress goal for each of the eight Class 1 Areas in Washington.

Chapter 10

- Describes future planning.
- Summarizes the Washington RH SIP.

Chapter 2. Visibility and Visibility Monitoring in Washington's Class 1 Areas

2.1 Natural sources of visibility impairment

Natural sources of visibility impairment are emissions not attributed to anthropogenic (human-caused) emissions, and they can be major contributors to visibility impairment. Natural sources include:

- Volcanos
- Wildfire
- Windblown dust
- Certain wildland prescribed fire

Even when there is an absence of emissions, the scattering of light by air molecules can degrade visibility. We refer to this as "Rayleigh scattering". The air molecules' temperature and density can cause this effect.

We cannot control these sources. We focus control strategies for visibility improvement on what we can control, anthropogenic sources. Current analysis methods for monitoring data do not provide a clear distinction between natural and anthropogenic emissions, but certain pollutant species, such as sulfur dioxide (SO_2) and nitrogen oxides (NOx) are more representative of anthropogenic sources, while organic mass (OM) and coarse particulate matter (PM_{10}) are usually more representative of natural sources such as wildfire and dust, respectively.

2.2 Anthropogenic sources of visibility impairment

Anthropogenic sources of visibility impairment include everything attributable to human activities that produces emissions of visibility impairing pollutants. Some examples include:

- Industrial activities
- Transportation
- Agricultural activities
- Residential heating
- Managed outdoor burning

Anthropogenic sources can be of local, regional, or international nature. Only anthropogenic sources and emissions within the boundaries of the United States can be controlled. Some anthropogenic sources of emission are beyond the scope of Washington's SIP. Emissions from Mexico, Canada, other international emissions, and offshore marine shipping emissions in the Pacific Ocean are examples of anthropogenic sources that contribute to visibility impairment in Washington, but are beyond the scope of this planning document.

2.3 Emissions

Natural sources and anthropogenic sources emit visibility-impairing pollutants. Particle and gas emissions may go through chemical changes before an air monitor captures them. For this reason, the chemical species causing visibility impairment may not be the same species emitted by a pollution source.

2.4 The IMPROVE program for visibility monitoring

The Interagency Monitoring of Protected Visual Environments (IMPROVE) program is a multi-agency cooperative effort with the primary purposes of protecting visibility in Class 1 Areas and characterizing regional haze. The objectives of IMPROVE program are to:

- Establish current visibility and aerosol conditions in Class 1 Areas.
- Identify chemical species and emission sources responsible for visibility impairment.
- Document long-term trends for assessing progress towards the national visibility goal.
- Provide regional haze monitoring representing visibility in Class 1 Areas, where practical, in support of the Regional Haze Rule (RHR).

A formal cooperative relationship operates and maintains the IMPROVE monitoring sites. This cooperative includes:

- EPA
- National Parks Service (NPS)
- Fish and Wildlife Service (USFWS)
- Bureau of Land Management (BLM)
- Forest Service (USFS)

IMPROVE monitors obtain a complete signature of the composition of the airborne particles affecting visibility. Each IMPROVE monitor collects a 24-hour sample of these particles onto a set of filters every three days to determine the standard chemical components causing visibility impairment at that site.

To facilitate the data analysis, we group together some elemental particles and compounds (based on scientific principles) into seven standard components that cause light extinction.

Table 2-1 lists the seven standard aerosol components of light extinction along with the default color used in graphics throughout this document.

Table 2-1: Monitor Aerosol Composition

Aerosol Component	Abbreviation (Color)
Ammonium Sulfate	$(NH_4)_2SO_4$ (yellow)
Ammonium Nitrate	NH_4NO_3 (orange)
Organic Mass	OM (green)
Elemental Carbon	EC (black)
Fine Soil	Soil (maroon)
Coarse Mass	CM (gray)
Sea Salt	Sea Salt (light blue)

The IMPROVE website (IMPROVE) has detailed information regarding the IMPROVE program, including history, sampling protocols, standard operating procedures, and data availability.

Data collected at the IMPROVE monitoring sites is used by:

- Land managers
- Industry planners
- Scientists
- Public interest groups
- Air quality regulators

2.5 The revised IMPROVE equation and measuring visibility impairment

Some of the particles that compose aerosols absorb light, while others reflect or scatter light. Both absorption and scattering of light result in light extinction. Light extinction is the technical term for visibility impairment between the viewer and the light source.

Each of the key components of particulate aerosols affect light extinction in different ways. The first IMPROVE equation underestimated the highest extinction values and overestimated the lowest extinction values. The revised algorithm was developed by Pitchford et al., 2007 (Marc Pitchford, 2007). The revised algorithm is relatively simple, it produces consistent estimates of light extinction for all IMPROVE aerosol monitoring sites, and it permits the individual particle component contributions to light extinction to be separately estimated (see

Figure 2–1). The revised IMPROVE equation also accounts for site-specific Rayleigh scattering values based on altitude. Rayleigh scattering is the scattering of light by molecules of air.

$b_{ext} \approx$	2.2 x fs(RH) x [Small Sulfate] + 4.8 x fL(RH) x [Large Sulfate] + 2.4 x fs(RH) x [Small Nitrate] + 5.1 x fL(RH) x [Large Nitrate] + 2.8 x [Small Organic Mass] + 6.1 x fL(RH) x [Large Organic Mass] + 10 x [Elemental Carbon] + 1 x [Fine Soil] + 1.7 x fs(RH) x [Sea Salt] + 0.6 x [Coarse Mass] + Rayleigh Scattering (site specific) + 0.33 x [NO2 (ppb)]

Figure 2–1: Revised Interagency Monitoring of Protected Visual Environments Equation

The result of the revised IMPROVE equation is referred to as the reconstructed light extinction (denoted as b_{ext}). It represents the light extinction due to the aerosol particulates measured at the IMPROVE monitor and is proportional to the mass measured at the monitor.

We express reconstructed light extinction in units of inverse megameters (Mm^{-1}). The RHR requires the tracking of visibility conditions in terms of the haze index metric expressed in the deciview (dv) unit (40 CFR 51.308(f)(1)(i)). Generally, we consider a one-dv change in the haze index a humanly perceptible change under ideal conditions, regardless of background visibility conditions. Figure 2–2 shows the relationship between extinction, Mm^{-1}, dv, and visual range (km).

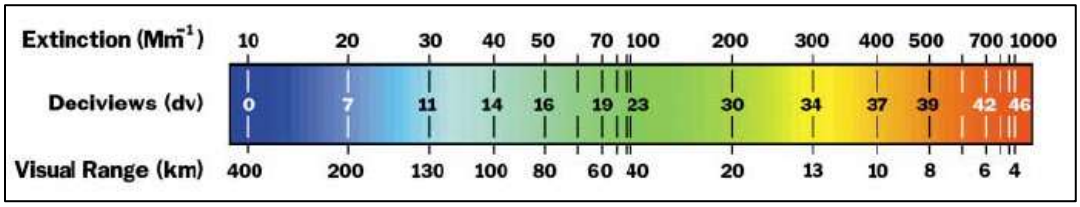


Figure 2–2: Comparison of extinction, deciview, and visual range
Source: (Malm, 2018).

2.6 Baseline conditions

The RHR requires the calculation of baseline conditions for each Class 1 Area. EPA has defined baseline conditions as the five-year average (annual values for 2000 - 2004) of IMPROVE monitoring data (expressed in dv) for the most impaired days (MID) and the clearest days. In the first regional haze plan, we defined the baseline conditions as reference points against which we tracked visibility improvement.

2.7 Natural conditions

The visibility under natural conditions (absent any anthropogenic impairment) could vary daily, based on the contribution of natural sources and meteorological conditions. Therefore, natural conditions consist of a level of visibility (in dv) for both the most impaired and clearest days.

Since no visibility monitoring data exists from the before anthropogenic impairment period, we base these estimates of natural conditions on EPA guidance (EPA, 2003) on how to estimate natural conditions.

2.8 Uniform rate of progress

The uniform rate of progress (URP) is the calculation of the uniform slope, or glidepath, of the line between baseline visibility conditions and natural visibility conditions over the 60-year period. For the first regional haze plan, the benchmark was the dv level that we planned to meet in 2018 (Figure 2–3). This was the 2018 milestone, and it applied to both the most impaired and clearest days. For the second regional haze planning period, the benchmark is the dv level achieved by 2028 (Figure 2–3).

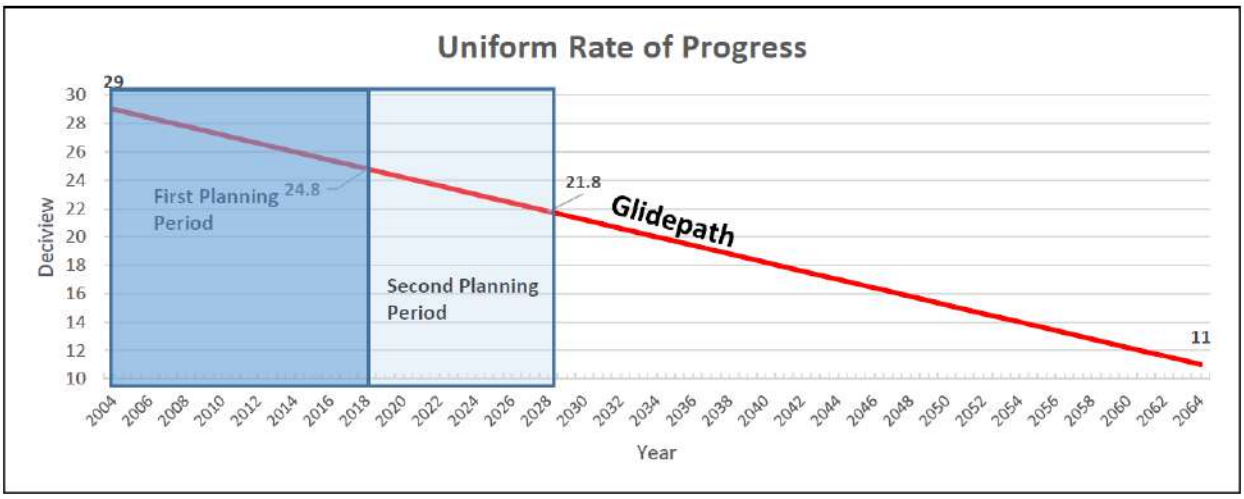


Figure 2–3: Example of How Uniform Rate of Progress is Determined Source: EPA Guidance for Setting Reasonable Progress Goals under the Regional Haze Program

The difference between baseline conditions and natural conditions represents the amount of progress needed to reach natural visibility conditions. In this example (not actual data), the State has determined that the baseline for the most impaired days for the Class 1 Area is 29 dv and estimated that natural background is 11 dv, a difference of 18 dv.

The annual average visibility improvement needed to reach natural conditions by 2064 is the total amount of improvement needed divided by 60 years (the period between 2005 and 2064). The visibility improvement per year is the uniform rate of progress (URP) expressed in dv per year. In this example, the average improvement needed is 0.3 dv/yr.

URP = [Baseline Condition - Natural Condition]/60 years

Multiply the annual average visibility improvement needed by the number of years in the first planning period (14 years from 2005 until 2018). In this example, this value is 4.2 dv. This is the visibility improvement that we would need during the first planning period to attain natural visibility conditions by 2064.

Calculate the visibility improvement needed to maintain a uniform rate of progress to 2028 (i.e. the amount of reduction in dv necessary for the second planning period) by multiplying the URP value by the number of years between the baseline period and the end of the second planning period (24 years). In this example, the value is 7.2 dv.

Visibility improvement from the baseline to 2018 = [uniform rate of progress] x [14 years]

Visibility improvement from the baseline to 2028 = [uniform rate of progress] x [24 years]

2.9 Washington's Class 1 Areas and visibility monitoring

Washington's Class 1 Areas

Washington has eight Class 1 Areas: three national parks and five wilderness areas. Visibility in the Class 1 Areas is monitored at the interagency monitoring of protected visual environments (IMPROVE) sites. Figure 2–4 shows Washington's eight Class 1 Areas along with the locations of the IMPROVE monitors for the Class 1 Areas.

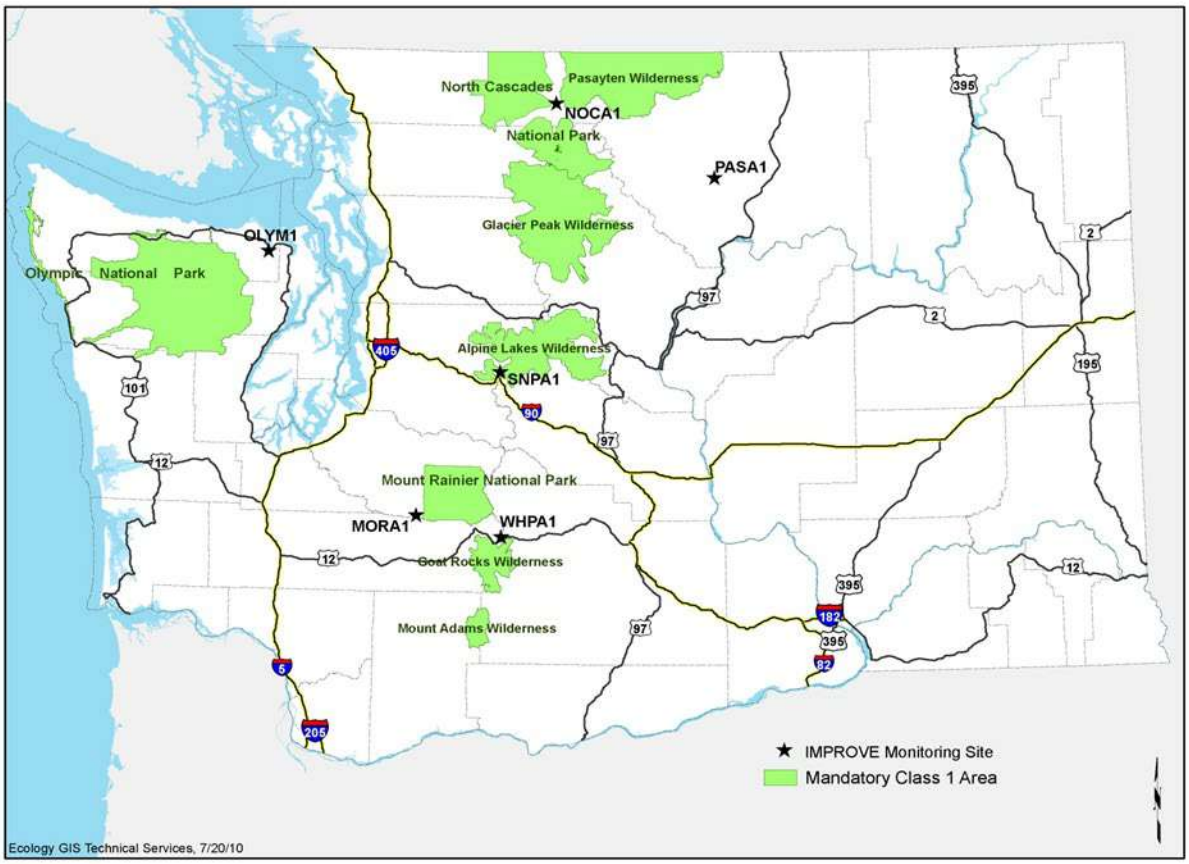


Figure 2–4: Washington's Class 1 Areas and visibility monitoring sites

Table 2-2 provides information on the size of and the federal agency that manages each Class 1 Area, as well as the name of the IMPROVE monitor for each area. The acreages are from 40 CFR 81.434. They may not match the current acreages of the national park or wilderness area for reasons including more accurate surveys or expansion of the area.

Table 2-2: Washington's Class 1 Areas

Class 1 Area	Acreage	Federal Land Manager	IMPROVE monitor
Olympic National Park	892,578	USDI-NPS	OLYM1
North Cascades National Park	503,277	USDI-NPS	NOCA1
Glacier Peak Wilderness	464,258	USDA-FS	NOCA1
Alpine Lakes Wilderness	303,508	USDA-FS	SNPA1
Mt. Rainier National Park	235,239	USDI-NPS	MORA1
Goat Rocks Wilderness	82,680	USDA-FS	WHPA1
Mt. Adams Wilderness	32,356	USDA-FS	WHPA1
Pasayten Wilderness	505,524	USDA-FS	PASA1
Total Acres	3,019,420		

The sections below briefly describe Washington's Class 1 Areas. Maps of these areas are included later in this chapter.

Olympic National Park

Olympic National Park includes a significant portion of the Olympic Peninsula in northwestern Washington. It consists of two segments: the Olympic Mountains, which form the mountainous core of the park, and a coastal strip, stretching for 90 km (56 mi) along the Pacific coast. Thirteen major rivers are flowing from the Olympic Mountains in all directions. Ninety-five percent of the park is designated wilderness.

Elevations range from sea level to 2,428 m (7,965 ft) at the crest of Mt. Olympus near the center of the peninsula. The area has the greatest precipitation gradient in the world for temperate latitudes. Annual precipitation is near 400 cm (150 in) in the western valleys and 500 cm (200 in) at the summit of Mt Olympus but as little as 41 cm (16 in) on the northeast shore of the peninsula in the rain shadow of the Olympic Mountains.

North Cascades National Park

North Cascades National Park is set in the rugged mountains and the beautiful scenery of the Cascade Mountain Range in northcentral Washington, about 80 km (50 mi) east of Bellingham. The area was set aside to preserve dramatic mountain scenery, alpine areas, and glaciers. Mountain summits rise abruptly 1,800-2,600 m (5,900-8,530 ft) above the valley floor. Approximately 93 percent of the park is designated wilderness.

North Cascades National Park lies less than 150 km (95 mi) from major metropolitan areas, most notably, Seattle, Washington and Vancouver, British Columbia.

Glacier Peak Wilderness

Glacier Peak Wilderness includes more than 200 lakes, many unnamed and tremendously difficult to access, in various cirques and hidden basins. The wilderness straddles the northern Cascade Range roughly between Suiattle River on the west and Lake Chelan on the east. North Cascades National Park is adjacent to the northern border.

The dominant topographic feature is Glacier Peak, a 3,214 m (10,541 ft) high volcanic cone. Other mountain summits are 2,500 m (8,200 ft) or lower in elevation. Most terrain lies below 2,000 m (6,500 feet) elevation.

Glacier Peak Wilderness drains on the west side of the Cascade crest to the Suiattle and Sauk Rivers, tributaries to the Skagit River, which flows into northern Puget Sound. East of the Cascade crest, streams flow to Lake Chelan and the Columbia River basin. The lowest elevations where streams exit the wilderness on the west side are around 400 m (1,300 ft). The lowest elevations east of the Cascade crest are 350 to 400 m (1,200 to 1,300 ft), close to the 335 m (1,099 ft) elevation of Lake Chelan.

Alpine Lakes Wilderness

When Congress passed the 1976 Alpine Lakes Wilderness Act to protect the area in its unique natural state they created the Alpine Lakes Wilderness. The name Alpine Lakes takes its origin from the nearly 700 small mountain lakes nestled among the high rock peaks and forested valleys of the region. The Mt. Baker-Snoqualmie National Forest and the Okanogan-Wenatchee National Forest jointly administer the wilderness.

Alpine Lakes Wilderness is located in the rugged central Cascade Range. It is accessible by 47 trailheads and 990 km (615 mi) of trail on both sides of the crest of the Cascade Range between Stevens Pass (US Hwy 2) on the north and Snoqualmie Pass (I-90) on the south.

Mount Rainier National Park

Mount Rainier National Park became the nation's fifth national park in 1899. The Park was set aside to protect timber, minerals, and other natural resources. One hundred kilometers (62 mi) southeast of Seattle, Mount Rainier is the highest of the chain of volcanoes comprising the Cascade Range. At 4,392 m (14,410 ft), Mount Rainier is the fifth tallest peak in the contiguous 48 states. The massive mountain occupies more than one-fourth of the park's area. The 27 major glaciers on its slopes form the largest mass of year-round ice in the United States outside of Alaska.

Mount Rainier National Park lies within 64 km (40 mi) of Puget Sound. The lowlands along the eastern shore of Puget Sound are the most populated and industrialized area of Washington.

Goat Rocks Wilderness

The Goat Rocks Wilderness is a portion of the volcanic Cascade Range in southwestern Washington located between Mount Rainier and Mount Adams. The Goat Rocks are remnants of a large volcano, which has been extinct for some two million years. The cluster of rocks and

peaks in this area earned the title “Goat Rocks” because of the bands of mountain goats that live there. The wilderness lies in both the Gifford Pinchot National and the Okanogan-Wenatchee National Forests.

Glaciation and erosion have worn away the terrain and left moderate summits east and west of the crest of the Cascades. Elevation in the Goat Rocks range from 900 m (3,000 ft) to 2,450 m (8,201 ft) at Gilbert Peak. The deep east-west drainages below the ridges often open into park-like alpine meadows dotted with small lakes and even smaller ponds.

Mount Adams Wilderness

Congress designated the Mount Adams Wilderness in 1964. The wilderness lies in the Gifford Pinchot National Forest on the crest of the Cascade Range in southwestern Washington. Second in height only to Mount Rainier statewide, 3,742 m (12,276 ft) Mount Adams looms over at least 10 glaciers and a wilderness of forested slopes and subalpine meadows. The huge volcanic bulk of the mountain takes up a considerable portion of the Wilderness. Since the eruption of Mount St. Helens, Mount Adams has become a popular attraction for mountain climbers.

Pasayten Wilderness

The Pasayten Wilderness stretches across the crest of the Cascade Range in northern Washington. The wilderness is bordered on the north by 80 km (50 mi) of the Canadian border and on the west by the Ross Lake National Recreation Area. The Pasayten Wilderness is located in both the Okanogan-Wenatchee and the Mount Baker-Snoqualmie National Forests.

The terrain of the western Pasayten is a series of high ridges that flatten out in the eastern portion to high plateaus. Almost 150 peaks in the Pasayten have elevations above 2,300 m (7,500 ft). The part west of the Cascade crest is in the upper Skagit River basin and drains into Ross Lake and the Skagit River and then into northern Puget Sound. From the eastern part of the wilderness, streams flow north into British Columbia or southeast into the central Columbia Plateau. The lowest elevations are around 1,000 m (3,000 ft) at the western boundary near Ross Lake and the southern boundary near Lost River Gorge.

Visibility monitoring of Washington's Class 1 Areas

Washington has six IMPROVE sites that monitor the visibility of the state's eight Class 1 Areas. Four have been combined into two clusters and one monitor is used to represent each cluster. We discuss each site briefly below. You can find additional information on nearby populations, industrial centers, and wind patterns for the sites in Appendix B.

Olympic IMPROVE site: OLYM1

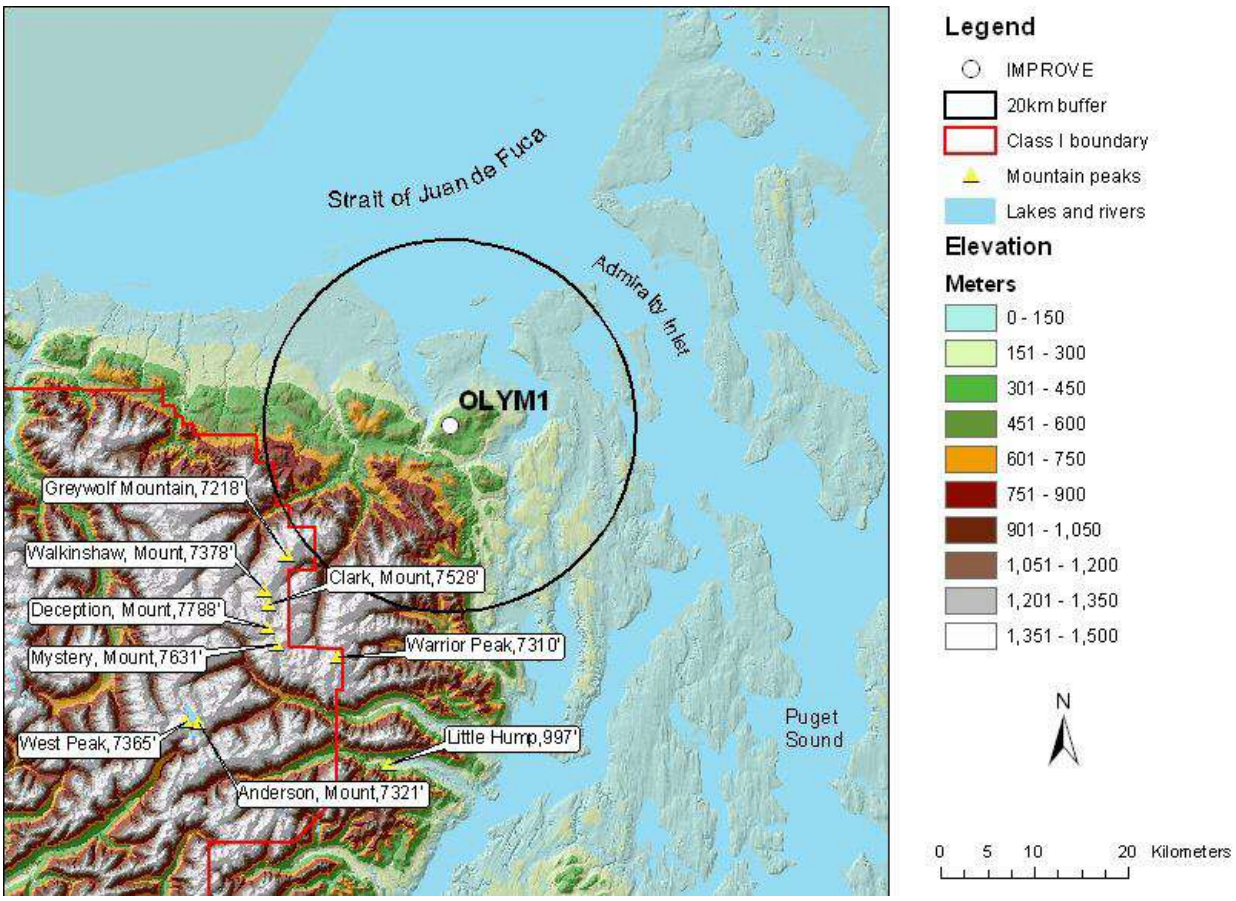


Figure 2–5: Location of the OLYM1 site
Source: Causes of Haze Assessment Descriptive Maps

The IMPROVE site representing the Olympic National Park is OLYM1, located northeast of the park boundary on an exposed hilltop (Blyn Lookout) near the northeastern extreme of the Olympic Peninsula at an elevation of 600 m (1,968 ft) (Figure 2–5).

Representativeness

OLYM1 is on the northeast shore of the peninsula near Sequim. Sequim is in the rain shadow of the Olympics, with sea level precipitation less than 50 cm (20 inches) annually. The rain shadow effect may be less severe at the OLYM1 elevation of 600 m. OLYM1 should be representative of eastern Olympic National Park areas most of the time, although at this elevation there may be periods when it is above inversion height.

Because of the size of the park, different sources may affect different areas. For the northeastern portion of the park, where the OLYM1 monitoring site is located, nearby industrial and urban emission sources that most immediately affect the area are in Port Angeles. For the western portions of the park, including the coastal section, there are no additional large source areas, although there may be timber and shipping related industries.

North Cascades IMPROVE Site: NOCA1

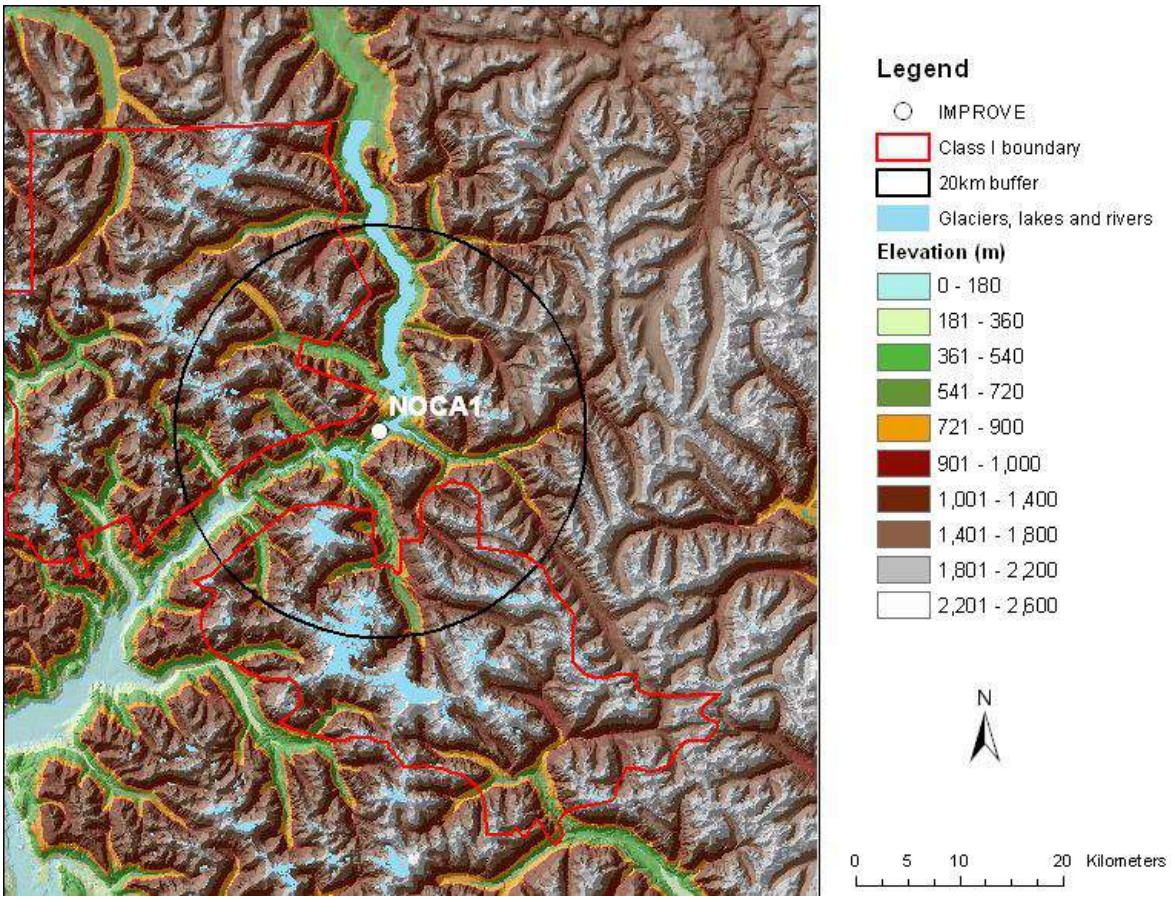


Figure 2–6: Location of the NOCA1 Site
Source: Causes of Haze Assessment Descriptive Maps

The NOCA1 IMPROVE site is the monitoring site for two Class 1 Areas, North Cascades National Park and Glacier Peak Wilderness. NOCA1 is located near Ross Lake on the upper reaches of the Skagit River just outside of the eastern boundary of the northern park section, located north of the Skagit River (Figure 2–6). The monitor is situated at an elevation of 576 m (1,889 ft) and is 87 m (285 ft) above the level of Ross Lake and about 200 m (650 ft) below the surrounding ridge tops.

Representativeness

The NOCA1 IMPROVE site is within the Skagit River Valley near Ross Lake and is in the lower slopes of a valley. It may at times be within surface-based valley inversions. The monitor is representative of the lower elevation air shed.

Snoqualmie Pass IMPROVE site: SNPA1

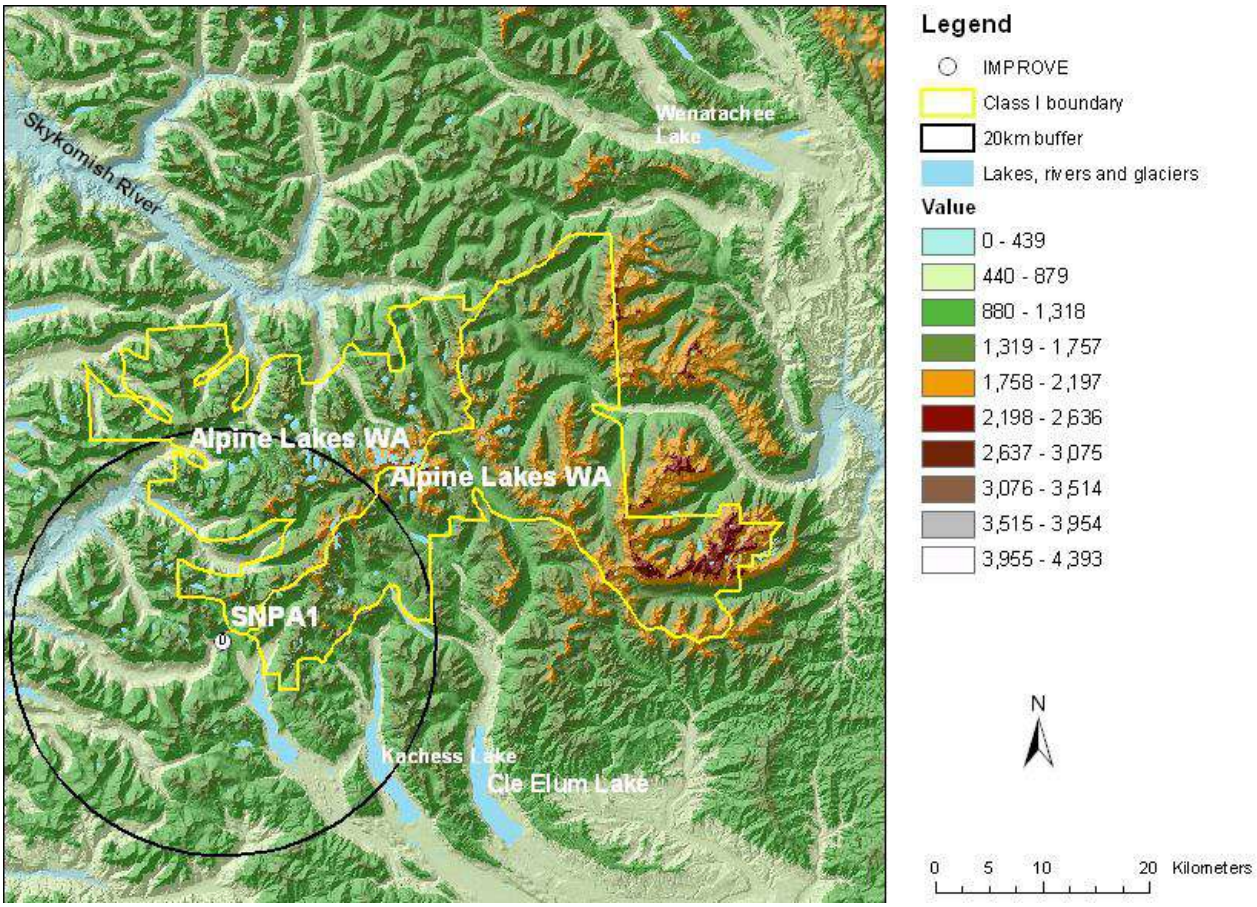


Figure 2–7: Location of the SNPA1 site
Source: Causes of Haze Assessment Descriptive Maps

SNPA1 is the IMPROVE site representing the Alpine Lakes Wilderness. SNPA1 is located near the southwest boundary of the wilderness in Snoqualmie Pass, a pass over the Cascade Range (Figure 2–7). The monitoring site elevation of 1,160 m (3,805 ft) is 239 m (784 ft) above the Snoqualmie Pass elevation of 921 m (3,022 ft). SNPA1 is located near a ski area on Snoqualmie Pass.

Representativeness

SNPA1 is at a well-exposed ridge crest location and should be very representative of the particulate aerosol concentration and composition at similarly exposed locations in the Alpine Lakes Wilderness. The elevation of SNPA1 is at the lower end of the range of elevations of the wilderness.

The mountain pass location of SNPA1 is representative of transport flow across the Cascade crest. Due to its location at a ridge crest, SNPA1 is probably above trapping inversions that may develop at valley bottom locations west and east of the Cascade crest.

Mount Rainier IMPROVE site: MORA1

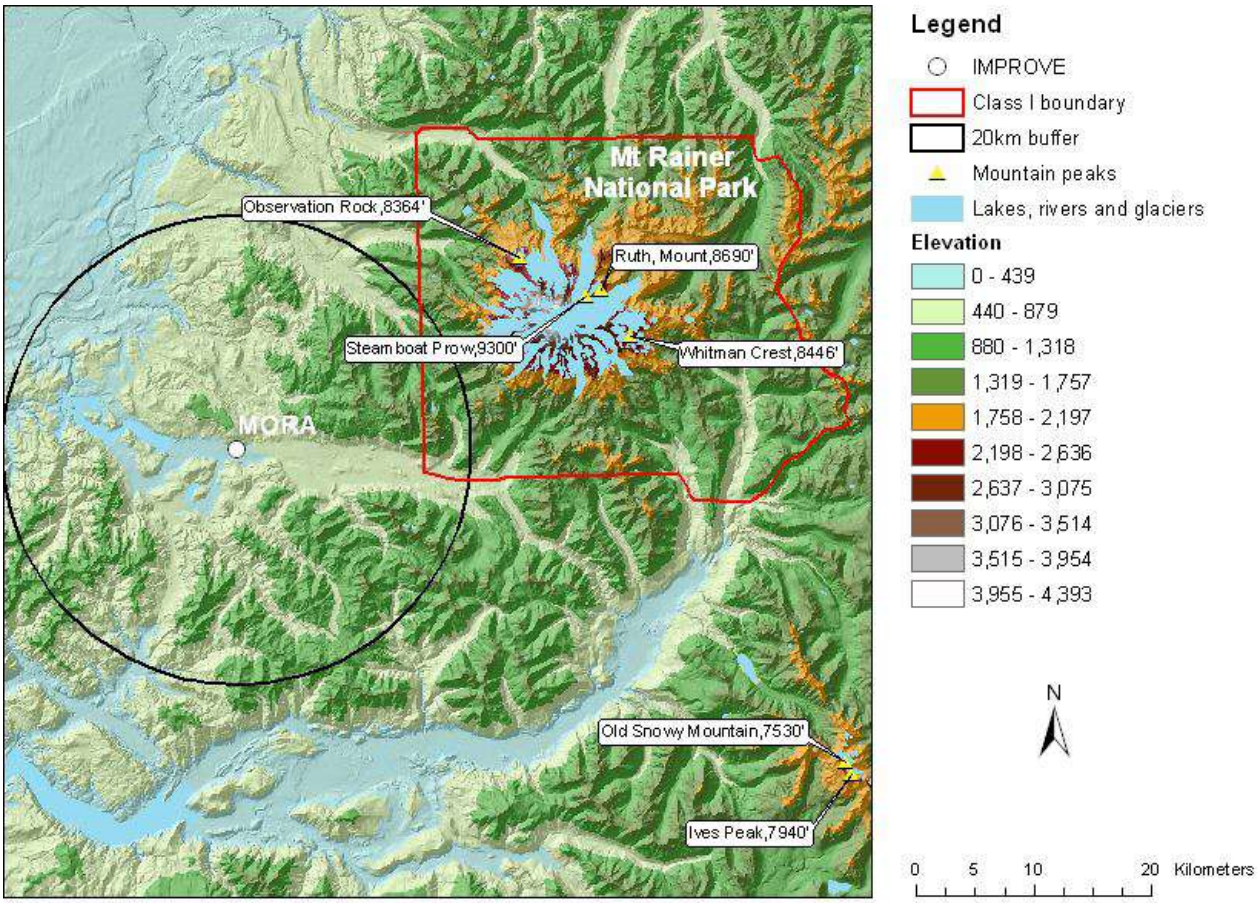


Figure 2–8: Location of the MORA1 site
Source: Causes of Haze Assessment Descriptive Maps

The IMPROVE site representing Mount Rainier National Park, MORA1, is situated southeast of the park at the Tahoma Woods park headquarters. MORA1 is located within the Nisqually River Valley at an elevation of 439 m (1,440 ft). The monitor is some 30 km (18.5 mi) west-southwest from the summit of Mount Rainer (Figure 2–8) as shown above.

The orientation of the drainage is east to west, with an elevation drop of about 60 ft/mile. Where the Nisqually River empties into Alder Lake Reservoir (5 km or 3 miles) west of the site the river elevation is 367 m (1,204 ft).

The valley bottom at the monitoring site is about 1.5 km (0.9 mi) wide. The monitoring site is at the northern edge of the valley bottom. Elevations rise to 450 m (1,475 ft) at a distance of 2 km (1.25 mi) north and 3 km (1.9 mi) south from the monitoring site. Regional ground cover is predominantly fir and pine forest.

Representativeness

The valley where the IMPROVE site is located may be subject to inversion and trapping of pollutants during periods of high pressure and stagnation. In those cases, the trapped stable

layer would contain the monitoring site. In those instances, the monitor would only be representative of the lower portions of the park.

Generally, wind directions at MORA1 channel to an east/west direction with characteristic mountain/valley circulations of easterly nighttime drainage flow and westerly daytime upslope flow in the valley.

White Pass IMPROVE site: WHPA1

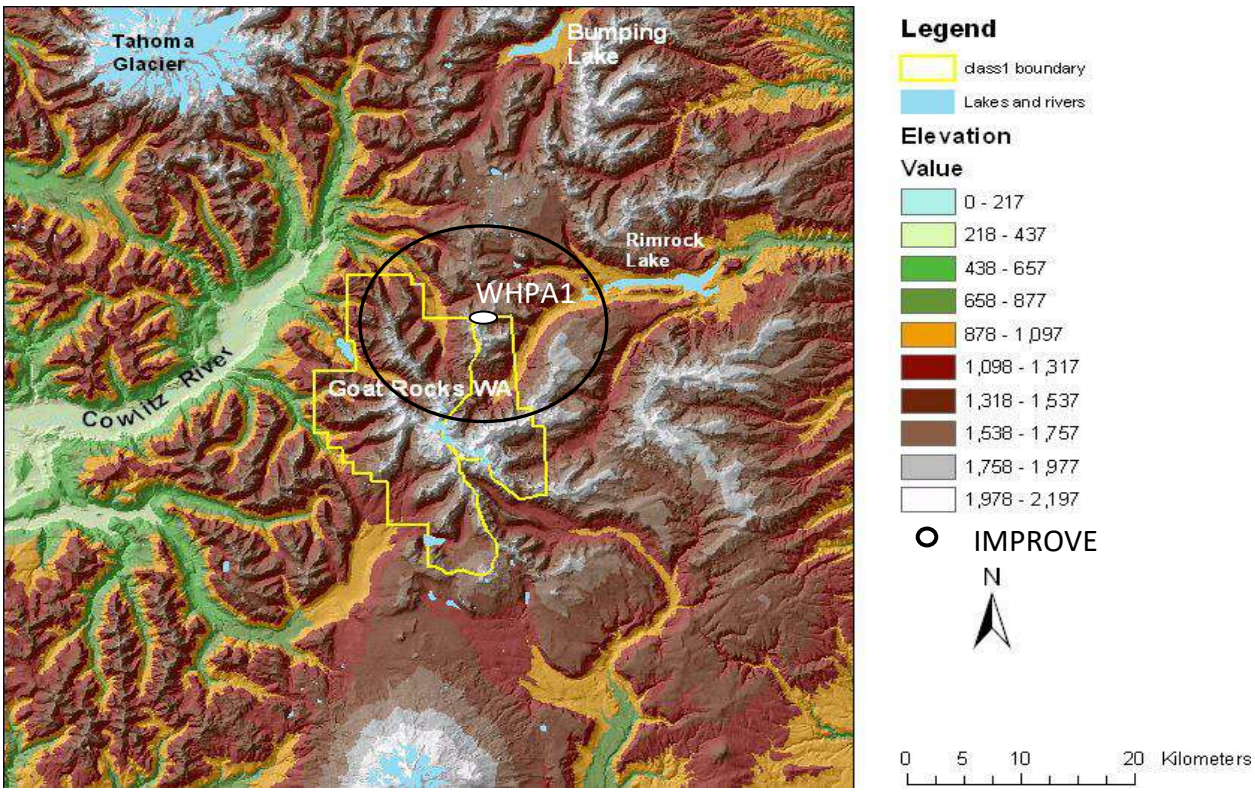


Figure 2–9: Location of the WHPA1 site
Source: Causes of Haze Assessment Descriptive Maps

The IMPROVE site representing Goat Rocks and Mount Adams Wilderness Areas, WHPA1, is located on the crest of the Cascade Range at the northern Goat Rocks Wilderness boundary at White Pass Ski Resort near White Pass Washington (Figure 2–9). The monitoring site elevation is 1,830 m (6,002 ft).

Representativeness

WHPA1 is at a ridge crest location well exposed to upper airflows and to aerosols transported aloft from upwind sources. WHPA1 should be representative of aerosol concentration and composition at similarly exposed locations in the Goat Rocks and Mount Adams Wilderness Areas. Its elevation and exposure should also make it representative of regional characteristics and transport from distant source regions at pressure heights near 850 mb that are relatively unperturbed by terrain effects.

Pasayten IMPROVE site: PASA1

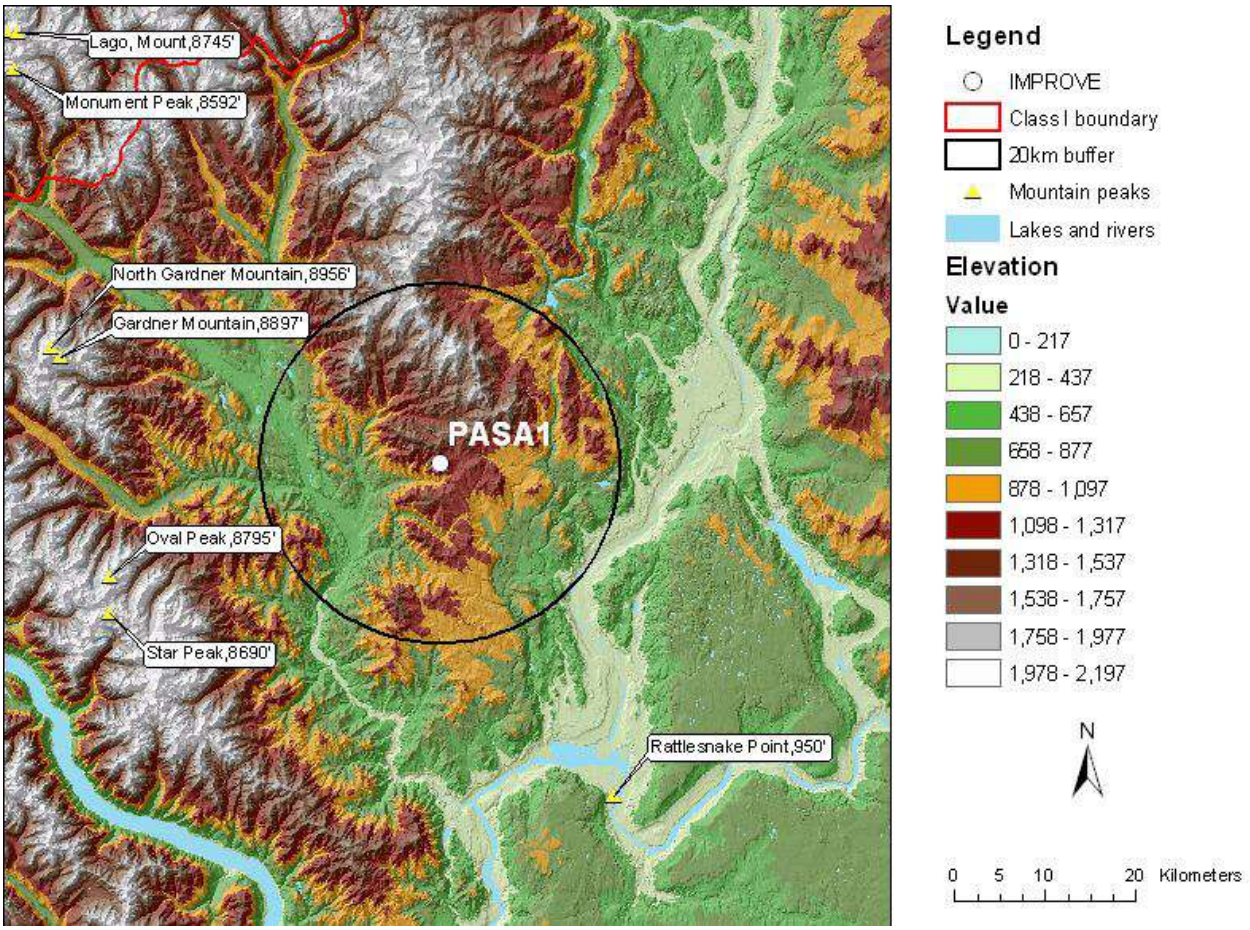


Figure 2–10: Location of the PASA1 site
Source: Causes of Haze Assessment Descriptive Maps

The IMPROVE site representing Pasayten Wilderness, PASA1, is situated near the crest of Little Buck Mountain, 50 km (30 mi) south and east of the wilderness boundary (Figure 2–10). PASA1 is located at an exposed elevation of 1,634 m (5,360 ft).

Representativeness

The PASA1 IMPROVE site is at a well-exposed ridge top location and is somewhat representative of regional conditions including high elevation locations in the Pasayten Wilderness. It is more representative of upper level (850 mb) aerosol characteristics of the central Columbia Plateau and Basin. This monitor is further away from the Class 1 Area it represents than any others in Washington. The PASA1 monitor is in an area that has frequent prescribed burning that may not actually impact the Pasayten Wilderness. Prescribed burning near the PASA1 monitor does not typically impact visibility in the Pasayten Wilderness because prevailing westerly winds and terrain limit the transport of smoke from the Columbia Plateau to the Cascade mountains.

The North Cascades National Park IMPROVE site, NOCA1, may be more representative of low elevations of the Pasayten Wilderness east of the Cascade crest.

Chapter 3.Current Visibility Conditions in Washington's Class 1 Areas

3.1 Overview of visibility conditions in Washington

3.1.1 Introduction

Washington Department of Ecology (Ecology) analyzed current visibility conditions in Washington's eight mandatory Class 1 Federal Areas (Class 1 Areas) as required by the Regional Haze Program (40 CFR 51.308(f)(1)). We compared current visibility conditions to both the historical baseline and natural conditions. The five-year period (2014 - 2018) is the most recent monitoring dataset available for regulatory use and is the period we refer to as "current conditions" throughout this document. The first Regional Haze State Implementation Plan (RH SIP) defined "baseline visibility conditions'' as the five-year period from 2000 - 2004. The Regional Haze Rule (RHR) sets the statutory deadline of 2064 to reach natural visibility conditions at all Class 1 Areas. Natural visibility represents the visibility conditions in the absence of human-caused impairment.

3.1.2 Methodology

Ecology used the monitoring data for the current conditions from the interagency monitoring of protected visual environments (IMPROVE) sites that track pollutants affecting visibility in Class 1 Areas. For more information on the pollutants, see Chapter 4 Emission Inventories. Washington has six IMPROVE sites and eight Class 1 Areas. Two of the sites cover four Class 1 Areas. Table 3-1 provides general information on the six sites[4]. For more information about the IMPROVE program see Chapter 2, Section 2.2: Visibility monitoring of Washington's Class 1 Areas.

Table 3-1: IMPROVE monitoring sites.

Site name	Site abbreviation	Site sponsor	Monitored Class 1 Area
Olympic	OLYM1	USDI-NPS	Olympic National Park
North Cascades	NOCA1	USDI-NPS	North Cascades National Park & Glacier Peak Wilderness
Snoqualmie Pass	SNPA1	USDA-FS	Alpine Lakes Wilderness
Mount Rainier	MORA1	USDI-NPS	Mount Rainier National Park
White Pass	WHPA1	USDA-FS	Goat Rocks Wilderness & Mount Adams Wilderness
Pasayten	PASA1	USDA-FS	Pasayten Wilderness

[4] See the map of the Class 1 Areas and the monitoring sites at: https://ecology.wa.gov/Air-Climate/Air-quality/Air-quality-targets/Regional-haze.

The Western Regional Air Partnership (WRAP) analyzed and compiled the IMPROVE monitoring data for consistency in planning among Western states. We used WRAP's technical data and analysis to determine current conditions. We also used the WRAP Technical Support System (TSS) online tool at https://views.cira.colostate.edu/tssv2/ to generate graphs and tables illustrating the results of the data analysis. Those interested in reviewing the data may access the observation-specific tools at https://views.cira.colostate.edu/tssv2/Express/VisTools.aspx.

During the first planning period, we used the worst (haziest) days from the IMPROVE monitoring data to determine the baseline visibility for the worst visibility days for the 2000 - 2004 period. However, the RHR revision in 2017 changed the metric on how to select a set of the worst visibility days during each year to track progress towards natural visibility conditions. The revised metric reflects the finding that natural events such as wildfires and dust storms overwhelmingly influence the haziest days. The rule revision removed five percent of the haziest days recorded at the IMPROVE sites from the calculations to create "the most impaired days" (MID) metric. The MID are the 20 percent of the worst visibility days in a calendar year, after removing the five percent haziest days. Thus, the design of the MID metric identifies the days with the largest amounts of anthropogenic visibility impairment. Because of the rule revision, EPA and WRAP recalculated the baseline conditions for all Class 1 Areas for the second implementation period.

The RHR requires that states track progress in visibility with a metric of haze known as the deciview (dv). We use the dv because under many circumstances, a person will perceive a change in one dv to be the same on both clear and hazy days. However, the dv does not easily relate to pollutant concentrations. Therefore, species contribution analysis uses a metric directly related to pollutant concentrations, known as "light extinction," with units of inverse megameters (Mm^{-1}). Light extinction does not linearly relate to a person's perception of changes in haze, but does linearly relate to pollutant concentrations in the atmosphere.

The glidepath from the baseline visibility conditions for the MID to the natural conditions over a 60-year period depicts the uniform rate of progress (URP). The uniform rate of visibility improvement for the MID is measured in deciviews of improvement per year. We need to maintain this average rate to attain natural visibility conditions by the end of 2064 in each Class 1 Area. Thus, the URP glidepath is a planning tool to help track ongoing improvements in visibility and to gauge whether there are sufficient controls over the emission sources to meet our progress goals during this planning period and stay on track to achieve the natural condition goals by 2064.

In the first planning period, natural conditions and the URP glidepath endpoint were the same by default. However, not all human-caused impairment comes from emission sources that the state can control. In accordance with the RHR (40 CFR 51.308(f)(1)(vi)(B)), the states can propose an adjustment to the endpoint of the glidepath to account for emissions they do not control such as international emissions. In this planning period, WRAP calculated the impacts of international anthropogenic sources on Washington's visibility in each Class 1 Area.

Washington is focusing on impairments that come from the sources within the states' control and is proposing an adjustment to the endpoint of the glidepath in Chapter 9 to account for international contributions.

In this chapter, the current visibility conditions are compared to the unadjusted glidepath for each of the eight Class 1 Areas in Washington (40 CFR 51.308(f)(1)(vi)). In Chapter 9, we adjusted the endpoint of the glidepath to account for the international contributions and use the international adjusted glidepath when we project reasonable progress goals.

For each Class 1 Area, we calculated the uniform rate of progress, and reviewed the visibility during MID and clearest days during 2014 - 2018. We compared the clearest days to the baseline, and the MID to the unadjusted URP glidepath. We provided an analysis of the annual and seasonal species' contributions to the visibility impairment during the current period. We also provided a visibility trend synopsis of annual species contributions to light extinction from 2002 - 2018.

3.1.3 Summary results

Table 3-2 and Table 3-3 show a summary of the 2000 - 2004 baseline, IMPROVE 2008 - 2012, IMPROVE 2014 - 2018, and estimated natural conditions for the clearest days and MID. This is required by the RHR (40 CFR 51.308(f)(1)(i – v)).

Table 3-2: Baseline, current, and estimated natural visibility conditions for the clearest days (in dv).

Class 1 Area	IMPROVE monitor	Baseline 2000-2004	Average 2008-2012	Current conditions 2014-2018	Estimated natural conditions 2064	Difference between current and natural conditions
Olympic National Park	OLYM1	6.0	3.9	3.6	2.7	0.9
Glacier Peak Wilderness Area	NOCA1	3.4	2.9	2.5	1.9	0.6
North Cascades National Park	NOCA1	3.4	2.9	2.5	1.9	0.6
Alpine Lakes Wilderness Area	SNPA1	5.5	4.0	3.3	2.3	1.0
Mount Rainier National Park	MORA1	5.5	4.2	3.9	2.6	1.3
Goat Rocks Wilderness Area	WHPA1	1.7	1.3	1.0	0.8	0.2
Mount Adams Wilderness Area	WHPA1	1.7	1.3	1.0	0.8	0.2
Pasayten Wilderness Area	PASA1	2.7	2.1	1.6	1.2	0.4

Table 3-3: Baseline, current, and estimated future visibility conditions for the most impaired days (in dv).

Class 1 Area	IMPROVE monitor	Baseline 2000-2004	Average 2008-2012	Current conditions 2014-2018	Estimated unadjusted natural conditions 2064	Difference between current and natural conditions
Olympic National Park	OLYM1	14.9	13.5	11.9	6.9	5.0
Glacier Peak Wilderness Area	NOCA1	12.6	11.1	10.0	6.9	3.1
North Cascades National Park	NOCA1	12.6	11.1	10.0	6.9	3.1
Alpine Lakes Wilderness Area	SNPA1	15.4	13.7	12.7	7.3	5.4
Mount Rainier National Park	MORA1	16.5	14.1	12.7	7.7	5.0
Goat Rocks Wilderness Area	WHPA1	10.5	9.1	8.0	6.1	1.9
Mount Adams Wilderness Area	WHPA1	10.5	9.1	8.0	6.1	1.9
Pasayten Wilderness Area	PASA1	10.4	9.6	9.5	6.0	3.5

3.2 Olympic National Park

The baseline visibility for the Olympic National Park is 6.0 dv for the clearest days and 14.9 dv for the MID. The unadjusted URP glidepath goes from 14.9 to 6.9 dv at a rate of 0.13 dv per year (8 dv divided by 60 years), which is the rate that would need to be maintained to reach natural visibility conditions in the park by 2064.

The current conditions (2014 - 2018) calculated from OLYM1 monitoring data are 3.6 dv for the clearest days and 11.9 dv for the MID. The clearest days' visibility improved by 2.4 dv from the baseline. The amount of visibility improvement from the baseline to 2018 required to stay below the 2018 URP unadjusted glidepath for MID is 1.8 dv. The MID visibility improved by 3 dv and is under the unadjusted URP glidepath.

Figure 3–1 shows the MID compared to the unadjusted URP glidepath, and the clearest days compared to the baseline at OLYM1 for the five-year averages 2000 - 2008, 2008 - 2012, and 2014 - 2018; and the annual averages for the MID and clearest days since 2002. The most recent annual average MID are below the glidepath, which indicates a rate of visibility improvement that will accomplish the 2064 natural conditions goal.

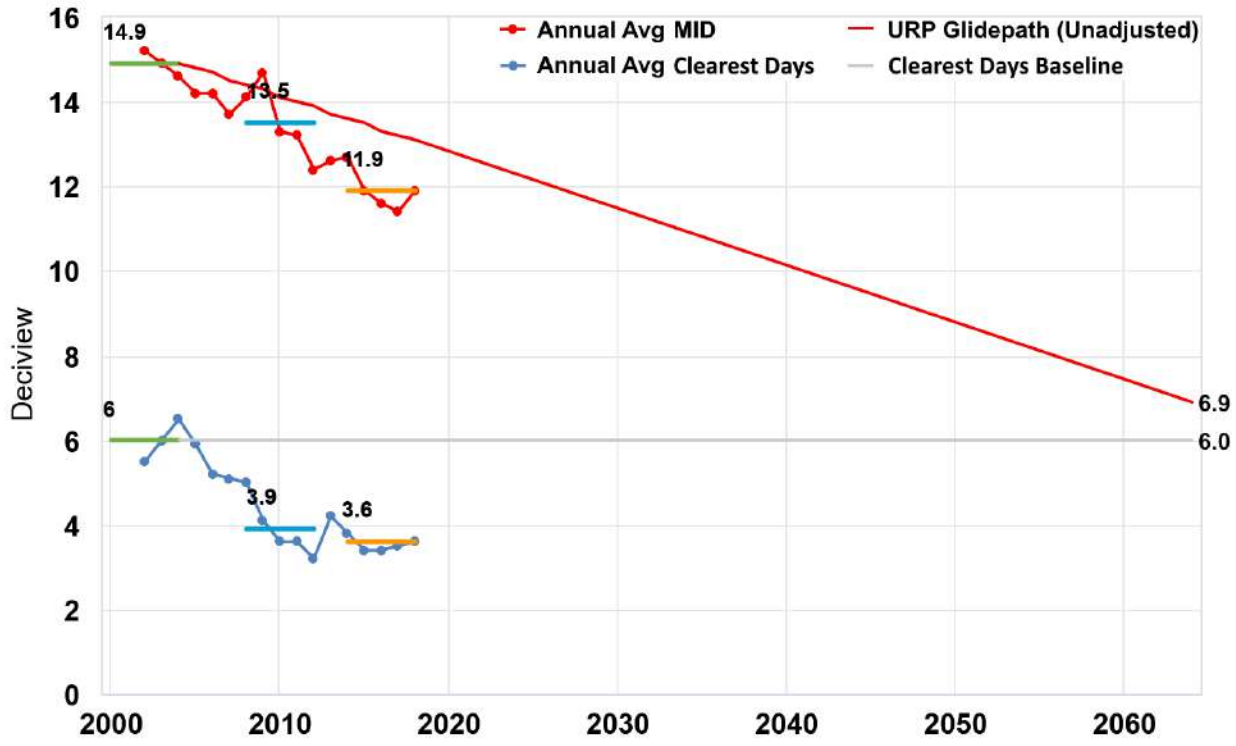


Figure 3–1: Current visibility conditions compared to the unadjusted URP glidepath and baseline (clearest days) at OLYM1.

Figure 3–2 shows the annual species contributions to light extinction from 2014 - 2018 for both MID and clearest days. Sulfates decreased in 2015 for both MID and clearest days and the decrease sustained through the rest of the five-year period. Nitrates showed very little change and organic mass showed some year-to-year variability.

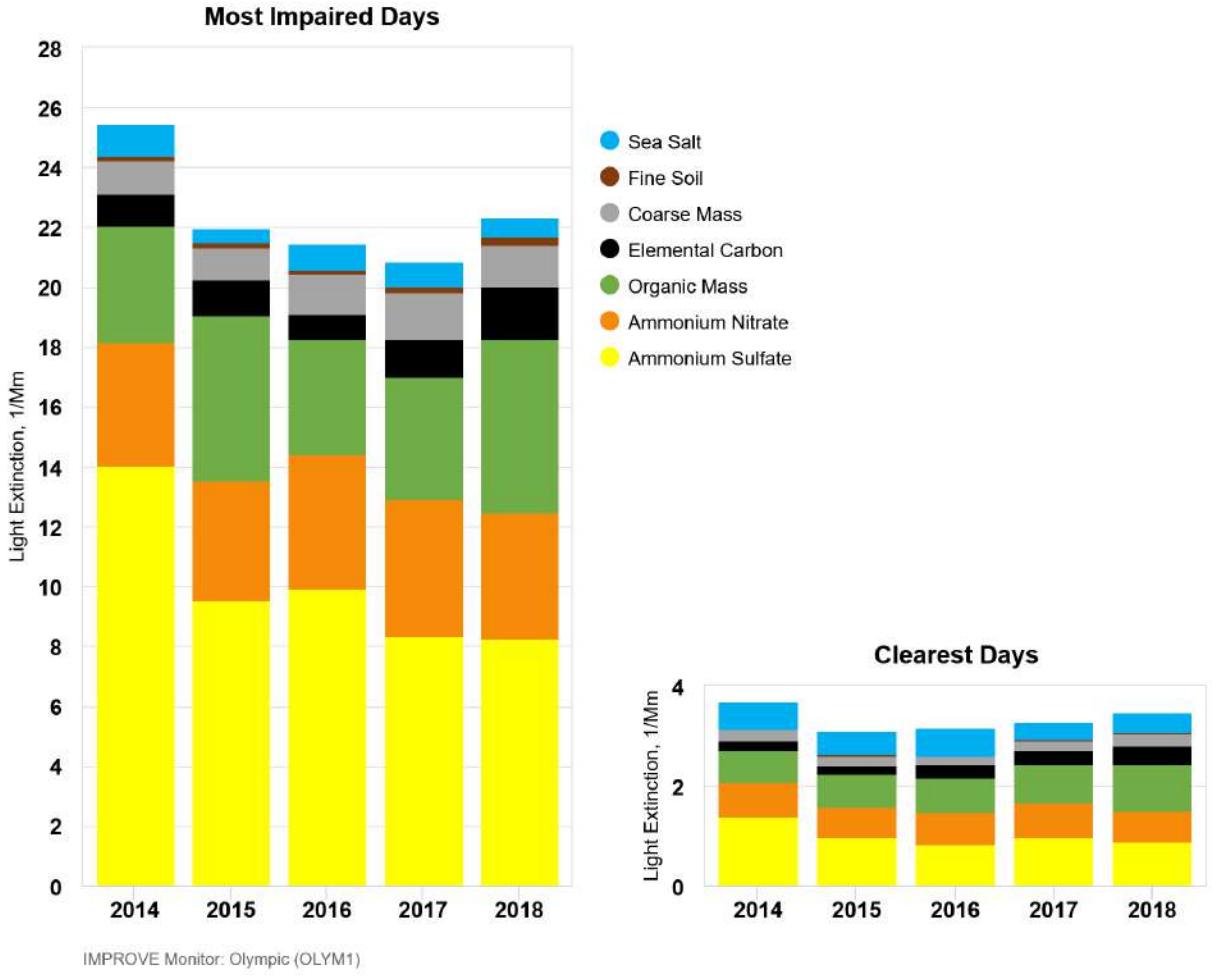


Figure 3–2: Annual species contributions to light extinction for MID and clearest days from 2014 - 2018 at OLYM1.

Table 3-4 shows the annual species' contribution during the five-year period from 2014 - 2018 for the MID. Sulfates contributed nearly half of the light extinction to MID from 2014 - 2018. The percentage of organic mass increased in 2015 and 2018. During the five-year period, sulfates (44%) were the largest contributor to light extinction, followed by organic mass (21%) and nitrates (19%). Elemental carbon, coarse mass, fine soil, and sea salt had minimal contributions to light extinction.

Table 3-4: Annual species contributions to light extinction for MID from 2014 - 2018 at OLYM1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	4%	2%	4%	4%	3%	3%
Fine Soil	1%	1%	1%	1%	1%	1%
Coarse Mass	4%	5%	6%	8%	6%	6%
Elemental Carbon	4%	5%	4%	6%	8%	5%
Organic Mass	15%	25%	18%	20%	26%	21%
Ammonium Nitrate	16%	18%	21%	22%	19%	19%
Ammonium Sulfate	55%	44%	46%	40%	37%	44%

Table 3-5 shows the annual species contributions during the five-year period for the clearest days. Sulfates (30%) contributed the most to light extinction followed by organic mass (22%), nitrates (20%), and sea salt (14%).

Table 3-5: Annual species contributions to light extinction for clearest days from 2014 - 2018 at OLYM1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	15%	15%	17%	11%	11%	14%
Fine Soil	0%	1%	0%	0%	1%	0%
Coarse Mass	6%	7%	6%	6%	8%	7%
Elemental Carbon	5%	5%	8%	9%	10%	7%
Organic Mass	17%	22%	22%	23%	27%	22%
Ammonium Nitrate	19%	19%	21%	22%	17%	20%
Ammonium Sulfate	38%	31%	26%	29%	26%	30%

Table 3-6 and Table 3-7 show the seasonality of MID from 2014 - 2018. Sulfates contributed nearly half of the visibility impacts in spring, summer, and fall. Nitrates contributed a third of visibility impacts in the winter, but less for other seasons. The majority of MID occurred during the spring and summer, which is also when sulfate impacts were largest.

Table 3-6: Number of MID at OLYM1, by season, from 2014 - 2018.

Year	Winter	Spring	Summer	Fall
2014	1	7	10	6
2015	2	12	3	7
2016	1	5	14	4
2017	3	4	13	4
2018	3	8	8	5
5-yr Total	10	36	48	26

Table 3-7: Seasonal species contributions to light extinction for MID from 2014 - 2018 at OLYM1.

Species	Winter	Spring	Summer	Fall
Sea Salt	3%	3%	4%	3%
Fine Soil	1%	2%	1%	1%
Coarse Mass	4%	6%	7%	4%
Elemental Carbon	7%	6%	4%	7%
Organic Mass	22%	19%	19%	25%
Ammonium Nitrate	32%	17%	17%	21%
Ammonium Sulfate	31%	46%	49%	40%

Figure 3–3 shows the long-term trends for OLYM1. Nitrates and sulfates decreased since the baseline period for both MID and clearest days. Organic mass decreased for the clearest days over the past 17 years of observations.

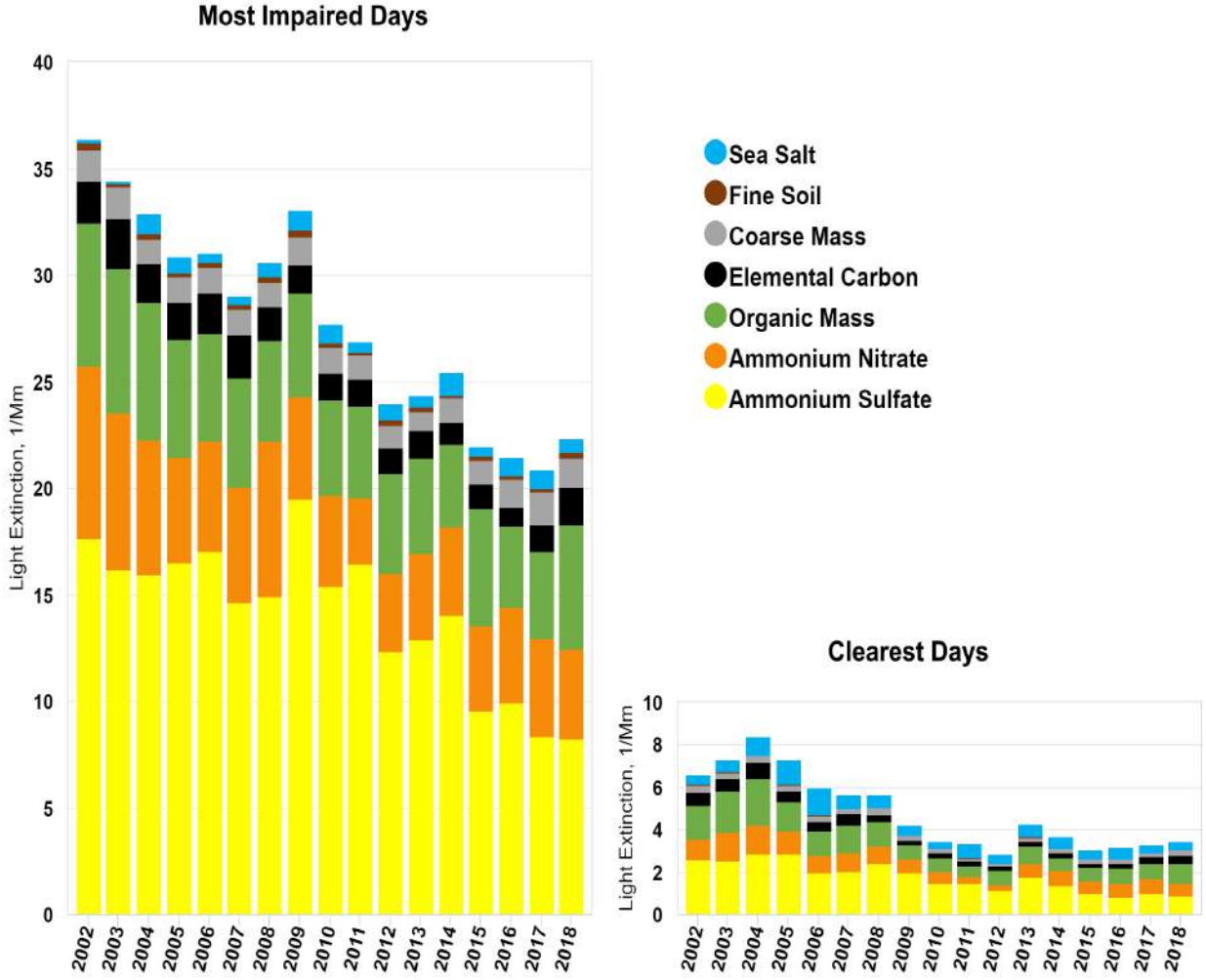


Figure 3–3: Annual species contributions to light extinction for MID and clearest days from 2002 - 2018 at OLYM1.

3.3 North Cascades National Park and Glacier Peak Wilderness

The NOCA1 monitoring site measures visibility in the North Cascades National Park and Glacier Peak Wilderness. Data for 2017 did not meet the data completeness requirements per the EPA document "Guidance for Tracking Progress under the RHR" (EPA, 2003). Twenty-three days (19% of the total) were missing for all species. WRAP performed data substitutions for 2017 using the OLYM1 IMPROVE site to address data completeness problems, due to the reasonable sulfate, elemental carbon, and organic mass correlation. See Appendix C for additional information on the WRAP data completeness memo.

The baseline visibility for the North Cascades National Park and Glacier Peak Wilderness is 3.4 dv for the clearest days and 12.6 dv for the MID. The unadjusted URP glidepath goes from 12.6 to 6.9 dv at a rate of 0.01 dv per year (5.7 dv divided by 60 years), which is the rate that needs to be maintained to reach natural visibility conditions in the park by 2064.

Based on the IMPROVE monitoring data, the 2014 – 2018 period visibility for the MID is 10.0 dv, and 2.5 dv for the clearest days. The amount of visibility improvement from the baseline to 2018 required to stay below the 2018 URP unadjusted glidepath for MID is 1.3 dv. The MID visibility improved by 2.6 dv from the baseline and is under the unadjusted URP glidepath. On the clearest days, the visibility improved by 0.9 dv.

Figure 3–4 shows the MID compared to the unadjusted URP glidepath, and the clearest days compared to the baseline at NOCA1 for the five-year averages 2000 - 2008, 2008 - 2012, and 2014 - 2018; and the annual averages for the MID and clearest days since 2002. The most recent annual average MID are below the glidepath, which indicates a rate of visibility improvement that will accomplish the 2064 natural conditions goal.

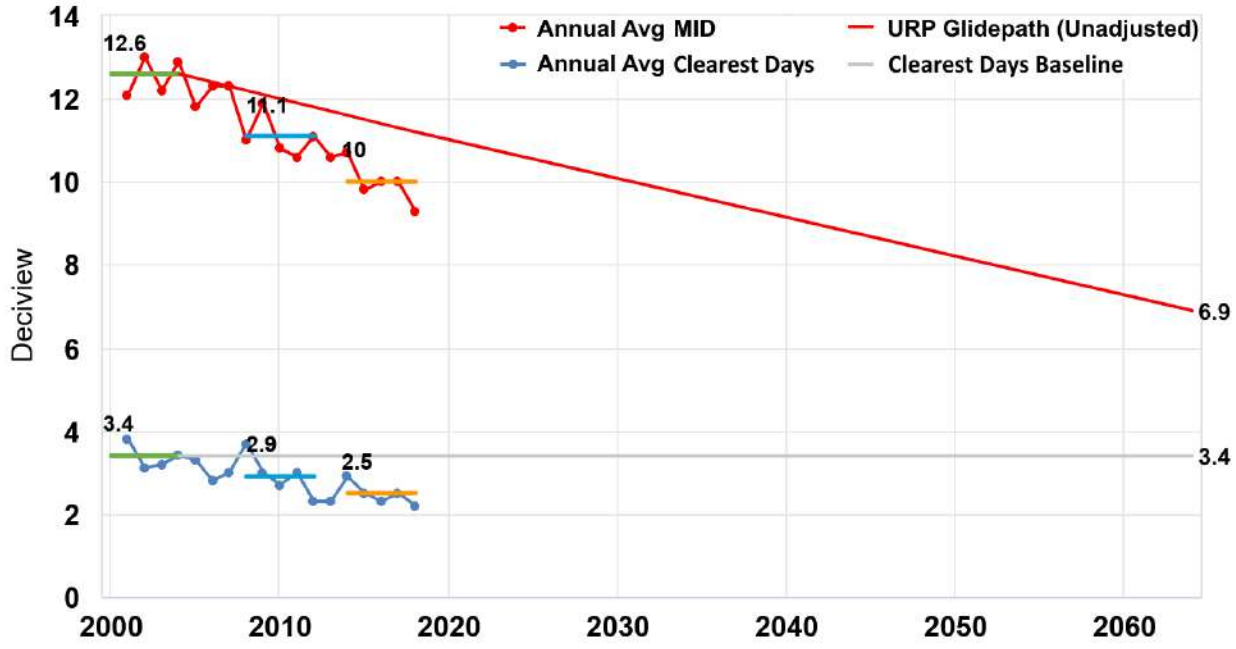


Figure 3–4: Current visibility conditions compared to the unadjusted glidepath (MID) and baseline (clearest days) at NOCA1.

Figure 3–5 shows the annual species contributions to light extinction from 2014 to 2018 for both MID and clearest days. Sulfates decreased for both MID and clearest days during the five-year period. Nitrates and organic mass showed some year-to-year variability.

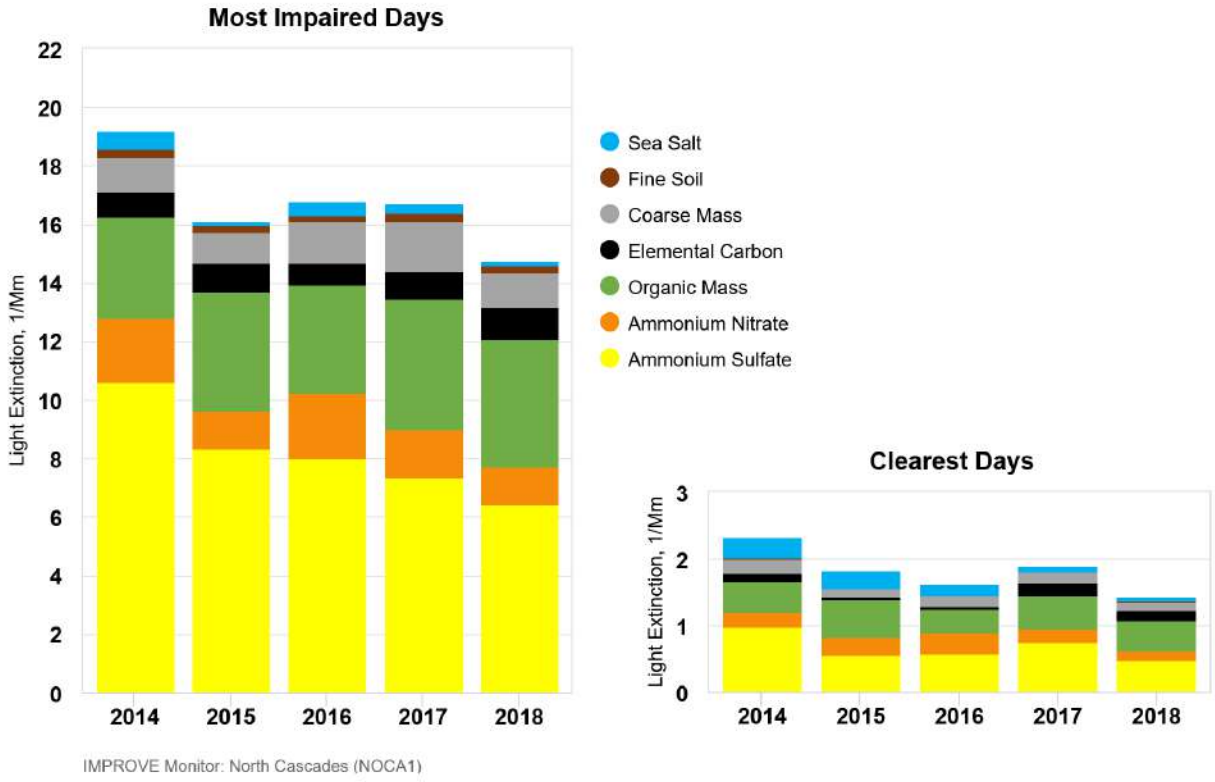


Figure 3–5: Annual species contributions to light extinction for MID and clearest days from 2014 - 2018 at NOCA1.

Table 3-8 shows the annual species contributions during the five-year period for the MID. Sulfates contributed half of the light extinction to MID from 2014 - 2018. The percentage of organic mass increased in 2015, 2017, and 2018. During the five-year period, sulfates (49%) were the largest contributor to light extinction, followed by organic mass (24%), nitrates (10%), and coarse mass (8%). Elemental carbon, fine soil, and sea salt had minimal contributions to light extinction.

Table 3-8: Annual species contributions to light extinction for MID from 2014 - 2018 at NOCA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	3%	1%	3%	2%	1%	2%
Fine Soil	2%	2%	1%	2%	2%	2%
Coarse Mass	6%	7%	9%	10%	8%	8%
Elemental Carbon	4%	6%	4%	6%	7%	5%
Organic Mass	18%	25%	22%	27%	30%	24%
Ammonium Nitrate	11%	8%	13%	10%	9%	10%
Ammonium Sulfate	55%	52%	48%	44%	44%	49%

Table 3-9 shows the annual species contributions during the five-year period for the clearest days. Sulfates (36%) contributed the most to light extinction, followed by organic mass (26%). Note the relatively low contribution of nitrates for both MID and clearest days at NOCA1.

Table 3-9: Annual species contributions to light extinction for clearest days from 2014 - 2018 at NOCA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	14%	14%	10%	4%	5%	9%
Fine Soil	1%	1%	1%	1%	1%	1%
Coarse Mass	9%	7%	9%	8%	9%	8%
Elemental Carbon	5%	2%	3%	10%	9%	6%
Organic Mass	19%	30%	23%	27%	31%	26%
Ammonium Nitrate	10%	15%	19%	11%	11%	13%
Ammonium Sulfate	41%	31%	36%	39%	33%	36%

Table 3-10 and Table 3-11 show the seasonality of MID from 2014 - 2018. Sulfates contributed to the majority of light extinction for all seasons. Organic mass contributed to nearly a third of light extinction in the fall. Coarse mass contributed to 10% of the light extinction in the summer, but less for other seasons. The majority of MID occurred during the spring and summer, when nitrate and coarse mass contributions were largest.

Table 3-10: Number of MID at NOCA1, by season, from 2014 - 2018.

Year	Winter	Spring	Summer	Fall
2014	1	11	7	4
2015	2	14	4	3
2016	0	8	13	3
2017	2	7	13	2
2018	1	13	5	5
5-yr Total	6	53	42	17

Table 3-11: Seasonal species contributions to light extinction for MID from 2014 - 2018 at NOCA1.

Species	Winter	Spring	Summer	Fall
Sea Salt	0%	1%	2%	3%
Fine Soil	1%	2%	1%	1%
Coarse Mass	4%	7%	10%	6%
Elemental Carbon	6%	6%	5%	7%
Organic Mass	18%	23%	24%	29%
Ammonium Nitrate	5%	10%	12%	8%
Ammonium Sulfate	67%	50%	46%	46%

Figure 3–6 shows the long-term trends for NOCA1. Sulfates decreased since the baseline period for both MID and clearest days. Organic mass showed some year-to-year variability over the past 17 years of observations.

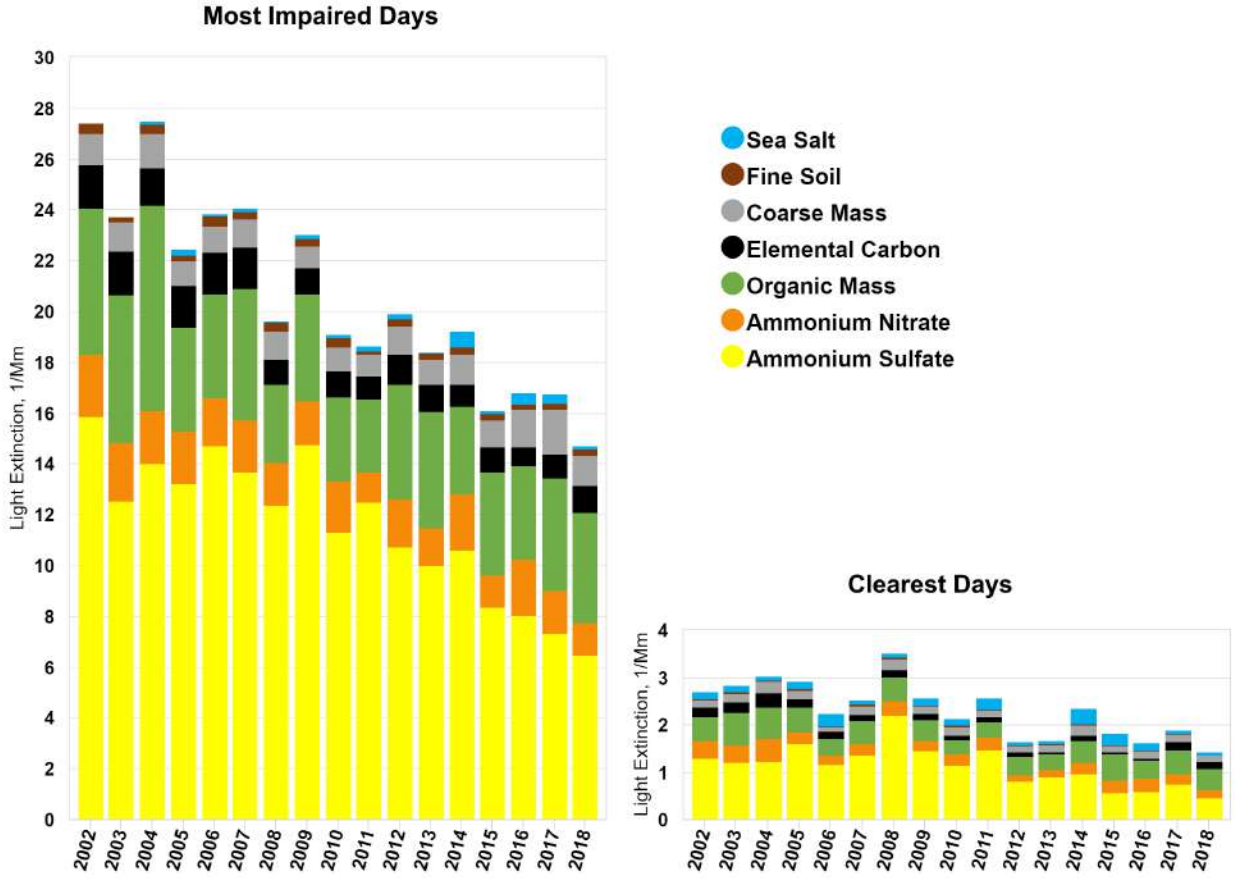


Figure 3–6: Annual species contributions to light extinction for MID and clearest days from 2002 to 2018 at NOCA1.

3.4 Alpine Lakes Wilderness

The SNPA1 monitoring site measures baseline visibility in the Alpine Lakes Wilderness for the MID and clearest days for the years 2001 - 2004. Data for 2013 did not meet the data completeness requirements per the EPA document "Guidance for Tracking Progress under the RHR." Fourteen days (12% of the total) were missing for all species. WRAP performed data substitutions for 2013 to using the MORA1 IMPROVE site to address data completeness problems, due to the strong sulfate and soil correlation, and reasonable elemental carbon, organic mass, and coarse matter correlation. See Appendix C for additional information on the WRAP data completeness memo.

The baseline visibility for the Alpine Lakes Wilderness is 5.5 dv for the clearest days and 15.4 dv for the MID. The unadjusted URP glidepath goes from 15.4 to 7.3 dv at a rate of 0.14 dv per year (8.1 dv divided by 60 years), which is the rate that would need to be maintained to reach natural visibility conditions in the park by 2064.

The current conditions (2014 – 2018) calculated from the SNPA1 monitoring data are 3.3 dv for the clearest day and 12.7 dv for the MID. The clearest days' visibility improved by 2.2 dv from the baseline. The amount of visibility improvement from the baseline to 2018 required to stay below the 2018 URP unadjusted glidepath for MID is 2.0 dv. The MID visibility improved by 2.7 dv and is below the unadjusted URP glidepath.

Figure 3–7 shows the MID compared to the unadjusted URP glidepath, and the clearest days compared to the baseline at SNPA1 for the five-year averages 2000 - 2008, 2008 - 2012, and 2014 - 2018; and the annual averages for the MID and clearest days since 2002. The most recent annual average MID are below the glidepath, which indicates a rate of visibility improvement that will accomplish the 2064 natural conditions goal.

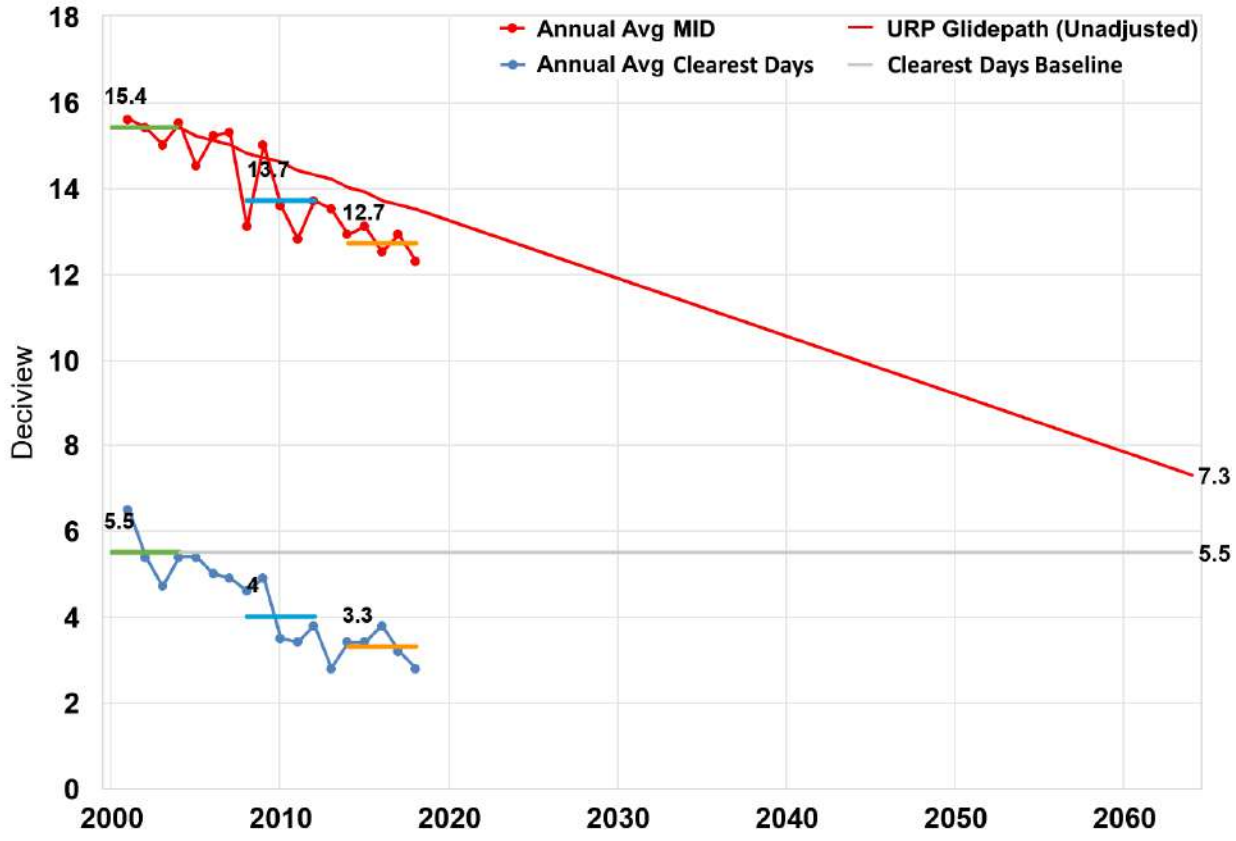


Figure 3–7: Current visibility conditions compared to the unadjusted URP glidepath and baseline (clearest days) at SNPA1.

Figure 3–8 shows the annual species contributions to light extinction from 2014 - 2018 for both MID and clearest days. Sulfates decreased for MID during the five-year period. Nitrates and organic mass showed some year-to-year variability.

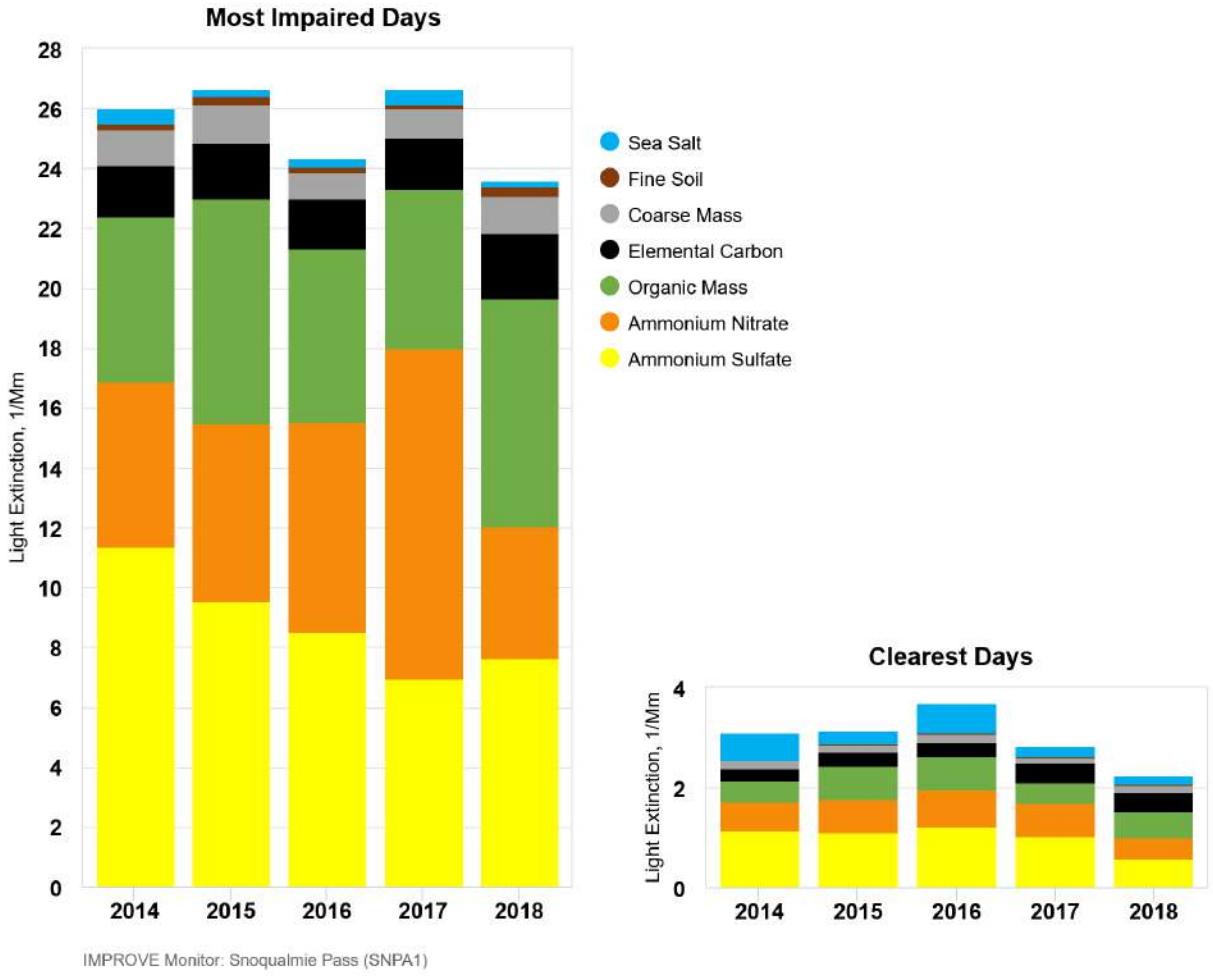


Figure 3–8: Annual species contributions to light extinction for MID and clearest days from 2014 - 2018 at SNPA1.

Table 3-12 shows the annual species contribution during the five-year period for the MID. Sulfates contributed more than a third of the light extinction on MID from 2014 to 2018. The percentage of nitrates increased in 2017 while the percentage of organic mass increase in 2015 and 2018. During the five-year period, sulfates (35%) were the largest contributor to light extinction, followed by nitrates (26%) and organic mass (25%). Elemental carbon, coarse mass, fine soil, and sea salt had minimal contributions to light extinction.

Table 3-12: Annual species contributions to light extinction for MID from 2014 - 2018 at SNPA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	2%	1%	1%	2%	2%	2%
Fine Soil	1%	1%	1%	1%	1%	1%
Coarse Mass	5%	5%	4%	4%	5%	5%
Elemental Carbon	7%	7%	7%	6%	9%	7%
Organic Mass	21%	28%	24%	20%	32%	25%
Ammonium Nitrate	21%	22%	29%	41%	19%	26%
Ammonium Sulfate	44%	36%	35%	26%	32%	35%

Table 3-13 shows the annual species contributions during the five-year period for the clearest days. Sulfates (33%) contributed the most to light extinction, followed by nitrates (20%), sea salt (19%), organic mass (18%), and elemental carbon (12%).

Table 3-13: Annual species contributions to light extinction for clearest days from 2014 - 2018 at SNPA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	18%	21%	18%	14%	23%	19%
Fine Soil	1%	1%	0%	1%	1%	1%
Coarse Mass	5%	4%	5%	4%	6%	5%
Elemental Carbon	9%	9%	8%	14%	18%	12%
Organic Mass	13%	21%	18%	14%	23%	18%
Ammonium Nitrate	19%	21%	20%	23%	19%	20%
Ammonium Sulfate	36%	35%	33%	37%	26%	33%

Table 3-14 and Table 3-15 show the seasonality of MID from 2014 - 2018. Sulfates contributed nearly half of the light extinction in spring and summer. Nitrates contributed two thirds of the light extinction in winter, but much less for other seasons. Organic mass contributed to nearly a third of light extinction in the summer and fall. The majority of MID occurred in spring, summer, and fall.

Table 3-14: Number of MID at SNPA1, by season, from 2014 - 2018.

Year	Winter	Spring	Summer	Fall
2014	2	8	9	5
2015	0	10	7	6
2016	2	4	10	6
2017	5	3	10	5
2018	1	7	6	9
5-yr Total	10	32	42	31

Table 3-15: Seasonal species contributions to light extinction for MID from 2014 - 2018 at SNPA1.

Species	Winter	Spring	Summer	Fall
Sea Salt	2%	2%	1%	1%
Fine Soil	0%	2%	1%	0%
Coarse Mass	2%	6%	6%	3%
Elemental Carbon	5%	7%	7%	8%
Organic Mass	10%	22%	29%	29%
Ammonium Nitrate	66%	19%	16%	32%
Ammonium Sulfate	16%	44%	40%	27%

Figure 3–9 shows the long-term trends for SNPA1. Sulfates have decreased since the baseline period for MID. Every species decreased since the baseline period for clearest days.

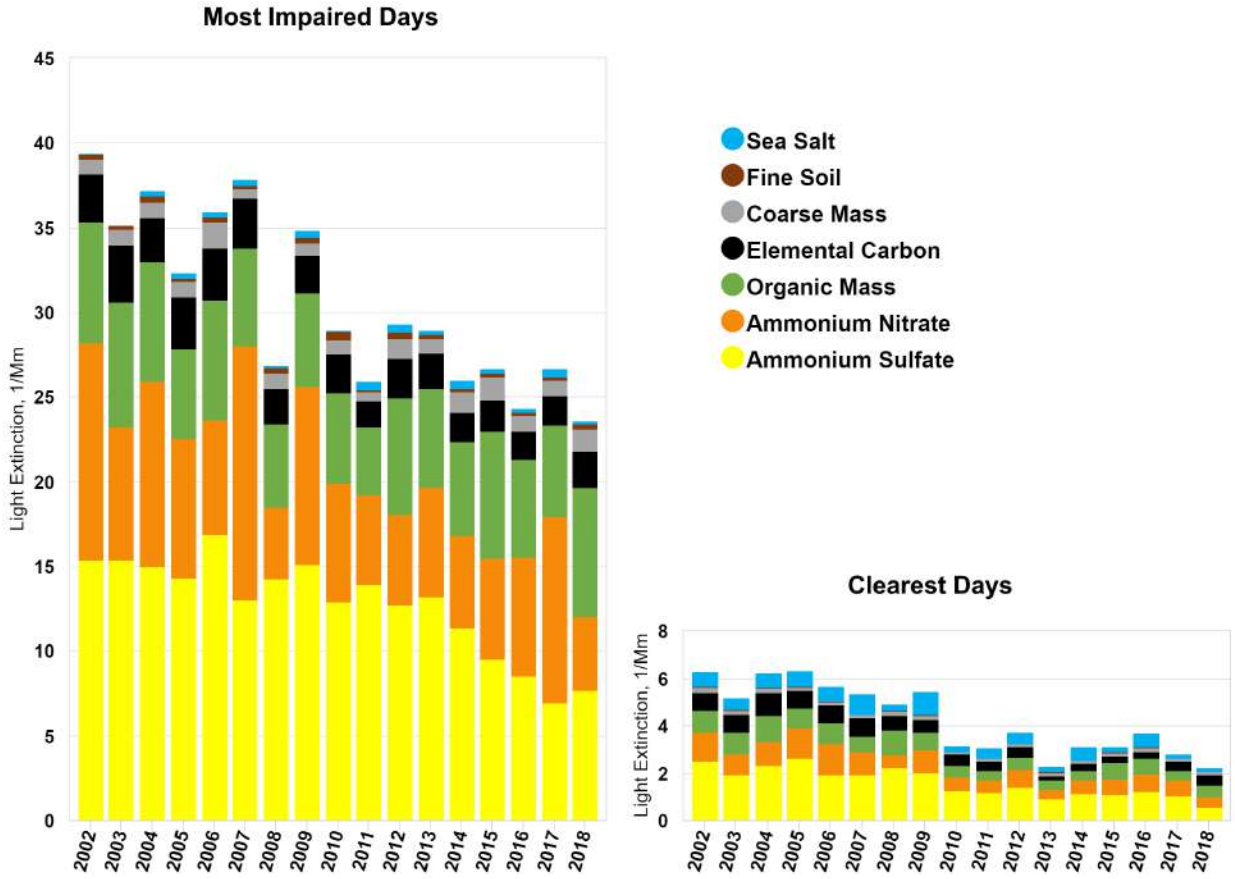


Figure 3–9: Annual species contributions to light extinction for MID and clearest days from 2002 - 2018 at SNPA1.

3.5 Mount Rainier National Park

The baseline visibility for the Mount Rainier National Park is 5.5 dv for the clearest days and 16.5 dv for the MID. The unadjusted URP glidepath goes from 16.5 to 7.7 dv at a rate of 0.15 dv per year (9.8 dv divided by 60 years), which is the rate that would need to be maintained to reach natural visibility conditions in the park by 2064.

The current conditions (2014 - 2018) calculated from the MORA1 monitoring data are 3.9 dv for the clearest days and 12.7 for the MID. The clearest days' visibility improved by 1.6 dv from the baseline. The amount of visibility improvement from the baseline to 2018 required to stay below the 2018 URP unadjusted glidepath for MID is 2.1 dv. The MID visibility improved by 3.8 dv and is under the unadjusted URP glidepath.

Figure 3–10 shows the MID compared to the unadjusted URP glidepath, and the clearest days compared to the baseline at MORA1 for the five-year averages 2000 - 2008, 2008 - 2012, and 2014 - 2018; and the annual averages for the MID and clearest days since 2002. The most

recent annual average MID are below the glidepath, which indicates a rate of visibility improvement that will accomplish the 2064 natural conditions goal.

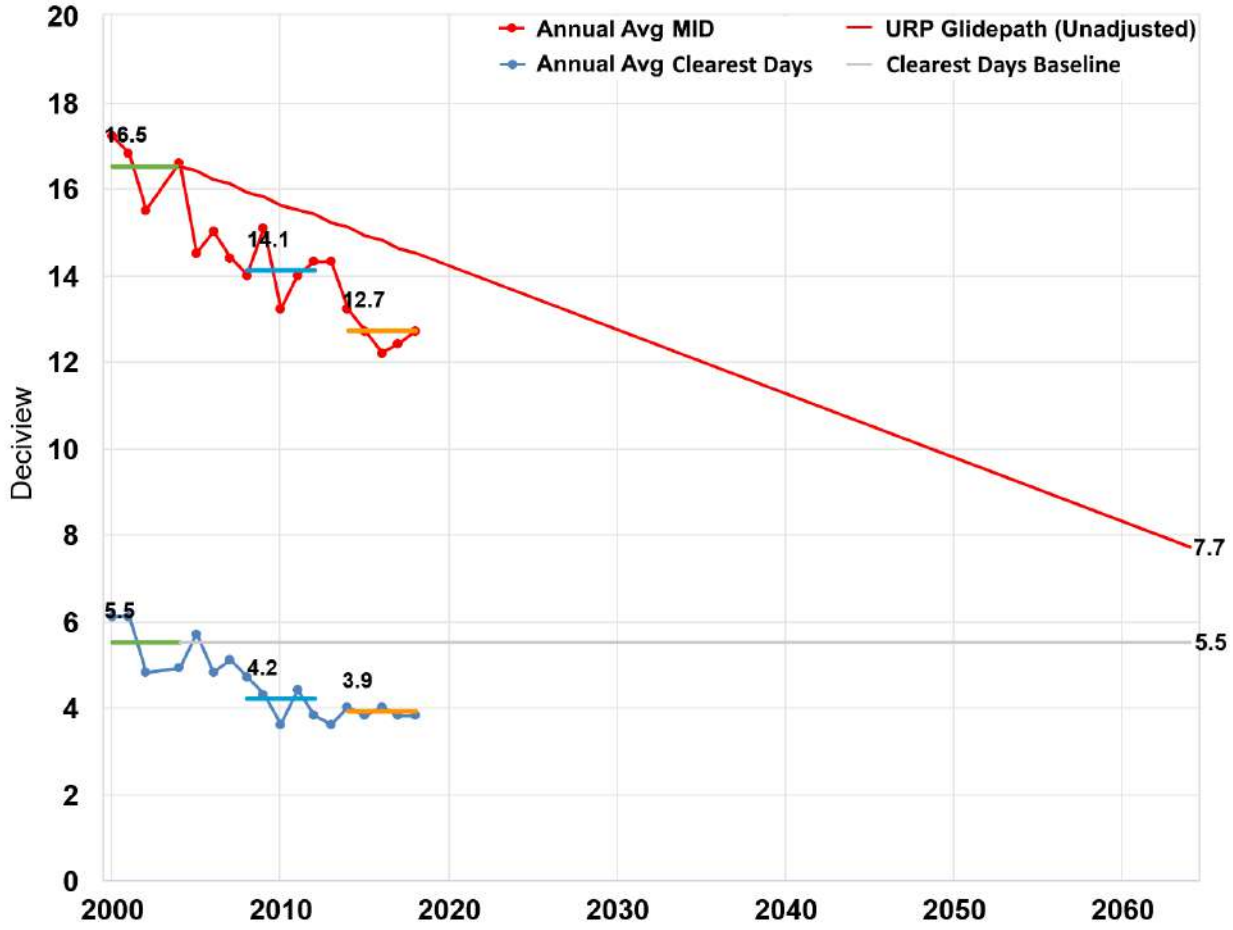


Figure 3–10: Current visibility conditions compared to the unadjusted URP glidepath and baseline (clearest days) at MORA1.

Figure 3–11 shows the annual species contributions to light extinction from 2014 - 2018 for both MID and clearest days. Sulfates decreased each year for MID. Organic mass increased in 2018 for MID. The clearest days showed very little change for all species.

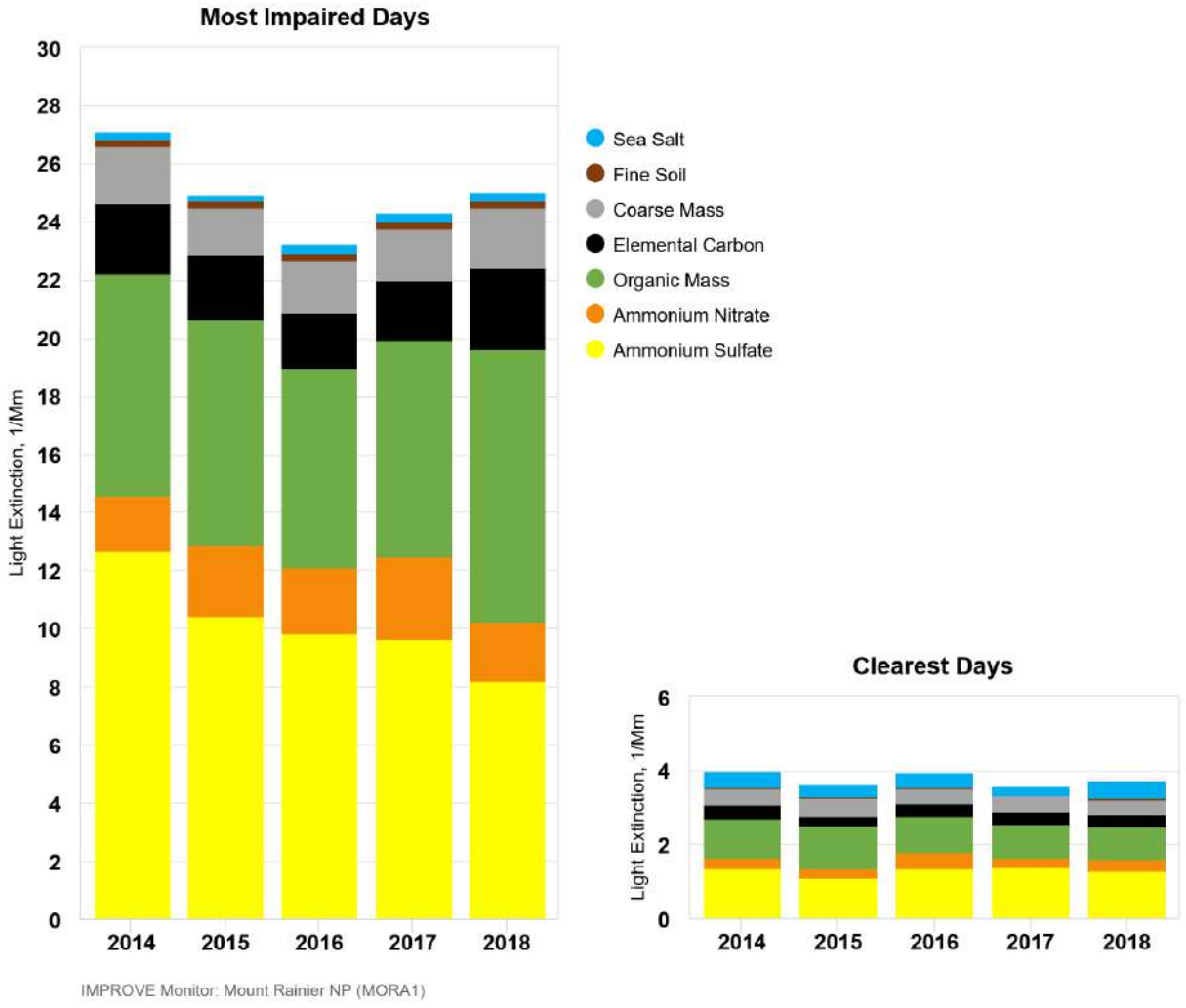


Figure 3–11: Annual species contributions to light extinction for MID and clearest days from 2014 - 2018 at MORA1.

Table 3-16 shows the annual species contributions during the five-year period for the MID. Sulfates contributed more than a third of the light extinction to MID from 2014 - 2018. Organic mass contributed to nearly a third of the light extinction, but increased in 2018. During the five-year period, sulfates (41%) were the largest contributor to light extinction, followed by organic mass (31%), nitrates (9%), and elemental carbon (9%).

Table 3-16: Annual species contributions to light extinction for MID from 2014 - 2018 at MORA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	1%	0%	1%	1%	1%	1%
Fine Soil	1%	1%	1%	1%	1%	1%
Coarse Mass	7%	7%	8%	7%	8%	7%
Elemental Carbon	9%	9%	8%	8%	11%	9%
Organic Mass	28%	31%	29%	31%	38%	31%
Ammonium Nitrate	7%	10%	10%	12%	8%	9%
Ammonium Sulfate	47%	42%	42%	40%	33%	41%

Table 3-17 shows the annual species contributions during the five-year period for the clearest days. Sulfates (35%) contributed the most to light extinction, following by organic mass (26%), coarse mass (12%), and sea salt (10%).

Table 3-17: Annual species contributions to light extinction for clearest days from 2014 - 2018 at MORA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	11%	10%	11%	7%	13%	10%
Fine Soil	0%	1%	0%	1%	1%	1%
Coarse Mass	11%	13%	11%	12%	11%	12%
Elemental Carbon	10%	7%	8%	9%	9%	9%
Organic Mass	26%	32%	25%	25%	24%	26%
Ammonium Nitrate	8%	7%	11%	7%	9%	8%
Ammonium Sulfate	34%	31%	35%	39%	34%	35%

Table 3-18 and Table 3-19 show the seasonality of MID from 2014 - 2018. Sulfates contributed nearly half of the light extinction in spring and summer. Organic mass contributed more than a third of the light extinction in fall and winter. The majority of MID occurred during the spring and summer, which is also when sulfate and nitrate impacts are highest.

Table 3-18: Number of MID at MORA1, by season, from 2014 - 2018.

Year	Winter	Spring	Summer	Fall
2014	3	3	14	3
2015	3	12	5	3
2016	1	6	12	5
2017	1	3	15	4
2018	1	8	8	7
5-yr Total	9	32	54	22

Table 3-19: Seasonal species contributions to light extinction for MID from 2014 - 2018 at MORA1.

Species	Winter	Spring	Summer	Fall
Sea Salt	1%	1%	1%	1%
Fine Soil	1%	1%	1%	0%
Coarse Mass	3%	7%	8%	8%
Elemental Carbon	19%	8%	8%	12%
Organic Mass	41%	29%	31%	36%
Ammonium Nitrate	6%	10%	9%	7%
Ammonium Sulfate	29%	43%	42%	36%

Figure 3–12 shows the long-term trends for MORA1. Sulfates decreased since the baseline period for both MID and clearest days.

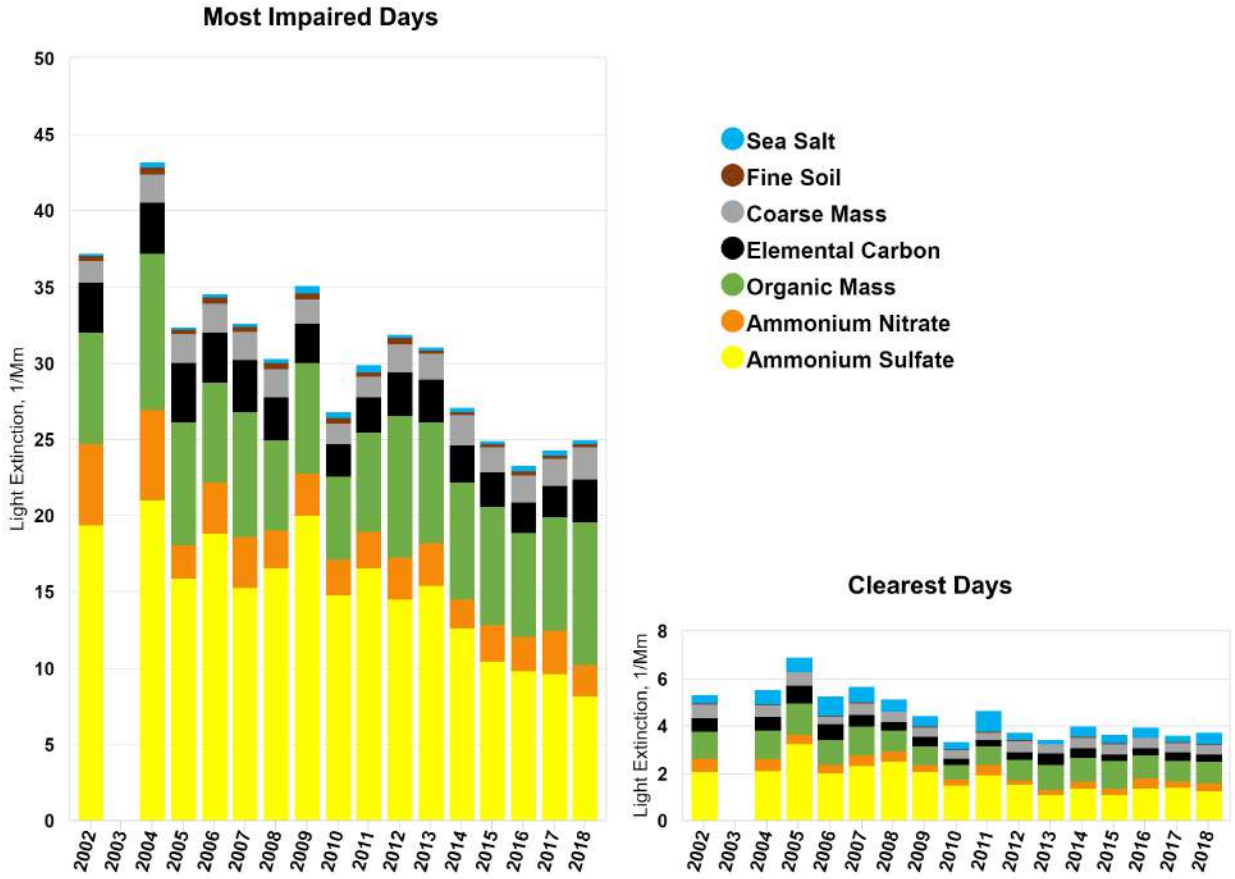


Figure 3–12: Annual species contributions to light extinction for MID and clearest days from 2002 - 2018 at MORA1.

3.6 Goat Rocks Wilderness and Mount Adams Wilderness

The baseline visibility for the Goat Rocks Wilderness and Mount Adams Wilderness is 1.7 dv for the clearest days and 10.5 dv for the MID. The unadjusted URP glidepath goes from 10.5 to 6.1 dv at a rate of 0.07 dv per year (4.4 dv divided by 60 years), which is the rate that would need to be maintained to reach natural visibility conditions in the park by 2064.

The current conditions (2014 - 2018) calculated from WHPA1 monitoring data are 1.0 dv for the clearest days and 8.0 dv for the MID. The clearest days' visibility improved by 0.7 dv from the baseline. The amount of visibility improvement from the baseline to 2018 required to stay below the 2018 URP unadjusted glidepath for MID is 1.0 dv. The MID visibility improved by 2.5 dv and is under the unadjusted URP glidepath.

Figure 3–13 shows the MID compared to the unadjusted URP glidepath, and the clearest days compared to the baseline at WHPA1 for the five-year averages 2000 - 2008, 2008 - 2012, and 2014 - 2018; and the annual averages for the MID and clearest days since 2002. The most recent annual average MID are below the glidepath, which indicates a rate of visibility improvement that will accomplish the 2064 natural conditions goal.

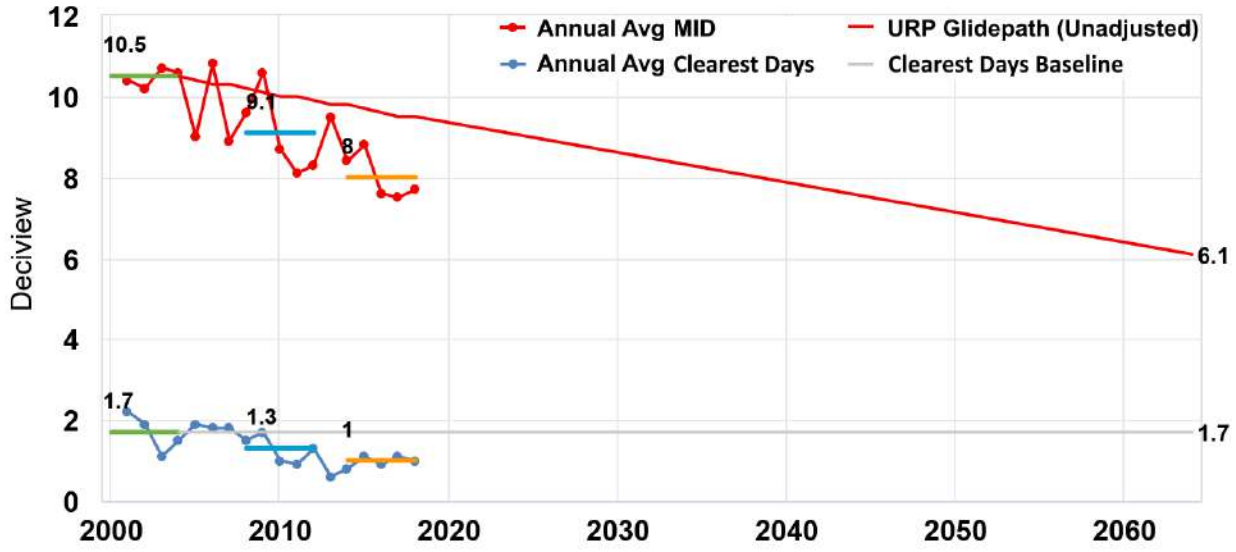


Figure 3–13: Current visibility conditions compared to the unadjusted URP glidepath and baseline (clearest days) at WHPA1.

Figure 3–14 shows the annual species contributions to light extinction from 2014 - 2018 for both MID and clearest days. Sulfates decreased in 2016 for MID, with the decrease sustained through the rest of the five-year period. Organic mass increased in 2015 and 2018 for MID. All species showed very little change for clearest days.

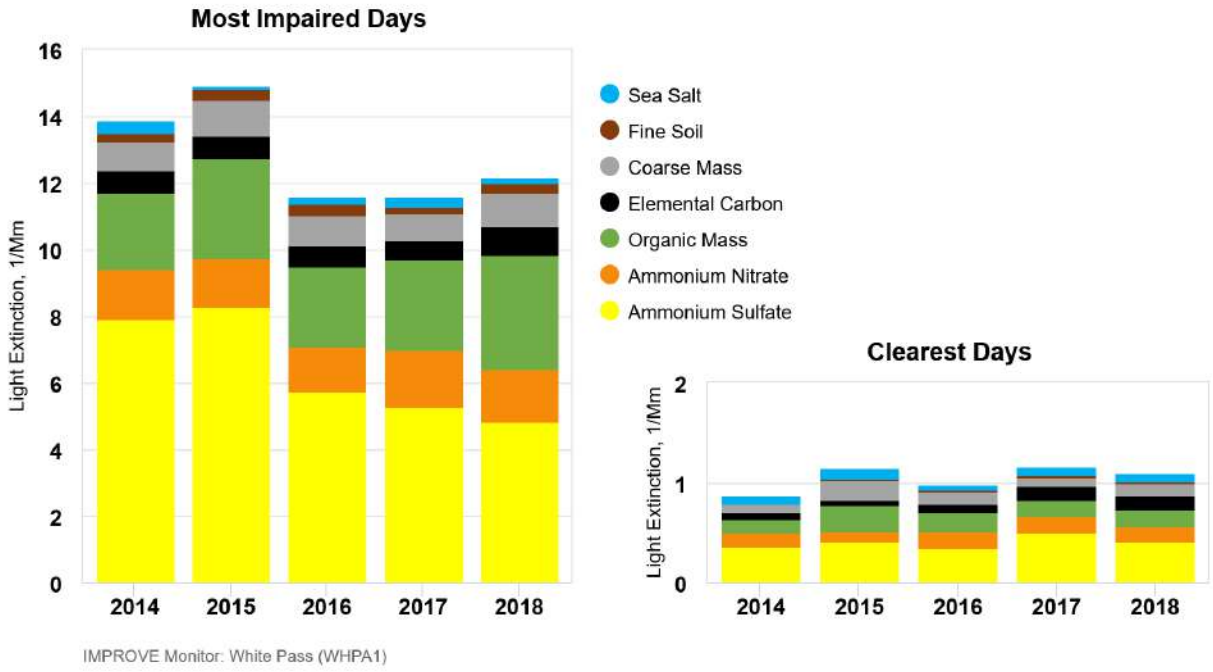


Figure 3–14: Annual species contributions to light extinction for MID and clearest days from 2014 - 2018 at WHPA1.

Table 3-20 shows the annual species contribution during the five-year period for the MID. Sulfates contributed half of the light extinction to MID from 2014 - 2018. During the five-year period, sulfates (50%) were the largest contributor to light extinction, followed by organic mass (22%) and nitrates (12%). Elemental carbon, coarse mass, fine soil, and sea salt had minimal contributions to light extinction.

Table 3-20: Annual species contributions to light extinction for MID from 2014 - 2018 at WHPA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	3%	1%	2%	2%	2%	2%
Fine Soil	2%	2%	3%	2%	2%	2%
Coarse Mass	6%	7%	8%	7%	8%	7%
Elemental Carbon	5%	4%	5%	5%	7%	5%
Organic Mass	16%	20%	21%	23%	28%	22%
Ammonium Nitrate	11%	10%	11%	15%	13%	12%
Ammonium Sulfate	57%	56%	50%	46%	40%	50%

Table 3-21 shows the annual species contributions during the five-year period for the clearest days. Sulfates (39%) contributed the most to light extinction followed by organic mass (18%), nitrates (14%), and coarse mass (12%).

Table 3-21: Annual species contributions to light extinction for clearest days from 2014 - 2018 at WHPA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	9%	10%	6%	8%	7%	8%
Fine Soil	1%	1%	1%	1%	2%	1%
Coarse Mass	9%	17%	13%	8%	12%	12%
Elemental Carbon	8%	5%	8%	11%	12%	9%
Organic Mass	17%	23%	20%	15%	15%	18%
Ammonium Nitrate	15%	9%	18%	14%	14%	14%
Ammonium Sulfate	42%	36%	35%	43%	38%	39%

Table 3-22 and Table 3-23 show the seasonality of MID from 2014 - 2018. Sulfates contributed most of the visibility impacts in all seasons. Organic mass contributed nearly a third of visibility impacts in the summer, but less for other seasons. The majority of MID occurred during the spring, when nitrate and coarse mass contributions were largest.

Table 3-22: Number of MID at WHPA1, by season, from 2014 - 2018.

Year	Winter	Spring	Summer	Fall
2014	3	11	3	5
2015	3	10	5	3
2016	0	8	8	7
2017	2	8	11	2
2018	3	9	3	8
5-yr Total	11	46	30	25

Table 3-23: Seasonal species contributions to light extinction for MID from 2014 - 2018 at WHPA1.

Species	Winter	Spring	Summer	Fall
Sea Salt	1%	1%	2%	3%
Fine Soil	2%	3%	1%	1%
Coarse Mass	6%	8%	8%	6%
Elemental Carbon	7%	5%	5%	6%
Organic Mass	14%	19%	29%	22%
Ammonium Nitrate	11%	14%	11%	9%
Ammonium Sulfate	60%	49%	45%	54%

Figure 3–15 shows the long-term trends for WHPA1. Sulfates, nitrates, and organic mass decreased since the baseline period for both MID and clearest days.

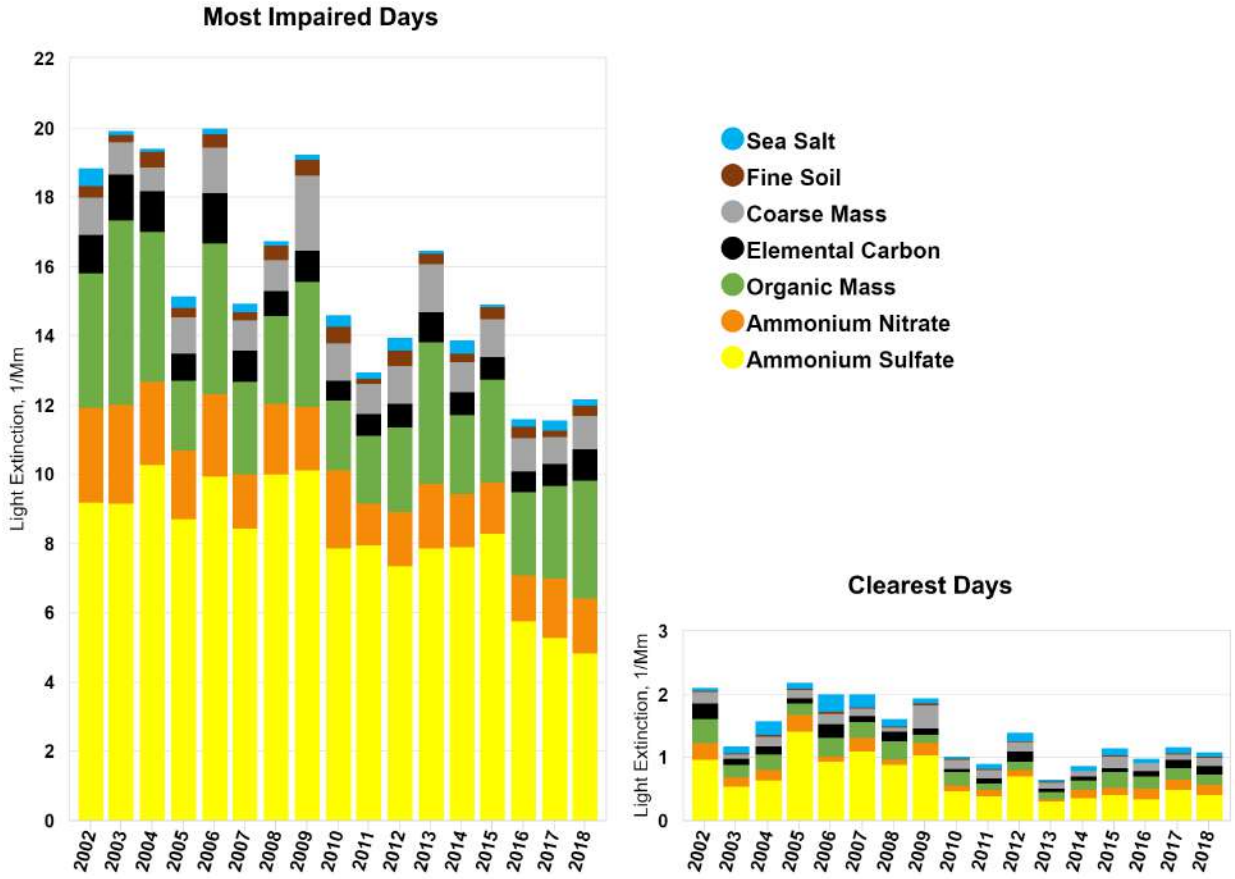


Figure 3–15: Annual species contributions to light extinction for MID and clearest days from 2002 - 2018 at WHPA1.

3.7 Pasayten Wilderness

The baseline visibility for the Pasayten Wilderness is 2.7 dv for the clearest days and 10.4 dv for the MID. Pasayten had the best baseline visibility conditions for the MID of all Washington's Class 1 Areas, and is the second best for the visibility on the clearest days. The unadjusted URP glidepath goes from 10.4 to 6.0 dv at a rate of 0.07 dv per year (4.4 dv divided by 60 years), which is the rate that would need to be maintained to reach natural visibility conditions in the park by 2064.

The current conditions (2014 – 2018) calculated from the PASA1 monitoring data are 1.6 dv for the clearest days and 9.5 dv for the MID. The clearest days' visibility improved by 1.1 dv from the baseline. The amount of visibility improvement from the baseline to 2018 required to stay below the 2018 URP unadjusted glidepath for MID is 1.0 dv. The MID visibility improved by 0.9 dv so the Pasayten's five-year average for MID is slightly above the unadjusted URP glidepath.

Figure 3–16 shows the MID compared to the unadjusted URP glidepath, and the clearest days compared to the baseline at PASA1 for the five-year averages 2000 - 2008, 2008 - 2012, and 2014 - 2018; and the annual averages for the MID and clearest days since 2002. The most recent annual average MID are above the glidepath. Note that some days included in the MID were influenced wildfire smoke. Ecology estimated that in Pasayten from 2014-2018, seven percent of the haziest days were influenced by wildfire, with considerable year-to-year variability. Thus, the removal of five percent of the haziest days as allowed by the RHR was insufficient to remove natural events such as wildfire from the MID. After the proposed endpoint adjustment for international emissions in **Chapter 9**, as allowed by the RHR, the most recent MID are below the adjusted glidepath, which indicates a rate of visibility improvement that will accomplish the adjusted 2064 natural conditions goal.

