Fact Sheet: Underground Injection Control Permit AK-1I024-A, Nanushuk Processing Facility, Pikka Unit, North Slope, Alaska

What does the permit allow?	This ten-year permit allows the Permittee to construct and operate up to three injection wells for permanent disposal of non-hazardous wastes. Injection will occur at the Nanushuk Processing Facility Pad which is located adjacent to the Pikka Unit on the North Slope of Alaska. Waste will be injected into geologic formations that are not considered Underground Sources of Drinking Water.
Will new wells be drilled?	Yes. This permit authorizes construction of up to three new injection wells. No injection wells are currently constructed.
Why was the permit requested?	Oil and gas production at the Pikka Unit will generate wastes with no commercial value. Under the authority of this permit, the Permittee will inject non-hazardous wastes into geologic formations for permanent disposal. Alternative disposal methods include transportation to off-site treatment facilities and direct discharge to surface waters, both of which are costly and/or harmful to the environment.
What will be injected into the wells?	The wastes that will be injected may include produced water, desalination brine, domestic wastewater, drilling fluids and drill cuttings; stormwater; and other non-hazardous wastes.
What were the outcomes of the public comment period?	EPA published a public notice of this proposed draft permit via the Anchorage Daily News on September 27, 2023, and accepted public comments from September 27, 2023, through 5:00 PM on October 27, 2023. Two comments were received during this period. They were comments from the applicant, Oil Search (Alaska), LLC, clarifying the following: • The NPF pad and the surface locations of the proposed wells lie outside of the Pikka Unit, though they will function in support of development of the Pikka Unit. The draft version of this document stated that the proposed wells would be located within the Pikka Unit. The permit and this Fact Sheet have been revised to state that NPF Pad and proposed wells are located adjacent to the Pikka Unit and will function in support of its development. • While approximate target surface locations for the injection wells were described in the permit application and in the draft version of this fact sheet. The exact surface locations of the proposed wells are subject to change and will be confirmed after they are drilled. The only requirement is that they must be located on the NPF Pad.
Where can I find more information?	If you are seeking more information related to this Fact Sheet, please contact James Robinson (robinson.james@epa.gov or 907-271-6627).

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The Permit Action

The U.S. Environmental Protection Agency (EPA) issued permit AK-1I024-A, which authorizes Oil Search (Alaska), LLC (OSA) to construct and operate up to three Class I Non-Hazardous injection wells (Class I wells) at the Nanushuk Processing Facility (NPF) Pad adjacent to the the Pikka Unit, North Slope, AK. The approximate surface location for these wells is located at NW 1/4 NW 1/4, S14, T11N, R06E [approximately latitude 70.313416, longitude, -150.558493]. The wells will be drilled for injection and disposal in the Ivashak or Lower Torok Formations. EPA has determined that these injection zones are not Underground Sources of Drinking Water (USDWs). Attachment 1 to this Fact Sheet memorializes EPA's review and determination. Exact bottom hole locations will be determined following the construction of the wells.

Background

On July 5, 2022, EPA received an application from OSA for a permit to construct and operate up to three Class I wells at the NPF Pad in support of development of the Pikka Unit on Alaska's North Slope. The Pikka Unit is located between the National Petroleum Reserve in Alaska and the Arctic National Wildlife Reserve, near existing roadways. A general overview of the North Slope is shown in Figure 1.

Figure 1 - Map of the North Slope, Alaska. The Pikka Unit is located west of Prudhoe Bay and east of the ConocoPhillips Alpine development. The approximate location of the Pikka Unit is marked by a red arrow. (https://pubs.usgs.gov/fs/2002/fs045-02/fs045-02.pdf)

The primary commercial, industrial, and transportation hub in this region is Prudhoe Bay, AK. The Pikka Unit, including the surface location of the NPF Pad, is located approximately 52 miles west of Prudhoe Bay. The nearest residential community is the native Village of Nuiqsut, approximately 12 miles southwest of the Pikka Development (Figure 2).

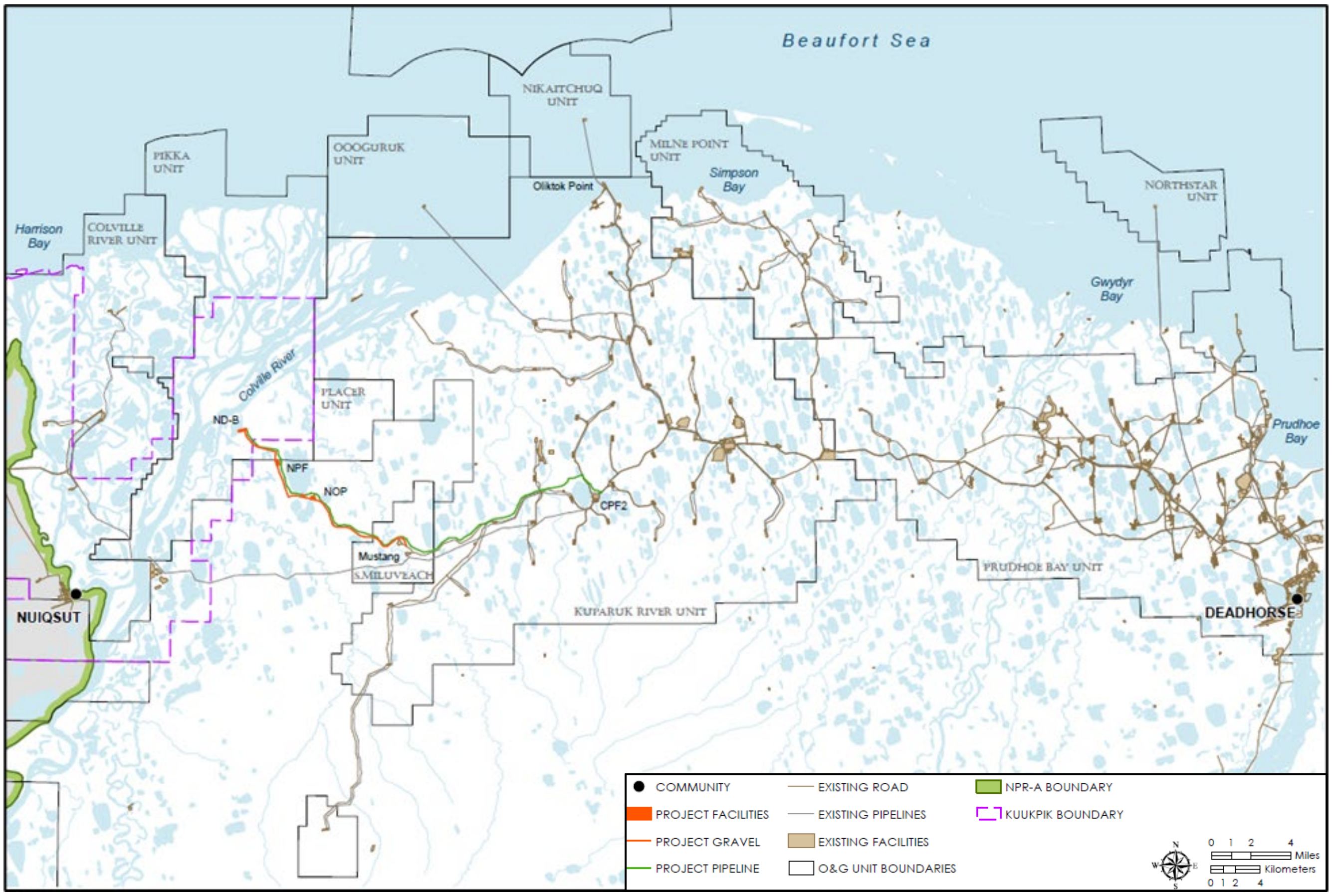

Figure 2 - Project Vicinity. The OSA project facilities are shown at the left within and adjacent to the Pikka Unit. The wells permitted by AK-1I024-A will be located at the Nanushuk Processing Facility (NPF) Pad which is near the border of the Pikka and Quokka (unlabeled) Units.

