Clean Air Act Compliance Inspection Report

United States Environmental Protection Agency
Region 10 – Seattle, WA

Clean Air Act Partial Compliance Evaluation Inspection Report

NW Pipeline Compressor Stations
Sumner, WA
Snohomish, WA

Inspection Dates: February 28 and March 1, 2024

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Date: 2024.03.26 08:37:39 -08'00'

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Air & Toxics Enforcement Acting Manager, Region 10

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Attachments

1. Basic Facility and Inspection Information

Facility 1:	NORTHWEST PIPELINE **SUMNER COMPRESSOR STATION** 3104 166TH AVE E, BONNEY LAKE, WA 98391
Facility Coordinates:	Latitude: 47.22899 Longitude: -122.20832
Facility 2:	NORTHWEST PIPELINE **SNOHOMISH COMPRESSOR STATION** 22902 ECHO LAKE RD, SNOHOMISH, WA 98296
Facility Coordinates:	Latitude: 47.78943 Longitude: -122.05728
AFS/FRS Number:	SUMNER COMPRESSOR STATION: WAPSC0005305300548 SNOHOMISH COMPRESSOR STATION: WAPSC0005306100763
SIC:	4922 – Natural Gas Transmission
NAICS:	486210 – Pipeline Transportation of Natural Gas
Permit Number:	SUMNER COMPRESSOR STATION: NOC No. 11186 (7/26/16) SNOHOMISH COMPRESSOR STATION: NOC No. 11187 (7/26/16)
Facility Contacts:	Monica Mogg Environmental Specialist III | Northwest Pipeline 8907 NE 219th Street, Battle Ground, WA 98604 360-600-1907 Monica.Mogg@Williams.com
Mailing Address:	Williams Company 295 Chipeta Way Salt Lake City, UT 84108 801-583-8800 800-972-7733 (Emergency)
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State or Local Inspector	Puget Sound Clean Air Agency (PSCAA) was invited to participate but did not participate.
Dates of Inspection:	February 28 and March 1, 2024
Inspection Start/End Times:	February 28, 2024, 9:15 am – 1:40 pm October 4, 2022, 8:55 am – 1:25 pm
Inspection Notice:	This was an announced inspection (Attachment 2).

This was a Clean Air Act ("CAA") compliance inspection of two Northwest Pipeline compressor stations ("facilities") by the United States Environmental Protection Agency ("EPA"). John Pavitt, EPA, led the inspection. Also participating in the inspection were EPA Inspectors Alyson Skeens and Andrew Gregory.

The purpose was to review whether the facilities are subject to federal air rules for oil and gas facilities, specifically New Source Performance Standards ("NSPS") Subpart OOOOa – Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015 ("Subpart OOOOa"), as well as compliance with other CAA regulations. EPA R10 covers a four-state area, and as described below, several NW Pipeline compressor stations in the area have become subject to Subpart OOOOa as a result of adding new equipment or being modified. To date, compressor stations visited for this inspection have not notified EPA that they became subject to the rule.

Disclaimer

This report is a summary of observations and information gathered from the facilities at the time of the inspection and from a subsequent records review. The information provided does

not constitute a final decision on compliance with CAA regulations or applicable permits, nor is it meant to be a comprehensive summary of all activities and processes conducted at the facility.

2. Facility Background

The facilities are natural gas compressor stations located in Pierce County and Snohomish County, Washington. For a general footprint and location of each facility, aerial images from Google Maps™ are attached to this report (Attachments 3 and 4).

Operations at the two facilities assist in the transmission of natural gas for the Northwest Pipeline, a 4,000 mile (approx.) bi-directional pipeline system providing access to gas supplies from British Columbia, Alberta, Rocky Mountain, and the San Juan Basin. Within the pipeline, natural gas is transported via an underground system of large diameter pipes and is propelled by pressure from a series of compressor stations. The compressor stations visited for this inspection are just two of approximately 41 compressor stations located about every 50 miles of the of the pipeline, across the states of Washington, Oregon, Idaho, Wyoming, Utah and Colorado. The facilities are owned and operated by Williams Corporation, Northwest Pipeline LLC, which does not own the natural gas within the pipeline, only the series of compressor stations.[1] Williams has announced an Emissions Reductions Program (ERP) that, among other commitments, would replace legacy natural gas reciprocating compressors at multiple locations with newer natural gas turbine compressors, which they stated would reduce nitrogen oxides (NOx) and methane emissions from compressor stations.[2]

As of 2020, gas control associated with the facilities is operated remotely, from a control center in Houston, Texas. The compressor stations visited for this inspection are sometimes unmanned.

Air permits issued by PSCAA to the Sumner and Snohomish facilities classify each compressor station as a "Synthetic Minor" source, limiting emissions of nitrogen oxides (NOx) and carbon monoxide (CO) to no more than 95 tons per year. Annual stack testing to demonstrate compliance for turbines at each station is also required. Testing results for the last five years posted in EPA's Enforcement and Compliance History Online ("ECHO"[3]) database show compliance with NOx and CO emission limits. In July 2016, PSCAA issued Notice of Construction permits to each facility, which removed voluntary limits to reduce greenhouse gas emissions.

