Public

Alaska LNG Liquefaction Plant Construction Permit Application

Project Information Form Attachment 4:

Alaska LNG Resource Report 9 (Air and Noise Quality)

and

Appendix H to RR9 (Project NSPS, NESHAPS and RMP Applicability Analysis)

March 2018

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DOCKET NO. CP17-___-000
RESOURCE REPORT NO. 9
AIR AND NOISE QUALITY
PUBLIC

DOCUMENT NUMBER: USAI-PE-SRREG-00-000009-000

RESOURCE REPORT NO. 9 SUMMARY OF FILING INFORMATION [1]	
FILING REQUIREMENT	**FOUND IN SECTION**
1. Describe existing air quality in the vicinity of the project – Title 18 Code of Federal Regulations (CFR) part (§) 380.12 (k) (1).	9.2.2, Appendix B
2. Quantify the existing noise levels (day-night sound level (Ldn) and other applicable noise parameters) at noise sensitive areas and at other areas covered by relevant state and local noise ordinances – 18 CFR § 380.12 (k) (2)	9.3.1
3. Quantify existing and proposed emissions of compressor equipment, plus construction emissions, including nitrogen oxides (NOx) and carbon monoxide (CO), and the basis for these calculations. Summarize anticipated air quality impacts for the project – 18 CFR § 380.12 (k) (3)	9.2.3, 9.2.5 Appendix C Appendix E
4. Describe the existing compressor units at each station where new, additional, or modified compression units are proposed, including the manufacturer, model number, and horsepower of the compressor units. For proposed, new, additional, or modified compressor units, include horsepower, type, and energy source – 18 CFR § 380.12 (k) (4)	9.2.5 Appendix E
5. Identify any nearby noise-sensitive area by distance and direction from the proposed compressor unit building/enclosure – 18 CFR § 380.12 (k) (4)	9.3.1
6. Identify any applicable state or local noise regulations – 18 CFR § 380.12 (k) (4).	9.3.3, 9.3.5
7. Calculate the noise impact at noise-sensitive areas of the proposed compressor unit modifications or additions, specifying how the impact was calculated, including manufacturer's data and proposed noise control equipment – 18 CFR § 380.12 (k) (4)	9.3.4
ADDITIONAL INFORMATION OFTEN MISSING AND RESULTING IN DATA REQUESTS	
Air Quality Information	
Include climate information as part of the air quality information provided for the project area.	9.2.1
Identify potentially applicable federal and state air quality regulations.	9.2.4, 9.2.6
Provide construction emissions (criteria pollutants, hazardous air pollutants, greenhouse gases) for proposed pipelines and aboveground facilities.	9.2.3, Appendix C
Provide copies of state and federal applications for air permits.	Not available at this time
Provide operation and fugitive emissions (criteria pollutants, hazardous air pollutants, greenhouse gases) for pipelines and aboveground facilities.	9.2.5, Appendices D, E, F
Provide air modeling for entire compressor stations.	9.2.5, Appendix E
Identify temporary and permanent emissions sources that may have cumulative air quality effects in addition to those resulting from the project.	9.2.5, Appendices D, E, F
Noise and Vibration Information	
Describe the existing noise environment and ambient noise surveys for compressor stations, liquefied natural gas facilities, meter and regulation facilities, and drilling locations.	9.3.1
Identify any state of local noise regulations applicable to construction and operation of the project.	9.3.3, 9.3.5
Indicate whether construction activities would occur over 24-hour periods.	9.3.2
Discuss construction noise impacts and quantify construction noise impacts from drilling, pile driving, dredging, etc.	9.3.2
Quantify operation noise from aboveground facilities, including blowdowns.	9.3.4
Describe the potential for the operation of the proposed facilities to result in an increase in perceptible vibration and how this would be prevented.	9.3.4.2.1.1

[11] Guidance Manual for Environmental Report Preparation, Volume I (FERC, 2017). Available online at: https://www.ferc.gov/industries/gas/enviro/guidelines/guidance-manual-volume-1.pdf.

RESOURCE REPORT NO. 9 SUMMARY OF FILING INFORMATION [1]	
FILING REQUIREMENT	**FOUND IN SECTION**
Identify temporary and permanent noise sources that may have cumulative noise effects in addition to those resulting from the project.	9.3.4

Resource Report No. 9 Agency Comments and Requests for Information Concerning Air and Noise Quality			
Agency	**Date**	**Comment**	**Response/Resource Report Location**
Bureau of Land Management (BLM)	9/26/2016	Not having an approved modeling protocol among the set of documents makes it difficult to assess modeling results. Having published modeling results, even interim results such as appear here, is most unconventional and contrary to concept of a modeling protocol. Several of them have a section “Model Selection”. Firstly, this topic should be addressed in the associated modeling protocol. Secondly, in all cases, AERMOD is indicated as the model of choice without any discussion of the potential for complex winds (paragraph 7.2.8 in App. W of 40 CFR. Part 51). There is no justification for why AERMOD was chosen as opposed to (say) a non-steadystate puff model. Once this is properly done, the protocol should be appropriately cited in appropriate places within the modeling report. Another issue is that, as stated, the modeling results reported here are preliminary. The implication/understanding is that “final” results, which will presumably supersede these, will be issued at a future date. This will necessitate another review, which is counterproductive. I have not confirmed that all tabulated values reported link with respective appendices (e.g., App. C) that document their development. The term “data” is plural. There is inconsistency throughout the main report and its appendices: in some cases it’s treaded as singular, in others, it (properly) treated as plural.	A modeling approach for all facilities, and preliminary modeling protocols for the Gas Treatment Plant (GTP) and Liquefaction Facility, were provided to agencies for review and comment. Additionally, several meetings with the Federal Energy Regulatory Commission (FERC) and interested agencies were held to discuss the modeling approach, protocols, and other details. Final modeling is consistent with the approach, protocols, and discussions. See Appendices D, E, and F.
BLM	9/26/2016	Put the report date on the cover page	Comment acknowledged.
BLM	9/26/2016	Fairly good spatial coverage. These monitoring stations operated by private entities and local, state, or federal agencies. Privately collected datasets are generally Prevention of Significant Deterioration (PSD) monitoring programs.	The text has been revised consistent with the comment.
BLM	9/26/2016	EPA, 2009a is an incorrect reference for the citation. Last 3 sentences of the 3rd paragraph: I don’t see this in the tables!. There are seven available datasets on the North Slope, which provide a good representation of air quality. Air quality data being collected at this station includes CO, NO2, SO2, O3, PM10, and PM2.5. The proposed location of the second station is identified in Figure 9.2.2-2 as the preconstruction station … This is NOT indicated in Fig. 9.2.2-2	There are multiple comments, and each is addressed sequentially and included in Section 9.2.2.2 and Appendix B. (1) The sentence has been revised to read "SPM data are not to be used for NAAQS compliance demonstrations without review and acceptance as required in 40 C.F.R. 58.20." with corrected citation. (2) The sentence is revised to state "Data collected at certain stations are above the level of the standards, which do not necessarily indicate exceedance of a standard." (3) The revised text has deleted "at North Slope oil and gas production facilities, as well as remote areas". (4) The data from the proposed location are not used in modeling compliance. The reference to use of data from the proposed location of the second station has

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			been removed, and the text is revised. The location is therefore not in Figure 9.2.2-2.
BLM	9/26/2016	The transient nature of fugitive emissions should be emphasized.	Section 9.2.3.1.1.3 is updated to state "Except for emissions from storage piles, fugitive emissions from construction activities are transient in nature and likely occur at any one location for short periods within a single day."
BLM	9/26/2016	caption: Total Annual Construction Emissions for the Liquefaction Facility and Marine Terminal	The caption has been revised.
BLM	9/26/2016	Combined PM10 emissions from all spreads peaks in Year 5.	This sentence is found in Section 9.2.3.3.1.1.
BLM	9/26/2016	1st full paragraph: as stated in general comments (above), the justification for use of AERMOD is not properly made. It should be properly made in the modeling protocol and then that document referenced here.	Justification for use of AERMOD is provided in Appendices D, E, and F.
BLM	9/26/2016	The statement above Table 9.2.5-2 is: "The model-predicted concentrations in Table 9.2.5-3 are below the respective increments." Yet in the table, 46.1 is not less than 30, and 15.6 is not less than 9.	To clarify the compliance demonstration, NAAQS/AAAQS compliance is presented in a separate table from increment compliance. See Tables 9.2.5-3 and 9.2.5-4.
BLM	9/26/2016	"For modeling annual average impacts, the maximum modeled one- hour average concentrations were converted to annual averages using the scaling factor of 0.1." I don't see the relationship in table 9.2.5-7. Also in that table, there is nothing to compare the values to, so it's difficult for readers to get the context.	The revised data are in Table 9.2.5-16. Revised modeling was completed without the SCREEN approach, and therefore the modeling approach uses virtual meteorological data and used AERMOD at each site. NAAQS/AAAQS values for comparison are provided at the bottom of Table 9.2.5-16.
BLM	9/26/2016	Table 9.2.5-9 is not referenced in the text.	The data are referenced and included as Table 9.2.5-20.
BLM	9/26/2016	Fugitive emissions of organic compounds,-would be emitted from piping components …	The comma is removed from the revised text in in Section 9.2.5.2.3.
BLM	9/26/2016	A Pad meteorological data is considered representative …	The text is revised to replace "is" with "are" in Section 9.2.5.2.3, paragraph 7.
BLM	9/26/2016	In Table 9.2.5-11, 57.3 is not less than 30.	To clarify the compliance demonstration, NAAQS/AAAQS compliance is presented in a separate table from increment compliance. See Tables 9.2.5-22 and 9.2.5-23.
BLM	9/26/2016	In Table 9.2.5-12, the model-predicted value for 1-hr NO_2 is very close to the standard.	Revised modeling shows that the one-hour nitrogen oxide (NO_2) maximum impact is 158 ug/m3, which is less than 85 percent of the standard. The new data are

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			provided in Table 9.2.5-24.
BLM	9/26/2016	The air quality station location is shown in Figure 9.2.2-4 of Resource Report No. 9.	Appendix B has been revised to refer to Figure 9.2.2-2 of Resource Report No. 9.
BLM	9/26/2016	No particular comments. The document seems to be adequate and references are appropriate.	Comment acknowledged.
BLM	9/26/2016	Is the wind rose pattern more a result of diurnal or seasonal changes?	No analysis has been carried out to determine the diurnal/seasonal wind pattern (Appendix D, Figure 5-1), and such data would not be directly relevant to assessing impacts.
BLM	9/26/2016	While model results indicate NAAQS and AAAQS compliance for all pollutants and averaging periods, the following conservative assumptions should be noted:	Comment acknowledged.
BLM	9/26/2016	Since Sagwon CS appears to be close to the GTP (report doesn't say what the distance is), shouldn't its emissions be combined with those from GTP for modeling? Since Rabideux Creek CS appears to be close to the Liquifaction Facility (report doesn't say what the distance is), shouldn't its emissions be combined with those from the Liquifaction Facility for modeling?	As shown in Resource Report No. 9, Table 9.2.3-2, Sagwon Compressor Station is at milepost (MP) 75.97 (approximately 122 kilometers from the GTP). Rabideux Creek Compressor Station is at MP 675.23 (approximately 208 kilometers from the LNG Plant). Given the Compressor Station/Heater Station emissions and these distances, the impacts are not significant. See Appendix D, Section 4.2, for Liquefaction Facility offsite source screening and Appendix E, Section 4.2, for GTP offsite source screening.
BLM	9/26/2016	"Tables 3-1 and 3-2 show the proposed background ambient air concentrations and the ambient air monitoring station locations and periods of record for each compressor station location, respectively."	Appendix E, Section 4.0, is corrected to read "Tables 7 and 8 show the proposed background ambient air concentrations and periods of record for each modeled pollutant at each compressor station. See Resource Report No. 9, Figure 9.2.2-1, for ambient air monitoring station locations."
BLM	9/26/2016	It's not clear whether screening (via AERSCREEN) or refined modeling (via AERMOD) were used. In Section 5.7, where OLM is discussed, it appears that refined modeling was used.	In the final report, AERMOD is for refined modeling. Text regarding AERSCREEN has been removed. See Appendix E.
BLM	9/26/2016	"but outside of the AERMOD screening mode" ? This is confusing. AERMOD run in a screening mode? AERSCREEN is the screening tool. This entire section must be rewritten to clarify what is going on.	Appendix E, Sections 5.1 and 5.2, are updated to clarify use of AERMOD.
BLM	9/26/2016	EPA defines ambient air as that portion of the atmosphere, external to buildings, to which the general public has access (40 CFR 50).	Appendix E, Section 5.4.1 is updated consistent with 40 C.F.R. 50.1(e).

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BLM	9/26/2016	RE: Scenarios 1-3, is it really reasonable to assume that only 2 of 3 turbines would operate concurrently? This is not discussed in the text	Sagwon is designed with a backup turbine to operate during equipment malfunction or maintenance.
BLM	9/26/2016	There is a reference to App. G for "Detailed classified post maps illustrating the location of the maximum modeled pollutant impacts with respect to the modeled emission units" Yet the label for this appendix in the ToC of the manual report says "Non-Jurisdictional Facilities Air Quality Report (to be filed with FERC application)". This is a disconnect.	The text is corrected to reference Appendix G of this Appendix E.
BLM	9/26/2016	I suggest merging Tables 7 & 8 since they present the same information.	The tables represent the same information, but for different NAAQS. They are generated separately for clarity.
BLM	9/26/2016	Applicable Increments are shown in Table 2-1.	The table has been renumbered as Table 2-2.
BLM	9/26/2016	Are the NO2 concentrations weighted by WS class? The discussion and explanation as to how the background NO2 concentrations are derived is poorly explained. Readers should not have to review the 3 cited EPA documents in order to understand the methodology used in this analysis for the GTP.	The background hourly NO_2 are sorted by wind speed category. Text is added in Appendix F to describe each of the references, and "Tiered approaches" including the Second Tier approach, under which backgrounds can vary by wind speed, direction, etc.
BLM	9/26/2016	Table 30-2 is not well documented or explained. It appears that a better caption for the table might be: 1-Hour NO2 Background Varying by Wind Speed For different concentration units, there are 2 series of values across WS classes. In Table 3-1, NO2 concentration values for volumetric and mass concentration are 32.8 and 61.7, resp. There is no explanation as to how the series of values in Table 3-2 yields the composite values reported in Table 3-1.	The text and table title in Appendix F are revised to clarify the data. The background one-hour NO_2 in Table 3-1 is deleted and text was inserted to reference Table 3-2.
BLM	9/26/2016	The USEPA-approved American Meteorological Society/EPA Regulatory Model (AERMOD) modeling system was used assess …	Appendix F text is corrected in Section 5.1.
BLM	9/26/2016	The processing of this data is provided …	The text is corrected as requested, and is now in Section 5.3.1.
BLM	9/26/2016	In Table 4-1, I suggest translating the values into percent of data capture, not data loss.	Appendix F, Table 5-1 is revised to provide data recovery.
BLM	9/26/2016	Is the wind rose pattern more a result of diurnal or seasonal changes?	No analysis has been carried out to determine the diurnal/seasonal wind pattern (Appendix D, Figure 5-1), and such data would not be directly relevant to assessing impacts.
BLM	9/26/2016	Following recommendations provided by USEPA's AERMOD modeling contractor (Brode 2005) any reported	Appendix F, Section 5.3.4 is updated accordingly.

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		values …	
BLM	9/26/2016	The grids were designed to accurately resolve the highest predicted pollutant impacts while at the same time minimizing model execution time. … the Building Profile Input Program program also calculates the Good Engineering Practice (GEP) stack height.	The grammatical correction is made, now in the fourth paragraph of Section 5.4 and in Section 5.6.
BLM	9/26/2016	The last of Table 4-5 bleeds onto p. 29 only to present footnote d. In the final edition, I suggest reducing the bottom margin so that this footnote appears on the previous page (w/ the other three notes).	Appendix F "Modeled Source Physical Parameters" is now Table 4-4 and is reformatted accordingly.
BLM	9/26/2016	In Table 4-6, the same emission rates are listed for different averaging times. For example, in Row 1a, for SO2, the same rate (1.245 g/s) appears for Annual and 1-hours. This same pattern appears many other places in the table with no explanation in the text for why this should be so. Also, how can a column be labeled both “3-hour” and “24-hour” ?	The data were intended to reflect the fact that the same instantaneous emission rate (g/sec) applies to all averaging periods for the model runs (1-hour, 3-hour, 24-hour, annual). In the revised modeling, now summarized in Table 4-3, the emission rates for the separate standards are revised to reflect different hourly and annual emission rates for the model input.
BLM	9/26/2016	The PVMRM2 option simulates the NOx to NO2 conversion by calculating a ratio of the amount of O3 available to the amount of NOx emitted into a plume at the downwind distance of a receptor from a source. To implement the PVMRM2 option, concurrent hourly ozone data is also required.	The text of Appendix F, Section 5.7, is updated accordingly.
BLM	9/26/2016	While model results indicate compliance with all applicable standards and thresholds, the following conservative assumptions should be noted:	The text of Appendix F, Section 7.1.2, is updated accordingly.
BLM	9/26/2016	In the list of acronyms, add “SOA” (= Secondary Organic Aerosol).	The text of Appendix F, Section 11.0, is updated accordingly.
BLM	9/26/2016	The lack of background sound scape data is evident throughout the proposed area of the project. Areas away from development nodes (per the BLM Utility Corridor Plan 1991) are of greatest concern for impacts from gas line project created sound. At present, the location of the compressor station at Tea Lake would in all likelihood create a constant sound scape impact on users in the Galbraith Lake area for many miles around.	Comment acknowledged. See Sections 9.3.1.1 and 9.3.1.3 for noise analysis approach for comparison of baseline noise and predicted noise level from Project facilities per FERC requirements.
BLM	9/26/2016	There are three permanent compressor station sites proposed that will affect BLM-managed lands near Galbraith Lake, Coldfoot, and the Ray River sites. The sites include clearing vegetation for 800-feet by 1200-feet, a 700-foot by 1000-foot gravel pad, multiple building (heights unknown), a 40-foot high communications tower, lights, fence, helipad, and access road. The current proposed sites are within 1000-feet of the highway and are expected to vent water vapor and emit a ”humming sound” at approximately 55 dB during normal operations.	Comment acknowledged. See Section 9.3.1.3 and Appendix Q. Noise projections comply with the FERC criteria of a Day-Night Level (Ldn) of 55 dBA at the existing identified Noise-Sensitive Areas (NSAs). This is equivalent to a measured sound level of 48.6 dBA.
U.S. Environmental	9/30/2016	Please be advised that on August 1, 2016, CEQ issued the Final Guidance for Federal Departments and Agencies on	Final Council of Environmental Quality (CEQ) greenhouse gas

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Protection Agency (EPA)		Consideration of Greenhouse Gas Emissions and the Effects of Climate Change in NEPA Reviews. We expect that FERC will apply the guidance as the NEPA process for this project moves forward. The guidance document can be found here: https://www.whitehouse.gov/sites/whitehouse.gov/files/documents/nepa final ghg guidance.pdf. Greenhouse gas emissions include carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, nitrogen trifluoride, and sulfur hexafluoride, and should be expressed in metric tons of CO2-equivalent (mt C02-e) per year.	(GHG) guidance has been removed from the White House website, so the status of the guidance is not clear. Nevertheless, Resource Report No. 9 provides estimates of direct GHG emissions. See Section 9.2.9.
EPA	9/30/2016	Consistent with the CEQ Guidance, the EPA recommends that the Reports estimate the direct and indirect GHG emissions caused by the proposal and its alternatives. We recommend that the GHG emissions quantification include an inventory of the air emissions units that were used to estimate the total GHG emissions from construction and operations. Examples of tools for estimating and quantifying GHG emissions can be found on CEQ' s website. Direct GHG emissions that we reconunend estimating in the Reports include: GHG emissions from mobile and stationary sources during all phases of project (e.g. construction, operations, maintenance, restoration); GHG emissions from project construction, operations and maintenance, and restoration. Indirect GHG emissions that we recommend estimating in the Repo1is include: Natmal gas end use, GHG emissions from "Connected Actions," such as Kenai Spur Highway Relocation Project, and the PBU and PTU expansion projects, and Net GHG emissions and carbon stock changes of biogenic resources, such as wetlands, vegetation, permafrost, etc. Estimates of GHG emissions should be provided from project construction activities disturbing these biogenic resources and <u>resulting in the loss of stored carbon/GHG.</u>	Resource Report No. 9 was developed considering the CEQ GHG guidance. Final CEQ GHG guidance has been removed from the White House website, so the status of the guidance is not clear. Nevertheless, Resource Report No. 9 provides estimates of direct GHG emissions, including Non-Jurisdictional Facilities. See Section 9.2.9.
EPA	9/30/2016	Estimated GHG emissions levels can serve as a basis of comparison for climate change impacts among alternatives and appropriate mitigation measures. We recommend that the Reports identify reasonable GHG emission reduction targets or goals for some or all of the project components and development phases over the lifetime of the project. As the project develops, periodic reporting could demonstrate progress toward reaching these targets.	One of the Project design goals is to reduce GHG and other environmental impacts to the extent feasible. Thus, mitigation is already built into the Project.
EPA	9/30/2016	The Reports do not include consideration of future climate scenarios, and how they may impact the proposal, alternatives, and impacts. Consistent with the CEQ guidance, we recommend that the Reports describe potential changes to the affected environment that may result from climate change. Including future climate scenarios, such as those provided by the USGCRP's National Climate Assessment, in the Reports would help decision makers and the public consider whether the proposal includes appropriate resilience and preparedness measures for climate change. We recommend that the Reports include potential modifications, or descriptions of already incorporated modifications, to the design of the project to improve its resilience to the future climate scenarios. For example, the Reports indicate that	Resource Report No. 1, Sections 1.3 and 1.3.2.1.1 include consideration of future climate scenarios, including geothermal/permafrost issues, marine issues, and wildfire issues.

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		permafrost soils would be impacted. Permafrost stability or anticipated changes to existing permafrost conditions can affect settlement and ground stability characteristics that would in turn significantly influence design and construction of the project components, such as facilities and infrastructure.	
EPA	9/30/2016	We recommend that the Reports describe mitigation measures to avoid, reduce, or mitigate GHG emissions that are reasonable and consisfent with achieving the purpose and need for the proposed Project. Such mitigation measures could include enhanced energy effi ciency, lower GHG-emitting technology, carbon capture and sequestration, capturing or beneficially using GHG emissions, such as methane: a) In July 2015, the EPA launched the Natural Gas STAR Methane Challenge. This is a new voluntary program for reducing methane emissions. Methane, the primary component of natural gas, is a potent greenhouse gas with a global warming impact of 25 times that of carbon dioxide. Companies who sign up for the program agree to make commitments for methane emission reductions, with accountability and transparency in progress in achieving those commitments, and with the potential for public recognition for leadership in reducing GHG emissions in the United States. It may be appropriate to include consideration of the applicant enrolling in or employing measures described on the Gas STAR website (https://www.epa.gov/natural-gas-starprogram) in the Reports.	GHG emissions mitigation measures are described in Section 9.2.9.3 of Resource Report No. 9.
EPA	9/30/2016	b) Use of natural gas rather than diesel fuel would reduce GHG emissions. Natural gas and/or LNG powered heavy construction equipment, vehicles, power generators, dredges, barges, LNG carriers, etc. should be evaluated as a reasonable alternative to diesel power.	GHG emissions mitigation measures are described in Section 9.2.9.3 of Resource Report No. 9.
EPA	9/30/2016	c) The reclamation and revegetation of certain disturbed areas could reduce the overall project climate change impacts and result in the conversion of a carbon emission source to a carbon storage or sink. We recommend the Reports evaluate mitigating climate change impacts through reclamation and revegetation of disturbed project areas, including wetland enhancement or restoration, and potential conversion fi:om a carbon source to a carbon sink and quantify the potential carbon sequestration from those actions.	The Applicant has considered the FERC Guidance Manual for Environmental Report Preparation and relevant guidance in the development of Resource Reports.
EPA	9/30/2016	d) We recommend that the Rep01 is describe in detail the proposed monitoring of GHG emissions and mitigation measures to ensure their effectiveness, including development of a GHG mitigation and monitoring plan. Adaptive management should be considered to evaluate whether there needs to be changes to the mitigation and monitoring plan.	The Applicant has considered the FERC Guidance Manual for Environmental Report Preparation and relevant guidance in the development of Resource Reports.
EPA	9/30/2016	We recommend including reference to the meteorology tables (9.2.1-3 to 9.2.1-7) for the climate zones of each facility.	See Sections 9.2.1.2 and 9.2.1.4 that include references to meteorological maps and tables

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			relevant to each facility.
EPA	9/30/2016	A meteorological monitoring station has been installed to supplement existing weather information in the vicinity of the Nikiski Liquefaction Facility. It is noted the Project representatives consulted and received approval from ADEC. We recommend providing footnotes or references outlining the correspondence related to these actions, including the quality assurance project plan (QAPP), if a QAPP was developed. Table 9.1.3-2 did provide reference to consultations regarding meteorological monitoring at the Deadhorse Gas Treatment Plant site, but not the Nikiski Liquefaction Facility. If the intention is to use the two monitoring station datasets for air quality modeling related to this or future projects, we recommend that the station be sited and operated in accordance with EPA Guidance provided in EPA-454/R-99-005. A Quality Assurance Project Plan (QAPP) should be developed and approved by ADEC and reviewed by the EPA. If a QAPP was developed in this case, please provide a reference to this document and related correspondence. Appendix B notes the Nikiski station is collecting air quality data and therefore assumed to be operating under a QAPP. We recommend including a reference to this document.	Section 9.2.1.3 includes a reference to Alaska Department of Environmental Conservation (ADEC) approval of monitoring methodology and the Quality Assurance Project Plan (QAPP).
EPA	9/30/2016	We recommend that this section be expanded to include wind-roses for a) the Nikiski LNG facility area, b) the Deadhorse GTP facility, and at least two other locations along the pipeline route. Wind-roses provide an effective method to illustrate wind climate at these locations.	Wind roses for the Nikiski LNG Plant, compressor stations along the pipeline route, and the GTP on the North Slope are provided in Appendices D, E, and F, respectively.
EPA	9/30/2016	We recommend removing the phrase "where water vapor becomes visible" To note, water vapor does not become "visible" at the dew point temperature (it is an invisible gas), but condenses into liquid form onto suspended particles, to form fog.	Section 9.2.1.4.5 has been revised per recommendation.
EPA	9/30/2016	We recommend including a reference to the QAPP for the ambient air quality station at the LNG site and the second site (the background ambient air monitoring station) if the QAPP is finalized.	A reference to the approved QAPP has been added to Section 9.2.2.2.
EPA	9/30/2016	A-PAD data were selected as representative of the North Slope site background for all criteria pollutants except PM (no PM monitor at A-PAD). CCP PM data selected as representative. A-PAD and CCP are the nearest monitoring sites to the Project GTP facility. CCP NO2 background values are much greater than A-PAD NO2 background values. We recommend some discussion be provided to justify why A-PAD data was selected as the more representative site for North Slope background values at the GTP site.	Detailed ambient air quality data summaries are provided in Appendix B. A Pad was chosen as the background site for GTP NO_2 impact analysis because the Central Compression Plant (CCP) and Central Gas Facility are modeled as separate sources in the cumulative analysis. See Appendix F, Sections 4.2.1 and 7.3.2.
EPA	9/30/2016	Compressor Stations. Figure 9.2.2-7 depicts the location of approximately 11 compressor stations along the mainline pipeline and the location of PSD Class I and Sensitive Class II areas. We note that the Minto Compressor Station is in a remote location and may need additional new roads for access. We recommend that the Minto Compressor Station be collocated along the Elliott Highway near	Comment acknowledged. The current proposal is to install eight compressor stations at the locations depicted in Figure 9.2.2-7.

