Notice of Construction (NOC) Worksheet

PUGET SOUND
Clean Air Agency

Source: Boeing Commercial Airplane Seattle	**NOC Number: 12564**
Installation Address: 7700 E Marginal Wy S, Seattle, WA 98108	**Registration Number: 21147**
Contact Name: Grant Peltier	**Contact Email: grant.r.peltier@boeing.com**
Applied Date: 07-01-2025	**Contact Phone: (206) 303-7534**
Engineer: Maggie Corbin	**Inspector: Phil Kilner**

A. DESCRIPTION

<u>For the Order of Approval:</u>

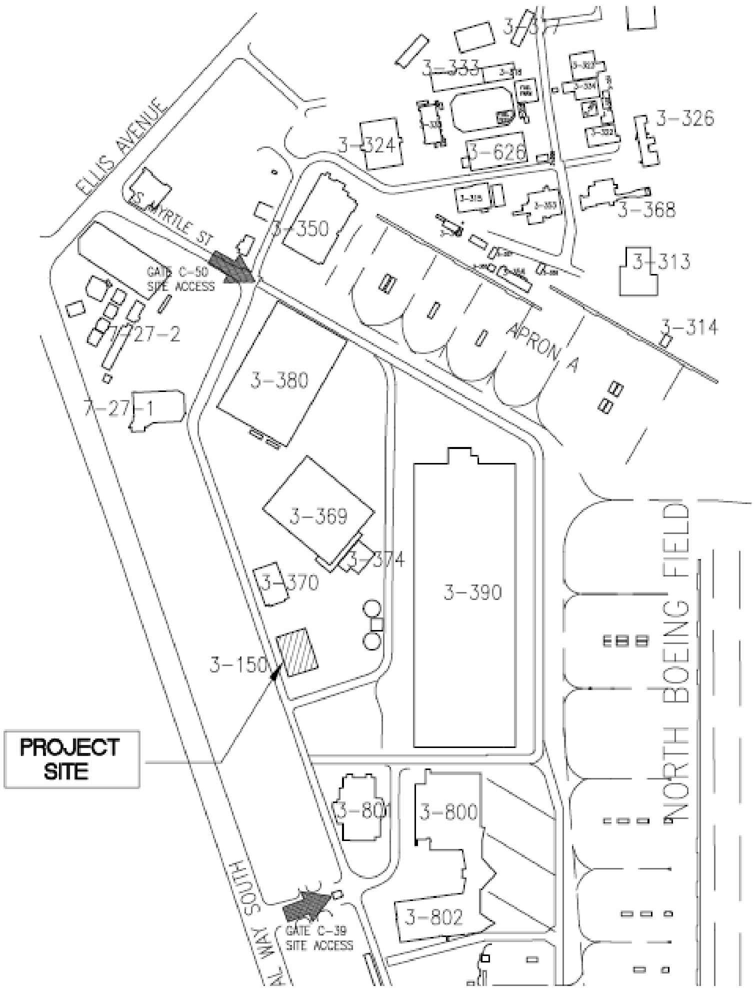
Two Cleaver Brooks D-Type Industrial Water-Tube boilers each with 30,000 pounds per hour capacity at an approximately 36.5 MMBtu/hr heat input and two Cleaver Brooks D-Type Industrial Water-Tube boilers each with 80,000 pounds per hour capacity at an approximately 96.9 MMBtu/hr heat input. The steam boilers will normally fire on natural gas with ultra-low sulfur diesel back-up. All boilers are equipped with flue gas recirculation, oxygen trim and low-NOx burners. The boilers will be located in Building 3-150.

Facility

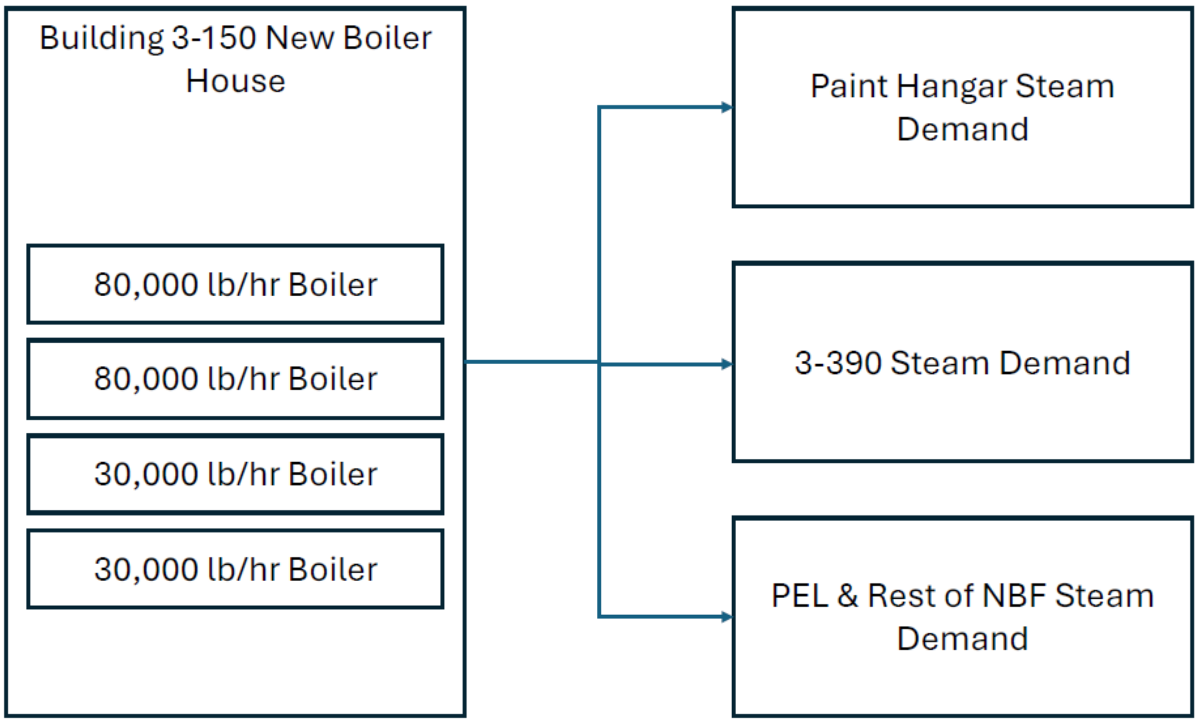
The Boeing Company North Boeing Field/Plant 2 facility (Boeing Seattle) is an aircraft manufacturing and assembling facility.

Proposed Equipment/Activities

The applicant is proposing to build a new boiler house (Building 3-150) and install four new boilers to provide steam, comfort heating, and hot water to the facility. The project site location on the North Boeing Field Site submitted in the application is shown below:


ELLIS AVENUE
S MYRTLE ST
GATE C-50
SITE ACCESS
3-333
3-324
3-626
3-326
3-350
3-368
3-313
3-314
APRON A
7-27-2
7-27-1
3-380
3-369
3-374
3-370
3-390
3-150
PROJECT SITE
NORTH BOEING FIELD
3-801
3-800
3-802
GATE C-39
SITE ACCESS
AL WAY SOUTH

A process flow diagram included in the application is shown below:



Existing boilers operating at Boeing Seattle are shown in the table below:

Bldg.	Col/Dr	Asset #	NOCOA	Date Installed	Source Description (rated input heating value, fuel used)	40 CFR 60 Subpart Dc?	40 CFR 63 Subpart DDDDD?	DDDDD Tune-up Frequency
2-15	*S. End*	*BOIL09*	*5208*	*1986*	*Boilers #1: 42 MMBtu/h, natural gas fired, jet fuel backup*	*No*	*Yes*	*5 yrs*
2-15	*S. End*	*BOIL10*	*5208*	*1986*	*Boilers #2: 42 MMBtu/hr, natural gas fired, jet fuel backup*	*No*	*Yes*	*5 yrs*
2-15	*S. End*	*BOIL11*	*5208*	*1989*	*Boilers #3; 99.5 MMBtu/hr, natural gas fired, jet fuel backup*	*No*	*Yes*	*5 yrs*
2-15	*S. End*	*BOIL12*	*5208*	*1989*	*Boilers #4; 99.5 MMBtu/hr, natural gas fired, jet fuel backup*	*No*	*Yes*	*5 yrs*
3-374	*----*	*BOIL53*	*Reg.*	*1986*	*Keeler 52.5 MMBTU/hr natural gas fired, jet A backup fuel*	*No*	*Yes*	*5 yrs*
3-374	*----*	*BOIL54*	*Reg.*	*1986*	*B&W 76.6 MMBTU/hr natural gas fired, jet A backup fuel*	*No*	*Yes*	*5 yrs*
3-801		*BOIL51*	*4861*	*1991*	*Bryan CL-150 1.5 MMBtu/hr natural gas fired*	*No*	*No*	*N/A*
3-800		*BOIL55*	*3825*	*1991*	*Bryan Steam Corp. 3.75 MMBtu/hr natural gas fired*	*No*	*Yes*	*5 yrs*

Bldg.	Col/Dr	Asset #	NOCOA	Date Installed	Source Description (rated input heating value, fuel used)	40 CFR 60 Subpart Dc?	40 CFR 63 Subpart DDDDD?	DDDDD Tune-up Frequency
3-800		*BOIL56*	*3825*	*1991*	*Bryan Steam Corp. 3.75 MMBtu/hr natural gas fired*	*No*	*Yes*	*5 yrs*
2-127		*BOIL1271*	*10190*	*2011*	*Cleaver Brooks, 24.5 MMBtu/hr, natural gas fired*	*Yes*	*Yes*	*5 yrs*
2-127		*BOIL1272*	*10190*	*2011*	*Cleaver Brooks, 24.5 MMBtu/hr, natural gas fired*	*Yes*	*Yes*	*5 yrs*

It is Boeing Seattle's intent to remove the existing boilers in Building 3-374 (BOIL53 and BOIL54) but that action is not included with this permit application review. Therefore, there was no consideration of emission reductions from boilers that will be removed from the facility in the future.

Permit History

These are new boilers – no permitting history.