3. Compliance History

A review of EPA's ECHO databaseshows the following air compliance activities at the two NW Pipeline facilities over the last five years:

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[1] Williams web site, https://www.williams.com/pipeline/northwest-pipeline/
[2] Williams 2022 Sustainability Report. https://www.williams.com/wp-content/uploads/sites/8/2023/07/Williams_2022SustainabilityReport_DigitallyAccessible_Update.pdf
[3] EPA web site, https://echo.epa.gov/

Table 1: Compliance Monitoring activity

Activity	Sumner, WA	Snohomish, WA
Formal Enforcement Actions	None	10/28/22. Administrative penalty. $1000
Informal Enforcement Actions	NOV 9/16/22 PSCAA	NOV 3/22/22 PSCAA
Full Compliance Evaluations (FCE) by State or local agency	Four	Four
Partial Compliance Evaluations (PCE) by State or local agency	Six	Seven
Quarters with Noncompliance (of 12)	None	None
Quarters on High Priority Violators (HPV) List	None	None

4. Greenhouse Gas Reporting

Northwest Pipeline submits annual reports to EPA's Greenhouse Gas Reporting Program (GHGRP) under Subpart C: General Stationary Fuel Combustion, and Subpart W: Petroleum and Natural Gas Systems.[4] The company reports that each compressor station has two stationary gas turbines with a combined horsepower (hp) rating of 22,638 hp (Attachments 8 and 9). In addition, NW Pipeline conducts surveys for fugitive emissions as part of its annual reporting effort.

From 2014 to 2022 (the most recent reporting year available), annual greenhouse gas emissions have varied considerably at both facilities, as shown below. The facilities reported emissions of carbon dioxide (CO2) and methane, with CO2 accounting for most emissions overall.