The NPF will consist of a 17-acre gravel pad with facilities capable of processing roughly 80,000 barrels per day (BPD) of oil. The NPF will convert multiphase fluid (i.e., water, oil, and gas), produced at drilling sites such as Nanushuk Drillsite B (ND-B), into sales-quality oil. The sales-quality oil will be transported via pipeline to the Trans-Alaska Pipeline System. The produced water separated at NPF will be disposed of in the Class I disposal wells permitted by AK-1I024-A.

Regulatory Framework

The UIC program is authorized by Part C of the Safe Drinking Water Act for the principal purpose of protecting USDWs from pollution by injection through wells. A USDW is defined as an aquifer that is currently serving as a source of potable water or could potentially serve as a public water supply based on its productivity and natural water quality.

Primary responsibility for implementing the Underground Injection Control (UIC) program in Alaska is shared between EPA and the Alaska Oil and Gas Conservation Commission (AOGCC). The AOGCC regulates Class II injection wells, which are defined as those wells used (1) to dispose of waste fluids brought to the surface from oil and gas production operations, (2) for enhanced recovery of oil and gas, or (3) for storage of hydrocarbons that are liquid at standard temperature and pressure (40 CFR § 144.6). Wastes that do not meet these criteria cannot be injected into Class II wells but may be eligible for Class I well injection.

EPA regulates all other classes of UIC wells in Alaska, including Class I injection wells. Applicable regulations concerning injection well requirements can be found in 40 CFR Parts 144 and 146. Criteria and standards applicable to Class I wells are found at 40 CFR Part 146 Subpart B.

Injection Well Operations and Waste Types

OSA plans to initially construct one injection well (PWD-02) at the NPF pad, with plans to drill a second and third injection well based on performance of the initial well. Each well will be designed for a maximum disposal capacity of 15,000 BPD and a planned injection rate of 10,000 BPD. Injectate will consist of exploration and production (E&P) exempt (per 40 CFR Part 261) and non-exempt non-hazardous wastes generated during drilling and production-related activities. These wastes may include:

- Fluids generated from sales oil production including produced water, seawater brine, glycols, anti-foaming agents, emulsion breaker, scale inhibitor/remover;
- Chemicals used for cleaning, maintenance, or freeze protection of the processing facility and systems;
- Low-solid drilling workover fluids;
- Used equipment fluids that include non-hazardous lube oil or hydraulic oil, laboratory wastes, camp wastewater, contaminated storm water, snowmelt, sump fluid, washwater, spill cleanup, boiler blowdown, and other chemicals that have not come into contact with the production stream; waste from internal coating of piping, small amounts of non-hazardous unused/leftover or off-spec material derived from the cleaning of storage tanks, and waste fluids from pigging;
- Grind and inject (G&I) waste steams (e.g., drill cuttings, mud, etc.) if the G&I Facility at ND-B (permitted by AK-1I019-A) is temporarily unable to accept waste or if the G&I Well is out of service;
- Third-party wastes of a similar nature.

Criteria and standards for E&P exempt material and the identification of hazardous/non-hazardous waste are detailed in Resource Conservation and Recovery Act (RCRA) Subtitle C (40 CFR Part 260 through Part 273) and the guidance document *Exhibit 28 U.S. Envtl. Prot. Agency, Office of Solid Waste, EPA530-K-01-004, Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations (2002).*

This permit authorizes the injection of wastes that are classified as non-hazardous under RCRA and those wastes that are exempt from classification under RCRA. This permit does not authorize injection of hazardous waste. Therefore, any listed hazardous wastes need to be collected, stored, and transported to a RCRA-approved hazardous waste treatment or disposal facility. Wastes that are considered hazardous because they exhibit an ignitability, corrosivity, and/or reactivity characteristic may be diluted and injected once all hazardous characteristics are removed. The Permittee is responsible for ensuring all RCRA requirements are met.

Table 1 shows projected volumes of injection waste, sorted by type.

Table 1 – Waste types and volumes over 30 year estimated life of Pikka NPF disposal wells.

Type of Waste	Volume (million barrels)
Produced Water	130
Camp Wastewater	0.008
Well Workover Fluids	0.1
Storm Water	0.005
Other Exempt or Non-Exempt Non-Hazardous Fluids	7
Third Party	0.5
Total Volume over 30 years:	**~138**

OSA anticipates that injection volume will gradually increase over the first five years of NPF operation as production wells come online and the facility builds capacity. Approximately 5 million barrels (bbls) will be injected annually under this permit once the facility is at peak operating capacity.

Geologic Setting of Injection and Confining Zones

Area of Review

The Area of Review (AOR) is defined as the three-dimensional area surrounding an injection well pattern in which the pressure change in the injection zone is great enough to make possible the migration of fluids out of the injection zone and into a USDW. The AOR can be defined through quantitative modeling or using a standard distance of ¼ mile radius from a well's injection zone. The AOR for this permit is defined by a rectangle containing all three proposed injection wells with a minimum bounding radius of 3,500 feet from each well's estimated injection zone (Figure 3). The bounding radius of 3,500 feet is based on pressure front modeling included within OSA's application package.