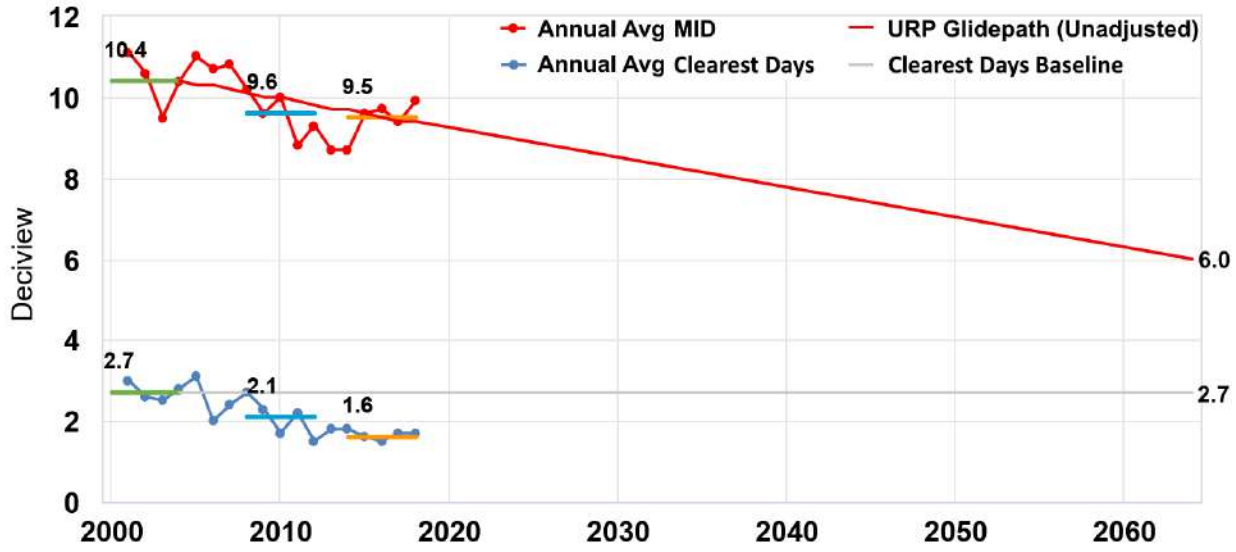


Figure 3–16: Current visibility conditions compared to the unadjusted URP glidepath and baseline (clearest days) at PASA1.

Figure 3–17 shows the annual species contributions to light extinction from 2014 - 2018 for both MID and clearest days. Sulfates decreased over the five-year period for MID and clearest days. Organic mass increased and nitrate showed year-to-year variability for MID. All species showed very little change for clearest days.

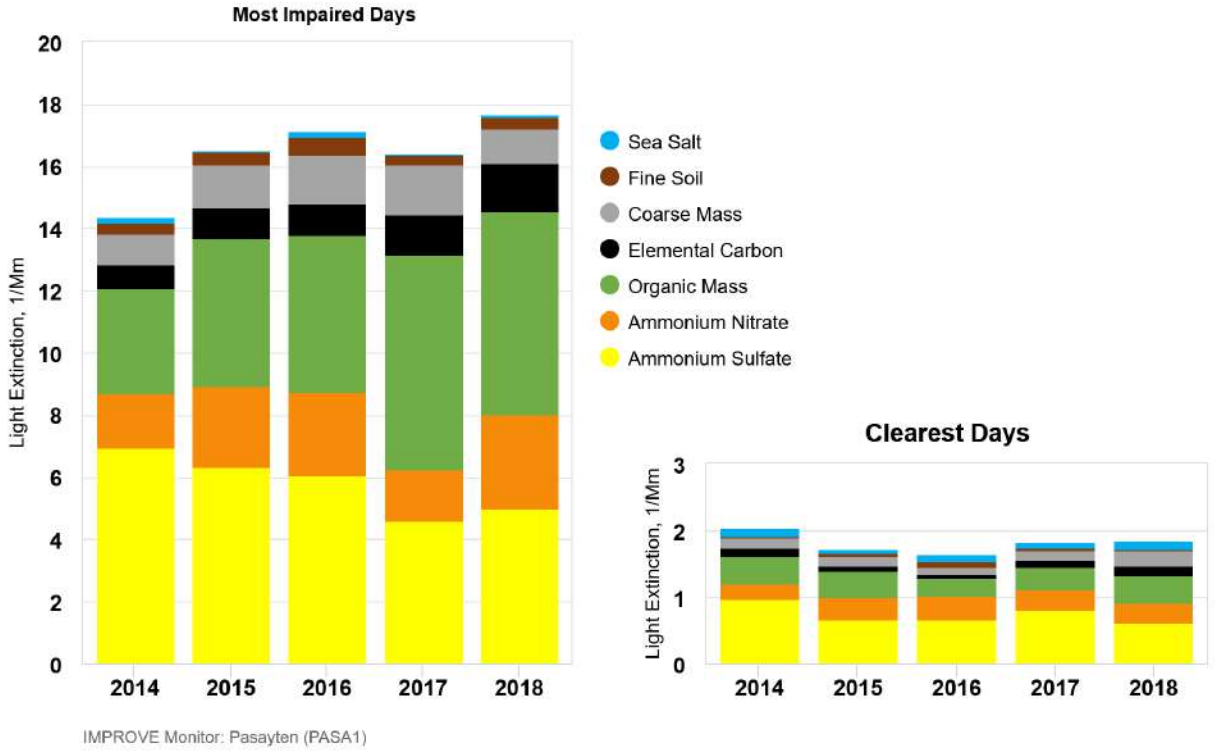


Figure 3–17: Annual species contributions to light extinction for MID and clearest days from 2014 - 2018 at PASA1.

Table 3-24 shows the annual species contributions during the five-year period for the MID. Sulfates and organic mass each contributed one third of the light extinction to MID from 2014 - 2018. Organic mass increased in 2017 and 2018. During the five-year period, contributions to light extinction were largest from sulfates (35%), organic mass (32%), and nitrates (14%). Elemental carbon, coarse mass, fine soil, and sea salt had minimal contributions to light extinction.

Table 3-24: Annual species contributions to light extinction for MID from 2014 - 2018 at PASA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	1%	1%	1%	0%	0%	1%
Fine Soil	2%	2%	3%	2%	2%	2%
Coarse Mass	7%	8%	9%	10%	6%	8%
Elemental Carbon	5%	6%	6%	8%	9%	7%
Organic Mass	24%	29%	30%	42%	37%	32%
Ammonium Nitrate	12%	16%	16%	10%	17%	14%
Ammonium Sulfate	48%	38%	35%	28%	28%	35%

Table 3-25 shows the annual species contributions during the five-year period for the clearest days. Sulfates (41%) contributed the most to light extinction followed by organic mass (20%) and nitrates (17%).

Table 3-25: Annual species contributions to light extinction for clearest days from 2014 - 2018 at PASA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	5%	4%	4%	4%	6%	5%
Fine Soil	1%	2%	6%	2%	2%	3%
Coarse Mass	7%	9%	7%	8%	12%	9%
Elemental Carbon	6%	5%	4%	6%	8%	6%
Organic Mass	20%	23%	16%	18%	22%	20%
Ammonium Nitrate	12%	18%	22%	17%	15%	17%
Ammonium Sulfate	48%	39%	41%	45%	34%	41%

Table 3-26 and Table 3-27 show the seasonality of MID from 2014 - 2018. Sulfates contributed nearly half the visibility impacts in winter and spring. Organic mass contributed more than a third of visibility impacts in summer and fall. The majority of MID occurred in the fall and spring, but summer MID increased in 2017 due to the large wildfire season in the Pacific Northwest. Six of the seven summer MID in 2017 were during regional wildfire events (Dates: July 12, 2017; July 15, 2017; July 24, 2017; August 14, 2017; August 17, 2017; September 19, 2017). Eleven regional wildfire days were included in the MID for PASA during the five-year period, suggesting that the standard threshold to remove wildfire impacts from MID (top 5% of large organic mass days) was insufficient.

Table 3-26: Number of MID at PASA1, by season, from 2014 to 2018.

Year	Winter	Spring	Summer	Fall
2014	4	11	0	8
2015	1	8	3	9
2016	0	9	4	11
2017	1	7	7	8
2018	2	8	2	12
5-yr Total	8	43	16	48

Table 3-27: Seasonal species contributions to light extinction for MID from 2014 to 2018 at PASA1.

Species	Winter	Spring	Summer	Fall
Sea Salt	0%	0%	1%	1%
Fine Soil	1%	4%	3%	1%
Coarse Mass	3%	11%	13%	5%
Elemental Carbon	6%	5%	6%	8%
Organic Mass	16%	25%	43%	37%
Ammonium Nitrate	24%	10%	5%	19%
Ammonium Sulfate	49%	44%	29%	28%

Figure 3–18 shows the long-term trends for PASA1. Sulfates decreased since the baseline period for both MID and clearest days. Organic mass and nitrates showed some year-to-year variability for MID.

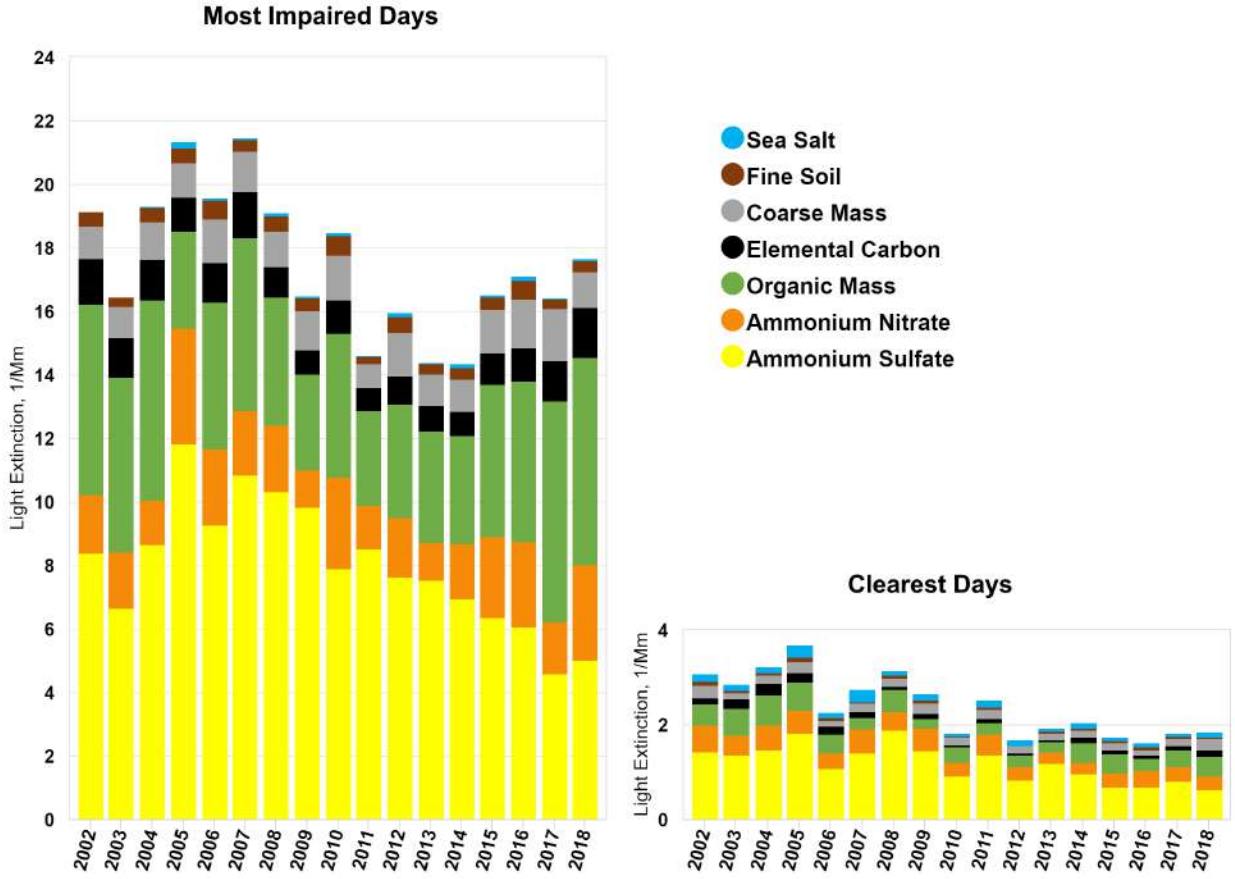


Figure 3–18: Annual species contributions to light extinction for MID and clearest days from 2002 to 2018 at PASA1.

3.8 Summary

All of Washington's Class 1 Areas have shown improvements in visibility on the MID since the baseline and since the first implementation period. The visibility also has not degraded on the clearest days. Sulfates, nitrates and organic mass are the largest contributors to regional haze, with organic mass showing variability from year-to-year. All the Class 1 Areas are also below the unadjusted glidepath for this implementation period except the current five-year MID average for the Pasayten Wilderness, although it has some of the best visibility in the state. The Pasayten's five-year average is slightly above the unadjusted glidepath due to effects of wildfire where the removal of five percent of the haziest days was insufficient to compensate for the effects of fire. The area also borders Canada and receives the most international contributions. In subsequent chapters, we propose adjusting the endpoint of the URP glidepath to account for the impact from international emissions. The Pasayten's 5-year MID average is below the URP glidepath when adjusted for international contributions.

Chapter 4.Emissions Inventory

This chapter summarizes emissions from sources located in Washington that could be affecting visibility in mandatory class 1 Federal areas (Class 1 Areas) in Washington and other states. The Regional Haze Rule (RHR) (40 CFR 51.308 (f)(6)(v)) requires a statewide emissions inventory (EI) of pollutants that we reasonably anticipate to cause or contribute to visibility impairment in any Class 1 Areas. This chapter describes the EI development process, the various EI scenarios developed for regional haze (RH) modeling, a summary of the emissions from each anthropogenic source category, and changes in emissions at facilities selected for a four-factor analysis (FFA).

4.1 Emissions inventory development

The emissions summaries presented in this chapter play an important role in the identification and evaluation of sources that we reasonably expect to influence visibility. An accurate EI helps prioritize emission reduction efforts and helps ensure that model predictions of 2028 visibility impairment are reasonable. The year 2028 represents the second milestone date for demonstrating reasonable progress toward the national visibility goal.

State, local, and tribal air pollution control programs regularly collect and report EI data to EPA. EPA publishes a national emissions inventory (NEI) every three years, which includes all sources of air pollution. Reviewing EI summaries, identifying issues, and correcting errors is an important process that provides a better understanding of emissions sources that could be contributing to visibility impairment.

Western Regional Air Partnership (WRAP) workgroups compiled EI data for use in WRAP modeling and individual state analyses. EI summaries are available from the WRAP Technical Support System (TSS) website[5]. The TSS website also provides references that describe the methods used for RH SIP EI development.

The EPA NEI is the cornerstone of regional haze state implementation plan (RH SIP) EI development. WRAP developed the EI data for RH modeling in collaboration with state, local, and tribal air pollution control programs and EPA, using the 2014 NEI as the starting point. WRAP made several improvements to the 2014 NEI using corrections submitted by the regulatory agencies and updates from the EPA 2016 modeling platform. EPA subsequently released the 2017 NEI in 2020, summarized in this chapter for reference.

4.2 Emissions inventory scenarios

The WRAP focused on EI development for three scenarios: 2014 Actual, Representative Baseline (RepBase), and 2028 On-the-Books (OTB):

- The 2014 Actual EI is a quality-controlled dataset, including state corrections to the 2014 NEI point and nonpoint sources. The purpose of the 2014 Actual EI is to represent the

[5] http://views.cira.colostate.edu/tssv2/

actual emissions of pollutants causing or contributing to visibility impairment during calendar year 2014. The WRAP considers the 2014 Actual EI to be the best available estimates of 2014 emissions for all states in the WRAP. The WRAP used the 2014 Actual EI as the basis to model visibility for the calendar year 2014 and to evaluate model performance.

- The RepBase EI is the modeling baseline used for comparison to future projections. The WRAP designed the Rep Base EI to be the best available data representative of the 2014-2018 five-year period. Ecology used the 2014 Actual EI to develop the RepBase EI with the following updates: states and WRAP workgroups submitted point source emissions, WRAP workgroups developed a representative fire EI, and used the EPA 2016 modeling platform for nonroad emissions. Industrial pulp and paper mill emissions in Washington used the 2017 values for the RepBase EI.
- The 2028 OTB EI is a projected inventory to evaluate reasonable progress toward achieving the national visibility goal. This EI uses the 2016 modeling platform projections for 2028 and emissions submitted by state, local, and tribal air pollution control programs and WRAP workgroups. It includes additional controls or plant closures, which have a planned completion prior to 2028.

The WRAP estimated emissions for the year 2028 by including "On-the-Books" (that is, adopted or soon to be adopted) controls, regulations, and major facility changes. The OTB EI also includes changes to mobile (on-road and non-road) sources as represented in the EPA 2016 modeling platform projections of 2028 emissions. EPA based 2028 mobile source emissions on known fuel standards and projections of population and mobile fleet make-up.

The documentation section of the webpage entitled "Inventory Collaborative 2016v1 Emissions Modeling Platform" [6] (WRAP) cites the methods for projecting mobile source emissions. In summary:

- EPA projected the Commercial Marine Vessel (CMV) (C1 & C2) emissions from 2016 to 2028 using factors derived from the Regulatory Impact Analysis (RIA) *Control of Emissions of Air Pollution from Locomotive Engines and Marine Compression Ignition Engines Less than 30 Liters per Cylinder (73 FR 37095)*.
- EPA developed growth rates for CMV (C3) emissions from 2016 to 2028 using an EPA report on projected bunker fuel demand. The EPA used bunker fuel usage as a surrogate for marine vessel activity.
- EPA estimated locomotive fuel use for 2028 based on the 2018 Annual Energy Outlook (U.S. Energy Information Administration) freight rail energy use growth rate projections for 2016 through 2028.
- EPA used the Motor Vehicle Emissions Simulator (MOVES) model for other non-road sources and for on-road sources, run specifically for 2028.
- EPA reduced medium and heavy-duty truck energy rates for 2014 and later model-year vehicles to account for the Phase 1 of the Greenhouse Gas Emissions Standards and Fuel

[6] http://views.cira.colostate.edu/wiki/wiki/10202

Efficiency Standards for Medium-and Heavy-Duty Engines and Vehicles. (U.S. EPA and NHTSA, 2012).

- Reductions of the Light-duty energy rates for 2017 and later model years vehicles to account for the Light-duty EPA and NHTSA greenhouse gas and fuel economy standards. (U.S. EPA & NHTSA, 2011).

4.3 Emissions inventory comparison

We analyzed anthropogenic EI data for the following visibility-impairing pollutants: sulfur dioxide (SO_2), nitrogen oxides (NOx), volatile organic compounds (VOC), particulate matter ($PM_{2.5}$ and PM_{10}), and ammonia (NH_3). The emissions tables in this section show the primary source categories for each visibility impairing pollutant. The primary emissions source categories vary by the type of pollutant. Using the following groups, we calculated the summaries for anthropogenic sources:

- Point Sources
  - Electric Generating Units (EGU)
  - Non-EGU
- On-road Mobile
- Non-road
  - Commercial Marine Vessel (CMV)
  - Rail
  - Other Non-road (vehicles and equipment)
- Non-point
  - Home heating (wood)
  - Agriculture and fugitive dust (from livestock, tilling, roads, construction)
  - Other non-point
- Fire Events
  - Prescribed fire
  - Agricultural fire

The EI data had two general issues identified:

- Prescribed fire calculations in the modeled scenarios (2014 Actual, RepBase, and 2028 OTB) used EPA methodology. This method is problematic for Washington because most accomplished prescribed burning is as pile burns, which the EPA methodology does not consider. The 2017 NEI prescribed fire emissions are based on our permitted tons burned and appropriate corresponding emission factors, which represents Ecology's best estimate of the category.
- Some non-point emissions in the modeled scenarios (2014 Actual, RepBase, and 2028 OTB) used methodology that Ecology has since revised. Non-point calculations in the 2017 NEI use updated methodology and represent Ecology's best estimate of the category.

Despite the known issues with the EI comparison, the RepBase is comparable to the 2028 OTB in a relative sense for projecting future visibility. However, when attempting to discern the best actual estimate of recent emissions, the 2017 NEI value is the best reference.

SO_2 emissions

Gaseous SO_2 emissions convert to sulfate particles, generally ammonium sulfate, in the atmosphere. Ammonium sulfate particles grow rapidly in size in the presence of water through water absorption and change from solid particles to solution droplets. The size of ammonium sulfate at high relatively humidity (>70%) makes it disproportionally responsible for visibility impairment compared to inorganic salts that do not take up water molecules.

SO_2 emissions in Washington come primarily from point sources, including a coal-fired power plant, oil refineries, primary aluminum plants, pulp and paper mills, and a cement plant. Ecology expects a large reduction in SO_2 emissions by 2028 because TransAlta will cease coal-fired power production by the end of 2025, with one boiler shut down at the end of 2020. CMV was a large source of SO_2 but recent adoption of low-sulfur fuels and port electrification efforts have reduced emissions, as represented in the 2017 NEI.

Table 4-1: Washington state anthropogenic SO_2 emissions (in tons/year)

Source Category	2014 Actual	Rep Baseline	2017 NEI	2028 OTB
EGU Point	3,229	1,588	2,134	62
Non-EGU Point	11,577	12,503	8,060	12,528
On-Road Mobile	552	552	410	241
CMV	10,232	374	478	516
Rail	10	10	11	10
Other Non-Road	52	50	47	34
Home Heating (Wood)	229	229	225	229
Agriculture and Dust				
Other Non-Point	2,042	2,042	1,097	2,042
Prescribed Fire	997	1,611	18	1,611
Agricultural Fire	111	111	152	111
Total (tons/year)	**29,031**	**19,070**	**12,632**	**17,384**

NOx emissions

The burning of any material or fuel can generate NOx (NO + NO_2) emissions because atmospheric oxygen and nitrogen chemically react at temperatures found in combustion. NOx reacts in the atmosphere to form nitrate particles such as Ammonium Nitrate (NO_3). Like Ammonium Sulfate ($(NH_4)_2SO_4$), NO_3 particles grow rapidly in the presence of water to reach a size that is disproportionately responsible for visibility impairment.

NOx emissions come predominantly from on-road mobile sources. Ecology expects those vehicular emissions to continue decreasing through 2028 due to new fuel efficiency standards and the transition to cleaner-burning (and electric) vehicles. We also expect total NOx

emissions from non-road mobile sources to decrease. Another sizable reduction in NOx will occur when coal-fired power production ceases at TransAlta. Overall, Ecology expects NO_X emissions in Washington to decline by more than 40 percent by 2028, primarily due to significant improvements in on-road and non-road mobile source emissions.

Table 4-2: Washington state anthropogenic NOx emissions (in tons/year)

Source Category	2014 Actual	Rep Baseline	2017 NEI	2028 OTB
EGU Point	10,023	8,482	10,196	2,250
Non-EGU Point	20,687	21,948	20,567	21,439
On-Road Mobile	130,500	130,500	89,319	34,366
CMV	16,767	19,062	23,458	17,652
Rail	15,202	15,202	14,258	11,631
Other Non-Road	28,398	24,509	23,200	13,886
Home Heating (Wood)	1,530	1,530	1,381	1,530
Agriculture and Dust				
Other Non-Point	12,050	12,050	10,455	12,050
Prescribed Fire	1,662	1,614	717	1,614
Agricultural Fire	479	479	1,063	479
Total (tons/year)	**237,298**	**235,376**	**194,614**	**116,897**

VOC emissions

VOCs emitted into the atmosphere can condense and oxidize to form secondary organic aerosols, which can degrade visibility. VOCs also play a role in the photochemical production of ozone in the troposphere. The dominant source of VOCs is biogenic emissions, which comprise more than half of the total Washington VOC emissions. Forests and other vegetation emit these natural emissions. VOCs react with NOx to produce nitrated organic particles that impact visibility in the same series of chemical events that lead to ozone. Thus, strategies to reduce ozone in the atmosphere often lead to visibility improvements. However, since natural biogenic VOCs are a dominant source, it is difficult to get visibility improvements by controlling VOCs from anthropogenic sources.

The largest sources of anthropogenic VOC emissions include on-road mobile sources and solvent use (included in the “other non-point” category). Population growth primarily drives significant VOC increases in the “other non-point” category for 2028. However, Ecology expects VOC reductions from mobile sources in the 2028 inventory to more than offset any increases due to population growth.

Table 4-3: Washington state anthropogenic VOC emissions (in tons/year)

Source Category	2014 Actual	Rep Baseline	2017 NEI	2028 OTB
EGU Point	114	65	285	36
Non-EGU Point	11,764	11,291	10,118	11,299
On-Road Mobile	71,971	71,971	59,158	26,295
CMV	596	1,073	1,173	1,252
Rail	744	716	611	494
Other Non-Road	36,508	25,629	24,166	19,189
Home Heating (Wood)	15,448	17,371	13,803	17,370
Agriculture and Dust	2,236	2,236	1,635	2,236
Other Non-Point	86,545	86,545	97,490	86,545
Prescribed Fire	29,998	72,388	3,406	72,388
Agricultural Fire	748	747	2,369	747
Total (tons/year)	**256,672**	**290,032**	**214,214**	**237,851**

$PM_{2.5}$ emissions

$PM_{2.5}$ in the EI includes primary emissions of particulate matter less than 2.5 microns in size, and is synonymous with smoke and fine aerosols. Depending on the year, wildfires generate the majority of $PM_{2.5}$ emissions in Washington. The primary anthropogenic sources are non-point, including fugitive dust (agriculture, construction, and roads) and residential wood combustion. Ecology expects modest $PM_{2.5}$ reductions from the on-road and non-road sectors as they use technology that is more efficient. However, there are large uncertainties when projecting categories like fugitive dust, prescribed burning, and wildfires.

Table 4-4: Washington state anthropogenic $PM_{2.5}$ emissions (in tons/year)

Source Category	2014 Actual	Rep Baseline	2017 NEI	2028 OTB
EGU Point	402	537	671	315
Non-EGU Point	4,007	4,040	2,978	4,057
On-Road Mobile	3,808	3,808	2,573	1,484
CMV	651	396	464	443
Rail	389	389	356	298
Other Non-Road	2,824	2,332	2,217	1,316
Home Heating (Wood)	12,371	12,371	10,614	12,371
Agriculture and Dust	18,304	18,304	29,822	18,304
Other Non-Point	12,932	12,932	6,383	12,932
Prescribed Fire	12,337	21,860	2,420	21,860
Agricultural Fire	1,895	1,894	2,703	1,894
Total (tons/year)	**69,920**	**78,863**	**61,200**	**75,274**

PM_{10} emissions

PM_{10} in the EI includes primary emissions of particulate matter less than 10 microns in size, representing the sum of coarse and fine particles. The primary anthropogenic source is fugitive dust (agriculture, construction, and roads), but fire categories do have significant influence on state totals. Small non-point category increases, which are sensitive to population growth, match the small reductions expected from the on-road and non-road sectors.

Table 4-5: Washington state anthropogenic PM_{10} emissions (tons/year)

Source Category	2014 Actual	Rep Baseline	2017 NEI	2028 OTB
EGU Point	427	586	914	334
Non-EGU Point	4,576	4,594	3,446	4,613
On-Road Mobile	6,913	6,913	5,219	5,029
CMV	819	418	490	469
Rail	404	404	367	307
Other Non-Road	2,973	2,451	2,331	1,402
Home Heating (Wood)	12,377	12,377	10,622	12,377
Agriculture and Dust[7]	237,282	237,282	183,637	237,282
Other Non-Point	14,854	14,854	7,505	14,854
Prescribed Fire	14,557	24,800	2,778	24,800
Agricultural Fire	2,718	2,717	2,769	2,717
Total (tons/year)	**297,900**	**307,396**	**220,078**	**304,184**

[7] The TSS data from this row showed dust emissions after meteorological adjustment. We replaced those values with the unadjusted numbers so that they are directly comparable to the 2017 NEI values.

Ammonia emissions

Agricultural related activities such as livestock operations and farming fertilizer applications are the primary sources of NH_3. NH_3 emissions can react with SO_2 and NOx to form sulfate and nitrate particles, which are significant contributors to visibility impairment. Washington has a strong agricultural community that will continue operating indefinitely. We expect no changes to agricultural practices that will decrease ammonia emissions.

Table 4-6: Washington state anthropogenic ammonia emissions (tons/year)

Source Category	2014 Actual	Rep Baseline	2017 NEI	2028 OTB
EGU Point	69	88	106	86
Non-EGU Point	436	449	388	449
On-Road Mobile	2,356	2,356	2,206	1,744
CMV	8	8	9	9
Rail	9	9	9	9
Other Non-Road	48	40	40	45
Home Heating (Wood)	735	735	656	735
Agriculture and Dust	27,538	27,538	34,570	27,538
Other Non-Point	1,562	1,562	1,252	1,562
Prescribed Fire	2,394	3,602	2,244	3,602
Agricultural Fire	1,952	1,950	6,164	1,950
Total	**37,107**	**38,337**	**47,644**	**37,729**

4.4 Facilities selected for Four-Factor Analysis (FFA)

This section provides emissions from major point sources identified for FFA. Ecology selected seventeen facilities for additional evaluation, spanning six categories:

- Aluminum Production
- Cement Manufacturing
- Glass Manufacturing
- Electric Power Generation
- Paper Manufacturing
- Petroleum Refineries

Table 4-7: Information for facilities selected for FFA

Category	Current Facility Name	FIPS	Site Code
Aluminum Production	Alcoa Primary Metals Intalco Works	53073	0001
Aluminum Production	Alcoa Wenatchee, LLC	53007	0001
Cement Manufacturing	Ash Grove Cement Company	53033	11339
Flat Glass Manufacturing	Cardinal FG Winlock	53041	2175
Electric Power Generation	TransAlta Centralia Generation, LLC	53041	754
Paper Manufacturing	Boise Paper	53071	0003
Paper Manufacturing	COSMO Specialty Fibers, Inc.	53027	0001
Paper Manufacturing	Georgia-Pacific Consumer Operations, LLC	53011	0005
Paper Manufacturing	Longview Fibre Paper and Packaging, Inc.	53015	0002
Paper Manufacturing	Nippon Dynawave Packaging Co.	53015	0003
Paper Manufacturing	Port Townsend Paper	53031	0001
Paper Manufacturing	WestRock Tacoma Mill	53053	0008
Petroleum Refineries	BP Cherry Point Refinery	53073	10007
Petroleum Refineries	Phillips 66 Ferndale Refinery	53073	00005
Petroleum Refineries	Shell Puget Sound Refinery	53057	00003
Petroleum Refineries	Tesoro Northwest Company	53057	00005
Petroleum Refineries	US Oil & Refining Co.	53053	12593

Aluminum production facilities

Alcoa has two aluminum smelters in Washington State under Ecology's Industrial Section jurisdiction: Intalco in Ferndale (Whatcom County) and Wenatchee Works (Chelan County). Alcoa curtailed the Wenatchee facility in 2015 and the Ferndale facility in 2020. Both facilities have a very large potential to emit SO_2, and would contribute to regional haze if Alcoa re-started aluminum production operations. Ecology held facility emissions constant at 2014 Actual levels for the RepBase and 2028 OTB scenarios.

Cement manufacturing

The Ash Grove Cement Company (King County; Puget Sound Clean Air Agency jurisdiction) is one of the largest NOx point sources in the state, emitting over 1,000 tons of NOx per year. Ecology held facility emissions constant at 2014 Actual levels for the RepBase and 2028 OTB scenarios.

Flat glass manufacturing

The Cardinal FG Winlock (Lewis County; SWCAA jurisdiction) glass manufacturing facility is one of the largest NOx point sources in the state, emitting over 800 tons per year. Facility emissions were set to 2014 Actual levels for the RepBase and the 2028 OTB scenario assumed reductions from a selective catalytic reduction control with ammonia injection, which will be installed in 2021.

Electric power generation

The TransAlta Centralia coal-powered EGU (Lewis County; SWCAA jurisdiction) has historically been one of the largest sources of NOx and SO_2 in the state, currently emitting over 5,000 tons of NOx and 1,500 tons of SO_2 per year. The facility will cease coal-fired energy production before 2028; one unit ceased coal-fired operation in 2020 and the other in 2025 with additional NOx reductions until then. Ecology set facility emissions to 2014 Actual levels for the RepBase and to zero for the 2028 OTB scenario.

Paper manufacturing

Seven paper-manufacturing facilities in the state collectively emit over 6,000 tons of NOx, 1,500 tons of SO_2, and 1,300 tons of PM_{10} per year. Facility emissions were set to 2017 NEI levels for the RepBase and 2028 OTB scenarios.

Petroleum refineries

Five petroleum refineries in the state collectively emit over 5,500 tons of NOx and 1,000 tons of SO_2 per year. Ecology held facility emissions constant at 2014 Actual levels for the RepBase and 2028 OTB scenarios.

Table 4-8: Annual NOx emissions for FFA facilities (tons/year)

Current Facility Name	2011	2012	2013	2014	2015	2016	2017	2018	2019	Rep Base	2028 OTB
Alcoa Primary Metals Intalco Works	152	185	220	227	213	188	192	183		227	227
Alcoa Wenatchee, LLC	63	66	67	70	63	1	0	0		70	70
Ash Grove Cement Company	918	665	997	1,144		1,343	1,368	1,159		1,144	1,144
Cardinal FG Winlock	810	657	774	791	807	808	809	809		791	250
TransAlta Centralia Generation, LLC	6,635	4,658	7,793	7,538	5,624	5,019	6,232	5,939		7,538	0
Boise Paper	861	760	629	742	676	681	637	600		637	637
COSMO Specialty Fibers, Inc.	367	364	374	465	644	606	402	384		402	402
Georgia-Pacific Consumer Operations, LLC	528	489	464	463	453	452	486	235		486	486
Longview Fibre Paper and Packaging, Inc.	1,372	1,389	1,498	1,215	952	1,044	1,041	1,092		1,041	1,041
Nippon Dynawave Packaging Co.	2,137	2,221	2,048	2,086	2,024	1,969	1,949	2,276		1,949	1,949
Port Townsend Paper	473	493	482	494	488	489	475	490		475	475
WestRock Tacoma Mill	945	985	890	940	1,032	1,084	1,121	1,035		1,121	1,121
BP Cherry Point Refinery	1,991	1,876	1,959	1,893	1,865	1,905	1,930	1,820		1,893	1,893
Phillips 66 Ferndale Refinery	788	702	784	723	726	769	674	691		723	723
Shell Puget Sound Refinery	1,101	1,319	1,409	1,230	1,076	1,109	1,054	1,146		1,230	1,230
Tesoro Northwest Company	1,882	2,051	1,731	1,918	1,826	2,020	1,971	1,878		1,918	1,918
US Oil & Refining Co.	134	127	135	133		63	115	116		133	133

Table 4-9: Annual SO_2 emissions for FFA facilities (tons/year)

Current Facility Name	2011	2012	2013	2014	2015	2016	2017	2018	2019	Rep Base	2028 OTB
Alcoa Primary Metals Intalco Works	4,538	4,723	4,672	4,794	5,022	4,374	3,987	4,103		4,794	4,794
Alcoa Wenatchee, LLC	2,906	3,127	3,712	2,935	2,741	0				2,935	2,935
Ash Grove Cement Company	51	37	42	57		68	69	67		57	57
Cardinal FG Winlock	56	47	54	57	59	59	56	55		57	71
TransAlta Centralia Generation, LLC	1,136	1,228	2,820	3,037	2,386	1,438	1,707	1,502		3,037	0
Boise Paper	793	604	534	186	68	692	885	393		885	885
COSMO Specialty Fibers, Inc.	214	206	230	237	353	369	242	255		242	242
Georgia-Pacific Consumer Operations, LLC	19	20	19	17	16	30	40	21		40	40
Longview Fibre Paper and Packaging, Inc.	202	302	133	141	220	126	198	258		198	198
Nippon Dynawave Packaging Co.	582	484	378	440	351	376	390	328		390	390
Port Townsend Paper	150	187	198	79	51	44	46	68		46	46
WestRock Tacoma Mill	349	347	263	261	244	190	190	224		190	190
BP Cherry Point Refinery	1,026	930	879	917	907	781	828	726		917	917
Phillips 66 Ferndale Refinery	108	73	46	49	44	45	38	43		49	49
Shell Puget Sound Refinery	369	445	466	349	233	246	225	228		349	349
Tesoro Northwest Company	315	284	237	191	130	125	80	80		191	191
US Oil & Refining Co.	5	4	4	4		7	6	7		4	4

Table 4-10: Annual PM_{10} emissions for FFA facilities (tons/year)

Current Facility Name	2011	2012	2013	2014	2015	2016	2017	2018	2019	Rep Base	2028 OTB
Alcoa Primary Metals Intalco Works	679	736	705	637	708	696	599	563		637	637
Alcoa Wenatchee, LLC	546	395	430	457	467	3	3	3		457	457
Ash Grove Cement Company	31	30	36	43		30	29	16		43	43
Cardinal FG Winlock	10	8	12	12	12	11	16	16		12	15
TransAlta Centralia Generation, LLC	415	209	236	187	140	299	423	347		187	0
Boise Paper	127	124	123	120	113	122	134	106		134	134
COSMO Specialty Fibers, Inc.	272	232	285	272	398	417	280	333		280	280
Georgia-Pacific Consumer Operations, LLC	167	193	178	173	181	151	163	95		163	163
Longview Fibre Paper and Packaging, Inc.	81	257	333	218	202	213	209	220		209	209
Nippon Dynawave Packaging Co.	76	75	121	129	133	129	124	144		124	124
Port Townsend Paper	314	264	291	275	247	220	193	181		193	193
WestRock Tacoma Mill	97	125	155	153	136	201	222	223		222	222
BP Cherry Point Refinery	131	128	98	83	107	118	84	130		83	83
Phillips 66 Ferndale Refinery	59	46	65	64	59	54	60	59		64	64
Shell Puget Sound Refinery	236	228	193	183	207	177	182	191		183	183
Tesoro Northwest Company	154	162	143	157	152	140	144	136		157	157
US Oil & Refining Co.	12	12	12	12		11	12	12		12	12

4.5 Summary

The EI summarizes emissions from sources located in Washington that we reasonably expect to affect visibility in Class 1 Areas in Washington and other states. We used the EI to summarize the anthropogenic emissions from each source category and the changes in emissions at the facilities subjected to a four-factor analysis. We used these emission summaries to prioritize emission reduction efforts and ensure that model predictions of 2028 visibility impairment are reasonable.

Chapter 5.Regional Haze Modeling

Washington relied on the Western Regional Air Partnership (WRAP) modeling for this Regional Haze (RH) State Implementation Plan (SIP). This chapter describes the modeling effort conducted by WRAP for the western contiguous states. Also discussed are model configuration, model performance, and source apportionment options.

WRAP used the Comprehensive Air Quality model and Extensions (CAMx) to perform the representative baseline and 20218 OTB scenarios. CAMx results were used to calculate Relative Response Factors (RRFs), which were applied to the measured baseline period concentrations at the IMPROVE sites. This provided a visibility projection for 2028. Chapter 9 discusses visibility projection results in the context of Reasonable Progress Goals and the Uniform Rate of Progress Glidepath, as determined by the RRFs derived from CAMx simulations.

The WRAP provided source apportionment results using the Weighted Emissions Potential (WEP) technique and the CAMx Particulate Matter Source Apportionment Technology (PSAT) tool. The WEP is a useful method for identifying sources that impair visibility at the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitors, and requires far less computational resources than CAMx PSAT. However, the CAMx PSAT analysis is more appropriate for computing projected visibility because it considers all possible sources of air pollution and atmospheric processes. Chapter 6 discusses the WEP and PSAT results.

5.1 CAMx simulations

The primary tool used by the WRAP for projecting future visibility is the CAMx v 7.0. CAMx is a state-of-the-science photochemical grid model that comprises a "one-atmosphere" treatment of tropospheric air pollution that includes source apportionment techniques[8]. The CAMx model takes into account emissions, advection and dispersion, photochemical transformation, aerosol thermodynamics and phase transfer, aqueous chemistry, and wet and dry deposition of trace species.

CAMx requires meteorological inputs of three-dimensional gridded variables such as wind, temperature, humidity, cloud cover, and precipitation. The CAMx simulations computed for WRAP utilized gridded meteorological data from the Weather Research and Forecasting model. The Weather Research and Forecasting model is the most common source of modeled meteorology in the U.S. used as input to photochemical grid models. Local, state, national, and international modeling efforts use the Weather Research and Forecasting model extensively.

WRAP and the Western Air Quality Study (WAQS) developed the modeling platform with two-way nesting between the continental U.S. (36 km grid-cells) and the western U.S. (12-km grid-cells) modeling domains. Ramboll Group A/S (Ramboll) conducted model simulations for the 2014 base case, the representative baseline, and the 2028 on-the-books (OTB) future U.S. anthropogenic emissions scenarios. Ramboll simulated two 2028 emission scenarios: one with

[8] http://www.camx.com/home.aspx

2014 actual fires and one with a representative fire dataset developed by the WRAP Fire and Smoke Work Group.

Ramboll compiled emissions updates submitted by local, state, and federal agencies and went through several updates as requested by states in the WRAP. Ramboll included a wind-blown dust pre-processor for better soil and coarse mass performance during dust events. They also implemented a bi-directional ammonia deposition scheme for better nitrate performance, especially in agricultural regions. The emission inventories were prepared for CAMx using the Sparse Matrix Operator Kernel Emissions (SMOKE) program. See Chapter 4 for more information about the anthropogenic emissions inventory data used in modeling.

CAMx simulations of the WRAP region required emission inventory data outside the WRAP region. Ramboll compiled emissions for Pacific offshore commercial marine vessels, non-WRAP states, Mexico, and Canada. WRAP posted results on the Technical Support System (TSS) website[9]. The CAMx model also requires input of specific concentrations of visibility-impairing pollutants at the boundaries of the modeling domain. Boundary conditions represent pollutants reaching North America from the rest of the world. Boundary conditions came from the WRAP Revised 2014 GEOS-Chem Base Case.

5.2 CAMx performance

RAMBOLL evaluated the performance of CAMx simulations by comparing CAMx model-simulated concentrations with 2014 ambient monitoring data from a large number of sites. This evaluation determined that the model's performance justified use of the model for simulating future conditions. RAMBOLL used the 2014 Actual emissions inventory for the simulation. They evaluated CAMx for both the most impaired days and the clearest days. See the CAMx 2014v2 Model Performance Evaluation section reported on the WRAP/WAQS 2014v2 Modeling Platform Description and Western Region Performance Evaluation (MPE)[10] site.

The following list summarizes model performance evaluation findings for particulate speciation monitors in the northwest part of the WRAP modeling domain at the locations of IMPROVE and Chemical Speciation Network (CSN) sites:

- Sulfate (SO_4)
  - Year-round overestimation in the northwest.
- Nitrate (NO_3)
  - Initial tests largely underestimated nitrate, but the addition of a bi-directional ammonia deposition scheme to the final 2014 modeling scenario-increased nitrate (NO_3). This may have been too much of an increase for the northwest.
  - Final result was year-round overestimation of nitrate (NO_3) in the northwest at IMPROVE sites but better nitrate (NO_3) performance in the northwest at CSN sites.
  - Better nitrate (NO_3) performance in cold months when monitored concentrations are greater.

[9] https://views.cira.colostate.edu/tssv2/

[10] http://views.cira.colostate.edu/iwdw/docs/WRAP_WAQS_2014v2_MPE.aspx

- Organic mass
    - Overestimation in many parts of the domain, including the northwest.
    - Overestimation of primary organic aerosol (POA) on days when fire impacts occur.
    - Dominated by fires and biogenic secondary organic aerosol (SOA), which are both large sources of uncertainty and generally due to uncontrollable emissions.
- Elemental carbon
    - Overestimated in the northwest during fire impacts, but otherwise concentrations are small.
- Soil and coarse mass
    - The model underestimates windblown dust emissions, causing underestimates of soil and coarse mass during windblown dust events.
    - Better soil performance than Round one RH SIPs due to new method to calculate elements from the model, which matches monitoring methods.
    - Coarse mass (CM) is underestimated in all climate regions and seasons.
        - Much of CM monitored is likely local as CM has a higher deposition rate and shorter transport distance.
        - Subgrid-scale impacts are difficult for a regional grid-model to simulate.
    - Given the uncertainties in the CM modeling results, future-year CM projections were held constant, with an RRF = 1.

Model performance was analyzed for IMPROVE monitors that represent mandatory Class 1 Areas in the state of Washington. Light extinction derived from the 2014 IMPROVE monitor data was compared to the 2014, representative baseline, and OTB model scenarios. CAMx over-predicted light extinction at every IMPROVE monitor for the average clearest days and most impaired days (MIDs).

All model species related to anthropogenic emissions consistently over-predicted for 2014 clearest days at Washington State IMPROVE monitors, across all months. Figure 5–1 shows the clearest days model performance for the 2014 model scenario. The representative baseline and 2028 OTB model scenarios were similar to the 2014 model scenario for clearest days at all sites, except for organic mass in October at NOCA1. The representative baseline and 2028 OTB modeling scenarios showed a tripling of the organic mass bias at NOCA1 for clearest days (not shown), due to change-over to the “representative” fire emissions dataset.

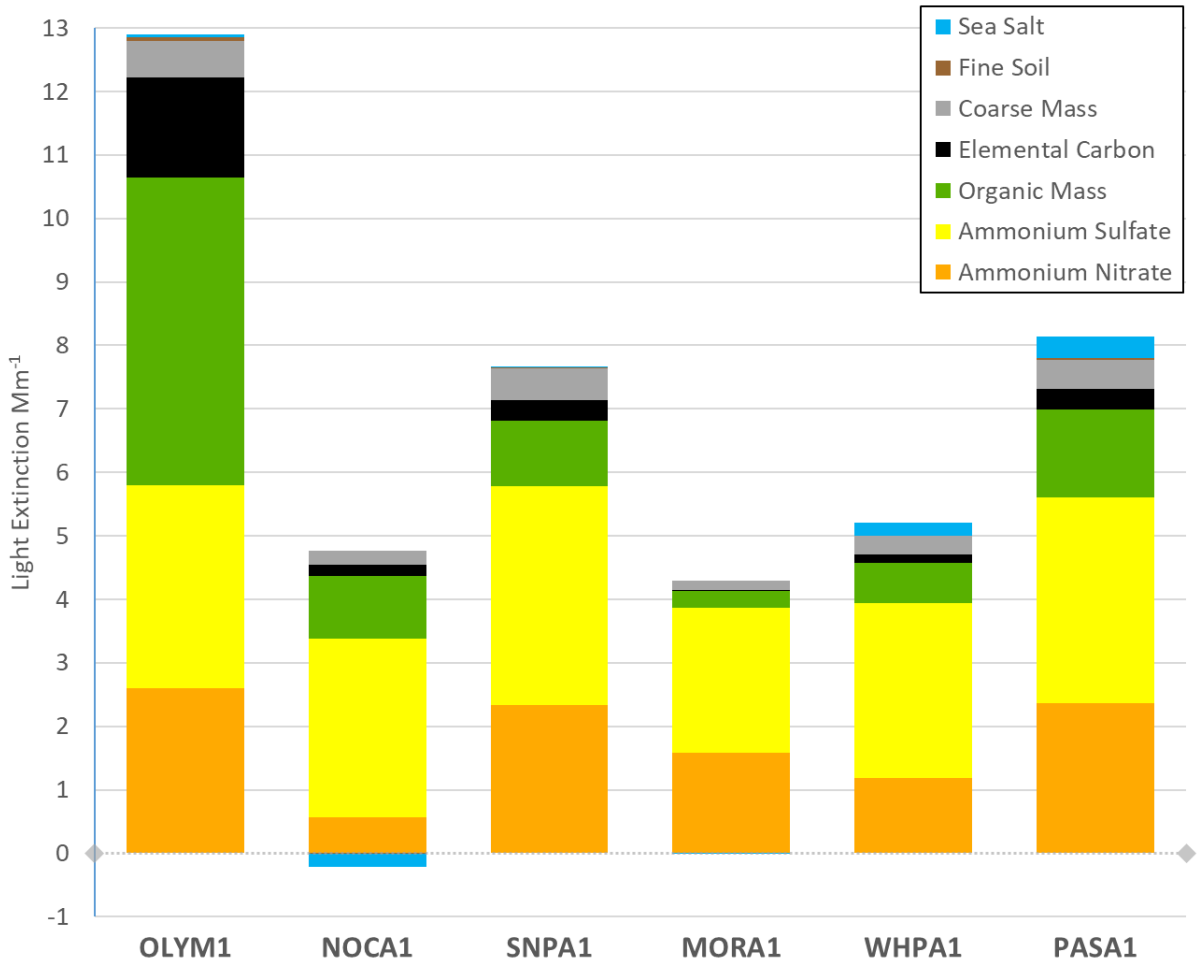


Figure 5–1. Average model bias of light extinction in the 2014 modeling scenario for 2014 clearest days at all sites.

The CAMx performance at Class 1 Area IMPROVE monitors in Washington State for MID is shown in Figures 5-2 thru 5-7. Sulfates, nitrates, and organic mass are over-predicted in the model for Washington State. Upon further analysis of individual model days, it is evident that fire emissions included in the modeling were severely over-estimated on MIDs. The representative baseline and 2028 OTB model simulations used a different fire dataset than the 2014 simulations, shifting the largest model bias from the PASA1 site to SNPA1 and other locations. Overestimation of emissions from prescribed burning in Washington State is not surprising, given that fire emissions calculations from EPA (2014 model scenario) and WRAP (representative baseline and 2028 OTB scenarios) do not accurately represent pile burning, which is the dominant form of prescribed burning in Washington. Wildfire emissions also had negative impacts on model performance, especially for representative baseline and 2028 OTB scenarios, because the wildfire days screened from the 2014 MID are not the same days with highest wildfire impacts in the model. Despite the model performance issues related to fire emissions, they do not negatively influence the RRFs (and therefore the future visibility projection) because the 2028 future scenario holds fire emissions constant relative to the baseline. In fact, over-prediction of model species causes visibility projections (RPGs) to be

more conservative since the proportional change in model scenario predictions due to OTB emissions controls is reduced, thereby constraining the RRF closer to one (no projected change).

Ecology used the CAMx modeling results with the understanding that they were the best tool available to forecast concentrations of visibility-impairing pollutants and projected visibility in 2028, the end of the second implementation period. Despite known model performance issues, we can still use CAMx results in combination with the RRF approach to evaluate the benefits of emission reduction strategies for nitrates and sulfates. The RRF allows us to project visibility changes at Class 1 Areas for regional haze planning purposes.

Model performance for MID at OLYM1

Figure 5–2 shows that elemental carbon, nitrates, and organic mass are over-predicted at OLYM1 for all model scenarios while sea salt is under-predicted. The representative fire emissions dataset used for the representative baseline and 2028 OTB scenarios increased model bias for MID due to clear over-predictions of organic mass in August and September. The largest model bias occurred in October, December, and January due to over-predictions of nitrates and organic mass, but these were not related to wildland fire emissions and persisted across all model scenarios.

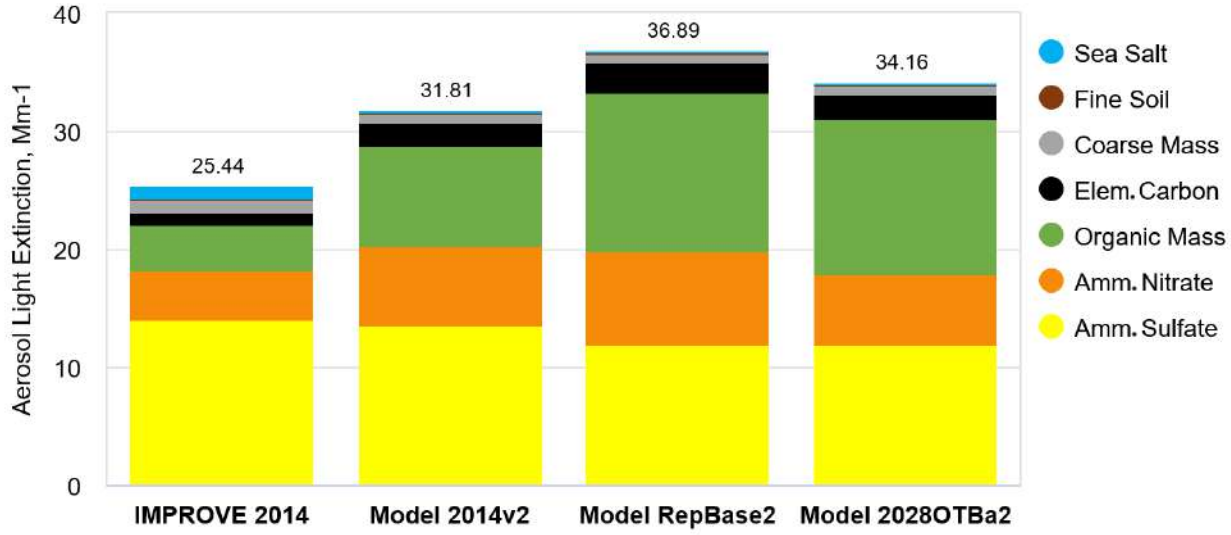


Figure 5–2. Average annual light extinction on MID observed at OLYM1 in 2014 compared to the 2014, representative baseline, and 2028 OTB model scenarios predictions.

Model performance for MID at NOCA1

Figure 5–3 shows that nitrates and organic mass are over-predicted at NOCA1 for all model scenarios. The representative fire emissions dataset used for the representative baseline and 2028 OTB scenarios greatly increased model bias for MID due to clear over-predictions of organic mass in September and October, likely due to over-predictions of prescribed burning emissions in the representative fire dataset. There is also consistent over-prediction of nitrates for 2014 MID across most months.

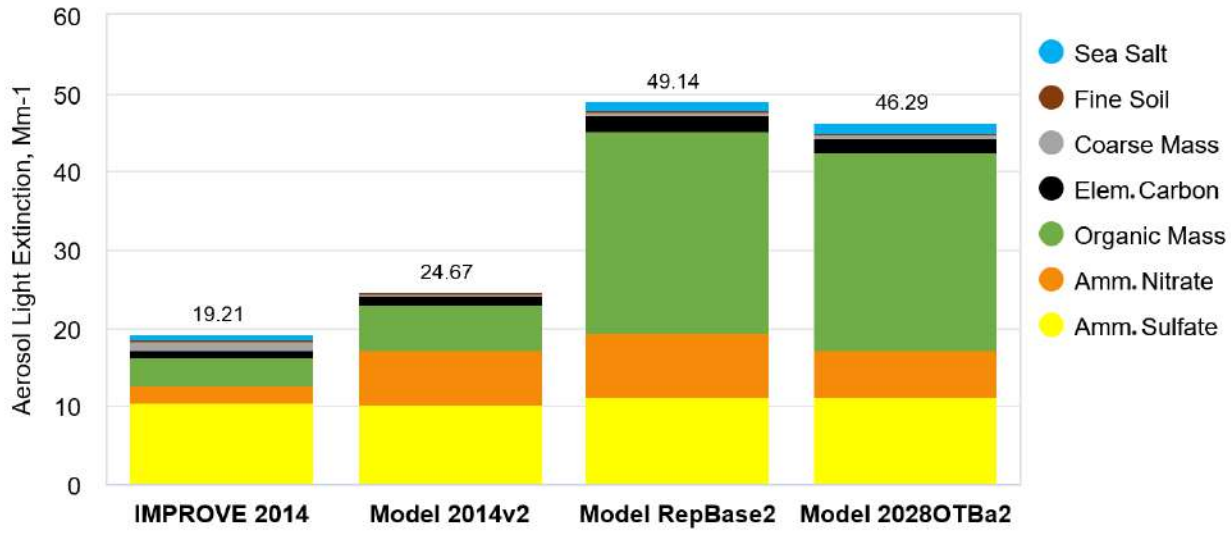


Figure 5–3. Average annual light extinction on MID observed at NOCA1 in 2014 compared to the 2014, representative baseline, and 2028 OTB model scenarios predictions.

Model performance for MID at SNPA1

Figure 5–4 shows that all pollutants are extremely over-predicted at SNPA1 for the representative baseline and 2028 OTB scenarios. The representative fire emissions dataset used for the representative baseline and 2028 OTB scenarios severely increased model bias for MID due to clear over-predictions of organic mass in August, due to over-predictions or incorrect timing of wildfire emissions in the representative fire dataset. There is also clear over-prediction of nitrates from all model scenarios on springtime MIDs.

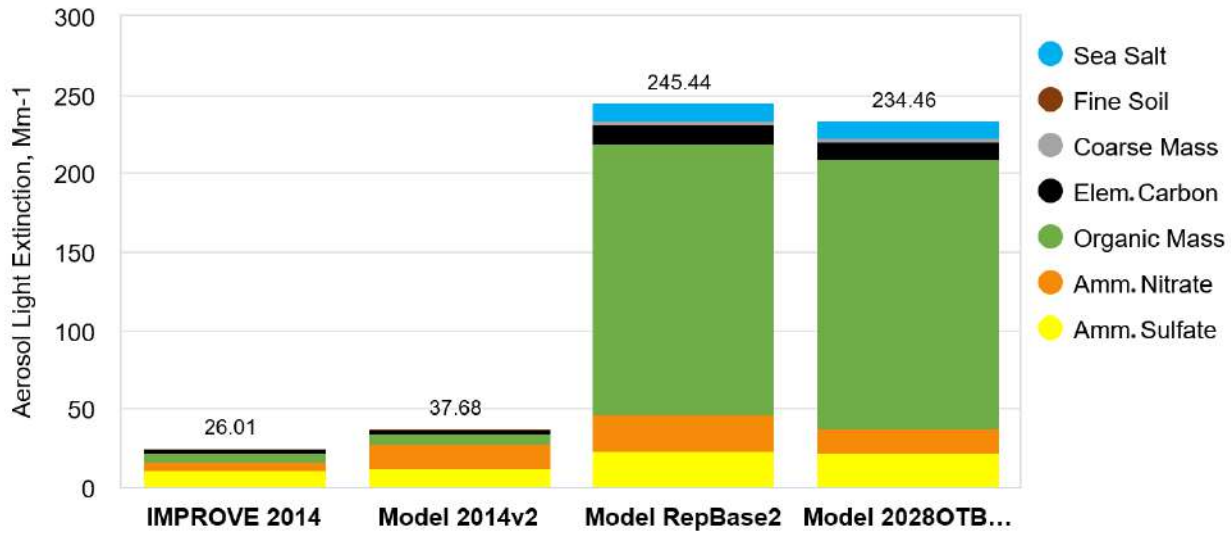


Figure 5–4. Average annual light extinction on MID observed at SNPA1 in 2014 compared to the 2014, representative baseline, and 2028 OTB model scenarios predictions.

Model performance for MID at MORA1

Figure 5–5 shows that nitrates and organic mass are over-predicted at MORA1 for all model scenarios. The representative fire emissions dataset used for the representative baseline and 2028 OTB scenarios greatly increased model bias for MID due to clear over-predictions of organic mass in August, likely due to over-predictions or incorrect timing of wildfire emissions in the representative fire dataset. There is also clear over-prediction of nitrates from all model scenarios on springtime MIDs.

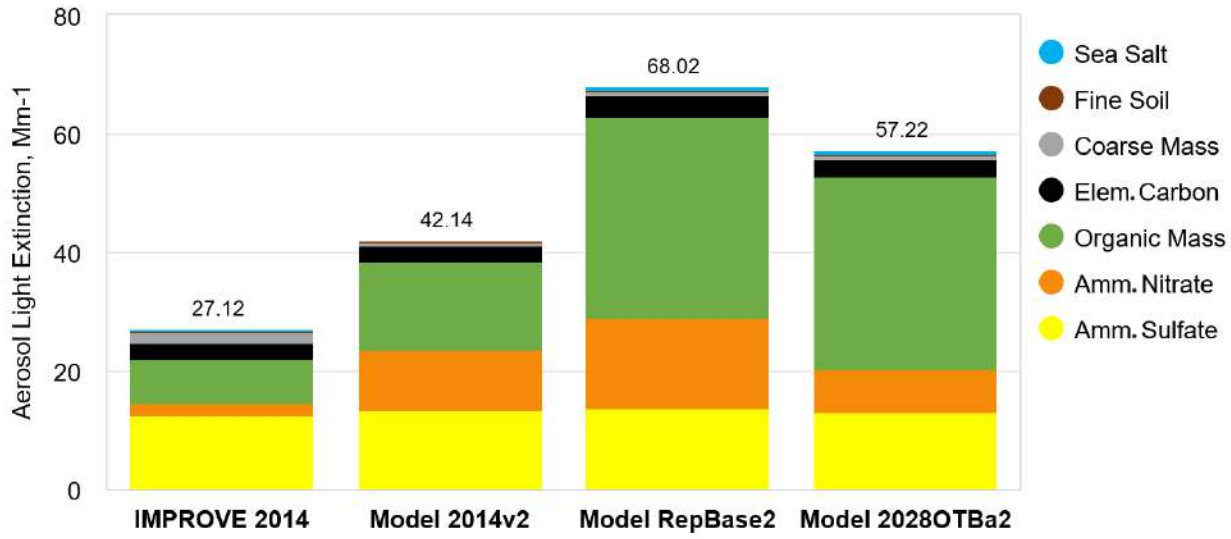


Figure 5–5. Average annual light extinction on MID observed at MORA1 in 2014 compared to the 2014, representative baseline, and 2028 OTB model scenarios predictions

Model performance for MID at WHPA1

Figure 5–6 shows that nitrates and organic mass are over-predicted at WHPA1 for all model scenarios. The representative fire emissions dataset used for the representative baseline and 2028 OTB scenarios had only a small effect on organic mass performance. There is a clear over-prediction of nitrates from all model scenarios on MIDs across all months.

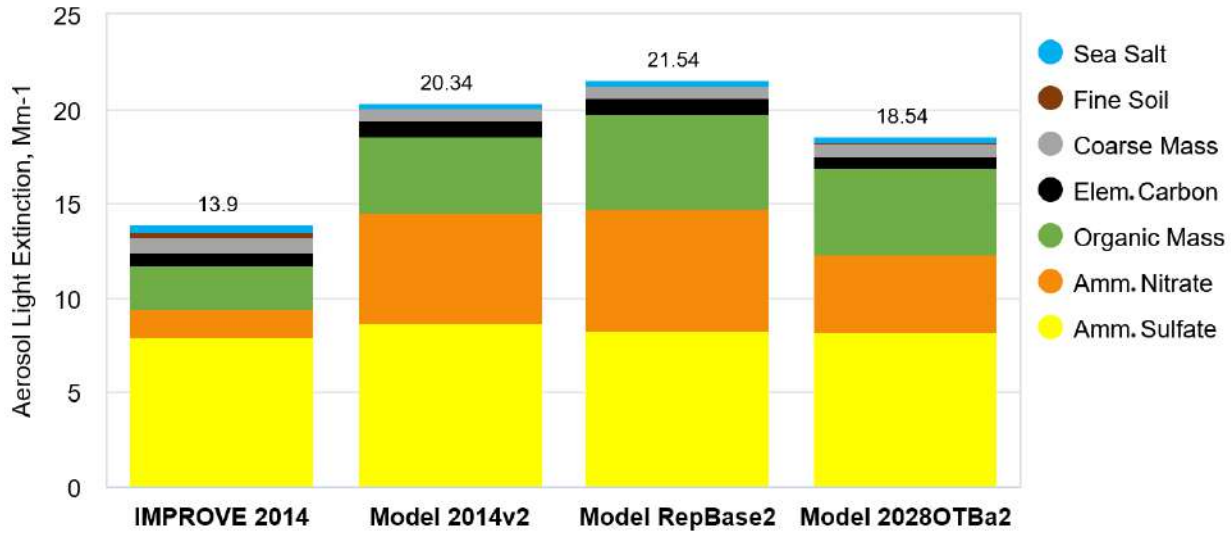


Figure 5–6. Average annual light extinction on MID observed at WHPA1 in 2014 compared to the 2014, representative baseline, and 2028 OTB model scenarios predictions.

Model performance for MID at PASA1

Figure 5–7 shows that nitrates and organic mass are over-predicted at PASA1 for all model scenarios. The representative fire emissions dataset used for the representative baseline and 2028 OTB scenarios greatly improved model performance, due to removal of an incorrectly modeled prescribed fire in October from the 2014 model scenario. There is a clear over-prediction of nitrates from all model scenarios on MIDs across all months.

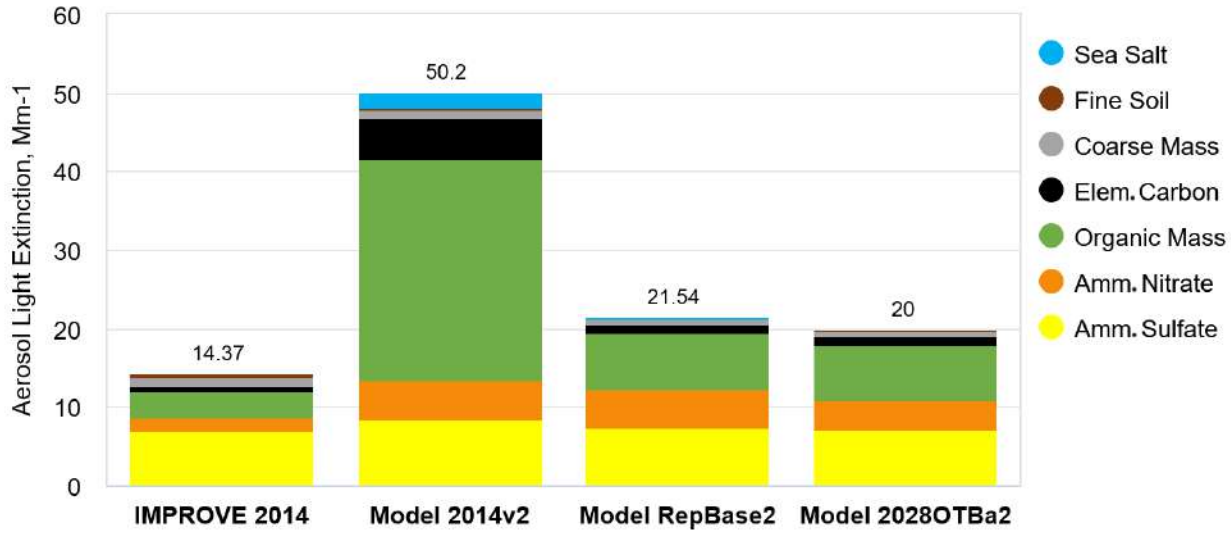


Figure 5–7. Average annual light extinction on MID observed at PASA1 in 2014 compared to the 2014, representative baseline, and 2028 OTB model scenarios predictions.

5.3 Source apportionment options

In order to determine the significant sources contributing to haze in Washington's Class 1 Areas, we rely upon source apportionment analysis provided on the WRAP TSS website[11].

WRAP provided two options for analyzing source apportionment of light extinction caused by pollutants at IMPROVE monitors:

1. The WEP tool, which was used to attribute sources of sulfate, nitrate, organic mass, and elemental carbon.
2. The PSAT tool, which was used to attribute sources of sulfate and nitrate. Source apportionment is especially important for anthropogenic sources of sulfate and nitrate because they have major impacts on visibility at Class 1 Areas.

The WEP is a screening tool that helps to identify source regions that have the potential to contribute to haze formation at specific Class 1 Areas. WEP combines emission inventories, meteorological model data, and the calculated residence time of air masses over each model grid-cell, to estimate the potential for a visibility-impairing pollutant to affect a specific Class 1

[11] http://views.cira.colostate.edu/tssv2/.

Area. WEP is obtained by combining the emissions weighted residence time at IMPROVE monitors with 2028 OTB emissions of light extinction precursors. The WEP analysis provided a broad overview of potential contributions from within and near Washington but does not look at emissions from outside the domain or Pacific offshore, nor does it account for chemistry or deposition. Ecology used the WEP tool to estimate anthropogenic source locations for light-extinction precursors: sulfur dioxide for ammonium sulfate extinction, nitrogen oxides for ammonium nitrate, primary organic aerosol for organic mass, and elemental carbon for itself. Chapter 6 discusses the WEP results.

The PSAT tool was used to further analyze sulfate and nitrate source apportionment for the 2028 OTB CAMx scenario that, unlike the WEP, accounts for all known physical and chemical processes in the atmosphere. The PSAT results also provide more information than the WEP, because they estimate contributions from all regions. PSAT allows a comparison of the relative contributions from Washington State, USA, international, natural, and wildland fire sources. PSAT results also estimate contributions from various emissions categories within the source regions. The PSAT analysis can be useful in determining contributing sources that may be controllable within Washington and in identifying potentially controllable sources, or the need for controls, in other jurisdictions (neighboring states, other countries, and Pacific offshore). Chapter 6 discusses the PSAT results.

Overall, while results from both tools provide relative information on sources of visibility-impairing pollutants, the PSAT results are more reliable and the WEP results more qualitative because of the way the results are developed. The PSAT results come from one-atmosphere, photochemical modeling simulations for sulfate and nitrate, and thus are a modeling prediction of how emissions impact a Class 1 Area. WEP only estimates impacts from the residence time of the air mass over an area and the total annual anthropogenic emissions in that area without consideration of natural sources, chemistry, or sources outside the model domain.

Chapter 6.Source Apportionment and Washington's Impacts on Mandatory Class 1 Areas

This chapter discusses the following:

- Expected contributions from regional anthropogenic emissions to light extinction at Washington's mandatory Class 1 Areas in 2028,
- Expected contributions from international, natural, and wildland fire sources to light extinction at Washington's Class 1 Areas in 2028,
- Expected sulfate and nitrate contributions from Washington anthropogenic emissions to light extinction at out-of-state Class 1 Areas in 2028.

The contributions from regions and source categories were determined using Particulate Matter Source Apportionment (PSAT) and Weighted Emissions Potential (WEP), described in Chapter 5. The WEP includes elemental carbon, organic mass, nitrates, and sulfates but is only for nearby anthropogenic emissions. PSAT only includes nitrates and sulfates, but accounts for all global sources.

The WEP and PSAT analyses presented in this chapter are based purely on model data generated by CAMx, the Hybrid Single-Particle Lagrangian Integrated Trajectory (HYSPLIT) model, and related pre-processors. Model simulations used 2014 meteorology and the 2028 on-the-books (OTB) emissions inventory. WEP and PSAT results did not adjust using relative response factors (RRFs), as is done for the reasonable progress goals (RPGs), due to the computational expense and time that would have been required to do source apportionment for all visibility-impairing species.

We discuss baseline monitored haze and the 2028 RPGs in this chapter for reference. This is because it is important to consider actual observations when attempting to extrapolate model results to the real world. W compared modeled light extinction by species to the baseline monitoring to take into account model bias. Model bias is a consideration when attempting to infer relative source contributions from PSAT and WEP analyses (see Chapter 5). In general, the model bias analysis shows an over-prediction of anthropogenic pollutants.

The Western Regional Air Partnership (WRAP) modeling does not include source apportionment analysis for the Representative Baseline (RepBase) model scenario. However, emissions inventory changes between RepBase and 2028 OTB are the only factors responsible for differences between the two model scenarios. We held constant emissions from non-point, international, natural, and wildland fire for both model scenarios. Reductions of projected visibility impairment in the model-generated results (and thereby the RPGs) are likely from a short list of notable changes:

- Shutdown of TransAlta Centralia coal-fired power plant boilers is a significant reduction in Washington State SO_2 emissions.
- Reduction in on-road mobile NOx emissions by 74 percent in Washington, which caused the majority of modeled nitrate reductions. Less significant reductions of NOx from other source categories were also included.

- There were significant reductions in point and mobile emissions outside of Washington. However, anthropogenic emissions from other states likely have a non-significant impact on visibility at Washington State Class 1 Areas. This is a result of the predominant wind-flow in Washington.

The WEP does not consider wildland fire. The PSAT model tracks wildland fire, but the model analyses do not provide the necessary information to make reasonable conclusions about source apportionment of wildland fire. This is because organic mass is not part of the PSAT analysis, the PSAT does not track wildland fire geographically, and a "representative" fire dataset in the CAMx model simulations replaced actual 2014 fire emissions. The WRAP state generally agreed that recent revisions to the Regional Haze Rule (RHR) make it clear that days impacted by wildland fire should not be used to track reasonable progress. Therefore, calculating modeled wildland fire contributions to Interagency Monitoring of Protected Visual Environments (IMPROVE) monitors by state was not needed. However, several conducted "no fire" simulations are viewable on the WRAP Technical Support System (TSS) website (https://views.cira.colostate.edu/tssv2/).

Each Class 1 Area organizes the data. Where two Class 1 Areas share an IMPROVE monitor the areas are discussed together. Presentation of the data is in the following order:

- Olympic National Park – OLYM1
- North Cascades National Park and Glacier Peak Wilderness - NOCA1
- Alpine Lakes Wilderness – SNPA1
- Mount Rainer National Park – MORA1
- Goat Rocks Wilderness and Mount Adams Wilderness – WHPA1
- Pasayten Wilderness – PASA1

The area of influence (AOI), determined by HYSPLIT, and the WEP analyses of sulfate, nitrate, organic mass, and elemental carbon on most impaired days (MID) are presented. The WEP considers 2028 OTB anthropogenic emissions in the Western US modeling domain but does not consider natural, international, or wildland fire (wildfire and prescribed fire) emissions. The WEP analyses summarizes using the following categories:

- EGU: includes emissions from major point sources that are electric generating units.
- Non-EGU: includes emissions from major point sources that are not electric generating units. Note that insignificant upstream and midstream processes from the oil & gas industry are included with non-EGU in Chapter 4 but not shown here.
- On-road: includes emissions from all vehicles that travel on roads.
- Non-road: includes emissions from locomotives, commercial marine vessels, mobile equipment, and other non-road vehicles.
- Non-point: includes emissions from all other anthropogenic sources, not categorized elsewhere such as institutional, commercial, residential, and agricultural.

Discussed in this chapter as well is the rank point analysis, which presents the relative contribution of out-of-state point sources to the total point source WEP.

Also presented are the PSAT analyses of sulfate and nitrate on MID and clearest days, which considers all sources. The following categories summarize the PSAT analyses:

- Washington anthropogenic: includes industrial, institutional, commercial, residential, agricultural, and mobile sources within Washington State. This source category has very little uncertainty because it was specifically developed for the RH modeling.
- USA anthropogenic: includes industrial, institutional, commercial, residential, agricultural, and mobile sources within the USA (but not Washington State). This source category has very little uncertainty because it was specifically developed for the RH modeling.
- International anthropogenic: includes industrial, institutional, commercial, residential, agricultural, and mobile sources outside of the USA. This source category has moderate uncertainty because it is influenced by international sources from many countries both inside and outside the model domain.
- Natural: vegetation, soils, sea salt, and volcanos. Note that this is not the same as the RHR definition of "natural" sources because wildfire is not included. This source category has moderate uncertainty due to the parameterization of natural emissions.
- Wildland fire: wildfire (WF) and prescribed fire (Rx) for USA, Canada, and Mexico. This source category has large uncertainty and is greatly overestimated in the CAMx modeling for MID in the state of Washington.

Within the state-level PSAT results, anthropogenic sources are further separated into similar categories as the WEP, except on-road and non-road sources are lumped together. Remaining anthropogenic sources are effectively the sum of all non-point categories. Most state-level PSAT results show similar expectations for 2028 light extinction impacts from within Washington State:

- Mobile sources will be the largest source of nitrates. For reference, the 2028 OTB mobile emissions inventory of NOx for Washington State is 44% on-road vehicles, 23% commercial marine vessels, 15% locomotives, and 18% other non-road vehicles and equipment.
- Non-EGU will be the largest source of sulfates. For reference, the 2028 OTB non-EGU emissions inventory of SO_2 for Washington State is 62% aluminum production, 16% paper manufacturing, and 12% petroleum refineries.

Note that there are small inconsistencies between the reported model species light extinction values in the various tools on the TSS, due to the processes needed to convert model concentrations to light extinction and the lack of PSAT results for all species. For consistency, the reported model values for each species in this chapter were taken from the model performance analysis on the TSS, which vary slightly compared to the total of all components in the state-level PSAT bar charts.

6.1 Olympic National Park

The OLYM1 IMPROVE monitoring site represents the visibility at Olympic National Park. The 2014 to 2018 average conditions in Chapter 3 show that sulfates (44%), organic mass (21%),

and nitrates (19%) together contribute to 84% of the light extinction on MID. On the clearest days, sulfates (30%), organic mass (22%), and nitrates (20%) contributed to 72% of the light extinction at OLYM1.

WEP and rank point analyses

The WEP analysis for the OLYM1 site on MID for the 2028 OTB scenario is summarized in Figure 6.1, showing an AOI of sources in western Washington and the Puget Sound region. There is also some minimal influence from sources in the Portland, OR and Vancouver, BC metropolitan areas. Nitrates at OLYM1 show considerable influence from non-EGU point, on-road, non-road, and non-point sources. Sulfates at OLYM1 show considerable influence from non-EGU Point, non-road, and non-point sources. Non-point sources mostly influence organic mass at OLYM1. Non-point sources mostly influence elemental carbon, but also shows a large influence from on-road and non-road sources.

The rank point WEP analysis attributed 98.9% of point source nitrates to Washington State, with 1.0% and 0.3% attributed to Oregon and California, respectively. The rank point WEP analysis attributed 99.4% of point source sulfates to Washington State, with 0.5% attributed to Oregon.

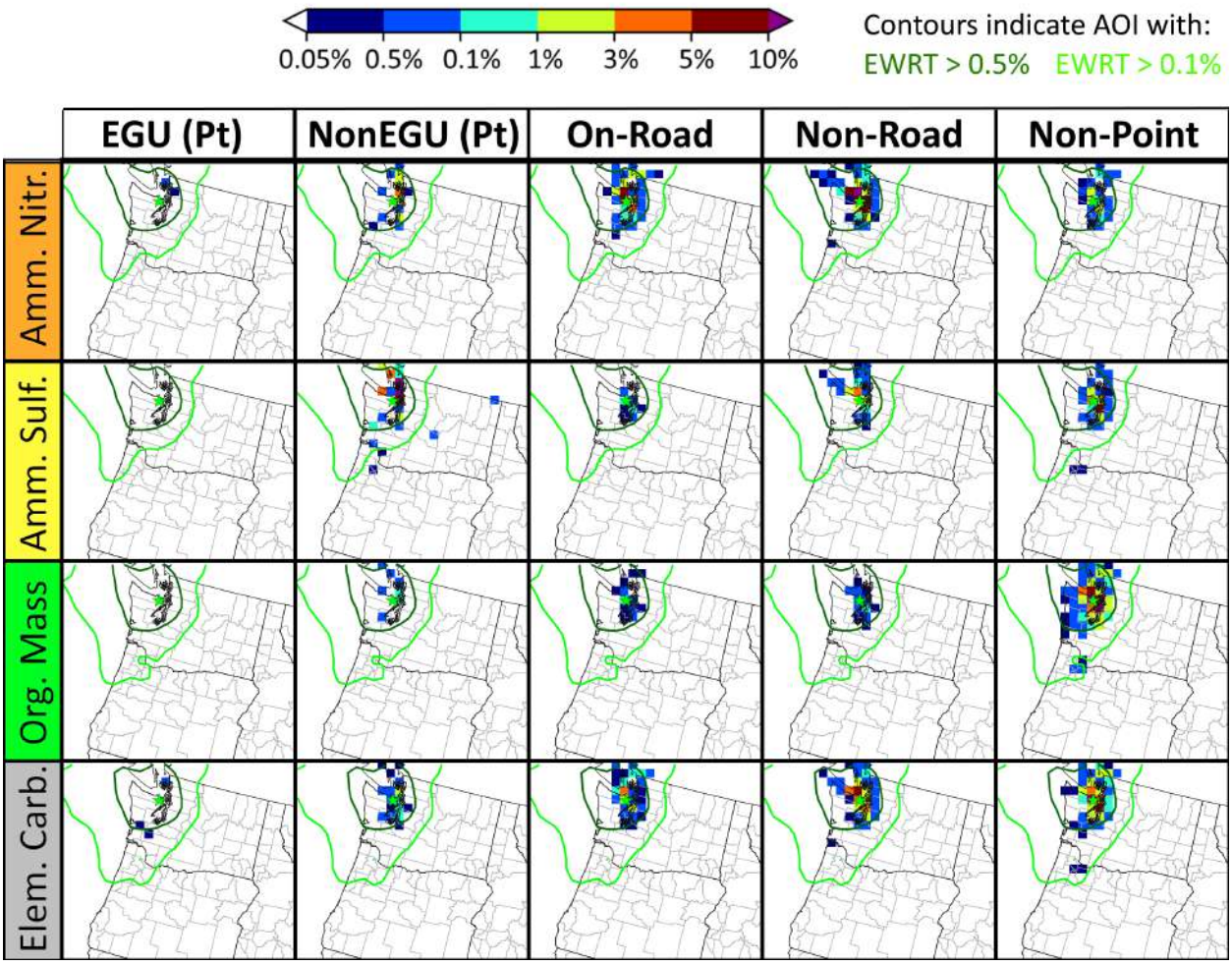


Figure 6-1: WEP for source area potential to contribute to extinction on MID by pollutant at the OLYM1 IMPROVE monitor (green star), using the 2028 OTB projected emissions. Contours indicate AOI with EWRT greater than 0.5% (dark green) and 0.1% (light green) for the corresponding pollutant.

Sulfates source apportionment

Monitoring data show that sulfates were the largest species contribution to light extinction for both the MID and clearest days during the 2014-2018 baseline at OLYM1.

Most Impaired Days

The PSAT tracer analysis shows that 2028 MID visibility impacts of sulfates at OLYM1 are expected to come primarily from natural (52%), international anthropogenic (22%) and wildland fire (13%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 9% of the sulfates responsible for light extinction at OLYM1. See Figure 6-2 for more information.

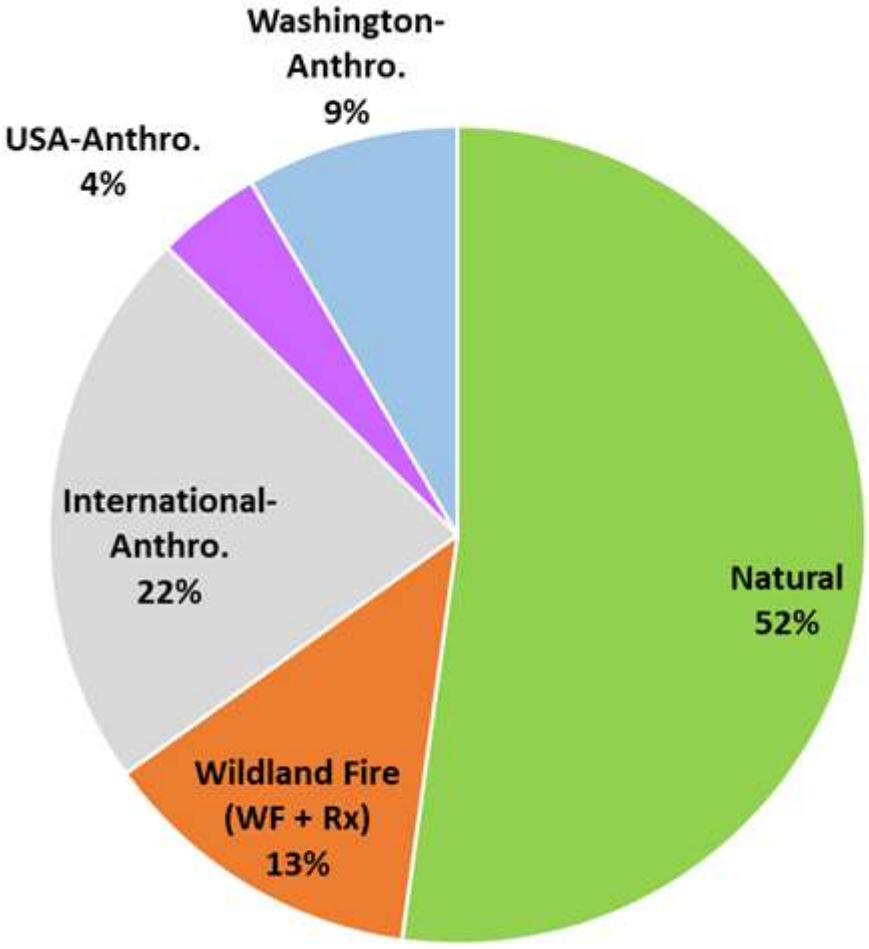


Figure 6-2: Expected source regions of sulfates (SO4) in 2028 at OLYM1 for MID (CAMx total = 11.9 Mm^{-1}).

The modeled sulfates for 2028 MID at OLYM1 was 11.9 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 10.03 Mm^{-1} and 10.00 Mm^{-1}, respectively.

Figure 6-3 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at the OLYM1 monitoring site on 2028 MID.

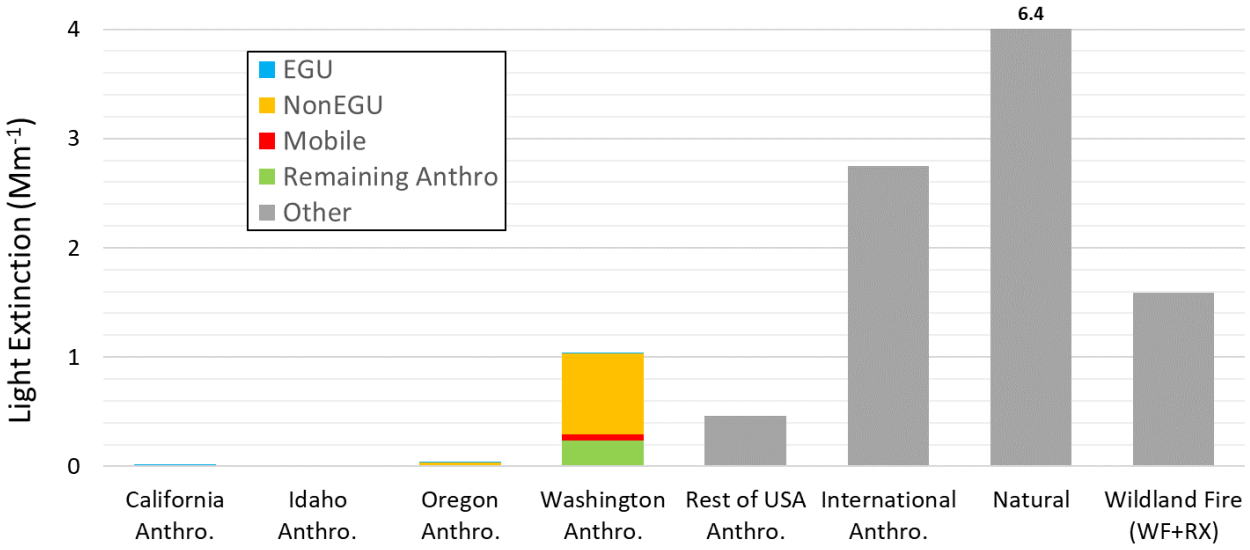


Figure 6-3: Expected source categories and regions of SO_4 in 2028 at OLYM1 for MID (CAMx total = 11.9 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of sulfates at OLYM1 are expected to come primarily from natural (37%), out-of-state US anthropogenic (24%), and international anthropogenic (19%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 16% of the sulfates responsible for light extinction at OLYM1. See Figure 6-4 for more information.

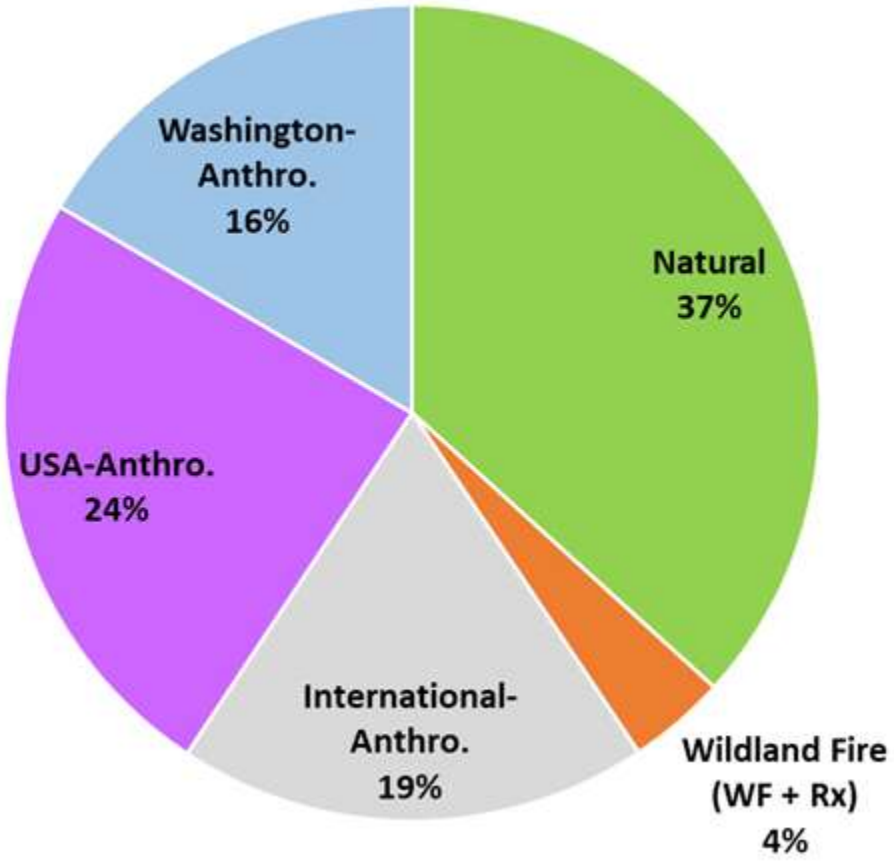


Figure 6-4: Expected source regions of SO_4 in 2028 at OLYM1 for clearest days (CAMx total = 4.2 Mm^{-1}).

The modeled sulfates for 2028 clearest days at OLYM1 was 4.2 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 1.01 Mm^{-1} and 1.00 Mm^{-1}, respectively. Figure 6-5 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at OLYM1 on 2028 clearest days.

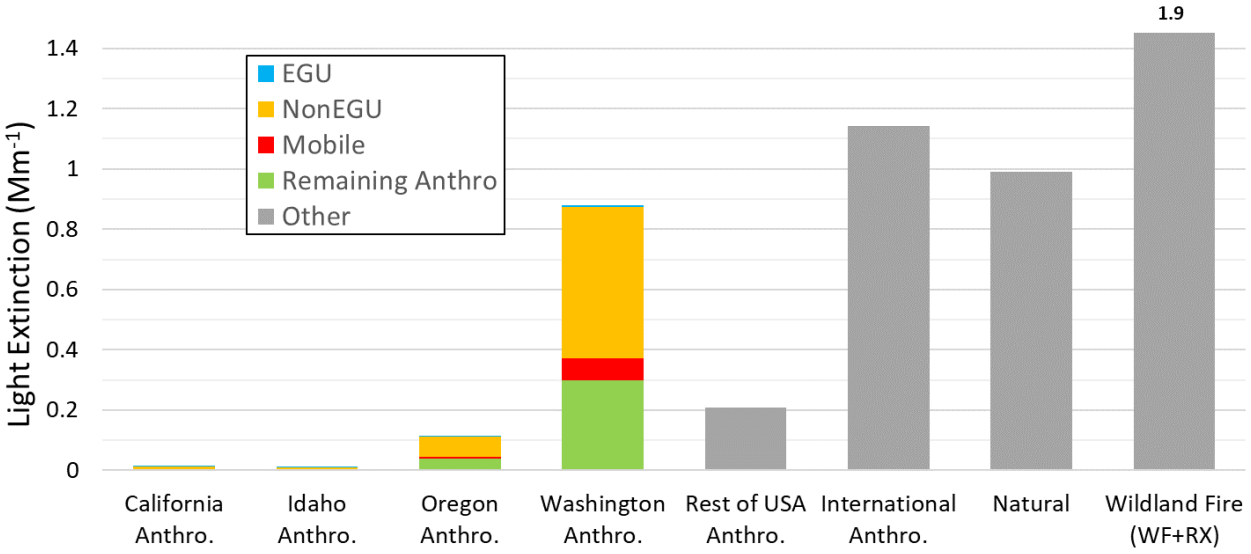


Figure 6-5: Expected source categories and regions of SO_4 in 2028 at OLYM1 for clearest days (CAMx total = 4.2 Mm^{-1}).

Nitrates source apportionment

Monitoring data show that nitrates were the third largest species contribution to light extinction for the MID and second largest species contribution for the clearest days during the 2014-2018 baseline at OLYM1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of nitrates at OLYM1 are expected to come primarily from international anthropogenic sources (47%) while natural sources (8%), and wildland fires (2%) are expected to have minimal impacts. All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 36% of the nitrates responsible for light extinction at OLYM1 on MID. See Figure 6-6 for more information.

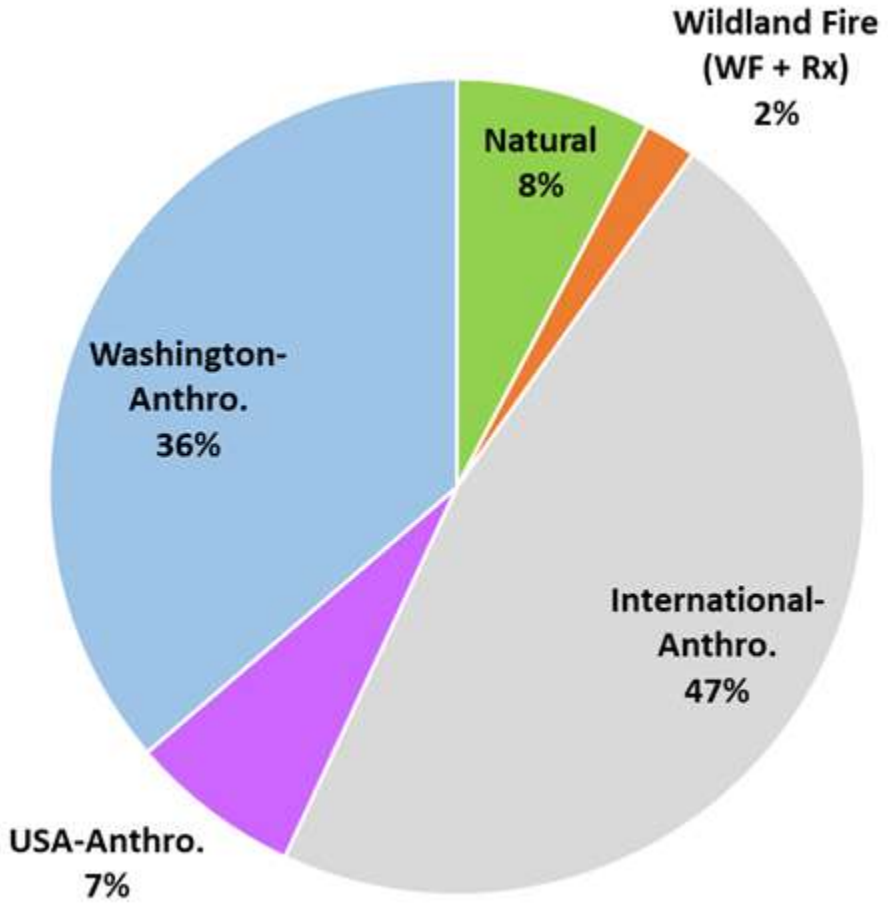


Figure 6-6: Expected source regions of NO_3 in 2028 at OLYM1 for MID (CAMx total = 5.9 Mm^{-1}).

The modeled nitrates for 2028 MID at OLYM1 was 5.9 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 4.28 Mm^{-1} and 3.28 Mm^{-1}, respectively.

Figure 6-7 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at OLYM1 on 2028 MID.

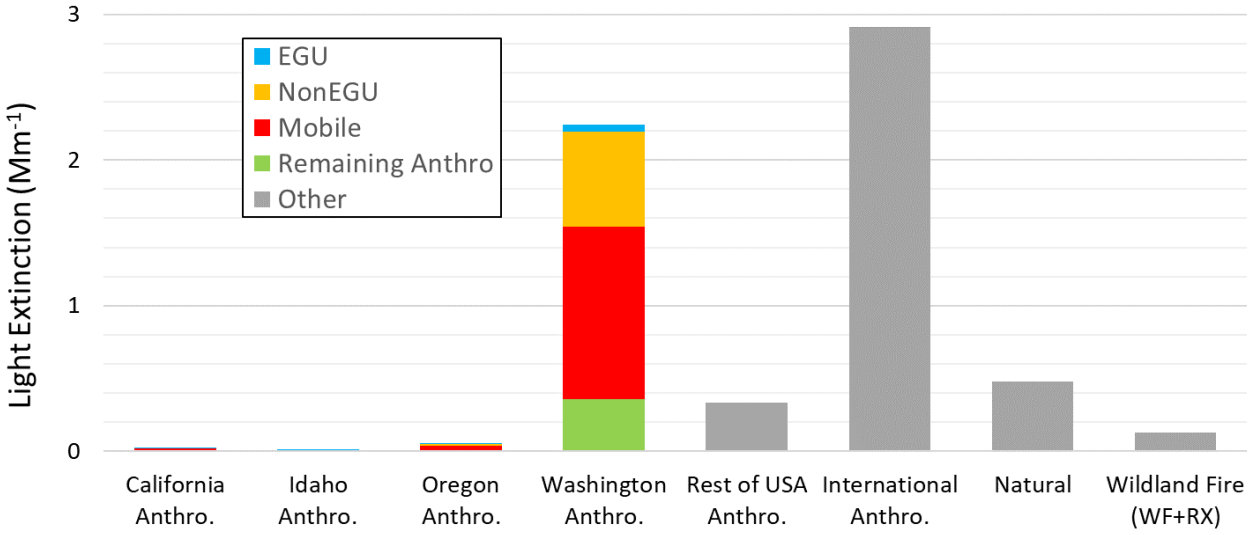


Figure 6-7: Expected source categories and regions of NO_3 in 2028 at OLYM1 for MID (CAM_X total = 5.9 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of nitrates at OLYM1 are expected to come primarily from out-of-state US anthropogenic (44%) sources. Washington anthropogenic sources are expected to contribute 33% of the nitrates responsible for light extinction at OLYM1 on clearest days. See Figure 6-8 for more information.

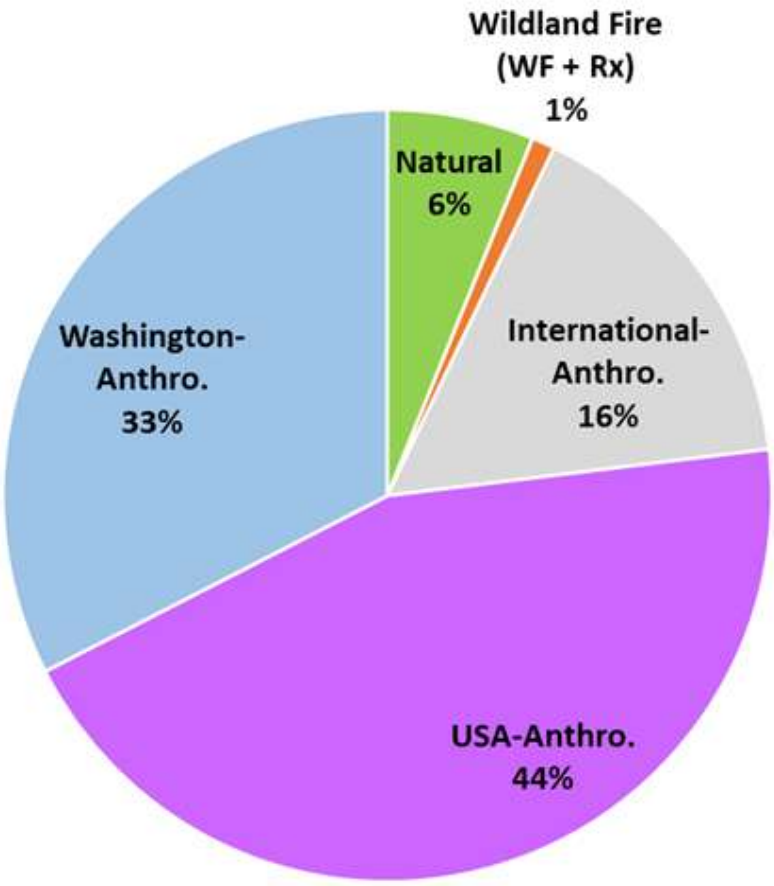


Figure 6-8: Expected source regions of NO_3 in 2028 at OLYM1 for clearest days (CAMx total = 2.5 Mm^{-1}).

The modeled nitrates for 2028 clearest days at OLYM1 was 2.5 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.65 Mm^{-1} and 0.46 Mm^{-1}, respectively. Figure 6-9 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at OLYM1 on 2028 clearest days.

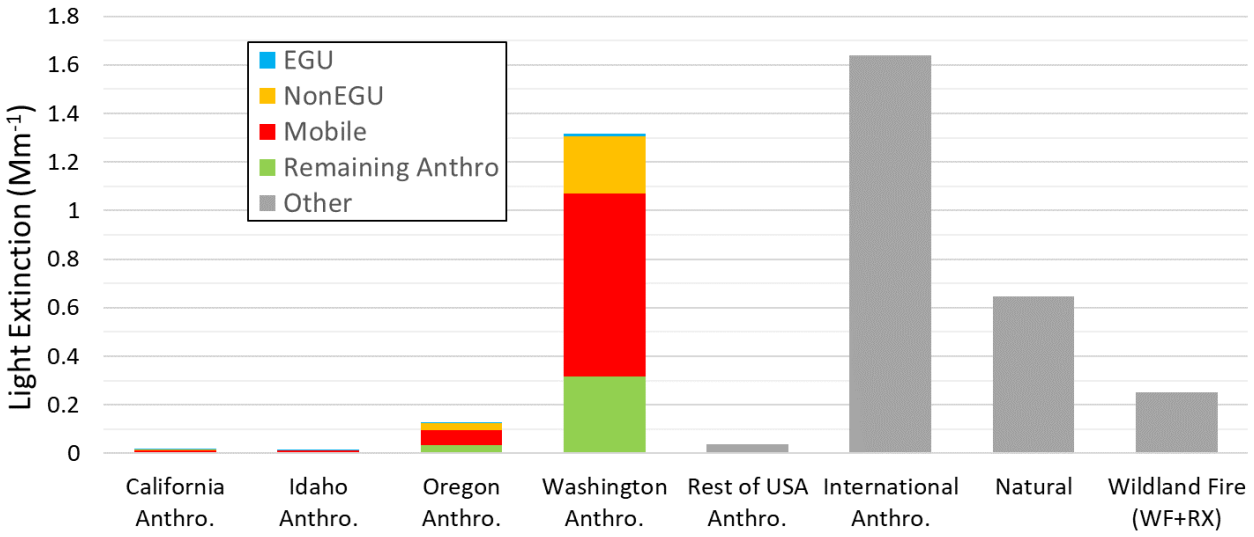


Figure 6-9: Expected source categories and regions of NO_3 in 2028 at OLYM1 for clearest days (CAMx total = 2.5 Mm^{-1}).

6.2 North Cascades National Park and Glacier Peak Wilderness

The North Cascades National Park and Glacier Peak Wilderness areas are represented by the NOCA1 IMPROVE monitoring site. The baseline conditions in Chapter 3 show that together organic mass (24%), sulfates (49%), and nitrates (10%) contributed to 83% of the light extinction on the MID at this monitoring site. On the clearest days, sulfates (36%), organic mass (26%), and nitrates (13%) contributed to 75% of the light extinction at this monitoring site.

WEP and rank point analyses

The WEP analysis for the NOCA1 site on MID for the 2028 OTB scenario is summarized in Figure 6-10, showing an AOI of sources in western Washington and the Puget Sound region, including considerable influence from the Vancouver, BC metropolitan area. Nitrates at NOCA1 show considerable influence from non-EGU Point, on-road, non-road, and non-point sources. Sulfates at NOCA1 show considerable influence from non-EGU point and non-point sources. Organic mass at NOCA1 is mostly influenced by non-point sources. Elemental carbon is mostly influenced by non-point sources but also shows a considerable influence from non-road sources. The rank point WEP analysis attributed 99.6% of point source nitrates to Washington State, with 0.3% attributed to Oregon. The rank point WEP analysis attributed 99.6% of point source sulfates to Washington State, with 0.3% attributed to Oregon.

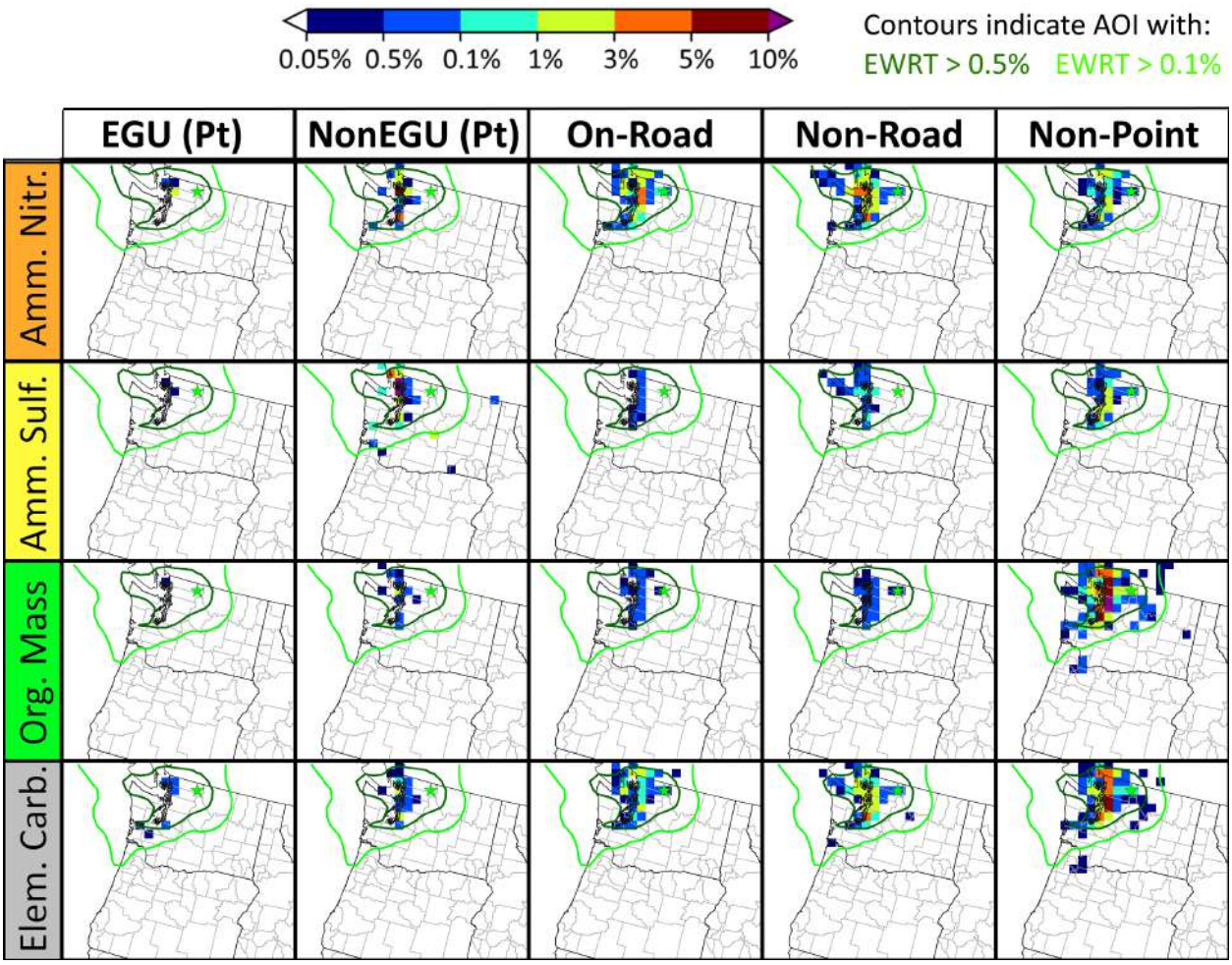


Figure 6-10: WEP for source area potential to contribute to extinction on MID by pollutant at the NOCA1 IMPROVE monitor (green star), using the 2028 OTB projected emissions. Contours indicate AOI with EWRT greater than 0.5% (dark green) and 0.1% (light green) for the corresponding pollutant.

Sulfates source apportionment

Monitoring data show that sulfates were the largest species contribution to light extinction for both the MID and clearest days during the 2014-2018 baseline at NOCA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of sulfates at NOCA1 are expected to come primarily from natural (35%), international anthropogenic (26%) and wildland fire (26%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 10% of the sulfates responsible for light extinction at NOCA1. See Figure 6-11 for more information.

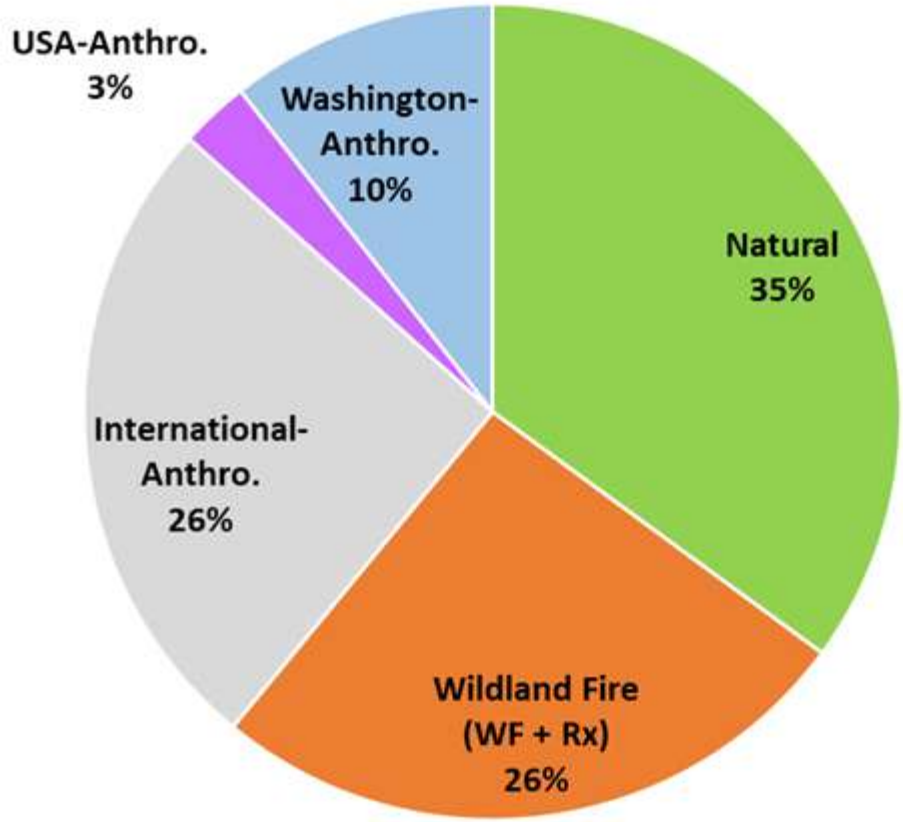


Figure 6-11: Expected source regions of SO_4 in 2028 at NOCA1 for MID (CAMx total = 11.3 Mm^{-1}).

The modeled sulfates for 2028 MID at NOCA1 was 11.3 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 8.14 Mm^{-1} and 8.16 Mm^{-1}, respectively. Figure 6-12 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at the NOCA1 monitoring site on 2028 MID.

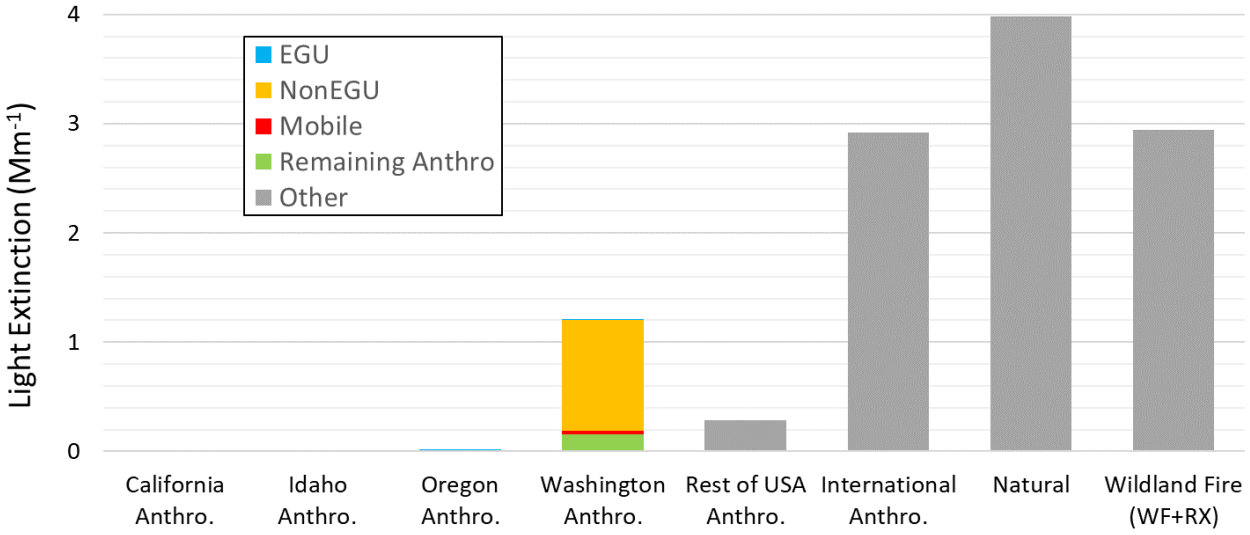


Figure 6-12: Expected source categories and regions of SO_4 in 2028 at NOCA1 for MID (CAMx total = 11.3 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of sulfates at NOCA1 are expected to come primarily from natural (46%), international anthropogenic (30%), and out-of-state US anthropogenic (12%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 8% of the sulfates responsible for light extinction at OLYM1. See Figure 6-13 for more information.

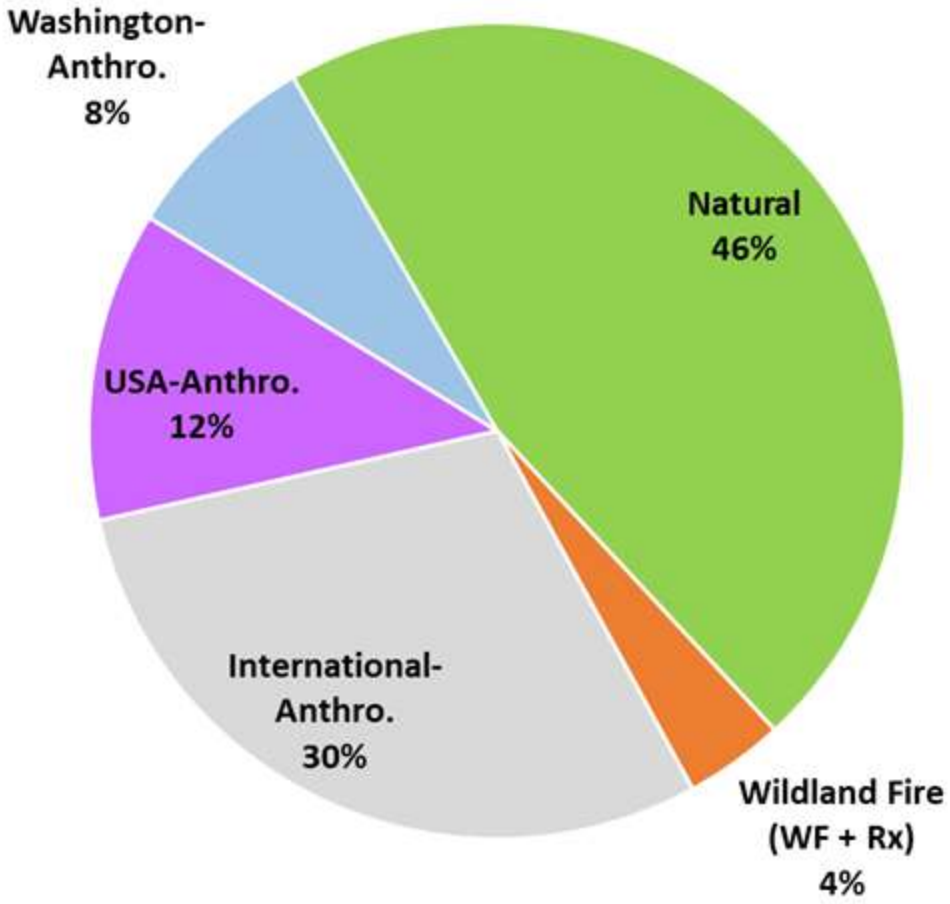


Figure 6-13: Expected source regions of SO_4 in 2028 at NOCA1 for clearest days (CAMx PSAT total = 3.6 Mm^{-1})

The modeled sulfates for 2028 clearest days at NOCA1 was 3.6 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.66 Mm^{-1} and 0.65 Mm^{-1}, respectively. Figure 6-14 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at NOCA1 on 2028 clearest days.

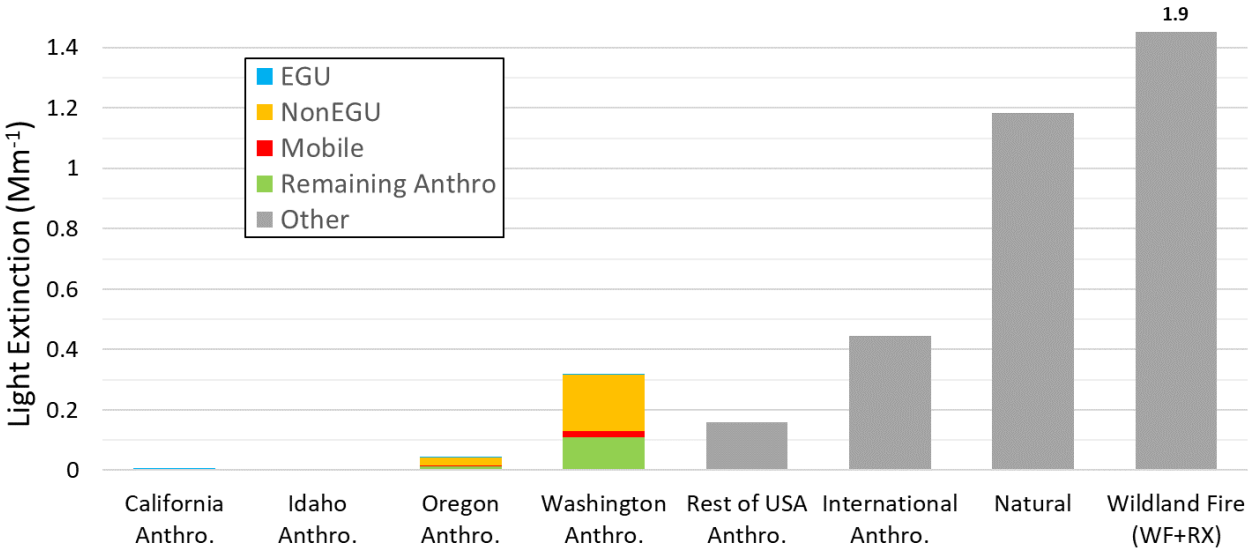


Figure 6-14: Expected source categories and regions of SO_4 in 2028 at NOCA1 for clearest days (CAMx total = 3.6 Mm^{-1}).

Nitrates source apportionment

Monitoring data show that nitrates were the third largest species contribution to light extinction for the MID and clearest days during the 2014-2018 baseline at NOCA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of nitrates at NOCA1 are expected to come primarily from international anthropogenic sources (45%) while natural sources (18%), and wildland fires (5%) are expected to have minimal impacts. All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 25% of the nitrates responsible for light extinction at NOCA1. See Figure 6-15 for more information.

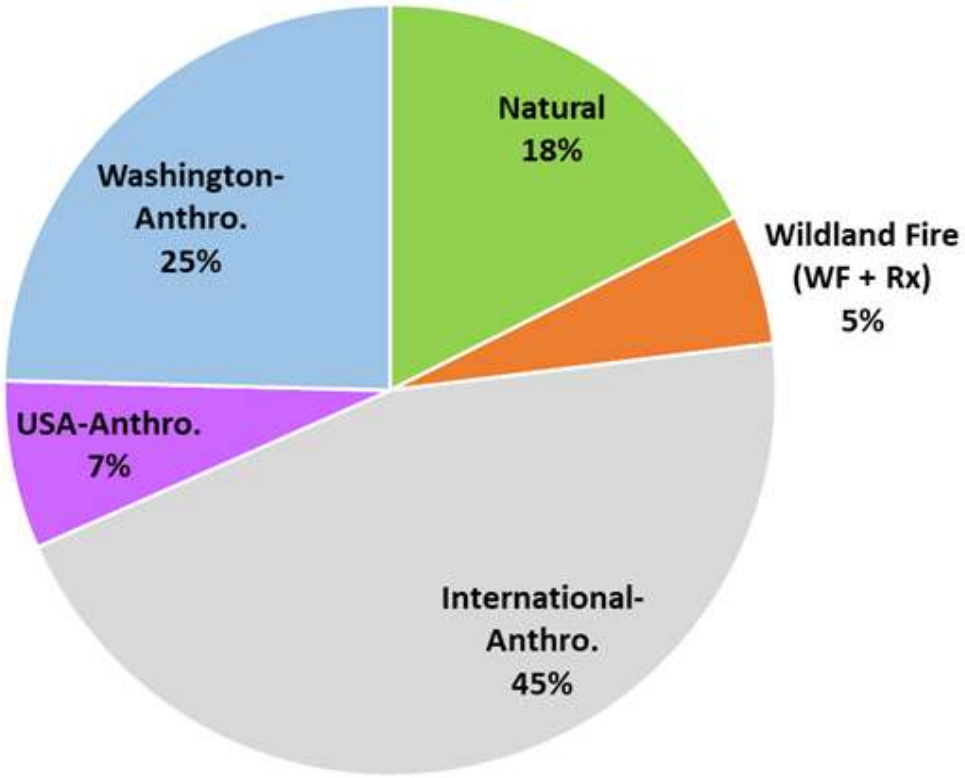


Figure 6-15: Expected source regions of NO_3 in 2028 at NOCA1 for MID (CAMx total = 5.9 Mm-1).

The modeled nitrates for 2028 MID at NOCA1 was 5.9 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 1.73 Mm^{-1} and 1.24 Mm^{-1}, respectively.

Figure 6-16 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at NOCA1 on 2028 MID.

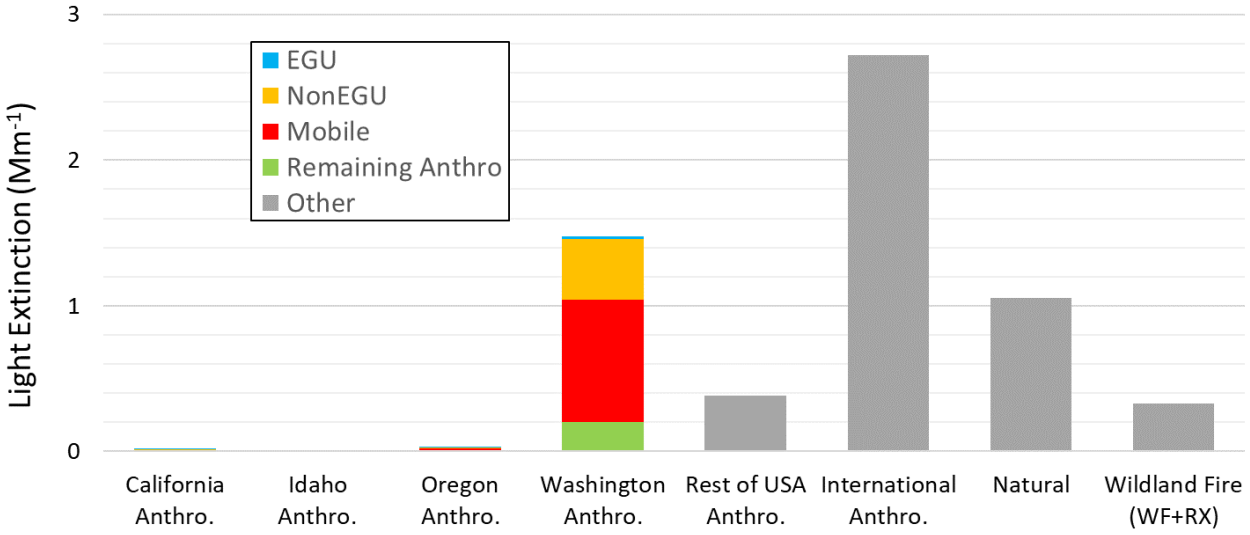


Figure 6-16: Expected source categories and regions of NO3 in 2028 at NOCA1 for MID (CAMx total = 5.9 Mm-1).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of nitrates at NOCA1 are expected to come primarily from out-of-state US anthropogenic (33%), and international anthropogenic (25%) sources. Washington anthropogenic sources are expected to contribute 22% of the nitrates responsible for light extinction at NOCA1 on clearest days. See Figure 6-17 for more information.

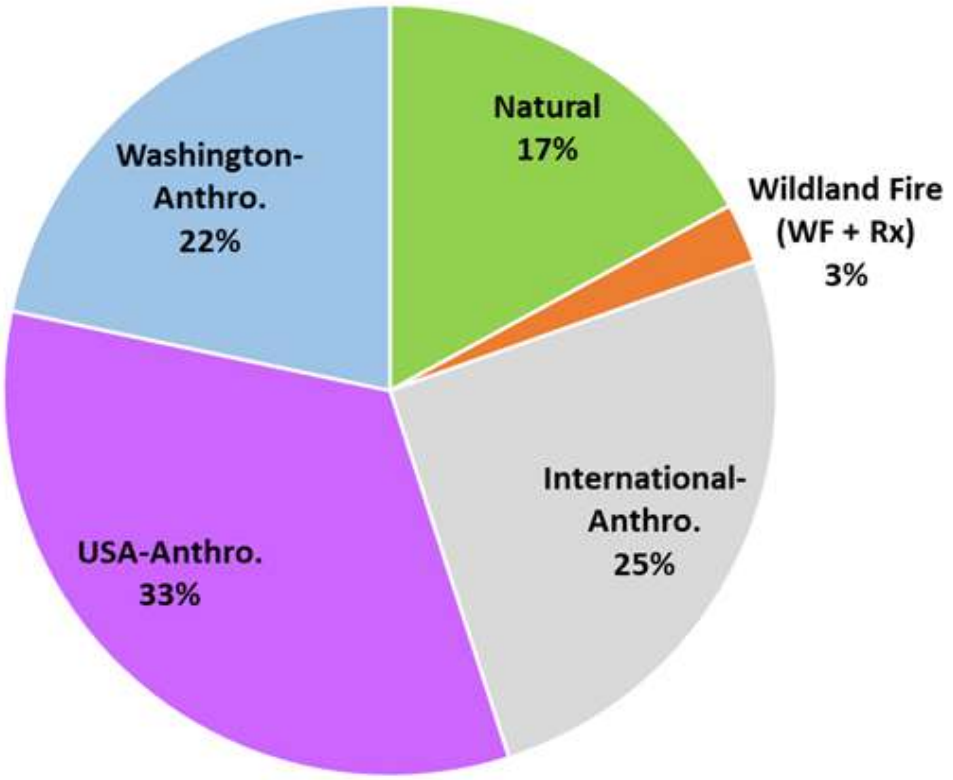


Figure 6-17: Expected source regions of NO_3 in 2028 at NOCA1 for clearest days (CAMx total = 0.8 Mm^{-1}).

The modeled nitrates for 2028 clearest days at NOCA1 was 0.8 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.24 Mm^{-1} and 0.19 Mm^{-1}, respectively. Figure 6-18 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at the NOCA1 monitoring site on 2028 clearest days.

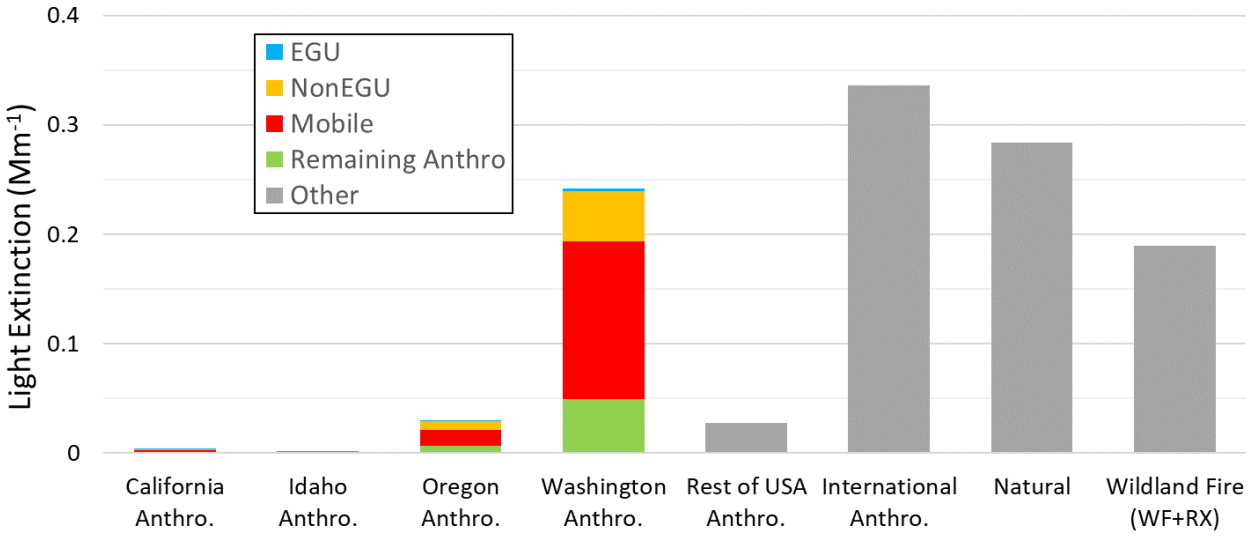


Figure 6-18: Expected source categories and regions of NO_3 in 2028 at NOCA1 for clearest days (CAMx total = 0.8 Mm^{-1}).

6.3 Alpine Lakes Wilderness

Alpine Lakes Wilderness is represented by the SNPA1 IMPROVE monitoring site. The baseline conditions presented in Chapter 3 show that sulfates (35%), organic mass (25%), and nitrates (26%) together contribute to 76% of the light extinction on the MID at this site. On the clearest days sulfates (33%), nitrates (20%), and organic mass (22%) contribute to 75% of the light extinction at this monitoring site.

WEP and rank point analyses

The WEP analysis for the SNPA1 site on MID for the 2028 OTB scenario is summarized in Figure 6-19, showing an AOI of sources that span western and central Washington, the Puget Sound area, and the Vancouver, BC and Portland, OR metropolitan areas. Nitrates at SNPA1 show considerable influence from on-road, Non-road, and non-point sources. Sulfates at NOCA1 show considerable influence from non-EGU Point and non-point sources. Organic mass at SNPA1 is mostly influenced by non-point sources. Elemental carbon is mostly influenced by non-point sources but also shows influence from non-EGU Point, on-road, and non-road sources. The rank point WEP analysis attributed 90.9% of point source nitrates to Washington State, with 8.2%, 0.4%, 0.3%, and 0.2% attributed to Oregon, California, Idaho, and Tribal Lands, respectively. The rank point WEP analysis attributed 98.3% of point source sulfates to Washington State, with 1.4% and 0.2% attributed to Oregon and California, respectively.