[4] Greenhouse Gas Reporting Program (GHGRP) | US EPA

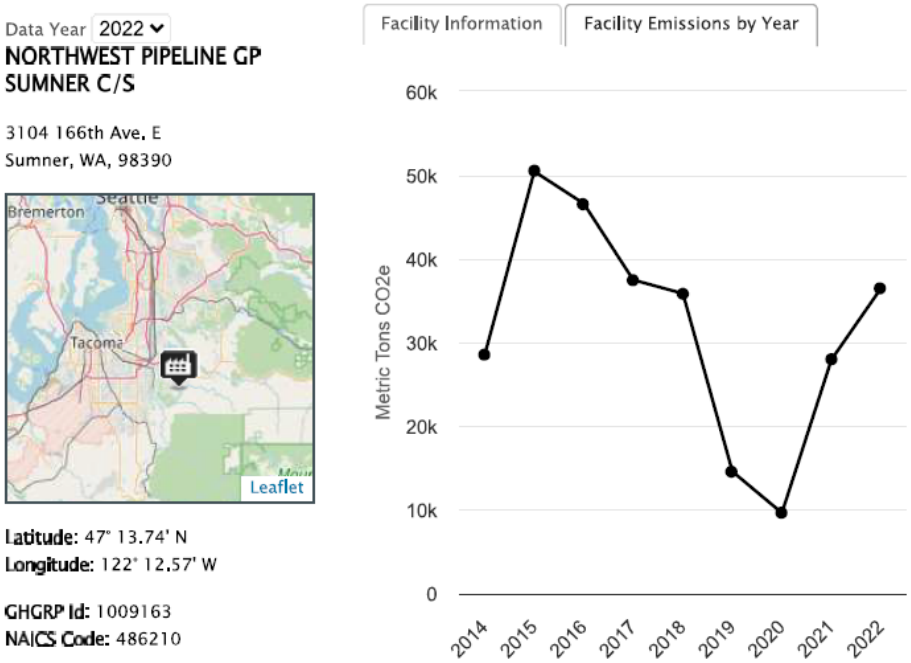

Figure 1: Total GHG Reported Emissions, Sumner, WA

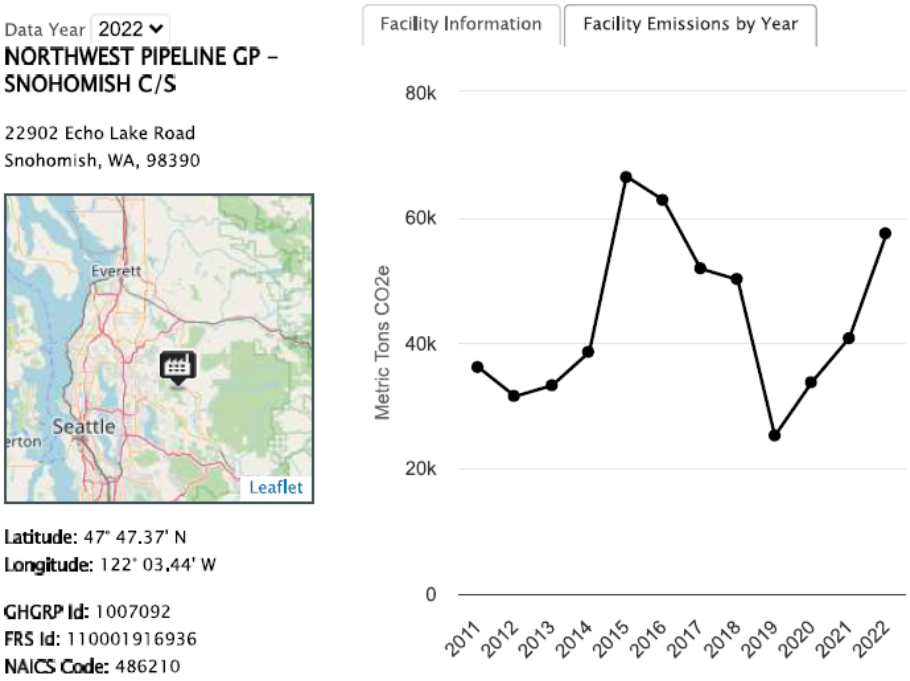

Figure 2: Total GHG Reported Emissions, Snohomish, WA

5. Inspection Chronology

This inspection involved on-site visits to two compressor stations on two different days. On February 9, 2024 I called the national contact number for NW Pipeline in Salt Lake City, UT and was eventually connected to Environmental Specialist Monica Mogg in the Battle Ground, WA office. Because the compressor stations selected for inspection are sometimes not manned, I provided advance notice of the inspection. I followed up with an email summarizing the basic details of the planned inspection (Attachment 2).

Pre-Inspection Observations

The inspectors went directly to the two NW Pipeline Facilities. No observations were made prior to the scheduled inspection. Records were reviewed after the on-site portion of the inspections were completed.

6. Day 1: Sumner Facility. Entry and Opening Conference

On February 28, 2024, I arrived along with EPA Inspectors Skeens and Gregory ("the inspectors") at the NW Pipeline, Sumner Compressor station ("the Sumner Facility" or "Facility") at approximately 9:15 am. The Facility is in a residential neighborhood. The weather was in the mid-40s ^{o}F, with a light drizzle which persisted, turning to rain throughout the day. Winds were approximately 10 miles per hour (mph). Upon arrival, I took photos of the front gate and a Williams Company sign posted there. We pushed a buzzer at the gate to let operators know we were there, and the gate opened a minute later. We drove through the gate and parked at the office.

The other inspectors and I walked into the office and introduced ourselves to Facility representatives gathered there. I showed my credentials. Because the compressor stations are sometimes unmanned, EPA provided advance notice for the inspection and we were expected (Attachment 2). Facility representatives attending this opening conference were:

Monica Mogg, Environmental Specialist, Battleground, WA office
Scott Bassett, Environmental Specialist, Salt Lake City, UT office
Jared Kuhl, Operations Technician
Martin Maculo, Facility Engineer
Matt Kautzman, Operations Lead

I explained the purpose of the inspection was to check on compliance with and applicability of NSPS Subpart OOOOa under the CAA and other air regulations which may apply. I said the inspection would consist generally of a walkthrough to see all equipment such as the compressors, pneumatic controllers and gas lines. Facility representatives said they had already prepared a hot work permit for our tour, and would carry a four-gas detector device as they escorted us through the compressor station. The device is for safety and measures concentrations of methane for lower explosive limit (LEL), oxygen (O2), hydrogen sulfide (H2S) and CO. I asked if the gas in the pipeline has an odorant (mercaptan) that we would notice.

Facility representatives said no odorant is in the gas at this point in the system, but we may notice a "pickling" odor which they described as being caused by corrosion or chemical reactions taking place upstream of their location. As noted below, during two days of inspection there were times when the inspectors noticed a slight odor when working around equipment.

Facility representatives said that the gas in the pipeline comes from the Enbridge Pipeline in British Columbia, which crosses into the United States at Sumas, Washington. They said the pipeline has "bi-directional flow" meaning it can be transported from north-to-south or south-to-north. They said they can transport gas as far east as Spokane, WA and as far south as Grants Pass, OR.

The other inspectors and I said we would use two types of instruments to check for leaks ("fugitive emissions"), consistent with the methods specified under Subpart OOOOa (40 CFR § 60.5397a(a)). We had an infrared camera manufactured by Teledyne FLIR as well as a flame ionization detector (FID) which is capable of measuring vapor concentrations in parts per million (ppm). I said if we find fugitive emissions, we will point it out to them and make a note of it. We also would look for dates of manufacture for equipment on site. We then discussed EPA's air rule, Subpart OOOOa which applies to certain equipment constructed, reconstructed or modified after 9/18/15. I said that three NW Pipeline compressor stations in the EPA Region 10 area[5] submit Subpart OOOOa reports to EPA. Those facilities are:

1. The Walla Walla Compressor Station in Umatilla, OR
2. The Willard Compressor Station in Skamania, WA
3. The Boise Compressor Station in Boise, ID

I said we would be checking to see if the Sumner or Snohomish compressor stations have been modified or added new equipment, which could make them subject to Subpart OOOOa, like the other three compressor stations (above).

I provided Ms. Mogg with a copy of EPA's Small Business Assistance fact sheet and EPA's instructions for claiming records are Confidential Business Information (CBI). I said we would be taking photos and asking for records as part of this inspection and if they believe records are CBI, there is a process to do so, as explained in the materials provided.