B. DATABASE INFORMATION

(44) boiler, water heater or oil heater (2)

Removal Comment:

Comments: Cleaver Brooks D-Type Industrial Water-Tube boilers each with 30,000 lb/hr capacity. ULSD Backup limited to gas curtailment or 48 hours/calendar year or periodic testing of liquid fuel, maintenance, or operator training (only one boiler permitted under OA12564 on oil at any one time except for gas curtailment)

Rated Units: 36.50 Million BTU/Hr ***Year Installed:*** 2026 ***NC/NOT #:*** 12564

Operating Requirements:

Natural Gas / Dist (#2 Oil or PS-300)

(45) boiler, water heater or oil heater (2)

Removal Comment:

Comments: Cleaver Brooks D-Type Industrial Water-Tube boilers each with 80,000 lb/hr capacity. ULSD Backup limited to gas curtailment or 48 hours/calendar year or periodic testing of liquid fuel, maintenance, or operator training (only one boiler permitted under OA12564 on oil at any one time except for gas curtailment)

Rated Units: 96.90 Million BTU/Hr ***Year Installed:*** 2026 ***NC/NOT #:*** 12564

Operating Requirements:

Natural Gas / Dist (#2 Oil or PS-300)

New NSPS due to this NOCOA?	**Yes**	**Applicable NSPS: Dc**	**Delegated? yes**
New NESHAP due to this NOCOA?	**Yes**	**Applicable NESHAP: DDDDD**	**Delegated? yes**

In accordance with 40 CFR 60.40c(a), the affected facility is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).

In accordance with 40 CFR 63.7480(a)(2), the affected source is each new or reconstructed industrial, commercial, or institutional boiler or process heater located at a major source. For existing sources, the affected source is the collection at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory.

C. NOC FEES AND ANNUAL REGISTRATION FEES

NOC Fees:

Fees have been assessed in accordance with the fee schedule in Regulation I, Section 6.04. All fees must be paid prior to issuance of the final Order of Approval.

Fee Description	Cost	Amount Received (Date)
Filing Fee	$ 3,000	
Equipment (4 boilers)	$4,000	
SEPA (DNS)	$1,200	
NESHAP fee	$1,050	
NSPS fee	$1,050	
Review of Modeling	$1,500	
Public Notice	$750 plus publication fees (to be invoiced after publication)	
Filing received		$ 3,000 (7/1/2025)
Additional fee received		$8,800 (12/8/2025)
		$750 plus publication fees (DUE)
Total	**$11,800**	

Registration Fees:
Operating permit fees are assessed to the facility on an annual basis. Fees are assessed in accordance with Regulation I, Section 7.07. No change in the structure of the fees with the addition of these boilers.

Invoice for Year 2025 Operating Permit Fees

Bill To:
Boeing Commercial Airplane Seattle **Jeffrey Mieth** **PO Box 3707, MC 6X2-06** **Seattle, WA 98124**

Invoice Date:	Invoice #:
November 22, 2024	20250013
Due Date:	**Terms:**
January 06, 2025	Net 45 Days
Facility ID (Permit #):	
21147	

Site Address: ***Boeing Commercial Airplane Seattle***
7700 E Marginal Wy S, Seattle, WA 98108

The annual operating permit fee is required by Washington State law and Puget Sound Clean Air Agency's Regulation I.
Your fees are based on your NAICS code and your actual emissions during 2023.

Facility Fees and Applicable Regulations				Charges
Facility Fee for Operating Permit Sources. Reg I, 7.07(b)(1)(i) NAICS 336411 -- Aircraft Manufacturing			$	**87,833.00**
Emission Surcharges - Reg I, 7.07(b)(2)	**Tons in 2023**	**Per Ton**		
HAP (Hazardous Air Pollutants)	15	$ 60	$	900.00
VOC (Volatile Organic Compounds)	132	$ 60	$	7,920.00
			$	**8,820.00**
Fee Totals				
Operating Permit Fee (After February 20, 2025, the fee is $104,778.00). *The Total Fee is due by January 06, 2025. If unpaid after February 20, 2025, an additional delinquent fee of $8,125.00 will be applied. The delinquent fee is equal to 25% of the Operating Permit Fee, not to exceed $8,125 (Reg I, 7.07(b)).*			**$**	**96,653.00**
WA State Department of Ecology surcharge, Reg I, 7.07(d) *For further information regarding the WDOE surcharge, please call 1-564-233-8692.*			**$**	**1,391.03**
TOTAL FEE			**$**	**98,044.03**

D. STATE ENVIRONMENTAL POLICY ACT (SEPA) REVIEW

State Environmental Policy Act (SEPA) review was conducted in accordance with Regulation I, Article 2. The SEPA review is undertaken to identify and help government decision-makers, applicants, and the public to understand how a project will affect the environment. A review under SEPA is required for projects that are not categorically exempt in WAC 197-11-800 through WAC 197-11-890. A new source review action which requires a NOC application submittal to the Agency is not categorically exempt.

PSCAA is the SEPA lead agency for this project. The applicant submitted a completed Environmental checklist that is included in the electronic NOC folder.

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The proposed location is shown below:

The location is within the existing facility footprint which is zoned as MH Heavy Manufacturing. A new structure will be built in the area of existing industrial structures. Approximately 490 cubic yards of fill will be imported to raise the grade of the proposed building location – all clean soil will be used. The existing project area is 100% impervious surface. Temporary erosion control measures will be implemented by the contractor during construction. Stormwater runoff will be collected in the existing plant's stormwater control system to mitigate potential runoff water impacts. Appropriate best management practices will be implemented during construction to reduce and control surface water runoff impacts.

Based on review of Ecology's "What's in Neighborhood: Toxics Cleanup", there are no cleanup sites where the new building will be located. There are two cleanups started to the northwest of the proposed location – NBF JP4 tanks and Arco 5218 but these would not impact the proposed project.

The Environmental Checklist lists government approvals to include a building permit and grading permit. The City of Seattle was consulted for comments on September 16, 2025, and replied that they reviewed the checklist and do not see any substantive issues. They noted that the applicant may require ministerial or construction permits, but that these permits would not require SEPA review by the City of Seattle.

The applicant will also be submitting a Notice of Intent under the Construction Stormwater General Permit. This Notice of Intent asks who the SEPA lead Agency is and if there is a determination. Ecology does not accept these Notices as complete without a SEPA final determination. Ecology's Stormwater Compliance Specialist was consulted on September 23, 2025, to verify this Notice of Intent would not trigger another SEPA review by Ecology. This was confirmed by Ecology's Compliance on September 24, 2025.

Pursuant to RCW 70A.65.080(9)(e), the Agency considers greenhouse gas emissions from these boilers to be mitigated through participation in the state's Cap and Invest program.

Based on the proposed action and the information in the checklist, the project will not: adversely affect environmentally sensitive or special areas, or endangered or threatened species; conflict with local, state, or federal laws or requirements for the protection of the environment, or establish a precedent for future actions with significant effects. This proposal is not likely to have a probable significant adverse environmental impact, and I recommend the issuance of a Determination of Non-Significance with an opportunity for public comment.

E. TRIBAL CONSULTATION

On November 21, 2019, the Agency's Interim Tribal Consultation Policy was adopted by the Board. Criteria requiring tribal consultation are listed in Section II.A of the policy and include establishment of a new air operating permit source, establishment of a new emission reporting source, modification of an existing emission reporting source to increase production capacity, or establishment or modification of certain equipment or activities. In addition, if the Agency receives an NOC application that does not meet the criteria in Section II.A but may represent similar types and quantities of emissions, the Agency has the discretion to provide additional consultation opportunities.

This project does not meet any of the criteria for consultation listed in Section II.A of the Agency's Interim Tribal Consultation Policy.

F. BEST AVAILABLE CONTROL TECHNOLOGY (BACT) REVIEW

Best Available Control Technology (BACT)

New stationary sources of air pollution are required to use BACT to control all pollutants not previously emitted, or those for which emissions would increase as a result of the new source or modification. BACT is defined in WAC 173-400-030 as, "an emission limitation based on the maximum degree of reduction for each air pollutant subject to regulation under Chapter 70A.15 RCW emitted from or which results from any new or modified stationary source, which the permitting authority, 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 and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each pollutant."

An emissions standard or emissions limitation means "a requirement established under the Federal Clean Air Act or Chapter 70A.15 RCW which limits the quantity, rate, or concentration of emissions of air contaminants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction and any design, equipment, work practice, or operational standard adopted under the Federal Clean Air Act or Chapter 70A.15 RCW."

Best Available Control Technology for Toxics (tBACT)

New or modified sources are required to use tBACT for emissions control for TAP. Best available control technology for toxics (tBACT) is defined in WAC 173-460-020 as, "the term defined in WAC 173-400-030, as applied to TAP."

<u>Similar Permits</u>

The Agency has permitted several non-temporary boilers fired on natural gas in the previous 10 years but only 7 were greater than 20 MMBtu/hr and only 1 was greater than 50 MMBtu/hr.

NOC	Name	Approval Date	Project Description	BACT Summary
12462	Baker Commodities, Inc.	10/23/2024	One 36.5 MMBtu/hr Superior Boiler model Custom 900 firetube natural gas fired boiler with a low-NOx burner.	• Natural gas only • One-hour average exhaust concentration of nitrogen oxides (NOx) from this boiler must not exceed 9 ppm when fired on natural gas on a dry, volumetric basis corrected to 3% O2. • One-hour average exhaust concentration of carbon monoxide from this boiler must not exceed 50 ppm when fired on natural gas on a dry, volumetric basis corrected to 3% O2. • No visible emissions other than steam from the boiler. Compliance Demonstration: • Initial compliance source test within 90 days of installation (NOx and CO) • Continuous compliance source test no less than once per calendar year while firing natural gas. (NOx and CO) • Compliance testing must be performed at a firing rate representative of maximum output. The boiler may not be operated at a firing rate greater than the firing rate sustained during the most recent annual compliance testing. • Compliance for visible emissions - once per month.
12463	Baker Commodities, Inc.	10/23/2024	One 23.43 MMBtu/hr Cleaver Brooks CBEX Elite-700-670 natural gas fired boiler with a low-NOx burner.	• Natural gas only • One-hour average exhaust concentration of nitrogen oxides (NOx) from this boiler must not exceed 9 ppm when fired on natural gas on a dry, volumetric basis corrected to 3% O2. • One-hour average exhaust concentration of carbon monoxide from this boiler must not exceed 50 ppm when fired on natural gas on a dry, volumetric basis corrected to 3% O2. • No visible emissions other than steam from the boiler. Compliance Demonstration: • Initial compliance source test within 90 days of installation (NOx and CO) • Continuous compliance source test no less than once per calendar year while firing natural gas. (NOx and CO) • Compliance testing must be performed at a firing rate representative of maximum output. The boiler may not be operated at a firing rate greater than the firing rate sustained during the most recent annual compliance testing. • Compliance for visible emissions - once per month.