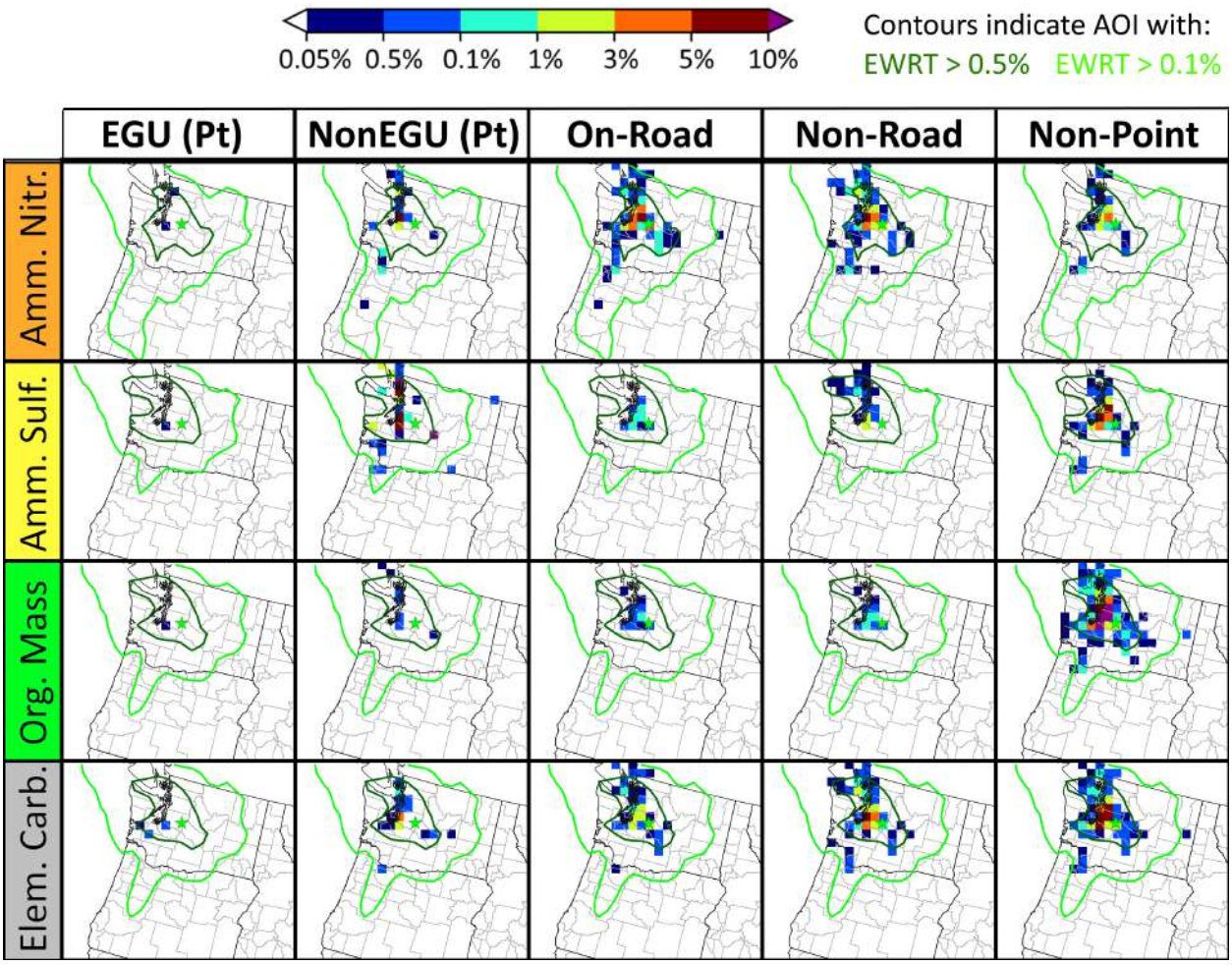


Figure 6-19: WEP for source area potential to contribute to extinction on MID by pollutant at SNPA1 (green star), using the 2028 OTB projected emissions. Contours indicate AOI with EWRT greater than 0.5% (dark green) and 0.1% (light green) for the corresponding pollutant.

Sulfates source apportionment

Monitoring data show that sulfates were the largest species contribution to light extinction for both the MID and clearest days during the 2014-2018 baseline at SNPA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of sulfates at SNPA1 are expected to come primarily from wildland fire (55%), natural (21%), and international anthropogenic sources (14%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 8% of the sulfates responsible for light extinction at SNPA1. See Figure 6-20 for more information.

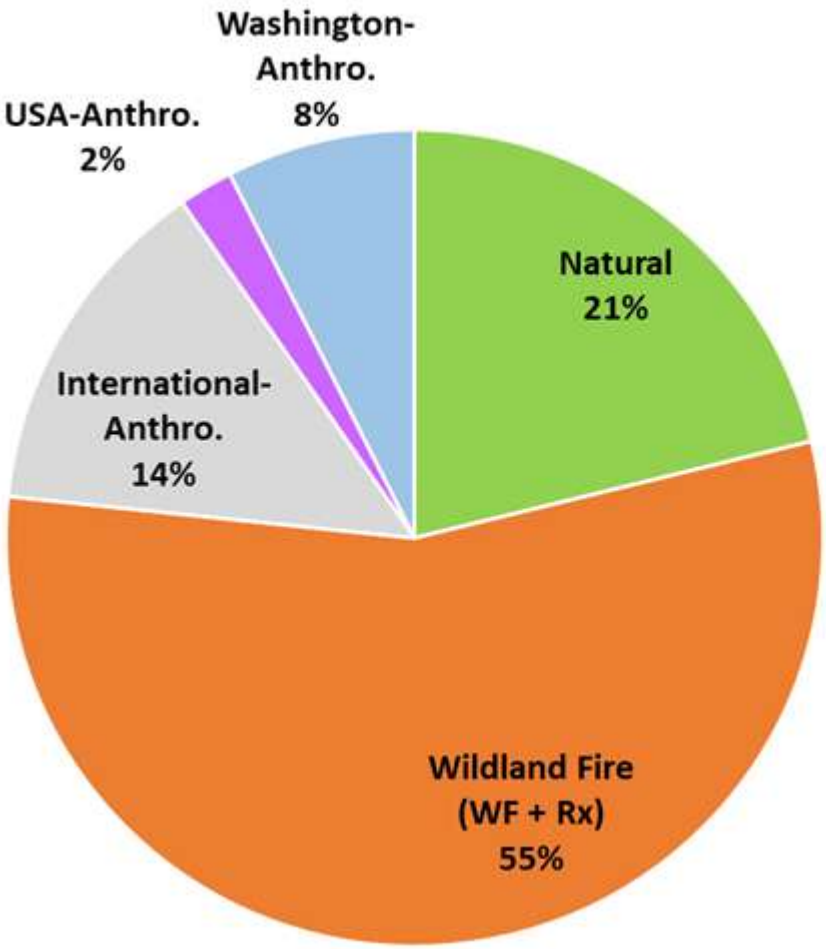


Figure 6-20: Expected source regions of SO_4 in 2028 at SNPA1 for MID (CAMx total = 22.9 Mm^{-1}).

The modeled sulfates for 2028 MID at SNPA1 was 22.9 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 8.84 Mm^{-1} and 8.75 Mm^{-1}, respectively. The impacts of wildland fire on MID are clearly overestimated in the model for SNPA1, which is supported by the immense organic mass modeled at the site (171.3 Mm^{-1}). Figure 6-21 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at the OLYM1 monitoring site on 2028 MIDs.

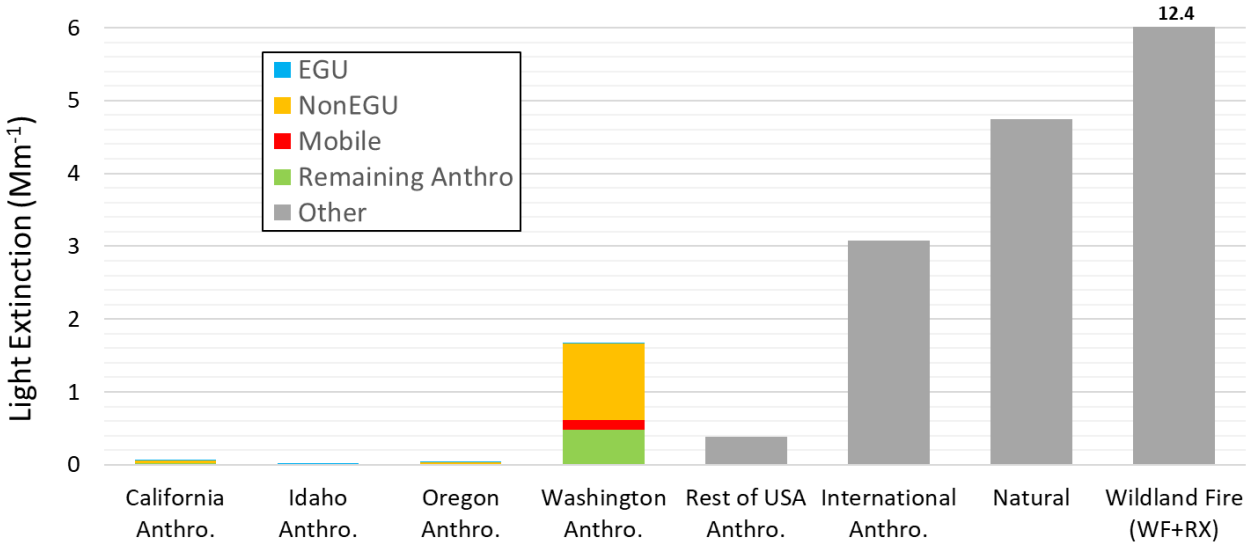


Figure 6-21: Expected source categories and regions of SO_4 in 2028 at SNPA1 for MID (CAMx total = 22.4 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of sulfates at SNPA1 are expected to come primarily from natural (47%), international anthropogenic (22%), and out-of-state US anthropogenic (18%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 11% of the sulfates responsible for light extinction at SNPA1. See Figure 6-22 for more information.

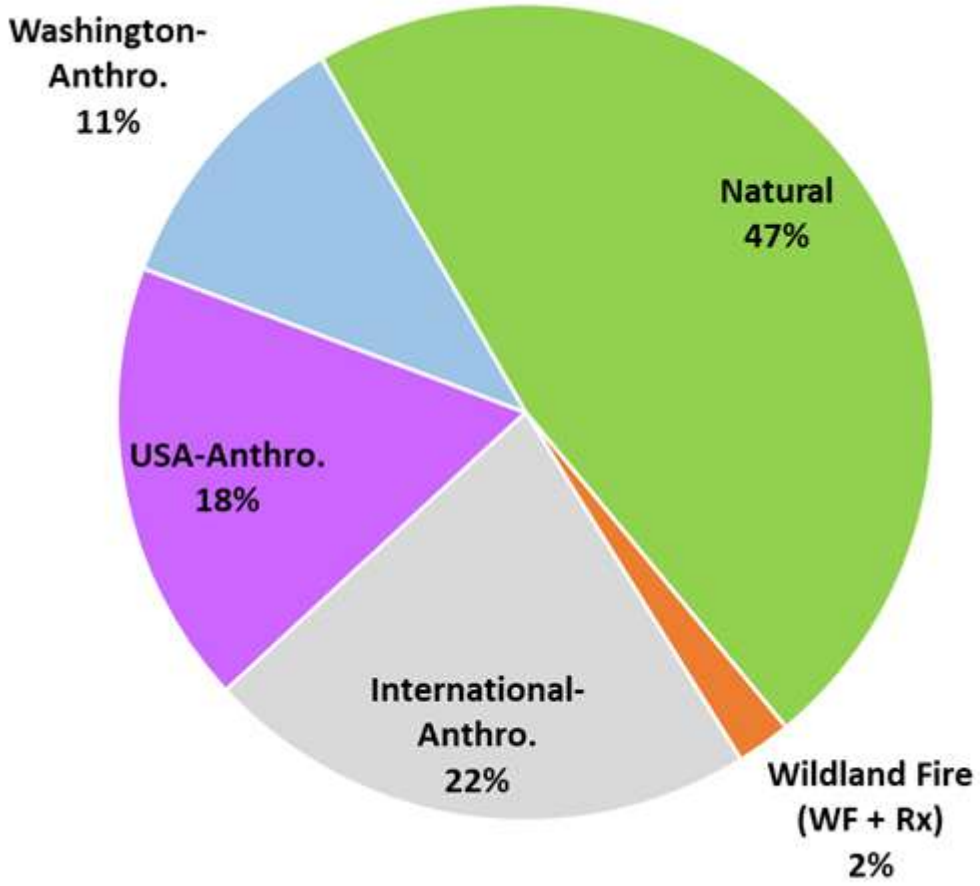


Figure 6-22: Expected source regions of SO_4 in 2028 at SNPA1 for clearest days (CAMx total = 4.4 Mm^{-1}).

The modeled sulfates for 2028 clearest days at SNPA1 was 4.4 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 1.01 Mm^{-1} and 0.98 Mm^{-1}, respectively.

Figure 6-23 shows an expectation within Washington that non-EGU point sources contribute the most sulfate light extinction at SNPA1 on 2028 clearest days.

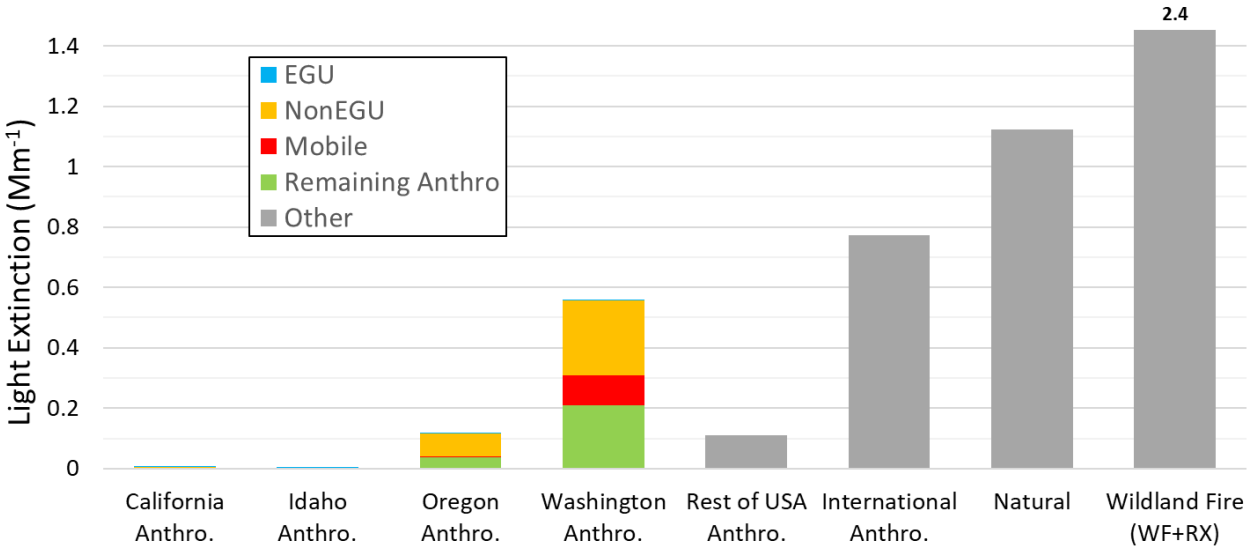


Figure 6-23: Expected source categories and regions of SO_4 in 2028 at SNPA1 for clearest days (CAMx total = 4.4 Mm^{-1}).

Nitrates source apportionment

Monitoring data show that nitrates were the 2nd largest species contribution to light extinction for the MID clearest days during the 2014-2018 baseline at SNPA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of nitrates at SNPA1 are expected to be most influenced from Washington anthropogenic sources (38%). Wildland fires (26%), international anthropogenic (19%), and natural sources (11%) are expected to have some impacts but are beyond Washington's control. See Figure 6-24 for more information.

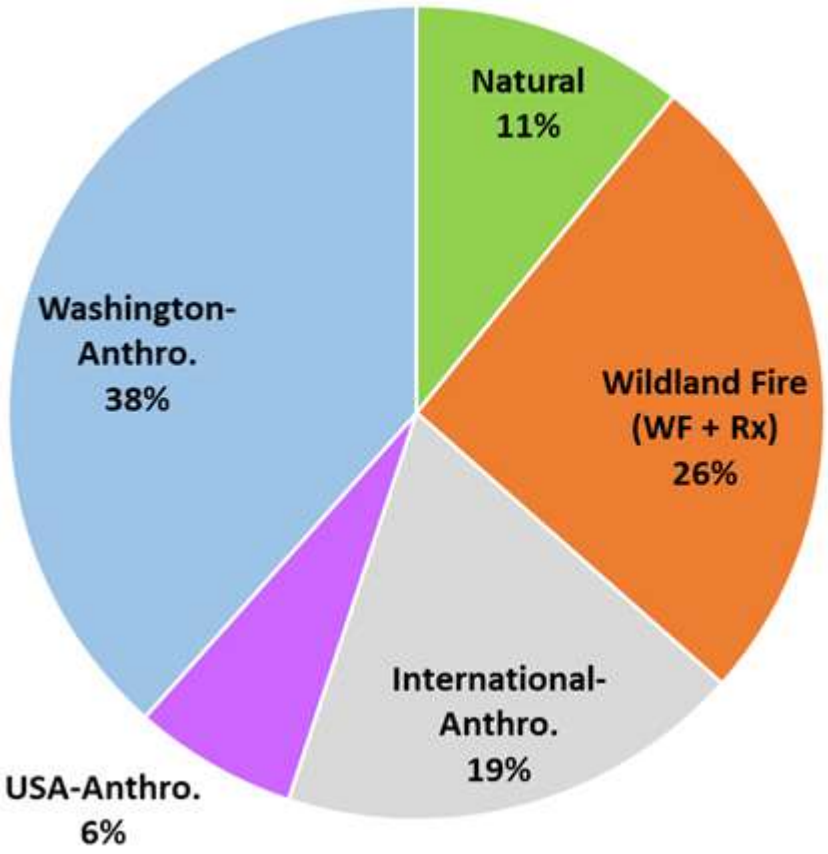


Figure 6-24: Expected source regions of NO_3 in 2028 at SNPA1 for MID (CAMx total = 14.9 Mm^{-1}).

The modeled nitrates for 2028 MID at SNPA1 was 14.9 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 6.75 Mm^{-1} and 4.26 Mm^{-1}, respectively.

Figure 6-25 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at SNPA1 on 2028 MIDs.

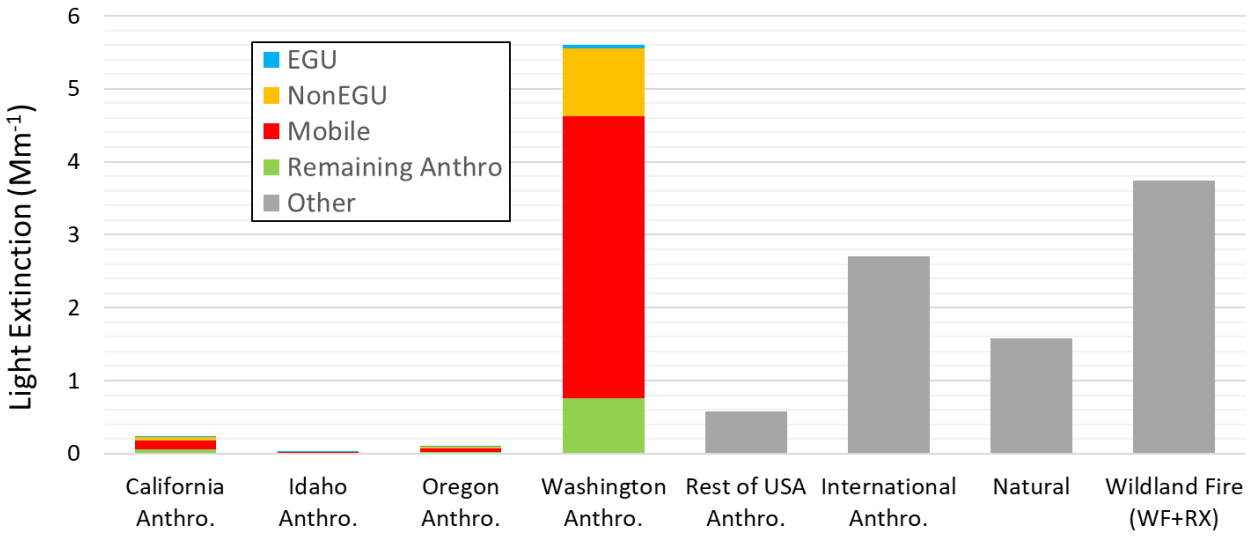


Figure 6-25: Expected source categories and regions of NO_3 in 2028 at SNPA1 for MID (CAMx total = 14.9 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days' visibility impacts of nitrates at SNPA1 are expected to come primarily from out-of-state US anthropogenic (40%) sources. Washington anthropogenic sources are expected to contribute 26% of the nitrates responsible for light extinction at SNPA1 on clearest days. See Figure 6-26 for more information.

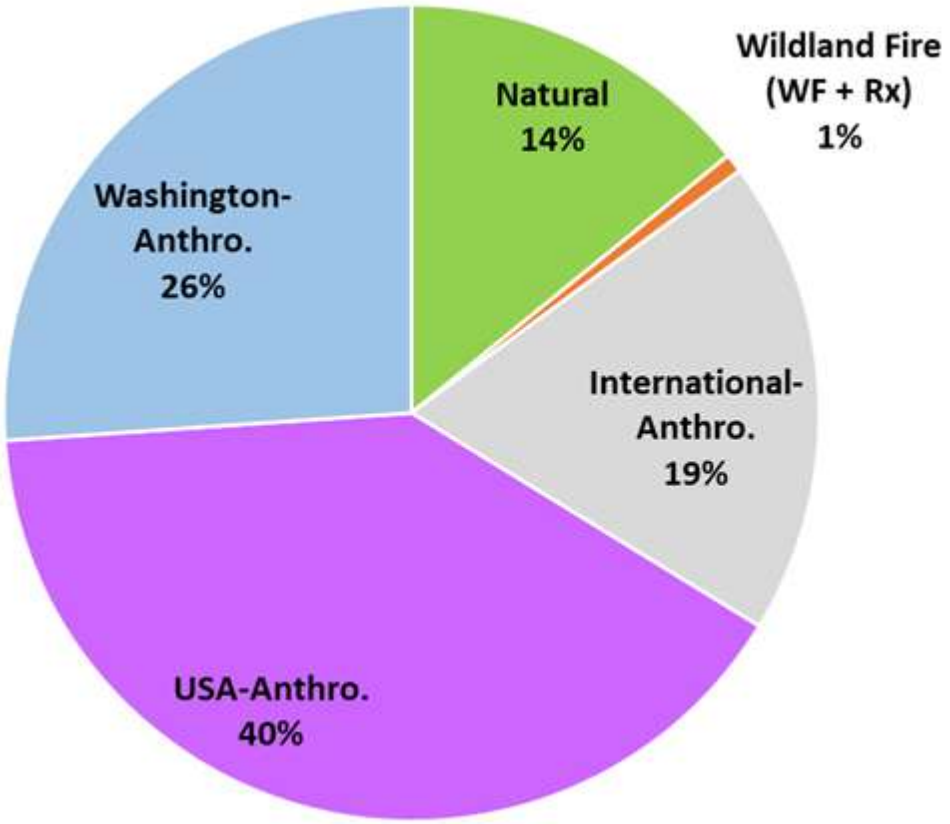


Figure 6-26: Expected source regions of NO_3 in 2028 at SNPA1 for clearest days (CAMx PSAT total = 2.2 Mm^{-1}).

The modeled nitrates for 2028 clearest days at SNPA1 was 2.2 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.61 Mm^{-1} and 0.45 Mm^{-1}, respectively.

Figure 6-27 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at the SNPA1 monitoring site on 2028 clearest days.

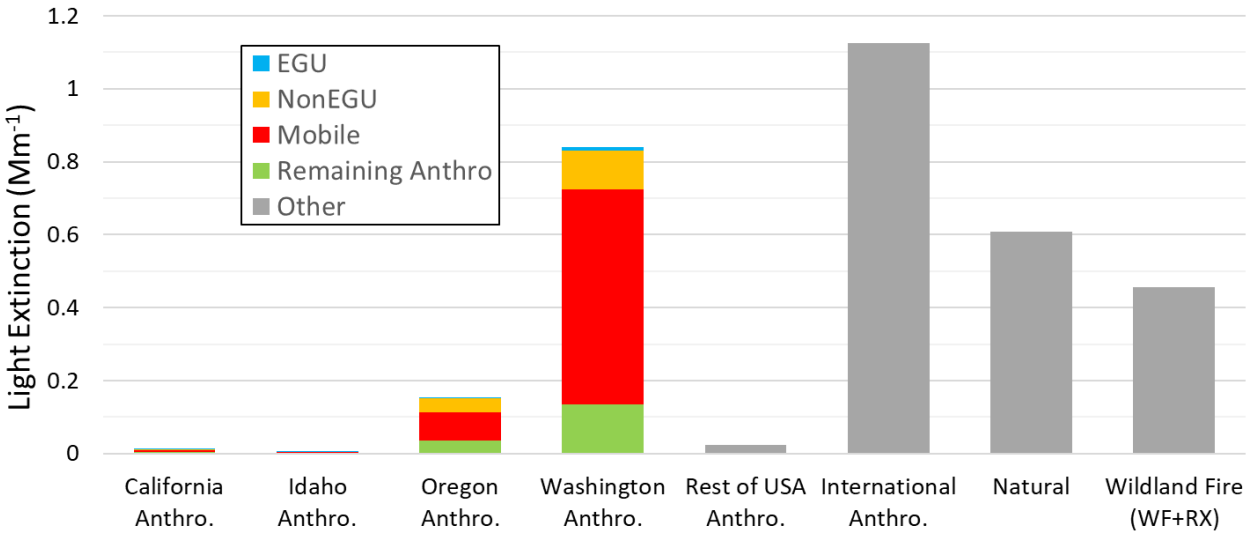


Figure 6-27: Expected source categories and regions of NO_3 in 2028 at SNPA1 for clearest days (CAMx PSAT total = 2.2 Mm^{-1}).

6.4 Mount Rainier National Park

Mount Rainier National Park is represented by the MORA1 IMPROVE monitoring site. The baseline conditions in Chapter 3 show that sulfates (41%) and organic mass (31%) make up 72% of the light extinction on the MID at this monitoring site. Nitrates (7%) and elemental carbon (9%) contribute to another 16% of the light extinction on the MID at this monitoring site. On the clearest days, sulfates (34%) and organic mass (26%) make up 60% of the light extinction at this monitoring site. Nitrates (8%) and elemental carbon (10%) contribute to another 18% of the light extinction on the clearest days at this monitoring site.

WEP and rank point analyses

The WEP analysis for the MORA1 site on MID for the 2028 OTB scenario is summarized in Figure 6-28, showing an AOI of sources in western Washington and the Puget Sound region. There is also some minimal influence from sources in the Portland, OR and Vancouver, BC metropolitan areas. Nitrates at MORA1 show considerable influence from non-EGU Point, on-road, non-road, and non-point sources. Sulfates at MORA1 show considerable influence from non-EGU Point, non-road, and non-point sources. Organic mass at MORA1 is mostly influenced by non-point sources. Elemental carbon is influenced by non-EGU Point, on-road, non-road, and non-point sources. The rank point WEP analysis attributed 97.3% of point source nitrates to Washington State, with 2.6% attributed to Oregon. The rank point WEP analysis attributed 95.6% of point source sulfates to Washington State, with 4.2% and 0.2% attributed to Oregon and California, respectively.

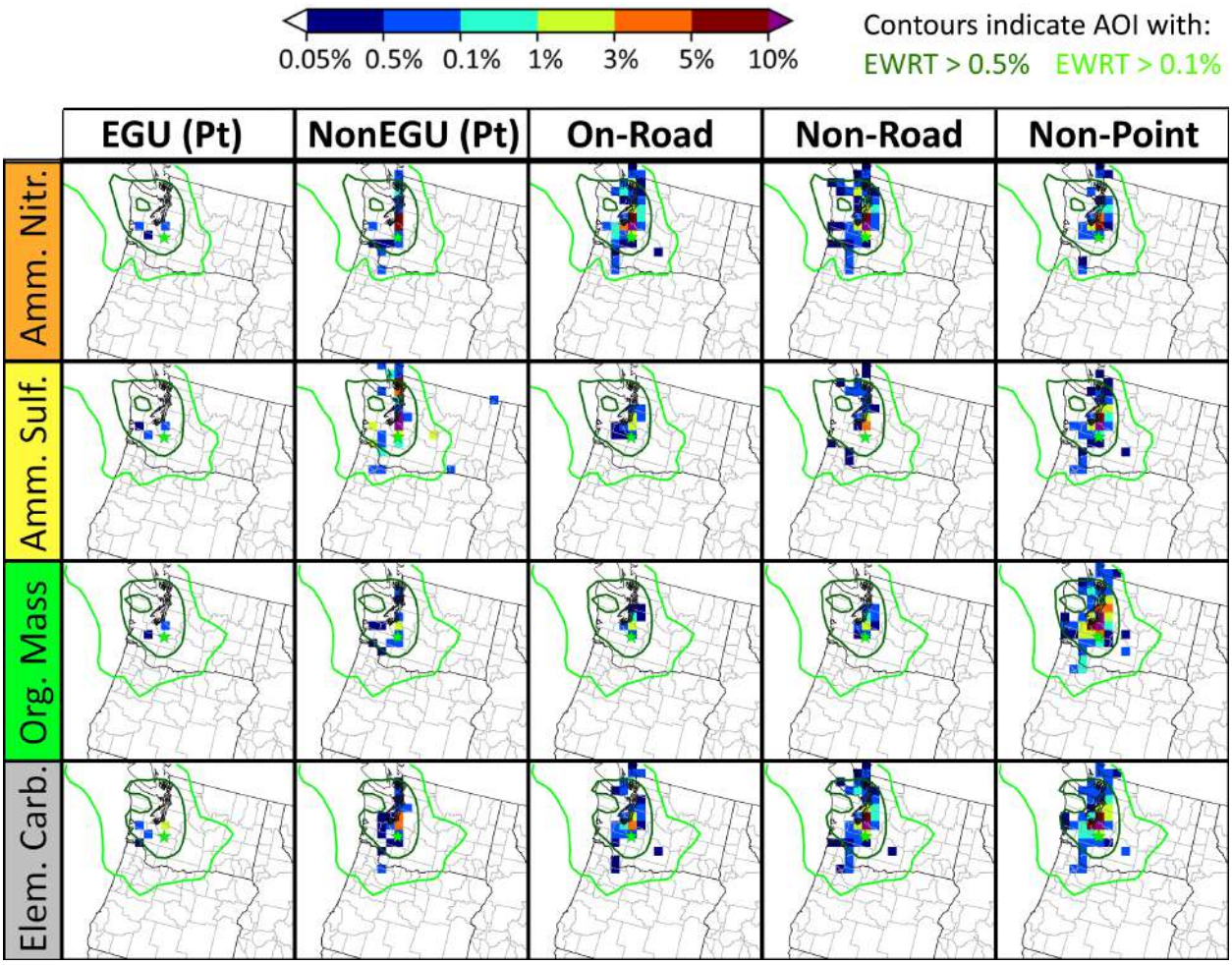


Figure 6-28: WEP for source area potential to contribute to extinction on MID by pollutant at the MORA1 IMPROVE monitor (green star), using the 2028 OTB projected emissions. Contours indicate AOI with EWRT greater than 0.5% (dark green) and 0.1% (light green) for the corresponding pollutant.

Sulfates source apportionment

Monitoring data show that sulfates were the largest species contribution to light extinction for both the MID and clearest days during the 2014-2018 baseline at MORA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of sulfates at MORA1 are expected to come primarily from natural (39%), wildland fire (25%), and international anthropogenic sources (23%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 10% of the sulfates responsible for light extinction at MORA1. See Figure 6-29 for more information.

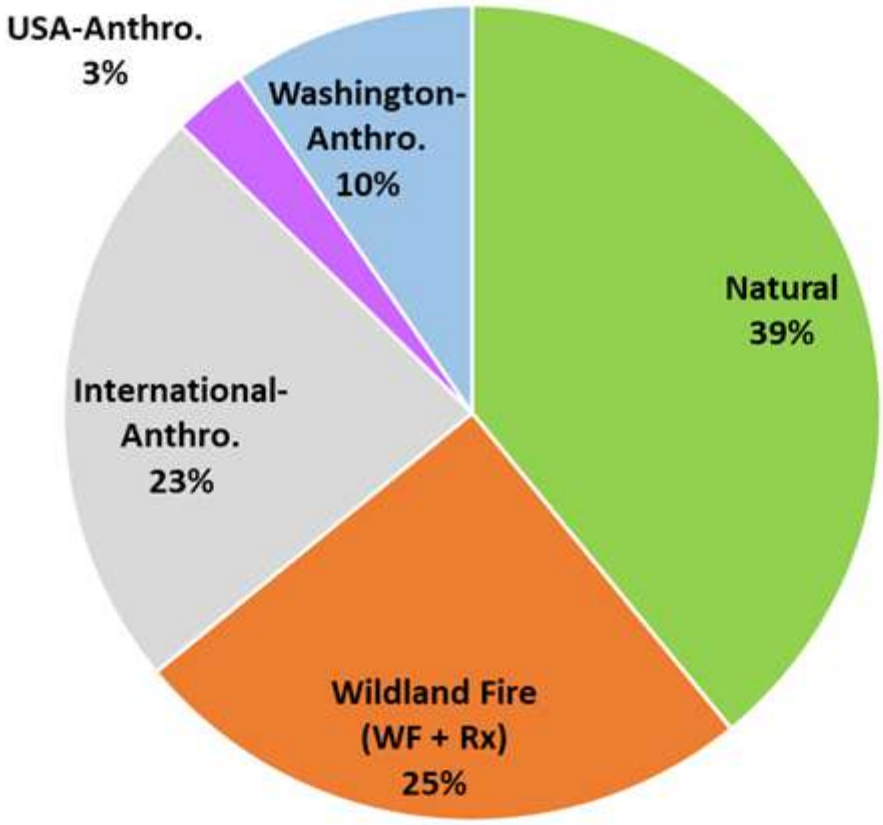


Figure 6-29: Expected source regions of SO_4 in 2028 at MORA1 for MID (CAMx total = 13.2 Mm^{-1}).

The modeled sulfates for 2028 MID at MORA1 was 13.2 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 10.15 Mm^{-1} and 9.7 Mm^{-1}, respectively.

Figure 6-30 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at the OLYM1 monitoring site on 2028 MIDs.

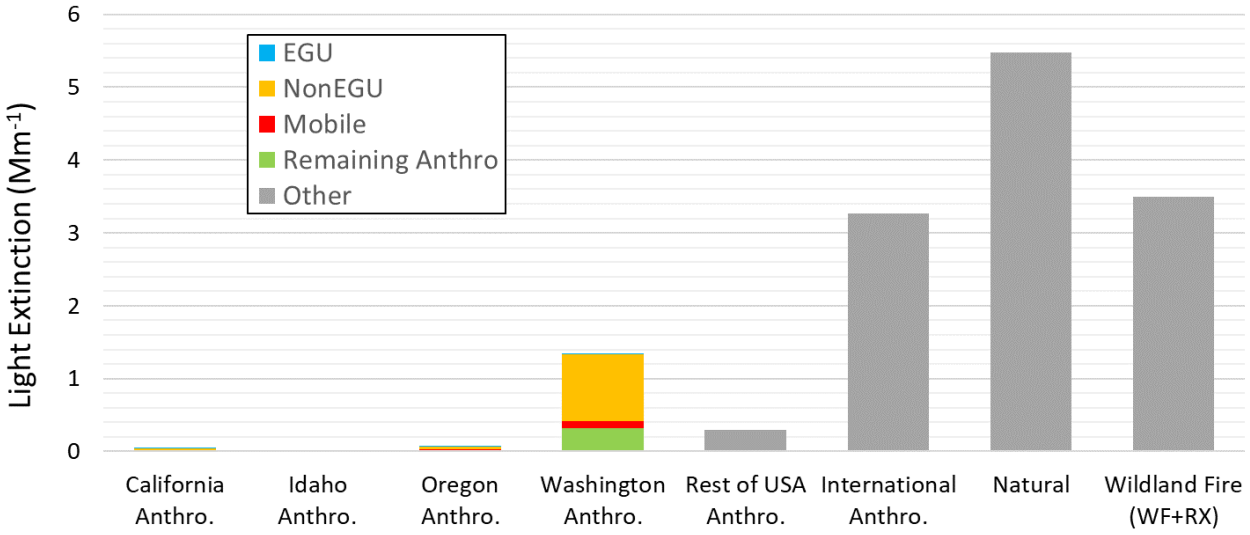


Figure 6-30: Expected source categories and regions of SO_4 in 2028 at MORA1 for MID (CAMx total = 13.2 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of sulfates at MORA1 are expected to come primarily from natural (36%), out-of-state US anthropogenic (28%), and international anthropogenic (26%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 7% of the sulfates responsible for light extinction at SNPA1. See Figure 6-31 for more information.

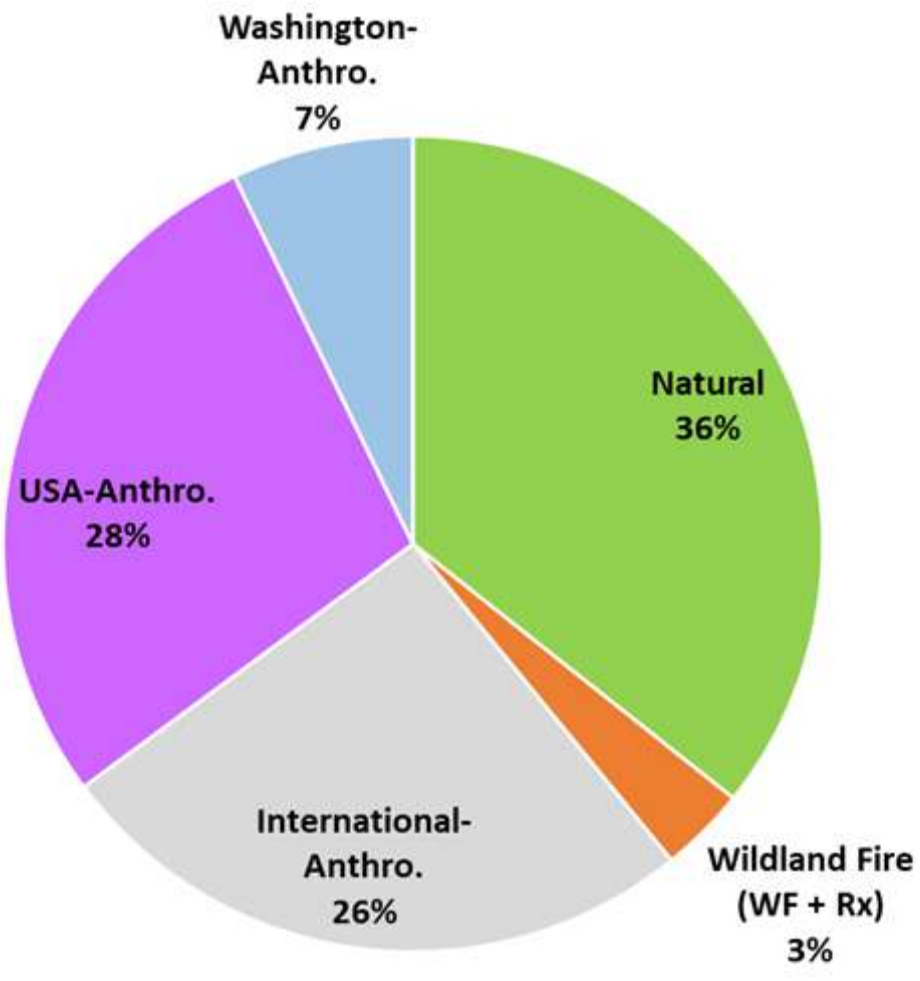


Figure 6-31: Expected source regions of SO_4 in 2028 at MORA1 for clearest days (CAMx total = 3.7 Mm^{-1}).

The modeled sulfates for 2028 clearest days at MORA1 was 3.7 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 1.3 Mm^{-1} and 1.22 Mm^{-1}, respectively.

Figure 6-32 shows an expectation within Washington that, non-EGU point sources contribute the majority of sulfate light extinction at MORA1 on 2028 clearest days.

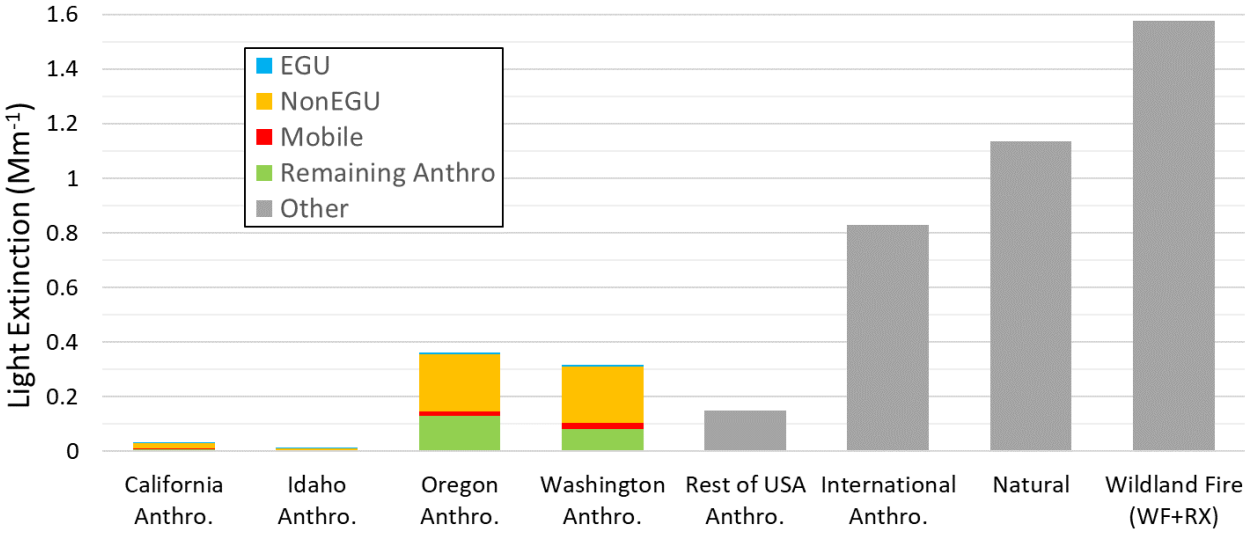


Figure 6-32: Expected source categories and regions of SO_4 in 2028 at MORA1 for clearest days (CAMx total = 3.7 Mm^{-1}).

Nitrates source apportionment

Monitoring data show that nitrates were the 3rd largest species contribution to light extinction for the MID and 6th largest species contribution for the clearest days during the 2014-2018 baseline at MORA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of nitrates at MORA1 are expected to be most influenced from Washington anthropogenic sources (46%). International anthropogenic (18%), Wildland fires (15%), and natural sources (14%) are expected to have some impacts but are beyond Washington's control. See Figure 6-33 for more information.

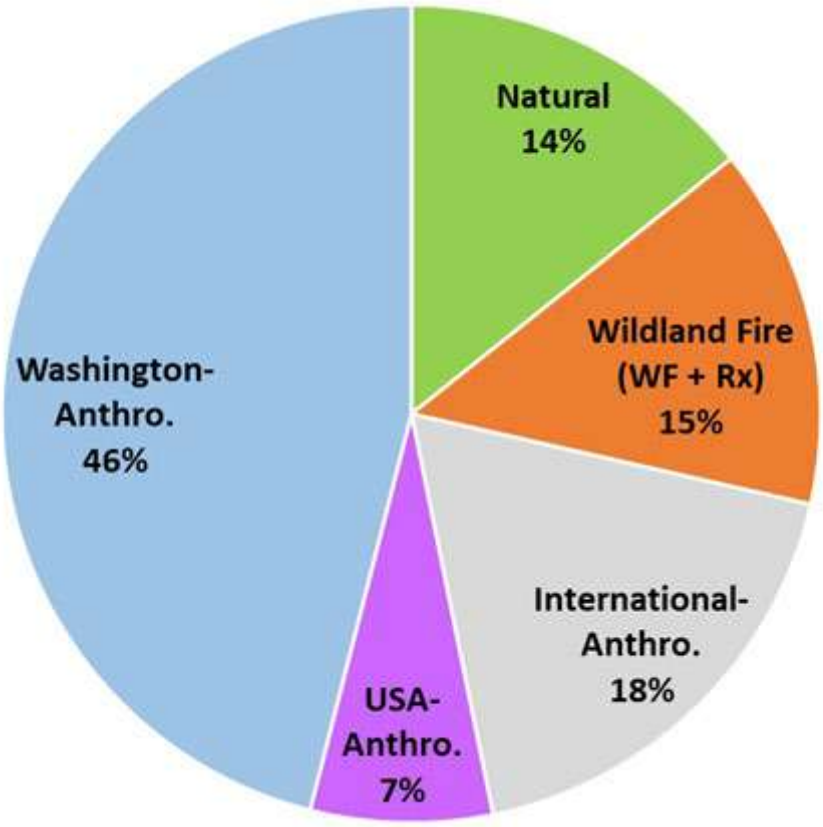


Figure 6-33: Expected source regions of NO_3 in 2028 at MORA1 for MID (CAMx total = 7.2 Mm^{-1}).

The modeled nitrates for 2028 MID at MORA1 was 7.2 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 2.27 Mm^{-1} and 1.13 Mm^{-1}, respectively.

Figure 6-34 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at MORA1 on 2028 MIDs.

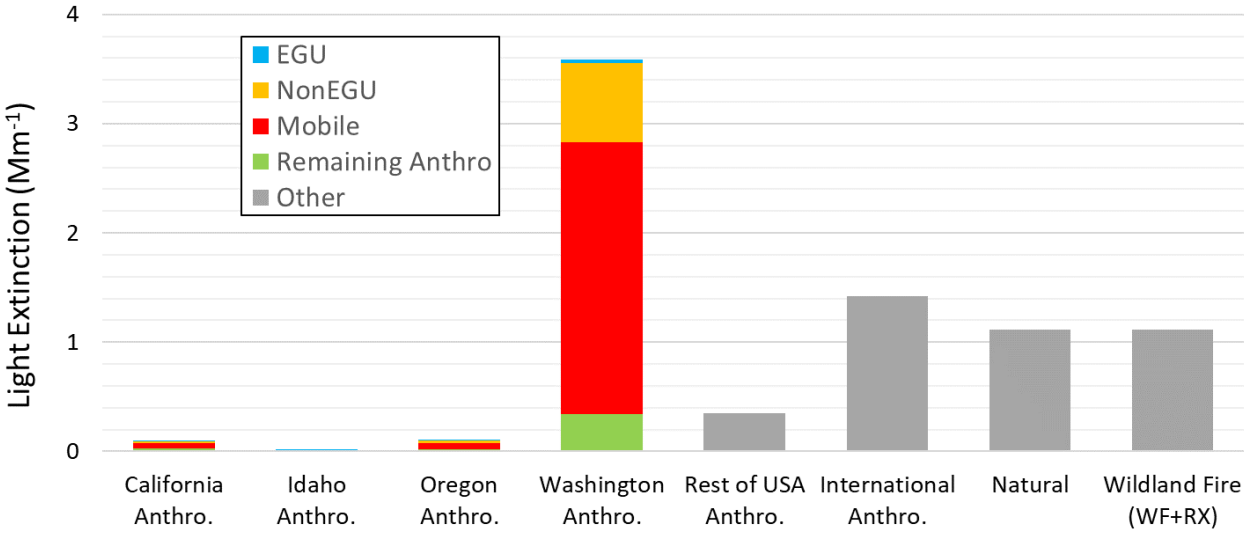


Figure 6-34: Expected source categories and regions of NO_3 in 2028 at MORA1 for MID (CAMx total = 7.2 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of nitrates at MORA1 are expected to come primarily from out-of-state US anthropogenic (54%) and international anthropogenic (20%) sources. Washington anthropogenic sources are expected to contribute 15% of the nitrates responsible for light extinction at MORA1 on clearest days. See Figure 6-35 for more information.

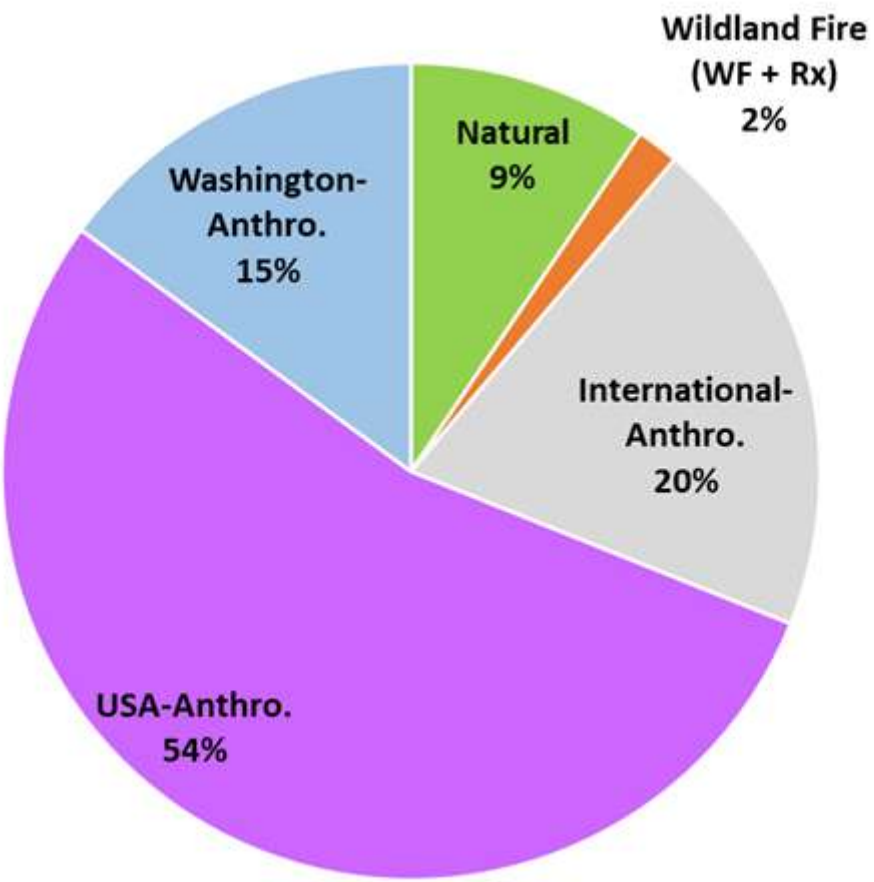


Figure 6-35: Expected source regions of NO_3 in 2028 at MORA1 for clearest days (CAMx total = 1.6 Mm^{-1}).

The modeled nitrates for 2028 clearest days at MORA1 was 1.6 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.32 Mm^{-1} and 0.24 Mm^{-1}, respectively.

Figure 6-36 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at MORA1 on 2028 clearest days.

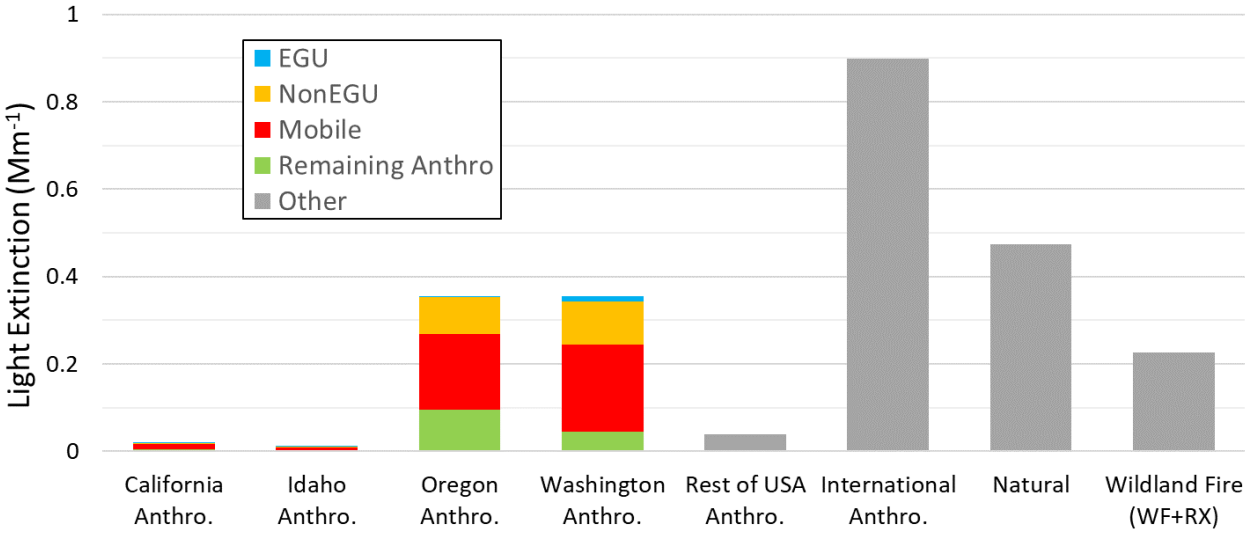


Figure 6-36: Expected source categories and regions of NO_3 in 2028 at MORA1 for clearest days (CAMx total = 1.6 Mm^{-1}).

6.5 Goat Rocks Wilderness and Mount Adams Wilderness

Goat Rocks Wilderness and Mount Adams Wilderness are represented by the WHPA1 IMPROVE monitoring site. The baseline conditions in Chapter 3 show that sulfates (50%), organic mass (22%), and nitrates (12%) together contribute to 84% of the light extinction on the MID at this monitoring site. On the clearest days sulfates (39%), organic mass (14%), and nitrates (14%) contribute to 67% of the light extinction at this monitoring site.

WEP and rank point analyses

The WEP analysis for the WHPA1 site on MID for the 2028 OTB scenario is summarized in Figure 6-37, showing an AOI of sources that span western and central Washington, the Puget Sound area, and the Vancouver, BC and Portland, OR metropolitan areas. Nitrates at WHPA1 show considerable influence from non-EGU Point, on-road, non-road, and non-point sources. Sulfates at WHPA1 show considerable influence from non-EGU Point and non-point sources. Organic mass at WHPA1 is mostly influenced by non-point sources. Elemental carbon is mostly influenced by non-point sources but also shows influence from non-EGU Point, on-road, and non-road sources. The rank point WEP analysis attributed 86.7% of point source nitrates to Washington State, with 11.9%, 0.9%, 0.3%, and 0.1% attributed to Oregon, Tribal Lands, Idaho, and California, respectively. The rank point WEP analysis attributed 89.1% of point source sulfates to Washington State, with 10.4%, 0.2%, and 0.2% attributed to Oregon, Tribal Lands, and California, respectively.

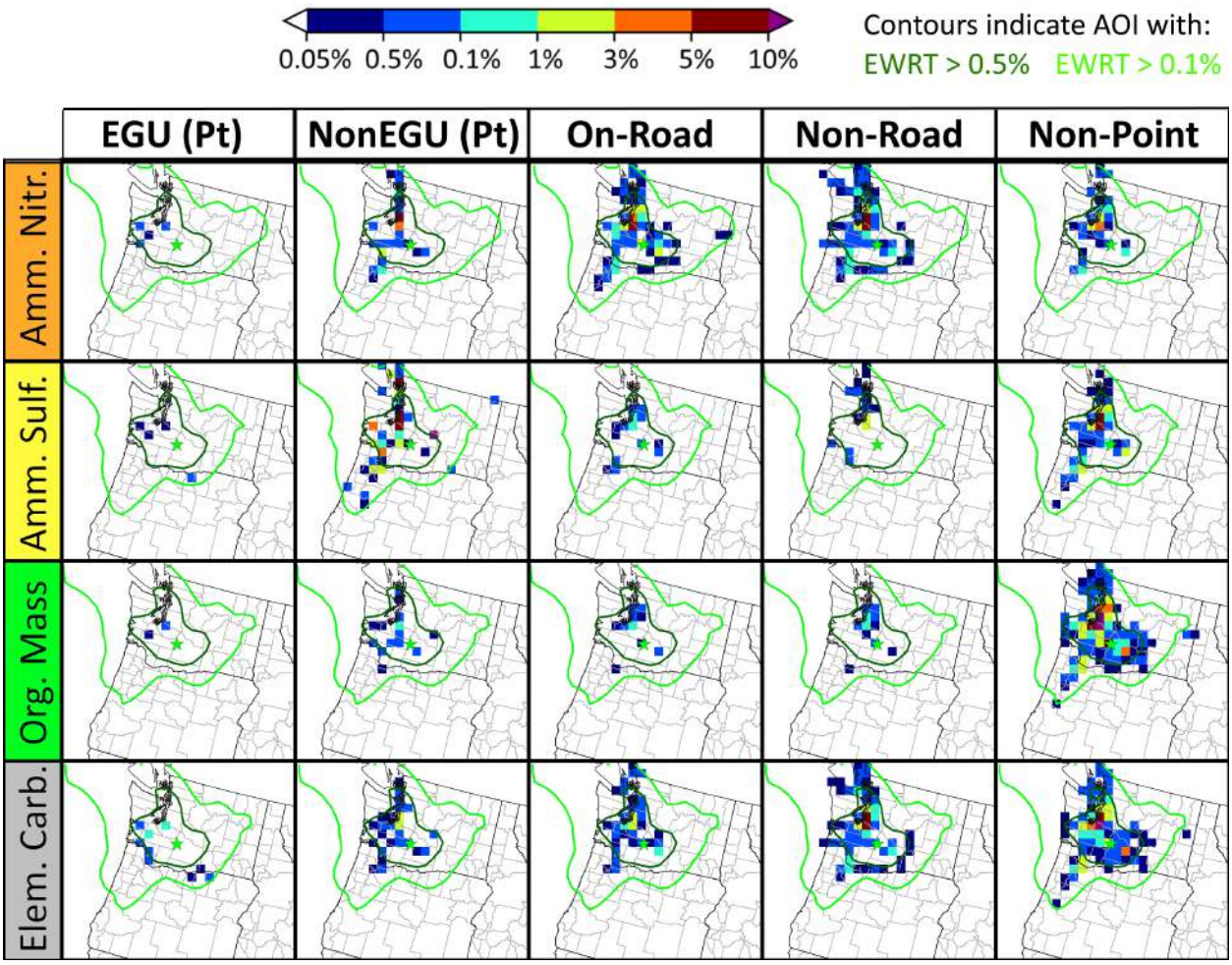


Figure 6-37: WEP for source area potential to contribute to extinction on MID by pollutant at the WHPA1 IMPROVE monitor (green star), using the 2028 OTB projected emissions. Contours indicate AOI with EWRT greater than 0.5% (dark green) and 0.1% (light green) for the corresponding pollutant.

Sulfates source apportionment

Monitoring data show that sulfates were the largest species contribution to light extinction for both the MID and clearest days during the 2014-2018 baseline at WHPA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of sulfates at WHPA1 are expected to come primarily from international anthropogenic (52%) and natural sources (35%). These sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 6% of the sulfates responsible for light extinction at WHPA1. See Figure 6-38 for more information.

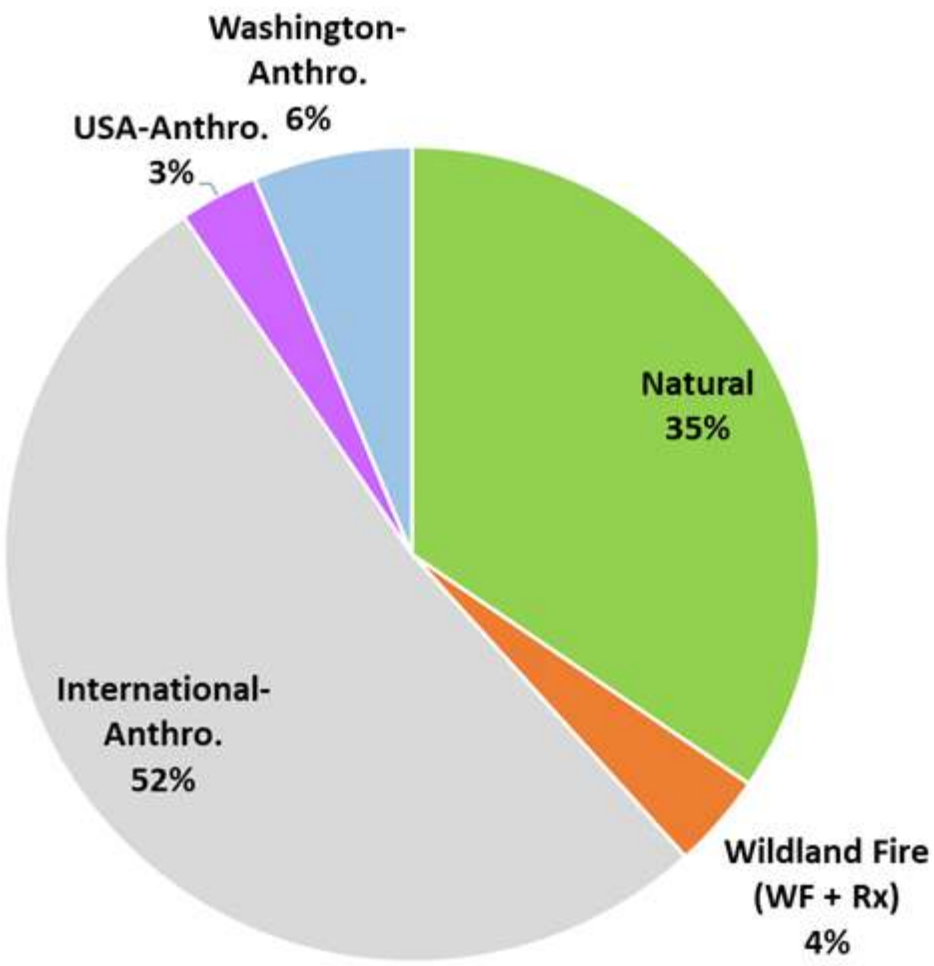


Figure 6-38: Expected source regions of SO_4 in 2028 at WHPA1 for MID (CAMx total = 8.2 Mm^{-1}).

The modeled sulfates for 2028 MID at WHPA1 was 8.2 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 6.37 Mm^{-1} and 6.32 Mm^{-1}, respectively.

Figure 6-39 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at the OLYM1 monitoring site on 2028 MIDs.

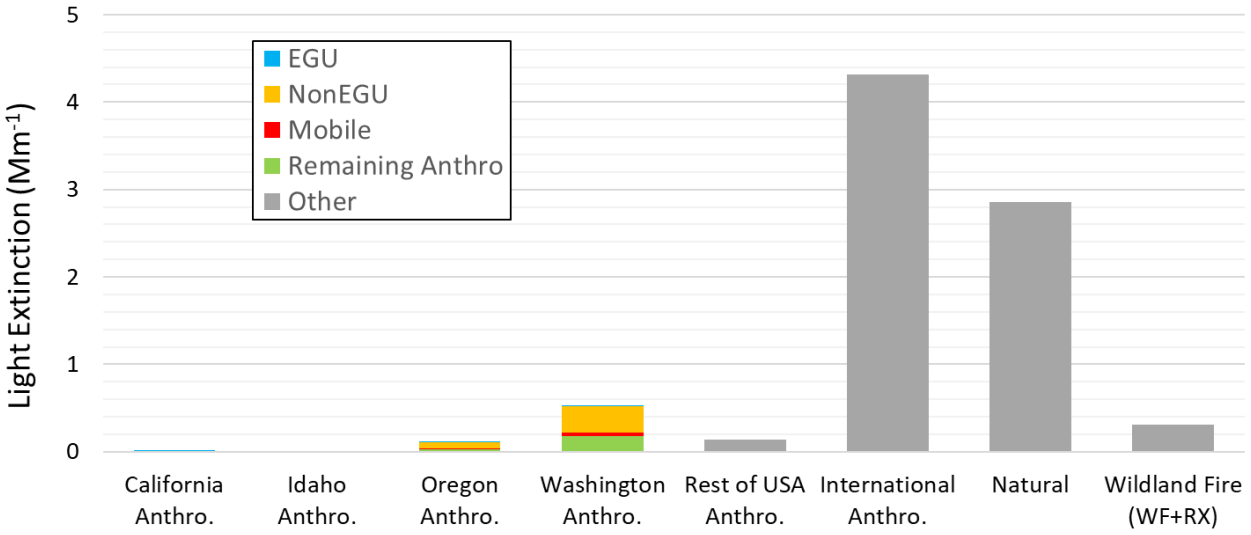


Figure 6-39: Expected source categories and regions of SO_4 in 2028 at WHPA1 for MID (CAMx total = 8.2 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of sulfates at WHPA1 are expected to come primarily from natural (49%), international anthropogenic (27%), and out-of-state US anthropogenic (18%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 5% of the sulfates responsible for light extinction at WHPA1. See Figure 6-40 for more information.

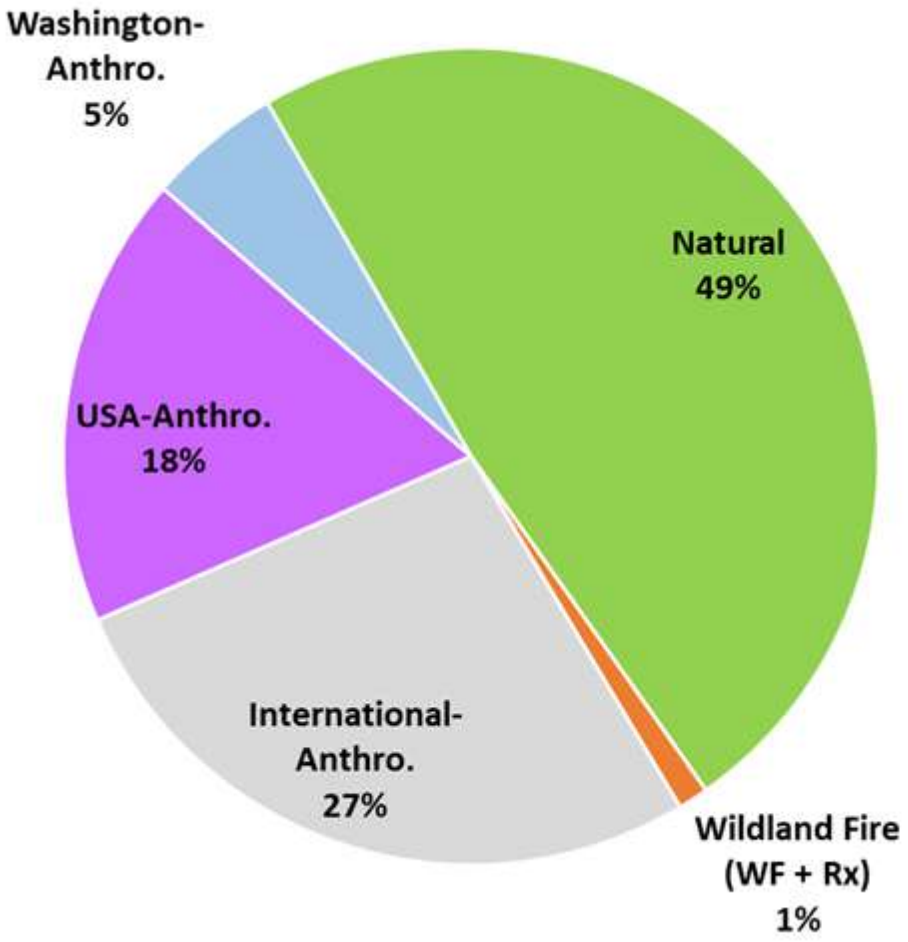


Figure 6-40: Expected source regions of SO_4 in 2028 at WHPA1 for clearest days (CAMx total = 3.0 Mm^{-1}).

The modeled sulfates for 2028 clearest days at WHPA1 was 3.0 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.41 Mm^{-1} and 0.39 Mm^{-1}, respectively.

Figure 6-41 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at WHPA1 on 2028 clearest days.

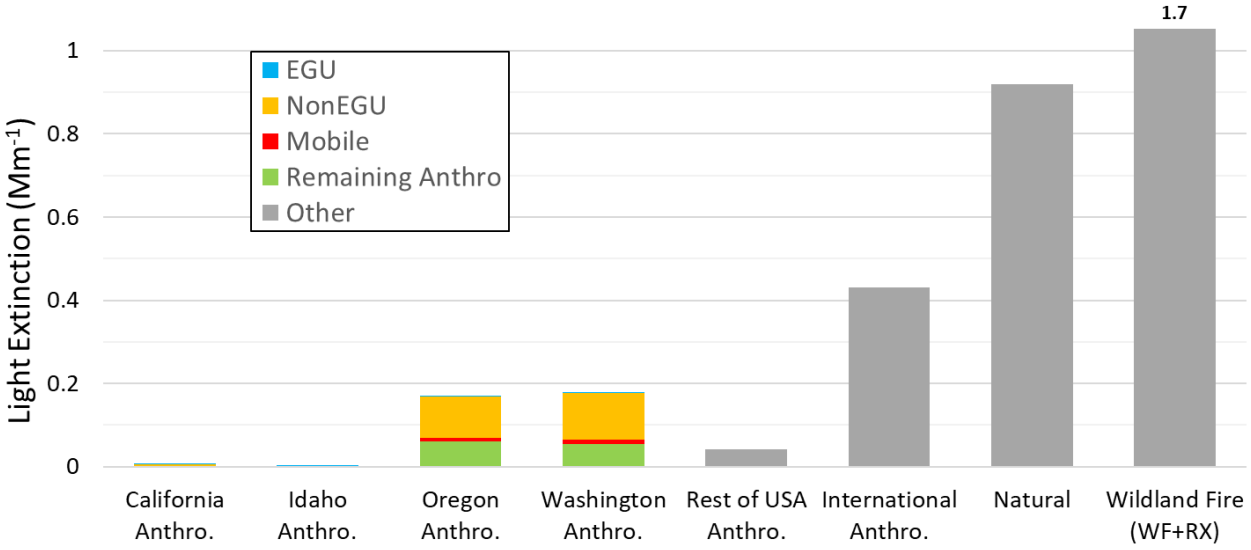


Figure 6-41: Expected source categories and regions of SO_4 in 2028 at WHPA1 for clearest days (CAMx total = 3.0 Mm^{-1}).

Nitrates source apportionment

Monitoring data show that nitrates were the 3rd largest species contribution to light extinction for the MID clearest days during the 2014-2018 baseline at WHPA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of nitrates at WHPA1 are expected to be considerably influenced by Washington anthropogenic sources (34%). International anthropogenic (35%) and natural sources (19%) are also expected to have considerable impacts but are beyond Washington's control. See Figure 6-42 for more information.

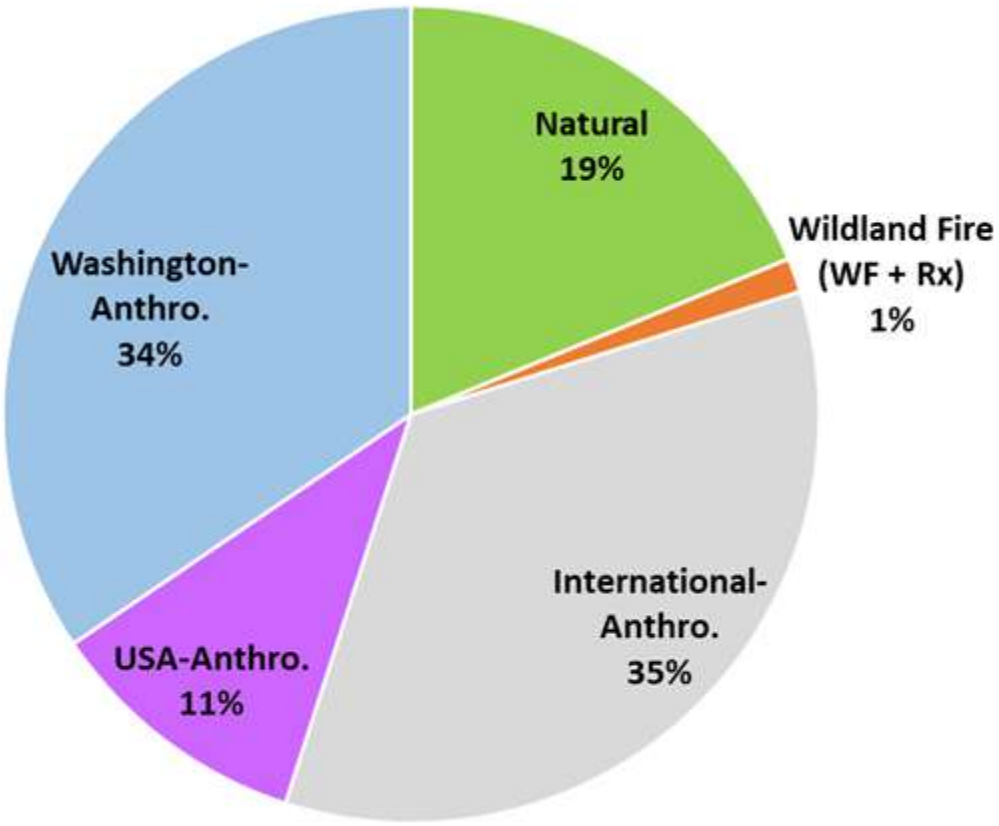


Figure 6-42: Expected source regions of NO_3 in 2028 at WHPA1 for MID (CAMx total = 4.1 Mm^{-1}).

The modeled nitrates for 2028 MID at WHPA1 was 4.1 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 1.53 Mm^{-1} and 0.97 Mm^{-1}, respectively.

Figure 6-43 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at WHPA1 on 2028 MIDs.

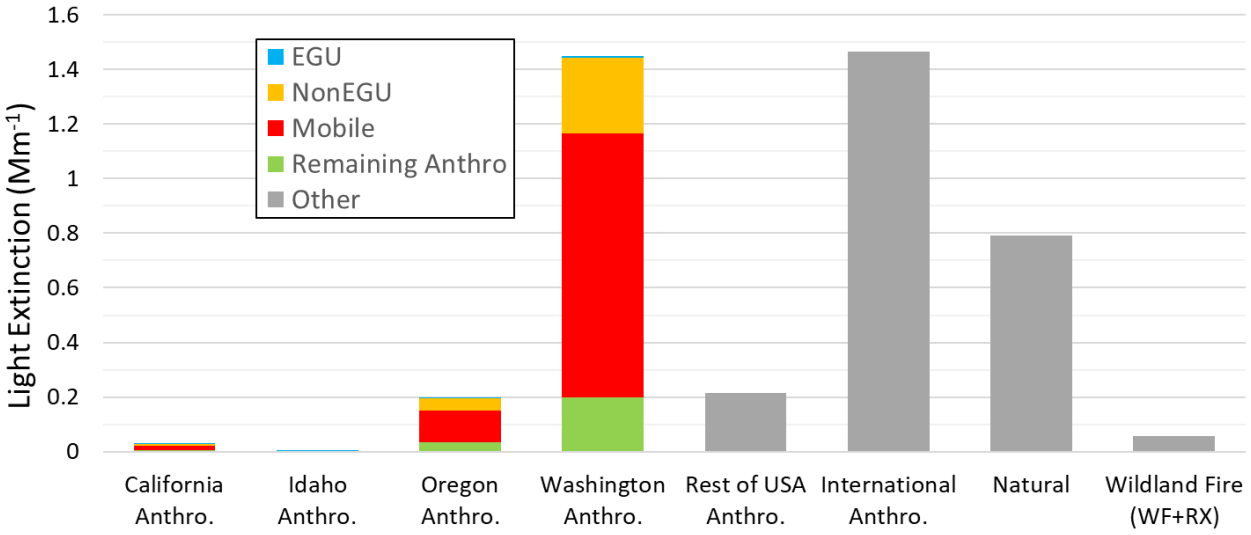


Figure 6-43: Expected source categories and regions of NO_3 in 2028 at WHPA1 for MID (CAMx total = 4.1 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of nitrates at WHPA1 are expected to come primarily from out-of-state US anthropogenic (44%) and international anthropogenic (25%) sources. Washington anthropogenic sources are expected to contribute 11% of the nitrates responsible for light extinction at WHPA1 on clearest days. See Figure 6-44 for more information.

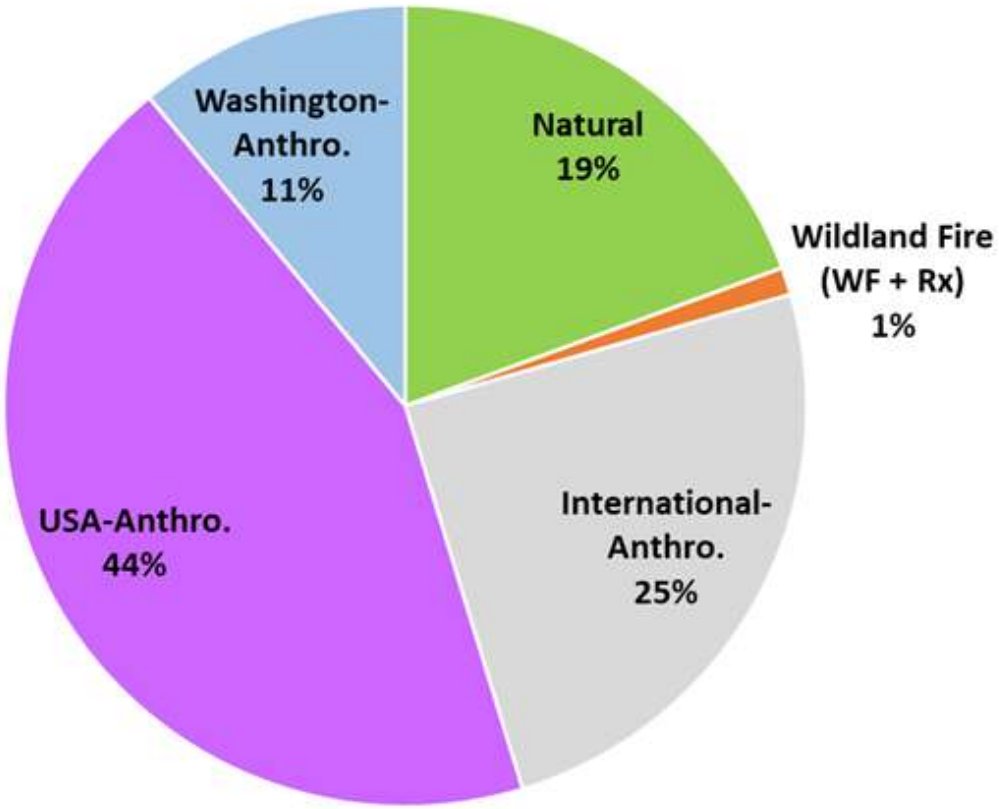


Figure 6-44: Expected source regions of NO_3 in 2028 at WHPA1 for clearest days (CAMx total = 1.1 Mm^{-1}).

The modeled nitrates for 2028 clearest days at WHPA1 was 1.1 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.15 Mm^{-1} and 0.12 Mm^{-1}, respectively.

Figure 6-45 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at WHPA1 on 2028 clearest days.

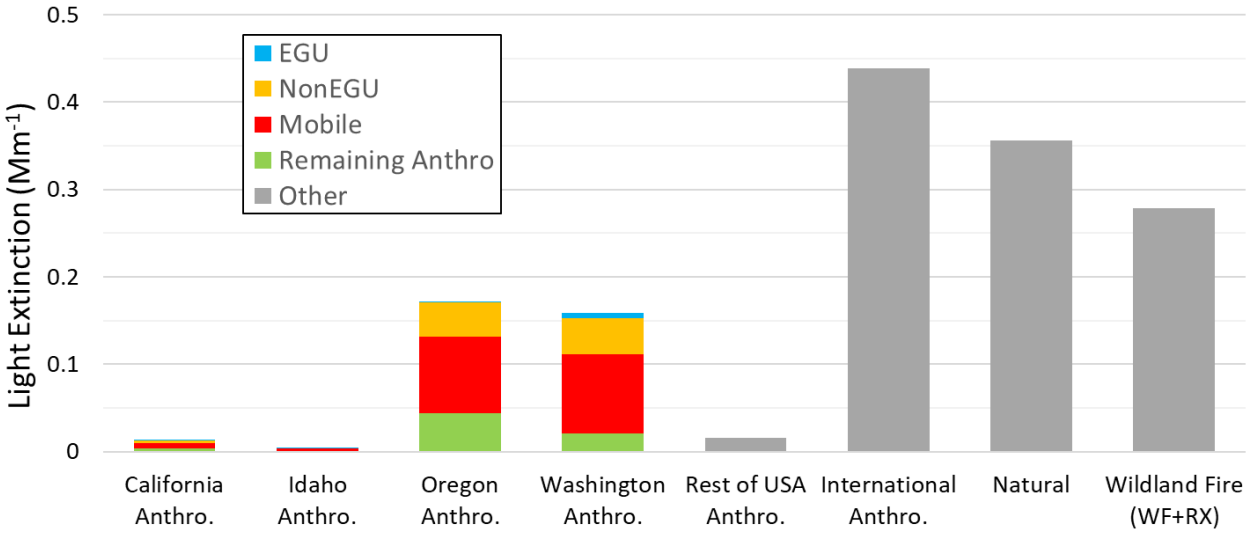


Figure 6-45: Expected source categories and regions of NO_3 in 2028 at WHPA1 for clearest days (CAMx total = 1.1 Mm^{-1}).

6.6 Pasayten Wilderness

Pasayten Wilderness is represented by the PASA1 IMPROVE monitoring site. The baseline conditions in Chapter 3 show that organic mass (32%) and sulfates (35%) make up 67% of the light extinction on the MID at this monitoring site. Elemental carbon (8%) and nitrates (14%) contribute to another 22% of the light extinction on the MID at this monitoring site. On the clearest days, sulfates make up 35% of the light extinction at this monitoring site. Organic mass (32%) and nitrates (14%) make up another 46% of the light extinction on the clearest days at this monitoring site.

WEP and rank point analyses

The WEP analysis for the PASA1 site on MID for the 2028 OTB scenario is summarized in Figure 6-46, showing an AOI of sources that span the entire state of Washington, the Puget Sound area, and the Vancouver, BC metropolitan area. Nitrates at PASA1 show considerable influence from non-EGU Point, on-road, non-road, and non-point sources. Sulfates at PASA1 show considerable influence from Non-Egu Point and non-point sources. Organic mass at PASA1 is mostly influenced by non-point sources. Elemental carbon is mostly influenced by non-point sources but also shows influence from non-EGU Point, on-road, and non-road sources. The rank point WEP analysis attributed 61.7% of point source nitrates to Washington State, with 26.5%, 8.2%, 2.7%, 0.6%, and 0.3% attributed to Tribal Lands, Oregon, Idaho, California, and Montana, respectively. The rank point WEP analysis attributed 89.5% of point source sulfates to Washington State, with 8.7%, 1.3%, 0.3%, 0.1%, and 0.1% attributed to Tribal Lands, Oregon, Idaho, Montana, and California, respectively.

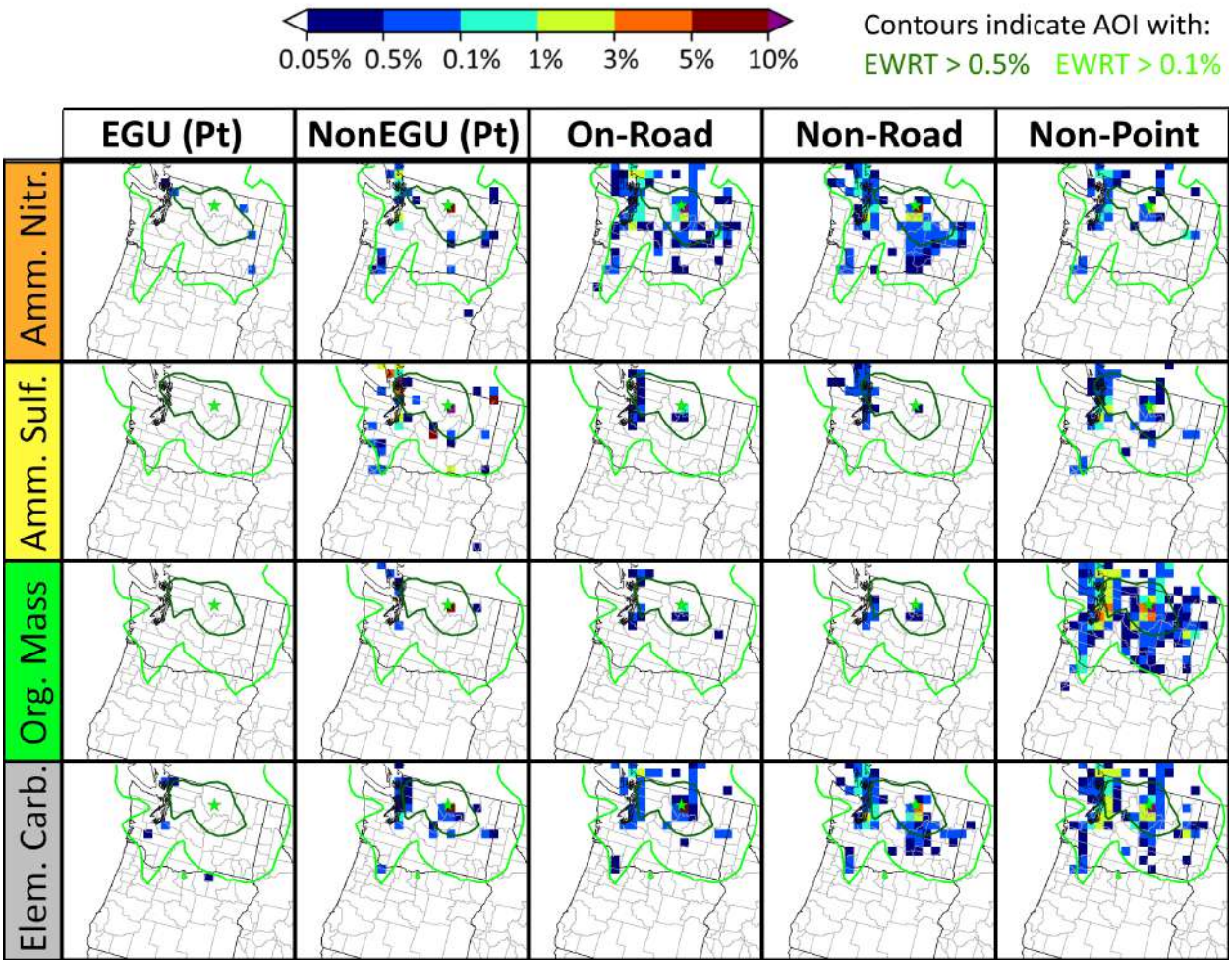


Figure 6-46: WEP for source area potential to contribute to extinction on MID by pollutant at the PASA1 IMPROVE monitor (green star), using the 2028 OTB projected emissions. Contours indicate AOI with EWRT greater than 0.5% (dark green) and 0.1% (light green) for the corresponding pollutant.

Sulfates source apportionment

Monitoring data show that sulfates were the largest species contribution to light extinction for both the MID and clearest days during the 2014-2018 baseline at PASA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of sulfates at PASA1 are expected to come primarily from international anthropogenic (49%) and natural sources (34%). These sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 7% of the sulfates responsible for light extinction at PASA1. Figure 6-47 for more information.

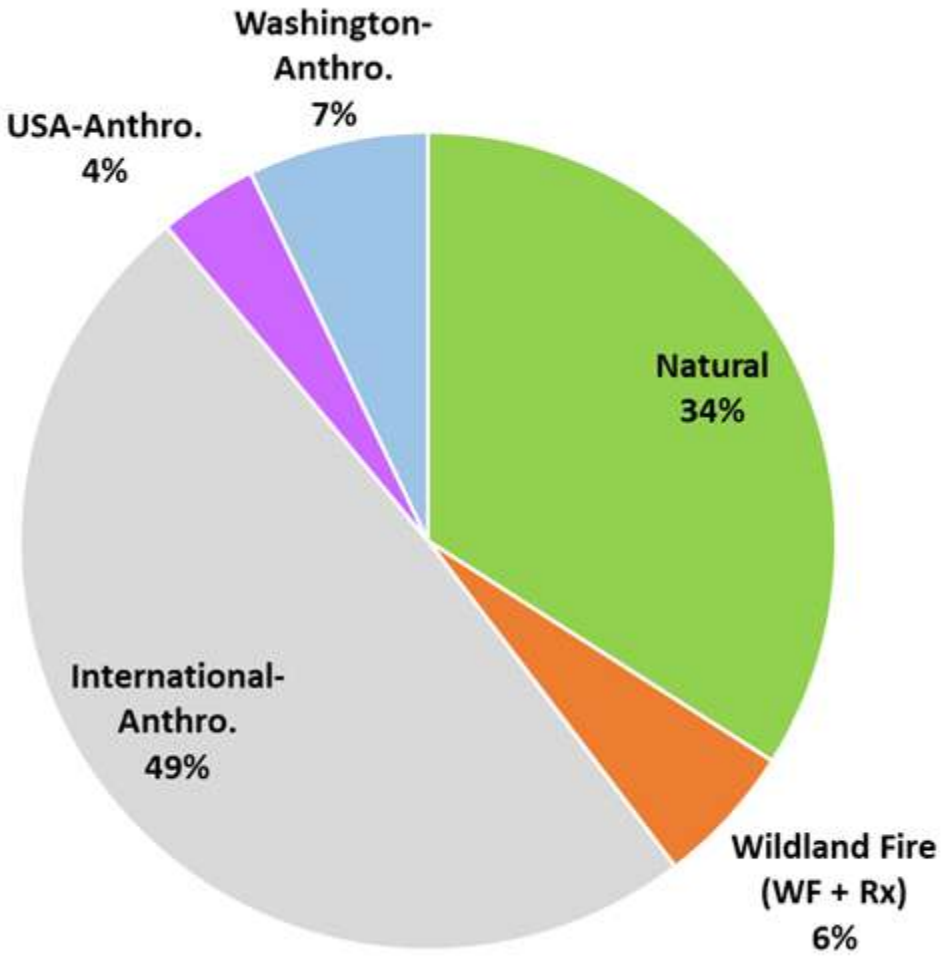


Figure 6-47: Expected source regions of SO_4 in 2028 at PASA1 for MID (CAMx total = 7.2 Mm^{-1}).

The modeled sulfates for 2028 MID at PASA1 was 7.2 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 5.78 Mm^{-1} and 5.77 Mm^{-1}, respectively.

Figure 6-48 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at the OLYM1 monitoring site on 2028 MIDs.

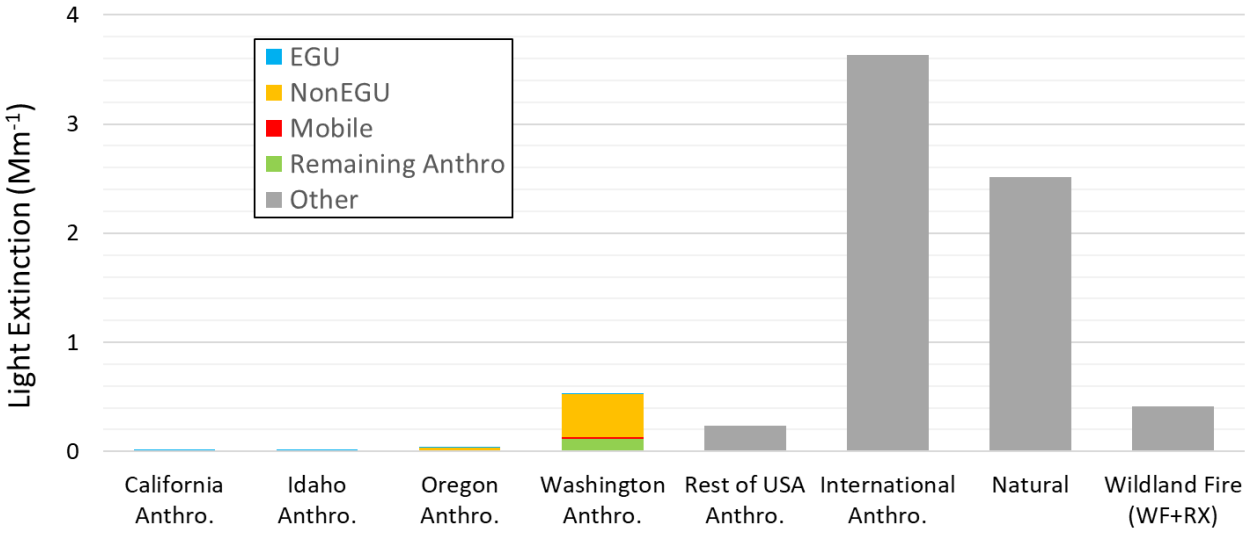


Figure 6-48: Expected source categories and regions of SO_4 in 2028 at PASA1 for MID (CAMx total = 7.2 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of sulfates at PASA1 are expected to come primarily from natural (42%), international anthropogenic (25%), and out-of-state US anthropogenic (17%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 13% of the sulfates responsible for light extinction at PASA1. See Figure 6-49 for more information.

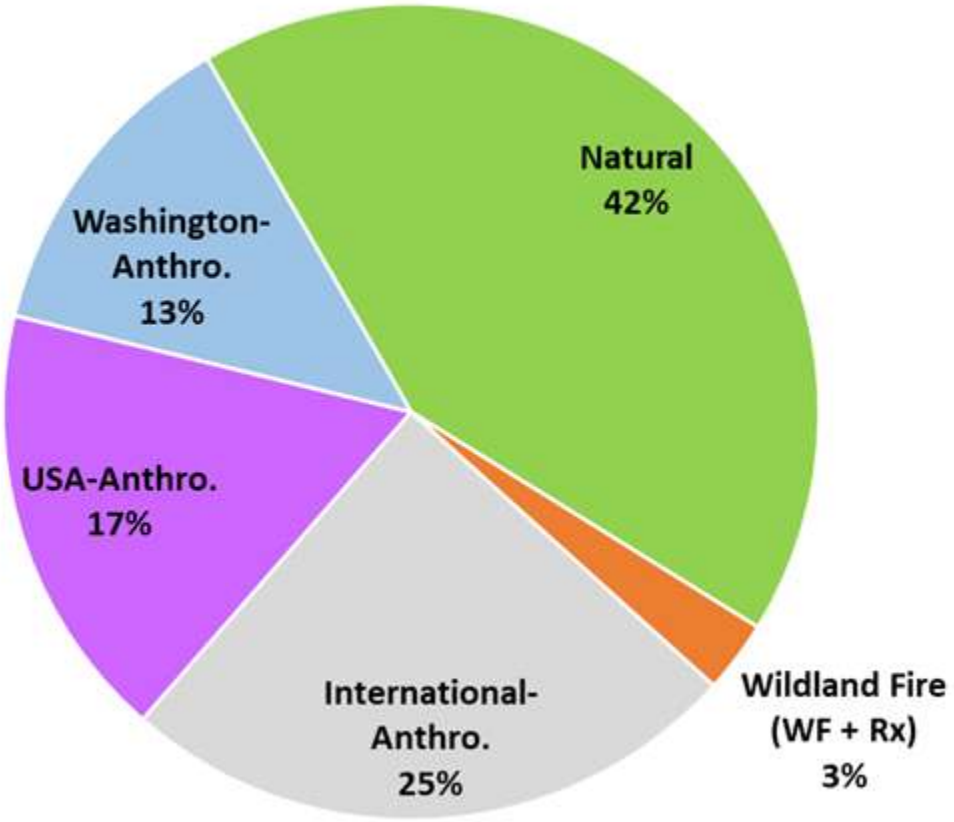


Figure 6-49: Expected source regions of SO_4 in 2028 at PASA1 for clearest days (CAMx total = 4.0 Mm^{-1}).

The modeled sulfates for 2028 clearest days at PASA1 was 4.0 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.75 Mm^{-1} and 0.71 Mm^{-1}, respectively.

Figure 6-50 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at PASA1 on 2028 clearest days.

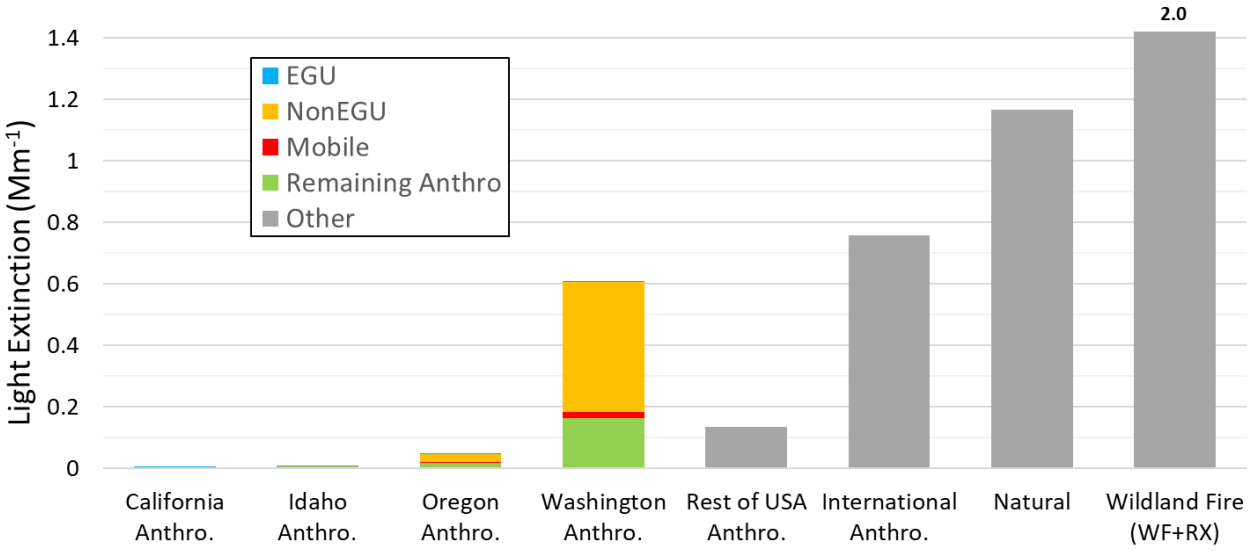


Figure 6-50: Expected source categories and regions of SO_4 in 2028 at PASA1 for clearest days (CAMx total = 4.0 Mm^{-1}).

Nitrates source apportionment

Monitoring data show that nitrates were the 3rd largest species contribution to light extinction for the MID clearest days during the 2014-2018 baseline at PASA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of nitrates at PASA1 are expected to be most influenced from international anthropogenic sources (46%), while natural sources (16%) and wildland fires (15%) are expected to have some impacts. All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 18% of the nitrates responsible for light extinction at PASA1. See Figure 6-51 for more information.

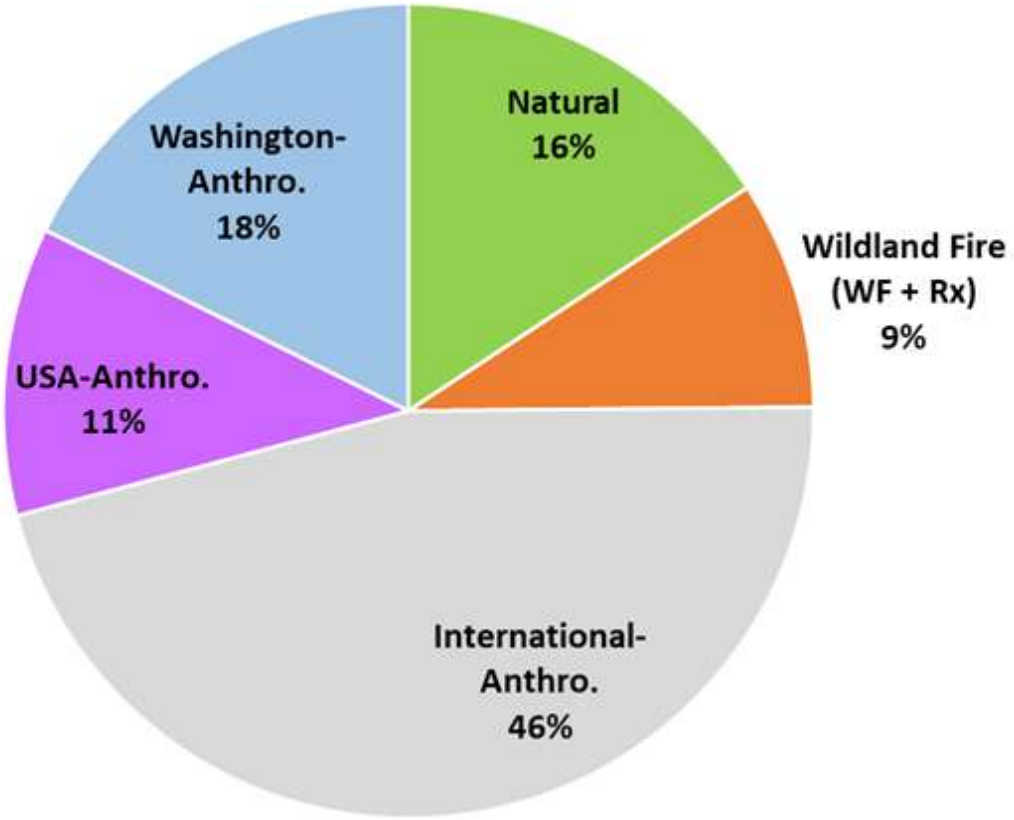


Figure 6-51: Expected source regions of NO_3 in 2028 at PASA1 for MID (CAMx total = 3.8 Mm^{-1}).

The modeled nitrates for 2028 MID at PASA1 was 3.8 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 2.34 Mm^{-1} and 1.79 Mm^{-1}, respectively.

Figure 6-52 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at PASA1 on 2028 MIDs.

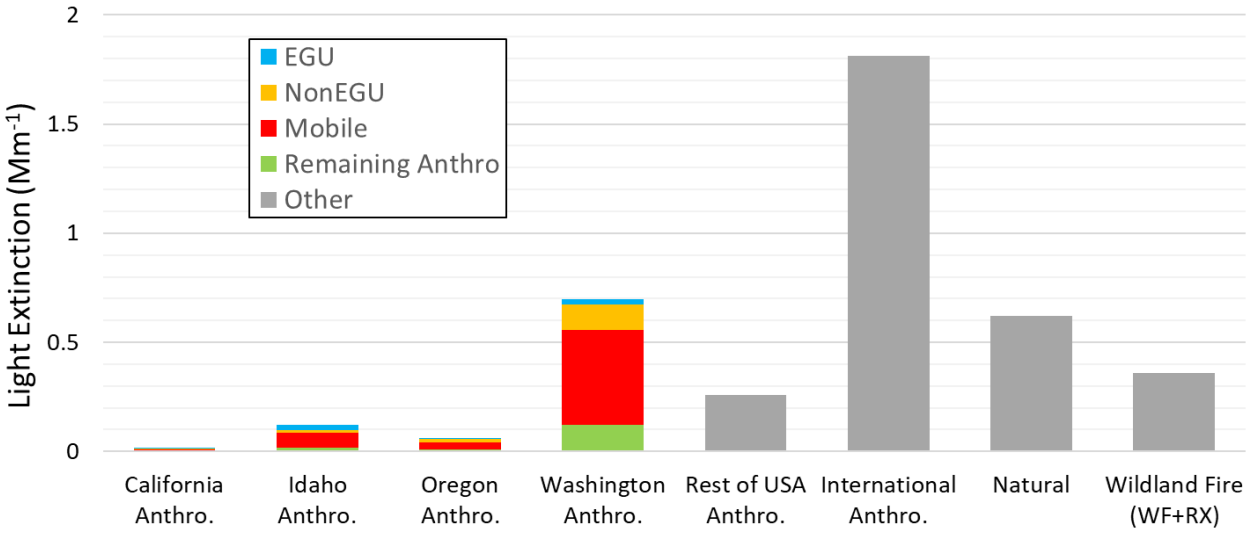


Figure 6-52: Expected source categories and regions of NO_3 in 2028 at PASA1 for MID (CAMx total = 3.8 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of nitrates at PASA1 are expected to come primarily from out-of-state US anthropogenic (39%) sources. Washington anthropogenic sources are expected to contribute 23% of the nitrates responsible for light extinction at PASA1 on clearest days. See Figure 6-53 for more information.

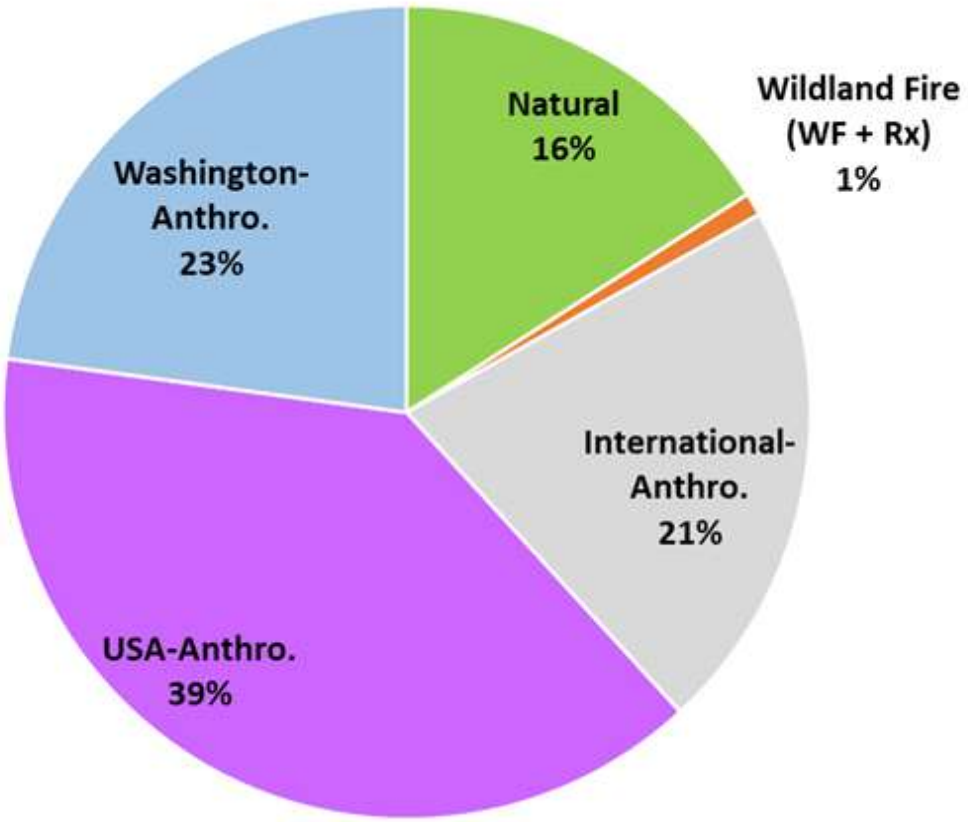


Figure 6-53: Expected source regions of NO_3 in 2028 at PASA1 for clearest days (CAMx total = 2.1 Mm^{-1}).

The modeled nitrates for 2028 clearest days at PASA1 was 2.1 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.30 Mm^{-1} and 0.23 Mm^{-1}, respectively.

Figure 6-54 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at PASA1 on 2028 clearest days.

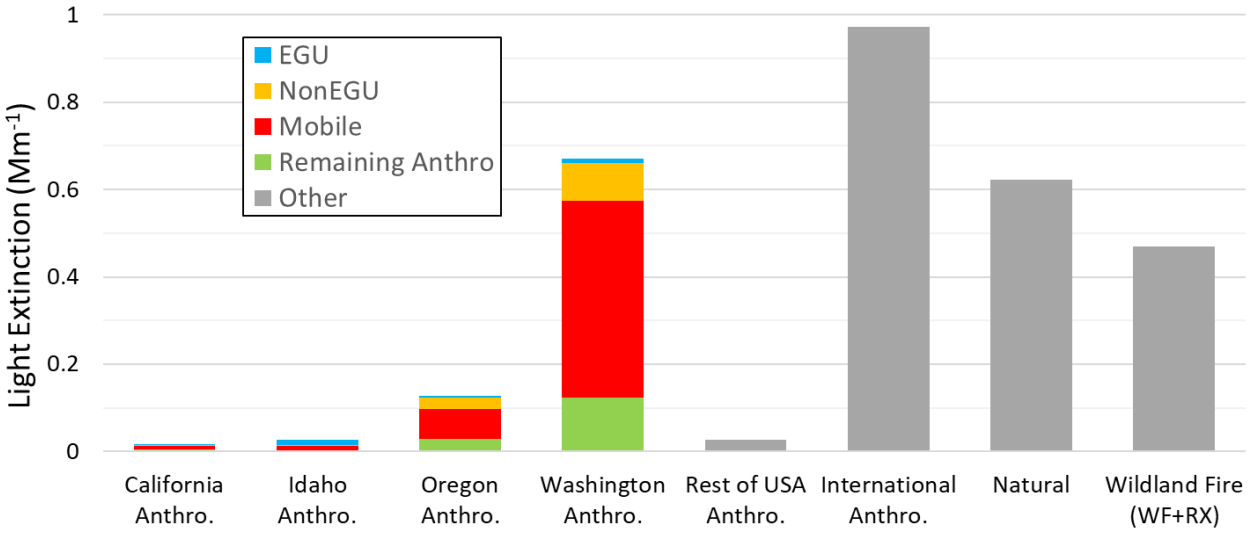


Figure 6-54: Expected source categories and regions of NO_3 in 2028 at PASA1 for clearest days (CAMx PSAT total = 2.1 Mm^{-1}).

6.7 In-State Contribution of Nitrates and Sulfates

Table 6-1 summarizes the in-state sources of sulfates by source category at each in-state mandatory Class 1 Area in 2028, as determined by the PSAT analysis. Table 6-2 summarizes the in-state sources of nitrates by source category at each in-state mandatory Class 1 Area in 2028, as determined by the PSAT analysis.

Table 6-1: Expected in-state anthropogenic sulfate contributions by source category for Washington's Mandatory Class 1 Areas in 2028.

Site	Days	Total WA Anthro.	WA EGU	WA non-EGU	WA Mobile	Remaining WA Anthro.
OLYM1	MID	8%	0%	6%	0%	2%
OLYM1	Clearest	17%	0%	9%	1%	6%
NOCA1	MID	11%	0%	9%	0%	1%
NOCA1	Clearest	8%	0%	5%	0%	3%
SNPA1	MID	7%	0%	5%	1%	2%
SNPA1	Clearest	11%	0%	5%	2%	4%
MORA1	MID	10%	0%	7%	1%	2%
MORA1	Clearest	7%	0%	5%	1%	2%
WHPA1	MID	6%	0%	4%	0%	2%
WHPA1	Clearest	5%	0%	3%	0%	2%
PASA1	MID	7%	0%	5%	0%	2%
PASA1	Clearest	13%	0%	9%	0%	3%

Table 6-2: Expected in-state anthropogenic nitrate contributions by source category for Washington's Mandatory Class 1 Areas in 2028.

Site	Days	Total WA Anthro.	WA EGU	WA non-EGU	WA Mobile	Remaining WA Anthro.
OLYM1	MID	36%	1%	11%	19%	6%
OLYM1	Clearest	33%	0%	6%	19%	8%
NOCA1	MID	25%	0%	7%	14%	3%
NOCA1	Clearest	22%	0%	4%	13%	4%
SNPA1	MID	38%	0%	6%	27%	5%
SNPA1	Clearest	26%	0%	3%	18%	4%
MORA1	MID	46%	0%	9%	32%	4%
MORA1	Clearest	15%	1%	4%	8%	2%
WHPA1	MID	34%	0%	7%	23%	5%
WHPA1	Clearest	11%	0%	3%	6%	1%
PASA1	MID	18%	1%	3%	11%	3%
PASA1	Clearest	23%	0%	3%	15%	4%

6.8 Other Mandatory Class 1 Areas Impacted by Washington Anthropogenic Emissions

The PSAT source apportionment modeling results were evaluated to determine which mandatory Class 1 Areas in nearby states are expected to be affected by emissions from Washington anthropogenic sources for sulfates and nitrates. Washington anthropogenic sources are expected to contribute a small percentage (e.g. less than 5%) of nitrates or sulfates to all IMPROVE monitors in nearby states on MID. However, some larger contributions are expected from Washington anthropogenic sources to several Montana (CABI1, FLAT1, GLAC1, MONT1, SULA1) and Oregon (KALM1, MOHO1, STAR1, THSI1) IMPROVE sites on MID that range from 5% to 22% of nitrates and 2% to 4% of sulfates. Though not shown here, the PSAT details confirm that the majority of anthropogenic emissions originating in Washington that affect out-of-state IMPROVE sites are from non-EGU (sulfates) and mobile sources (nitrates) identifies the percentage of the total modeled light extinction by species due to anthropogenic emissions from sources within Washington at IMPROVE monitors in California, Oregon, Idaho, Nevada, Montana, Utah, and Wyoming. Table 6-3 identifies all IMPROVE monitors where Washington anthropogenic sources are expected to contribute at least 0.1% of the nitrate or sulfate light extinction, based on the PSAT results. The percentage contribution is based on contributions from all modeled source areas relative to the total sulfates or nitrates, separately.

Washington anthropogenic sources are expected to contribute a small percentage (e.g. less than 5%) of nitrates or sulfates to all IMPROVE monitors in nearby states on MID. However, some larger contributions are expected from Washington anthropogenic sources to several Montana (CABI1, FLAT1, GLAC1, MONT1, SULA1) and Oregon (KALM1, MOHO1, STAR1, THSI1) IMPROVE sites on MID that range from 5% to 22% of nitrates and 2% to 4% of sulfates. Though not shown here, the PSAT details confirm that the majority of anthropogenic emissions originating in Washington that affect out-of-state IMPROVE sites are from non-EGU (sulfates) and mobile sources (nitrates).

The PSAT identified sulfate contributions from non-EGU point sources in Washington, originating from the 12,053 tons of non-EGU SO2 emissions included in the model (see Chapter 6). However, 64 percent of those modeled SO2 emissions (7,729 tons) are from the two aluminum facilities in Washington (Alcoa Wenatchee and Alcoa Intalco). WRAP modeled these facilities using historical emissions data and with no assumed emissions reductions. The Alcoa Wenatchee facility curtailed in 2015, going to zero emissions, and announced on December 13, 2021, that it will permanently close. The Alcoa Intalco facility curtailed in 2020 and went to zero emissions. Ecology and Intalco entered into an Agreed Order in January 2021 requiring Intalco to conduct a four-factor analysis before restarting (see Chapter 7 and appendix Q for more details).

As a result of the above analysis, we have determined that sources in Washington do not have significant impacts in other States' mandatory Class 1 Areas beyond the measures already addressed in this SIP submittal. Ecology did not receive any request for additional reductions from neighboring states during our consultations with them.

Table 6-3: Washington's Anthropogenic Emissions Contribution to Sulfate and Nitrate Light Extinction at Mandatory Class 1 Areas outside of Washington.

State	Site	MID Sulfates (% from WA Anthro)	Clearest Days Sulfates (% from WA Anthro)	MID Nitrates (% from WA Anthro)	Clearest Days Nitrates (% from WA Anthro)
CA	AGTI1	0.1%	0.1%	0.0%	0.1%
CA	BLIS1	0.2%	0.3%	0.1%	0.3%
CA	DOME1	0.1%	0.2%	0.1%	0.2%
CA	HOOV1	0.1%	0.1%	0.1%	0.2%
CA	JOSH1	0.1%	0.3%	0.0%	0.2%
CA	KAIS1	0.1%	0.0%	0.1%	0.0%
CA	LABE1	0.1%	0.3%	0.3%	0.1%
CA	LAVO1	0.2%	0.4%	0.5%	0.1%
CA	PINN1	0.3%	0.1%	0.3%	0.0%
CA	PORE1	0.3%	0.2%	1.1%	1.3%
CA	RAFA1	0.2%	0.1%	0.2%	0.1%
CA	REDW1	0.5%	0.5%	4.6%	4.4%
CA	SAGA1	0.1%	0.1%	0.0%	0.0%
CA	SAGO1	0.1%	0.1%	0.0%	0.1%
CA	SEQU1	0.2%	0.1%	0.1%	0.1%
CA	TRIN1	0.2%	0.3%	0.3%	0.1%
CA	YOSE1	0.1%	0.2%	0.1%	0.1%
ID	CRMO1	0.8%	1.8%	1.7%	4.5%
ID	SAWT1	1.4%	3.2%	3.3%	7.2%
MT	CABI1	2.6%	10.1%	8.6%	21.7%
MT	FLAT1	2.7%	7.1%	6.6%	15.3%
MT	FOPE1	0.6%	0.8%	0.8%	0.8%
MT	GAMO1	2.1%	2.1%	4.5%	6.0%
MT	GLAC1	2.4%	3.9%	6.3%	8.1%
MT	MELA1	0.5%	0.4%	0.5%	0.5%
MT	MONT1	2.3%	4.2%	5.1%	10.8%
MT	NOCH1	0.5%	1.3%	0.6%	2.5%
MT	SULA1	2.8%	2.2%	7.4%	7.6%
MT	ULBE1	0.5%	2.8%	0.7%	4.3%
NV	JARB1	1.0%	1.5%	2.9%	4.8%
OR	CRLA1	0.9%	0.1%	3.9%	0.2%
OR	HECA1	2.0%	2.6%	3.6%	10.1%
OR	KALM1	1.5%	0.2%	7.3%	0.9%
OR	MOHO1	4.4%	2.0%	22.1%	13.1%

State	Site	MID Sulfates (% from WA Anthro)	Clearest Days Sulfates (% from WA Anthro)	MID Nitrates (% from WA Anthro)	Clearest Days Nitrates (% from WA Anthro)
OR	STAR1	3.5%	2.0%	15.3%	8.7%
OR	THSI1	1.9%	0.2%	9.4%	0.4%
UT	BRCA1	0.2%	0.2%	0.4%	0.3%
UT	CANY1	0.2%	0.5%	0.4%	1.0%
UT	CAPI1	0.2%	0.5%	0.4%	0.8%
UT	ZICA1	0.1%	0.5%	0.1%	0.7%
WY	BRID1	0.6%	1.0%	1.4%	2.6%
WY	NOAB1	1.4%	0.9%	1.9%	2.5%
WY	YELL2	1.2%	1.1%	2.9%	1.6%

Chapter 7.Source Selection and Four-factor Analysis

7.1 Introduction

The Regional Haze Rule (RHR, 40 CFR 51) requires Washington State to submit a long-term strategy that includes enforceable emissions limitations, compliance schedules, and other measures necessary to make reasonable progress toward 2064 natural visibility conditions in Class 1 Areas. The state must determine what new emission reductions, if any, are necessary to make reasonable progress by considering the four statutory factors:

- Costs of compliance,
- The time necessary for compliance,
- The energy and non-air quality environmental impacts of compliance, and
- The remaining useful life of any potentially affected sources.

This chapter describes Washington's source selection criteria and describes the analyses to determine controls that are reasonable and needed to make reasonable progress. Controls identified are part of the long-term strategy described in Chapter 8.

EPA issued a memorandum[12] on July 8, 2021, to "help support SIP development, submittal, review, and action for the second planning period". The RHR SIP submittal was due to EPA on July 31, 2021, and Ecology has been developing the SIP submittal for the last few years. Ecology has attempted to implement the items addressed in the clarification memorandum to the maximum extent practicable considering the limited time provided between issuance of the memorandum and the due date of the RHR SIP.

7.2 Source screening analysis (Q/d)

Ecology used annual emissions and distance from the nearest Class 1 Area to select sources for the additional analysis. Q/d is a ratio of visibility-impairing emissions (in tons) produced by a source (Q) to its distance from the nearest Class 1 Area (d). We did not screen mobile sources or non-point sources with Q/d; we discuss them in Chapter 8, Long-term Strategy.

Ecology used Washington's 2014 point-source emissions data to calculate Q values. The Western Regional Air Partnership used 2014 as the base year for modeling as it was the most recent year of certified available data when the analysis was initiated. Ecology maintains an annual point-source Emissions Inventory (EI) for all major sources in the state. Many non-major point-source emissions totals were also received from regional offices and local clean air agencies. The reported emissions of compounds that contribute to regional haze (NOx, PM_{10}, SO_2, and NH_3) were summed (Q) for each point-source. We calculated the distance (d) from the source to the nearest Class 1 Area. Sources with larger Q/d values represent larger visibility impacts on Class 1 Areas.

[12] Peter Tsirigotis, Director, "Clarifications Regarding Regional Haze Second Implementation Plans for the Second Implementation Period," memo, addressed to Regional Air Division Directors, Regions 1-10, July 8, 2021

Major and non-major point-source data from 2014 were screened initially, but the analysis was biased by the approximately 1,100 non-major sources in the inventory with a Q/d of less than one. Ecology conducted a second screening of only the major sources. The selected major sources represent approximately 80 percent of the haze-causing emissions for the entire EI.

For the second Q/d screening we removed the non-major sources and only evaluated the 119 major sources in the EI. We focused on major sources because they contribute 90 percent of the total Q/d value even though they represent only 10 percent of the total number of all stationary sources. We screened the major sources using two thresholds: the sources with a Q/d ratio of 10 or greater and the sources that were in the top 80 percent of the sum of Q/d values of all major sources. The results are shown in **Error! Reference source not found.**. The sum of all major Q/d values was 756. Eighty percent of the Q/d sum for major sources is 605 with a Q/d threshold of 15.6. We then considered a Q/d value of 10 or greater. The Q/d threshold of 10 or greater includes more sources than the 80 percent threshold. Therefore, we chose the Q/d value of 10 or greater for the threshold to require a four-factor analysis (FFA) since it includes more sources.

There are 16 major sources with a Q/d ≥ 10. We added two sources with a Q/d ≤ 10 so that all the facilities in a selected source category were included in the FFA. The two facilities added are Packaging Corporation of America (PCA), a paperboard mill, and US Oil, an oil refinery. See Chapter 4 for more information about the annual emissions from these selected facilities.

Ecology conducted reasonableness analyses on major facilities with a Q/d of ≥ 10 along with two additional facilities. These identified stationary sources contribute 90 percent of the haze-causing emissions in the state.

Table 7-1: Q/d of sources selected for FFA

Facility Site Name	Q (tons) of NOX, PM10, SO2, and NH3	d (km) to nearest CIA	Q/d	Nearest CIA	Category 1	Agency
TransAlta Centralia Generation, LLC	10749.4	71.8	149.8	Mount Rainier NP	Coal powered electric	SWCAA
McKinley Paper Company	367.2	4.4	83.1	Olympic NP	Pulp and Paper Plant	ORCAA
Alcoa Primary Metals Wenatchee Works	3461.7	42.8	80.9	Alpine Lakes Wilderness	Alumina Refining and Aluminum Production	Ecology - Industrial
Alcoa Primary Metals Intalco Works	5658.5	78.9	71.7	North Cascades NP	Alumina Refining and Aluminum Production	Ecology - Industrial
BP Cherry Point Refinery	2945.0	80.8	36.4	North Cascades NP	Petroleum Refineries	NWCAA
Tesoro Northwest Company	2312.3	75.4	30.7	Olympic NP	Petroleum Refineries	NWCAA
WestRock Tacoma	1353.7	48.4	27.9	Mount Rainier NP	Pulp, Paper, and Paperboard Mills	Ecology - Industrial
Nippon Dynawave Packaging Company Longview	2656.0	104.8	25.3	Mount Adams Wilderness	Paperboard Mills	Ecology - Industrial
Puget Sound Refining Company (Shell)	1793.1	73.0	24.5	Olympic NP	Petroleum Refineries	NWCAA

Facility Site Name	Q (tons) of NOX, PM10, SO2, and NH3	d (km) to nearest CIA	Q/d	Nearest CIA	Category 1	Agency
Pt Townsend Paper Corporation	848.0	35.0	24.2	Olympic NP	Paper (not Newsprint) Mills	Ecology - Industrial
Ash Grove Cement Co, E Marginal	1243.6	53.8	23.1	Alpine Lakes Wilderness	Cement Manufacturing	PSCAA
Cosmo Specialty Fibers, Inc.	973.8	58.2	16.7	Olympic NP	Paperboard Mills	Ecology - Industrial
WestRock Longview, LLC	1574.2	100.7	15.6	Mount Adams Wilderness	Paperboard Mills	Ecology - Industrial
Georgia-Pacific Consumer Operations LLC	653.0	45.4	14.4	Mount Hood Wilderness	Paper (except Newsprint) Mills	Ecology - Industrial
Phillips 66	840.6	77.2	10.9	North Cascades NP	Petroleum Refineries	NWCAA
Cardinal FG Winlock	859.8	80.1	10.7	Mount Rainier NP	Flat Glass Manufacture	SWCAA
Packaging Corporation of America (PCA) Wallowa	1048.3	111.5	9.4	Eagle Cap Wilderness	Paperboard Mills	Ecology - Industrial
US Oil & Refining Co	149.2	46.4	3.2	Mount Rainier NP	Oil Refinery	PSCAA
Total	39487.5		658.7			

Facility notification of selection for four-factor analysis

Ecology contacted the facilities selected in Spring of 2019, and informed them that we had selected them for additional RH emission analyses (see Appendix G). Some of these facilities had existing legal requirements or pending permit actions to reduce emissions, so Ecology did not request a FFA from them. We requested that facilities in the pulp and paper and the refinery source categories perform a FFA and provide the results to Ecology. Ecology also requested that the Ash Grove Cement Company and Cardinal Glass perform an FFA.

7.3 Reasonableness evaluation

When performing a reasonableness analysis on the selected facilities, the emission controls already in place and enforceable are the baseline controls in the analysis. Facilities with no new controls identified rely on the existing controls for the state to make reasonable progress.

Ecology conducted a reasonableness analysis on emission control technology for the sources selected in the Q/d analysis. This analysis determined if there were new reasonable emission controls needed to make reasonable progress at each Class 1 Area.

Four-factor analysis and reasonably available control technology (RACT) equivalency

The RHR requires States to perform a Four-Factor Analysis (FFA) to determine whether the installation of new emission controls at certain facilities is necessary for the State to make reasonable progress toward the national visibility goal. In Washington State, RCW 70A.15.2230 (the "RACT statute") is the legal mechanism that Ecology can use to require existing sources to install new emission controls that are determined to be reasonable. Because the analysis performed under the State's RACT process is equivalent to the RHR's FFA, Ecology will use the RACT process to require the installation of reasonable emission controls for purposes of compliance with the RHR.

40 CFR 51.308(f) requires the State's long-term strategy to include all measures that are "necessary to make reasonable progress, as determined pursuant to [40 CFR 51.308](f)(2)(i) through (iv)." In turn, 40 CFR 51.308(f)(2)(i) requires the State to consider the following four statutory factors in determining which emission reductions measures are necessary to make reasonable progress:

- the costs of compliance,
- the time necessary for compliance,
- the energy and non-air quality environmental impacts of compliance, and
- the remaining useful life of any potentially affected anthropogenic source of visibility impairment.

Pursuant to RCW 70A.15.1030(20) and 70A.15.2230(5), the RACT evaluation of new emission controls at existing stationary sources requires Ecology to consider the following:

- the impact of the source upon air quality,
- the availability of additional controls,

- the emission reduction to be achieved by additional controls,
- the impact of additional controls on air quality,
- and the capital and operating costs of the additional controls.

The costs of compliance

Under the RACT analysis, Ecology characterizes and considers the cost of compliance consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. The cost of compliance factor in 40 CFR 51.308(f)(2)(i) directly correlates to the RACT analysis consideration of capital and operating costs of the additional controls. The capital and operating costs in RACT are for purchase, installation, and operation of all equipment. These costs include the actual emission control equipment, any non-air quality equipment, and the energy costs to operate the equipment.

The time necessary for compliance

Under the RACT analysis, Ecology characterizes and considers the time necessary for compliance consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. Under the RACT analysis requirements, Ecology determines the time necessary for compliance as part of considering the capital and operating costs of the additional controls and impact of the source upon air quality. Specifically, a shorter amount of time for compliance would involve costs distributed over a shorter time and thus have a larger annualized cost. The impact of the source on air quality is also a consideration in the time for compliance. The longer it takes to install and operate the control equipment the greater the negative impact on air quality.

The energy and non-air quality environmental impacts of compliance

Under the RACT analysis, Ecology characterizes and considers the energy and non-air quality environmental impacts of compliance consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. Ecology considers the energy and non-air quality environmental impacts of compliance factor as part of analyzing the capital and operating costs of the additional controls in the RACT analysis. The RACT analysis includes costs for equipment directly related to the emissions and all indirectly required equipment needed to install and operate the new controls. The operating cost requirement in the RACT analysis also covers the energy impacts of the controls and supporting equipment.

The remaining useful life of any potentially affected anthropogenic source of visibility impairment

Under the RACT analysis, Ecology characterizes and considers the remaining useful life of any potentially affected anthropogenic source of visibility impairment consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. Ecology considers the remaining useful life of an emissions control system as part of calculating the capital and operating costs of the system. Specifically, the annualized costs of the emissions control system are affected by the remaining useful life. The shorter the useful life, the larger the annual costs associated with control equipment.

Additionally, RACT requires consideration of the impact of the source upon air quality.' This is consistent with the CAA, RHR, and EPA guidance. While the four statutory factors must be considered in determining what is necessary to make reasonable progress, they are not the only factors that States may consider in this evaluation. As explained by EPA in its 2019

guidance, States have the flexibility to consider other factors, including visibility benefits, when determining the emission reduction measures that are necessary to make reasonable progress:

> "Section 51.308(f)(2)(i) of the Regional Haze Rule requires consideration of the four factors listed in CAA section 169A(g)(1) and does not mention visibility benefits. However, neither the CAA nor the Rule suggest that only the listed factors may be considered. Because the goal of the regional haze program is to improve visibility, it is reasonable for a state to consider whether and by how much an emission control measure would help achieve that goal. Likewise, it is reasonable that such information on visibility benefits be considered in light of other factors that may weigh for or against the control at issue. Such a balancing of outcomes is consistent with CAA section 169A(b)(2), which states that SIPs must contain elements as may be necessary to make reasonable progress towards meeting the national visibility goal. Thus, EPA interprets the CAA and the Regional Haze Rule to allow a state reasonable discretion to consider the anticipated visibility benefits of an emission control measure along with the other factors when determining whether a measure is necessary to make reasonable progress."[13]

Therefore, Ecology will use the RACT process to (1) evaluate and determine the emissions reduction measures that are necessary to make reasonable progress and (2) incorporate these measures into its long-term strategy and Regional Haze SIP in a manner that is enforceable as a legal and practical matter.

Reasonable control evaluation

The Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring data shows that ammonium sulfate ($(NH_4)_2SO_4$) and ammonium nitrate (NH_4NO_3) are two of the most significant pollutants impairing visibility in Washington's Class 1 Areas. $(NH_4)_2SO_4$ is primarily from point sources and offshore sources (shipping traffic), and NH_4NO_3 is primarily from point and mobile sources, with slight contributions from non-point sources. After the initial screening for source selection, the FFA in this chapter evaluates reasonable controls for point sources of nitrogen oxides (NOx) and sulfur dioxides (SO_2) emissions.

Ecology relies on current Washington state laws and regulations to implement any controls identified as reasonable. Washington has four potential mechanisms for implementing identified emission controls:

- Agreed order (AO) – a legally binding order that requires agreement between the parties
- Permit modification – permittee initiated change to their facility
- Reasonably available control technology – Revised Code of Washington (RCW 70A.15.2230)

Ecology prefers to use permit modifications and AOs to achieve emission reductions as these methods have the source and Ecology working together to achieve reductions. These options

[13] EPA-457/B-10-003, *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, Section II.B.5.

are currently not available for use with the refinery or pulp & paper industry categories during this implementation period.

Ecology will use the RACT process to evaluate reasonable emission reductions for facilities without an AO or permit modification. The result of the RACT process is a determination of the minimum emissions controls required at a facility. The determination is made through rule making for a category of sources, or a source specific order. RACT identifies the emission control equipment and the timelines for installation and operation of the equipment. The RACT rule or RACT order is federally enforceable when EPA approves it into the SIP.

Ecology has limited resources and is choosing to prioritize the implementation of reasonable controls. As discussed in EPA's guidance:[14]

"Another potentially reasonable approach might be for a state that identifies cost-effective new controls at a multitude of sources to choose to require controls at only a subset of those sources that constitute the vast majority of the visibility benefit. In this case, the state could rely on visibility benefits to prioritize which sources would receive new controls."

Ecology identified potential reasonable controls at a multitude of sources and is prioritizing a subset of those sources that constitute a vast majority of the visibility benefit during this implementation period. Ecology's first priority is to identify reasonable controls at the refinery facilities.

A number of factors supports the selection of refineries as the first priority. These factors include:

- Four of the five refinery facilities are located in the Puget trough, west of several Class 1 Areas. Their cumulative regional haze causing emissions influence the same Class 1 Areas.
- Predominant winds direct the emissions from the refineries towards several Class 1 Areas.
- The refineries' potential emission reductions of 4,200 tons per year account for the vast amount of potential emission reductions.