Operator Tech Kuhl gave us a safety briefing. He said that in the event of an emergency our rally point is the front gate. He said personal protective equipment ("PPE") needed on site were flame retardant clothing, hard hat, steel toed boots, eye shields and hearing protection.

I asked for a site diagram or drawing to carry along during the tour. The Facility representatives attempted to print a site diagram but ran into a problem with the printer. As an alternative, I

[5] EPA Region 10 covers the States of WA, OR, ID and AK.

took a photo of a framed photo of the compressor station. Referencing the framed photo, operators described the general flow of operations at the compressor as including:

- Main Control Center (MCC)
- Office Building
- Turbine Building
- Emergency Generator Building
- Air Tanks
- Auxiliary Fuel (Natural Gas)
- Oil Waste Tank
- Gas Coolers (two units)
- Filter Separators
- Unit Valve Buildings
- Block Valves (Suction and Discharge)
- Cyclone Separator

Facility representatives said their compressor stations do not have a glycol dehydrator. The gas in their pipeline has already been processed to make it "pipeline quality" gas.

Facility operators said that currently, they were operating one of the two compressors on site, and that the Houston office has control of the operations. They said gas discharge was going out to the south, but they could reverse direction if needed.

At approximately 9:50 am, EPA Inspectors Skeens and Gregory calibrated a Thermo Scientific, portable Flame Ionization Detector (FID), Model TVA2020, for Method 21[6] leak detection, Attachment 12. They also started up an Optical Gas Imaging (OGI) camera manufactured by Teledyne FLIR ("OGI," or "FLIR"), model number Gx620. The FLIR camera was intrinsically safe, but the FID was not. The digital camera I carried was also not intrinsically safe.

We put on our PPE: flame resistant clothing (FRC), hard hats, steel toe boots and eye shields. We carried ear protection with us.

7. Facility Walk-Through

At approximately 10:45 am, we began a walkthrough of the Sumner Facility with the Facility representatives named above.

During the tour, I used a digital camera to take photos, Inspector Skeens used a FLIR camera to look for vapor leaks in various modes, including high sensitivity mode,[7] and Inspector Gregory

[6] Method 21 - Volatile Organic Compound Leaks | US EPA

[7] High sensitivity mode is an adjustment method that is specifically designed for gas detection applications.

took measurements with the FID. I wrote down observations as Inspectors Skeens and Gregory called out information. Vapor leaks discovered during the tour are described below.

Our walkthrough followed the process flow of natural gas through the compressor station, from entry into the station to exit out of the station. I noted the following highlights, below.

MCC

Operators explained the overall process flow at the Facility. They said:

- Natural gas arriving at the Sumner Facility flows into a Cyclone Separator which removes liquids and other possible contaminants.
- Next, gas flows to the Inlet Valve Building.
- Next, to Unit 1 Compressor Building for compression.
- Next, to Discharge Cooling Fans (to drop temperature of gas to approximately 110 ^{o}F).
- Next, to Unit 1, Valve Discharge Side.
- Gas leaving the Facility flows south, to Chehalis, WA

Additional lines connect to the main line, allowing delivery to customers along the pipeline. The pipeline is transporting approximately 585 MM scf/day, they said.

Pig Receivers

On the north end of the Facility, we looked at pig receivers. This equipment is for the purpose of receiving "pig" devices which are placed into the pipeline for a variety of maintenance and testing purposes. The Sumner Facility is equipped with two lines (a 30-inch line and a 36-inch line) to receive such a devices and pull them out of the pipeline. It is also equipped to place the devices into the pipeline, on the south side of the Facility. Facility representatives also pointed out an abandoned, 26-inch pig receiver line in this area. No leaks were identified in this area.

Cyclone Separator

We continued our observations. Operators said the Cyclone Separator removes water from the incoming gas, although the gas is already pipeline quality and typically does not have water or other contaminants and they are considering removing it from their station. They said the pressure of incoming gas is approximately 600 pounds per square inch (psi), and increases to approximately 800 psi before being discharged from the Facility. No leaks were identified in this area.

Unit Valve Building

There are two valve buildings, one for each compressor. Each building has a "suction" side (to pull gas towards the compressor turbine units) and a "discharge" side (to send gas back to the pipeline). We walked into the Unit 2 side. At the doorway, our FID instrument measured a methane background concentration of 17 ppm. I notice a low level of gas odor in the building. Facility Engineer Maculo said the smell was caused by the pipeline being "pickled" from activity further upstream. I asked how old the compressor station was. The facility representatives said

they weren't sure; they would have to check. They said the entire Facility was rebuilt sometime around 2003. Reciprocating compressor engines were replaced with compressor turbines at that time. No leaks were identified in this area.

Particulate Filters

Just outside of the Valve Building we saw particulate filters. Gas is filtered through a series of tubes inside the filter, before flowing into the Compressor Building, the facility representatives said. No leaks were identified in this area.