12383	Boeing Developmental Center	3/19/2024	Installation of a new 36.1 MMBtu/hr Cleaver Brooks Nebraska D watertube steam boiler. The steam boiler will normally fire on natural gas with diesel back-up. The boiler includes a forced draft design, flue gas recirculation system, economizer and a low NOx burner package.	• Natural gas only except during times of curtailment by the gas supplier or during testing, training or maintenance of the boiler on fuel oil. Periodic testing, maintenance or operator training on fuel oil shall not exceed a combined total of 48 hours during any calendar year and 8 hours during any 24-hr period • One-hour average exhaust concentration of nitrogen oxides (NOx) from this boiler must not exceed 9 ppm when fired on natural gas or 80 ppm when fired on fuel oil, on a dry, volumetric basis corrected to 3% O2. • One-hour average exhaust concentration of carbon monoxide from this boiler must not exceed 50 ppm when fired on natural gas or fuel oil on a dry, volumetric basis corrected to 3% O2. • No visible emissions other than steam from the boiler when fired on natural gas. When fired on fuel oil, opacity limit of 5% exempt during startup and shutdown when opacity limit is 20%. Compliance Demonstration: • Initial compliance source test within 90 days of installation (NOx and CO) • Continuous compliance source test no less than once per calendar year while firing natural gas. (NOx and CO) • Compliance testing must be performed at a firing rate representative of maximum output. The boiler may not be operated at a firing rate greater than the firing rate sustained during the most recent annual compliance testing. • Compliance for visible emissions - once per month and during compliance testing.
11386	Puget Sound Energy	9/14/2022	Included LNG processing facility with one 66 MMBtu/hr LNG vaporizer	• BACT based on 10 days of operation per year so did not require SCR (cost effectiveness analysis submitted) • Operate no more than 240 hours per any 12 consecutive month period • 4.0 ppmv VOC @ 3% O2 dry - VOC testing shall be conducted in accordance with EPA Test Method 25 or 25A or an alternative method approved by the Agency. Testing to quantify exempt compounds, such as methane, shall be conducted in accordance with EPA Test Method 18 or an alternative method approved by the Agency. • 50.0 ppm CO @ 3% O2 dry - CO testing shall be conducted in accordance with EPA Test Method 10 or an alternative method approved by the Agency. • 9.0 ppmv NOx @ 3% O2 dry - NOX testing shall be conducted in accordance with EPA Test Method 7E or an alternative method approved by the Agency

12113	Mystic Sheets dba Graphic Sheets	6/11/2021	Installation of a new permanent Cleaver Brooks CBEX-2W-700-900-250ST 900 hp boiler. The boiler will normally fire on natural gas with diesel back-up. The boiler includes a forced draft design, flue gas recirculation system, oxygen trimmer and a low NOx burner package. The boiler has a rated capacity of 33,549 lbs of steam per hour at 190 psia and 384oF. The rated heat input is 37.7 MMBtu per hour.	• Natural gas only except during times of curtailment by the gas supplier or during testing, training or maintenance of the boiler on fuel oil. Periodic testing, maintenance or operator training on fuel oil shall not exceed a combined total of 48 hours during any calendar year and 8 hours during any 24-hr period. Only burn fuel oil that has a maximum sulfur content of 15 ppm by weight. • One-hour average exhaust concentration of nitrogen oxides (NOx) from this boiler must not exceed 9 ppm when fired on natural gas or 35 ppm when fired on fuel oil, on a dry, volumetric basis corrected to 3% O2. • One-hour average exhaust concentration of carbon monoxide from this boiler must not exceed 50 ppm when fired on natural gas or fuel oil on a dry, volumetric basis corrected to 3% O2. • No visible emissions other than steam from the boiler when fired on natural gas. When fired on fuel oil, opacity limit of 5% exempt during startup and shutdown when opacity limit is 20%. Compliance Demonstration: • Initial compliance source test within 180 days of installation (NOx and CO) • Continuous compliance source test no less than once every 5 years. (NOx and CO) • Compliance testing must be performed at least 90% of boiler's firing rate. • Compliance for visible emissions - once per month and during compliance testing.
11606	Commencement Bay Corrugated	9/24/2018	Installation of a new Cleaver Brooks CBEX fire tube boiler rated at 37.5 MMBtu/hr to be fired solely on natural gas. Storage silo with 12â€™ diameter and 42â€™ eave height for storage of pearl cornstarch with 600 cfm cartridge bin vent dust collector.	• Natural gas only. • One-hour average exhaust concentration of nitrogen oxides (NOx) from this boiler must not exceed 9 ppm on a dry, volumetric basis corrected to 3% O2. • One-hour average exhaust concentration of carbon monoxide from this boiler must not exceed 50 ppm on a dry, volumetric basis corrected to 3% O2 • One-hour average exhaust concentration of volatile organic compounds (VOCs) from the boiler must not exceed 4.0 ppm on a dry volumetric basis corrected to 3% O2. • No visible emissions from the boiler. Compliance Demonstration: • Initial compliance source test within 90 days of installation (NOx and CO) • Continuous compliance- boiler tuneup include portable analyzer check no less than once per calendar year. (NOx and CO) • Compliance testing must be performed at 100% of boiler's firing rate • Compliance for visible emissions - once per calendar quarter and during compliance testing.

11562	Boeing Developmental Center	4/30/2018	Installation of a new Cleaver Brooks Nebraska D watertube steam boiler. The steam boiler will normally fire on natural gas with diesel back-up. The boiler includes a forced draft design, flue gas recirculation system, economizer and a low NOx burner package. The rated heat input is 36.1 MMBtu per hour.	• Natural gas only except during times of curtailment by the gas supplier or during testing, training or maintenance of the boiler on fuel oil. Periodic testing, maintenance or operator training on fuel oil shall not exceed a combined total of 48 hours during any calendar year and 8 hours during any 24-hr period. Only burn fuel oil that has a maximum sulfur content of 15 ppm by weight. • One-hour average exhaust concentration of nitrogen oxides (NOx) from this boiler must not exceed 9 ppm when fired on natural gas or 80 ppm when fired on fuel oil, on a dry, volumetric basis corrected to 3% O2. • One-hour average exhaust concentration of carbon monoxide from this boiler must not exceed 50 ppm when fired on natural gas or fuel oil on a dry, volumetric basis corrected to 3% O2. • No visible emissions other than steam from the boiler when fired on natural gas. When fired on fuel oil, opacity limit of 5% exempt during startup and shutdown when opacity limit is 20%. Compliance Demonstration: • Initial compliance source test within 90 days of installation (NOx and CO) • Continuous compliance source test no less than once per calendar year. (NOx and CO) • Compliance testing must be performed at 100% of boiler's firing rate. • Compliance for visible emissions - once per month and during compliance testing.
11345	Aerojet Rocketdyne, Inc.	3/6/2018	Installation of a new Babcock & Wilcox FM-10-66 watertube boiler rated at 65.61 MMBtu/hr to be fired solely on natural gas. This boiler replaces an existing 51.75 MMBtu/hr boiler originally authorized under Order of Approval 8453.	• Boiler must only fire on natural gas. • One-hour average exhaust concentration of nitrogen oxides (NOx) from this boiler must not exceed 9 ppm on a dry, volumetric basis corrected to 3% O2. • One-hour average exhaust concentration of carbon monoxide from this boiler must not exceed 50 ppm on a dry, volumetric basis corrected to 3% O2. • Visible emissions from this boiler must not exceed zero percent opacity for more than 3 minutes in any 1 hour as determined by Ecology Method 9A. Compliance Demonstration: • Initial compliance demonstrated by testing within 90 days of starting-up the boiler. • Continuous compliance by testing no less than once per calendar year. • Compliance testing must be conducted at 100% of the boiler's firing rate. • Check the boiler stack for the presence of visible emissions once per month during the operation of the boiler.

Other Regulatory Agencies BACT

The Agency reviewed the BACT determinations from recent permitting decisions in addition to other Agency determinations or regulatory requirements.

NO_x BACT review for natural gas fired boilers (< 100 MMBtu)

Origin	BACT Determinations
Bay Area Air Quality Management District (BAAQMD) (Boilers >33.5 to <50 MMBtu/hr (Date 8/4/2010)	Low NOx burners and flue gas recirculation and Selective Catalytic Reduction (SCR) or Low NOx Burners and Flue Gas Recirculation

Origin	BACT Determinations
Bay Area Air Quality Management District (BAAQMD) (Boilers >=50 MMBtu/hr (Date 8/4/2010)	Low NOx burners and flue gas recirculation and Selective Catalytic Reduction (SCR) or Ultra Low NOx Burners and Flue Gas Recirculation
South Coast Air Quality Management District (SCAQMD) – Rule 1146 (Amended 12/4/2020)	9.0 ppmv @ 3% O_2 dry or 0.0085 lb/MMBtu
South Coast AQMD – Permit #F23622	Low NOx burners – 9.0 ppmv @ 3% O_2 dry 15 min average
South Coast AQMD – Permit #359772	SCR – 7.0 ppmv @ 3% O_2 dry 15 min average
Santa Barbara County APCD Rule 342 (Boilers >20 MMBtu/hr, gaseous fuel) (revised 5/16/2024)	7.0 ppmv @ 3% O_2 Multiple fuels – heat input weighted average limit
San Diego County APCD (Boilers <50 MMBtu/hr) (Revised 11/2023)	BACT Control Option: Low NOx Burner, FGR and oxygen controller (NG using No. 2 oil as backup fuel) 9 ppm @ 3% O_2
San Diego County APCD (Boilers 50 to <250 MMBtu/hr) (Revised 11/2023)	BACT Control Option: Low NOx Burner, FGR and oxygen controller (NG using No. 2 oil as backup fuel) 9 ppm @ 3% O_2 NG or LPG fuel only: 5 ppm @ 3% O_2
EPA RBLC ID OH-0387	0.0110 lb/MMBtu
Summary of NOCOA from above	9.0 ppmv @ 3% O2 dry 60 min average when firing natural gas
Ecology – General Order 08-AQ-G003 (Boilers between 1 and 50 MMBtu/hr, using diesel at any time)	9.0 ppmv @ 3% O_2 dry
Most stringent from the listed determinations (NG or LPG fuel with oil as backup fuel) – with SCR	**7.0 ppmv @ 3% O_2 dry**
Most stringent from the listed determinations (NG or LPG fuel with oil as backup fuel) – without SCR	**9.0 ppmv @ 3% O_2 dry**