Pulp & paper mills are a subset of sources that are lower priority than refineries because:

- The pulp & paper mills are not located as close to each other as the refineries so they do not have as great of a cumulative effect.
- One mill identified with potential reasonable cost controls, Packaging Corporation of America (PCA) Wallula, is located in a direction that is downwind from the nearest Class 1 Areas. This lessens, but does not remove, the influence the mill's emissions have on Class 1 Areas.
- The potential reduction of 450 tons per year in regional haze emissions from the pulp & paper mills reasonable controls is vastly less than potential refinery emission reductions.

[14] Peter Tsirigotis, Director, "Clarifications Regarding Regional Haze Second Implementation Plans for the Second Implementation Period," memo, addressed to Regional Air Division Directors, Regions 1-10, July 8, 2021.

7.4 Facility specific reasonableness analyses

The following sections contain the facility specific FFA information and Ecology's analysis of additional emission controls. TransAlta and Cardinal Glass emission reductions were included in the long-term strategy and the 2028 modeled emission projections (on-the-books) for determining reasonable progress goals. Emission reductions from the remaining facilities were not included in the modeled 2028 projection since implementation will likely occur during the next implementation period. This is due to long planning timelines at these types of facilities combined with coordination of control installation and scheduled facility maintenance shutdowns.

Ash Grove Cement Company

Ash Grove Cement Company (Ash Grove) operates a dry process cement kiln in the Duwamish Industrial area of Seattle. The primary haze causing emissions at the plant comes from the cement kiln and its associated clinker cooler baghouses. Clinker is an intermediate product in cement production.

The existing particulate controls installed at the plant meet the regulatory requirements for dry material handling. The plant also complies with the Portland Cement Manufacturing National Emission Standards for Hazardous Air Pollutants (NESHAP). This standard regulates particulate matter (PM) as a surrogate for metals (40 CFR Part 63 Subpart LLL). This NESHAP was last updated mid 2018 when the EPA determined that there were no developments in practices, processes, and control technologies that warrant revisions to the Maximum Achievable Control Technology (MACT) standards for this source category (83 FR 35122-35136, 2018).

SO_2 emissions at the plant come from burning sulfur containing fuels. The plant is capable of burning coal, natural gas, and tire-derived fuels. The plant has not been using coal for the last couple of years, but still has the ability to use it. As the facility can still use coal, SO2 emissions from the 2014 EI (with coal combustion) were included in the modeling to determine progress. The alkaline cement clinker removes some SO2 from the combustion gases. The facility uses this as a primary method of SO2 control. Nitrogen oxides (NOx) emissions from the plant also come from the combustion of all fuels allowed by permit.

Consent decree

Ash Grove entered into a consent decree with EPA, Ecology, the Puget Sound Clean Air Agency (PSCAA), and other state agencies in 2013 [SEE APPENDIX E]. The consent decree required the Seattle facility to submit an optimization protocol for the Seattle Kiln. The purpose of the protocol was to optimize the operation of the Seattle Kiln to reduce NOx emissions to the maximum extent practicable from that kiln. EPA reviewed the optimization plan in consultation with the PSCAA.

The protocols for the optimization plan included key operating parameters resulting in the minimization of emissions of NOx. The consent decree required minimization of NOx to the greatest extent practicable without:

- Incurring unreasonable cost.
- Causing an exceedance of any other applicable emissions limit.

- Impairing production quality or quantity.

The protocols also required the facility to identify all potential process and/or operational changes that they could implement to reduce emissions of NOx.

On June 30, 2016, the facility submitted the NOx demonstration period report and data related to optimization. On August 25, 2016, EPA, in consultation with Ecology and PSCAA, reviewed the data and approved the limit of 5.1 pounds of NOx per ton of clinker on a 30-day rolling average.

Four Factor Analysis

The following analysis recognizes that EPA approved the consent decree of 2013 and the optimization of the facility to limit NOx emissions in 2016. The goal was to reduce NOx emissions to the greatest extent practicable within reasonable costs. Ecology does not typically perform RACT analysis on single facilities that have had a reasonable analysis performed within the last five years. The following evaluates possible additional controls.

NOx emission controls by selective catalytic reduction

Selective catalytic reduction (SCR) is a potentially viable method to reduce NOx emissions. Efficient operation of an SCR requires consistent exhaust temperatures. Changes in the temperature of the exhaust gas result in reduced NOx removal efficiency. The exit stack temperature at the facility is typically around 350°F. The typical SCR operation temperature is 650°F so the exhaust would require heating When exhaust stream temperatures are too low, there is the potential that injected ammonia (the reducing agent) won't react (ammonia slip). Conversely, when the exhaust stream temperature is too high, ammonia (NH_3) can oxidize to NO, potentially reducing efficiencies. The reducing process needs excess NH_3 to achieve removal efficiencies in excess of 80 percent and can result in ammonia slip.

There is a risk of fouling the catalyst bed when operating an SCR. Installing the catalyst bed downstream of the particulate matter controls, (this facility uses baghouse dust collectors), can reduce fouling. The low exhaust gas temperature exiting the baghouse would require the installation of a heat exchanger system to reheat the exhaust stream to the desired reaction temperature range of between 480 °F to 800 °F. The use of a preheater or heat recovery would be required, however the use of a preheater would require additional fuel consumption and create even more NOx.

Installation of an SCR system would require storage and handling equipment for ammonia. An SCR system requires a catalytic reactor, heat exchanger, and potentially additional NOx control equipment for the emissions associated with the heat exchanger fuel combustion.

Installing the SCR in the high dust exhaust stream (e.g. before the baghouse) would put the SCR in the optimal temperature zone but there is a risk of fouling the catalyst. Faster fouling of the catalyst would result in increased operation cost and increased plant down time. A larger catalyst volume and mechanical mechanism to clean the catalyst could mitigate the fouling impacts but would require a larger physical footprint for installation.

NOx emission controls by selective non-catalytic reduction

The Consent Decree described above required the facility to optimize a selective non-catalytic reduction (SNCR) emission control system. Ash Grove submitted a new source review application with Puget Sound Clean Air Agency (PSCAA) in 2016 for the installation of the SNCR system. A permit has not been issued because of unresolved technical issues.

The main technical issue is that the permit application requested to operate the SNCR process on an "as needed" basis to achieve NOx limits determined during a 2016 demonstration period for the EPA Consent Decree. PSCAA and Ash Grove are working on resolving the technical issues in the application with the goal of issuing a permit for the SNCR system. This permit will form the basis for emission standards that will apply to the SNCR system. Ecology intends to supplement the RHR SIP once the permit is issued. In the interim, Ecology has determined the EPA Consent Decree limit of 5.1 pounds of NOx per ton of clinker on a 30-day rolling average is adequate for reasonable progress at this time until a final permit for the SNCR system is issued by Puget Sound Clean Air Agency.

Particulate matter emission controls

The facility upgraded their emission controls in 2019 with the installation of a Dustex 10-module pulse jet baghouse with rated flow rate of 185,000 actual cubic feet per minute (ACFM). They performed this upgrade under a permit modification with PSCAA. The permit modification requires the facility to meet the requirements of the Best Available Control Technology (BACT) requirements. PSCAA accepted the upgrade as BACT, so additional control analyses are not required.

Under the EPA's July 8, 2021 Clarification Memo (page 9) "if a state can demonstrate that a source will continue to implement its existing measures and will not increase its emission rate, it may not be necessary to require those measures under the regional haze program in order to prevent future emission increases." We note that the existing particulate controls installed at the plant meet the regulatory requirements for dry material handling. The plant also complies with the Portland Cement Manufacturing National Emission Standards for Hazardous Air Pollutants (NESHAP). This standard regulates particulate matter (PM) as a surrogate for metals (40 CFR Part 63 Subpart LLL). This NESHAP was last updated mid 2018 when the EPA determined that there were no developments in practices, processes, and control technologies that warrant revisions to the Maximum Achievable Control Technology (MACT) standards for this source category (83 FR 35122-35136, 2018). Because these emissions are unlikely to increase and are subject to a federally enforceable control, Ecology has determined that incorporation of a PM emission limit in the SIP is not necessary for reasonable progress.

SO_2 emission controls

The primary emission of SO_2 from the facility is from the burning of coal, tires, and various oils. The primary emission control for SO_2 is a wet scrubber. Space is limited at the site and installation of a wet scrubber would require extensive facility rearrangement and a retention pond for the waste water, in addition to the capital cost of the wet scrubber. Based on this, we do not consider the cost of a wet scrubber reasonable at this time.

The existing controls for SO_2 emissions at the facility limiting emissions to 200 ppm at 10% O2 for one hour average and a not to exceed of 176 tons per year were deemed adequate to meet reasonable progress.

Cost of compliance

Installing SCR NOx or SO_2 emission controls would require significant facility reconstruction. The Ash Grove facility brochure in [APPENDIX E] shows how congested the site is. To create room the emission devices would have to be elevated above the existing facility and would run into area height restrictions. The other option of raising existing plant equipment or positioning the emission control device above other equipment would require extensive structural work and would require that the facility shut down operations during construction and reconfigure the site. This would result in significant additional costs above capital expenditure and operational cost for the emission control equipment.

Ash Grove submitted a permit application for an SNCR system, and this indicates that the cost of SNCR installation is reasonable. Ecology is working with PSCAA and Ash Grove to optimize the proposed SNCR system so that the permitted system maximizes NOx emission reductions without excessive ammonia emissions.

Time necessary for compliance

Typical planning periods to design and then install SCR NO_X or SO_2 controls are two to three years. A tuning period after installation is required to understand the physical operation of the equipment. For the Ash Grove facility, the time required to plan and then install any equipment would increase by one to two years to allow for extensive facility modifications to accommodate any equipment.

With the base infrastructure of the SNCR system already in place at the facility, an analysis and subsequent optimization study would take six to twelve months. This time estimate comes from the actual time required to perform an optimization study at a coal-fired power plant in the state. Most of the time involved in the optimization study is in setting the system parameters and then operating the facility under the parameters long enough to collect stabilized data.

Energy and non-air quality environmental impacts of compliance

SCR equipment would require preheating the exhaust stream before it enters the SCR. Preheaters burn fuel to generate heat and this would consume additional energy and create additional emissions.

The installation of a wet scrubber for SO_2 controls would require obtaining a water quality permit for use with the liquid in the wet scrubber. Depending on the permit requirements, the facility could need additional energy to treat the liquid from the wet scrubber before discharge off-site.

The SNCR system is already in place and the facility is working on obtaining a permit.

Remaining useful life of any potentially affected sources

Proper maintenance of this facility should allow it to continue operations well into the future.

Summary and preliminary recommendations

Ecology does not recommend installation of additional emission control equipment. The particulate matter controls at the site were recently upgraded. The cost for SCR NOx and wet scrubbing SO_2 equipment installation is also unreasonable due to the confined space at the site. The existing controls for particulate matter and SO_2 where used in the model to determine reasonable progress. The installation of a new SNCR system will be permitted by PSCAA identifying use requirements.

Cardinal Glass

Cardinal FG Company Winlock (Cardinal) operates a flat glass manufacturing plant in Winlock, near the intersection of Avery Road and Highway 603, in Lewis County, Washington. In 2019, Cardinal submitted a permit modification application to SWCAA to install an SCR emission control device and increase production of plate glass. The application also proposed removing the current emission control of limiting excess oxygen. SWCAA is working with the facility to issue a permit to add SCR to the existing plant.

Ecology identified Cardinal in the Q/d analysis as a facility to review under the RH program. On January 17, 2020, Cardinal FG Company submitted a four-factor analysis.

Four-factor analysis

Cardinal FG Company Winlock submitted an application to SWCAA to modify the facility's permit by:

- Installing an SCR system to control NO_X emissions from the glass furnace;
- Increasing rated furnace production from 650 tpd to 750 tpd;
- Removing an SCR from Emergency Generator #1;
- Installing a new emergency generator; and
- Establishing voluntary emission limits at levels below major source thresholds.

The use of the current emission control system will cease once the SCR system commences operation. The facility will also install a new supplemental heater between the Electrostatic Precipitator (ESP) and the SCR system. This heater will raise the exhaust stream temperatures to the range required for proper SCR operation.

Table 7-2 shows the emissions, by pollutant in tons, after the requested modification is complete. The table also shows the change in emissions from the current permit values to the requested modified permit values.

Table 7-2: Emissions summary

Pollutant	Facility-wide potential to emit after permit modification in tons per year (tpy)	Pollutant emissions change between current limits and permit modification limits in tons per year (tpy)
NOx	249.62	-583.05

CO	249.00	-522.48
VOC	57.79	1.92
SO_2	114.21	41.75
PM	141.96	16.84
PM_{10}	141.96	6.84
$PM_{2.5}$	141.96	16.84

Cost of compliance

Oxides of Nitrogen (NOx) – cost and cost/ton

Cardinal's permit modification application estimated a reduction of glass furnace annual NOx emissions from 828.05 to 245.0 tons per year (tpy). This is an annual reduction of 583.05 tpy. The estimated cost of the new SCR control system is $10 million. Based on 3.5 percent interest and 20-year life, the annual cost is $944,000 per year. Using the annualized cost and emissions reduction, the estimated cost effectiveness is $1,469 per ton of NOx. The actual cost will be higher since this does not include operating costs.

Ecology requested additional data needed to use the EPA Control Cost Manual from Cardinal to compare the EPA Control Cost Manual results to actual data for quality purposes. Ecology received the following unit specific information from Cardinal on June 15, 2020:

- Exhaust rate of 181,157 acfm @ 600 F
- SCR inlet NOx = 437.5 lbs/hr (above current emission limit)
- SCR outlet NOx = 49.1 lbs/hr
- Capital cost updated to $11 million (annualized cost not updated)

SO_2, PM – Temperature change – higher scrubber temperature and reheat - cost and cost/ton

The operating temperature of the new SCR system will require the existing spray dryer and electrostatic precipitator (ESP) to operate at higher temperatures, reducing their collection efficiency and requiring a reheat burner. This increased temperature results in a greater fuel consumption and SO_2 emissions. The SO_2 emissions limit will increase from 0.6 to 0.8 lbs of SO_2/ton of glass. The natural gas-fired reheat burner will have a capacity of 17 - Million British Thermal Units (MMBtu)/hr.

The permit modification application includes a production increase at the facility from 650 to 750 tons per day (TPD). This results in an increase of total annual PM emissions even though the total PM emission limits of 0.94 lbs/ton will not change.

Time necessary for compliance

Cardinal expects to have the proposed SCR installed and operational in 2021. The permit was issued by SWCAA to the facility on February 11, 2021, and the SCR should be operating by the end of 2021.

Energy and non-air quality environmental impacts of compliance

SCR - Ammonia and PM increases

The design of the SCR system at the facility assumes a 19 percent ammonia reagent usage of 816 lbs/hr. Appendix D of the permit modification application calculates ammonia emissions. SWCAA permit 20-3409 contains the permit modification application. Based on an ammonia slip limit of 10 parts per million (ppm), estimated ammonia emissions based on continuous operation will be 9.58 tpy.

The total particulate matter (PM) emission limits of 0.94 lbs PM/ton of glass will not change. Total PM emissions will increase, however, due to the facility increasing throughput capacity from 650 to 750 tpd of glass.

Appendix C of the permit modification application (in Appendix S) calculates PM emissions. The PM emissions from the glass furnace will increase from 111.0 to 127.84 tpy, for an increase of 16.84 tpy.

The SO_2 emissions limit will increase from 0.6 to 0.8 lbs/ton. SO_2 emission increases will occur due to the increase in capacity from 650 to 750 tpd of glass. Appendix C of the permit modification application calculates SO_2 emissions. The SO_2 emissions from the glass furnace will increase from 75.6 to 117.35 tpy, for an increase of 41.75 tpy.

SO_2/PM controls - additional fuel if needed – added emissions

The existing SO_2 and PM controls for the glass furnace do not use fuel.

Remaining useful life of any potentially affected sources

The Cardinal facility has operated since 2006. The new SCR system's design life will last at least 30 years if the facility performs proper maintenance.

Ecology's review

The RH program does not prohibit or limit construction of new stationary sources of emissions or modification of existing stationary sources of emissions. Cardinal submitted a permit modification application for increased glass production and a change in emission control devices. The NOx emission reductions resulting from the installation of the SCR are part of Ecology's long-term strategy for achieving reasonable progress goals in Class 1 Areas for this implementation period. Based on the above information and SWCAA's technical support document for the permit action, Ecology concludes:

- The new SCR will reduce NOx emissions. The permitted emissions will be reduced to 250 tpy. Ecology's independent review of the cost for installation of the SCR determined approximately $1,600/ton of NOx reduced. The facility's estimate was slightly higher as the company included the additional equipment (temporary stack and larger crane) to install the new system while the facility stays in operation. This could explain the higher actual cost when compared to the EPA Control Cost Manual when using a base reconstruction factor of 1.0.
- This cost is reasonable for NOx reductions. If the facility were not taking action on their own initiative to install a SCR system, Ecology would have pursued Cardinal Glass to install one. The permit modification with SWCAA is the only action needed for RH reductions.

Table 7-3: Cardinal cost vs Ecology using the EPA Control Cost Manual with June 15, 2020, updated exhaust flow and capital cost

Company	Actual cubic feet per minute	Capital costs ($)	Annualized costs ($)
Cardinal FG Winlock	181,157	11,000,000	944,000
EPA Model - R =1.0	181,157	10,899,998	750,225

Summary and preliminary recommendations

- The operating temperature of the new SCR system will require the existing spray dryer and ESP to operate at higher temperatures, reducing the collection efficiency and requiring a reheat burner. Ecology concluded that the resulting minor increase in PM and SO_2 is offset by the larger decrease in NOx.
- The facility is working to obtain local permits needed for the installation of the SCR.
- The new permit limit for ammonia of 10 ppm and 9.5 tpy is reasonable. New SCR systems will typically have actual ammonia emissions less than 2 ppm after tuning.

Coal-fired electrical generation unit

TransAlta Centralia Generation (TransAlta) is a coal-fired power plant located east of Centralia, WA. This is the largest source of NOx in the state. TransAlta's large quantity of emissions and tall stacks create NOx impacts to all of the Class 1 areas within 300 km of the facility. TransAlta operates a two unit, pulverized coal-fired power plant. Each unit of the plant rates at 702.5-megawatt (MW) net output. Operation of a coal-fired power plant results in visibility impairing emissions of PM, SO_2, and NOx.

The Coal-Fired Electric Generation Facility Bill was signed in 2011, with an effective date of July 22, 2011. The state's greenhouse gas emission performance standard for power plants codified at RCW 80.80.040determined the main environmental impacts of the bill. The requirements in RCW 80.80.040 have compliance dates for one boiler to cease coal-fired generation by December 31, 2020, and the other boiler to cease coal-fired generation by December 31, 2025. TransAlta has ceased coal-fired power generation on one boiler and plans to cease coal-fired power generation in the other boiler by December 31, 2025.

Ecology identified TransAlta as a best available retrofit technology (BART) eligible facility in the first implementation period of RH. Ecology issued a BART Order to TransAlta on June 18, 2010 (2010BARTtransalta). This BART Order required the installation of a SNCR emission control device. Ecology issued a revision to the BART Order on December 13, 2011. The revision incorporated an optimization study on urea volume injections for the SNCR. Ecology issued a second revision to the BART order on July 29, 2020. The second revision required the installation of automated controls on the combustion system, a lower NOx emission limit, and removal of specific urea injection volumes.

In the summer of 2019, TransAlta experienced emission opacity readings that would have exceeded the opacity limits if TransAlta had not reduced plant capacity to compensate. During a maintenance shutdown, the facility examined their ESPs. The ESPs had a visual fouling of all

interior components, which dramatically reduced their efficiency. The facility analyzed the material in the ESPs and identified it as ammonia sulfate. The source of ammonia in the system was from the reactions of urea in the SNCR system.

In coordination with SWCAA and Ecology, TransAlta installed a computerized emission control system called a Combustion Optimization System with Neural Network program (Neural Net) to decrease the ammonia slip in the SNCR. SWCAA agreed to use enforcement discretion in 2019 on the urea injection rate mandated in the 2011 BART Order revision while TransAlta was tuning the Neural Net. TransAlta collected enough process data during tuning of the neural net to agree to a more stringent NOx emission standard of 0.18 lb/MMBtu, a decrease from the 0.21 lb/MMBtu allowed under the 2011 BART Order revision.

Because the Neural Net is able to maintain a more stringent emission standard, Ecology eliminated unnecessary requirements when issuing the second BART order revision. Specifically, the 2020 order:

- Removed the requirement of a specific urea injection rate to allow TransAlta to inject urea as required to meet the new emission standard.
- Removed the requirement to analyze and report nitrogen and sulfur coal content as the facility would have to meet NOx, SO_2, and PM emission standards regardless of the coal used.
- Changed the requirement for ammonia emission monitoring to require monitoring only when using a urea injection rate of greater than 1.5 gallons per minute.

The BART Order was submitted to EPA and approved into the Washington SIP on May 11, 2021.

Four factor analysis

The FFA of TransAlta reflects the RCW 80.80 and the Memorandum of Agreement (MOA) between TransAlta and the Governor of Washington that TransAlta will completely cease coal-fired power generation by December 31, 2025. It also discusses the second BART Order revision that reduces NOx emissions at the facility.

Cost of compliance

The agreement to cease coal-fired power generation greatly influences the compliance cost for installing any emission controls at TransAlta. The first unit ceased operation on December 31, 2020. This decreased by approximately half the plant emissions from coal-fired power generation. This emission reduction requires no capital cost. Operational costs to ensure that the unit will no longer be able to generate power from coal will occur, but all parties already considered this as part of the MOA.

The second BART Order revision includes the installation of the Neural Net to control combustion variables in one of the boilers. TransAlta proposed this installation and during optimization testing, the data confirmed that the controls could reduce NOx emissions. Ecology did not request the costs associated with installing, testing, and optimizing of the neural net as TransAlta proposed it and resulted in decreased NOx emissions for the remaining coal-fired power generation life of the facility.

Time necessary for compliance

TransAlta ceased coal-fired power generation on one of their units in December 2020. TransAlta will cease coal-fired power generation on their last unit by December 31, 2025. The Neural Net installation has already occurred and the more stringent emission limit applies to the facility until it ceases coal-fired power generation.

Energy and non-air quality environmental impacts of compliance

The energy required to meet compliance for ceasing coal-fired power operation is zero. We did not take non-air quality environmental impacts for the future of the facility into account for this analysis.

For the Neural Net, TransAlta is anticipating payback within a couple of years. This is because more efficient combustion controls reduce the amount of coal required to produce the same amount of heat.

Remaining useful life of any potentially affected sources

The facility useful life for coal-fired power generation is until December 31, 2025.

Summary and preliminary recommendations

TransAlta already has an agreement to cease coal-fired power generation by December 31, 2025. This will result in coal-related emissions from the facility going to zero. Ecology used the zero emission level in determining 2028 projected emissions and reasonable progress goals in Washington's Class 1 Areas, as well as potential effects in Class 1 Areas of neighboring states. With the installation of the neural net, the facility will also have a reduced NOx emission standard for the remaining life of the facility. For these reasons, Ecology does not anticipate further emission reductions or emission control devices for Regional Haze purposes.

Primary aluminum production

The state of Washington currently has two primary aluminum reduction facilities:

- Alcoa Primary Metals Wenatchee Works located in Wenatchee, Washington.
- Alcoa Primary Metals Intalco Works located in Ferndale, Washington

Alcoa curtailed the Wenatchee facility in 2015 and the Ferndale facility in 2020, while keeping both air permits active. Ecology did not include emission reductions from either facility when modeling on-the-books visibility projections for 2028 or determining reasonable progress goals in the state's Class 1 Areas although future emissions inventories may show emission reductions resulting from curtailment.

In 2014, the emissions from the sites were as follows:

Table 7-4: Primary aluminum facility 2014 emissions

Facility	Tons $PM_{2.5}$	Tons SO_2	Tons NOx
Alcoa Intalco	637	4,794	227
Alcoa Wenatchee	457	2,935	70

Alcoa Wenatchee Works

The Wenatchee Works facility, curtailed since 2015, has very low emissions. The facility is performing all the requirements of their air permits and could restart at any time. Wenatchee Works would need time to expand their work force from the current curtailment level and additional physical activities would need to occur prior to returning to production.

The four-factor analysis of Wenatchee Works is complicated by the curtailment status. Annual emissions are very low while in curtailment and not typical of emissions during operation. In 2016-2018, annual emissions were less than 10 tpy for all pollutants. A facility in curtailment is also not generating revenue because the facility is not selling any aluminum.

Four-factor analysis

The primary haze-causing pollutant from the facility when it is operating is SO_2. A wet scrubber and associated liquid handling structures is often used for SO_2 emission control. The following FFA details how installation of a wet scrubber system is not reasonable when the facility is in curtailment.

Cost of compliance

The cost of compliance will always be unreasonable for a facility in curtailment since the analysis is based on cost/ton of actual emissions. The facility reported 10 tons of total annual emissions in 2016. Assuming the facility could install control equipment for the entire 10 tons, the cost per ton of emissions reduced will exceed $10,000 per ton of pollutants removed with only a $100,000 expenditure. A cost of $10,000 per ton is not a reasonable cost for primary aluminum facilities at this time.

Facilities with large emissions of SO_2, in tons per year, typically use wet scrubbers for emission control. Direct capital equipment costs for wet scrubbers are typically in the millions of dollars range and installing a wet scrubber would require spending at least $100,000 per ton of SO_2 removed based on current emissions, which is not reasonable.

Because the facility has the potential to restart at any time, emissions could potentially return to pre-curtailment levels. In this situation, an analysis of the facility could potentially result in reasonable emission control costs. Calculations of the cost of compliance would depend on numerous variables, from the number of pot lines brought back on line, amount of aluminum produced, regaining experienced operators for efficient operations, and other operational determinations.

We would need to determine numerous variables associated with a restart of the facility before performing a cost analysis. At the time of facility restart, we would need to do an analysis to determine the reasonableness of the cost of potential controls.

Time necessary for compliance

With the facility in curtailment and no emission control equipment deemed reasonable, the facility is already complying with reasonable emission control. If the facility comes out of curtailment, we would need a new FFA to determine time for compliance if we identify control equipment.

Energy and non-air environmental impacts

With the facility in curtailment and no emission control equipment deemed reasonable, the facility would not have any new non-air environmental impacts. If the facility comes out of curtailment, we would need a new four-factor analysis to determine non-air environmental impacts if we identify control equipment.

Remaining useful life

The facility is currently in curtailment and not operating. The facility is performing maintenance on equipment to keep the facility in position to restart in the future. The facility has permanently closed a pot line within the last five years.

Summary and preliminary recommendations

Wenatchee Works is currently in curtailment and installation of additional emission control devices is not reasonable at this time. With the potential of the facility to restart at any time, Ecology entered into an Agreed Order (AO #18100) (WenatcheeAORH) with the facility that requires the facility perform a FFA before restarting and provide the analysis to Ecology.

The AO conditions stipulate that Alcoa shall:

1. Prepare and submit a four-factor analysis to Ecology for review and approval at least 180 days prior to restarting any of the facility's potlines. Alcoa will base the analysis on the facility's permitted emission limits and will assess potential emission control measures against the following four statutory factors:
    - The cost of compliance,
    - Time necessary for compliance,
    - Energy and non-air quality impacts of compliance, and
    - Remaining useful life of the source.
2. Within 60 days of receipt of Ecology's comments on the four-factor analysis provide all additional information and/or documentation requested by Ecology, if any, and submit an updated four-factor analysis that adequately addresses Ecology's comments.
3. Install or otherwise implement and begin operating all emission control measures identified in the final four-factor analysis submitted within three years of Ecology's approval.

Alcoa Intalco

The Intalco facility near Ferndale is capable of making approximately 307,000 tons of aluminum metal each year. The facility is located in an area that had air monitor readings that were exceeding the one-hour sulfur dioxide (SO_2) National Ambient Air Quality Standards (NAAQS). Ecology and Intalco entered into Agreed Order 16449 on July 25, 2019 (IntalcoAO16449). Intalco agreed in the AO to submit a complete Notice of Construction (NOC) application for the installation of a wet scrubber design and engineering report by October 31, 2020.

We anticipated using the information required under the terms of the AO to perform the FFA for our RH SIP. Ecology did not request the facility to perform a FFA as the AO obviated the need to perform one. On April 22, 2020, the Intalco facility announced that it was curtailing production. The AO contains a clause that "[n]ot withstanding anything else in this Order, in the event that Intalco announces the closure or curtailment of one of its three potlines (A, B, or C line, or any combination or equivalent measure thereof), then upon thirty days' prior written notice to Ecology, this Order and Intalco's obligations hereunder will become null and void."

With the curtailment and subsequent voiding of the wet scrubber AO Ecology cannot count potential emissions reductions from that control.

The Intalco facility is planning to perform all requirement of their permits and could restart at any time. Intalco would need time to expand their work force from the current curtailment level and additional physical activities would need to occur prior to returning to production.

The FFA of Intalco during curtailment is more complicated than on an operating facility. Annual emissions are very low while in curtailment and not typical of emissions during operation. Emissions should be comparable to the Wenatchee Work primary aluminum facility that is already in curtailment. The Wenatchee Works facility had annual emissions in 2016-2018 that were less than 10 tpy total for all pollutants. The Intalco facility in curtailment is also not generating revenue because the facility is not selling any aluminum.

Four-factor analysis

The primary haze-causing pollutant from the facility when it is operating is SO_2. A wet scrubber and associated liquid handling structures is often used for SO_2emission control. The following FFA details how installation of a wet scrubber system is not reasonable when the facility is in curtailment.

Cost of compliance

The cost of compliance will always be unreasonable for a facility in curtailment since the analysis is based on cost/ton of actual emissions. If Intalco curtailed emissions are similar to the Wenatchee Works facility's reported 10 tons of total annual emissions in the 2016 EI, then Intalco will also have around 10 tons of annual emissions. Assuming the facility could install control equipment for the entire 10 tons, the cost per ton of emissions reduced will exceed $10,000 per ton of pollutants removed with only a $100,000 expenditure. A cost of $10,000 per ton is not a reasonable cost for primary aluminum facilities at this time.

Facilities with large emissions of SO_2, in tons per year, typically use wet scrubbers as emission control. Direct capital equipment costs for wet scrubbers are typically in the millions of dollars

range and installing a wet scrubber would require spending at least $100,000 per ton of SO_2 removed based on current emissions, which is not reasonable.

Because the facility has the potential to restart at any time, emissions could potentially return to 2014 EI (2014EI) levels. In this situation, an analysis of the facility could potentially result in reasonable emission control costs. Calculations of the cost of compliance would depend on numerous variables from the number of pot lines brought back on line, amount of aluminum produced, regaining experienced operators for efficient operations, and other operational determinations.

Numerous variables associated with a restart of the facility need to be determined before performing a cost analysis. At the time of facility restart, we would need to do an analysis to determine the reasonableness of the cost of compliance.

Time necessary for compliance

With the facility in curtailment and no emission control equipment deemed reasonable, the facility is already complying with reasonable emission control. If the facility comes out of curtailment, we would need a new FFA to determine time for compliance if we identify control equipment.

Energy and non-air environmental impacts

With the facility in curtailment and no emission control equipment deemed reasonable, the facility would not have any new non-air environmental impacts. If the facility comes out of curtailment, we would need a new FFA to determine non-air environmental impacts if we identify control equipment.

Remaining useful life

The facility is currently in curtailment and not operating. The facility is performing maintenance on equipment to keep the facility in position to restart in the future. Because of the uncertainties, we cannot determine the remaining useful life of the facility at this time.

Summary and preliminary recommendations

Intalco is currently in curtailment and installation of additional emission control devices is not reasonable at this time. With the potential of the facility to restart at any time, Ecology entered into an Agreed Order (AO) with the facility that requires the facility perform a FFA before restarting and provide the analysis to Ecology.

The AO conditions stipulate that Intalco shall:

1. Prepare and submit a four-factor analysis to Ecology for review and approval at least 180 days prior to restarting any of the facility's potlines. Intalco will base the analysis on the facility's permitted emission limits and will assess potential emission control measures against the following four statutory factors:
    - The cost of compliance,
    - Time necessary for compliance,
    - Energy and non-air quality impacts of compliance, and

- Remaining useful life of the source.

2. Within 60 days of receipt of Ecology's comments on the four-factor analysis provide all additional information and/or documentation requested by Ecology, if any, and submit an updated four-factor analysis that adequately addresses Ecology's comments.
3. Install or otherwise implement and begin operating all emission control measures identified in the final four-factor analysis submitted within three years of Ecology's approval.

7.5 Chemical pulp & paper mill four-factor analysis

The pulp & paper facilities include six sulfate (Kraft) and one sulfite chemical processing facilities. Cosmo Specialty Fiber is currently the only sulfite mill in Washington. The modeled 2028 reasonable progress goals did not include any emission reductions from any of the pulp & paper mills. Ecology has limited resources and is choosing to prioritize the sequence of implementation of reasonable controls. Ecology has identified potential cost-effective controls at a multitude of sources and is choosing to require reasonable controls at only a subset of those sources.

As discussed in EPA's guidance:

> "Another potentially reasonable approach might be for a state that identifies cost-effective new controls at a multitude of sources to choose to require controls at only a subset of those sources that constitute the vast majority of the visibility benefit. In this case, the state could rely on visibility benefits to prioritize which sources would receive new controls." [15]

Ecology is prioritizing implementation of potential new controls starting with refinery facilities because:

- The pulp & paper mills are not located as close to each other as the refineries so they do not have as great of a cumulative effect.
- One mill identified with potential reasonable cost controls, Packaging Corporation of America (PCA) Wallula, is located in a direction that is downwind from the nearest Class 1 Areas. This lessens, but does not remove, the influence the mill's emissions have on Class 1 Areas.
- A potential reduction of 470 tons per year in regional haze emissions from the pulp & paper mills reasonable controls is vastly less than potential refinery emission reductions.

After we complete the reasonability analysis and determination for the refinery facilities, we plan to identify and implement any reasonable controls at pulp and paper facilities. Ecology will update the SIP if new emission controls are installed at pulp and paper facilities during this

[15] Peter Tsirigotis, Director, "Clarifications Regarding Regional Haze Second Implementation Plans for the Second Implementation Period," memo, addressed to Regional Air Division Directors, Regions 1-10, July 8, 2021, Section 5.1, at page 12-13.

implementation period. In the interim, Ecology has determined that no additional controls are necessary for RP at this time or included in the LTS.

Four-factor request and initial review

On September 10, 2019, Ecology requested an FFA from the seven chemical pulp mills in Washington State. Ecology received a combined FFA report from the six Kraft mills and a separate FFA from the sulfite mill (Cosmo) on December 5, 2019. After review, on January 13 2020, Ecology requested that six of the seven mills provide additional information to Ecology by February 28, 2020 [APPENDIX I].

Ecology did not request additional information from GP Camas because they are no longer a Kraft mill and facility emissions were reduced below the Q/d screening threshold. The 2019 Emission Inventory indicates regional haze causing emissions for the GP Camas facility reduced from 653 tons to 83.1 tons. The reduced emission mass changes the Q/d value from 23.1 to 1.8. With the new Q/d value being less than the threshold value of 10 for consideration, Ecology removed the facility from further analysis. If GP Camas pursues operation as a chemical pulp mill in the future, they will need to go through new source review.

On February 20, 2020, Cosmo requested a time extension for submitting additional information due to impacts of the coronavirus in China, where delivery of their product was delayed. Ecology agreed to a time extension to April 30, 2020.

Ecology received follow-up information from each of the mills in a timely manner. The FFAs and follow-up information from the pulp mills are in Appendix O. The FFA supplied from the mills all indicate that additional emission controls are unreasonable. Ecology evaluated and adjusted this information for NOx, SO_2, and PM control. Appendix J is a summary of Ecology's revised costs/ton for controls for NOx, SO_2, and PM, costs/ton, and estimated useful life at a 3.25 percent interest rate for the facilities.

Potentially reasonable controls at current chemical pulp mills

Ecology identified some potential reasonable controls at three Kraft mills and a sulfite mill. The Kraft mills are Nippon Dynawave Packaging Company Longview (Nippon), Packaging Corporation of America (PCA) Wallula, and WestRock PC, LLC Tacoma. The sulfite mill is Cosmo Specialty Fibers, Inc. (Cosmo) mill. Because Ecology has identified potential cost-effective controls at a multitude of sources, we are choosing to require any potential reasonable controls at only a subset of those sources. Ecology has chosen to perform a more extensive and in-depth engineering evaluation at refinery facilities first. This decision is based on the refineries having a greater potential amount of reductions to regional haze causing emissions than pulp & paper mills. The refineries are also geographically located such that they influence the same Class 1 Areas concurrently. The pulp & paper mills are more dispersed and have less of a combined influence on the Class 1 Areas.

For NOx control using a low-NOx burner, the following units have estimated cost/ton value less than the potential reasonableness threshold of $6,300/ton. Adding these controls could potentially reduce NO_X emissions by approximately 150 tpy.

- Nippon Boiler #9 ($2,754/ton) with approximately 97 tons potential reduction

- PCA boiler #1 ($5,893/ton); with approximately 26 tons potential reduction
- PCA boiler #2 ($4,834/ton) with approximately 30 tons potential reduction

For NOx control using an SCR or SNCR, the following units have a cost/ton value less than the potential reasonableness threshold of $6,250/ton. Adding one of these controls could potentially reduce NOx emissions by approximately 500 tpy to 1025 tpy.

- Nippon hog fuel (HF) boiler #11 ($5,413 for SNCR); ($5,466/ton for SCR); with approximately 329 tons or 848 tons potential reduction respectively.
- Nippon Boiler #9 ($6,041 for SCR) with approximately 175 tons potential reduction.
    - This unit was discussed above in the low-NOx burner section. Please note that only one of these options would be used.

For PM_{10} control, the following units have a cost/ton value less than the potential reasonableness threshold of $7,800/ton. Adding these controls could potentially reduce PM_{10}emissions by approximately 30 to 225 tpy depending whether Cosmo is included (see footnotes for Cosmo).

- WestRock Tacoma Lime Kiln #1 ($6,964/ton) with approximately 33 tons potential reduction.

For SO_2 control, Ecology did not receive recent cost incurred information from the pulp mills (the scrubber at WestRock Tacoma was for HCl control). The SO_2 control cost estimates that the pulp mills submitted to Ecology are greater than the potential cost threshold range of the other RH pollutant costs of $6,250 - $7,800.

Additional considerations

Ecology considered the following information as part of the reasonability analysis:

- GP Camas is no longer operating as a chemical pulp mill and the emissions will change. The facility would have to apply as a new source if it ever wanted to become a chemical pulp mill in the future. This would result in evaluation of emission controls requirements at that time.
- The Cosmo mill was in curtailment from May 10, 2020 until January 27, 2021. This shows the mills sensitivity to market conditions and impacts what the reasonable cost threshold for new emission equipment is.
- Currently, no one has practically demonstrated using SCRs for recovery furnaces (boilers), but they could potentially progress to a level of technical feasibility during a future implementation period. Since this is not shown to be technically feasible at this time, those controls will not be considered for analysis during this implementation period.

Conclusion

The pulp & paper mills identified no reasonable controls in their FFAs. Ecology will need to perform a more extensive and in-depth engineering evaluation on potential control to generate more accurate and defensible cost estimates. Ecology has limited resources and is choosing to prioritize the sequence of implementation of reasonable controls. Ecology has identified

potential cost-effective controls at a multitude of sources and is choosing to require reasonable controls at only a subset of those sources at this time.

Pulp & paper mill sources are not the first priority for new control implementation. This decision is based on:

- The pulp & paper mills are not located as close to each other as the refineries so they do not have as great of a cumulative effect.
- One mill identified with potential reasonable cost controls, Packaging Corporation of America (PCA) Wallula, is located in a direction that is generally downwind from the nearest Class 1 Areas. This lessens, but does not remove, the influence the mill's emissions have on Class 1 Areas.
- The potential reduction of 450 tons per year in regional haze emissions from the pulp & paper mills reasonable controls is vastly less than potential refinery emission reductions (approximately 4,000 tons).

After we complete the reasonability analysis and determination for the refinery facilities, we plan to conduct a reasonability analysis at pulp and paper facilities. This will be included in a SIP revision or the next implementation period, depending on the timing.

7.6 Refineries

Five petroleum refineries are located in the state of Washington. The refineries are Cherry Point refinery (BP Cherry Point), Shell Anacortes refinery (Shell), Marathon Anacortes refinery (Tesoro), Ferndale refinery (Phillips 66), and U.S. Oil refinery (U.S. Oil).

Refineries have extended timeframes for design, acquisition, and installation of equipment. Work at refineries must be scheduled during narrow time windows to coincide with other work during facility shutdowns. Performing work outside of these periods significantly increases cost if the facilities would shut down solely for the equipment installation. The next facility shutdowns may occur outside of this implementation period so no emission reductions were included in the modeled 2028 visibility projections.

The refineries in Washington are over 40 years old and the facilities have maintained the majority of the equipment in a manner that has not required updating emission controls to current standards. EPA national enforcement actions and the installation of new equipment have led to the updating of some equipment. All the refineries have made changes to accommodate the new fuel standards, lower sulfur requirements, and benzene content.

Table 7-5. General refinery information.

Refinery	Process Capacity (barrels/day)	Footprint (acres)	Year Built
BP	234,000	3,300	1971
Phillips 66	107,500	900	1954
Shell	149,000	800	1958
MPC	125,000	900	1955
US Oil	42,000	136	1957

Each refinery has the same NAICS code, but are uniquely configured with different considerations for each. The major difference is in how they handle the heavy crude bottom fraction:

- BP Cherry Point uses hydrocracker and coker units.
- Phillips 66 uses a Fluidized Catalytic Cracking Unit (FCCU).
- Shell uses a FCCU and coker.
- Tesoro uses a FCCU.
- U.S. Oil produces asphalt or exports it to other refineries for further processing.

All the refineries have flexibility to send intermediate products to other refineries for final processing.

Table 7-6 shows how Washington refineries compare nationally based on NOx emissions per barrel of production capacity. The data is from the 2014 EPA emission data (2014 NEI Data, 2014) of 88 refineries located in nine states: AK, CA CO, IL, LA, MT, TX, WA, and WY. Table 7-6 only shows a subset of the 88 refineries and all Washington refineries are shown. The table is sorted from highest to lowest NOx emissions divided by production capacity. Washington refineries represent four of the top five facilities in the nine states in NOx emissions per 1,000 barrels produced per day. Three Washington refineries emit more oxides of nitrogen per barrel of production capacity than per year of any other refinery in the U.S.

Table 7-6: Washington refineries annual emissions and production capacity

State	Company	NOX tpy 2014	Ranking NOx tpy	1,000 BPD	NOx tpy/1,000 BPD
WA	Tesoro Northwest Company	1,918	3	119	16.12
WA	Shell Puget Sound Refinery	1,230	16	145	8.48
WA	BP Cherry Point Refinery	1,882	4	242	7.78
LA	Equilon Enterprises LLC - Shell Oil Products US Norco Refinery	1,626	11	225	7.23
WA	Phillips 66 Ferndale Refinery	723	31	105	6.89
IL	Exxon Mobil Oil Corp	1,386	13	238	5.83
LA	Phillips 66 Co - Alliance Refinery	1,432	12	253	5.66
IL	ConocoPhillips Co	1,863	6	334	5.58
LA	Citgo Petroleum Corp - Lake Charles Manufacturing Complex	2,197	1	418	5.25
TX	Beaumont Refinery	1,868	5	365	5.12
LA	ExxonMobil Refinery & Supply Co - Baton Rouge Refinery	1,944	2	540	3.60
TX	Deer Park Plant	1,702	9	500	3.40
TX	Baytown Refinery	1,828	8	560	3.26
WA	US Oil & Refining Co	133	68	41	3.24
TX	Port Arthur Refinery	1,858	7	603	3.08
TX	Galveston Bay Refinery	1,692	10	571	2.96
LA	Marathon Petroleum Co LP - LA Refining Division - Garyville Refinery	1,379	14	564	2.45

Refinery planning process

Ecology offered to enter into a cooperative AO with each refinery to achieve enforceable NOx emission reductions. We proposed to calculate the total amount of NOx reductions each refinery would achieve if they implemented Subpart Ja of the New Source Performance Standards (40 CFR 60 Subpart Ja). The Ja NOx total emission values would be used to calculate NOx emissions reductions that would need to occur over the remaining implementation periods prior to 2064. The refinery could meet the calculated NOx emission reductions through any NOx reduction work and not specifically tied to Ja requirements.

Ecology met with the refineries and the Western States Petroleum Association (WSPA) on September 17, 2019, to discuss this approach. At that meeting, Ecology also discussed not using the Subpart Ja option but doing a reasonability analysis at each facility. This would require a RACT determination for each facility based on their unique configurations. Ultimately, the refineries selected the reasonability analysis option over the AO approach.

On November 27, 2019, Ecology requested that the refineries perform a FFA review of equipment at the refineries. Ecology limited the scope of the FFA to equipment with large emissions of NOx. Ecology limited the scope to facilitate timely returns of the FFA to fit the timeline for RH SIP submittal. We requested the FFA for NOx emission reductions on specific pieces of equipment.

The refineries requested time extensions to the FFA request date and Ecology extended the final deadline to May 1, 2020. All of the refineries delivered their FFA's to Ecology prior to May 1, 2020.

Two refineries did not submit information on FCCU controls following criteria in Ecology's FFA request. Ecology agrees that the facilities did not need to submit a FFA on the units. Ecology subsequently decided to evaluate NOx controls using the EPA Control Cost Manual on the FCCUs since they are a large source of NOx emissions.

The refineries' FFAs indicated selective catalytic reduction (SCR) controls were not a cost-effective emissions control for any units analyzed. The refineries also indicated that low-NOx burners were either not a cost-effective emissions control or that more extensive and in-depth engineering evaluation would be required to establish costs on a unit-by-unit basis.

Ecology did a preliminary analysis using the EPA Control Cost Manual for SCR systems and worksheet model. Preliminary results indicate that SCR controls are cost-effective for the FCC units and various heaters and boilers. Ecology will perform a more extensive and in-depth engineering evaluation on each refinery to generate more accurate and defensible cost estimates. Ecology will perform a detailed reasonability analysis to determine what controls are reasonable.

During formal consultation with the Federal Land Managers, Ecology received a request to include analysis of the calciner units at the Cherry Point Refinery. Ecology will perform a detailed reasonability analysis to determine what controls are reasonable in regards to SO_2 emissions.

All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

Cherry Point Refinery (BP)

BP operations

BP has a total crude oil capacity of 250,000 barrels per calendar day. The refinery processes Canadian crude, domestic crude from North Dakota and Alaska North Slope and international crudes to manufacture gasoline, distillates, heavy fuel oil and propane. The refinery distributes products through pipeline-connected terminals, marine terminal via ships and barges. BP is the only refinery in the Pacific Northwest capable of manufacturing diesel made from biomass-based feed stocks. The refinery processes bio-mass feed stocks alongside conventional feed stocks in an existing ultra-low-sulfur diesel unit. Over the past decade, BP invested more than $1.5 billion in capital improvements at the refinery (BP, 2021).

PSD permit

Ecology issued a PSD permit to BP Cherry Point (BP) on May 23, 2017. During the PSD permit's public comment period, the National Park Service submitted comments regarding impacts to the Olympic National Park (NP).

Below is a summary of the Federal Land Manager's comments that directly pertain to RH and visibility:

- According to modeling performed by the NPS, the NPS believes that "emissions from the refinery are currently causing visibility impairment at Olympic NP and North Cascades NP and significantly contributing to excess nitrogen deposition at both parks." In addition, the NPS also believes that the Coker Replacement project itself "will significantly increase the impacts of visibility-impairing pollutants at Olympic NP and significantly increase nitrogen deposition at North Cascades NP."
- On October 14, 2016, the NPS provided helpful clarifications of their concerns in a document submitted to Ecology. The letter from NPS documented no dispute that the facility followed PSD regulations, or that the BP application was complete, but rather emphasized the different approaches used to address PSD regulatory applicability from approaches used to address project impacts on the Class 1 Areas Air Quality Related Values (AQRV).
- On December 25, 2016, the NPS sent a letter to Ecology stating that emissions from the Cherry Point refinery were adversely impacting air quality related values at North Cascades and Olympic National Parks.

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BP submitted a FFA to Ecology in April 2020 and determined that it was not reasonable to install new emissions control equipment. Ecology used the EPA Control Cost Manual with a retrofit factor of one to generate baseline costs for installation of SCR controls. These costs indicate that it might be reasonable to install new SCR controls. The refineries and the Western

States Petroleum Association (WSPA) contend that Ecology did not use the EPA Control Cost Manual for SCR systems appropriately.

Ecology's preliminary analysis using the EPA Control Cost Manual for SCR systems and worksheet model indicates that SCR controls are cost-effective for the FCC units and various heaters and boilers. Ecology will perform a more extensive and in-depth engineering evaluation on each refinery to generate more accurate and defensible cost estimates. Ecology will perform a detailed reasonability analysis to determine what controls are reasonable.

All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

The following is Ecology's review of the FFA supplied by BP Cherry Point on selected equipment compared to the Cost Reports and Guidance for Air Pollution Regulations- Section 4 - NOx Controls spreadsheet[16]:

Table 7-7: BP Cherry Point equipment identified for RACT analysis

Company	Equipment	EPA Control Cost Manual $/Ton	Refinery $/Ton	TPY Reduced	Comment
BP	#1 Reformer heaters	3,101	24,378	304	
BP	Crude heater	2,051	24,378	393	
BP	Reforming furnace #1 (N H2 Plant)	6,161	78,065	262	Combined North & South stacks
BP	Reforming furnace #2 (S H2 Plant)				

Ecology reviewed the following equipment using the EPA Control Cost Manual:

Reformer Heaters

BP supplied a table with limited supporting data.

[16] Cost Reports and Guidance for Air Pollution Regulations- Section 4 - NOx Controls spreadsheet: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

Table 7-8 shows the costs for the retrofit that BP supplied compared to the costs from the EPA Control Cost Manual (EPA, 2021). Ecology determined that a more detailed RACT analysis is justified to refine costs.

Table 7-8: Reformer heaters cost comparison

Costs	BP FFA costs	Ecology – EPA Control Cost Manual
Capital cost $	94,809,582	9,929,730
Maintenance $/yr	420,048	49,649
Reagent $/yr	284,001	57,895
Catalyst $/yr	180,467	33,548
Annualized cost $/yr	7,827,719	943,315
NOX tpy reduced	321	304
$/ton NOX reduced	24,378	3,101

Ecology used the EPA Control Cost Manual cost with 90 percent control efficiency. BP did not supply the data they used to scale their costs.

Crude Heater

BP supplied a table with limited supporting data. Table 7-9 shows the costs for the retrofit that BP supplied compared to the costs from the EPA Control Cost Manual (EPA, 2021). Ecology determined that a more detailed RACT analysis is justified to refine costs.

Table 7-9: Crude heater cost comparison

Costs	BP FFA costs	Ecology – EPA Control Cost Manual
Capital cost $	94,809,582	9,325,358
Maintenance $/yr	420,048	46,627
Reagent $/yr	284,001	51,515
Catalyst $/yr	180,467	29,852
Annualized cost $/yr	7,827,719	871,136
NOX tpy reduced	321	425
$/ton NOX reduced	24,378	2,051

The EPA Control Cost Manual (EPA, 2021) uses current cost with 90 percent controls. BP did not supply the cost data they used to scale their cost data.

Two Reforming Furnace #1 (H2 PLANT)

BP supplied a table with limited supporting data. Table 7-10 shows the costs for the retrofit that BP supplied compared to the costs from the EPA Control Cost Manual (EPA, 2021). Ecology determined that a more detailed RACT analysis is justified to refine costs.

Table 7-10: Two reforming furnace #1 (H2 Plant) cost comparison

Costs	BP FFA costs	Ecology – EPA Control Cost Manual
Capital cost $	143,325,183	9,325,358
Maintenance $/yr	479,126	46,627
Reagent $/yr	125,031	51,515
Catalyst $/yr	65,513	29,852
Annualized cost $/yr	11,038,382	871,136
NOx tpy reduced	141	141
$/ton NOx reduced	78,065	6,161

The EPA Control Cost Manual uses current cost with 90 percent controls. BP did not supply the data they used to scale their cost data.

Summary

Ecology's preliminary review of the industry supplied FFA data was inconclusive for determining reasonable controls. Therefore, Ecology is performing a detailed cost-analysis to ensure the most effective reasonable controls are identified. All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

Ecology's baseline and initial four-factor review using the EPA Control Cost Manual and a retrofit factor of one determined the following:

- Factor #1 – The costs of compliance
  - $2,100/ton to $6,200/ton
- Factor #2 – The time necessary for compliance.
  - Accommodation for the time necessary for design, and installation of the equipment during a planned shutdown is required to ensure reasonable costs.
- Factor #3 – The energy and non-air quality environmental impacts of compliance
  - The power needed to drive the exhaust fans is included in the analysis.
- Factor #4 – The remaining useful life on existing source subject to such requirement

BP Cherry Point did not indicate that any of the equipment had a limited lifetime.

Conclusion

Ecology will do a reasonability analysis to develop detailed cost-analysis to ensure the most effective reasonable controls are identified. Emission control equipment that is determined to be reasonable will then be required for installation at the facility. The RHR SIP will be amended to reflect any new control requirements. To allow for scheduling flexibility needed to maintain cost-effectiveness, installation of controls will likely occur in the next implementation period.

Phillips 66

Operations

The Phillips 66 refinery has an average annual processing rate of approximately 108,000 barrels of crude oil per day. Located outside of Ferndale in Whatcom County, this petroleum refinery uses crude oil as a feedstock that is processed into a variety of petroleum products including gasoline, diesel, fuel oil, liquefied petroleum gas (LPG), and butane. The refinery receives crude oil via marine vessels, railcars, and by pipeline (Phillips 66 Refinery, 2021).[17]

Regional Haze, Four Factor Analysis 2020

Phillips 66 submitted a FFA to Ecology in April 2020 and determined that it was not reasonable to install new emissions control equipment. Ecology used the EPA Control Cost Manual with a retrofit factor of one to generate baseline costs for installation of a SCR controls. These costs indicate that it might be reasonable to install new SCR controls. The refineries and the Western States Petroleum Association (WSPA) contend Ecology's application of the EPA Control Cost Manual for SCR systems at refineries is not appropriate.

Ecology's preliminary analysis using the EPA Control Cost Manual for SCR systems and worksheet model indicates that SCR controls are cost-effective for the FCC units and various heaters and boilers. Ecology will perform a more extensive and in-depth engineering evaluation on each refinery to generate more accurate and defensible cost estimates. Ecology will perform a detailed reasonability analysis to determine what controls are reasonable.

All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

As part of our analysis, Ecology compared cost data provided by Phillips 66 with corresponding costs from the EPA Control Cost Manual's SCR tools with the results shown in Table 7-11 below.

Table 7-11: Phillips 66 Equipment identified for RACT

Company	Equipment	EPA Control Cost Manual $/Ton	Refinery $/Ton	TPY Reduced	Comment
Phillips 66	Crude heater 1F-1	2,640	12,225	166	
Phillips 66	FCCU/CO Boiler/Wet Gas Scrubber 4F-100, 4F-101	3,954		247	NSCR is installed.

Ecology reviewed the following equipment using the EPA SCR Cost Model:

[17] https://www.phillips66.com/refining/ferndale-refinery

Crude heater 1F-1

Phillips 66 supplied a table with limited supporting data. Table 7-12 shows the costs for the retrofit that Phillips 66 supplied compared to the costs from the EPA Control Cost Manual. Ecology determined that a more detailed reasonableness is justified to refine costs.

Table 7-12: Crude heater 1F-1 cost comparison

Costs	Facility FFA costs	Ecology – EPA Control Cost Manual
Capital cost $	16,615,487	5,084,927
Maintenance $/yr	83,077	25,425
Reagent $/yr	17,691	20,677
Catalyst $/yr	18,680	11,982
Annualized cost $/yr	1,944,651	437,150
NOX tpy reduced	159	166
$/ton NOX reduced	12,225	2,640

Ecology used the EPA Control Cost Manual cost with 90 percent controls. Phillip 66 did not supply the data they used to scale their cost data.

FCCU/CO Boiler

In 2006, Phillips 66 modified the FCCU to include ESNCR for NOx controls and so was not required to submit a FFA for this unit. As FCC units are a large source of NOx emission at refineries that have them, Ecology decided to use the EPA Control Cost Manual anyway to review reasonableness of installing SCR systems on the FCCUs.

Table 7-13: FCCU/CO boiler cost

Costs	Ecology – EPA Control Cost Manual
Capital cost $	8,983,013
Maintenance $/yr	44,915
Reagent $/yr	49,624
Catalyst $/yr	27,183
Annualized cost $/yr	976,820
NOX tpy reduced	247
$/ton NOX reduced	3,954

Ecology used the EPA Control Cost Manual cost with 90 percent controls.

Summary

Ecology's preliminary review of the industry supplied FFA data was inconclusive for determining reasonable controls. Therefore, Ecology is performing a detailed cost-analysis to ensure the most effective reasonable controls are identified. All controls identified as reasonable in the reasonability analysis have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

Ecology's baseline and initial four-factor review using the EPA Cost Control Manual and a retrofit factor of one determined the following:

- Factor #1 – The costs of compliance
  - $2,600/ton to $4,000/ton
- Factor #2 – The time necessary for compliance
  - Accommodation for the time necessary for design, and install the equipment during a planned shutdown is required to result in reasonable costs.
- Factor #3 – The energy and non-air quality environmental impacts of compliance
  - The power needed to drive the exhaust fans is included in the analysis.
- Factor #4 – The remaining useful life on existing source subject to such requirements.
  - Phillips 66 did not indicate that any of the equipment had a limited lifetime.

Conclusion

Ecology will do a reasonability analysis to develop detailed cost-analysis to ensure the most effective reasonable controls are identified. Emission control equipment that is determined to be reasonable will then be required for installation at the facility. The RHR SIP will be amended to reflect any new control requirements. To allow for scheduling flexibility needed to maintain cost-effectiveness, installation of controls will likely occur in the next implementation period.

Shell

Operations

The Shell refinery has an average annual processing rate of approximately 145,000 barrels (5.7 million gallons) of crude oil per day. When the refinery first began operating, most of its crude oil came from Canada via pipeline. Although it continues to receive crude from central and western Canada, feedstock also arrives by tanker from oilfields on Alaska's North Slope.

On an annual basis, the refinery produces multiple types of gasoline in addition to fuel oil, diesel fuel, propane, jet fuel, butane, and petroleum coke. It also produces two chemicals---nonene and tetramer---that industry uses in a variety of plastic products. Shell also owns and operates a cogeneration facility on the refinery site.[18]

The cogeneration facility was originally the March Point Cogeneration Company (MPCC), which Puget Sound Refinery (PSR) took possession of in February 2010. Air Liquide and Linde operate

[18] https://www.shell.us/about-us/projects-and-locations/puget-sound-refinery/about-shell-puget-sound-refinery.html

hydrogen plants on property owned by PSR and adjacent to the refinery. However, both Air Liquide and Linde are independent companies and permitted separately from Shell. This report does not address emission sources from Air Liquide and Linde in this report.

Regional Haze, Four-Factor Analysis 2020

Shell submitted a FFA to Ecology in April 2020 and determined that it was not reasonable to install new emissions control equipment. Ecology used the EPA Control Cost Manual with a retrofit factor at one to generate baseline costs for installation of a SCR controls. These costs indicate that it might be reasonable to install new SCR controls. The refineries and the Western States Petroleum Association (WSPA) contend the use of the EPA Control Cost Manual for SCR systems at refineries is not appropriate in how Ecology applied it.

Ecology's preliminary analysis using the EPA Control Cost Manual for SCR systems and worksheet model indicates that SCR controls are cost-effective for the FCC units and various heaters and boilers. Ecology will perform a more extensive and in-depth engineering evaluation on each refinery to generate more accurate and defensible cost estimates. Ecology will perform a detailed reasonability analysis to determine what controls are reasonable.

All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

Table 7-14: Shell equipment identified for RACT rule development

Company	Equipment	EPA Model $/Ton	Refinery $/Ton	TPY Reduced	Comment
Shell	Boiler #1 Erie City--31G-F1	2,441	12,511	179	8-yr life
Shell	Cogen turbine 1 MW	---	---	---	Current SCR controls – Study
Shell	Cogen turbine 2 MW	---	---	---	Current SCR controls – Study
Shell	Cogen turbine 3 MW	---	---	---	Current SCR controls – Study
Shell	FCCU Regenerator Unit	1,948	---	521	
Shell	CRU #2 HTR, INTERHTR--10H-101,102,103	6,346	10,813	69	

Ecology reviewed the following equipment using the EPA Control Cost Manual:

BOILER #1 ERIE CITY--31G-F1

Shell's FFA supplied a table with limited supporting data. Table 7-15 shows the costs for the retrofit that Shell supplied compared to the costs from the EPA Control Cost Manual. Ecology determined that a more detailed reasonableness analysis is justified to provide more credible and defensible costs.

Table 7-15: Boiler #1 Erie City--31G-F1 cost comparison

Costs	Shell	Ecology – EPA Control Cost Manual
Capital cost $	11,420,745	5,084,927
Maintenance $/yr	57,104	25,425
Reagent $/yr	17,221	20,677
Catalyst $/yr	39,340	11,982
Annualized cost $/yr	2,053,888	437,150
NOX tpy reduced	164	179
$/ton NOX reduced	12,511.00	2,441

Ecology used the EPA Control Cost Manual cost with 90 percent controls. Shell did not supply the cost data they used to scale their cost data and had only an eight-year life for the boiler. The limited eight-year lifetime of the boiler caused the cost/ton value to be significantly higher than a 25-year lifetime. With an eight-year lifetime, a requirement for the boiler to be retired after this period would be justified and the boiler should be required to decommission. Any new boiler brought in to replace it would need to go through the permitting process as a new source.

FCCU/CO Boiler

It was Shell's understanding that the addition of particulate matter and SO_2 controls on the FCCU in 2014 meant that they were not required to submit a NOx FFA. Current emissions limit on the FCCU is 1,380 tpy and 142.2 ppm NOx on a yearly average. As FCC units are a large source of NOx emission at refineries that have them, Ecology decided to use the EPA Control Cost Manual anyway to review reasonableness of installing SCR systems on the FCCUs.

Table 7-16: FCCU/CO boiler cost

Costs	Ecology – EPA Control Cost Manual
Capital cost $	10,680,913
Maintenance $/yr	53,405
Reagent $/yr	62,274
Catalyst $/yr	36,086
Annualized cost $/yr	1,014,677
NOX tpy reduced	521
$/ton NOX reduced	1,948

Ecology used the EPA Control Cost Manual cost with 90 percent controls.

CRU #2

Shell supplied a table with limited supporting data. Table 7-17 shows the costs for the retrofit that Shell supplied compared to the costs from the EPA Control Cost Manual. Ecology determined that a more detailed reasonableness analysis is justified to provide more credible and defensible costs.

Table 7-17: CRU #2 cost comparison

Costs	Facility FFA costs	Ecology – EPA Control Cost Manual
Capital cost $	5,939,772	5,084,927
Maintenance $/yr	29,699	25,425
Reagent $/yr	6,165	20,677
Catalyst $/yr	13,454	11,982
Annualized cost $/yr	635,480	437,150
NOX tpy reduced	59	77
$/ton NOX reduced	10,813	6,346

Ecology used the EPA Control Cost Manual cost with 90 percent controls. Shell's cost was similar but they used a lower emission reduction.

Three turbines have SCR installed on the units. The current emission limit is 74 tpy at 9 ppm NO_X. Actual emissions vary from 46-64 tpy (5.6-7.8 ppm) with less than 2 tpy (less than 0.5 ppm) ammonia. As part of the reasonableness analysis an engineering optimization study to minimize NOx emissions is needed to see if emissions can match similar new units permitted below 2 ppm NOx.

Summary

Ecology's preliminary review of the industry supplied FFA data was inconclusive for determining reasonable controls. Therefore, Ecology is performing a detailed cost-analysis to ensure the most effective reasonable controls are identified. All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

Ecology's four-factor review has determined the following:

- Factor #1 – The costs of compliance
  - $1,900/ton to $ 6,300/ton
- Factor #2 – The time necessary for compliance
  - Accommodation for the time necessary for design, and installation of the equipment during a planned shutdown is required to validate reasonable costs.
- Factor #3 – The energy and non-air quality environmental impacts of compliance
  - The power needed to drive the exhaust fans is included in the analysis.
- Factor #4 – The remaining useful life on existing source subject to such requirements
  - Shell indicates that the BOILER #1 ERIE CITY--31G-F1 had a limited lifetime of 8 years. Ecology will work with NWCAA to have a regulatory order on the boiler to shut the unit down by January of 2028.

Conclusion

Ecology will do a reasonability analysis to develop detailed cost-analysis to ensure the most effective reasonable controls are identified. Emission control equipment that is determined to be reasonable will then be required for installation at the facility. The RHR SIP will be amended to reflect any new control requirements. To allow for scheduling flexibility needed to maintain cost-effectiveness, installation of controls will likely occur in the next implementation period.

Marathon Petroleum Company

Process

Marathon Petroleum Company (MPC) is the current owner of the Anacortes refinery. Located in Anacortes, the refinery has a total crude oil capacity of 119,000 barrels per calendar day.

The refinery processes Canadian crude, domestic crude from North Dakota and Alaska North Slope, and international crudes to manufacture gasoline, distillates, heavy fuel oil, and propane.

The refinery distributes products through pipeline-connected terminals and MPC's marine terminal via ships and barges.[19]

Table 7-18: MPC emission rates pre - and post - best available retrofit technology (BART)

Pollutant	Pre-BART, tpy	Post-BART, tpy	Basis of comparison	Sources included in comparison
NOX	1360	1303	2005 vs. post-BART projects (F-103 ULNB)	BART sources only
SO2	5540	474	2005 vs. 2008 (FGS; RFG treatment*)	All refinery sources
PM/PM10	588	140	2005 vs. post BART projects (FGS); no oil burning at F-103)	BART sources plus F-302

* Refinery Fuel Gas (RFG) treatment improvements affected all combustion sources

2010 regional haze best available retrofit technology

During the first regional haze implementation period the MPC facility was operated by Tesoro. Tesoro had a BART determination and Federal Implementation Plan for Tesoro (MPC) found that four of the BART-eligible sources contribute approximately 93 percent of the NOx emissions from the 14 combustion sources: F-103, F-304, F-6650, and F-6651. Tesoro (MPC) identified that it was cost effective to add NOx controls on these four units. The cost was found unreasonable if the facility needed to have a special outage just for the NOx controls. These outages usually occur every five to six years.

PSD permit

On July 18, 2017, Ecology issued a PSD permit to Tesoro (MPC). During the public comment period, the Federal Land Managers made comments regarding the impacts to the Olympic Class 1 area. These comments are contained in the PSD technical support document, https://fortress.wa.gov/ecy/ezshare/AQ/PSD/PSD_PDFS/Tesoro_Anacortes_TSD.pdf

Federal Land Manager's comments 4-6, pages 45-51 indicated the major issues with the issued PSD permit were:

- Tesoro (MPC) should be reviewed in the next RH period
- Supported the installation of SCR on the new boiler and control of vapors from loading marine vessels

Regional Haze

Ecology's preliminary analysis using the EPA Control Cost Manual for SCR systems and worksheet model indicates that SCR controls are cost-effective for the FCC units and various heaters and boilers. Ecology will perform a more extensive and in-depth engineering evaluation on each refinery to generate more accurate and defensible cost estimates. Ecology will perform a detailed reasonability analysis to determine what controls are reasonable.

[19] https://www.marathonpetroleum.com/Operations/Refining/Anacortes-Refinery/

All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

The following is Ecology's review of the four-factor analysis supplied by MPC on selected equipment compared to BART and the EPA Control Cost Manual:

Table 7-19: Tesoro equipment identified for RACT rule development

Company	Equipment	EPA Model 2020 $/Ton	MPC 2020 $/Ton	BART 2008 $/Ton	TPY reduced
Tesoro	FCCU [20]	1,159	14,381	4,592	843.3
Tesoro	F 102 Crude Heater	2,962	16,086	---	147.6
Tesoro	F 201 Vacuum Flasher Heater	7,589	35,279	---	57.6
Tesoro	F 6650 CAT Reformer Heater	3,736	21,196	3,349	117
Tesoro	F 6651 CAT Reformer Heater	3,520	21,196	3,349	124.2
Tesoro	F 751 Main Boiler	2,159	10,060	---	202.5
Tesoro	F 752 Main Boiler	2,570	10,513	---	170.1

Ecology reviewed the following equipment using the EPA SCR Cost Model:

[20] FCCU is SNCR, others LNB.

FCCU

MPC supplied a table with limited supporting data. Table 7-20 shows the costs for the retrofit that MPC supplied compared to the costs from the EPA Control Cost Manual. Ecology determined that a more detailed reasonableness analysis is justified to provide more credible and defensible costs.

Table 7-20: FCCU cost comparison

Cost	MPC	Ecology EPA Control Cost Manual
Capital cost $	114,030,975	10,286,436
Maintenance $/yr	570,155	51,432
Reagent $/yr	1,340,590	59,974
Catalyst $/yr	116,845	34,754
Annualized cost $/yr	10,747,992	977,202
$/ton NOX reduced	14,381	1,159

Ecology used the EPA Control Cost Manual cost with 90 percent controls. MPC did not supply the cost data they used to scale their cost data. The MPC data is based on SNCR controls at about 60 percent controls, which account for the higher $/ton cost.

F 102 CRUDE HEATER

Both MPC and Ecology used the EPA Control Cost Manual with different results. To reconcile the difference a more detailed reasonableness analysis is justified to provide more credible and defensible costs:

Table 7-21: Crude heater cost comparison

Costs	MPC EPA Control Cost Manual	Ecology EPA Control Cost Manual
Ft3/min-MMBtu/hr	55,577	484
Ammonia $/gal	3.513	0.293
acfm	6,381,721	115,784
Vspace	19,760.72	112
Catalyst Ft2	6,648	121
Capital cost $	20,876,000	5,084,927
Maintenance $/yr	104,380	25,425
Reagent $/yr	315,021	20,677
Catalyst $/yr	3,548	11,982
Annualized cost $/yr	2,021,692	437,150
$/ton NOX reduced	16,086	2,962

MPC incorrectly changed the default value in the model for the ft^3/min-MMBtu/hr input. Ecology used the default value and determined the minimum cost of $439,065/yr.

Other equipment

We used the default cost of $437,150/yr for the other equipment. MPC incorrectly changed the default value for the Ft^3/min-MMBtu/hr input to the EPA Control Cost Manual for all their determinations other than the FCCU.

Summary

Ecology's preliminary review of the industry supplied FFA data was inconclusive for determining reasonable controls. Therefore, Ecology is performing a detailed cost-analysis to ensure the most effective reasonable controls are identified. All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

- Factor #1 – The costs of compliance
  - $1,200/ton to $7,600/ton
- Factor #2 – The time necessary for compliance
  - Accommodation for the time necessary for design, and installation of the equipment during a planned shutdown is required to validate reasonable costs.
- Factor #3 – The energy and non-air quality environmental impacts of compliance
  - The power needed to drive the exhaust fans is included in the analysis.
- Factor #4 – The remaining useful life on existing source subject to such requirements
  - MPC did not indicate that any of the equipment had a limited lifetime.

Conclusion

Ecology will do a reasonability analysis to develop detailed cost-analysis to ensure the most effective reasonable controls are identified. Emission control equipment that is determined to be reasonable will then be required for installation at the facility. The RHR SIP will be amended to reflect any new control requirements. To allow for scheduling flexibility needed to maintain cost-effectiveness, installation of controls may occur in the next implementation period.

US Oil

Operations

The US Oil Refinery has an average daily processing rate of approximately 41,000 barrels of crude oil per day. It uses crude oil as a feedstock processed into a variety of petroleum products including gasoline, diesel, fuel oil, and asphalt.[21]

Regional Haze, State Implementation Plan, Final December 2010

During the first implementation period, BART was not triggered for US Oil based on their emissions.

Regional Haze four-factor analysis 2020

US Oil submitted a FFA to Ecology in April 2020 and concluded that additional emission control devices were not reasonable. Ecology analyzed the data and concluded that US Oil based the analysis on the EPA Control Cost Manual and the results were similar to Ecology's analysis using the EPA Control Cost Manual. The emissions were only 28 tpy for the largest unit and the cost effectiveness was over $15,000/ton of NO_X reductions.

The following is Ecology's review of the four-factor analysis supplied by US Oil on selected equipment compared to the EPA Control Cost Manual:

[21] http://usor.com/about/about

HEATER H11

The facility supplied a table with the limited supporting data.

Table 7-22: Heater H11 cost comparison

Cost	Facility	Ecology EPA Control Cost Manual
Capital cost $	4,894,235	5,084,927
Maintenance $/yr	24,471	25,425
Reagent $/yr	2,979	20,677
Catalyst $/yr	9,862	11,982
Annualized cost $/yr	522,175	437,150
NOx tpy reduced	28	28
$/ton NOx reduced	18,649	15,612

Ecology and US Oil used the EPA Control Cost Manual with minor differences.

Summary and preliminary recommendations

Ecology's review indicates that additional controls are likely not cost reasonable, but recommends a more detailed and defensible cost reasonableness analysis to verify this initial review. Any reasonable emission control equipment from the analysis will result in a determination of equipment to install with federally enforceable conditions.

- Factor #1 – The costs of compliance
  - Over $15,000/ton for SCR controls
- Factor #2 – The time necessary for compliance
  - Accommodation for the time necessary for design, and installation of the equipment during a planned shutdown is required to validate reasonable costs.
- Factor #3 – The energy and non-air quality environmental impacts of compliance
  - The power needed to drive the exhaust fans is included in the analysis.
- Factor #4 – The remaining useful life on existing source subject to such requirements
  - US Oil did not indicate that any of the equipment had a limited lifetime

Conclusion

Ecology will do a reasonability analysis to develop more robust and defensible cost data. Emission control equipment that is determined to be reasonable will then be required for installation at the facility. The RHR SIP will be amended. Installation of any reasonable emission controls for implementation may occur in the next implementation period to be reasonable.

7.7 Summary

Ecology performed a four-factor analysis on sources selected using the EPA approved Q/d screening process. Ecology focused on major point sources that had a Q/d of 10 or greater. We selected sources emitting approximately 80 percent of all haze-causing emissions in the entire emission inventory for a four-factor analysis.

The selected sources included:

- a flat glass facility,
- five petroleum refineries,
- six pulp &paper facilities,
- a coal-fired power plant,
- a cement plant
- two aluminum smelters

Two facilities have enforceable emission reductions that were used in on-the-books emission projections. The power plant is ceasing coal-fired power production by the end of 2025 and the flat glass facility is changing their emission controls to a SCR system.

The aluminum facilities are currently in curtailment and their actual emissions are essentially zero. An Agreed Order with the two facilities was issued to have the facilities perform a FFA if

and when they restart. This will provide an accurate evaluation of the facilities' impacts on regional haze using actual restart operating conditions.

Ecology has preliminarily identified potential cost-effective controls at a multitude of sources and is choosing to require reasonable controls at only a subset of those sources.[22] Ecology is prioritizing the sequence of implementation of reasonable controls. The first priority is to identify reasonable controls at the refinery facilities. A number of factors supports the selection of refineries as the first priority:

- Four of the five refinery facilities are located in the Puget trough, west of several Class 1 Areas. Their cumulative regional haze causing emissions influence the same Class 1 Areas.
- Predominant winds direct the emissions from the refineries towards several Class 1 Areas.
- The refineries' potential emission reductions of 4,200 tons per year account for the vast amount of potential emission reductions.

Our second priority is to identify and implement reasonable controls at pulp and paper facilities after the refinery facilities. Pulp & paper mills are a subset of sources that are lower priority than refineries because:

- The pulp & paper mills are not located as close to each other as the refineries so they do not have as great of a cumulative effect.
- One mill identified with potential reasonable cost controls, Packaging Corporation of America (PCA) Wallula, is located in a direction that is downwind from the nearest Class 1 Areas. This lessens, but does not remove, the influence the mill's emissions have on Class 1 Areas.
- The potential reduction of 450 tons per year in regional haze emissions from the pulp & paper mills reasonable controls is vastly less than potential refinery emission reductions.

Ecology will supplement the SIP when new controls are determined to be reasonable and scheduled for implementation.

[22] Peter Tsirigotis, Director, "Clarifications Regarding Regional Haze Second Implementation Plans for the Second Implementation Period," memo, addressed to Regional Air Division Directors, Regions 1-10, July 8, 2021.

Chapter 8.Long-term Strategy for Visibility Improvement

8.1 Introduction

Section 169A(b)(2) of the federal Clean Air Act requires each state to submit a Regional Haze (RH) State Implementation Plan (SIP) revision approximately every 10 years. The SIP revision includes a long-term strategy (LTS) for making reasonable progress toward the national visibility goal, which is to remedy any existing visibility impairment in Class 1 Areas resulting from human-caused air pollution and to prevent future visibility impairment.

Washington's LTS for visibility improvement is a set of "enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress, as determined pursuant to [40 CFR 51.308](f)(2)(i) through (iv)" (40 CFR 51.308(f)(2)). Specifically:

(i) The State must evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment.

(ii) The State must consult with those States that have emissions that are reasonably anticipated to contribute to visibility impairment in the mandatory Class I Federal area to develop coordinated emission management strategies containing the emission reductions necessary to make reasonable progress.

(iii) The State must document the technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress in each mandatory Class I Federal area it affects.

(iv) The State must consider the following additional factors in developing its long-term strategy:

- (A) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
- (B) Measures to mitigate the impacts of construction activities;
- (C) Source retirement and replacement schedules;
- (D) Basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs; and
- (E) The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy.

Washington's LTS protects Class 1 Areas within and outside the state. It includes controls Ecology determined to be reasonable when we considered the four statutory factors, as well as federal, state, and local controls on haze-causing emissions.

Ecology relied on the Western Regional Air Partnership (WRAP) for air quality modeling and other analytical tools to identify pollutants, the sources of those pollutants, and to predict future levels of visibility impairment. WRAP fostered a regionally consistent approach to haze planning in the western states and provided a sound mechanism for consultation. Consultation among the 15 western states within WRAP has occurred through meetings of WRAP committees, workgroups, and forums with participation by conference calls, face-to-face meetings, and workshops (Appendix K).

The LTS covers a 10-year period from 2018 - 2028 and focuses both on existing regulatory mechanisms and those needed in the future to control and reduce visibility-impairing emissions. The administrative rules the EPA promulgated to implement the federal Clean Air Act's LTS requirements are in 40 CFR 51.308(f)(2)(i). In establishing its LTS for the 2018–2028 implementation period, Ecology evaluated the feasibility of implementing new controls at major and minor stationary sources, mobile sources, and non-point sources (40 CFR 51.308(f)(2)(i)). A detailed summary of that evaluation and the methods used for source selection are in Chapter 7.

Ecology designed the LTS to include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress, as determined pursuant to (f)(2)(i) through (iv). The reasonable progress goals (RPGs) reflect the emissions reductions achieved through implementation of the LTS in each of the state's Class 1 Areas during this implementation period (2018 - 2028). The reasonable progress goals (RPGs) serve as benchmarks for progress toward meeting the national visibility goal by 2064. The description of RPGs for Washington's Class 1 Areas are in Chapter 9 in detail. We measure the success of our LTS by evaluating the resulting RPGs to improvements in visibility on the most impaired days (MID). Chapter 3 has more information about the MID metric.

8.2 Washington's approach to long-term strategy

We identified three categories of pollutants that contribute significantly to the MIDs, which we need to reduce during this second implementation period. Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring data shows that sulfates (primarily), nitrates (secondarily), and organic mass are the dominant pollution species affecting visibility in the Class 1 Areas during the MIDs. We identified sources of these pollutants from within and outside Washington State. Chapter 7 describes the source selection and evaluation process that we used to identify potential pollution controls on selected point sources within Washington.

In order to calculate anticipated progress and set toward the RPGs, Ecology incorporated the results of federally mandated controls applicable to out-of-state sources of emissions that contribute to visibility impairment in Washington's Class 1 areas. However, Ecology's emissions control authority only applies to sources and pollutants within the state's regulatory jurisdiction. Emission sources that contribute to visibility impairment in Washington but are outside of Ecology's regulatory jurisdiction include wildfires, prescribed burns, marine vessels,

and both stationary and mobile sources that are located offshore, in other states, or in other countries.

We also identified federal, state and local rules, permits, and standards that limit haze-causing emissions that are already in place, or put in place during this implementation period. We rely in part on these existing emission controls to decrease emissions during and beyond this implementation period of 2018 - 2028.

Federal fuel and engine rules are of special importance to our progress towards RPGs because they have resulted in large reductions in mobile source air pollution during the last 30 years. Improvements in vehicle and engine design, and cleaner, higher-quality fuels have substantially reduced mobile source emissions and we expect the progress to continue, even with more miles driven and more power equipment used every year. We also expect on-going efforts to increase electrification of cars and trucks to reduce mobile source pollution in this second implementation period.

For example, President Biden signed an executive order in August of 2021 that establishes a goal for new cars and trucks sold in the U.S. in 2030 – specifically, that 50 percent be electric vehicles, including battery electric, plug-in hybrid electric or fuel-cell electric vehicles. Although this goal is non-binding, its inclusion in an executive order is likely to drive technological innovation. President Biden also called on EPA and the U.S. Department of Transportation to begin working on rules for:

- new fuel economy standards for passenger cars and light trucks for model year (MY) 2027 through at least MY 2030,
- new fuel economy standards for HD pickup trucks and vans for MY 2028 through at least MY 2030, and
- new fuel economy standards for medium- and HD-engines and vehicles to begin as soon as MY 2030.

In addition to these developments on federal fuel and engines standards, Washington State is currently engaged in rulemaking to reduce mobile source emissions by adopting California's more protective vehicle emission standards for new vehicles sold in Washington, starting with model year 2025 (Chapter 173-423 WAC, Low Emission Vehicles). Ecology expects to finalize this rule by December 30, 2021. In addition, in May 2021, Governor Inslee signed into law the Transportation Fuels-Clean Fuels Program (E3SHB 1091[23], codified at RCW Chapter 70A.535), which requires Ecology to adopt a rule establishing a clean fuels standard to reduce the carbon intensity of transportation fuels used in Washington. The intent of the clean fuels standard is to reduce emissions of not only greenhouse gases but also "conventional air pollutants from diesel and gasoline." (RCW 70A.535.005(3)(a)). Ecology is currently preparing to begin this rulemaking and expects to finalize the rule by December 30, 2022.

[23] https://lawfilesext.leg.wa.gov/biennium/2021-22/Pdf/Bills/Session Laws/House/1091-S3.SL.pdf?q=20210929134724

8.3 Development of Washington's long-term strategy

The Regional Haze Rule (RHR) requires consultation between states on the development of coordinated emission management strategies. Appendix R is a record of our inter-state consultation. (40 CFR 51.308(f)(2)(ii)). This requirement applies both to Class 1 Areas within Washington and to Class 1 Areas outside of Washington where we reasonably anticipate emissions from sources in Washington to contribute to visibility impairment. The RHR also requires that states consider five additional factors in developing their LTS (40 CFR 51.308(f)(2)(iv)). We discuss those five factors later in this chapter.

Through WRAP technical collaborations, the western states agreed upon the RPGs for 2028 (the end of the second implementation period) and a regionally consistent approach to addressing visibility impairment in the west.

8.4 Major visibility-impairing pollutants

Ecology's evaluation of potential controls focused primarily on reduction of sulfates and nitrates during the 2018 - 2028 implementation period. The first (or foundational) RH SIP that covered 2005 - 2018 dealt with both regional haze and reasonably attributable visibility impairment (RAVI). RAVI is visibility impairment clearly attributed to individual sources instead of collective effects from multiple sources over a large area.

IMPROVE monitoring data shows that sulfates (primarily), nitrates (secondarily), and organic mass are the dominant pollution species affecting visibility in the Class 1 Areas during the MIDs. See Chapter 3 for more information on monitoring.

Sulfates

Sulfates are the primary pollutant contributing to total light extinction (including Rayleigh scattering) for the MIDs in 2014 - 2018. Sulfates range from 35 to 50 percent of the total light extinction. In the 2028 projections, sulfates range from 37 to 53 percent of total light extinction and remain the primary pollutant contributing to total light extinction at all of the IMPROVE sites. The 2028 projections show a reduction in sulfate emissions largely due to cessation of coal-fired operation at TransAlta by 2025 and large reductions in marine fuel sulfate levels.

Nitrates

The 2014 – 2018 five-year average of MIDs in Class 1 Areas shows that nitrates contribute 9 to 26 percent of species contribution to light extinction. In the 2028 projections, nitrate contribution to the total light extinction ranges from 5 to 19 percent. The 2028 projections show a reduction in nitrate emissions primarily due to decreases in on-road and non-road mobile source emissions.

Organic mass

Organic mass contributes approximately 21 to 32 percent of total light extinction at IMPROVE sites in Washington in the 2014 – 2018 period. In the 2028 projections, organic mass contributes a similar amount of 21 to 33 percent of total light extinction. Organic mass from fire is an important contributor to light extinction. Several Class 1 Areas see large contributions to

visibility impairment due to smoke from fire; it is the highest in the Pasayten Wilderness. Organic mass is composed of either primary organic aerosols or secondary organic compounds. Primary organic aerosols are particulates directly emitted from combustion processes due to natural and anthropogenic causes. Secondary organic aerosols form particulates from condensation or photo-oxidization of volatile organic compounds from biogenic or anthropogenic sources.

Volatile organic compounds

Non-point sources are the largest human-generated source category of volatile organic compounds in 2018. Emissions from solvent use and residential wood combustion dominate these contributions. Both of these reflect the impact population growth has on the total amount of emissions.

8.5 State, federal, and local rules and controls that limit emissions of visibility-impairing pollutants

Washington's LTS to achieve reasonable progress goals relies on federal, state, and local controls on sources of visibility-impairing pollutants. WRAP identified all existing (adopted) rules and upcoming rules and limits, and incorporated the data into the calculations of expected reductions and improvements in visibility in 2028 (WRAP 2028 modeling). The modeling used the following regulations that limit emissions.

Adopted rules, programs, and permits

Federal fuel and engine rules for on-road and nonroad engines are of special importance. These result in large projected percent decreases in visibility-impairing emissions in Washington by 2028.

- Mobile source controls:
  - Heavy Duty Diesel (2007 and later model year) Engine Standard (40 CFR 86.007-11).
  - Tier 3 Tailpipe Standards (79 Fed. Reg. 23414 (Apr. 28, 2014)). Starting in 2017, these reduced both tailpipe and evaporative emissions from passenger cars, light-duty trucks, medium duty passenger vehicles, and some heavy-duty vehicles. The gasoline sulfur standard will enable more stringent vehicle emissions standards and make emissions control systems more effective.
  - Large Spark Ignition and Recreational Engines and Vehicle Rule (67 Fed. Reg. 68242 (Nov. 8, 2002)).
  - Tier 4 Nonroad Diesel Engines and Fuel Rule (40 CFR Part 1039).
  - Low sulfur fuel requirements for gasoline engines, on-road diesel engines, nonroad diesel engines, and locomotives (40 CFR 80 Subpart I).
  - Ultra-low sulfur diesel fuel for highway, nonroad, locomotive, and marine diesel necessary for new advanced emission control technologies. This contributes to particulate matter reductions in the existing fleet of nonroad engines and equipment (40 CFR 80.500).

- Maximum Achievable Control Technology (MACT) emission standards (40 CFR Part 63): Combustion Turbines (Subpart YYYY), Industrial Boilers and Process Heaters (Subpart DDDDD), and Reciprocating Internal Combustion Engines (RICE) (Subpart ZZZZ).
- Permits and state/EPA consent agreements.
- Ozone and Coarse Particulate Matter (PM_{10}) SIPs in place in the WRAP region.
- State oil and gas emissions control programs.

Additional federal and international rules leading to emission reductions and visibility improvement:

- MACT emission standards (40 CFR Part 63):
  - Petroleum Refineries (Subparts CC and UUU).
  - Boilers (area sources) (Subpart 6J).
  - Revised Utility Boilers (Subpart UUUUU).
  - Various area source MACTs.
- Stationary Spark Ignition Internal Combustion Engine Rules (40 CFR 60 Subpart JJJJ).
- Locomotive and Marine Diesel Emission Standards for engines with a cylinder displacement of less than 30 liters (73 Fed. Reg. 37096 (June 30, 2008)).
- Corresponding EPA rules for Category 3 Marine Diesel Engines with a cylinder displacement equal to or greater than 30 liters (75 Fed. Reg. 22896 (Apr. 30, 2010)).
- International Maritime Organization (IMO) rules reducing NO_2 and SO_2 emissions from commercial marine vessels.

8.6 Controls on visibility-impairing pollutants not in previous RH SIP

Since approval of Washington's 2010 RH SIP, Ecology, EPA, and other federal agencies, have adopted or implemented the following programs to reduce emissions from stationary and mobile sources.

Table 8-1. Control Strategies not in previous RH SIP.

Regulatory Program	Affected Sources	Affected Visibility Impairing Air Pollutants
North American Maritime Emission Control Area (ECA) and Maritime Pollution (MARPOL) Annex VI	Marine vessels operating within 200 nautical miles of United States and Canada's Pacific and Atlantic Ocean coast lines	SOx, NOx, $PM_{2.5}$
40 CFR Part 94 Marine Engine Requirements	Marine vessels operating in US Waters.	NOx, SOx, $PM_{2.5}$
Motor Vehicle CAFE/GHG standards	Light and medium duty on-road vehicles	NOx, $PM_{2.5}$
On-road Tier 3 diesel standards	Diesel fueled engines, especially on road vehicles	SOx, $PM_{2.5}$
Utility Boiler MACT	Coal fired boilers at electric generating stations	$PM_{2.5}$, SOx
Large and Area Source Boiler MACTs	All commercial/industrial boilers	NOx, $PM_{2.5}$, SOx
Commercial and Industrial Solid Waste Incineration Units (CISWI) New Source Performance Standards (NSPS)	Industrial/commercial boilers burning designated solid wastes	NOx, $PM_{2.5}$, SOx
SSI NSPS	Sewage sludge incinerators	NOx, $PM_{2.5}$
Revised Petroleum Refinery NSPS and MACT requirements	Petroleum refineries, very large petroleum storage tanks	VOC, $PM_{2.5}$

The most current emission inventory reflects the effects of many of these rules. Specific marine programs not included in the previous inventory that have significant impacts on Washington air quality include the North American Maritime Emission Control Area (ECA) regulations, the MARPOL VI annex, and the Marine Engine Requirements (40 CFR Part 94).

Starting in August 2012, the ECA required marine vessels within 200 nautical miles of the North American coast to use fuels with no more than 1 percent sulfur content, which decreased to 0.1 percent in 2015. EPA and the U.S. Coast Guard share implementation responsibilities for these requirements and have allowed some shipping companies delayed compliance dates for these requirements. Together, these programs require marine vessels to reduce SO_2 emissions by the equivalent of changing from 3.5–5 percent sulfur by weight fuel to 0.1 percent sulfur by weight

fuel. We expect a 70–90 percent reduction in SOx emissions from marine vessels in the ECA area. According to the EPA, ships complying with the ECA will reduce annual emissions of NOx, SOx and $PM_{2.5}$ by 23 percent, 74 percent and 86 percent, respectively, below the predicted levels without the ECA by 2020 (EPA Fact sheet 420-F-10-105, March 2010).

MARPOL (the International Convention for the Prevention of Pollution from Ships) Annex VI addresses air pollution from ocean-going ships. The MARPOL VI set limits on NOx emissions and has required the use of fuel with lower sulfur content since June of 2011.

40 CFR Part 94 marine engine requirements phase in NOx reductions as manufacturers build new vessels or install new replacement engines. Part 94 requires that new engines meet Tier 2 requirements in 2011 (equal to the MARPOL requirement) and Tier 3 requirements starting in 2016. EPA estimates that these NOx requirements will reduce national marine vessel NOx by 80 percent from 2009 levels.

The effects of the marine vessel fuel sulfur requirements are reflected in the IMPROVE data, though the effects of the ECA are not fully reflected in the data due to the long lead time for the phase-in of the MARPOL requirements and the relatively recent date (2013) for vessels to meet the first stage requirements.

Washington State emission limits and shutdowns

The following emission limits and shutdown schedules have gone into effect since the last implementation period or will occur prior to the end of the second implementation period and are part of Washington's LTS.

- TransAlta Centralia Generation, LLC Power Plant: best available retrofit technology (BART) Order revision and shutdown of coal-fired boilers. TransAlta is the only coal-fired power generation facility in Washington State. The facility ceased coal-fired operation in one boiler in December 2020 and will completely cease coal-fired operation by the end of 2025. Ecology updated the TransAlta BART Order in 2020, and EPA approved its incorporation into the SIP in June 2021 (86 Fed. Reg. 24502). This revised BART Order established lower NOx emissions limits from the remaining coal-fired boiler until the facility ceases coal-fired operation by the end of 2025.
- Cardinal Glass, a flat glass facility, submitted a permit modification application to Southwest Clean Air Agency (SWCAA) to install a selective catalytic reduction (SCR) emission control device and increase production of plate glass. The application also proposed removing the permit's emission controls of limiting excess oxygen. SWCAA issued the permit to the facility on February 11, 2021, and the SCR should be installed and operating in 2022. Ecology is submitting this permit as part of the LTS in our SIP.
- Ash Grove consent decree: The Ash Grove Cement Company entered into a consent decree with EPA, Ecology, the Puget Sound Clean Air Agency (PSCAA), and other state agencies in 2013 (Appendix E). The consent decree required the Seattle facility to submit an optimization protocol for the Seattle Kiln to optimize the operation of this unit to reduce NOx emissions to the maximum extent practicable. On August 25, 2016, EPA, in consultation with affected state agencies, approved the new limit of 5.1 pounds of NOx

per ton of clinker on a 30-day rolling average. Ecology is submitting this consent decree as part of the LTS in our SIP.

Non-regulatory factors can also result in decreased emissions. Economic and market conditions can drive business decisions that may result in decreased or curtailed production. In Washington, two aluminum smelters are currently in curtailment due to market conditions, one since 2014 and the second one since 2020. Ecology worked with these facilities to develop Agreed Orders (AOs 18100 and 18216 in Appendix Q) that require them to complete a four-factor analysis to evaluate emission controls prior to start-up, should they decide to resume operations. The four-factor analysis developed by the smelters will be subject to Ecology's approval, and any controls identified as necessary to make reasonable process must be installed and operational within three years of start-up. In addition, one of the smelters is in an area that EPA designated as being in nonattainment for the 2010 1-hour SO_2 NAAQS, effective April 31, 2021. Nonattainment is a separate and distinct regulatory program of the Clean Air Act, but the emission controls required for purposes of attainment will have visibility benefits. The SO_2 attainment plan will describe any emission controls required to bring the area back into attainment, such as installation of new control equipment and/or new emission limits. Future RH SIP analyses will incorporate the effects of the RH Agreed Orders and the attainment plan on visibility for new controls installed at the smelters as a result. Chapter 7 discusses these facilities in more detail. Ecology is submitting Agreed Orders AO 18100 and AO 18216 in Appendix Q as part of the LTS in our SIP.

Non-point and mobile sources

The RHR requires that states identify all anthropogenic sources of visibility impairment considered by the state when developing its LTS, including stationary, mobile, and non-point sources (40 CFR 51.308(f)(2)(i)). We discuss stationary sources in the previous section and in Chapter 6 (Source Apportionment) and Chapter 7 (four-factor Analysis).

Woodstoves

Woodstove smoke in Washington contributes to visibility impairment in the state. However, since 2007, Washington has decreased emissions from woodstoves by supporting a woodstove buy-back and exchange program (Chapter 173-433 WAC). This program provides grant funding to local clean air agencies and Ecology's regional offices to use in programs that replace older woodstoves with new, cleaner burning woodstoves or cleaner heat sources such as heat pumps, gas stoves, or furnaces. Some of these grant recipients have also run woodstove recycling programs where they buy back and destroy older stoves to remove them from use. Ecology estimates that in the past 13 years, state and local government agencies have bought back or exchanged more than 8,000 stoves for an estimated total reduction of 194 tons of $PM_{2.5}$. Since 2007, Ecology and the local clean air agencies have provided grants to replace 6,068 old woodstoves with cleaner sources of heat and incentives to recycle 2,472 woodstoves that did not meet current emission standards. This has reduced $PM_{2.5}$ emissions by over 200 tons.

Recent federal actions also contribute to the reduction of woodstove emissions. EPA's 2015 NSPS for new woodstoves established "Step 2" emission standards that went into effect in May

2020, limiting $PM_{2.5}$ emissions to 2.0 grams per hour if using crib wood (has standard characteristics) or 2.5 grams per hour if the manufacturer choses to use cord wood for performance testing (40 CFR 60 Subpart AAA). Prior to May 2020, Washington state law was more stringent than the applicable NSPS, limiting $PM_{2.5}$ emissions to 2.5 grams per hour for catalytic devices and 4.5 grams per hour for all other devices (RCW 70A.15.3530). Because the federal standards are now more stringent, Ecology is using its delegated CAA authority to enforce the NSPS Step 2 standards.

Mobile sources

Although Ecology does not directly regulate emissions from mobile sources, we actively participate in programs that reduce mobile source emissions and manage grants that result in reduced emissions and higher fuel economy.

Mobile sources are the largest contributors to NOx emissions in Washington. Population growth has contributed to increased mobile source emissions. Factors that have decreased mobile source emissions include fleet turnover to more fuel efficient or electric vehicles, low sulfur fuel requirements, and adoption of California's low emission vehicle standards.

Motor Vehicle Emission Inspection program retirement

Another program that has contributed to emission reductions from mobile sources was Washington's vehicle emission testing program. The program required vehicles registered in Washington to meet state emission limits as a condition of vehicle registration. The combination of the vehicle emission testing program and advances in vehicle technology led to reduced mobile source emissions. The legislature phased the emission testing program out starting in 2005 based on Ecology's prediction that more fuel efficient and electric vehicles would replace the need for it by 2020 (RCW 70A.25.030). The program ended on January 1, 2020.

New state laws and regulations

Washington has also pursued mobile source emission reductions through the technology of zero emission vehicles (ZEV) and low-emission vehicles (LEV). Special provisions in the federal Clean Air Act (Section 177) allow states to adopt California's standards instead of the federal motor vehicle emission standards. California's standards contain both LEV and ZEV requirements.

In 2005, the Washington Legislature adopted the California vehicle emission standards for passenger cars, light duty trucks, and medium duty passenger vehicles (ESHB 1397). However, the law did not adopt the ZEV standards or the LEV standards for medium duty trucks (trucks generally weighing between 8,500 and 14,000 pounds). The 2020 Legislature expanded Washington's program to include the entire California program and directed Ecology to adopt rules to implement the ZEV program (SB 5811). We are currently in the process of adopting rules to reflect our expanded statutory authority

In addition, Ecology submitted a SIP revision to EPA in 2019 to adopt by reference California's LEV program. The purpose of the SIP revision was to implement programs to reduce vehicle emissions that contribute to formation of ground level ozone and fine particulate matter

($PM_{2.5}$). The precursors to ground level ozone and $PM_{2.5}$ also contribute to regional haze. EPA is currently proposing to approve this revision to the Washington SIP (86 FR 46169).

State grant programs

Ecology has also pursued grant opportunities that result in decreased emissions from mobile sources. Volkswagen (VW) violated federal and state clean air laws by installing illegal emissions software on some diesel vehicles. In January 2016, the U.S. Department of Justice filed a lawsuit on behalf of EPA against VW. After admitting fault, VW reached multiple settlements with EPA and Ecology. Ecology is managing $140 million in settlement funds used to reduce air pollution from transportation. As of February 2020 we have committed $91 million statewide to projects that decrease diesel emissions such as electrification of school buses, transit buses, ferries, state fleet vehicles, port drayage trucks, shore power, and installing light duty electric vehicle charging stations.

Factors required for the long-term strategy

In addition to the FFA, the RHR requires states to consider the following five factors in developing a LTS (40 CFR 51.308(f)(2)(iv)).

Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment (40 CFR 51.308(f)(2)(iv)(A)).

In addition to the ongoing air pollution control programs described above, current state and federal rules and state and local air agency permits limit visibility-impairing emissions from point, non-point, and mobile sources. The projected 2028 emissions inventory reflects the emission reductions from most rules and permits in existence in 2018.

To obtain a permit, future major and minor new sources, or modifications to existing sources, will need to meet state permitting requirements; including meeting Best Available Control Technology (BACT) emission limits. Major New Source Review (NSR) permits include requirements to meet Air Quality Related Values (AQRV) protection criteria established by EPA for Class 1 Areas.

Ecology and local air pollution control authorities work to reduce emissions from existing emission producing units and to minimize new emissions through the state NSR program. This program requires BACT emission reductions for all new sources and modifications that result in an increase of emissions.

State law (RCW 70A.15.2220) requires that when a source decides to modify or replace an existing emission control system, Ecology or the local air pollution control authority must assure that the modified or replacement control system meets a reasonably available control technology (RACT) level of emissions control at a minimum.

Measures to mitigate the impacts of construction activities (40 CFR 51.308(f)(2)(iv)(B)).

Ecology or a local air quality agency regulates construction activities as a source of air pollution. The following State air quality rules (WAC 173-400-040(3) and (9)) address air emissions associated with construction activities.

- WAC 173-400-040(3) (Fallout)
- WAC 173-400-040(4) (Fugitive emissions)
- WAC 173-303-040(9) (Fugitive dust)

Local clean air agencies and local governments have additional rules and policies governing mitigation of air pollution from construction activities. We describe types of construction permits in Washington below. These are all part of a federally enforceable permitting program.

A prevention of significant deterioration (PSD) permit applies to new large facilities or major changes at existing large facilities that could increase air pollution in an area that meets air quality standards. The intent is to prevent that area's air quality from getting worse.

A notice of construction (NOC) approval order is required before installing a new source of air pollution or modifying an existing source of air pollution.

Regulators issue a general order for similar sources of air pollution, instead of a series of individual NOC permits.

An air operating permit (AOP) combines all applicable rules and requirements for operation and procedures, emission standards, monitoring, recordkeeping, and reporting. An AOP is required for major sources that emit or have the potential to emit more than 100 tons per year of any air pollutant, 10 tons per year or more of any hazardous air pollutant, or more than 25 tons per year of a combination of hazardous air pollutants.

Source retirement and replacement schedules (40 CFR 51.308(f)(2)(iv)(C)).

TransAlta's Centralia Power Plant boiler number one ceased coal-fired energy production in December of 2020. The remaining boiler (boiler number two), and thus the entire facility, is required to cease coal-fired operation by the end of 2025. A 2020 revised BART Order requires reduced NOx levels until coal-fired production ceases in 2025.

Basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs (40 CFR 51.308(f)(2)(iv)(D)).

As part of the regional haze LTS, states are required to consider basic smoke management practices for prescribed fire used for agricultural and wildland vegetation (silvicultural) management purposes and smoke management programs (40 CFR Section 51.308(f)(2)(iv)(D)). Under Washington State law, Ecology and the local air agencies regulate agricultural burning (WAC 173-430). The state has established controls required for agricultural burning to minimize adverse health and environmental impacts. The state works with a variety of stakeholders including agricultural burners, agricultural interest groups, and air quality interest groups to encourage development, research, and use of alternatives to burning.

The Washington State Department of Natural Resources (DNR) issues silvicultural burning permits in Washington according to the regulatory direction provided in the SIP-approved 1998 Washington Department of Natural Resources Smoke Management Plan.[24][25] The goal of the plan is to coordinate and facilitate statewide regulation of silvicultural burning on lands under DNR jurisdiction, and on unimproved federally managed forestlands and participating tribal lands. The strategy of DNR's Smoke Management Plan is to balance the protection of public health and visibility with the need for silvicultural burning to improve ecosystem health and reduce the damaging effects of catastrophic wildfires. Prescribed silvicultural burning is a non-point source and prescribed burn plumes can have significant impacts on visibility. Washington proactively addressed this source in its RAVI SIP. Washington incorporated the state's Smoke Management Plan into the September 1999 revisions to the RAVI SIP and EPA approved the Smoke Management Plan's incorporation into the SIP in 2003. DNR is currently revising and preparing to update the Smoke Management Plan in the SIP. Ecology will provide status of the RAVI SIP in the 2025 RH Progress Report.

The anticipated net effect on visibility due to projected changes in point, non-point, and mobile source emissions over the period addressed by the long-term strategy (40 CFR 51.308(f)(2)(iv)(E)).

Ecology used the WRAP modeled inventory for this RH SIP to determine the expected net effect of projected changes to visibility due to emission changes over the control period for the second RH SIP ending in 2028. The modeled effects reflect the implementation of controls on the books.

[24] https://www.epa.gov/sips-wa/epa-approved-nonregulatory-provisions-and-quasi-regulatory-measures-washington-sip

[25] http://file.dnr.wa.gov/publications/rp_burn_smptoc.pdf

Table 8-2 below presents the net effects of emission changes on visibility. The net effect for the MID was considered in establishing RPGs for Washington's mandatory Class 1 Areas. The modeling results show that we meet the goal of no degradation of visibility for the clearest days.

Table 8-2: Anticipated net effect on visibility of emission reductions over the second control period for MID, in deciviews (dv)

Class 1 Area	2014 to 2018 (dv)	2028 projected visibility (dv)	Improvement (dv)
Olympic National Park	11.9	11.5	0.4
North Cascades National Park and Glacier Peak Wilderness	10	9.8	0.2
Alpine Lakes Wilderness	12.7	12.0	0.7
Mount Rainier National Park	12.7	12.0	0.7
Goat Rocks Wilderness and Mount Adams Wilderness	8	7.6	0.4
Pasayten Wilderness	9.5	9.2	0.3

Table 8-3: Anticipated net effect on visibility of emission reductions over the second control period for clearest days, (dv)

Class 1 Area	2014 to 2018 (dv)	2028 projected visibility (dv)	Improvement (dv)
Olympic National Park	3.6	3.4	0.2
North Cascades National Park and Glacier Peak Wilderness	2.5	2.4	0.1
Alpine Lakes Wilderness	3.3	3.1	0.2
Mount Rainier National Park	3.9	3.7	0.2
Goat Rocks Wilderness and Mount Adams Wilderness	1.0	0.9	0.1
Pasayten Wilderness	1.6	1.5	0.1

8.7 Summary

Washington State's LTS for visibility improvement reduces haze-causing emissions that contribute to visibility impairment in Washington's Class 1 Areas and in Class 1 Areas outside of Washington, where we reasonably anticipate Washington emissions contribute to visibility impairment.

The LTS for this second RH SIP includes the following key elements:

- Existing federal and state laws and regulations, including federal fuel and engine rules for on-road and non-road vehicles, are important for making reasonable progress by 2028.
- Additional reductions from mobile sources due to state legislation, rulemaking, and grants will continue to decrease vehicle emissions.
- New emission controls to reduce NOx emissions, including the cessation of all coal-fired energy generation in the state by 2025 (and reductions in NOx at the coal-fired facility until 2025), and SCR operation at Cardinal Glass.
- Organic mass emissions resulting primarily from fire are an important contributor to total light extinction in Washington's Class 1 Areas.
- Regional contributions beyond the direct control of Ecology, from Canada and Pacific offshore sources and wildfires, play a significant role in visibility impairment in Washington's Class 1 Areas.
- Washington's LTS prioritizes improvement to visibility on the MID.

Chapter 9. Reasonable Progress Goals

9.1 Introduction

The Regional Haze Rule requires states to establish reasonable progress goals (RPGs) for mandatory Class 1 Areas within the state. The RPGs, expressed in deciviews (dv), reflect projected visibility improvements achieved by the end of the current implementation period (2018 to 2028) for the most impaired days (MID) and ensure no degradation in visibility on the clearest days. The RPGs are based on the long-term strategy that addresses visibility impairment for each Class 1 Area (see Chapter 8). The long-term strategy includes the measures that are necessary to make reasonable progress during this implementation period.

In the establishment of RPGs, the Regional Haze Rule requires states to consider both:

- The uniform rate of progress (URP) needed to attain natural conditions by 2064 (shown as a glidepath), and
- The four statutory factors required by the federal Clean Air Act to use in determining what measures are necessary to make reasonable progress.

Ecology's calculation of RPGs relies on technical data and analysis developed by the Western Regional Air Partnership (WRAP). Data are available on WRAP's Technical Support System (TSS2) website[26].

WRAP determined the RPGs for each Class 1 Area using the guidance "Procedures for Making Visibility Projections and Adjusting Glidepaths using the WRAP-WAQS 2014 Modeling Platform" (Appendix D). Projected 2028 emissions for mobile sources and major facilities were obtained by WRAP from EPA and states, representing existing and expected controls. The modeled baseline and projections were used to calculate relative response factors (RRFs), which were applied to the measured baseline period concentrations at the IMPROVE sites, thus providing 2028 RPG visibility projections (see Chapter 5 for more information on modeling). The RPGs for Washington's Class 1 Areas are shown in Table 9-1.

[26] http://views.cira.colostate.edu/tssv2/

Table 9-1: Washington's Class 1 Areas and their 2028 reasonable progress goals in deciviews (dv)

Class 1 Area	Reasonable progress goal
Olympic National Park	11.5 dv
North Cascades National Park	9.8 dv
Glacier Peak Wilderness Area	9.8 dv
Alpine Lakes Wilderness Area	12.0 dv
Mount Rainier National Park	12.0 dv
Goat Rocks Wilderness Area	7.6 dv
Mount Adams Wilderness Area	7.6 dv
Pasayten Wilderness Area	9.2 dv

Uniform rate of progress glidepath adjustment

The charts in this chapter illustrate the regional haze glidepath as defined by EPA guidance and an alternative glidepath with a 2064 endpoint adjustment. The adjusted endpoint of the glidepath and thus the associated slope is consistent with methods described in the EPA's September 2019 regional haze modeling Technical Support Document. Per the Regional Haze Rule, a state can select the default glidepath slope or propose to use endpoint adjustment options for international sources and prescribed fire contributions to visibility at each Class 1 Area (40 CFR 51.308(f)(1)(vi)).

Washington's Class 1 Areas are all affected by international anthropogenic contributions that Washington cannot control. Source apportionment results (Chapter 6) show that sulfates from international anthropogenic sources are expected to impact visibility more than in-state sources at all Washington Class 1 Areas. Source apportionment results also show that nitrates from international anthropogenic sources are expected to impact visibility more than in-state sources at most Washington Class 1 Areas, with the exception of Alpine Lakes Wilderness Area and Mount Rainier National Park. We propose to use the international adjustment added to the EPA estimated natural conditions endpoint, calculated using the 2028 modeling results normalized to the monitored visibility.

Four-factor analysis

The RHR requires states to perform a four factor analysis (FFA) to determine whether the installation of new emission controls at certain facilities is necessary for the state to make reasonable progress toward the national visibility goal. 40 CFR 51.308(f)(2)(i) requires the state to consider the following four statutory factors in determining which emission reductions measures are necessary to make reasonable progress:

- Costs of compliance,
- The time necessary for compliance,
- The energy and non-air quality environmental impacts of compliance, and
- The remaining useful life of any potentially affected sources.

Ecology selected point sources with the largest "Q/d" to undergo a FFA, where the annual emissions (Q) is divided by the distance to the nearest Class 1 Area (d). The Q/d point-source screening is discussed in Chapter 7, while the long-term strategies for non-point and mobile sources are discussed in Chapter 8. Ecology requested a FFA from facilities chosen in the source-selection process. Ecology reviewed the FFA information submitted by the sources. The conclusions from this review are described in Chapter 7 and summarized here.

The Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring data show that sulfate (SO_4) and nitrate (NO_3) are two of the most significant pollutants impairing visibility in Washington's Class 1 Areas. SO_2 and NOx emissions are precursors of SO_4 and NO_3, respectively. The WRAP visibility projections show that SO_4 and NO_3, which are mostly anthropogenic in origin, are expected to continue impairing visibility in 2028 more than the other monitored pollutant species. The majority of SO_4 impairment at Class 1 Areas from in-state sources is attributed to non-EGU (electric generating units) point sources, as discussed in Chapter 6. The majority of NO_3 impairment at Class 1 Areas from in-state sources is attributed to mobile vehicles.

Ecology is focusing on SO_2 and NOx emission reductions from major point sources for this implementation period (2018 – 2028) because major point sources contribute the majority of the haze-causing emissions that the state can potentially control. SO_2 and NOx make up the majority of the haze-causing emissions from the major sources. NOx emissions from mobile sources decreased significantly prior to 2018 due to the vehicle and engine provisions of Title II of the Clean Air Act and other regulations (40 C. F. R. Parts 85, 86, 88 through 94, 600, and 1033 through 1068), and are expected to continue decreasing each year due to fleet turnover and recent legislation requiring Ecology to adopt California's low emission vehicle standards (SB 5811, 2020)[27] and to establish a clean transportation fuels standard (E3SHB 1091, 2021)[28].

Ecology evaluated projected 2028 emissions of SO_2 and NOx from specific emission processes as defined by Source Classification Codes (SCCs). We identified the SCCs projected to have the largest SO_2 and NOx emissions from in-state point sources. The resulting three groups were industrial processes, external combustion boilers, and internal combustion engines. Emissions of SO_2 and NOx from specific industries and emission source categories vary greatly across these three groups.

Ecology calculated the total emissions of SO_2, NOx, PM_{10}, and NH_3 from each major facility to inform source-selection. The majority of sources selected for FFA are located in the Puget Sound lowlands in western Washington, and may contribute to visibility impairment at multiple Class 1 Areas. Seven of Washington's eight Class 1 Areas are directly to the east of the Puget Sound lowlands, in the Cascade Mountains. The eighth Class 1 Area is located directly to the

[27] https://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/Session Laws/Senate/5811.SL.pdf?cite=2020%20c%20143%20%C2%A7%201

[28] https://lawfilesext.leg.wa.gov/biennium/2021-22/Pdf/Bills/Session Laws/House/1091-S3.SL.pdf?q=20210929134724

west of the Puget Sound lowlands on the Olympic Peninsula. See Chapter 7 for details about the process used and the final list of sources selected for FFA.

Based on the FFAs, we concluded that there is potential for SO_2 and NOx emission reductions from a number of emission points, principally boilers, process heaters, and fluidized catalytic cracking unit/carbon monoxide boiler systems.

Reasonably available control technology

As discussed in Chapter 7, in Washington State, RCW 70A.15.2230 (the "RACT statute") is the legal mechanism that Ecology can use to require existing sources to install new emission controls that are determined to be reasonable. Because the analysis performed under the State's RACT process is equivalent to the RHR's FFA, Ecology will use the RACT process to require the installation of reasonable emission controls for purposes of compliance with the RHR.

After the RACT analysis is complete, Ecology will make a determination of what constitutes reasonable emission control(s) for each selected source. The determination will result in an enforceable requirement to install and operate the controls identified in the analysis. The results of the analysis and the subsequent determinations will be included in a supplement to our Regional Haze SIP revision. Development of controls is discussed more as part of Washington's long-term strategy in Chapter 6 (Source Apportionment) and Chapter 7 (FFA).

Progress in reducing visibility impairing pollutants

As discussed in Chapter 4, projected 2028 emissions and the resulting RPGs reflect controls "on-the-books" (OTB) throughout the WRAP region. OTB controls are existing, legally adopted controls that will reduce visibility impairing pollutants during the second implementation period of 2018 to 2028. Large statewide reductions in NOx (50 percent) are expected by 2028 as a result of engine and fuel rules that reduce vehicle emissions. Significant reductions in NOx and SO_2 are also expected after the full cessation of coal-burning at TransAlta Centralia Generation facility in 2025. Additionally, recent emission reductions measures for TransAlta and Cardinal Glass were included in the long-term strategy and the 2028 modeled emission projections for determining reasonable progress goals. For the purpose of the WRAP modeling and this document these recent emission reduction measures were included in the "2028 OTB projection" because the TransAlta reduction measures were approved by the EPA in the SIP on May 7, 2021 (86 FR 24502) and the revised Cardinal Glass permit was issued by SWCAA to the facility on February 11, 2021 for inclusion in the LTS. These and other controls are discussed in Chapter 8 (long-term strategy).

9.2 Olympic National Park

Most impaired days

Baseline, adjusted glidepath, and projected visibility

Visibility conditions at Olympic National Park are monitored at the IMPROVE site OLYM1. The monitored 2000-2004 baseline visibility at this site on the most impaired days (MID) is 14.9 dv. The calculated natural conditions for the adjusted glidepath are 8.9 dv, a difference of 6 dv and

a rate of 0.1 dv per year (6 dv divided by 60 years). This is the rate that needs to be maintained to reach natural visibility conditions in the park by 2064. The amount of visibility improvement from the baseline to 2028 required to stay below the 2028 URP adjusted glidepath for MID is 1.4 dv. The 2028 RPG is projected to be 11.5 dv, which is a visibility improvement of 3.4 dv from the baseline.

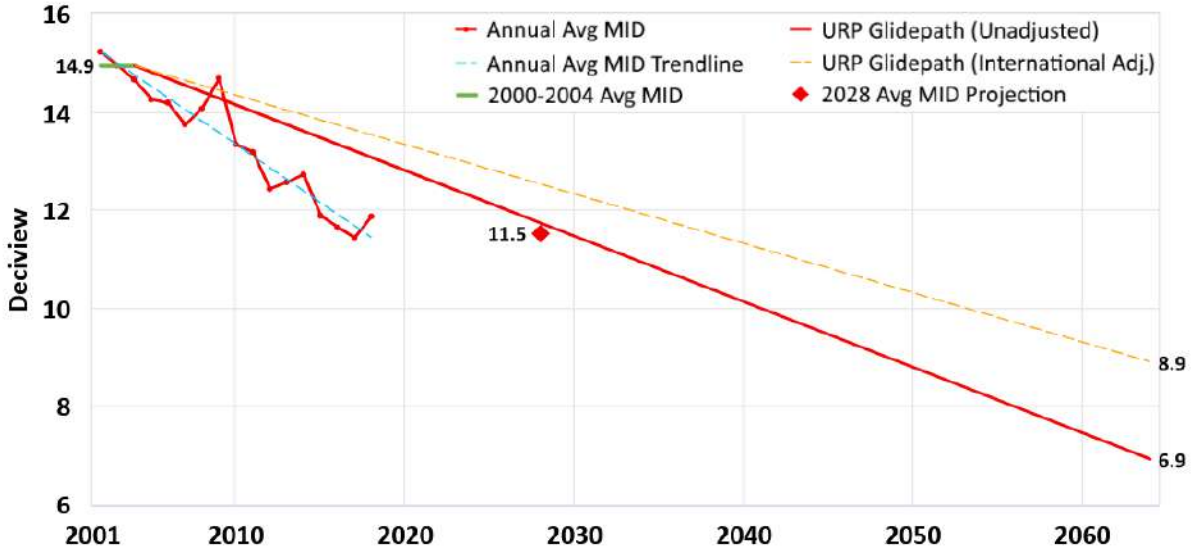


Figure 9-1: Projected 2028 visibility conditions on the MID in Olympic National Park.

Progress in reducing visibility impairing pollutants

Table 9-2: Projected changes in light extinction (Mm^{-1}) from 2014 – 2018 baseline to 2028 in Olympic National Park.

	Ammonium sulfate	Ammonium nitrate	Organic mass	Elemental carbon	Coarse mass	Fine soil	Sea salt
IMPROVE 2014-2018 average	10.0	4.3	4.6	1.2	1.3	0.2	0.8
2028 OTB projection	10.0	3.3	4.5	1.0	1.3	0.2	0.8
Percent change	0%	-23%	-3%	-14%	0%	-1%	0%

Summary: Ecology concludes from this analysis that progress is being made in reducing visibility impairing pollutants impacting Olympic National Park. The 2028 RPG for Olympic National Park is 11.5 dv assuming emission controls that are on the books.

Clearest days

The monitored 2000-2004 baseline conditions at OLYM1 on the Clearest Days are 6 dv. This second SIP covers the 2018 - 2028 period. WRAP modeling projects no degradation on the

clearest days because the 2028 visibility of 3.37 dv for the clearest days is below the baseline for the clearest days.

9.3 North Cascades National Park and Glacier Peak Wilderness

Most impaired days

Baseline, adjusted glidepath, and projected visibility

Visibility conditions at North Cascades National Park and Glacier Peak Wilderness are monitored at the IMPROVE site NOCA1. The monitored 2000-2004 baseline visibility at this site on the most impaired days (MID) is 12.6 dv. The calculated natural conditions for the adjusted glidepath are 8.2 dv, a difference of 4.4 dv and a rate of 0.07 dv per year (4.4 dv divided by 60 years). This is the average rate that needs to be maintained to reach natural visibility conditions in these Class 1 Areas by 2064. The amount of visibility improvement from the baseline to 2028 required to stay below the 2028 URP adjusted glidepath for MID is 1.8 dv. The 2028 RPG is projected to be 9.8 dv, which is a visibility improvement of 2.8 dv from the baseline and 0.2 dv below the 2014 to 2018 average.

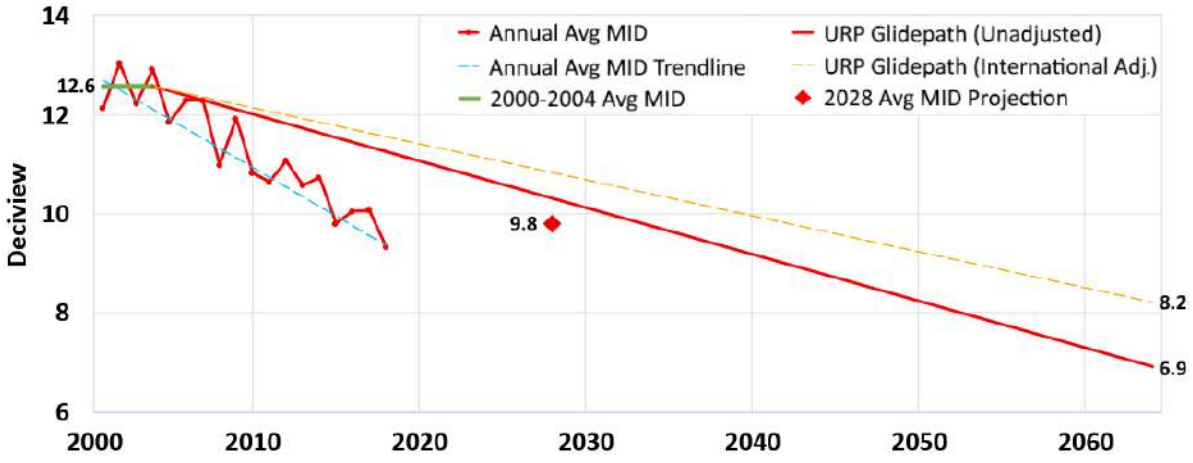


Figure 9-2: Projected 2028 visibility conditions on the MID in North Cascades National Park and Glacier Peak Wilderness

Progress in reducing visibility impairing pollutants

Table 9-3: Projected changes in light extinction (Mm^{-1}) from 2014 – 2018 baseline to 2028 in North Cascades National Park and Glacier Peak Wilderness.

	Ammonium sulfate	Ammonium nitrate	Organic mass	Elemental carbon	Coarse mass	Fine soil	Sea salt
IMPROVE 2014-2018 average	8.1	1.7	4.0	0.9	1.3	0.2	0.3
2028 OTB projection	8.2	1.2	4.0	0.9	1.3	0.2	0.3
Percent change	0%	-28%	-1%	-4%	0%	-1%	0%

Summary: Ecology concludes from this analysis that progress is being made in reducing visibility impairing pollutants that impact the North Cascades National Park and Glacier Peak Wilderness. The 2028 RPG is 9.8 dv assuming emission controls that are on the books.

Clearest days

The monitored 2000-2004 baseline conditions at NOCA1 on the clearest days are 3.4 dv. WRAP modeling projects no degradation on the clearest days because the 2028 visibility of 2.38 dv for the clearest days is below the clearest days baseline.

9.4 Alpine Lakes Wilderness

Most impaired days

Baseline, adjusted glidepath, and projected visibility

Visibility conditions at Alpine Lakes Wilderness are monitored at the IMPROVE site SNPA1. The monitored 2000-2004 baseline visibility at this site on the most impaired days (MID) is 15.4 dv. The calculated natural conditions for the adjusted glidepath are 8.2 dv, a difference of 7.2 dv and a rate of 0.1 dv per year (7.2 dv divided by 60 years). This is the average rate that needs to be maintained to reach natural visibility conditions in the park by 2064. The amount of visibility improvement from the baseline to 2028 required to stay below the 2028 URP adjusted glidepath for MID is 2.9 dv. The 2028 RPG is projected to be 12.0 dv, which is a visibility improvement of 3.4 dv from the baseline and 0.7 dv below the 2014 to 2018 average.

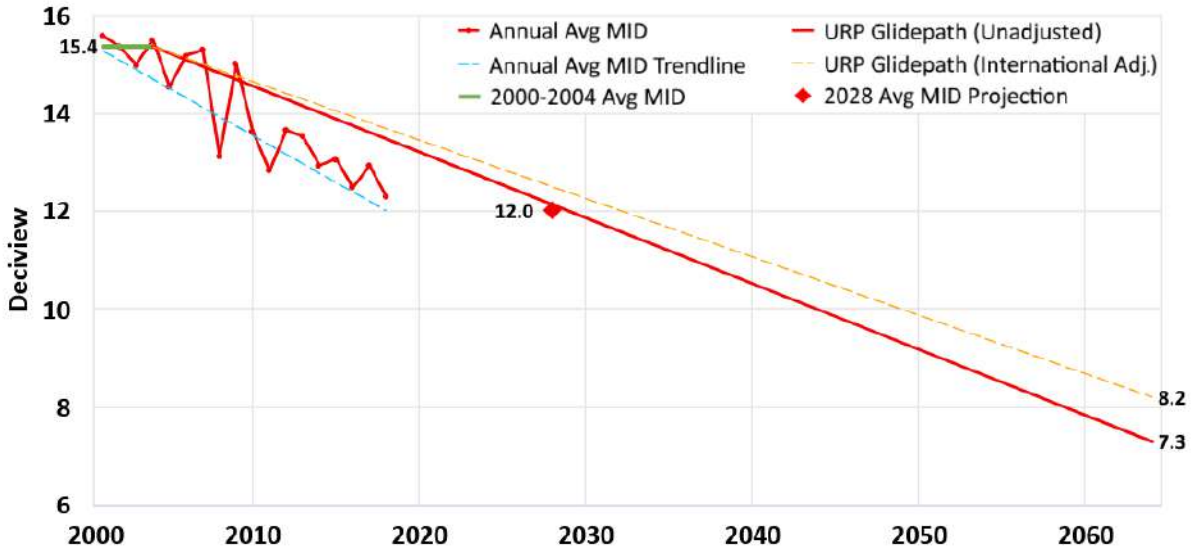


Figure 9-3: Projected 2028 visibility conditions on the MID in Alpine Lakes Wilderness

Progress in reducing visibility impairing pollutants

Table 9-4: Projected changes in light extinction (Mm^{-1}) from 2014 – 2018 baseline to 2028 in the Alpine Lake Wilderness.

	Ammonium sulfate	Ammonium nitrate	Organic mass	Elemental carbon	Coarse mass	Fine soil	Sea salt
IMPROVE 2014-2018 average	8.8	6.7	6.4	1.8	1.1	0.2	0.3
2028 OTB projection	8.8	4.3	6.3	1.8	1.1	0.2	0.3
Percent change	-1%	-37%	-1%	-4%	0%	-1%	-1%

Summary: Ecology concludes from this analysis that Washington is making progress in reducing visibility impairing pollutants impacting Alpine Lakes Wilderness. The 2028 RPG is 12.0 dv assuming emission controls that are on the books.

Clearest days

The monitored 2000-2004 baseline conditions at SNPA1 on the clearest days are 5.5 dv. WRAP modeling projects no degradation on the clearest days because the 2028 visibility of 3.0 dv is below the clearest days baseline.

9.5 Mount Rainier National Park

Most impaired days

Baseline, adjusted glidepath, and projected visibility

Visibility conditions at Mount Rainier National Park are monitored at the IMPROVE site MORA1. The monitored 2000-2004 baseline visibility at this site on the most impaired days (MID) is 16.5 dv. The calculated natural conditions for the adjusted glidepath are 8.9 dv, a difference of 7.6 dv and a rate of 0.1 dv per year (7.6 dv divided by 60 years). This is the average rate that needs to be maintained to reach natural visibility conditions in the park by 2064. The amount of visibility improvement from the baseline to 2028 required to stay below the 2028 URP adjusted glidepath for MID is 3.0 dv. The 2028 RPG is projected to be 12.0 dv, which is a visibility improvement of 4.5 dv from the baseline and 0.7 below the 2014 to 2018 average.

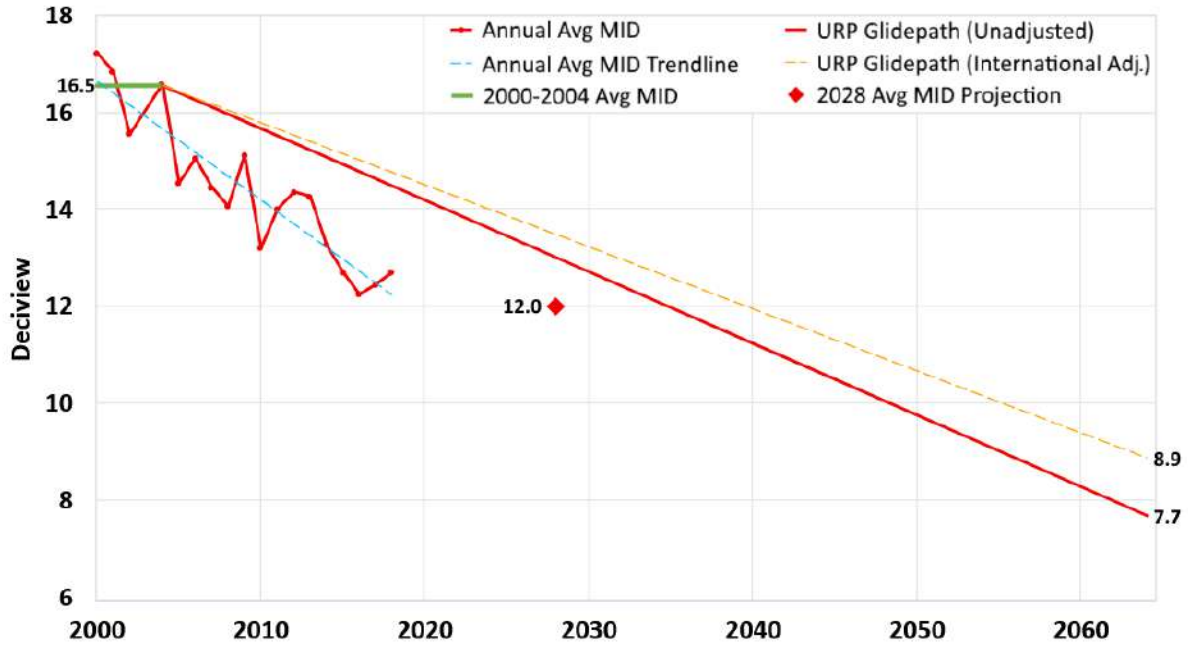


Figure 9-4: Projected 2028 visibility conditions on the MID in Mount Rainier National Park

Progress in reducing visibility impairing pollutants

Table 9-5: Projected changes in light extinction (Mm^{-1}) from 2014 – 2018 baseline to 2028 in Mount Rainier National Park.

	Ammonium sulfate	Ammonium nitrate	Organic mass	Elemental carbon	Coarse mass	Fine soil	Sea salt
IMPROVE 2014-2018 average	10.1	2.3	7.8	2.3	1.9	0.2	0.3
2028 OTB projection	9.7	1.1	7.4	1.9	1.9	0.2	0.3
Percent change	-4%	-50%	-5%	-16%	+1%	-3%	0%

Sulfate:

Statewide emissions of SO_2 are projected to decline almost 40% between the 2000-2004 baseline period and 2028. This decline results from a 29% reduction in point source emissions and a 95% reduction in on-road and off-road mobile source emissions. The mobile source reduction reflects the removal of sulfur from on-road and off-road fuels.