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		Livengood to avoid the need for additional new access roads.	
EPA	9/30/2016	Combustion emissions should include any sources associated with the transportation of cargo, fuel, personnel, etc. during construction of the Project. Transportation related emission sources should include marine barges/vessels, airplanes, railroad, passenger vehicle/trucks, etc. We recommend that the transportation related emissions be included in the emission estimates for the construction of the LNG Facility and Marine Terminal, Compressor and Heater Stations and Mainline Pipeline Spreads, PBTL and PBU Transmissions Line, and the GTP. We recommend including an inventory list of the number of air emissions units required for each facility used for project construction.	Construction emissions, including from combustion sources, are included in Appendix C.
EPA	9/30/2016	Table 9.2.3-2. We recommend that estimates of the GHG emissions (metric tonnes of CO2-e/year) for the Compressor and Heater Stations be included as part of the mainline pipeline construction.	GHG emission estimates for construction and operation of compressor and heater stations are included in Tables 9.2.3-3 and 9.2.5-15.
EPA	9/30/2016	We recommend rewording the description for Minor Permits from "Owner or operator can establish permit limits to avoid compliance with specific regulations" to "Owner or operator can establish enforceable emission limits in a permit to avoid applicability of specific regulations."	Table 9.2.4-2 for 18 Alaska Administrative Code (AAC) 50.508 is reworded to be consistent with the comment.
EPA	9/30/2016	Combustion emissions should include any sources associated with the transportation of cargo, fuel, personnel, etc. during project operations. Transportation related emission sources should include marine barges/vessels, airplanes, railroad, passenger vehicle/trucks, etc. We recommend that transportation related emissions be included in the emission estimates for operation of the LNG Facility and Marine Terminal, LNG Carriers, Compressor and Heater Stations and Mainline Pipeline Spreads, PBTL and PBU Transmissions Line, and the GTP. We recommend including an inventory list of the number of air emissions units required for each facility used for project operations.	Emissions from operations, including from combustion sources, are included in Appendices D (Liquefaction Facility Air Quality Modeling Report), E (Main Pipeline Compressor Stations Air Quality Modeling Report), F (Gas Treatment Plant Air Quality Modeling Report), and G (Non-Jurisdictional Facilities Air Quality Report). Fine-grain details, such as number of air emissions units used during construction, can be found in the Appendices to these Appendices cited above, and available associated workbooks.
EPA	9/30/2016	We recommend that the project evaluate the feasibility of using natural gas powered LNG carriers to reduce diesel emissions. Our understanding is that the existing Kenai LNG facility in Nikiski has previously utilized natural gas powered LNG carriers.	Because the Applicant proposes to transport gas and transfer custody to LNG carriers (LNGCs) at the Marine Terminal, the Applicant would not have control over the type of propulsion systems to be used for LNGCs.
EPA	9/30/2016	We recommend including a reference for the draft modeling protocol. We recommend including a reference to isopleth figures that demonstrate the spatial distribution of maximum pollutant concentrations for each pollutant in the Appendix D modeling report. We recommend including isopleth figures in the Appendix D modeling report for the LNG facility. We recommend including the results of the	A modeling approach for all facilities, and preliminary modeling protocols for the GTP and Liquefaction Facility, were provided to agencies for review and comment. Additionally, several meetings with FERC and

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		Class I air quality and AQRV analysis as well as the secondary PM2.5 modeling analysis. We recommend including this analysis in the Appendix D modeling report also. The methodology for these modeling analyses were outlined in the LNG facility modeling protocol. Initial AQRV analysis was conducted and is included in version 2T of RR9 and associated appendices. Finalization of AQRV analysis should proceed in consultation with FERC and the Federal Land Managers (FLMs). We recommend including the qualitative ozone assessment discussed in the LNG facility modeling protocol.	interested agencies were held to discuss the modeling approach, protocols, and other details. Final modeling is consistent the approach, protocols, and discussions. See Appendices D, E, and F. Isopleths are not necessary to determine compliance, but they are included where available.
EPA	9/30/2016	We recommend including a reference to the compressor station modeling protocol.	See Appendix E related to modeling protocols.
EPA	9/30/2016	We recommend including a reference for the draft modeling protocol for the GTP facility. We recommend including a reference to isopleth figures that demonstrate the spatial distribution of maximum pollutant concentrations for each pollutant in the Appendix F modeling report. We recommend including isopleth figures in the Appendix F modeling report for the GTP facility. We recommend including the results of the Class I air quality and AQRV analysis as well as the secondary PM2.5 modeling analysis. We also recommend including the results of these analyses in the Appendix F modeling report. The methodology for these modeling analyses were outlined in the GTP facility modeling protocol. Initial AQRV analysis was conducted and is included in version 2T of RR9 and associated appendices. Finalization of AQRV analysis should proceed in consultation with FERC and the Federal Land Managers (FLMs) Qualitative analysis of ozone and PM2.5 is provided in RR9 draft 2T section 9.2.3.1.7, section 9.2.5.2.3 and associated appendices.We recommend including the qualitative ozone assessment discussed in the GTP facility modeling protocol. Such an analysis is included in section 9.2.5.2.3 of Draft 2T RR9.	See Appendix F related to modeling protocols.
EPA	9/30/2016	We encourage AK LNG and FERC to prepare a General Conformity Determination to address the Fairbanks non-attainment SIPs for both the construction and operations of the project as part of the public disclosure requirement under NEPA. During construction, pipe and cargo would be delivered to Fairbanks via the Alaska Rail Road and/or trucks along the major highways. Between Fairbanks and the North Slope, trucks would be transporting cargo and supplies via the existing highway system. Emissions from the railroad and trucks may represent a significant contribution of particulate matter.	See Section 9.2.6.10 and Appendix M.
EPA	9/30/2016	On August 1, 2016, Council on Environmental Quality issued final guidance on Consideration of Greenhouse Gas Emissions and the Effects of Climate Change in National Environmental Policy Act Reviews (Guidance). We expect that FERC will apply the guidance as the NEPA process for this project moves forward: https://www.whitehouse.gov/sites/whitehouse.gov/files/documents/nepa_final_ghg_guidance.pdf .Consistent with the CEQ Guidance, EPA recommends that Reports estimate the direct and indirect GHG emissions caused by the proposal <u>and its alternatives</u>. Examples of tools for	The Applicant has considered the *FERC Guidance Manual for Environmental Report Preparation* and relevant guidance in the development of Resource Reports. Resource Report No. 1, Sections 1.3 and 1.3.2.1.1) include consideration of future climate scenarios, including geothermal/permafrost issues, marine issues, and

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		estimating and quantifying GHG emissions can be found on CEQ's website. Direct GHG emissions that we recommend estimating in the Reports include: GHG emissions from mobile and stationary sources during all phases of project (e.g., construction, operations, maintenance, restoration); GHG emissions from project construction, operations and maintenance, and restoration, Indirect GHG emissions that we recommend estimating in the Reports include: Natural gas end use; GHG emissions from "Connected Actions," such as the Kenai Spur Highway Relocation Project, and the PBU and PTU expansion projects; Net GHG emissions and carbon stock changes of biogenic resources, such as wetlands, vegetation, permafrost, etc. Estimates of GHG emissions should be provided from project construction activities disturbing these biogenic resources and resulting in the loss of stored carbon/GHG. GHG Emissions Targets - We recommend that the Reports identify reasonable GHG emission reduction targets or goals for some or all of the project components and development phases over the lifetime of the project. As the project develops, periodic reporting could demonstrate progress toward reaching these targets. The Reports do not include consideration of future climate scenarios, and how they may impact the proposal, alternatives, and impacts. Consistent with the CEQ guidance, we recommend that the Reports describe potential changes to the affected environment that may result from climate change. Including future climate scenarios, such as those provided by the USGCRP's National Climate Assessment, in the Reports would help decision makers and the public consider whether the proposal includes appropriate resilience and preparedness measures for climate change. We recommend that the Reports include potential modifications, or descriptions of already incorporated modifications, to the design of the project to improve its resilience to the future climate scenarios. For example, the Reports indicate that permafrost soils would be impacted. Permafrost stability or anticipated changes to existing permafrost conditions can affect settlement and ground stability characteristics that would in turn significantly influence design and construction of the project components, such as facilities and infrastructure. Including future climate scenarios can also provide context for the impacts of the proposal, and help inform whether the impacts may be exacerbated by climate change. We recommend FERC consider how the impacts of the proposal, including all alternatives, may be affected by future climate scenarios. If impacts of the proposal may be exacerbated by climate change,	wildfire issues. In regard to permafrost thaw, the chilling of the pipeline would help to mitigate future climate change and permafrost thaw; some thaw settlement is likely to occur, but the pipeline would be monitored, inspected, and maintained through in-line inspection and through a comprehensive field monitoring program over the life of the Project to ensure safe operation.
EPA	9/30/2016	We recommend that the GHG emissions quantification include an inventory of the air emissions units that were used to estimate the total GHG emissions from construction and operations.	See Appendices C, D, E, and F.
EPA	9/30/2016	GHG Mitigation Measures - We recommend that the Reports describe mitigation measures to avoid, reduce, or mitigate GHG emissions that are reasonable and consistent with achieving the purpose and need for the proposed Project. Such mitigation measures could include	The comment is noted. GHG emissions mitigation measures are described in Section 9.2.9.3 of Resource Report No. 9.

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		enhanced energy efficiency, lower GHG-emitting technology, carbon capture and sequestration, capturing or beneficially using GHG emissions, such as methane:	
EPA	9/30/2016	• In July 2015, the EPA launched the Natural Gas STAR Methane Challenge. This is a new voluntary program for reducing methane emissions. Methane, the primary component of natural gas, is a potent greenhouse gas with a global warming impact of 25 times that of carbon dioxide. Companies who sign up for the program agree to make commitments for methane emission reductions, with accountability and transparency in progress in achieving those commitments, and with the potential for public recognition for leadership in reducing GHG emissions in the United States. It may be appropriate to include consideration of the applicant enrolling in or employing measures described on the Gas STAR website (https://www.epa.gov/natural-gas-star-program) in the Reports.	Comment acknowledged. The Applicant would monitor progress of this program for applicability to this Project.
EPA	9/30/2016	• Use of natural gas rather than diesel fuel would reduce GHG emissions. Natural gas and/or LNG powered heavy construction equipment, vehicles, power generators, dredges, barges, LNG carriers, etc. should be evaluated as a reasonable alternative to diesel power.	GHG emissions mitigation measures are described in Section 9.2.9.3 of Resource Report No. 9.
EPA	9/30/2016	• The reclamation and revegetation of certain disturbed areas could reduce the overall project climate change impacts and result in the conversion of a carbon emission source to a carbon storage or sink. We recommend the Reports evaluate mitigating climate change impacts through reclamation and revegetation of disturbed project areas, including wetland enhancement or restoration, and potential conversion from a carbon source to a carbon sink and quantify the potential carbon sequestration from those actions.	The Applicant has considered the *FERC Guidance Manual for Environmental Report Preparation* and relevant guidance in the development of Resource Reports.
EPA	9/30/2016	• We recommend that the Reports describe in detail the proposed monitoring of GHG emissions and mitigation measures to ensure their effectiveness, including development of a GHG mitigation and monitoring plan. Adaptive management should be considered to evaluate whether there needs to be changes to the mitigation and monitoring plan.	The Applicant has considered the *FERC Guidance Manual for Environmental Report Preparation* and relevant guidance in the development of Resource Reports.
EPA	9/30/2016	Noise-Sensitive Areas (NSAs). The Reports should include additional noise receptors, such as cemeteries (during services); local, state, and national parks and preserves; federal wildlife refuges and state game refuges; designated critical habitat areas under ESA; etc.	See Sections 9.3.1.1 and 9.3.5 for the criteria used in selection and analyzing NSAs.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. a. Qualitative discussion regarding the formation of secondary air pollutants (e.g., ozone, sulfates, and nitrates).	Ozone and secondary particulate matter formation are discussed in Section 9.2.5.1.7 for the Liquefaction Facility and Section 9.2.5.2.3 for the GTP. For further details, see Appendices D and F.
FERC	10/26/2016	The following commitments were made by AKLNG in	See information included in

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		resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. b. Chemical Accident Prevention Provisions applicability, specifically addressing the need for a risk management plan. (page 9-xii)	Section 9.2.6.8, and Appendix H.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. c. Permit applications and agency determinations. (page 9-xiii)	Sufficient data have been provided in Resource Report No. 9 to support the analysis of air quality impacts in the Environmental Impact Statement (EIS). The Applicant would be required to obtain air permits from ADEC prior to construction. A Prevention of Significant Deterioration (PSD) permit application would be provided to ADEC and copied to FERC during the development of the Draft EIS (DEIS).
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. d. Monitoring results from the meteorological station installed on January 1, 2015 for the Liquefaction Facility. (section 9.2.1.3, page 9-11)	2015 monitoring results have been submitted to ADEC and have been approved. References to the 2015 monitoring results and approval have been included in Resource Report No. 9.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. e. Impact analysis for the Class I and Sensitive Class II Areas that have been identified to date. (section 9.2.2.3.4, page 9-31 and section 9.2.6.11, page 9-73)	Impacts at Class I and Sensitive Class II areas are included in Sections 9.2.5.1.5 and 9.2.1.6 for the Liquefaction Facility, in Section 9.2.5.2.1.3 for compressor stations, and in Section 9.2.5.2.3 for the GTP. For further details, see Appendices D, E, and F.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. f. Updated construction emission details as outlined in section 9.2.3. (section 9.2.3, page 9-34).	Section 9.2.3 provides updated construction emissions summaries. For further details, see Appendix C.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the	Open burning activity will depend on the construction contractors selected and cannot be provided at this time.

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		requesting agency as applicable. g. Open burning activity levels required for an estimate of combustion emissions of open burning of brush cleared from construction right-of-way. (section 9.2.3.1.1.1, page 9-35)	
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. h. Non-combustion construction emissions, such as vented vapors from tanks. (section 9.2.3.1.1.2, page 9-35)	Non-combustion construction emissions are provided in Appendix C.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. i. Fugitive dust and particulate emissions from construction activities. (section 9.2.3.1.1.3, page 9-35)	Fugitive dust and particulate matter emissions from construction activities are provided in Appendix C.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. j. Liquefaction Facility vendor data and emissions estimates for equipment and operations based upon final design. In addition, provide the following operational emissions for the LNG Plant: i. startup and shutdown scenarios (including flare operations); ii. on-road vehicles; and iii. off-road support equipment. (section 9.2.5.1.1, page 9-47)	Vendors have not been selected and therefore vendor data are not available. However, vendor data are not necessary to estimate maximum project impacts. Maximum impacts are modeled and provided for each Project component. Emissions from startup flare operations, on-road vehicles, and off-road support equipment are estimated for the Liquefaction Facility and GTP and included in Appendices D and F. Emissions from routine startup/shutdown during long-term operations are a detail that is not yet addressed, but are expected to fit within the emissions envelope of the facilities. These data would be included in the final air permit applications, and provided at that time.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. k. Dispersion modeling results for the Jack River Heating Station. (section 9.2.5.2.1.2, page 9-56)	The Jack River Heater Station is no longer part of the Project design.
FERC	10/26/2016	The following commitments were made by AKLNG in	Estimates of fugitive GHG

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		resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. l. Estimated annual fugitive greenhouse gas (GHG) emissions for the Mainline, PTTL, and the Prudhoe Bay Gas Transmission Line pipelines. (section 9.2.5.2.1.3, table 9.2.5-9, pages 9-56, 9-57)	(methane) emissions from pipelines are provided in Table 9.2.5-20.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. m. Gas Treatment Plant facility vendor data and emissions estimates for equipment and operations based upon final design. In addition, provide the following operational emissions for the GTP: i. startup and shutdown scenarios (including flare operations); ii. on-road vehicles, and iii. off-road support equipment. (section 9.2.5.2.3, page 9-59)	Vendors have not been selected and therefore vendor data are not available. However, vendor data are not necessary to estimate maximum project impacts. Maximum impacts are modeled and provided for each Project component. Emissions from startup flare operations, on-road vehicles, and off-road support equipment are estimated for the Liquefaction Facility and GTP and included in Appendices D and F. Emissions from routine startup/shutdown during long-term operations are a detail that is not yet addressed, but are expected to fit within the emissions envelope of the facilities. These data would be included in the final air permit applications, and provided at that time.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. n. determination whether minor New Source Review (NSR) permitting would be required for any construction sources. (sec 9.2.6.4, pg 9-70)	At this time, no New Source Review (NSR) permits have been identified for construction sources. A final determination would be made after construction contractors are selected.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. o. Final analysis of New Source Performance Standards, codified in 40 CFR, Part 60, based on final facility design of the planned Project facilities. (section 9.2.6.6, table 9.2.6-5, page 9-71)	Preliminary New Source Performance Standards (NSPS) (40 Code of Federal Regulations [C.F.R.] 60) determinations are provided in Section 9.2.6.6 and Appendix H. Final determinations would be made after construction contractors are selected.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in	Preliminary NESHAPS (40 C.F.R. 61 and 63) determinations are

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		response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. p. Analysis of the applicability of National Emission Standards for Hazardous Air Pollutants, codified in 40 CFR, Part 61, based on final facility design. (section 9.2.6.7, pages 9-71 and 9-72; table 9.2.6-6, page 9-72)	provided in Section 9.2.6.7 and Appendix H. Final determinations would be made after construction contractors are selected.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. q. General Conformity analysis for areas the Project would affect, including emissions from mobile sources and where Project activities occur in the Fairbanks particulate matter less than 2.5 microns in aerodynamic diameter (PM2.5) non-attainment area and applicable maintenance areas (section 9.2.6.9, page 9-73)	See Section 9.2.6.10 and Appendix M.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. r. Detailed Project plans describing mitigation measures that meet or exceed applicable regulations and standards, including the: i. Construction Emissions Control Plan (appendix I); ii. Fugitive Dust Control Plan (appendix J); and iii. Open Burning Plan (appendix K). (section 9.2.7, page 9-74)	Mitigation measures for construction, fugitive dust, and open burning would be developed in conjunction with contractor selection. These plans are outlined at this time to show the regulators what information would be provided once contractors are selected and construction planning completed.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. s. Operations emissions control plan (appendix L), including a description of emission control devices. (section 9.2.8, page 9-74)	Emission control devices would be determined as part of the Alaska Department of ADEC air permit Best Available Control Technology (BACT) process, and would be made available when permits are completed.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. t. Estimates of both construction and operational GHG emissions from jurisdictional and non-jurisdictional connected actions, including those identified in section 1.3.9 of Resource Report 1. (section 9.2.9.1.1.1, pages 9-62, 9-75, 9-76).	Estimates of emissions of GHGs from construction and operation of jurisdictional and non-jurisdictional facilities are provided in Section 9.2.9.1.
FERC	10/26/2016	The following commitments were made by AKLNG in	Emissions and impacts from

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		resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. u. Associated operations accommodations camps (including dormitory emergency generator, communication tower generator, and three firewater pumps) in the GTP modeling analysis. (appendix F, section 4.7.1, page 25, and footnotes “d” and “e” of table 4-3)	operations camps are included in the GTP modeling analysis. See Appendix F.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. v. Modeling analysis that includes cumulative impacts from other sources. The exception is the planned Galbraith Lake compressor station located near the Alyeska Pipeline Service Company, Trans Alaska Pipeline System Pump Station 4. The next version of the modeling report for the compressor stations should include a modeling analysis for the Galbraith Lake station that would include the potential impacts from Pump Station 4 (appendix E, section 5.8, page 16)	Emissions and cumulative impacts from Pump Station 4 are included in the modeling results for Galbraith Compressor Station. See Appendix E.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. w. Baseline ambient sound survey for the planned Jack River Heater Station and Honolulu Creek Compressor Station and estimated noise impacts from facility operation at nearby noise sensitive areas (NSA), including, if necessary, planned mitigation measures to ensure that the noise attributable to the facilities would not exceed a day-night noise level of 55 A-weighted decibels (dBA) at any nearby NSA. (section 9.3.1.3.2, page 9-84)	The Jack River Heater Station is no longer part of pipeline design and the Honolulu Creek Compressor Station has moved such that the nearest NSA is greater than 1 mile away. With these changes, baseline survey and noise impact assessments are no longer relevant.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. x. Baseline ambient sound survey for the planned metering stations and mainline valves and estimated noise impacts from facility operation at nearby NSA, including, if necessary, planned	See Section 9.3.1.3.2.3 for noise analysis completed for metering stations and mainline valves. The baseline noise survey conducted for the for the Liquefaction Facility discussed in Section 9.3.1.2 included the associate meter station and Mainline block valve (MLBV) 30 given it is located at the facility.

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		mitigation measures to ensure that the noise attributable to the facilities would not exceed a day-night noise level of 55 dBA at any nearby NSA. (section 9.3.1.3.2.3, page 9-88)	The baseline surveys conducted for Galbraith Lake, Coldfoot, and Healy compressor stations included the associated MLBVs, located at each station. No baseline surveys were conducted at the remaining MLBVs and GTP meter stations. The requested information would be provided during DEIS development.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. y. Blasting plans for construction of the Project, including an analysis of noise and vibration impacts on affected NSAs. (section 9.3.2.1, page 9-88)	The Applicant will address this comment after the Final EIS (FEIS) but prior to construction start.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. z. Predicted sound levels for the Yukon River crossing as identified in table 9.3.2-2. (section 9.3.2-2, page 9-90)	See Section 9.3.2.2.1.1 and Appendix U.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the applicationas indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. aa. Construction noise abatement plan including NSAs in the Project vicinity, predicted construction noise levels, and site-specific mitigation measures to be used to minimize construction noise impacts. (section 9.3.6, page 9-98)	See Appendix T Draft Template Construction Noise Abatement Plan. The Applicant will fully address this comment after the FEIS but prior to construction start.
FERC	10/26/2016	2. Construction activities for the Project have the following planned schedule for completion: LNG Plant: 8 years; Marine terminal: 2 years beginning Project year two; Mainline pipeline: 6 years; and the GTP: 9 years. These timelines do not represent short-term temporary Project construction emissions. Include modeling of these long-term construction impacts and confirmation of ADEC air quality permit exemptions for these construction activity emissions.(section 9.2.3, pages 9-34 to 9-37)	Impacts from construction emissions have not been included. Analysis of construction impacts consistent with ADEC requirements will be included in the air permit application.
FERC	10/26/2016	3. Include details on the permitting required for the construction camps. (section 9.2.3, pages 9-34 to 9-35)	See response to comment #89, Resource Report No. 9.
FERC	10/26/2016	4. Include a final list of both federal and state air quality regulations that would apply to the planned Project	A final list of both federal and state air quality regulations

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		construction activities. (section 9.2.4, tables 9.2.4-1 and 9.2.4-2, pages 9-41 to 9-45)	applicable to the Project is included in Section 9.2.4 and Appendix H (Project NSPS, NESHAPs, and RMP Applicability Analysis).
FERC	10/26/2016	5. Include the horsepower of each compressor. (section 9.2.5.1.1, page 9-53).	Heat input data (MMBtu/hour) as a surrogate for horsepower are provided in Appendix E.
FERC	10/26/2016	6. Include a final list of both federal and state air quality regulations that would apply to the planned Project operational activities for each applicable equipment type (e.g., gas turbines, emergency back-up engines, flares, fugitive emissions, etc.) (section 9.2.6.1, table 9.2.6-1, table 9.2.6-2, pages 9-63 to 9-67)	An updated list is provided in Section 9.2.6.
FERC	10/26/2016	7. Based on the information provided in section 9.2.5, both the LNG Plant and the GTP would be major sources subject to Prevention of Significant Deterioration review. Identify emission control technology or mitigation measures for criteria pollutants and GHGs, including any best available control technologies that would be implemented at these facilities to reduce emissions, along with details about control efficiency. (section 9.2.6.2, pages 9-67 to 9-69)	Emission control devices would be determined as part of the Alaska Department of ADEC air permit Best Available Control Technology (BACT) process, and would be made available when permits are completed.
FERC	10/26/2016	8. Update the Project General Conformity applicability analysis to include all direct and indirect Project emissions subject to General Conformity review. Direct emissions should include all direct construction emissions located in non- attainment or maintenance areas (vehicle traffic emissions, including worker commuting and equipment delivery; on- and off-road construction equipment emissions; fugitive dust and open burning emissions; and all operational emissions not permitted under a major or minor source NSR or Non-attainment NSR Permit), and all indirect emissions in non-attainment or maintenance areas, including additional passenger vehicle, truck, rail, barge, and air traffic emissions above existing load levels as identified in the current State Implementation Plan, induced by Project construction, and operation that would occur in a non- attainment or maintenance area. a. Direct and indirect emissions should be aggregated by non-attainment or maintenance area and calendar year for comparison to applicable General Conformity de minimis thresholds. b. If applicable General Conformity de minimis thresholds are exceeded for any calendar year(s), identify how the applicable Project emissions would conform with the State Implementation Plan for the applicable non- attainment or maintenance area and calendar year(s) using a method described in 40 CFR 93.158.	See Section 9.2.6.10 and Appendix M.
FERC	10/26/2016	9. Include a final list of federal regulations that would apply to Project marine vessel activities ranging from small service vessels to oceangoing vessels and detail how compliance with the regulations will be achieved (section 9.2.6.10, page 9-73)	A preliminary determination of applicable marine vessel regulations is provided Section 9.2.6.11. A final determination would be made after vessel contractors are selected.

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FERC	10/26/2016	10. states that the influence of Project GHG emissions on global climate change is not addressed in Resource Report 9. Per numerous agency and public comments, include a discussion of the Project's contribution to climate change in the Cumulative Impacts for the Project. As a guide for these cumulative impacts, reference the Southeast Market Pipelines Project, Final Environmental Impact Statement. Include discussion of the following climate change topics where applicable (Docket Nos. CP14-554-000, CP15-16-000, and CP15-17-000, FERC/EIS-0262F): a. sea-level rise; b. storm surge; c. flood events; and d. permafrost thaw, including incidental CO2 liberation.	The requested information will be provided during DEIS development
FERC	10/26/2016	11. Clarify whether receptors are required to be added in the offsite source boundaries for GTP modeling analysis	Receptors within the offsite sources are included in the modeling for GTP alone; however, receptors within offsite sources are not included in the cumulative modeling. See Appendix F Section 5.4, third paragraph.
FERC	10/26/2016	12. Update the summary of applicable ADEC and Alaska Administrative Code (AAC) 50 regulations to include revised standards that went into effect on August 20, 2016. (LNG Plant - appendix D, section 2.1 and table 2-1, page 9-10; GTP - appendix F, section 2.1 and table 2-1, page 7-8; Mainline Compressor Plants - appendix E, section 3.0 and table 2, page 8-9)	The summary has been updated based on the December 2016 regulations.
FERC	10/26/2016	13. Update footnote "c"/"1" of table to include limits for both nitrogen dioxide (NO2) (188 micrograms per cubic meter [µg/m3]) and PM2.5 (35 µg/m3) or refer to the standard generally. (LNG Plant - appendix D, section 2.1, table 2-1, page 10; GTP - appendix F, section 2.1, table 2-1, page 8; Mainline Compressor Plants – appendix E, section 3.0, table 2, page 9)	The values for $PM_{2.5}$ and NO_2 are included in the body of the tables.
FERC	10/26/2016	14 Include modeling input and output files to confirm that modeling described in report was completed as stated. Due to file size limitations on eLibrary, this information may need to be filed as text files. (LNG Plant - appendix D; GTP – appendix F; Mainline Compressor Plants – appendix E))	Electronic files for modeling will be made available.
FERC	10/26/2016	15. Include the background data that was used to develop the air quality data included in table 3-1. (appendix D, section 3.0, page 12)	See Appendix B.
FERC	10/26/2016	16. Include documentation for the emission factors used to calculate benzene annual emission rate. (appendix A of appendix D, page 13)	See Appendix D (specifically Appendix A of Appendix D, Section 8.2.).
FERC	10/26/2016	17. Update "Note 2" which is incomplete, referring to CO2. (appendix A of appendix D, page 14)	Appendix D has been revised and updated.
FERC	10/26/2016	18. Verify that AERMOD model version 15181 as discussed in appendix D was used for modeling and that the reference to model version 14134 in the text of the resource report is out of date. (section 9.2.5.1.3, page 9-49)	As documented in Appendix D, AERMOD version 15181 was used for modeling the LNG Plant. Section 9.2.5.1.4 has been updated accordingly.

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FERC	10/26/2016	19. Include consistent Ambient Background Concentration and Total Concentration (μg/m3) for the 24-hour sulfur dioxide analysis in table 9.2.5-3 of Resource Report 9 and table 5.1 from appendix D. (section 9.2.5.1.3, pages 9-50; appendix D, section 5.5, page 33)	Table 9.2.5-3, Appendix B, and Appendix D are updated to be internally consistent.
FERC	10/26/2016	20. Update reference to ADEC's Modeling Review Procedures Manual (ADEC 2013), which has been updated as of May 16, 2016. (appendix F, section 1, page 4)	Appendix F is updated accordingly.
FERC	10/26/2016	21. Include BP Exploration (Alaska), Inc. (BPXA) A-Pad and Central Compression Plan (CPP) monitoring station data or reference in order to confirm background data used in modeling. (appendix F, section 3.0, page 10)	Documentation of sources for all ambient air quality data is provided in Appendix B.
FERC	10/26/2016	22. Particulate matter less than 2.5 microns in aerodynamic diameter background values included only 1 year of data (2014). Include the 98th percentile of the maximum daily averaged over a 3-year period. (appendix F, section 3.1, page 10)	See Appendix B.
FERC	10/26/2016	23. Include clarification of the use of AERMAP terrain pre-processors for the dispersion modeling. Section 9.2.5.2.3 describes AERMAP being used, but appendix F describes AERMAP as not being required due to flat terrain. (section 9.2.5.2.3, page 9-60; appendix F, section 4.4, page 19)	The reference to AERMAP has been deleted from the text in Section 9.2.5.2.3.
FERC	10/26/2016	24. In the air quality impact report, the description of the receptor grid should identify that the receptor locations are sufficient to cover employee housing. (page 9-xi)	Section 5.1 in Appendix E has been updated to indicate model versions.
FERC	10/26/2016	25. The modeling analysis reflects preliminary compressor station design parameters. Include a revised modeling analysis and report if the final design parameters (equipment, stack parameters, etc.) differ from the preliminary parameters. (appendix E, section 1.0, page 4)	Compressor station design parameters and air modeling analyses are updated for the latest project design information. See Appendix E.
FERC	10/26/2016	26. Update AERMOD, AERSCREEN, MAKEMET, and AERSURFACE modeling software to indicate updated versions of the modeling software were used. (appendix E, section 5.7, page 13)	See Appendix E, Section 5.1.
FERC	10/26/2016	27. Clarify how the nitrogen dioxide / nitrogen oxides ratio of 0.1 was derived from the ADEC data for application to the generators, heaters, and waste incinerators. (appendix E, section 5.7, page 16)	A reference to the source of the 0.1 in-stack ratio is included in the revised Appendix E, Section 5.7.
FERC	10/26/2016	28. In section 5.7, the text refers to table 3-2 which appears to be incorrect and suggest that it be revised to refer to table 4. (appendix E, section 5.7, page 16)	The text in Appendix has been revised accordingly.
FERC	10/26/2016	29. Ensure that all noise levels (background sound levels collected by Alaska LNG, noise estimates for construction and operational impacts) are provided in unweighted octave band centers and as A-weighted decibels. (section 9.3)	The background sound levels discussed in Section 9.3.1 and Appendices N and O are un-weighted octave band sound levels.
FERC	10/26/2016	30. Update the noise portion of Resource Report 9 to ensure that all noise related appendices are summarized within the text of the resource report. Include within the text of the resource report summaries of background noise data, construction and operational noise estimates, and mitigation measures proposed to be implemented for the	See Section 9.3 and various subsections for revised text and references that address this comment.