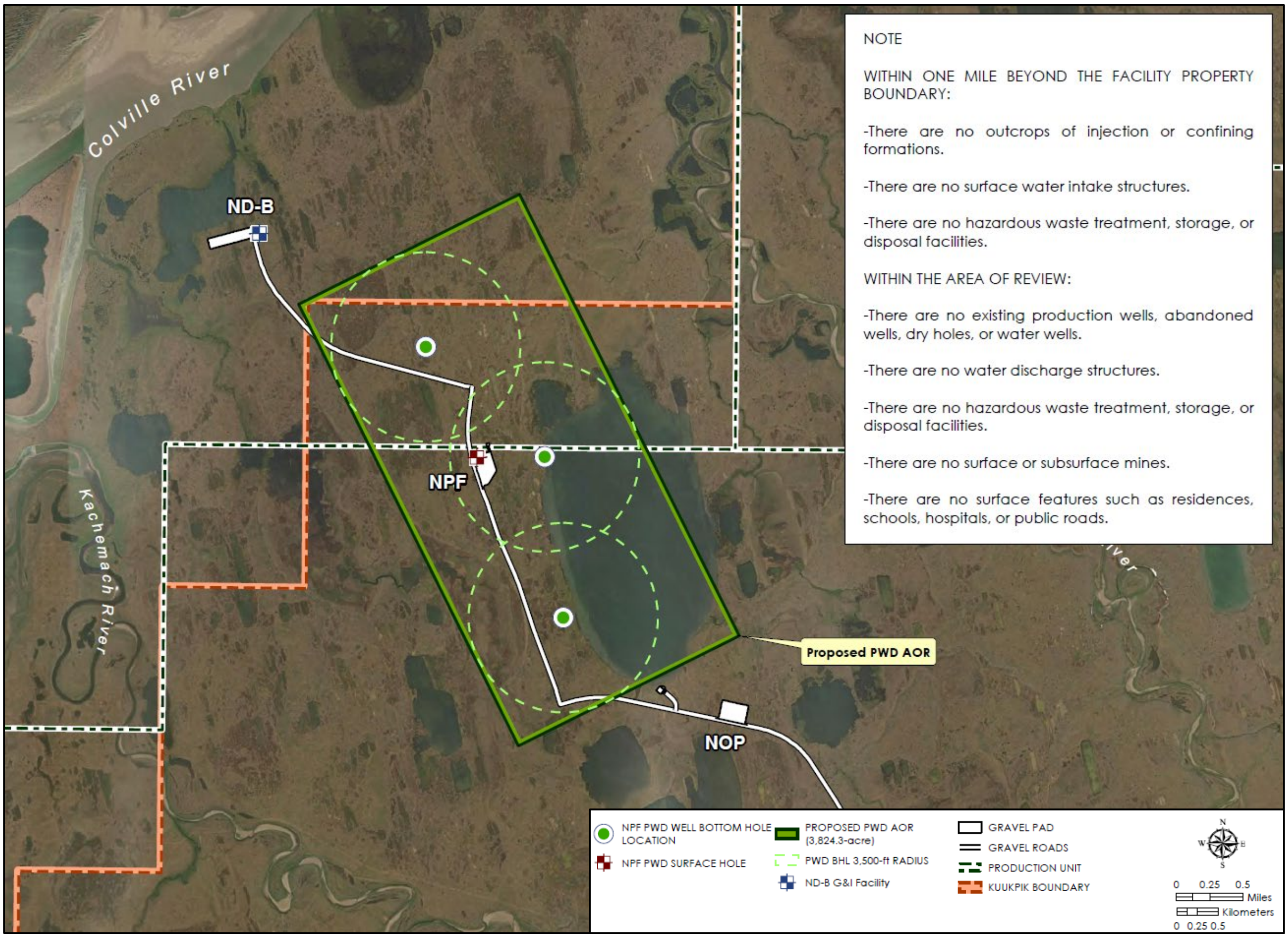

Figure 3 - Area of Review. Map showing the AOR for wells permitted under AK-1I024-A. The information provided on the map was provided by OSA.

The primary oil pool targeted by OSA at the Pikka Unit is held within the Nanushuk Formation. The Ivashak and Torok Formations are the primary and alternate target disposal zones for the PWD wells, respectively. Brief descriptions and depth estimations of the geologic formations underlying the proposed NPF facility are included below. Additional detail is provided about the formations that are intended to function as upper/lower confining zones and injection targets.

<u>Prince Creek Formation</u> (surface to 950 feet total vertical depth subsea [TVDSS]): unconsolidated sands and gravels deposited in a fluvial setting. The entire unit is within the permafrost interval at Pikka.

<u>Shrader Bluff Formation</u> (950 – 2470 feet TVDSS): claystone, mudstone, and shale interbedded with volcanic ash deposited in a shallow marine to outer shelf setting.

<u>Tuluvak Formation</u> (2,470 to 3,145 feet TVDSS): claystone, siltstone, and thin interbedded sandstones deposited in a shallow marine setting. This formation is hydrocarbon-bearing in the Pikka Unit and expected to contain a gas column with an oil rim.

<u>Seebee Formation</u> (3,145 to 3,895 TVDSS): claystone, shale, and volcanic tuff deposited in a deep marine setting. This formation is the confining unit above the Nanushuk Formation reservoirs.

Nanushuk Formation (3,895 to 4,675 TVDSS): laminated sand, silt, and shale deposited in fluvial, deltaic, and shallow marine settings. This is the primary oil production zone in the Pikka Unit.

Alternate Upper Confining Zone

Upper Torok Formation (Hue Shale; 4,675 to 5,190 TVDSS): shale with some thin interbedded siltstones deposited in a marine environment. Several condensed impermeable shale layers called the maximum flooding surfaces (MFS) are present within the unit. These MFS are regionally extensive and likely to provide suitable confining characteristics for the underlying alternate injection zone. This formation was identified by OSA as the upper confining unit above the Lower Torok alternate injection zone. Within the AOR, OSA estimates that the formation varies in thickness from about 450 to 620 feet.

Alternate Injection Zone

- Lower Torok Formation (5,190 to 5,885 TVDSS): fine grained, laminated sandstones interbedded with shale, mudstone, and siltstone deposited as lower slope turbidites in a deep marine environment. Sand within this formation was identified by OSA as the alternate injection zone. Although individual sand layers within the unit are thin, the overall package of sands is relatively thick and identifiable in all surrounding well logs. Porosity for the sand reservoirs within the unit is estimated to range from 10-23% with permeability ranging from 0.1-150 millidarcies (md). The Lower Torok Formation is the injection zone for existing permitted Class I wells elsewhere on the North Slope including at AK-1I019-A (the ND-B drillsite within the Pikka Unit) and AK-1I009-B located within the Oooguruk Unit (refer to Figure 2).

Alternate Lower Confining Zone

- Highly Radioactive Zone (HRZ, consisting of Hue Shale; 5,885 to 6,095 TVDSS): Condensed marine shale identified by OSA as the lower confining unit for the alternate Lower-Torok injection zone. This unit is characterized by distinct high readings on gamma ray profiles. Over the AOR, its thickness is estimated to range from about 110 to 175 feet.

Kalubik Formation (Pebble Shale Unit; 6,095 to 6,245 TVDSS): shale and siltstones deposited in a marine setting. This unit is generally considered impermeable and functions as a cap rock for other reservoirs on the North Slope.

Kuparuk Formation (6,245 to 6,570 TVDSS): multiple shale and silt packages grading upward from very fine to medium grained with some interbedded sandstones. This is a developed reservoir east of the Pikka Unit.

Alpine Formation (6,570 to 6,820 TVDSS): multiple sands deposited in a shallow marine setting, straddling the Upper Jurassic Unconformity. This unit is hydrocarbon bearing elsewhere on the North Slope.

Nuiqsut Formation (6,820 to 7,085 TVDSS): sands deposited in a marine shoreface setting with some interbedded siltstone and shale. This unit is hydrocarbon bearing elsewhere on the North Slope.

Kingak Formation (7,085 to 7,995 TVDSS): fine-grained bioturbated sand interbedded with silt and shale. OSA identified this formation as the source rock for the overlying hydrocarbon reservoirs layered above.

Sag River Formation (7,995 to 8,030 TVDSS): fine-grained bioturbated sandstone and shale deposited in a marine environment.

Primary Upper Confining Zone

- Shublik Formation (8,030 to 8,405 TVDSS): organic-rich calcareous mudstone deposited in an upwelling marine environment. OSA identified the Shublik Formation as the upper confining unit for the primary injection target – the Ivishak Formation. The Shublik formation is estimated to vary in thickness from about 300 to 350 feet within the AOR.

Primary Injection Zone

- Ivishak Formation (8,405 to 9,000 TVDSS): sandstone deposited in a fluvio-deltaic setting. This is the primary injection target under this permit. Although it is hydrocarbon bearing elsewhere on the North Slope, OSA does not expect the Ivishak Formation to bear hydrocarbons within/adjacent to the Pikka Unit. The surface of the reservoir dips to the southeast within the AOR. Reservoir characteristics within the Ivishak Formation show significant variance based on available core plug data from the nearby Nechelik 1 well, with porosity ranging from 9-19% and permeability ranging from 0.03-300 millidarcies (md) and 4 distinct lithofacies evident within the formation. This uncertainty is the reason OSA applied for an alternate injection zone within the Lower Torok Formation. The Ivishak Formation is the injection zone for existing Class I wells elsewhere on the North Slope including at AK-1I003-C and AK-1I010-B (at ConocoPhillips's Coleville River Unit Development; refer to Figure 2.