Turbine Building

There are two stationary gas turbines in this building. We entered the building at about 11:30 am, through the side with Compressor Unit # 2. The unit was not operating. The FID measured a background reading of 17 ppm in this area. The operators pointed out a group of supply air tubes near the doorway, saying they were for air-driven controllers in the compressor building. They said the gas-driven controllers are outside, and air-driven controllers are inside because the Compressor Building has electricity.

We observed Compressor Unit # 2, a Solar Turbines, Mars 90 Model. S/N OHI16-M1125. The rated hp was 12,513 and the unit was equipped with Engine SoLoNOx™. A control panel for the unit showed its operating status as having 0 rpm and a temperature of 65 ^{o}F. The fuel line into the unit was white or light gray, wrapped in a cloth sleeve.

We found a nameplate on the turbine skid, with a manufacture date of 2002. The work area was clean, with no oily stains on the equipment or floor.

We continued through the building to Compressor Unit # 1, which was operating and hearing protection was required in this area. It is a similar Solar Turbines, Mars 90 Model. S/N OHG17-M2615. The site rated power was 12,513 hp, and the unit was equipped with Engine SoLoNOx™. A control panel for the unit showed its operating had a temperature of 114 ^{o}F. I did not find the RPM reading on the display. The incoming gas pressure was 605 psi and the outgoing gas was 858 psi at the compressor unit.

The FID measured a methane concentration of 1,500 – 2,000 ppm, where the fuel line connected to a flange. The FLIR camera was not able to see a vapor leak here, however the camera was able to see heat waves coming from the equipment and operators stated that the surface was hot. Moving back a few feet, the FID reading fell to just 13 ppm. I said that a FID reading above 500 ppm was a leak and made a note of it.

Discharge Line to Cooling Fans

Stepping outside, we examined the discharge line from the Compressor Unit # 1 Turbine to Cooling Fans. The line was insulated and operators removed a small, round plug from the line so we could measure methane concentrations there. The reading from the outside of the line was 0 ppm. The reading from inside the insulation layer (through the plug) was the same. The

FID showed a concentration of 17 ppm from a box-shaped valve on the exterior of the discharge line. No leaks were identified in this area.

Our FLIR Camera battery was running low at this time, and we shut it down. We continued our inspection using the FID for Method 21 leak detection.

Cooling Fans

Natural gas is heated from the compression process and the Facility cools it down by having large fans blow across the gas pipes. We walked along the cooling fans. The FID reading in this area was 0 ppm. No leaks were identified in this area.

Compressor Shutdown Activity

During our tour of the facility, at approximately 12:21 pm, we heard a loud sound, like air being released. The facility representatives said Compressor #1 was shutting down and a Surge Control Valve was unloading the compressor. They said the Suction and Discharge lines were equalizing. They said the station was not having a blowdown; the natural gas in the Suction and Discharge lines was being held in a "pressurized hold." They escorted us into the MCC to view control panels there, which showed the pressure in the station was slowly falling, and was currently 772 psi, compared to 800 psi earlier that day. Facility representatives said the pressurized hold was activated by the Houston control center. They said that the pressurized hold would maintain its current condition for approximately 30 minutes, perhaps longer. After that, if they didn't restart the compressor they would have a blowdown to prevent damage to the compressor (the gas would be sent to the blowdown stack).

We discussed operation of the blowdown stack with the facility representatives. I said their Greenhouse Gas Reporting to EPA shows that they do an annual survey for fugitive emissions (see description above). I asked if the fugitive emission survey includes the blowdown stack. They said it does, as their service contractor looks at the entire compressor station, including the blowdown stack. I ask how they would respond if the survey found gas emissions coming from the blowdown stack during a "normal day" when they're not having a blowdown event. They said they would identify such emissions as fugitive emissions. They said if they saw vapors coming out of the blowdown stack that would indicate a worn valve was leaking.

They said Williams has a policy of putting all fugitive emissions on a 30-day repair schedule. (See Attachment 6, Records Response.) I asked, what could be the source of fugitive emissions coming from the blowdown stack? Could they trace it back to the source? The facility representatives said yes, they could track it back. They described two ways to do that: 1) use acoustical sensing (listening for a distinctive sound in the pipes and valves), or 2) just manually trace it back by closing and opening valves up the line, systematically, until they discovered where it was coming from.

Williams Environmental Specialist Bassett added that they test their blowdown system on a regular basis, as required by The Pipeline and Hazardous Materials Safety Administration (PHMSA). He said there are ways to test the system without blowing gas to atmosphere.

Unit Valve Building

We walked back inside the Unit Valve Building, Compressor Unit #1 side. FID readings climbed slightly when we stepped through the door, to 11 ppm. No methane leaks were found inside or outside the building.