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		Project. (section 9.3)	
FERC	10/26/2016	31. Include background noise estimates for all facilities identified in table 9.3.1-1 of Resource Report 9, regardless of the facility's proximity to NSAs. Include noise isopleths demonstrating noise impacts of the facility and distance attenuation until facility noise would be no longer perceptible (i.e., equal to or less than background noise estimates). (section 9.3.1, page 9-77)	See revised Section 9.3.1 and Table 9.3.1-1 for Project Facilities proximity to NSAs and Appendix N and O for background noise estimates. See Section 9.3.2 for predicted noise levels and impacts, and supporting modeling results in Appendices P through U. Noise isopleths demonstrating noise impacts of the facility and distance attenuation would require further quantification of the background sound at remote distances from facilities. The Applicant will address that requirement prior to the issuance of the DEIS.
FERC	10/26/2016	32. Revise the list of NSAs to include, as appropriate, Key Observation Points (KOP), as identified in Resource Report 8, any additional KOPs identified in comments on the draft resource reports, and subsistence use areas. For KOPs or subsistence use areas not included as an NSA, include justification for not considering the area as an NSA. Update noise impact assessments to demonstrate potential facility noise levels at the revised NSAs. (section 9.3.1.1, page 9-77)	See revised Section 9.3.1 and Table 9.3.1-1 for the NSAs analyzed and Section 9.3.2 for projected noise impacts on those NSAs. Further analysis related to Key Observation Points (KOPs) in Resource Report No. 8 will be addressed prior to the issuance of the DEIS. The Applicant requests clarification on definition of subsistence use areas to be considered for noise analysis.
FERC	10/26/2016	33. Include in the construction noise impact assessment potential noise impacts from construction activities on all NSAs. Identify proposed noise mitigation measures to limit noise impacts from construction activities on NSAs. (section 9.3.2, pages 9-88 to 9-91)	See Section 9.3.2 for predicted construction noise levels and impacts, and supporting modeling results in Appendices P through U for NSAs within 1 mile of Project facilities. The Applicant will further address this comment for other NSAs prior to the issuance of the DEIS.
FERC	10/26/2016	34. Include a detailed schedule showing all Project components where 24-hour construction activities are planned, including construction work camps. Include the season during which 24-hour construction activities would occur and the length of time that 24-hour construction activities would last. For major aboveground facilities (e.g., Liquefaction Facility, Marine Terminal, and GTP), also include the location within the site where the 24-hour activities would occur. (section 9.3.2, pages 9-88 to 9-91)	The Applicant will address this comment prior to the issuance of the DEIS.
FERC	10/26/2016	35. Estimate noise effects of increased vehicle traffic along the Dalton Highway and sensitive corridors of Highway 3 in proximity to Denali State Park and Denali National Park. (section 9.3.2, pages 9-88 to 9-91; section 9.3.4, pages 9-91 to 9-94)	The Applicant will address this comment prior to the issuance of the DEIS.
FERC	10/26/2016	36. Include noise impact analyses for the activities identified below: a. Construction and operational air traffic, including areas of Project-specific air traffic, estimated	The Applicant will address this comment prior to the issuance of

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		number of air trips per day during construction and facility operation in each air traffic area separated by vehicle type, estimated noise generated by air traffic based on vehicle type, and estimated noise impacts from air traffic at nearby NSAs. (section 9.3.2, page 9-88); b. On-land noise impacts from dredging and pile driving activities, including a map identifying all proposed areas of dredging and pile driving activities, the season and duration of pile driving activities, estimated noise generated by dredging and pile driving activities (peak sound levels and equivalent sound levels), and estimated noise impacts from dredging and pile driving activities at nearby NSAs. (sec9.3.2, page 9-88)	the DEIS.
FERC	10/26/2016	37. Include estimates of noise contributions attributable to Project construction and operation in lands managed by NPS and FWS located in proximity to Project. Estimates should include existing background noise levels, estimated noise levels attributable to Project construction and/or operation, season and duration of Project activities that would result in noise contributions to lands managed by NPS and FWS, and proposed mitigation measures to limit sound contribution from Project activities on NPS and FWS managed lands.(section 9.3.2, page 9-88)	The Applicant will address this comment prior to the issuance of the DEIS.
FERC	10/26/2016	38. Consult with NPS and FWS superintendents regarding noise contributions from Project activities in proximity to NPS and FWS managed lands during both construction and operation. Include documentation of the results of the consultations, including agreed upon mitigation measures.	Comment acknowledged. It is presumed that FERC will consult with the NPS and the USFWS during the FERC-led EIS process on these issues.
National Park Service (NPS)	9/26/2016	Much of the emissions information has not been compiled and was deferred until the FERC application, including emissions associated with construction (open burning, fugitive emissions, etc.). We cannot comment on the overall adequacy of the inventory until we have the entire inventory available.	Comment acknowledged.
NPS	9/26/2016	The analysis is incomplete because it did not include an assessment of air quality and AQRV impacts to Class I and sensitive Class II areas. The analysis was limited to air dispersion modeling results for NAAQS impacts using the near-field AERMOD model. Again, it does not include an AQRV assessment as requested by the NPS, nor does it include a far-field modeling assessment using CALPUFF or a PGM model. An FLM approved AQRV assessment needs to be included in the FERC application. Without this, direct effects to AQRVs cannot be discussed or evaluated in the NEPA document, nor can NPS comment on impacts in units of the National Park System or appropriate mitigation measures.	The report includes an assessment of Air Quality Related Values (AQRVs) and impacts at Class I and Sensitive Class II areas. CALPUFF is used for some assessments beyond 50 kilometers from the individual sources, for GTP and the Liquefaction Facility. Accepted EPA and ADEC protocols were used for determining which offsite sources to include in the cumulative impact modeling. Extensive details are provided in Appendices D, E, and F.
NPS	9/26/2016	Cumulative Impact - the analysis should evaluate the cumulative impact of all LNG connected sources (e.g., liquefaction facility, compressor stations and heater stations) within 300 km of the Denali National Park and Preserve (DNPP). In other words, the analysis needs to include a far-field modeling assessment that evaluates the 'direct effects' of the AK LNG facilities combined. The analysis should center on the Class I/sensitive Class II	Cumulative analyses are provided for Denali National Park and Preserve (DNPP) and other Class I and Sensitive Class II areas. See Appendices D, E, and F.

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		areas, and incorporate all LNG sources which are located within 300 km of given Class I/sensitive Class II area. This was not included in RR9 and needs to be included in the FERC application, as it is the only way to effectively evaluate the direct effects of all LNG facilities to AQRVs in Class I and sensitive Class II areas.	
NPS	9/26/2016	The analysis of compressor and heater station impacts only incorporates air dispersion modeling results for NAAQS impacts using the near-field AERMOD model - it does not include an AQRV assessment as requested by the NPS, nor does it include a far-field modeling assessment using CALPUFF or a PGM model. An FLM approved AQRV assessment needs to be included in the FERC application. A 'cumulative look' at all LNG facilities needs to be incorporated in the final application to effectively evaluate the direct effects to AQRVs in Class I and sensitive Class II areas.	Compressor station visibility impacts are provided for plume blight (contrast and color) using VISCREEN and for acid deposition using AERMOD. Using the Q/d methodology prescribed in FLAG, compressor stations are below the de minimus for regional haze analyses using CALPUFF. See Appendix E, Section 3.2.4.
NPS	9/26/2016	Regional Haze Rule discussion: The NPS will evaluate the final modeling results to ensure adverse effects to visibility do not occur as a result of the proposed project. However, as stated previously, we need an FLM-approved AQRV analysis, including visibility to be able to comment on the visibility impacts.	Visibility impacts are provided for plume blight (contrast and color) near compressor stations, and for regional haze impacts from the Liquefaction Facility and GTP. See Appendices D, E, and F.
NPS	9/26/2016	Natural and cultural sounds are integral components of the suite of resources and values that NPS managers are charged with preserving and restoring. NPS evaluates actions which may impact the human and natural environment within our parks with respect to our Organic Act mandates, including "…to conserve the scenery and the natural and historic objects and the wildlife therein and to provide for the enjoyment of the same in such a manner and by such means as will leave them unimpaired for the enjoyment of future generations." The "scenery," includes the natural soundscape, as well as the landscape (NPS Management Policies 2006). The NPS Director's Order #47 delegates to parks the responsibility to preserve natural soundscapes and eliminate or mitigate inappropriate noise sources. (NPS 2000). The NPS mission to preserve unimpaired the natural and cultural resources and values of the national park system results in a different perspective on "significant impacts" compared to that of the EPA and other agencies. In recognition of the differences in mission and acknowledgement that special consideration needs to be given to the evaluation of noise impacts on noise sensitive areas, it is imperative to provide information for the NPS to be able characterize the noise impacts from the proposed action. Only then can park managers make decisions about impacts to park resources, values and visitor experience. While the EPA's document 'Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety' suggests a sound level of Ldn 55 dBA is appropriately protective for human health and welfare, NPS Management Policies 2006 §8.2.3 suggests an ecological paradigm for managing noise impacts, stating, "The natural ambient sound level—that is, the	Comment acknowledged. See revised Section 9.3.1 for additional details regarding noise analysis approach. Other than during construction for one season, there would be no noise signatures different than the vehicles, trains, and tourists that utilize the same corridor that would be utilized by the pipeline.

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		environment of sound that exists in the absence of human-caused noise—is the baseline condition, and the standard against which current conditions in a soundscape will be measured and evaluated." (NPS 2006b)	
NPS	9/25/2016	Data from a decade-long acoustic inventory project in Denali can be used to address a typical natural ambient sound level in the park. (Withers 2010, Withers 2011, Withers 2012, Withers and Betchkal 2013, Betchkal 2013a, Betchkal 2013b) Within the Denali vicinity the AK-LNG project spans a range of elevations from approximately 425 - 650 meters. During acoustic inventory sixteen summer-season sites were sampled within same elevation range. These sites have natural ambient levels ranging from 19.3 to 44.6 dBA, with a median of 26.3 dBA and a median absolute deviation of 3.2 dBA. Two winter monitoring sites in same elevation band had natural ambient levels of 20.1 and 21.2 dBA. Additionally, an Alaska-wide geospatial model of natural summer-season daytime sound levels (Mennitt 2013) can be used to estimate levels where empirical results do not exist. When considering areas within 3km of the pipeline route, the model suggests a median level of 29.8 dBA Leq(day) near Denali and a median level of 28.5 dBA Leq(day) near Gates of the Arctic. Both of these estimated ranges, empirically-derived 26.3 ± 3.2 dBA Leq(24), or model-derived 28.5 to 29.8 dBA Leq(day), are several orders of magnitude less energetic than 55 dBA Ldn or the corresponding equivalent level 48.6 dBA Leq(24), as referenced in §9.3.5.1. Managing noise impacts to this EPA human health and welfare threshold would allow an environment approximately 4 times as loud as a typical natural ambient level in Denali or Gates of the Arctic. Furthermore, impacts at 55 dBA Ldn / 48.6 dBA Leq(24) would reduce the listening area of humans and other animals in these environments by 99% or more. (Listening area reduction is calculated as follows: if N is an increase in background level measured in decibels, the fraction of the original listening area is given by k = 10^-N/10.) (Barber 2010, Box 2)	Comment acknowledged. The Applicant will further address this comment prior to the issuance of the DEIS.
NPS	9/25/2016	To better understand the impacts of the proposed project due to noise, the National Park Service requests the following information: 1) At the boundary of Denali National Park or Gates of the Arctic National Park and Preserve, please describe potential noise impacts from construction and operations phases of the project using a 20 dBA Leq(24) criterion. This threshold represents the approximate lower bound of observed natural acoustic conditions during summer months, and typical natural acoustic conditions in winter. For routing options that pass through park lands, please describe the approximate sound power level at the noise source. 2) Please clarify which, if any, standard methodologies (ISO, ANSI, etc) were employed when conducting acoustic field surveys and when performing propagation calculations. 3) Management of aviation noise in Denali NP&P and Gates of the Arctic NP&P is a well-developed concern addressed by Denali's Backcountry Management Plan (NPS 2006) and the Gates of the Arctic Wilderness Character Map (NPS 2016.) In addition, a number of best-practices have	Comment acknowledged. The Applicant will further address this comment prior to the issuance of the DEIS.

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		been developed to mitigate aviation noise impacts in Denali. (Denali Aircraft Overflight Advisory Committee 2012) Please describe aviation-related noise impacts that will occur due to routine patrols of the pipeline corridor, including the expected aircraft type, rate of patrol efforts, expected landings (if any), and the typical altitude above ground level at which these patrols will occur. For a portion of the proposed pipeline route, overflight noise footprints will affect Congressionally-designated Wilderness areas. Within designated Wilderness the Denali Backcountry Management Plan limits the maximum sound pressure level (Lmax) of motorized noise to 40 dBA Leq(1 second). If land-based mechanized patrols of pipeline corridor are expected to occur, describe the expected access vehicle(s), rate of patrol efforts, and any acoustic information necessary to describe compliance with Denali Backcountry Management Plan noise standards at Wilderness boundary. With these clarifications and additional analysis, NPS may better evaluate the environmental consequences of the proposed action to units of the national park system, and better support the conclusions reached in these Resource Reports.	
ADEC - Air Quality	9/25/2016	Table 9.2.2-1 The AAAQS value for ozone should be changed to 0.070 ppmv. This change was effective August 20, 2016.	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
ADEC - Air Quality	9/25/2016	Table 9.2.2-5 The Minor Source Baseline Date for the Southcentral Alaska Intrastate Air Quality Control Region for PM-2.5 should be changed to read " October 15, 2015"	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
ADEC - Air Quality	9/25/2016	The National Park Service and U.S. Fish and Wildlife Service have identified "sensitive Class II Areas" in the past, but we are not aware of Chugach National Forest making the same determination. Please provide details on when this determination has been made and by whom.	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
ADEC - Air Quality	9/25/2016	Paragraph two on this page mentions that a single hazardous air pollutant (HAP), formaldehyde will be emitted at a rate greater than 10 tons per year. It might be worthwhile to explain to the general public that formaldehyde is formed from the combustion of methane.	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
ADEC - Air Quality	9/25/2016	This paragraph notes that "the extent to which air quality, GHG emissions, and climate might be improved through this replacement cannot be quantified at this time." It should be noted that the Council on Environmental Quality (CEQ) released guidance on August 1, 2016 that sets a higher standard for the treatment of climate change and GHG emissions in NEPA documents. The current explanation may no longer be sufficient to meet the criteria found in the CEQ guidance.	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
ADEC - Air Quality	9/25/2016	Table 2-1 The AAAQS value for ozone should be changed to 0.070 ppmv. This change was effective August 20, 2016.	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
ADEC - Air Quality	9/25/2016	The final paragraph on this page notes that "ADEC has yet to revise the annual PM2.5 AAAQS to the same level as	The Applicant will address State of Alaska agency comments

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		the primary annual PM2.5 NAAQS promulgated in December 2012." This statement is incorrect, as the revision was effective as of March 2, 2016.	during the State permitting processes and timeframes.
ADEC - Air Quality	9/25/2016	Table 2 The AAAQs value for "particulate matter less than 2.5 Microns should be changed to 12 µg/m3. This revision was effective as of March 2, 2016. The NAAQS 8 hour value of 0.075ppmv is in error and should be changed to 0.070. The AAAQS value for ozone should be changed to 0.070 ppmv, as the revision was effective August 20, 2016.	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
ADEC - Air Quality	9/25/2016	The second bullet at the top of this page cites to the "Alaska Department of Environmental Conservation's (ADEC's) Modeling Review Procedures Manual (ADEC 2013)." This citation should be updated to refer to the 2016 version.	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
ADEC - Air Quality	9/25/2016	Table 2-1 The AAAQS value for ozone should be changed to 0.070 ppmv. This change was effective August 20, 2016.	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
ADEC - Air Quality	9/25/2016	The references on this page cite to the "Alaska Department of Environmental Conservation's (ADEC's) Modeling Review Procedures Manual (ADEC 2013)." This citation should be updated to refer to the 2016 version.	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
USFS	9/26/2016	1. We have reviewed emission inventory reported in Tables 9.2.5-1 and 9.2.5-2 to determine if an air quality modeling analysis for sensitive Class II area, the Chugach NF, would be necessitated by emissions from the proposed LNG Plant and Marine Terminal. Based upon the summation of emissions from these tables and the relative distance from the proposed LNG facility to the Chugach NF, the Q/d ratio exceeds the FLAG threshold of 10. When this threshold is exceeded, the affected FLM typically requests that a formal modeling analysis for air quality related values be conducted. We request an air quality modeling analysis be conducted for deposition focusing upon the Chugach NF.	An assessment of AQRV impacts at Chugach National Forest is provided in Tables 9.2.5-10 through 9.2.5-13. See also Appendix D.
USFS	9/26/2016	2. We requested development of an air quality modeling protocol in our July 30, 2015 letter regarding the Memorandum: Modeling Approach for Federal Conservation Unites (June 2015). However, no action has been taken upon this request as Resource Report 9 focuses exclusively upon near field modeling for NAAQS and PSD Class II increments. We again request development of an air quality modeling protocol, focusing upon application of the CALPUFF for deposition impacts. We would be happy to provide our guidance on the use of CALPUFF to assist in the development of a modeling protocol.	A modeling approach for all facilities, and preliminary modeling protocols for the Gas Treatment Plant (GTP) and Liquefaction Facility, were provided to agencies for review and comment. Additionally, several meetings with FERC and interested agencies were held to discuss the modeling approach, protocols, and other details. Final modeling is consistent with the approach, protocols, and discussions. See Appendices D, E. and F.

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ACRONYMS AND ABBREVIATIONS

Abbreviation	Definition
Abbreviations for Units of Measurement	
°F	degrees Fahrenheit
dBA	A-weighted decibels
L_{dn}	day-night sound level
L_{eq}	equivalent sound level
m^3	cubic meters
mg	Milligrams
mg/m^3	milligrams per cubic meter
MMBtu/hr	million British thermal units per hour
mph	miles per hour
ppb	parts per billion
ppbv	parts per billion by volume
ppm	parts per million
ppmv	parts per million by volume
psig	pounds per square inch gage
tpy	tons per year
µg	Microgram
µg/kg	micrograms per kilogram
$µg/m^3$	micrograms per cubic meter
Other Abbreviations	
§	section or paragraph
AAAQS	Alaska Ambient Air Quality Standards
AAC	Alaska Administrative Code
ACRC	Alaska Climate Research Center
ADEC	Alaska Department of Environmental Conservation
ADOT&PF	Alaska Department of Transportation and Public Facilities
AGDC	Alaska Gasline Development Corporation
ANWR	Arctic National Wildlife Refuge
Applicant	The Alaska Gasline Development Corporation
AQ	air quality
AQCR	Air Quality Control Region
AQRV	Air Quality Related Value
ASOS	Automated Surface Observation System
AWOS	Automated Weather Observing System
BACT	Best Available Control Technology
BLM	United States Department of the Interior, Bureau of Land Management
BMP	best management practice
BOEM	United States Department of the Interior, Bureau of Ocean Energy Management
CEQ	Council on Environmental Quality

Abbreviation	Definition
C.F.R.	Code of Federal Regulations
CAA	Clean Air Act
CASTNET	Clean Air Status and Trends Network
CCP	Central Compression Plant
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	total greenhouse gas emissions, in CO_2-equivalent global warming potential
COOP	National Weather Service, Cooperative Observer Program
CSN	Chemical Speciation Network
DAT	Deposition Analysis Threshold
DEIS	Draft Environmental Impact Statement
DGGS	Alaska Department of Natural Resources, Division of Geological & Geophysical Surveys
DNPP	Denali National Park and Preserve
ECA	Emission Control Act
EIAPP	Engine International Air Pollution Prevention
EIS	Environmental Impact Statement
EPA	United States Environmental Protection Agency
ERL	Environmental, Regulatory, and Lands
FAA	United States Department of Transportation, Federal Aviation Administration
FEIS	Final Environmental Impact Statement
FERC	United States Department of Energy, Federal Energy Regulatory Commission
FLAG	Federal Land Managers’ Air Quality Related Values Work Group
FLM	Federal Land Manager
GHG	greenhouse gas
GIS	geographic information system
GTP	gas treatment plant
GWP	Global Warming Potential
H_2S	hydrogen sulfide
H_2SO_4	sulfuric acid mist
HAP	hazardous air pollutant
HEA	Homer Electric Association
HDD	Horizontal Directional Drill
IMO	International Maritime Organization
IMPROVE	Interagency Monitoring of Protected Visual Environments
IPS	Initial Production System
ISO	International Organization for Standardization
KOP	Key Observation Point
Liquefaction Facility	natural gas liquefaction facility
LLC	limited liability company
LNG	liquefied natural gas

Abbreviation	Definition
LNGC	liquefied natural gas carrier
MACT	maximum achievable control technology
Mainline	An approximately 807-mile-long, large-diameter gas pipeline
MARPOL	Marine Pollution Protocol
MGS	Major Gas Sales
MOF	marine offloading facility
MP	milepost
MSB	Matanuska-Susitna Borough
MW	Megawatt (10^6 watts)
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
NCDC	National Climatic Data Center
NCore	National Core Network
NEPA	National Environmental Policy Act
NESHAPs	National Emission Standards for Hazardous Air Pollutants
NGA	Natural Gas Act
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NOAA	National Oceanographic and Atmospheric Administration
North Slope	Alaska North Slope
NPS	United States Department of the Interior, National Park Service
NSA	Noise-Sensitive Area
NSPS	New Source Performance Standards
NSR	New Source Review
NWR	National Wildlife Refuge
O_2	oxygen
O_3	ozone
Pb	the element lead
PBTL	Prudhoe Bay Gas Transmission Line
PBU	Prudhoe Bay Unit
$PM_{2.5}$	particulate matter having an aerodynamic diameter of 2.5 microns or less
PM_{10}	particulate matter having an aerodynamic diameter of 10 microns or less
Project	Alaska LNG Project
PSD	Prevention of Significant Deterioration
PTTL	Point Thomson Gas Transmission Line
QAPP	Quality Assurance Project Plan
RICE	Reciprocating Internal Combustion Engine
SIP	State Implementation Plan
SLAMS	State and Local Air Monitoring Stations
SO_2	sulfur dioxide
SOA	secondary organic aerosol

Abbreviation	Definition
SPM	special purpose monitors
TBD	to be determined
U.S.	United States
USFS	United States Department of Agriculture, Forest Service
USFWS	United States Department of the Interior, Fish and Wildlife Service
VOC	volatile organic compound
WRCC	Western Regional Climate Center

9.0 RESOURCE REPORT NO. 9 – AIR AND NOISE QUALITY

9.1 PROJECT DESCRIPTION

The Alaska Gasline Development Corporation (Applicant) plans to construct one integrated liquefied natural gas (LNG) Project (Project) with interdependent facilities for the purpose of liquefying supplies of natural gas from Alaska, in particular from the Point Thomson Unit (PTU) and Prudhoe Bay Unit (PBU) production fields on the Alaska North Slope (North Slope), for export in foreign commerce and for in-state deliveries of natural gas.

The Natural Gas Act (NGA), 15 U.S.C. § 717a(11) (2006), and Federal Energy Regulatory Commission (FERC) regulations, 18 Code of Federal Regulations (C.F.R.) § 153.2(d) (2014), define "LNG terminal" to include "all natural gas facilities located onshore or in State waters that are used to receive, unload, load, store, transport, gasify, liquefy, or process natural gas that is ... exported to a foreign country from the United States." With respect to this Project, the "LNG Terminal" includes the following: a liquefaction facility (Liquefaction Facility) in Southcentral Alaska; an approximately 807-mile gas pipeline (Mainline); a gas treatment plant (GTP) within the PBU on the North Slope; an approximately 63-mile gas transmission line connecting the GTP to the PTU gas production facility (PTU Gas Transmission Line or PTTL); and an approximately 1-mile gas transmission line connecting the GTP to the PBU gas production facility (PBU Gas Transmission Line or PBTL). All of these facilities are essential to export natural gas in foreign commerce and will have a nominal design life of 30 years.

These components are shown in Resource Report No. 1, Figure 1.1-1, as well as the maps found in Appendices A and B of Resource Report No. 1. Their proposed basis for design is described as follows.

The new Liquefaction Facility would be constructed on the eastern shore of Cook Inlet just south of the existing Agrium fertilizer plant on the Kenai Peninsula, approximately 3 miles southwest of Nikiski and 8.5 miles north of Kenai. The Liquefaction Facility would include the structures, equipment, underlying access rights, and all other associated systems for final processing and liquefaction of natural gas, as well as storage and loading of LNG, including terminal facilities and auxiliary marine vessels used to support Marine Terminal operations (excluding LNG carriers [LNGCs]). The Liquefaction Facility would include three liquefaction trains combining to process up to approximately 20 million metric tons per annum (MMTPA) of LNG. Two 240,000-cubic-meter tanks would be constructed to store the LNG. The Liquefaction Facility would be capable of accommodating two LNGCs. The size of LNGCs that the Liquefaction Facility would accommodate would range between 125,000–216,000-cubic-meter vessels.

In addition to the Liquefaction Facility, the LNG Terminal would include the following interdependent facilities:

- Mainline: A new 42-inch-diameter natural gas pipeline approximately 807 miles in length would extend from the Liquefaction Facility to the GTP in the PBU, including the structures, equipment, and all other associated systems. The proposed design anticipates up to eight compressor stations; one standalone heater station, one heater station collocated with a compressor station, and six cooling stations associated with six of the compressor stations; four meter stations; 30 Mainline block valves (MLBVs); one pig launcher facility at the GTP meter station, one pig receiver facility at the Nikiski meter station, and combined pig launcher and receiver facilities at each of the compressor stations; and associated infrastructure facilities.

Associated infrastructure facilities would include additional temporary workspace (ATWS), access roads, helipads, construction camps, pipe storage areas, material extraction sites, and material disposal sites.

Along the Mainline route, there would be at least five gas interconnection points to allow for future in-state deliveries of natural gas. The approximate locations of three of the gas interconnection points have been tentatively identified as follows: milepost (MP) 441 to serve Fairbanks, MP 763 to serve the Matanuska-Susitna Valley and Anchorage, and MP 807 to serve the Kenai Peninsula. The size and location of the other interconnection points are unknown at this time. None of the potential third-party facilities used to condition, if required, or move natural gas away from these gas interconnection points are part of the Project. Potential third-party facilities are addressed in the Cumulative Impacts analysis found in Appendix L of Resource Report No. 1;

- GTP: A new GTP and associated facilities in the PBU would receive natural gas from the PBU Gas Transmission Line and the PTU Gas Transmission Line. The GTP would treat/process the natural gas for delivery into the Mainline. There would be custody transfer, verification, and process metering between the GTP and PBU for fuel gas, propane makeup, and byproducts. All of these would be on the GTP or PBU pads;
- PBU Gas Transmission Line: A new 60-inch natural gas transmission line would extend approximately 1 mile from the outlet flange of the PBU gas production facility to the inlet flange of the GTP. The PBU Gas Transmission Line would include one-meter station on the GTP pad; and
- PTU Gas Transmission Line: A new 32-inch natural gas transmission line would extend approximately 63 miles from the outlet flange of the PTU gas production facility to the inlet flange of the GTP. The PTU Gas Transmission Line would include one-meter station on the GTP pad, four MLBVs, and pig launcher and receiver facilities—one each at the PTU and GTP pads.

Existing State of Alaska transportation infrastructure would be used during the construction of these new facilities including ports, airports, roads, railroads, and airstrips (potentially including previously abandoned airstrips). A preliminary assessment of potential new infrastructure and modifications or additions to these existing in-state facilities is provided in Resource Report No. 1, Appendix L. The Liquefaction Facility, Mainline, and GTP would require the construction of modules that may or may not take place at existing or new manufacturing facilities in the United States.

Resource Report No. 1, Appendix A, contains maps of the Project footprint. Appendices B and E of Resource Report No. 1 depict the footprint, plot plans of the aboveground facilities, and typical layout of aboveground facilities.

Outside the scope of the Project, but in support of or related to the Project, additional facilities or expansion/modification of existing facilities would be needed to be constructed. These other projects may include:

- Modifications/new facilities at the PTU (PTU Expansion project);

- Modifications/new facilities at the PBU (PBU Major Gas Sales [MGS] project); and
- Relocation of the Kenai Spur Highway.

9.1.1 Purpose of Resource Report

As required by 18 Code of Federal Regulations (C.F.R.) § 380.12, this Resource Report has been prepared in support of a FERC application under Section 3 of the NGA to construct and operate the Project facilities. The purpose of this Resource Report is to:

- Describe the existing air quality and noise environment in the general vicinity of the Project;
- Summarize potential impacts to these resources resulting from construction and operation of the Project; and
- Identify appropriate mitigation measures to avoid or minimize potential adverse impacts to air quality and noise in the vicinity of the Project.

Appendices included in this Resource Report include the following:

- Appendix A Regional Climate Summaries for Meteorological Stations within the Project Vicinity;
- Appendix B Air Quality Monitoring Data within the Project Vicinity;
- Appendix C Emissions Associated with Project Construction;
- Appendix D Liquefaction Facility Quality Modeling Report;
- Appendix E Main Pipeline Compressor Stations Air Quality Modeling Report;
- Appendix F Gas Treatment Plant Air Quality Modeling Report;
- Appendix G Non-Jurisdictional Facilities Air Quality Report;
- Appendix H Project NSPS, NESHAPs, and RMP Applicability Analysis
- Appendix I *Construction Emissions Control Plan*;
- Appendix J *Fugitive Dust Control Plan*;
- Appendix K *Open Burning Plan*;
- Appendix L *Operations Emissions Management Plan*;
- Appendix M Air Conformity Report;
- Appendix N Baseline Noise Level Report – Liquefied Natural Gas (LNG) Facility;

- Appendix O Baseline Noise Level Report – Mainline;
- Appendix P Liquefaction Facility Environmental Sound Level Assessment Report;
- Appendix Q Coldfoot Compressor Station Environmental Sound Level Assessment Report;
- Appendix R Healy Compressor Station Environmental Sound Level Assessment Report;
- Appendix S Horizontal Direction Drilling Environmental Sound Level Assessment Report; and
- Appendix T *Construction Noise Abatement Plan*.

The data for this Resource Report were compiled based on a review of the following:

- Feedback from FERC and other federal, state, and local agencies on Drafts 1 and 2 of the Environmental Report;
- Engineering design and proposed construction plans;
- Recent aerial photography;
- Meteorological and air quality data collected by Project representatives;
- Emissions modeling for the proposed facilities;
- Baseline noise surveys;
- Agency-supplied comments and data;
- Review of data from adjacent projects;
- Scientific literature; and
- Data from federal and state agencies.

9.1.2 Effect Determination Terminology

The following definitions were used when assessing the duration, significance, and outcome of potential effects related to the Project:

- Duration**:** ***Temporary*** effects are those that may occur only during a specific phase of the Project, such as during construction or installation activities. ***Short-term effects*** could continue up to five years. ***Long-term*** effects are those that would take more than five years to recover. ***Permanent*** effects could occur as a result of any activity that modified a resource to the extent that it would not return to preconstruction conditions during the 30-year life of the Project.

- Significance: ***Minor*** effects are those that may be perceptible but are of very low intensity and may be too small to measure. ***Significant*** effects are those that, in their context, and due to their intensity, have the potential to result in a substantial adverse change in the physical environment.

- Outcome: A ***positive*** effect may cause positive outcomes to the natural or human environment. In turn, an ***adverse*** effect may cause unfavorable or undesirable outcomes to the natural or human environment. ***Direct effects*** are "caused by the action and occur at the same time and place" (40 C.F.R. 1508.8). ***Indirect effects*** are "caused by an action and are later in time or farther removed in distance but are still reasonably foreseeable. Indirect impacts may include growth-inducing effects and other effects related to induced changes in the pattern of land use, population density, or growth rate, and related effects on air and water and other natural systems, including ecosystems" (40 C.F.R. 1508.8). Indirect impacts are caused by the Project, but do not occur at the same time or place as the direct impacts.

9.1.3 Agency and Organization Consultations

This section describes consultations that have been conducted with agencies and other interested parties related to the Project, as Project details are refined during preparation of Resource Report No. 9.

9.1.3.1 Federal Agencies

Discussions were held with several federal agencies regarding various Project details, including meetings and correspondence specific to air and noise quality, and those consultations are listed, along with a summary, in Table 9.1.3-1. A list of the required federal permits for the Project is provided in Resource Report No. 1, Appendix C. A summary of the agency, public, and stakeholder engagement is provided in Resource Report No. 1, Appendix D.