Primary Lower Confining Zone

- Kavik Formation (9,000+ TVDSS): shales deposited in a marine setting which OSA has identified as a lower confining unit for the primary target injection zone – the Ivishak Formation. The Kavik Formation is estimated to vary in thickness from about 200 to 300 feet within the AOR. Similar to the Ivishak Formation, this unit dips to the southeast within the AOR.

Geological Structure

Faults within the Pikka Unit and AOR generally trend northwest to southeast. Deep basement-involved normal faults have been mapped throughout the Unit. In the shallower Brookian stratigraphy (from the HRZ upwards), various north-south trending extensional faults have been mapped within the Unit. These shallow faults generally terminate within the Torok Formation while deeper basement-involved faults typically terminate in the Kuparuk Formation.

Within the AOR, OSA identified four faults within the primary injection target – the Ivishak Formation. The maximum fault offset within the AOR is estimated at 50 feet within the injection and confining zones. OSA believes this level of displacement will not significantly affect the ability of the confining units to retain injected fluids within the Ivishak Formation. Based on fracture modeling performed by

Tordillo Oilfield Solutions, LLC, faults within the AOR will not be reactivated at the permit-specified injection pressure limit of 4,000 pounds per square inch (psi) for the Ivishak Formation.

Within the AOR, OSA identified eight faults within the alternate injection target – the Lower Torok Formation. The maximum fault offset within the AOR is estimated at less than 50 feet within the injection and confining zones. OSA believes this level of displacement will not significantly affect the ability of the confining units to retain injected fluids within the Lower Torok Formation. Based on fracture modeling performed by Tordillo Oilfield Solutions, LLC, faults within the AOR will not be reactivated at the permit-specified injection pressure limit of 2,500 psi for the Lower Torok Formation.

Seismic History of Area

Within recent geologic history, the North Slope has not experienced significant seismic activity. The most powerful earthquake in the region occurred on August 12, 2018, as a magnitude 6.4 event located approximately 120 miles east-southeast of the AOR. It was associated with faults in the Brooks Range.

Additional Review

Environmental Justice

EPA has evaluated the possible impacts of this permit on nearby communities. EPA utilized a demographic tool called Environmental Justice Screen ("EJ Screen" https://www.epa.gov/ejscreen) to identify any at-risk populations. The tool uses publicly available data to analyze and quantify at-risk population exposure to environmental factors in the form of "EJ Indices." These EJ Indices are represented as percentiles which can be used to compare how environmental factors in a selected area compare to state and national average populations.

EPA completed an EJ Screen assessment centered on the NPF Pad with a bounding radius of 50-miles. Census summary data provided through this screen indicated a total population of 2,689 (2020); 72% of which identified as people of color, with the subgroup American Indian comprising 55% of the overall population. A total of 38% of the population reported speaking a language other than English at home. The average annual income per capita is estimated at $47,585.

EJ Indices were generated for a number of environmental parameters, detailed here: https://www.epa.gov/ejscreen/overview-environmental-indicators-ejscreen. A percentile in EJ Screen tells the reviewer approximately what share of the U.S. or State population experiences a lower burden for a given environmental risk factor. For example, ranking in the 90th percentile within Alaska would mean that a given community is experiencing an environmental burden at a level higher than 90% of the population in Alaska. As a percentile ranking within the state of Alaska, the NPF Pad area ranked above 50th percentile for Lead Paint (77%).

Construction, maintenance, use, and abandonment of injection wells is not expected to lead to any discernable increase in the environmental burden referenced by the EJ indices. The use of injection wells should reduce the amount of traffic on nearby roadways that would otherwise be required for waste disposal off site. Injection well use requires energy generation for powering pumps, but the resulting exhaust emissions are considered *de minimis* in comparison with the planned construction and operation of the other facilities within the development.

To ensure all local populations are afforded the opportunity to learn about this project and express their sentiments as community stakeholders, EPA is required to provide public review and accept comments on proposed permit actions. Additionally, because many people in this area belong to tribal villages, EPA performs tribal outreach and offers tribal consultation. EPA invited the village of Nuiqsut and the Inupiat Community of the Arctic Slope to consult on the project prior to publishing a notice of the proposed permit action in the Anchorage Daily News on September 27, 2023.

Endangered Species Act

EPA is required by Section 7 of the Endangered Species Act (ESA) to ensure that actions it authorizes, funds, or carries out do not jeopardize the continued existence of endangered or threatened species or destroy or adversely modify critical habitat. Previously the Agency has investigated possible effects of injection on species and/or their habitat. On August 18, 2017, the U.S. Fish and Wildlife Service concluded that injection of non-hazardous waste will have no effect on listed species nor their critical habitat. This conclusion was general to the injection of wastes on the North Slope, and not specific to any project.

The injection wells central to this application process are part of a much larger Pikka Development Project that had involved prior environmental reviews. The U.S. Army Corp of Engineers (“USACE”) previously issued an Environmental Impact Statement (“EIS”) for the Pikka (previously, “Nanushuk”) Project. In their EIS, they concluded that two bird species and four marine mammal species that are threatened or endangered occur regularly in or near the EIS area: Steller’s eiders, spectacled eiders, Beringia Distinct Population Segment of bearded seals, Arctic ringed seals, Southern Beaufort Sea polar bears, and Western Arctic bowhead whales. In a Biological Opinion, the U.S. Fish and Wildlife Service determined that this project is not likely to adversely affect Alaska-breeding Steller’s eiders, is not likely to jeopardize the continued existence of spectacled eiders or polar bears, and is not likely to destroy or adversely modify polar bear critical habitat. The National Marine Fisheries Service determined that the portion of the Nanushuk Project proposed to occur at Oliktok Dock may affect, but is not likely to adversely affect, bowhead whales, Beringia Distinct Population Segment bearded seals, or Arctic ringed seals.

National Historic Preservation Act

EPA has determined that this action will not affect historical properties. The primary, direct effect of underground injection is the emplacement of waste fluids into the Earth’s geologic formations below the surface. Injection occurs into deep formations, where it can be reasonably assured that no known historic sites exist. EPA permit conditions include construction requirements and ongoing testing requirements which ensure no release of injectate into shallow geologic formations harboring underground sources of drinking water.

Underground injection wells may cause indirect effects on the above ground environment. EPA considered these indirect effects and determined that they are unlikely to affect any potential historical sites. Indirect effects of injection are no more impactful than other activities occuring on the associated well pad considered in the Environmental Impact Statement for the Nanushuk project. Three recorded cultural resources were identified within or overlapping the Environmental Impact Statement analysis eligible for listing in the National Register of Historic Places; however, none of these sites are located at or near the NPF Pad.

Summary of Specific Permit Conditions

The conditions specified in the draft permit are for the construction and operation, monitoring, reporting, and plugging and abandonment of the well. The following summary briefly describes the permit conditions and the reasons for them. These conditions will ensure the protection of USDW.

Well Construction Specifications (Part II. A. of the Draft Permit)

The permittee must provide at least a 30-day notice to ensure that EPA can witness the construction procedures to determine compliance with the draft permit and applicable regulations.