VOC BACT review for natural gas fired boilers (< 100 MMBtu)

Origin	BACT Determinations
Bay Area Air Quality Management District (BAAQMD) (Boilers >33.5 to <50 MMBtu/hr (Date 8/4/2010)	Good combustion practices and fuel selection
Bay Area Air Quality Management District (BAAQMD) (Boilers >=50 MMBtu/hr (Date 8/4/2010)	Good combustion practices and fuel selection
EPA RBLC ID OH-0387	0.0050 lb/MMBtu
EPA RBLC ID TX-0751	4.0 ppmv @ 3% O_2 dry or 0.00170 lb/MMBtu
Summary of NOCOA from above (if limit included	4.0 ppmv @ 3% O2 dry 60 min average

Most stringent from the listed determinations (ppmv)	**4.0 ppmv @ 3% O_2 dry**

CO BACT review for natural gas fired boilers (< 100 MMBtu)

Origin	BACT Determinations
Bay Area Air Quality Management District (BAAQMD) (Boilers >33.5 to <50 MMBtu/hr (Date 8/4/2010)	Good combustion practices and 100 ppmv @ 3% O_2 dry
Bay Area Air Quality Management District (BAAQMD) (Boilers >=50 MMBtu/hr (Date 8/4/2010)	Oxidation catalyst or good combustion practice in conjunction with SCR system or ultra-low NOx burners and FGR 10 ppmv @ 3% O2 dry with oxidation catalyst 50 ppmv @3% O2 dry without oxidation catalyst
Santa Barbara County APCD Rule 342 (revised 6/2019)	400 ppmv @ 3% O_2
EPA RBLC ID OH-0387	0.0370 lb/MMBtu
Summary of NOCOA from above	50.0 ppmv 60 min average
Ecology – General Order 08-AQ-G003 (Boilers between 1 and 50 MMBtu/hr, using diesel at any time)	50.0 ppmv @ 3% O_2 dry
Most stringent from the listed determinations (ppmv)	**50.0 ppmv @ 3% O_2 dry**

NOx BACT for diesel/liquid fuel fired boilers (< 100 MMBtu)

Origin	BACT Determinations
Bay Area Air Quality Management District (BAAQMD) (Boilers >=50 MMBtu/hr (Date 8/4/2010)	25 ppmvd @3% O2 with SCR 40 ppmvd @3% O2 without SCR
NC# 12383 (3/19/2024	80 ppmv @ 3% O2 dry 60 min average
NC# 12113 (issued 6/2021)	35.0 ppmv @ 3% O2 dry 60 min avg (based on diesel)
NC # 11562 (issued 4/2018)	80.0 ppmv @ 3% O2 dry 60 min average when firing fuel oil
NC #12090 (issued 5/2021)	80 ppmv @ 3% O2 dry 60 min average
Ecology – General Order 08-AQ-G003 (Boilers between 1 and 50 MMBtu/hr, using diesel at any time)	35 ppmv @ 3% O_2
Most stringent from the listed determinations (NO_x ppmv)	**35.0 ppmv @ 3% O_2 dry**

The San Joaquin Valley APCD updated their boiler BACT analysis from 2022 (natural gas or propane with LPG backup). The boiler-dual fuel BACT guideline for facilities requiring liquid backup fuel was rescinded. The information is saved in the electronic NOC folder, but was not used in the BACT determination since the BACT was specific to natural gas fuel only.

Analysis

At the Agency's request, the applicant submitted a BACT analysis with their supplemental application. Similar to the Agency's review, the applicant identified control technologies obtained from industry standards and Agency BACT databases included BAAQMD permit handbook and BACT/Toxics Best Available Control Technology Workbook, California EPA Air Resource Board BACT clearinghouse, SJVAPCD BACT clearinghouse, SCAQMD BACT determinations, TCEQ BACT guidelines, EPA's RACT/BACT/LAER Clearinghouse database and SDAPCD guidance document for BACT.

Since early discussions indicated lower emission limits were not feasible since the boilers are required to use diesel fuel as backup during natural gas curtailments, the Agency requested an evaluation of whether a gaseous fuel could be used as a backup fuel. The applicant provided an analysis and concluded that propane or LPG was not feasible as a backup fuel based on the limited amount of space available on the site and the need to allow for movement of vehicles and manufacturing materials around the site. The Boeing Fire Department recommends a 75-foot setback distance from buildings and likely a fixed fire suppression system for propane or diesel (additional space). Since diesel has a higher energy content than propane, smaller tanks can be used. Boeing has the capability to refuel diesel tanks while the use of propane or LPG would require an outside vendor to fill the tank. This would add additional costs. Although a cost analysis comparison was not submitted, the applicant has determined that propane or LPG was not feasible.

BACT for NOX, CO and VOCs – Boilers 10 to 50 MMBtu/hr

The applicant's BACT analysis included the following potential control technologies for dual-fuel boilers:

- Low NOx burners (LNB)
- Ultra-low NOX burners (ULNB)
- Flue gas recirculation (FGR)
- LNB plus FGR
- Selective catalytic reduction (SCR)

The applicant reviewed BACT and LAER limits, but noted that the lower NO_x limit of 5.0 pppmvd @3% O_2 was a LAER determination in an area that is nonattainment for ozone. To achieve LAER or California BACT emission rates, SCR may be added. The applicant did not submit a full cost analysis for SCR for this sized boiler.

Table 1. BACT Determinations for Boilers 10 to 50 MMBtu/hr

Agency	NO_x BACT Limit	CO BACT Limit	Technology
BAAQMD	No limit provided	100 ppmv @ 3% O_2 dry	Achieved in Practice: LNB+FGR Good Combustion Practice
SDAPCD	Firing Natural Gas: 9.0 ppmvd @ 3% O_2 Firing Backup Fuel: No limit provided	No limit provided	Achieved in Practice: LNB+FGR+Oxygen Controller Good Combustion Practice
SCAQMD	Firing Natural Gas: 5.0 ppmvd NO_x @ 3% O_2, 15-min average Firing Backup Fuel: 40 ppmvd NO_x @ 3% O_2, 15-min average Ammonia Slip: 5.0 ppmvd NH_3 @ 3% O_2, 60-min average	Firing Natural Gas: 100 ppmvd CO @ 3% O_2, 15-min average Firing Backup Fuel: 400 ppmvd CO @ 3% O_2, 15-min average	Major Source/LAER LNB+SCR Good Combustion Practice
TCEQ	Case-by-case analysis required	Case-by-case analysis required	Case-by-case analysis required

ppmv = parts per million by volume

SCR can achieve NO_x reduction efficiencies greater than 70%, however, for similarly sized boilers permitted by PSCAA an SCR has not been required. The lower emission rates of NO_x can be offset with an increase in CO emissions and emissions of ammonia due to ammonia slip. SCR was determined to be BACT for some California agencies, but this stringency reflects non-attainment status for ozone and the use of SCR to reduce ozone precursors.

Given that the Puget Sound region is not currently in ozone non-attainment, the Agency has determined that the reduction of NO_x emissions with an SCR from 9.0 ppmv @ 3% O_2 to 7.0 ppmv @ 3% O_2 or 5.0 ppmv @ 3% O_2 does not, in this case, constitute BACT. Recommended BACT limits will be achieved by implementing the following technologies, combustion controls and best management practices:

1. Cleaver-Brooks "Ultra-Low NO_x" burner package with the following emission values

"Ultra Low-NOx" Burner Emissions Values (in lb/mmbtu)

	Natural Gas	#2 Oil	#6 Oil
NOx	0.011	0.075	NA
CO	0.037	0.057	NA
SO_x	0.0006	0.051	NA
VOC	0.004	0.006	NA
PM_{total}	0.005	0.024	NA

Natural Gas
Pipeline quality, HHV of 1,040 BTU/SCF, 0.2 grain/100SCF total sulfur as sulfur.
#2 fuel oil
ASTM D975 S500, HHV of 140,000 BTU/gal, < 0.02 % wt fbn, < 0.05 % wt sulfur, < 0.01 % wt ash.

2. Flue gas recirculation.
3. Good combustion practices.
4. Use of ultra-low sulfur diesel for the back-up fuel.

BACT for NOX, CO and VOCs – Boilers 50 to 100 MMBtu/hr

The applicant's BACT analysis included the following potential control technologies for dual-fuel boilers:

- Low NOx burners (LNB)
- Ultra-low NOX burners (ULNB)
- Flue gas recirculation (FGR)
- LNB plus FGR
- Selective catalytic reduction (SCR)

The applicant included published BACT determinations for natural gas/fuel oil boilers greater than 50 and less than 250 MMBtu/hr.

Table 2. BACT Determinations for Boilers 50 to 250 MMBtu/hr

Agency	NO_x BACT Limit	CO BACT Limit	Technology
BAAQMD	No limit provided	50 ppmv @ 3% O_2 dry	Achieved in Practice: ULNB+FGR Good Combustion Practice
SDAPCD	Firing Natural Gas: 5.0 ppmvd @ 3% O_2 Firing Backup Fuel: Not an option	No limit provided	LAER/California BACT SCR on Uncontrolled Boiler Good Combustion Practice
SDAPCD	Firing Natural Gas: 9.0 ppmvd @ 3% O_2 Firing Backup Fuel: < 170 ppmvd @ 3% O_2	No limit provided	Achieved in Practice: LNB+FGR+Oxygen Controller Good Combustion Practice
TCEQ	Firing Natural Gas: 0.01 Lb NO_x/MMBtu Firing Fuel Oil: Limited to 760 hours per year	Case-by-case analysis required	Emission limits typically achieved using dry-low NO_x combustors, limiting fuel consumption, SCR, and/or water or steam injection. Specify technique(s).