TABLE 9.1.3-1
Summary of Consultations with Federal Agencies (as of March 17, 2017)

Contact	Date Contacted	Summary
Project Federal Land Managers (FLMs) Air Quality Meeting	April 21, 2015	Familiarize FLM agencies with the Project. Obtain feedback on the Project's proposed data sources for ambient air quality and meteorological data for impact assessment purposes. Request Air Quality Related Values (AQRVs) for Denali National Park and Preserve (DNPP) and Tuxedni National Wildlife Refuge (NWR). Identify any other FLM agency issues not already captured in the Project's plan to assess and manage AQRVs.
Letter from Debora Cooper (U.S. Department of the Interior, National Park Service [NPS]) to Norm Scott (Project)	June 8, 2015	Designation of sensitive Class II areas for the Project
Letter from Tamara McCandless (U.S. Department of the Interior, U.S. Fish and Wildlife Service (USFWS]) to Norm Scott (Project)	June 24, 2015	Response to request made during Federal Land Managers Air Quality Meeting on April 21, 2015
Letter from Karen Wuestenfeld (Project) to Brooke Merrell (NPS)	June 25, 2015	Project air quality modeling approach for Federal Conservation Units. Included Memorandum of Modeling Approach for Federal Conservation Units, Project, June 2015
Letter from Karen Wuestenfeld (Project) to Jewel Bennett (USFWS)	June 25, 2015	Project air quality modeling approach for Federal Conservation Units. Included Memorandum of Modeling Approach for Federal Conservation Units, Project, June 2015
Letter from Karen Wuestenfeld (Project) to Alan Peck, U.S. Department of the Interior, Bureau of Land Management (BLM)	June 25, 2015	Project air quality modeling approach for Federal Conservation Units. Included Memorandum of Modeling Approach for Federal Conservation Units, Project, June 2015
Letter from Karen Wuestenfeld (Project) to Deyna Kuntzsch U.S. Department of Agriculture, Forest Service (USFS)	June 25, 2015	Project air quality modeling approach for Federal Conservation Units. Included Memorandum of Modeling Approach for Federal Conservation Units, Project, June 2015

TABLE 9.1.3-1
Summary of Consultations with Federal Agencies (as of March 17, 2017)

Contact	Date Contacted	Summary
Letter from Earle Williams (BLM) to Karen Wuestenfeld (Project)	July 15, 2015	BLM comments on the Memorandum of Modeling Approach for Federal Conservation Units for the Project, dated June 2015
Letter from Joan Darnell (NPS) to Norm Scott (Project)	July 24, 2015	NPS comments on the Project's proposed Air Quality Modeling Approach.
Letter from Terri Marceron (USFS) to Karen Wuestenfeld (Project)	July 30, 2015	USFS Response to Modeling Approach for Federal Conservation Units, dated June 2015.
Letter from Karen Wuestenfeld (Project) to Herman Wong (U.S. Environmental Protection Agency [EPA])	July 31, 2015	Letter requested review of attached "Memorandum on Modeling Approach for Federal Conservation Units".
Project EPA Region 10 Air Quality Meeting	August 5, 2015	Familiarize EPA air quality staff with the Project. Obtain feedback on the Project's proposed data sources for ambient air quality and meteorological data for impact assessment purposes. Obtain feedback on the Project's proposed modeling approach. Identify other EPA air-related National Environmental Policy Act (NEPA) issues not already captured in the Project's plan.
Memorandum from Herman Wong (EPA) to Norm Scott (Project)	August 12, 2015	Letter responding to July 31, 2015, request and commenting on August 5, 2015 presentation
Email from Herman Wong (EPA) to Norm Scott (Project)	September 12, 2015	Weather research and forecasting solutions for the Project. Use of five-year simulation generated for the U.S. Department of the Interior, Bureau of Ocean Energy Management (BOEM) Alaska North Slope Study.
Letter from Karen Wuestenfeld (Project) to James Martin (FERC)	September 28, 2015	Response to FERC's May 15, 2015, request to the Project for information prior to submittal of the Draft 2 Resource Reports. Addresses comments 1a, 2a and 2b, and 3 in relation to Resource Report No. 9.
Project and FERC Air Quality Meeting	November 9, 2015	Obtain feedback from FERC on Project air modeling protocol, seeking general alignment with FERC prior to further agency engagement.
Project FLM Air Quality Meeting	April 26, 2016	Provide FLMs with project update and overview of draft modeling protocols for Liquefaction Facility and GTP. Obtain feedback from FLMs on overview of draft modeling protocols.
Project FLM Air Quality Meeting	June 30, 2016	Discuss protocols for conducting AQRV analyses for the liquefaction facility.

9.1.3.2 State Agencies

Discussions were held with several State of Alaska representatives regarding the Project details contained in this Resource Report, including meetings and correspondence specific to air and noise quality; those consultations are listed, along with a summary, in Table 9.1.3-2. A list of the required state permits for the Project is provided in Resource Report No. 1, Appendix C. A summary of the agency, public, and stakeholder engagement is provided in Resource Report No. 1, Appendix D.

TABLE 9.1.3-2
Summary of Consultations with Alaska State Agencies (as of March 17, 2017)

Contact	Date Contacted	Summary

TABLE 9.1.3-2
Summary of Consultations with Alaska State Agencies (as of March 17, 2017)

Contact	Date Contacted	Summary
Project (Alaska Department of Environmental Conservation [ADEC]) Ambient Monitoring Presentation	February 18, 2014	Seek ADEC concurrence on ambient and meteorological monitoring approach—site locations and monitoring parameters. Discuss key requirements/issues related to the monitoring program. Discuss proposed monitoring schedule.
ADEC Air Quality Briefing	May 5, 2015	Familiarize ADEC with Project components, schedule, anticipated air permits, and contemplated sources of meteorological and ambient air quality data to support the air permit applications.
Letter from Karen Wuestenfeld (Project to Alan Schuler (ADEC)	July 1, 2015	Letter requesting review of attached “Memorandum on Modeling Approach for Federal Conservation Units”
Letter from Alan Schuler (ADEC) to Karen Wuestenfeld (Project)	July 14, 2015	Letter responding to July 1, 2015 request
Letter from Charlie Kominas (Project/ExxonMobil) to Elizabeth Nakanishi (ADEC)	July 17, 2015	Meteorological Monitoring Site Approval Request, Gas Treatment Plant, Deadhorse, Alaska
Letter from Charlie Kominas (Project/ExxonMobil) to Elizabeth Nakanishi (ADEC)	October 14, 2015	Meteorological Monitoring Site Amendment Request, Gas Treatment Plant, Deadhorse, Alaska
Email from Elizabeth Nakanishi (ADEC) to Adrienne Rosecrans (Project/ExxonMobil)	October 28, 2015	Includes memo dated October 27, 2015, from Michael Gravier (ADEC) to Patrick Dunn, Response to Meteorological Monitoring Site Approval Request, Gas Treatment Plant, Deadhorse, Alaska
Project Fairbanks Metropolitan Area Transportation System (FMATS) Conference Call	June 6, 2016	Overview of the Project, transportation conformity, and general conformity.

9.2 METEOROLOGY AND AIR QUALITY

This section describes the meteorological conditions and existing air quality in the vicinity of the Project, as well as designated air quality management areas, such as Class I areas. This section also includes a description of the applicable air quality regulations, including requirements to submit site-specific permit applications for the proposed operations. Furthermore, this section provides estimates of Project impacts to air quality.

9.2.1 Regional Climate

Alaska’s diverse climate is characterized by widely varying temperature ranges and weather phenomena due to the state’s size, highly variable topographical features, and location within the high latitudes. The climate and meteorological conditions in localized areas of the Project will influence the design and operation of Project facilities. Meteorological conditions will also play an important role in determining (1) the direction of atmospheric transport and (2) the degree of dispersion of air pollutants emitted from emission sources associated with Project construction and operation.

9.2.1.1 Topographic Features and Elevation

Climate conditions are dramatically affected by topography and elevation, especially in Alaska where the influences of the Arctic Ocean and the Pacific Ocean are demarcated by major mountain ranges. The Brooks Range extends across northern Alaska and the Alaska Range extends across the southern third of

Alaska, eastward into Canada. These two mountain ranges delineate the major climatic zones (see Section 9.2.1.2) that affect the Project, with smaller transitional areas between each of the zones.

9.2.1.2 Climate and Regional Zones

The National Oceanic and Atmospheric Administration (NOAA) recently established 13 climate divisions for Alaska. Four of those divisions are relevant to the Project:

- North Slope;
- Central Interior;
- Cook Inlet; and
- Northwest Gulf.

The number of discrete climatic zones has sometimes been expanded to include two smaller, transitional alpine regions between the Central Interior and Cook Inlet zones (the Alaska Range) and between the North Slope and Central Interior zones (the Brooks Range). The climatic zones of Alaska relevant to this Project are depicted in Figure 9.2.1-1, and the applicable regions within these zones are as follows:

- North Slope – The North Slope region, north of the Brooks Range, is within the Beaufort Coastal Plain Ecoregion and is dominated by a traditionally described Arctic climate, with elevations ranging from sea level to approximately 1,500 feet in the Brooks Range foothills.

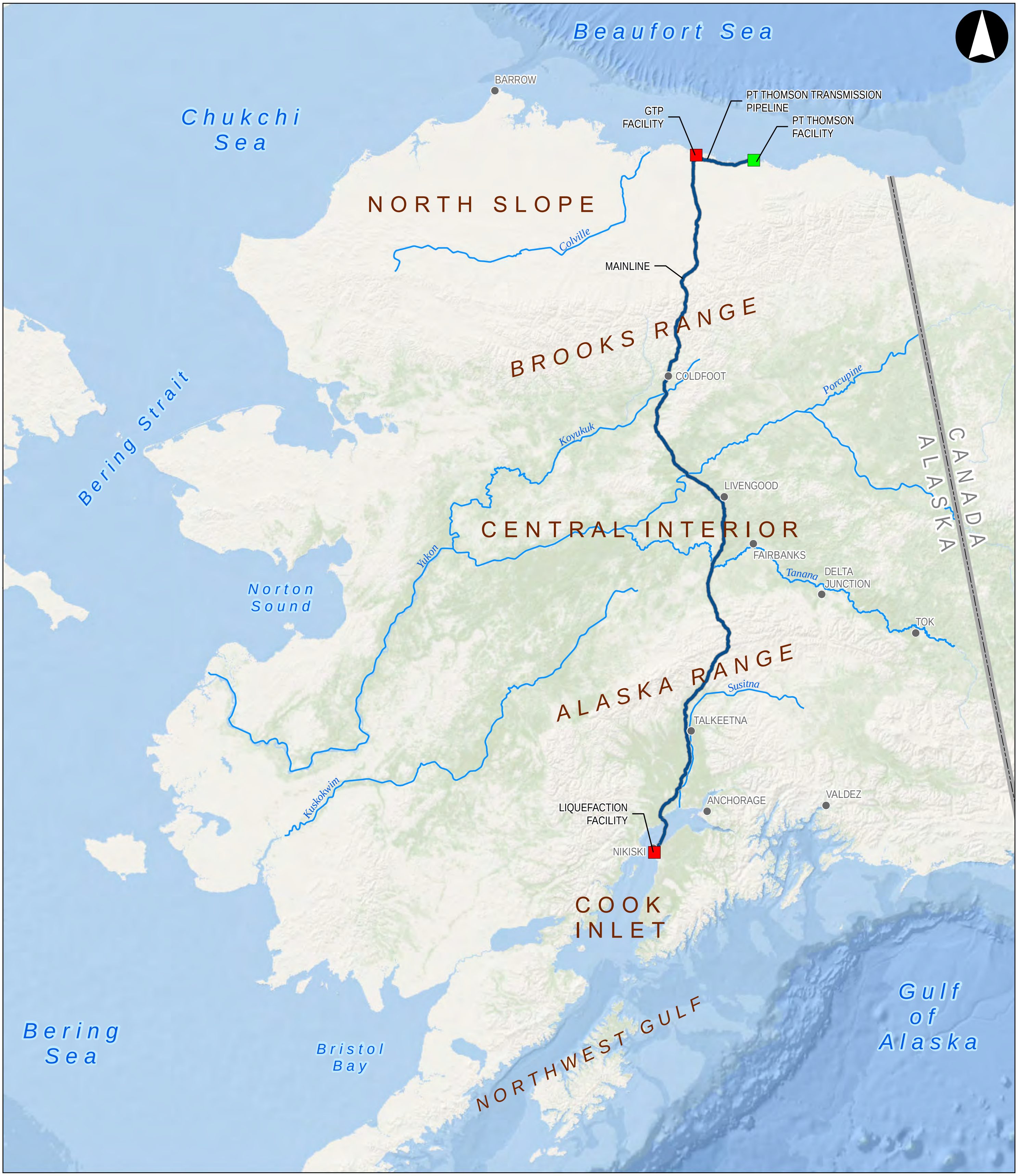
- Brooks Range – The Brooks Range, with elevations reaching 4,800 feet at Atigun Pass, is not a separate climatic zone; however, local elevation and topography, especially at locations in narrow valleys, leads to unique climate features in this region.

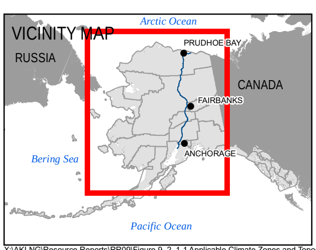
- Central Interior of Alaska – The Interior of Alaska, between the Brooks Range and the Alaska Range, is dominated by a traditionally described continental climate, with elevations ranging from a few hundred feet to approximately 1,000 feet.

- Alaska Range – The Alaska Range is not a separate climatic zone; however, local elevation and topography dominate the local climatic features. Elevations along the Project corridor range from approximately 1,000 feet in the foothills to 2,400 feet.

- Cook Inlet – The Southcentral portion of Alaska, south of the Alaska Range and including lands around Cook Inlet, is dominated by a traditionally described maritime climate, with a transitional zone in the southern foothills of the region. Elevations along the Project corridor range from approximately 1,000 feet in the Alaska Range foothills to sea level along Cook Inlet.

- Northwest Gulf – The climate conditions in and around Kodiak Island and over the open waterbodies, including Shelikof Strait and the Kennedy Entrance to Cook Inlet, represent climate conditions for LNG carriers (LNGCs) entering and exiting Cook Inlet for access to the Marine Terminal.





LEGEND

- Project Facility
- Existing Facility
- Alaska Place Names
- Alaska LNG Rev C2 Route
- Major Rivers

0 45 90 180 Miles

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DATE:	2017-03-08	SHEET:	1 of 1

APPLICABLE CLIMATE ZONES AND TOPOGRAPHY OF ALASKA

FIGURE 9.2.1-1

ALASKA LNG

X:\AKLNG\Resource Reports\RR09\Figure 9_2_1-1 Applicable Climate Zones and Topography of Alaska.mxd

Descriptions of meteorological conditions in the vicinity of Project[2] components follow. Summary climatic statistics are provided in the next section.

9.2.1.2.1 Liquefaction Facility

At the proposed location of the Liquefaction Facility on Cook Inlet, a maritime climate prevails. The maritime climate is influenced by exposure to the Gulf of Alaska and is wetter and, overall, warmer than the climate in the rest of the Project area. Frequent precipitation occurs in all months, with average precipitation above 3 inches in July and a seasonal peak in the fall. Snowfall occurs in winter months, with an average snow depth of 1 foot in January and February, along with cloudiness and comparatively milder temperatures than the other regions of the Project. Summer daily maximum temperatures average slightly above 60 degrees Fahrenheit (°F) and winter average daily minimum temperatures are below 10 °F. LNGCs would transit Cook Inlet from the Marine Terminal at Nikiski 115 nautical miles south to Kennedy Entrance, which is the recommended passage to and from Cook Inlet. It is also possible to use Stevenson Entrance (125 nautical miles south of the Marine Terminal) or Shelikof Straight Entrance (235 nautical miles south of the Marine Terminal). As the LNGCs approach the Gulf, the climate becomes increasingly mild and wet.

9.2.1.2.2 Interdependent Project Facilities

In addition to the Liquefaction Facility, Project facilities would include the Mainline, GTP, PBTL, and PTTL to move and process natural gas from the North Slope to the Liquefaction Facility. On the North Slope, the Project facilities, including Mainline, GTP, PBTL, and PTTL, would be exposed to cold Arctic weather and associated windflow patterns. The Arctic climate is characterized by very cold winters, persistent high wind episodes (any season), and frequent fog conditions that are influenced by windflow from the ice shield, especially in the warmer months.

For the Mainline components in the Alaska Interior, there are very cold, stable air episodes in the winter with a warmer growing season in the summer. Occasional periods of high temperature, dry conditions, and stable atmospheric conditions occur in the summer.

The Mainline corridor will cross mountain range transition zones, which generally involve cold winter conditions, an abundance of precipitation (mainly snow), and rapidly changing weather. Local climatic conditions are heavily influenced by local topographic features in these mountainous regions.

In Southcentral Alaska, the southernmost portion of the Mainline corridor, a maritime climate similar to the one described for the Liquefaction Facility prevails.

In subsequent sections of this Resource Report, climatological and air quality data are provided for the Project area, including data from some stations that are representative of the Brooks and Alaska Ranges.

[2] The terms "Project area" and "Project footprint" are defined to include the Project facilities and land requirements for construction and operation. The term "Project vicinity" is used to mean the region near or surrounding the Project area and draws its meaning from the context in which the term is used.

9.2.1.2.3 Non-jurisdictional Facilities

As outlined in Resource Report No. 1, there are three categories of non-jurisdictional facilities, discussed in more detail in the following sections, that warrant environmental analysis as connected actions: (i) the PTU Expansion project; (ii) the PBU MGS project; and (iii) the Kenai Spur Highway relocation project.

The PTU Expansion project and PBU MGS project located on the North Slope would be subject to similar North Slope climatic conditions as the existing Point Thomson project and GTP, respectively.

The Kenai Spur Highway relocation project would be subject to Cook Inlet climatic conditions similar to those at the Liquefaction Facility.

9.2.1.3 Meteorological Stations

A number of existing weather stations are maintained in the Project vicinity and provide data useful for characterizing weather conditions that would exist during Project construction and operation. Table 9.2.1-1 lists the stations that have been identified in the Project vicinity and Figure 9.2.1-2 depicts their location. Information from these stations has been obtained from several climate agencies, including the National Climatic Data Center (NCDC), Alaska Climate Research Center (ACRC), and Western Regional Climate Center (WRCC). Detailed monthly climate statistics from a number of stations within the general Project vicinity are presented in Appendix A, and average monthly data for the designated groups (Liquefaction Facility, North Slope, Brooks Range, Central Interior of Alaska, Alaska Range, Cook Inlet, and the Northwest Gulf) are shown Figures 9.2.1-3 through 9.2.1-7. Although the Liquefaction Facility is not located in a separate climate division, data are provided separately given the potential sensitivity of LNG terminal operations to ongoing weather. The Northwest Gulf division climate conditions would be representative of LNGC operations entering Cook Inlet through the Shelikof Strait and the Stevenson and Kennedy Entrances to Cook Inlet. A meteorological monitoring station was installed and operated to supplement existing weather station information in the vicinity of the Liquefaction Facility. That monitoring was initiated on January 1, 2015. The station location is shown in Figure 9.2.2-2. Prior to choosing this monitoring site and the meteorological parameters, the Project representatives consulted with and received approval from ADEC (Alaska LNG Project, 2015), including the Quality Assurance Project Plan (QAPP). The results of that monitoring effort for 2015 are summarized in an annual data report that has been approved by ADEC (Alaska LNG Project, 2016).

TABLE 9.2.1-1

Description of Meteorological Measurement Stations within the Project Vicinity

Station Name	Station Type	Data Record Summarized	North Latitude	West Longitude	Elevation (feet)	Information Source
LIQUEFACTION FACILITY						
Nikiski Terminal	COOP	1967–1978	60.66667	-151.38333	110	NCDC
Kenai FAA Airport	Airways, ASOS, COOP	1949–2012	60.56667	-151.25	91	NCDC
Interdependent Project Facilities						
NORTH SLOPE						
Prudhoe Bay	COOP	1986–1999	70.25	-148.3333	50	WRCC
Deadhorse	Airways, ASOS, COOP	1999–2010	70.1917	-148.4772	61	ACRC/NCDC

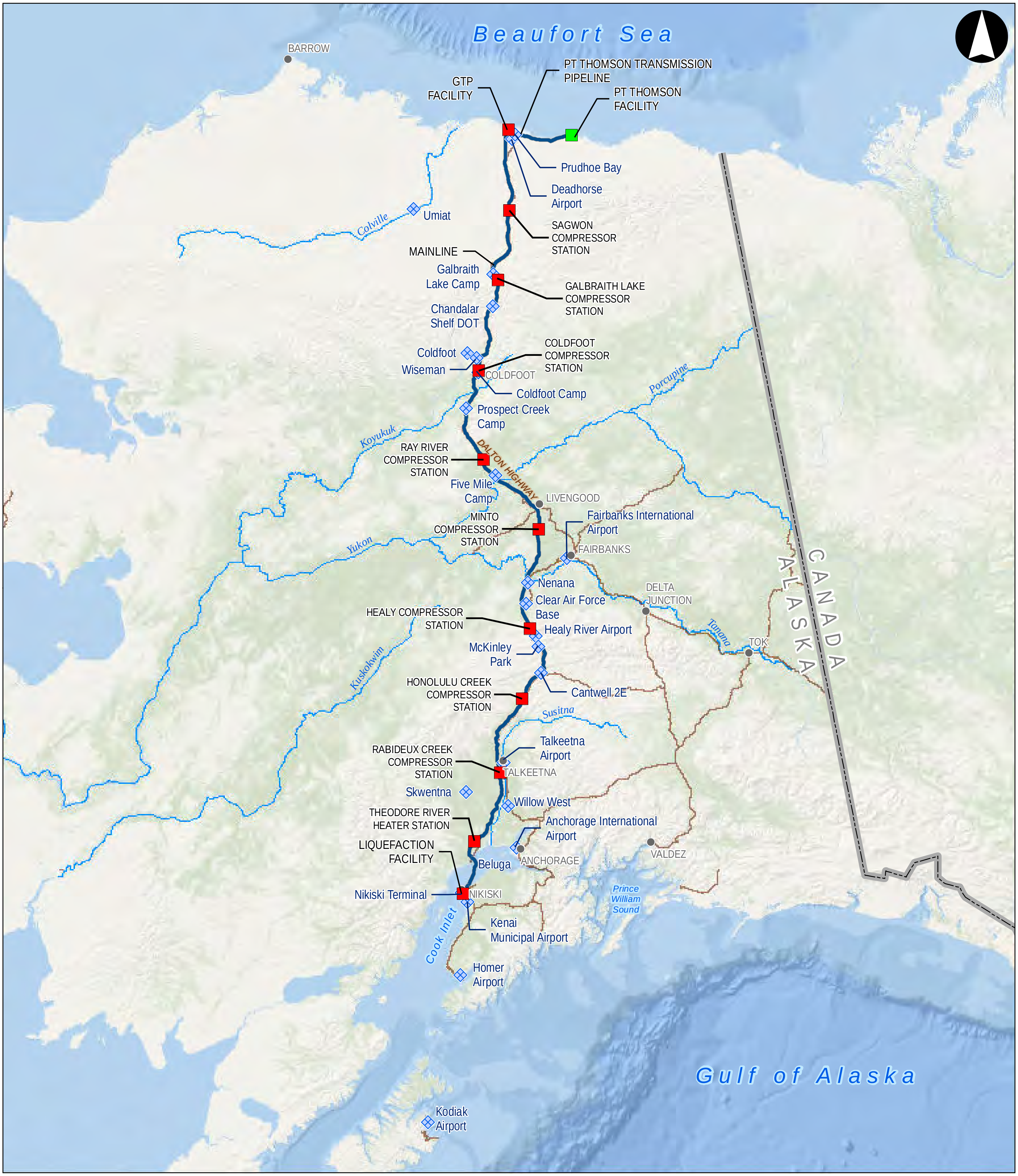
TABLE 9.2.1-1

Description of Meteorological Measurement Stations within the Project Vicinity

Station Name	Station Type	Data Record Summarized	North Latitude	West Longitude	Elevation (feet)	Information Source
Umiat	COOP	1949–2001	69.36944	-152.14	266	NCDC
BROOKS RANGE						
Galbraith Lake	COOP	1970–1980	68.47889	-149.49	2,666	WRCC
Chandalar ADOT&PF	COOP	2000–2010	68.0781	-1495647	3,250	NCDC
Wiseman	COOP	1949–2010	67.4192	-150.1069	1,147	WRCC
Coldfoot Camp	COOP	1970–1977	67.2667	-150.2333	1,102	WRCC
CENTRAL INTERIOR						
Bettles Airport	Airways, ASOS, COOP	1951–2010	66.92	-151.52	643	ACRC/NCDC
Prospect Creek Camp	Airways, COOP	1970–2001	66.82361	-150.66889	955	NCDC
Five Mile Camp	COOP	1970–1980	65.9333	-149.8333	440	WRCC
Fairbanks International Airport	ASOS, COOP	1949–2010	64.8039	-147.8761	432	ACRC/NCDC
Nenana Municipal Airport	ASOS	1949–2001	64.55	-149.07167	360	NCDC
Clear Air Force Base	COOP	1965–1997	64.3	-149.18333	580	NCDC
ALASKA RANGE						
Healy River Airport	Airways, AWOS	1976–2012	63.86611	-148.96889	1,294	NCDC
McKinley Park	AWOS	1949–2012	63.73333	-148.91667	1,720	NCDC
Cantwell 2E	COOP	1983–2011	63.3952	-148.895	2,132	NCDC
COOK INLET						
Talkeetna Airport	ASOS, COOP	1949–2012	62.32	-150.095	350	NCDC
Willow West	COOP	1960–2011	61.748	-150.0541	205	NCDC
Skwentna	COOP	1949–2012	61.9772	-151.2169	150	NCDC
Anchorage International Airport	Airways, ASOS, COOP	1931–2012	61.169	-150.0278	120	NCDC
Beluga	COOP	1973–1992	61.18333	-151.03333	79	NCDC
Homer Airport	ASOS, COOP	1932–2012	59.642	-151.4908	64	NCDC
NORTHWEST GULF						
Kodiak Airport	ASOS, COOP	1973-2012	57.75111	-152.48556	72	NCDC

Sources: NCDC, National Climate Data Center, http://www.ncdc.noaa.gov/oa/climate
WRCC, Western Regional Climate Center, http://www.wrcc.dri.edu/summary/Climsmak.html

Abbreviations:
Airways: Airport
FAA – Federal Aviation Administration
ASOS – Automated Surface Observation System
COOP – National Weather Service Cooperative Observer Program
ADOT&PF – Alaska Department of Transportation and Public Facilities
AWOS – Automated Weather Observing System
NCDC – National Climatic Data Center
WRCC – Western Regional Climate Center
ACRC – Alaska Climate Research Center



VICINITY MAP

X:\AKLNG\Resource Reports\RR09\Figure 9_2_1-2 Meteorological Stations within the Project Vicinity.mxd

LEGEND

- Project Facility
- Existing Facility
- Meteorological Station
- Alaska LNG Rev C2 Route
- Major Highways
- Major Rivers