Pneumatic Controllers

We examined the pneumatic controllers we could find, all of which were located outdoors. The Facility's GHG Report states that the Sumner Facility has 11 pneumatic controllers (Attachment 9). We found 10. All controllers were painted green and were manufactured by the company BETTIS. The controllers were connected to ball valves and function to open and close the valves. Some were at ground level, and some were elevated on platforms. Operators also referred to the units as "pneumatic actuators." These were individually labeled with unique numbers, as shown in Table 1, below. None of the controllers were active at the time of the inspection. Facility representatives said all controllers are intermittent leak, not continuous leak. We found no gas leaks in this area. The FID measured 0 ppm around the controllers. I noted the following labels on the controllers:

Table 2: Pneumatic Controllers at Sumner Compressor Station

	Unit Label	Description
1	SBD-1	Suction ESD
2	DBD-1	Discharge ESD
3	S-1	Station Suction
4	D-1	Station Discharge
5	16L-8SD	South Discharge
6	16L-8SS	South Suction
7	16L-8D	--- "Block" (Label partially not visible)
8	16L-8ND	North Discharge
9	16L-8NS	North Suction
10	16L-8CK	Cyclone Block

Blowdown Stack

We walked past the blowdown stack. Operators said no blowdown gases were flowing to the stack at that time. No leaks were identified in this area.

Emergency Power Generator

We walked into the emergency power building. The facility maintains a Caterpillar, Model 3412, spark ignition electric power generator, s/n 7DB01139. The unit was not operating at the time of the inspection. The nameplated showed the unit was manufactured in 1995 and is rated at 566 hp. Operators described their preventative maintenance as having a third-party service contractor to do monthly start-ups for reliability testing, annual oil testing to ensure the oil is still acceptable, checking the air filter, belts and hoses, plus other conditions. The air filter was

equipped with a visual "pop-up" indicator when the filter gets coated with dust. Facility representatives said Williams has a national preventative maintenance program for its engines.

8. Closing Conference

The walkthrough ended at approximately 1:30 pm. I provided the NW Pipeline representatives a brief summary of the events that day. The group made plans to continue with a second day of inspection on March 1st (in two days), at the Snohomish, WA compressor station, at 9:00 am. I said our plans were to do a similar site tour, looking for possible vapor leaks and verifying the age of equipment on site.

EPA Inspectors Skeens and Gregory did a quality assurance "bump check" on the FID analyzer, using three different hydrogen gas concentrations (0 gas, 500 ppm and 10,000 ppm methane). The analyzer passed the bump check with all three gases.

We left the Sumner Facility at about 1:40 pm.

9. Day 2: Snohomish Facility. Entry and Opening Conference

On March 1, 2024, the EPA inspectors arrived at the Snohomish Compressor Station ("Snohomish Facility" or "Facility") at approximately 8:55 am. I photographed the company sign at the front gate and used the buzzer to announce our arrival. Operators opened the gate and we drove in.

I entered the Snohomish Facility office and signed in for the EPA inspection team. The Facility representatives attending the opening conference were:

Monica Mogg, Environmental Specialist, Battleground, WA office
Scott Bassett, Environmental Specialist, Salt Lake City, UT office
Martin Maculo, Facility Engineer
Matt Kautzman, Operations Lead
Amy Dearman, Coordinator of Maintenance
Jon Berger, Operations Tech

Operations Tech Jon Berger gave us a safety briefing. In case of emergency, we were to go to the muster point at the front gate. Slips, trips and falls are a hazard on uneven walking surfaces, he said. There were no construction projects taking place on-site that day.

We discussed the Facility's GHG Reports to EPA (Attachment 10). According to their 2022 report for the Snohomish Facility, which I pulled and showed to the Facility representatives, the Facility has 20 Intermittent Bleed Pneumatic Devices. I asked if we would be able to see all 20 today. The Facility representatives said another office prepares the report so they didn't know the exact number, but they would help us to find all the pneumatic controllers on-site today. The GHG Report states that the two compressors at the Snohomish Facility have dry seals. The Facility representatives said that was correct.

I said I wanted to be sure to see the Blowdown Valve and Isolation Valve at the Facility today. Both valves are included in the list of Facility equipment in their 2022 GHG Report. Facility Engineer Maculo explained how the Blowdown and Isolation Valves work.

EPA Inspectors Skeens and Gregory calibrated the FID instrument as they had done on the first day of inspection, Attachment 12. They waited to turn on the FLIR camera until we were touring the facility, to make the battery last longer. I stepped outside and took a wind and temperature reading using a portable instrument. There was no wind. The instrument showed a temperature of 49 ^{o}F, which seemed too warm compared to how the weather felt. I later checked with the National Weather Service which showed the temperature that morning was approximately 40 ^{o}F. The sky was partially sunny when we started the inspection, becoming overcast as the day went on.

I took a photo of a framed aerial photograph in the office, to help guide us during our tour of the Facility. I checked in with Operations Tech Berger, letting him know I would turn my camera flash off to take photos on-site. Mr. Berger carried a four-gas detector device as he escorted us through the Snohomish Facility. He said the Facility's fire detection system includes heat detectors and "fire eyes." He said if a fire is detected, their system would trigger a shutdown.

Environmental Specialist Monica Mogg said that Williams carries out annual, routine surveillance for fugitive leaks at existing compressor stations (the stations that pre-date NSPS Subpart OOOOa). She said if they find a leak, they put in on a 30-day repair schedule. She said Williams also conducts surveys for gas leaks along the pipeline, using helicopters equipped with a laser sensor.