Summary: Ecology concludes from this analysis that overall Washington is making progress in reducing visibility impairing pollutants impacting Mount Rainier National Park. The 2028 RPG is 12.0 dv assuming emission controls that are on the books.

Clearest days

The monitored 2000-2004 baseline conditions at MORA on the clearest days are 5.5 dv. WRAP modeling projects no degradation on the clearest days because the 2028 visibility of 3.68 dv is below the clearest days baseline.

9.6 Goat Rocks Wilderness and Mount Adams Wilderness

Most impaired days

Baseline, adjusted glidepath, and projected visibility

Visibility conditions at Goat Rocks Wilderness and Mount Adams Wilderness are monitored at the IMPROVE site WHPA1. The monitored 2000-2004 baseline visibility at this site on the most impaired days (MID) is 10.5 dv. The calculated natural conditions for the adjusted glidepath are 8.1 dv, a difference of 2.4 dv and a rate of 0.04 dv per year (2.4 dv divided by 60 years). This is the average rate that needs to be maintained to reach natural visibility conditions in the park by 2064. The amount of visibility improvement from the baseline to 2028 required to stay below the 2028 URP adjusted glidepath for MID is 0.96 dv. The 2028 RPG is projected to be 7.6 dv, which is a visibility improvement of 2.9 dv from the baseline and 0.4 dv below the 2014 to 2018 average. Natural conditions have been reached at these Class 1 Areas and air quality is projected to continue to be better than natural conditions by 2028. However, we anticipate that there may be additional visibility improvements with improved air quality in the state over the remaining implementation periods.

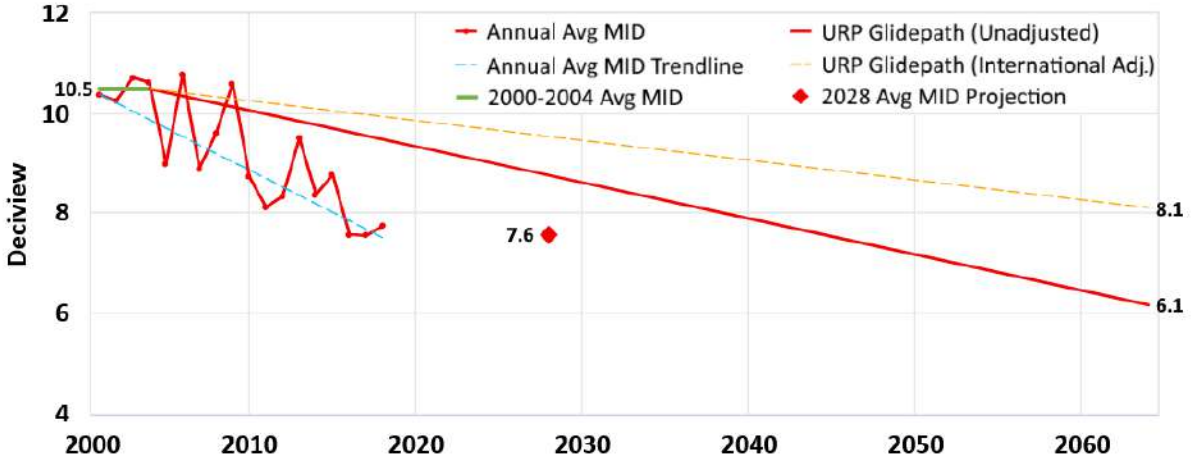


Figure 9-5: Projected 2028 Visibility Conditions on the MID in Goat Rocks Wilderness and Mount Adams Wilderness

Progress in reducing visibility impairing pollutants

Table 9-6: Projected changes in light extinction (Mm^{-1}) from 2014 – 2018 baseline to 2028 in Mount Adams Wilderness and Goat Rocks Wilderness

	Ammonium sulfate	Ammonium nitrate	Organic mass	Elemental carbon	Coarse mass	Fine soil	Sea salt
IMPROVE 2014-2018 average	6.4	1.5	2.8	0.7	0.9	0.3	0.2
2028 OTB Projection	6.3	1.0	2.6	0.5	0.9	0.3	0.2
Percent Change	-1%	-36%	-7%	-21%	0%	-3%	-1%

Summary: Ecology concludes from this analysis that overall Washington is making progress in reducing visibility impairing pollutants impacting Goat Rocks Wilderness and Mount Adams Wilderness. The 2028 RPG is 7.5 dv assuming emission controls that are on the books. This is less than projected natural conditions of 8.1 with the glidepath adjusted endpoint.

Clearest days

The monitored 2000-2004 baseline conditions at WHPA1 on the clearest days are 1.7 dv. WRAP modeling projects no degradation on the clearest days because the 2028 visibility of 0.91 dv is below the clearest days baseline.

9.7 Pasayten Wilderness

Most impaired days

Baseline, adjusted glidepath, and projected visibility

Visibility conditions at Pasayten Wilderness are monitored at the IMPROVE site PASA1 The monitored 2000-2004 baseline visibility at this site on the most impaired days (MID) is 10.4 dv. The calculated natural conditions for the adjusted glidepath are 8.0 dv, a difference of 2.4 dv and a rate of 0.04 dv per year (2.4 dv divided by 60 years). This is the average rate that needs to be maintained to reach natural visibility conditions in the park by 2064. The amount of visibility improvement from the baseline to 2028 required to stay below the 2028 URP adjusted glidepath for MID is 0.96 dv. The 2028 RPG is projected to be 9.2 dv, which is a visibility improvement of 1.2 dv from the baseline and 0.3 dv below the 2014 to 2018 average.

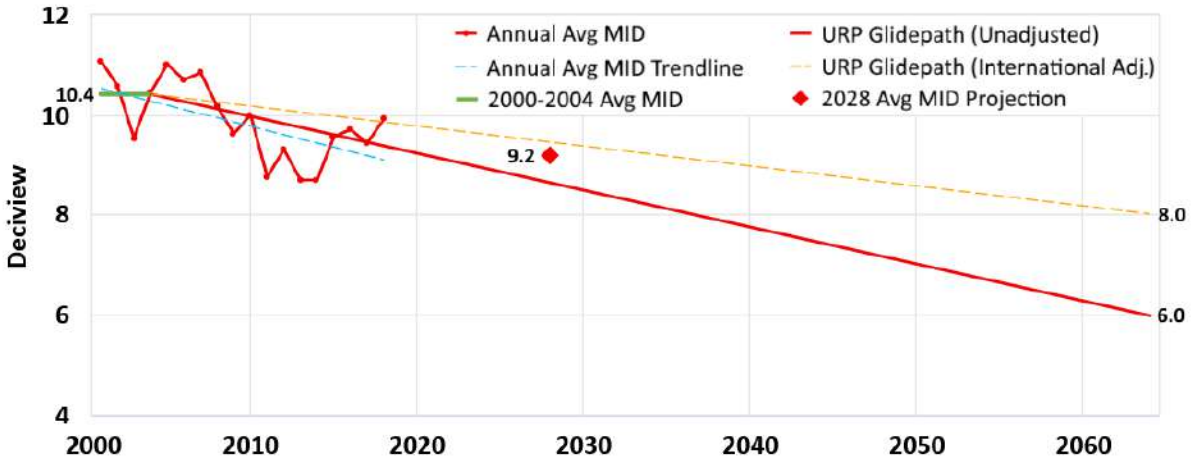


Figure 9-6: Projected 2028 visibility conditions on the MID in Pasayten Wilderness

Progress in reducing visibility impairing pollutants

Table 9-7: Projected changes in light extinction (Mm^{-1}) from 2014 – 2018 baseline to 2028 in Pasayten Wilderness

	Ammonium sulfate	Ammonium nitrate	Organic mass	Elemental carbon	Coarse mass	Fine soil	Sea salt
IMPROVE 2014-2018 average	5.8	2.3	5.4	1.1	1.3	0.4	0.1
2028 OTB projection	5.8	1.8	5.2	1.0	1.3	0.4	0.1
Percent change	0%	-23%	-2%	-9%	0%	-1%	-1%

Summary: Ecology concludes from the analysis provided above that Washington is making progress in reducing visibility impairing pollutants impacting Pasayten Wilderness. The 2028 RPG is 9.2 dv assuming emission controls that are on the books.

Clearest days

The monitored 2000-2004 baseline conditions at PASA1 on the clearest days are 2.7 dv. WRAP modeling projects no degradation on the clearest days because the 2028 visibility of 1.46 dv is below the clearest days baseline.

9.8 Summary

Ecology established RPGs, in deciviews, for the MID and the clearest days as required by the Regional Haze Rule. These are summarized in Table 9-8 and Table 9.9. It is projected that Washington will continue to make progress during this implementation period and the 2028 MID RPGs are below the URP adjusted glidepath. The 2028 RPGs for the clearest days are projected to stay below the baseline and therefore show no degradation in visibility.

Table 9-8: 2028 reasonable progress goals in deciviews (dv) for the MID

Mandatory Class 1 Areas	Baseline conditions 2000-2004	Five-year average 2014 to 2018	MID reasonable progress goal 2028	Unadjusted glidepath 2028	Adjusted glidepath 2028
Olympic National Park	14.9	11.9	11.5	11.7	12.5
North Cascades National Park & Glacier Peak Wilderness	12.6	10	9.8	10.3	10.8
Alpine Lakes Wilderness	15.4	12.7	12.0	12.1	12.5
Mount Rainier National Park	16.5	12.7	12.0	13	13.9
Goat Rocks Wilderness & Mount Adams Wilderness	10.5	8.0	7.6	8.7	9.5
Pasayten Wilderness	10.4	9.5	9.2	8.6	9.4

Table 9-9: 2028 projections in deciviews (dv) for the clearest days

Mandatory Class 1 Areas	2000-2004 Baseline Conditions	2028 projection
Olympic National Park	6	3.37
North Cascades National Park & Glacier Peak Wilderness	3.4	2.38
Alpine Lakes Wilderness	5.5	3.03
Mount Rainier National Park	5.5	3.68
Goat Rocks Wilderness & Mount Adams Wilderness	1.7	0.91
Pasayten Wilderness	2.7	1.46

International anthropogenic emissions contribute to visibility impairment in all of Washington's Class 1 Areas. International emissions include emissions from Canada, Asia, international commercial marine vessels from outside and inside the Emissions Control Areas, and all other non-US anthropogenic emission sources from outside and inside the modeling domain. Thus Washington is adding the international contributions to the endpoint (natural conditions) of the glidepaths for all the State's Class 1 Areas since those emissions are significant and are not controllable by the state. If prescribed fire has a significant influence on regional haze in the future, natural conditions may need to be adjusted further, as allowed by the Regional Haze Rule.

Under the Regional Haze Rule, RPGs for the clearest days are required to ensure no degradation of visibility from baseline visibility conditions. WRAP's modeling analysis indicates these goals will be met. Washington's average decrease in dv (visibility improvement) is summarized in Table 9-10. The required average decrease in dv per year from 2004–2064 to achieve natural conditions is listed in the second column. For both 2004–2018 and 2004–2028, Washington's visibility improvement per year exceeds the average per year rate needed to achieve natural conditions by 2064.

Table 9-10: Average visibility improvement in deciviews (dv) on MIDs at Washington's Class 1 Areas

Monitor	2004 to 2064 dv average needed per year to stay on track to meet 2064 natural conditions	Actual dv decrease per year 2004 to 2018	Projected 2004 to 2028 RPG dv decrease per year
MORA1	0.13	0.27	0.19
WHPA1	0.04	0.18	0.12
SNPA1	0.12	0.19	0.14
NOCA1	0.07	0.19	0.12
PASA1	0.04	0.06	0.05
OLYM1	0.10	0.21	0.14

Chapter 10.Future Planning Process and Summary

10.1 Future planning process

The Regional Haze Rule requires each state to prepare a long-term monitoring strategy and commit to the periodic collection, reporting, and analysis of monitoring and emissions inventory data. The Regional Haze Rule also includes other requirements regarding periodic progress reports, State Implementation Plan (SIP) revisions, and continuing consultation. These future planning requirements are:

- Submitting a monitoring strategy with the SIP
- Including a commitment to update the statewide emissions inventory of visibility impairing pollutants
- Submitting periodic reports describing progress towards the reasonable progress goals
- Determining the adequacy of the existing SIP
- Revising the SIP every ten years
- Continuing interstate coordination and consultation
- Continuing consultation with the Federal Land Managers (FLMs)

Monitoring strategy

Ecology will continue to work in collaboration with the Western Regional Air Partnership (WRAP) and rely upon their adequate technical support to meet its commitment to conduct the analyses necessary to meet the requirements of the Regional Haze Rule.

Ecology will depend on the Inter-Agency Monitoring of Protected Visual Environments (IMPROVE) monitoring program to collect and report aerosol monitoring data for long-term reasonable progress tracking as specified in the Regional Haze Rule. The Regional Haze Rule is a long-term tracking program with an implementation period set for 60 years and states expect the IMPROVE program will provide data based on the following goals:

- Maintain a stable configuration of the individual monitors and sampling sites, and stability in network
- Continue operations for the purpose of continuity in tracking reasonable progress trends
- Assure sufficient data capture at each site of all visibility-impairing species
- Comply with EPA's quality control and assurance requirements
- Prepare and disseminate periodic reports on IMPROVE program operations

Ecology is relying on the IMPROVE program with the fundamental assumption that network data collection operations will not change, or if changed, will remain directly comparable to those operated by the IMPROVE program during the 2000-04 Regional Haze Rule baseline period. Ecology based the technical analyses and reasonable progress goals in this implementation plan on data from these sites.

Federal agencies provide the human resources to operate these monitors. Ecology will collaborate with the EPA, FLMs, other states, tribes, and the IMPROVE committee to ensure adequate and representative data collection and reporting by the IMPROVE program.

Ecology will use data reported by the IMPROVE program as part of the regional technical support analysis tools found at the Technical Support System (TSS2), as well as other analysis tools and efforts sponsored by WRAP. Ecology will participate in the ongoing regional analysis activities of WRAP to collectively assess and verify the progress toward reasonable progress goals and natural conditions. We will also support interstate consultation as the Regional Haze Rule is implemented, and collaborate with WRAP members to ensure the continued operation of these technical support analysis tools and systems. Ecology may conduct additional analyses as needed.

Statewide emissions inventory updates

Ecology has prepared a statewide inventory of emissions that we reasonably expect to cause or contribute to visibility impairment in Class 1 Areas. Chapter 4 of this plan summarizes the emissions by pollutant and source category.

Ecology will update statewide emissions and will use the data for tracking emission changes and trends. We will update the inventories every three years on the same schedule as the three-year reporting required by EPA's Consolidated Emissions Reporting Rule.

Ecology is a member of WRAP and will continue to use WRAP to store and access emission inventory data for the region. Ecology will also depend on and participate in additional periodic emissions inventory efforts by the WRAP. Further, Ecology will continue to depend on and use the capabilities of the WRAP's regional modeling to simulate the air quality impacts of emissions for haze and other related air quality planning purposes.

Periodic progress reports

The Regional Haze Rule requires states to submit a progress report to EPA every five years evaluating progress towards the reasonable progress goals. The requirements for the progress report are in the Regional Haze Rule (40 CFR 51.308(g)) and are discussed in Chapter 1 of this document.

Washington commits to submitting a report on reasonable progress to EPA every five years. The reasonable progress report will evaluate progress made towards the reasonable progress goals for each mandatory class 1 area. Ecology's review will address each of the required elements listed above. The state will also evaluate the monitoring strategy adequacy in assessing reasonable progress goals.

Determination of State Implementation Plan Adequacy

The Regional Haze Rule requires states to make a determination of the adequacy of the implementation plan as part of its five-year progress report. Based on the findings of the five-year progress report, Ecology finds that no further substantive SIP revisions of the existing plan are required in order to meet established visibility goals at this time.

Future State Implementation Plan Revisions

In addition to a SIP revision made for plan inadequacy, the Regional Haze Rule requires the states to revise and submit a comprehensive regional haze implementation plan revision to EPA every ten years. Future SIP revisions must evaluate and reassess all of the elements required

under40 CFR 51.308(f) and specifically address the items listed in 40 CFR 51.308(f)(1-3). The plan revision must take into account improvements in monitoring data collection and analysis, control technologies and other relevant factors. Washington's commitments to comply with Regional Haze Rule requirements for future plans follows:

Approximately every 10 years, Washington commits to completing and submitting a comprehensive regional haze SIP revision to EPA, evaluating and reassessing all of the elements required under 40 CFR 51.308(f). In evaluating and reassessing these elements, Washington commits to:

- Determine current visibility (most recent five-year period preceding the required date of the SIP submittal for which data is available) conditions for the most impaired and least impaired days and determine the actual progress made towards natural conditions.
- Determine the effectiveness of the long-term strategy for achieving the reasonable progress goals for the prior SIP period as well as include enforceable emission limitations and compliance schedules.
- Affirm or revise the current reasonable progress goals based on assessment of new or updated information, improved technologies and on-going legislation. If the reasonable progress goals are insufficient to attain natural conditions by 2064, Washington will analyze whether there are additional or new control measures to adopt to achieve the degree of visibility improvement projected by the analysis contained in the SIP.

Continuing Interstate Coordination and Consultation

In accordance with 40 CFR 51.308(f)(2)(ii), Washington commits to continue consultation with other states which may reasonably be anticipated to cause or contribute to visibility impairment in Washington's mandatory Class 1 Areas. Washington will also continue consultation with any state for reasonably anticipated Washington's emissions that cause or contribute to visibility impairment in those states' mandatory Class 1 Areas.

Should disagreement arise between another state, or group of states and Washington, Washington will describe the actions taken to resolve the disagreement in its regional haze SIP submittal for EPA's consideration. Washington commits to coordinate its emission management strategies with affected states and will continue to include in its future regional haze SIP revisions all measures necessary to obtain its share of emissions reductions for meeting other states' reasonable progress goals.

Washington commits to continued participation in the WRAP, to the extent possible, and to coordinating future plan revisions with other WRAP member states in addressing regional haze.

Continuing Consultation with the Federal Land Managers

Section 51.308(i)(2) of the Regional Haze Rule requires that the state provide FLMs the opportunity for consultation in person and at least 60 days prior to holding any public hearing on plan revisions.

Washington commits to continuing to provide FLMs the opportunity for consultation in accordance with 40 CFR 51.308(i)(2).

The designated visibility protection program coordinators for the National Park Service and the U.S. Forest Service will coordinate the consultation.

Tribal Communication

Ecology will continue outreach and communication with WA Tribes and tribes in neighboring states to provide the opportunity for engagement with the tribes regarding the regional haze program.

10.2 Amendments to the 2021 regional haze SIP revision

The RHR requires States to perform a Four-Factor Analysis (FFA) to determine whether the installation of new emission controls at certain facilities is necessary for the State to make reasonable progress toward the national visibility goal. In Washington State, RCW 70A.15.2230 (the "RACT statute") is the legal mechanism that Ecology can use to require existing sources to install new emission controls that are determined to be reasonable. Because the analysis performed under the State's RACT process is equivalent to the RHR's FFA, Ecology will use the RACT process to require the installation of reasonable emission controls for purposes of compliance with the RHR.

40 CFR 51.308(f) requires the State's long-term strategy to include all measures that are "necessary to make reasonable progress, as determined pursuant to [40 CFR 51.308](f)(2)(i) through (iv)." In turn, 40 CFR 51.308(f)(2)(i) requires the State to consider the following four statutory factors in determining which emission reductions measures are necessary to make reasonable progress:

- the costs of compliance,
- the time necessary for compliance,
- the energy and non-air quality environmental impacts of compliance, and
- the remaining useful life of any potentially affected anthropogenic source of visibility impairment.

Pursuant to RCW 70A.15.1030(20) and 70A.15.2230(5), the RACT evaluation of new emission controls at existing stationary sources requires Ecology to consider the following:

- the impact of the source upon air quality,
- the availability of additional controls,
- the emission reduction to be achieved by additional controls,
- the impact of additional controls on air quality,
- and the capital and operating costs of the additional controls.

The costs of compliance

Under the RACT analysis, Ecology characterizes and considers the cost of compliance consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. The cost of compliance factor in 40 CFR 51.308(f)(2)(i) directly correlates to the RACT analysis consideration of capital and operating costs of the additional controls. The capital and operating costs in RACT are for purchase, installation, and operation of all equipment. These costs include the actual emission

control equipment, any non-air quality equipment, and the energy costs to operate the equipment.

The time necessary for compliance

Under the RACT analysis, Ecology characterizes and considers the time necessary for compliance consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. Under the RACT analysis requirements, Ecology determines the time necessary for compliance as part of considering the capital and operating costs of the additional controls and impact of the source upon air quality. Specifically, a shorter amount of time for compliance would involve costs distributed over a shorter time and thus have a larger annualized cost. The impact of the source on air quality is also a consideration in the time for compliance. The longer it takes to install and operate the control equipment the greater the negative impact on air quality.

The energy and non-air quality environmental impacts of compliance

Under the RACT analysis, Ecology characterizes and considers the energy and non-air quality environmental impacts of compliance consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. Ecology considers the energy and non-air quality environmental impacts of compliance factor as part of analyzing the capital and operating costs of the additional controls in the RACT analysis. The RACT analysis includes costs for equipment directly related to the emissions and all indirectly required equipment needed to install and operate the new controls. The operating cost requirement in the RACT analysis also covers the energy impacts of the controls and supporting equipment.

The remaining useful life of any potentially affected anthropogenic source of visibility impairment

Under the RACT analysis, Ecology characterizes and considers the remaining useful life of any potentially affected anthropogenic source of visibility impairment consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. Ecology considers the remaining useful life of an emissions control system as part of calculating the capital and operating costs of the system. Specifically, the annualized costs of the emissions control system are affected by the remaining useful life. The shorter the useful life, the larger the annual costs associated with control equipment.

Additionally, RACT requires consideration of the impact of the source upon air quality.' This is consistent with the CAA, RHR, and EPA guidance. While the four statutory factors must be considered in determining what is necessary to make reasonable progress, they are not the only factors that States may consider in this evaluation. As explained by EPA in its 2019 guidance, States have the flexibility to consider other factors, including visibility benefits, when determining the emission reduction measures that are necessary to make reasonable progress:

> "Section 51.308(f)(2)(i) of the Regional Haze Rule requires consideration of the four factors listed in CAA section 169A(g)(1) and does not mention visibility benefits. However, neither the CAA nor the Rule suggest that only the listed factors may be considered. Because the goal of the regional haze program is to improve visibility, it is reasonable for a state to consider whether and by how much an emission control measure would help achieve that goal. Likewise, it is reasonable that such information

on visibility benefits be considered in light of other factors that may weigh for or against the control at issue. Such a balancing of outcomes is consistent with CAA section 169A(b)(2), which states that SIPs must contain elements as may be necessary to make reasonable progress towards meeting the national visibility goal. Thus, EPA interprets the CAA and the Regional Haze Rule to allow a state reasonable discretion to consider the anticipated visibility benefits of an emission control measure along with the other factors when determining whether a measure is necessary to make reasonable progress."[29]

Washington received four-factor analyses from the refineries that indicated there were no reasonable controls at the refineries. Ecology then conducted preliminary analyses using emission inventory data and the EPA Control Cost Manual. The results from the four-factor analyses and the preliminary control cost model were vastly different. This indicated the need for a more robust analysis to determine reasonableness of controls. Therefore, Ecology will use the RACT process to (1) evaluate and determine the emissions reduction measures that are necessary to make reasonable progress and (2) incorporate these measures into its long-term strategy and Regional Haze SIP in a manner that is enforceable as a legal and practical matter.

Ecology will supplement this plan with the results of the reasonableness analysis. The analysis will include an implementation schedule that will be coordinated with scheduled maintenance shutdowns at the refineries when necessary to maintain costs at a reasonable level. These shutdowns occur approximately every two to six years. Emission reductions from refineries were not included in the 2028 projected emissions for the second implementation period, so this does not affect the modeled 2028 reasonable progress goals.

10.3 Summary

National Visibility Goal

In 1977, Congress amended the Clean Air Act and declared a national visibility goal:

> *"The prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution." (CAA § 169A).*

The objectives of the Regional Haze Rule are to improve existing visibility in all 156 mandatory Class 1 Areas, prevent future impairment of visibility by human-caused sources, and meet the national goal of natural visibility conditions by 2064. Emissions from numerous sources that are often mixed and transported long distances cause visibility impairment related to regional haze

Washington's State Implementation Plan

There are planning phases from 2005 to 2064; each planning phase covers approximately 10 years. The first regional haze state implementation plan (regional haze SIP) revision covered the

[29] EPA-457/B-10-003, *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, Section II.B.5.

initial planning period from 2005 to 2018. It provided the basis for future SIPs to continue reducing visibility-impairing emissions and meet the national visibility goal by 2064.

This second regional haze SIP sets reasonable progress goals for each of the eight mandatory Class 1 Areas in Washington. The reasonable progress goals reflect already adopted controls for sources that cause or contribute to visibility impairment. Ecology will supplement this second SIP revision with reasonable controls that we determine during the next phase of this implementation period.

Washington developed a long-term strategy that addresses reasonably attributable visibility impairment and regional haze. The long-term strategy applies to mandatory Class 1 Areas both within the state and outside the state where emissions from the state are reasonably anticipated to contribute to visibility impairment. We designed the coordinated strategy to achieve the reasonable progress goals for mandatory Class 1 Areas inside Washington and the reasonable progress goals established by other states for mandatory Class 1 Areas outside of Washington where emissions from Washington are reasonably anticipated to contribute to visibility impairment.

Long-Term Challenges and Issues

Under the Regional Haze Rule, the state of Washington is responsible for doing its share of visibility improvement to achieve the national goal for mandatory Class 1 Areas within Washington and Class 1 Areas outside of Washington that it may affect. The Western Regional Air Partnership (WRAP) has provided a technical framework for understanding and dealing with the source regions and sources of visibility impairment. The WRAP analysis has also revealed significant challenges to long-term reasonable progress and raised technical and regulatory issues.

Significant challenges to meeting the national visibility goal in Washington's mandatory Class 1 Areas:

- Emissions from outside the modeling domain, Pacific offshore, and Canada significantly impact visibility. These are all beyond the state's control. In this regional haze SIP, we have proposed an adjustment to the glidepath endpoint to compensate for these international contributions.
- It will be difficult to achieve natural conditions, at some Class 1 Areas, unless we can either reduce the contribution of organic mass from fire to visibility impairment or not include it in the most impaired days metric. The most impaired days (MID) metric as it is currently calculated is insufficient to remove the effect of all wildfire smoke in Washington. With an increase in catastrophic fire in the Pacific Northwest, this will continue to be a challenge and requires an acceptable method to adjust the MID metric within each state as needed.

Meeting the national goal also requires addressing technical and regulatory issues including:

- Better understanding of the role of biogenic organic aerosols in visibility impairment and analytical technical tools

- Reconsideration of natural conditions especially in light of the expectation that prescribed fire will be more widespread in the future
- Continued development of federal rules reducing visibility-impairing pollutants
- Continued development of controls for on-road and off-road mobile sources

Meeting these challenges and dealing with the issues presented by our changing environment will ultimately enable Washington to achieve natural conditions within the state and contribute to meeting natural conditions in Class 1 Areas outside the state.

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EXHIBIT 20

News Release

TransAlta Signs Long-Term Agreement for 700 MW at Centralia Facility Enabling Coal to Natural Gas Conversion

CALGARY, Alberta (December 9, 2025)

Highlights

- TransAlta to perform coal-to-gas conversion on its Centralia Unit 2 facility in Washington state, with a planned contracted capacity of 700 MW
- The converted facility will deliver reliable power to Puget Sound Energy under a long-term, 16-year fixed price contract through Dec. 31, 2044
- The project is currently projected to deliver a build multiple[1] of approximately 5.5 times
- The converted facility maintains TransAlta's position in its strategic core jurisdiction of the Pacific Northwest and extends the life of one of its legacy assets

TransAlta Corporation (TransAlta or the Company) (TSX: TA) (NYSE: TAC) is pleased to announce that it has signed a long-term tolling agreement (the Agreement) with Puget Sound Energy, Inc. (PSE) to convert its Centralia Unit 2 facility from coal to natural gas-fired generation. The Agreement provides a fixed-price capacity payment that provides PSE the exclusive right to the capacity, energy and ancillary service attributes of, as well as the dispatch rights to, the 700 MW facility.

"Our Centralia facility has a long history of providing reliable and affordable power in the Pacific Northwest region. We are pleased to extend the useful life of this asset and support the ongoing reliability needs of PSE and, by extension, its customers" said John Kousinioris, President and Chief Executive Officer.

"The facility is scheduled to cease coal-fired generation at the end of 2025, and the conversion to natural gas will lower the emission intensity profile of the facility by approximately 50 per cent. We are grateful for the constructive and solution-oriented engagement we have received from the Department of Ecology and other state and local regulatory bodies through the development of this project and we are well positioned to receive required regulatory approvals in a timely manner. This project demonstrates the valuable role that legacy assets can play in supporting the State's clean energy laws and system reliability in a cost effective and timely fashion," added Mr. Kousinioris.

"When the facility re-enters operations, it will generate long-term contracted cash flow for TransAlta, earning a full return on and of capital within the contract term. The Company is well positioned to execute this project given our deep technical, operational and engineering experience gained in previous coal-to-gas conversions," concluded Mr. Kousinioris.

Approximately US$600 million of capital expenditures will be required to extend the useful life of the facility and convert it from coal to natural gas-fired generation, delivering an anticipated build multiple[1] of approximately 5.5 times. The target commercial operation date is late-2028 and the facility will operate until the end of 2044 under the terms of the Agreement. TransAlta anticipates declaring a final investment decision (FID) after receipt of all required approvals in early 2027. The Agreement is subject to customary regulatory approvals, including PSE receiving satisfactory approval from the Washington Utilities and Transportation Commission.

[1] Build multiple is a non-IFRS ratio which is calculated using capital expenditures and adjusted EBITDA[2]. We believe build multiple provides investors with a useful measure to evaluate capital projects. Readers are cautioned that our method for calculating build multiple may differ from methods used by other entities. Therefore, it may not be comparable to similar measures presented by other entities.

[2] Adjusted EBITDA is a non-IFRS measure. It does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Adjusted EBITDA is calculated by adjusting earnings before income taxes for certain items that may not be reflective of ongoing business performance. Please refer to the "Non-IFRS and Supplementary Financial Measures" section of our management's discussion and analysis for the three and nine months ended September 30, 2025 ("MD&A") for more information about the non-IFRS measures we

use, including a reconciliation of adjusted EBITDA to earnings before income tax, the most directly comparable IFRS measure, which section of the MD&A is incorporated by reference herein. The MD&A can be found on SEDAR+ (www.sedarplus.ca) under TransAlta's profile.

About TransAlta Corporation:

TransAlta owns, operates and develops a diverse fleet of electrical power generation assets in Canada, the United States and Australia with a focus on long-term shareholder value. TransAlta provides municipalities, medium and large industries, businesses and utility customers with affordable, energy efficient and reliable power. Today, TransAlta is one of Canada's largest producers of wind power and Alberta's largest producer of thermal generation and hydro-electric power. For over 114 years, TransAlta has been a responsible operator and a proud member of the communities where we operate and where our employees work and live. TransAlta aligns its corporate goals with the UN Sustainable Development Goals and the Future-Fit Business Benchmark, which also defines sustainable goals for businesses. Our reporting on climate change management has been guided by the International Financial Reporting Standards (IFRS) S2 Climate-related Disclosures Standard and the Task Force on Climate-related Financial Disclosures (TCFD) recommendations. TransAlta has achieved a 70 per cent reduction in GHG emissions or 22.7 million tonnes CO2e since 2015 and received an upgraded MSCI ESG rating of AA.

For more information about TransAlta, visit our web site at transalta.com.

Cautionary Statement Regarding Forward-Looking Information

This news release includes "forward-looking information," within the meaning of applicable Canadian securities laws, and "forward-looking statements," within the meaning of applicable United States securities laws, including the Private Securities Litigation Reform Act of 1995 (collectively referred to herein as "forward-looking statements"). Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "believe", "expect", "estimate", "anticipate", "intend", "plan", "forecast", "continue" or other similar words. In particular, this news release contains forward-looking statements about the following, among other things: contracted capacity of 700MW; build multiple; the facility's emission intensity profile; receipt of required regulatory approvals in a timely manner; expected capital expenditure; the target commercial operation date and the timing of a final investment decision with respect to the conversion.

Forward-looking statements and future-oriented financial information in this news release are intended to provide the reader information about management's current expectations and plans and readers are cautioned that such information may not be appropriate for other purposes. Forward-looking statements are subject to important risks and uncertainties and are based on certain key assumptions. All forward-looking statements reflect TransAlta's beliefs and assumptions based on information available at the time the statements were made and as such are not guarantees of future performance. As actual results could vary significantly from the forward-looking statements, you should not put undue reliance on forward-looking statements and should not use future-oriented information or financial outlooks for anything other than their intended purpose. We do not update our forward-looking statements due to new information or future events, unless we are required to by law. For additional information on the assumptions made, and the risks and uncertainties which could cause actual results to differ from the anticipated results, refer to our most recent MD&A and the 2024 Integrated Report, including the section titled "Governance and Risk Management" in our MD&A for the year ended December 31, 2024, filed under TransAlta's profile on SEDAR+ at www.sedarplus.ca and with the U.S. Securities and Exchange Commission at www.sec.gov.

Note: All financial figures are in Canadian dollars unless otherwise indicated.

For more information:

News Release

Investor Inquiries:
Phone: 1-800-387-3598 in Canada and US
Email: investor_relations@transalta.com

Media Inquiries:
Phone: 1-855-255-9184
Email: ta_media_relations@transalta.com

EXHIBIT 21

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Prevention of Significant Deterioration Permit Application

TransAlta Centralia Generation, LLC

Lewis County, Washington

December 2025

Prepared for

TransAlta Centralia Generation, LLC
913 Big Hanaford Road
Centralia, WA 98531

Prepared by



828 Great Northern Blvd, Suite 300
Helena, MT 59601

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

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Acronyms/Abbreviations

ADP	Air Discharge Permit
AP-42	U.S. Environmental Protection Agency Compilation of Air Pollutant Emission Factors
ASIL	Acceptable source impact level
BACT	Best available control technology
BART	Best available retrofit technology
CAM	Compliance Assurance Monitoring
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CH_4	Methane
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
EU	Emissions unit
FCAA	Federal Clean Air Act
FR	Federal Register
GHG	Greenhouse gas
gr/dscf	Grains per dry standard cubic foot
HAP	Hazardous air pollutant
lb/MMBtu	Pounds per million British thermal units
lb	Pounds
lb/hr	Pounds per hour
MACT	Maximum Achievable Control Technology
MMBtu	Million British thermal units
MMBtu/hr	Million British thermal units per hour
N_2O	Nitrous oxide
NAAQS	National Ambient Air Quality Standards
NAA	Nonattainment Area

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NNSR	Nonattainment Area New Source Review
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_2	Nitrogen dioxide
NO_X	Nitrogen oxides
NSPS	New Source Performance Standards
NSR	New Source Review
PM	Particulate matter
PM_{10}	Particulate matter with a diameter of 10 micrometers or less
$PM_{2.5}$	Particulate matter with a diameter of 2.5 micrometers or less
PSD	Prevention of Significant Deterioration
PTE	Potential to emit
RCW	Revised Code of Washington
SO_2	Sulfur dioxide
SWCAA	Southwest Clean Air Agency
TAPs	Toxic Air Pollutants
tpy	Tons per year
VOC	Volatile organic compounds
WDOE	Washington Department of Ecology
WAC	Washington Administrative Code

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1.0 INTRODUCTION

TransAlta Centralia Generation, LLC (TransAlta) operates the Centralia electrical generation facility at the Big Hanaford site in Lewis County, Washington. The site originally included two coal-fired combustion units with associated generation equipment – Unit #1 and #2 are both rated at 7,500 million British Thermal Units per hour (MMBtu/hr). Unit #1 was retired in 2020. Unit #2 is operational and continues to generate electricity. The Facility operates under Southwest Clean Air (SWCAA) Operating Permit #SW-98-8-R5. The Project Site, shown in Figure 1-1, is 5 miles northeast of Centralia in Lewis County with a physical address at 913 Big Hanaford Road, Centralia, Washington. The air quality classification for the immediate area is "Unclassifiable or Better Than National Standards" (40 Code of Federal Regulations, CFR, 81.327) for all pollutants.

TransAlta proposes to modify the existing Unit #2 coal-fired electrical generation facility from coal to natural gas combustion, referred to as a coal to gas (CTG) conversion (the Project). Unit #2 will cease using coal as a fuel source in December 2025. Once converted, Unit #2 will burn natural gas to generate steam and convert that steam to electrical energy for use by the customer. Unit #2 will be operated at a maximum 59% capacity factor, which may entail operating at maximum heat input for fewer hours or operating at a lower megawatt (MW) output for extended hours. However, current expectations are that the facility will operate for less than 40% of all hours on an annual basis over the life of the Project; at a capacity factor of less than 20% as the majority of operating hours are expected to be at either half load (~350 MW) or at minimum stable generation (~190 MW). TransAlta is requesting an operational limitation based on the annual 59% capacity factor. Emissions calculated for Unit #2 are based on this limitation.

The framework and function of the boiler will remain unchanged after the conversion, including most of the existing boiler parts related to absorbing the heat from the combustion of fuels and converting it to superheated steam. To change the fuels, the burners in each corner of the boiler will be modified to create the proper mixture of natural gas and air for proper combustion.

Unit #2 will use low NO_x burners (LNB), separated overfire air (SOFA), a combustion optimization system (COS), and flue gas recirculation (FGR) to minimize formation of oxides of nitrogen (NO_x) during combustion. Emissions of carbon monoxide (CO) and volatile organic compounds (VOC) will be controlled using good combustion practices. Particulate matter (PM), sulfur dioxide (SO_2)[1], and sulfuric acid mist (H_2SO_4) emissions will be controlled through good combustion practices and the use of clean-burning pipeline-quality natural gas.

The Project will also require replacing the existing oil-fired auxiliary boiler with a new natural gas-fired unit and replacing the existing Unit #2 cooling towers. New units associated with the modification will include two natural gas-fired water bath heaters (10 MMBtu/hr each).

[1] Unit #2 is currently equipped with PM and SO_2 controls associated with coal combustion. These controls will be removed as a part of the conversion to natural gas combustion as natural gas produces far less of both pollutants than prior operations.

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1.1 Regulatory Overview

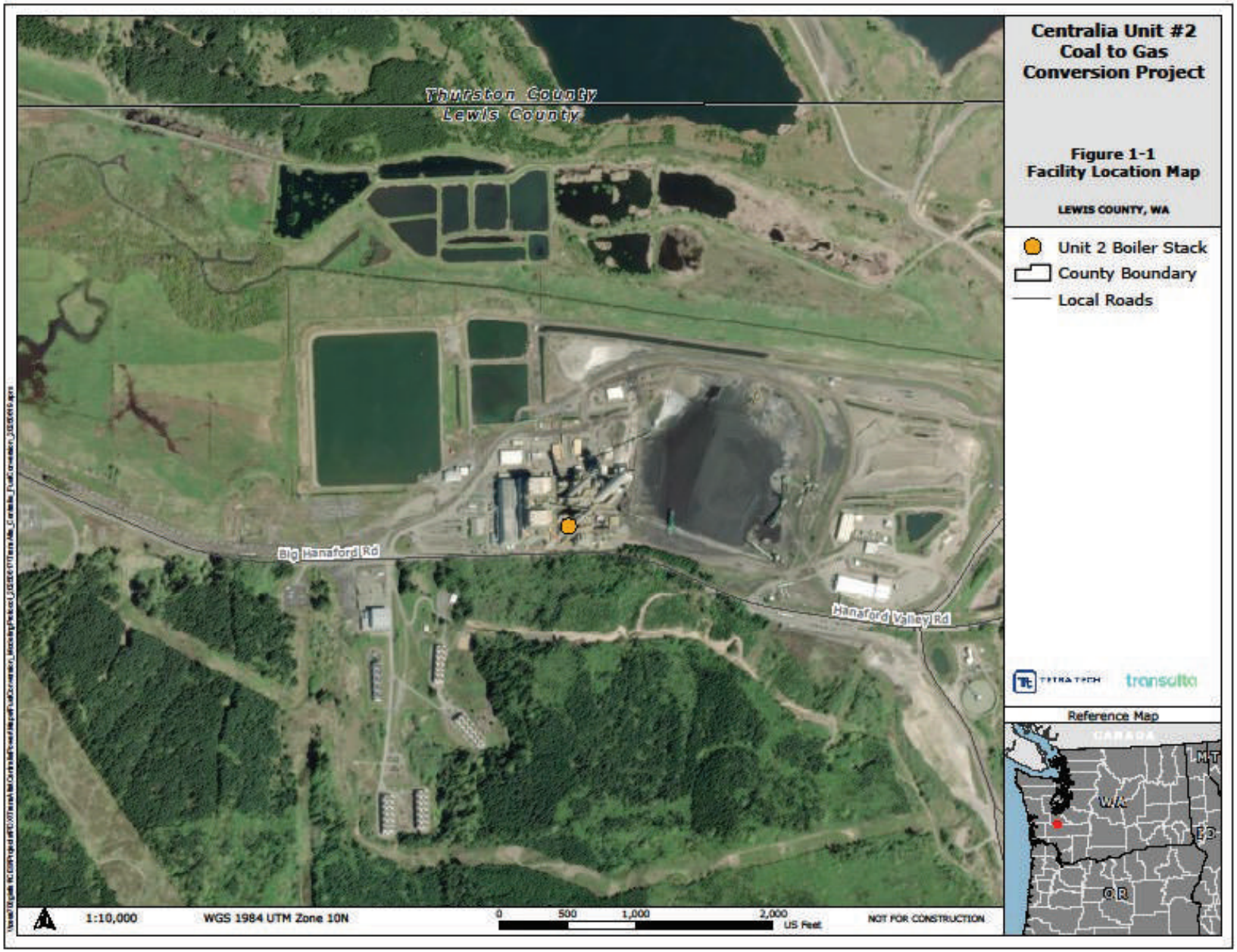
Air emissions from the proposed Project primarily consist of combustion products from Unit #2. Because Lewis County is designated as unclassifiable/attainment with respect to the National Ambient Air Quality Standards (NAAQS) for all criteria pollutants and the Facility is a major stationary source under the Prevention of Significant Deterioration (PSD) permitting program, a PSD applicability analysis is required. Based on that analysis, VOC emissions trigger PSD review requirements by exceeding its major modification significant emissions rate (SER). The PSD program is implemented by the Washington Department of Ecology (WDOE). TransAlta is submitting this PSD permit application to WDOE to address Project VOC emissions.

The other criteria pollutants do not trigger PSD and will be subject to the minor source air discharge permit (ADP) program as administered by SWCAA. Those pollutants include[2]: NO_x, CO, PM with a diameter equal to or less than 10 micrometers (PM_{10}), and PM with a diameter equal to or less than 2.5 micrometers ($PM_{2.5}$), SO_2, and H_2SO_4. A separate ADP application will be submitted to SWCAA. The required air toxics analysis will also be submitted to SWCAA because that analysis is within the jurisdiction of the minor source permitting program.

The Project will be in compliance with federal, state, and SWCAA air quality requirements, including the NAAQS, WDOE AAQS, and WDOE's air toxics requirements, as well as all applicable New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP).

[2] Greenhouse gas (GHG) emissions also fall below the SER and therefore do not trigger PSD. In addition, they are not subject to minor source permitting because GHGs are not regulated at the minor source permitting level.

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1.2 Application Overview

1.2.1 Application Organization

This permit application is divided into six sections. Section 1 provides an overview of the Project and regulatory requirements. Section 2 provides a detailed description of the Project, including calculated emissions. Section 3 provides a more detailed discussion of applicable regulations. Section 4 provides the Best Available Control Technology (BACT) emissions control technology evaluations for the applicable criteria pollutants. Section 5 provides air quality modeling analyses demonstrating compliance with the NAAQS. Section 6 provides a list of references.

The WDOE PSD application form is included as Appendix A. Emission calculation spreadsheets providing supporting calculations for the application are provided in Appendix B. Appendix C presents supporting documents for the regulatory analysis. Appendix D presents supporting documents for the BACT analysis. Appendix E provides the air dispersion modeling analysis including detailed emissions and stack parameter data used in the dispersion modeling, a schematic Project layout diagram and Building Profile Input Program (BPIP) model output, detailed model results, and a summary of the Project's Modeling Protocol, submitted to WDOE and SWCAA on September 26, 2025. Similarly, the visibility modeling demonstration and supporting analysis is provided in Appendix F.

1.2.2 Application Contacts

To facilitate agency review of this application, individuals familiar with the Facility and this application are identified below.

Conrad Wieclaw
TransAlta Corporation
Phone: 360-807-8093
e-mail: Conrad_Wieclaw@transalta.com

Debbie Skibicki
Tetra Tech, Inc.
Phone: 406-437-9830
e-mail: debbie.skibicki@tetratech.com

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2.0 PROJECT DESCRIPTION

2.1 Project Summary

TransAlta operates the Centralia electrical generation facility at the Big Hanaford site, in Lewis County, Washington. The site originally included two coal-fired combustion units with associated generation equipment – Unit #1 and #2 are both rated at a nominal heat input rate of 7,500 MMBtu/hr. Unit #1 was retired in 2020. Unit #2 is operational and continues to generate electricity.

The Project Site, shown in Figure 1-1, is 5 miles northeast of Centralia in Lewis County with a physical address at 913 Big Hanaford Road, Centralia, Washington. The air quality classification for the immediate area is "Unclassifiable or Better Than National Standards" (40 CFR 81.327) for all pollutants.

2.2 Description of Major Equipment

2.2.1 Unit #2

The updated Unit #2, rated at 723 megawatts (MW, net), will generate steam from natural gas combustion. The steam produced will be converted to electrical energy in the existing steam turbine. The electrical energy will be sold for use by the customer. The Project is expected to operate at a capacity factor of less than 20 percent of all hours on an annual basis over the life of the Project. Unit #2 will be operated up to (and limited to) a maximum 59% capacity factor. Figure 2-1 provides the process flow diagram for Unit #2 operations.

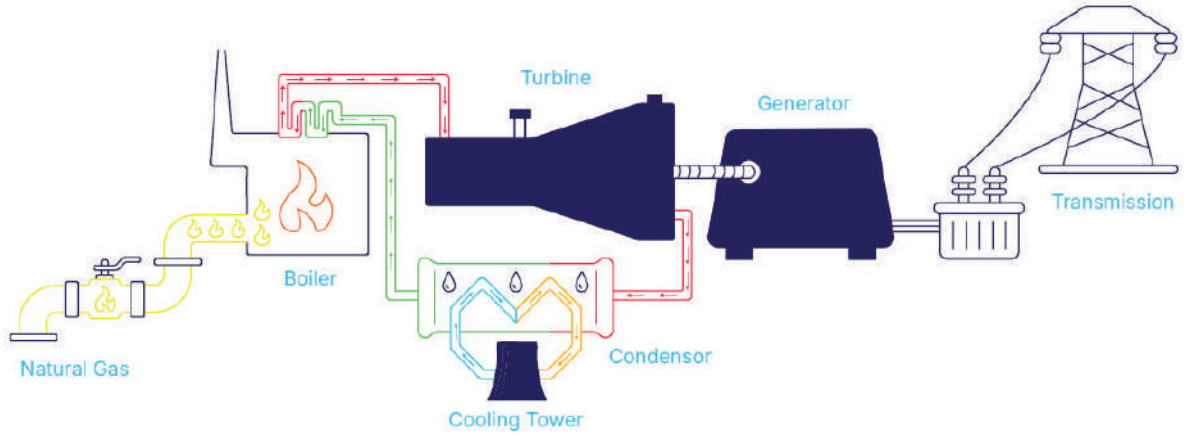


Figure 2-1. Unit #2 Process Flow Diagram

2.2.2 Auxiliary Boiler

The new auxiliary boiler will use natural gas, operating as needed to keep Unit #2 warm during periods of shutdown and to provide steam to Unit #2 during startup and shutdown. It also provides building heat in cold weather periods when Unit #2 is offline. The auxiliary boiler will have a maximum heat input capacity of 149.13 MMBtu/hr and will be limited to 1,300 hours of total operation per year.

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2.2.3 Unit #2 Cooling Towers

The Project includes the replacement of the Unit #2 Cooling Towers with new units. Cooling towers cool the circulating water from the Unit #2 steam turbine. This cooling will be accomplished by means of two twelve-cell mechanical draft low-mist wet cooling tower, operating only when Unit #2 operates (emissions are calculated using 8,760 hours per year of operation to be conservative). A mechanical draft cooling tower will cool the circulating water by spraying the warm circulating water over sheets of plastic material known as fill. This exposes the circulating water to ambient air being drawn in through the sides of the tower towards a fan generally located above the fill. A fraction of the circulating water evaporates into this air, warming it and causing it to become saturated with moisture. A small portion of the circulating water will be entrained in this air flow; this water entrainment is called drift. Each cell of the cooling tower will be equipped with drift eliminators that are typically located above the water sprays to remove the vast majority of the entrained water droplets and return them to the fill. However, a small fraction of these droplets will escape into the fan discharge and be released to the atmosphere. The droplets that are released to the atmosphere contain dissolved solids that form particulates when the droplets evaporate and, therefore, are a source of particulate matter emissions ($PM/PM_{10}/PM_{2.5}$). The water contains no additives or cleaning products that would contribute to or produce emissions.

2.2.4 Water Bath Heaters

The Project includes two water bath heaters to heat the natural gas fuel for combustion in Unit #2 and the auxiliary boiler. Water bath heaters indirectly heat incoming gas to keep the temperature above the point where water or hydrocarbon hydrates could condense in the gas, particularly as pressure drops to meet Unit #2 and the auxiliary boiler fuel input requirements. The proposed water bath heaters are each rated at 10 MMBtu/hr and are planned to operate 8,760 hours per year.

2.3 Emissions Estimates

Emissions from the Project primarily consist of products of combustion from Unit #2. The auxiliary boiler, cooling towers, and water bath heaters are smaller sources of overall Project emissions.

2.3.1 Unit #2

As previously mentioned, Unit #2 emissions are evaluated at a maximum 59% capacity factor at full load burning natural gas. Unit #2 is also assessed at minimum stable generation (190 MW). This load scenario does not impact the potential emissions calculations but is evaluated in the air dispersion modeling analysis to ensure compliance with standards at those specific exhaust parameters. VOC emissions rates are based on the anticipated vendor guarantee of 0.003 lb/MMBtu across generation profiles. VOC emissions rates are expected to follow fuel combustion rates during startup and shutdown operations (as in when the amount of fuel combusted decreases, so do the emission rates of VOC).

Beyond the combustion emissions, when Unit #2 is shutdown, there may be need for the venting of natural gas remaining in the boiler. Those emissions, listed under “shutdown methane venting” are calculated based on a worst-case 50 shutdowns per year and the anticipated venting rate. TransAlta will employ best fuel management practices to minimize the methane venting including slowing of

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fuel into Unit #2 if shutdown is anticipated and firing Unit #2 longer into shutdown to combust excess fuel. Methane is not a regulated pollutant under this action or under the ADP regulatory process, but the information and emissions are provided for administrative completeness.

2.3.2 Auxiliary Boiler and Water Bath Heaters

The VOC emissions for the auxiliary boiler and the water bath heater are based on AP-42, Chapter 1.4 (External Combustion Sources - Natural Gas Combustion) emission factors.

2.3.3 Emissions for CTG Operations

The emissions for the proposed operations are provided in the table below. Importantly, the "Total CTG Project Emissions" line does not take into account that the Project's emissions (except VOC) will be significantly less than the baseline of coal-fired emissions. Unit #2 CTG emissions are based on operations being limited to the annual 59% capacity factor. The overall net decrease in emissions is provided in the applicability analysis in Section 3.1. All pollutants are included for completeness.

Table 2-1. Summary of Project Emissions

TransAlta Coal to Gas Operations (at potential/worst-case emissions rates, in tons per year)										
	PM/TSP	PM_{10}	$PM_{2.5}$	NOx[1]	CO	VOC	SO_2	H_2SO_4	Lead	CO_{2e}
New or Modified Emissions Unit										
Unit 2 CTG	133.06	133.06	133.06	2,131.97	2,907.23	58.14	13.92	0.21	0.01	2,269,524
Methane shutdown venting	0	0	0	0	0	0	0	0	0	595
Auxiliary Boiler	0.67	0.67	0.67	1.45	3.59	0.48	0.07	1E-03	4E-05	11,351
Water Bath Heater #1	0.30	0.30	0.30	0.66	1.62	0.22	0.03	5E-04	2E-05	5,129
Water Bath Heater #2	0.30	0.30	0.30	0.66	1.62	0.22	0.03	5E-04	2E-05	5,129
Cooling tower #1	0.76	0.76	0.45	0	0	0	0	0	0	0
Cooling tower #2	0.76	0.76	0.45	0	0	0	0	0	0	0
TOTAL CTG Project	**135.84**	**135.84**	**135.24**	**2,134.73**	**2,914.05**	**59.06**	**14.05**	**0.21**	**0.01**	**2,291,727**

[1]The Unit #2 NOx emissions are based on emission rates for the first year of operation that includes the COS learning period. NOx emissions will be reduced following the system optimization.

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3.0 REGULATORY APPLICABILITY EVALUATION

This section contains an analysis of the applicability of federal and state air quality regulations to the Facility. The specific regulations and programs that are included in this review include:

- PSD/New Source Review (NSR);
- New Source Performance Standards (NSPS);
- Federal National Emission Standards for Hazardous Air Pollutants (NESHAP);
- Title V Operating Permits;
- Federal Acid Rain Permits;
- Federal Greenhouse Gas (GHG) Reporting Requirements;
- Other WDOE requirements; and
- Other SWCAA requirements.

3.1 PSD/NSR

In accordance with 40 CFR 52.21(2), PSD review applies in attainment areas for the "construction of any new major stationary source or the major modification of any existing major stationary source." The Centralia Plant is in an attainment area[3] and is an existing major stationary source as defined in 40 CFR 52.21(b)(1)[4]. Both the “new major stationary source” and “major modification of any existing major stationary source” analyses are provided below, in addition to information on PSD requirements for this application.

3.1.1 New Major Stationary Source Test

The Centralia Plant is a major stationary source that is currently operating. Because the Facility would need to temporarily cease operations to allow for the conversion of Unit #2 and construction of the new associated emissions units, WDOE requested discussing the United States Environmental Protection Agency’s (EPA) “Reactivation Policy.” The “Guidance on Washington State’s Prevention of Significant Deterioration Permitting Program” (WDOE PSD Guidance), Section 2.2.2.1.3 – Restarting Emissions Units states that “when an emissions unit is restarted after being shut down, PSD permitting may be triggered in one of several ways.” Those ways include the amount of time the facility was out of operation, the reason for the shutdown, statements by the owner or operator regarding intent, and others.

WDOE PSD Guidance under “Reactivation Policy,” states the following:

> *“EPA’s policy on whether a shutdown plant if restarted is subject to PSD review as a new source is outlined in a number of EPA memoranda.[5] Reactivating a “permanently” shut down source*

[3] *See, e.g.,* Air Quality Modeling Results: Levels of Sulfur Dioxide in the Ambient Air Around TransAlta Centralia Generation Power Plant (WDOE 2017).
[4] The Centralia Plant is a fossil fuel-fired steam electric plant of more than 250 MMBtu/hr heat input which emits 100 tons per year or more of any regulated NSR pollutant.
[5] WDOE lists as an example, a September 6, 1978, EPA Memorandum from Edward E. Reich, Director, Division of Stationary Source Enforcement, to Stephen A. Dvorkin, Chief, General Enforcement Branch, Region II.

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> *makes the source a new source under current PSD guidance. A source shutting down for more than two years is a new source if restarted, unless Ecology continued to carry the source in the emission inventory.* ***This presumption can be rebutted by providing evidence that the shutdown was not intended to be permanent****. Owners or operators of facilities that have been shut down must continuously demonstrate concrete plans to restart the facility sometime in the reasonably foreseeable future. The source would not be a new source if the shutdown was not permanent, and the owners kept records of the type and amount of maintenance performed on the temporary shutdown source [emphasis added]."*

The WDOE PSD Guidance also states:

> *"Permanence is determined by the intention of the owner or operator* ***at the time of the shutdown*** *as determined from all the facts and circumstances, including the cause of the shutdown, duration of the shutdown, and the handling of the shutdown by Washington State. A shutdown lasting for two years or more, or resulting in removal of the source from the emissions inventory of the State, should be presumed permanent. The owner or operator proposing to reopen the source would have the burden of showing that the shutdown was not permanent, and of overcoming any presumption that it was [emphasis added]."*

The intention of the owner or operator "at the time of the shutdown" is repeated in numerous guidance documents issued by EPA[6] and is the primary criteria evaluated by EPA for the permanence of shutdowns. Further, the May 27, 1987, EPA Memorandum from John S. Seitz, Director Stationary Source Compliance Division, Office of Air Quality Planning and Standards to David Howekamp, Director Air Management Division, Region IX, states "EPA evaluates the permanence of the shutdown based on the demonstrated intent of the owner or operator to reopen the source. Facts and circumstances surrounding the shutdown, including duration of the shutdown and the handling of the shutdown by the source and State, are evidence of the owner's intent."

The intent is further clarified in the June 11, 1999, Monroe Electric Generating Plant Petition No. 6-99-2 Order signed by Carol M Browner, EPA Administrator, "EPA assesses whether the owner or operator has demonstrated a continuous intent to reopen." TransAlta in its discussions with Lewis County; SWCAA, the regional air permitting authority, and WDOE in addition to vendors, customers, interested stakeholders, etc. has specifically and repeatedly expressed their intent to continue operation of the Centralia Plant as a natural gas generation resource. These plans were developed well before the anticipated end of coal combustion and will continue to build in depth and intensity through the startup of operations.

As mentioned in the WDOE PSD Guidance document, as well as heavily emphasized in EPA guidance, the intention of the owner or operator "at the time of the shutdown" is the primary criteria evaluated

[6] **September 6, 1978, EPA Memorandum** from Edward E. Reich, Director, Division of Stationary Source Enforcement, to Stephen A. Dvorkin, Chief, General Enforcement Branch, Region II; **October 9,1979 EPA Memorandum** from William A. Spratlin, Jr., PE, Chief Air Support Branch, Air and Hazardous Materials Division, Region VII to Harvey D. Shell, Shell Engineering and Associates; **April 5, 2018, EPA Memorandum** from William L. Wehrum, Assistant Administrator, Office of Air and Radiation to LeAnne Johnson Koch, Perkins Coie; **June 11, 1999, In the Matter of Monroe Electric Generating Plant Entergy Louisiana, Inc**., Proposed Operating Permit, Petition No. 6-99-2.

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by EPA for the permanence of shutdowns. TransAlta's intentions have been and continue to be clear – the Unit #2 shutdown is intended only to occur long enough to acquire the appropriate permitting and perform needed unit modifications for the fuel conversion and construction of auxiliary units in support of continued operation. This intent, along with additional EPA criteria support the conclusion that the limited shutdown of Unit #2 was "not intended to be permanent." Thus, Unit #2 is not a new source under these circumstances. The criteria are individually evaluated in a Reactivation Analysis provided in Appendix C – Supporting Documents for Regulatory Analysis.[7]

3.1.2 Major Modification Test

Pursuant to 40 CFR 52.21(b)(1), a modification of an existing major stationary source is considered a "major modification" if it results in a "a significant emissions increase… of a regulated NSR pollutant… and a significant net emissions increase of that pollutant from the major stationary source." The analysis of emissions increases is divided into two steps as described in the WDOE PSD Guidance. The first step evaluates if the change will result in a significant emissions increase of any regulated PSD pollutant, based on the application of federal regulations. If there is a significant increase in a PSD pollutant, the second step determines whether the change will result in a significant net emissions increase.

An emissions increase is significant if the increase is greater than one or more of the SERs listed in 40 CFR § 52.21(b)(23). Although EPA guidance states that both increases and decreases resulting from a project shall be accounted for under Step 1 of the applicability process,[8] also known as project emissions accounting or project netting, such accounting is explicitly prohibited under WDOE PSD Guidance. Therefore, consistent with WDOE's policy, no project netting was undertaken when calculating the baseline emissions for Unit #2.

An emissions increase is calculated by subtracting the baseline actual emissions from the projected actual emissions. Baseline emissions for any existing electric utility steam generating unit are "the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project" as described in 40 CFR 52.21(b)(48). Because Unit #2 is the emissions unit being modified, the 24-month baseline period was considered specifically for that unit. The baseline period (2022-2023) chosen by TransAlta meets the criteria of being within the 5-year period immediately preceding when actual construction is anticipated to begin (2026-2027) and being representative of normal operations. Other units/equipment associated with the coal combustion operations being retired or removed are not

[7] On September 18, 2025, EPA issued an updated guidance memorandum on the "Reactivation Policy." In that guidance, EPA states that it "will no longer apply any form of the Reactivation Policy in its NSR permitting determinations and enforcement proceedings, or in its oversight of state, local and tribal air permitting programs." EPA also stated that it "will continue to apply the modification provisions of the NSR program to shut down sources in accordance with the CAA and applicable EPA regulations." The modification analysis for this project is provided in Section 3.1.2 - Major Modification Test.

[8] See discussion: Federal Register :: Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Regulations Related To Project Emissions Accounting; Withdrawal of Proposed Rule, July 21, 2025.

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included in this analysis as reductions. The projected actual emissions for Unit #2 are the future potential emissions associated with operating at the maximum 59% capacity factor.

Table 3-1 provides the 2022-2023 baseline for Unit #2 (as reported to and accepted by SWCAA for the criteria pollutants and EPA's GHG Reporting System for the GHGs) and the future potential emissions for Unit #2 and the other Project emissions units[9]. VOC is the only pollutant that triggers PSD requirements in the first step. Because no project netting is undertaken, the second step is unnecessary and the conclusion in the first step is confirmed. The other pollutants are included for completeness in the analysis.

Table 3-1. Summary of Permitted Potential Emissions and Applicable Regulatory Thresholds

TransAlta Coal to Gas Baseline - Unit 2										
	PM (TSP)	PM_{10}	$PM_{2.5}$	NOx[1]	CO	VOC	SO_2	H_2SO_4	Lead	CO_{2e}
	(tons per year)									
2022-2023 Baseline[2,3]	304.15	262.81	236.48	3,680.34	4,251.78	0.23	1,211.54	3.07	0.015	4,677,602
CTG (100% NG)	133.06	133.06	133.06	2,131.97	2,907.23	58.14	13.92	0.21	0.009	2,269,524
Difference from Baseline	**(171.09)**	**(129.74)**	**(103.41)**	**(1,548.37)**	**(1,344.55)**	**57.91**	**(1,197.62)**	**(2.86)**	**(0.006)**	**(2,408,078)**
CTG Unit #2 Emissions Increase	0	0	0	0	0	57.91	0	0	0	0
Methane shutdown venting	0	0	0	0	0	0	0	0	0	595
Auxiliary Boiler	0.67	0.67	0.67	1.45	3.59	0.48	0.07	1.1E-03	4.4E-05	11,351
Water Bath Heater #1	0.30	0.30	0.30	0.66	1.62	0.22	0.03	4.8E-04	2.0E-05	5,129
Water Bath Heater #2	0.30	0.30	0.30	0.66	1.62	0.22	0.03	4.8E-04	2.0E-05	5,129
Cooling tower #1	0.76	0.76	0.45	0	0	0.00	0	0	0	0
Cooling tower #2	0.76	0.76	0.45	0	0	0.00	0	0	0	0
Total PSD Project Emissions	2.78	2.78	2.18	2.77	6.83	58.83	0.13	0.00	0.00	22,204
PSD Significant Emissions Rate	**25**	**15**	**10**	**40**	**100**	**40**	**40**	**7.00**	**0.60**	**75,000**
PSD Applies (Yes/No?)	No	No	No	No	No	**Yes**	No	No	No	No

[1]The Unit #2 NOx emissions are based on emission rates for the first year of operation that includes the COS learning period. NOx emissions will be reduced following the combustion optimization process.

As previously discussed, VOC is the only pollutant that triggers PSD requirements.

3.1.3 Control Technology Review

Pursuant to 40 CFR 52.21(j), major sources conducting a major modification must meet the BACT standard for all pollutants for which PSD permitting is required. The BACT analysis for the Project VOC emissions is included in Section 4.0.

3.1.4 Ambient Air Quality Analysis Requirements

In accordance with the requirements of 40 CFR 52.21(m), a PSD permit application must contain an analysis of existing ambient air quality data in the affected area for all regulated pollutants for which PSD permitting is required and a demonstration that the Project will not cause or contribute to a violation of the NAAQS or PSD increments. The definition of existing air quality can be satisfied by air

[9] The above described approach is also consistent with WDOE PSD Guidance. Baseline emissions for Unit #2 were evaluated as described/required in Section 2.2.2.2.2 of that guidance. In addition, the project emissions increase (also referred to as the "Step 1" increase) was calculated pursuant to Section 2.2.2.2.4. No netting was contemplated or requested, therefore the requirements in Section 2.2.2.2.5 - "Calculate the net emissions increase" were not applicable.

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measurements from either a state-operated or private network, or by a pre-construction monitoring program that is specifically designed to collect data in the vicinity of the proposed source. To fulfill the pre-construction monitoring requirement for PSD without conducting on-site monitoring a source may either:

- Justify that data collected from existing monitoring sites are conservatively representative of the air quality in the vicinity of the Project site; or
- Demonstrate that the Project is less than the de minimis monitoring concentrations established by EPA in 40 CFR 52.21(i)(5).

There are no NAAQS or PSD increments for VOC emissions, and therefore ozone (O_3, for which VOC is a precursor) is the pollutant which represents the potential trigger for an ambient impact analysis and the gathering of pre-construction ambient monitoring data. However, in the note associated with 40 CFR 52.21(i)(5)(i)(F), the regulations state that "No de minimis air quality level is provided for ozone. However, any net emissions increase of 100 tons per year or more of volatile organic compounds or nitrogen oxides subject to PSD would be required to perform an ambient impact analysis, including the gathering of ambient air quality data." As shown in Table 3-1, the proposed Project would result in an increase in VOC emissions of 58.83 tons per year, so it will meet the criteria for exemption from the ambient impacts analysis and preconstruction monitoring requirements for O_3.

Nevertheless, as previously mentioned, an ambient air quality demonstration for all NAAQS pollutants (including O_3) is summarized in Section 5.0 and provided in detail in Appendix E.

3.1.5 Source Impact Analysis

Pursuant to 40 CFR 52.21(k), a source impact analysis is required to be performed when a proposed project triggers PSD review for at least one regulated pollutant for which NAAQS exist. An increment consumption analysis is also required for projects that will increase emissions of pollutants with PSD increments have been established for Class I and Class II areas: PM_{10}, $PM_{2.5}$, SO_2, CO and NO_2. As described in Section 3.1, the Project triggers PSD review for VOCs only and no VOC-specific source impact analysis is required.

3.1.6 Additional Impact Analyses

Pursuant to 40 CFR 52.21(o), the additional impact analyses include an analysis of impairment to visibility (expanded upon in 40 CFR 52.21(p)), soils and vegetation, and the growth-related impacts associated with the source or modification, as described below.

3.1.6.1 Visibility Analysis

PSD Class I areas are areas of special national or regional value from a natural, scenic, recreational, or historical perspective. The PSD program provides special protection for such areas. According to 40 CFR 52.21(p), sources with emissions that may affect a Class I area may be required to demonstrate that modifications subject to PSD review will not cause or contribute to an exceedance of any PSD Class I increment or adversely affect certain air quality related (AQRVs, including visibility and acid deposition). As previously noted, there are no PSD increments or air quality related values for VOC. As the Project is only subject to PSD review for VOC, no Class I area impacts analysis is required under this section.

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However, a visibility analysis was required for this Project under other requirements, specifically because "any request to repower one or both units at the Centralia plant would require that the impact of repowering on visibility be modeled" (as described in the Technical Support Document for Second BART Order Revision – TransAlta Centralia Generation Plant, (WDOE, July 2020)). The CALPUFF visibility analysis is included in Appendix F.

3.1.6.2 Soils and Vegetation

The PSD program also provides an assessment of the potential impacts that a project subject to PSD will have on soils and vegetation. Such assessments are often conducted by comparing predicted maximum offsite ambient impacts determined by air dispersion modeling for secondary NAAQS. Secondary NAAQS define maximum concentration levels for protecting soils, vegetation, wildlife, and other aspects of public welfare. Secondary NAAQS thresholds have been established for NO_2, PM_{10}, $PM_{2.5}$, and O_3 but not for VOC. Because the Project is only subject to PSD review for VOC, a soils and vegetation impacts assessment is not required. However, as noted above, the ambient air quality demonstration for all NAAQS pollutants (including O_3 for both the primary and secondary standards) is included in Appendix E.

3.1.6.3 Growth Related Impacts

A qualitative evaluation of the general commercial, residential, industrial, and other potential growth that may be associated with the proposed Project was conducted. As Unit #2 is currently operating as an electrical generation unit combusting coal, its operations in the same function combusting natural gas are not anticipated to change employment patterns at the Centralia Plant or its vicinity. Therefore, secondary growth is not anticipated as a result of the Project.

3.2 New Source Performance Standards (40 CFR Part 60)

New Source Performance Standards (NSPS) are technology-based standards applicable to new and modified stationary sources. NSPS standards were delegated to SWCAA on July 1, 2015 (and incorporated by reference pursuant to SWCAA 400-115). Several NSPS subparts apply to the Project. The following is a description of the applicable subparts, potentially applicable subparts, and the Facility's compliance with these standards.

3.2.1 40 CFR 60, Subpart A – General Provisions

Any source subject to an applicable standard under 40 CFR 60 is also subject to the general provisions under Subpart A. Because the Centralia Plant is subject to other Subparts of the regulation, the requirements of Subpart A also apply. These requirements include notification of the start of construction, notification of the start of operation, performance emissions testing, monitoring, recordkeeping, and reporting.

3.2.2 40 CFR 60, Subpart Da – Standards of Performance for Electric Utility Steam Generating Units

40 CFR 60, Subpart Da applies to each electric utility steam generating unit capable of combusting more than 250 MMBtu/hr heat input of fossil fuel (alone or in combination with any other fuel); for which construction, modification, or reconstruction is commenced after September 18, 1978. Unit #2

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has the capability of combusting more than 250 MMBtu/hr of fossil fuel; it is rated at 7,500 MMBtu/hr. The original Unit #2 was not subject to Subpart Da as construction occurred prior to the applicability date of September 18, 1978 (construction was authorized in 1969, with operation commencing in August of 1971). However, the Unit #2 CTG conversion will happen after the applicability date and must be evaluated with respect to triggering modification or reconstruction under this subpart.

Per 40 CFR 60.14, modification is considered as any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies under Section 111 of the Federal Clean Air Act. Further, no physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change. None of the maximum hourly emissions rates as described above would increase for Unit #2 with the proposed change, therefore, modification under this subpart is not triggered[10].

Per 40 CFR 60.15, reconstruction means the replacement of components of an existing facility to such an extent that:

1. The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and
2. It is technologically and economically feasible to meet the applicable standards set forth in this part.

The analysis focuses on the first criteria. EPA has clarified the term “fixed capital cost” to mean “the capital needed to provide all the depreciable components and is intended to include such things as the costs of engineering, purchase, and installation of major process equipment, contractors’ fees, instrumentation...” In addition, per EPA guidance dated February 28, 2008, “Costs outside of the affected facility, such as the building, air pollution control, testing, and monitoring equipment, site preparation, removal of the old turbine, and contingency costs should not be included” in the fixed capital cost for this calculation.

As a basis, the United States Energy Information Administration (EIA) publishes capital costs associated with constructing new electrical generation facilities categorized by fuel, nominal capacity in MW, and general technology[11]. Because natural gas-fired boilers are not a listed technology[12], the

[10] The permitted NOx emissions rate was 0.21 lb/MMBtu over a 30-operating day average for Units 1 and 2 operating on coal. The proposed NOx emissions rate following full operations of the emissions control suite is 0.083 lb/MMBtu, also on a 30-operating day average for Unit #2, far below the previously permitted NOx limit, both in that form and if converted to a lb/hr value. In addition, as discussed with SWCAA, compliance testing performed in 2021 showed VOC test results of 0.0125 lb/MMBtu for Unit #2. VOC test results of that magnitude were also reported in 2019 for Unit #2. This short-term emissions rate exceeds the proposed natural gas VOC rate of 0.003 lb/MMBtu, both in that form and if converted to a lb/hr value.

[11] US EIA - Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies.

[12] Listed technologies for natural gas combustion include variations on simple and combined cycle combustion turbines in both simple and advanced configurations with and without carbon capture technology.

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closest similar unit type would be an "ultra-critical coal plant without carbon capture." A nominal 650 MW plant today of that type at $4,103/kilowatt-net would cost $2.67 billion in 2023$ (all the dollar amounts that follow are in 2023$). In the EIA analysis, the boiler cost component is shown at $395.7 million. The total equipment cost is $997.5 million; therefore, the boiler accounts for 40% of the total equipment cost shown. Applying that percentage to the total plant cost provides a boiler cost including labor; engineering, procurement, and construction (EPC) fees; contingency and owners costs of $1.07 billion. The Unit #2 boiler scope including those same components is currently estimated at approximately $173 million, equating to approximately 17% of the replacement cost. Both of those cost estimates include site preparation and contingency costs, which are calculated as a percent of the capital costs. As a result, the overall percent of replacement cost is valid without pulling out those items specifically. Therefore, Unit #2 boiler scope falls below the 50% reconstruction standard under 40 CFR 60.15(1).

Given that neither modification per §60.14 nor reconstruction per §60.15 is triggered for Subpart Da, the Unit #2 conversion is not subject to this standard.

3.2.3 40 CFR 60, Subpart Db – Standards of Performance for Electric Utility Steam Generating Units

Subpart Db applies to steam generating units with a maximum input capacity greater than 100 MMBtu/hr and less than 250 MMBtu/hr that commences construction, modification, or reconstruction after June 19, 1984. The auxiliary boiler has a maximum input capacity of 149.13 MMBtu/hr, would commence construction after the applicability date and is, therefore, subject to the standard. For a subject unit combusting natural gas with a low heat release rate, such as the auxiliary boiler, NO_x emissions are limited to 0.10 lb/MMBtu. The auxiliary boiler has a proposed NOx emissions rate of 12 parts per million, which equates to approximately 0.015 lb/MMBtu on a rolling 30-day average. As such, the Facility meets the applicable emission limits under Subpart Db. The standard also requires a continuous emissions monitoring system (CEMS) for monitoring NO_x emissions. A continuous opacity monitoring system (COMS) is not required pursuant to §60.48b(j)(2) if records are maintained for the sulfur content of the natural gas burned (due to the low sulfur content and particulate emissions from natural gas). Similarly, as described in §60.42b(k)(2), units burning natural gas are also exempt from SO_2 limitations and monitoring requirements.

3.2.4 40 CFR 60, Subpart Dc – Standards of Performance for Electric Utility Steam Generating Units

Subpart Dc is applicable to steam generating units with a maximum heat input capacity greater than or equal to 10 MMBtu/hr and less than 100 MMBtu/hr for which construction, modification, or reconstruction is commenced after June 9, 1989. The natural gas-fired water bath heaters heat a water bath, have a maximum heat input of 10 MMBtu/hr, and would commence construction after the applicability date; therefore, the water bath heaters are subject to this standard. The standard requires initial notifications at the start of construction and at initial start-up. In addition, records must be maintained regarding the amount of fuel burned on a monthly basis. No emission or operating limits are imposed by this standard on natural gas-fired units.

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3.2.5 40 CFR 60, Subpart TTTT – Greenhouse Gas Emissions for New or Modified Electric Generating Units

Subpart TTTT is applicable to electric utility generating units (EGUs) with a heat input greater than 250 MMBtu/hr of fossil fuel that serve a generator capable of selling greater than 25 MW of electricity to a utility power distribution system that commences construction on or after January 8, 2014, or commenced reconstruction or modification on or after June 8, 2014. As an existing unit, Unit #2 is not currently subject to Subpart TTTT. Therefore, the requirements of Subpart TTTT can only become applicable if Unit #2 undergoes a modification or reconstruction, as defined under 40 CFR 60.14 and 60.15.

As previously discussed under Section 3.2.2 (Subpart Da), neither modification nor reconstruction has been triggered for Unit #2, therefore, Subpart TTTT is not applicable to this Project.

3.2.6 40 CFR 60, Subpart TTTTa – Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

Subpart TTTTa applies to any steam generating unit or Integrated Gasification Combined Cycle (IGCC) unit that combusts coal and that commences modification after May 23, 2023, in addition to any stationary combustion turbine that commences construction or reconstruction after May 23, 2023, that meets the relevant applicability conditions in §60.5509a(a)(1) and (2).

As previously discussed under Section 3.2.2 (Subpart Da), Unit #2 will not combust coal after December 31, 2025, and thus would not be subject to the first set of applicability requirements. In addition, no stationary combustion turbines exist onsite, and none are currently planned for the site. Therefore, Subpart TTTTa is not applicable to this Project.

3.3 National Emission Standards for Hazardous Air Pollutants (40 CFR Parts 61 and 63)

The Clean Air Act of 1970 required EPA to identify hazardous air pollutants (HAPs) and promulgate standards for each HAP. Between 1971 and 1990, EPA identified and published standards for eight HAPs (asbestos, benzene, beryllium, coke oven emissions, inorganic arsenic, mercury, radionuclides, and vinyl chloride) under 40 CFR 61. The Clean Air Act Amendments of 1990 added 189 HAPs to Section 112 of the Clean Air Act and gave EPA a specific schedule to issue final standards on sources of these HAPs. EPA has published more than 100 standards under 40 CFR 63 in accordance with the Clean Air Act Amendments of 1990. The 40 CFR 61 standards are pollutant-specific, whereas the 40 CFR 63 standards are source category-specific.

3.3.1 40 CFR 61 – National Emission Standards for Hazardous Air Pollutants (NESHAPs)

3.3.1.1 40 CFR 61, Subpart A – General Provisions

Any source subject to an applicable standard under 40 CFR 61 is also subject to the general provisions under Subpart A. Because the Centralia Plant is subject to other Subparts of the regulation, the

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requirements of Subpart A also apply. These obligations include compliance requirements; performance-based emissions testing; and monitoring, recordkeeping, and reporting requirements.

3.3.1.2 40 CFR 61, Subpart M – General Provisions

Subpart M shall apply, but not be limited to, the demolition and/or renovation of regulated asbestos containing material. The Facility will comply with this standard as applicable during the conversion of Unit #2 and other affected units. Further, the Facility shall comply with the provisions of SWCAA 476 "Standards for Asbestos Control, Demolition and Renovation" when conducting any renovation, demolition, or asbestos storage activities at the facility.

3.3.2 40 CFR 63 – NESHAPs for Source Categories

3.3.2.1 40 CFR 63, Subpart A – General Provisions

Any source subject to an applicable standard under 40 CFR 63 is also subject to the general provisions under Subpart A. Because the Facility is subject to other Subparts of the regulation, the requirements of Subpart A also apply. These requirements include compliance dates; operation and maintenance requirements; startup, shutdown, and malfunction plans; performance emissions testing; and monitoring, recordkeeping, and reporting. The Facility has complied with and will continue to comply with the applicable requirements, performance testing, recordkeeping, and reporting outlined in Subpart A.

3.3.2.2 40 CFR 63, Subpart DDDDD – NESHAPs for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

40 CFR 63, Subpart DDDDD applies to industrial, commercial, or institutional boilers or process heaters as described in §63.7485 located at a major source of HAP emissions. The Facility is a major source of HAPs. Pursuant to §63.7499 and to §63.7575, Unit #2 following CTG conversion falls into the Gas 1 subcategory of “new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater.” As described by Table 3 of Subpart DDDDD, the Facility must conduct a tune-up of Unit #2 annually as specified in §63.7540. In addition, Unit #2 (as an existing unit at a major source of HAPs) must have a one-time energy assessment performed by a qualified energy assessor. The specifics of that energy assessment are described in Table 3, Section 4 of Subpart DDDDD. The auxiliary boiler falls into the Gas 1 category *with* a continuous oxygen trim system and will be subject to an every-five-year tune-up requirement. The water bath heaters will be categorized when their detailed specifications are available.

3.3.2.3 40 CFR 63, Subpart UUUUU – NESHAPs for Coal- and Oil-Fired Electric Utility Steam Generating Units

40 CFR 63, Subpart UUUUU, also known as the Mercury Air Toxics Standard (MATS), previously applied to Unit #2 in the existing EGU category (specifically the “coal-fired unit not low rank virgin coal” subcategory). Pursuant to §63.9981, MATS only applies to coal-fired or oil fired EGUs as they are defined in §63.10042 of that subpart. Unit #2 firing only natural gas would no longer be subject to MATS.

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3.4 Title V

Title V of the Federal Clean Air Act Amendments of 1990 sets forth operating permit requirements that apply to major sources as defined in the statute. The Air Operating Permit program is authorized under the procedures established in WAC 173-401. Several alternative criteria establish major source status, but the primary criteria that most often trigger applicability are:

- The facility's potential to emit any pollutant from a stationary point source is greater than 100 tpy.
- The facility's potential to emit any single listed HAP is greater than 10 tpy, or its potential to emit all HAPs combined is greater than 25 tpy.

The Centralia Plant meets the above criteria and currently holds SWCAA Air Operating Permit #SW98-8-R5, issued on October 14, 2019. The Air Operating Permit renewal application was submitted on March 15, 2023, and determined to be administratively complete on September 18, 2024, in accordance with WAC 173-401-710(1) and WAC 173-401-500.

Pursuant to WAC 173-401-500(3)(c), TransAlta will apply for a Title V modification within 12 months after commencing operation to address the requested modification.

3.5 Acid Rain Program

Unit #2 meets the definition of an affected Phase II "utility unit" under the Acid Rain Program pursuant to 40 CFR 72.6 because it is a fossil-fuel fired combustion device used to generate electricity for sale, and it serves a generator that exceeds 25 MW in capacity. Unit #2 has an existing Phase II Acid Rain Permit that has been incorporated into Centralia Plant's 40 CFR Part 70 Air Operating Permit #SW98-8-R5.

Under the Acid Rain Rule, the Centralia Plant is required to hold allowances equivalent to annual NOx and SO_2 emissions. The Centralia Plant will amend the existing Phase II Acid Rain Permit to address the conversion of Unit #2 to natural gas combustion, that application is incorporated into the ADP application submitted to SWCAA.

With respect to the monitoring requirements, NO_x CEMS remain a requirement under 40 CFR 75.10 and 75.12. Pursuant to 40 CFR 75.11(d), SO_2 monitoring for gas-fired units shall elect the use of SO_2 CEMS or the fuel monitoring and sulfur in fuel measurement allowed for under 40 CFR 75, Appendix D. Pursuant to 40 CFR 75.14(c) and (d), gas-fired units are exempt from the opacity monitoring provisions of Subpart 75.

3.6 Greenhouse Gas Reporting Rule

The GHG Reporting Rule (40 CFR Part 98 – Mandatory GHG Reporting) requires the reporting of specific GHG emissions by direct GHG emitters, as well as upstream indirect sources such as fossil fuel suppliers and manufacturers of heavy-duty and off-road vehicles and engines.

Electricity generation units that report CO_2 mass emissions year-round through 40 CFR Part 75 are subject to GHG reporting pursuant to 40 CFR 98.2(a)(1) and are subject to the specific provisions of 40 CFR Part 98, Subpart C. Therefore, the Centralia Plant has been reporting GHG emissions under this

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program since the 2010 reporting year and the Project will continue to comply with these requirements.

3.7 State of Washington Agency Regulations

In addition to regulations already discussed in preceding sections, state air regulations that pertain to the Facility are listed in Table 3-2. The rules are addressed individually in the following sections as they pertain to the Facility.

Table 3-2. State of Washington Potentially Applicable Regulations

Rule	Description
RCW 70A.15.2040	Air Pollution Control Authority – Powers and Duties
RCW 70A.15.2210	Construction of Proposed New Contaminant Sources
WAC 173-400-700, et seq.	Prevention of Significant Deterioration
WAC 173-460	Controls for New Sources of Toxic Air Pollutants
WAC 173-476	Ambient Air Quality Standards

3.7.1 Air Pollution Control Authority – Powers and Duties

The Revised Code of Washington (RCW) 70A.15.2040 (previously codified at RCW 70.94.141) delineates and empowers activated air pollution control authorities to develop plans for the prevention, abatement and control of air pollution within its jurisdiction. An air pollution control authority may issue such orders as may be necessary to effectuate the purposes of the Washington Clean Air Act and enforce the same by all appropriate administrative and judicial proceedings subject to the rights of appeal as provided in state law.

3.7.2 Construction of Proposed New Contaminant Sources

RCW 70A.15.2210 (previously codified at RCW 70.94.152) provides for the inclusion of conditions of operation as are reasonably necessary to assure the maintenance of compliance with the applicable ordinances, resolutions, rules and regulations when issuing Air Discharge Permits for installation and establishment of air contaminant sources.

3.7.3 Prevention of Significant Deterioration

WAC 173-400-700 through 750 includes the requirements that incorporate the federal PSD program by reference and provide authority for WDOE's State Implementation Plan (SIP)-approved PSD program. As previously mentioned, PSD review applies in attainment areas for the "construction of any new major stationary source or the major modification of any existing major stationary source." The Centralia Plant is in an attainment area and is an existing major stationary source as defined in 40 CFR 52.21(b)(1). This application is being submitted to WDOE to address the PSD requirements for the Facility with respect to VOC.

3.7.4 Controls for New Sources of Toxic Air Pollutants

WAC 173-460 establishes requirements for toxic air pollutants (TAPs, listed in WAC 173-460-150) including BACT for TAPs, TAPs emissions quantifications, and analysis of human health and safety

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protection. The TAPs emissions calculations, BACT analysis, and compliance analysis are included in the ADP permit application.

3.7.5 Ambient Air Quality Standards

WAC 173-476 establishes maximum acceptable levels in the ambient air for PM/PM_{10}/$PM_{2.5}$, lead, SO_2, NO_x, O_3, and CO. The air quality of the Project site is classified as "Better than National Standards" or unclassifiable/attainment of the NAAQS for criteria pollutants (40 CFR 81.327). The air dispersion modeling analysis/demonstration of compliance with these standards is provided in Section 5.0 and Appendix E.

3.8 Southwest Clean Air Agency Regulations

In addition to regulations already discussed in preceding sections, local agency air regulations that will pertain to the Project are listed in Table 3-3. The rules are addressed individually in the following sections as they pertain to the facility.

Table 3-3. SWCAA Potentially Applicable Regulations

Rule	Description
SWCAA 400-040	General Standards for Maximum Emissions
SWCAA 400-050	Emissions Standards for Combustion and Incineration Units
SWCAA 400-076	Emissions Standards for Stationary Sources Emitting Toxic Air Pollutants
SWCAA 400-081	Startup and Shutdown
SWCAA 400-103	Operating Permit Fees
SWCAA 400-105	Records, Monitoring and Reporting
SWCAA 400-109	Air Discharge Permit Applications
SWCAA 400-110	Application Review Process for Stationary Sources (New Source Review)
SWCAA 400-113	Requirements for New Sources in Attainment or Nonclassifiable Areas

3.8.1 General Standards for Maximum Emissions

SWCAA 400-040 requires all new and existing sources and emission units to meet certain performance standards with respect to Reasonably Available Control Technology (RACT), visible emissions, fallout, fugitive emissions, odors, emissions detrimental to persons or property, sulfur dioxide, concealment and masking, and fugitive dust. The Facility will continue to comply with all the applicable requirements and general provisions in SWCAA 400-040.

3.8.2 Emissions Standards for Combustion and Incineration Units

SWCAA 400-050 requires that no person shall cause or permit the emission of particulate material from any combustion or incineration unit in excess of 0.23 grams per dry cubic meter (0.1 grains per dry standard cubic foot, gr/dscf) of exhaust gas at standard conditions. This standard is applicable to Unit #2, the auxiliary boiler, and the water bath heaters. All of the listed units have calculated PM values of less than 0.004 gr/dscf, in compliance with this standard.

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3.8.3 Emissions Standards for Stationary Sources Emitting Toxic Air Pollutants

SWCAA 400-076 provides that if an ADP application is required under both SWCAA 400 and Chapter 173-460 WAC, then the applications shall be combined. TransAlta includes the required air toxics review and analysis in the ADP application, Sections 4.0 (for the air toxics BACT) and Section 5.0 (for the impact analysis).

3.8.4 Startup and Shutdown

SWCAA 400-081 requires the consideration of any physical and operational constraints on the ability of a "stationary source" or source category to comply with the applicable technology-based standard during startup or shutdown. In addition, modeling of the emissions must consider any increase in allowable emissions under startup or shutdown conditions authorized by an emission limitation or other operating parameter adopted under this rule section. Startup and shutdown impacts were evaluated and studied for Unit #2. Based on those evaluations, VOC emissions are anticipated to be consistent across a lb/MMBtu basis, as when the amount of fuel combusted decreases, the emissions associated with fuel combustion would also decrease. Therefore, the VOC emissions expressed in lb/MMBtu account for the startup and shutdown emissions without further need for clarification or allowances. The modeling analysis evaluates the worst case lb/hr emissions rates, which are associated with full load operations. Further discussion on the non-VOC startup and shutdown emissions for Unit #2 is included in the ADP application submitted to SWCAA.

3.8.5 Operating Permit Fees

SWCAA 400-103 requires the owner or operator of all "stationary sources" required to obtain an Operating Permit under 40 CFR Part 70, Chapter 173-401 WAC or RCW 70A.15.2260, to pay an annual fee as specified in this section, sufficient to cover all reasonable (direct and indirect) costs required to develop and administer the Operating Permit Program, including the fees associated with review and acting on applications and the associated application analyses. TransAlta has and will continue to pay the appropriate operating fees to SWCAA.

3.8.6 Records, Monitoring and Reporting

SWCAA 400-105 provides for all Title V stationary sources to maintain records of type and quantity of emissions, applicable emission limitations, operating limitations, and control measures. TransAlta currently maintains those calculations, records, and compliance demonstrations associated with its current Title V Operating Permit and will continue to do so under the requested permit modification.

3.8.7 Air Discharge Permit Applications

SWCAA 400-109 requires an ADP application for new construction or installation; modification, alteration or replacement of existing process or control equipment; and review of case-by-case control technology determinations (e.g., BACT) among other activities. The Project would trigger an ADP application for all of the above activities. The ADP application will be submitted with the appropriate fees as detailed in the Consolidated Fee Schedule established in accordance with SWCAA 400-098.

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3.8.8 Application Review Process for Stationary Sources (New Source Review)

SWCAA 400-110 includes provisions for application completeness. Applications shall include a demonstration that all applicable emissions standards have been met (including BACT, NSPS, NESHAPs, etc.), compliance with the ambient air quality standards, and PSD applicability review. TransAlta has included the required analyses in this Section 3.1.

3.8.9 Requirements for New Sources in Attainment or Nonclassifiable Areas (if PSD)

SWCAA 400-113 provides requirements for new or modified PSD sources in an attainment or unclassifiable area. Those requirements include compliance with emissions standards, BACT, allowable impact levels, PSD applicability, TAPs review, and visibility analyses. The Project will meet the requirements described with respect to the PSD pollutant under review - VOC.

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4.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

The Washington Clean Air Act requires all new sources and modifications which increase emissions to employ BACT. As previously discussed, VOC is the only pollutant triggering major source permitting under PSD pursuant to 40 CFR 52.21(j) (as referenced by WAC 173-400-710(1)). BACT is defined under 40 CFR 52.21(b)(12) as:

> *"an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, 62, and 63. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results*."

EPA has consistently interpreted the BACT requirement as containing two core criteria: (i) the BACT analysis must include consideration of the most stringent available technologies, (i.e., those that provide the "maximum degree of emissions reduction"; and (ii) any decision to require as BACT a control alternative that is less effective than the most stringent available must be justified by an analysis of objective indicators showing that energy, environmental, and economic impacts render the most stringent alternative unreasonable or otherwise not achievable.

EPA has developed what it terms the "top-down" approach for conducting BACT analyses and has indicated that this approach will generally yield a BACT determination satisfying the two core criteria. Under the "top-down" approach, progressively less stringent control technologies are analyzed until a level of control considered BACT is reached based on the environmental, energy, and economic impacts. WDOE requires the "top-down" approach for PSD BACT, which is described in more detail below.

This section provides the basis of the analysis prior to evaluating BACT for the new or modified sources. The sources subject to BACT for VOC include Unit #2, the auxiliary boiler, and water bath heaters.

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4.1 Top-Down BACT Approach and Analysis Organization

The “top down” general procedures are outlined in the *New Source Review Workshop Manual*, Office of Air Quality Planning and Standards, EPA, Draft - October 1990. The Manual was written for use in BACT analyses under the PSD or federal NSR program. The methodology described in the manual consists of five basic steps, which are described below.

4.1.1 Step 1 - Identify All Control Technologies

In a complete BACT analysis, the first step is to identify all “available” control options for the emissions unit being evaluated. “Available” control options are air pollution control technologies or techniques with a practical potential for application to the emissions unit and regulated pollutant being evaluated.

4.1.2 Step 2 - Eliminate Technically Infeasible Options

In the second step, the technical feasibility of the control options identified in the first step is evaluated with respect to source-specific factors. A demonstration of technical infeasibility must be clearly documented and exhibit – based on physical, chemical, and/or engineering principles – that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are eliminated from further consideration. Note that the NSR Manual (at page B-17) states, “a source is not required to experience extended time delays or resource penalties to allow research to be conducted on a new technique or control technology. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type.”

4.1.3 Step 3 - Rank Remaining Technologies by Control Effectiveness

Available control technology options deemed technically feasible are ranked in order of pollutant removal effectiveness. The control option that results in the highest pollutant removal value or lowest pollutant emission limit is considered the "top" control option.

4.1.4 Step 4 - Evaluate Most Effective Controls and Document Results

The fourth step is to consider the directly associated energy, environmental, and economic impacts of the most stringent control option ascertained. Both beneficial and adverse impacts are discussed and quantified where possible.

Energy impact analyses estimate direct energy impacts of the control alternatives in units of energy consumption. Environmental impact analyses consider effects of unregulated air pollutants or non-air impacts such as liquid, solid, or hazardous waste disposal and whether they would justify selection of an alternative control option. Economic impact analyses assess costs associated with installation and operation of the various BACT alternatives.

As a guide in determining excessive control costs, alternative control systems are compared in terms of certain cost-effectiveness ratios. These ratios include the following:

- Ratio of total control costs to total investment costs;
- Cost per unit of pollution removed (for example, dollars per ton);

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- Unit production costs (for example, costs per unit of product); and
- Cost per dollar of total sales.

If energy, environmental, or economic impacts show the top control option to be infeasible, then the next most stringent alternative becomes the new top control option and is similarly evaluated. This process continues until the top control technology under consideration cannot be eliminated due to any source-specific energy, environmental, or economic impact(s).

4.1.5 Step 5 - Select BACT

The last step in evaluating BACT is to propose the most effective control option that remains after eliminating all non-viable options as part of Step 4.

4.2 Unit #2

Unit #2 currently operates as a coal-fired EGU using diesel as a startup fuel. Following the ceasing of coal combustion at the end of 2025, the Project proposes converting Unit #2 to generate electricity from natural gas. Unit #2 proposed to operate at a maximum capacity factor of 59%. However, current expectations are that the facility will operate for less than 40% of all hours on an annual basis over the life of the Project; at a capacity factor of less than 20% as the majority of operating hours are expected to be at either half load (~350 MW) or at minimum stable generation (~190 MW).

Natural gas combustion produces NO_x, CO, PM_{10}, $PM_{2.5}$, SO_2, H_2SO_4, and VOC. VOC is the only pollutant subject to PSD, therefore, for this application, VOC is the pollutant subject to review under this major source BACT process. GHGs, expressed as CO_{2e}, are also produced but are not subject to BACT review as the modification of Unit #2 does not trigger PSD permitting for GHG emissions. Unit #2 is evaluated as an existing source undergoing a fuel conversion; potentially applicable NSPS requirements (specifically Subpart Da) do not apply as neither modification nor reconstruction are being triggered. Therefore, new similar source installations are not comparable with respect to control technology requirements.

However, to provide a more comprehensive outline of the potential options, a review of EPA's Reasonably Available Control Technology (RACT)/BACT/ Lowest Achievable Emissions Rate (LAER) Clearinghouse (collectively, RBLC) was conducted to review control measures associated with similar units over the last 10 years (specifically, RBLC process code 11.310 – Utility and Large Industrial Sized Boilers/Furnaces > 250 MMBtu/hr, Natural Gas Fired). Twelve boilers were identified between June 2017 and July 2024, all of which were smaller than Unit #2, with the largest being two units: 1,100 MMBtu/hr and 1,200 MMBtu/hr in size. In addition, nine known coal to gas converted utility boilers (units very consistent with Unit #2) were also surveyed. That information is available in Appendix D and will be discussed as applicable.

4.2.1 Step 1 – Identify All Control Technologies

The rate of VOC emissions from boilers and furnaces depends on combustion efficiency. VOC emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air. Trace amounts of VOC species in the natural gas fuel (e.g., formaldehyde, hexane, and benzene) may also contribute to VOC emissions if they are not completely combusted in the boiler.

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As previously discussed, a review of the RBLC natural gas fired boilers and known converted units was conducted to identify control technology alternatives for Unit #2. The VOC control technologies for those units included good combustion practices, clean fuel usage (i.e., natural gas), compliance with 40 CFR 63, Subpart DDDDD (the Boiler MACT), and following manufacturer specifications for startup and shutdown events. Those options can be summarized as good combustion practices. Optimized boiler operation minimizes emissions overall.

The search results did not identify any listings in which the use of catalytic oxidation was found to represent BACT; however, it is an option used for VOC control in natural gas combustion. A catalytic oxidation system is a post-combustion technology that removes VOC from the exhaust gas of a combustion source via incineration. VOC is oxidized/converted to H_2O and CO_2 in a combustion chamber in which the VOC-containing waste stream is burned. Since the inlet waste gas stream temperature is generally much lower than that required for combustion, energy must be supplied to the incinerator to raise the waste gas temperature via auxiliary fuel. In the catalytic incinerator a catalyst is used to increase the rate of the combustion reaction, allowing the combustion to occur at lower temperatures. Because the catalytic process operates at a lower temperature than the thermal process, less auxiliary fuel may be required in the catalytic process to preheat the waste gas.

4.2.2 Step 2 – Eliminate Technically Infeasible Options

Both good combustion practices (including boiler tune-ups per the Boiler MACT) and catalytic oxidation are feasible options. Technology-specific impacts are discussed in Step 4.

4.2.3 Step 3 – Rank Remaining Technologies by Control Effectiveness

Table 4-1. Unit #2 VOC Control Technology Options and Costs, Ranked by Control Efficiency

Rank	Control Technology	Estimated Control Efficiency (%)	Anticipated Emissions Rate (lb/MMBtu)	Annual Cost (in 2023$)	Cost Effectiveness ($ per ton)
1	Catalytic Oxidation	99%	0.00003	$47,947,931	$838,100
2	Good combustion practices	Base case	0.003	N/A	N/A

The default control efficiency in EPA's Air Pollution Control Estimation Spreadsheet for Thermal and Catalytic Oxidizers (December 2024) is 99% and remains so in this analysis to be conservative. Economic impacts associated with catalytic oxidation were compared using estimated annualized capital, operating, and maintenance costs[13] evaluated using that EPA spreadsheet.

4.2.4 Step 4 – Evaluate Most Effective Controls and Document Results

A potential adverse environmental impact for a catalytic oxidizer results from the handling of the spent catalyst. Many of the catalyst formulations are potentially toxic and subject to hazardous waste disposal regulations under RCRA. Costs for the installation of catalytic oxidation are exorbitantly high

[13] Where appropriate, assumptions were made from suggested/typical data that were supplied in the manual and if data was not available from the manual, best engineering judgment was used.

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at $838,100 per ton of VOC removed. This falls far beyond generally acceptable dollar per ton costs for pollution control for PSD or minor source BACT analyses.

4.2.5 Step 5 – Select BACT

Given the consistency of requiring no add-on control for all the boilers surveyed and the cost associated with the installation and operation of catalytic oxidation, TransAlta proposes that the use of good combustion practices (including compliance with the Boiler MACT) coupled with the use of pipeline quality natural gas is VOC BACT for Unit #2.

4.3 Auxiliary Boiler

The auxiliary boiler will have a maximum heat input capacity of 149.13 MMBtu/hr, will be limited to 1,300 hours of total operation per year to support startups and shutdowns for Unit #2, and will fire only natural gas as fuel. A search of EPA's RBLC was conducted to review control measures associated with similar units over the last 10 years (specifically, RBLC process code 12.310 –Industrial Sized Boilers/Furnaces between 100 and 250 MMBtu/hr, Natural Gas Fired, see Appendix D). However, the units surveyed did not indicate the same limited use as with the auxiliary boiler.

As described above with respect to Unit #2, the rate of VOC emissions from boilers and furnaces, depends on combustion efficiency. VOC emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air.

4.3.1 Step 1 – Identify All Control Technologies

A review of the RBLC was conducted to identify control technology alternatives for the auxiliary boiler. The VOC control technologies for those units included good combustion practices for all units and catalytic oxidation for one within the search window.

4.3.2 Step 2 – Eliminate Technically Infeasible Options

Both good combustion practices and catalytic oxidation would be technically feasible.

4.3.3 Step 3 – Rank Remaining Technologies by Control Effectiveness

Table 4-2. Auxiliary Boiler VOC Control Technology Options, Ranked by Control Efficiency

Rank	Control Technology	Estimated Control Efficiency (%)	Anticipated Emissions Rate (lb/MMBtu)
1	Catalytic Oxidation	99%	0.00005
2	Good combustion practices	Base case	0.005

The default control efficiency in EPA's Air Pollution Control Estimation Spreadsheet for Thermal and Catalytic Oxidizers (December 2024) is 99% and remains so in this analysis to be conservative. Using that spreadsheet, annual cost (in 2023$) was estimated at $569,479 per year with a cost effectiveness of $1,231,413 per ton based on the anticipated emissions rate at the limited hours of operation (0.48 tpy of VOC).

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4.3.4 Step 4 – Evaluate Most Effective Controls and Document Results

Catalytic oxidation would be the most effective control. However, based on the limited use of the auxiliary boiler and the minimal emissions generated, no add-on control technology would be economically feasible. Good combustion practices, including compliance with the Boiler MACT, is a consistent VOC BACT requirement for boilers in this size range.

4.3.5 Step 5 – Select BACT

TransAlta proposes that the use of good combustion practices, including compliance with the Boiler MACT, coupled with the use of pipeline quality natural gas as VOC BACT for the auxiliary boiler.

4.4 Water Bath Heaters

Combustion emissions (including VOC) are generated from the two water bath heaters. The units are small natural gas-fired heaters, rated at 10 MMBtu/hr each. Due to their size, the pollutants generated are small with the VOC emission rates for each heater at 0.22 tpy. Based on the small size of the heater and the minimal emissions generated, no add-on control technology would be economically feasible. VOC emissions will be minimized through the combustion of pipeline quality natural gas and by following good combustion practices for these units. Therefore, TransAlta proposes the use of pipeline quality natural gas and good combustion practices (including compliance with the Boiler MACT) as BACT for VOCs.

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5.0 AMBIENT AIR IMPACT DEMONSTRATION/RESULTS

The following is a summary of the air dispersion modeling analysis/ambient air quality impact demonstration and results. Detailed information on the modeling methodology is provided in Appendix E.

5.1 Introduction

The dispersion modeling for the Project evaluates the maximum design scenario to predict the appropriate maximum concentration for each pollutant and averaging period. In addition to the assessment of primary $PM_{2.5}$ emissions, secondary $PM_{2.5}$ formed in the atmosphere from precursor NOx and SO_2 emissions are also assessed. The assessment of secondary $PM_{2.5}$ formation is based on EPA guidance described in the Protocol. The total $PM_{2.5}$ concentration that is used in the SIL and NAAQS analyses is defined as the sum of the primary modeled concentration plus the secondary $PM_{2.5}$ concentration. O_3 can also be formed as a secondary pollutant from precursor NOx and VOC emissions. Secondary O_3 emissions have also been assessed. The appropriate maximum concentrations from the maximum design scenarios are compared to the SILs. If the maximum concentration is less than the corresponding SIL, then compliance is demonstrated, and no additional analysis is necessary for that pollutant and averaging period. However, if the maximum predicted concentration is equal to or greater than the SIL, a NAAQS modeling assessment has been conducted and summed with measured ambient background concentrations to represent the cumulative air quality concentrations resulting from the Project and existing air quality in the region. AERMOD modeling has been conducted in accordance with the procedures described above and in the approved Modeling Protocol (Tetra Tech, 2025). It should be noted that the Modeling Protocol included the firing of ultra-low sulfur diesel fuel in Unit #2. Unit #2 will now only fire natural gas.

5.2 Load Analysis

AERMOD modeling was conducted for Unit #2 operating at 100% load and the minimal stable generation (~190 MW) load to determine the worst-case impact scenario for each pollutant and averaging period. A unit emission rate was modeled, then the normalized concentrations for each averaging period were scaled by the appropriate emission rate for each pollutant. Separate AERMOD load runs with 1-hour NO_2, 1-hour SO_2, and 24-hour $PM_{2.5}$ emission rates were also made so that the proper form of those standards would be assessed in the load analysis. Detailed model results for both operating scenarios/loads are provided in Appendix E, Attachment A. Based on the load analysis, the 190 MW operating scenario resulted in higher predicted impacts due to the less favorable dispersion parameters. Therefore, the modeling assessment used the 190 MW scenario for Unit #2 to evaluate short-term and annual impacts for the SIL, NAAQS, and toxics modeling analyses.

5.3 Secondary Pollutant Assessment

5.3.1 Secondary $PM_{2.5}$ Assessment

Impacts of the Project on secondary $PM_{2.5}$ levels were estimated using the approach described in Appendix E, Section 3.10. The MERPs View Qlik application tool was used to obtain the highest daily

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(24-hour) and highest annual secondary $PM_{2.5}$ impacts, respectively, from sources of NOx and SO_2 based on EPA photochemical modeling. The most representative EPA hypothetical source for this Project is the Klickitat, Washington site. Therefore, the Project estimates the expected secondary $PM_{2.5}$ formation based on the high-level stack modeling with 3,000 tpy on NOx emissions and 500 tpy for SO_2 precursor emissions. Section 4.3.1 of Appendix E provides the calculations used to estimate the Project-only secondary $PM_{2.5}$ impacts.

It is important to note that these secondary impacts will not be experienced in the same location as the Project's maximum primary $PM_{2.5}$ impacts, as the secondary particulate formation will occur well downwind of the Project. Furthermore, these levels represent an insignificant fraction of existing $PM_{2.5}$ background levels.

5.3.2 O_3 Ambient Impact Assessment

Chemical transformation of NOx and VOC can contribute to the formation of ambient O_3 in the atmosphere. The photochemical processes that lead to O_3 formation occur over many hours and are affected by precursor emissions over a large region, often 100 miles or more. Even a large facility will generally represent a very small contribution to regional concentrations. Similar to the description in Appendix E, Section 3.10 (analysis for secondary $PM_{2.5}$), a Tier 1 demonstration for ozone formation is based on the existing EPA modeling.

The MERPs View Qlik application tool was used to obtain the highest 8-hour O_3 impacts, respectively, from sources of NOx and VOC based on the EPA photochemical modeling. The amount of O_3 that would be formed from the proposed Project using the EPA-estimated O_3 in Klickitat, Washington is based on the impacts presented for the high-level release of 3,000 tpy of NOx emissions and 500 tpy of VOC precursor emissions. Section 4.3.2 of Appendix E provides the calculations used to estimate the Project-only secondary O_3 impacts

5.4 Project Impacts Compared to the SILS

The Project sources that emit criteria pollutants were modeled with AERMOD. The primary $PM_{2.5}$ predicted impacts (modeled) were summed with the secondary $PM_{2.5}$ concentration to result in a total $PM_{2.5}$ concentration prior to comparison with the SILs and/or NAAQS. The maximum annual NO_2 concentration was predicted at a receptor approximately 8.8 km to the north-northeast of Unit #2 (514216, 5186128) in an area of 600-meter spacing within the receptor grid. A higher-resolution receptor grid extending between the adjacent 600-meter receptors with 50-meter spacing was used to ensure the maximum predicted concentration was captured. All other pollutant/averaging periods maxima were predicted within dense receptor spacing (50-meter or less). The maximum results of the modeling for criteria pollutants are summarized in Table 5-1. Maximum predicted impacts are less than the corresponding SILs for CO, PM_{10}, and SO_2. Compliance with the NAAQS is demonstrated for pollutants with predicted insignificant impacts (i.e., less than SILs), and therefore, no additional modeling demonstration for these pollutants/averaging periods is necessary. As shown in Table 5-1, NAAQS modeling is necessary for 1-hour and annual NO_2, 24-hour and annual $PM_{2.5}$ for NAAQS compliance. In addition, the secondary O_3 concentration is above the 8-hour O_3 SIL of 1 ppb and requires a comparison with the NAAQS.

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Table 5-1. SILs Analysis Results

Pollutant	Averaging Period	Rank for SIL Assessment	Project Impact Concentration (µg/m³)	SIL (µg/m³)
NO_2[a]	1-hour	H1H[b] (5-year average)	**98.49**[c]	7.5
	Annual	H1H	**1.14**[c]	1
CO	1-hour	H1H	296.54	2,000
	8-hour	H1H	147.34	500
PM_{10}	24-hour	H1H	2.71	5
$PM_{2.5}$[d]	24-hour	H1H (5-year average)	**1.86**[c]	1.2
	Annual	H1H (5-year average)	**0.26**[c]	0.13
SO_2	1-hour	H1H	0.92	7.8
	Annual	H1H	0.01	1
O_3	8-hour	MERPs Tier 1	**5.66 ppb**[c]	1 ppb

[a] NO_2 concentrations based on the ARM2 method for NOx to NO2 conversion.
[b] Highest first-high concentration
[c] Bold font indicates concentration is above the respective SIL.
[d] $PM_{2.5}$ is the sum of primary (modeled) and secondary (calculated) $PM_{2.5}$ concentrations.

5.5 NAAQS Analysis and Results

As noted above, model results indicate that a NAAQS assessment was necessary for 1-hour and annual NO_2, and 24-hour and annual $PM_{2.5}$. The refined receptor grid described in Appendix E, Section 4.4 was used for the annual NO_2 NAAQS assessment. Compliance with the NAAQS is based on the sum of modeled impacts attributable to the Project, modeled impacts from other nearby background sources, and representative ambient background concentrations (as described in Appendix E, Section 3.8). For this analysis, the ambient background concentrations are inclusive of the emissions from constantly emitting surrounding sources and monitored concentrations. Therefore, these ambient background concentrations can be summed to the modeled Project design value concentrations to represent a cumulative impact. The summary of the design value concentrations for comparison with the NAAQS are presented in Table 5-2. All pollutants demonstrate compliance with their respective NAAQS. The locations of the maximum predicted Project impacts for each modeled pollutant and averaging period listed in Table 5-2 are shown in contour plots provided in Attachment B of Appendix E.

Table 5-2. NAAQS Analysis Results

Pollutant	Averaging Period	Rank for NAAQS Assessment	Project Contribution (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	Percent of NAAQS
NO_2[a]	1-hour	H8H[b] (5-year average)	66.10	51.89	117. 98	188	63%
	Annual	H1H[c] (over 5 years)	1.14	11.66	12.80	100	13%
$PM_{2.5}$[d]	24-hour	H8H (5-year average)	1.04	17.80	18.97	35	54%

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Pollutant	Averaging Period	Rank for NAAQS Assessment	Project Contribution (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	Percent of NAAQS
	Annual	H1H (5-year average)	0.26	6.00	6.26	9	70%
O_3	8-hour	H4H[e]	11.12[f]	106.01	117.13	137	85%

[a] NO_2 concentrations based on the ARM2 method for NO_x to NO_2 conversion.
[b] Highest eight-high (98th percentile) of 1-hour daily maximum concentrations averaged over 5 years.
[c] Highest first-high annual concentration over the 5 years modeled.
[d] $PM_{2.5}$ is the sum of primary (modeled) and secondary (calculated) $PM_{2.5}$ concentrations.
[e] Annual fourth-highest daily maximum 8-hour concentration averaged over 3 years.
[f] Secondary formation of ozone due to Project emissions calculated using the MERPs methodology guidance.

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APPENDIX A: WDOE APPLICATION FORMS

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Prevention of Significant Deterioration Permit Application

EARLY PLANNING

In order to develop an appropriate application, the source should engage in an early planning process to assess the needs of the facility. An opportunity for a pre-application meeting with ecology is available to any potential applicant. We recommend meeting with Ecology before preparing a PSD application.

INSTRUCTIONS

Use this form for all projects in Washington that are subject to the Prevention of Significant Deterioration (PSD) Program. If you want Ecology to determine whether your project is subject to the PSD Program, submit a Request for a PSD Program Applicability Determination form (ECY 070-413).

Fill out the front and back of this form. Attach a check for the initial fee and mail the form and your application to:

Department of Ecology
Cashiering Unit
PO Box 47611
Olympia, WA 98504-7611

For Fiscal Office Use Only:
001-NSR-216-0299-000404

Check the box to indicate what you are submitting for review.

Project	**Initial Fee**
☑ For new major stationary source or major modification. The initial fee covers 158 hours of review	$18,802
PSD Permit Revision	
☐ Administrative permit amendment. The initial fee covers 20 hours of review Please contact PSD section for eligibility prior to submittal.	$2,380
☐ All other PSD permit revision. The initial fee covers 40 hours of review	$4,760
Other Actions	
☐ Permit extension. This is a flat fee.	$625
☐ Plant-wide applicability emission limit: establish limit. The initial fee covers 158 hours of review	$18,802
☐ Plant-wide applicability emission limit: all other requests. Other requests may include increasing a limit, renewing a limit, or processing an expired limit. The initial fee covers 79 hours of review. Contact PSD section prior to submittal.	$9,401

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Prevention of Significant Deterioration Permit Application

Read each statement, and then check the box next to it to acknowledge what you have read.

The initial fee you submit may not cover the cost of processing your application. Ecology will track the number of hours spent on your project. If the number of hours exceeds the number of hours included in your initial fee, Ecology will send you a bill for that extra time.

Ecology will bill you $119 per hour for each hour worked beyond the initial hours.

You must pay the bill before we will issue your permit or finalize an action or decision.

Note:

An additional fee does not apply when a request to establish a plant-wide applicability limit is part of an application covered by the new project, all other permit revisions, or major modification fees on this form

FOR MORE INFORMATION

MengChiu Lim
Department of Ecology Air Quality Program
Engineering and Permitting Section Ecology Headquarters Office

PO Box 47600
Olympia, WA 98504-7600
Phone: 360-407-6812
email: mengchiu.lim@ecy.wa.gov

The Department of Ecology is committed to providing people with disabilities access to information and services by meeting or exceeding the requirements of the Americans with Disabilities Act (ADA), Section 504 and 508 of the Rehabilitation Act, and Washington State Policy #188.

To request an ADA accommodation, contact Ecology by phone at 360-407-6800 or email at melanie.forster@ecy.wa.gov. For Washington Relay Service or TTY call 711 or 877-833-6341. Visit Ecology's website for more information.

If you need this document in a format for the visually impaired, call the Air Quality Program at 360-407-6800. Persons with hearing loss can call 711 for Washington Relay Service. Persons with a speech disability can call 877-833-6341.

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Prevention of Significant Deterioration Permit Application

I. Project, Facility, and Company Information

a. Project Name: Centralia Coal to Gas Conv

b. Facility Name: TransAlta Centralia Plant

c. Facility Street Address: 913 Big Hanaford Road, Centralia, WA 98531

d. Company Legal Name: TransAlta Centralia Generat

II. Application Contact Information

Project Manager:

a. Name: Conrad Wieclaw

b. Mailing Address: 913 Big Hanaford Road, Ce

c. Phone Number: (360)807-8093

d. Email: Conrad_Wieclaw@transalta

Project Consultant

If you hired a consultant to prepare the application (or materials), check this box and provide the required information.

e. Consultant name: Debbie Skibicki

f. Consultant Mailing Address: 828 Great Northern Ave, Ste 300, Helena, MT 59601

g. Consultant Phone Number: (406)437-9830

h. Email: debbie.skibicki@tetratech.c

Project Billing Contact

Ecology will send the Project Manager the bills if there are any

☐ If the Project Billing Contact is different from the Project Manager, check this box and provide the required information.

i. Name, Title:

j. Mailing Address:

k. Phone Number:

l. Email:

III. Responsible Official Certification

Responsible Official Signature

I certify, based on information and belief formed after reasonable inquiry, the statements and information in this application are true, accurate, and complete.

Printed name: Conrad Wieclaw Title: Engineering and Environmental Manager

Signature: Signed by: Conrad Wieclaw 130F85AFA0D74B4... Date: 23 December 2025 | 2:20 PM MST

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Prevention of Significant Deterioration Permit Application

IV. Project Information

For any project involves new major stationary source or major modification of any existing major stationary source, the application shall include the following information, but not limited to:

a. **Project description.** Please provide a detail description of the project and identify the scope of the project. This shall include the new and modified emission unit (s), and other affected existing unit (s) of the project. The project description shall also include an aggregation analysis to evaluate if nominally-separate projects occurring at the source shall be treated as a single project from PSD standpoint. The baseline actual emissions and the projected actual emissions.
b. **Project emission increase.** Please provide a summary of the project emission increase. Please also provide a detail emission increase estimation for each unit included as part of the project.
c. **BACT evaluation.** The applicant shall use top-down procedure similar to that in the draft 1990 NSR workshop manual. Startup/shutdown shall be evaluated as part of the BACT analysis. For economy impact analysis as part of the evaluation, the application shall show the assumptions made and provide the supporting information for the assumptions.
d. **Impact review.** For impact analysis purpose, actual emissions is based on the last two years of emissions that is representative of normal source operation.
e. **State Environmental Policy Act (SEPA) Determination.** If SEPA review is completed, please include a copy of the final SEPA checklist and SEPA determination. If SEPA review has not been conducted, please identify the agency reviewing SEPA and provide a copy of the final SEPA checklist and SEPA determination before Ecology issues your permit

Ecology has developed a PSD guidance that can be helpful when conducting PSD applicability analysis. The guidance can be found at https://fortress.wa.gov/ecy/publications/SummaryPages/1702014.html.

Please note that the applicant shall provide a copy of PSD application to each of the following agencies:

a. U.S. Department of the Interior—National Park Service
b. U.S. Department of Agriculture—U.S. Forest Service
c. The permitting authority with authority over the source under Chapter 173-401 WAC
d. EPA

Ecology recommends that the applicant provides an electronic copy of the application to Ecology's PSD program.

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APPENDIX B: EMISSIONS CALCULATIONS

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

TransAlta Coal to Gas Baseline - Unit 2										
	PM (TSP)	PM_{10}	$PM_{2.5}$	NOx[1]	CO	VOC	SO_2	H_2SO_4	Lead	CO_{2e}
					(tons per year)					
2022-2023 Baseline[2,3]	304.15	262.81	236.48	3,680.34	4,251.78	0.23	1,211.54	3.07	0.015	4,677,602
CTG (100% NG)	133.06	133.06	133.06	2,131.97	2,907.23	58.14	13.92	0.21	0.009	2,269,524
Difference from Baseline	**(171.09)**	**(129.74)**	**(103.41)**	**(1,548.37)**	**(1,344.55)**	**57.91**	**(1,197.62)**	**(2.86)**	**(0.006)**	**(2,408,078)**
CTG Unit #2 Emissions Increase	0	0	0	0	0	57.91	0	0	0	0
Methane shutdown venting	0	0	0	0	0	0	0	0	0	595
Auxiliary Boiler	0.67	0.67	0.67	1.45	3.59	0.48	0.07	1.1E-03	4.4E-05	11,351
Water Bath Heater #1	0.30	0.30	0.30	0.66	1.62	0.22	0.03	4.8E-04	2.0E-05	5,129
Water Bath Heater #2	0.30	0.30	0.30	0.66	1.62	0.22	0.03	4.8E-04	2.0E-05	5,129
Cooling tower #1	0.76	0.76	0.45	0	0	0.00	0	0	0	0
Cooling tower #2	0.76	0.76	0.45	0	0	0.00	0	0	0	0
Total PSD Project Emissions	2.78	2.78	2.18	2.77	6.83	58.83	0.13	0.00	0.000	22,204
PSD Significant Emissions Rate	**25**	**15**	**10**	**40**	**100**	**40**	**40**	**7.00**	**0.60**	**75,000**
PSD Applies (Yes/No?)	No	No	No	No	No	**Yes**	No	No	No	No

[1]The Unit #2 NOx emissions are based on emission rates for the first year of operation that includes the COS learning period. NOx emissions will be reduced following the system optimization.

[2]Baseline emissions compiled from emission inventories submitted to and approved by Southwest Clean Air Agency for the respective reporting years with the exception of CO_{2e}. CO_{2e} emissions were compiled from 40 CFR 98, Greenhouse Gas Reporting summaries.

[3]Pursuant to 40 CFR 52.21(b)(i), "For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project." TransAlta chose the 2022-2023 period for Unit 2.

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TransAlta Coal to Gas Operations (at potential/worst-case emissions rates, in tons per year)										
	PM/TSP	PM_{10}	$PM_{2.5}$	NOx[1]	CO	VOC	SO_2	H_2SO_4	Lead	CO_{2e}
New or Modified Emissions Unit										
Unit 2 CTG	133.06	133.06	133.06	2,131.97	2,907.23	58.14	13.92	0.21	0.01	2,269,524
Methane shutdown venting	0	0	0	0	0	0	0	0	0	595
Auxiliary Boiler	0.67	0.67	0.67	1.45	3.59	0.48	0.07	1E-03	4E-05	11,351
Water Bath Heater #1	0.30	0.30	0.30	0.66	1.62	0.22	0.03	5E-04	2E-05	5,129
Water Bath Heater #2	0.30	0.30	0.30	0.66	1.62	0.22	0.03	5E-04	2E-05	5,129
Cooling tower #1	0.76	0.76	0.45	0	0	0	0	0	0	0
Cooling tower #2	0.76	0.76	0.45	0	0	0	0	0	0	0
TOTAL CTG Project	**135.84**	**135.84**	**135.24**	**2,134.73**	**2,914.05**	**59.06**	**14.05**	**0.21**	**0.009**	**2,291,727**

*The Unit #2 NOx emissions are based on emission rates for the first year of operation that includes the COS learning period. NOx emissions will be reduced following the system optimization.

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Transalta
Unit 2 Full load, 59% capacity operating scenario (100% natural gas)

Max. Fuel Combustion Rate =	7,500.00	MMBtu/hr
Total Possible Hours =	8,760	hr/yr
Capacity Factor =	59%	
Hours of Operation =	5,168	hr/yr

Global Warming Potential [1]	
CO_2	1
CH_4	28
N_2O	265

Fuel Scenario Natural Gas	100%	
NG Hours	5,168	hr/yr
NG Fuel Usage =	35,016.26	MMscf/yr
NG Fuel High Heating Value [2] =	1,107	MMBtu/MMscf
NG Fuel Total Sulfur Value [3] =	2650	gr/MMscf
Conversions:	2.2046	lb/kg
	2,000	lbs/ton

Criteria Pollutants (HAPs)

Pollutant	NG Emission Factor	Units	Emission Factor Reference	Emissions (lbs/hr)	Emissions (tons/yr)
PM	7.6	lb/MMscf	AP-42, Table 1.4-2	5.15E+01	133.06
PM_{10}	7.6	lb/MMscf	AP-42, Table 1.4-2	5.15E+01	133.06
$PM_{2.5}$	7.6	lb/MMscf	AP-42, Table 1.4-2	5.15E+01	133.06
NOx	0.11	lb/MMBtu	COS learning period (0.083 lb/MMBt	8.25E+02	2,131.97
CO	0.15	lb/MMBtu	TA Predicted	1.13E+03	2,907.23
VOC	0.003	lb/MMBtu	TA Predicted	2.25E+01	58.14
SO_2	0.795	lb/MMscf	AP-42, Table 1.4-2	5.39E+00	13.92
H_2SO_4 [4]	1.53E-02	ton/ton SO_2	EPRI, 2018 H_2SO_4 Emissions Est.	8.24E-02	0.21
CO_2	53.06	kg/MMBtu	40 CFR 98, Subpart C, Table C-1	8.77E+05	2,267,195
CH_4	0.001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	1.65E+01	42.73
N_2O	0.0001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	1.65E+00	4.27
CO_{2e}	-			8.78E+05	2,269,524
HAPs	See table below				33.06

[1] Global Warming Potentials (GWP) from 40 CFR 98 Table A-1, reflects data updated on 1/1/2025.

[2] NG Fuel High Heating Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025

[3] NG Fuel Total Sulfur Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025

[4] H_2SO_4 emissions based on sulfuric acid manufactured by combustion from EPRI's "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants - 2018 Update," Equation 4-1 and Table 4-1

Sample Calculation:

PM Emissions = (Emission Factor, lbs/MMscf) / (Fuel Heating Value, MMBtu/MMscf) x (Fuel Combustion Rate MMBtu/hr)
PM Emissions (lb/hr) = (7.6 lb/MMscf) / (1107 MMBtu/MMscf) x (7500 MMBtu/hr) = 51.4905 lbs/hr
PM Emissions (tons/yr) = (51.4905 lbs/hr) x (5168.4 hrs/yr) / (2000 lbs/ton) = 133.062 tons/yr

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Hazardous and Toxic Air Pollutants (HAPs & TAPs) Natural Gas

Pollutant	CAS No.	HAP?	Natural Gas Emission Factor (lb/MMscf)	Emission Factor Reference	Potential Boiler Emissions - Natural Gas (ton/yr)
1,1,1-Trichloroethane	71-55-6	HAP	--		
2-Methylnaphthalene	91-57-6	HAP	2.4E-05	AP-42, Table 1.4-3	4.2E-04
3-Methylcholanthrene	56-49-5	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
7,12-Dimethylbenz(a)anthracene	57-97-6	HAP	1.6E-05	AP-42, Table 1.4-3	2.8E-04
Acenaphthene	83-32-9	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Acenaphthylene	203-96-8	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Anthracene	120-12-7	HAP	2.4E-06	AP-42, Table 1.4-3	4.2E-05
Benz(a)anthracene	56-55-3	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Benzene	71-43-2	HAP	2.1E-03	AP-42, Table 1.4-3	3.7E-02
Benzo(a)pyrene	50-32-8	HAP	1.2E-06	AP-42, Table 1.4-3	2.1E-05
Benzo(b)fluoranthene	205-99-2	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Benzo(g,h,i)perylene	191-24-2	HAP	1.2E-06	AP-42, Table 1.4-3	2.1E-05
Benzo(k)fluoranthene	207-08-9	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Chrysene	218-01-9	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Dibenzo(a,h) anthracene	53-70-3	HAP	1.2E-06	AP-42, Table 1.4-3	2.1E-05
Dichlorobenzene	106-46-7	HAP	1.2E-03	AP-42, Table 1.4-3	2.1E-02
Ethylbenzene	100-41-4	HAP	--		
Fluoranthene	206-44-0	HAP	3.0E-06	AP-42, Table 1.4-3	5.3E-05
Fluorene	86-73-7	HAP	2.8E-06	AP-42, Table 1.4-3	4.9E-05
Formaldehyde	50-00-0	HAP	7.5E-02	AP-42, Table 1.4-3	1.3E+00
Hexane	110-54-3	HAP	1.8E+00	AP-42, Table 1.4-3	3.2E+01
Indo(1,2,3-cd)pyrene	193-39-5	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Naphthalene	91-20-3	HAP	6.1E-04	AP-42, Table 1.4-3	1.1E-02
OCDD	3268-87-9	HAP	--		
Phenanthrene	85-01-8	HAP	1.7E-05	AP-42, Table 1.4-3	3.0E-04
Pyrene	129-00-0	HAP	5.0E-06	AP-42, Table 1.4-3	8.8E-05
Toluene	108-88-3	HAP	3.4E-03	AP-42, Table 1.4-3	6.0E-02
o-Xylene	95-47-6	HAP	--		
Arsenic	7440-38-2	HAP	2.0E-04	AP-42, Table 1.4-4	3.5E-03
Beryllium	7440-41-7	HAP	1.2E-05	AP-42, Table 1.4-4	2.1E-04
Cadmium	7440-43-9	HAP	1.1E-03	AP-42, Table 1.4-4	1.9E-02
Chromium III	7440-47-3	HAP	1.1E-03	AP-42, Table 1.4-4 [1]	2.0E-02
Chromium VI	18540-29-9	HAP	2.5E-04	AP-42, Table 1.4-4 [1]	4.4E-03
Cobalt	7440-48-4	HAP	8.4E-05	AP-42, Table 1.4-4	1.5E-03
Copper	7440-50-8	-	8.5E-04	AP-42, Table 1.4-4	1.5E-02
Lead	7439-92-1	HAP	5.0E-04	AP-42, Table 1.4-2	8.8E-03
Manganese	7439-96-5	HAP	3.8E-04	AP-42, Table 1.4-4	6.7E-03
Mercury	7439-97-6	HAP	2.6E-04	AP-42, Table 1.4-4	4.6E-03
Nickel	7440-02-0	HAP	2.1E-03	AP-42, Table 1.4-4	3.7E-02
Selenium	7782-49-2	HAP	2.4E-05	AP-42, Table 1.4-4	4.2E-04
Vanadium	7440-62-2	-	2.3E-03	AP-42, Table 1.4-4	4.0E-02
				NG HAPs Total	**33.06**

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[1] Hexavalent chromium is assumed to be eighteen percent (18%) of the total chromium emission factor for natural gas. This is a conservative estimate based on the review of the literature.

Cr VI % **18%**

For natural gas, there is limited information on Cr VI emissions. One source states "As part of the 2011 and previous National Air Toxics Assessments (NATA), EPA assumes that 4% of total chromium produced from natural gas combustion is in the hexavalent form" (PSE Tacoma LNG Facility NOC Application Response to PSCAA Request Regarding Hexavalent Chromium Emissions, September 27, 2017). We were unable to verify this number. Alternatively, in Emissions Estimation Protocol for Petroleum Refineries Version 3 (April 2015), Table 4-3 provides a Summary of Emission Factors for Boilers and Process Heaters Firing Natural Gas/Refinery Gas with a note that says hexavalent chromium emission factors for gas turbines are between 10 and 15 percent of the total chromium emission factor. No reference was provided for those numbers.

https://www.aqmd.gov/docs/default-source/planning/annual-emission-reporting/combustion-default-emission-factors-2024.pdf?sfvrsn=9
https://pscleanair.gov/DocumentCenter/View/2889/PSE_09-27-17-Tacoma-LNG----Hex-Chrom-Response
https://www.epa.gov/sites/default/files/2020-11/documents/protocol_report_2015.pdf
https://19january2021snapshot.epa.gov/sites/static/files/2015-11/documents/eurtc1.pdf

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Transalta
Unit 2 190 MW operating scenario (100% natural gas)

Max. Fuel Combustion Rate =	2,529.00	MMBtu/hr
Total Possible Hours =	8,760	hr/yr
Capacity Factor =	100%	
Hours of Operation =	8,760	hr/yr

Global Warming Potential [1]	
CO_2	1
CH_4	28
N_2O	265

Fuel Scenario Natural Gas	100%	
NG Hours	8,760	hr/yr
NG Fuel Usage =	20,012.68	MMscf/yr
NG Fuel High Heating Value [2] =	1,107	MMBtu/MMscf
NG Fuel Total Sulfur Value [3] =	2650	gr/MMscf
Conversions:	2.2046	lb/kg
	2,000	lbs/ton

Criteria Pollutants (HAPs)

Pollutant	NG Emission Factor	Units	Emission Factor Reference	Emissions (lbs/hr)	Emissions (tons/yr)
PM	7.6	lb/MMscf	AP-42, Table 1.4-2	1.74E+01	76.05
PM_{10}	7.6	lb/MMscf	AP-42, Table 1.4-2	1.74E+01	76.05
$PM_{2.5}$	7.6	lb/MMscf	AP-42, Table 1.4-2	1.74E+01	76.05
NOx	0.11	lb/MMBtu	COS learning period (0.083 lb/MMBt	2.78E+02	1,218.47
CO	0.15	lb/MMBtu	Proposed BACT	3.79E+02	1,661.55
VOC	0.003	lb/MMBtu	TA Predicted	7.59E+00	33.23
SO_2	0.795	lb/MMscf	AP-42, Table 1.4-2	1.82E+00	7.96
H_2SO_4 [4]	1.53E-02	ton/ton SO_2	EPRI, 2018 H_2SO_4 Emissions Est.	2.78E-02	0.12
CO_2	53.06	kg/MMBtu	40 CFR 98, Subpart C, Table C-1	2.96E+05	1,295,760
CH_4	0.001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	5.58E+00	24.42
N_2O	0.0001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	5.58E-01	2.44
CO_{2e}	-			2.96E+05	1,297,091
HAPs	See table below				18.90

[1] Global Warming Potentials (GWP) from 40 CFR 98 Table A-1, reflects data updated on 1/1/2025.