0 50 100 200 Miles

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METEOROLOGICAL STATIONS WITHIN THE PROJECT VICINITY

FIGURE 9.2.1-2

ALASKA LNG

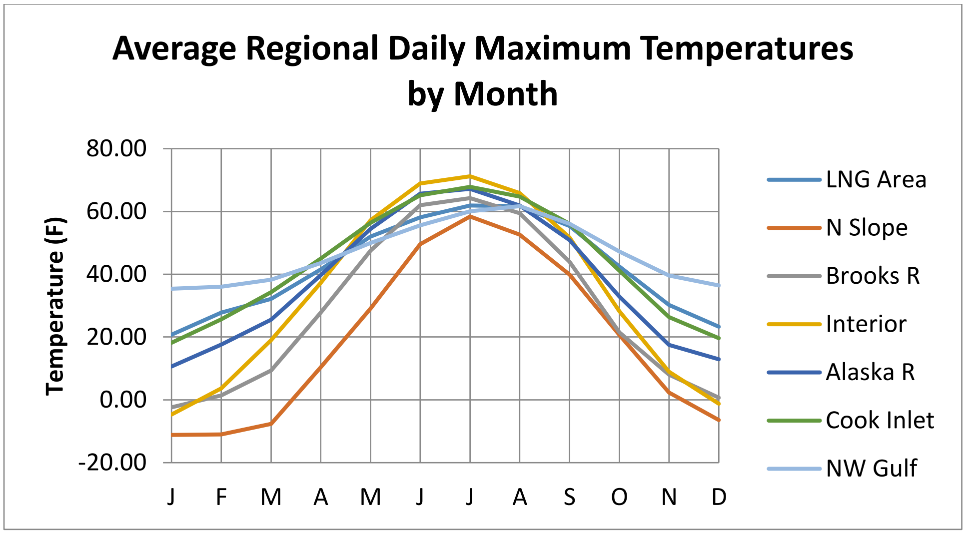


FIGURE 9.2.1-3 Average Regional Daily Maximum Temperatures by Month

Sources: See Appendix A

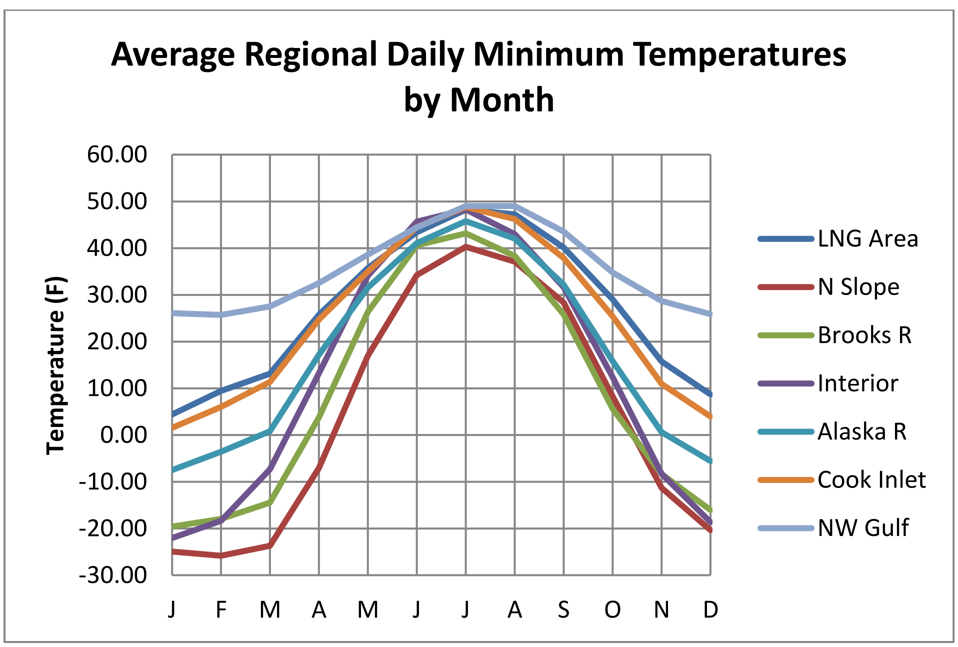


FIGURE 9.2.1-4 Average Regional Daily Minimum Temperatures by Month

Sources: See Appendix A

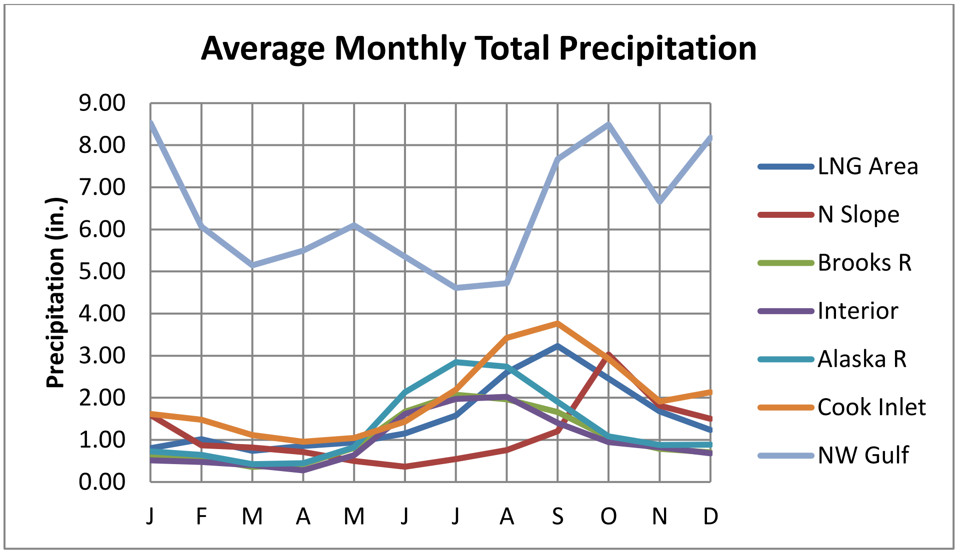


FIGURE 9.2.1-5 Average Monthly Total Precipitation

Sources: See Appendix A

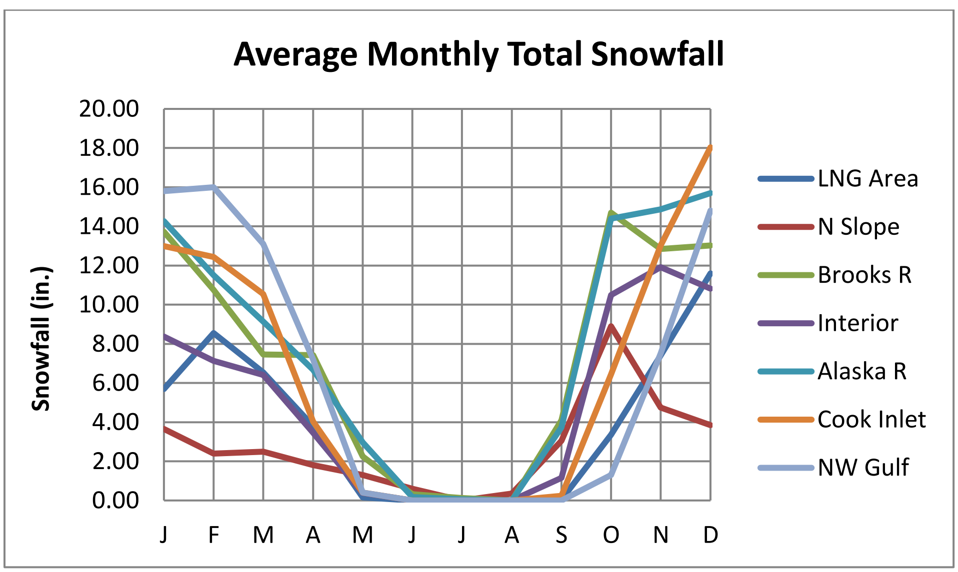


FIGURE 9.2.1-6 Average Monthly Total Snowfall

Sources: See Appendix A

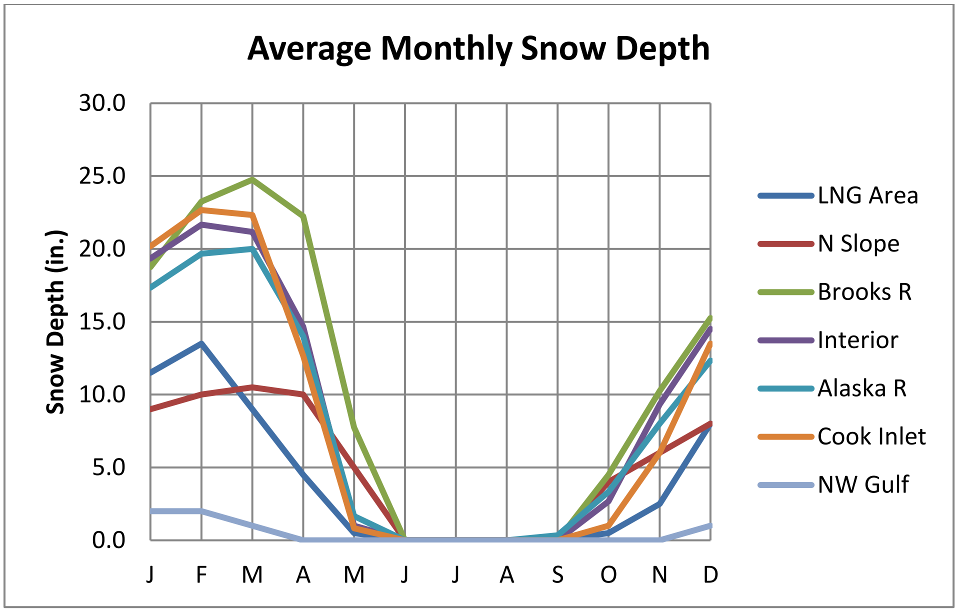


FIGURE 9.2.1-7 Average Monthly Snow Depth

Sources: See Appendix A

9.2.1.4 Summary of Meteorological Conditions

The following is a summary of the meteorological conditions within the Project area based on the information listed in Figures 9.2.1-3 through 9.2.1-7 and Appendix A.

9.2.1.4.1 Temperature

Based on available data detailed in Appendix A, the coldest locations in the Project area are (1) on the North Slope at Prudhoe Bay and Deadhorse and (2) on the north side of the Brooks Range near Galbraith Lake. Extreme cold persists in the winter months over the North Slope, with daily average temperatures below 0 °F during the months of December through March. In July and August, average daily high temperatures are above 50 °F, with average daily lows above freezing.

The Central Interior of Alaska exhibits the largest seasonal range in temperatures, as well as the largest daily range of temperatures. Extremely cold weather can persist during the winter months, with occasional two- or three-week periods of temperatures below -40 °F. The coldest temperature recorded in the Project vicinity was in the -80 ºF range at Prospect Creek on January 23, 1971. In the summer months, average high temperatures are above 70 °F, with occasional days above 90 °F. The warmest location in the Project vicinity is around Fairbanks. The warmest summer temperature recorded in the Project vicinity was at Fairbanks, which reached 96 ºF on June 15, 1969.

In the Cook Inlet region, temperature ranges are more moderate, with average summer temperatures in the 60 °F range and winter temperatures in the 20 °F range. The Northwest Gulf division has the mildest temperature conditions of all these regions, with average wintertime temperatures higher than the other regions. In the transition zone, temperatures are slightly cooler but still exhibit a comparatively moderate annual and daily temperature range.

9.2.1.4.2 Precipitation

A clear seasonal cycle in average precipitation is evident for all climate divisions, but less pronounced in the Northwest Gulf division. Other regions show a clear maximum precipitation pattern in the late summer and fall months, with a sharp peak in October for the North Slope. Precipitation on the North Slope is generally low, with an average of fewer than 10 inches per year. The Brooks Range and areas just south have a relatively high amount of snowfall (70 inches or more annually). The maximum annual snowfall recorded in the Project area was at Prospect Creek with more than 163 inches of snow in 1971.

As a location representative of the Central Interior of Alaska, Fairbanks receives 65 inches of snow per year, on average. Total annual precipitation generally averages more than 10 inches per year, with the bulk of that amount occurring as rainfall during the summer months.

Precipitation in the Cook Inlet region is both heavier and more frequent than in the other areas, generally occurring throughout the year. The Northwest Gulf division has the highest average precipitation, and it generally occurs in all months. Some areas in the Alaska Range have precipitation averages more than 60 inches per year. Relatively heavy precipitation can also occur with the passage of large mid-latitude cyclone systems.

Snowfall often occurs in the region from October through April, with relatively high monthly average snow depth in the late winter and early spring months.

9.2.1.4.3 Relative Humidity

Humidity and dew point data are not available for many Alaska meteorological stations; however, NCDC has reported average humidity for some areas. The annual average relative humidity at Fairbanks and Bettles are both around 60 percent.

9.2.1.4.4 Wind

The more-exposed North Slope locations experience much stronger wind speeds than the rest of the Project area. Except for localized strong wind conditions from passing storms, winds are generally light in the Central Interior of Alaska, especially at lower elevations.

Wind speed data (speed and direction) are sparse at most of the stations within the Project vicinity; however, wind speed has been recorded at Fairbanks and Bettles. In Fairbanks, the highest wind speeds occur during the summer with an annual mean wind speed of 5.4 miles per hour (mph). The prevailing wind direction recorded at the Fairbanks Airport is from the north. Blizzard conditions are almost never seen, as winds in Fairbanks are above 20 mph less than 1 percent of the time. The Bettles station seldom sees strong winds during any season of the year or any significant directional variation from a prevailing northerly wind (WRCC, 2011). In Cook Inlet, stronger winds generally occur with passing mid-latitude storms and higher than average winds are found along exposed ridges and coastlines.

Local windflow patterns tend to be channeled or diverted by topographical features, such as mountain passes, valleys, and waterbodies. Thus, due to the complex terrain found in the Brooks and Alaska Ranges, wind speeds and directions are expected to be highly localized due to long-valley channeling and cross-valley slope flow. Wind roses for individual project site locations are provided in the modeling reports in Appendices D, E, and F.

9.2.1.4.5 Fog, Clouds, and Visibility

Fog forms when the dew point temperature equals the ambient temperature. Except on the North Slope, fog rarely forms in the summer in Alaska because the ambient temperature is significantly higher than the dew point temperature, even near waterbodies. Spring and fall are the times of the year when fog is more likely to form, especially in areas near large waterbodies that have higher dew point temperatures. Fog is almost always less than 300 feet thick, so the surrounding uplands are usually clear, with warmer temperatures. A dense "ice fog," composed of suspended fine ice crystals, develops at times in the Interior of Alaska and on the North Slope, and visibility in the ice fog is sometimes quite low, hindering aircraft operations for as much as a day in severe cases (WRCC, 2011).

Central Interior Alaska winter temperatures can reach low enough levels (-20 °F to -60 °F) to create ice fog on a fairly frequent basis. As cold air is denser, cold high-pressure systems are formed, which are very difficult to displace. Thus, stable conditions with no wind can persist for several days to weeks, causing long-lasting ice fogs in Interior locations (NCDC, 2011). Cold snaps in Fairbanks accompanied by winter ice fog generally last about a week, but these conditions can last up to three weeks in unusual situations.

Cloud cover and storm observations are also limited in the Project vicinity. In Fairbanks and Bettles, cloudy days occur for approximately 200 days of the year, while 90 days per year are partly cloudy, and approximately 70 days are clear (NCDC, 2011).

9.2.2 Existing Ambient Air Quality

9.2.2.1 Ambient Air Quality Standards

Federal and state air emissions regulations are designed to ensure that new sources do not cause or contribute to an exceedance of ambient standards for criteria air pollutants. The criteria pollutants are as follows: sulfur dioxide (SO_2); carbon monoxide (CO); nitrogen dioxide (NO_2); ozone (O_3); particulate matter having an aerodynamic diameter of 10 microns or less (PM_{10}); particulate matter having an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$); and lead (Pb).

EPA has established National Ambient Air Quality Standards (NAAQS) for these seven pollutants. The NAAQS are set at levels EPA believes are necessary to protect public health (primary standards) and welfare (secondary standards).

The Alaska Department of Environmental Conservation (ADEC) has established similar ambient air quality standards referred to as Alaska Ambient Air Quality Standards (AAAQS). AAAQS are similar to the federal NAAQS for criteria pollutants, except that ADEC has yet to remove the 24-hour and annual standards for SO_2. ADEC also has an eight-hour AAAQS for ammonia. Table 9.2.2-1 lists both the federal and state ambient air quality standards.

TABLE 9.2.2-1

National and Alaska Ambient Air Quality Standards

Air Pollutant	Averaging Period	NAAQS	AAAQS
Sulfur Dioxide	1-Hour[a]	75 ppbv	196 μg/m^3
	3-Hour[b]	0.5 ppmv	1,300 μg/m^3
	24-Hour[b]	---	365 μg/m^3
	Annual	---	80 μg/m^3
Carbon Monoxide	1-Hour[b]	35 ppmv	40 mg/m^3
	8-Hour[b]	9 ppmv	10 mg/m^3
Nitrogen Dioxide	1-Hour[c]	100 ppbv	188 μg/m^3
	Annual	53 ppbv	100 μg/m^3
Ozone	8-Hour[d]	0.070 ppmv	0.070 ppmv
Particulate Matter less than 10 Microns	24-Hour[b]	150 μg/m^3	150 μg/m^3
Particulate Matter less than 2.5 Microns	24-Hour[e]	35 μg/m^3	35 μg/m^3
	Annual	12 μg/m^3	12.0 μg/m^3
Lead	Rolling 3-Month Average	0.15 μg/m^3	0.15 μg/m^3
Ammonia	8-Hour[b]	----	2.1 mg/m^3

Sources: EPA 2015a; ADEC 2016a

Abbreviations:

--- = Not applicable

μg/m^3 = micrograms per cubic meter

mg/m^3 = milligrams per cubic meter

ppbv = parts per billion by volume

ppmv = parts per million by volume

Notes:

[a] Standard is attained when the 3-year average of the annual, 99th percentile, daily maximum, one-hour concentration is less than or equal to 75 ppb, or 196 μg/m^3.

[b] Not to be exceeded more than once in a year.

[c] Standard is attained when the 3-year average of the annual, 98th percentile, daily maximum, one-hour concentration is less than or equal to 100 ppb, or 188 μg/m^3.

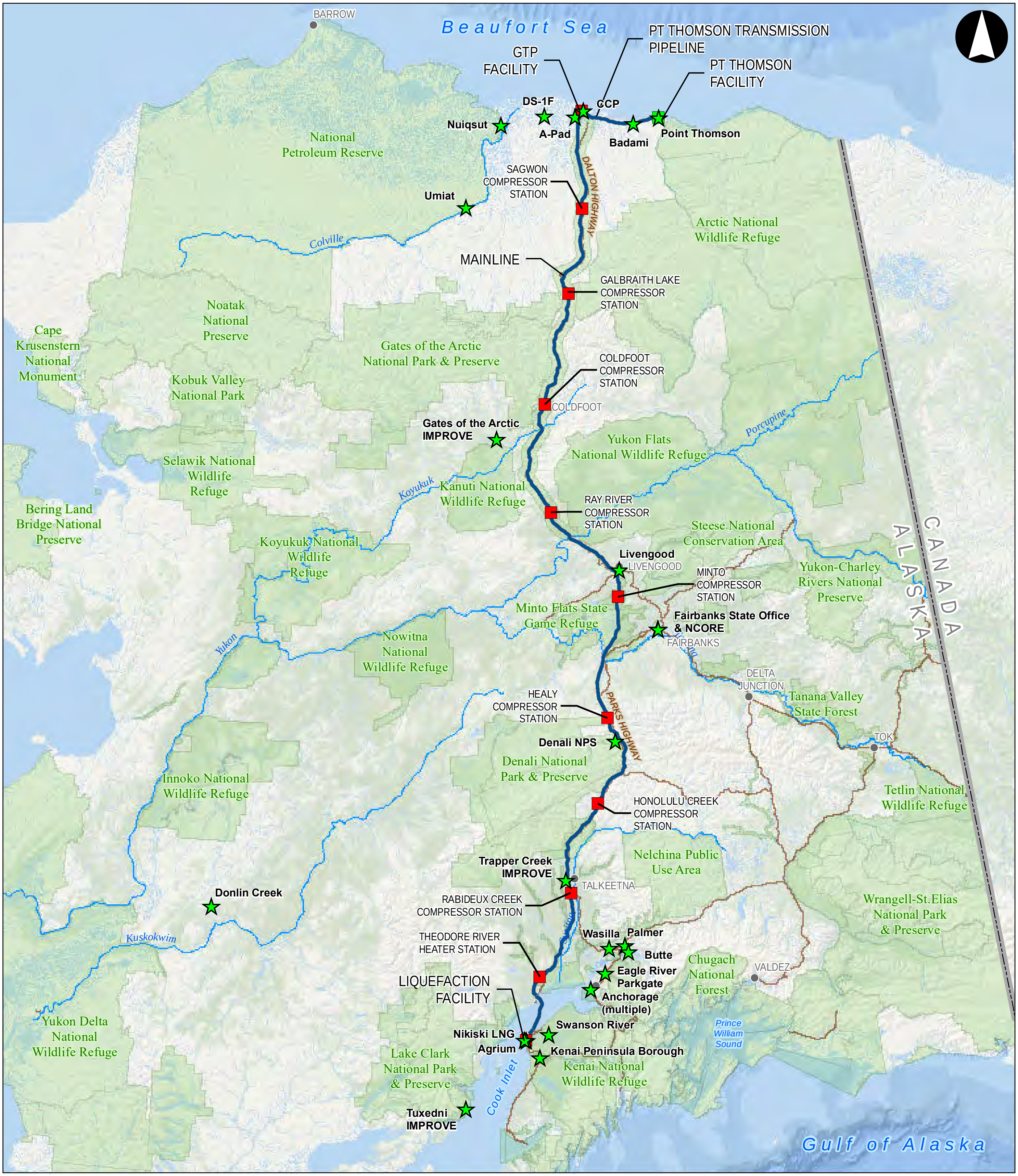
[d] Standard is attained when the 3-year average of the annual fourth-highest daily maximum eight-hour average ozone concentration is less than or equal to 0.070 ppm.

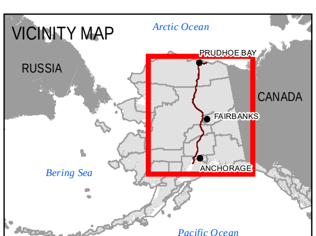
[e] Standard is attained when the 3-year average of the annual 98th percentile 24-hour concentration is less than or equal to 35 μg/m^3.

9.2.2.2 Existing Air Quality Concentrations

Air quality data were gathered from all publicly available sources in the Project vicinity and evaluated for data quality. Figure 9.2.2-1 shows the locations of monitoring stations with data that are reasonably current (generally collected since 2010), complete (80 percent or better data capture), and publicly available. Existing air quality data from these stations, which depict the regional air quality conditions, are summarized in Appendix B.

These monitoring stations are operated by private entities and local, state, or federal agencies. Privately collected datasets are generally for Prevention of Significant Deterioration (PSD) monitoring programs.





X:\AKLNG\Resource Reports\RR09\Figure 9_2_2-1 Ambient Air Quality Monitoring Stations.mxd

LEGEND

- Project Facility
- Existing Facility
- Ambient Air Quality Monitoring Stations
- Alaska LNG Rev C2 Route
- Major Highways
- Major Rivers
- State and Federal Conservation Lands

0 25 50 100 150 Miles

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AMBIENT AIR QUALITY MONITORING STATIONS

FIGURE 9.2.2-1

ALASKA LNG

Local, state, and federal monitoring stations include State and Local Air Monitoring Stations (SLAMS) (EPA 2014a), Interagency Monitoring of Protected Visual Environments (IMPROVE), National Core Network (NCore), and Clean Air Status and Trends Network (CASTNET). Certain SLAMS $PM_{2.5}$ monitoring data are also part of the Chemical Speciation Network (CSN). Although data from the SLAMS and related ambient air monitoring networks may not necessarily meet all of the PSD criteria, data collected at these stations are valuable in describing the existing ambient air quality of the Project area, particularly because much of the Project area in the vicinity of the Mainline route has limited air quality monitoring data available.

Some data presented in Appendix B were collected by Special Purpose Monitors (SPMs). However, SPM data are not to be used for NAAQS compliance demonstrations without review and acceptance as required in 40 C.F.R. 58.20. The concentrations measured by SPMs have been included in this Resource Report to ensure a complete presentation of existing air quality.

Monitoring data from Appendix B are summarized in Tables 9.2.2-2, 9.2.2-3, and 9.2.2-4 for the North Slope, Interior Alaska and Alaska Range, and Southcentral Alaska and Cook Inlet. Those tables also provide the most representative air quality level that is available from existing data at the time of this submittal. However, updates to these air quality levels may be provided from later monitoring efforts as background concentrations for the required air quality analyses. For the most part, the data demonstrate that existing air quality complies with the ambient standards. Data collected at certain stations indicate levels above the air quality standards, but which do not necessarily indicate an exceedance of the standards. While these data are included for completeness, the higher levels are not necessarily representative of air quality at Project facilities, but rather reflect local circumstances (such as the Fairbanks $PM_{2.5}$ nonattainment area [see Section 9.2.2.3.2]) or exceptional events (such as forest fires).

There are seven available datasets on the North Slope, which provide a good representation of air quality at North Slope oil and gas production facilities as well as remote areas.

In the Interior, there are limited data. The most complete Interior dataset is being collected in the Fairbanks urban area, which is nonattainment for $PM_{2.5}$ and not representative of the Project Mainline corridor. Outside of Fairbanks and Healy, Interior Alaska is sparsely populated with few existing significant sources of air pollutants near the Project area.

In Southcentral Alaska, there are several data collection programs with special purposes, but few complete PSD monitoring programs. Many of these monitoring programs were established to gather specific data for the Anchorage urban area or to characterize fugitive dust issues in the Matanuska Valley. Thus, datasets should be carefully evaluated before identifying the best one for representing air quality at Project facilities. Rather than using existing publicly available datasets to characterize ambient air quality in the vicinity of the Liquefaction Facility, the Project initiated its own background data collection program beginning on January 1, 2015. The air quality station location is identified as the background station in Figure 9.2.2-2. Air quality data being collected at this station includes CO, NO_2, SO_2, O_3, PM_{10}, and $PM_{2.5}$. Prior to choosing this monitoring site and the air quality parameters, the Project representatives consulted with and received approval from ADEC (Alaska LNG Project, 2015). Data from the background station are included in this Resource Report for the Liquefaction Facility (see Appendix B).

Representative air quality data for Project impact analyses are presented as part of the impact assessment in Section 9.2.5.

TABLE 9.2.2-2

Monitored Air Quality Data from the North Slope

Air Pollutant	Averaging Period	Range of Maximum Monitored Concentrations[a]	Representative Background Concentration at GTP	Standard
Sulfur Dioxide	1-Hour[b]	6.29 – 75.9 μg/m^3	9.39 μg/m^3	196 μg/m^3
	3-Hour	5.5 – 65.5 μg/m^3	20.96 μg/m^3	1,300 μg/m^3
	24-Hour	3.0 – 26.0 μg/m^3	8.12 μg/m^3	365 μg/m^3
	Annual	0.3 – 5.2 μg/m^3	1.8 μg/m^3	80 μg/m^3
Carbon Monoxide	1-Hour	0.0022 – 1.36 mg/m^3	1.15 mg/m^3	40 mg/m^3
	8-Hour	0.0013 – 1.15 mg/m^3	1.15 mg/m^3	10 mg/m^3
Nitrogen Dioxide	1-Hour[c]	61.69 – 471.4 μg/m^3	61.69 μg/m^3	188 μg/m^3
	Annual	1.88 – 20.6 μg/m^3	6.0 μg/m^3	100 μg/m^3
Ozone	8-Hour[d]	0.047 – 0.056 ppmv	0.056 ppmv	0.070 ppmv
Particulate Matter less than 10 Microns	24-hour	35.6– 70 μg/m^3	50.0 μg/m^3	150 μg/m^3
Particulate Matter less than 2.5 Microns	24-Hour[e]	9 – 22.5 μg/m^3	15 μg/m^3	35 μg/m^3
	Annual	2.1 – 3.7 μg/m^3	3.7 μg/m^3	12 μg/m^3

Source: See Appendix B for the datasets and methodology for selection of monitored concentrations.

Abbreviations:

μg/m^3 – micrograms per cubic meter

mg/m^3 – milligrams per cubic meter

ppmv – parts per million by volume

Notes:

[a] Concentrations for the short-term standards (1 to 24 hours) are based on the design calculations for the standards. See notes in Table 9.2.2-1.

[b] The one-hour SO_2 average shown in the table reflects the annual 99th percentile of the daily maximum one-hour SO_2 concentration averaged over the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects.

[c] The one-hour average shown in the table reflects annual 98th percentile of the daily maximum one-hour NO_2 concentration averaged over the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects.

[d] The annual fourth-highest daily maximum eight-hour O_3 concentrations averaged over the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects.

[e] The annual 98th percentile $PM_{2.5}$ concentrations averaged over the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects.

TABLE 9.2.2-3

Monitored Air Quality Data from Interior Alaska and the Alaska Range

Air Pollutant	Averaging Period	Range of Maximum Monitored Concentrations[a]	Standard
Sulfur Dioxide	1-Hour[b]	146.5 µg/m^3	196 µg/m^3
	3-Hour	5.33 – 131 µg/m^3	1,300 µg/m^3
	24-Hour	5.33 – 85.9 µg/m^3	365 µg/m^3
	Annual	1.33 – 33.2 µg/m^3	80 µg/m^3
Carbon Monoxide	1-Hour	0.7 – 5.41 mg/m^3	40 mg/m^3
	8-Hour	0.3 – 3.21 mg/m^3	10 mg/m^3
Nitrogen Dioxide	1-Hour[c]	26.32 µg/m^3	188 µg/m^3
	Annual	1.91 µg/m^3	100 µg/m^3
Ozone	8-Hour[d]	0.054 – 0.064 ppmv	0.070 ppmv
Particulate Matter less than 10 Microns	24-hour	15 – 111 µg/m^3	150 µg/m^3
Particulate Matter less than 2.5 Microns	24-Hour[e]	11.2 – 83.2[f] µg/m^3	35 µg/m^3
	Annual	1.45 – 13.2[f] µg/m^3	12 µg/m^3

Source: See Appendix B for the datasets and methodology for selection of monitored concentrations.

Abbreviations:

µg/m^3 – micrograms per cubic meter

mg/m^3 – milligrams per cubic meter

ppmv – parts per million by volume

Notes:

[a] Concentrations for the short-term standards (1 to 24 hours) are based on the design calculations for the standards. See notes in Table 9.2.2-1

[b] The one-hour SO_2 average shown in the table reflects the annual 99[th] percentile of the daily maximum one-hour SO_2 concentration averaged over the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects.

[c] The one-hour average shown in the table reflects annual 98[th] percentile of the daily maximum one-hour NO_2 concentration averaged over the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects.

[d] The annual fourth-highest daily maximum eight-hour O_3 concentrations averaged over the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects.

[e] The annual 98[th] percentile $PM_{2.5}$ concentrations averaged over the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects.

[f] Includes measured concentrations from the Fairbanks urban $PM_{2.5}$ nonattainment area.

Note: See Section 9.2.5.2 for concentrations at each compressor station site.

TABLE 9.2.2-4

Monitored Air Quality Data from Southcentral Alaska and Cook Inlet

Air Pollutant	Averaging Period	Range of Maximum Monitored Concentrations[a]	Representative Background Concentration at the LNG Plant	Standard
Sulfur Dioxide	1-Hour[b]	8.1 μg/m^3	5.0 μg/m^3	196 μg/m^3
	3-Hour	5.0μg/m^3	5.0 μg/m^3	1,300 μg/m^3
	24-Hour	2.4 μg/m^3	2.4 μg/m^3	365 μg/m^3
	Annual	0.0 μg/m^3	0.0 μg/m^3	80 μg/m^3
Carbon Monoxide	1-Hour	1.1– 9.39 mg/m^3	1.145 mg/m^3	40 mg/m^3
	8-Hour	1.1 – 7.9 mg/m^3	1.145 mg/m^3	10 mg/m^3
Nitrogen Dioxide	1-Hour[c]	35.7 – 222.6[f] μg/m^3	32.3μg/m^3	188 μg/m^3
	Annual	2.6– 28.2 μg/m^3	2.6μg/m^3	100 μg/m^3
Ozone	8-Hour[d]	0.048 – 0.061 ppmv	0.047ppmv	0.070 ppmv
Particulate Matter less than 10 Microns	24-hour	35.2 – 376[g] μg/m^3	40 μg/m^3	150 μg/m^3
Particulate Matter less than 2.5 Microns	24-Hour[e]	8.7 – 70.7[g] μg/m^3	12μg/m^3	35 μg/m^3
	Annual	0.94 – 7.94[g] μg/m^3	3.7μg/m^3	12 μg/m^3

Source: See Appendix B for the datasets and methodology for selection of monitored concentrations.

Abbreviations:

μg/m^3 – micrograms per cubic meter

mg/m^3 – milligrams per cubic meter

ppmv – parts per million by volume

Notes:

[a] Concentrations for the short-term standards (1 to 24 hours) are based on the design calculations for the standards. See notes in Table 9.2.2-1

[b] The one-hour SO_2 average shown in the table reflects the annual 99th percentile of the daily maximum one-hour SO_2 concentration averaged over the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects.

[c] The 1-hour average shown in the table reflects annual 98th percentile of the daily maximum one-hour NO_2 concentration averaged over the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects.

[d] The annual fourth-highest daily maximum eight-hour O_3 concentrations averaged over the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects.

[e] The annual 98th percentile $PM_{2.5}$ concentrations averaged over the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects.

[f] Includes measured concentrations from the Anchorage urban area.

[g] Includes data from several special purpose monitoring stations in Anchorage and the Matanuska Valley.

VICINITY MAP

LEGEND

- Agrium Ambient Air Quality Monitoring Station
- Ambient Air Quality Monitoring Station
- Meteorological Monitoring Station
- Roads

0 0.2 0.4 Miles

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LIQUEFACTION FACILITY AMBIENT AIR MONITORING AND METEOROLOGICAL STATION LOCATIONS

FIGURE 9.2.2-2

ALASKA LNG

X:\AKLNG\Resource Reports\RR09\Figure 9_2_2-2 Liquefaction Facility Ambient Air Monitoring and Meteorological Station Locations.mxd

9.2.2.3 Existing Ambient Air Quality Management and Regulation

9.2.2.3.1 Air Quality Control Regions

Air quality in Alaska is regulated by ADEC through an approved State Implementation Plan (SIP) for air quality. The specific regulations that may apply to the Project are identified in Sections 9.2.4 (construction) and 9.2.6 (operations). The Alaska SIP divides the state into four separate Air Quality Control Regions:

- AQCR 008[3] – Cook Inlet Intrastate Air Quality Control Region;
- AQCR 009 – Northern Alaska Intrastate Air Quality Control Region;
- AQCR 010 – South Central Alaska Intrastate Air Quality Control Region; and
- AQCR 011 – Southeastern Alaska Intrastate Air Quality Control Region.

A depiction of the Air Quality Control Regions is provided in Figure 9.2.2-3. The Project involves only two of the regions, the Cook Inlet and Northern Alaska Regions, which are generally separated by the center of the Alaska Range (ADEC, 1972).