The permittee is authorized to fill the inner annulus with corrosion/freeze-inhibiting fluids that protect against chemical and physical damage to the tubular goods. Permafrost at this location is located from the ground surface to approximately 1,000 ft TVD and the annulus space must remain unfrozen for operational and safety reasons.

The Permittee must submit a Waste Analysis Plan, in accordance with the permit, prior to receiving authorization to inject. This plan and any other relevant manifesting procedures must be followed to ensure only non-hazardous or exempt wastes are injected. There may be times when batch waste streams will require lab analysis to prove non-hazardous determinations.

Construction – Packer Specifications

EPA requires that Class I injection wells inject wastes through tubing with a packer set immediately above the injection zone. The Permittee must place the packer in each well no more than 200 feet from the top of the injection zone unless a different offset distance is approved by EPA.

Well Operation and Testing Requirements (Part II. C. of the Draft Permit)

EPA requires annual pressure testing of the annular space between the tubing and long string casing. This testing is required to ensure the adequate isolation of the injection stream from the surrounding formation and to test the integrity of the tubing/packer/long string casing annulus. For wells injecting into the Ivishak Formation (the primary injection target), a passing test will demonstrate that the annulus can hold a pressure of at least 4,000 psi for at least 30 minutes, and that any pressure decrease shows a stabilizing trend. For wells injecting into the Lower Torok Formation (the alternate injection target), a passing test will demonstrate that the annulus can hold a pressure of at least 2,500 psi for at least 30 minutes, and that any pressure decrease shows a stabilizing trend. These values are based on the anticipated injection pressure, which is directly proportional to depth/subsurface pressure, and the assumptions used to calculate the expected fracture gradient of the injection zones.

The maximum allowable annular pressure is 1,500 psi to account for pressure swings and thermal effects on the inner annulus. During injection, the Permittee must maintain a clear pressure differential between the inner annulus and the tubing as measured at the wellhead.

As an additional measure to demonstrate that fluids are not flowing up behind the pipe or along the wellbore, EPA requires that the Permittee conduct an approved fluid movement test at a pressure equal to at least the average continuous injection pressure at the wellhead observed over the previous six months. Fluid movement tests are required upon completion of the injection well to determine adequacy of initial construction and every two years thereafter until the expiration of the permit to ensure that injection does not result in the movement of fluids outside of the permitted formation(s). The Permittee may request a due date extension of up to three months to accommodate for travel and logistical delays. This request must be approved by the Director or an EPA authorized representative.

The injection of drilling muds, cuttings, other slurried solids, and other non-hazardous wastes at high pressures presents erosive and corrosive risks to the internal tubing components of the injection well. The draft permit requires that the Permittee conduct tubing inspection tests (such as a caliper log) every two years. The Permittee may request a due date extension of up to three months to accommodate for travel and logistical delays. This request must be approved by the Director or an EPA authorized representative.

Monitoring, Record Keeping, and Reporting (Part II, Section D of the Draft Permit)

During injection, the well must be continuously monitored by trained and qualified personnel. The permittee must monitor injection pressure, tubing-casing inner annulus pressure, and injection rate on a continuous basis. Continuous monitoring and automatic shut-off systems are required to ensure a timely response to any suspected non-compliance.

If injection operations exceed the limits of the permit, the permittee shall notify EPA verbally and in writing pursuant to permit conditions in Part I, Section E. 12.

The Permittee shall continuously staff and visually monitor direct waste injection operations at the well site. During these operations, the permittee shall maintain a record of the time of day, a description of the waste pumped, injection rate and pressure, and well annulus pressure observations.

The Permittee shall require a written manifest for each batch load of waste received for waste streams that are not hard piped and continuous, and a determination that the waste meets the requirements for exempt and/or non-hazardous injection. Staff completing manifest forms and certifying the characteristics of waste must be properly trained to identify wastes sources.

All injection must meet the conditions of a site-specific Waste Analysis Plan, and under no circumstance may the Permittee inject hazardous waste. The Permittee is required to maintain all operational and monitoring records, and to submit quarterly summary reports to EPA.

Financial Responsibility (Part I, Section G of the Draft Permit)

The Permittee must meet the financial assurance requirements pursuant with 40 CFR § 44.52(a)(7). EPA Region 10 has chosen to apply the criteria found at 40 CFR Part 144 Subpart F for hazardous injection wells in the evaluation of the Permittee's financial assurance instrument due to the sensitive arctic environment of the North Slope, the injection zone fracture waiver requested by the Permittee, and the clarity provided by these rules. OSA has submitted a Trust Agreement to satisfy their financial assurance responsibility pursuant to 40 CFR § 144.63(a).

Pursuant to § 144.63(a), the Trust Fund must be funded over a "Pay-in-period." Regulations require payments to be made into the Trust Fund "annually by the owner or operator over the term of the initial permit or over the remaining operating life of the injection well as estimated in the plugging and abandonment plan, whichever period is shorter; this period is hereafter referred to as the "pay-in period."

EPA is proposing to issue this first permit for 10 years, so the pay-in-period is 10 years.

The first payment into the Fund must take place before the initial injection of waste. A receipt from the trustee for this payment must be submitted by the owner or operator to the EPA R10 Regional Administrator before this initial injection of waste. The first payment must be at least equal to the current plugging and abandonment cost estimate, except as provided in § 144.70(g), divided by the number of years in the pay-in period.

Subsequent payments must be made no later than 30 days after each 1-year anniversary date of the first payment. The amount of each subsequent payment must be determined by this formula:

$$\text{Next payment} = \frac{\mathrm{PE} - CV}{Y}$$

where PE is the current plugging and abandonment cost estimate, CV is the current value of the trust fund, and Y is the number of years remaining in the pay-in period. The pay-in period is ten years, since the permit lifespan is ten years.

Additional requirements and information are provided at §144.63(a).

Waivers Granted

EPA intends to waive certain Class I UIC requirements. EPA has the authority to waive these requirements under Title 40 CFR § 144.16, as these wells will not inject through, into, or above any USDW.

(1) <u>Compatibility of Formation and Injectate</u> (40 CFR §§ 146.12(e)(4)-(5) and 146.14(a)(8)):

Based upon the injection history taking place on the North Slope of Alaska and the performance of nearby Class I injection wells injecting into the same stratigraphic sequence, EPA intends to waive the requirement to sample and characterize formation fluids and the rock matrix in order to determine whether or not they are compatible with the approved injectate stream.

(2) Injection Zone Fracturing (40 CFR § 146.13(a)(1)):

The Permittee has requested a waiver to the prohibition against fracturing the subsurface in order to inject drilling slurry, suspended solids, and other oilfield wastes. Class I injection wells are generally prohibited from injecting at pressures that would initiate new fractures or propagate existing fractures within the injection zone. EPA intends to waive this prohibition and would instead allow fracturing of the injection zone so long as fractures do not propagate into the upper and lower confining zones. The Shublik Formation and the Kavik Formation are identified as the Upper and Lower Confining Zones, respectively, for the Ivashak Formation (the primary injection target). The Upper Torok Formation and HRZ are identified as the Upper and Lower Confining Zones, respectively, for the Lower Torok Formation (the alternate injection target).

(3) Ambient Monitoring Above the Confining Zone (40 CFR § 146.13(b)(1) and (4) and 40 CFR § 146.13(d)):

EPA intends to waive the requirement to monitor the strata overlying the confining zone for fluid movement since the Permittee's application demonstrates that there are no improperly sealed, completed, or abandoned wellbores within the area of review.