The applicant notes that California has areas of nonattainment for ozone, and NO_x is a precursor to ozone so frequently BACT determinations in California are LAER. The proposed project will be located in an area that is in attainment for ozone.

The applicant did not submit a cost analysis for the addition of SCR since they determined the proposed control with a limit of 9 ppm for NOx is the most effective, feasible control technology for NO_x. The Agency did review potential emission reductions with a lower emission limit of 5 ppmv that would require the addition of SCR. This would result in a project emission decrease from 13.7 tons/year of NOx to approximately 9.5 tons/year of NO_x. Given that the Puget Sound region is not currently in ozone non-attainment, the Agency has determined that the reduction of NO_x emissions with an SCR from 9.0 ppmv @ 3% O_2 to 7.0 ppmv @ 3% O_2 or 5.0 ppmv @ 3% O_2 does not, in this case, constitute BACT. BACT limits will be achieved by implementing the following technologies, combustion controls and best management practices:

1. Cleaver-Brooks “Ultra-Low NO_x“ burner package with the following emission values

“Ultra Low-NOx” Burner Emissions Values (in lb/mmbtu)

	Natural Gas	#2 Oil	#6 Oil
NOx	0.011	0.075	NA
CO	0.037	0.057	NA
SO_x	0.0006	0.051	NA
VOC	0.004	0.006	NA
PM_{total}	0.005	0.024	NA

Natural Gas
Pipeline quality, HHV of 1,040 BTU/SCF, 0.2 grain/100SCF total sulfur as sulfur.
#2 fuel oil
ASTM D975 S500, HHV of 140,000 BTU/gal, < 0.02 % wt fbn, < 0.05 % wt sulfur, < 0.01 % wt ash.

2. Flue gas recirculation.
3. Good combustion practices.
4. Use of ultra-low sulfur diesel for the back-up fuel.

BACT Determinations

Summary BACT/tBACT determination for Boilers <50 MMBtu/hr

Pollutant	BACT Limit	Implementation Method
SO_2	Good combustion practices and fuel selection. Natural gas or ultra-low sulfur diesel.	
VOCs	4.0 ppmv @ 3% O_2 dry when firing natural gas	Tested for compliance every three years using EPA Reference Methods. Compliance demonstration based on the average of three 60-minute tests.
CO	50.0 ppmv @ 3% O_2 dry when firing natural gas or diesel	
NO_x	9.0 ppmv @ 3% O_2 dry when firing natural gas 35.0 ppmv @ 3% O_2 dry when firing diesel	
PM	0% opacity	Ecology Method 9A

Summary BACT/tBACT determination for Boilers =>50 MMBtu/hr and <100 MMBtu/hr

Pollutant	BACT Limit	Implementation Method
SO_2	Good combustion practices and fuel selection. Natural gas or ultra-low sulfur diesel.	

Pollutant	BACT Limit	Implementation Method
VOCs	4.0 ppmv @ 3% O_2 dry when firing natural gas	For natural gas, test annually for compliance for first 3 years using EPA Reference Methods, then testing can be reduced if emissions below standards. For fuel, test for compliance every three years using EPA Reference Methods. Compliance demonstration based on the average of three 60-minute tests.
CO	50.0 ppmv @ 3% O_2 dry when firing natural gas or diesel	
NO_x	9.0 ppmv @ 3% O_2 dry when firing natural gas 35.0 ppmv @ 3% O_2 dry when firing diesel	
PM	0% opacity	Ecology Method 9A

G. EMISSION ESTIMATES

Proposed Project Emissions

<u>Potential Emissions</u>

The applicant provided potential emissions for the project based on all four boilers operating 8,712 hours on natural gas and 48 hours on ultra-low sulfur diesel. The 48 hours on ultra-low sulfur diesel (ULSD) is included for maintenance and testing operations on each boiler and restricted in Condition No. 4 of the permit to no more than 8 hours in a 24-hour period. Although the boilers are set up to fire on ULSD if there is a gas curtailment, that is not considered normal operations. Boeing is required to provide notice to the Agency when there is a natural gas curtailment or natural gas interruption. In the previous 5 years, this happened once in 2023 and lasted 22 hours.

For natural gas combustion, NO_x and CO emission factors for the boilers are based on manufacturer's specification and typical emissions data. These are reflected as limits in the permit. PM_{10}, $PM_{2.5}$ and SO_2 emission factors for natural gas are from EPA's AP-42, Chapter 1.4. The VOC emission factor uses the BACT determination for the natural gas boiler in NOC 12383.

For combustion on ULSD, NOx and CO emission factors are from Manufacturer's Specifications and Expected Emissions Data. PM10, PM2.5 , and VOC emission factors are from the typical emissions summary from the manufacturer. Per AP-42 Chapter 1.3 Table 1.3-7, PM10 is 55% cumulative mass % stated size and PM2.5 is 42%. The SO_2 is derived based on 15 ppm sulfur content.

Emission factors for toxic air pollutants are consistent with recent permit reviews for natural gas boilers with ULSD backup fuel.

The Agency reviewed the calculations submitted and did not revise emission factors or calculations. A summary of potential emissions from the project is included below:

Table 1. Project Criteria Emissions Summary

Source	Quantity	Potential to Emit (tons/year)								
		NOx	CO	PM_{10}	$PM_{2.5}$	SO_2	VOC	HAPs	WAC TAPs	CO_2e
30,000 lb/hr (36.5 MMBtu/hr) Dual Fuel (Natural Gas and ULSD) Boiler	2	3.7	11.6	2.3	2.3	0.19	1.6	1.0	13.0	36,951
80,000 lb/hr (96.9 MMBtu/hr) Dual-Fuel (Natural Gas and ULSD) Boiler	2	9.9	30.9	6.2	6.2	0.50	4.3	2.7	34.5	98,097
Total Emissions (tpy)		13.6	42.5	8.6	8.6	0.7	5.9	3.8	47.5	135,048

Notes:
PTE based on 8,712 hours of operation run on natural gas and 48 hours on ultra-low sulfur diesel (ULSD) for all boilers.

Facility-wide Emissions

Potential Emissions

The applicant submitted updated facility-wide potential emissions as part of their AOP Renewal process. Boeing Seattle is a major source for CO, NOx, VOC and HAP.

Table 1. Potential Emissions from the Facility, tons per year

PTE Emissions (tons/year)					
CO	NO_x	PM_{10}	SO_2	VOC	HAP
103	513	20	1	251.5	32

The applicant is required to report actual emissions annually. Annual emissions as reported by the facility:

Year	NO2	SO2	PM10	PM2.5	VOC	TAC	HAP
2024	24.83	1.75	1.73	1.73	57.06	34.92	4.81
2023	Below Reporting Thresholds				131.58	62.19	14.51
2023					88.48	43.88	8.71

H. OPERATING PERMIT OR PSD

The facility is a Title V air operating permit source and conditions of this Order will be incorporated into the AOP during the next AOP opening. This change does not require an air operating permit revision in accordance with AOP 21147, Section VI.C.

1. *Boeing Seattle is authorized to make the changes described in WAC 173-401-722 without a permit revision, provided that the following conditions are met:*
    a. *The proposed changes are not Title I modifications;*
    b. *The proposed changes do not result in emissions which exceed those allowable under the permit, whether expressed as a rate of emissions, or in total emissions;*
    c. *The proposed changes do not alter permit terms that are necessary to enforce limitations on emissions from the units covered by the permit; and*

   d. *The facility provides the administrator and PSCAA with written notification at least seven days prior to making the proposed changes except that written notification of a change made in response to an emergency shall be provided as soon as possible after the event.*

2. *The permit shield does not apply to any 502(b)(10) change or SIP authorized emission trading but does extend to terms and conditions that allow for the trading of emissions increases or decreases for the purpose of complying with a federally enforceable emissions cap.*
3. *Boeing Seattle shall comply with applicable preconstruction review requirements.*
4. *Boeing Seattle and PSCAA shall attach each notice to their copy of the relevant permit.*

Emission increases associated with this project were reviewed for Prevention of Significant Deterioration (PSD) Program applicability. The facility is an existing PSD major source – NBF and Boeing Plant II qualify as a major source because, combined, they emit more than 250 tons per year of VOC. PSD-90-04, Amendment 1 was issued in 1995.

A project is a major modification for a regulated NSR pollutant if it causes two types of emissions increase: a significant emissions increase and a significant net emissions increase. Since this project only involves construction of new emission units, a significant emission increase is projected to occur if the sum of the difference between potential to emit from each new emission unit (in this case, the new boilers) following the completion of the project and the baseline actual emissions of these units before the project equals or exceeds the significant emission rates in 40 CFR 52.21(23)(i). The baseline emissions are zero since these are new units.

The applicant submitted an updated emissions analysis that compared potential emissions to the PSD significant emission rates on December 16, 2025. None of the significant emission rates were exceeded.

Table 1. Project Criteria Emissions Summary

Source	Quantity	Potential to Emit (tons/year)					
		NOx	CO	PM_{10}	$PM_{2.5}$	SO_2	VOC
30,000 lb/hr (36.5 MMBtu/hr) Dual Fuel (Natural Gas and ULSD) Boiler	2	3.7	11.6	2.3	2.3	0.19	1.6
80,000 lb/hr (96.9 MMBtu/hr) Dual-Fuel (Natural Gas and ULSD) Boiler	2	9.9	30.9	6.2	6.2	0.50	4.3
Total Emissions (tpy)		**13.6**	**42.5**	**8.6**	**8.6**	**0.7**	**5.9**
Prevention of significant deterioration Significant Emission Rate (SER)		40	100	15	10	40	(40 for Ozone)
Above the SER?		**No**	**No**	**No**	**No**	**No**	**N/A**

Notes:
N/A - not applicable
PTE based on 8,712 hours of operation run on natural gas and 48 hours on ultra-low sulfur diesel (ULSD) for all boilers.
SER based on 40 CFR 52.21 (23) (i)

I. CRITERIA POLLUTANT AMBIENT ANALYSIS

The impact of the project on ambient concentrations of criteria pollutants and compliance with the National Ambient Air Quality Standards (NAAQS) has been reviewed.