[2] NG Fuel High Heating Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025

[3] NG Fuel Total Sulfur Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025

[4] H_2SO_4 emissions based on sulfuric acid manufactured by combustion from EPRI's "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants - 2018 Update," Equation 4-1 and Table 4-1

Sample Calculation:

PM Emissions = (Emission Factor, lbs/MMscf) / (Fuel Heating Value, MMBtu/MMscf) x (Fuel Combustion Rate MMBtu/hr)
PM Emissions (lb/hr) = (7.6 lb/MMscf) / (1107 MMBtu/MMscf) x (2529 MMBtu/hr) = 17.3626 lbs/hr
PM Emissions (tons/yr) = (17.3626 lbs/hr) x (8760 hrs/yr) / (2000 lbs/ton) = 76.048 tons/yr

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Hazardous and Toxic Air Pollutants (HAPs & TAPs) Natural Gas

Pollutant	CAS No.	HAP?	Natural Gas Emission Factor (lb/MMscf)	Emission Factor Reference	Potential Boiler Emissions - Natural Gas (ton/yr)
1,1,1-Trichloroethane	71-55-6	HAP		--	
2-Methylnaphthalene	91-57-6	HAP	2.4E-05	AP-42, Table 1.4-3	2.4E-04
3-Methylcholanthrene	56-49-5	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
7,12-Dimethylbenz(a)anthracene	57-97-6	HAP	1.6E-05	AP-42, Table 1.4-3	1.6E-04
Acenaphthene	83-32-9	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Acenaphthylene	203-96-8	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Anthracene	120-12-7	HAP	2.4E-06	AP-42, Table 1.4-3	2.4E-05
Benz(a)anthracene	56-55-3	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Benzene	71-43-2	HAP	2.1E-03	AP-42, Table 1.4-3	2.1E-02
Benzo(a)pyrene	50-32-8	HAP	1.2E-06	AP-42, Table 1.4-3	1.2E-05
Benzo(b)fluoranthene	205-99-2	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Benzo(g,h,i)perylene	191-24-2	HAP	1.2E-06	AP-42, Table 1.4-3	1.2E-05
Benzo(k)fluoranthene	207-08-9	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Chrysene	218-01-9	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Dibenzo(a,h) anthracene	53-70-3	HAP	1.2E-06	AP-42, Table 1.4-3	1.2E-05
Dichlorobenzene	106-46-7	HAP	1.2E-03	AP-42, Table 1.4-3	1.2E-02
Ethylbenzene	100-41-4	HAP		--	
Fluoranthene	206-44-0	HAP	3.0E-06	AP-42, Table 1.4-3	3.0E-05
Fluorene	86-73-7	HAP	2.8E-06	AP-42, Table 1.4-3	2.8E-05
Formaldehyde	50-00-0	HAP	7.5E-02	AP-42, Table 1.4-3	7.5E-01
Hexane	110-54-3	HAP	1.8E+00	AP-42, Table 1.4-3	1.8E+01
Indo(1,2,3-cd)pyrene	193-39-5	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Naphthalene	91-20-3	HAP	6.1E-04	AP-42, Table 1.4-3	6.1E-03
OCDD	3268-87-9	HAP		--	
Phenanthrene	85-01-8	HAP	1.7E-05	AP-42, Table 1.4-3	1.7E-04
Pyrene	129-00-0	HAP	5.0E-06	AP-42, Table 1.4-3	5.0E-05
Toluene	108-88-3	HAP	3.4E-03	AP-42, Table 1.4-3	3.4E-02
o-Xylene	95-47-6	HAP		--	
Arsenic	7440-38-2	HAP	2.0E-04	AP-42, Table 1.4-4	2.0E-03
Beryllium	7440-41-7	HAP	1.2E-05	AP-42, Table 1.4-4	1.2E-04
Cadmium	7440-43-9	HAP	1.1E-03	AP-42, Table 1.4-4	1.1E-02
Chromium III	7440-47-3	HAP	1.4E-03	AP-42, Table 1.4-4 [1]	1.4E-02
Chromium VI	18540-29-9	HAP	0.0E+00	AP-42, Table 1.4-4 [1]	0.0E+00
Cobalt	7440-48-4	HAP	8.4E-05	AP-42, Table 1.4-4	8.4E-04
Copper	7440-50-8	-	8.5E-04	AP-42, Table 1.4-4	8.5E-03
Lead	7439-92-1	HAP	5.0E-04	AP-42, Table 1.4-2	5.0E-03
Manganese	7439-96-5	HAP	3.8E-04	AP-42, Table 1.4-4	3.8E-03
Mercury	7439-97-6	HAP	2.6E-04	AP-42, Table 1.4-4	2.6E-03
Nickel	7440-02-0	HAP	2.1E-03	AP-42, Table 1.4-4	2.1E-02
Selenium	7782-49-2	HAP	2.4E-05	AP-42, Table 1.4-4	2.4E-04
Vanadium	7440-62-2	-	2.3E-03	AP-42, Table 1.4-4	2.3E-02
				NG HAPs Total	**18.90**

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

[1] Hexavalent chromium is assumed to be eighteen percent (18%) of the total chromium emission factor for natural gas. This is a conservative estimate based on the review of the literature.

Cr VI % **18%**

For natural gas, there is limited information on Cr VI emissions. One source states "As part of the 2011 and previous National Air Toxics Assessments (NATA), EPA assumes that 4% of total chromium produced from natural gas combustion is in the hexavalent form" (PSE Tacoma LNG Facility NOC Application Response to PSCAA Request Regarding Hexavalent Chromium Emissions, September 27, 2017). We were unable to verify this number. Alternatively, in Emissions Estimation Protocol for Petroleum Refineries Version 3 (April 2015), Table 4-3 provides a Summary of Emission Factors for Boilers and Process Heaters Firing Natural Gas/Refinery Gas with a note that says hexavalent chromium emission factors for gas turbines are between 10 and 15 percent of the total chromium emission factor. No reference was provided for those numbers.

https://www.aqmd.gov/docs/default-source/planning/annual-emission-reporting/combustion-default-emission-factors-2024.pdf?sfvrsn=9

https://pscleanair.gov/DocumentCenter/View/2889/PSE_09-27-17-Tacoma-LNG----Hex-Chrom-Response

https://www.epa.gov/sites/default/files/2020-11/documents/protocol_report_2015.pdf

https://19january2021snapshot.epa.gov/sites/static/files/2015-11/documents/eurtc1.pdf

https://19january2021snapshot.epa.gov/sites/static/files/2015-11/documents/eurtc1.pdf

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Transalta
Natural gas venting re: shutdown

Natural gas vented per shutdown:	20,000	scf/shutdown
NG % methane (CH_4) composition:	95%	
CH_4 vented per shutdown:	19,000	scf/shutdown
Number of shutdowns per year:	50	shutdowns/yr
CH_4 vented per year:	950,000	scf/yr
Conversion	2,000	lb/ton
CH_4 density at STP:	0.04475	lb/scf
CH_4 Global Warming Potential [1]	28	
Mass of CH_4 vented per year:	42,513	lb/yr
Mass of CH_4 vented per year:	21	tons/yr
CO_{2e} vented per year:	595	tons/yr

[1] Global Warming Potentials (GWP) from 40 CFR 98 Table A-1, reflects data updated on 1/1/2025.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Transalta
Auxiliary Boiler

Max. Fuel Combustion Rate =	149.13	MMBtu/hr	Global Warming Potential [1]	
Fuel Usage =	175.13	MMscf/yr	CO_2	1
Hours of Operation =	1,300	hr/yr	CH_4	28
NG Fuel High Heating Value [2] =	1,107	MMBtu/MMscf	N_2O	265
NG Fuel Total Sulfur Value [3] =	2650	gr/MMscf		
Conversions:	2.2046	lb/kg		
	2,000	lbs/ton		

Criteria Pollutants

Pollutant	Emission Factor	Units	Emission Factor Reference	Emissions (lbs/hr)	Emissions (tons/yr)
$PM/PM_{10}/PM_{2.5}$	7.6	lb/MMscf	AP-42, Table 1.4-2	1.02E+00	0.67
NO_x	0.015	lb/MMBtu	Proposed BACT (12 ppm)	2.24E+00	1.45
CO	0.037	lb/MMBtu	Proposed BACT (50 ppm)	5.52E+00	3.59
VOC	5.5	lb/MMscf	AP-42, Table 1.4-2	7.41E-01	0.48
SO_2 [3]	0.8	lb/MMscf	AP-42, Table 1.4-2	1.07E-01	0.07
H_2SO_4 [4]	1.53E-02	ton/ton SO_2	EPRI, 2018 H_2SO_4 Emissions Est.	1.64E-03	0.00
CO_2	53.06	kg/MMBtu	40 CFR 98, Subpart C, Table C-1	1.74E+04	11,339
CH_4	0.001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	3.29E-01	0.21
N_2O	0.0001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	3.29E-02	0.02
CO_{2e}	-			1.75E+04	11,351
HAPs	See table below				0.17

[1] Global Warming Potentials (GWP) from 40 CFR 98 Table A-1, reflects data updated on 1/1/2025.

[2] NG Fuel High Heating Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025

[3] NG Fuel Total Sulfur Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2024

[4] H_2SO_4 emissions based on sulfuric acid manufactured by combustion from EPRI's "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants - 2018 Update," Equation 4-1 and Table 4-1

Sample Calculation:

PM Emissions = (Emission Factor, lbs/MMscf) / (Fuel Heating Value, MMBtu/MMscf) x (Fuel Combustion Rate MMBtu/hr)
PM Emissions (lb/hr) = (7.6 lb/MMscf) / (1107 MMBtu/MMscf) x (149.13 MMBtu/hr) = 1.0238 lbs/hr
PM Emissions (tons/yr) = (1.0238 lbs/hr) x (1300 hrs/yr) / (2000 lbs/ton) = 0.665 tons/yr

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Hazardous and Toxic Air Pollutants (HAPs & TAPs) Natural Gas

Pollutant	CAS No.	HAP?	Natural Gas Emission Factor (lb/MMscf)	Emission Factor Reference	Potential Aux Boiler Emissions - Natural Gas (ton/yr)
1,1,1-Trichloroethane	71-55-6	HAP	--		
2-Methylnaphthalene	91-57-6	HAP	2.4E-05	AP-42, Table 1.4-3	2.1E-06
3-Methylcholanthrene	56-49-5	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
7,12-Dimethylbenz(a)anthracer	57-97-6	HAP	1.6E-05	AP-42, Table 1.4-3	1.4E-06
Acenaphthene	83-32-9	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Acenaphthylene	203-96-8	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Anthracene	120-12-7	HAP	2.4E-06	AP-42, Table 1.4-3	2.1E-07
Benz(a)anthracene	56-55-3	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Benzene	71-43-2	HAP	2.1E-03	AP-42, Table 1.4-3	1.8E-04
Benzo(a)pyrene	50-32-8	HAP	1.2E-06	AP-42, Table 1.4-3	1.1E-07
Benzo(b)fluoranthene	205-99-2	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Benzo(g,h,i)perylene	191-24-2	HAP	1.2E-06	AP-42, Table 1.4-3	1.1E-07
Benzo(k)fluoranthene	207-08-9	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Chrysene	218-01-9	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Dibenzo(a,h) anthracene	53-70-3	HAP	1.2E-06	AP-42, Table 1.4-3	1.1E-07
Dichlorobenzene	106-46-7	HAP	1.2E-03	AP-42, Table 1.4-3	1.1E-04
Ethylbenzene	100-41-4	HAP	--		
Fluoranthene	206-44-0	HAP	3.0E-06	AP-42, Table 1.4-3	2.6E-07
Fluorene	86-73-7	HAP	2.8E-06	AP-42, Table 1.4-3	2.5E-07
Formaldehyde	50-00-0	HAP	7.5E-02	AP-42, Table 1.4-3	6.6E-03
Hexane	110-54-3	HAP	1.8E+00	AP-42, Table 1.4-3	1.6E-01
Indo(1,2,3-cd)pyrene	193-39-5	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Naphthalene	91-20-3	HAP	6.1E-04	AP-42, Table 1.4-3	5.3E-05
OCDD	3268-87-9	HAP	--		
Phenanthrene	85-01-8	HAP	1.7E-05	AP-42, Table 1.4-3	1.5E-06
Pyrene	129-00-0	HAP	5.0E-06	AP-42, Table 1.4-3	4.4E-07
Toluene	108-88-3	HAP	3.4E-03	AP-42, Table 1.4-3	3.0E-04
o-Xylene	95-47-6	HAP	--		
Arsenic	7440-38-2	HAP	2.0E-04	AP-42, Table 1.4-4	1.8E-05
Beryllium	7440-41-7	HAP	1.2E-05	AP-42, Table 1.4-4	1.1E-06
Cadmium	7440-43-9	HAP	1.1E-03	AP-42, Table 1.4-4	9.6E-05
Chromium III	7440-47-3	HAP	1.1E-03	AP-42, Table 1.4-4 [1]	1.0E-04
Chromium VI	18540-29-9	HAP	2.5E-04	AP-42, Table 1.4-4 [1]	2.2E-05
Cobalt	7440-48-4	HAP	8.4E-05	AP-42, Table 1.4-4	7.4E-06
Copper	7440-50-8	-	8.5E-04	AP-42, Table 1.4-4	7.4E-05
Lead	7439-92-1	HAP	5.0E-04	AP-42, Table 1.4-2	4.4E-05
Manganese	7439-96-5	HAP	3.8E-04	AP-42, Table 1.4-4	3.3E-05
Mercury	7439-97-6	HAP	2.6E-04	AP-42, Table 1.4-4	2.3E-05
Nickel	7440-02-0	HAP	2.1E-03	AP-42, Table 1.4-4	1.8E-04
Selenium	7782-49-2	HAP	2.4E-05	AP-42, Table 1.4-4	2.1E-06
Vanadium	7440-62-2	-	2.3E-03	AP-42, Table 1.4-4	2.0E-04
				NG HAPs Total	**0.17**

[1] Hexavalent chromium is assumed to be eighteen percent (18%) of the total chromium emission factor for natural gas. This is a conservative estimate based on the review of the literature.

Cr VI % **18%**

For natural gas, there is limited information on Cr VI emissions. One source states "As part of the 2011 and previous National Air Toxics Assessments (NATA), EPA assumes that 4% of total chromium produced from natural gas combustion is in the hexavalent form" (PSE Tacoma LNG Facility NOC Application Response to PSCAA Request Regarding Hexavalent Chromium Emissions, September 27, 2017). We were unable to verify this number. Alternatively, in Emissions Estimation Protocol for Petroleum Refineries Version 3 (April 2015), Table 4-3 provides a Summary of Emission Factors for Boilers and Process Heaters Firing Natural Gas/Refinery Gas with a note that says hexavalent chromium emission factors for gas turbines are between 10 and 15 percent of the total chromium emission factor. No reference was provided for those numbers.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Transalta
Water Bath Heater 1

Max. Fuel Combustion Rate =	10.00	MMBtu/hr	Global Warming Potential [1]	
Fuel Usage =	79.13	MMscf/yr	CO_2	1
Hours of Operation =	8,760	hr/yr	CH_4	28
NG Fuel High Heating Value [2] =	1,107	MMBtu/MMscf	N_2O	265
NG Fuel Total Sulfur Value [3] =	2650	gr/MMscf		
Conversions:	2.2046	lb/kg		
	2,000	lbs/ton		

Criteria Pollutants

Pollutant	Emission Factor	Units	Emission Factor Reference	Emissions (lbs/hr)	Emissions (tons/yr)
$PM/PM_{10}/PM_{2.5}$	7.6	lb/MMscf	AP-42, Table 1.4-2	6.87E-02	0.30
NO_x	0.015	lb/MMBtu	Proposed BACT (12 ppm)	1.50E-01	0.66
CO	0.037	lb/MMBtu	Proposed BACT (50 ppm)	3.70E-01	1.62
VOC	5.5	lb/MMscf	AP-42, Table 1.4-2	4.97E-02	0.22
SO_2 [3]	0.8	lb/MMscf	AP-42, Table 1.4-2	7.18E-03	0.03
H_2SO_4 [4]	1.53E-02	ton/ton SO_2	EPRI, 2018 H_2SO_4 Emissions Est.	1.10E-04	0.00
CO_2	53.06	kg/MMBtu	40 CFR 98, Subpart C, Table C-1	1.17E+03	5,124
CH_4	0.001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	2.20E-02	0.10
N_2O	0.0001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	2.20E-03	0.01
CO_{2e}	-			1.17E+03	5,129
HAPs	See table below				0.07

[1] Global Warming Potentials (GWP) from 40 CFR 98 Table A-1, reflects data updated on 1/1/2025.
[2] NG Fuel High Heating Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025.
[3] NG Fuel Total Sulfur Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025.
[4] H_2SO_4 emissions based on sulfuric acid manufactured by combustion from EPRI's "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants - 2018 Update," Equation 4-1 and Table 4-1

Sample Calculation:

PM Emissions = (Emission Factor, lbs/MMscf) / (Fuel Heating Value, MMBtu/MMscf) x (Fuel Combustion Rate MMBtu/hr)
PM Emissions (lb/hr) = (7.6 lb/MMscf) / (1107 MMBtu/MMscf) x (10 MMBtu/hr) = 0.0687 lbs/hr
PM Emissions (tons/yr) = (0.0687 lbs/hr) x (8760 hrs/yr) / (2000 lbs/ton) = 0.301 tons/yr

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Hazardous and Toxic Air Pollutants (HAPs & TAPs) Natural Gas

Pollutant	CAS No.	HAP?	Natural Gas Emission Factor (lb/MMscf)	Emission Factor Reference	Potential Water Bath Heater 1 Emissions - Natural Gas (ton/yr)
1,1,1-Trichloroethane	71-55-6	HAP		--	
2-Methylnaphthalene	91-57-6	HAP	2.4E-05	AP-42, Table 1.4-3	9.5E-07
3-Methylcholanthrene	56-49-5	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
7,12-Dimethylbenz(a)anthracer	57-97-6	HAP	1.6E-05	AP-42, Table 1.4-3	6.3E-07
Acenaphthene	83-32-9	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Acenaphthylene	203-96-8	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Anthracene	120-12-7	HAP	2.4E-06	AP-42, Table 1.4-3	9.5E-08
Benz(a)anthracene	56-55-3	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Benzene	71-43-2	HAP	2.1E-03	AP-42, Table 1.4-3	8.3E-05
Benzo(a)pyrene	50-32-8	HAP	1.2E-06	AP-42, Table 1.4-3	4.7E-08
Benzo(b)fluoranthene	205-99-2	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Benzo(g,h,i)perylene	191-24-2	HAP	1.2E-06	AP-42, Table 1.4-3	4.7E-08
Benzo(k)fluoranthene	207-08-9	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Chrysene	218-01-9	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Dibenzo(a,h) anthracene	53-70-3	HAP	1.2E-06	AP-42, Table 1.4-3	4.7E-08
Dichlorobenzene	106-46-7	HAP	1.2E-03	AP-42, Table 1.4-3	4.7E-05
Ethylbenzene	100-41-4	HAP		--	
Fluoranthene	206-44-0	HAP	3.0E-06	AP-42, Table 1.4-3	1.2E-07
Fluorene	86-73-7	HAP	2.8E-06	AP-42, Table 1.4-3	1.1E-07
Formaldehyde	50-00-0	HAP	7.5E-02	AP-42, Table 1.4-3	3.0E-03
Hexane	110-54-3	HAP	1.8E+00	AP-42, Table 1.4-3	7.1E-02
Indo(1,2,3-cd)pyrene	193-39-5	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Naphthalene	91-20-3	HAP	6.1E-04	AP-42, Table 1.4-3	2.4E-05
OCDD	3268-87-9	HAP		--	
Phenanthrene	85-01-8	HAP	1.7E-05	AP-42, Table 1.4-3	6.7E-07
Pyrene	129-00-0	HAP	5.0E-06	AP-42, Table 1.4-3	2.0E-07
Toluene	108-88-3	HAP	3.4E-03	AP-42, Table 1.4-3	1.3E-04
o-Xylene	95-47-6	HAP		--	
Arsenic	7440-38-2	HAP	2.0E-04	AP-42, Table 1.4-4	7.9E-06
Beryllium	7440-41-7	HAP	1.2E-05	AP-42, Table 1.4-4	4.7E-07
Cadmium	7440-43-9	HAP	1.1E-03	AP-42, Table 1.4-4	4.4E-05
Chromium III	7440-47-3	HAP	1.1E-03	AP-42, Table 1.4-4 [1]	4.5E-05
Chromium VI	18540-29-9	HAP	2.5E-04	AP-42, Table 1.4-4 [1]	1.0E-05
Cobalt	7440-48-4	HAP	8.4E-05	AP-42, Table 1.4-4	3.3E-06
Copper	7440-50-8	-	8.5E-04	AP-42, Table 1.4-4	3.4E-05
Lead	7439-92-1	HAP	5.0E-04	AP-42, Table 1.4-2	2.0E-05
Manganese	7439-96-5	HAP	3.8E-04	AP-42, Table 1.4-4	1.5E-05
Mercury	7439-97-6	HAP	2.6E-04	AP-42, Table 1.4-4	1.0E-05
Nickel	7440-02-0	HAP	2.1E-03	AP-42, Table 1.4-4	8.3E-05
Selenium	7782-49-2	HAP	2.4E-05	AP-42, Table 1.4-4	9.5E-07
Vanadium	7440-62-2	-	2.3E-03	AP-42, Table 1.4-4	9.1E-05
				NG HAPs Total	**0.07**

[1] Hexavalent chromium is assumed to be eighteen percent (18%) of the total chromium emission factor for natural gas. This is a conservative estimate based on the review of the literature.

Cr VI % **18%**

For natural gas, there is limited information on Cr VI emissions. One source states "As part of the 2011 and previous National Air Toxics Assessments (NATA), EPA assumes that 4% of total chromium produced from natural gas combustion is in the hexavalent form" (PSE Tacoma LNG Facility NOC Application Response to PSCAA Request Regarding Hexavalent Chromium Emissions, September 27, 2017). We were unable to verify this number. Alternatively, in Emissions Estimation Protocol for Petroleum Refineries Version 3 (April 2015), Table 4-3 provides a Summary of Emission Factors for Boilers and Process Heaters Firing Natural Gas/Refinery Gas with a note that says hexavalent chromium emission factors for gas turbines are between 10 and 15 percent of the total chromium emission factor. No reference was provided for those numbers.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Transalta
Water Bath Heater 2

Max. Fuel Combustion Rate =	10.00	MMBtu/hr
Fuel Usage =	79.13	MMscf/yr
Hours of Operation =	8,760	hr/yr
NG Fuel High Heating Value [2] =	1,107	MMBtu/MMscf
NG Fuel Total Sulfur Value [3] =	2650	gr/MMscf
Conversions:	2.2046	lb/kg
	2,000	lbs/ton

Global Warming Potential [1]	
CO_2	1
CH_4	28
N_2O	265

Criteria Pollutants

Pollutant	Emission Factor	Units	Emission Factor Reference	Emissions (lbs/hr)	Emissions (tons/yr)
$PM/PM_{10}/PM_{2.5}$	7.6	lb/MMscf	AP-42, Table 1.4-2	6.87E-02	0.30
NO_x	0.015	lb/MMBtu	Proposed BACT (12 ppm)	1.50E-01	0.66
CO	0.037	lb/MMBtu	Proposed BACT (50 ppm)	3.70E-01	1.62
VOC	5.5	lb/MMscf	AP-42, Table 1.4-2	4.97E-02	0.22
SO_2 [3]	0.8	lb/MMscf	AP-42, Table 1.4-2	7.18E-03	0.03
H_2SO_4 [4]	1.53E-02	ton/ton SO_2	EPRI, 2018 H_2SO_4 Emissions Est.	1.10E-04	0.00
CO_2	53.06	kg/MMBtu	40 CFR 98, Subpart C, Table C-1	1.17E+03	5,124
CH_4	0.001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	2.20E-02	0.10
N_2O	0.0001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	2.20E-03	0.01
CO_{2e}	-			1.17E+03	5,129
HAPs	See table below				0.07

[1] Global Warming Potentials (GWP) from 40 CFR 98 Table A-1, reflects data updated on 1/1/2025.

[2] NG Fuel High Heating Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025.

[3] NG Fuel Total Sulfur Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025.

[4] H_2SO_4 emissions based on sulfuric acid manufactured by combustion from EPRI's "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants - 2018 Update," Equation 4-1 and Table 4-1.

Sample Calculation:

PM Emissions = (Emission Factor, lbs/MMscf) / (Fuel Heating Value, MMBtu/MMscf) x (Fuel Combustion Rate MMBtu/hr)
PM Emissions (lb/hr) = (7.6 lb/MMscf) / (1107 MMBtu/MMscf) x (10 MMBtu/hr) = 0.0687 lbs/hr
PM Emissions (tons/yr) = (0.0687 lbs/hr) x (8760 hrs/yr) / (2000 lbs/ton) = 0.301 tons/yr

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Hazardous and Toxic Air Pollutants (HAPs & TAPs) Natural Gas

Pollutant	CAS No.	HAP?	Natural Gas Emission Factor (lb/MMscf)	Emission Factor Reference	Potential Water Bath Heater 2 Emissions - Natural Gas (ton/yr)
1,1,1-Trichloroethane	71-55-6	HAP	--		
2-Methylnaphthalene	91-57-6	HAP	2.4E-05	AP-42, Table 1.4-3	9.5E-07
3-Methylcholanthrene	56-49-5	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
7,12-Dimethylbenz(a)anthracer	57-97-6	HAP	1.6E-05	AP-42, Table 1.4-3	6.3E-07
Acenaphthene	83-32-9	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Acenaphthylene	203-96-8	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Anthracene	120-12-7	HAP	2.4E-06	AP-42, Table 1.4-3	9.5E-08
Benz(a)anthracene	56-55-3	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Benzene	71-43-2	HAP	2.1E-03	AP-42, Table 1.4-3	8.3E-05
Benzo(a)pyrene	50-32-8	HAP	1.2E-06	AP-42, Table 1.4-3	4.7E-08
Benzo(b)fluoranthene	205-99-2	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Benzo(g,h,i)perylene	191-24-2	HAP	1.2E-06	AP-42, Table 1.4-3	4.7E-08
Benzo(k)fluoranthene	207-08-9	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Chrysene	218-01-9	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Dibenzo(a,h) anthracene	53-70-3	HAP	1.2E-06	AP-42, Table 1.4-3	4.7E-08
Dichlorobenzene	106-46-7	HAP	1.2E-03	AP-42, Table 1.4-3	4.7E-05
Ethylbenzene	100-41-4	HAP	--		
Fluoranthene	206-44-0	HAP	3.0E-06	AP-42, Table 1.4-3	1.2E-07
Fluorene	86-73-7	HAP	2.8E-06	AP-42, Table 1.4-3	1.1E-07
Formaldehyde	50-00-0	HAP	7.5E-02	AP-42, Table 1.4-3	3.0E-03
Hexane	110-54-3	HAP	1.8E+00	AP-42, Table 1.4-3	7.1E-02
Indo(1,2,3-cd)pyrene	193-39-5	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Naphthalene	91-20-3	HAP	6.1E-04	AP-42, Table 1.4-3	2.4E-05
OCDD	3268-87-9	HAP	--		
Phenanthrene	85-01-8	HAP	1.7E-05	AP-42, Table 1.4-3	6.7E-07
Pyrene	129-00-0	HAP	5.0E-06	AP-42, Table 1.4-3	2.0E-07
Toluene	108-88-3	HAP	3.4E-03	AP-42, Table 1.4-3	1.3E-04
o-Xylene	95-47-6	HAP	--		
Arsenic	7440-38-2	HAP	2.0E-04	AP-42, Table 1.4-4	7.9E-06
Beryllium	7440-41-7	HAP	1.2E-05	AP-42, Table 1.4-4	4.7E-07
Cadmium	7440-43-9	HAP	1.1E-03	AP-42, Table 1.4-4	4.4E-05
Chromium III	7440-47-3	HAP	1.1E-03	AP-42, Table 1.4-4 [1]	4.5E-05
Chromium VI	18540-29-9	HAP	2.5E-04	AP-42, Table 1.4-4 [1]	1.0E-05
Cobalt	7440-48-4	HAP	8.4E-05	AP-42, Table 1.4-4	3.3E-06
Copper	7440-50-8	-	8.5E-04	AP-42, Table 1.4-4	3.4E-05
Lead	7439-92-1	HAP	5.0E-04	AP-42, Table 1.4-2	2.0E-05
Manganese	7439-96-5	HAP	3.8E-04	AP-42, Table 1.4-4	1.5E-05
Mercury	7439-97-6	HAP	2.6E-04	AP-42, Table 1.4-4	1.0E-05
Nickel	7440-02-0	HAP	2.1E-03	AP-42, Table 1.4-4	8.3E-05
Selenium	7782-49-2	HAP	2.4E-05	AP-42, Table 1.4-4	9.5E-07
Vanadium	7440-62-2	-	2.3E-03	AP-42, Table 1.4-4	9.1E-05
				NG HAPs Total	**0.07**

[1] Hexavalent chromium is assumed to be eighteen percent (18%) of the total chromium emission factor for natural gas. This is a conservative estimate based on the review of the literature.

Cr VI % **18%**

For natural gas, there is limited information on Cr VI emissions. One source states "As part of the 2011 and previous National Air Toxics Assessments (NATA), EPA assumes that 4% of total chromium produced from natural gas combustion is in the hexavalent form" (PSE Tacoma LNG Facility NOC Application Response to PSCAA Request Regarding Hexavalent Chromium Emissions, September 27, 2017). We were unable to verify this number. Alternatively, in Emissions Estimation Protocol for Petroleum Refineries Version 3 (April 2015), Table 4-3 provides a Summary of Emission Factors for Boilers and Process Heaters Firing Natural Gas/Refinery Gas with a note that says hexavalent chromium emission factors for gas turbines are between 10 and 15 percent of the total chromium emission factor. No reference was provided for those numbers.

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Transalta
Cooling Tower 1 - Serving Unit 2

Water flow:	120,000	gpm
Hours of Operation:	8760	hrs/yr
Water flow:	63,072	MMgal/yr
Total Dissolved Solids in circulating water (TDS)*	576	ppm
Drift (η_{Drift}) [1]	0.0005	%
Density of water (ρ_{H2O})	8.34E+06	lb/MMgal

Equation [2]

$$EF = \frac{TDS}{10^6} \times \frac{\eta_{Drift}}{100} \times \rho_{H_2O} \qquad \text{(Eq. 2)}$$

Where:

EF = emission factor (lb/MMgal)

TDS = Concentration of total dissolved solids in circulating water (PPM by weight)

η_{Drift} = Drift loss of circulating water (%)

ρ_{H_2O} = Density of Water (lb/MMgal) = Density of Water (lbs/gal × 10^6)

PM Emission Factor (EF) =	2.40E-02	lb/MMgal	
PM =	0.76	tons/yr	1.51
PM_{10} =	0.76	tons/yr	1.51
$PM_{2.5}$ [3]=	0.45	tons/yr	

[1] Current BACT requirement for DOE and SWCAA.

[2] South Coast Air Quality Management District, Guidelines for Calculating Emissions from Cooling Towers, December 2022

[3] PM2.5 fraction = 0.6*PM10 fraction, Maricopa County Air Quality, Reporting Emissions From Cooling Towers, January 2025

Hazardous and Toxic Air Pollutants (HAPs & TAPs) Cooling Towers

*Transalta Unit #2 cooling tower testing (12/3/24-01/02/25) - only listed constituent is silica

Total TDS**	576 ppm		
Silica CAS No. 7631-86-9 (TAPs only)	144 ppm	Ratio of silica to TDS	25%
Silica emissions			0.19 tons/yr

**Assume that PM emissions are representative of TDS, therefore 25% of PM emissions are silica

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Transalta
Cooling Tower 2- Serving Unit 2

Water flow:	120,000	gpm
Total Possible Hours (hrs/yr):	8,760	hrs/yr
Water flow:	63,072	MMgal/yr
Total Dissolved Solids in circulating water (TDS)*	576	ppm
Drift (η_{Drift}) [1]	0.0005	%
Density of water (ρ_{H2O})	8.34E+06	lb/MMgal

Equation [2]

$$EF = \frac{TDS}{10^6} \times \frac{\eta_{Drift}}{100} \times \rho_{H_2O} \qquad \text{(Eq. 2)}$$

Where:

EF = emission factor (lb/MMgal)

TDS = Concentration of total dissolved solids in circulating water (PPM by weight)

η_{Drift} = Drift loss of circulating water (%)

ρ_{H_2O} = Density of Water (lb/MMgal) = Density of Water (lbs/gal × 10^6)

PM Emission Factor (EF) =	2.40E-02	lb/MMgal
PM =	0.76	tons/yr
PM10 =	0.76	tons/yr
PM2.5=	0.45	tons/yr

[1] Current BACT requirement for DOE and SWCAA.
[2] South Coast Air Quality Management District, Guidelines for Calculating Emissions from Cooling Towers, December 2022
[3] PM2.5 fraction = 0.6*PM10 fraction, Maricopa County Air Quality, Reporting Emissions From Cooling Towers, January 2025

*Transalta Unit #2 cooling tower testing (12/3/24-01/02/25) - only listed constituent is silica

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Silica CAS No. 7631-86-9 (TAPs only)	144 ppm	Ratio of silica to TDS	25%
Silica emissions			0.19 tons/yr

**Assume that PM emissions are representative of TDS, therefore 25% of PM emissions are silica

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APPENDIX C: SUPPORTING DOCUMENTATION FOR REGULATORY ANALYSIS

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

TETRA TECH

Technical Memo

To:	Scott Jeffers and Vincent Light, TransAlta
From:	Debbie Skibicki, PE
Date:	April 22, 2025
Subject:	PSD Analysis for TransAlta Centralia Generating Station Coal-to-Gas Conversion, Reactivation Policy

In discussions with the Washington Department of Ecology (DOE) on April 9, 2025, on the TransAlta Coal-to-Gas (CTG) conversion at the Centralia Generating Station, DOE brought up their interpretation of reactivation policy with respect to that project. DOE specifically mentioned the November 1, 2017 "Guidance on Washington's Prevention of Significant Deterioration [PSD] Permitting Program" (DOE Guidance, Publication no. 17-02-014), Section 2.2.2.1.3 – Restarting Emissions Units. DOE's Guidance document states that "when an emissions unit is restarted after being shut down, PSD permitting may be triggered in one of several ways." Section 2.2.2.1.3 of that guidance focuses on reactivation, described as a "permanently" shutdown plant being restarted as a new source. This discussion elaborates on both DOE and EPA guidance and associated site-specific criteria for the TransAlta Centralia site and the CTG project.

1.0 DOE REACTIVATION POLICY

Section 2.2.2.1.3 of the DOE Guidance, under "Reactivation Policy," states the following:

> "*EPA's policy on whether a shutdown plant if restarted is subject to PSD review as a new source is outlined in a number of EPA memoranda.[1] Reactivating a "permanently" shut down source makes the source a new source under current PSD guidance. A source shutting down for more than two years is a new source if restarted, unless Ecology continued to carry the source in the emission inventory.* ***This presumption can be rebutted by providing evidence that the shutdown was not intended to be permanent****. Owners or operators of facilities that have been shut down must continuously demonstrate concrete plans to restart the facility sometime in the reasonably foreseeable future. The source would not be a new source if the shutdown was not permanent, and the owners kept records of the type and amount of maintenance performed on the temporary shutdown source [emphasis added]."*

DOE further states:

> *Permanence is determined by the intention of the owner or operator* ***at the time of the shutdown*** *as determined from all the facts and circumstances, including the cause of the shutdown, duration of the shutdown, and the handling of the shutdown by Washington State. A shutdown lasting for two years or more, or resulting in removal of the source from the emissions inventory of the State, should be presumed permanent. The owner or operator proposing to reopen the source would have the burden of showing that the shutdown was not permanent, and of overcoming any presumption that it was [emphasis added]."*

[1] DOE lists as an example, a September 6, 1978, EPA Memorandum from Edward E. Reich, Director, Division of Stationary Source Enforcement, to Stephen A. Dvorkin, Chief, General Enforcement Branch, Region II.

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The intention of the owner or operator "at the time of the shutdown" is repeated in numerous guidance documents issued by EPA[2] with that intention being the primary criteria evaluated by EPA for the permanence of shutdowns. Further, the May 27, 1987, EPA Memorandum from John S. Seitz, Director Stationary Source Compliance Division, Office of Air Quality Planning and Standards to David Howekamp, Director Air Management Division, Region IX, states "EPA evaluates the permanence of the shutdown based on the demonstrated intent of the owner or operator to reopen the source. Facts and circumstances surrounding the shutdown, including duration of the shutdown and the handling of the shutdown by the source and State, are evidence of the owner's intent."

The intent is further clarified in the June 11, 1999, Monroe Electric Generating Plant Petition No. 6-99-2 Order signed by Carol M Browner, EPA Administrator, "EPA assesses whether the owner or operator has demonstrated a continuous intent to reopen." TransAlta in their discussions with Lewis County; the regional air permitting authority, Southwest Clean Air Agency (SWCAA), and DOE in addition to vendors, customers, interested stakeholders, etc. has specifically defined their intent to continue operation of the Centralia Plant as a CTG generation resource. These plans were developed prior to the impending ceasing of coal combustion and will continue to build in depth and intensity through the startup of the CTG operations.

DOE refers to the following factors to determine the intent of the owner or operator (the factors will be discussed individually).

1. **The amount of time the facility was out of operation.**

The drivers behind Unit 2 being out of operation are the regulatory process and the construction required for the CTG conversion and life extension of Unit 2. With a smooth regulatory process (started prior to the shutdown, as evidenced in our meetings with DOE), the construction processes could be accomplished with a shutdown of approximately 2 years.

2. **The reason for the shutdown.**

In the 2017 First Amendment to the 2011 Memorandum of Agreement (MOA) between TransAlta and State of Washington, TransAlta agreed to "permanently cease coal-fired power generation" of Unit 2 at the end of 2025. That 2017 Amendment also clarified the anticipated future use of the plant on fuel other than coal. DOE acknowledged TransAlta's consideration of a CTG conversion of Unit 2 in its 2020 Second Revision to its Best Available Retrofit Technology (BART) Order No. 6426 and related Technical Support document for Second BART Order Revision.

3. **Statements by the owner and operator regarding intent.**

As described above, in 2017, TransAlta was actively exploring the possibility of converting the boilers (one or both units) to operate on natural gas instead of coal. To clarify the MOA parties' mutual intent that the plant might continue to generate electricity as long as coal was not the fuel, the parties modified MOA Recital D(5) to clarify that TransAlta would: "permanently cease coal-fired power generation operations of one Boiler in 2020 and the other Boiler in 2025, which dates are prior to the 2035 end of their expected useful lives, in each case pursuant to the terms and subject to the conditions of this MOA." Similarly, Section 6 of the 2017 Amendment revised MOA Section 7, Sentence 2 to read: "Further the State agrees to recognize the Company's cessation of coal fired generation at the

[2] **September 6, 1978, EPA Memorandum** from Edward E. Reich, Director, Division of Stationary Source Enforcement, to Stephen A. Dvorkin, Chief, General Enforcement Branch, Region II; **October 9,1979 EPA Memorandum** from William A. Spratlin, Jr., PE, Chief Air Support Branch, Air and Hazardous Materials Division, Region VII to Harvey D. Shell, Shell Engineering and Associates; **April 5, 2018, EPA Memorandum** from William L. Wehrum, Assistant Administrator, Office of Air and Radiation to LeAnne Johnson Koch, Perkins Coie; **June 11, 1999, In the Matter of Monroe Electric Generating Plant Entergy Louisiana, Inc**., Proposed Operating Permit, Petition No. 6-99-2.

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Facility's boilers prior to the end of their useful lives by taking the early cessation into consideration during future environmental regulatory processes that may adversely affect the Facility's operations."

As recently as this week, TransAlta has been open with Lewis County, SWCAA, DOE and others regarding its intent for fuel conversion at Unit 2 for continued power generation purposes.

4. **The cost and time required to reactivate the facility.**

EPA's reactivation guidance largely applies to facilities shutting down/being mothballed and subsequently being restarted. The DOE referenced guidance (and that mentioned here) does not include conversion to another fuel type, as is discussed in this instance. The costs to reactivate after being mothballed (deactivated for extended period) are approximately $1.5 million including efforts to dehumidify/dry out the boiler and turbine, maintain the units with respect to moisture and corrosion, and then prepare the unit to run again.

For this project, TransAlta is proposing fuel conversion of Unit 2 in addition to life extension, for which the total cost would approximately 1/3 or less of the cost of new build natural gas fired combined cycle turbine unit (including contingency and engineering, procurement, and construction premium). The life extension costs would be incurred to allow the facility to run for another 17 years and are not directly related to the fuel conversion. Those costs would include replacing the cooling towers, feedwater heaters, etc. As discussed above, the total effort could be accomplished in approximately 2 years.

5. **Status of the facility's permits.**

TransAlta will be applying for the appropriate construction permits for their proposed action, as current agency discussions indicate. Other permits (including the Title V Operating Permit #SW98-8-R5 and Acid Rain permit) will remain in force. TransAlta will apply for a Title V modification to update the permit to reflect current operations per the Title V modification requirements in WAC 173-401-725 and would provide an updated compliance plan under the Acid Rain rules. In addition, TransAlta will continue to maintain emissions inventory reporting as required by SWCAA rules 400-105(1).

6. **The record of ongoing maintenance and inspections that were conducted during the shutdown.**

TransAlta will be performing ongoing maintenance and inspections while construction on Unit 2 is taking place for the fuel conversion. The maintenance and inspections would occur on the facility as a whole, in maintaining existing, unchanged units; in the construction of new units; and in the removal of no longer needed components. TransAlta can provide those records during the conversion/construction/shutdown period upon request.

7. **Whether the shutdown was considered as a decrease in a "netting" calculation.**

The temporary shutdown of Unit 2 has not been considered as a decrease in a "netting calculation." The previous 2-year average emissions baseline is being used to determine if a major modification has been triggered for Unit 2 in the CTG conversion. However, no netting occurred or is proposed in the regulatory applicability process.

8. **Whether the allowable emissions level after restarting the facility are higher than as of the date of the shutdown.**

The allowable emissions level of Unit 2 following the CTG conversion will be less than the previous coal 2-year average baseline for all PSD pollutants with the possible exception of volatile organic compounds (VOC). Coal combustion creates negligible VOC emissions, so the previous baseline level was essentially zero.

In addition to the criteria above and TransAlta's clear intent to continue operation of the Centralia Plant as a CTG generation resource, DOE also was aware of the plans and indicated as such in its July 2020 Second Revision to its Best Available Retrofit Technology (BART) Order (Order No. 6426) and related Technical Support Document. The Technical Support document states on Page 1, "Ecology is also modifying the compliance schedule to eliminate

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the requirement to demolish the coal units to align the BART order's language with language in the MOA between the State of Washington and TransAlta."

DOE's Technical Support Document also quotes the 2017 MOA and notes that SWCAA would have authority over air permitting for conversion: "If TransAlta decides to ***switch to non-coal power generation***, a Notice of Construction application would need to be submitted ***to Southwest Clean Air Agency*** by the company." This language implies that the question of reactivation was not at issue in those discussions.

2.0 CONCLUSION

As mentioned in the DOE PSD Guidance document as well as heavily emphasized in EPA guidance, the intention of the owner or operator "at the time of the shutdown" is the primary criteria evaluated by EPA for the permanence of shutdowns. TransAlta's intentions have been and continue to be clear – the Unit 2 shutdown is intended only to occur long enough to acquire the appropriate permitting and perform needed unit modifications for the fuel conversion and construction of auxiliary units in support of that goal. That driver and the other criteria support the conclusion that the limited shutdown of Unit 2 was "not intended to be permanent." Thus, Unit 2 should not be viewed as a new source under these circumstances.

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APPENDIX D: SUPPORTING DOCUMENTATION FOR BACT ANALYSES

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

RBLC CLEARINGHOUSE LISTINGS
LARGE NATURAL GAS FIRED BOILERS (Process code 11.310)

RBLC ID	FACILITY NAME	STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	CONTROL METHOD DESCRIPTION - VOCs	EMISSION LIMIT - VOCs
LA-0406	MCA GEIMAR SITE	LA	7/24/2024	CO MeOH Auxiliary Boiler (EQT0001)	321 MMBtu/hr	Good combustion practices	0.0027 lb/MMBtu
TX-0967	QUAIL RUN CARBON CAPTURE PLANT	TX	2/5/2024	Auxiliary Boiler	>250 MMBtu/hr	Good combustion practices	0.016 lb/MMBtu
LA-0401	KOCH METHANOL (KME) FACILITY	LA	12/20/2023	BLR • Auxiliary Boiler	1100 MMBtu/hr	Good combustion practices	0.0016 lb/MMBtu
LA-0394	SHELL CHEMICAL GEISMAR PLANT	LA	12/12/2023	01-22 • A0-5 Boiler	350 MMBtu/hr	Good combustion practices	0.0054 lb/MMBtu
TX-0936	VALERO BILL GREEHEY REFINERY	TX	3/29/2022	BOILER	334 MMBtu/hr	Good combustion practices	0.0054 lb/MMBtu
LA-0364	FG LA COMPLEX	LA	1/6/2020	Boilers	1200 MMBtu/hr	Good combustion practices and compliance with 40 CFR 63, Subpart DDDDD	0.0055 lb/MMBtu
KY-0111	PHOENIX PAPER WICKLIFFE LLC	KY	12/18/2019	#1 Power Boiler	325 MMBtu/hr	Natural gas only, good combustion practices, following manufacturing specs for SU/SD	0.0054 lb/MMBtu
	PHOENIX PAPER WICKLIFFE LLC	KY	12/18/2019	#2 Power Boiler	325 MMBtu/hr	Natural gas only, good combustion practices, following manufacturing specs for SU/SD	0.0054 lb/MMBtu
MI-0440	MICHIGAN STATE UNIVERSITY*	MI	5/22/2019	EUSTMBoiler	300 MMBtu/hr	Good combustion practices	0.0053 lb/MMBtu
LA-0346	GULF COAST METHANOL COMPLEX	LA	1/4/2018	Auxiliary Boller	773 MMBtu/hr	Good combustion practices	
LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	B1-13 • Boiler 1 (EQT0003)	350 MMBtu/hr	Good combustion practices	0.0054 lb/MMBtu
	ST. JAMES METHANOL PLANT	LA	6/30/2017	B2-13 • Boiler 2 (EQT0004)	350 MMBtu/hr	Good combustion practices	0.0054 lb/MMBtu

Original construction dates 1970, modified in 2019

* Uses No 2 fuel oil as backup

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EXISTING COAL TO GAS CONVERSIONS

FACILITY NAME	STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	CONTROL METHOD DESCRIPTION - VOCs	EMISSION LIMIT (or FACTOR) - VOCs
Nevada Power Company dba Nevada Energy	NV	7/2/2024 (app submittal date, not final)	North Valmy Generating Station - Unit 1	2708 MMBtu/hr	Good combustion practices	0.0054 lb/MMBtu
			North Valmy Generating Station - Unit 2	3048 MMBtu/hr	Good combustion practices	0.0054 lb/MMBtu
PacifiCorp Energy	WY	4/3/25 (app submittal date, not yet issued)	Naughton Unit 1	1850 MMBtu/hr	None listed	0.004 lb/MMBtu
			Naughton Unit 2	2400 MMBtu/hr	None listed	0.004 lb/MMBtu
PacifiCorp Energy	WY	12/28/2022	Bridger Unit 1	3000 MMBtu/hr	None listed	0.0054 lb/MMBtu
			Bridger Unit 2	3000 MMBtu/hr	None listed	0.0054 lb/MMBtu
Midwest Generation, LLC	IL	10/16/2015	Unit 6	3543 MMBtu/hr	None listed	0.0027 lb/MMBtu
			Unit 7 (two boilers, combined capacity)	6034 MMBtu/hr	None listed	0.0027 lb/MMBtu
			Unit 8 (two boilers, combined capacity)	6384 MMBtu/hr	None listed	0.0027 lb/MMBtu

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Data Inputs

Select the type of oxidizer: Catalytic Oxidizer - Fixed Bed

Enter the following information for your emission source:

Composition of Inlet Gas Stream

Pollutant Name	Concentration (ppmv)	Lower Explosive Limit (LEL) (ppmv)*	Heat of Combustion (Btu/scf)	Molecular Weight
Hexane	1	11,000	4,667	86
Formaldehyde	0	70,000	1,020	30
Butane	1	19,000	3,101	58

Note: The lower explosion limit (LEL), heat of combustion and molecular weight for some commonly used VOC/HAP are provided in the table below. In addition, the heat of combustion to be entered in column D is a lower heating value (LHV), not a higher heating value (HHV).

Enter the design data for the proposed oxidizer:

Number of operating hours/year	5,168	hours/year	
Inlet volumetric flow rate(Q_{wi}) at 77°F and 1 atm.	1,770,219	scfm	
Pressure drop (ΔP)	23	inches of water*	* 23 inches of water is a default pressure drop for catalytic oxidizers. User should enter actual value, if known.
Motor/Fan Efficiency (ε)	60	percent*	* 60% is a default fan efficiency. User should enter actual value, if known.
Inlet Waste Gas Temperature (T_{wi})	330	°F	
Operating Temperature (T_{fi})	900	°F	* Note: Default value for Tfi is 900°F for catalytic oxidizers. Use actual value if known. Tfi for catalytic oxidizers is typically between 300 and 900°F.
Destruction and Removal Efficiency (DRE)	99	percent*	* 99 percent is a default control efficiency. User should enter actual value, if known.
Estimated Equipment Life	17	Years	

Percent Energy Recovery (HR) = 70 percent

0
35
50
70

Catalyst Data:

Estimated catalyst life (γ)	4	years	* 4 years is a default value. User should enter actual value, if known.
Catalyst Unit Cost (CC)	888	$/ft^3	
Space velocity for catalyst (Φ)	30,000	/hour	* 30,000 per hour is a default value. User should enter actual value, if known.

Enter the cost data:

Desired dollar-year	2023				
CEPCI* for 2023	797.9	Enter the CEPCI value for 2023	390.6	1999 CEPCI	*Enter dollar year first.
Annual Interest Rate (i)	7.50	%			
Electricity ($Cost_{elect}$)	0.068	$/kWh			
Natural Gas Fuel Cost ($Cost_{fuel}$)	0.01428	$/scf			
Operator Labor Rate	$70.00	per hour			
Maintenance Labor rate	$70.00	per hour			
Contingency Factor (CF)	10.0	Percent			* 10 percent of the total capital investment F45is a default value for construction contingencies. User may enter values between 5 and 15 percent.

* CEPCI is the Chemical Engineering Plant Cost Escalation/De-escalation Index. The use of CEPCI in this spreadsheet is not an endorsement of the index for purposes of cost escalation or de-escalation, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Data Sources for Default Values Used in Calculations:

Parameters for Common Compounds:

Compound	LEL (ppmv)	Heat of Combustion (Btu/scf)	Molecular Weight
Methane*	50,000	911	16.04
Ethane	30,000	1,631	30.07
Propane	21,000	2,353	44.09
Butane	19,000	3,101	58.12
Pentane	14,000	3,709	72.15

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Hexane	11,000	4,404	86.17
Octane	10,000	5,796	114.23
Nonane	8,000	6,493	128.25
Decane	8,000	7,190	142.28
Ethylene**	27,000	1,499	28.05
Propylene	20,000	2,182	42.08
Cyclohexane	13,000	4,180	84.16
Benzene**	14,000	3,475	78.11
Toluene**	11,000	4,274	92.14
Methyl Chloride (Chloromethane)**	82,500	705	50.49
Footnotes * Greenhouse gas. ** Hazardous air pollutant.			

Data Element	Default Value	Sources for Default Values used in the calculation . . .	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Catalyst Cost ($/ft^3)	650	Based on 2014 vendor data for base metal oxide catalyst.	$888, used consumer price index inflation calculator (https://www.bls.gov/data/inflation_calculator.htm) to update December 2014 data to April 2025	Check with catalyst vendor.
Electricity Cost ($/kWh)	0.0641	Average annual electricity cost for industrial plants is based on 2016 price data compiled by the U.S. Energy Information Administration from data reported on Form EIA-861 and 861S, (https://www.eia.gov/electricity/annual/html/epa_02_04.html).	$0.068/kWh, https://www.eia.gov/state/print.php?sid=WA, industrial rate in Washington as of February 2025	Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at http://www.eia.gov/electricity/data.cfm#sales.
Fuel Cost ($/Mscf)	3.51	Annual average price paid for natural gas by industrial facilities in 2016 from the U.S. Energy Information Administration. Available at http://www.eia.gov/dnav/ng/hist/n3035us3A.htm.	14.28 $/Mscf - March 2025 rate for industrial facilities in Washington https://www.eia.gov/dnav/ng/hist/n3035wa3m.htm	Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/dnav/ng/hist/n3035us3A.htm.
Operator Labor ($/hour)	26.61	Bureau of Labor Statistics, May 2016 National Occupational Employment and Wage Estimates – United States, May 2016 (https://www.bls.gov/oes/current/oes_nat.htm). Hourly rates for operators based on data for plant and System Operators – other (51-8099).	$70/hour plant rate (not including benefits)	Use plant-specific labor rate.
Maintenance Labor ($/hour)	27.40	Bureau of Labor Statistics, May 2016 National Occupational Employment and Wage Estimates – United States, May 2016 (https://www.bls.gov/oes/current/oes_nat.htm). Hourly rates for maintenance workers based on electrical and electronics commercial and industrial equipment repairers (49-2094).	$70/hour plant rate (not including benefits)	Use plant-specific labor rate.

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Design Parameters

The following design parameters for the oxidizer were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Composition of Inlet Gas Stream		
Pollutant Name	Concentration in Waste Stream (ppmv) From Data Inputs Tab	Adjusted Concentration with Dilution Air (ppmv)
Hexane	1	NA
Formaldehyde	0	NA
Butane	1	NA
0	0	NA
0	0	NA
0	0	NA
0	0	NA
0	0	NA
0	0	NA
0	0	NA
Total	1	0

Constants used in calculations:

Temperature of auxiliary fuel (T_{af}) =	Reference Temperature (T_{ref}) =	77.0	°F
Density of auxiliary Fuel at 77 °F (ρ_{af}) =		0.0408	lb/ft^3
Heat Input of auxiliary fuel ($-\Delta h_{caf}$) =		21,502	Btu/lb
Density of waste gas at 77 °F (ρ_{wi}) =		0.0739	lb/ft^3
Mean Heat Capacity of Air (C_{pmair}) =	(For catalytic oxidizers)	0.248	Btu/lb °F

Parameter	Equation	Calculated Value	Units	Value	Units
Sum of volume fraction of combustible components =	= ($\sum x_i$) =	1	ppmv		
Lower Explosive Limit of waste gas (LEL_{mix})	= $[\sum((x_j)/((\sum x_i) \times LEL_j))]^{-1}$ =	15,319	ppmv		
	Where x_j is the volume fraction and LEL_j the lower explosive limit for each combustible component in the waste gas.				
% LEL_{mix}	= (Total Combustible Conc. In Mixture/LEL_{mix}) × 100 =	0.01	percent	* Note: Since the LEL of the waste gas stream is below 25%, no dilution air is needed.	
Dilution Factor	= (LEL_{mix} x 0.249)/($\sum x_i$) =	Not applicable			
Lower Explosive Limit (LEL) of waste gas after addition of dilution air	= (Total Adjusted Conc. With Dilution Air/LEL_{mix}) × 100 =	Not Applicable			
Inlet volumetric flow rate(Qwi) at 77°F and 1 atm.	(From Data Entry Tab) =	1,770,219	scfm		
Oxygen Content of gas stream	= 100 - ($\sum x_j \times 100/10^6$) =	20.90	percent		
Fan Power Consumption (FP)	= $[(1.17 \times 10^{-4}) \times Q_{wi} \times \Delta P]/\varepsilon$	7939.4	kW		
Q_{wo}	≈ Q_{wi} =	1,770,219	scfm		
Operating temperature of oxidizer (T_{fi})	(From Data Entry Tab)	900	°F		
Temperature of waste gas at outlet to preheater (T_{wo})	= Heat Recovery × (T_{fi} - T_{wi}) + T_{wi} =	729	°F	Note: this temperature is relevant for incinerators, but not for th	
Temperature of flue gas exiting the oxidizer (T_{fo})	= T_{fi} - T_{wo} + T_{wi} =	501	°F		
Heat Input of waste gas ($-\Delta h_{cwi}$)					
	= $\sum (-\Delta h_{ci})\, x_i$ Where ($-\Delta h_{ci}$) is the heat of combustion and x_i the fraction of component "i" at 77 °F.	0.00	Btu/scf	0.1	Btu/lb

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Estimated Auxiliary Fuel Flow (Q_{af}) at 77 °F and 1 atm.	(Calculated using Equation 2.21 in Chapter 2 of the Cost Manual)	9,457.42 scfm
Auxiliary fuel Energy Input =		8,296,824 Btu/min
Minimum Energy required for combustion stabilization =	= 5% × Total Energy Input = $0.05 \times \rho_{fi} \times Q_{fi} \times C_{pmfi} \times (T_{fi} - T_{ref})$ =	1,380,052 Btu/min
Is the calculated auxiliary fuel sufficient to stabilize combustion?	(Note: If the auxiliary fuel energy input > 5% of Total Energy Input, then the auxilary fuel is sufficient.)	Yes
Auxiliary fuel flow (Qaf) at 77°F and 1 atm. =		9,457 scfm
Total Volumetric Throughput (Q_{tot}) at 77 °F and 1 atm.	$= Q_{fi} = Q_{wo} + Q_a + Q_{af} = Q_{wi} + Q_{af}$ =	1,779,676 scfm

Calculation of Catalyst Volume and Estimated Temperature of Waste Gas Entering the Catalyst Bed

Volumetric Flow Rate at 60 °F and 1 atm (Q_{ft})	$= Q_{tot} \times (519)/(77\ °F + 460)$ =	1,720,022 scfm
Catalyst Volume (Vol_{cat})	Where Q_{ft} is the volumetric flow rate of the waste gas (Q_{fi}) corrected to 60 °F and 1	3440.04 ft^3
Estimated inlet temperature to the catalyst bed (T_{ri}) =	(Calculated using Equation 2.28 in Chapter 2 of the Cost Manual)	900 °F

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i\ (1+ i)^n/(1+ i)^n - 1$ =	0.1060
	Where n = Equipment Life and i= Interest Rate	

Future Worth Factor

Parameter	Equation	Calculated Value
Future Worth Factor (FWF) =	$i\ [1/(1+ i)^y - 1]$ =	0.2236
	Where y = Catalyst Life and i= Interest Rate	

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Cost Estimate

Direct Costs			
Total Purchased equipment costs (in 2023 dollars)			
Incinerator + auxiliary equipment[a] (A) =			
Equipment Costs (EC) for a Fixed Bed Catalytic Oxidizer	= (1,443 x Qtot^(0.5527)) x (2023 CEPI/1999 CEPCI) =	$8,395,490	in 2023 dollars
Instrumentation[b] =	0.10 × A =	$839,549	
Sales taxes =	0.03 × A =	$251,865	
Freight =	0.05 × A =	$419,775	
	Total Purchased equipment costs (B) =	$9,906,678	in 2023 dollars

Footnotes
a - Auxiliary equipment includes equipment (e.g., duct work) normally not included with unit furnished by incinerator vendor.
b - Includes the instrumentation and controls furnished by the incinerator vendor.

Direct Installation Costs (in 2023 dollars)			
Foundations and Supports =	0.08 × B =	$792,534	
Handling and Erection =	0.14 × B =	$1,386,935	
Electrical =	0.04 × B =	$396,267	
Piping =	0.02 × B =	$198,134	
Insulation for Ductwork =	0.01 × B =	$99,067	
Painting =	0.01 × B =	$99,067	
Site Preparation (SP) =		$0	
Buildings (Bldg) =		$0	
	Total Direct Installaton Costs =	$2,972,003	
Total Direct Costs (DC) =	B + C + SP + Bldg =	$12,878,682	in 2023 dollars
Total Indirect Installation Costs (in 2023 dollars)			
Engineering =	0.10 × B =	$990,668	
Construction and field expenses =	0.05 × B =	$495,334	
Contractor fees =	0.10 × B =	$990,668	
Start-up =	0.02 × B =	$198,134	
Performance test =	0.01 × B =	$99,067	
	Total Indirect Costs (IC) =	$2,773,870	
Continency Cost (C) =	CF(IC+DC)=	$1,565,255	
Total Capital Investment =	**DC + IC +C =**	**$17,217,807**	**in 2023 dollars**

Direct Annual Costs

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Catalyst Replacement Cost	= 1.08 × CC × Vol_{cat} × FWF Where CC is the $/ft^3 cost for the replacement catalyst; Vol_{cat} is the volume of catalyst required based on the waste gas flow rate (Q_{ft}) and the catalyst space velocity (Φ); and FWF is the future worth factor.	$737,581
Annual Electricity Cost	= Annual Electricity Usage × Operating Hours/year × Electricity Price =	$2,790,107
Annual Fuel Costs for Natural Gas	= $Cost_{fuel}$ × Fuel Usage Rate × 60 min/hr × Operating hours/year	$41,876,927
Operating Labor	Operator = 0.5hours/shift × Labor Rate × (Operating hours/8 hours/shift)	$22,610
	Supervisor = 15% of Operator	$3,392
Maintenance Costs	Labor = 0.5 hours/shift × Labor Rate × (Operating Hours/8 hours/shift)	$22,610
	Materials = 100% of maintenance labor	$22,610
Direct Annual Costs (DC) =		**$45,475,836 in 2023 dollars**

Indirect Annual Costs

Overhead	= 60% of sum of operating, supervisor, maintenance labor and maintenance materials	$42,733
Administrative Charges	= 2% of TCI	$344,356
Property Taxes	= 1% of TCI	$172,178
Insurance	= 1% of TCI	$172,178
Capital Recovery	= CRF[TCI-1.08(cat. Cost)]	$1,740,650
Indirect Annual Costs (IC) =		**$2,472,095 in 2023 dollars**
Total Annual Cost =	**DC + IC =**	**$47,947,931 in 2023 dollars**

Cost Effectiveness

Cost Effectiveness = (Total Annual Cost)/(Annual Quantity of VOC/HAP Pollutants Destroyed)

Total Annual Cost (TAC) =	$47,947,931	per year in 2023 dollars
VOC/HAP Pollutants Destroyed =	57.2	tons/year
Cost Effectiveness =	$838,100	per ton of pollutants removed in 2023 dollars

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RBLC CLEARINGHOUSE LISTINGS

INDUSTRIAL-SIZE NATURAL GAS FIRED BOILERS (Between 100 and 250 MMBtu/hr, Process code 12.310)

RBLC ID	FACILITY NAME	STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	CONTROL METHOD DESCRIPTION - VOCs	EMISSION LIMIT - VOCs
IN-0382	DUKE ENERGY INDIANA - CAYUGA GENERATING STATION	IN	2/14/2025	Auxiliary Boiler	225 MMBtu/hr	Good combustion practices	0.005 lb/MMBtu
IN-0371	WABASH VALLEY RESOURCES	IN	1/11/2024	Auxiliary Boiler - Unit 1C	217.65 MMBtu/hr	None	
IL-0134	CRONUS CHEMICALS, LLC	IL	12/21/2023	Boiler	179.4 MMBtu/hr	Oxidation catalyst, good combustion practices	0.0014 lb/MMBtu
OH-0391	VALENCIA PROJECT LLC	OH	10/27/2023	Boiler #1 and 2	122 MMBtu/hr	Good combustion practices	0.005 lb/MMBtu
LA-0397	INDORAMA VENTURES OLEFINS, LLC - WESTLAKE ETHYLENE	LA	4/29/2022	EQT0011	248 MMBtu/hr	None	
AK-0086	KENAI NITROGEN OPERATIONS	AK	3/26/2021	PKG Boiler	243 MMBtu/hr	Good combustion practices	0.0054 lb/MMBtu
LA-0397	SHINTECH LOUISIANA LLC - PLAQUEMINE PLANT 3	LA	1/19/2021	Boiler D	250 MMBtu/hr	Good combustion practices	0.0026 lb/MMBtu
MI-0445	INDECK NILES, LLC	MI	11/26/2019	AuxBoiler	182 MMBtu/hr	Good combustion practices	0.004 lb/MMBtu

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APPENDIX E: AIR DISPERSION MODELING ANALYSIS

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Air Quality Dispersion Modeling Report

Unit #2 Conversion from Coal to Natural Gas Combustion

Lewis County, Washington

December 2025

Prepared for

TransAlta Centralia Generation, LLC
913 Big Hanaford Road
Centralia, Washington 98531

Submitted to

Southwest Clean Air Agency
5101 NE 82nd Ave.
Vancouver, Washington 98662
and
Washington Dept. of Ecology
300 Desmond Drive SE
Lacey, Washington 98503

Prepared by

TETRA TECH
10 Post Office Square, 11th Floor
Boston, MA 02109

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

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Appendix A: Unit #2 Load Analysis
Appendix B: Project Predicted Concentration Contours for NAAQS Analyses

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Acronyms/Abbreviations

µg/m^3	micrograms per cubic meter
ARM2	Ambient Ratio Method 2
ASIL	Acceptable Source Impact Levels
BPIP	Building Profile Input Program
CFR	Code of Federal Regulations
CO	carbon monoxide
GEP	Good Engineering Practice
GHGs	greenhouse gases
GRSM	Generic Reaction Set Method
H1H	highest first high
H2H	highest second high
H_2SO_4	sulfuric acid
H4H	highest fourth high
H6H	highest sixth high
H8H	highest eighth high
km	kilometer
lb	pound
m	meters
MMBtu/hr	million British thermal units per hour
MW	megawatts
NAAQS	National Ambient Air Quality Standards
NED	National Elevation Data
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NSR	New Source Review
O_3	ozone
OLM	Ozone Limiting Method
Pb	lead
PM_{10}	particulate matter with a diameter equal to or less than 10 microns

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$PM_{2.5}$	particulate matter with a diameter equal to or less than 2.5 microns
ppb	parts per billion
ppm	parts per million
The Project	Conversion of coal to natural gas firing in Unit #2 project
PSD	Prevention of Significant Deterioration
PVMRM	Plume Volume Molar Ratio Method
Report	Air Quality Modeling Report for the Project (this document)
SER	Significant Emission Rate
SIL	Significant Impact Level
SO_2	sulfur dioxide
SQER	small quantity emission rates
TAP	toxic air pollutant
tBACT	toxics Best Available Control Technology
tpy	tons per year
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
VOC	volatile organic compounds
WAC	Washington Administrative Code
WDOE	Washington Department of Ecology

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1.0 INTRODUCTION

TransAlta Centralia Generation, LLC (Applicant) proposes to modify their existing Centralia Unit #2 coal-fired electrical generation facility, which will cease using coal as a fuel source in December 2025. The modified facility will instead generate electricity from natural gas (Project). The Project is proposed within an approximately 9.6-acre Project Area on private land owned by the Applicant located in unincorporated Lewis County, Washington (Figure 1-1). Once converted, Unit #2 will burn natural gas to generate steam and convert that steam to electrical energy.

Coal firing equipment will be decommissioned in place, unless the conversion requires its removal to allow new equipment to be installed. The existing precipitators and flue gas desulphurization equipment will no longer be effective or required and will be passed through or bypassed.

The Unit will operate at a maximum of 723 net megawatts (MW) and will convert from diesel-fired starting systems to full natural gas-starting capabilities. The current minimum stable generation level of 300 net MW is expected to be reduced to 190 net MW as determined by the Applicant. The Unit would operate at a maximum 59% capacity factor, which is the basis for the annual emissions calculations.

The project also includes extending the life of the Unit to the end of 2044 by making a substantial investment into the existing infrastructure to ensure it can continue to operate to the end of the contract.

TransAlta is submitting a new air permit application which requires an ambient air quality impact analysis compliance demonstration based on dispersion modeling. The proposed methodology for the air quality dispersion modeling analyses was submitted to the Washington Department of Ecology (WDOE) and the Southwest Clean Air Agency (SWCAA) in a Modeling Protocol. WDOE (in the role of designated model reviewer) reviewed and approved the proposed approach on 10/13/2025. This document is the air quality dispersion modeling report (Report).

This Report consists of five sections including this introduction. Section 2 contains a Project description, including information regarding the Project's location and expected emissions, along with an applicability assessment relative to key regulations related to the air quality impact analysis. Section 3 presents a detailed description of the modeling approach proposed for evaluating air quality impacts of the proposed Project including: source data and operating scenarios, model selection criteria, an urban/rural land use determination, Good Engineering Practice (GEP) stack height determination and building dimensions for model input, meteorological data, the receptor grids, ambient monitored background concentrations, as well as assessments for secondary ozone (O_3) and particulate matter with diameters of less than 2.5 micrometers ($PM_{2.5}$). The air quality modeling results demonstrating compliance are presented in Section 4. References cited in the document are presented in Section 5. Electronic modeling files are being submitted to the agencies with this Report. To facilitate the review of this Report and modeling files, the individual familiar with the dispersion modeling for the Project is identified below. Please contact this individual if additional information or clarification is required during the review process.

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Modeling Consultant: Liz Hendrick, CCM
Tetra Tech, Inc.
10 Post Office Square, 11th Floor
Boston, MA 02109
Telephone: (978) 303-8524
Email: Liz.Hendrick@tetratech.com

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

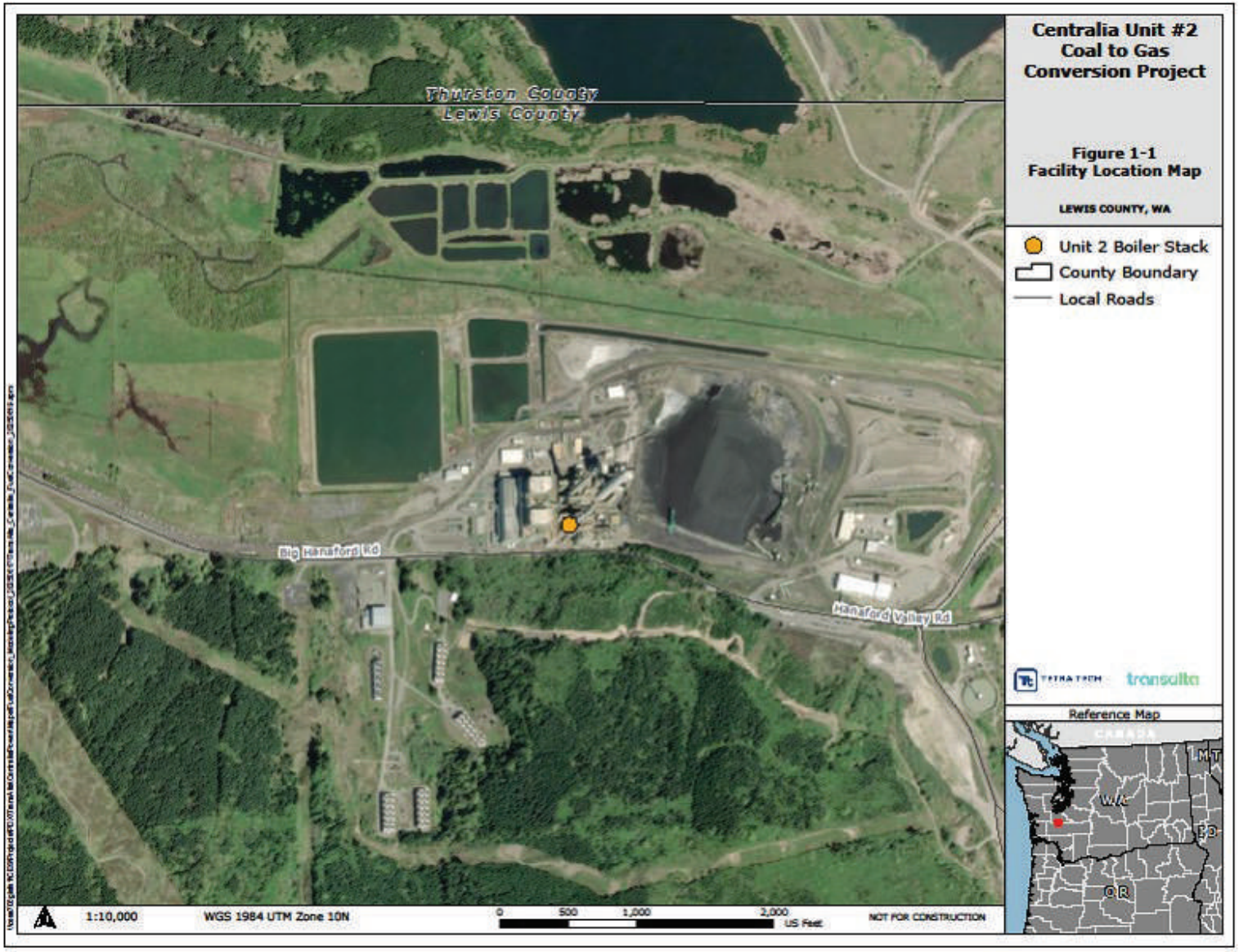


Figure 1-1. Facility Location Map

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2.0 FACILITY DESCRIPTION AND REGULATORY APPLICABILITY

2.1 Site Location

The Project will be constructed at the existing Centralia Generating Station in Centralia, Washington. The Project is proposed within an approximately 9.6-acre Project Area on private land owned by TransAlta. The Project site is located adjacent to the TransAlta Centralia Mining LLC coal mine. The Project is surrounded by two fences to restrict public access to the generation area and the cooling tower area. The generation area is north of Big Hanaford Road, and the cooling tower area is south of Big Hanaford Road. The Generating Station is generally surrounded by undeveloped land.

2.2 Project Description

The Applicant's Centralia Power Plant is a unique facility capable of providing generating capacity to be used to support the Washington grid; particularly when there is need or market signal for firm power that could be driven by intermittent renewables, system conditions, environmental factors or demand. The Project will be fully contracted to Puget Sound Energy (the Customer), and the Customer will be responsible for procuring and delivering all fuel to the converted facility and will also control dispatch of the facility. The Project is not designed nor intended to operate continuously or at a high capacity or baseload factor. The Project is expected to operate at a capacity factor of less than 20 percent of all hours on an annual basis over the life of the Project. In any event, the facility will not operate for more than 59 percent of all hours on an annual basis over the life of the Project. TransAlta is requesting an operational limitation based on the annual 59% capacity factor. Emissions calculated for Unit #2 are based on this limitation.

Given the marginal cost of the unit, it is expected only during periods of high demand and reliability need, with the majority of operating hours expected at either half load (~350 MW) or the minimal stable generation (~190 MW).

The Project includes modification of the existing Unit #2 coal-fired boiler to fire natural gas to generate steam. The boiler makes steam independent of what fuel is used to generate that steam. As a result, the steam turbines and electrical generation components in the facility will not require any modifications for the facility to operate on natural gas. The Project will include the replacement of the existing auxiliary boiler (currently diesel-fired, will be solely natural gas-fired), two (2) water bath heaters, and two (2) cooling towers that will be installed in the exact footprint of the existing cooling towers. The natural gas will be delivered to a metering station at the existing Big Hanaford site and then delivered to the Unit and auxiliary boilers via a short 1,300-foot lateral pipeline. A fuel gas system will be provided on site to supply natural gas at suitable pressure and temperature.

2.3 Summary of Annual Potential Emissions

The proposed potential annual emissions from the Facility are summarized in Table 2-1. Potential emissions of regulated air pollutants from these sources have been largely based upon applicable regulatory limits, equipment vendor emissions data, United States Environmental Protection Agency (USEPA) emission factors, and mass balance calculations; engineering estimates have been applied,

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as necessary. Potential emission rates for Unit #2 are based upon full load operation for 5,168 hours per year (i.e., 59% capacity factor) combusting natural gas. Potential emission rates of the auxiliary boiler are based upon full load operation for 1,300 hours per year. Potential emission rates for the water bath heaters and cooling towers are based upon full load operation for 8,760 hours per year.

Table 2-1. Project Annual Potential Emissions (tons per year, tpy)

Pollutant	Unit #2[a, b]	Auxiliary Boiler[c, b]	Water Bath Heaters (2)[d, b]	Cooling Towers (2)	Project Wide Totals[e]
	tpy	tpy	tpy	tpy	tpy
NO_X	2,132.0	1.5	1.3	-	2,134.7
CO	2,907.2	3.6	3.2	-	2,914.1
VOC	58.14	0.5	0.4	-	59.1
PM_{10}	133.1	0.7	0.6	3.0	137.4
$PM_{2.5}$	133.1	0.7	0.6	1.8	136.1
SO_2	13.9	0.1	0.1	-	14.1
Pb	0.01	4.4E-05	4.0E-05	-	0.01

[a] Based on Unit #2 operation at full load (100%, 723 MW) combusting natural gas. These emissions do not include the Unit #2 reductions from baseline.
[b] Emissions may decrease following the vendor selection process, these are worst-case emissions.
[c] Based on 1,300 hours per year of operation for the Auxiliary Boiler.
[d] Based on 8,760 hours of operation for two Water Bath Heaters.
[e] The emissions listed are slightly different than those provided in the application due to rounding.

2.4 Ambient Air Quality Regulatory Criteria

The USEPA has promulgated regulations that establish National Ambient Air Quality Standards (NAAQS) and Prevention of Significant Deterioration (PSD) increments. The NAAQS are established in 40 Code of Federal Regulations (CFR) 50 and incorporated in the Washington air pollution regulations. The PSD regulations are established in 40 CFR 52 and incorporated in Washington's air pollution control regulations. These regulations and guidelines provide the basis for an evaluation of the potential impacts of the proposed Project on air quality.

2.4.1 National Ambient Air Quality Standards

The USEPA has developed NAAQS for six air contaminants, known as criteria pollutants, for the protection of public health and welfare. These criteria pollutants are sulfur dioxide (SO_2), particulate matter with diameters of less than 10 micrometers (PM_{10}), $PM_{2.5}$, nitrogen dioxide (NO_2), carbon monoxide (CO), O_3, and lead (Pb). The NAAQS have been developed for short-term periods of 24 hours or less and annual averages. The NAAQS include both "primary" and "secondary" standards, where the primary standards are set to protect human health, allowing an adequate margin of safety. Secondary standards are set to protect public welfare from any known or anticipated adverse effects associated with the presence of air pollutants in the ambient air. The current NAAQS are provided in Table 2-2.

Table 2-2. National Ambient Air Quality Standards

Pollutant	Averaging Period	NAAQS (µg/m³)[a]	
		Primary	Secondary
NO_2	Annual[b]	100	Same

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Pollutant	Averaging Period	NAAQS (µg/m³) [a]	
		Primary	Secondary
	1-hour[c]	188	None
SO_2	Annual[b,d]	80	26.2
	1-hour[e]	196	None
CO	8-hour[f]	10,000	None
	1-hour[f]	40,000	None
PM_{10}	24-hour[g]	150	Same
$PM_{2.5}$	Annual[h]	9	15
	24-hour[i]	35	Same
O_3	8-hour[j]	0.070 ppm[k]	Same
Pb	3-month[b]	0.15	Same

[a] µg/m³ = micrograms per cubic meter
[b] Not to be exceeded.
[c] To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average must not exceed 100 parts per billion (ppb) (188 µg/m³).
[d] The annual average secondary standard for SO_2 is based on the annual mean averaged over 3 years and must not exceed 10 ppb.
[e] To attain this standard, the 3-year average of 99th percentile of the daily maximum 1-hour average must not exceed 75 ppb (196 µg/m³).
[f] Not to be exceeded more than once per year.
[g] Not to be exceeded more than once per year on average over 3 years.
[h] To attain this standard, the 3-year average of weighted annual mean $PM_{2.5}$ concentrations must not exceed 9 µg/m³.
[i] To attain this standard, the 3-year average of 98th percentile of 24-hour concentrations must not exceed 35 µg/m³.
[j] To attain this standard, the 3-year average of the fourth highest daily maximum 8-hour average O_3 concentrations averaged over 3 years must not exceed 0.070 ppm.
[k] ppm = parts per million

One of the primary goals of federal and state air pollution regulations is to ensure that ambient air quality is in compliance with the NAAQS. Toward this end, every area of the United States has been designated as “attainment”, “unclassifiable” or “nonattainment” for each criteria pollutant. In areas designated as attainment, the air quality with respect to the pollutant is equal to or better than the NAAQS. These areas are under a mandate to maintain, i.e., prevent significant deterioration of such air quality. In areas designated as unclassifiable, there is limited air quality data, and these areas are treated as attainment areas for regulatory purposes. In areas designated as nonattainment for a particular pollutant, the air quality with respect to that pollutant is worse than the NAAQS. These areas must take actions to improve air quality and attain compliance with the NAAQS within a certain period of time.

If a new major source of air pollution is proposed, it must undergo New Source Review (NSR) air permitting. The NSR air permitting regulations contain two distinct programs, one for sources proposed in attainment/unclassifiable areas and one for sources in nonattainment areas. The NSR program for sources proposed in attainment/unclassifiable areas is known as the PSD program. The NSR program for sources proposed in non-attainment areas is known as nonattainment new source review (NNSR).

The Facility location in Lewis County, Washington state is presently classified as attainment/unclassifiable for all criteria pollutants. Thus, emissions of criteria pollutants from the Project are evaluated with respect to the PSD program. The requirements of the NSR program are discussed in more detail in the following subsections.

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2.4.2 New Source Review

NSR applies to new major sources of air pollutants and major modifications of existing major sources. The NSR program includes two distinct permitting programs, PSD permitting for projects located in areas designated as unclassified or attainment with the NAAQS, and NNSR permitting for projects located in areas designated as nonattainment with the NAAQS. As an area may be in attainment with one or more NAAQS, but in nonattainment with one or more other NAAQS at the same time, an individual project may be subject to both PSD and NNSR permitting, depending upon its potential emissions on a pollutant-by-pollutant basis. The federal PSD program under 40 CFR 52.21 applies to subject sources in the U.S. and the program is administered by the USEPA.

2.4.3 Prevention of Significant Deterioration

The Project is located at the TransAlta Centralia Generating facility which is currently an existing major source for emissions of nitrogen oxides (NO_X), CO, SO_2, particulate matter (PM), PM_{10}, $PM_{2.5}$, volatile organic compounds (VOCs), sulfuric acid (H_2SO_4), and greenhouse gases (GHGs). Accordingly, the Project is considered a modification of the existing Centralia facility and is subject to PSD permitting if it meets the definition of a major modification under this permitting program. This analysis focused on Unit #2, evaluating the proposed overall project emissions with respect to the Unit #2 baseline emissions, and using 2022-2023 as the baseline period. The modification results in a net decrease in emissions from Unit #2 at the existing generating facility (except for VOC). Table 2-3 provides a comparison of the Project's potential emissions to the PSD Significant Emission Rates (SER). VOC is the only pollutant that exceeds the SER. As such, the Project will not result in a significant emissions increase (i.e. greater than the respective SER) for all criteria pollutants and does not trigger a PSD modeling analysis. An air dispersion modeling analysis was conducted in accordance with USEPA guidance as described in the Modeling Protocol. Modeling was conducted for Facility emissions of CO, NO_X, PM_{10}, $PM_{2.5}$ and SO_2 because NAAQS for these pollutants have been established. VOC is not modeled, as there is no NAAQS for that pollutant. However, because VOC is a precursor to the formation of photochemical oxidants, O_3 impacts are assessed (as described in Section 3.10).

Table 2-3. Centralia Coal to Gas Baseline Net Emissions and PSD Applicability Thresholds

Pollutant	Unit #2[a]	Auxiliary Boiler[b]	Water Bath Heaters (2)[c]	Cooling Towers (2)	Project Wide Totals	PSD Significant Emission Rate
	tpy	tpy	tpy	tpy	tpy	tpy
NO_X	-	1.5	1.3	-	2.8	40
CO	-	3.6	3.2	-	6.8	100
VOC	57.9	0.5	0.4	-	58.8	40
PM_{10}	-	0.7	0.6	3.0	4.3	15
$PM_{2.5}$	-	0.7	0.6	1.8	3.1	10
SO_2	-	0.07	0.06	-	0.1	40
Pb	-	4E-05	4E-05	-	8E-05	0.6

[a] Based on Unit #2 operation at full load (100% load).
[b] Based on 1,300 hours per year of operation for the Auxiliary Boiler.
[c] Based on 8,760 hours of operation for two Water Bath Heaters.

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2.4.4 Toxic Air Pollution Sources Review

The permitting authority on the air discharge permit (ADP) application, SWCAA, requires a review of new or modified toxic air pollution sources as part of that application, per SWCAA 400-076 and Washington Administrative Code (WAC) Chapter 173-460. The air toxics program uses a tiered review approach for regulating toxic air pollutant (TAP) emissions increases that are greater than de minimis levels. The regulations under WAC 173-460-060 also require the use of the "toxics Best Available Control Technology" (tBACT) for emission control on new or modified sources where emissions exceed de minimis thresholds. The first-tier review, outlined in WAC 173-460-080, involves evaluating the aggregate potential emissions increase of each TAP in an acceptable source impact analysis. The acceptable source impact analysis involves either comparing the increase in emissions against established small quantity emission rates (SQER) or comparing the increase in impact at any location outside of property boundaries against the Acceptable Source Impact Levels (ASILs). The current de minimis, SQER, and ASIL limits are listed in WAC 173-460-150. SWCAA additionally requires an acceptable source impact analysis to be conducted for first tier review based on the 1998 version of the WAC 173-460-080 air toxic rules. The 1998 rules have different SQER and ASIL values and do not have de minimis levels. In some cases, the 1998 rules regulate different TAPs than the current regulation. To show TAP emissions are below ASILs, dispersion modeling is required.

The first-tier review determines if the TAP source meets health-based standards without requiring additional review. If the TAP is below either the SQER or the ASIL threshold, that TAP shows an acceptable source impact and has passed the first-tier review. If compliance cannot be demonstrated in this first tier, the source may be subject to a second-tier review, which involves more detailed analysis and possibly stricter controls. A third-tier review may be conducted if further evaluation is needed.

The Project's cumulative potential increase in TAP emissions from the new and modified sources were quantified and compared to the limits in the current and the 1998 version of the WAC 173-460-080 air toxic rules. It should be noted that TAP emissions reductions from past baseline operations for Unit #2 combusting coal were taken into account for NO_2, CO, SO_2, and H_2SO_4.[1] Cumulative emissions from these four TAPs will decrease as a result of the Project. Therefore, they are not included in the acceptable source impact analysis. Aside from these four TAPs, pollutant reductions from the Unit #2 baseline were not considered and the acceptable source impact analysis is expected to be a conservative proposal for certain TAPs.

2.4.4.1 Toxic Air Pollutants to Model Based on Current Air Toxic Rules

The first-tier review of TAPs based on the current WAC 173-460-080 air toxic rules commenced by first comparing potential TAP emissions increases to de minimis thresholds. Table 2-4 shows Project TAPs that are below their respective de minimis limits. The remaining significant TAPs were then compared to the SQER thresholds. Table 2-5 shows Project TAPs that are below their respective SQER limits. To compare a TAP's impact to the ASIL threshold, dispersion modeling of the toxic air pollutant sources must be conducted. Table 2-6 lists the project's TAP emissions that exceed SQER limits, indicating that a dispersion modeling analysis with the AERMOD model is required for these TAPs.

Table 2-4. TransAlta Project De Minimis TAP Emissions

[1] The Unit #2 emissions reductions from baseline are discussed at length in the ADP application narrative with respect to PSD applicability.

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Toxic Air Pollutant	CAS #	Units	Project Potential Emissions Totals	De Minimis Threshold	Proposed Emissions Less than De Minimis?
Chrysene	218-01-9	lb/year	6.4E-02	4.5E-01	Yes
Toluene	108-88-3	lb/24-hr	5.7E-01	1.9E+01	Yes
Copper	7440-50-8	lb/1-hr	5.9E-03	9.3E-03	Yes
Selenium	7782-49-2	lb/24-hr	4.0E-03	7.4E-02	Yes

Table 2-5. TransAlta Project SQER TAP Emissions

Toxic Air Pollutant	CAS #	Units	Project Potential Emissions Totals	SQER Threshold	Proposed Emissions Less than SQER?
Benz(a)anthracene	56-55-3	lb/year	6.4E-02	8.9E-01	Yes
Benzo(a)pyrene	50-32-8	lb/year	4.2E-02	1.6E-01	Yes
Benzo(b)fluoranthene	205-99-2	lb/year	6.4E-02	8.9E-01	Yes
Benzo(k)fluoranthene	207-08-9	lb/year	6.4E-02	8.9E-01	Yes
Dibenzo(a,h)anthracene	53-70-3	lb/year	4.2E-02	4.1E-03	Yes
Indo(1,2,3-cd)pyrene	193-39-5	lb/year	6.4E-02	8.9E-01	Yes
Chromium III	7440-47-3	lb/24-hr	1.9E-01	3.7E-01	Yes

Table 2-6. TransAlta Project TAP Emissions for Dispersion Modeling

Toxic Air Pollutant	CAS #	Units	Project Potential Emissions Totals	ASIL ($\mu g/m^3$)
3-Methylcholanthrene	56-49-5	lb/year	6.4E-02	9.6E-05
7,12-Dimethylbenz(a)anthracene	57-97-6	lb/year	5.7E-01	8.5E-06
Benzene	71-43-2	lb/year	1.0E+02	1.3E-01
Dichlorobenzene	106-46-7	lb/year	4.2E+01	9.1E-02
Formaldehyde	50-00-0	lb/year	8.1E+03	1.7E-01
n-Hexane	110-54-3	lb/24-hr	3.0E+02	7.0E+02
Naphthalene	91-20-3	lb/year	1.8E+02	2.9E-02
Silica	7631-86-9	lb/24-hr	4.2E+00	3.0E+00
Arsenic	7440-38-2	lb/year	8.2E+01	3.0E-04
Beryllium	7440-41-7	lb/year	5.9E+01	4.2E-04
Cadmium	7440-43-9	lb/year	7.9E+01	2.4E-04
Chromium VI	18540-29-9	lb/year	1.5E+01	4.0E-06
Cobalt	7440-48-4	lb/24-hr	1.4E-02	1.0E-01
Lead	7439-92-1	lb/year	1.9E+02	8.3E-02
Manganese	7439-96-5	lb/24-hr	5.8E-01	3.0E-01
Mercury	7439-97-6	lb/24-hr	3.0E-01	3.0E-02
Nickel	7440-02-0	lb/year	9.6E+01	3.8E-03
Vanadium	7440-62-2	lb/24-hr	3.8E-01	1.0E-01

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2.4.4.2 Toxic Air Pollutants to Model Based on 1998 Air Toxic Rules

The first-tier review of TAPs based on the 1998 version of the WAC 173-460-080 air toxic rules commenced by first comparing potential TAP emissions increases to SQER thresholds. Table 2-7 shows Project TAPs that are below their respective SQER limits. To compare a TAP's impact to the ASIL threshold, dispersion modeling of the toxic air pollutant sources must be conducted. Table 2-8 lists the project's TAP emissions that exceed 1998 SQER limits, indicating that a dispersion modeling analysis with the AERMOD model is required for these TAPs.

Table 2-7. TransAlta Project 1998 SQER TAP Emissions

Toxic Air Pollutant	CAS #	Project Potential Emissions Totals (lb/hr)	Project Potential Emissions Totals (lb/yr)	SQER Threshold (lb/hr)	SQER Threshold (lb/yr)	Proposed Emissions Less than SQER?
Naphthalene	91-20-3	4.2E-03	22	2.6	22,750	Yes
Toluene	108-88-3	2.4E-02	120	5.0	42,748	Yes
Chromium III	7440-47-3	8.0E-03	41	0.02	175	Yes
Cobalt	7440-48-4	5.8E-04	3	0.02	175	Yes
Copper	7440-50-8	5.9E-03	30	0.02	175	Yes
Lead	7439-92-1	3.5E-03	18	-	50	Yes
Manganese	7439-96-5	2.6E-03	13	0.02	175	Yes
Mercury	7439-97-6	1.8E-03	9	0.02	175	Yes
Selenium	7782-49-2	1.7E-04	1	0.02	175	Yes
Vanadium	7440-62-2	1.6E-02	81	0.02	175	Yes

Table 2-8. TransAlta Project 1998 TAP Emissions for Dispersion Modeling

Toxic Air Pollutant	CAS #	Units	Project Potential Emissions Totals	ASIL (µg/m^3)
Benzene	71-43-2	lb/year	7.4E+01	1.2E-01
Formaldehyde	50-00-0	lb/year	2.7E+03	7.7E-02
n-Hexane	110-54-3	lb/24-hr	3.0E+02	2.0E+02
Arsenic	7440-38-2	lb/year	7.1E+00	9.6E-05
Beryllium	7440-41-7	lb/year	4.2E-01	8.5E-06
Cadmium	7440-43-9	lb/year	3.9E+01	1.3E-01
Chromium VI	18540-29-9	lb/year	8.9E+00	9.1E-02
Nickel	7440-02-0	lb/year	7.4E+01	1.7E-01
PAH as benzo(a)pyrene	50-32-8	lb/year	7.3E-02	7.0E+02

3.0 AIR QUALITY IMPACT ASSESSMENT METHODOLOGY

3.1 Introduction

The dispersion modeling analyses for the Project was conducted in accordance with the USEPA's *Guideline on Air Quality Models* (USEPA 2024a), as supplemented by additional agency guidance. The modeling methodology was described in an *Air Quality Dispersion Modeling Protocol* (Tetra Tech, 2025), which was submitted to and approved by WDOE (WDOE also provided support with respect to

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the SWCAA-relevant components, the air toxics and the non-PSD pollutants). It should be noted that the Project has changed to only natural gas firing in Unit #2 and therefore the Project emissions have been updated accordingly.

As described in Section 2.4.3, the Project triggers a PSD major modification for VOC, due to the significant net emissions of that pollutant. CO, NO_2, PM_{10}, $PM_{2.5}$, and SO_2 are not subject to PSD review because the Project emissions did not exceed the PSD SERs for those pollutants, and therefore, these pollutants are not subject to the specific PSD modeling requirements. As a result, dispersion modeling was conducted for CO, NO_2, PM_{10}, $PM_{2.5}$, and SO_2, to demonstrate compliance with the NAAQS as required under SWCAA 400-110(3)(c). As there is no NAAQS for VOC, this pollutant was not subject to dispersion modeling requirements, however it is considered in the NAAQS demonstration for secondary O_3.

The dispersion modeling for the Project evaluated worst-case operating conditions associated with a 59% capacity factor at full load to predict the appropriate maximum ground-level concentration for each pollutant and averaging period. The appropriate maximum concentrations from the worst-case scenarios are compared to the significant impact levels (SILs). If the maximum concentration is below the corresponding SILs, then compliance is demonstrated, and no additional analysis is necessary for that pollutant and averaging period. However, if the maximum predicted concentration is equal to or greater than the SIL, a cumulative impact analysis was conducted with ambient background concentrations that include other major emission sources in the area. The modeled impacts are added to ambient monitored background concentrations and the sum compared to the NAAQS. Table 3-1 provides the SILs and NAAQS, as well as the modeling rank basis, as defined by USEPA, used for the assessment of compliance with the various criteria.

Table 3-1. SILs and NAAQS

Pollutant	Averaging Period	Rank for SIL Assessment	SIL (µg/m³)	Rank for NAAQS Assessment	NAAQS (µg/m³)
NO_2	1-hour	H1H [a] (5-year average)	7.5	H8H [b] (5-year average)	188
	Annual	H1H	1	H1H	100
CO	1-hour	H1H	2,000	H2H [c]	40,000
	8-hour	H1H	500	H2H	10,000
PM_{10}	24-hour	H1H	5	H6H [d] over 5 years	150
$PM_{2.5}$	24-hour	H1H (5-year average)	1.2 [e]	H8H (5-year average)	35
	Annual	H1H (5-year average)	0.13 [e]	H1H (5-year average)	9
SO_2	1-hour	H1H	7.8	H4H (5-year average)	196
	Annual	H1H	1	H1H (5-year average)	26.2

[a] Highest first-high concentration
[b] Highest eighth-high concentration
[c] Highest second-high concentration
[d] Highest sixth-high concentration
[e] Use of SILs can be justified using ambient monitoring data, see text below.

The $PM_{2.5}$ SILs at 40 CFR 52.21(k)(2) and 40 CFR 51.165(k)(2) were vacated and remanded by the January 22, 2013 United States Court of Appeals for the District of Columbia Circuit Decision on a Sierra Club v. USEPA case. The $PM_{2.5}$ SILs that were vacated and remanded concerned portions of the

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$PM_{2.5}$ SIL regulations that automatically exempted sources from further analyses for demonstration of compliance with NAAQS and PSD increments if the predicted $PM_{2.5}$ impacts were less than the $PM_{2.5}$ SILs. The January 22, 2013 Decision specifically did not vacate the $PM_{2.5}$ SILs at 40 CFR 165(b)(2), which provides that a major source or major modification will be considered to cause or contribute to a violation of the NAAQS when such source or modification is predicted to exceed the SIL at any locality that does not or would not meet the applicable NAAQS. Under USEPA modeling guidance issued subsequent to this January 22, 2013 Decision, $PM_{2.5}$ SILs may still be used to justify permitting decisions for $PM_{2.5}$ NAAQS and increment compliance if appropriate justification is provided that the use of such SILs is protective of NAAQS and increment compliance. For NAAQS demonstrations, a key portion of this justification typically would include demonstrating that a large margin exists between the ambient background and the standard. As shown in Section 3.8 of this Protocol, existing ambient monitoring data representative of ambient background for the Project site and surrounding area indicate that there is a substantial margin between the ambient background levels and the NAAQS (see Table 3-6). Therefore, predicted Project impacts below the respective SILs will allow for adequate protection of the NAAQS, leaving considerable margin for contributions from other interacting sources.

3.2 Source Data and Operating Scenarios

The modeling analyses included the following emission sources:

- Unit #2 boiler combusting natural gas. Unit #2 will have an operational capacity factor of 59% (5,168 hours per year) and will be limited to that 59% capacity;
- One (1) auxiliary boiler that will combust natural gas and be limited to no greater than 1,300 hours of operation per year;
- Two (2) water bath heaters combusting natural gas, each with an exhaust stack; and
- Two (2) cooling towers with twelve (12) cells each.

Table 3-2 summarizes the physical stack characteristics modeled for the NAAQS analysis. Detailed emissions and source parameter data are provided in Table 3-3. The Unit #2 boiler was modeled at full load (100% load or 723 MW) and minimum stable load (190 MW) to determine which scenario resulted in the worst-case predicted impacts[2]. Then the worst-case Unit #2 scenario was modeled in combination with the auxiliary boiler, dew point heaters and cooling towers to determine total Project impacts for the NAAQS modeling analysis. The conversion of NO_X emission rates to modeled NO_2 concentrations employed the Tier 2 Ambient Ratio Method (ARM2) NO_X to NO_2 conversion assumptions.

[2] Startup and shutdown impacts were evaluated and studied for Unit #2. Based on those evaluations, combustion emissions are anticipated to be consistent across a lb/MMBtu basis, as in when the amount of fuel combusted decreases, the emissions associated with fuel combustion would also decrease. Therefore, the VOC emissions expressed in lb/MMBtu account for the startup and shutdown emissions without further need for clarification or allowances. The modeling analysis evaluates the worst case lb/hr emissions rates, which are associated with full load operations.

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Table 3-2. Physical Stack Characteristics

Source ID	Description	Stack Location [a]		Ground-Level Elevation (meters above mean sea level)	Stack Height (meters above the ground)	Stack Inner Diameter (meters)
		UTM E (m)	UTM N (m)			
U2_100	Unit #2 Boiler (100% load)	510831.55	5177972.72	68.12	140.21	7.32
U2_190MW	Unit #2 Boiler (190 MW)	510831.55	5177972.72	68.12	140.21	7.32
AUXBLR	Auxiliary Boiler	510761.14	5178008.60	68.12	76.20	1.52
DPH_1	Dew Point Heater 1	510404.72	5177875.40	71.37	7.62	0.61
DPH_2	Dew Point Heater 2	510405.42	5177866.41	71.37	7.62	0.61
COOLT1_A	Cooling Tower 1 Cell A	510533.56	5177641.83	93.89	19.91	7.62
COOLT1_B	Cooling Tower 1 Cell B	510534.41	5177654.90	93.89	19.91	7.62
COOLT1_C	Cooling Tower 1 Cell C	510534.92	5177668.14	93.89	19.91	7.62
COOLT1_D	Cooling Tower 1 Cell D	510535.60	5177680.53	93.89	19.91	7.62
COOLT1_E	Cooling Tower 1 Cell E	510536.28	5177695.13	93.89	19.91	7.62
COOLT1_F	Cooling Tower 1 Cell F	510537.13	5177708.37	93.89	19.91	7.62
COOLT1_G	Cooling Tower 1 Cell G	510544.53	5177640.47	93.89	19.91	7.62
COOLT1_H	Cooling Tower 1 Cell H	510544.87	5177653.54	93.89	19.91	7.62
COOLT1_I	Cooling Tower 1 Cell I	510545.38	5177666.78	93.89	19.91	7.62
COOLT1_J	Cooling Tower 1 Cell J	510546.06	5177679.17	93.89	19.91	7.62
COOLT1_K	Cooling Tower 1 Cell K	510546.74	5177693.77	93.89	19.91	7.62
COOLT1_L	Cooling Tower 1 Cell L	510547.59	5177707.01	93.89	19.91	7.62
COOLT2_A	Cooling Tower 2 Cell A	510638.31	5177504.10	93.89	19.91	7.62
COOLT2_B	Cooling Tower 2 Cell B	510629.05	5177513.44	93.96	19.91	7.62
COOLT2_C	Cooling Tower 2 Cell C	510619.50	5177523.28	93.96	19.91	7.62
COOLT2_D	Cooling Tower 2 Cell D	510610.29	5177533.36	93.96	19.91	7.62
COOLT2_E	Cooling Tower 2 Cell E	510600.63	5177543.17	93.96	19.91	7.62
COOLT2_F	Cooling Tower 2 Cell F	510591.37	5177552.48	93.96	19.91	7.62
COOLT2_G	Cooling Tower 2 Cell G	510630.64	5177496.41	93.96	19.91	7.62
COOLT2_H	Cooling Tower 2 Cell H	510621.64	5177506.20	93.96	19.91	7.62
COOLT2_I	Cooling Tower 2 Cell I	510612.30	5177515.69	93.96	19.91	7.62
COOLT2_J	Cooling Tower 2 Cell J	510602.94	5177525.64	93.96	19.91	7.62

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Source ID	Description	Stack Location [a]		Ground-Level Elevation (meters above mean sea level)	Stack Height (meters above the ground)	Stack Inner Diameter (meters)
		UTM E (m)	UTM N (m)			
COOLT2_K	Cooling Tower 2 Cell K	510593.39	5177535.37	93.96	19.91	7.62
COOLT2_L	Cooling Tower 2 Cell L	510584.10	5177544.87	93.96	19.91	7.62

[a] UTM Zone 10, WGS-84 datum

Table 3-3. Stack Exhaust Parameters and Emission Rates

Source ID	Stack Exit Temperature (K)	Stack Exit Velocity (m/s)	Emission Rates (g/s)								
			CO	NO_2		PM_{10}		$PM_{2.5}$		SO_2	
			Short-term	Short-term	Annual	Short-term	Annual	Short-term	Annual	Short-term	Annual
U2_100	441.48	29.77	141.747	103.948	61.331	6.488	3.828	6.488	3.828	0.679	0.400
U2_190MW	388.71	9.55	47.797	35.051	35.052	2.188	2.188	2.188	2.188	0.229	0.229
AUXBLR	422.04	11.73	0.695	0.282	0.042	0.129	0.019	0.129	0.019	0.013	0.002
DPH_1	644.26	10.51	0.047	0.019	0.019	0.009	0.009	0.009	0.009	0.0009	0.0009
DPH_2	644.26	10.51	0.047	0.019	0.019	0.009	0.009	0.009	0.009	0.0009	0.0009
COOLT1_A	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_B	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_C	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_D	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_E	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_F	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_G	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_H	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_I	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_J	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_K	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_L	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_A	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_B	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Source ID	Stack Exit Temperature (K)	Stack Exit Velocity (m/s)	Emission Rates (g/s)								
			CO	NO_2		PM_{10}		$PM_{2.5}$		SO_2	
			Short-term	Short-term	Annual	Short-term	Annual	Short-term	Annual	Short-term	Annual
COOLT2_C	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_D	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_E	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_F	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_G	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_H	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_I	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_J	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_K	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_L	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-

[a] UTM Zone 10, WGS-84 datum.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

3.3 Model Selection

The USEPA-recommended AERMOD modeling system (USEPA 2024b) was used to conduct the dispersion modeling. The current versions of the model (AERMOD version 24142, AERMET version 24142 and AERMAP version 24142) were used to model criteria and toxic pollutants.

3.4 Meteorological Data for AERMOD

AERMOD was run in refined mode with five years (2020-2024) of hourly surface meteorological data collected at the Olympia Regional Airport meteorological station in Thurston, Washington, along with corresponding upper air data collected at McNary Field Airport in Salem, Oregon. These data were processed using the AERMET program (v24142) along with the associated programs AERMINUTE (v15272) and AERSURFACE (v20060). AERSURFACE was run based on land use data around the meteorological data collection site (Olympia Regional Airport) and considered 12 equal 30-degree sectors. The following seasonal variations were assigned:

- Winter (no snow): December, January, and February
- Transitional Spring: March, April, and May
- Midsummer: June, July, and August
- Autumn: September, October, and November

The monthly moisture conditions (average, wet, or dry) were determined for each year based on precipitation data measured in Centralia, Washington with missing data filled in from Olympia, Washington. The moisture conditions for each month were input to AERSURFACE to determine surface characteristics and results were input to AERMET for meteorological data processing. Default settings were used for the AERMET processing including the adjustment of truncated 1-minute ASOS winds. A minimum wind speed threshold of 0.5 m/s and the friction velocity adjustment (adj_u*) option were used.

A joint frequency distribution of the winds (wind rose) for the five years of meteorological data used in the AERMOD modeling analysis is presented in Figure 3-1. The predominant winds are also the strongest winds and they are from the south through southwest sector.

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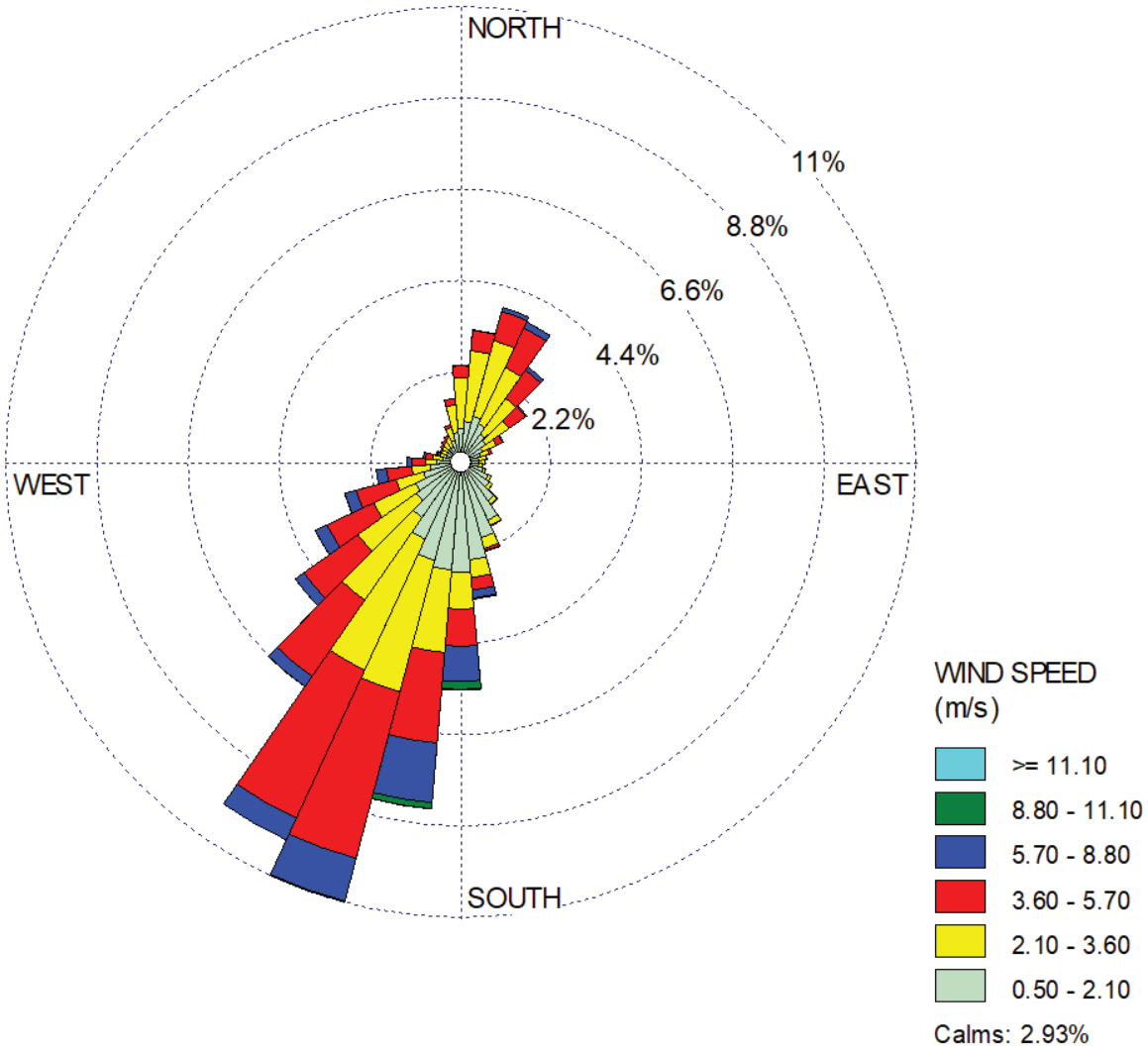


Figure 3-1. Five-year (2020-2024) Wind Rose of Wind Measurements at Olympia Meteorological Station

3.5 Land Use

It is necessary to determine whether the land-use pattern in the environs of a Project is urban or rural for modeling purposes. A land use determination has been made following the classification technique suggested by Auer (1978) in accordance with USEPA modeling guidance. The classification determination was conducted by assessing land-use categories within a 3-kilometer (km) radius of the proposed site. Figure 3-2 provides a section of an aerial photograph with the 3-km radius around the Project Site shown. Inspection of aerial photography indicates that the majority of the area is rural, with urban land uses (i.e., industrial, commercial, and dense residential) comprising less than 50% of the area within a 3 km radius. Therefore, rural dispersion coefficients were used for the air quality modeling analysis.

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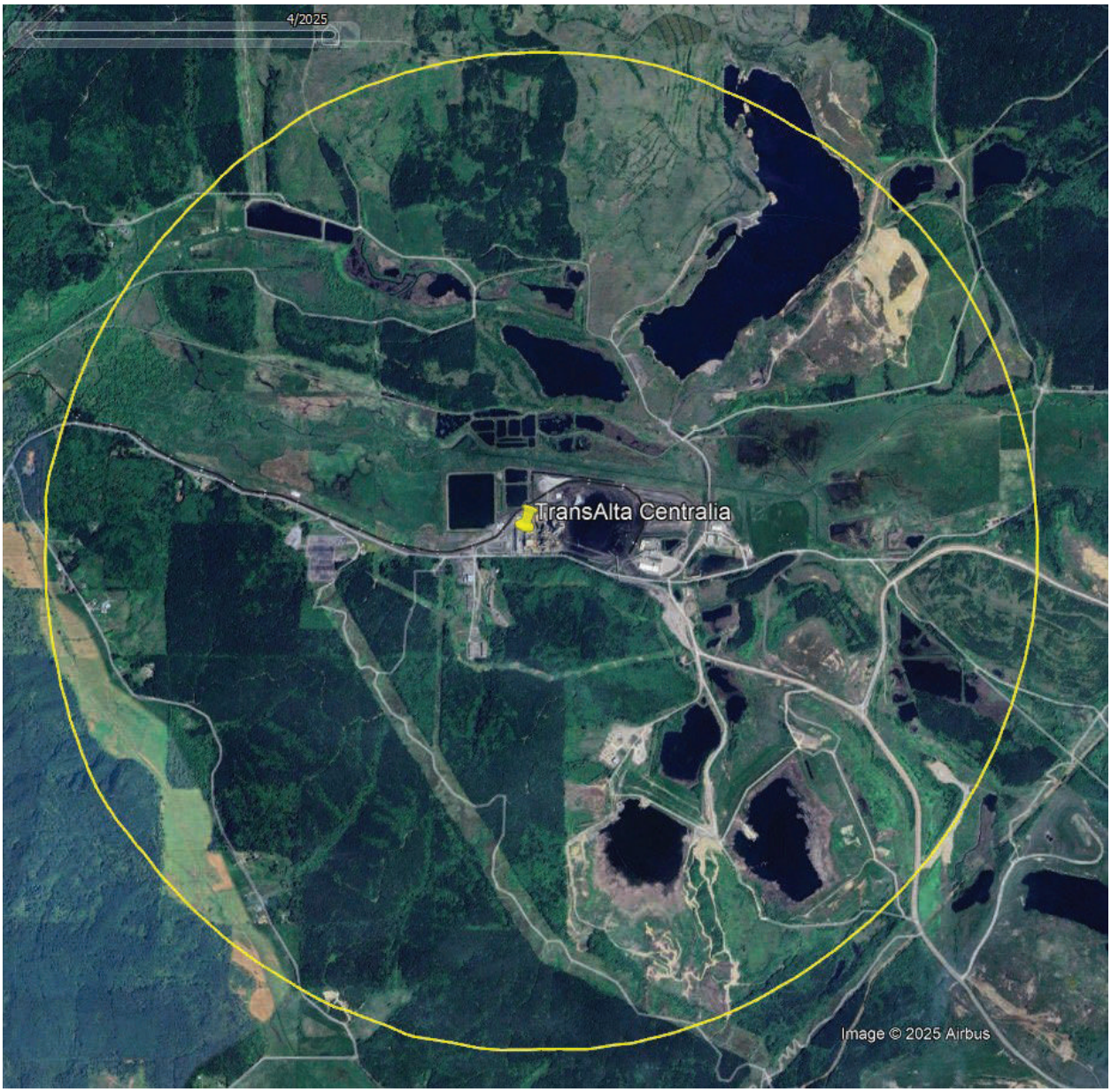


Figure 3-2. Urban / Rural Land Use Determination within a 3 km radius

3.6 Good Engineering Practice Stack Height Analysis

A GEP stack height analysis was performed based on the Project and Facility structures to determine the potential for building-induced aerodynamic downwash for the stacks. The analysis procedures described in USEPA's Guidelines for Determination of Good Engineering Practice Stack Height (USEPA 1985) guidance and included in SWCAA 400-200 Creditable Stack Height regulations were used.

The "GEP stack height" is defined as the greater of 65 meters or the formula height. The "formula height" is based on the observed phenomena of disturbed atmospheric flow in the immediate vicinity of a structure resulting in higher ground-level concentrations at a closer proximity than would

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otherwise occur. It identifies the minimum stack height at which significant aerodynamic downwash is avoided.

The GEP formula stack height, as defined in the 1985 final regulation, is calculated as follows:

$$H_{GEP} = H_{BLDG} + 1.5L$$

Where:

- H_{GEP} is the calculated GEP formula height;
- H_{BLDG} is the height of the nearby structure; and
- L is the lesser dimension (height or projected width) of the nearby structure.

Both the height and width of the structure are determined from the frontal area of the structure projected onto the plane perpendicular to the direction of the wind. The GEP stack height is based on the plane projection of any structure that results in the greatest calculated height. For the purpose of the GEP analysis, nearby refers to the "sphere of influence" defined as 5 times L (the lesser dimension – height or projected width – of the nearby structure), downwind from the trailing edge of the structure.

The USEPA's Building Profile Input Program (BPIP-Prime, v04274) that is appropriate for use with the PRIME algorithms in AERMOD was used. The building dimensions and coordinates for each potentially influencing structure was input to BPIP-Prime to determine direction-specific building dimension data for input to AERMOD.

If the stack heights are below their calculated GEP height, the exhaust emissions will experience the aerodynamic effects of downwash. As determined by BPIP-Prime, all of the stack heights are below their calculated GEP height. For each stack, the controlling structures differ by direction, and wind-direction specific building dimensions are generated by BPIP-Prime for input to AERMOD. AERMOD accounts for potential downwash from nearby structures in the dispersion calculations. The PRIME algorithms in AERMOD calculate the dimensions of the structure's wake, from the cavity immediately downwind of the structure to the far wake.

3.7 Receptor Grid and AERMAP Processing

Discrete receptors were placed at 12.5-meter intervals along the Facility fence lines. There will be two fences, one surrounding the generation area of the plant and one surrounding the cooling towers across the road from the generation area. The WDOE recommended[3] a nested receptor grid with spacing as follows:

- At 12.5-meter intervals to 150 meters;
- At 25-meter intervals from 150 meters to 400 meters;
- At 50-meter intervals from 400 meters to 900 meters;
- At 100-meter intervals from 900 meters to 2,000 meters;
- At 300-meter intervals from 2,000 meters to 4,500 meters; and

[3] Email communication from Beth Friedman (WDOE) to Liz Hendrick (Tetra Tech) on 3/4/2025.

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- At 600-meter intervals from 4,500 meters to 10,000 meters.

The spacing recommendations were followed; however, because the Project involves multiple emission sources at different locations, the nested grid was extended to at least 150 meters beyond the bounding box of the sources. Per Section 9.2.2 of 40 CFR Part 51, higher-resolution receptor grids (50m spacing) will be used at predicted maxima located within coarser grid areas. Figure 3-3 shows the full nested Cartesian receptor grid including a refined grid that was used for annual NO_2 and toxics modeling. A zoomed-in view of the inner grids is provided in Figure 3-4.

Terrain elevations at receptors were obtained using Lake Environmental's AERMOD View program and United States Geological Survey (USGS) digital terrain data. AERMOD View implements the AERMAP model, which includes processing routines that extract National Elevation Data (NED) at 10-meter spacing based on North American Datum of 1983 (NAD83). The four nearest data points surrounding each receptor are used to determine receptor terrain elevations (by interpolation) for air quality model input. At WDOE's request, each receptor was assigned a flagpole height of 1.5 meters above the ground.

3.8 Ambient Background Data

Based on the recommendation of Washington WDOE, model and monitoring data from July 2014 through June 2017 were used to estimate background concentrations of criteria air pollutant design values for use in air permit analysis. The tool located at Background Concentrations 2014 - 2017 facilitates the retrieval and exploration of the estimated design values at user-specified locations in Washington, Idaho, and Oregon. These values are assumed to be inclusive of the emissions from constantly emitting surrounding sources including the coal-fired emissions from TransAlta Centralia. This results in a conservative estimate of ambient background because coal-firing at TransAlta Centralia will cease in December 2025. Significant wildfire smoke and windblown dust events have mostly been filtered out. In general, WDOE recommends using the highest value at the grid cell close to your project site as representative background concentrations. The grid cell across the road from the TransAlta Centralia Station (latitude 46.75 °N, Longitude 122.85 °W) was used. The selected representative ambient air quality background concentrations are summarized in Table 3-4.

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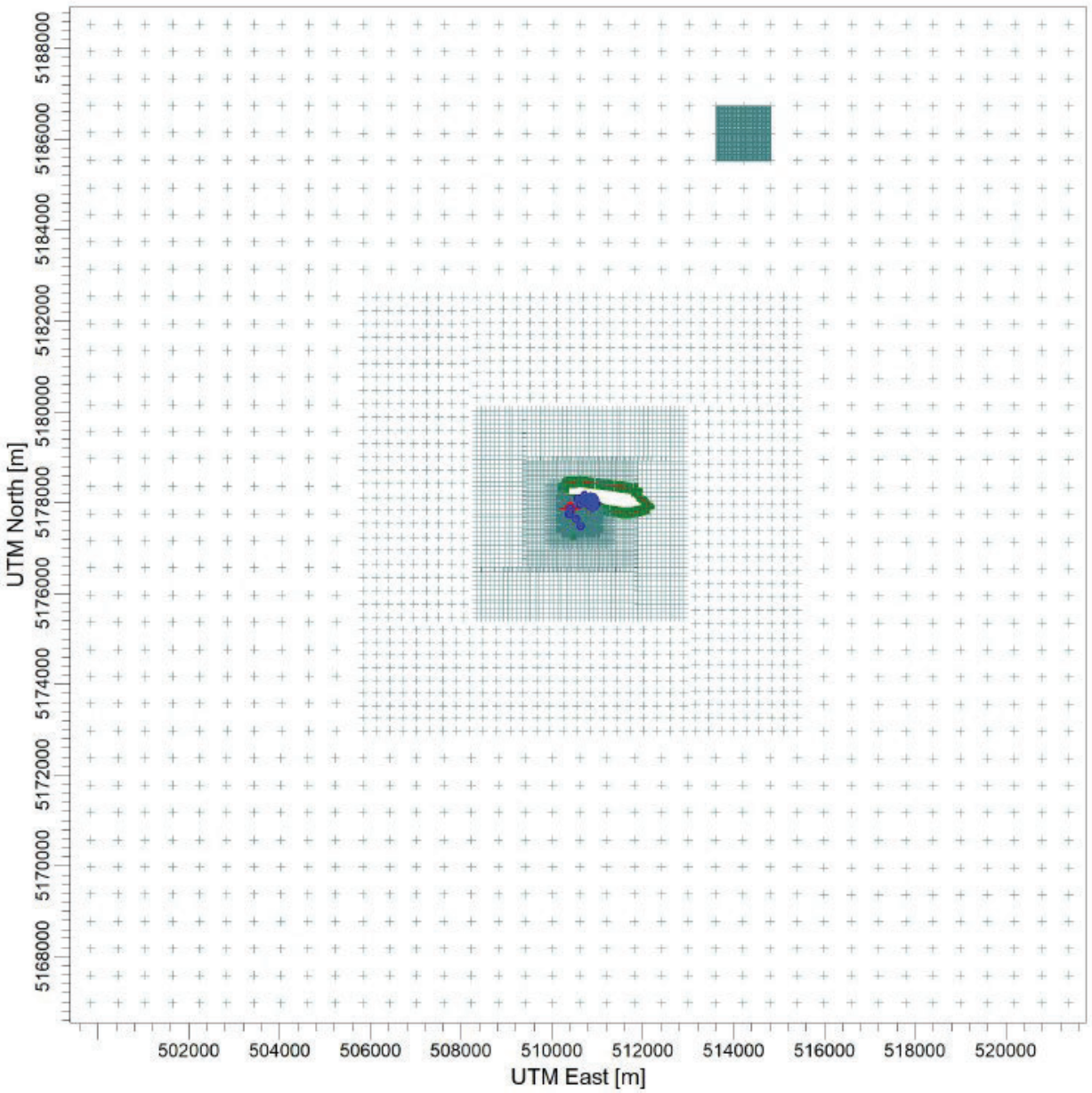


Figure 3-3. Full Nested Cartesian Receptor Grid including the Refined Receptor Grid

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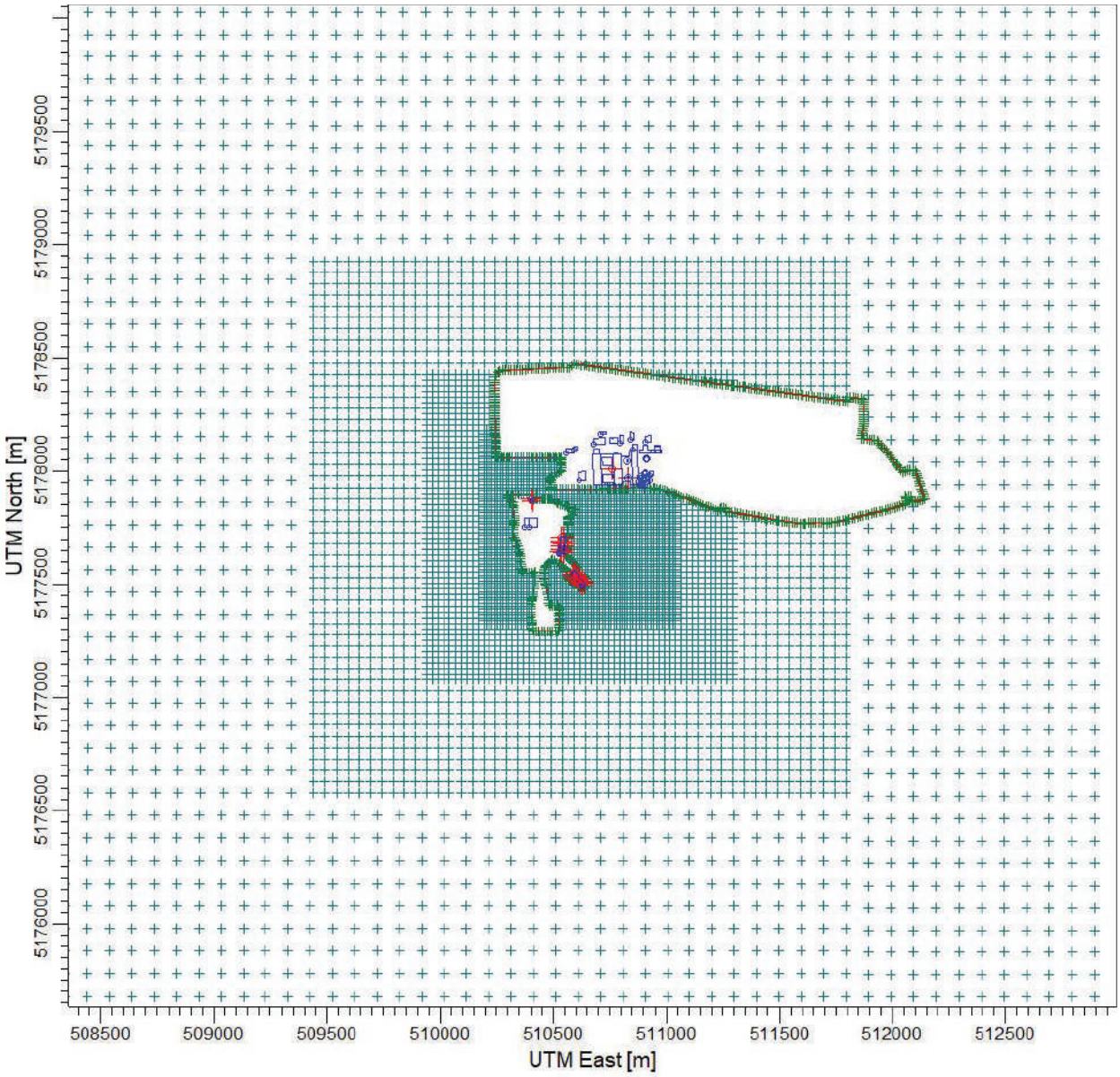


Figure 3-4. Zoomed to Inner Grids of the Nested Cartesian Receptor Grid

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Table 3-4. Proposed Air Quality Background Concentrations

Pollutant	Averaging Period	Grid Cell[a]	Background Conc.		
			ppm	ppb	µg/m³
CO	1-hour	A	1.07		1,241.20
	8-hour	A	0.72		835.20
NO_2	1-hour	A		27.60	51.89
	Annual	A		6.2	11.66
PM_{10}	24-hour	A			43.70
$PM_{2.5}$	24-hour	A			17.80
	Annual	A			6.00
SO_2	1-hour	A		5.2	13.62
	24-hour	A		2.4	6.29
	Annual	A		0.5	1.31
O_3	8-hour	A		54	106.01

[a] Grid Cell across the Road from TransAlta Centralia Station (Latitude 46.75 ° N, Longitude 122.85 ° W).

Table 3-5 presents the difference between the NAAQS and the representative background concentration, compared to the SILs. As shown in Table 3-5, all averaging periods for each pollutant have a margin between the monitored value and the NAAQS that is greater than the respective SIL; therefore, use of the SILs as *de minimis* levels for all pollutants is appropriate.

Table 3-5. Margin between Ambient Air Quality Concentrations and the NAAQS

Pollutant	Averaging Period	Background Concentration (µg/m³)	NAAQS (µg/m³)	Margin (NAAQS-Background) (µg/m³)	Significant Impact Level (µg/m³)
CO	1-Hour	1241.2	40,000	38,758.8	2,000
	8-Hour	835.2	10,000	9,164.8	500
NO_2	1-Hour	51.89	188	136.1	7.5
	Annual	11.66	100	88.3	1
PM_{10}	24-Hour	43.7	150	106.3	5
$PM_{2.5}$	24-Hour	17.8	35	17.2	1.2
	Annual	6.0	9	3.0	0.2
SO_2	1-Hour	13.62	196	182.4	1.2
	Annual	1.31	26.2	24.9	0.2
O_3	8-Hour	54 ppb	70 ppb	16 ppb	1 ppb

3.9 Modeling Methodology

The modeling analyses were conducted using the most current version of AERMOD (v24142) along with the meteorological data as described in Section 3.4. The analysis was conducted to demonstrate compliance with the NAAQS. The worst-case Unit #2 boiler operating condition was evaluated and modeled with other project sources as described in Section 3.2 to assess compliance with the NAAQS. If the maximum concentrations from any Project criteria pollutant emissions were predicted to be equal to or greater than their respective SILs, shown in Table 3-1, a modeling analysis including ambient background concentrations was conducted to determine compliance with the NAAQS.

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3.9.1 NO_2 Modeling Methods

The NO_2 impact analysis was consistent with the EPA guidance on 1-hour NO_2 dispersion modeling, Guideline on Air Quality Models (EPA 2024a). The 2024 EPA guidance describes a multi-tiered screening approach for modeling 1-hour NO_2. The key issue is that NO_X emissions are released primarily in the form of nitric oxide, which convert to NO_2 in the atmosphere. Tier 1 in the screening approach assumes that all NO_X converts to NO_2. Tier 2 assumes NO_X converts to NO_2 at a rate consistent to an appropriate NO_2/NO_X ambient ratio derived from ambient measurement data. Tier 2 ARM2 method is a regulatory default conversion approach in AERMOD.

The Tier 2 ARM2 conversion methodology was used with the default minimum (0.5) and maximum (0.9) NO_2/NO_X ratios.

3.10 Assessment of Secondary Particulate and Ozone

The analysis of $PM_{2.5}$ impacts is consistent with the *Guidance for Ozone and Fine Particulate Matter Permit Modeling* (USEPA 2022). If the Project has an annual potential to emit (PTE) of direct $PM_{2.5}$, NO_x, or SO_2 greater than their respective SER thresholds, air quality impacts from both primary and secondary $PM_{2.5}$ emissions must be assessed. For this Project, $PM_{2.5}$ and NO_x emissions are greater than their respective SERs, triggering the secondary $PM_{2.5}$ analysis. Impacts of primary $PM_{2.5}$ emissions were determined with dispersion modeling using AERMOD, as described above.