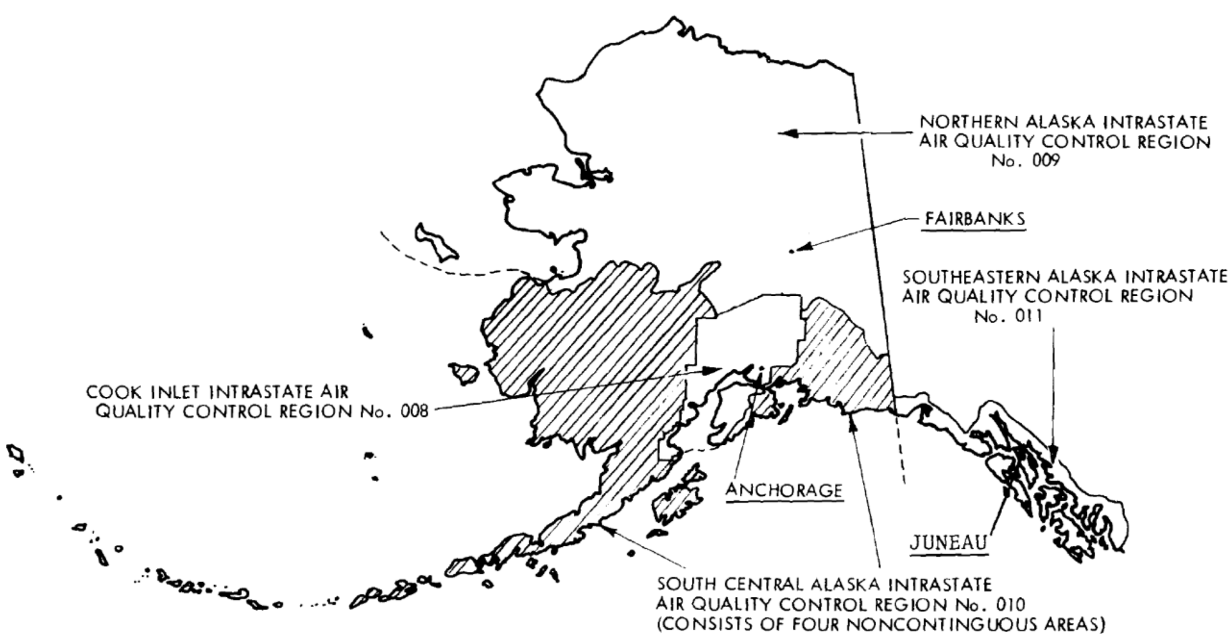


FIGURE 9.2.2-3 Alaska Air Quality Control Regions

[3] Air Quality Control Region numbers are established nationally for all states in alphabetical order. Alaska begins with AQCR 008.

Air quality is regulated by the federal Clean Air Act (CAA) in part through its PSD rules implemented in 40 C.F.R. §52.21 and in the Alaska Administrative Code (AAC) 18 AAC 50.020. The PSD rules limit the future increases in ambient air concentrations of NO_2, SO_2, PM_{10}, and $PM_{2.5}$, and establish "minor source baseline dates" for determining a date, after which the air quality deterioration must be within the PSD increments or regulatory limits. The baseline dates are established for all Air Quality Control Regions in 18 AAC 50.020, and are also provided in Table 9.2.2-5.

The Cook Inlet and Northern Alaska Air Quality Control Regions are relevant to the Project. Increases in emissions after the baseline dates for each of the four respective pollutants consume part of the allowable ambient air quality increment within the respective regions. This increment consumption is formally regulated on a source-specific permitting basis, as discussed in Sections 9.2.5.1 and 9.2.5.2.

TABLE 9.2.2-5

Alaska Baseline Areas and Dates

Baseline Area	Air Pollutant	Minor Source Baseline Date
Cook Inlet Intrastate Air Quality Control Region	Nitrogen dioxide	February 8, 1988
	Sulfur dioxide	October 12, 1979
	PM-10	March 20, 1982
	PM-2.5	September 14, 2012
Northern Alaska Intrastate Air Quality Control Region	Nitrogen dioxide	February 8, 1988
	Sulfur dioxide	June 1, 1979
	PM-10	November 13, 1978
	PM-2.5	November 2, 2012
South Central Alaska Intrastate Air Quality Control Region	Nitrogen dioxide	February 8, 1988
	Sulfur dioxide	October 26, 1979
	PM-10	October 26, 1979
	PM-2.5	October 15, 2015
Southeast Alaska Intrastate Air Quality Control Region	Nitrogen dioxide	February 8, 1988
	Sulfur dioxide	November 10, 1986
	PM-10	To be established under 40 C.F.R. 52.21(b)(14)(ii), adopted by reference in 18 AAC 50.040(h)
	PM-2.5	To be established under 40 C.F.R. 52.21(b)(14)(ii), adopted by reference in 18 AAC 50.040(h)

Source: 18 AAC 50.020 (ADEC 2016b)

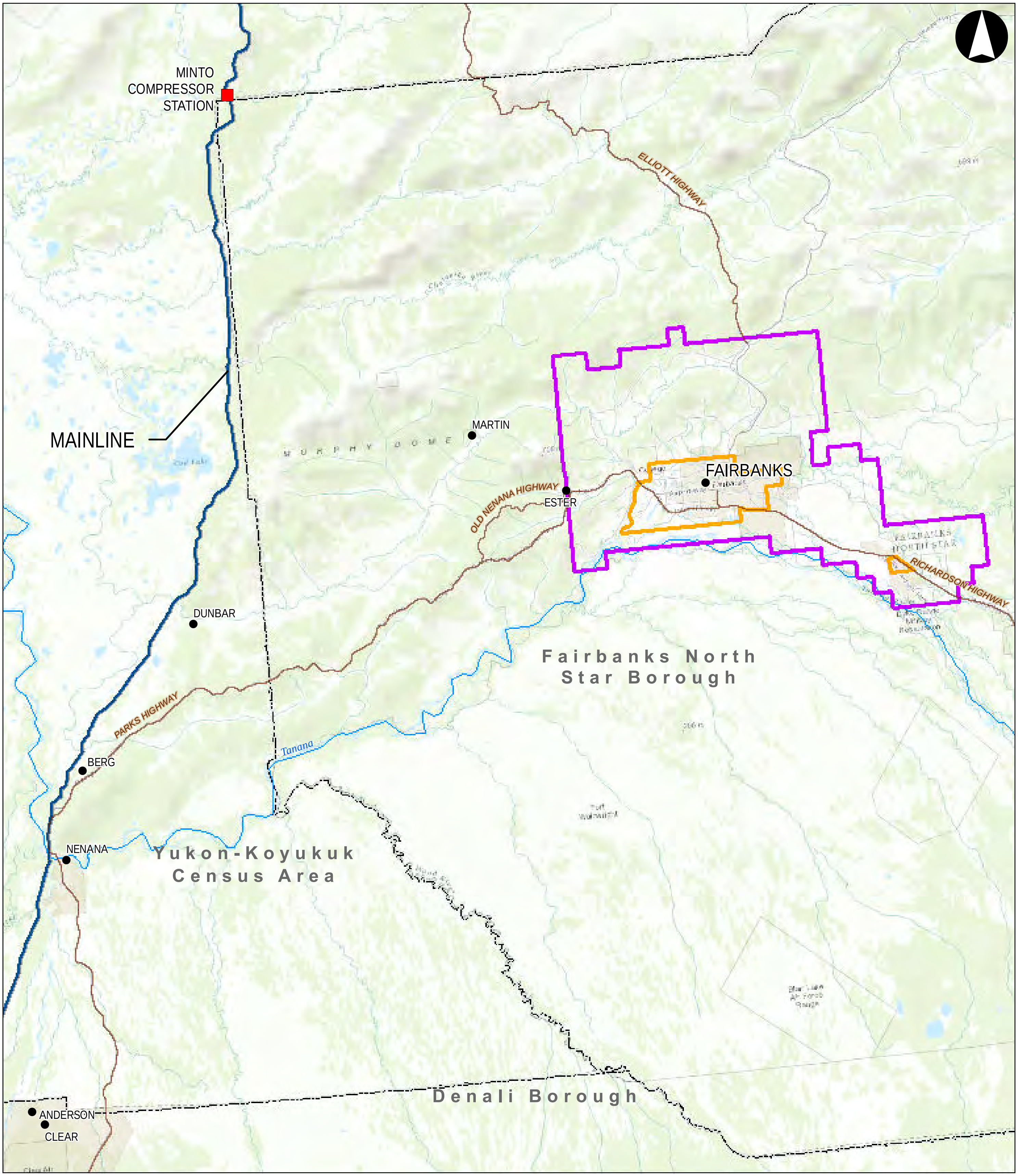
9.2.2.3.2 NAAQS Attainment and Non-Attainment Areas

The CAA requires geographic areas that do not meet a particular NAAQS to be designated as "non-attainment" for that individual standard. Other areas can be designated as "in attainment" if data show that the area meets the standard, as "unclassified," or as "unclassified/attainment" with respect to the standards. An area may also be designated as a "maintenance" area if it has previously been in non-attainment for a pollutant, but has since implemented a SIP that has brought the area back into attainment for the pollutant.

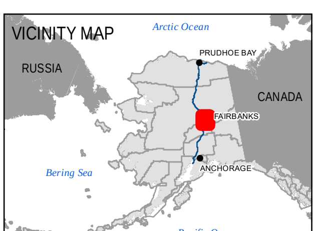
Alaska has one non-attainment area and four maintenance areas (ADEC, 2016b; EPA, 2015b; and 40 C.F.R 81.302). The Fairbanks and North Pole urban area is designated as non-attainment for $PM_{2.5}$.[4] The Mendenhall Valley in the City and Borough of Juneau and the Eagle River area in the Municipality of Anchorage are designated as maintenance areas for PM_{10}. The Municipality of Anchorage and the Fairbanks and North Pole urban area are designated as maintenance areas for CO. ADEC's SIP describes how the State of Alaska will comply with the CAA and achieve attainment with the NAAQS and/or AAAQS.

The Project area is currently designated as attainment or unclassified for all criteria pollutants. A short segment of the Mainline corridor extends into the Fairbanks North Star Borough, but the location of the Project corridor and nearest compressor station (Minto) is approximately 21 miles west and 25 miles northwest, respectively, of the border of the established $PM_{2.5}$ non-attainment area and a greater distance from the Fairbanks CO maintenance area. Figures 9.2.2-4 and 9.2.2-5, respectively, provide the proximity of the Project to the Fairbanks and Anchorage non-attainment and maintenance areas.

[4] On November 20, 2015, ADEC filed a request with EPA to divide the Fairbanks PM2.5 non-attainment area into two non-attainment areas—a western area that would include the City of Fairbanks and an eastern area that would include the City of North Pole. ADEC states that dividing into two areas would allow development of air quality plans and controls tailored to the situation in each area.



VICINITY MAP



LEGEND

- Project Facility
- Alaska Place Names
- Alaska LNG Rev C2 Route
- Major Highways
- Major Rivers
- CO Maintenance Area
- PM-2.5 Non-Attainment Area
- Borough/ Census Area Boundary

0 2.5 5 10 Miles

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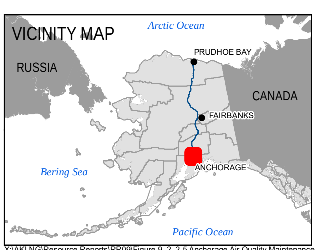
FAIRBANKS AIR QUALITY NON-ATTAINMENT AND MAINTENANCE AREAS

FIGURE 9.2.2-4

ALASKA LNG

X:\AKLNG\Resource Reports\RR09\Figure 9_2_2-4 Fairbanks Air Quality Non-Attainment and Maintenance Areas.mxd



LEGEND

- Alaska Place Names
- Alaska LNG Rev C2 Route
- Roads
- Borough/ Census Area Boundary
- CO Maintenance Area
- PM 10 Maintenance Area

0 2.5 5 10 Miles

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ANCHORAGE AIR QUALITY MAINTENANCE AREAS

FIGURE 9.2.2-5

ALASKA LNG

X:\AKLNG\Resource Reports\RR09\Figure 9_2_2-5 Anchorage Air Quality Maintenance Areas.mxd

9.2.2.3.3 PSD Class I Areas

Under the CAA, certain lands are designated as Class I Areas. Class I Areas are so designated because their air quality is considered a special attribute of these locations (e.g., national parks, wilderness areas). Class I Areas have more stringent requirements for incremental changes in criteria pollutant concentrations and impacts on air quality related values (AQRVs), such as visibility and acidic deposition.

There are four Class I areas in the State of Alaska (EPA, 2011):

- Bering Sea Wilderness Area;
- Denali National Park and Preserve (DNPP);
- Simeonof Wilderness Area; and
- Tuxedni Wilderness Area.

As shown on Figure 9.2.2-6, the Tuxedni Wilderness Area and DNPP are the Class I areas in proximity to the Project. The Liquefaction Facility is the only Project PSD facility within 300 kilometers of a Class I area. The Liquefaction Facility is estimated to be approximately 50 miles (80 kilometers) from the Tuxedni Wilderness Area, which is southwest of the Liquefaction Facility and across Cook Inlet. The Liquefaction Facility is about 115 miles (185 kilometers) from DNPP. LNGC traffic traversing Cook Inlet could travel within approximately 12 to 19 miles (20 to 30 kilometers) of the Tuxedni Class I area. In some areas, the Mainline corridor approaches within less than 1 mile of the eastern boundary of DNPP; however, there are no PSD-reviewed facilities to be constructed along this corridor[5].

9.2.2.3.4 Sensitive Class II Areas

In addition to PSD Class I Areas, federal land managers (FLMs) have identified "Sensitive Class II Areas," which are federal conservation units deemed to merit analysis of ambient air quality and AQRVs. Through consultation with FLMs, the following Sensitive Class II Areas and the respective Federal Land Management agencies have been identified for further analysis of impacts from the Project:

- Arctic National Wildlife Refuge (NWR) (U.S. Fish and Wildlife Service [USFWS]);
- Gates of the Arctic National Park and Preserve (National Park Service [NPS]);
- Kanuti NWR (USFWS);
- Yukon Flats NWR (USFWS);
- Lake Clark National Park and Preserve (NPS);
- Kenai NWR (USFWS);
- Chugach National Forest (U.S. Forest Service [USFS]);
- Kenai Fjords National Park (NPS); and
- Kodiak NWR (USFWS).

[5] Air-shed impacts at DNPP would be considered for nearby compressor station/heater station facilities. See locations in Section 9.2.2.3.4.

Figure 9.2.2-7 shows where these Class I and Sensitive Class II Areas are in relationship to Project facilities.

9.2.2.3.5 Air Quality Related Values (AQRVs)

AQRVs are resources, as defined by FLMs, that may be adversely affected by a change in air quality, and include visibility (either regional haze or plume impairment) and sulfur and nitrogen deposition, often called "acid deposition." The FLMs' AQRV Work Group (FLAG) issued a guidance document (FLAG 2010) for the methodology and AQRV criteria used to evaluate adverse impacts. This guidance and associated screening thresholds were developed primarily for evaluating impacts at Class I areas.

Because the AQRVs only have screening thresholds below which no concern exists, rather than strict regulatory standards, AQRV impacts are typically evaluated on a case-by-case basis by FLMs. As part of the impact evaluation, the FLMs consider such factors as magnitude, frequency, duration, location, geographic extent, timing of impacts and current and projected conditions of AQRVs. In practice, this methodology often results in the need to place AQRV impacts into context.

Note that the location of these Class I or Sensitive Class II areas in the near field (within approximately 50 kilometers) or in the far field (beyond approximately 50 kilometers) determines the applicable model and AQRVs to be evaluated. In the case of visibility, "plume impairment" is the AQRV analysis conducted in the near field whereas "regional haze" is the AQRV analyzed in the far field.

Plume Impairment

Plume impairment is generally defined as the pollutant loading of a portion of the atmosphere such that the plume becomes visible, by contrast or color difference, against a viewed background such as a landscape feature or the sky. The evaluation criteria for plume impairment are the color difference index (ΔE) and plume contrast (Cp). Plume impairment below the values in Table 9.2.2-6 are considered negligible and no further analysis is warranted. This AQRV is generally applicable for near-field (approximately less than 50 kilometers) source-receptor distances and modeled using the VISCREEN screening model or the PLUVUE II model if more information is required.

According to FLAG 2010, if the screening thresholds are met with VISCREEN, the FLM is likely not to object to the project on the basis of near-field visibility. If screening thresholds are not met, then use of the more refined PLUVUE II model can be implemented. The PLUVUE analysis provides additional information designed to assess the magnitude and frequency of plume impairment.

TABLE 9.2.2-6

Plume Impairment Initial Screening Thresholds

Model	Color Difference Index (ΔE)	Contrast (Cp)
VISCREEN	2.0	0.05
PLUVUE II	1.0	0.02

Regional Haze

Visibility impairment is also manifested by the general alteration in the appearance of landscape features or the sky as the light between the observer and target becomes scattered or absorbed by pollutant loading in the atmosphere. This impairment results in a reduction of contrast between distant landscape features causing the view of the landscape features to deteriorate. This AQRV is generally applicable for far field (greater than approximately 50 kilometers) source-receptor distances or for multiple source analyses. CALPUFF is currently the recommended model to assess regional haze impacts using methodologies and inputs described in FLAG 2010.

Screening criteria, shown in Table 9.2.2-7, represent the incremental increases above a reference background level. According to FLAG 2010, if the 98th percentile change in light extinction is less than 5 percent, the visibility threshold of concern is not exceeded. Regional haze impacts due to project sources alone that are below this threshold are considered negligible and often no further analysis is warranted.

Cumulative regional haze impacts due to both project and offsite sources are typically compared to a 10 percent change in light extinction. If this threshold is exceeded at an area being evaluated, the FLM may consider the impacts on a case-by-case basis by taking into account the context when making an adverse impact determination.

TABLE 9.2.2-7

Regional Haze Initial Screening Thresholds

Description	Change in Extinction
Contribute to visibility impairment	5%
Cause visibility impairment	10%

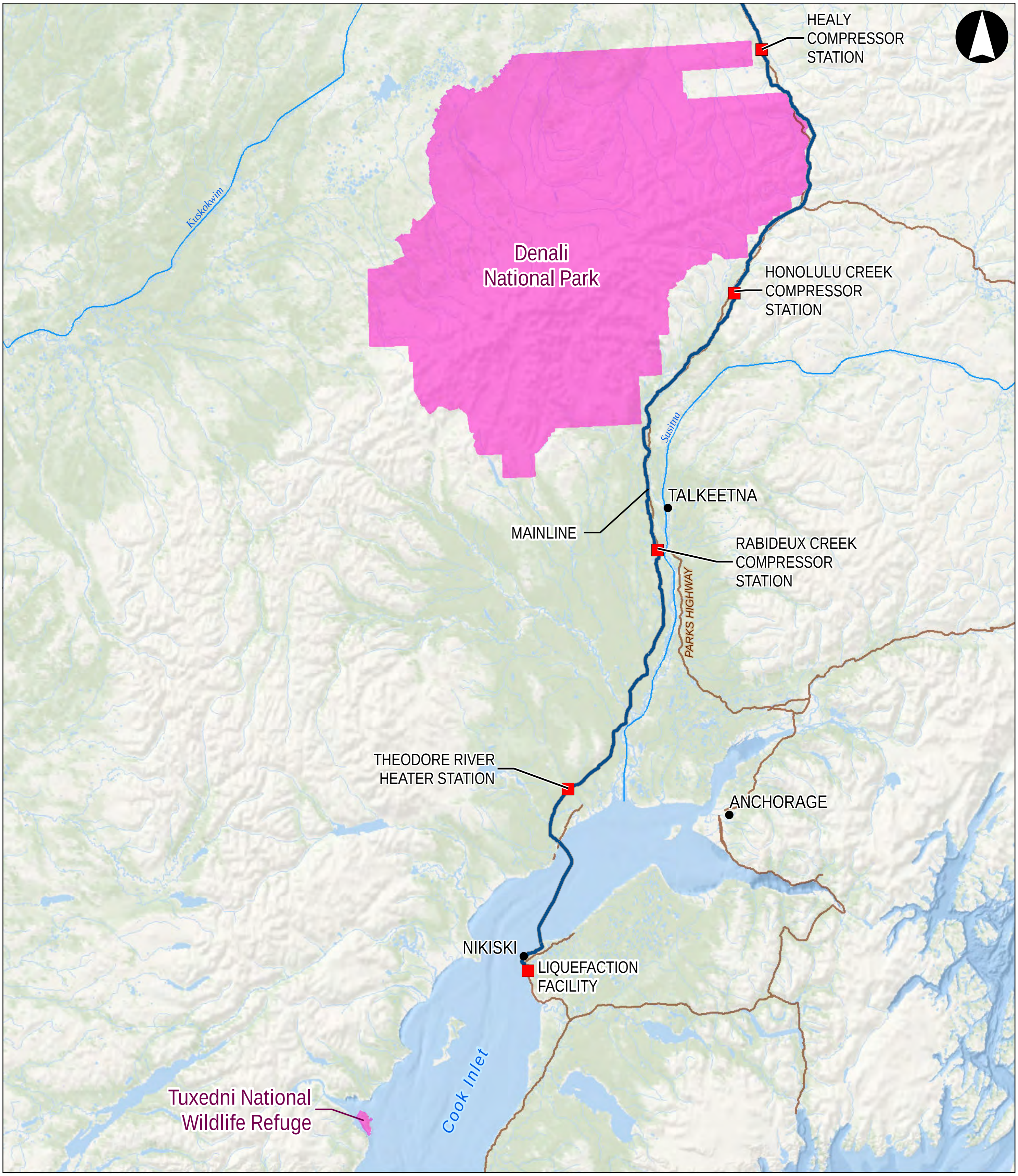
Acid Deposition

Increased nitrogen (N) or sulfur (S) deposition may result from emissions from new facilities and have a negative impact on AQRVs sensitive to N or S deposition. Dry and wet atmospheric deposition of N and S compounds is also an AQRV that is discussed in FLAG 2010. FLMs have established Deposition Analysis Thresholds (DATs), listed in Table 9.2.2-8 to use as screening levels for incremental increases in N or S compounds due to a proposed facility. Facility-only deposition of N or S below the DAT of 0.005 kilogram/hectare/year (kg/ha/yr) is considered negligible.

TABLE 9.2.2-8

Deposition Analysis Thresholds

Pollutant	Facility Deposition (kg/ha/yr)
Nitrogen	0.005
Sulfur	0.005



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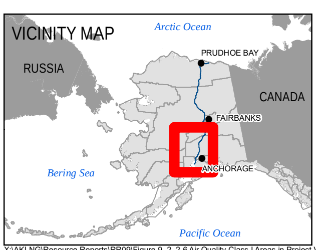

LEGEND

- Project Facility
- Alaska Place Names
- Alaska LNG Rev C2 Route
- Major Highways
- Major Rivers
- Air Quality Class I Areas

0 25 50 Miles

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AIR QUALITY CLASS I AREAS IN THE PROJECT VICINITY

FIGURE 9.2.2-6

ALASKA LNG

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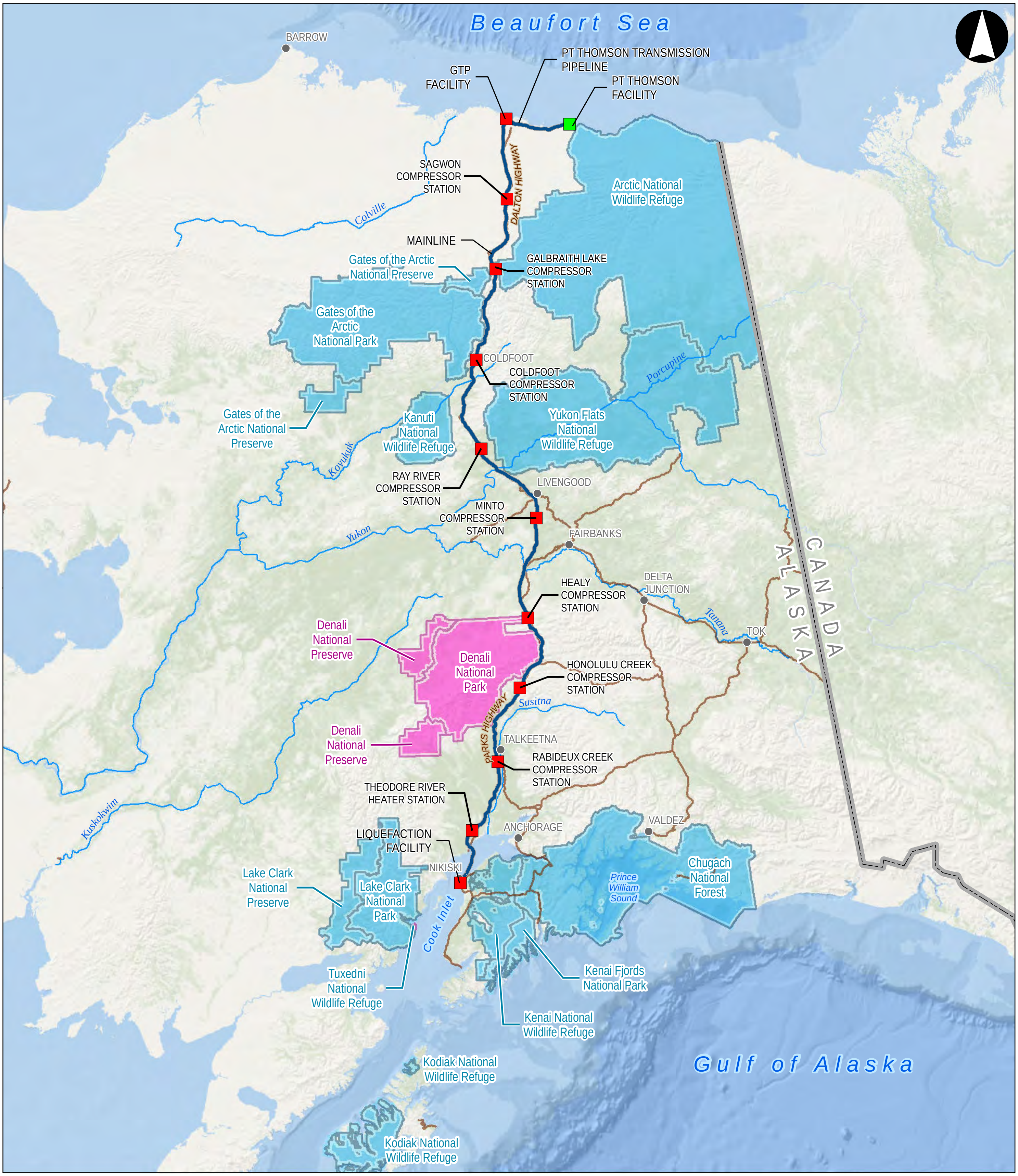

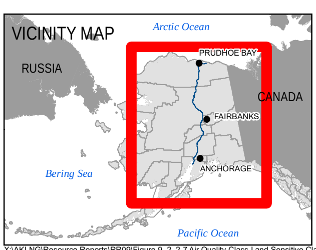

LEGEND

- Project Facility
- Existing Facility
- Alaska Place Names
- Alaska LNG Rev C2 Route
- Major Highways
- Major Rivers
- Air Quality Class I Areas
- Sensitive Class II Areas

0 50 100 200 Miles

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AIR QUALITY CLASS I AND SENSITIVE CLASS II AREAS IDENTIFIED FOR THE ALASKA LNG PROJECT

FIGURE 9.2.2-7

ALASKA LNG

X:\AKLNG\Resource Reports\RR09\Figure 9_2_2-7 Air Quality Class I and Sensitive Class II Areas Identified for the Alaska LNG Project.mxd

9.2.3 Air Quality Emissions and Potential Impacts from Construction Sources

Impacts to air quality from Project construction would include temporary emissions from construction equipment and support operations (e.g., construction camps), as well as fugitive dust from soil handling, storage, and replacement activities; and from gravel and other dust generating materials. This section provides a summary of estimated construction emissions for the major Project facilities, which are supported by calculations based on Project execution data provided in Appendix C: Emissions Associated with Project Construction.[6] Emissions are also estimated for construction of marine systems and the marine offloading facility (MOF) at the Liquefaction Facility Marine Terminal, the marine component of the pipeline, and for construction of marine offloading facilities in support of the GTP construction. Construction emission details are based on information available to date.

9.2.3.1 Methodology for All Project Components

Project construction would result in air emissions of federal and Alaska criteria air pollutants (nitrogen oxides [NO_X], SO_2, CO, PM_{10}, $PM_{2.5}$, and volatile organic compounds [VOCs]) and greenhouse gases (GHGs) (carbon dioxide [CO_2], methane [CH_4], and nitrous oxide [N_2O]). Emissions of these pollutants are estimated from available data for the full range of construction activities, including combustion, non-combustion, and fugitive sources, using generally accepted emission factors for construction equipment and activity.

9.2.3.1.1.1 Combustion Emissions

Combustion sources include tailpipe emissions from heavy equipment (non-road engines used to power construction equipment), mobile vehicles used to support construction, diesel-fired engines to support power generation, portable equipment, and support systems such as construction camps. Typical non-road engines, portable equipment, and mobile sources include:

- Surface operations, including excavators, trenchers, graders, scrapers, and compactors, which are used to build roads, structure foundations, laydown areas, and temporary surfaces;
- Construction equipment, including cranes, loaders, forklifts, pile drivers, and aerial lifts;
- Support equipment engines, including pumps, compressors, electric power generators, saws, and welders; and
- On-road support vehicles and trucks, including construction and use of access roads.

Construction of each Project facility and the pipeline would include the installation of a construction camp to house employees near the Project site. The camp would provide a full range of services related to maintaining a construction crew, including sleeping quarters, a dining hall, personnel comfort features, and other services to support construction. Camp operations would require several combustion sources,

[6] Note, the schedule provided in Appendix C is subject to change..

including power generators, waste incinerators, and space heating operations. Camp operation would also provide urban-style commuter buses to transport crew members between camps and construction sites.

Estimated combustion emissions are based on the equipment design (e.g., horsepower), projected fuel use or hours of operation, fuel type, and an average load factor for equipment operation from available emissions databases. Key emission factors were based on the following:

- Vendor-specific emission factors, where available;
- EPA diesel engine "Tier" standards in 40 C.F.R. Part 89 and Part 1039;
- EPA (2009) emission factors for non-road equipment operating in Alaska;
- EPA (2014b) MOVES2014 data for on-road vehicles;
- EPA (1995) AP-42 emission factors for internal and external combustion equipment; and
- Specific emission factors for marine sources, locomotives, aircraft, and other equipment.

Operational data for equipment and other construction activities, including a listing of equipment, horsepower, and hours of operation, were used to estimate the combustion emissions in Appendix C. Emissions from construction camp electric power generators and waste incinerators are estimated based on expected peak personnel at each camp. Generally, however, engine horsepower ratings for specific construction equipment are estimated from typical equipment.