The Agency requested the applicant submit an analysis showing compliance with the NAAQS and this was submitted to the Agency in the supplemental application (November 2025). The basis of the report is the Modeling Protocol submitted to PSCAA on October 8, 2025, and approved by PSCAA on October 15, 2025.

The modeling was conducted in accordance with EPA's Guideline on Air Quality Models. Criteria pollutants were compared to either WAC 173-400-113 Table 4a or the NAAQS.

The table below summarizes the criteria pollutant emission rates used in the modeling:

Table 1-1. Criteria Air Pollutant Emission Summary for Modeling

Pollutant	Averaging Period	Unit	Value
Carbon monoxide	1-hour	lb/hr	13.9
Carbon monoxide	8-hour	lb/hr	13.9
Sulfur dioxide	1-hour	lb/hr	0.25
Sulfur dioxide	3-hour	lb/hr	0.25
Sulfur dioxide	24-hour	lb/hr	0.18
Sulfur dioxide	Annual	tpy	0.68
Particulate matter 10	24-hour	lb/hr	2.14
Particulate matter 10	Annual	tpy	8.55
Particulate matter 2.5	24-hour	lb/hr	2.03
Particulate matter 2.5	Annual	tpy	8.54
Nitrogen dioxide	1-hour	lb/hr	14.5
Nitrogen dioxide	Annual	tpy	13.1

I verified inputs are consistent with the most current emissions spreadsheet. Emission rates reflect normal operations on natural gas except periodic testing, training and maintenance (enforceable limit in Condition No. 4 of the permit). Although the boilers are set up to fire on ULSD if there is a gas curtailment, that is not considered normal operations. Boeing is required to provide notice to the Agency when there is a natural gas curtailment or natural gas interruption. In the previous 5 years, this happened once in 2023 and lasted 22 hours.

The predicted modeling concentrations were compared to the WAC 173-400-113 Table 4a "Cause or Contribute Threshold Values for Nonattainment" shown in the table below. Most pollutants were below these levels.

Table 3-1. Predicted Criteria Air Pollutant Modeling Results Compared Against the WAC 173-400-113 Table 4a Thresholds

Pollutant	Averaging Period	Predicted Modeling Results (μg/m³) [a]	WAC 173-400-113 Table 4a (μg/m³)	Above WAC 173-400-113 Table 4a? (yes/no)
Carbon monoxide	1-hour	185	2,000	No
Carbon monoxide	8-hour	40	500	No
Sulfur dioxide	1-hour	2.7	30	No
Sulfur dioxide	3-hour	1.2	25	No
Sulfur dioxide	24-hour	0.3	5	No
Sulfur dioxide	Annual	0.05	1.0	No
Particulate matter 10	24-hour	4.0	5	No
Particulate matter 10	Annual	0.6	1.0	No
Particulate matter 2.5	24-hour	3.3	1.2	Yes
Particulate matter 2.5	Annual	0.6	0.3	Yes
Nitrogen dioxide	Annual	0.9	1.0	No

[a] Maximum modeled concentrations over 5 years of MET data.

The applicant compared modeled results to the 24-hour PM2.5 NAAQS, the annual PM2.5 NAAQS, and the 1-hour NO2 NAAQS which does not have a threshold value in WAC 173-400-113.

Table 3-2. Predicted Criteria Air Pollutant Modeling Results Compared Against the NAAQS

Pollutant	Averaging Period	Predicted Modeling Results (μg/m³)	Ambient Background Concentration (μg/m³)	Total Predicated Modeling Impact (μg/m³)	NAAQS (μg/m³)	Above NAAQS?? (yes/no)
Particulate matter 2.5	24-hour	2.3 [a]	22.5	24.8	35	No
Particulate matter 2.5	Annual	0.6 [b]	8.3	8.9	9	No
Nitrogen dioxide	1-hour	92 [c]	94	186	188	No

[a] 5-year average of the maximum 8th highest (98th percentile of maximum daily impacts by receptor).
[b] 5-year average of maximum annual impact.
[c] 5-year average of the maximum 8th highest (98th percentile of maximum daily 1-hour impacts by receptor).

The Agency requested additional information regarding the use of the 5-year average to compare to the NAAQS. The applicant responded:

- *For NAAQS comparison to 1-hour NO2 we followed this EPA guidance https://www.epa.gov/sites/default/files/2020-10/documents/additional_clarifications_appendixw_hourly-no2-naaqs_final_03-01-2011.pdf specifically page 17. Using one uniform highest area background concentration should add the needed conservatism for a "first tier" approach.*

This EPA Guidance document issued March 1, 2011 from EPA's Air Quality Modeling Group was saved in the electronic NOC folder. This section of the guidance document addresses combining modeled results and monitored background to determine compliance. EPA's June 29, 2010 memo clarified applicability of the current guidance in 40 CFR Part 51, Appendix W for modeling NO2 impacts in accordance with the PSD permit requirements to demonstrate compliance with the 1-hour standard. This memo indicated that a "first tier" assumption for a uniform monitored background contribution that may be applied without further justification is to add the overall highest hourly background NO2 concentration (across the most recent three years) from a representative monitor to the modeled design value for comparison to the NAAQS. The model design value refers to the highest (across all modeled receptors) of the 5-year average of the 98th-percentile (8th-highest) of the annual distribution of daily maximum 1-hour values based on NWS meteorological data, or the multiyear average of the 98th-percentile of the annual distribution of daily maximum 1- hour values based on one or more complete years (up to 5 years) of site-specific meteorological data. This is consistent with the results submitted in the report. The memo specifies:

- the use of a single uniform monitored background contribution is the simplest approach to implement since it can be applied outside of the modeling system.
- the overall highest hourly background concentration may be overly conservative in many cases, but that conservatism also provided the basis for indicating that this approach could be used without further justification

The Agency requested the results for each year to determine if there was consistency with the average, but the applicant noted that the model was run as a 5-year average and there are no results on a yearly basis.

The Agency verified with Ecology's modeling expert, Beth Friedman, that this was an appropriate approach.

- *For the NAAQS comparison to annual and 24-hour PM2.5 we followed this EPA guidance https://www.epa.gov/system/files/documents/2022-07/Guidance_for_O3_PM25_Permit_Modeling.pdf specifically page 51 of the guidance (pdf page 61). There EPA recommends adding the model design value to the monitor design value. The guidance then lists the various examples of model design values depending on meteorological data available.*

  This EPA Guidance document issued July 29, 2022 from EPA's Air Quality Assessment Division was saved in the electronic NOC folder. This document provides guidance for ozone and fine particulate matter permit modeling in support of PSD permitting. The section references by the applicant is guidance for comparison of the combined modeled and monitored concentrations with the applicable NAAQS to determine if there are any predicted violations. The EPA guidance provided three options for the primary PM2.5 modeled design concentration and includes the 5-year average of the modeled annual 98th percentile 24-hour PM2.5 concentrations (for the 24-hour PM2.5 NAAQS) or 5-year average of the modeled annual average PM2.5 concentration (for the annual PM2.5 NAAQS) predicted each year at each receptor, based on 5 years of representative NWS data.

The Agency requested the results for each year to determine if there was consistency with the average, but the applicant noted that the model was run as a 5-year average and there are no results on a yearly basis.

The Agency verified with Ecology's modeling expert, Beth Friedman, that this was an appropriate approach.

Conclusion: Based on the information provided in the modeling report and the additional information provided by the applicant, the Agency has determined that the impact of the project on ambient concentrations of criteria pollutants are predicted to be in compliance with the NAAQS.

J. AMBIENT TOXICS IMPACT ANALYSIS

The estimated potential toxic air pollutant (TAP) emissions based on the following assumptions:

- 1-hour emissions are calculated by taking the maximum of all four boilers operation on natural gas or three boilers (2 smaller and 1 larger) operating on natural gas and one large boiler operating on ULSD.

- 24-hour emissions are calculated by taking the maximum of all four boilers operation on natural gas or three boilers (2 smaller and 1 larger) operating on natural gas for 24 hours and one large boiler operating on natural gas for 16 hours and on ULSD for 8 hours.

- Annual emissions are calculated for three boilers (2 smaller and 1 larger) operating on natural gas for 8760 hours and one large boiler operating on natural gas for 8712 hours and on ULSD for 48 hours.

These give the maximum potential emissions reflecting normal operations on natural gas except periodic testing, training and maintenance (enforceable limit in Condition No. 4 of the permit). Although the boilers are set up to fire on ULSD if there is a gas curtailment, that is not considered normal operations. Boeing is required to provide notice to the Agency when there is a natural gas curtailment or natural gas interruption. In the previous 5 years, this happened once in 2023 and lasted 22 hours.

The table below includes estimated potential emissions of all TAP and compares those to the Small Quantity Emission Rates (SQER) in WAC 173-460-150. Detailed emission calculations are included in a spreadsheet in the electronic NOC folder (revised).