Impacts of the Project on secondary $PM_{2.5}$ levels were estimated using the approach described in the 2024 *EPA Guideline on Air Quality Models*. This guideline promulgated a two-tier approach for addressing single-source impacts on 8-hour O_3 and 24-hour and annual secondary $PM_{2.5}$. A Tier 1 analysis was used, which involves the use of technically credible relationships between precursor emissions and secondary ambient impacts based on existing modeling studies deemed sufficient for evaluating a project source's impacts. Specifically, USEPA modeling described in the *Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier I Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program* (USEPA 2019) was used. USEPA has generated empirical relationships between single sources and O_3 and $PM_{2.5}$ impacts for hundreds of hypothetical sources that vary in stack height, emission rate, and geographic location. The MERPs View Qlik application tool[4] was used. The tool provides illustrative hypothetical single-source modeled impacts for annual and daily maximum average $PM_{2.5}$ and annual maximum daily 8-hour O_3 for use in NAAQS Tier 1 demonstrations. The sources represented "high" releases (90 meters) and "low" releases (10 meters) at multiple emissions levels. For this Project, the high-level stack scenario is most appropriate because the Project Unit #2 stack height is 140.2 meters. Hypothetical sources were evaluated by USEPA at three geographic locations in Washington state; Klickitat in south central Washington approximately 168 km southeast of the Project site, Skagit located approximately 184 km north-northeast of the Project and situated along the bay, and Spokane which is approximately 425 km away in the eastern part of the state. The most representative hypothetical source for this Project is the Klickitat, Washington site. It is the closest to the Project site and the environment surrounding the Klickitat area is most like the Centralia area. Therefore, the Project estimates the expected secondary

[4] Located at https://www.epa.gov/scram/merps-view-qlik.

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$PM_{2.5}$ formation based on the high-level stack modeling with 3,000 tpy on NO_x emissions and 500 tpy for SO_2 precursor emissions. The hypothetical modeling results are scaled by the ratio of the USEPA scenario emission rate to the Project emission rate for each pollutant. The contributions to secondary $PM_{2.5}$ formation from the precursor emissions of NO_X and SO_2 are summed to estimate the total secondary $PM_{2.5}$. Total $PM_{2.5}$ impacts include the primary modeled $PM_{2.5}$ plus the estimated secondary $PM_{2.5}$ formed from precursor emissions.

Chemical transformations of NO_x and VOC contribute to the formation of ambient O_3 in the atmosphere. The photochemical processes that lead to O_3 formation occur over many hours and are affected by precursor emissions over a large region, often 100 miles or more. Even a large facility will generally represent a very small contribution to regional emissions. Section 5.3 of the *Guideline on Air Quality Models* recommends a two-tiered approach for an ambient O_3 analysis (USEPA 2024a). For this Project, NO_x and VOC emissions are greater than their respective SERs, triggering the requirement for an analysis of secondary formation of ozone. Like the analysis for secondary $PM_{2.5}$, a Tier 1 demonstration for O_3 formation was scaled from the existing USEPA modeling from the Klickitat site which was obtained using the MERPs View Qlik tool. To demonstrate the effect of Project emissions on regional O_3 levels, the estimated secondary formation of O_3 are compared to the USEPA 8-hour O_3 SIL, and if necessary, ambient background will be added to the secondary O_3 concentration for a NAAQS compliance demonstration.

3.11 Toxic Air Pollutant Source Impact analysis

Consistent with the first-tier review specified in both the current and 1998 version of WAC 173-460-080, the TAPs associated with the development of the Project and described in Section 2.4.4 were evaluated with modeling. TAPs were modeled with AERMOD for each source that emits any of the eighteen TAPs that are being evaluated under the current rule and ten TAPs that are being evaluated under the 1998 rule. The AERMOD modeling was based on a unit emission rate of 1 gram/second (g/s). Then the TAP emission rates for each pollutant for each source were multiplied by modeled maximum normalized concentrations (assuming 1 g/s emission rates) and the contribution from each source summed to calculate a total impact concentration for each pollutant. This methodology is conservative because it sums all individual maximum impacts for a specific TAP for comparison with the ASIL thresholds regardless of where or when each maximum is predicted. The maximum predicted impacts from each source will likely not occur at the same time or at the same location. If this unit analysis shows noncompliance with the ASIL for any specific TAP, the TAP(s) were then modeled separately with specific pollutant emission rates by source to evaluate the total maximum cumulative predicted impact. This approach ensures that modeled impacts are not overestimated when compared to the ASIL.

4.0 AIR QUALITY MODELING RESULTS

4.1 Introduction

The dispersion modeling for the Project evaluates the maximum design scenario to predict the appropriate maximum concentration for each pollutant and averaging period. In addition to the assessment of primary $PM_{2.5}$ emissions, secondary $PM_{2.5}$ formed in the atmosphere from precursor NO_x

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and SO_2 emission are also assessed. The assessment of secondary $PM_{2.5}$ formation is based on EPA guidance described in the Protocol. The total $PM_{2.5}$ concentration that is used in the SIL and NAAQS analyses is defined as the sum of the primary modeled concentration plus the secondary $PM_{2.5}$ concentration. O_3 can also be formed as a secondary pollutant from precursor NO_x and VOC emissions. Secondary O_3 emissions have also been assessed. The appropriate maximum concentrations from the maximum design scenarios are compared to the SILs. If the maximum concentration is less than the corresponding SIL, then compliance is demonstrated, and no additional analysis is necessary for that pollutant and averaging period. However, if the maximum predicted concentration is equal to or greater than the SIL, a NAAQS modeling assessment has been conducted and summed with measured ambient background concentrations to represent the cumulative air quality concentrations resulting from the Project and existing air quality in the region. AERMOD modeling has been conducted in accordance with the procedures described above and in the approved Modeling Protocol (Tetra Tech, 2025). It should be noted that the Modeling Protocol included the firing of both natural gas and ultra low sulfur diesel fuel in Unit #2 (with worst-case impacts being modeled for each respective pollutant). The diesel usage was later eliminated from the project and Unit #2 will now only fire natural gas. This report includes the air dispersion modeling from that natural gas combustion and its associated impacts.

4.2 Load Analysis

AERMOD modeling was conducted for Unit #2 operating at 100% load and the minimal stable generation (~190 MW) load to determine the worst-case impact scenario for each pollutant and averaging period. A unit emission rate was modeled, then the normalized concentrations for each averaging period were scaled by the appropriate emission rate for each pollutant. Separate AERMOD load runs with 1-hour NO_2, 1-hour SO_2 and 24-hour $PM_{2.5}$ emission rates were also made so that the proper form of those standards would be assessed in the load analysis. Detailed model results for both operating scenarios are provided in Appendix A. Based on the load analysis, the 190 MW operating scenario resulted in higher predicted impacts due to the less favorable dispersion parameters. Therefore, the modeling assessment used the 190 MW scenario for Unit #2 to evaluate short-term and annual impacts for the SIL, NAAQS and toxics modeling analyses.

4.3 Secondary Pollutant Assessment

4.3.1 Secondary $PM_{2.5}$ Assessment

Impacts of the Project on secondary $PM_{2.5}$ levels were estimated using the approach described in Section 3.10. The MERPs View Qlik application tool was used to obtain the highest daily (24-hour) and highest annual secondary $PM_{2.5}$ impacts, respectively, from sources of NO_x and SO_2 based on the USEPA photochemical modeling. The most representative USEPA hypothetical source for this Project is the Klickitat, Washington site. Therefore, the Project estimates the expected secondary $PM_{2.5}$ formation based on the high-level stack modeling with 3,000 tpy on NO_x emissions and 500 tpy for SO_2 precursor emissions. The following calculations are used to estimate the Project only secondary $PM_{2.5}$ impacts.

For 24-hour secondary $PM_{2.5}$,

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- NO_x – 3,000 tons/year (90 m source), Klickitat 24-hour $PM_{2.5}$ impact = 0.177 µg/m^3
  - Project NO_x emissions = 2,134.7 tpy
  - Estimated $PM_{2.5}$ impact due to Project = (2,134.7 /3000) * 0.177 µg/m^3= 0.126 µg/m^3
- SO_2 - 500 tpy (90 m source), Klickitat 24-hour $PM_{2.5}$ impact = 0.233 µg/m^3
  - Project SO_2 emissions = 14.05 tpy
  - Estimated $PM_{2.5}$ impact due to Project = (14.05 /500) * 0.233 = 0.007 µg/m^3

Total 24-hour secondary $PM_{2.5}$ impact due to Project = 0.126 + 0.007 = **0.133 µg/m^3**

For annual secondary $PM_{2.5}$,

- NO_x – 3.000 tpy (90 m source), Klickitat annual $PM_{2.5}$ impact = 0.0084 µg/m^3
  - Project NO_x emissions = 2,134.7 tpy
  - Estimated $PM_{2.5}$ impact due to Project = (2,134.7 /3000) * 0.0084 µg/m^3= 0.0060 µg/m^3
- SO_2 - 500 tpy (90 m source), Klickitat annual $PM_{2.5}$ impact = 0.0086 µg/m^3
  - Facility SO_2 emissions = 14.05 tpy
  - Estimated $PM_{2.5}$ impact due to Project = (14.05 /500) * 0.0086 = 0.0002 µg/m^3

Total annual secondary PM2.5 impact due to Project = 0.0060 + 0.0002 = 0.0062 µg/m3

It is important to note that these secondary impacts will not be experienced in the same location as the Project's maximum primary $PM_{2.5}$ impacts, as the secondary particulate formation will occur well downwind of the Project. Furthermore, these levels represent an insignificant fraction of existing $PM_{2.5}$ background levels.

4.3.2 Ozone Ambient Impact Assessment

Chemical transformation of NO_x and VOC can contribute to the formation of ambient O_3 in the atmosphere. The photochemical processes that lead to O_3 formation occur over many hours and are affected by precursor emissions over a large region, often 100 miles or more. Even a large facility will generally represent a very small contribution to regional concentrations. Similar to the description in Section 3.10 (analysis for secondary $PM_{2.5}$), a Tier 1 demonstration for ozone formation is based on the existing USEPA modeling.

The MERPs View Qlik application tool was used to obtain the highest 8-hour O_3 impacts, respectively, from sources of NO_x and VOC based on the USEPA photochemical modeling. The amount of O_3 that would be formed from the proposed Project using the USEPA-estimated O_3 in Klickitat, Washington is based on the impacts presented for the high-level release of 3,000 tpy of NO_x emissions and 500 tpy of VOC precursor emissions. The following calculations are used to estimate the Project only O_3 impacts.

- NO_x – 3,000 tpy (90 m source), Klickitat 8-hour O_3 impact = 7.954 ppb
  - Project NO_x emissions = 2,134.7 tpy
  - Estimated O_3 impact due to Project = (2,134.7 /3000) * 7.954 ppb = 5.660 ppb
- VOC - 500 tpy (90 m source), Klickitat 8-hour O_3 impact = 0.031 ppb

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- Project VOC emissions = 59.06 tpy
- Estimated O_3 impact due to Project = (59.06 /500) * 0.031 ppb = 0.004 ppb

Total 8-hour O3 impact = 5.660 + 0.004 = 5.664 ppb

4.4 Project Impacts Compared to the SILs

The Project sources that emit criteria pollutants were modeled with AERMOD. The primary $PM_{2.5}$ predicted impacts (modeled) were summed with the secondary $PM_{2.5}$ concentration to result in a total $PM_{2.5}$ concentration prior to comparison with the SILs and/or NAAQS. The maximum annual NO_2 concentration was predicted at a receptor approximately 8.8 km to the north-northeast of Unit #2 (514216, 5186128) in an area of 600-meter spacing within the receptor grid. A higher-resolution receptor grid extending between the adjacent 600-meter receptors with 50-meter spacing was used to ensure the maximum predicted concentration was captured. All other pollutant/averaging periods maxima were predicted within dense receptor spacing (50-meter or less). The maximum results of the modeling for criteria pollutants are summarized in Table 4-1. Maximum predicted impacts are less than the corresponding SILs for CO, PM_{10}, and SO_2. Compliance with the NAAQS is demonstrated for pollutants with predicted insignificant impacts (i.e., less than SILs), and therefore, no additional modeling demonstration for these pollutants/averaging periods is necessary. As shown in Table 4-1, NAAQS modeling is necessary for 1-hour and annual NO_2, 24-hour and annual $PM_{2.5}$ for NAAQS compliance. In addition, the secondary O_3 concentration is above the 8-hour O_3 SIL of 1 ppb and requires a comparison with the NAAQS.

Table 4-1. SILs Analysis Results

Pollutant	Averaging Period	Rank for SIL Assessment	Project Impact Concentration (µg/m³)	SIL (µg/m³)
NO_2[a]	1-hour	H1H[b] (5-year average)	**98.49**[c]	7.5
	Annual	H1H	**1.14**[c]	1
CO	1-hour	H1H	296.54	2,000
	8-hour	H1H	147.34	500
PM_{10}	24-hour	H1H	2.71	5
$PM_{2.5}$[d]	24-hour	H1H (5-year average)	**1.86 c**	1.2
	Annual	H1H (5-year average)	**0.26 c**	0.13
SO_2	1-hour	H1H	0.92	7.8
	Annual	H1H	0.01	1
O_3	8-hour	MERPs Tier 1	**5.66 ppb c**	1 ppb

[a] NO_2 concentrations based on the ARM2 method for NOx to NO2 conversion.
[b] Highest first-high concentration
[c] Bold font indicates concentration is above the respective SIL.
[d] $PM_{2.5}$ is the sum of primary (modeled) and secondary (calculated) $PM_{2.5}$ concentrations.

4.5 NAAQS Analysis

As noted above, model results indicate that a NAAQS assessment was necessary for 1-hour and annual NO_2, and 24-hour and annual $PM_{2.5}$. The refined receptor grid described in Section 4.4 was used for the annual NO_2 NAAQS assessment. Compliance with the NAAQS is based on the sum of modeled impacts attributable to the Project, modeled impacts from other nearby background sources, and

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representative ambient background concentrations (as described in Section 3.8). For this analysis, the ambient background concentrations are inclusive of the emissions from constantly emitting surrounding sources and monitored concentrations. Therefore, these ambient background concentrations can be summed to the modeled Project design value concentrations to represent a cumulative impact. The summary of the design value concentrations for comparison with the NAAQS are presented in Table 4-2. All pollutants demonstrate compliance with their respective NAAQS. The locations of the maximum predicted Project impacts for each modeled pollutant and averaging period listed in Table 4-2 are shown in contour plots provided in Appendix B.

Table 4-2. NAAQS Analysis Results

Pollutant	Averaging Period	Rank for NAAQS Assessment	Project Contribution (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	Percent of NAAQS
NO_2[a]	1-hour	H8H[b] (5-year average)	66.10	51.89	117. 98	188	63%
	Annual	H1H[c] (over 5 years)	1.14	11.66	12.80	100	13%
$PM_{2.5}$[d]	24-hour	H8H (5-year average)	1.04	17.80	18.97	35	54%
	Annual	H1H (5-year average)	0.26	6.00	6.26	9	70%
O_3	8-hour	H4H[e]	11.12[f]	106.01	117.13	137	85%

[a] NO_2 concentrations based on the ARM2 method for NO_x to NO_2 conversion.
[b] Highest eight-high (98th percentile) of 1-hour daily maximum concentrations averaged over 5 years.
[c] Highest first-high annual concentration over the 5 years modeled.
[d] $PM_{2.5}$ is the sum of primary (modeled) and secondary (calculated) $PM_{2.5}$ concentrations.
[e] Annual fourth-highest daily maximum 8-hour concentration averaged over 3 years.
[f] Secondary formation of ozone due to Project emissions calculated using the MERPs methodology guidance.

4.6 Toxic Air Pollutant Modeling Results

Consistent with the first-tier review specified in both the current and 1998 versions of WAC 173-460-080, the TAPs associated with the development of the Project and described in Section 2.4.4, Tables 2-6 and 2-8, were evaluated with AERMOD modeling. As described in Section 3.11, the modeling was first conducted based on a unit emission rate in a conservative unit analysis. Individual TAP modeling was conducted if the unit analysis showed noncompliance with the ASIL for any specific TAP, so as not to overestimate the TAP cumulative impacts. It should be noted that the refined receptor grid for annual impacts was incorporated into the toxics modeling and that impacts from the highest scenario for Unit #2 (i.e., 190 MW) were included in the TAP analysis results.

Table 4-3 shows the modeling results for the eighteen TAPs modeled for the current rule compared to the current ASILs. All TAPs demonstrate compliance with their respective ASILs. Individual TAP modeling was conducted for one TAP, Chromium VI. Chromium VI was the TAP closest to their ASIL at 79%. The next TAP closest to their ASIL is Silica, at 23% of its ASIL. Additionally, Silica's impact is expected to be lower than is shown in Table 4-3 because results are based on the unit analysis, which sums the maximum predicted impacts from each source although the impacts may not align in time and space.

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Table 4-3 TAPs Analysis Results

Chemical	CAS Number	Avg. Period[a]	ASIL (µg/m³)	Total Project Offsite Impacts (µg/m³)	% ASIL	Meets ASIL?
3-Methylcholanthrene	56-49-5	year	9.6E-05	4.7E-08	0%	Yes
7,12-Dimethylbenz(a)anthracene	57-97-6	year	8.5E-06	4.2E-07	5%	Yes
Benzene	71-43-2	year	1.3E-01	5.5E-05	0%	Yes
Dichlorobenzene	106-46-7	year	9.1E-02	3.1E-05	0%	Yes
Formaldehyde	50-00-0	year	1.7E-01	2.0E-03	1%	Yes
n-Hexane	110-54-3	24-hr	7.0E+02	1.5E+00	0%	Yes
Naphthalene	91-20-3	year	2.9E-02	1.6E-05	0%	Yes
Arsenic	7440-38-2	year	3.0E-04	5.2E-06	2%	Yes
Beryllium	7440-41-7	year	4.2E-04	3.1E-07	0%	Yes
Cadmium	7440-43-9	year	2.4E-04	2.9E-05	12%	Yes
Chromium VI[b]	18540-29-9	year	4.0E-06	3.2E-06	79%	Yes
Cobalt	7440-48-4	24-hr	1.0E-01	6.9E-05	0%	Yes
Lead	7439-92-1	year	8.3E-02	1.3E-05	0%	Yes
Manganese	7439-96-5	24-hr	3.0E-01	3.1E-04	0%	Yes
Mercury	7439-97-6	24-hr	3.0E-02	2.1E-04	1%	Yes
Nickel	7440-02-0	year	3.8E-03	5.5E-05	1%	Yes
Vanadium	7440-62-2	24-hr	1.0E-01	1.9E-03	2%	Yes
Silica	7631-86-9	24-hr	3.0E+00	6.8E-01	23%	Yes

[a] PTE of each listed TAP was scaled to the required averaging period specified in WAC 173-460-150.
[b] Chromium VI was modeled individually with its specific pollutant emission rates by source to evaluate the total maximum cumulative predicted impact.

Table 4-4 shows the modeling results for the ten TAPs modeled for the 1998 rule compared to the 1998 ASILs. All TAPs demonstrate compliance with their respective ASILs. Chromium VI was the TAP closest to their ASIL at 8%. Note that all impacts shown in Table 4-4 are conservative because results are based on the unit analysis, which sums the maximum predicted impacts from each source although the impacts may not align in time and space.

Table 4-4 1998 TAPs Analysis Results

Chemical	CAS Number	Avg. Period[a]	ASIL (µg/m³)	Total Project Offsite Impacts (µg/m³)	% ASIL	Meets ASIL?
Benzene	71-43-2	year	1.2E-01	5.5E-05	0%	Yes
Formaldehyde	50-00-0	year	7.7E-02	2.0E-03	3%	Yes
n-Hexane	110-54-3	24-hr	2.0E+02	1.5E+00	1%	Yes
Arsenic	7440-38-2	year	2.3E-04	5.2E-06	2%	Yes
Beryllium	7440-41-7	year	4.2E-04	3.1E-07	0%	Yes
Cadmium	7440-43-9	year	5.6E-04	2.9E-05	5%	Yes
Chromium VI	18540-29-9	year	8.3E-05	6.6E-06	8%	Yes
Nickel	7440-02-0	year	2.1E-03	5.5E-05	3%	Yes
Vanadium	7440-62-2	24-hr	1.7E-01	1.9E-03	1%	Yes
PAH as benzo(a)pyrene	50-32-8	year	4.8E-04	3.1E-08	0%	Yes

[a] PTE of each listed TAP was scaled to the required averaging period specified in WAC 173-460-150.

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APPENDIX A: UNIT #2 LOAD ANALYSIS

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Unit #2 Load Analysis		100%	190 MW
Stack Temperature	°F	335.0	240.0
Stack Mass Flow	acfm	2,651,430	850,074
Stack Diameter	ft	24	24
Stack Velocity	ft/s	97.7	31.3
Stack Temperature	K	441.5	388.7
Stack Diameter	m	7.32	7.32
Exhaust Velocity	m/s	29.77	9.55
Emissions, Annual			
NOx Emissions	tpy	2131.97	1218.47
CO Emissions	tpy	2907.23	1661.55
PM10 Emissions	tpy	133.06	76.05
PM2.5 Emissions	tpy	133.06	76.05
Sulfur Dioxide	tpy	13.92	7.96
Emissions, Short-term (g/s)			
NO_x	g/s	103.95	35.05
CO	g/s	141.75	47.80
PM_{10}	g/s	6.49	2.19
$PM_{2.5}$	g/s	6.49	2.19
SO_2	g/s	0.68	0.23
Emissions, Annual (g/s)			
NO_x	g/s	61.33	35.05
SO_x	g/s	0.40	0.23
PM_{10}	g/s	3.83	2.19
$PM_{2.5}$	g/s	3.83	2.19

UNIT IMPACT, chi/Q (ug/m^3 per g/s)		100%	190 MW
1-HR	1ST	0.63126	6.20683
8-HR	1ST	0.17836	3.08345
24-HR	1ST	0.07753	1.19912
1-HR	2ND	0.46679	6.20254
8-HR	2ND	0.15141	1.65954
24-HR	2ND	0.07569	0.73757
24-HR	6TH	0.06817	0.49674
ANNUAL	5-yr avg	0.01594	0.02831
ANNUAL Y1		0.01731	0.03220
ANNUAL Y2		0.01597	0.02836
ANNUAL Y3		0.01508	0.02637
ANNUAL Y4		0.01528	0.02624
ANNUAL Y5		0.01605	0.02862
Max. Indiv. Yr. Ann.		**0.01731**	**0.03220**

Worst Case Load Analysis - Unit 2 only (		100%	190 MW
1-hr NO_2 (full conversion)	H1H (5YA)	47.42412	135.7798
1-hr NO_2 (full conversion)	H8H (5YA)	40.84117	72.9494
Annual NO_2 (full conversion)	H1H	1.06	1.13
1-hr CO	H1H	89	297
1-hr CO	H2H	66	296
8-hr CO	H1H	25	147
8-hr CO	H2H	21	79
24-hr PM_{10}	H1H	0.50	2.62
24-hr PM_{10}	H6H	0.442	1.087
24-hr $PM_{2.5}$	H1H	0.45396	1.28112
24-hr $PM_{2.5}$	H8H	0.31579	0.45843
Annual $PM_{2.5}$	H1H (5YA)	0.06	0.06
1-hr SO_2	H1H (5YA)	0.30978	0.89097
1-hr SO_2	H4H (5YA)	0.28518	0.50281
24-hr SO2	H1H	0.05	0.27
24-hr SO2	H2H	0.05	0.17
Annual SO_2	H1H	0.007	0.007
Annual SO_2	H1H (5YA)	0.006	0.006

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APPENDIX B: PROJECT PREDICTED CONCENTRATION CONTOURS FOR NAAQS ANALYSES

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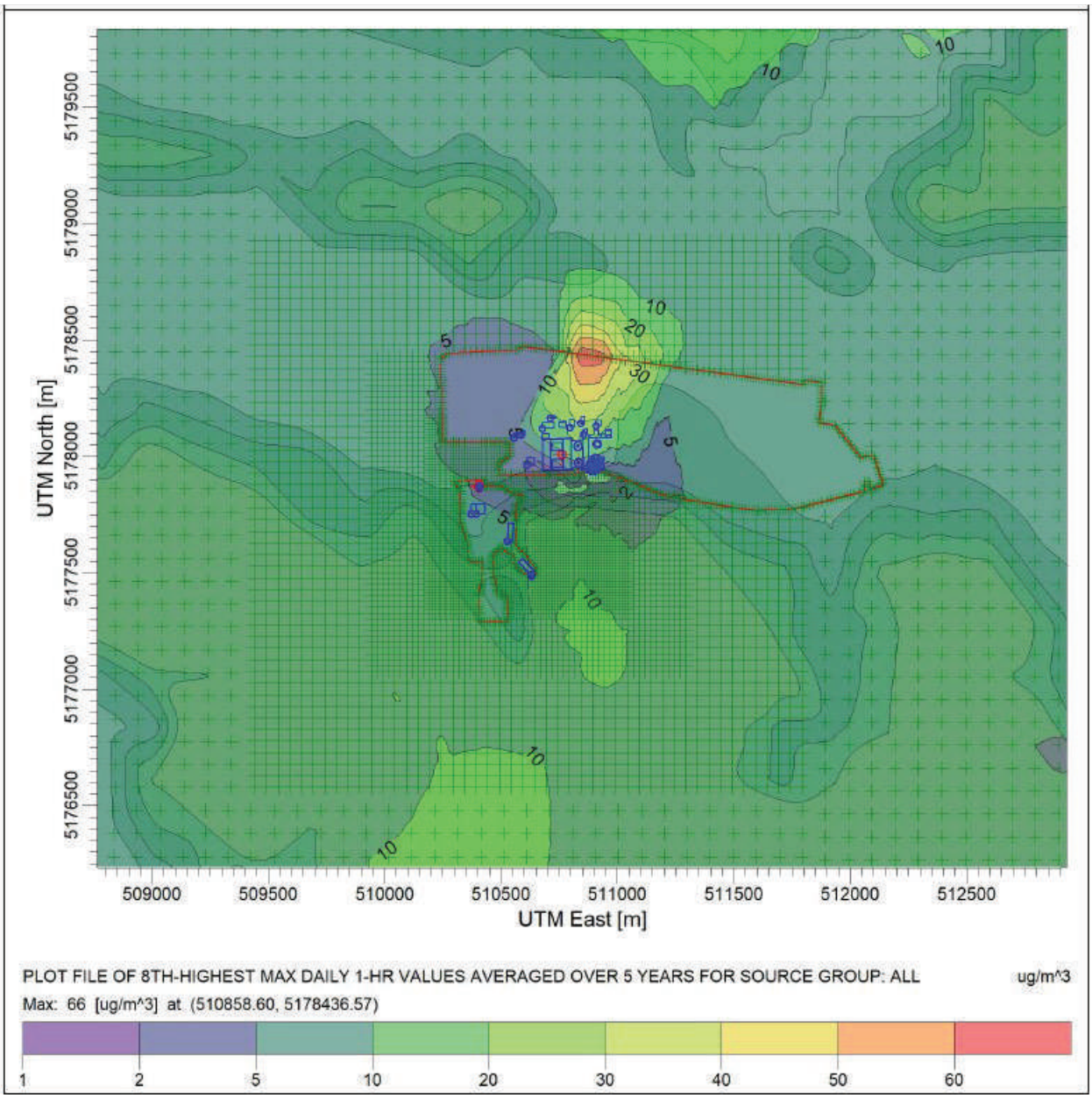


Figure B-1. AERMOD Predicted 1-hour NO_2 Concentration Contours

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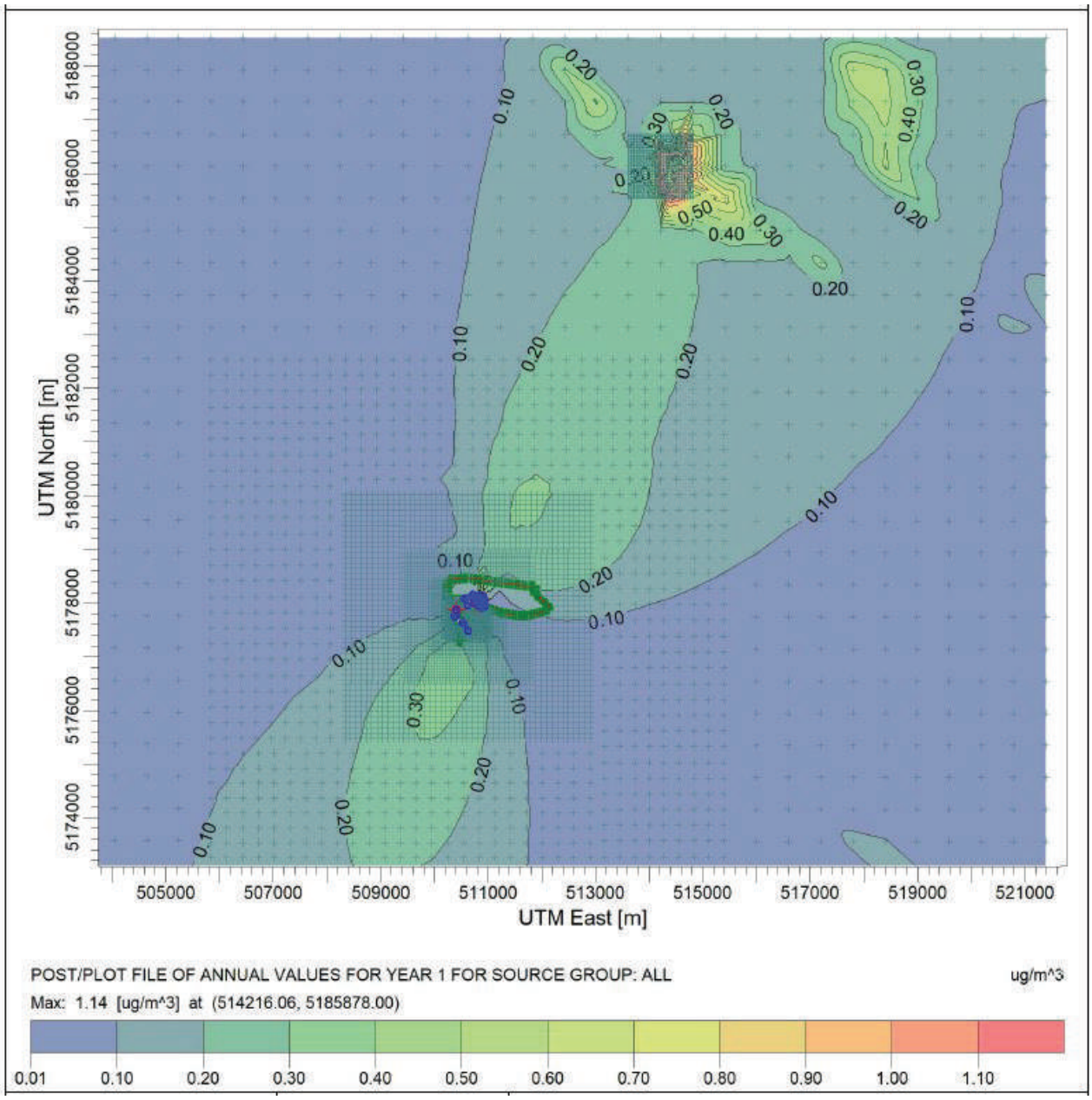


Figure B-2. AERMOD Predicted Annual (2020) NO_2 Concentration Contours

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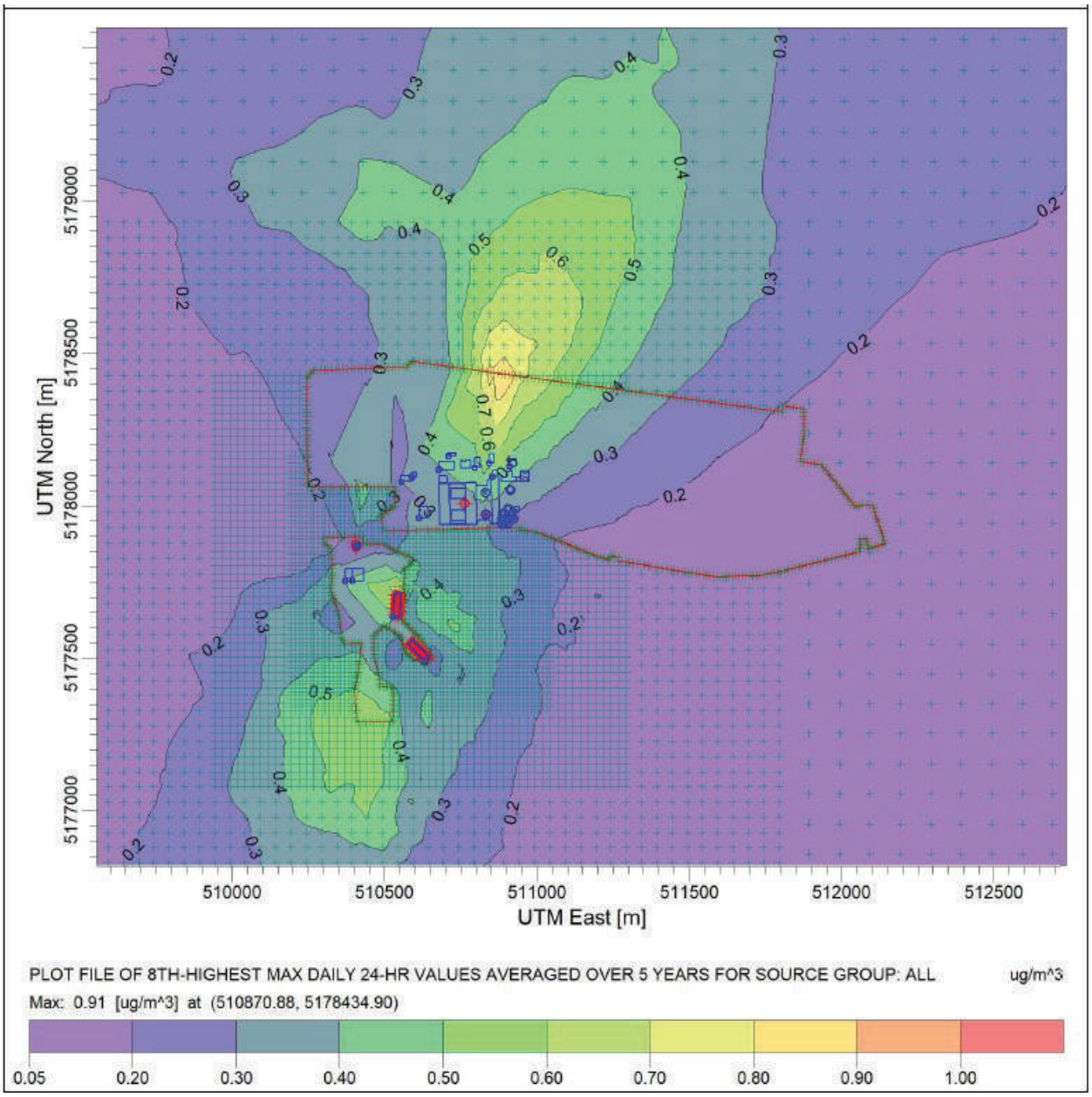


Figure B-3. AERMOD Predicted 24-Hour $PM_{2.5}$ Concentration Contours

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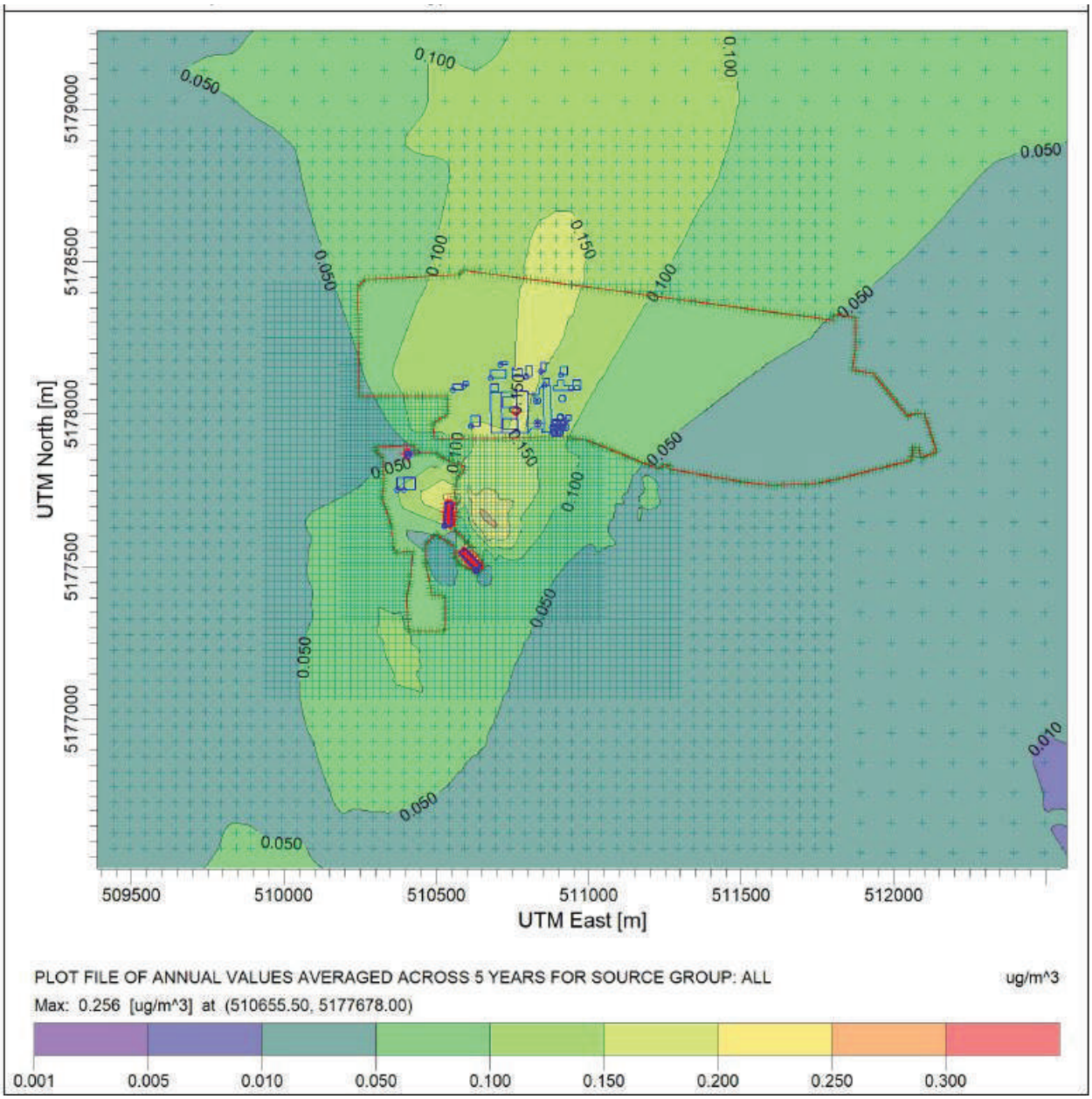


Figure B-4. AERMOD Predicted Annual $PM_{2.5}$ Concentration Contours

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APPENDIX F: VISIBILITY MODELING ANALYSIS

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CALPUFF Class I Visibility Modeling Report

Unit #2 Conversion from Coal to Natural Gas Combustion

TransAlta Centralia Generation Station

Centralia, Washington

December 2025

Prepared for

TransAlta
913 Big Hanaford Road
Centralia, Washington 98531

For Submittal to

Southwest Clean Air Agency
5101 NE 82nd Ave.
Vancouver, Washington 98662
and
Washington Dept. of Ecology
300 Desmond Drive SE
Lacey, Washington 98503

Prepared by



10 Post Office Square, 11th Floor
Boston, MA 02109

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

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Acronyms/Abbreviations

AMoN	Ammonia Monitoring Network
AQRV	Air Quality Related Value
BACT	Best Available Control Technology
BART	Clean Air Act Best Available Retrofit Technology
CALMET	The Meteorological Processing Model of the CALPUFF Modeling System
CALPOST	The Postprocessing Program of the CALPUFF Modeling System
CALPUFF	The CALPUFF Dispersion and Deposition Model
CTG	USGS composite theme grid land use files
dv	deciview
ddv	Delta-deciview
Ecology	Washington State Department of Ecology
FLAG	Federal Land Manager's Air Quality Related Values Work Group
FLM	Federal Land Manager
GHGs	greenhouse gases
HNO_3	nitric acid
H_2SO_4	sulfuric acid
IMPROVE	Interagency Monitoring of Protected Visual Environments
IWAQM	Interagency Workgroup on Air Quality Modeling
km	kilometer
LCC	Lambert Conformal Conic projection
m	meters
MMIF	EPA Mesoscale Model Interface Program
MW	megawatts
NAAQS	National Ambient Air Quality Standards
NH_3	ammonia
NO_3^-	nitrates
NO_X	nitrogen oxides
NPS	National Park Service
O_3	ozone
PMC	coarse particulate matter with a diameter greater than 2.5 microns

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$PM_{2.5}$	particulate matter with a diameter equal to or less than 2.5 microns
The Project	Conversion of coal to natural gas firing in Unit 2 project
PSD	Prevention of Significant Deterioration
QA/QC	quality assurance/quality control
SO_2	sulfur dioxide
SO_4^{2-}	sulfate
tpy	tons per year
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
VOC	volatile organic compounds
WAC	Washington Administrative Code
WRF	Weather Research Forecast Model

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1.0 INTRODUCTION

TransAlta Centralia Generation, LLC (Applicant) proposes to modify their existing Centralia Unit #2 coal-fired electrical generation facility (Facility), which will cease using coal as a fuel source in December 2025. The modified facility will instead generate electricity from natural gas (Project). The Project is proposed within an approximately 9.6-acre Project Area on private land owned by the Applicant located in unincorporated Lewis County, Washington (Figure 1-1). Once converted, Unit #2 will burn natural gas to generate steam and convert that steam to electrical energy.

Coal firing equipment will be decommissioned in place, unless the conversion requires its removal to allow new equipment to be installed. The existing precipitators and flue gas desulphurization equipment will no longer be effective or required and will be bypassed.

The Unit will operate at a maximum of 723 net megawatts (MW) and will convert from diesel-fired starting systems to full natural gas starting capabilities. The current minimum stable generation level of 300 net MW is expected to be reduced to 190 net MW as determined by the Applicant. The Unit would operate at a maximum 59% capacity factor, which is the basis for the emissions calculations.

The project also includes extending the life of the Unit to the end of 2044 by making a substantial investment into the existing infrastructure to ensure it can continue to operate to the end of the contract.

TransAlta is submitting a new air permit application that requires an ambient air quality impact analysis compliance demonstration based on dispersion modeling. This facility is a recognized regional haze source and has Clean Air Act Best Available Retrofit Technology (BART) requirements in place. The BART program was instituted by Congress to reduce regional haze and restore visibility in national parks and wilderness areas (mandatory federal Class I areas). A CALPUFF visibility analysis was required for this Project because “any request to repower one or both units at the Centralia plant would require that the impact of repowering on visibility be modeled” (as described in the Technical Support Document for Second BART Order Revision – TransAlta Centralia Generation Plant, (Ecology, July 2020)). Detailed visibility modeling procedures were presented in the *CALPUFF Class I Visibility Modeling Protocol* submitted to the Southwest Clean Air Agency (SWCAA), Washington Department of Ecology (Ecology), and the Federal Land Managers (FLM) at the National Park Service (NPS), National Forest Service (NFS) and United States Fish and Wildlife Service (USFWS) on October 22, 2025. This document is the Class I visibility modeling report (Report).

This Report consists of five sections including this introduction. Section 2 contains a Project description, including information regarding the Project’s location and expected emissions. Section 3 presents a detailed description of the modeling approach proposed for evaluating visibility impacts of the proposed Project including: source data, model selection, modeling domain, meteorological data, Class I Area receptors, CALPUFF model options, monthly ambient monitored ozone and ammonia background concentrations, as well as postprocessing for visibility impacts. Section 4 presents the visibility results at all Class I areas within 300 km of the Project. References cited in the document are presented in Section 5. To facilitate the review of this Report, the individual familiar with the CALPUFF

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modeling for the Project is identified below. Please contact this individual if additional information or clarification is required during the review process.

Modeling Consultant: Liz Hendrick, CCM
Tetra Tech, Inc.
10 Post Office Square, 11th Floor
Boston, MA 02109
Telephone: (978) 303-8524
Email: Liz.Hendrick@tetratech.com

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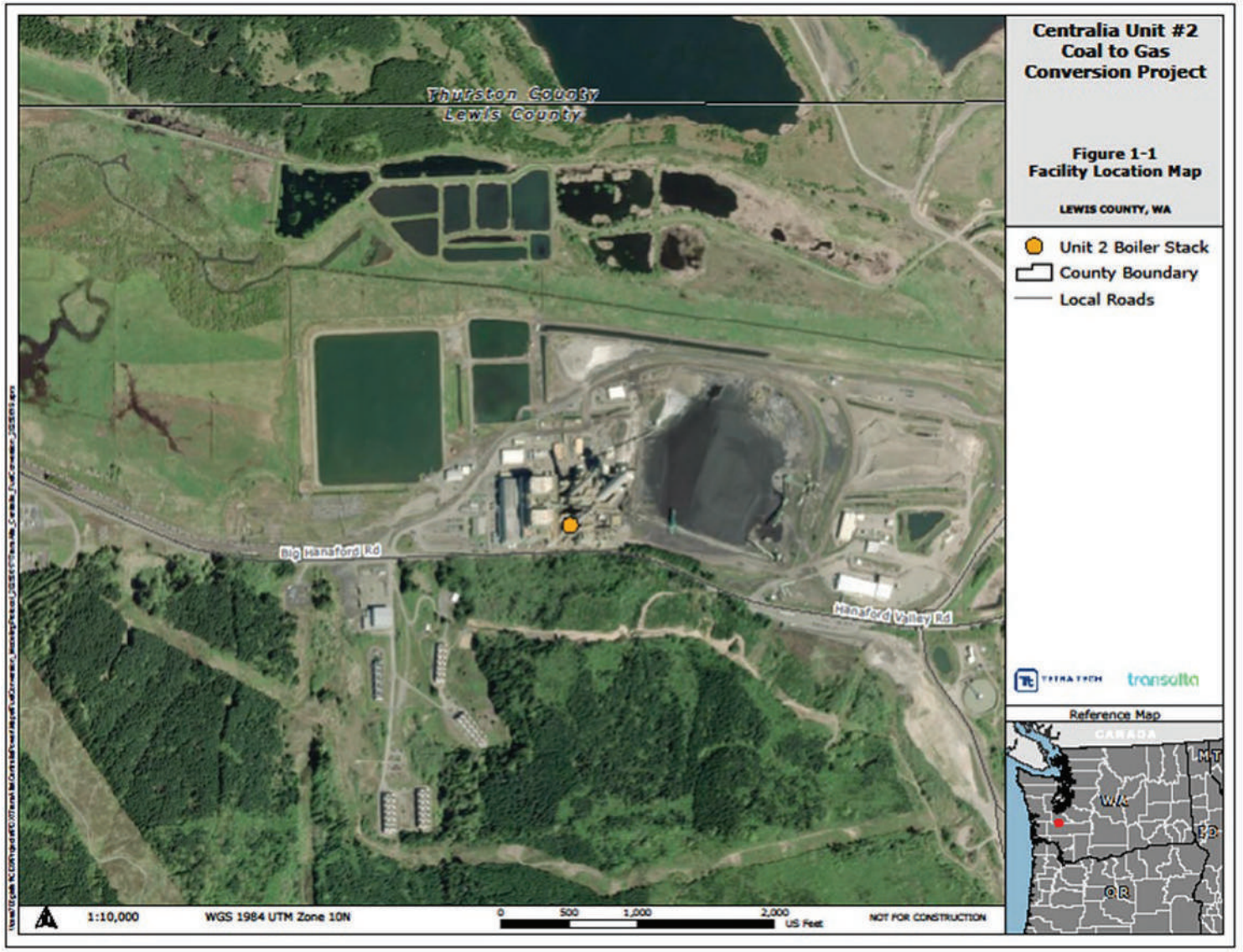


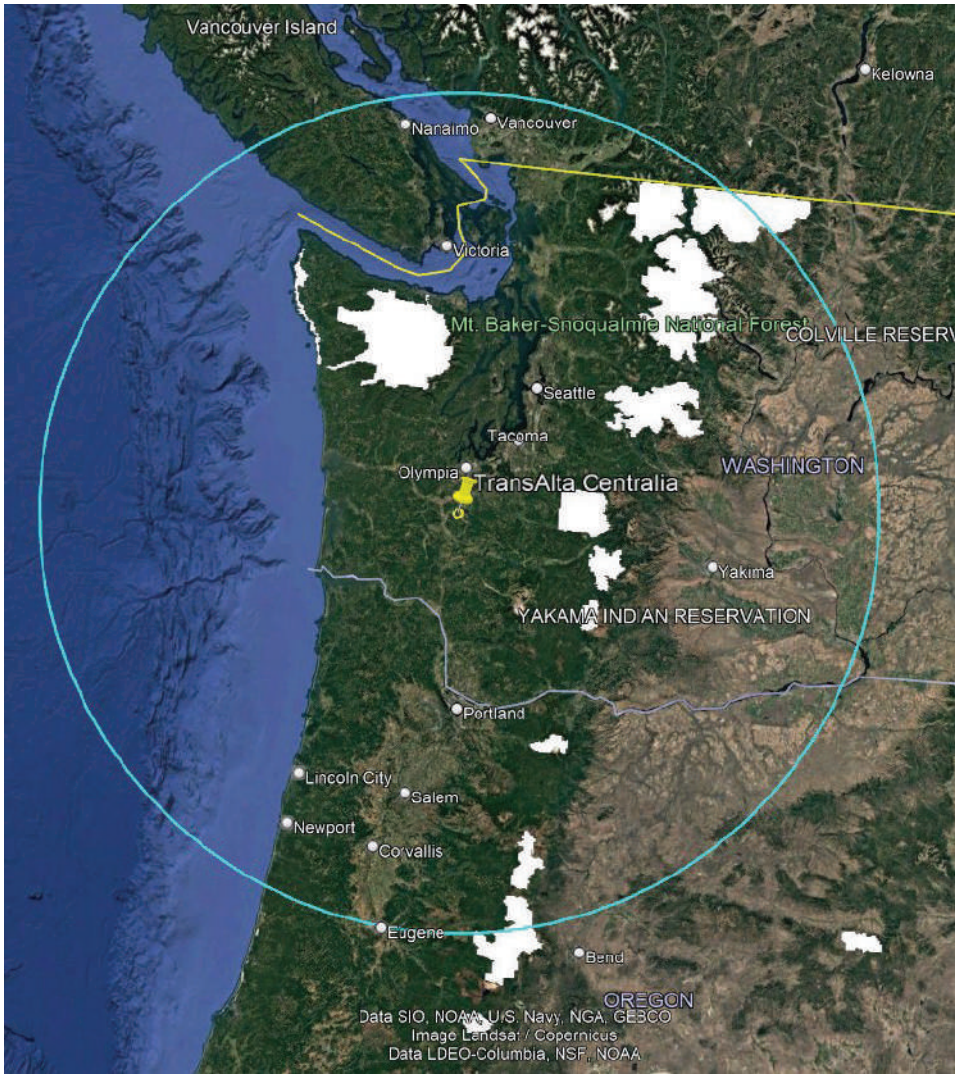
Figure 1-1. Facility Location Map

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2.0 FACILITY DESCRIPTION

2.1 Site Location

The Project will be constructed at the existing Centralia Generating Station in Centralia, Washington. The Project is proposed within an approximately 9.6-acre Project Area on private land owned by TransAlta. The Project site is located adjacent to the TransAlta Centralia Mining LLC coal mine. The generation area is north of Big Hanaford Road, and the cooling tower area is south of Big Hanaford Road. The Generating Station is generally surrounded by undeveloped land. Figure 2-1 presents an aerial graphic showing the TransAlta Plant location with a 300-kilometer (km) radius circle. The Class I areas are shown in white. There are 12 Class I areas within 300 km of the Project. Table 2-1 lists the Class I areas and closest distance from the Project Unit #2 stack to the nearest edge of the Class I area. A visibility analysis has been conducted for each Class I area.



Source: Google Earth

Figure 2-1. Project location with Class I Areas (white) within 300-km radius (circle)

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Table 2-1. Class I Areas within 300 km of the TransAlta Centralia Generation Station

Class I Area	Distance (km)
Mount Rainier National Park	71.7
Olympic National Park	90.3
Goat Rocks Wilderness Area	97.2
Mount Adams Wilderness Area	110.5
Alpine Lakes Wilderness Area	122.8
Mount Hood Wilderness Area	170.1
Glacier Peak Wilderness Area	185.0
Mount Jefferson Wilderness Area	230.2
North Cascades National Park	231.2
Pasayten Wilderness Area	260.9
Mount Washington Wilderness Area	273.7
Three Sisters Wilderness Area	286.5

2.2 Project Description

The Applicant's Centralia Power Plant is a unique facility capable of providing generating capacity to support the Washington grid; particularly when there is need or market signal for firm power that could be driven by intermittent renewables, system conditions, environmental factors or demand. The project is not designed nor intended to operate continuously or at a high capacity or baseload factor. While additional modeling is needed, current expectations are that the facility will operate for less than 40% of hours on an annual basis over the life of the project; at a capacity factor of approximately 20% as the majority of operating hours are expected to be at either half load (~350 MW) or the minimal stable generation (~190 MW).

The Project includes modification of the existing Unit #2 coal-fired boiler to fire natural gas to generate steam. The boiler makes steam independent of what fuel is used to generate that steam. As a result, the steam turbines and electrical generation components in the facility will not require any modifications for the facility to operate on natural gas. The Project includes the replacement of the existing diesel-fired auxiliary boiler with a new natural gas-fired auxiliary boiler, two (2) water bath heaters, and two (2) cooling towers that will be installed in the exact footprint of the existing cooling towers. The facility's primary fuel will be natural gas, which will be delivered to a metering station at the existing Big Hanaford site and then delivered to the Unit and auxiliary boiler via a short 1300-foot lateral pipeline. A fuel gas system will be provided on site to supply natural gas at suitable pressure and temperature.

2.3 Summary of Annual Potential Emissions

The proposed potential annual emissions from the Facility are summarized in Table 2-2. Potential emissions of regulated air pollutants from these sources have been largely based upon applicable regulatory limits, equipment vendor emissions data, United States Environmental Protection Agency (USEPA) emission factors, and mass balance calculations; engineering estimates have been applied, as necessary. Potential emission rates for Unit #2 are based upon natural gas combustion at full load

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operation for 5,168 hours per year (i.e., 59% capacity factor). Potential emission rates of the auxiliary boiler are based upon full load operation for 1,300 hours per year. Potential emission rates for the water bath heaters and cooling towers are based upon full load operation for 8,760 hours per year. Note: the pollutants in Table 2-2 are listed for completeness; not all are visibility-impacting pollutants.

Table 2-2. Project Annual Potential Emissions (tons per year, tpy)

Pollutant	Unit #2[a, b]	Auxiliary Boiler[b,c]	Water Bath Heaters (2) [b,d]	Cooling Towers (2)	Project Wide Totals
	tpy	tpy	tpy	tpy	tpy
NO_X	2,132.0	1.5	1.3	-	2,134.7
CO	2,907.2	3.6	3.2	-	2,914.1
VOC	58.14	0.5	0.4	-	59.1
PM_{10}	133.1	0.7	0.6	3.0	137.4
$PM_{2.5}$	133.1	0.7	0.6	1.8	136.1
SO_2	13.9	0.1	0.1	-	14.1
Pb	0.01	4.4E-05	4.0E-05	-	0.01

[a] Based on Unit #2 operation at full load (100%, 723 MW) combusting natural gas. These emissions do not include the Unit #2 reductions from baseline.
[b] Emissions may decrease following the vendor selection process, these are worst-case emissions.
[c] Based on 1,300 hours per year of operation for the Auxiliary Boiler.
[d] Based on 8,760 hours of operation for two Water Bath Heaters.

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3.0 CLASS I VISIBILITY IMPACT ASSESSMENT METHODOLOGY

3.1 Model Selection

CALPUFF is a Lagrangian modeling system recommended for Class I area air quality impact assessments by the Federal Land Managers (FLM) Workgroup. From April 2003 until January 2017, CALPUFF was the USEPA's preferred model for assessing National Ambient Air Quality Standards (NAAQS) and/or Prevention of Significant Deterioration (PSD) increments in situations of long-range transport (at distances greater than 50 km [31 mi]) of emission sources. With the 2017 revisions to the Guideline on Air Quality Models (Appendix W to 40 CFR Part 51) (USEPA 2017), CALPUFF was delisted as a USEPA-preferred model, yet retained as a screening technique for long-range transport assessments for NAAQS and PSD increments. Nevertheless, the CALPUFF modeling system has remained the FLM's preferred model for assessing Air Quality Related Values (AQRV) at Class I areas and is used in this visibility assessment. AERMOD, a steady-state Gaussian model, is the USEPA's preferred model for regulatory applications within 50 km of a source and was used for this Project's NAAQS and toxics assessments. However, because the Class I areas are over 50 km away (Table 2-1) and AERMOD does not account for chemical transformations during long-range transport, it is unsuitable for the Class I visibility analysis. Therefore, CALPUFF is recommended for long-range visibility modeling. The current USEPA-approved version of CALPUFF, version 5.8.5, was used in this modeling analysis.

CALPUFF is a multi-layer, multi-species, non-steady-state puff dispersion model that simulates the effects of time- and space-varying meteorological conditions on the transport, transformation, dispersion, and removal of air pollutants. It treats emissions as a series of discrete puffs, each tracked individually until it exits the modeling domain. The model calculates each puff's contribution to receptor concentrations or deposition fluxes separately, allowing users to analyze individual source impacts or aggregate impacts over source groups.

CALPUFF utilizes three-dimensional meteorological fields generated by the CALMET model, which can be based on prognostic meteorological model outputs (e.g., the Weather Research and Forecasting model, WRF), station data (surface observations and upper air soundings), or a hybrid combination of both. CALPUFF can also accept prognostic meteorological data that is processed through the USEPA Mesoscale Model Interface Program (MMIF).

Designed for application over spatial scales ranging from tens to hundreds of kilometers, CALPUFF incorporates algorithms to address sub-grid scale effects such as terrain impingement, as well as longer-range processes including pollutant removal by wet scavenging and dry deposition, chemical transformations, and visibility impacts from particulate matter.

The model is especially well suited for complex flow situations involving spatially variable meteorological conditions influenced by factors like complex terrain or nearby water bodies. CALPUFF can simulate plume fumigation events (e.g., coastal fumigation or inversion breakup), low wind speed or calm conditions, and other scenarios where steady-state, straight-line models are inadequate. Additionally, it can assess the cumulative impact of multiple, spatially distributed sources with temporally varying emissions over large regions.

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CALPOST, the CALPUFF modeling system postprocessor, will be used to generate the visibility impacts from the CALPUFF runs of concentrations. The current USEPA-approved version is CALPOST version 6.221. CALPOST performs the extinction coefficient calculations using the IMPROVE equation in accordance with the latest USEPA/FLM recommendations.

CALPUFF View

CALPUFF View is a CALPUFF model graphical user interface (GUI) developed and maintained by Lakes Environmental (Ontario, Canada). The software amalgamates the various CALPUFF pre- and post-processing programs, providing a user-friendly model setup wizard interface and other tools to create a graphical display of the various model inputs and outputs for visualization and quality assurance/quality control (QA/QC). CALPUFF View has been specifically developed to facilitate long-range visibility and deposition assessments for Class I areas as described in the Federal Land Manager's Air Quality Related Values Work Group (FLAG) 2010, containing a database of the various parameters for each specific Class I area as defined in Tables 5 through 10 of FLAG 2010. The CALPUFF View software was used to facilitate the visibility modeling assessment.

3.2 Meteorological Data for CALPUFF

The USFWS provided three-dimensional gridded meteorological files for the 3-year period of 2018-2020 for use as input to CALPUFF. The USFWS prepared the files using the USEPA MMIF that converts prognostic meteorological model output fields to the parameters and formats required for direct input into CALPUFF. The CALPUFF meteorological grid has a 12 km horizontal resolution with ten vertical layers, defined as consistent with the default layers specified by USEPA/FLM guidance (cell face heights of 20, 40, 80, 160, 320, 640, 1200, 2000, 3000 and 4000 meters).

3.3 Model Domain

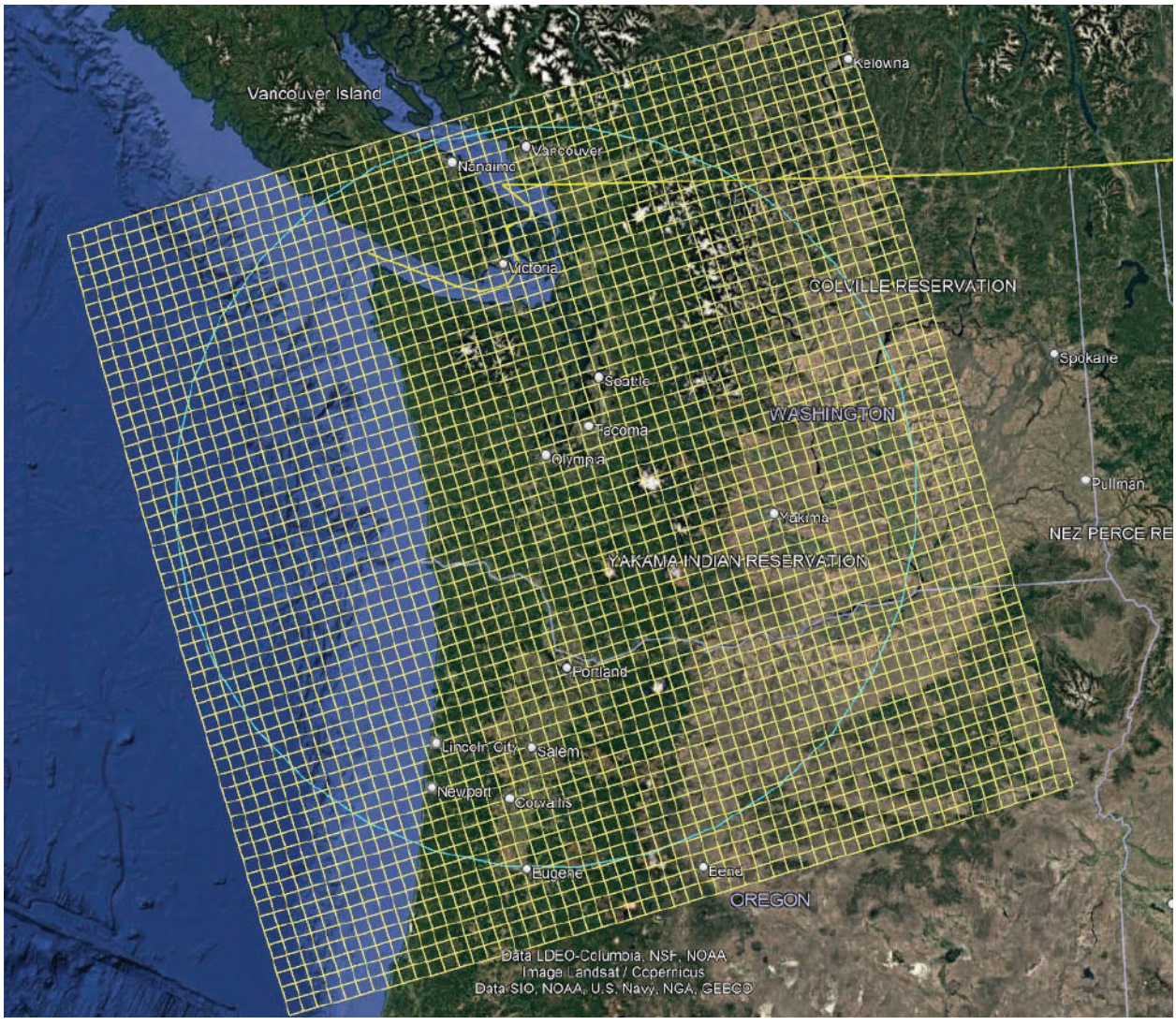
The modeling domain was defined by a 300 km radius with a buffer area beyond the radius (to allow for modeling of potential contaminant re-circulation), 660 km x 660 km, centered at Unit #2 at approximately 46.756°N, 122.858°W. The domain extends over the Pacific Ocean to the west, into Canada to the north and into Oregon to the south. Because the modeling domain covers such a large region, to account for the curvature of the earth, Lambert Conformal Conic (LCC) projection coordinates were used to define the meteorological grid points and source and receptor locations in CALPUFF. The parameterization of the CALPUFF domain is described in Table 3-1. The CALPUFF modeling domain is shown in Figure 3-1.

Table 3-1. CALPUFF Domain LCC Projection Parameterizations

CALPUFF Domain Parameter	Setting
XBTZ (Time Zone)	-8 (Pacific)
RLAT0 (degrees)	40.574°N
RLON0 (degrees)	97.000°W
XLAT (degrees)	33.000°N
XLAT2 (degrees)	45.000°N
NX	55
NY	55

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CALPUFF Domain Parameter	Setting
NZ	10
DGRIDKM (km)	12
ZFACE (m)	0., 20, 40, 80, 160, 320, 640, 1,200, 2,000, 3,000, 4,000
XORIGKM (km)	-2268.0
YORIGKM (km)	618.0



Basemap: Google Earth

Figure 3-1. CALPUFF Modeling Domain (LCC Projection)

3.4 Source Data and Operating Scenarios

The modeling analyses included the following emission sources:

- Unit #2 boiler combusting natural gas. Unit #2 will have an operational capacity factor of 59% (5,168 hours per year);

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- One (1) auxiliary boiler that will combust natural gas and be limited to no greater than 1,300 hours of operation per year;
- Two (2) dew point (water bath) heaters combusting natural gas, each with an exhaust stack; and
- Two (2) cooling towers with twelve (12) cells each.

As required by USEPA and Washington regulations, air permit applications for new major facilities must include a BACT review in accordance with 40 CFR 52.21(j) and WAC 173-400-830(1)(d) (for affected pollutants where the Project area is designated as an attainment area). Washington and Southwest Clean Air Agency (SWCAA) regulations also require a BACT review for minor new source review pollutants in accordance with WAC 173-400-030(13) and SWCAA 400-110. Table 3-2 lists the preliminarily proposed BACT control options for each source.

Table 3-2. Project BACT Summary

Source/Pollutant	Control Technology
Unit #2	
NO_X	**Low NOx burners, combustion optimization system, flue gas recirculation**
VOC	Good combustion practices
CO	Good combustion practices
$PM/PM_{10}/PM_{2.5}$	Good combustion practices, low ash and low sulfur fuel (pipeline quality natural gas)
SO_2	Good combustion practices, low sulfur fuel
Auxiliary Boiler	
NO_X	Low NOx burners
VOC	Good combustion practices
CO	Good combustion practices
$PM/PM_{10}/PM_{2.5}$	Good combustion practices, low ash and low sulfur fuel (pipeline quality natural gas)
SO_2	Good combustion practices, low sulfur fuel (pipeline quality natural gas)
Dew Point Heaters	
NO_X	Low NOx burners
VOC	Good combustion practices
CO	Good combustion practices
$PM/PM_{10}/PM_{2.5}$	Good combustion practices, low ash and low sulfur fuel (pipeline quality natural gas)
SO_2	Good combustion practices, low sulfur fuel (pipeline quality natural gas)

Table 3-3 summarizes the physical stack characteristics used in the modeling. Detailed emissions and source parameter data are provided in Table 3-4. The particulate matter is speciated into PMC (coarse particulate matter with a diameter greater than 2.5 microns) and $PM_{2.5}$ (particulate matter with a diameter equal to or less than 2.5 microns). For Class I visibility impairment modeling, the FLMs request that maximum 24-hour emission scenarios be evaluated. The Unit #2 boiler is modeled firing natural gas at full load (100%) assuming simultaneous operation of the auxiliary boiler, dew point heaters and cooling towers to determine total Project visibility impacts.

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Table 3-3. Physical Stack Characteristics

Source ID	Description	Stack Location [a]		Ground-Level Elevation (meters above mean sea level)	Stack Height (meters above the ground)	Stack Inner Diameter (meters)
		LLC E (m)	LLC N (m)			
U2_100	Unit 2 Boiler (100% load)	-1950623.51	965448.66	68.12	140.21	7.32
AUXBLR	Auxiliary Boiler	-1950677.81	965513.85	68.12	76.20	1.52
DPH_1	Dew Point Heater 1	-1951061.05	965475.59	71.37	7.62	0.61
DPH_2	Dew Point Heater 2	-1951062.93	965466.73	71.37	7.62	0.61
COOLT1_A	Cooling Tower 1 Cell A	-1951003.57	965214.12	93.89	19.91	7.62
COOLT1_B	Cooling Tower 1 Cell B	-1950999.04	965226.47	93.89	19.91	7.62
COOLT1_C	Cooling Tower 1 Cell C	-1950994.80	965239.08	93.89	19.91	7.62
COOLT1_D	Cooling Tower 1 Cell D	-1950990.63	965250.83	93.89	19.91	7.62
COOLT1_E	Cooling Tower 1 Cell E	-1950985.83	965264.70	93.89	19.91	7.62
COOLT1_F	Cooling Tower 1 Cell F	-1950981.26	965277.22	93.89	19.91	7.62
COOLT1_G	Cooling Tower 1 Cell G	-1950993.42	965209.71	93.89	19.91	7.62
COOLT1_H	Cooling Tower 1 Cell H	-1950989.38	965222.20	93.89	19.91	7.62
COOLT1_I	Cooling Tower 1 Cell I	-1950985.14	965234.82	93.89	19.91	7.62
COOLT1_J	Cooling Tower 1 Cell J	-1950980.97	965246.56	93.89	19.91	7.62
COOLT1_K	Cooling Tower 1 Cell K	-1950976.17	965260.44	93.89	19.91	7.62
COOLT1_L	Cooling Tower 1 Cell L	-1950971.60	965272.95	93.89	19.91	7.62
COOLT2_A	Cooling Tower 2 Cell A	-1950942.03	965051.80	93.89	19.91	7.62
COOLT2_B	Cooling Tower 2 Cell B	-1950948.28	965063.42	93.96	19.91	7.62
COOLT2_C	Cooling Tower 2 Cell C	-1950954.66	965075.60	93.96	19.91	7.62
COOLT2_D	Cooling Tower 2 Cell D	-1950960.64	965087.92	93.96	19.91	7.62
COOLT2_E	Cooling Tower 2 Cell E	-1950967.14	965100.10	93.96	19.91	7.62
COOLT2_F	Cooling Tower 2 Cell F	-1950973.39	965111.69	93.96	19.91	7.62
COOLT2_G	Cooling Tower 2 Cell G	-1950951.58	965046.56	93.96	19.91	7.62
COOLT2_H	Cooling Tower 2 Cell H	-1950957.45	965058.54	93.96	19.91	7.62
COOLT2_I	Cooling Tower 2 Cell I	-1950963.72	965070.32	93.96	19.91	7.62
COOLT2_J	Cooling Tower 2 Cell J	-1950969.89	965082.56	93.96	19.91	7.62
COOLT2_K	Cooling Tower 2 Cell K	-1950976.30	965094.63	93.96	19.91	7.62
COOLT2_L	Cooling Tower 2 Cell L	-1950982.53	965106.41	93.96	19.91	7.62

[a] Converted from UTM Zone 10, WGS-84 datum to Lambert Conformal Conic NWS-84 using the Lakes Environmental Coordinate Converter. Projection origin (Lat, Lon) = 40.574 deg N, 97.0 deg W with standard parallels of 33 deg N and 45 deg N.

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Table 3-4. Stack Exhaust Parameters and Maximum Emission Rates used in the CALPUFF Modeling

Source ID	Stack Exit Temperature (K)	Stack Exit Velocity (m/s)	Emission Rates (g/s)				
			NO_x	PMC	$PM_{2.5}$	SO_2	SO_4
U2_100	441.48	29.77	103.948	0.0	6.488	0.679	0.010
AUXBLR	422.04	11.73	0.282	0.0	0.129	0.013	3.06-05
DPH_1	644.26	10.51	0.0189	0.0	0.0086	0.0009	1.38E-05
DPH_2	644.26	10.51	0.0189	0.0	0.0086	0.0009	1.38E-05
COOLT1_A	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_B	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_C	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_D	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_E	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_F	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_G	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_H	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_I	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_J	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_K	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_L	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_A	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_B	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_C	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_D	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_E	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_F	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_G	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_H	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_I	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_J	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_K	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_L	293.15	9.70	-	0.0015	0.0022	-	-

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The CALPUFF modeling does not include building downwash, as the Class I areas are more than 50 km away from the sources. Downwash is the phenomena of disturbed atmospheric flow in the immediate vicinity of a structure that results in higher ground-level concentrations at a closer proximity to the source than would otherwise occur if the structures were not there. For long-range transport it is more conservative to allow the plume to travel undisturbed by local structures.

3.5 Class I Area Receptors

The National Park Service (NPS) provides receptors for use in Class I area modeling analyses. There are a total of 5,881 receptors in the Class I areas within 300 km of the source. Table 3-5 lists the number of receptors at each Class I area provided by the NPS and used in this modeling analysis.

Table 3-5. Number of Receptors at Each Class I Areas within 300 km of the TransAlta Centralia Generation Station

Class I Area	Number of Receptors
Mount Rainier National Park	405
Olympic National Park	714
Goat Rocks Wilderness Area	181
Mount Adams Wilderness Area	313
Alpine Lakes Wilderness Area	693
Mount Hood Wilderness Area	310
Glacier Peak Wilderness Area	444
Mount Jefferson Wilderness Area	183
North Cascades National Park	888
Pasayten Wilderness Area	931
Mount Washington Wilderness Area	359
Three Sisters Wilderness Area	460

The Class I receptor locations are provided by the NPS in latitude/longitude format. CALPUFF View allows for the direct download and import of Class I area receptors into the model and converts them to LCC format for use in CALPUFF consistent with the original WRF projection. The receptor elevations provided in the NPS receptor file were used in the CALPUFF modeling.

The receptors used in the modeling in each Class I area are shown in Figures 3-2 through 3-13 (figures courtesy of the NPS website). Some of the Class I areas straddle the 300 km radius circle with the nearest receptors within 300 km of TransAlta Centralia and some of the receptors beyond 300 km. The modeling domain is large enough so that the Class I area receptors were modeled (including those that are beyond 300 km from the source).

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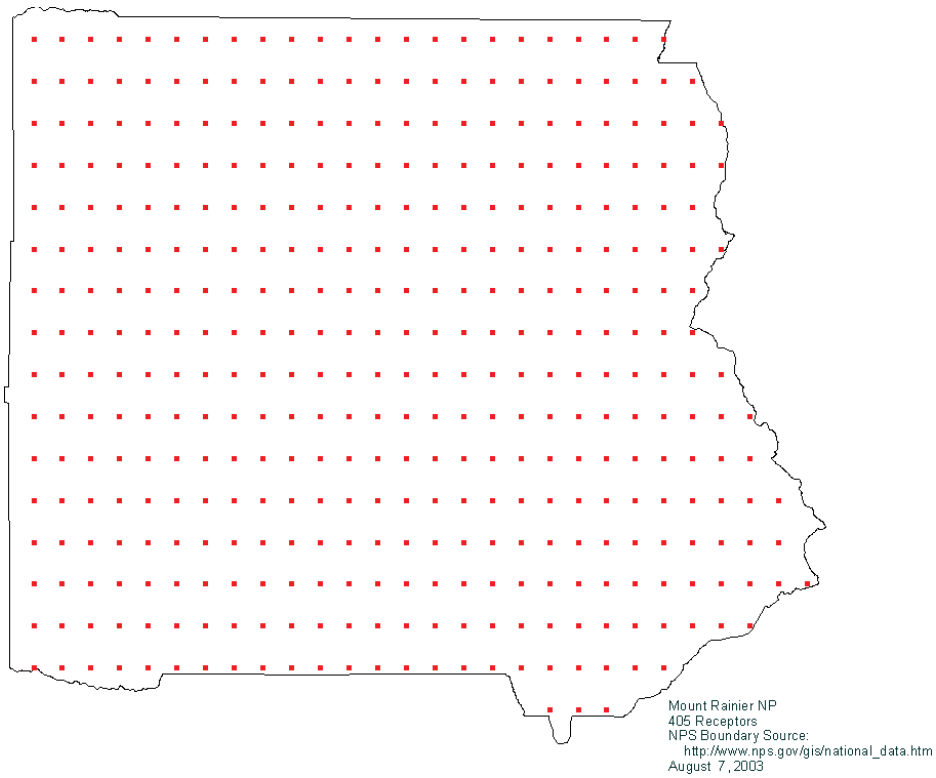


Figure 3-2. Mount Rainier National Park Receptors Proposed for CALPUFF Modeling

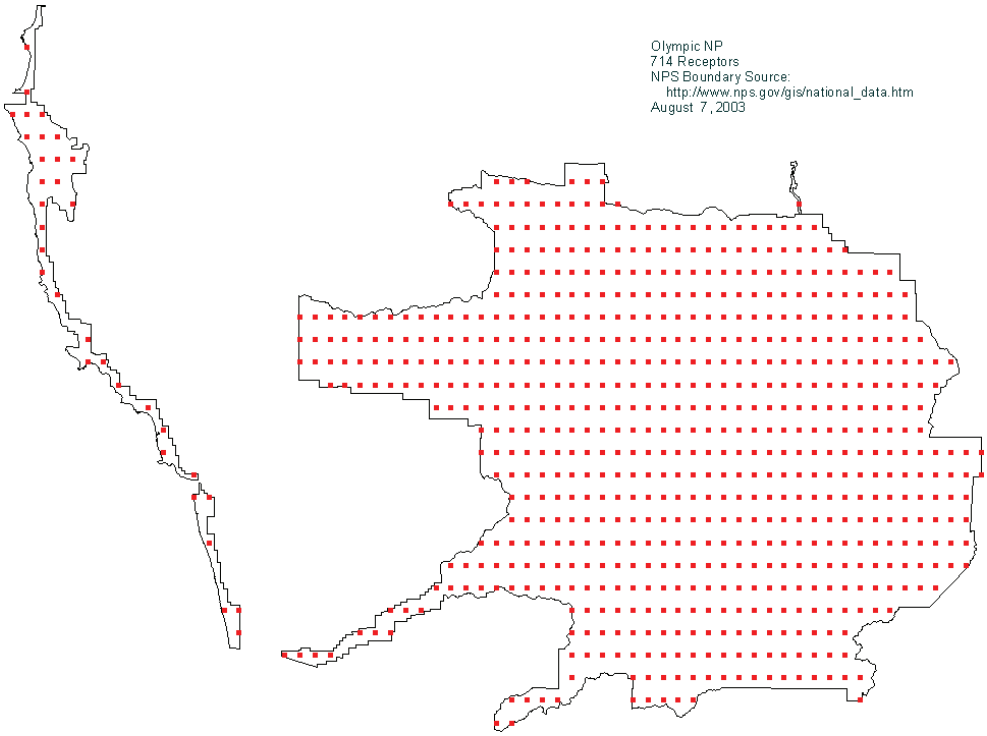


Figure 3-3. Olympic National Park Receptors Proposed for CALPUFF Modeling

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

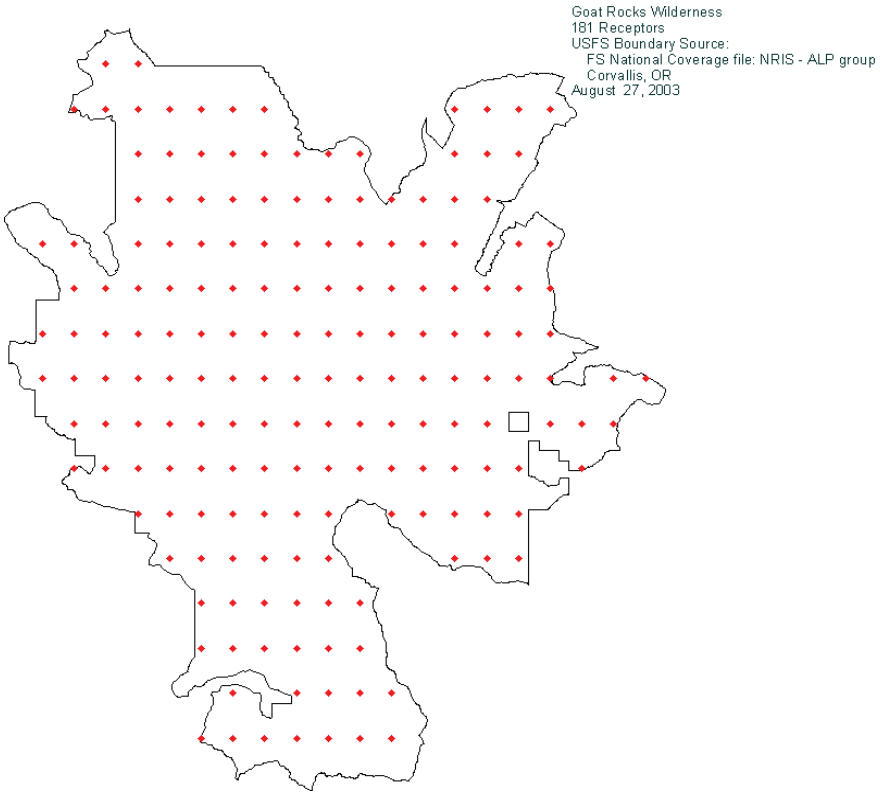


Figure 3-4. Goat Rocks Wilderness Area Receptors Proposed for CALPUFF Modeling

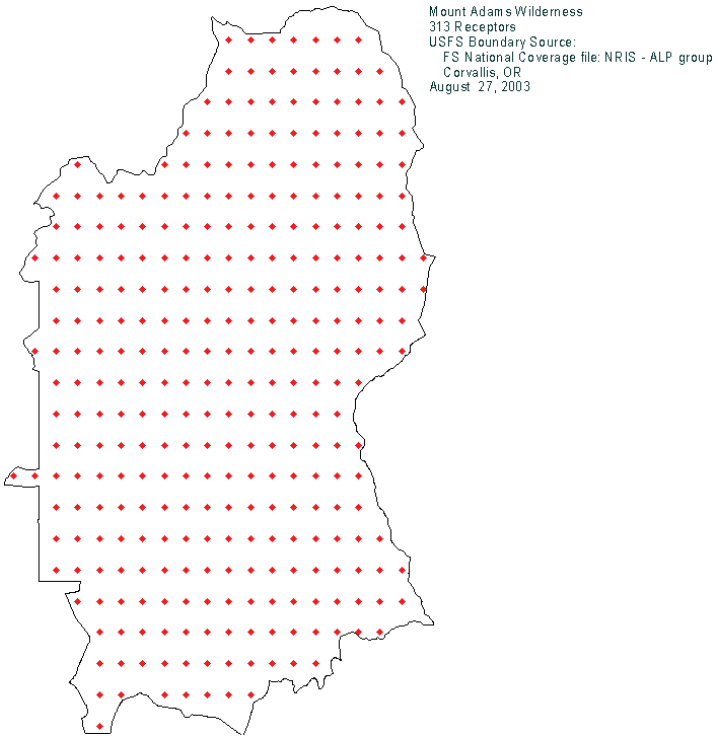


Figure 3-5. Mount Adams Wilderness Area Receptors Proposed for CALPUFF Modeling

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

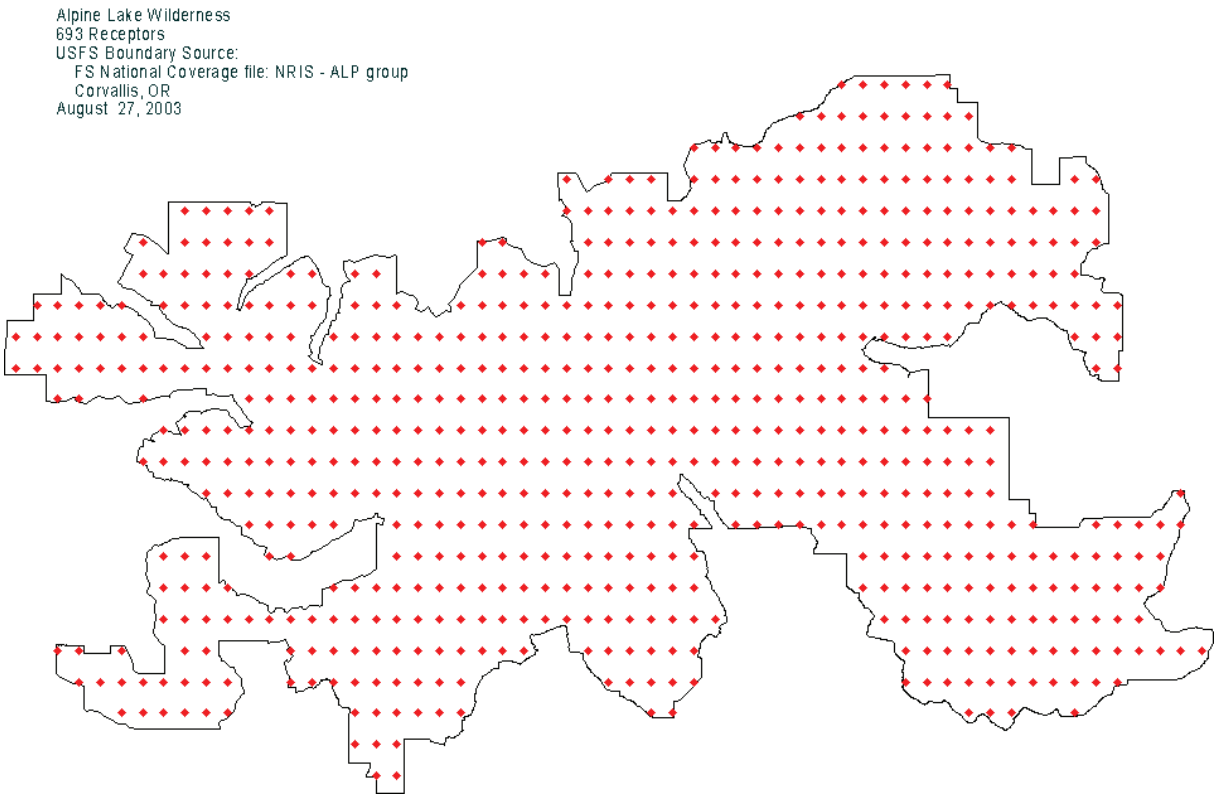


Figure 3-6. Alpine Lakes Wilderness Area Receptors Proposed for CALPUFF Modeling

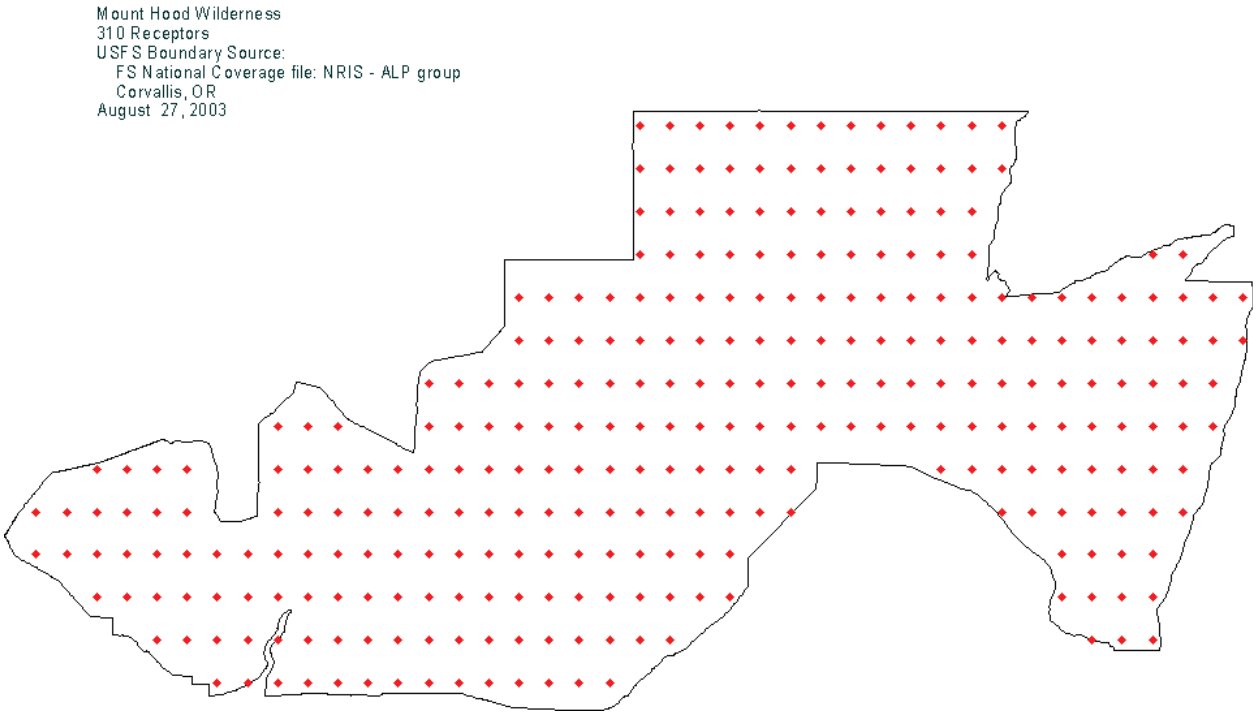


Figure 3-7. Mount Hood Wilderness Area Receptors Proposed for CALPUFF Modeling

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

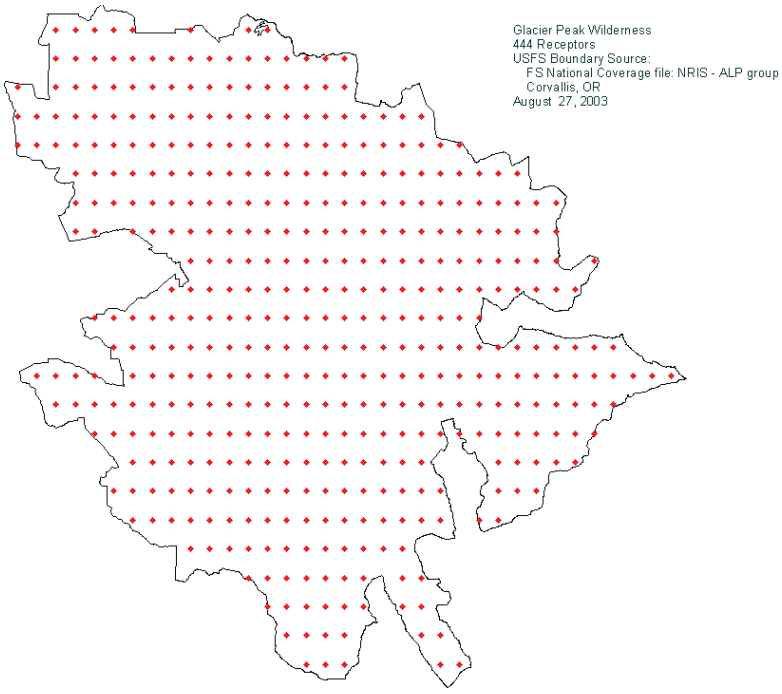


Figure 3-8. Glacier Peak Wilderness Area Receptors Proposed for CALPUFF Modeling

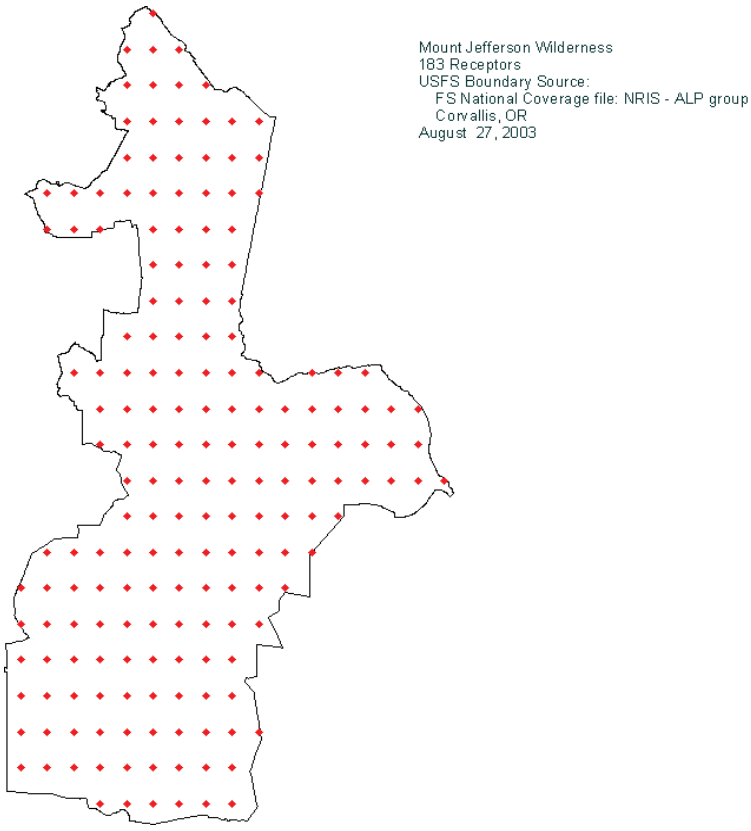


Figure 3-9. Mount Jefferson Wilderness Area Receptors Proposed for CALPUFF Modeling

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD



Figure 3-10. North Cascades National Park Receptors Proposed for CALPUFF Modeling

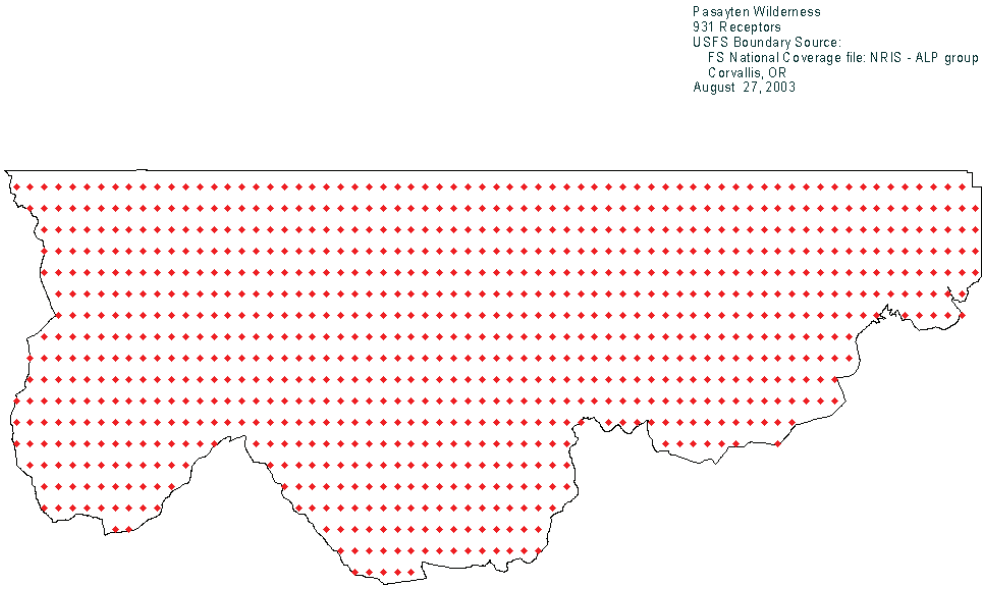


Figure 3-11. Pasayten Wilderness Area Receptors Proposed for CALPUFF Modeling

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

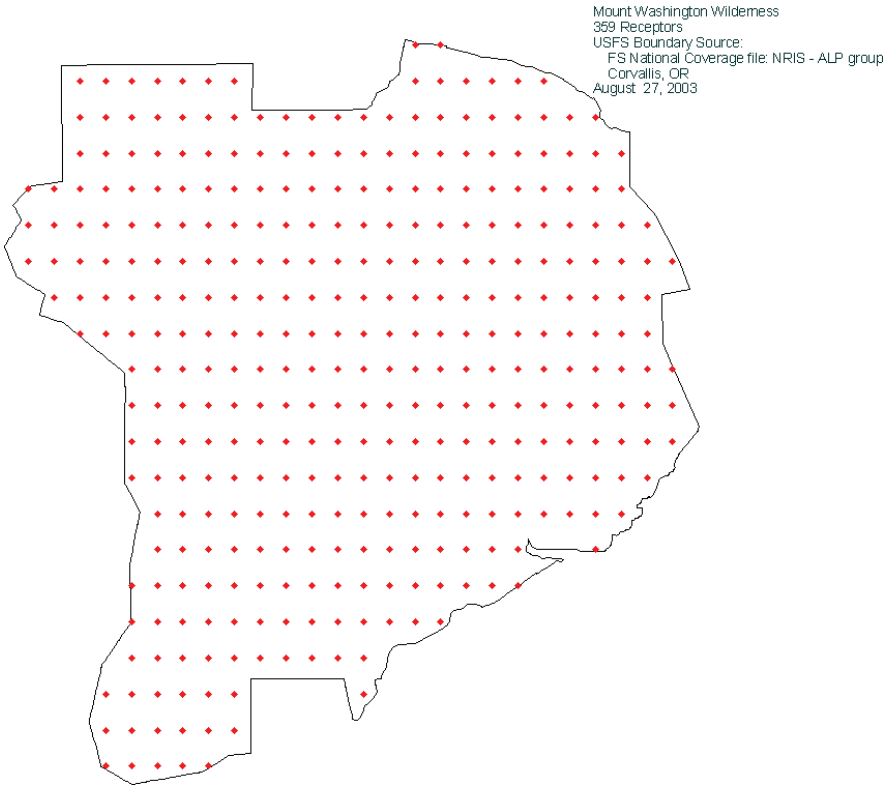


Figure 3-12. Mount Washington Wilderness Area Receptors Proposed for CALPUFF Modeling

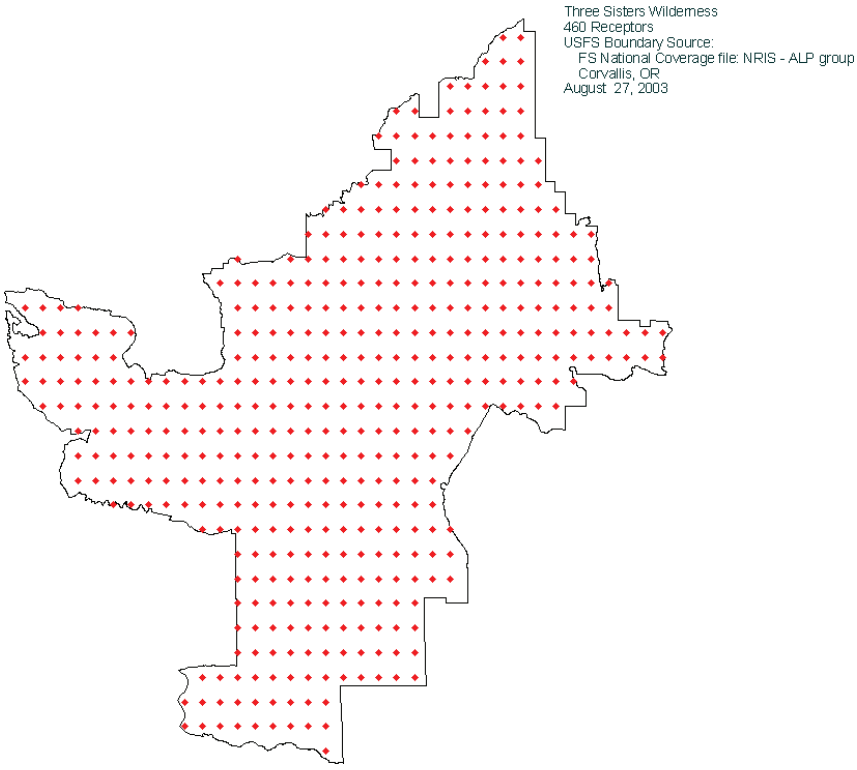


Figure 3-13. Three Sisters Wilderness Area Receptors Proposed for CALPUFF Modeling

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

3.6 CALPUFF Model Options and Switch Settings

The CALPUFF switch settings used in the modeling correspond to the regulatory options specified in Appendix B of the IWAQM Phase 2 document (EPA 1998).

Both dry and wet deposition were modeled using CALPUFF's default depositional parameters. Gaseous phase dry deposition was modeled for NOx, HNO_3, and SO_2, while particle deposition was assumed for NO_3-, SO_4^{2-} as well as particulate matter. H_2SO_4 emissions were treated as primary SO_4^{2-}. Default scavenging coefficients for the wet deposition algorithm provided in CALPUFF were used for SO_2, SO_4^{2-}, HNO_3, NH_3, NO_3^-, PMC and $PM_{2.5}$. The deposition parameters used in the modeling are presented in Table 3-6.

Table 3-6. CALPUFF Input Parameters for Deposition

Parameter	SO_2	NO_X	HNO_3	NH_3
Dry Deposition of Gases				
Diffusivity (cm^2/s)	0.1509	0.1656	0.1628	0.23
Alpha Star	1000	1	1	1
Reactivity	8	8	18	18
Mesophyll Resistance (s/cm)	0	5	0	0
Henry's Law Coefficient	0.04	3.5	8.0E-8	7.0E-7
	SO_4	NO_3-	PMC	$PM_{2.5}$
Dry Deposition of Particles				
Geometric Mass Mean Diameter (microns)	0.48	0.48	0.48	0.48
Geometric Standard Deviation (microns)	2.0	2.0	2.0	1.5
Other Dry Deposition Parameters				
Reference cuticle resistance (s/cm)		30		
Reference ground resistance (s/cm)		10		
Reference pollutant reactivity		8		
Number of particle-size intervals		9		
Vegetation state in unirrigated areas		Active and unstressed		

Pollutant	Scavenging Coefficient Liquid (1/sec)	Scavenging Coefficient Frozen (1/sec)
Precipitation Scavenging Coefficients		
SO_2	3.0×10^{-5}	0
SO_4	1.0×10^{-4}	3.0×10^{-5}
NO_X	0	0
HNO_3	6.0×10^{-5}	0
NH_3	7.9×10^{-5}	3.0×10^{-5}
NO_3-	1.0×10^{-4}	3.0×10^{-5}
$PM_{2.5}$	1.0×10^{-4}	3.0×10^{-5}
PMC	1.0×10^{-4}	3.0×10^{-5}

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Chemical transformations of NOx to nitrates (NO_3^-) and nitric acid (HNO_3), and SO_2 to sulfate (SO_4^{2-}) were evaluated using CALPUFF's MESOPUFF II chemistry scheme as recommended for long-range transport in IWAQM 1998. The rate of chemical transformations in the MESOPUFF II scheme is dependent on the concentration of ozone and ammonia in the ambient air. Representative ozone concentrations for May through September were defined on a monthly basis as the average of 8-hour observations at the Lacey-Olympia air quality monitor (Monitor ID #53-067-0013) located approximately 22.5 miles to the north-northeast of the source. This is the closest most representative monitor but only operates during the ozone season. For the remainder of the year (i.e., January through April and October through December) the data set was supplemented with observations from the Seattle monitor (Monitor ID #53-033-0080). The Seattle monitor is approximately 66 miles to the northeast of the source and operates year-round. The monitored ozone concentrations at the Lacey-Olympia and Seattle monitors are similar during the ozone season months; therefore, the Seattle monitor can serve as a suitable surrogate for the rest of the year. There is an ozone monitor on Mount Rainier, which is slightly closer to the source (~62 miles to the east) than the Seattle monitor, but it is situated at an elevation of 1615 meters. Both the Lacey-Olympia and the Seattle monitors are at base elevations (70 m and 105 m, respectively) much closer to the source base elevation (between 68-93m). Therefore, the Lacey-Olympia and Seattle ozone data are more representative of background concentrations near the source than the Mount Rainier data. The ozone concentrations from the most recently available three-year period (2022-2024) were used.

Washington state has only one ambient monitor measuring ammonia concentrations, which is part of the Ammonia Monitoring Network (AMoN). This monitor, AMoN-WA99, is in Mount Rainier National Park at an elevation of 424 meters, lower than the nearby ozone monitor. Monthly background ammonia concentrations were calculated using data collected from 2022 to 2024.

The CALPUFF modeling system postprocessor, CALPOST will be used to generate the visibility impacts from the CALPUFF runs. CALPOST Version 6.221 performs the extinction coefficient calculations using the IMPROVE equation in accordance with the latest EPA/FLM recommendations. CALPOST will run separately for each Class I area for each year modeled. The CALPOST parameter MVISBK will be set to 8, sub-mode five (M8_MODE = 5), and the background hygroscopic and non-hygroscopic aerosol levels are derived from the annual average natural conditions for each Class I area as provided in Table 6 of the FLAG 2010 guidance. When calculating the sulfate and nitrate components of the visibility extinction coefficient, relative humidity adjustment factors are applied because these aerosols are hygroscopic, and the addition of water enhances their scattering efficiencies. The monthly relative humidity adjustment factors from Tables 7 through 9 in FLAG 2010 for each Class I area are input to the RHFAC array in CALPOST (which are auto-populated for each specific Class I area by the CALPUFF View software).

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4.0 CLASS I VISIBILITY IMPACT ASSESSMENT RESULTS

Visibility is typically characterized by visual range (VR) - the greatest distance at which a large dark object can be seen - or by the light-extinction coefficient (b_{ext}), which measures light attenuation per unit distance due to scattering and absorption by atmospheric gases and particles (EPA 1998). A constant fractional change in b_{ext} produces a similar perceptual change in a scene regardless of baseline conditions. Based on this perceived visual change, an alternate visibility index called the deciview (dv) has been defined by the USEPA's Regional Haze Rule (USEPA, 1999). This unitless index is a logarithmic scale based on the light extinction coefficient (b_{ext}), specifically designed to correlate with human perception. It ensures that uniform changes in haziness correspond to consistent incremental changes in perceived visibility across the full range of conditions, from pristine to highly impaired. The deciview scale increases as visibility worsens. The delta deciview (ddv) is the difference between total visibility and natural visibility, quantifying the impairment caused by human-generated pollution.

The visibility impairment threshold of concern for Class I areas is not exceeded if the 98th percentile change in light extinction is less than 5% for each modeled year when compared to the annual average natural condition value. The 98th percentile test applies to the number of days that any modeled receptor in a Class I area exceeds the 5% degradation threshold. If the analysis indicates the 98th percentile value of change in light extinction is equal to or greater than 5% for any year (i.e., 5% change exceeded on 8 or more days per year), then FLAG 2010 guidance indicates the results may be further scrutinized to determine the frequency of the exceedances and the conditions under which the exceedances are predicted.

CALPOST, the CALPUFF modeling system postprocessor, was used to generate visibility impacts from the CALPUFF output. CALPOST Version 6.221 performs the extinction coefficient calculations using the IMPROVE equation in accordance with the latest USEPA/FLM recommendations. For the assessment of a 24-hour average regional haze visibility impact, light extinction was determined as a function of the modeled concentrations of primary (H_2SO_4) and secondary sulfate (SO_4^{2-}), secondary nitrate (NO_3^-), nitrogen dioxide (NO_2, assumed as 100% of NO_X emissions) and fine and coarse particulate matter ($PM_{2.5}$ and PMC, respectively) based on maximum allowable 24-hour mass emission rates.

The CALPUFF visibility analysis was conducted for this Project because any request to repower one or both units at the Centralia plant requires modeling the impact of repowering on visibility, as stated in the Technical Support Document for the Second BART Order Revision – TransAlta Centralia Generation Plant (July 2020). When the plant operated two coal-fired units, TransAlta prepared visibility impairment modeling following the Oregon/Idaho/Washington/USEPA Region 10 BART modeling protocol. Ecology prepared a BART Determination Support Document in 2009, revised in 2010 (Ecology, 2010). Ecology determined that BART controls for NOx and SO_2 would "result in a visibility improvement from the baseline impacts at Mount Rainier National Park of approximately 1.13 dv, with improvements of 0.67 to 1.45 dv at other affected Class I areas" (Ecology, 2010).

The conversion from two coal-fired units to a single natural gas unit will further reduce emissions and enhance visibility in these Class I areas. Table 4-1 summarizes the expected visibility improvements based on the Project's predicted CALPUFF modeling results compared to the 2010 BART

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determination. In 2010, four control scenarios were evaluated against the baseline operation; Table 4-1 presents the control scenario with the lowest deciview change (ddv) from the Ecology 2010 BART Determination, representing the cleanest outcome. The improvement of visibility is shown as a range in Table 4-1 because the 2010 document reported only the maximum of three years of modeling, while the current analysis includes results for all three years modeled.

All twelve Class I areas within 300 km of the Project will experience significant visibility improvements. The largest improvement is predicted at Mount Rainier National Park, with a 2.459 ddv reduction, and the smallest at Pasayten Wilderness Area, with a 0.619 ddv reduction.

Table 4-1. Natural Gas Conversion Project Visibility Improvement from 2010 BART Determination for the TransAlta Centralia Generation Station

Class I Area	Natural Gas Conversion Project Largest Predicted Delta Deciview (ddv)			2010 BART [a] Single year Lowest Control Scenario (ddv)	Range of Visibility Improvement (reduction in ddv)
	2018	2019	2020		
Mount Rainier National Park	1.069	1.302	0.900	3.359	2.057 – 2.459
Olympic National Park	1.148	1.075	0.322	2.506	1.358 – 2.184
Goat Rocks Wilderness Area	1.035	0.674	0.835	3.069	2.034 – 2.395
Mount Adams Wilderness Area	0.695	0.575	0.695	1.984	1.289 – 1.409
Alpine Lakes Wilderness Area	0.602	0.904	0.679	2.949	2.045 – 2.347
Mount Hood Wilderness Area	0.243	0.661	0.233	1.978	1.317 – 1.745
Glacier Peak Wilderness Area	0.297	0.320	0.216	2.036	1.716 – 1.820
Mount Jefferson Wilderness Area	0.148	0.148	0.163	1.150	0.987 – 1.002
North Cascades National Park	0.209	0.263	0.239	1.570	1.307 – 1.361
Pasayten Wilderness Area	0.456	0.196	0.211	1.075	0.619 – 0.879
Mount Washington Wilderness Area	0.130	0.136	0.115	1.106	0.970 – 0.991
Three Sisters Wilderness Area	0.126	0.150	0.158	1.139	0.981 – 1.013

[a] Data obtained from Table 3-1 in the 2010 BART Determination (Ecology, 2010)

Table 4-2 presents the results of light extinction calculations for each of the twelve Class I areas within 300 km of the Project. It shows the predicted maximum change in light extinction and the number of days per year with a predicted change exceeding 5%. Note that the 98th percentile threshold for a change in light extinction of 5% or more is considered exceeded if it occurs on 8 or more days per year. For ten of the twelve Class I areas modeled, predicted changes in light extinction do not exceed the 98th percentile threshold in any modeled year. At the closest Class I area, Mount Rainier National Park, the predicted change exceeds the threshold by 2 days for both 2018 and 2020 meteorological conditions, and by 8 days in 2019. At the Goat Rocks Wilderness Area, the threshold is exceeded by 2 days in 2018 but not exceeded in 2019 or 2020.

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Table 4-2. Predicted Number of Days with greater than 5% Change in Light Extinction at each Class I Area within 300 km of the TransAlta Centralia Generation Station

Class I Area	Approx. Distance and Direction from Project	Number of Days >5% Change in Light Extinction		
		2018	2019	2020
Mount Rainier National Park	71.7 km to E	**9**	**15**	**9**
Olympic National Park	90.3 km to NNW	3	2	0
Goat Rocks Wilderness Area	97.2 km to ESE	**9**	3	7
Mount Adams Wilderness Area	110.5 km to SE	3	1	2
Alpine Lakes Wilderness Area	122.8 km to NE	1	2	5
Mount Hood Wilderness Area	170.1 km to SSE	0	1	0
Glacier Peak Wilderness Area	185.0 km to NNE	0	0	0
Mount Jefferson Wilderness Area	230.2 km to SSE	0	0	0
North Cascades National Park	231.2 km to NNE	0	0	0
Pasayten Wilderness Area	260.9 km to NNE	0	0	0
Mount Washington Wilderness Area	273.7 km to SSE	0	0	0
Three Sisters Wilderness Area	286.5 km to SSE	0	0	0

Note: Bold font indicates the 98th percentile value (i.e., 8 days or more per year) is exceeded.

Although Table 4-2 shows four exceedances of the visibility impairment threshold, these results should be interpreted in the context of the modeling assumptions. The CALPUFF model assumes continuous plant operation - 24 hours a day, every day of the year at full load. In reality, the plant will not be a baseload facility, and it is being permitted to operate up to an annual capacity factor of 59%, or approximately 215 days per year with varying levels of operation, the majority of which are expected to be at half-load or minimum stable generation levels (see Section 2.2). Therefore, the frequency of visibility impairment on the 98th percentile worst days must be considered alongside the likelihood that meteorological conditions causing higher visibility impacts will coincide with the days the plant is operational.

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Notary Events	Signature	Timestamp

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If you elect to receive required notices and disclosures only in paper format, it will slow the speed at which we can complete certain steps in transactions with you and delivering services to you because we will need first to send the required notices or disclosures to you in paper format, and then wait until we receive back from you your acknowledgment of your receipt of such paper notices or disclosures. Further, you will no longer be able to use the DocuSign system to receive required notices and consents electronically from us or to sign electronically documents from us.

All notices and disclosures will be sent to you electronically

Unless you tell us otherwise in accordance with the procedures described herein, we will provide electronically to you through the DocuSign system all required notices, disclosures, authorizations, acknowledgements, and other documents that are required to be provided or made available to you during the course of our relationship with you. To reduce the chance of you inadvertently not receiving any notice or disclosure, we prefer to provide all of the required notices and disclosures to you by the same method and to the same address that you have given us. Thus, you can receive all the disclosures and notices electronically or in paper format through the paper mail delivery system. If you do not agree with this process, please let us know as described below. Please also see the paragraph immediately above that describes the consequences of your electing not to receive delivery of the notices and disclosures electronically from us.

How to contact TransAlta Corporation:

You may contact us to let us know of your changes as to how we may contact you electronically, to request paper copies of certain information from us, and to withdraw your prior consent to receive notices and disclosures electronically as follows:
To contact us by email send messages to: HR_Services@transalta.com

To advise TransAlta Corporation of your new email address

To let us know of a change in your email address where we should send notices and disclosures electronically to you, you must send an email message to us at HR_Services@transalta.com and in the body of such request you must state: your previous email address, your new email address. We do not require any other information from you to change your email address.

If you created a DocuSign account, you may update it with your new email address through your account preferences.

To request paper copies from TransAlta Corporation

To request delivery from us of paper copies of the notices and disclosures previously provided by us to you electronically, you must send us an email to HR_Services@transalta.com and in the body of such request you must state your email address, full name, mailing address, and telephone number. We will bill you for any fees at that time, if any.

To withdraw your consent with TransAlta Corporation

To inform us that you no longer wish to receive future notices and disclosures in electronic format you may:

i. decline to sign a document from within your signing session, and on the subsequent page, select the check-box indicating you wish to withdraw your consent, or you may;

ii. send us an email to HR_Services@transalta.com and in the body of such request you must state your email, full name, mailing address, and telephone number. We do not need any other information from you to withdraw consent.. The consequences of your withdrawing consent for online documents will be that transactions may take a longer time to process..

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The minimum system requirements for using the DocuSign system may change over time. The current system requirements are found here: https://support.docusign.com/guides/signer-guide-signing-system-requirements.

Acknowledging your access and consent to receive and sign documents electronically

To confirm to us that you can access this information electronically, which will be similar to other electronic notices and disclosures that we will provide to you, please confirm that you have read this ERSD, and (i) that you are able to print on paper or electronically save this ERSD for your future reference and access; or (ii) that you are able to email this ERSD to an email address where you will be able to print on paper or save it for your future reference and access. Further, if you consent to receiving notices and disclosures exclusively in electronic format as described herein, then select the check-box next to 'I agree to use electronic records and signatures' before clicking 'CONTINUE' within the DocuSign system.

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- You can print on paper this Electronic Record and Signature Disclosure, or save or send this Electronic Record and Disclosure to a location where you can print it, for future reference and access; and
- Until or unless you notify TransAlta Corporation as described above, you consent to receive exclusively through electronic means all notices, disclosures, authorizations, acknowledgements, and other documents that are required to be provided or made available to you by TransAlta Corporation during the course of your relationship with TransAlta Corporation.

EXHIBIT 22

November 19, 2025

The Honorable Bob Ferguson
Governor of Washington
Office of the Governor
PO Box 40913
Olympia WA 98504-0913

The Honorable Sarah Bannister
Secretary of the Senate
312 Legislative Building
PO Box 40482
Olympia WA 98504-0482

The Honorable Bernard Dean
Chief Clerk of the House of Representatives
338 Legislative Building
PO Box 40482
Olympia WA 98504-0482

Re: Summary of the 2025 Long-term Resource Adequacy Meeting

Dear Governor Ferguson, Secretary Bannister, and Chief Clerk Dean,

We submit this attached summary of the 2025 long-term resource adequacy meeting held Sept. 22, 2025, as required by statute. This year, in response to public feedback to expand our schedule under RCW 19.280.065, we hosted three meetings: one each for summer readiness, long-term resource adequacy, and winter preparedness. The meeting agendas, recordings of each meeting, and presentation materials are available on the Department of Commerce webpage and the Utilities and Transportation Commission webpage.

Reliability assessments presented at the September 22 meeting indicated that the Northwest's electric grid meets national resource adequacy criteria over the near and medium terms under a broad range of operating conditions. As a region assessed as "normal risk," the Northwest has a low likelihood of electricity supply shortfall.

However, "normal risk" is not the same as "no risk." Although areas categorized as normal risk are expected to have sufficient resources for plausible extreme conditions, they are not immune to the effects of high-impact, low frequency weather events that affect demand and generation

simultaneously. Presentations also indicated that normal conditions are shifting with the impacts of climate change, large new electricity uses like data centers and building and vehicle electrification. If significant new electricity usage materializes and more extreme weather continues, the grid could face reliability challenges. Presentations emphasized that no electric system is 100% resource adequate, and there is no resource that provides perfect capacity. We also underscore that it is important to incorporate risks associated with fossil generating resources, including fuel supply risk and weather-driven forced outages.

With this uncertainty, it is clear that utilities and policy makers must increase efforts to make customer energy demand more flexible, reduce delays in siting and interconnecting new clean energy projects, expand regional transmission capacity, and improve transparency and accuracy of load forecasts and planned resource additions. There is also a need to consider potential changes to the mix of generating resources with greater focus on the capacity and fuel requirements of the power system during critical periods, such as days of extreme cold combined with low hydroelectric and wind generation.

Lack of Clarity Surrounding New Load Growth
There is limited visibility into whether large customer (including data center) interconnection requests are duplicative or speculative, and utility-submitted data on planned resource additions are less predictable than in recent history.

Discussions at the meeting underscored that, under some forecasts presented, if the region did not add new generation capacity by 2030, it would have a resource gap equivalent to the current electricity requirements of the State of Oregon, approximately 9 gigawatts. Existing utility integrated resource plans (IRPs) show this gap closing. In addition, collaborative utility efforts, such as the Northwest Energy Efficiency Association's End-Use Load Flexibility project,[1] show progress on reducing peak electricity demand through grid-connected consumer products and dynamic services.

New Resource Challenges
We should be cautious of the assumptions behind the finding of adequacy. Bringing new resources online continues to be difficult due to:

- Changes in federal policy and corresponding increased costs,
- Lack of in-state and regional transmission capacity, and
- Permitting and interconnection challenges.

Voluntary Resource Adequacy Program Struggles
Shortly after our meeting, six utilities announced they would not join the Western Resource Adequacy Program (WRAP). This is an industry-led, voluntary regional resource adequacy program to help utilities share resources during scarcity. PacifiCorp, which serves approximately 141,000 customers in Washington, opted out of the program, while Avista and Puget Sound

[1] End-Use Load Flexibility - Northwest Energy Efficiency Alliance (NEEA).

Energy remain in. Reduced WRAP participation means that there will be fewer resources to share, and therefore the benefits of the program potentially diminish for Washington utilities and customers. Some utilities that have opted out of WRAP are now in talks to potentially create their own regional program. We continue to monitor this dynamic and encourage continued development and participation in regional resource adequacy initiatives.

Meanwhile, climate change is making extreme weather more frequent, posing the gravest threat to grid reliability. The experts who gathered at this meeting continue to stress that the increased severity and frequency of extreme weather events from climate change pose the greatest threat to resource adequacy.

We look forward to continuing to partner with you on this work.

Sincerely,





Brian J. Rybarik
Chair
WA Utilities and Transportation Commission

Jennifer Grove
Assistant Director, Energy Division
Washington Department of Commerce

Enclosure (1)
cc:

2025 Long-Term Resource Adequacy Meeting Summary

Introduction

On September 22, 2025, the Washington Utilities and Transportation Commission (UTC) and the Washington Department of Commerce (Commerce) convened a public meeting to review the adequacy of energy resources to serve the state's electricity needs and receive an update from regional experts and Washington utilities on the long-term resource adequacy of the electric grid. We convened this meeting and submit this summary in response to public feedback to expand our annual resource adequacy meeting under RCW 19.280.065 to three meetings: one meeting in the spring focused on summer readiness, one meeting in late summer to discuss long-term resource adequacy, and another in late fall to focus on winter preparedness.
RCW 19.280.065(1) says:

> At least once every twelve months, the department and the commission shall jointly convene a meeting of representatives of the investor-owned utilities and consumer-owned utilities, regional planning organizations, transmission operators, and other stakeholders to discuss the current, short-term, and long-term adequacy of energy resources to serve the state's electric needs, and address specific steps the utilities can take to coordinate planning in light of the significant changes to the Northwest's power system including, but not limited to, technological developments, retirements of legacy baseload power generation resources, and changes in laws and regulations affecting power supply options. The department and commission shall provide a summary of these meetings, including any specific action items, to the governor and legislature within sixty days of the meeting.

Maintaining an adequate supply of electricity is a core obligation of the utilities that provide electric service to Washington residents and businesses. State policy reinforces this obligation as Washington transforms its electric power system and economy, reducing and eventually eliminating emissions from fossil fuel combustion for electricity generation.[2]

The state's 100% clean electricity law, the Clean Energy Transformation Act,[3] includes requirements for utilities to establish specific standards for resource adequacy and incorporate those standards into their planning and compliance.[4] As utilities reduce reliance on fossil fuels and add renewable resources such as wind and solar, new approaches and resources will be required to maintain resource adequacy.

While resource adequacy is an obligation of each electric utility serving end-use customers in the state, it also is a shared responsibility of the overall electric power system and the entities that operate, plan, regulate, design, and fund that system.

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[2] Washington 2021 State Energy Strategy, page 119-120. https://commerce.wa.gov/energystrategy

[3] Chapter 19.405 RCW.

[4] RCW 19.280.030. This resource planning statute was amended by the CETA legislation to add explicit resource adequacy provisions.

The following summarizes the presentations and discussion at the September 2025 meeting.

Resource Adequacy 101—Energy Systems Integration Group
Energy Systems Integration Group (ESIG) is a non-profit organization and a leading source of expertise for energy systems around the world. ESIG described resource adequacy as "the ability of the electric system to supply firm demand at all times (up to some criteria)." This definition highlights two important aspects of resource adequacy.

- Resource adequacy refers to the ability to generate and move power over transmission lines to where it is needed; it does not include local distribution line disruptions.
- It is measured against criteria, such as a One-day-in-ten-years loss-of-load event, which determines an acceptable amount of risk of resource shortfall.

In other words, resource adequacy is the likelihood we will have enough power and transmission to meet electricity demand based on defined criteria. Changes in resource adequacy criteria may impact whether an electric system is deemed adequate. The industry is increasingly moving to multi-metric criteria to examine the adequacy of the electric system and the capacity contributions of individual resources to account for shifting resource adequacy risks, such as potential weather-related and fuel supply outages.

Key takeaways from the presentation were that no electric system is 100% resource adequate, and there is no resource that provides perfect capacity. Meeting resource adequacy will require utilities to develop diverse resource portfolios and secure transmission capacity necessary to meet multi-metric criteria. Utilities should continue to evaluate the adequacy of their resource portfolios as the region adds new loads. ESIG observed a system that was 100% adequate would be cost prohibitive.

ESIG offered a number of ways to improve resource adequacy while lowering system costs, including energy efficiency and demand response, expansion of regional transmission and energy markets, and adoption of a binding regional resource adequacy program, such as the WRAP, that would allow utilities to coordinate their diverse resources to avoid shortfalls.

Reliability Assessments — North American Electric Reliability Corporation and Western Electric Coordinating Council
The North American Electric Reliability Corporation (NERC) is the Electric Reliability Organization for North America. Its mission is to assure the effective reduction of risks to the reliability and security of the grid. It is subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. The Western Electricity Coordinating Council (WECC) is one of six regional entities under NERC that has authority delegated under the Federal Power Act to ensure a reliable and secure bulk power system throughout the Western Interconnection. WECC has the responsibility to create, monitor, and enforce reliability standards and promote activities, such as regional resource adequacy assessments, of the bulk power system in the Western Interconnection.

NERC presented its 2024 Long-Term Reliability Assessment (LTRA), as its 2025 LTRA was not yet complete at the time of the meeting. The LTRA found that unlike some parts of the United

States, which have an elevated risk of resource inadequacy, the Western Interconnection has a normal level of risk as of the 2024 assessment.

Study results show WECC is in the top one-third of all assessment areas for demand growth. Demand growth is being driven primarily by data centers, but also industrial onshoring and electrification of transportation and buildings. Meanwhile, resource projections reflect slower rates of additional resources being interconnected to the grid due to project delays and cancellations.

Data presented by WECC shows the Northwest adding 14 GW in new generation between 2026 and 2035. Nearly all these resource additions are intermittent power sources, and almost half of the generation comes from wind. Meanwhile, nearly 345 MW of generation over the same time period is planned to be retired, roughly 85% of which are clean resources. In the Northwest subregion, annual demand is expected to grow 24% between 2026 and 2035 with peak demand expected to increase by 20.6%.

The information that goes into the LTRA is aggregated from data provided by balancing authorities that collect and aggregate resource plans of utilities (not all utilities are balancing authorities). WECC explained they have been working more closely with balancing authorities and utilities to standardize and ensure the integrity of reporting to WECC.

Northwest Utilities Resource Adequacy Study — Energy and Environmental Economics, Inc.
Energy and Environmental Economics, Inc. (E3) is a nationally recognized consultant specializing in decarbonization and the clean energy transition, including climate policy analysis, integrated system planning, and asset valuation and strategy. E3 was retained by Pacific Northwest utilities and generation owners to evaluate resource adequacy in the Pacific Northwest today and in the future. The industry hired E3 to do a similar study prior to adoption of Washington's 100% clean electricity law, the Clean Energy Transformation Act (CETA), in 2019. The findings are similar.

The preliminary results of the 2025 study suggest the planned resource additions in utility IRPs are likely sufficient to meet the region's resource adequacy needs, but that meeting the pace of growth anticipated in utility IRPs will require annual resource additions equal to four to five times historic levels. The study finds the region experiencing significant headwinds due to permitting and interconnection delays, changes in federal policy, and higher costs. Without any new resource additions, the region would have a gap in resources beginning in 2026 and growing to 9 gigawatts by 2030, which is approximately the load of the state of Oregon. Data centers and the electrification of buildings and transportation are the principal contributors to load growth.

The study finds the most constraining reliability conditions are extended cold weather events in the winter during very low water years. The preliminary results suggest utilities will need to deploy some natural gas resources under the 2030 carbon neutral standard of CETA to meet demand during these extreme and infrequent conditions. The second phase of the study, expected by the end of this year, will evaluate resource options for meeting near-term and long-term resource adequacy and clean energy needs.

Update on Data Center Working Group under Governor's EO 25-05 — UTC and Commerce

UTC and Commerce provided an update on the Data Center Workgroup convened by the Department of Revenue and Governor's Office, in response to the Governor's Executive Order 25-05. Representatives from the UTC and Commerce provided a summary of each agency's priorities, which include:

- **Accurate load forecasting:** Speculation and duplicative load forecasts make it hard to forecast regional resource needs.
- **Conformance with state energy and climate laws:** Data center loads should comply with state clean energy and climate laws.
- **Load flexibility:** Data centers should exercise available load flexibility to help the electric grid during peak periods.
- **Leveraging tech investments in transmission and generation:** The state should work with hyperscalers who have immense experience deploying transmission and clean energy technologies and the funding needed to deploy them to the benefit of data centers and the overall electric grid.
- **Adequate resources to maintain reliability:** Utilities should not feel obligated to serve large loads if serving these loads threatens the resource adequacy and reliability of the electric grid.
- **Impacts on hydropower resources and fish populations:** Data center operations should not affect the operation of the hydropower system or fish populations.
- **Rate impacts:** Existing ratepayers should be insulated and protected against potential rate impacts of adding data centers to the electric grid.
- **Clean energy for economic development:** The development of data centers should support the growth of clean energy jobs.

Demand-side Resource Opportunities — Northwest Energy Efficiency Alliance and Tacoma Power

Northwest Energy Efficiency Alliance (NEEA) is an alliance of utilities and partners that pools resources and shares risks to transform the market for energy efficiency to the benefit of all consumers in the Northwest.

Recently NEEA announced that 10 regional utilities are funding an End-Use Load Flexibility initiative, exploring ways that grid-connected consumer products and dynamic services can fill regional winter-time power constraints within the next five years.

NEEA forecasts the project will deliver a 1-to-3-gigawatt resource to the region within the next four years, reducing the region's peak load by 10%. NEEA is developing its strategic and business plans for the 2026-2029 period, which include testing and refining projects and scaling and adapting utility load-flex programs by codifying best practices and providing tools to support market awareness.

Tacoma Power shared the potential for demand flexibility in its service territory and the technical and economic challenges of being an early adopter of demand response. The utility shared that

industrial partners were often eager to participate in demand response programs. Residential customers have varied responses and often require intentional outreach before participating.

EXHIBIT 23

An official website of the United States government Here's how you know

2025 DOE 202(c) Orders

- On December 30, 2025, Department of Energy (DOE) issued emergency order 202-25-14, pursuant to section 202(c) of the Federal Power Act, to Tri-State Generation and Transmission Association (Tri-State), Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy ("co-owners"). The order directs Tri-State and the co-owners, in coordination with the Western Area Power Administration (WAPA) - Rocky Mountain Region and Southwest Power Pool (SPP) West, to take all measures necessary to ensure that Unit 1 at the Craig Station in Craig, Colo. is available to operate. This order is in effect beginning on December 30, 2025, and continues until March 30, 2026.
- On December 23, 2025, Department of Energy (DOE) issued emergency order 202-25-13, pursuant to section 202(c) of the Federal Power Act, to CenterPoint Energy and the Midcontinent Independent System Operator, Inc. (MISO). The order directs CenterPoint Energy and MISO to take all measures necessary to ensure that Unit 2 at the F.B. Culley Generating Station in Warrick County, Ind. is available to operate. This order is in effect beginning on December 23, 2025, and continues until March 23, 2026.
- On December 23, 2025, Department of Energy (DOE) issued emergency order 202-25-12, pursuant to section 202(c) of the Federal Power Act, to

Northern Indiana Public Service Company (NIPSCO) and the Midcontinent Independent System Operator, Inc. (MISO). The order directs NIPSCO and MISO to take all measures necessary to ensure that Units 17 and 18 at the Schahfer Generating Station in Wheatfield, Ind. are available to operate. This order is in effect beginning on December 23, 2025, and continues until March 23, 2026.

- On December 16, 2025, the Department of Energy (DOE) issued emergency order 202-25-11, pursuant to section 202(c) of the Federal Power Act, to TransAlta. The order directs TransAlta to ensure Unit 2 of the Centralia Generating Station in Centralia, Washington remains available for operation. This order is in effect beginning on December 16, 2025, and continues until March 16, 2026.
- On November 25, 2025, the Department of Energy (DOE) issued emergency order 202-25-10, pursuant to section 202(c) of the Federal Power Act, to PJM Interconnection (PJM). The order directs PJM, in coordination with Constellation Energy, to ensure Units 3 and 4 of the Eddystone Generating Station in Pennsylvania remain available for operation. This order is in effect beginning on November 26, 2025, and continues until February 24, 2026.
- On November 18, 2025, the Department of Energy (DOE) issued emergency order 202-25-9, pursuant to section 202(c) of the Federal Power Act, to the Midcontinent Independent System Operator (MISO). The emergency order directs MISO, in coordination with Consumers Energy, to ensure that the J.H. Campbell Power Plant in West Olive, Michigan remains available for operation, minimizing any potential generation shortfall that could lead to unnecessary power outages. Additionally, MISO is directed to take every step to minimize cost to the American people. This order is in effect beginning on November 19, 2025, and continues until February 17, 2026.
- On November 12, 2025, the Department of Energy (DOE) issued emergency orders No. 202-25-1B and No. 202-25-2B, pursuant to section 202(c) of the Federal Power Act, to the Puerto Rico Electric Power Authority (PREPA). PREPA is ordered to operate specified generation units under certain circumstances, perform vegetation

management, and asset management to ensure operational availability of specified transmission facilities. These orders are in effect beginning on November 13, 2025, and continue through February 10, 2026.