10. Facility Walk-Through

Before beginning a walk-through of the Facility, at 10:15 am we checked in with the MCC control room to see current operating conditions. A process monitor showed that the Facility was having a southerly flow of gas, displaying readings from Mount Vernon, WA to Sumner, WA. Compressor Unit # 1 was shut down and Compressor Unit # 2 was on. Compressor Unit # 2 was operating at 103.6 "NGP" which Mr. Berger explained is a unit of power for gas turbines, equivalent to about 12,000 hp. He said the pipeline was transporting approximately 779 million standard cubic feet per day (MMSCF/day). The gas incoming pressure was 697 psi and the outgoing pressure was 799 psi.

We began our walk-through at about 10:30 am. During the walkthrough, I took photos with a digital camera, Inspector Skeens took videos in various modes, including high sensitivity mode with the FLIR (see Attachment 3), Inspector Gregory took measurements with the FID. I wrote down observations as Inspectors Skeens and Gregory called out information. I noted the following highlights.

Pig Receivers and Launchers

The Snohomish Facility receives pigs on the north end of the facility through a single, 30-inch line painted green. Facility representatives said they run a pig through the line at least once every seven years, sometimes more often. They said the last time was two years ago. The pointed out that equipment painted blue in this area was abandoned. On the receiving line, a short, vertical pipe with a visual indicator pops-up to show when a pig has arrived.

The FID measured a background methane concentration of 1.2 ppm near the pig receiver equipment. As EPA Inspector Gregory approached the pig receiver the concentration began to increase. A concentration of 120 ppm was found on a Pig Pull Port Valve. This leak was visible with the FLIR camera. Operations Tech Berger pinpointed the leak by using soap bubbles (spraying a commercial product, "Snoop," onto to valve, where a bubble formed. The "bubble test" is part of Method 21.[8] Operators said they would attempt to repair the leak that day.

The Facility has two pig launchers on the south end of the property (a 30-inch line and a 36-inch line). We examined this area at approximately 11:15 am. The FID measured a methane concentration of zero or close to zero ppm in this area.

Pneumatic Controllers

We examined all pneumatic controllers we could find, all of which were outdoors. These are described below in Table 3. Similar to what we saw at the Sumner Facility, all pneumatic controllers at the Snohomish Facility were manufactured by BETTIS and are painted green. Pneumatic controllers are positioned on top of valves and serve to open and close the valves. No controllers were found to be leaking. As shown below, one valve (connected to a controller) was found to be leaking.

Except as noted below, all pneumatic controllers were manufactured in September 2002.

Table 3: Pneumatic Controllers at Snohomish Compressor Station

	Unit Label	Description
1	17L2-1A-B	Pigging isolation valve (2006)
2	S-1-S	Suction valve
3	17L-1D	Bypass valve
4	D-1-N	Isolation valve, **leaking**
5	S-1-N	Suction valve
6	D-1-S	Discharge valve
7	DBD-1	Discharge blowdown valve
8	SBD-1	Suction blowdown valve
9	D-3	(2016)

[8] Method 21, Section 8.3.3. – Alternative Screening Procedure.

We observed a methane leak from valve D-1-N, from valve stem packing. The FID measured a concentration of 9.2% (92,000 ppm). The FLIR camera was able to see vapors from the valve stem packing. Operators said they could repair the leak by adding grease, and that the valve was already scheduled for routine maintenance next month (in April) and they would add this to the list. The Facility representatives said they use a software program called "Leak Tracker Pro" to track repairs.[9]

We discussed with Facility representatives how the emergency shutdown (ESD) system works at the compressor station. They said blowdown valves are part of the ESD system. They said there are six possible steps in an ESD situation, and their response can be scaled up, from partial to complete (a complete station blowdown is not always necessary). The steps are:

1. Isolation valves close.
2. Compressor units shut down.
3. Compressor units blow down.
4. Compressor isolation valves close.
5. Station isolation valves close.
6. Station blowdown.

I asked, if gas is leaking through a blowdown valve to the blowdown stack, would they be able to trace it back to the source? Operations Tech Berger said they have several methods to trace a leak back to the source. He said they can use "acoustic" testing to listen for gas moving through a valve or line. He said they can use visual methods, where he may see a problem. He also pointed out a pressure sensor that was physically inserted into the blowdown stack supply line. If gas is passing through the pipe, he said, the sensor will detect it and send a signal to the MCC. We walked over to the blowdown stack and the FID measured -0.7 ppm in this area (background level).

<u>Particulate Filters</u>

Unlike the Sumner Facility, the Snohomish Facility does not have a cyclonic seperator to remove moisture from incoming gas. Instead, it has a set of three particulate filters. The Facility representatives said the pneumatic controllers for the filters are air-driven, not gas-driven, which they demonstrated by pulling a lever to open an air supply line which released air. No leaks were found coming from the pneumatic controllers in this area.

We examined the filters themselves for leaks. The FLIR camera did not see leaks. The FID measured a background level of 20 ppm, which increased to 220 ppm at a valve which we pointed out to Facility representatives. According to NSPS Subpart OOOOa, a "fugitive emission" is defined as any fugitive emission observed using optical gas imaging or an

[9] See https://www.trihydro.com/software/environmental-software/leaktracker-pro

instrument reading of 500 ppm or greater using Method 21. A reading with less than 500 ppm is not considered a fugitive emission (§ 60.5397a(a)).