Open burning of brush cleared from the construction right-of-way would generate combustion emissions. Open burning activity levels will be determined when construction contractors are selected.

9.2.3.1.1.2 Non-Combustion Point Sources

Construction may also include non-combustion emissions, such as vented vapors from tanks. Estimates of these emissions are included in Appendix C.

9.2.3.1.1.3 Fugitive Emissions

Civil construction leads to fugitive dust and particulate matter emissions from a wide array of activities. Clearing, grubbing, site preparation, excavation, drilling and blasting, soil handling, storage piles, construction materials handling, vehicular traffic on paved or unpaved roads, and other activities emit fugitive dust. Emission calculations for fugitive dust are based on commonly accepted methods, including the EPA's AP-42, which often include site-specific parameters such as soil moisture, silt content, exposed acreage, wind speed, and frequency of precipitation. Activity levels are derived from estimates of parameters, such as vehicle weight, vehicle speed, volumes handled, and hours of operation. Additionally, fugitives may result from activities that emit organic compounds, such as solvent application, coatings, and painting during construction. Except for emission from storage piles, fugitive emissions from construction activities are transient in nature and likely to occur at any one location for a few hours within a single day.

Estimated emissions are provided in Appendix C.

9.2.3.2 Liquefaction Facility

Construction of the Liquefaction Facility would occur on an approximate 900-acre site located near Nikiski, and would include construction of facilities for LNG production, storage, transfer (all considered the LNG Plant), and construction of a MOF and carrier loading facilities at the Marine Terminal. Construction would take place over an eight-year period and include construction equipment both on the Project site and within Cook Inlet waters. A construction camp for workers would be operated during construction. See Resource Report No. 1 for further details on Liquefaction Facility construction. See Section 9.2.3.1 for a general description of the methodology for calculating construction emissions.

9.2.3.2.1 LNG Plant Construction Emissions

Construction of the LNG Plant and adjacent Marine Terminal is planned for an eight-year period with the total annual emissions for each of those years summarized in Table 9.2.3-1. See Resource Report No. 1 for additional details regarding construction activities. Construction activities would begin with site clearing and stabilization, and include roadway construction, installation of a worker camp, and operating specific project construction equipment noted earlier in this report. See Appendix C for further details on construction emissions, including limitations in data.

TABLE 9.2.3-1

Total Annual Construction Emissions for the Liquefaction Facility and Marine Terminal (Combined)

Project Construction Year	Tons/Year						Data in Metric Tonnes CO_2e/Year
	VOC	NOx	CO	PM_{10}	$PM_{2.5}$	SO_2	GHG
2	19	366	60	649	76	6	28,534
3	29	637	80	483	62	17	46,077
4	106	1,260	705	2,555	285	27	158,307
5	125	836	1,047	4,701	503	15	170,477
6	97	293	1,004	4,509	478	8	83,941
7	76	224	774	4,227	446	7	64,595
8	43	157	435	3,522	368	4	42,951
9	33	110	396	2,120	222	3	27,043
TOTAL	528	3,883	4,501	22,766	2,440	87	621,925

9.2.3.2.2 Marine Terminal Construction Emissions

Construction of the Marine Terminal adjacent to the LNG site would include the installation of various in-water structures related to the Marine Terminal operations. Many construction activities would take place from barges and tugs, and include cranes, loaders, pile drivers, and support vehicles and operations. Support equipment includes power generators and compressors and haul trucks during construction.

Construction of the Marine Terminal is planned for a two-year period beginning in Year 2 of the Liquefaction Facility construction schedule. The total annual emissions for each of those years are included in Table 9.2.3-1.

9.2.3.3 Interdependent Project Facilities

9.2.3.3.1 Pipeline Construction Emissions

9.2.3.3.1.1 Mainline

A description of construction of the Mainline components follows. See Resource Report No. 1 for additional details on pipeline construction. See Section 9.2.3.1 for a general description of the methodology for calculating construction emissions for the pipeline and associated aboveground facilities. See Appendix C for further details on construction emissions, including known current gaps in data.

The Mainline pipeline would be constructed simultaneously in four separate spreads of approximately 200 miles each, over six years. Eight compressor stations, including one combined compressor station and collocated heater station, plus one standalone heater station would be constructed over a three-year period at same time as construction of the Mainline. The location of each station is identified in Table 9.2.3-2. Due to their proximity to Mainline pipeline construction, each station's emissions were included in the emissions with the associated construction spread at that location. Actual station construction would occur using three separate pipeline facility construction contractors operating independently from Mainline spread contractors.

TABLE 9.2.3-2

Compressor and Heater Station Locations for Mainline Pipeline

Compressor or Heater Station	MP	Pipeline Facility Construction Contractor (CC)	Mainline Spread
Sagwon Compressor Station	75.97	CC1	1
Galbraith Lake Compressor Station	148.51	CC1	1
Coldfoot Compressor Station	240.10	CC1	2
Ray River Compressor Station	332.64	CC2	2
Minto Compressor Station	421.55	CC2	3
Healy Compressor Station	517.62	CC2	3
Honolulu Creek Compressor Station	597.35	CC3	3/4
Rabideux Creek Compressor Station	675.23	CC3	4
Theodore River Heater Station	749.11	CC3	4

Pipeline construction for all four spreads would begin in the first year following authorization. The depictions of the areas of the separate spreads are provided in Resource Report No. 1. Emissions from marine construction of the pipeline section crossing Cook Inlet are included in Spread 4.

Table 9.2.3-3 lists the estimated construction emissions for each spread for each of the six years of planned construction. Each spread covers a distance of approximately 200 miles; as such, the emissions are spread over 200 miles instead of being concentrated. To illustrate the spread/distribution of construction over time, Figure 9.2.3-1 provides the total annual PM_{10} construction emissions for each Mainline spread, and the data depict the comparative level of construction activity for each Mainline spread for each year of construction. Data include fugitive and equipment PM_{10} emissions. The highest yearly emissions for each spread corresponds with the highest level of construction activity. For example, construction activities and emissions for Spread 3 and 4 peak in Years 3 and 4, respectively. Combined PM_{10} emissions from all spreads peaks in Year 5.

TABLE 9.2.3-3

Total Annual Construction Emissions for the Mainline Spreads

Data in ton/year								Data in Metric Tonnes CO_2e/year
Project Construction Year		**VOC**	**NOx**	**CO**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**GHG**
	Spread							
2	1	8	43	44	273	33	1	12,212
	2	15	95	110	451	85	3	26,782
	3	12	80	63	417	53	1	21,664
	4	11	56	63	321	40	1	15,327
	Total	46	274	280	1,462	211	6	75,985
3	1	17	118	107	757	120	2	37,971
	2	21	139	194	710	143	4	43,885
	3	26	164	148	1,469	181	2	53,448
	4	14	76	80	542	64	2	21,130
	Total	78	497	529	3,478	508	10	156,434
4	1	19	139	130	678	104	3	38,658
	2	14	117	113	401	82	3	26,041
	3	21	125	110	694	82	3	33,030
	4	39	386	187	1,498	173	7	74,543
	Total	93	767	540	3,271	441	16	172,272
5	1	33	236	176	1,911	243	5	68,321
	2	35	253	196	1,229	167	5	69,744
	3	36	244	179	1,518	183	5	68,158
	4	208	5,001	521	1,104	185	150	261,141
	Total	312	5,734	1,072	5,762	778	165	467,364
6	1	24	212	117	1,936	229	3	57,717
	2	20	168	87	953	118	2	46,861
	3	15	125	74	863	105	2	31,419
	4	19	237	68	862	95	5	36,487
	Total	78	742	346	4,614	547	12	172,484
7	1	4	27	16	275	29	0	8,994
	2	2	11	4	87	9	0	3,201
	3	2	7	9	1	1	0	2,958
	4	1	5	2	31	3	0	1,463
	Total	9	50	31	394	42	0	16,616
Spread								
All	1	105	775	590	5,830	758	14	223,873
	2	107	783	704	3,831	604	17	216,514
	3	112	745	583	4,962	605	13	210,676
	4	292	5,761	921	4,358	560	165	410,092

TABLE 9.2.3-3

Total Annual Construction Emissions for the Mainline Spreads

Data in ton/year								Data in Metric Tonnes CO_2e/year
Project Construction Year		**VOC**	**NOx**	**CO**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**GHG**
	Total	6,16	8,064	2,798	18,981	2,527	209	1,061,155

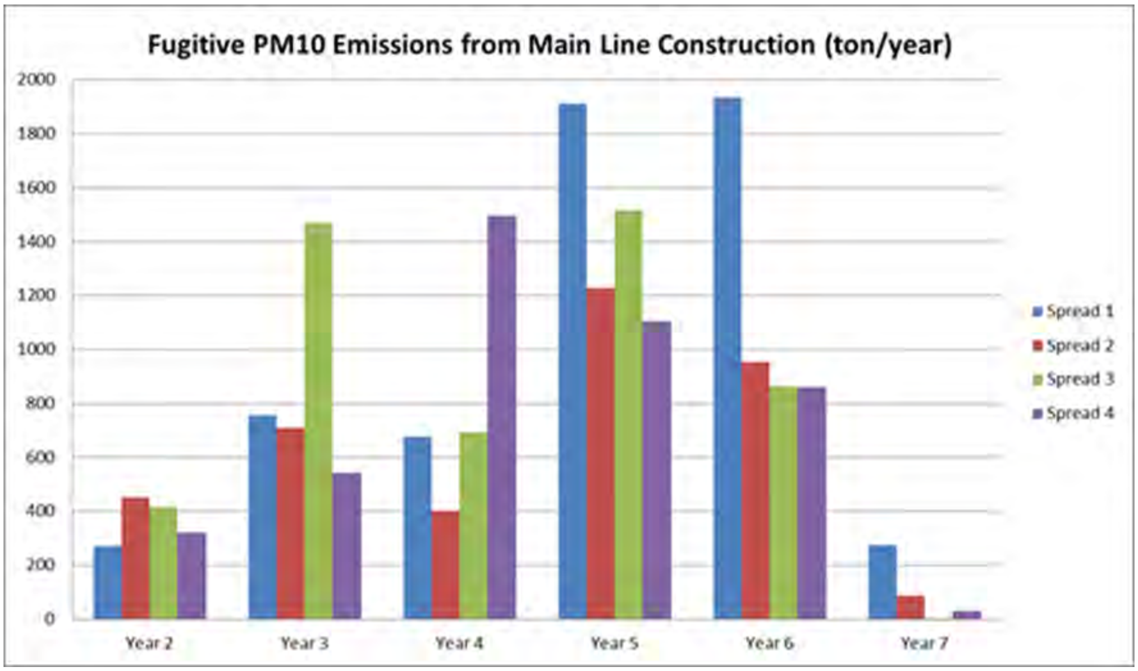


FIGURE 9.2.3-1 Total Annual PM_{10} Construction Emissions for the Mainline Spreads

9.2.3.3.1.2 Prudhoe Bay Gas Transmission Line (PBTL)

The methodologies for estimating construction emissions from the PBTL are identical to those of the Mainline, including both the available and unavailable data. See Resource Report No. 1 and Section 9.2.3.1 for more details. Supporting documentation is provided in Appendix C.

As noted in Resource Report No. 1, the PBTL would be constructed during the winter. Because there are no trees or brush on the PBTL corridor, there would be no open burning. Emissions from construction of this line would occur within a one- to two-year period, and would not involve a separate construction camp.

Table 9.2.3-4 provides a summary of the total annual emissions of criteria air pollutants and GHGs for construction of the PBTL. Due to its proximity, PBTL construction emissions are also included in the total GTP construction emissions.

TABLE 9.2.3-4

Total Annual Construction Emissions for the Prudhoe Bay Gas Transmission Line

Project Construction Year	tons/year						Metric Tonnes CO_2e/year
	VOC	NOx	CO	PM_{10}	$PM_{2.5}$	SO_2	GHG
2	0.0	0.1	0.0	2.1	0.2	0.0	11
3	0.5	4.0	1.9	11.4	2.0	0.0	940
TOTAL	0.5	4.1	1.9	13.5	2.2	0	951

9.2.3.3.1.3 Point Thomson Gas Transmission Line (PTTL)

The methodologies for estimating construction emissions from the PTTL are identical to those of the Mainline, including both the available and unavailable data. See Resource Report No. 1 and Section 9.2.3.1 for more details. Supporting documentation is provided in Appendix C.

As noted in Resource Report No. 1, the PTTL would be constructed during the winter. Because there are no trees and limited brush on the PTTL corridor, there would be no open burning. Emissions from construction of this line occur within a two-year period, beginning in Year 3 and completing in Year 4, and do not involve a separate construction camp. Pipeline construction would occur over two spreads.

Table 9.2.3-5 provides a summary of the total annual emissions of criteria air pollutants and GHGs for construction of the PTTL.

TABLE 9.2.3-5

Total Annual Construction Emissions for the Point Thomson Gas Transmission Line (PTTL)

Project Construction Year	tons/year						Metric Tonnes CO_2e/year
	VOC	NO_X	CO	PM_{10}	$PM_{2.5}$	SO_2	GHG
3	9	62	56	395	49	1	15,279
4	15	56	87	374	52	2	21,877
5	0	0	0	0	0	0	0
6	0	2	1	24	2	0	352
TOTAL	24	120	144	793	103	3	37,508

9.2.3.3.2 Gas Treatment Plant (GTP) Construction Emissions

The GTP would be constructed at Prudhoe Bay on the North Slope near the Beaufort Sea coast. In addition to the GTP facilities, construction would include installation of improvements at West Dock to support marine sealift operations, module staging area, haul roads from West Dock to the GTP site, quarry operations, installation of several support pipelines within the PBU, custody transfer facilities, and appurtenant support facilities (e.g., electrical interconnections). Construction activities would take place over nine years, beginning in Year 1 of the Project construction schedule. See Resource Report No. 1 for further details on GTP construction. See Section 9.2.3.1 for a general description of the methodology for calculating construction emissions. See Appendix C for further details on construction emissions, including gaps in data.

Table 9.2.3-6 provides a summary of the total annual emissions of criteria air pollutants and GHGs for construction of the GTP and appurtenant facilities, including the PBTL.

TABLE 9.2.3-6

Total Annual Construction Emissions for the Gas Treatment Plant (GTP)

Project Construction Year	tons/year						Metric Tonnes CO_2e/year
	VOC	NOx	CO	PM_{10}	$PM_{2.5}$	SO_2	GHG
1	3	29	20	140	15	0	6,897
2	17	147	141	683	137	3	50,110
3	21	244	184	597	117	7	49,861
4	18	217	168	515	73	6	45,462
5	22	245	223	572	71	8	58,961
6	23	241	234	565	70	8	61,684
7	21	227	198	604	72	6	55,536
8	14	187	93	537	64	6	32,979
9	4	28	22	247	26	0	11,475
TOTAL	143	1,565	1,283	4,460	645	44	372,965

9.2.3.4 Non-jurisdictional Facilities

Construction emissions from the PTU Gas Expansion project and PBU MGS project would be similar to GTP, PBTL, and PTTL project elements based on the following:

- North Slope construction methods for logistics and winter/summer timing of activities;
- Use of granular pads for infrastructure components;
- Aboveground pipeline design and installation methods;
- Use of modular facilities that are fabricated elsewhere; and
- Use of drilling equipment and procedures adapted to North Slope conditions.

The PTU Gas Expansion is expected to begin construction in Year 3 and with construction completed in Year 7. PTU drilling to support the Project would begin in Year 5 and would be completed in Year 8. For the PBU MGS project, construction would begin in Year 2 and would be completed in Year 6. Drilling at the PBU to support the Project would begin in Year 6 and be completed in Year 10.

Kenai Spur Highway relocation project construction emissions would be similar to site preparation, granular material source development, and road construction elements for the Liquefaction Facility and site clearing construction elements of the Mainline based on the following:

- Kenai and Nikiski area construction methods and logistics based on vegetation, soil, and groundwater conditions;
- Use of local area material sources; and
- Typical paved road design and construction methods for classified fill, compaction, and paving.

Construction to relocate the Kenai Spur Highway would begin in Year 1 and would be complete in two construction seasons.

Table 9.2.3-7 provides a summary of the total annual emissions of criteria air pollutants and GHGs for construction of the non-jurisdictional facilities, including the PTU Expansion project, PBU MGS project, and Kenai Spur Highway relocation. These emissions include drilling at the PTU and PBU. See Appendix G for further details.

TABLE 9.2.3-7

Total Annual Construction and Drilling Emissions for Non-Jurisdictional Facilities

Project Construction Year	tons/year						Metric Tonnes CO_2e/year
	VOC	NOx	CO	PM_{10}	$PM_{2.5}$	SO_2	GHG
1	1	9	6	8	2	0	1,384
2	4	26	30	105	13	0	7,490
3	363	911	1,450	274	134	2	73,827
4	720	1,732	2,864	558	267	3	139,301
5	949	3,214	3,525	589	306	76	310,684
6	1,007	3,749	3,679	541	312	76	358,659
7	1,006	4,461	3,669	312	288	76	355,720
8	176	1,619	501	47	35	37	137,732
9	60	545	165	13	13	1	50,859
10	60	545	165	13	13	1	50,859
TOTAL	4,347	16,811	16,054	2,460	1,382	271	1,486,513

9.2.4 Applicable Air Quality Regulatory Requirements – Construction

Air quality regulations, both federal and state, address some aspects of the proposed construction activities. Table 9.2.4-1 lists potentially applicable federal regulations under Title 40 of the C.F.R. The cited regulations may apply directly to some construction equipment or activities.

TABLE 9.2.4-1

Federal Air Quality Regulations Potentially Applying to the Project – Construction

Citation/Part of 40 C.F.R.	Title	Description
50	NAAQS	Modeling and any monitoring must comply with NAAQS.
51 Appendix W	Guideline on Air Quality Modeling	Dispersion modeling in support of permit applications must comply with this regulation.
58 Appendix E	Air Quality Monitoring	Applies for stationary sources that submit ambient air monitoring data in support of applications
60 Subpart A	General Provisions for New Source Performance Standards (NSPS)	Includes general notifications, recordkeeping, reporting, and sampling requirements for affected units
60 Subpart Db	NSPS for boilers and heaters > 100 MMBtu/hr	Regulates NOx, SO_2, PM emissions from boilers and heaters from stationary sources
60 Subpart Dc	NSPS for boilers and heaters > 10 MMBtu/hr	Standards for small boilers, generally regulating SO_2 and PM emissions from oil (and solid fuel) fired units.
60 Subpart Kb	NSPS for Tanks <75 m^3	Can apply to tanks storing volatile organic liquids
60 Subpart OOO	NSPS for Non-metallic mineral processing plants	Applies to crushed stone, and sand and gravel processing plants above thresholds with crushers or grinding mills
60 Subpart IIII	NSPS for Compression Ignition Engines	Emissions limits, monitoring, testing requirements for diesel-fired engines based on use, horsepower, and engine sizes
60 Subpart JJJJ	NSPS for Spark Ignition Engines	Emissions limits, monitoring, testing requirements for spark ignition natural gas-fired engines based on use, horsepower, and engine sizes
68	Chemical Accident Prevention	Applies to stationary sources that have more than the threshold quantity of a regulated toxic or flammable substance
63 Subpart ZZZZ	National Emission Standards for Hazardous Air Pollutants (NESHAPs) for stationary engines	Applies to reciprocating internal combustion engines (RICE), including generators, emergency generators, firewater pumps, etc. Generally excluded if complying with NSPS Subparts IIII or JJJJ.
63 Subpart CCCCCC	NESHAPs for Gasoline Dispensing Facilities	Applies to an onsite gasoline dispensing facility, with requirements based on monthly throughput.
80 Subpart I	Emission Control Act (ECA) Marine Fuel Standards	May apply to end-users of marine fuel
82	Stratospheric Ozone Protection	Applies to facilities with listed refrigerants, to manage and control emissions or releases from those units
89	Non-road compression ignition engines	Applies to pre-2014 non-road compression-ignition engines, including portable units
91	Marine spark-ignition engines	May apply to specific marine spark-ignition engines.
93 Subpart B	General Conformity	May apply to construction activities within the Fairbanks $PM_{2.5}$ nonattainment area
94	Marine compression-ignition engines	May apply to specific marine compression-ignition engines.
98 Subparts A and C	Mandatory GHG reporting rule	Sources with > 25,000 metric tons/year of CO_2e emissions must calculate and submit annual reports of GHG emissions.
1042	Marine compression-ignition engines	May apply to certain end-users of marine compression-ignition engines
1043	Control of Emissions under Marine Pollution Protocol (MARPOL)	Controls NOx, SO_2, and PM emissions from marine vessels subject to MARPOL Protocol.

Table 9.2.4-2 provides a listing and brief description of the potentially applicable Alaska air quality regulations in Title 18 of the AAC.

TABLE 9.2.4-2

Alaska Air Quality Regulations Potentially Applying to the Project – Construction

Citation to 18 AAC 50	Title	Description
50.010	Ambient air quality	Facility must be designed and permitted to operate in compliance with ambient air quality standards
50.020	PSD Baseline dates and maximum allowable increases	Facility must be designed and permitted to operate in compliance with applicable PSD increments. Affects permitting of major sources (LNG and GTP, based on preliminary information)
50.025	Visibility and other special protection areas	Establishes visibility protections for three areas, including (1) Mt. Deborah and the Alaska Range East, as viewed from approximately the Savage River Campground area, (2) Mt. McKinley, Alaska range, and Interior Lowlands as viewed from the vicinity of wonder Lake, and (3) geographic areas classified as Class I under 18 AAC 50.15(c). This last group is also an area with federally enforceable visibility protection, but this provision allows ADEC to interpret and regulate visibility impacts under its own rules.
50.035 (a) (1) and (2)	Documents adopted by reference	Adopts the (1) ADEC *In situ Burning Guidelines for Alaska, Revision 1, revised August 2008* and (2) *Workbook for Plume Visual Impact Screening and Analysis (Revised)* EPA 454/R-92-023, October 1992 as a means of addressing visibility impacts.
50.040 (a)	New Source Performance Standards	Adopts the Federal New Source Performance Standards, including Subpart A general provisions, Subpart IIII for compression ignition reciprocating internal combustion engine, Subpart JJJJ for spark ignition reciprocating internal combustion engines, and subpart KKKK for stationary combustion turbines.
50.040(c)	National Emission Standards for Hazardous Air Pollutants	Adopts the Federal National Emission Standards for Hazardous Air Pollutants, including Subpart ZZZZ for stationary reciprocating internal combustion engines.
50.045 (d)	Prohibitions.	A person who causes or permits bulk materials to be handled, transported, or stored, or who engages in any industrial activity or construction project shall take reasonable precautions to prevent particulate matter from being emitted into the ambient air. No specific permitting or approval for compliance is required; however, the agency may take action if this provision is violated, particularly in response to a complaint by the general public.
50.050	Incinerator emission standards.	Requires opacity to be 20 percent or less averaged over any six consecutive minutes. No limit exists for particulate matter emissions for incinerators that have a rated capacity less than 1,000 pounds per hour. Project design indicates that no incinerators will exceed that design threshold, but if rated capacity is above that level, the PM emission standards would apply.
50.055	Industrial Processes and fuel burning equipment.	This rule limits visible emissions from industrial process or fuel-burning equipment to 20 percent or less for any consecutive six-minute period. Particulate matter emissions from fuel-burning equipment also must comply with grain loading standards in § (b) of the regulation. Sulfur compound emissions from an industrial process or fuel-burning equipment may not exceed 500 ppm averaged over three hours.

TABLE 9.2.4-2

Alaska Air Quality Regulations Potentially Applying to the Project – Construction

Citation to 18 AAC 50	Title	Description
50.065	Open burning	The rule specifies requirements for open burning standards. The regulation includes an array of requirements, including minimizing emissions, prohibiting combustion of toxic compounds, and avoidance of open burning during periods of adverse dispersion, as well as provisions for dealing with complaints. When construction contractors are selected, the Open Burning Plan for the Project would address the requirements of this regulation.
50.070	Marine Vessel visible emission standards	Establishes marine vessel visible emission standards and would apply to marine vessels that are used in support of construction both of the pipeline across Cook Inlet and of the LNG terminal facilities. Specific visibility standards apply to these vessels.
50.080	Ice fog standards	Allows ADEC to require a permit to reduce water vapor emissions for fuel burning equipment or an incinerator in areas of potential ice fog
50.100	Nonroad engines	Specifies that the emissions from non-road engines (heavy equipment, portable generators, and any engines that are temporary) are not included when determining the classification of a stationary source or modification for a permit
50.110	Air pollution prohibited	ADEC can restrict emissions which may be injurious to health, welfare, property or unreasonably interfere with the enjoyment of life or property. Construction activities that may cause excessive dust, particularly near residences or sensitive receptors, may be curtailed under this regulation if a complaint is received and ADEC considers the impacts to be within these adverse determinations.
50.215	Ambient air quality analysis methods	Provides methods for analyzing (or modeling) ambient air quality impacts for permitting
50.215 (b)(2)(A)	Ambient air quality analysis methods	Excludes temporary construction emissions from the need to predict ambient air quality compliance with PSD increments
50.220	Test methods	References test methods for demonstrating compliance with emission limits
50.225	Owner requested limits	Operators and owners can request emission limits that limit applicability of other air quality regulations
50.235	Unavoidable emergencies	Establishes rules for reporting and responding to emergencies related to air pollution
50.240	Excess emissions	Provides requirements for reporting excess emissions including startup and shutdown.
50.245 and 50.246	Air Quality episodes	Allows ADEC to declare an air quality episode based on actual or potential impacts, and subsequently request voluntary reductions in emissions from stationary sources.
50.326	Title V operating permits	Sources with emissions of 100 ton/year or greater of any regulated criteria pollutant (not GHG) must obtain an operating permit, renewable on a five-year basis, and when new applicable requirements affect the source.
50.345 50.346	Construction minor and operating permits standard permit conditions	Compliance requirements (standard conditions) for Title V operating and minor sources permits and for modifications to existing stationary sources. Includes requirements for notifications, document submittals, and inventory reporting.
50.400 - 50.499	User Fees	Establishes fee schedules for permits and permit renewals.
50.502	Minor construction permits	Specifies provisions for requiring a minor source construction

TABLE 9.2.4-2

Alaska Air Quality Regulations Potentially Applying to the Project – Construction

Citation to 18 AAC 50	Title	Description
		permit for certain activity, based on the potential emissions from a stationary source or modification. Certain components of the construction activity may qualify as a stationary source depending on the duration of activity at a specific location. Minor permits must be obtained for the following potential activities under §(b) of this regulation: (1) An asphalt plant with a rated capacity of at least 5 tons/hour of product (2) A rock crusher with a rated capacity of 5 tons/hour (3) One or more incinerators with a cumulative rated capacity of 1,000 lbs./hour or more
50.508	Minor permits requested by owner or operator	Owner or operator can establish enforceable emission limits in a permit to avoid applicability of specific regulations.
50.540	Minor Permits	A minor source construction permit is required based on potential emissions.
50.544	Minor permits: content	Requires permit conditions for minor sources.
50.990	Definitions	Includes specific definitions for activity regulated under state air quality rules. Includes (107) temporary construction activity is defined as a construction activity that is 24 months or less (including intervening periods of inactivity).

9.2.5 Air Quality Emissions and Potential Impacts from Operations Sources

Federal and state air quality regulations govern emissions of criteria air pollutants, hazardous air pollutants (HAPs), state-only specified pollutants (ammonia), VOCs in general, ozone-depleting substances, and GHGs in certain cases. Under its New Source Review (NSR) and Title V operating permit programs, ADEC issues construction and/or operating permits to new, modified, and existing stationary sources or facilities. These permits would establish terms and conditions for compliance with air quality standards, require compliance with source-specific emission standards, and provide a monitoring, recordkeeping, and reporting mechanism to verify continued compliance. Specific air permitting and regulatory requirements are discussed in Section 9.2.6. Compliance with these regulations requires, among other things, detailed Project data on operations and emissions, as well as analyses of potential ambient air quality impacts and impacts on other air quality related values.

The assessments provided in this section evaluate air quality emissions and impacts from Project operations and include emissions from facility equipment and marine vessels in the immediate vicinity of the berths. Specifically, marine operations occurring within 1,640 feet (500 meters) of the berths were modeled, which includes: loading and hoteling operations for LNGCs while in port, maneuvering of the carriers into and out of port, and maneuvering and idling of marine tugs while assisting the carriers. Support equipment sources, such as onsite vehicles, are not included in modeling impacts because they are negligible.

Following applicable regulatory guidance, dispersion modeling ambient air quality and AQRV impacts for the Project are assessed in a matrix presented as:

- Near-field analyses – impacts within 50 kilometers of a facility (the accepted limit of EPA's AERMOD air quality dispersion model);

- Far-field analyses – impacts more than 50 kilometers up to 300 kilometers of a facility (the accepted range of EPA's CALPUFF model is out to 300 kilometers);

- Criteria pollutant analyses – compliance with applicable NAAQS, AAAQS, and PSD Increments; and

- Air quality related values analyses – evaluation of AQRVs at Class I and designated Sensitive Class II areas (see Sections 9.2.2.3.3 and 9.2.2.3.4).

Criteria pollutant impacts are assessed by following established regulatory modeling procedures to estimate maximum facility impacts and, if applicable, cumulative impacts from other nearby facilities. These modeled impacts are either (1) added to measured ambient air background concentrations to determine compliance with the NAAQS and AAAQS, or (2) compared to the PSD increments. These comparisons follow established, complex statistical analyses for ascertaining compliance.

AQRVs are evaluated using metrics established by the FLMs. Unlike the NAAQS, AAAQS, and PSD increments, there are no strict pass/fail criteria for AQRVs. Rather, there are screening levels below which no concern exists. If modeling analyses yield results above the screening criteria, further investigation may be warranted on a case-by-case basis in consultation with the relevant FLM.

Complete details on each of these aspects of the air quality analyses are provided in Appendices D, E, and F, respectively for the Liquefaction Facility, Mainline Compressor and Heater Stations, and GTP.

9.2.5.1 Liquefaction Facility

9.2.5.1.1 LNG Plant Emissions

Natural gas delivered via the Mainline would flow from the LNG Plant receipt point (plant inlet flange) through a pressure regulating station and undergo flow control, separation, and filtration. A detailed process description is provided in Resource Report No. 1. LNG would then be transferred to the LNG storage tanks for subsequent delivery to LNGCs. The processing operations would include the following general sources of emissions:

- Approximately 550 megawatts (MW) of natural gas turbine compressor capacity. These turbines are expected to be equipped with lean premix air/fuel controls designed to reduce NO_x and CO emissions to nominally 10 ppm, respectively, at 15 percent O_2. Precise emissions performance data was genericized as potentially commercially sensitive information, and the use of installed capacity is a better reflection of potential impacts;

- Natural gas power generation turbines with potential for supplemental firing and heat recovery steam generators. Total power generation capacity will be approximately 115 MW;

- A gas-fired thermal oxidizer for controlling breathing and working losses from the C5+ storage tank and the C5+ loading facilities;

- One reciprocating internal combustion engine for an emergency firewater pump, and one for auxiliary air compression;

- Four flares, including ground flares and elevated low pressure flare for emergency and routine control of excess gas; and

- At least one liquid-fired auxiliary diesel-generator set of docked LNGCs handling the hotel load, sea water, and freshwater cooling pumps, as well as ballast pumps.