Public Comment

EPA published a public notice of this draft permit via the Anchorage Daily News on September 27, 2023, and accepted public comments from September 27, 2023, through 5:00 PM on October 27, 2023. One comment was received during this period. It was a comment by the applicant (OSA) clarifying the following:

- The NPF pad and the surface locations of the proposed wells lie outside of the Pikka Unit, though they will function in support of development of the Pikka Unit. The draft version of this document stated that the proposed wells would be located within the Pikka Unit. The permit and this Fact Sheet have been revised to state that NPF Pad and proposed wells are located adjacent to the Pikka Unit and will function in support of its development.
- While approximate target surface locations for the injection wells were described in the permit application and in the draft version of this Fact Sheet, the exact surface locations of the proposed wells are subject to change and will be confirmed after they are drilled.

Attachment 1: No USDW Determination

EPA has determined that neither the Ivishak nor Lower Torok Formations at the site of the proposed injection wells meet the definition of Underground Sources of Drinking Water (USDWs). This attachment summarizes the information used by EPA to make this determination.

40 CFR § 144.12(a) dictates that "[n]o owner or operator shall construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of fluid containing any contaminant into [USDWs], if the presence of that contaminant may cause a violation of any primary drinking water regulation under [the National Primary Drinking Water Standards] or may otherwise adversely affect the health of persons."

If an aquifer does not meet the definition of an USDW, it is not a USDW. Determining whether portions of aquifers are not USDWs is important for creating clarity around the impact of injecting into geologic formations. Class I injection wells cannot inject into USDWs, so the receiving formation (i.e., injection zone) must either be exempted from status as a USDW (see below), or not meet the definition of a USDW.

By reviewing water-use information, lithologic details, and water chemistry data, one can determine whether portions of an aquifer meet the definition of a USDW. EPA Region 10 has historically provided responses to requests submitted by Class I UIC permit applicants regarding USDW status. This process is taken to assure stakeholders that waste will not be injected into a USDW. Primary aspects for review in making this determination include:

1. **Presence of public water system(s)**, to determine that there are no public water systems withdrawing groundwater from the aquifer identified.

2. **Quantity of water available for extraction,** to determine whether the aquifers identified contain a sufficient quantity of water to serve future potential public water supplies.

3. **Instances of groundwater being used for human consumption,** to determine whether the aquifers identified demonstrate current drinking water capabilities.

4. **Total Dissolved Solids in Aquifer,** as a measure of the possible value of these aquifers as a future drinking water source. Federal regulations consider all aquifers with a Total Dissolved Solids (TDS) value over 10,000 mg/l not to meet USDW status.

Evaluating the Ivishak and Lower Torok Formations at the Pikka Unit

EPA received a No USDW determination request from Oil Search (Alaska), LLC (OSA) along with their Class I Permit Application on July 5, 2022. OSA submitted structure maps, geophysical well type logs, formation water salinity estimates, records of direct salinity measurements, and other information to support this request. The surface projection of the rectangular "No USDW" area request is shown in Figure 1, and is bound by vertices located at:

Vertex Location	Latitude	Longitude
Northeast	70.3401	-150.5465
Northwest	70.3287	-150.6125
Southeast	70.2957	-150.4795
Southwest	70.2843	-150.5454

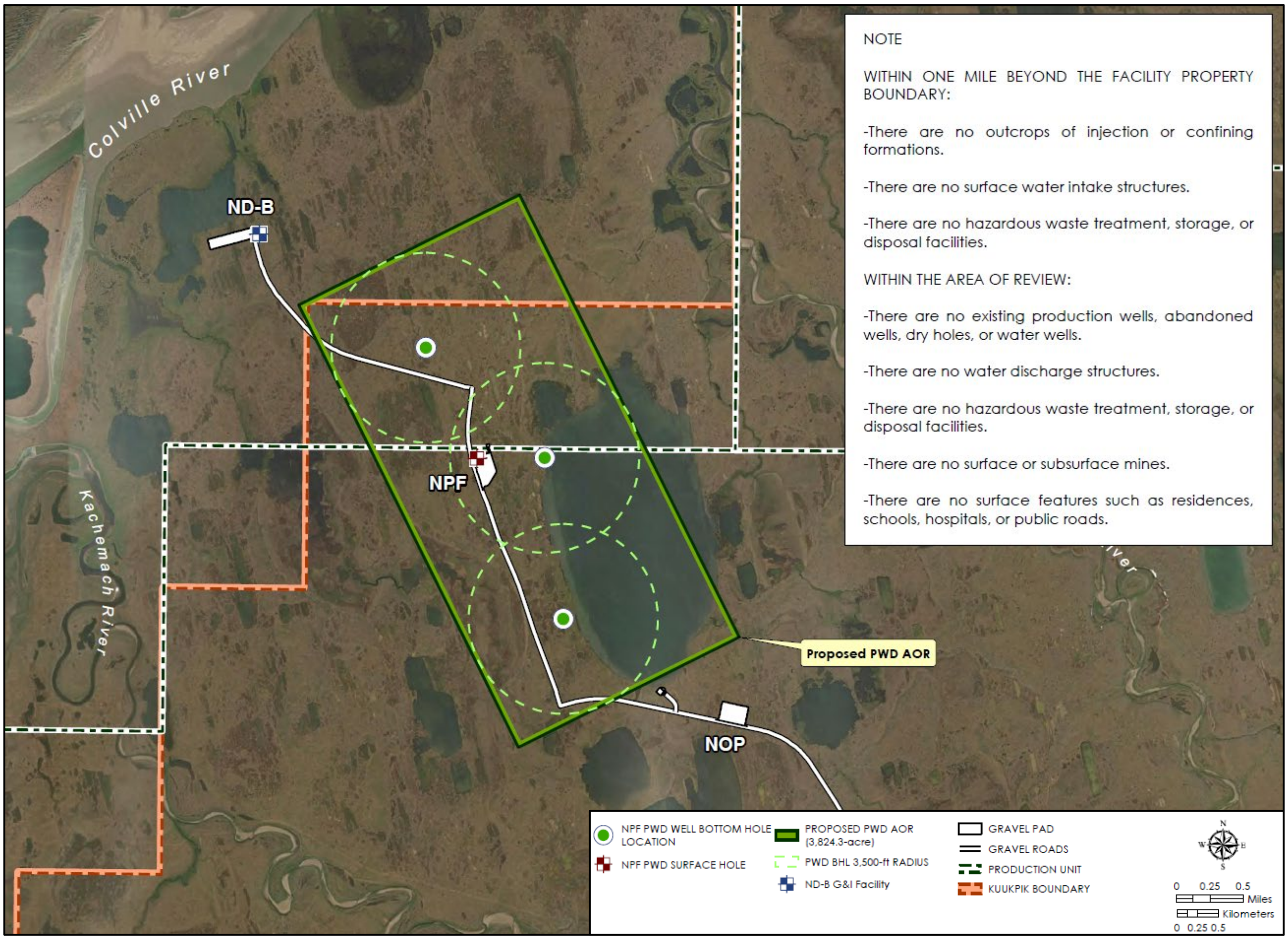

Figure 1 – Surface trace "No USDW" determination. From Exhibit A-2 of OSA's June 30, 2022 Class I UIC Application.

1. Presence of Public Water Systems

OSA states in its request that the Pikka Development project and surrounding area does not contain a public water system that relies on groundwater. EPA is aware of no Public Water Systems (PWSs) that rely on water from the Torok and/or Ivishak Formation.