Compressor Building

We found pneumatic controllers located on the exterior of the Compressor Building which were air-driven (not gas-driven).

Stepping into the Compressor Building, the FID recorded a background level of 0.5 ppm. Compressor Unit # 2 was operating, and Unit # 1 was shut down. Both compressors are Solar Mars, 90 S Gas Turbine compressor sets, manufactured in 2002. The rated power for both units was 12,513 hp. We continued looking for leaks. The FID measured 2.2 ppm at the compressor fuel line. We did not find methane leaks in this area.

Other observations at the Snohomish Facility:

- Several types of pig devices were stored outdoors along the east fence line. Pigs were designed with scrapers, brushes and magnets.
- A ground level Chromatograph Vault was observed along the east fence line. Facility representatives said the vault is a confined space. I did not see a confined space warning sign at the vault. They said that within the vault, gas is extracted from the pipeline and flows to a control room where it is analyzed for composition, which is typically about 96% methane, with the rest composed of nitrogen, CO2 and smaller amounts of ethane and propane.
- Gaskets, approximately 12 inches in diameter and colored green were laying on the ground adjacent to the pig devices along the east fence line. Asbestos was historically used in the manufacture of gaskets, and I cautioned operators to get a Safety Data Sheet for the gaskets to verify whether they were manufactured with asbestos.

11. Closing Conference

At approximately 12:50 pm, the inspectors and facility representatives returned to the office space for a closing conference. I briefly summarized our two days of inspection at the Sumner and Snohomish compressor stations.

I said we conducted a walk-through of both facilities to look at compressors, pneumatic controllers and sources of potential fugitive emissions. I thanked everyone for their help to see the operations at both sites.

At the Sumner facility, we identified one gas leak:

- Coming from a fuel line to Compressor Unit # 1. Gas was found with the FID instrument.

At the Snohomish facility, we identified gas leaks:

- From a Pig Pull Port Valve. The gas was found with a FLIR camera and also confirmed using the Method 21 bubble test.
- From valve D-1-N, valve stem packing. The gas was observed with a FLIR camera and the FID analyzer.

I said we confirmed turbine compressors at both facilities were manufactured prior to the Subpart OOOOa applicability date of September 18, 2015, as were most of the pneumatic controllers. At the Snohomish facility we found one pneumatic controller, D-3, which was manufactured in 2016 and therefore was potentially subject to NSPS Subpart OOOOa based on the date of manufacture. To check this further while we were still there, I pulled out a copy of Subpart OOOOa and read out loud the description of "pneumatic controller affected facility" (§ 60.5365a(d)). The rule states that it applies to each "continuous bleed" pneumatic controller. The facility representatives said all their gas-driven pneumatic controllers are intermittent bleed, not continuous bleed. I said based on that, it appears their pneumatic controllers would not be subject to Subpart OOOOa, however, in December 2023 EPA finalized changes to Subpart OOOOa and added Subparts OOOOb (for new equipment) and OOOOc (for existing equipment), and recommended they review the rules to see if anything changed for their pneumatic controllers.

I said I had not identified any compliance concerns at that time, but I would write an inspection report and information may change. I said EPA's policy is to send the facility a copy of the inspection report within about 70 days.

I asked if anyone had questions. The facility representatives asked if EPA would come back for another inspection next year. I said that, in general, EPA and State and local agencies do inspections at least every two years for Title V major sources and at least every five years for SM80s, such as their compressor stations. The local agency that wrote their air permit, PSCAA, comes out once a year.

I asked if any facility representatives had a CBI claim for anything related to this inspection. They did not.

Before leaving, EPA Inspectors Skeens and Gregory did a quality assurance "bump check" on the FID analyzer, using three different hydrogen gas concentrations (0 gas, 500 ppm and 10,000 ppm methane). The analyzer passed the bump check with all three gases.

12. Post Inspection Activities

On March 4, 2024, I sent an email to NW Pipeline Environmental Specialist Monica Mogg to request records as part of the inspection (Attachment 5). On March 7, 2024, I received a response via email from Ms. Mogg (Attachments 6-8).

13. Records Review

I reviewed records provided by NW Pipeline as part of this inspection. My comments are below.

Table 4: Records Review for NW Pipeline Compressor Stations Sumner and Snohomish

Record	Description	Comment
1	Photographs of five pneumatic controllers at the Sumner Facility, showing manufacturing dates.	Photos provided as requested and are representative of controllers observed during EPA''s inspection. Photos show the controllers were manufactured between 2000 – 2002.
2	Site diagram of each compressor station.	Diagrams of each compressor station were provided as requested.
3	Show all equipment with the potential to send gas to the blowdown stack at each facility.	Included with item #2.
4	Email, providing description of Williams Company policy on conducting leak detection and repair (LDAR) at compressor stations	Company policy commits to conduct LDAR at facilities even if they are not subject to federal or state regulations requiring LDAR, using an optical gas imaging (OGI) camera and other methods.