Table 2. Project TAP Emissions Summary

TAP Emissions from Dual-Fuel (Natural Gas and Ultra-Low Sulfur Diesel) Boilers

Pollutant	CAS #	Washington Administrative Code Toxic Air Pollutant (WAC TAP)	Hazardous Air Pollutant (HAP)	Total Project Emissions[2] (Natural Gas + ULSD)			SQER Thresholds[3]			Do emissions exceed the SQER thresholds?		
				(lbs/hr)	(lb/24-hr)	(lb/yr)	(lbs/hr)	(lbs/24-hr)	(lbs/yr)	(lbs/hr)	(lbs/24-hr)	(lbs/yr)
1,3-butadiene	106-99-0	X	X	0.01	0.08	0.50	--	--	5.4	No	No	No
Acetaldehyde	75-07-0	X	X	0.24	1.97	24.61	-	-	60	No	No	No
Acrolein	107-02-8	X	X	0.13	1.01	12.02	-	0.026	-	No	Yes	No
Ammonia	7664-41-7	X	X	0.30	7.17	2,617.15	-	37	-	No	No	No
Arsenic	7440-38-2	X	X	2.34E-03	0.02	0.57	-	-	0.049	No	No	Yes
Benzene	71-43-2	X	X	2.92E-03	0.04	6.91	-	-	21	No	No	No
Cadmium	7440-43-9	X	X	1.11E-03	0.01	2.51	-	-	0.039	No	No	Yes
Carbon Monoxide	630-08-0	X		13.87	264.62	84,342.70	43	-	-	No	No	No
Chlorobenzene	108-90-7	X	X	1.38E-04	1.11E-03	6.64E-03	-	74	-	No	No	No
Copper	--	X		2.66E-03	0.02	0.13	0.19	-	-	No	No	No
Dichlorobenzene	--		X	3.07E-04	7.37E-03	2.69	N/A	N/A	N/A	No	No	No
Ethylbenzene	100-41-4	X	X	1.77E-03	0.04	15.47	-	-	65	No	No	No
Formaldehyde	50-00-0	X	X	0.13	1.24	135.31	-	-	27	No	No	Yes
Hexane	110-54-3	X	X	0.23	5.54	2,021.99	-	52	-	No	No	No
Hexavalent chromium	--	X	X	1.01E-04	8.08E-04	4.85E-03	-	-	6.50E-04	No	No	Yes
Hydrogen chloride	7647-01-0	X	X	0.13	1.03	6.18	-	0.67	-	No	Yes	No
Hydrogen fluoride	7664-39-3	X	X	0.13	1.03	6.18	-	1.00	-	No	Yes	No
Hydrogen sulfide	7783-06-4	X	X	0.13	1.03	6.18	-	0.15	-	No	Yes	No
Lead	--	X	X	3.12E-03	0.02	0.15	-	-	14	No	No	No
Manganese	--	X	X	1.06E-03	8.47E-03	0.05	-	0.022	-	No	No	No
Mercury	7439-97-6	X	X	1.53E-03	0.01	0.65	-	2.20E-03	-	No	Yes	No
Naphthalene	91-20-3	X	X	2.25E-03	0.02	1.12	-	-	4.8	No	No	No
Nickel	--	X	X	1.72E-03	0.01	0.08	-	-	0.62	No	No	No
Nitrogen dioxide (NO2)	10102-44-0	X		1.45	16.27	2,626.23	0.87	-	-	Yes	No	No
Propylene	115-07-1	X	X	0.14	3.26	1,188.09	-	220	-	No	No	No
Selenium	--	X	X	4.15E-03	0.03	0.20	-	1.5	-	No	No	No
Sulfur dioxide (SO2)	7446-09-5	X	X	0.25	4.42	1,349.40	1.2	-	-	No	No	No
Toluene	108-88-3	X	X	4.84E-03	0.08	24.76	-	370	-	No	No	No
Xylenes	1330-20-7	X	X	5.12E-03	0.12	44.83	-	1.6	-	No	No	No
Total TAP Emissions				**17.15**	**309.13**	**94,433.99**						
Total HAP Emissions				**1.83**	**28.22**	**7,467.61**						

Dispersion modeling was conducted for pollutants that exceed the SQER (highlighted in pink in the table above). The modeling for toxic air pollutants was consistent with the Modeling Protocol submitted to PSCAA on October 8, 2025, and approved by PSCAA on October 15, 2025, and conducted in accordance with Ecology's Guidance Document: First, Second and Third Tier Review of Toxic Air Pollutant Sources.

Project emissions for TAP emissions used in modeling are shown below:

Table 1-2. Toxic Air Pollutant Emission Summary for Modeling

Pollutant	CAS Number	Total Project Emissions (Natural Gas + ULSD)			SQER Thresholds		
		lb/hr	lb/24-hr	lb/yr	lb/hr	lb/24-hr	lb/yr
Acrolein	107-02-8	1.25E-01	1.01	12.02	-	0.026	-
Arsenic	7440-38-2	2.34E-03	1.95E-02	5.67E-01	-	-	0.049
Cadmium	7440-43-9	1.11E-03	1.34E-02	2.51	-	-	0.039
Formaldehyde	50-00-0	1.25E-01	1.24	135	-	-	27
Hexavalent chromium	--	1.01E-04	8.08E-04	4.85E-03	-	-	6.50E-04
Hydrogen chloride	7647-01-0	1.29E-01	1.03	6.18	-	0.67	-
Hydrogen fluoride	7664-39-3	1.29E-01	1.03	6.18	-	1.00	-
Hydrogen sulfide	7783-06-4	1.29E-01	1.03	6.18	-	0.15	-
Mercury	7439-97-6	1.53E-03	1.33E-02	6.53E-01	-	2.20E-03	-
Nitrogen dioxide	10102-44-0	1.45	16.3	2,626	0.87	-	-

- = not applicable; CAS = Chemical Abstracts Service; lb/24-hr = pound(s) per 24-hours; lb/yr = pound(s) per year ; ULSD = ultra-low sulfur diesel

Modeled concentrations were compared to the Acceptable Source Impact Levels in WAS 173-460-150. The applicant used the maximum model concentration out of all meteorological years modeled.

Table 1-4. Acceptable Source Impact Levels

Pollutant	Washington Pollutant Common Name	CAS Number	Averaging Period	Applicable ASIL (µg/m^3)
Acrolein	Acrolein	107-02-8	24-Hour	0.35
Arsenic	Arsenic & inorganic arsenic compounds, NOS	7440-38-2	Annual	0.0003
Cadmium	Cadmium & compounds, NOS	7440-43-9	Annual	0.00024
Formaldehyde	Formaldehyde	50-00-0	Annual	0.17
Hexavalent chromium	Chromium (VI) & compounds, NOS	--	Annual	0.000004
Hydrogen chloride	Hydrogen chloride	7647-01-0	24-Hour	9
Hydrogen fluoride	Hydrogen fluoride	7664-39-3	24-Hour	14
Hydrogen sulfide	Hydrogen sulfide	7783-06-4	24-Hour	2
Mercury	Mercury, elemental	7439-97-6	24-Hour	0.03
Nitrogen dioxide	Nitrogen dioxide	10102-44-0	1-Hour	470

Source: WAC 173-460-150.

= not applicable; NOS = Not Otherwise Specified

Based on the information submitted, the proposed project is in compliance with WAC 173-460.

K. APPLICABLE RULES & REGULATIONS

Puget Sound Clean Air Agency Regulations

SECTION 7.09(b): The owner or operator of a registered source shall develop and implement an operation and maintenance plan to ensure continuous compliance with Regulations I, II, and III. A copy of the plan shall be filed with the Control Officer upon request. The plan shall reflect good industrial practice and shall include, but not be limited to, the following:
(1) Periodic inspection of all equipment and control equipment;
(2) Monitoring and recording of equipment and control equipment performance;
(3) Prompt repair of any defective equipment or control equipment;
(4) Procedures for startup, shut down, and normal operation;
(5) The control measures to be employed to ensure compliance with Section 9.15 of this regulation; and
(6) A record of all actions required by the plan.
The plan shall be reviewed by the source owner or operator at least annually and updated to reflect any changes in good industrial practice.

SECTION 6.09: Within 30 days of completion of the installation or modification of a stationary source subject to the provisions of Article 6 of this regulation, the owner or operator or applicant shall file a Notice of Completion with the Agency. Each Notice of Completion shall be submitted on a form provided by the Agency, and shall specify the date upon which operation of the stationary source has commenced or will commence.

SECTION 9.03: (a) It shall be unlawful for any person to cause or allow the emission of any air contaminant for a period or periods aggregating more than 3 minutes in any 1 hour, which is:
(1) Darker in shade than that designated as No. 1 (20% density) on the Ringelmann Chart, as published by the United States Bureau of Mines; or
(2) Of such opacity as to obscure an observer's view to a degree equal to or greater than does smoke described in Section 9.03(a)(1).
(b) The density or opacity of an air contaminant shall be measured at the point of its emission, except when the point of emission cannot be readily observed, it may be measured at an observable point of the plume nearest the point of emission.
(c) This section shall not apply when the presence of uncombined water is the only reason for the failure of the emission to meet the requirements of this section.

SECTION 9.09: General Particulate Matter (PM) Standard. It shall be unlawful for any person to cause or allow the emission of particulate matter in excess of the following concentrations:
Fuel Burning Equipment for fuel other than wood: 0.05 gr/dscf at 7% oxygen.

SECTION 9.11: It shall be unlawful for any person to cause or allow the emission of any air contaminant in sufficient quantities and of such characteristics and duration as is, or is likely to be, injurious to human health, plant or animal life, or property, or which unreasonably interferes with enjoyment of life and property.

SECTION 9.13: It shall be unlawful for any person to cause or allow the installation or use of any device or use of any means designed to mask the emission of an air contaminant which causes detriment to health, safety or welfare of any person.

SECTION 9.15: It shall be unlawful for any person to cause or allow visible emissions of fugitive dust unless reasonable precautions are employed to minimize the emissions. Reasonable precautions include, but are not limited to, the following:
(1) The use of control equipment, enclosures, and wet (or chemical) suppression techniques, as practical, and curtailment during high winds;
(2) Surfacing roadways and parking areas with asphalt, concrete, or gravel;
(3) Treating temporary, low-traffic areas (e.g., construction sites) with water or chemical stabilizers, reducing vehicle speeds, constructing pavement or rip rap exit aprons, and cleaning vehicle undercarriages before they exit to prevent the track-out of mud or dirt onto paved public roadways; or
(4) Covering or wetting truck loads or allowing adequate freeboard to prevent the escape of dust-bearing materials.

REGULATION I, SECTION 9.20(a): It shall be unlawful for any person to cause or allow the operation of any features, machines or devices constituting parts of or called for by plans, specifications, or other information submitted pursuant to Article 6 of Regulation I unless such features, machines or devices are maintained in good working order.

Washington State Administrative Code

WAC 173-400-040(3): Fallout. No person shall cause or allow the emission of particulate matter from any source to be deposited beyond the property under direct control of the owner or operator of the source in sufficient quantity to interfere unreasonably with the use and enjoyment of the property upon which the material is deposited.

WAC 173-400-040(4): Fugitive emissions. The owner or operator of any emissions unit engaging in materials handling, construction, demolition or other operation which is a source of fugitive emission:

(a) If located in an attainment area and not impacting any nonattainment area, shall take reasonable precautions to prevent the release of air contaminants from the operation.

WAC173-400-111(7): Construction limitations.