The Alaska of Department of Environmental Conservation (ADEC) provides a publicly available map of source water protection areas. Figure 2 presents listed public water system sources in the vicinity of the Pikka Unit. Each water source in the area is a surface water body.

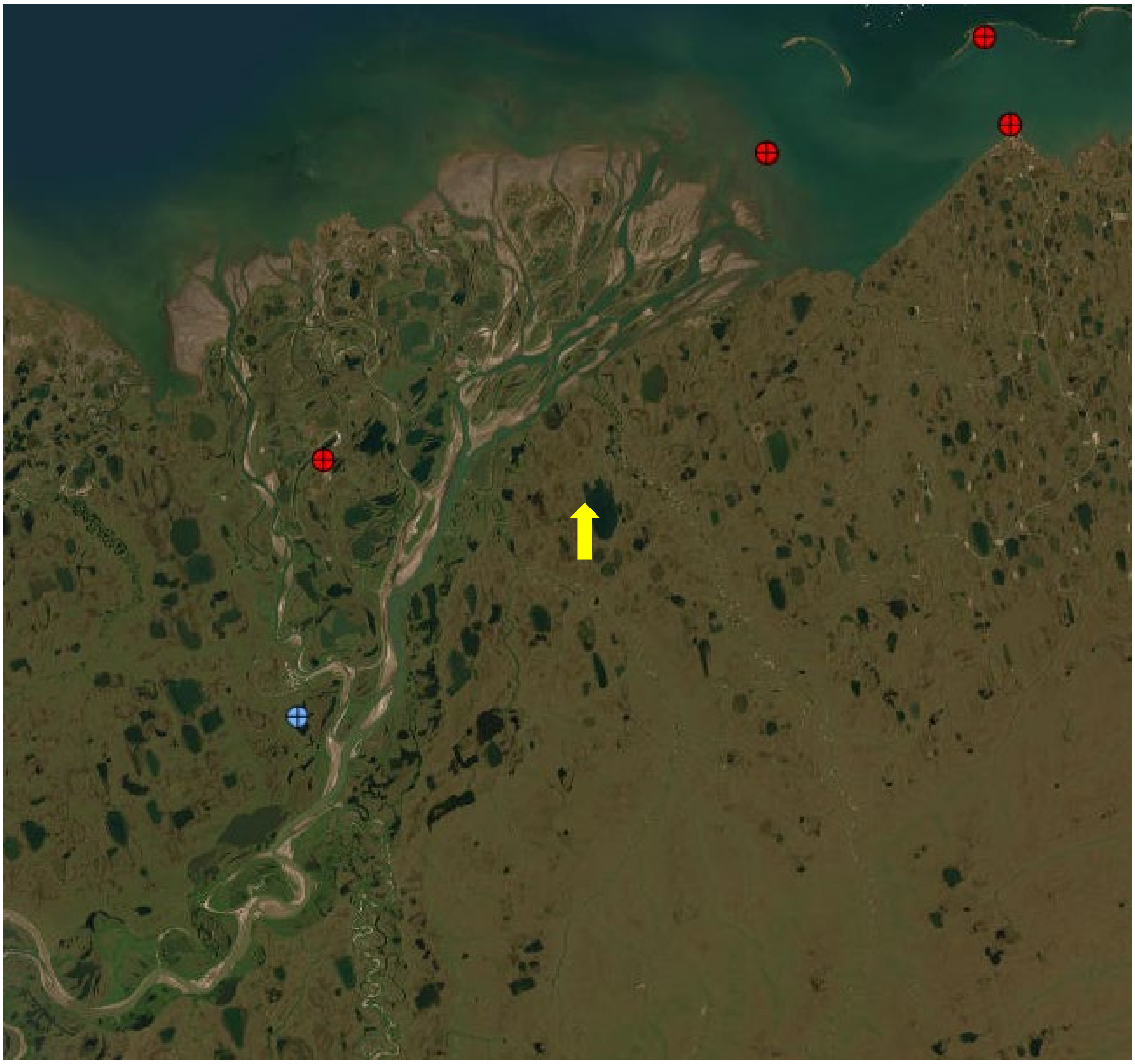

Figure 1 – Public Water System Source Map from Alaska Department of Environmental Conservation Online Viewer. The NPF Pad is marked by a yellow arrow. The blue symbol represents the Village of Nuiqsut's public water system. The red symbols indicate non-transient Non-Community Water Systems. Each water source shown in this image is a surface water body.

Much of the shallow soil and geology in the northern stretches of Alaska remain frozen throughout the year. This permafrost on the North Slope can reach depths of over 2,000 feet in some areas and drinking water is either collected from lakes or produced by desalinating seawater[a]. At the Pikka Unit,

[a] Review: Groundwater in Alaska (USA). Callegary, J. B., et. al. January 1, 2013. https://www.researchgate.net/publication/257471726_Review_Groundwater_in_Alaska_USA

permafrost extends to depths ranging from 1,000 to 1,600 feet below ground surface based on a previous regional assessment[b]. OSA assumes a permafrost depth of 1,000 feet in its request based on temperature profile studies from nearby wellbores. EPA is not aware of any public water sources that rely on groundwater sourced and/or produced from the Ivishak or Torok formations in the vicinity of the Pikka Unit.

Hydrologic connection between the permitted injection intervals and shallower, freshwater sources (including surface water) is not expected, as there are multiple aquitards between the permitted injection zones and the surface water bodies which will restrict the vertical migration of injected fluids.

2. Quantity of Water Available for Extraction

The Code of Federal Regulations (See, 40 CFR § 144.3) defines an "aquifer" as a "…geological 'formation,' group of formations, or part of a formation that is capable of yielding a significant amount of water to a well or spring." For groundwater to be characterized as an aquifer it needs to be able to "[yield] a significant amount of water". There are few if any studies available that focus on the water quantity potential for the Ivishak and Torok formations (for drinking water purposes), so an appropriately conservative approach is to assume that these formations *do* contain enough water to supply a public water supply. This assumption is supported by available geologic data. Outcrop samples of the Torok taken from the East bank of Chandler River were characterized with a porosity (~6-16%) and permeability (~.1-.3 millidarcies)[c] making them suitable for groundwater extraction. Both the Ivishak and Torok Formations have been used as injection and production zones elsewhere on the North Slope, indicating that they likely have sufficient pore space and permeability to produce enough water to support a community water system[d].

3. Occurrences of ground water being used for human consumption

OSA identified no wells, including no drinking water wells, within the AOR. The nearest community, the Village of Nuiqsut, supplies community water from a surface water lake located about one mile south of the village, and over ten miles from the NPF Pad.

4. Total Dissolved Solids in Aquifer

Aquifers that are not used for drinking water and contain a Total Dissolved Solids (i.e., salinity) concentration of greater than 10,000 milligrams per liter (mg/L) do not meet the federal criteria for USDWs. OSA has provided estimated and measured TDS values for each of the formations present at

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[b] Map showing the depth to the base of the deepest ice-bearing permafrost as determined from well logs, North Slope, Alaska. USGS https://pubs.usgs.gov/om/222/plate-1.pdf

[c] http://dggs.alaska.gov/webpubs/dggs/pir/text/pir2004_005.pdf

[d] Note that this is a hypothetical statement assuming both a demand for water production and water quality of such level that it is useful for consumption. As seen elsewhere in this document, neither of these assumptions appears to be true.