- On October 24, 2025, the Department of Energy (DOE) issued an emergency order No. 202-25-6A, pursuant to section 202(c) of the Federal Power Act, to PJM Interconnection (PJM). PJM shall, in coordination with the Talen Energy Corporation, operate specified units at the Wagner Generating Station to meet anticipated electricity demand heading into the winter months. This order is in effect beginning on October 26, 2025, and continues until December 31, 2025.
- On August 28, 2025, the Department of Energy (DOE) issued emergency order No. 202-25-8, pursuant to section 202(c) of the Federal Power Act, to PJM Interconnection (PJM). The order directs PJM, in coordination with Constellation Energy, to ensure Units 3 and 4 of the Eddystone Generating Station in Pennsylvania remain available for operation. This order is in effect beginning on August 28, 2025, and continues until November 26, 2025.
- On August 20, 2025, the Department of Energy (DOE) issued emergency order No. 202-25-7, pursuant to section 202(c) of the Federal Power Act, to Midcontinent Independent System Operator (MISO). The emergency order directs MISO, in coordination with Consumers Energy, to ensure that the J.H. Campbell Power Plant in West Olive, Michigan remains available for operation, minimizing any potential generation shortfall that could lead to unnecessary power outages. This order is in effect beginning on August 21, 2025, and continuing until November 19, 2025.
- On August 14, 2025, the Department of Energy (DOE) issued emergency orders No. 202-25-1A and No. 202-25-2A, pursuant to section 202(c) of the Federal Power Act, to the Puerto Rico Electric Power Authority (PREPA). The first emergency order directs PREPA to continue dispatching generation units necessary to maintain grid reliability and closing the gap in generation shortfall. The second order directs PREPA to continue performing vegetation management activities. These orders are in effect beginning on August 15, 2025, and continuing through November 12, 2025.

- On July 28, 2025, the Department of Energy (DOE) issued emergency order No. 202-25-6, pursuant to section 202(c) of the Federal Power Act, to PJM Interconnection (PJM). PJM shall, in coordination with Talen Energy Corporation, operate Unit 4 at the Wagner Generating Station as PJM deems necessary beyond its environmental run-hour limitations through October 26, 2025.
- On June 24, 2025, the Department of Energy (DOE) issued emergency order No. 202-25-5, pursuant to section 202(c) of the Federal Power Act, to Duke Energy Carolinas authorizing specific electric generating units (specified resources) located within the Duke Energy Carolinas area to operate at their maximum generation output levels due to ongoing extreme weather conditions and to preserve the reliability of bulk electric power system. The order is in effect until 10:00 PM ET on June 25, 2025.
- On May 30, 2025, the Department of Energy (DOE) issued emergency order No. 202-25-4, pursuant to section 202(c) of the Federal Power Act, to PJM Interconnection. The emergency order directs PJM, in coordination with Constellation Energy, to ensure specified generation units at the Eddystone Generation Station in Pennsylvania remain available for operation, minimizing the risk of generation shortfall that could lead to unnecessary power outages.
- On May 23, 2025, the Department of Energy (DOE) issued emergency order No. 202-25-3, pursuant to section 202(c) of the Federal Power Act, to Midcontinent Independent System Operator (MISO). The emergency order directs MISO, in coordination with Consumers Energy, to ensure that the J.H. Campbell Power Plant in West Olive, Michigan remains available for operation, minimizing any potential generation shortfall that could lead to unnecessary power outages.
- On May 16, 2025, the Department of Energy (DOE) issued emergency orders No. 202-25-1 and No. 202-25-2, pursuant to section 202(c) of the Federal Power Act, to the Puerto Rico Electric Power Authority (PREPA). The first emergency order directs the PREPA to dispatch generation units necessary to expand baseload generation for the island and maintain grid reliability, closing the gap in generation shortfall. The second order directs PREPA to perform vegetation management

activities –that mitigate risk of shortages and fire – to help ensure operational availability of the Specified Transmission Facilities.

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EXHIBIT 23-1

Department of Energy
Washington, DC 20585

December 14, 2000

Order Pursuant to Section 202(c) of the Federal Power Act

Pursuant to Section 202(c) of the Federal Power Act (16 U.S.C. 824a(c)) and 10 C.F.R. § 205.370, in this order I consider the question of whether an emergency exists in California by reason of a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes, and whether to require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as will best meet the emergency and serve the public interest. Because of a shortage of currently operational electric generation facilities, a shortage of water used to generate electricity, unusual volatility of electricity and natural gas markets, and for other reasons, California is experiencing an unexpected shortage of electric energy. Therefore, pursuant to Section 202(c) of the Federal Power Act, I find an emergency exists in California by reason of the shortage of electric energy.

Accordingly, I hereby order the entities listed in Attachment A to make arrangements to generate, deliver, interchange, and transmit electric energy when, as, and in such amounts as may be requested by the California Independent System Operator (California ISO), acting as agent for and on behalf of Scheduling Coordinators (as that term is defined in the California ISO tariff on file at the Federal Energy Regulatory Commission), consistent with the terms of this order. The entities listed in Attachment A are only required to sell electricity to the California ISO that is available in excess of electricity needed by each entity to render service to its firm customers.

This order is effective immediately and expires at 3:00 a.m., EST, December 21, 2000, unless altered or revoked by further order. However, the entities in Attachment A are not required to deliver energy or services under the terms of this order until 12 hours after the California ISO has filed with the Department of Energy (DOE) a signed certification that it has been unable to acquire in the market adequate supplies of electricity to meet system demand, and, as a consequence, it has, or reasonably anticipates, an "inadequate fuel or energy supply" as defined in 10 C.F.R. § 205.375. In order to continue to avail itself of this order, the California ISO is required to submit to DOE a further certification as set forth in the preceding sentence every twenty-four hours until the expiration of the order. The California ISO shall provide a signed copy of all certifications to the entities in Attachment A at the time it provides them to DOE.

The California ISO must inform each entity subject to this order of the amount and type of energy or services requested by 9:00 p.m., EST, the day before the requested service. In making requests for power pursuant to this order, to the extent feasible, the California ISO is directed to

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allocate those requests among the entities listed in Attachment A in proportion to each entity's available excess power.

The terms of any arrangement made between the entities subject to this order and the California ISO pursuant to this order are to be as agreed to by the parties. If no agreement as to terms can be reached, I will immediately prescribe the conditions of service and refer the rate issue to the Federal Energy Regulatory Commission for a determination at a later date by that agency in accordance with its standards and procedures, and will prescribe by supplemental order such rates as it finds to be just and reasonable.

ORDER

For the reasons set forth above, pursuant to Section 202(c) of the Federal Power Act, it is ordered that:

A. Consistent with the requirements set forth below, the entities listed on Attachment A will make arrangements to generate, deliver, interchange, and transmit electric energy when, as, and in such amounts as may be requested by the California Independent System Operator (California ISO), acting as agent for and on behalf of Scheduling Coordinators (as that term is defined in the California ISO tariff on file at the Federal Energy Regulatory Commission).

B. The entities listed in Attachment A are only required under the terms of this order to sell electricity to the ISO that is available in excess of electricity needed by each entity to render service to its firm customers.

C. This order is effective immediately and expires at 3:00 a.m., EST, December 21, 2000, unless altered or revoked by further order.

D. The entities in Attachment A are not required to deliver energy or services under the terms of this order until 12 hours after the California ISO has filed with the Department of Energy (DOE) a signed certification that it has been unable to acquire in the market adequate supplies of electricity to meet system demand, and, as a consequence, it has, or reasonably anticipates, an "inadequate fuel or energy supply" as defined in 10 C.F.R. § 205.375. In order to continue to avail itself of this order, the California ISO is required to submit to DOE a further certification as set forth in the preceding sentence every twenty-four hours until the expiration of the order. This certification should be submitted to Paul Carrier, Department of Energy, Office of Energy Emergencies, Office of Policy, PO-5, 1000 Independence Avenue, S. W., Washington, D.C. 20585, (202) 586-5659, fax: (202) 586-5391, e-mail: Paul.Carrier@hq.doe.gov. The California ISO shall provide a copy of all certifications to the entities in Attachment A at the time it provides them to DOE.

E. The California ISO must inform each entity subject to this order of the amount and type of energy or services requested by 9:00 p.m., EST, the day before the requested service. In making requests for power pursuant to this order, to the extent feasible, the California ISO is directed to allocate those requests among the entities listed in Attachment A in proportion to each entity's available excess power.

F. The terms of any arrangement made between the entities subject to this order and the California ISO pursuant to this order are to be as agreed to by the parties. If no agreement as to terms can be reached, I will immediately prescribe the conditions of service and refer the rate issue to the Federal Energy Regulatory Commission for a determination at a later date by that agency in accordance with its standards and procedures, and will prescribe by supplemental order such rates as it finds to be just and reasonable.

Issued in Washington, D. C., on December 14, 2000

Bill Richardson

Bill Richardson
Secretary

Attachment

EXHIBIT 23-2

Order No. 202-05-1

Pursuant to the authority vested in me by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in Texas due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, a shortage of facilities for the transmission of electric energy and other causes, and that issuance of this order will serve to alleviate the emergency and serve the public interest.

As a result of the massive devastation caused by Hurricane Rita, which further exacerbated the dire conditions caused by Hurricane Katrina, large portions of the areas affected by the hurricanes are without electricity, posing a threat to human life and health. It is my judgment that in these circumstances, the order I am issuing today will meet the emergency and serve the public interest because it will alleviate electricity shortages and protect the life and health of the people in the affected areas.

Based on my determination set forth above, I hereby order:

Effective immediately, CenterPoint Energy is authorized and directed to temporarily connect at distribution and transmission level voltages such as 12.5kV, 13.2kV, 25kV, 69kV, 138kV, and 230kV to restore power to Entergy Gulf States, Inc. as well as electric cooperatives and municipal customers within the State of Texas. Pursuant to section 202(d) of the Federal Power Act, during the continuance of this order, any person engaged in the transmission and sale of electric energy and not otherwise subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) may make such temporary connections with any public utility subject to the jurisdiction of FERC and shall not become subject to FERC jurisdiction as a result of that temporary connection.

This order shall be effective upon its issuance and shall expire at 12:01 a.m., November 1, 2005.

Issued in Washington, D.C. at 12:40 pm this 28th day of September, 2005.

Samuel W. Bodman
Secretary of Energy

EXHIBIT 23-3

Department of Energy
Washington, DC 20585

September 30, 2005

Order No. 202-05-2

Pursuant to the authority vested in me by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in the State of Texas due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, a shortage of facilities for the transmission of electric energy and other causes, and that issuance of this order will serve to alleviate the emergency and serve the public interest.

As a result of the massive devastation caused by Hurricane Rita, which further exacerbated the dire conditions caused by Hurricane Katrina, large portions of the areas affected by the hurricanes are without electricity, posing a threat to human life and health. It is my judgment that in these circumstances, the order I am issuing today will meet the emergency and serve the public interest because it will alleviate electricity shortages and protect the life and health of the people in the affected areas.

Based on my determination set forth above, I hereby order:

Effective immediately, TXU Electric Delivery is authorized and directed to temporarily connect and energize its existing Huntington to Etoile 138kV line for the purpose of delivering electricity to Deep East Texas Electric Cooperative, a utility that under normal conditions is served by Entergy Gulf States, Inc. Pursuant to section 202(d) of the Federal Power Act, during the continuance of this order, any person engaged in the transmission and sale of electric energy and not otherwise subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) may make such temporary connections with any public utility subject to the jurisdiction of FERC and shall not become subject to FERC jurisdiction as a result of that temporary connection.

This order shall be effective upon its issuance and shall expire at 12:01 a.m., November 1, 2005.

Issued in Washington, D.C. at 3:45 PM this 30th day of September, 2005.

Samuel W. Bodman
Secretary of Energy

Printed with soy ink on recycled paper

EXHIBIT 23-4

The Secretary of Energy
Washington, DC 20585

Order No. 202-08-1

Pursuant to the authority vested in me by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in Texas due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, a shortage of facilities for the transmission of electric energy and other causes, and that issuance of this order will serve to alleviate the emergency and serve the public interest.

As a result of the massive devastation caused by Hurricane Ike, large portions of the areas affected by the hurricane are without electricity, posing a threat to human life and health. It is my judgment that in these circumstances, the order I am issuing today will meet the emergency and serve the public interest because it will alleviate electricity shortages and protect the life and health of the people in the affected areas.

Based on my determination set forth above, I hereby order:

Effective immediately, CenterPoint Energy is authorized and directed to temporarily connect at distribution and transmission level voltages such as 12.5kV, 13.2kV, 25kV, 69kV, 138kV, and 230kV to restore power to Entergy Gulf States, Inc. as well as electric cooperatives and municipal customers within the State of Texas. Pursuant to section 202(d) of the FPA, 16 U.S.C. 824a(d), during the continuance of this order, any person engaged in the transmission and sale of electric energy and not otherwise subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) may, pursuant to this order, make such temporary connections with any public utility subject to the jurisdiction of FERC and shall not become subject to FERC jurisdiction as a result of that temporary connection.

This order shall be effective upon its issuance and shall expire at 12:01 a.m., November 1, 2008.

Issued in Washington, D.C. at 1600 this 14th day of September, 2008.

Samuel W. Bodman
Secretary of Energy

Printed on recycled paper

EXHIBIT 23-5

The Secretary of Energy

Washington, DC 20585

Order No. 202-20-1

Pursuant to the authority vested in me by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in Texas due to Hurricane Laura (13L) making landfall the morning of August 27th as a strong Category 4 Hurricane. Large portions of the areas affected by Hurricane Laura are and will be without reliable electricity for a period of time, posing a threat to human life and health. It is my judgment that in these circumstances, the order I am issuing today will meet the emergency and serve the public interest because it will alleviate electricity shortages and protect the life and health of the people in the affected areas.

On August 23 and 24, 2020, the President issued Emergency Declarations for Louisiana (EM-3538) and Texas (EM-3540), ordering Federal assistance to supplement State and local response efforts due to the emergency conditions resulting from Hurricane Laura. On August 25, 2020, the President amended the emergency declarations for Louisiana and Texas, expanding the declarations to cover emergency protective response actions that State, local, and tribal officials take in the areas affected by Hurricane Laura.

On August 26, 2020, CenterPoint Energy Houston Electric, LLC (CEHE) filed an application requesting that the Secretary of Energy determine that an emergency exists in Texas within the meaning of FPA section 202(c), and issue an order authorizing a temporary connection as necessary for CEHE to assist in the restoration of power to Entergy Texas, Inc. (Entergy) and electric cooperatives and municipal customers within the State of Texas, and for CEHE to receive similar assistance due to the devastating effects of Hurricane Laura making landfall near the Texas-Louisiana border as a dangerous Category 4 hurricane on the Saffir-Simpson Hurricane Wind Scale. The proposed connection would occur via an existing, permanent tie-line authorized by the Federal Power Commission for emergency use only pursuant to section 202(d) of the FPA.[1] The tie-line is maintained in "open" condition on both ends and is only closed in emergency situations that necessitate its use consistent with the FPA and applicable orders. Without this emergency service, restoration of electric service to customers in the area could be delayed.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. As any temporary connection would affect an existing tie-line, it should not result in generation that would exceed emissions limitations. Therefore, this order is not anticipated to result in a conflict with a requirement of any Federal, State, or local environmental law or regulation.

Based on my determination set forth above, I hereby order:

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[1] *See Houston Lighting & Power Co.*, 19 FPC 819 (1958).

Effective immediately, CEHE is authorized and directed to temporarily connect, at transmission and distribution levels such as 12.5 kilovolts (kV), 13.2-kV, 25-kV, 34.5-kV, 69-kV, 138-kV, and 230-kV to the system of Entergy so that CEHE and Entergy may provide emergency assistance to each other if necessary to restore electric service. CEHE will utilize an existing, permanent 138-kV tie-line located between Dayton, Texas and Crosby, Texas, to accomplish the interconnection.

Pursuant to section 202(d) of the Federal Power Act, during the continuance of this order, any person or municipality engaged in the transmission and sale of electric energy and not otherwise subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) may make such temporary connections with any public utility subject to the jurisdiction of FERC, and shall not become subject to FERC jurisdiction as a result of that temporary connection.

CEHE is directed to report all dates that temporary connection of distribution and transmission lines occurred, the location of the temporary connection of distribution or transmission lines, and the quantity of energy delivered (in watt-hours) by October 26, 2020.

This order shall be effective upon its issuance and shall expire at 23:59 Central Daylight Time on October 12, 2020.

Issued in Washington, D.C. at 5:00 PM Eastern Daylight Time on this 27th day of August 2020.

Dan Brouillette
Secretary of Energy

EXHIBIT 23-6

Department of Energy

Washington, DC 20585

Order No. 202-20-2

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated to the Deputy Secretary of Energy by paragraph 1.11(A) of Delegation Order No. 00-001.00G (Apr. 10, 2018), and re-delegated to the Assistant Secretary for Electricity on September 6, 2020, and for the reasons set forth below, I hereby determine that an emergency exists in California due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

On September 6, 2020, the California Independent System Operator (CAISO), the Regional Transmission Organization whose service territory includes California and a portion of Nevada, filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of bulk electric power system."

Since August, California has experienced several periods of extreme heat, some of which have resulted in rolling blackouts. On September 2, 2020, California Governor Gavin Newsom issued an emergency proclamation to help alleviate the stress on the state's power grid due to an "Extreme Heat Event." In declaring a statutory emergency, the proclamation cited a number of factors and observations, including the following:

- "[B]eginning on September 2, 2020, a significant heat wave struck California, bringing widespread temperatures well in excess of 100 degrees throughout the State;"
- "[T]he National Weather Service [has] issued multiple Excessive Heat Warnings within [California];"
- "[T]he Extreme Heat Event has and will continue to put significant demand and strain on California's energy grid; and"
- "[T]he Extreme Heat Event is expected to last through at least September 7, 2020."

The proclamation authorizes emergency use of stationary generators, portable generators, and "auxiliary engines by ocean-going vessels berthed in California ports," and directs the state's Air Resources Board to "exercise maximum discretion to permit the use of stationary and portable generators or auxiliary ship engines to reduce the strain on the energy infrastructure and increase energy capacity." The proclamation also

suspends "[a]ny permit, regulation or law prohibiting, restricting or penalizing the use of stationary or portable generators or auxiliary ship engines" as allowed by the proclamation order.

On September 3, the CAISO issued a statewide flex alert for September 5-7, encouraging voluntary load reduction between 3:00 p.m. and 9:00 p.m. local time each day. The alert warns that consumers should "be prepared for potential power outages, both planned and unplanned during heat waves, especially in extremely high temperatures that last multiple days," noting that "[h]ot weather can also impact generation and transmission equipment, as it runs harder and longer with less time to cool, which can cause machinery failure." The alert explains that there is little energy available to import due to high heat predicted throughout the West, and that the wildfires in the state may take out transmission lines or cause lines to be shut down for the safety of firefighters in the area.

The CAISO notes that "[e]lectric demand forecasts have continued to increase since the issuance of the California Governor's emergency proclamation and the CAISO balancing authority area has lost additional generation supply because of wildfires." Application at 3. To address the situation, the "CAISO has started to direct all generators in its balancing authority area to produce to their maximum capability during certain times of the day," and has gone so far as to allow, when reliable and safe based on currently operating conditions, "certain generators to generate more than their interconnection capacity to provide additional power to the grid." *Id.* at 3. The impetus for the Application, however, arose on September 5, 2020, when the operator of the natural gas-fired resources identified in Exhibit A of the Application informed the CAISO that it could not produce to its maximum generation capability without exceeding its federal air quality or other permit limitations. *Id.* "The CAISO is informed and believes these limitations involve both permit limitations under federal law for nitrogen oxide emissions and ammonia releases as well as a limitations regarding fuel and ammonia throughput." *Id*.

The CAISO requests "that the Secretary issue an order immediately, effective September 6, 2020, authorizing specific electric generating units located within the CAISO balancing authority area to operate at their maximum generation output levels when directed to do so by the CAISO, notwithstanding air quality or other permit limitations." *Id.* at 1. The generating units specified are units 1 - 5 at the Walnut Creek Energy Park in the City of Industry, California; units 5/6 and 7/8 at the El Segundo Energy Center in El Segundo, California; and units 1 - 4 at the Long Beach Generating Station located in Long Beach, California. *Id.* For purposes of this Order, these units are referred to as the "Specified Resources." Collectively, they represent up to as much as 100 MW. The CAISO requests "such order be entered today, September 6, 2020, and remain effective for a period of seven (7) days, without prejudice to the possible issuance of further orders as necessary to address the emergency…[to] ensure additional supply is

available during a period in which California may continue to experience extreme weather and wildfires that have forced generation out of service." *Id*. at 2.

Given the emergency nature of the expected load stress, the responsibility of the CAISO to ensure maximum reliability on its system, and the ability of the CAISO to identify and dispatch generation necessary to meet the additional load, I have determined that additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. The CAISO anticipates that this Order may result in exceedance of National Ambient Air Quality Standards under the Clean Air Act and notes that the Specified Resources are located in different communities within California and should not result in any disproportionate impact on a single community. *Id.* at 4. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by the CAISO for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From September 6, 2020, to September 13, 2020, in the event that the CAISO determines that generation from the Specified Resources is necessary to meet the exceptional levels of electricity demand that the CAISO anticipates in California, I direct the CAISO to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in California between the hours of 14:00 Pacific Daylight Time and 22:00 Pacific Daylight Time on days when the demand on the CAISO system exceeds expected energy and reserve requirements.

B. The CAISO shall select the combination of units that meets the reliability emergency and minimizes environmental impact. Consistent with good utility practice, the CAISO shall exhaust all reasonably and practically available resources, including demand response and identified behind-the-meter generation resources to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources.

C. By September 21, 2020, the CAISO shall report all dates between September 6, 2020, and September 13, 2020, on which the Specified Resources were

operated, the hours of operation, and the estimated air emissions (including nitrogen oxides and ammonia releases) and fuel and ammonia throughput associated with operating each unit. The CAISO shall submit a final report by October 13, 2020, with any revisions to the information reported on September 21.

D. This Order shall be effective upon its issuance, and shall expire at 23:59 Pacific Daylight Time on September 13, 2020, with the exception of the reporting requirements in paragraph C. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. this 6th day of September, 2020.

Bruce J. Walker

Digitally signed by Bruce J. Walker
Date: 2020.09.06 17:19:49 -04'00'

Bruce Walker
Assistant Secretary for Electricity

EXHIBIT 23-7

Department of Energy
Washington, DC 20585

Order No. 202-21-1

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in Texas due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

On February 14, 2021, the Electric Reliability Council of Texas (ERCOT), the Independent System Operator (ISO) whose service territory includes 90 percent of the electric customers in the state of Texas, filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of bulk electric power system."

ERCOT is in the beginning stages of an unprecedented cold weather event brought on by a rare, southward excursion of the jet stream into the South Central United States. Temperatures for Sunday and Monday in many parts of Texas are forecasted to drop well below the lowest temperatures experienced in several decades, and abnormally low temperatures are expected to persist for several more days. This weather event is expected to result in record winter electricity demand that will exceed even ERCOT's most extreme seasonal load forecasts.

On February 12, 2021, Greg Abbott, the Governor of the State of Texas declared a state of disaster in all 254 Texas counties due to severe weather posing an "imminent threat of widespread and severe property damage, injury, and loss of life due to prolonged freezing temperatures, heavy snow, and freezing rain statewide." On the morning of February 14, ERCOT issued a system-wide conservation notice addressing the expected system emergency and describing steps that homeowners and businesses can take to reduce system demand.[1] ERCOT has also worked with state agencies to take measures that maximize generation availability in Texas. For example, on February 12, the Railroad Commission of Texas issued an Emergency Order pursuant to Texas Utilities Code affecting the gas utility systems in the state. The order specified increasing the priority of gas supplies to ERCOT generators. ERCOT's application also noted that the "Texas Commission on Environmental Quality has indicated that it will provide enforcement discretion to generators in the ERCOT region that may exceed state emissions requirements during emergency conditions."

According to ERCOT, the measures taken by ERCOT and other state agencies may not prove sufficient to avoid rotating outages of as much as 4,000 MW. Moreover,

[1] ERCOT, *Grid Operator Requests Energy Conservation for System Reliability*, www.ercot.com/news/releases/show/225151.

ERCOT has been alerted that numerous generation units will be unable to operate at full capacity without violating federal air quality or other permit limitations.

ERCOT requests that the Secretary issue an order immediately, effective February 14, 2021 through February 19, 2021, authorizing "the provision of additional energy from all generation units subject to emissions or other permit limits" in the ERCOT region. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-21-1 Resources List, as described below.

Given the emergency nature of the expected load stress, the responsibility of ERCOT to ensure maximum reliability on its system, and the ability of ERCOT to identify and dispatch generation necessary to meet the additional load, I have determined that additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. ERCOT anticipates that this Order may result in exceedance of emissions of sulfur dioxide, nitrogen oxide, mercury, and carbon monoxide emissions, as well as wastewater release limits. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by ERCOT for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From February 14, to February 19, 2021, in the event that ERCOT determines that generation from the Specified Resources is necessary to meet the electricity demand that ERCOT anticipates in Texas during this event, I direct ERCOT to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in the ERCOT region when the demand on the ERCOT system exceeds expected energy and reserve requirements. Specified Resources are those natural gas, coal, or distillate fuel oil generating units set forth on the Order 202-21-1 Resource List, subject to updates directed here and as described in paragraph D, which the Department shall post on www.energy.gov. ERCOT is directed to update Exhibit A to its Application with the anticipated category of environmental impact (i.e. sulfur dioxide, nitrogen oxide, mercury, carbon monoxide emissions, wastewater release, other air pollutants) by 21:00 Central Standard Time on February 15, 2021.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by ERCOT for reliability purposes. Consistent with good utility practice, ERCOT shall exhaust all reasonably and

practically available resources, including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions, to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources. ERCOT shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

In furtherance of the foregoing and, in each case, subject to the exhaustion of all available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions available to support grid reliability:

(i) with respect to any Specified Resource that is an ERCOT Generation Resource or Settlement Only Generator whose operator notifies ERCOT that the unit is unable, or expected to be unable, to produce at its maximum output due to an emission or effluent limit in any federal environmental permit, ERCOT shall ensure that such Specified Resource is only allowed to exceed any such limit during a period for which ERCOT has declared an Energy Emergency Alert (EEA) Level 2 or Level 3. This incremental amount of restricted capacity would be offered at a price no lower than $1,500/MWh. Once ERCOT declares that such an EEA Level 2 or Level 3 event has ended, the unit is required to immediately return to operation within its permitted limits; and

(ii) with respect to any Specified Resource that is an ERCOT Generation Resource whose operator notifies ERCOT that the unit is offline or would need to go offline due to an emission or effluent limit in any federal environmental permit, and to which ERCOT has issued a Reliability Unit Commitment (RUC) instruction, the operator may make all of the unit's capacity available to ERCOT for dispatch during a period for which ERCOT has declared an EEA Level 2 or Level 3. This incremental amount of restricted capacity would be offered at a price no lower than $1,500/MWh. Once ERCOT declares that such an EEA Level 2 or Level 3 event has ended, the unit is required to immediately return to operating at a level below the higher of its minimum operating level or the maximum output allowable under the permitted limit.

In the event ERCOT identifies the need to exceed other relevant environmental permitting levels, ERCOT shall specifically identify such permitting levels and DOE will consider ERCOT's request in good faith.

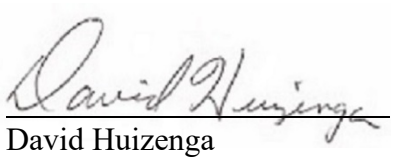
C. All entities must comply with environmental requirements to the maximum extent necessary to operate consistent with the emergency conditions. This Order does not provide relief from an entity's obligations to purchase allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. In the event that ERCOT identifies additional generation units that it deems necessary to operate in excess of federal environmental permitting limits in order to maintain the reliability of the power grid in the ERCOT region when the demand on the ERCOT system exceeds expected energy and reserve requirements, including any such entity to which ERCOT intends to issue a Reliability Unit Commitment (RUC), ERCOT shall provide prompt written notice to the Department of Energy at AskOE@hq.doe.gov identifying in an updated Exhibit A to its Application such additional generation units, the fuel type of such unit, and the anticipated category of environmental impact, at 9:00 Central Standard Time or 21:00 Central Standard Time, whichever follows closest in time to the unit identification by ERCOT to the greatest extent feasible. Such additional generation unit shall be deemed a Specified Resource for the purpose of this Order for the hours prior to the required written notice to the Department, and ERCOT may dispatch such additional generation units, provided that if the Department of Energy notifies ERCOT that its does not approve of such generation unit being designated as a Specified Resource, such generation unit shall not constitute a Specified Resource upon notification from the Department. The Department shall post an updated Order 202-21-1 Resource List as soon as practicable following notification from ERCOT under this paragraph.

E. ERCOT shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By March 1, 2021, ERCOT shall report all dates between February 14, 2021, and February 19, 2021, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting limits, including sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. ERCOT shall submit a final report by March 31, 2021, with any revisions to the information reported on March 1, 2021. In addition, ERCOT shall provide information to the Department quantifying the net revenue associated with generation in excess of environmental limits accruing to non-RUC units in connection with orders issued by the Department pursuant to Section 202(c) of the Federal Power Act.

F. This Order shall be effective upon its issuance, and shall expire at 11:59 p.m. Central Standard Time Friday, February 19, 2021, with the exception of the reporting requirements in paragraph E. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 8:51 PM Eastern Standard Time on this 14th day of February, 2021.



David Huizenga
Acting Secretary of Energy

EXHIBIT 23-8

Department of Energy

Washington, DC 20585

Order No. 202-21-2

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated to the Deputy Secretary of Energy by paragraph 1.12(A) of Delegation Order No. 00-001.00H (Oct. 2, 2020), and for the reasons set forth below, I hereby determine that an emergency exists in California due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On September 7, 2021, the California Independent System Operator Corporation (CAISO), the Independent System Operator whose service territory includes California and a portion of Nevada, filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department or DOE) "to preserve the reliability of [the] bulk electric power system in California."

California has experienced several periods of extreme heat, drought conditions, and wildfires. Such conditions are expected to occur over the next 60 days and threaten the reliable operation of the bulk electric power system in California. Application at 2-3.

Since June 2021, California Governor Gavin Newsom has issued three proclamations of a state of emergency regarding electricity. In declaring a statutory emergency, the proclamations cited a number of factors and observations, including the following as set forth in the July 30 proclamation:

- As a result of drought conditions, "water supplies in California's reservoirs have dropped to levels so low that hydroelectric power plants have had to reduce or cease production, leading to a reduction of nearly 1,000 megawatts of capacity and further exacerbating the drought's impact on California"

- In June and July 2021, states of emergencies were proclaimed due to "record-breaking extreme heat events that hit California and other Western states, increasing residents' demand and putting significant demand and strain on California's energy grid"

- "[A]t the same time as the July 2021 Extreme Heat Event, the Bootleg Fire in Southern-Central Oregon threatened the California-Oregon Intertie, which delivers power from the Pacific Northwest into California, and reduced electricity supply into California by almost 4,000 megawatts"

- Due to "continuing wildfires, ongoing drought, and extreme heat conditions caused by climate change, California currently faces an additional projected energy supply shortage of up to 3,500 megawatts during the afternoon-evening 'net-peak' period of high power demand on days when there are extreme weather conditions, which is even greater than projected in May 2021"

The July 30, 2021 emergency proclamation further describes the extreme climate impacts across the West and their ongoing impacts on electric reliability. The "proclamation identifies an energy supply shortage in California this summer and in the summer of 2022." *Id*. at 4. The proclamation authorizes several measures aimed at mitigating the emergency, including authorizing the California Energy Commission (CEC) "to expedite amendments to existing power plant licenses and issue new licenses to emergency and temporary generators." *Id*. The proclamation also directs the California Air Resources Board (CARB) "to develop and implement a plan to mitigate the effects of additional emissions authorized by the proclamation. The mitigation plan must include plans to invest in programs to improve air quality in communities, with a particular focus on disadvantaged communities, and to reduce risk to sensitive populations." *Id*.

The Application includes a letter from the CARB to DOE regarding the environmental mitigation plan. *Id*. at Exhibit F. In its letter, the CARB confirms to the Department that the state-funded environmental mitigation plan will address emissions authorized by the Order and that the CARB will determine details of environmental mitigation options through a public process. *Id*. Further, the CARB will gather "local perspectives on how best to mitigate the effects of local increases of emissions to potential and historically affected parties." *Id*. The CARB letter also supports the continued application of the requirements under its Mandatory Reporting of Greenhouse Gas Emissions Regulation (MRR) and California's Cap-and-Trade Regulation during the pendency of an order under FPA section 202(c). *Id*.

Description of Mitigation Measures

In its Application, the CAISO described actions it has taken in order to alleviate the generation shortfall, including: 1) denying requests of five existing generating facilities that notified the CAISO of their intent to mothball or retire and designating those facilities as Reliability Must-Run units; 2) declaring a capacity procurement mechanism significant event that triggers authority to procure additional electric generating capacity under its tariff approved by Federal Energy Regulatory Commission; 3) working to accelerate energization of projects in its interconnection queue; and 4) consulting with other California stakeholders in "implementing a utility load reduction program that provides some relief to the bulk power system during stressed grid conditions." *Id*. at 4-5. In addition, the Application explains that the California Department of Water Resources (CDWR) has "undertaken procurement efforts to deploy mobile, modular General Electric TM2500 aero-derivative gas turbine generators at existing generating facility sites," four of which are included as Covered Resources (defined below). *Id*. at 5.

California is also engaged in long term efforts to mitigate the supply shortfall and address the reliability of the bulk electric power system in California. In June 2021, the California Public Utility Commission (CPUC) "issued an order directing its jurisdictional load serving entities to procure 11,500 MW of new electricity resources to come online between the years 2023 and 2026." *Id.* The CPUC order includes requirements that this additional capacity come solely from zero-emission sources, including specific requirements for long-duration storage and clean firm generation. CPUC Decision No. 21-06-035 - Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026), 35-38, 46-48.

The Application describes emergency procedures the CAISO can use to meet insufficient supply in the day-ahead market, such as "restricting transmission and generator maintenance activities, calling for voluntary conservation, requesting additional supply bids to meet expected energy and reserve requirements, seeking emergency assistance from neighboring balancing authorities, and deploying emergency demand response." Application at 5. The CAISO plans to "direct generators to produce more MW than their interconnection capacity for specific hours and day(s) during the emergency event if reliability studies find the transmission system can support their increased output." *Id*. at 5-6. However, the CAISO Application indicates "that these measures may not be sufficient to avoid load curtailments absent issuance of an emergency order." *Id*. at 6.

Request for Order

The CAISO "requests that the Secretary issue the requested emergency order by September 10, 2021, or a[s] soon as possible thereafter, authorizing specific electric generating resources (Covered Resources) located within California to test and operate at their maximum generation output levels when directed to do so by the CAISO, notwithstanding air quality or other permit limitations." *Id*. at 1. The Covered Resources that this Order pertains to are listed below and more fully described in Application Exhibit A – List of Covered Resources:

- Midway Sunset Cogeneration Facility Unit C in Fellows, California (Midway Sunset Unit C);
- The Alamitos Energy Center in Long Beach, California;
- The Huntington Beach Energy Project in Huntington Beach, California;
- The Walnut Creek Energy Park in the City of Industry, California;
- Greenleaf Unit 1 in Yuba City, California (Greenleaf Unit 1); and
- The Roseville Energy Park in Roseville, California (Roseville Energy Park).

The CAISO indicates that "the owners of the Covered Resources will not make additional identified capacity available absent an order from the Secretary under FPA section 202(c)." *Id*. at 6. The CAISO noted that the electric generating units identified in its Application "have de-rated their facilities based on conditions set forth in their permits regarding nitrogen oxide emissions, heat output as well as fuel throughput." Accordingly, the CAISO anticipates that the emergency order it requested "may result in exceedance of National Ambient Air Quality Standards (NAAQS) under the Clean Air Act." *Id*. In addition, the Midway Sunset Unit C is unable to satisfy a permit requirement that it operate in support of an industrial host. *Id*. The new General Electric TM2500 aero-derivative gas turbine generators deployed at the Greenleaf Unit 1 site and Roseville Energy Park do not yet have required best available control technology to control emissions and have not completed permitting processes to obtain their pre-construction permits under Title I, or operating permits under Title V, of the Clean Air Act. *Id*. The CAISO expects that, in the absence of an order under FPA section 202(c), over 200 megawatts of available generating capacity will not be available for dispatch as a result of these constraints. *Id*. "Authorizing these facilities to operate, notwithstanding permit and other limitations, would help mitigate shortages of expected energy and reserve requirements." *Id*.

ORDER

Given the emergency nature of the expected load stress, the responsibility of the CAISO to ensure maximum reliability on its system, and the ability of the CAISO to identify and dispatch generation necessary to meet the additional load, I have determined that additional dispatch of the Covered Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). These factors, including as declared in the Governor's July 30 emergency proclamation and as described in the Application, have led to my determination that an emergency exists in California due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest. In line with the emergency proclamation's anticipation of energy shortages this summer, this Order is limited to a 60-day period. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. The CAISO anticipates that this Order may result in exceedance of NAAQS under the Clean Air Act and other conflicts with environmental law. Based on the CAISO Application, the distance between the Covered Resources is large enough that no two of the Covered Resources are expected to impact the same community. *Id.* at 6-7. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by the CAISO for reliability purposes, and subject to the conditions set forth in this Order.

Based on my determination of an emergency set forth above, I hereby order:

A. From September 10, 2021 to November 9, 2021, in the event that the CAISO determines that generation from the Covered Resources is necessary to preserve the reliability of the bulk electric power system in California, I direct the CAISO to dispatch such unit or units and to order their operation solely under the following conditions:

   i. the issuance and continuation of an Energy Emergency Alert Level 2[1] condition or greater between the hours of 14:00 Pacific Daylight Time and 22:00 Pacific Daylight Time after exhausting all reasonably and practically available resources;

   ii. a transmission emergency[2] that requires operation of the Covered Resource to prevent or mitigate load curtailment during any operating hour; or

   iii. limited testing directed by the CAISO or synchronization of Midway Sunset Unit C, Greenleaf Unit 1, and Roseville Energy Park during periods of lowest electric demand for natural gas resources, as determined by the CAISO.

B. Consistent with good utility practice, the CAISO shall exhaust all reasonably and practically available resources, including demand response and identified behind-the-meter generation resources to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Covered Resources.

C. All operation of the Covered Resources must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators. Covered Resources must comply with the requirements of the CARB MRR and California's Cap-and-Trade regulation, to the extent applicable.

D. The CAISO shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time. By December 1, 2021, the CAISO shall report source specific data for all dates

[1] For the purposes of this Order, "Energy Emergency Alert Level 2" has the meaning set forth in Section 3.6.4 of the California ISO System Emergency Operating Procedure Version 13.1, Effective Date August 20, 2021 (CAISO Emergency Operating Procedure).
[2] For the purposes of this Order, "transmission emergency" has the meaning set forth in Section 3.5 of the CAISO Emergency Operating Procedure.

between September 10, 2021 and November 9, 2021, on which the Covered Resources were operated, including, for each unit, (1) the hours of operation, as well as the hours in which any permit limit was exceeded and (2) a preliminary description of each permit term that was exceeded and the manner in which such exceedance occurred. The CAISO shall also submit a final report by January 7, 2022, with any revisions to the information reported on December 1, 2021. The environmental information submitted in the final report shall also include the following information:

i. Emissions data in pounds per hour for each Covered Resource unit, for each hour of the operational scenario, for CO, NOx, PM2.5, PM10, volatile organic compounds (VOC), and SO_2;

ii. Emissions data must include the actual emissions (lbs/hr), permitted operating/emission limits, and the actual incremental emissions above the permit limits, except that for emissions units not equipped with continuous emission monitoring systems, actual emissions shall be calculated using source test data;

iii. Stack parameters for each Covered Resource unit: stack height, exit diameter, exit gas temperature, and exit velocity (or volumetric flow rate). Temperature and velocity must be the values applicable to the operations above permit limits;

iv. The actual hours that each Covered Resource unit operated in excess of permit limits or operated without otherwise-required permits;

v. Information provided to the CARB in response to the CARB's development and implementation of the plan to mitigate the effects of additional emissions authorized by the July 30, 2021 proclamation; and

vi. Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order.

E. The CAISO shall inform all affected communities where all Covered Resources operate that the CAISO has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows the CAISO to do. The CAISO shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph D above.

F. This Order shall not preclude the need for any Covered Resource to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. The CAISO shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

H. This Order shall be effective upon its issuance, and shall expire at 23:59 Pacific Daylight Time on November 9, 2021, with the exceptions of paragraphs F and G and the reporting and analysis requirements in paragraphs D and E. Renewal or amendment of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 16:26 Eastern Time on this 10th day of September, 2021.

David M. Turk
Deputy Secretary of Energy

EXHIBIT 23-9

Department of Energy
Washington, DC 20585

Order No. 202-22-1

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated to the Deputy Secretary of Energy by paragraph 1.12(A) of Delegation Order No. S1-DEL-S2-2022 (Mar. 14, 2022), and further delegated by the Deputy Secretary by email correspondence (Sept. 2, 2022), and for the reasons set forth below, I hereby determine that an emergency exists in California due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On September 1, 2022, the California Independent System Operator Corporation (CAISO), the Independent System Operator whose service territory includes most of California and a portion of Nevada, filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of the bulk electric power system in California."

California has experienced several periods of extreme heat, drought conditions, and threat of wildfires. Such conditions are expected to occur over the next several days and threaten the reliable operation of the bulk electric power system in California. Application at 2-3.

On August 31, 2022, California Governor Gavin Newsom issued a proclamation declaring a state of emergency regarding electricity from September 2 through September 7, 2022. In declaring a statutory emergency, the proclamation cited a number of factors and observations, including the following:

- A significant heat wave will bring temperatures "in excess of 100 degrees throughout the State and is forecast to bring record temperatures 10–20 degrees above normal throughout the State, exceeding 110 degrees in some areas"

- The extreme heat will put a significant demand and strain on California's energy grid and is forecast to be a "West-wide event" meaning that energy demand will be high across the region and "California will have limited ability to import energy from [out of state]"

- The CAISO issued a Heat Bulletin forecasting high electric demand during the extreme heat event that will "stress the energy grid, with peak load for electricity projected to reach its highest level of the year, exceeding 48,000 megawatts on September 5, 2022"

- The CAISO is forecasting supply deficiencies of "over 3,000 megawatts during evening hours from September 4, 2022, through September 6, 2022" and advised that emergency interventions would allow energy customers to make contingency plans ahead of the Labor Day holiday weekend.

The proclamation authorizes several measures aimed at mitigating the emergency and avoiding jeopardizing public health or safety, including directing the California Air Resources Board (CARB) to "implement its State-funded Climate Heat Impact Response Program (CHIRP) to mitigate emissions from any operation pursuant to this Proclamation." The proclamation also directs the California Energy Commission (CEC) to "provide information requested by [CARB] to assist with its implementation" of CHIRP.

The Application includes a statement that the CAISO prepared its request in consultation with both CEC and CARB. Application at 2. Furthermore, the CAISO states that both state entities have informed the CAISO they will support any reporting DOE may require under an emergency order. *Id.*

Description of Mitigation Measures

In its Application, the CAISO described actions it has taken in order to alleviate the generation shortfall, including: 1) utilizing its day-ahead market to ensure it has secured sufficient supply to meet its demand for the next operating day and its real-time market to increase incremental supply to meet changes in the day-ahead demand forecast; 2) directing generators to produce more megawatts than their interconnection capacity for specific hours and day(s) during the emergency event if reliability studies find the transmission system can support their increased output; 3) denying requests of generating facilities that notified the CAISO of their intent to mothball or retire and designating those facilities as Reliability Must-Run units to run as cost-of-service units under the terms of the CAISO tariff; and 4) working with the owner of Midway Sunset Cogeneration under its Reliability Must Run agreement to deploy emission controls at one of its units and make an additional 80 megawatts available to the CAISO system. *Id.* at 4-5. In addition, the Application explains that the California Department of Water Resources (CDWR) has "deployed [four] mobile, modular General Electric TM2500 aero-derivative gas turbine generators at existing generating facility sites." *Id.* at 4.

California is also engaged in long-term efforts to mitigate the supply shortfall and address the reliability of the bulk electric power system in California in response to increasing climate change-induced heat waves and drought conditions. The California Public Utilities Commission (CPUC) has issued an order directing its jurisdictional load serving entities to procure 11,500 megawatts of new electricity resources to come online between the years 2023 and 2026. *Id.*; *see also* CPUC Decision No. 21-06-035, Decision Requiring Procurement To Address Mid-Term Reliability (2023-2026), June 30, 2021. Additionally, California enacted Assembly Bill 205 this year, which adopts various measures to enhance electric grid reliability, including the creation of a strategic reserve for use to meet electric demand in extreme events, such as heatwaves. Application at 4–5.

The Application describes emergency procedures the CAISO can use to meet insufficient supply in the day-ahead market, such as "restricting transmission and generator maintenance activities, calling for voluntary conservation, requesting additional supply bids to meet expected energy and reserve requirements, seeking emergency assistance from neighboring balancing authorities, and deploying emergency demand response." *Id.* at 5. The CAISO plans to "direct generators to produce more MW than their interconnection capacity for specific hours and day(s) during the emergency event if reliability studies find the transmission system can support their increased output." *Id*. However, the CAISO Application indicates "that these measures may be insufficient to avoid load curtailments in the coming days" and issuing an emergency Order will "provide another tool for the CAISO to help mitigate this risk." *Id*.

Request for Order

The CAISO "requests that the Secretary issue the requested emergency order by Friday, September 2, 2022, or a[s] soon as possible thereafter, authorizing specific electric generating resources (Covered Resources) located within California to operate at their maximum generation output levels between 2:00 p.m. and 10:00 p.m., when directed to do so by the CAISO, notwithstanding air quality or other permit limitations." *Id*. at 1. The Covered Resources that this Order pertains to are the three natural gas-fired electric generating facilities listed below and more fully described in Application Exhibit A – List of Covered Resources:

- The Alamitos Energy Center in Long Beach, California;
- The Huntington Beach Energy Project in Huntington Beach, California;
- The Walnut Creek Energy Park in the City of Industry, California;

The CAISO indicates that "the owners of the Covered Resources cannot make additional identified capacity available absent an order from the Secretary under FPA [section] 202(c)." *Id*. at 5. The CAISO noted that the electric generating units identified in its Application "have de-rated their facilities based on conditions set forth in their permits regarding nitrogen oxide emissions, heat output, and fuel throughput." *Id.* Accordingly, the CAISO anticipates that, if the Covered Resources are dispatched in exceedance of their permit limits pursuant to the emergency order it has requested, there will be an increase in nitrogen oxide, ammonia, and carbon monoxide emissions that "may result in exceedance of National Ambient Air Quality Standards (NAAQS) under the Clean Air Act." *Id*. The CAISO expects that, in the absence of an order under FPA section 202(c), these constraints will collectively preclude CAISO dispatch of approximately 28 megawatts of available generating capacity. *Id*. "Authorizing these facilities to operate, notwithstanding permit and other limitations, would help mitigate shortages of expected energy and reserve requirements." *Id*.

ORDER

Given the emergency nature of the expected load stress and generation shortfall, the responsibility of the CAISO to ensure maximum reliability on its system, and the ability of the CAISO to identify and dispatch generation necessary to meet additional load if an order is issued, I have determined that additional dispatch of the Covered Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). These factors, including as declared in the Governor's August 31 emergency proclamation and as described in the Application, have led to my determination that an emergency exists in California due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest. In line with the emergency proclamation's anticipation of near-term energy shortages, this Order is limited to a 7-day period. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation, under the conditions and with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. The CAISO anticipates that this Order may result in exceedance of NAAQS under the Clean Air Act and other conflicts with environmental law. Based on the CAISO Application, while all three Covered Resources are located in Southern California—two in Los Angeles County and one in Orange County—no two Covered Resources are located in the same community. This will limit the cumulative burden of the Order on any one community. *See Id.* at 6. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by the CAISO for reliability purposes, and subject to the conditions set forth in this Order.

Based on my determination of an emergency set forth above, I hereby order:

A. From September 2, 2022, to September 8, 2022, in the event that the CAISO determines that generation from the Covered Resources is necessary to preserve the reliability of the bulk electric power system in California, I direct the CAISO to dispatch such unit or units and to order their operation solely under the following conditions:

   i. the issuance and continuation of an Energy Emergency Alert Level 2[1] condition or greater between the hours of 14:00 Pacific Daylight Time and 22:00 Pacific Daylight Time after exhausting all reasonably and practically available resources; or,

[1] For the purposes of this Order, "Energy Emergency Alert Level 2" has the meaning set forth in Section 3.6.3 of the California ISO System Emergency Operating Procedure, Procedure No. 4420, Version 14.0, Effective Date May 1, 2022 (CAISO Emergency Operating Procedure).

ii. a transmission emergency[2] that requires operation of the Covered Resource to prevent or mitigate load curtailment during any operating hour.

B. Consistent with good utility practice, the CAISO shall exhaust all reasonably and practically available resources, including demand response and identified behind-the-meter generation resources to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Covered Resources.

C. All operation of the Covered Resources must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators. Covered Resources must comply with the requirements of the CARB MRR and California's Cap-and-Trade regulation, to the extent applicable.

D. The CAISO shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time. By October 10, 2022, the CAISO shall report source-specific data for all dates between September 2, 2022, and September 8, 2022, on which the Covered Resources were operated, including, for each unit, (1) the hours of operation, as well as the hours in which any permit limit was exceeded, and (2) a preliminary description of each permit term that was exceeded and the manner in which such exceedance occurred. The CAISO shall also submit a final report by November 14, 2022, with any revisions to the information reported on December 12, 2022. The environmental information submitted in the final report shall also include the following information:

i. Emissions data in pounds per hour for each Covered Resource unit, for each hour of the operational scenario, for CO, NOx, PM2.5, PM10, volatile organic compounds (VOC), and SO_2;

ii. Emissions data must include the actual emissions (lbs/hr), permitted operating/emission limits, and the actual incremental emissions above the permit limits, except that for emissions units not equipped with continuous emission monitoring systems, actual emissions shall be calculated using source test data;

iii. Stack parameters for each Covered Resource unit: stack height, exit diameter, exit gas temperature, and exit velocity (or volumetric flow

[2] For the purposes of this Order, "transmission emergency" has the meaning set forth in Section 3.5 of the CAISO Emergency Operating Procedure.

rate). Temperature and velocity must be the values applicable to the operations above permit limits;

iv. The actual hours that each Covered Resource unit operated in excess of permit limits or operated without otherwise-required permits;

v. Information provided to the CARB in response to the CARB's development and implementation of the plan to mitigate the effects of additional emissions authorized by the August 31, 2022 proclamation;

vi. Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

vii. Information provided by Covered Resources describing how these requirements were met by the Covered Resources while operating under the provisions of this Order.

E. The CAISO shall inform all affected communities where all Covered Resources operate that the CAISO has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows the CAISO to do. The CAISO shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph D above.

F. This Order shall not preclude the need for any Covered Resource to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. The CAISO shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

H. This Order shall be effective upon its issuance, and shall expire at 23:59 Pacific Daylight Time on September 8, 2022, with the exceptions of paragraphs F and G and the reporting and analysis requirements in paragraphs D and E. Renewal or amendment of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 16:00 Eastern Time on this 2nd day of September, 2022.



Kathleen Hogan
Acting Under Secretary for
Infrastructure

EXHIBIT 23-10

Department of Energy
Washington, DC 20585

Order No. 202-22-2

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated to the Deputy Secretary of Energy by paragraph 1.12(A) of Delegation Order No. S1-DEL-S2-2022 (Mar. 14, 2022), and further delegated by the Deputy Secretary by email correspondence (Sept. 2, 2022), and for the reasons set forth below, I hereby determine that an emergency exists in California due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On September 2, 2022, the Balancing Authority of Northern California (BANC) filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department or DOE) "to preserve the reliability of the bulk electric power system in California," and more specifically to allow the BANC Balancing Authority Area (BAA) to request the dispatch of generation within the BANC BAA "that may be necessary for BANC to meet demand in the face of extreme heat." BANC is a joint powers authority whose members include the Sacramento Municipal Utility District and other municipalities, irrigation districts, and public utilities districts. BANC is a registered Balancing Authority with the North American Electric Reliability Corporation and operates as a neighboring BAA to the California Independent System Operator Corporation (CAISO) BAA. On September 4, 2022, BANC filed an *Amended, Supplemented and Clarified Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Amended Application) in response to questions from DOE.

California has experienced several periods of extreme heat, drought conditions, and threat of wildfires. Such conditions are expected to occur over the next several days and threaten the reliable operation of the bulk electric power system in California. The loads from the forecasted heat wave over the next week are expected to push demand for electric energy by BANC members to at or over historical peaks and higher than normally expected planning targets for this time of year. Amended Application at 2.

On August 31, 2022, California Governor Gavin Newsom issued a proclamation declaring a state of emergency regarding electricity from September 2 through September 7, 2022.[1] In declaring a statutory emergency, the proclamation cited a number of factors and observations, including the following:

- A significant heat wave will bring temperatures "in excess of 100 degrees throughout the State and is forecast to bring record temperatures 10–20 degrees

[1] GSS_9534-1E-20220831133826 (ca.gov)

above normal throughout the State, exceeding 110 degrees in some areas (the 'Extreme Heat Event');"

- The extreme heat will put a significant demand and strain on California's energy grid and is forecast to be a "West-wide event" meaning that energy demand will be high across the region and "California will have limited ability to import energy from out-of-state;"

- The CAISO issued a Heat Bulletin forecasting high electric demand during the extreme heat event that will "stress the energy grid, with peak load for electricity projected to reach its highest level of the year, exceeding 48,000 megawatts on September 5, 2022;" and

- The CAISO is forecasting supply deficiencies of "over 3,000 megawatts during evening hours from September 4, 2022, through September 6, 2022" and advised that emergency interventions would allow energy customers to make contingency plans ahead of the Labor Day holiday weekend.

The proclamation authorizes several measures aimed at mitigating the emergency and avoiding jeopardizing public health or safety, including directing the California Air Resources Board (CARB) to "implement its State-funded Climate Heat Impact Response Program (CHIRP) to mitigate emissions from any operation pursuant to this Proclamation." The proclamation also directs the California Energy Commission (CEC) to "provide information requested by [CARB] to assist with its implementation" of CHIRP.

BANC noted that it "has prepared this request in consultation with the California Energy Commission (CEC), the California Governor's Office, and the CAISO." Application at 2.

Description of Mitigation Measures

In its Application, BANC described actions it has taken in order to alleviate the generation shortfall. Electric utilities within BANC, in coordination with CEC, CAISO, and the California Governor's Office, have implemented conservation and other extraordinary efforts to procure additional supply. BANC members have been able to obtain some purchases from the Pacific Northwest (PNW) bilateral wholesale markets to help offset the additional need, but the physical interties with PNW are near physical limits. BANC members have also been making use of demand-side programs, including commercial interruptible load programs, residential peak shaving programs, and public appeals for conservation. Amended Application at 2.

Request for Order

BANC has requested an emergency order to allow the BANC BAA to dispatch the Covered Resource described below within the BANC BAA that may be necessary for

the BANC to meet demand in the face of extreme heat, subject to the terms set forth herein.

The generators for which BANC is seeking this emergency order consist of 24 diesel-fired generator units owned by NTT Global Data Centers Americas (NTT), located at 1312 Striker Ave, Sacramento, CA 95834, known as "CA 2" and more fully described in the Application Exhibit A – List of Covered Resources (NTT Generators or Covered Resource). The Covered Resource plans to participate in the CEC-administered Demand Side Grid Support program that facilitates availability of resources for emergency purposes. Application at 3; Amended Application at 3-4. Therefore, while the Covered Resource has an aggregate installed capacity of 48MW, BANC requests that this emergency order apply only to capacity necessary to supply the load at the NTT facility served by the Covered Resource, up to 26.1 MW (Covered Maximum Output). Amended Application at 3-4.

BANC has requested that the Secretary issue the requested emergency order by Sunday, September 4, 2022, or as soon as possible thereafter, authorizing the Covered Resource to operate at the Covered Maximum Output level between 2:00 p.m. and 10:00 p.m., when directed to do so by BANC, notwithstanding air quality or other permit limitations.

ORDER

Given the emergency nature of the expected load stress and generation shortfall, the responsibility of BANC as the Balancing Authority to balance generation and load in its BAA to ensure maximum reliability on its system, and the ability of BANC to identify and dispatch generation necessary to meet additional load if an order is issued, I have determined that, under the conditions specified below, generation from the Covered Resource is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c) up to the Covered Maximum Output. This determination is based on, among other things:

- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the State of California and within the BANC BAA, including as declared in the Governor's August 31 emergency proclamation and as described in the Application and Amended Application, demonstrate the need for the Covered Resource to contribute to the reliability of the BANC BAA.

- The availability of 26.1 MW of reduced load as enabled by generation from the Covered Resource up to the Covered Maximum Output provides significant assistance by freeing up system generating resources to help alleviate the shortage of generation and meet demand in the BANC BAA.

- The Covered Resource is enrolled in CEC's Demand Side Grid Support (DSGS) program. The DSGS program establishes procedures for qualification, operation, and reporting to ensure that enrolled generation such as the Covered Resource

provides verifiable load reduction and thereby increase available system capacity during energy emergency events.

- The conditions in CEC's DSGS and those specified below restrict operation of the Covered Resource to those circumstances necessary to avoid load shed.

In line with the emergency proclamation's anticipation of near-term energy shortages, this Order is limited to a 5-day period, from September 4, 2022, through September 8, 2022. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation, under the conditions and with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law, and minimize any adverse environmental impacts. BANC anticipates that this Order may result in exceedance of National Ambient Air Quality Standards (NAAQS) under the Clean Air Act and other conflicts with environmental law. This Order would permit operation of the Covered Resource and corresponding emissions of volatile organic compounds (VOCs), nitrogen oxides (NOx), sulfur dioxide (SO_2), coarse particles (PM10), and carbon monoxide (CO), in circumstances not contemplated by the units' Title V permit. Namely, under its Title V permits, the Covered Resource is permitted to operate at certain emission rates during maintenance and when electric service from the serving utility is interrupted by an unforeseeable event, but not in order to assist the utility in avoiding service interruptions for other customers. The Order would permit operation under grid emergency conditions; however, under the conditions specified below, it would not permit exceedance of the emission limits otherwise applicable to the units constituting the Covered Resource, including limits on the pounds of VOC, NOx, SO_2, PM10, and CO emitted per year.

Based on my determination of an emergency set forth above, I hereby order:

A. From September 4, 2022, to September 8, 2022, in the event that BANC determines that generation from the Covered Resource is necessary to preserve the reliability of the bulk electric power system in California, I direct BANC to dispatch such unit or units and to order their operation solely under the following conditions: the issuance and continuation of an Energy Emergency Alert Level 2[2] condition or greater between the hours of 14:00 Pacific Time and 22:00 Pacific Time after exhausting all reasonably and practically available resources.

B. Consistent with good utility practice, BANC shall exhaust all reasonably and practically available resources, including other demand response and

[2] For the purposes of this Order, "Energy Emergency Alert Level 2" has the meaning set forth in Section 3.6.3 of the California ISO System Emergency Operating Procedure, Procedure No. 4420, Version 14.0, Effective Date May 1, 2022 (CAISO Emergency Operating Procedure).

identified behind-the-meter generation resources to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Covered Resource.

C. All operation of the Covered Resource must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators. The Covered Resource must comply with the requirements of the CARB Mandatory Reporting Regulation and California's Cap-and-Trade regulation, to the extent applicable. This Order allows operation of the Covered Resource under operating conditions not otherwise permitted by the Covered Resource's Title V permit but does not provide relief from the obligation to operate the Covered Resource within the equipment-specific or cumulative emission limit requirements specified in the Covered Resource's Title V permit.

D. BANC shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time. By October 10, 2022, BANC shall report source-specific data for all dates between September 4, 2022, and September 8, 2022, on which the Covered Resource was operated, including, for each unit, (1) the hours of operation, as well as the hours in which any permit limit was exceeded, and (2) a preliminary description of each permit term that was exceeded and the manner in which such exceedance occurred. BANC shall also submit a final report by November 14, 2022, with any revisions to the information reported on December 12, 2022. The environmental information submitted in the final report shall also include the following information:

i. Emissions data in pounds per hour for each Covered Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, VOC, and SO_2;

ii. Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

iii. The number and actual hours each day that each Covered Resource unit operated in excess of permit limits or conditions, e.g. "Generator #1; September 5, 2022; 4 hours; 18:00-22:00 PT";

iv. Amount, type and formulation of any fuel used by each Covered Resource;

v. All reporting provided over the last three years to the United States Environmental Protection Agency or Sacramento Metropolitan Air Quality Management District pursuant to operating permit requirements;

vi. Information provided to the CARB in response to the CARB's development and implementation of the plan to mitigate the effects of additional emissions authorized by the August 31, 2022 proclamation;

vii. Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

viii. Information provided by the Covered Resource describing how the requirements in paragraph C above were met by the Covered Resource while operating under the provisions of this Order.

E. BANC shall inform all affected communities where the Covered Resource operates that BANC has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explain clearly what the Order allows BANC to do, including potential impacts to the community where the Covered Resource is located and communities adjacent to the Covered Resource. BANC shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph D above.

F. This Order shall not preclude the need for the Covered Resource to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. BANC shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

H. This Order shall be effective upon its issuance, and shall expire at 23:59 Pacific Time on September 8, 2022, with the exceptions of paragraphs F and G and the reporting and analysis requirements in paragraphs D and E. Renewal or amendment of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 16:20 Eastern Time on this 4th day of September, 2022.



Kathleen Hogan
Acting Under Secretary for
Infrastructure

EXHIBIT 23-11

Department of Energy

Washington, DC 20585

Order No. 202-22-3

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated by email correspondence (Dec. 23, 2022), and for the reasons set forth below, I hereby determine that an emergency exists in Texas due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On December 23, 2022, the Electric Reliability Council of Texas, Inc. (ERCOT), the Independent System Operator (ISO) whose service territory includes 90 percent of the electric customers in the state of Texas, filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of the bulk electric power system."

ERCOT, like many regions across the country, is currently being impacted by a severe winter weather system. For Texas, this severe winter weather system has caused a significant drop in temperatures over the last day. This temperature drop, accompanied by high winds in excess of 40 mph, has resulted in wind chill values across the state generally below ten degrees Fahrenheit, with some areas of Texas experiencing wind chills values well below zero degrees. As a consequence, the demand for electricity in ERCOT rose to an all-time winter peak on the morning of Friday, December 23, 2022, in excess of 74,000 MW. This severely cold weather is expected to last through Sunday morning.

While the vast majority of generating units in the ERCOT region continue to operate without any problem, a small number of units have experienced operating difficulties due to cold weather or gas curtailments. Specifically, approximately 11,000 MW of thermal generating units, 4,000 MW of wind generating units, and 1,700 MW of solar generating units are currently outaged or derated to to the weather conditions. Most of these units are expected to return to service before anticipated demand peak through Saturday, December 24, 2022. However, if these units do not return to service, or if ERCOT experiences additional generating unit outages, it is possible that ERCOT would need to curtail some amount of firm load until 10:00 Central Time on December 25, 2022 in order to maintain the security of the ERCOT system.

Description of Mitigation Measures

ERCOT is taking measures to ensure the supply of generation will continue to be sufficient to meet system demand and reserve requirements. On December 22, 2022, at ERCOT's request, the Texas Commission on Environmental Quality announced that it will provide enforcement discretion to generators in the ERCOT region that may exceed state emissions requirements during emergency conditions. On December 23, 2022, ERCOT directed certain dual-fuel units enrolled in ERCOT's new Firm Fuel Supply Service to begin operating on fuel oil due to natural gas delivery limitations. Moreover, if generating reserves do eventually diminish to a level that requires ERCOT to declare an Energy Emergency Alert (EEA), ERCOT will take additional measures to provide additional reserves prior to exceeding air quality and other federal permit limitations as authorized under this Order, including:

- Utilizing all available DC Tie import capacity
- Issuing a public conservation appeal
- Deploying capacity enrolled in ERCOT's Emergency Response Service
- Instructing transmission and distribution service providers to implement distribution voltage reduction measures and to deploy customers enrolled in load management programs
- Instructing Load Resources providing Responsive Reserve Service (RRS) to curtail their demand, and instruct Generation Resources providing RRS to make their provide additional capacity available for ERCOT's dispatch
- Instructing Energy Storage Resources to suspend charging

According to ERCOT, the measures taken by ERCOT and other state agencies may not prove sufficient to avoid the need to curtail firm load to ensure system reliability.

Request for Order

ERCOT requests that the Secretary issue an order immediately, effective December 23, 2022, through 10:00 Central Time on December 25, 2022, authorizing "the provision of additional energy from the units identified in Exhibit A, as well as any other generating units subject to emissions or other permit limitations" in the ERCOT region. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-22-3 Resources List, as described below.

ORDER

Given the emergency nature of the expected load stress, the responsibility of ERCOT to ensure maximum reliability on its system, and the ability of ERCOT to identify and dispatch generation necessary to meet the additional load, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the expected load stress caused by the current cold weather event threatens to cause loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the State of Texas and within the ERCOT region demonstrate the need for the Specified Resources to contribute to the reliability of ERCOT.
- ERCOT's responsibility to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Specified Resources, necessary to meet the additional load resulting from the cold weather event.

In line with the anticipated circumstances precipitated by the cold weather event, this Order is limited to the period beginning with the issuance of this Order on December 23, 2022 through 10:00 Central Time on December 25, 2022. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. ERCOT anticipates that this Order may result in exceedance of emissions of sulfur dioxide, nitrogen oxide, mercury, and carbon monoxide emissions, as well as wastewater release limits. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by ERCOT for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on December 23, 2022 to 10:00 Central Time on December 25, 2022, in the event that ERCOT determines that generation from the Specified Resources is necessary to meet the electricity demand that ERCOT anticipates in Texas during this event, I direct ERCOT to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in the ERCOT region when the demand on the ERCOT system exceeds expected energy and reserve requirements. Specified Resources are those generating units set forth on the Order 202-22-3 Resource List, subject to updates directed here and as described in paragraph D, which the Department shall post on www.energy.gov. ERCOT is directed to update Exhibit A to its Application with the anticipated category of environmental impact(s) (i.e., sulfur dioxide, nitrogen oxide, mercury, carbon monoxide emissions, wastewater release, other air pollutants) by 21:00 Central Time on December 25, 2022.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by ERCOT for reliability purposes. Consistent with good utility practice, ERCOT shall exhaust all reasonably and practically available resources, including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions, to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources. ERCOT shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

In furtherance of the foregoing and, in each case, subject to the exhaustion of all available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions available to support grid reliability:

(i) For any Generation Resource or Settlement Only Generator whose operator notifies ERCOT that the unit is unable, or expected to be unable, to produce at its maximum output due to an emissions or other limit in any federal environmental permit at any point before 12:00 Central Time on Saturday, December 24, 2022, and between 18:00 Central Time on Saturday, December 24, 2022 and 10:00 Central Time on Sunday, December 25, 2022, the unit will be allowed to exceed any such limit only during any period for which ERCOT has declared an Energy Emergency Alert (EEA) Level 2 or Level 3. This incremental amount of restricted capacity would be offered at a price no lower than $1,500/MWh. Once ERCOT declares that the EEA Level 2 event has ended, the unit would be required to immediately return to operation within its permitted limits. And at all other times, the unit would be required to operate within its permitted limits.

(ii) For any Generation Resource whose operator notifies ERCOT that the unit is offline or would need to go offline at any point before 12:00 Central Time on Saturday, December 24, 2022, and between 18:00 Central Time on Saturday, December 24, 2022 and 10:00 Central Time on Sunday, December 25, 2022 due to an emissions or other limit in any federal environmental permit, ERCOT may issue a Reliability Unit Commitment (RUC) instruction directing the unit operator to bring the unit online, or to keep the unit online, and to operate at the minimum level at which the Resource can be sustainably operated. In this circumstance, the operator would be allowed to make all of the unit's capacity available to ERCOT for dispatch during any period for which ERCOT has declared an Energy Emergency Alert (EEA) Level 2 or Level 3. This incremental amount of restricted capacity would be offered at a price no lower than $1,500/MWh. Once ERCOT declares that such an EEA Level 2 event has ended, the unit would be required to immediately return to operating at a level below the higher of its minimum operating level or the maximum output allowable under the permitted limit.

C. All operation of the Specified Resource must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. In the event that ERCOT identifies additional generation units that it deems necessary to operate in excess of federal environmental permitting limits in order to maintain the reliability of the power grid in the ERCOT region when the demand on the ERCOT system exceeds expected energy and reserve requirements, including any such entity to which ERCOT intends to issue a Reliability Unit Commitment (RUC), ERCOT shall provide prompt written notice to the Department of Energy at AskCR@hq.doe.gov with the name and location of those units that ERCOT has identified, as well as notice by the same means as an updated Exhibit A to its Application such additional generation units, the fuel type of such unit, and the anticipated category of environmental impact, at 09:00 Central Time or 21:00 Central Time, whichever follows closest in time to the unit identification by ERCOT to the greatest extent feasible. Such additional generation unit shall be deemed a Specified Resource for the purpose of this Order for the hours prior to the required written notice to the Department, and ERCOT may dispatch such additional generation units, provided that if the Department of Energy notifies ERCOT that it does not approve of such generation unit being designated as a Specified Resource, such generation unit shall not constitute a Specified Resource upon notification from the Department. The Department shall post an updated Order 202-22-3 Resource List as soon as practicable following notification from ERCOT under this paragraph.

E. ERCOT shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By January 25, 2023, ERCOT shall report all dates between December 23, 2022 and December 25, 2022, inclusive, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting limits, including sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. ERCOT shall submit a final report by February 25, 2023 , with any revisions to the information reported on January 25, 2023. The environmental information submitted in the final report shall also include the following information:

(i) Emissions data in pounds per hour for each Specified Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, VOC, and SO2;

(ii) Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

(iii) The number and actual hours each day that each Specified Resource unit operated in excess of permit limits or conditions, e.g. "Generator #1; December 24, 2022; 4 hours; 04:00-08:00 CT";

(iv) Amount, type and formulation of any fuel used by each Specified Resource;

(v) All reporting provided under the Specified Resource's operating permit requirements over the last three years to the United States Environmental Protection Agency or local Air Quality Management District for the location of a Specified Resource that operates pursuant to this Order;

(vi) Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

(vii) Information provided by the Specified Resource describing how the requirements in paragraph C above were met by the Specified Resource while operating under the provisions of this Order.

In addition, ERCOT shall provide information to the Department quantifying the net revenue associated with generation in excess of environmental limits accruing to non-RUC units in connection with orders issued by the Department pursuant to Section 202(c) of the Federal Power Act.

F. ERCOT shall take reasonable measures to inform affected communities where all Specified Resources operate that ERCOT has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows ERCOT to do. At a minimum, ERCOT shall post a description of this Order on its website (with a link to this Order) and identify the name, municipality or other political subdivision, and zip code of Specified Resources covered by this Order, as the Specified Resources may be updated pursuant to paragraph D above. In addition, in the event that a Specified Resource operates pursuant to this Order, a general description of the action authorized by this Order will be included in any press release issued by ERCOT with respect to the cold weather event and will include a reference to the website posting required by the preceding sentence for further information. ERCOT shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph E above.

G. This Order shall not preclude the need for the Specified Resource to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. ERCOT shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

I. This Order shall be effective upon its issuance, and shall expire at 10:00 Central Time on Sunday, December 25, 2022, with the exception of the reporting requirements in

paragraph E. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 9:30 PM Eastern Standard Time on this 23rd day of December 2022.

Kathleen B. Hogan

Digitally signed by Kathleen B. Hogan
Date: 2022.12.23 21:53:39 -05'00'

Undersecretary of Energy for Infrastructure

EXHIBIT 23-12

Department of Energy
Washington, DC 20585

Order No. 202-22-4

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated by email correspondence (Dec. 23, 2022), and for the reasons set forth below, I hereby determine that an emergency exists in the electricity grid operated by PJM Interconnection, LLC (PJM) due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On December 24, 2022, PJM, the Regional Transmission Operator (RTO) for 65 million people in thirteen states and the District of Columbia (the PJM Region), filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of the bulk electric power system."

The PJM Region, like many regions across the country, is currently being affected by a severe winter weather system. PJM states that this weather system caused a significant drop in temperatures across the PJM Region on December 23, 2022, accompanied by high winds in excess of 40 mph. As a consequence of the impact of wind and decreasing temperatures, the demand for electricity in the PJM Region rose to an unusually high peak load on the evening of December 23, 2022, in excess of 135,000 MW. This severely cold weather is expected to last through Sunday morning.

While the vast majority of generating units in the PJM Region continue to function adequately under these stressed conditions, some units have experienced operating difficulties due to cold weather or fuel limitations, primarily gas. Specifically, approximately 45,000 MW of generating units (the majority of which are thermal) are currently outaged or derated. PJM has expressed its concern that these units will be unable to return to service over at least the next 48 hours, which coincides with the time period for which PJM is requesting this Order. Since these units may not promptly return to service, and in the event PJM experiences additional generating unit outages, PJM states that it may need to curtail some amount of firm load on December 24, December 25, or December 26, 2022 in order to maintain the security and reliability of the PJM system.

Description of Mitigation Measures

In its Application, PJM identifies the measures it is taking to ensure the supply of generation will continue to be sufficient to meet system demand and reserve requirements. On December 20, 2022, PJM issued a cold weather advisory in the PJM Region in anticipation of the forecasted weather conditions. Then on December 23, 2022, PJM issued

a PJM Region-wide cold weather alert which further highlighted PJM's expected need to call higher-than-normal generation resources in light of the anticipated weather.

On December 23, 2022, generating reserves diminished to a level that required PJM to declare an Energy Emergency Alert (EEA) Level 2 and take other emergency actions. PJM states that after having exhausted economic operation, PJM triggered a Maximum Generation Emergency Action to increase the PJM Region generation above the maximum economic level. Further, PJM triggered its load management reduction actions to provide additional load relief by using PJM-controllable load management programs. PJM called on demand response providers and curtailment service providers to reduce load. PJM also issued public appeals for consumers to reduce usage. PJM has continued to employ these emergency actions through December 24, 2022, and anticipates needing to continue them through the order end date that it has requested.

Since December 23, 2022, PJM has also taken additional measures to provide additional reserves, including:

- Reducing exports to neighboring regions and requested shared reserves for neighboring regions; consistent with joint operating agreements and other regulatory requirements, PJM has continued to communicate and collaborate with its interconnected neighboring systems when the demand on the PJM system has exceeded expected energy and reserve requirements and when emergency transfers were required to support PJM's interconnected neighboring systems;
- Issuing additional public conservation appeals;
- Running uneconomic generation during lower load periods to ensure their availability during peak conditions;
- Utilizing its Emergency Procedures to assist in maximizing the pumped storage hydro generation levels;
- Communicating and preparing transmission and distribution service providers to implement distribution voltage reduction measures; and
- Communicating and preparing transmission and distribution service providers to implement firm load shed.

In its Application, PJM committed to continue to take such actions, including utilizing other supply resources before calling upon any generators to operate in excess of permitting levels. According to PJM, it is nevertheless possible that the measures it has and will take may not be sufficient to avoid the need to curtail firm load in order to ensure system reliability.

Request for Order

PJM requests that the Secretary issue an order immediately, effective today, December 24, 2022, through 12:00 p.m. Eastern Time on Monday, December 26, 2022, authorizing the electric generating units identified in Exhibit A, as well as any other

generating units subject to emissions or other permit limitations in the PJM Region to operate up to their maximum generation output levels under the limited circumstances described in this Order, notwithstanding air quality or other permit limitations. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-22-4 Resources List, as described below.

ORDER

Given the emergency nature of the expected load stress, the responsibility of PJM to ensure maximum reliability on its system, and the ability of PJM to identify and dispatch generation necessary to meet the additional load, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the expected load stress caused by the current cold weather event threatens to cause loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the PJM Region demonstrate the need for the Specified Resources to contribute to the reliability of the PJM Region.
- PJM is responsible to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Specified Resources, necessary to meet the additional load resulting from the cold weather event is enhanced.

In line with the anticipated circumstances precipitated by the cold weather event, this Order is limited to the period beginning with the issuance of this Order on December 24, 2022 through 12:00 pm Eastern Time on December 26, 2022. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. PJM anticipates that this Order may result in exceedance of emissions of sulfur dioxide, nitrogen oxide, mercury, and carbon monoxide emissions, as well as wastewater release limits. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on December 24, 2022, to 12:00 pm Eastern Time on December 26, 2022, in the event that PJM determines that generation from the Specified Resources is necessary to meet the electricity demand that PJM anticipates in the PJM Region during this event, I direct PJM to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements. Specified Resources are those generating units set forth on the Order 202-22-4 Resource List, subject to updates directed here and as described in paragraph D, which the Department shall post on www.energy.gov.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions, to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

In furtherance of the foregoing and, in each case, subject to the exhaustion of all available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions available to support grid reliability:

(i) For any generation resource whose operator notifies PJM that the unit is unable, or expected to be unable, to produce at its maximum output due to an emissions or other limit in any federal environmental permit, and during the pendency of a PJM-triggered Maximum Generation Emergency Action, at any point before 12:00 Eastern Time on Monday, December 26, 2022, the unit will be allowed to exceed any such limit only during any period for which PJM has declared an Energy Emergency Alert (EEA) Level 2 or Level 3 (during which time PJM will have triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that the EEA Level 2 event has ended, the unit would be required to immediately return to operation within its permitted limits. And at all other times, the unit would be required to operate within its permitted limits, except for the limited exceptions provided herein for operations in anticipation of an EEA Level 2 to prevent the cycling of units or facilitate the charging or pumping of other resources necessary for the EEA Level 2.

(ii) For any generation resource whose operator notifies PJM that the unit is offline or would need to go offline at any point before 12:00 Eastern Time on Monday, December 26, 2022, due to an emissions or other limit in any

federal environmental permit, PJM may direct the unit operator to bring the unit online, or to keep the unit online, and to operate at the level consistent with its permits but subject to the exceptions set forth in this Order. In this circumstance, the operator is allowed to make all of the unit's capacity available to PJM for dispatch during any period for which PJM has declared an EEA Level 2 or 3 (during which time PJM has triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that such an EEA Level 2 event has ended and the Maximum Generation Emergency Action is discontinued, the unit would be required to immediately return to operating at a level below the higher of its minimum operating level or the maximum output allowable under the permitted limit.

(iii) PJM is hereby granted authority to operate the Specified Units that are combined cycle generating units in certain limited circumstances in advance of declaring an EEA Level 2, Maximum Generation Emergency, or in between such events, where such operation or continued operation of the Specified Resource is reasonably necessary to avoid shutting down and restarting the Specified Unit. PJM has represented that such cycling of units can cause reliability issues regarding restarting, delays, and increased emissions during start up. PJM is further authorized to operate the Specified Units in certain limited circumstances in advance of the declaring an EEA Level 2, Maximum Generation Emergency where such operation or continued operation of the Specified Resource is reasonably necessary to facilitate charging storage resources or pumping for pumped storage facilities that will needed during an anticipated EEA Level 2. PJM is required to take measures to dispatch units for which cycling would otherwise be required in a manner reasonably intended to limit the duration and operating level of those units in such a way as to minimize exceedance of permit limitations consistent with the security and reliability of the PJM Region.

(iv) To minimize adverse environmental impacts as set forth herein, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, and notwithstanding standard merit order dispatch, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response and identified behind-the-meter generation resources selected to minimize an increase in emissions to the extent that such resources provide support to maintain grid reliability prior to dispatching the Specified Resources at levels above their permitted emissions levels. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

C. All operation of the Specified Resource must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. In the event that PJM identifies additional generation units that it deems necessary to operate in excess of federal environmental permitting limits in order to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements, PJM shall provide prompt written notice to the Department of Energy at AskCR@hq.doe.gov with the name and location of those units that PJM has identified, as well as additional notice by the same means through updating Exhibit A to its Application with such additional generation units, the fuel type of such unit, and the anticipated category of environmental impact, at 09:00 Eastern Time or 21:00 Eastern Time, whichever follows closest in time to the unit identification by PJM to the greatest extent feasible. Such additional generation unit shall be deemed a Specified Resource for the purpose of this Order for the hours prior to the required written notice to the Department updating Exhibit A, and PJM may dispatch such additional generation units, provided that if the Department of Energy notifies PJM that it does not approve of such generation unit being designated as a Specified Resource, such generation unit shall not constitute a Specified Resource upon notification from the Department. The Department shall post an updated Order 202-22-4 Resource List as soon as practicable following notification from PJM under this paragraph.

E. PJM shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By January 26, 2023, PJM shall report all dates between December 24, 2022, and December 26, 2022, inclusive, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting limits, including sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. PJM shall submit a final report by February 27, 2023, with any revisions to the information reported on January 26, 2023. The environmental information submitted in the final report shall also include the following information:

(i) Emissions data in pounds per hour for each Specified Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, VOC, and SO2;

(ii) Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

(iii) The number and actual hours each day that each Specified Resource unit operated in excess of permit limits or conditions, e.g., "Generator #1; December 25, 2022; 4 hours; 04:00-08:00 CT";

(iv) Amount, type and formulation of any fuel used by each Specified Resource;

(v) All reporting provided under the Specified Resource's operating permit requirements over the last three years to the United States Environmental Protection Agency or local Air Quality Management District for the location of a Specified Resource that operates pursuant to this Order;

(vi) Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

(vii) Information provided by the Specified Resource describing how the requirements in paragraph C above were met by the Specified Resource while operating under the provisions of this Order.

In addition, PJM shall provide information to the Department quantifying the net revenue in aggregate associated with generation in excess of environmental limits in connection with orders issued by the Department pursuant to Section 202(c) of the Federal Power Act.

F. PJM shall take reasonable measures to inform affected communities where all Specified Resources operate that PJM has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows PJM to do. At a minimum, PJM shall post a description of this Order on its website (with a link to this Order) and identify the name, municipality or other political subdivision, and zip code of Specified Resources covered by this Order, as the Specified Resources may be updated pursuant to paragraph D above. In addition, in the event that a Specified Resource operates pursuant to this Order, a general description of the action authorized by this Order will be included in any press release issued by PJM with respect to the cold weather event and will include a reference to the website posting required by the preceding sentence for further information. PJM shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph E above.

G. This Order shall not preclude the need for the Specified Resource to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. PJM shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

I. This Order shall be effective upon its issuance, and shall expire at 12:00 Eastern Time on Monday, December 26, 2022, with the exception of the reporting requirements in

paragraph E. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 5:30 PM Eastern Standard Time on this 24th day of December 2022.

Kathleen B. Hogan

Digitally signed by Kathleen B. Hogan
Date: 2022.12.24 17:38:01 -05'00'

Undersecretary of Energy for Infrastructure

EXHIBIT 23-13

Department of Energy
Washington, DC 20585

Order No. 202-24-1

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in Florida due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On October 9, 2024, Duke Energy Florida, LLC (Duke), an investor-owned utility, whose service territory includes electric customers in Florida, filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of the bulk electric power system." As of 4 PM EDT on October 9, 2024, Hurricane Milton is a Category 3 storm forecast to remain a major hurricane and expand in size as it approaches the west coast of Florida. The center is likely to make landfall along the west-central coast of Florida during the night on Wednesday, October 9, 2024, or in the early morning on Thursday, October 10, 2024, and move east-northeastward across central Florida through October 10, 2024. Hurricane Milton follows the landfall of Hurricane Helene in Florida on September 26, 2024, which resulted in over 230 deaths in the southeast United States and for which recovery and restoration efforts remain ongoing. As of 5:00 PM EDT on October 9, 2024, Florida was experiencing 118,000 outages related to the approaching Hurricane Milton, with the number increasing rapidly.

On October 7, 2024, President Biden declared that an emergency exists in the State of Florida and ordered Federal assistance to supplement State, tribal, and local response efforts due to the emergency conditions resulting from Hurricane Milton beginning on October 5, 2024, and continuing.

Duke has indicated that its service territory is being impacted by Hurricane Milton. Duke expects that Hurricane Milton will cause hurricane-force-gusts across the St. Petersburg/Tampa metropolitan region at the height of the storm overnight into early Thursday, October 10, 2024. Elsewhere, strong tropical-storm to near hurricane-force-gusts are projected to impact highly populated zones along the I-4 corridor served by Duke. The combination of damaging winds,

torrential rain and subsequent flooding, storm surge at the coast, and possible tornadoes, will result in major power outages, damaging distribution and transmission infrastructure, and threaten several generation stations along the path. Application at 1.

While many generating units in the Duke service territory continue to function adequately under these stressed conditions, several of Duke's generating units are expected to be forced to shut down due to facility limits on wind speeds and storm surge, as well as staffing issues caused by mandatory evacuations. Additionally, Crystal River Units 4 and 5 remain in forced outage from storm surge impacts from Hurricane Helene. Specifically, approximately 4,000 MW of generating units are currently offline and will remain offline during Hurricane Milton. Application at 2.

Additionally, several units at Citrus Combined Cycle, the subject of this Order, may be forced offline by conditions in its Title V operating permit. With projected outages and low demand, in order to keep the Citrus Combined Cycle units online, they would potentially need to operate at low load for an extended period of time, which could result in noncompliance with its Title V permit. If these units are brought offline due to these compliance requirements, they may not be able ramp up quickly enough to meet demand as load increases following power restoration, particularly in light of the amount of generation predicted to be offline due to hurricane impacts. For example, ramp-up times from a cold start could be eight or nine hours, and could be further delayed by pre-generation start-up checks. Additionally, shutting down also increases the risk or equipment failure, as well as the risk of water intrusion due to thermal and pressure gradient changes. If equipment fails or is damaged by Hurricane Milton, units may not be able to start without additional maintenance. In that case, Duke may have to declare an Energy Emergency Alert (EEA) Level 3 and institute rotating load shed. Such impacts would hinder post-hurricane restoration and recovery activities and overall grid reliability. Although Duke would attempt to mitigate such impacts through alternative generation as well as power purchases, it is unknown what will be available following Hurricane Milton and whether the necessary transmission infrastructure will remain for this purpose. Application at 2.

The Florida Reliability Coordinating Council, Inc. (FRCC), the Reliability Coordinator for Duke's service territory and others, filed a formal endorsement on October 9, 2024, of Duke's Application, specifically the need to continue operation of the Specified Resources in Application Exhibit A at low load operation to help reduce the likelihood of any firm load shedding during the hurricane event. FRCC Letter at 1. The endorsement explains:

> It is the FRCC's firm opinion that granting this relief request will provide an immeasurable benefit to this mission and in turn, the public served by the FRCC and its member entities. Allowing this relief will not only serve the reliability of [Duke's] service territory, but also the many local electric cooperatives served by [Duke] and other interconnected electric utilities and service providers.

FRCC Letter at 2.

Description of Mitigation Measures

Duke has indicated that it will attempt to keep the Citrus Combined Cycle units operating at a load level compliant with its Title V permit whenever possible, including attempting to sell power to keep load higher. Duke anticipates needing to continue these efforts through October 13, 2024. Subject to the exceptions included in this Order, Duke has committed to continuing to take such actions, including attempting to sell power, before operating any units in a manner that will result in a conflict with a requirement of any federal, state, or local environmental statute or regulation, including requirements in permits issued pursuant to such laws or regulations.

Request for Order

Duke requests that the Secretary issue an order immediately, effective October 9, 2024, through 00:00 EDT on October 13, 2024, authorizing "continued operation of the Specified Resources" in the Duke service territory. Application at 3. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-24-1 Resources List, as described below.

ORDER

Given the emergency nature of the expected load stress, the responsibility of Duke to ensure maximum reliability on its system, and the ability of Duke to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the expected load stress caused by the current extreme weather event and its aftermath threatens to cause loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the State of Florida and within the region demonstrate the need for the Specified Resources to contribute to system reliability.
- Duke's responsibility to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Specified Resources, necessary to meet the load resulting from the extreme weather event and its aftermath.

In line with the anticipated circumstances precipitated by Hurricane Milton, this Order is limited to the period beginning with the issuance of this Order on October 9, 2024, through 00:00 EDT on October 13, 2024. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. Duke anticipates that this Order may result in exceedance of emissions of Volatile Organic Compounds (VOC), specifically formaldehyde. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by Duke for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on October 9, 2024, to 00:00 EDT on October 13, 2024, in the event that Duke determines that generation from the Specified Resources is necessary to meet the electricity demand that Duke anticipates in Florida during and immediately following this event, I direct Duke to dispatch such unit or units and to order their operation only as needed to maintain the necessary expected generation in the Duke service territory. Specified Resources are those generating units set forth on the Order 202-24-1 Resource List, which the Department shall post on www.energy.gov. Duke is directed to provide updates, if any, to Exhibit A to its Application with the anticipated category of environmental impact(s) (i.e., formaldehyde, sulfur dioxide, nitrogen oxide, mercury, carbon monoxide emissions, wastewater release, other air pollutants) by 21:00 EDT on October 10, 2024.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by Duke for maintaining grid reliability to avoid adverse health and safety impacts to customers from shedding firm customer load. Duke shall exhaust all possible measures to run the Specified Units at a load level in compliance with permit requirements, including attempting to sell power. Duke shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

C. All operation of the Specified Resource must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. Duke shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By October 20, 2024, Duke shall report all dates between October 9, 2024, and October 13, 2024, inclusive, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting

limits, including formaldehyde, sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. Duke shall submit a final report by November 20, 2024, with any revisions to the information reported on October 20, 2024. The environmental information submitted in the final report shall also include the following information:

(i) Emissions data in pounds per hour for each Specified Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, formaldehyde, VOC, and SO2;

(ii) Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

(iii) The number and actual hours each day that each Specified Resource unit operated in excess of permit limits or conditions, e.g. "Generator #1; October 10, 2024; 4 hours; 04:00-08:00 EDT";

(iv) Amount, type and formulation of any fuel used by each Specified Resource;

(v) All reporting provided under the Specified Resource's operating permit requirements over the last three years to the United States Environmental Protection Agency or local Air Quality Management District for the location of a Specified Resource that operates pursuant to this Order;

(vi) Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

(vii) Information provided by the Specified Resource describing how the requirements in paragraph C above were met by the Specified Resource while operating under the provisions of this Order.

In addition, Duke shall provide information to the Department quantifying the net revenue associated with generation in excess of environmental limits accruing to the Specified Resources in connection with any order issued by the Department pursuant to Section 202(c) of the Federal Power Act.

E. Duke shall take reasonable measures to inform affected communities where all Specified Resources operate that Duke has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows Duke to do. At a minimum, Duke shall post a description of this Order on its website (with a link to this Order) and identify the name, municipality or other political subdivision, and zip code of any Specified Resource covered by this Order. In addition, in the event that a Specified Resource operates pursuant to this Order, a general description of the action authorized by this Order will be included in any press release issued by Duke with respect to the extreme weather event and will include a reference to the website posting required by the preceding sentence for further information. Duke shall describe the actions taken to comply with this paragraph in the

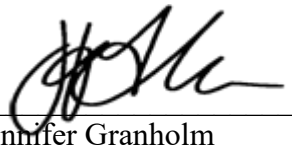
reports delivered to the Department pursuant to paragraph D above.

F. This Order shall not preclude the need for the Specified Resource to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Duke shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

H. This Order shall be effective upon its issuance, and shall expire at 00:00 EDT on Sunday, October 13, 2024, with the exception of the reporting requirements in paragraph D. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 8:00 PM Eastern Daylight Time on this 9th day of October 2024.



Jennifer Granholm
Secretary of Energy

EXHIBIT 23-14

United States of America
Department of Energy

District of Columbia Public Service Commission) Docket No. EO-05-01

Order No. 202-05-3

I. Summary

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, a shortage of facilities for the transmission of electric energy and other causes, and that issuance of this order will meet the emergency and serve the public interest. Therefore, Mirant Corporation and its wholly owned subsidiary, Mirant Potomac River, LLC (collectively referred to herein as Mirant), are hereby ordered to generate electricity at their Potomac River Generating Station (the "Plant") pursuant to the terms of this order.

II. Procedural History

On August 19, 2005, Mirant submitted to the Virginia Department of Environmental Quality (DEQ) a computerized emissions modeling study Mirant had conducted of its Plant that indicated that emissions from the Plant caused or contributed to significant localized exceedances of the National Ambient Air Quality Standards (NAAQS).[1] Also on August 19, 2005, DEQ issued a letter to Mirant which requested "that Mirant *immediately* undertake such action as is necessary to ensure protection of human health and the environment, in the area surrounding the Potomac River Generating Station, including the potential reduction of levels of operation, or potential shut down of the facility." (emphasis in original). The letter asked Mirant to provide DEQ with a summary of the actions taken and the progress toward eliminating NAAQS exceedances by August 24, 2005. At midnight on August 21, 2005, Mirant reduced production of all units at the Plant to their minimum load, and at midnight on August 24, 2005, Mirant shut down all five of the generating units at the Plant.

On August 24, 2005, the District of Columbia Public Service Commission (DCPSC) filed an *Emergency Petition and Complaint* with both the United States Department of Energy (DOE or Department) and the Federal Energy Regulatory Commission (FERC or Commission) pursuant to the FPA. The DCPSC requested the Secretary of Energy to find that an emergency exists under section 202(c) of the FPA and to issue an order directing Mirant to continue

[1] The Clean Air Act, 42 U.S.C. § 7401 *et seq.*, authorizes the United States Environmental Protection Agency (EPA) to establish NAAQS, 42 U.S.C. §§ 7408-7409, and states that it is the responsibility of the states and local governments for assuring that they are attained, 42 U.S.C. §§ 7401(a)(3) and 7416.

operation of the Plant. The basis for the petition was that the shutdown of the Plant "...will have a drastic and potentially immediate effect on the electric reliability in the greater Washington, D.C., area and could expose hundreds of thousands of consumers, agencies of the Federal Government and critical federal infrastructure to curtailments of electric service, load shedding and, potentially, blackouts." The DCPSC requested that the Commission issue a similar order under sections 207 and 309 of the FPA. Numerous parties filed interventions and comments in response to DCPSC's emergency petition, as well as subsequent comments and responses.[2] Further, both FERC and DOE issued information requests to Mirant, the Potomac Electric Power Company (PEPCO), the company responsible for supplying electricity to retail customers in the District of Columbia, and PJM Interconnection, LLC (PJM), the grid operator responsible for the administration of the bulk power grid and electricity market in the region.[3] In addition to the DCPSC petition proceedings, DOE has hosted and participated in numerous conference calls and meetings to gather information on the shutdown of the Plant and its effect on the reliability of D.C.'s electricity system.[4]

III. Background

The coal-fired Mirant Plant, which began operation in 1949, is located in Alexandria, Virginia, and is capable of producing 482 megawatts of electricity primarily for delivery to Washington, D.C. The Plant consists of five generating units, two of which are cycling units that range in output from 35 MW to 88 MW, and three of which are baseload units that range in output from 35 MW to 102 MW. It is one of only three sources of electricity that serve the central business district of the District of Columbia, many federal institutions, the Georgetown area in D.C., as well as other portions of Northwest, D.C., and the District of Columbia Water and Sewer Authority's Blue Plains Advanced Water Treatment Plant, the largest wastewater

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[2] Several of these filings were only made in the FERC docket and not in DOE's docket. Even though a number of filers did not submit their comments in the DOE docket, the Department has, in the interest of rendering an appropriate and fully informed determination, reviewed all the filings in the FERC docket for any pertinent facts that will assist the Department in making its decision. Also, to the extent the filings contained analysis or legal arguments pertaining to the Department's 202(c) authority, they have been considered in the Department's decision making process.

[3] The data submitted contained Critical Energy Infrastructure Information and was submitted in both confidential and redacted versions, as defined in FERC's rules at 18 C.F.R. § 388.13. All information contained in this order is from public filings in the DOE and FERC dockets.

[4] The Administrative Procedure Act's prohibitions on ex parte communications in an adjudicatory proceeding, 5 U.S.C. § 557(d)(1), do not apply to DOE's 202(c) proceedings, because section 202(c) explicitly authorizes the Department to issue a 202(c) order "either upon its own motion or upon complaint, with or without notice, hearing, or report. . ." 16 U.S.C. § 824a(c).

treatment plant in the world.[5] The other two sources are two 230 kV lines that deliver electricity from other generating sources in the regional electric grid operated by PJM. Although there are other generating units in close physical proximity to the Central D.C. area, (e.g., the Benning Road and Buzzard Point generating facilities, which are dual-fueled oil and natural gas generating power plants, owned by PEPCO) there are no transmission lines that would allow delivery of power from these other units to reach the Central D.C. area. With regard to the sources of power that serve the Central D.C. area, PEPCO owns and operates the transmission lines, and PJM determines electricity demand.

Although Mirant shut down all of the Plant's generating units on August 24, 2005, it has since restarted unit number one which, the Department understands, is currently operating. Mirant is operating the unit on an 8/8/8 basis --- that is, in any given twenty-four hour period, the unit runs for eight hours at its maximum level of 88 MW, eight hours at its minimum level of 35 MW, and has eight hours when it does not run. DOE has been informed that both EPA and DEQ acknowledge that the operation of this unit in this manner does not result in any NAAQS exceedances. In addition, DOE understands that Mirant is taking other steps to increase production at the Plant in a manner which will be acceptable to DEQ and EPA.

PEPCO has applied to the DCPSC to construct two new 230 kV lines that would supply electricity to the Central D.C. area. In the same application, PEPCO has proposed building two new 69kV lines to supply the Blue Plains wastewater treatment plant. PEPCO proposes having the two 69 kV lines installed by the summer 2006 peak season, and the two 230 kV lines installed in 18 to 24 months. The two existing 230 kV lines that supply the Central D.C. area would need to be temporarily taken out of service sequentially in order to connect the new lines to the Central D.C. area. Once completed, these lines apparently would provide a high level of electric reliability in the Central D.C. area, even in the absence of production from the Plant.

IV. Discussion

A. Reliability Issues

The Department has conducted an independent analysis of the electricity reliability situation in the Central D.C. area and has analyzed the Plant's role in ensuring a sufficiently reliable supply of electricity to that area. DOE's analysis was conducted by the Department's Oak Ridge National Laboratory. Under North American Electric Reliability Council standards, at a minimum, the power system must carry at least enough contingency reserves of electricity to cover the most severe single contingency. The standards require that an area's system always be operated with sufficient reserves to compensate for the sudden failure of the area's most important single generator or transmission line.

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[5] For purposes of this order, the area supplied with electricity by these three sources will be referred to as the "Central D.C. area," and the retail customers in this area will be referred to as the "Central D.C. area customers."

Based on the fact that the Central D.C. area has only three sources of supply, the Plant and the two 230 kV transmission lines, the Department's analysis concludes that in order to maintain a minimally reliable electric power system, the Plant must be available to run when one of the 230 kV lines is out of service, because if the remaining line failed there would be no other source of electricity to serve the Central D.C. area load. In addition, the analysis concludes that if one of the 230 kV lines failed unexpectedly, enough generation must be started as rapidly as possible so as to be able to serve all of the Central D.C. area load as a contingency reserve in the event the other line were to fail. The analysis also indicates that the Plant should be operated in such a way as to minimize the amount of time needed to bring it into production.

PEPCO has asserted that:

> Absent the generating capacity of the Plant, if the two 230 kV transmission circuits into the [Central D.C. area] fail, there will be a blackout in much of the District of Columbia until the circuits are repaired or the Plant's generators are restarted and can operate at a level that matches load. All electric customers in Georgetown, Foggy Bottom and major portions of downtown Washington will be affected. The affected customers will also include Blue Plains wastewater treatment plant. It is PEPCO's understanding that within 24 hours of the loss of electric supply, Blue Plains will have no option but to release untreated sewage directly into the Potomac River, which would result in a significant adverse impact to human health, aquatic wildlife and other environmental resources. Affected customers will also include numerous hospitals, schools, universities, commercial buildings, and residential customers. Importantly, numerous federal facilities will lose power, including those critical to the security, safety, and welfare of the whole country, such as the FBI, the Justice Department, the State Department, the Federal Emergency Management Agency, the Department of the Interior, and the Department of Energy to name but a few.[6]

No commenter has disputed these statements by PEPCO, and they have been generally corroborated by DOE's own independent analysis; therefore, DOE will accept them as correct statements of fact. Further, the 230 kV lines do go out of service on occasion; since 2000, there have been 34 one-line outages for maintenance, and seven occasions where one of the lines has tripped unexpectedly. DOE has been informed that, prior to 2000, there were two occasions when both of the lines failed simultaneously.

B. Environmental Issues

Some commenters have asserted that the renewed operation of the Plant would result in NAAQS exceedances and a violation of the Clean Air Act, and that DOE could not issue a 202(c) order which would contravene the Clean Air Act (42 U.S.C. §§ 7401-7626). In response to this assertion, DCPSC, PEPCO and PJM contend that there were no actual monitored

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[6] *See* Potomac Electric Power Company's Leave to Answer and Answer to Comments, FERC Docket No. EL05-145-000 at pages 2 & 3 (September 9, 2005).

exceedances of the NAAQS at the Plant during operation, and that operation of the plant at full power does not exceed the emissions limits contained in the Plant's operating permit and therefore the operation of the Plant pursuant to a DOE order would not violate the Clean Air Act. EPA has shared information with DOE regarding NAAQS modeled results and other environmental issues at the Plant. In response to the environmental concerns raised, this order seeks to minimize, to the extent reasonable, any adverse environmental impacts. Should EPA issue a compliance order directed to operation of the Plant, DOE will consider whether and how this order should conformed to such order.

Another assertion raised is that DOE cannot issue an order without complying with the National Environmental Policy Act (NEPA), 42 U.S.C. § 4321 *et seq.* Responders to that assertion stated that NEPA review requirements do not apply because any order would merely require the Plant to operate in the manner and at the level it has historically operated, and thus is not a "major federal action" triggering NEPA. In addition, responders assert that "...the emergency nature of the relief sought in this case permits the [the Secretary] to act without conducting a NEPA analysis, even if it were required."[7] DOE has determined that the emergency circumstances here make it necessary to take action without performing a NEPA analysis. Indeed, in order for an order under FPA section 202(c) to be issued at all, the Secretary of Energy must determine that an emergency exists, and I have made that determination here. DOE has consulted with CEQ about alternative arrangements pursuant to 40 C.F.R. § 1506.11.

C. Other Issues

Commenters opposed to the issuance of a FPA section 202(c) order cited *Richmond Power & Light v. FERC*, 574 F. 2d 610 (D.C. Cir. 1978) as imposing a limit on the Secretary's authority to make an emergency finding under section 202(c). In *Richmond*, the New England Power Pool (NEPOOL) petitioned the Federal Power Commission (the Secretary's predecessor in exercising section 202(c) authority) for an order pursuant to FPA section 202(c) to have utilities east of the Mississippi River with excess electric generating capacity supply NEPOOL with that excess capacity. The request was based on fears of an oil shortage due to the 1973 Arab oil embargo. The Commission responded by holding a conference and a series of meetings which resulted in an agreement among the purchasing, transmitting and supplying utilities and participating state regulatory commissions. As a result of the agreement, NEPOOL moved to withdraw its petition, which the Commission allowed. Richmond Power & Light Company challenged the decision to allow the withdrawal and the court found that the Commission did not abuse its discretion in declining to issue an order under section 202(c), but rather settling on the temporary-voluntary agreement program reached by the interested parties. Instead of limiting its

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[7] District of Columbia Public Service Commission Answer to Motion of the Virginia Department of Environmental Quality at page 24 (October 26, 2005), FERC Docket No. EL05-145-000. *See also* Answer of Potomac Electric Power Company and PJM Interconnection, LLC at page 18, (October13, 2005), FERC Docket No. EL01-145-000.

reach, *Richmond* underscores the discretionary nature of the Secretary's authority under section 202(c).[8]

Another case asserted to limit the Secretary's authority to issue an order under section 202(c) was *National Fuel Gas Supply v. FERC*, 909 F2d 1519 (D.C. Cir. 1990). In that case, National Fuel applied under section 7 of the Natural Gas Act (NGA), 15 U.S.C. § 717 *et seq.*, for a certificate of public convenience and necessity to allow it to make interruptible sales of natural gas. The Commission imposed a condition that National Fuel accept a blanket transportation certificate to provide open access transportation. The court ruled that the Commission was improperly using a NGA section 7 certificate condition in place of an individual or generic proceeding under section 5 of the NGA. The Department does not see the relevance of *National Fuel* here. I am using section 202(c) of the FPA for precisely the type of situation contemplated by section 202(c) of the FPA.

V. Decision

Section 202(c) of the FPA vests in the Secretary of Energy the authority to issue an order when "an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of the fuel or water for generating facilities, or other causes...." 16 U.S.C. § 824a(c). DOE's regulations acknowledge that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated by these regulations." 10 C.F.R. § 205.371.

I find that in the circumstances presented here, an emergency exists that justifies the issuance of a section 202(c) order. My determination is not based on any single factor, but on the combination of all relevant facts and circumstances. In particular, I find that an emergency exists because of the reasonable possibility an outage will occur that would cause a blackout, the number and importance of facilities and operations in our Nation's Capital that would be potentially affected by such a blackout, the extended number of hours of any blackout that might in fact occur, and the fact that the current situation violates applicable reliability standards.

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[8] The facts in *Richmond* and in the current situation are very different. *Richmond* dealt with a wide regional or even national energy shortage situation, while we are considering electricity reliability in a discrete geographic area. The facts here more closely resemble those considered by the Federal Power Commission in *City of Cleveland, Ohio v. Cleveland Electric Illuminating Company*, 47 FPC 747 (1972). In that case, the City of Cleveland petitioned the Commission pursuant to section 202(c) to order an interconnection with Cleveland Electric Illuminating Company to provide services during shortages caused by outages of the City of Cleveland's generating facilities, or delays getting generation on line. The Commission found that the City of Cleveland had an emergency due to periodic shortages of generating facilities caused by outages and ordered the establishment of a 69kV temporary emergency interconnection between the electric systems of the City and Cleveland Electric Illuminating. Similarly, here DOE is ordering the Plant to provide electricity in certain limited situations.

More specifically, if the Mirant plant is not available to generate electricity and one of the two transmission lines serving the Central D.C. area goes out of service, the Central D.C. area would be served by only one transmission line. Should that remaining line fail for any reason, a blackout would occur in the Central D.C. area, potentially for an extended period of time. In fact, if one or both of the transmission lines could not be brought back into service immediately and the only source of energy for the Central D.C. area was the Mirant Plant, in the absence of today's order it would take several hours at a minimum to bring the Plant into full operation.

The outage of one of these two lines is not merely a theortetical possibility. On Friday, December 16, 2005, PJM informed DOE that on the previous night, "one of the two circuits critical to providing service to the District tripped. Continued [electric] service to certain load within the District was at that time entirely dependent on the remaining circuit." As a result, PJM requested dispatch of a second generating unit at the Plant, but Mirant refused to do so. PJM informed DOE that "service was not interrupted because load was low and the remaining circuit performed without incident." Fortunately, full service to the line that had tripped was restored by the morning of December 16. Nonetheless, there can be no assurance that the Central D.C. area will be so lucky next time, either with respect to the timing of the event, the operation of the second transmission line, or the ability to bring the first transmission line back into service.

Furthermore, it is periodically necessary for an outage to occur on one of the transmission lines because of the need to perform maintenance. In fact, maintenance is scheduled on one of the lines in the next few weeks. Thus, as occurred on the night of December 15, 2005 and as will certainly occur again in the future, if the Mirant Plant is not made operational Central D.C. will find itself relying solely on one transmission line. The duration of an outage can range from up to several days (for maintenance) or even longer (up to weeks) if the outage of a line is due to a major equipment failure. Throughout such a period, if the Plant is not fully operational a blackout in Central D.C. is only one step away, i.e., if an event should occur that causes the second line to fail. Such a blackout could last for hours or days.

I recognize that, if past experience is any guide, the simultaneous failure or outage of both transmission lines serving the Central D.C. area is not a high probability. While this event has occurred in the past, it has not happened often. Moreover, the recent tripping of one circuit does not in itself dictate the existence of an emergency justifying issuance of a 202(c) order.

The facilities and functions that would be adversely affected by an extended blackout in this instance, however, is an important consideration. The Central D.C. area includes offices, facilities and operations involved in all three branches of government, and that are critically important to the Nation's national security, law enforcement and regulatory functions. The Central D.C. area also includes hundreds of thousands of residents and workers, and all manner of public safety and protection facilities, including hospitals, police, and fire facilities. Moreover, DOE has been informed that within 24 hours of a blackout in the Central D.C. area, untreated sewage from the Blue Plains Wastewater Treatment plant would be discharged into the Potomac River.

Finally, it is noteworthy that a blackout in the Central D.C. area not only would affect critically important facilities and operations, it could last for an extended period. Depending on the reason for the outage of the transmission lines, the lack of service on those lines accompanied by the lack of generation by the Plant could result in a large portion of the District of Columbia being without electricity for a period that could last hours or days. At the very least, if the two transmission lines were made unavailable with no advance notice and the only source of electricity for the Central D.C. area was the Mirant plant, in the absence of today's order DOE understands it would take at least 28 hours, and likely longer, to bring the Plant into full operation, during which time all or a substantial part of the Central D.C. area would be without electric power The results would be hardship and physical risk to hundreds of thousands of persons from loss of heat, elevator outages, medical equipment failure and numerous other causes. In addition, critical portions of the nation's government would also be severely impacted, with resulting adverse effects on a national scale.

Of course, the fact that the Department did not act immediately on the DCPCS petition does not argue against my finding that an emergency currently exists. After the petition was filed, DOE took several weeks to gather the relevant information, consider the facts, talk with environmental regulatory authorities, and develop an order that balanced the appropriate considerations. As explained in the text of this order, the current facts fully justify my finding that an emergency exists and that this order will meet that emergency. There certainly is nothing in the Federal Power Act that requires me to wait until a blackout actually has occurred, lives are put in jeopardy, and a significant disruption of National government functions already has happened before exercising my section 202(c) authority.

Accordingly, and based on all of the facts and circumstances, I find that an emergency exists justifying the issuance of this order under Federal Power Act section 202(c).

After finding the existence of an emergency, DOE has the authority, "either upon its own motion or upon complaint, with or without notice, hearing, or report, to order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest." 16 U.S.C. § 824a(c). The statute gives the Secretary of Energy broad discretion to fashion the terms of an order that will, in the Secretary's judgment, "best meet the emergency and serve the public interest." Based on the circumstances described above in this order, I hereby direct Mirant to generate electricity at the Plant pursuant to the terms of this order.

While I am issuing this order to help ensure a reliable supply of electric energy to the Central D.C. area, I am cognizant of the concerns that have been expressed concerning the potential adverse environmental consequences of operating the Plant, and of the national interest in attainment of the NAAQS that have been established under the Clean Air Act. Ordering action that may result in even local exceedances of the NAAQS is not a step to be taken lightly. However, it would not be reasonable for the Department of Energy to stand by and take no positive action on the DCPSC petition, even though the Central D.C. area is in danger of an extended blackout and the Department and private parties have available to them the legal and operational tools to prevent such a blackout from occurring. In this order, I have sought to harmonize those interests to the extent reasonable and feasible by ordering Mirant to operate in a

manner that provides reasonable electric reliability, but that also minimizes any adverse environmental consequences from operation of the Plant.

DOE expects that the DCPSC, having sought an emergency order, will take such actions as are within its authority to provide adequate and reliable electric service for the Central D.C. area including, for example, expediting approval of PEPCO transmission system upgrades and instituting demand response programs.[9] Indeed, DOE views this order not as a permanent solution to the Central D.C. area's reliability issues, but rather as a bridge between the current untenable situation and a more permanent solution that must be crafted by appropriate parties, including the DCPCS, FERC, environmental regulatory authorities, and relevant private sector parties. This permanent solution may include the installation of the new transmission lines discussed above, the installation of new pollution control equipment at the Mirant Plant, or other means.

As explained above, in the event that one of the two transmission lines that serve the Central D.C. area is out of service (due either to a necessary planned outage or to unforeseen events) and sufficient electricity from the Mirant power plant were not available, then the Central D.C. area would experience an immediate blackout should the one remaining source of electricity fail. This situation must be avoided, and ordering paragraph A of this order ensures that this situation will be avoided. When an outage is planned, Mirant is to be given advance notice and is required to supply necessary generation throughout the period of the outage.[10] In the event of an unexpected outage, Mirant must provide such generation as soon as possible. In the very unlikely eventuality of both transmission lines failing at the same time, Mirant is required to provide sufficient generation to supply the electrical demands of the affected area as soon as possible.

It is essential to determine the level of operation and other steps that will enable Mirant to rapidly respond to an unplanned transmission line outage. Some commenters have urged the Department to order the Plant to run continuously, even if doing so causes ongoing exceedances of the NAAQS. This would assure a high level of reliability of the electricity supply, but of course would not be tailored to particular circumstances in which operation of the Plant would be most necessary to provide needed reliability for the Central D.C. area and might also cause local air quality concerns. Other commenters have urged the Department to do nothing.

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[9] Demand response programs prompt electricity customers to reduce demand, especially during periods of short supply.

[10] In making certain portions of this order effective only upon notice to Mirant by PEPCO of a planned or unplanned outage of one or both of the 230 kV lines, it is similar to the FPA section 202(c) orders issued during the 2000/2001 California energy crisis. In those, DOE ordered certain entities to generate, deliver, interchange and transmit electricity to the California Independent System Operator (California ISO), but the entities were not required to deliver energy or services unless the California ISO had filed with DOE a certificate that it had been unable to acquire adequate supplies of electricity in the market. *See* Order pursuant to Section 202(c) of the Federal Power Act (December 14, 2000); Order Pursuant to Section 202(c) of the Federal Power Act (January 11, 2001).

The Department is not prepared to order actions that could cause more localized NAAQS exceedances than are necessary in order to assure adequate electric reliability for the Central D.C. area. At the same time, the Department should address the risks that delays in responding to an unplanned transmission line outage would present if measures are available to mitigate that risk. In my judgment, the appropriate balance is struck by (1) requiring Mirant to keep as many units in operation, and take all other measures to reduce the start-up time of units not in operation, for the purpose of providing electrical reliability, as feasible (as further defined in the ordering paragraphs below). Thus, Mirant must take actions to reduce the time it takes to respond to an unplanned outage. This will serve to reduce the risk of a blackout but not at the price of unnecessary exceedances of health-based NAAQS. As Mirant improves its environmental performance, in cooperation with environmental regulators, its ability to react to an unforeseen outage also will improve. Environmental regulators and Mirant can work together, with the Department, to reduce, and perhaps eliminate, any conflict between environmental goals and electric reliability.

This order is effective immediately and will terminate at 12:01 a.m. October 1, 2006. This order may be modified or extended at any time upon order of the Secretary of Energy.

VI. Ordering Paragraphs

For the reasons set forth above, pursuant to section 202(c) of the Federal Power Act, it is hereby ordered that:

A. During any period in which one or both of the 230kV lines serving the Central D.C. area is out of service, whether planned or unplanned, Mirant will operate the Potomac River Generating Plant to produce the amount of power (up to its full capacity) needed to meet demand in the Central D.C. area as specified by PJM for the duration of the outage.

In the event of a planned outage, Potomac River units will generate that amount of electricity specified by PJM to meet demand.

In the event of an unplanned 230 kV line outage, Potomac River units will generate that amount of electricity specified by PJM to meet demand as soon as possible.

When producing electricity pursuant to this paragraph, Mirant shall utilize pollution control equipment and measures to the maximum extent possible to minimize the magnitude and duration of any exceedance of the NAAQS.

B. Mirant shall keep as many units in operation, and shall take all other measures to reduce the start-up time of units not in operation, for the purpose of providing electricity reliability, as "feasible." For purposes of this paragraph, "feasible" means as determined by the Department of Energy, after consideration of the plan submitted by Mirant pursuant to paragraph D of this order and after consultation with the Environmental Protection Agency, without regard to cost and without causing or significantly contributing to any exceedance of the NAAQS.

C. Notice

In instances of scheduled outages of one of the 230kV lines, PEPCO will give advance notice of the planned outage and the estimated duration of such outage to Mirant, PJM, DOE, FERC, EPA, and DEQ. The notice must be sufficiently in advance of the outage to allow Mirant to bring the required amount of generation needed for reliability purposes on line by the time the outage is scheduled. PEPCO will ensure that only those planned outages needed to maintain or enhance the reliability of the 230 kV lines (or to install new lines) are scheduled and that such outages are scheduled to minimize the environmental effects of the operation of the Plant.

PEPCO will notify DOE, PJM, FERC, EPA, and DEQ of any unplanned outage of one or both of the 230 kV lines as soon as possible, but in no event later than two hours after informing Mirant.

In the event of either a planned or unplanned outage, PJM will specify the amount of electricity that Mirant must provide in order to meet demand.

D. Mirant shall submit a plan to DOE, within 10 days of the date of this order, detailing the steps it will take to ensure compliance with this order. This compliance plan shall include, at minimum, information regarding adequate staffing, materials, and supplies; emissions controls; and length of time necessary to start-up the Plant's generating units in the event of an unplanned or planned outage. DOE will review the compliance plan and order additional requirements if necessary.

E. Pursuant to the terms of FPA section 202(c) and DOE regulations at 10 C.F.R. § 205.376, Mirant and its customers should agree to mutually satisfactory terms for any costs incurred by Mirant under this order. If no agreement can be reached, just and reasonable terms shall be established by a supplemental order.

F. DOE expects that the DCPSC will take all reasonable actions to augment electrical reliability and to reduce electricity demand in the Central D.C. area.

G. DOE will periodically reexamine the need for this order with particular emphasis on: (1) Mirant's progress, working with environmental regulators, in reducing emissions and/or the impact of emissions; and (2) whether the DCPSC is taking all reasonable actions available to it to support electricity reliability in the Central D.C. area.

H. Pursuant to section 313 of the Federal Power Act (16 U.S.C. § 8251), any person, State, municipality, or State commission that is a party to this proceeding and is aggrieved by this order may apply for a rehearing within thirty days. Requests for rehearing may be submitted by mail, facsimile, or electronic mail to the following: (1) mail should be directed to Lawrence Mansueti of the Permitting, Siting, and Analysis Division of the Office of Electricity Delivery and Energy Reliability at the United States Department of Energy, Routing Symbol OE-20, 1000

Independence Avenue, S.W., Washington, D.C. 20585; (2) facsimiles may be submitted to 202-586-5860; (3) e-mail may be submitted to Lawrence.Mansueti@hq.doe.gov.

Issued in Washington, D.C. at 1:45 PM this 20th day of December, 2005.

Samuel W. Bodman
Secretary of Energy

EXHIBIT 23-15

Department of Energy
Washington, DC 20585

Order No. 202-17-1

Pursuant to the authority vested in me by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in Oklahoma due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this order will meet the emergency and serve the public interest.

On April 11, 2017, the Grand River Dam Authority (GRDA), an agency of the state of Oklahoma, filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* with the United States Department of Energy (Department) to ensure electric system reliability. The GRDA Grand River Energy Center has three generation units: coal-fired Unit No. 1, coal-fired Unit No. 2, and natural gas combined cycle Unit No. 3. GRDA planned to retire Unit No. 1 effective April 16, 2017, because it is not compliant with the Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards, 40 C.F.R. part 63 subpart UUUUU. GRDA was granted two one-year extensions for compliance, but the EPA is barred under the Clean Air Act from issuing further extensions. 42 U.S.C. § 7413(a)(4). Unit No. 1 is needed, however, because the other Grand River Energy Center units are unavailable. Due to a lightning-caused fire, Unit No. 2 is currently offline for repairs, and due to flooding in Louisiana, Unit No. 3's construction is delayed until mid-July at the earliest. Unit No. 1 is thus GRDA's only available unit to provide dynamic reactive power support to the region's Reliability Coordinator, the Southwest Power Pool, Inc. (SPP), during low-load, high-voltage events.

GRDA's application includes a March 1, 2017 letter of support from SPP in which SPP stated it "concurs with GRDA's assessment regarding GRDA Unit 1's importance for reliability." SPP observed that, in the past, it has needed "to commit GRDA Unit 1 for relief from high voltages" and noted that SPP created a Temporary Operating Guide for October 15-November 4, 2014, when Unit No. 2 was undergoing maintenance, to ensure Unit No. 1 would be available during light load conditions. SPP stated Unit No. 1 "will be a critical resource in maintaining proper system voltage."

Without sufficient reactive power support, electric system reliability is at risk because excessive voltage could force transmission lines offline, consequently leading to other reliability problems, or could cause electric arcing that would damage transmission facilities. The Federal Energy Regulatory Commission, through the North American Electric Reliability Corporation, regulates grid reliability through mandatory reliability standards, several of which are implicated if Unit No. 1 is unavailable to SPP. These include Reliability Standard VAR-001-4.1 (Voltage and Reactive Control) and transmission operations standards.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. The provision of reactive power support necessitates operation of Unit No. 1, but at levels far below maximum output. The Department has consulted with the EPA and reviewed emissions data provided by GRDA. This Order will continue the operational limitations described in EPA Administrative Compliance Order AED-CAA-113(a)-2016-002, as amended.[1] To minimize adverse environmental impacts and remain consistent with the approach taken by the EPA, this Order limits operation of Unit No. 1 to the provision of dynamic reactive power support and not real power generation, and only when called upon by SPP for reliability purposes.

Based on my determination set forth above, I hereby order:

From April 16, 2017 to (1) July 15, 2017, or (2) the date on which GREC Unit No. 3 or No. 2 is brought online, whichever is earlier, in the event that SPP determines that generation from Unit No. 1 is needed to maintain grid reliability, I direct GRDA to generate electricity to provide dynamic reactive power support from Unit No. 1 of the Grand River Energy Center, subject to the requirement that Unit No. 1 remain offline unless requested to generate by SPP. GRDA and SPP are directed to adopt a Temporary Operating Guide for the period of this Order based on the 2014 guide in Attachment B of the April 11 application, with the additional operational limitations set forth above. GRDA is further required to report to the Department all dates on which Unit No. 1 is run during the effectiveness of this Order and the estimated emissions associated with running Unit No. 1.

Issued in Washington, D.C. at 2:35 pm this 14th day of April, 2017.

Rick Perry

Rick Perry
Secretary of Energy

[1] Specifically, Unit No. 1 shall achieve a total annual capacity factor of not more than 80% during the period from July 15, 2016, through July 15, 2017.

EXHIBIT 23-16

Department of Energy
Washington, DC 20585

Order No. 202-17-2

Pursuant to the authority vested in me by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in the Commonwealth of Virginia due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

On June 13, 2017, PJM Interconnection, L.L.C. (PJM), the Regional Transmission Organization (RTO) whose service territory includes the North Hampton Roads area east of Richmond, Virginia, filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* with the United States Department of Energy (Department) "to preserve the reliability of [the] bulk power transmission system in the North Hampton Roads area." Virginia Electric and Power Company (Dominion Energy Virginia), the electric utility serving the area, owns two coal-fired units at its Yorktown Power Station (Yorktown Unit 1 and Yorktown Unit 2). In November 2011, and again in October 2012, Dominion Energy Virginia notified PJM of its plan to deactivate both units, effective December 31, 2014, because the units were not equipped to comply with the Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS), 40 C.F.R. part 63 subpart UUUUU. On June 24, 2014, pursuant to 40 C.F.R. 63.6(i)(4)(i)(A), the Virginia Department of Environmental Quality granted Dominion Energy Virginia a one-year MATS compliance extension for Yorktown Units 1 and 2. On April 16, 2016, pursuant to section 113(a) of the Clean Air Act, 42 U.S.C. § 7413(a)(3) and (4), EPA issued an Administrative Compliance Order (ACO) through April 15, 2017. Since the ACO expired, Dominion Energy Virginia has not achieved full compliance with the MATS for Yorktown Units 1 and 2. Section 113(a) of the Clean Air Act bars further compliance extensions.

Due to anticipated heightened electricity demand or peak load conditions associated with hot summer weather, PJM load flow studies indicate that generation from Yorktown Units 1 and 2 will likely be needed to prevent the possibility of uncontrolled power disruptions and shedding of critical loads in the North Hampton Roads area. The application refers to the need to run Yorktown Units 1 and 2 in this situation as "Scenario One." The application also introduces a "Scenario Two," which concerns the need for Yorktown Units 1 and 2 during transmission outages to support construction of system upgrades previously ordered by PJM through its Regional Transmission Expansion Planning Process (RTEPP). Scenario Two will not be applicable until Dominion Energy Virginia obtains permitting approval for the RTEPP upgrade, which the application indicates has not yet occurred.

On June 12, 2017, Dominion Energy Virginia wrote to the Department of Energy that it "agrees with [PJM's] Emergency Request and will operate in accordance with its provisions."

Electric system reliability is at risk during the next ninety days absent the availability of Yorktown Units 1 and 2 during peak load conditions and contingency events detailed in the application. The Federal Energy Regulatory Commission, through the North American Electric Reliability Corporation, regulates grid reliability through mandatory reliability standards, several of which are implicated if Yorktown Units 1 and 2 are unavailable to PJM, including Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements).

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law or regulation and minimize any adverse environmental impacts. Anticipated load conditions may necessitate operation of Yorktown Units 1 and 2. To minimize adverse environmental impacts and remain consistent with the approach taken by the EPA, this Order authorizes operation of Yorktown Units 1 and 2 only when called upon by PJM for reliability purposes. The Department has consulted with the EPA and authorities in York County, Virginia and has reviewed estimated emissions and water usage data provided by PJM. This Order will continue the operational limitations described in EPA's above-referenced ACO, AED-CAA-113(a)-2016-0005.

Based on my determination set forth above, I hereby order:

From June 16, 2017 to September 14, 2017, in the event that PJM determines that generation from Yorktown Units 1 and 2 is needed to maintain grid reliability, I order Dominion Energy Virginia to operate Units 1 and 2 of the Yorktown Power Station as directed by PJM only as needed to address reliability issues. PJM and Dominion Energy Virginia must develop and implement a dispatch methodology to operate Yorktown Units 1 and 2 only when called upon to address reliability needs. PJM and Dominion Energy Virginia are directed to provide the dispatch methodology to the Department upon implementation, and to report all dates on which Yorktown Units 1 and 2 are operated as well as the estimated emissions and water usage data associated with their operation by September 14, 2017, or the date upon which a renewal request is submitted, whichever occurs first.

Renewal of this Order, should it be needed, must be requested prior to its expiration. If the conditions creating the emergency remain substantially unchanged, a renewal request should be submitted at least 14 calendar days before this Order expires. If the conditions change—for example, if Dominion Energy Virginia obtains all permitting approvals for the RTEPP upgrade and identifies the date on which construction would begin—a renewal request should be submitted a minimum of 21 calendar days in advance of the expiration of this Order.

Issued in Washington, D.C. at 5:14 pm this 16th day of June, 2017.

Rick Perry

Rick Perry
Secretary of Energy

EXHIBIT 23-17

Department of Energy
Washington, DC 20585

Order No. 202-17-4

On August 24, 2017, PJM Interconnection, L.L.C. (PJM) submitted *Order No. 202-17-2 Renewal Application Filing* (Renewal Application) to the U.S. Department of Energy (DOE or Department). PJM is the Regional Transmission Operator (RTO) responsible for the reliability of the bulk power grid across several states, including in the North Hampton Roads area of Virginia.[1] Previously, on June 16, 2017, DOE issued Order No. 202-17-2 under section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c). That order authorized PJM to direct Virginia Electric and Power Company[2] (Dominion) to operate coal-fired Units 1 and 2 of its Yorktown Power Station, under certain specified circumstances, and only for a 90-day period. Order No. 202-17-2 expires at the end of today, by its own terms and by statute. 16 U.S.C. § 824a(c)(4)(A). In its Renewal Application, PJM asserts that there is a continuing emergency in the North Hampton Roads area of Virginia and asks the Department to renew Order No. 202-17-2 for an additional 90-day period.

Based on data and information submitted to the Department, and as explained in the accompanying Summary of Findings, I have determined that an emergency continues to exist in the North Hampton Roads area of Virginia due to a shortage of electric energy and a shortage of facilities for the generation and transmission of electric energy. I find that issuance of this Order will meet the emergency and serve the public interest in the North Hampton Roads area, as required by FPA section 202(c). I have imposed limitations on operations outlined in this Order to ensure, to the maximum extent practicable, consistency with applicable environmental laws and regulations, and the reporting requirements for operations and estimated emissions ensure transparency of implementation. Accordingly, I hereby grant PJM's Renewal Application and issue Order No. 202-17-4 to allow operation of Yorktown Units 1 and 2, with modifications as explained below, for an additional 90-day period to expire on December 13, 2017.

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[1] PJM states that "[t]he North Hampton Roads load area includes . . . Charles City County, James City County, York County, Williamsburg, Yorktown, Newport News, Poquoson, Hampton, Essex County, King William County, King and Queen County, Middlesex County, Mathews County, Gloucester County, the City of West Point, King George County, Westmoreland County, Northumberland County, Richmond County, Lancaster County, and the City of Colonial Beach." *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act*, at 1 n.4 (June 13, 2017). Williamsburg, Newport News, Poquoson, and Hampton are independent cities; Yorktown is a Census-Designated Place and the county seat of York County; West Point is a town in King William County; and Colonial Beach is a town in Westmoreland County.

[2] Virginia Electric and Power Company's parent company is Dominion Energy, Inc.

As I have determined that an emergency exists in the North Hampton Roads area of Virginia, I hereby order:

A. By Eastern Prevailing Time, beginning on September 15, 2017 and continuing through December 13, 2017, in the event that PJM determines that generation from Yorktown Units 1 and/or 2 is needed to maintain grid reliability, Dominion shall operate Units 1 and/or 2 of the Yorktown Power Station as directed by PJM only as needed to address reliability issues. This directive applies under either or both of Scenario One and Scenario Two as described in the accompanying Summary of Findings. This directive incorporates and maintains the operational limitations described in the Environmental Protection Agency's Administrative Compliance Order, AED-CAA-113(a)-2016-0005. Consistent with good utility practice, PJM and Dominion shall exhaust all reasonably and practically available resources, including demand response and behind-the-meter generation resources, prior to operating Yorktown Unit 1 or Yorktown Unit 2.

B. Dominion shall continue to comply with the dispatch methodology submitted by PJM on June 27, 2017.

C. Every two weeks, PJM and Dominion shall report all dates between September 14, 2017 and December 13, 2017 on which Yorktown Units 1 and/or 2 are operated, and the associated air emissions and water usage for those dates. Specifically, PJM and Dominion shall report, in units that align with those used in 40 C.F.R. Part 63, Subpart UUUUU, Table 2, the daily air emissions of: 1) filterable particulate matter (PM) or total non-mercury hazardous air pollutant (HAP) metals or individual HAP metals, 2) hydrogen chloride (HCl) or sulfur dioxide (SO_2), and 3) mercury (Hg). PJM and Dominion shall also report daily air emissions of greenhouse gases and nitrogen oxides (NO_x) and daily water usage. In the event that the outage schedule or estimates change from those presented in the Renewal Application, PJM and Dominion shall also provide updated outage schedules and associated Yorktown Unit 1 and Yorktown Unit 2 emissions estimates.

D. Renewal of this Order, should it be needed, must be requested before this Order expires. If the conditions creating the emergency remain substantially unchanged, a renewal request should be submitted at least 14 calendar days before this Order expires. If the conditions change, a renewal request should be submitted at least 21 calendar days before this Order expires.

Issued in Washington, D.C. at 3:00 p.m. this 14th day of September, 2017.

Rick Perry

Rick Perry
Secretary of Energy