(a) Approval to construct or modify a stationary source becomes invalid if construction is not commenced within eighteen months after receipt of the approval, if construction is discontinued for a period of eighteen months or more, or if construction is not completed within a reasonable time. The permitting authority may extend the eighteen-month period upon a satisfactory showing by the permittee that an extension is justified.

Federal

40 CFR Part 60, Subparts A and Dc apply to the boilers.

40 CFR part 60 Subpart Dc Section 60.48c: Reporting and Recordkeeping Requirements

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by 40 CFR Section 60.7 of Part 60. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(g)

(1) Except as provided under paragraphs (g)(2) and (g)(3) of Section 60.48c, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) As an alternative to meeting the requirements of paragraph (g)(1) of Section 60.48c, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO_2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(3) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in 40 CFR Section 60.42c to use fuel certification to demonstrate compliance with the SO_2 standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

40 CFR Part 63, Subparts A and DDDDD apply to these boilers.

§ 63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in § 63.7575 that is located at, or is part of, a major source of HAP, except as specified in § 63.7491. For purposes of this subpart, a major source of HAP is as defined in § 63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in § 63.7575.

These boilers are categorized as Units designed to burn gas 1 fuels.

> *Unit designed to burn gas 1 subcategory* includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply interruptions of any duration are also included in this definition.

40 CFR 63.7500(e):

> (e) Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or Tables 11 through 15 to this subpart, or the operating limits in Table 4 to this subpart.

40 CFR 63.7510(g)

> (g) For new or reconstructed affected sources (as defined in § 63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable annual, biennial, or 5-year schedule as specified in § 63.7515(d) following the initial compliance date specified in § 63.7495(a). Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in § 63.7515(d).

40 CFR 63.7515(d):

> (d) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to § 63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in § 63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in § 63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in § 63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in § 63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after April 1, 2013 or the initial startup of the new or reconstructed affected source, whichever is later.

Table 3 to Subpart DDDDD – New boiler with continuous oxygen trim system that maintains an optimum air to fuel ratio; unit designed to burn gas 1

If your unit is . . .	You must meet the following . . .
1. A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or a limited use boiler or process heater	Conduct a tune-up of the boiler or process heater every 5 years as specified in § 63.7540.

40 CFR 63.7540 - Tune-up requirements:

(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. You must conduct the tune-up while burning the type of fuel (or fuels in case of units that routinely burn a mixture) that provided the majority of the heat input to the boiler or process heater over the 12 months prior to the tune-up. This frequency does not apply to limited-use boilers and process heaters, as defined in § 63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

(ii) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection;

(iv) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_X requirement to which the unit is subject;

(v) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and

(vi) Maintain on-site and submit, if requested by the Administrator, a report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

(A) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater;

(B) A description of any corrective actions taken as a part of the tune-up; and

(C) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.

(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or meets the definition of limited-use boiler or process heater in § 63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months. If an oxygen trim system is utilized on a unit without emission standards to reduce the tune-up frequency to once every 5 years, set the oxygen level no lower than the oxygen concentration measured during the most recent tune-up.

(13) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

40 CFR 63.7550 – Reporting Requirements
40 CFR 63.7555 – Recordkeeping Requirements

§ 63.7560 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). You can keep the records off site for the remaining 3 years.

L. PUBLIC NOTICE

This project does not meet the criteria for mandatory public notice under WAC 173-400-171(3). Criteria requiring public notice includes, but is not limited to, a project that exceeds emission threshold rates as defined in WAC 173-400-030 (e.g. 40 tpy NOx, VOC, or SO_2, 100 tpy CO, 15 tpy PM_{10}, 10 tpy $PM_{2.5}$, 0.6 tpy lead), includes a WAC 173-400-091 synthetic minor limit, has a toxic air pollutant emission increase above the acceptable source impact level in WAC 173-460-150, or has significant public interest. However, the Agency has determined that because of the location of the project and size of the boilers, a public comment period is warranted.

A notice of application was posted on the Agency's website for 15 days. No requests or responses were received. A copy of the website posting is below:

New Construction Projects

Company	Address	Project Description	Date Posted	Contact Engineer
Boeing Commercial Airplane Seattle	7700 E Marginal Wy S, Seattle, WA 98108	The applicant is proposing to construct two natural gas-fired boilers with an input capacity of 36.5 MMBtu/hr and two natural gas-fired boilers with an input capacity of 96.9 MMBtu/hr. All boilers will use ultra-low sulfur diesel as backup fuel.	7/22/25	Maggie Corbin

Public notice will be published in the Seattle Times, the Daily Journal of Commerce and on the Agency website on December 22, 2025. The comment period will run through January 30, 2026.

M. RECOMMENDED APPROVAL CONDITIONS

Standard Conditions:

1. Approval is hereby granted as provided in Article 6 of Regulation I of the Puget Sound Clean Air Agency to the applicant to install or establish the equipment, device or process described hereon at the installation address in accordance with the plans and specifications on file in the Engineering Division of the Puget Sound Clean Air Agency.

2. This approval does not relieve the applicant or owner of any requirement of any other governmental agency.

Specific Conditions:

3. These boilers are subject to the applicable requirements established in 40 CFR Part 60, Subparts A and Dc, and 40 CFR Part 63, Subparts A and DDDDD.

Operational Requirements:

4. The boilers must only fire on natural gas except during times of gas curtailment by the gas supplier or for periodic testing, maintenance, or operator training or maintenance. Periodic testing,

maintenance or operator training on fuel oil shall not exceed a combined total of 48 hours during any calendar year and 8 hours during any 24-hr period for each boiler, and only one boiler permitted under this Order may operate on fuel oil during period testing, maintenance or operating training.

5. The boilers may only burn fuel oil that has a maximum sulfur content of 15 ppm by weight. A fuel certification from the fuel supplier may be used to demonstrate compliance with this requirement.

Emission Limits:

6. The exhaust concentration of nitrogen oxides (NO_x) from each boiler must not exceed 9 ppm when fired on natural gas, or 35 ppm when fired on fuel oil, on a dry, volumetric basis corrected to 3% O_2, as measured by the average of three 60-minute tests using EPA Methods 7E and 3A.
7. The exhaust concentration of carbon monoxide (CO) from each boiler must not exceed 50 ppm when fired on natural gas or fuel oil, on a dry, volumetric basis corrected to 3% O_2, as measured by the average of three 60-minute tests using EPA Methods 10 and 3A.
8. When fired on natural gas, there shall be no visible emissions other than steam from the boiler.
9. When fired on fuel oil, except during periods of startup and shutdown, the opacity of the emissions shall not exceed 5% for a period or periods aggregating more than 3 minutes in any 1 hour, as determined by Ecology Method 9A. During periods of startup and shutdown when firing on fuel oil, the opacity of the emissions shall not exceed 20% for a period or periods aggregating more than 3 minutes in any 1 hour, as determined by Ecology Method 9A.

Compliance Demonstrations:

10. Initial compliance with Condition Nos. 6 and 7 must be demonstrated by conducting a compliance test on each boiler when firing on natural gas and fuel oil within 90 days of start-up of that boiler in accordance with Section 3.07 of PSCAA Regulation I.
11. Ongoing compliance for the two 30,000 pounds per hour capacity boilers must be demonstrated by conducting compliance tests on each boiler when firing on natural gas and fuel oil within 37 months of the previous compliance test.
12. Ongoing compliance for the two 80,000 pounds per hour capacity boilers must be demonstrated by conducting compliance tests on each boiler when firing on fuel oil within 37 months of the previous compliance test.
13. Ongoing compliance for the two 80,000 pounds per hour capacity boilers must be demonstrated by conducting a compliance test on each boiler annually when firing on natural gas. Each test much be completed within 13 months of the previous compliance test. If results from the three previous compliance tests for a boiler demonstrate that emissions are at or below 80 percent of the emission limit, and if there are no changes in the operation of the individual boiler, the owner or operator may choose to conduct biennial performance tests for that boiler (within 25 months of the previous compliance test). If a compliance test for a boiler shows emissions exceeded 80 percent of the emission limit, the owner or operator must conduct annual performance tests until all tests over a consecutive 3-year period meet the required level at or below 80 percent of the emission limit.

14. Compliance tests must be conducted using EPA Methods 1, 3A, 4, 7E and 10 from Appendix A of 40 CFR Part 60. Compliance testing must consist of at least three separate 60-min test runs when firing on natural gas and three separate 60-min test runs when firing on fuel oil.
15. Compliance testing must be conducted at 90% or higher of the boiler's maximum operational firing rate. The maximum firing rate is set by performance test and can be less than the maximum rated capacity.
16. If a boiler is out of service when the compliance test is required, the owner or operator must conduct the compliance test within 30 days after repairs are completed and the boiler is recertified for operation.
17. Compliance with Condition No. 8 and 9 must at a minimum be demonstrated by inspecting each boiler's stack for visible emissions once each week when the boiler is in operation while firing on natural gas and during each test run when conducting compliance testing on the boiler when firing on natural gas and oil. These inspections must be performed during daylight hours when the boiler is in operation. If a boiler does not operate during a week, then a weekly inspection is not required for that boiler.

Recordkeeping Requirements

18. All records required by this Order of Approval must be maintained for at least five years.
19. The following records must be kept onsite and up-to-date, and be made readily available to Agency personnel upon request:
    a. Compliance test results.
    b. Visible emissions inspection results required by Condition No. 17 including the date and time of the observation, the operation status of the boiler, whether visible emissions were observed, and any corrective action or mitigation measure to eliminate the visible emissions.
    c. Certified opacity reading results.
    d. Records of the dates when fuel oil was burned and the reasons for burning fuel oil.
    e. Records of the sulfur content of the fuel oil from each supplier. Each record must have the following information:
        i. The name of the fuel oil supplier, and
        ii. Documentation from the oil supplier that the fuel oil complies with the specifications of ultra-low sulfur diesel.

N. CORRESPONDENCE AND SUPPORTING DOCUMENTS

All supplemental information submitted for this project by e-mail has been saved to the electronic NOC folder and/or saved to the Agency's e-mail management system.

O. REVIEWS

Reviews	Name	Date
Engineer:	Maggie Corbin	12/16/2025
Inspector:	Phil Kilner	12/17/2025
Second Review:	John Dawson	12/17/2025
Applicant Name:	Grant Peltier	12/18/2025