NPF Pad from surface to the lower confining layer for the primary injection zone. The two primary methods for determining formation water salinity are: 1) estimations made from geophysical well logging using the physical property of electrical resistivity and, 2) direct sampling/chemical analysis measuring the chemical concentrations of dissolved salts. These methods are briefly described, below.

Salinity Estimates by Rwa

Estimated TDS values are derived from the apparent water resistivity (Rwa) method, relying on empirically derived resistivity and assumed porosity values to calculate TDS values. This method was developed from the relationship between porosity and saline saturation of a formation with a tested electrical conductivity ("Archie's Equation/Law"). For determining apparent water resistivity:

$$R_{wa} = (R_t * ø^m) / a$$

Where,

R_{wa}= Apparent water resistivity,

R_t= Fluid-saturated rock resistivity (bulk resistivity),

ø= Density porosity, derived from density logs,

m= Cementation exponent accounting for varying pore arrangement and complexity[e],

a= Tortuosity factor, related to path and fluid flow[f].

Apparent resistivity values must be temperature corrected with known resistivity measurements. This is done at a formation temperature of 75 degrees Fahrenheit:

$$R_{wa}\ @75\ \mathrm{degF} = R_{wa} * (T_f + 6.77) / (75 + 6.77)$$

Water resistivity values are converted to TDS mg/L estimates using the industry standard Baker Atlas interpretation charts:

$$TDS = 10^{((3.562 - \log10\ (Rwa75 - 0.0123))\ /0.955)}$$

[e] Consolidated sandstones typically fall between 1.8 and 2.0, assumed to be 2.15 from the Humble Equation for sandstones. https://www.researchgate.net/publication/223250823_The_Cementation_Factor_of_Archie's_Equation_for_Shaly_Sandstone_Reservoirs

[f] Value assumed to be 0.62 from the Humble equation (F=0.62/ *ø)* for sandstones. Otherwise, often value 1.

Estimating formation salinity by geophysical logs is useful for determining TDS but has been associated with a margin of error up to 15% in comparison with direct formation sampling[g]. Estimating salinity of formation water depends on properly accounting for several factors, including the presence of clay, the total saturation of the formation, and the tortuosity of the pore structure. That said, while the most direct method of measuring the salinity of formation water is by direct sampling, there are advantages to estimating salinity by the Rwa method. Direct sampling introduces the concern of mud filtrate contaminating the sample, possibly providing an inaccurate representation, and possible errors in laboratory analysis. When possible, correlating multiple data points from multiple sources will provide the most accurate representation of formation water salinity.

Salinity Measurements by Direct Sampling

In addition to apparent water resistivity estimates, formation salinity values are obtained from drill stem test recovery samples and sent to analytical laboratories for analysis of major ion concentrations (Na^+, Cl^-, Mg^{2+}, Ca^{2+}, K^+, etc.). Chemical sampling is the benchmark method to determine TDS concentrations, as laboratory methods have proven to be the most precise method for sample character elucidation. Errors may be imparted by the quality of the original input data, laboratory error, or non-representative sampling.

Correlation Across the Colville Delta and Nearshore Locations

OSA provided salinity measurements from the targeted intervals at locations along the North Slope. These measurements were made by either of the two methods described above—estimation from geophysical logging tools with the Rwa method, or direct sampling of the formation water—and provide data indicating that the Ivishak and Torok Formations do not qualify as USDWs. Table 1 below provides the estimated formation salinity calculations provided by OSA for the formations of interest around the AOR.

[g] Survey of Methods to Determine Total Dissolved Solids Concentrations. US EPA UIC Program. September, 1988.

Well	Formation	Depth (feet MD)	Salinity	Comments
Bergschrund 1	Nanushuk	4,220	15,000 ppm NaCl eq. (calc.)	Calculated from petrophysics
Alpine 1	Albian (Nanushuk/ Torok)	5,150–5,204	15,000 ppm NaCl eq. (calc.)	Calculated from petrophysics
Kalubik 1	Albian (Nanushuk/ Torok)	5,050–5,250	24,300 mg/L TDS (avg.)	Drill Stem Test (DST): Recovered 151 bbls fluid (146 formation water)
Colville Delta 1	Torok	4,637–4,601	23,600 ppm NaCl eq. (calc.)	Calculated from petrophysics
Colville Delta 1A	Torok	4,762 -4,796	17,770 ppm NaCl eq. (calc.)	Calculated from petrophysics
Colville Delta 2	Torok	5,133–5,100	17,140 ppm NaCl eq. (calc.)	Calculated from petrophysics
E Harrison Bay 1	Torok	5,588–5,555	19,870 ppm NaCl eq. (calc.)	Calculated from petrophysics
Ivik 1	Torok	5,248–5,196	23,130 ppm NaCl eq. (calc.)	Calculated from petrophysics
Kalubik 3	Torok	5,108–5,025	21,820 ppm NaCl eq. (calc.)	Calculated from petrophysics
Natchiq 1	Torok	5,740–5,263	18,620 ppm NaCl eq. (calc.)	Calculated from petrophysics
Oooguruk 1	Torok	5,423–5,371	21,860 ppm NaCl eq. (calc.)	Calculated from petrophysics
Thetis Island 1	Torok	5,583–5,549	18,010 ppm NaCl eq.(calc.)	Calculated from petrophysics
Colville 1	Lisburne	9,023–9,073	24,004 mg/L TDS	DST: Recovered 8,743-foot column of gas cut formation water
Colville 1	Shublik	7,872–7,922	22,485 mg/L TDS	DST: Recovered 720-foot column of gas cut formation water
Kalubik Creek 1	Lisburne	9,047–9,188	21,847 mg/L TDS	DST: Recovered 325 bbls of water
Mukluk 1	Ivishak	7,490–7,520	19,129 mg/L TDS 11,000 ppm Cl	DST: Recovered 765 bbls fluid (all formation water)
Mukluk 1	Lisburne	8,145–9,860	11,000 ppm Cl	DST: Recovered 953 bbls fluid (all formation water)
Nechelik 1	Sag River	8,432–8,480	18,000 ppm NaCl eq. (calc.)	Calculated from petrophysics
Nechelik 1	Ivishak	9,420–9,460	17,000 ppm NaCl eq. (calc.)	Calculated from petrophysics
OP21-WW02	Ivishak	12,018–8,700 TVD	21,118 mg/L TDS	Modular Dynamics Test sample
Kookpuk 1	Ivishak	8,570–8,880	19,600–26,600 ppm NaCl eq (calc)	Calculated from petrophysics
Till 1	Torok	5,731	19,300-19,600 mg/L Cl	FMT Sample
Qugruk 3A	Torok	7,450–8,875	17,800 ppm NaCl eq (calc)	Calculated from petrophysics

Table 1 – Formation water salinity correlations from wells near the Pikka Unit. Qugruk-3A and Colville River 1 are situated at top-hole locations within the Pikka Unit. All TDS values come from either apparent resistivity (Rwa) estimates from geophysical data, or from water sampling.

Conclusion

Based on the information submitted by OSA and supported by previous studies, EPA has determined that there are no USDWs within the Ivishak Formation, bounded by the Shublik Shale (the upper confining unit) and Kavik Shale (lower confining unit), or the Lower Torok Formation, bounded by the

Upper Torok Formation (upper confining unit) and HRZ/Kalubik Shale (lower confining unit) within the AOR defined by:

Vertex Location	Latitude	Longitude
Northeast	70.3401	-150.5465
Northwest	70.3287	-150.6125
Southeast	70.2957	-150.4795
Southwest	70.2843	-150.5454