Emissions estimates are based on Project design data for equipment and operations. Key input data are the total firing rate for turbines, hours of operation, projected load, projected gas heat content, and projected use of diesel fired engines, including air compression and support for LNGC hoteling and running equipment when at berth. Emission factors are derived from standard databases or vendor data from typical sources such as turbines, heaters, and engines. Vendor data that are used are considered representative of emissions, but should not be treated as a representation of equipment to be used in the final design. Details of the equipment design, fuel use, hours of operation, emission factors, projected load factors, and other operational considerations are provided in Appendix D.

Fugitive emissions of volatile organic compounds and methane would be emitted from piping components and connectors throughout the LNG Plant. Emissions are estimated from component counts (valves, flanges, pumps, compressors, etc.) and EPA and industry emission factors.

Based on the design that is available, short-term and annual emissions from operation of this equipment, including fugitive emissions and potential HAPs, are provided in Table 9.2.5-1. Emission calculations are included in Appendix D. Hourly and short-term emissions are based on worst-case assumptions regarding performance and maximum facility design capabilities, using vendor-supplied emission data, where available, or standard emission factors. Emissions are for normal operation of the LNG Plant and include mobile and non-road emissions associated with operation, but do not include flaring except for pilot/purge.

TABLE 9.2.5-1

Total Emissions from LNG Plant Operations

Pollutant	**Potential to Emit (pounds per hour)**	**Potential to Emit (tons per year)**
Nitrogen Oxides (NO_X)	363	1,181
Carbon Monoxide (CO)	741	1,734
Volatile Organic Compounds (VOCs)	609	216
Particulate Matter (PM_{10})	91	260
Particulate Matter ($PM_{2.5}$)	91	260
Sulfur Dioxide (SO_2)	24.7	90
Largest Individual Hazardous Air Pollutant (Formaldehyde)[c]	7.0	25.8
Total Hazardous Air Pollutants (HAPs)	11.5	37.7

TABLE 9.2.5-1

Total Emissions from LNG Plant Operations

Pollutant	Potential to Emit (pounds per hour)	Potential to Emit (tons per year)
Total Greenhouse Gas (GHG) Emissions (CO_2e)[a,b]	Not Applicable	3,850,732

[a] Annual emissions of GHGs are reported in metric tons (tonnes) per year.
[b] The total GHG emissions are calculated as CO_2 equivalent (CO_2e) emissions, i.e., the sum of individual GHGs with the annual tons of each gas multiplied by its Global Warming Potential (GWP) relative to CO_2. CH_4 is converted to CO_2e by multiplying its emissions by the GWP of 25, and N_2O is converted to CO_2e by multiplying its emissions by the GWP of 298.
[c] Product of incomplete combustion

9.2.5.1.2 LNG Carrier Emissions

Marine vessels (both LNGCs and support vessels) would be used to transport LNG from the Marine Terminal in Cook Inlet to various international destinations. On March 26, 2010, the International Maritime Organization (IMO) amended the International Convention for the Prevention of Pollution from Ships (Marine Pollution Protocol [MARPOL]) designating specific portions of U.S., Canadian, and French waters as an Emission Control Area (ECA), including the waters of Cook Inlet and the Nikiski vicinity. Vessels subject to the rule and operating in ECAs must use fuel (typically marine diesel oil) with sulfur no greater than 0.1 percent and must use engines on new or reconstructed ships that meet Tier III NO_X standards. See 40 C.F.R. 1043.60 for details.

In compliance with 40 C.F.R. 1043, vessels subject to the rule operating in U.S. ECA waters are generally required to obtain from EPA an Engine International Air Pollution Prevention (EIAPP) Certificate or otherwise provide evidence of conformance with MARPOL Annex VI. Compliance requirements for various potentially applicable regulations could include engine design data, certifications, date of engine manufacture, emissions test data, and in-use fuel specifications, including sulfur limits in fuel. Tugs used in marine operations must comply with rules distinct from the IMO/MARPOL rules. The rules applicable to tugs are administered by EPA and require engines to meet tier standards based on year of manufacture. In addition, the tugs using diesel engines must fuel those engines with ultra-low sulfur diesel containing 15 ppm sulfur or less.

Emissions estimates for marine operations are provided in Appendix D for tugs and LNGCs both in transit through Alaska waters and in dock. Consistent with guidance from FERC, marine operations transit emissions are limited to those emitted while a vessel is within "state waters." The Project design is for production up to 20 million metric tonnes per year of LNG shipping (44 million cubic meters per year for average density LNG). LNG carriers are assumed to hold 216,000 cubic meters, resulting in about 204 calls per year, with a mix of 98 percent of the units driven by combustion engines and two percent by steam turbines. Five percent of each group arrives in a "warm" status and would have to be cooled down prior to loading. Emissions were calculated for this mix of carriers based on 18 hours of LNG loading (including potentially 18 hours of hoteling and running auxiliary machinery) and a total of 16.5 hours in all phases of transit. Four tugs of 90-ton bollard pull capacity would support each carrier arrival and departure at the terminal and one tug would be in standby near the LNGC while the carrier is at berth.

Total emissions for these operations, including transit, loading, and hoteling, are provided in Table 9.2.5-2. Detailed calculations of LNGC and marine emissions are provided in Appendix D.

TABLE 9.2.5-2

Total Annual Emissions from LNGC and Tug Support Operations (tons per year)

Pollutant	Total
Nitrogen Oxides (NO_X)	380
Carbon Monoxide (CO)	630
Volatile Organic Compounds (VOCs)	117
Particulate Matter (PM_{10})	14.0
Particulate Matter ($PM_{2.5}$)	13.0
Sulfur Dioxide (SO_2)	1.2
Total Hazardous Air Pollutants (HAPs)	0.3
Total GHG Emissions (CO_2e)[a,b]	81,248

[a] Annual emissions of GHGs are given in metric tons (tonnes) per year.

[b] The total GHG emissions are calculated as CO_2 equivalent (CO_2e) emissions, i.e., the sum of individual GHGs with the annual tons of each gas multiplied by its Global Warming Potential (GWP) relative to CO_2. CH_4 is converted to CO_2e by multiplying its emissions by the GWP of 25, and N_2O is converted to CO_2e by multiplying its emissions by the GWP of 298.

Note that LNGCs, when not loading, and tug emissions are not included in LNG Plant emissions for permit applicability purposes.

9.2.5.1.3 Air Quality Impacts

Air quality impacts from the Liquefaction Facility operation would result from the emissions units identified in the previous section—primarily natural gas-fired compression turbines, power generation turbines, and marine operations. Additionally, the LNG Plant would include a thermal oxidizer to control vent emissions from hydrocarbon tanks, auxiliary and emergency reciprocating internal combustion engines (RICEs), and emergency flares, which will also generate emissions from pilot and purge gas. Impact assessment includes emissions from carriers and tugs within 1,640 feet (500 meters) of the dock that are docking, loading, and hoteling. Consistent with guidance from FERC, carrier transit emissions are included in the total annual emissions expressed in Table 9.2.5-2, but are not modeled.

9.2.5.1.4 Near-Field Analyses – Ambient Air Quality Impacts

To assess near-field air quality impacts, dispersion modeling was conducted using the AERMOD model Version 15181, with AERMAP and AERMET pre-processors, in accordance with EPA's Guideline on Air Quality Models (40 C.F.R. 51 Appendix W) and ADEC's Modeling Review Procedures Manual (ADEC, 2016b). Five years of meteorological data from the Kenai Airport site and upper air data from Anchorage were used in this analysis. This meteorological dataset had been approved by ADEC for previous air permit application modeling requirements in this region. A nested receptor grid was established at the facility fence line and at a 500-foot (152-meter) buffer around the Marine Terminal area. Receptor spacing of 82 feet (25 meters) was established along the fence line out to 656 feet (200 meters) from the fence line, extending through additional grids of 328 feet (100 meters), 820 feet (250 meters), 1,640 feet (500 meters), 3,280 feet (1,000 meters), and 6,560 feet (2,000 meters) out to 12.4 miles (20 kilometers) from the LNG Plant. Background air quality data were taken from a Project monitoring site that collected data near Nikiski during 2015. A total of one year of existing air quality data were used to characterize background for this analysis. Details of this modeling effort are included in Appendix D.

A formal modeling protocol would be submitted to ADEC for concurrence, then an ambient air quality impact analysis would be completed as part of the air permit application for the Liquefaction Facility. In advance of the formal protocol, a "modeling approach" and draft modeling protocol were circulated to the EPA, FLMs, ADEC, and FERC. Subsequent dialogue and correspondence with these agencies has helped to guide the modeling impact analysis, including AQRV analysis, for Resource Report No. 9.

Based on the Project modeling results detailed in Appendix D, the predicted maximum air quality impacts for criteria air pollutants are summarized in Table 9.2.5-3, along with the NAAQS, and Alaska AAQS. These results are based on emissions from the normal operations of the Liquefaction Facility including marine operations within 500 meters of the dock. In addition to modeling Project sources associated with the Liquefaction Facility, the Appendix D dispersion analysis also addressed the cumulative ambient air quality impacts from the proposed Project and nearby offsite sources (see Appendix L of Resource Report No. 1). The following offsite sources are included in the analysis:

- Tesoro Refinery;
- Existing ConocoPhillips Company Kenai LNG Facility (including ships);
- Tesoro Kenai Pipe Line (KPL) Marine Loading Terminal (including ships);
- Homer Electric Association (HEA) Bernice Lake Power Plant;
- Agrium Kenai Nitrogen Plant and Loading Terminal (including ships) (Agrium); and
- HEA Nikiski Generation Plant.

No other sources were explicitly modeled because they were either not expected to produce a significant concentration gradient in the impact area or were included as part of the background concentration. As shown in Table 9.2.5-3, the modeling results for normal operations of the Liquefaction Facility, when added to the measured background air quality concentrations, demonstrate compliance with the NAAQS and AAAQS. The model-predicted concentrations in Table 9.2.5-4 demonstrate compliance with the increments.

TABLE 9.2.5-3

Air Quality Impact NAAQS/AAAQS Analysis for the LNG Plant and Marine Terminal – Normal Operations

Air Pollutant	Averaging Period	Model-Predicted (Project-only) Concentration (μg/m³)	Ambient Background Concentration (μg/m³)	Total Concentration (μg/m³)	NAAQS (μg/m³)	AAAQS (μg/m³)
Sulfur Dioxide	1-Hour[a]	57.5	5.0	62.5	196	196
	3-Hour[b]	39.6	5.0	44.6	1,300	1,300
	24-Hour[b]	17.1	2.4	19.5	---	365
	Annual[d]	0.11	0.0	0.11	---	80
Carbon	1-Hour[b]	2,721	1,145	3,866	40,000	40,000

TABLE 9.2.5-3

Air Quality Impact NAAQS/AAAQS Analysis for the LNG Plant and Marine Terminal – Normal Operations

Air Pollutant	Averaging Period	Model-Predicted (Project-only) Concentration (μg/m³)	Ambient Background Concentration (μg/m³)	Total Concentration (μg/m³)	NAAQS (μg/m³)	AAAQS (μg/m³)
Monoxide	8-Hour[b]	1,071	1,145	2,216	10,000	10,000
Nitrogen Dioxide	1-Hour[c]	140.1	32.3	172.4	188	188
	Annual[d]	8.4	2.6	11.0	100	100
Particulate Matter less than 10 Microns	24-Hour[f]	5.1	40	45.1	150	150
Particulate Matter less than 2.5 Microns	24-Hour[e]	3.6	12	15.6	35	35
	Annual[g]	0.38	3.7	4.1	12	12

TABLE 9.2.5-4

Increment Analysis for the LNG Plant and Marine Terminal – Normal Operations

Air Pollutant	Averaging Period	Model-Predicted Concentration (μg/m³)	Class II Increments (μg/m³)
Sulfur Dioxide	1-Hour [a]	NA	NA
	3-Hour [b]	39.6	512
	24-Hour [b]	17.1	91
	Annual [c]	0.11	20
Nitrogen Dioxide	Annual [c]	8.4	25
Particulate Matter less than 10 Microns	24-Hour [b]	5.4	30
	Annual [c]	0.43	17
Particulate Matter less than 2.5 Microns	24-Hour [b]	4.8	9
	Annual [c]	0.43	4

Abbreviations:
NA = not applicable
μg/m³ = micrograms per cubic meter

Notes:

[a] Neither EPA nor ADEC have established increment thresholds for 1-hr NO_2, 1-hr SO_2, 1-hr CO, or 8-hr CO.

[b] Value reported is the maximum of the highest-second-high values from each of the five modeled years.

[c] Value reported is the maximum annual average concentration for the five-year period.

Cumulative model-predicted concentrations from the Liquefaction Facility and offsite sources are compared to the NAAQS and AAAQS in Table 9.2.5-5 and to the increments in Table 9.2.5-6. All model-predicted impacts are below the applicable standards and increments.

TABLE 9.2.5-5

Cumulative Air Quality NAAQS/AAAQS Impact Analysis for the LNG Plant and Marine Terminal – Normal Operations

Air Pollutant	Averaging Period	Model-Predicted Concentration (μg/m³)	Ambient Background Concentration (μg/m³)	Total Concentration (μg/m³)	NAAQS (μg/m³)	AAAQS (μg/m³)
Sulfur Dioxide	1-Hour[a]	63.4	5.0	68.4	196	196
	3-Hour[b]	50.6	5.0	55.6	1,300	1,300
	24-Hour[b]	32.0	2.4	34.4	---	365
	Annual[d]	0.6	0.0	0.6	---	80
Carbon Monoxide	1-Hour[b]	2,721	1,145	3,866	40,000	40,000
	8-Hour[b]	1,071	1,145	2,216	10,000	10,000
Nitrogen Dioxide	1-Hour[c]	149.5	32.3	181.8	188	188
	Annual[d]	20.4	2.6	23.0	100	100
Particulate Matter less than 10 Microns	24-Hour[f]	23.9	40	63.9	150	150
Particulate Matter less than 2.5 Microns	24-Hour[e]	6.4	12	18.4	35	35
	Annual[d]	2.8	3.7	6.5	12	12

μg/m³ = micrograms per cubic meter
[a] Value is the 99th percentile of the annual distribution of daily maximum values averaged over the five-year period.
[b] Value is the highest, second highest concentration of the values determined for each of the five modeled years.
[c] Value is the 98th percentile of the annual distribution of daily maximum values averaged over the five-year period.
[d] Value is the maximum annual average concentration for the five-year period.
[e] Value reported is the 98th percentile averaged over the five-year period.
[f] Value reported is the highest, 6th highest concentration over the five-year period.

TABLE 9.2.5-6

Cumulative Increment Analysis for the LNG Plant and Marine Terminal – Normal Operations

Air Pollutant	Averaging Period	Model-Predicted Concentration (μg/m³)	Class II Increments (μg/m³)
Sulfur Dioxide	1-Hour [a]	NA	NA
	3-Hour [b]	39.6	512
	24-Hour [b]	17.5	91
	Annual [c]	0.6	20
Nitrogen Dioxide	Annual [c]	12.5	25
Particulate Matter less than 10 Microns	24-Hour [b]	24.7	30
	Annual [c]	2.7	17
Particulate Matter less than 2.5 Microns	24-Hour [b]	8.7	9

TABLE 9.2.5-6

Cumulative Increment Analysis for the LNG Plant and Marine Terminal – Normal Operations

Air Pollutant	Averaging Period	Model-Predicted Concentration ($\mu g/m^3$)	Class II Increments ($\mu g/m^3$)
	Annual [c]	1.3	4

Abbreviations:
NA = not applicable
$\mu g/m^3$ = micrograms per cubic meter

Notes:

[a] Neither USEPA nor ADEC have established increment thresholds for 1-hr NO_2, 1-hr SO_2, 1-hr CO, or 8-hr CO.

[b] Value reported is the maximum of the highest-second-high values from each of the five modeled years.

[c] Value reported is the maximum annual average concentration for the five-year period.

9.2.5.1.5 Near-Field Analyses – Air Quality Related Values (AQRVs)

There are no Class I areas within 50 kilometers of the Liquefaction Facility and there is one Sensitive Class II area (see Appendix D, Figure 2-1) Kenai National Wildlife Refuge – Sensitive Class II Area (10 kilometers).

Complete details of the visibility and deposition AQRV analyses at the Kenai NWR are provided in Appendix D.

The model used for Liquefaction Facility near-field visibility analysis was VISCREEN using the Level II assessment methodology. VISCREEN requires emission rates of NO_X and primary particulate, which were based on the Liquefaction Facility emissions in Sections 9.2.5.2.1 and 9.2.5.2.2. Two observer locations were chosen for visibility: (1) the nearest point in the Kenai NWR to the proposed Liquefaction Facility site, which is a distance of about 10 kilometers, and (2) Skilak Lake, a popular visitor destination about 52 kilometers from the Liquefaction Facility. Meteorological conditions were based on an analysis of the same five years of Kenai Airport NWS data (2008–2012) that were used for the ambient air quality modeling. Background visual range was based on the FLAG (2010) for the Tuxedni NWR Class I area. The VISCREEN default ozone background value of 40 parts per billion by volume (ppbv) was used, which is consistent with measurements collected at the DNPP. See Appendix D for more details.

A total of 40 visibility scenarios were modeled including perceptibility (ΔE) and contrast (Cp) for the two observer locations at Kenai NWR with both sky and terrain background. Results for all but three scenarios were below the Class I screening criteria wherein no concern exists. For the three scenarios that were not below the screening criteria, all were for compressor turbine plume scenarios at either the closest wildlife refuge boundary point or at Skilak Lake with perceptibility as the primary issue. These results are still low.

Deposition modeling at Kenai NWR used the CALPUFF model, which is consistent with FLAG (2010) for near-field deposition analyses. CALPUFF deposition modeling is both complex and conservative (see Appendix D for details). The results for Kenai NWR compared to the Class I screening deposition analysis thresholds (DATs) are provided in Table 9.2.5-7. As shown in Table 9.2.5-7, the sulfur and nitrogen deposition from the Liquefaction Facility would be above the Class I DATs at Kenai NWR.

TABLE 9.2.5-7

Deposition Modeling Results for Kenai NWR

Scenario	Pollutant	CALPUFF Model Predicted Impact (kg/ha/yr)	Class I Deposition Analysis Thresholds (kg/ha/yr)
Liquefaction Facility	Sulfur	0.0058	0.005
	Nitrogen	0.031	0.005

9.2.5.1.6 Far-Field Analyses – Ambient Air Quality and AQRVs

Generally ambient air quality impacts decrease with distance from an emission source due to mixing and dilution in the atmosphere. The results for ambient air quality in Section 9.2.5.2.3 demonstrate that there are no issues for the Liquefaction Facility complying with NAAQS, AAAQS, or increments in the near field, and therefore by extension there are no issues in the far field. Thus, the far-field analyses focus on impacts at Class I and Sensitive Class II areas.

Class I and Sensitive Class II areas in the range of 50–300 kilometers of the Liquefaction Facility, with the distances away, are (see Appendix D, Figure 2-1):

- Lake Clark National Park & Preserve – Sensitive Class II Area (50 kilometers);
- Chugach National Forest – Sensitive Class II Area (74 kilometers);
- Tuxedni NWR – Class I Area (86 kilometers);
- Kenai Fjords National Park – Sensitive Class II Area (92 kilometers);
- DNPP – Class I Area (183 kilometers); and
- Kodiak NWR – Sensitive Class II Area (256 kilometers).

Complete details of the ambient air quality, visibility, and deposition analyses at each of the areas is provided in Appendix D.

EPA's CALPUFF model was used to assess impacts at each of these areas. CALPUFF uses a prognostic meteorological input dataset. The most recent available dataset for the domain around the Liquefaction Facility is the three-year (2002–2004) Fifth Generation Penn State/NCAR Mesoscale Model (MM5) dataset developed for the Alaska BART Coalition. This dataset has been used for previous CALPUFF modeling in the Cook Inlet area and has been approved by ADEC for this region. The MM5 modeling domain is a 540-kilometer by 650-kilometer grid centered on Cook Inlet and encompassing each of the Class I and Sensitive Class II areas listed in this section. See Appendix D, Figure 6-1, for a location map.

For cumulative impact analyses, the far-field modeling included existing sources and reasonably foreseeable development not close enough to the Liquefaction Facility to cause a significant concentration gradient. A total of 23 other facilities were included in the far-field modeling to account for these impacts. See Appendix D, Figure 4-1, for the locations of these facilities.

The NAAQS, AAAQS, and increment modeling results for the six Class I and Sensitive Class II areas listed are all well below the applicable standards. The most sensitive of these are the Class I increment analyses at Tuxedni NWR and the DNPP. These results are provided in Tables 9.2.5-8 and 9.2.5-9, respectively, demonstrating that the Liquefaction Facility would not cause or contribute to a violation of the increments at Alaska Class I areas. The remainder of the results are provided in Appendix D.

TABLE 9.2.5-8

Increment Analysis for the LNG Plant and Marine Terminal – Tuxedni NWR

Air Pollutant	Averaging Period	Liquefaction Facility Only Model-Predicted Concentration (μg/m³)	Cumulative Analysis Model-Predicted Concentration (μg/m³)	Class I Increments (μg/m³)
Sulfur Dioxide	1-Hour [a]	NA	NA	NA
	3-Hour [b]	0.12	0.64	25
	24-Hour [b]	0.05	0.30	5
	Annual [c]	0.003	0.03	2
Nitrogen Dioxide	Annual [c]	0.02	0.18	2.5
Particulate Matter less than 10 Microns	24-Hour [b]	0.34	1.74	8
	Annual [c]	0.02	0.10	4
Particulate Matter less than 2.5 Microns	24-Hour [b]	0.38	1.78	2
	Annual [c]	0.02	0.10	1

Abbreviations:
NA = not applicable
μg/m³ = micrograms per cubic meter
Notes:
[a] Neither USEPA nor ADEC have established increment thresholds for 1-hr NO_2, 1-hr SO_2, 1-hr CO, or 8-hr CO.
[b] Value reported is the maximum of the highest-second-high values from each of the five modeled years.
[c] Value reported is the maximum annual average concentration for the five-year period.

TABLE 9.2.5-9

Increment Analysis for the LNG Plant and Marine Terminal – DNPP

Air Pollutant	Averaging Period	Liquefaction Facility Only Model-Predicted Concentration (μg/m³)	Cumulative Analysis Model-Predicted Concentration (μg/m³)	Class I Increments (μg/m³)
Sulfur Dioxide	1-Hour [a]	NA	NA	NA
	3-Hour [b]	0.10	15.5	25
	24-Hour [b]	0.04	4.05	5
	Annual [c]	0.002	0.26	2
Nitrogen Dioxide	Annual [c]	0.02	0.12	2.5

TABLE 9.2.5-9

Increment Analysis for the LNG Plant and Marine Terminal – DNPP

Air Pollutant	Averaging Period	Liquefaction Facility Only Model-Predicted Concentration ($\mu g/m^3$)	Cumulative Analysis Model-Predicted Concentration ($\mu g/m^3$)	Class I Increments ($\mu g/m^3$)
Particulate Matter less than 10 Microns	24-Hour [b]	0.31	1.67	8
	Annual [c]	0.01	0.08	4
Particulate Matter less than 2.5 Microns	24-Hour [b]	0.34	1.76	2
	Annual [c]	0.01	0.08	1

Abbreviations:
NA = not applicable
$\mu g/m^3$ = micrograms per cubic meter

Notes:

[a] Neither USEPA nor ADEC have established increment thresholds for 1-hr NO_2, 1-hr SO_2, 1-hr CO, or 8-hr CO.

[b] Value reported is the maximum of the highest-second-high values from each of the five modeled years.

[c] Value reported is the maximum annual average concentration for the five-year period.

For far-field AQRV analysis, regional haze impacts were modeled at each of the six Class I and Sensitive Class II areas using the CALPUFF model and the same domain and modeling inputs as the far-field ambient air quality impact analyses. See Appendix D for complete details.

Regional haze impacts are estimated based on the change in light extinction. If the predicted change in light extinction due to Project sources is less than 5 percent, there is no concern. Furthermore, if the predicted change in light extinction due to Project and offsite sources is less than 10 percent, there is no concern. If modeled impacts are above either of these thresholds, further investigation may be warranted on a case-by-case basis in consultation with the relevant FLM.

TABLE 9.2.5-10

Regional Haze Results for the LNG Plant and Marine Terminal Only

Class I/II Area	Year	Number of Days with Extinction Above		8th Highest Change in Extinction (%)	Visibility Extinction Threshold for a Project (%)
		5%	10%		
Tuxedni NWR	2002	2	0	2.9	5.0
	2003	1	0	3.5	5.0
	2004	5	0	4.5	5.0
DNPP	2002	2	0	2.8	5.0
	2003	2	0	3.1	5.0
	2004	3	0	3.7	5.0
Kenai Fjords National Park	2002	0	0	1.6	5.0
	2003	0	0	2.0	5.0
	2004	0	0	1.5	5.0
Chugach National Forest	2002	2	0	2.9	5.0
	2003	0	0	2.8	5.0

TABLE 9.2.5-10

Regional Haze Results for the LNG Plant and Marine Terminal Only

Class I/II Area	Year	Number of Days with Extinction Above		8th Highest Change in Extinction (%)	Visibility Extinction Threshold for a Project (%)
		5%	10%		
	2004	1	0	2.9	5.0
Lake Clark National Park	2002	7	0	4.9	5.0
	2003	8	0	5.1	5.0
	2004	13	0	5.3	5.0
Kodiak NWR	2002	0	0	0.5	5.0
	2003	0	0	0.4	5.0
	2004	0	0	0.4	5.0

TABLE 9.2.5-11

Cumulative Regional Haze Results for the LNG Plant and Marine Terminal Plus Offsite Sources

Class I/II Area	Year	Number of Days with Extinction Above		8th Highest Change in Extinction (%)	Cumulative Visibility Extinction Threshold (%)
		5%	10%		
Tuxedni NWR	2002	144	70	24.5	10.0
	2003	136	67	28.5	10.0
	2004	142	75	25.3	10.0
DNPP	2002	194	100	46.7	10.0
	2003	198	102	53.3	10.0
	2004	208	127	47.8	10.0
Kenai Fjords National Park	2002	35	9	11.3	10.0
	2003	35	8	10.2	10.0
	2004	26	2	7.5	10.0
Chugach National Forest	2002	214	121	34.8	10.0
	2003	220	136	38.2	10.0
	2004	206	113	43.9	10.0
Lake Clark National Park	2002	261	157	40.2	10.0
	2003	243	138	40.3	10.0
	2004	261	153	50.8	10.0
Kodiak NWR	2002	29	10	11.2	10.0
	2003	46	9	10.3	10.0
	2004	32	11	**13.2**	10.0

Table 9.2.5-10 demonstrates the Liquefaction Facility generally would not contribute to visibility impairments at Class I and Sensitive Class II areas within 300 kilometers. The exception is at Lake Clark National Park where results are slightly above the screening thresholds.

As for the cumulative impact results presented in Table 9.2.5-11, modeled impacts are above the screening criteria at each of the six Class I and Sensitive Class II areas.

The far-field deposition modeling using CALPUFF followed the same procedure as described for near-field impacts in Section 9.2.5.2.4. Details are provided in Appendix D. Results for the Liquefaction Facility only and cumulative sources are provided in Tables 9.2.5-12 and 9.2.5.13, respectively.

TABLE 9.2.5-12

Deposition Results for the LNG Plant and Marine Terminal Only

Class I/II Area	Year	Sulfur Predicted Impact (kg/ha/yr)	Nitrogen Predicted Impact (kg/ha/yr)	Class I Deposition Analysis Thresholds (kg/ha/yr)
Tuxedni NWR	3-Year Max	**0.0052**	**0.014**	0.005
DNPP	3-Year Max	0.0037	**0.014**	0.005
Kenai Fjords National Park	3-Year Max	0.0003	0.002	0.005
Chugach National Forest	3-Year Max	0.001	0.0048	0.005
Lake Clark National Park	3-Year Max	**0.0059**	**0.020**	0.005
Kodiak NWR	3-Year Max	0.0002	0.002	0.005

TABLE 9.2.5-13

Cumulative Deposition Results for the LNG Plant and Marine Terminal Plus Offsite Sources

Class I/II Area	Year	Sulfur Predicted Impact (kg/ha/yr)	Nitrogen Predicted Impact (kg/ha/yr)	Class I Deposition Analysis Thresholds (kg/ha/yr)
Tuxedni NWR	3-Year Max	0.054	0.119	0.125
DNPP	3-Year Max	0.080	0.093	0.125
Kenai Fjords National Park	3-Year Max	0.002	0.014	0.125
Chugach National Forest	3-Year Max	0.030	0.073	0.125
Lake Clark National Park	3-Year Max	0.053	0.122	0.125
Kodiak NWR	3-Year Max	0.027	0.018	0.125

As shown in Table 9.2.5-12, modeled sulfur deposition is slightly above the DAT at Tuxedni NWR and Lake Clark National Park while modeled nitrogen deposition is above the DAT at Tuxedni NWR, the DNPP, and Lake Clark National Park. At the same time Table 9.2.5-13 demonstrates that modeled cumulative deposition rates for sulfur and nitrogen are below the DAT for all Class I and Sensitive Class

II areas in the far-field analysis. Thus, overall cumulative impacts from the Liquefaction Facility and other emission sources should not be a concern.

9.2.5.1.7 Ozone and Secondary Particulate Matter Assessment

The processes involved in the formation and reduction of ozone and secondary $PM_{2.5}$ were reviewed to provide a qualitative assessment of the level of concern. The intent is to help with the understanding of the formation and loss processes in general, but also in relation to the specific characteristics of the sub-arctic atmosphere. A complete analysis is provided in Appendix D.

A review of available monitoring data near the Project vicinity showed that neither ozone nor $PM_{2.5}$ current concentrations are or have been in exceedance of the NAAQS/AAAQS despite continual development in Southcentral Alaska. Furthermore, back trajectory analysis for selected episodes identified from the monitoring data suggests that observed concentrations could be at least in part the result of pollution transported from Anchorage and mid-latitude regions.

Using available tools, a conservative quantification of the potential regional impact of the Liquefaction Facility in both ozone and $PM_{2.5}$ was developed. The information provided in this analysis is very conservative as it relies on photochemical modeling performed for the continental United States, which does not account for the chemical complexities (halogen chemistry), the seasonal pattern (photochemical shutdown in the winter), and the global boundary influences (long-range transport contribution to pollution from Asia and Europe) known to occur in Alaska.

The analysis presented in Appendix D indicates that emissions from the Liquefaction Facility would at most lead to ozone increments of about 3 ppbv. Note that this increase is not additive, otherwise the cumulative effect of existing sources would have already affected the monitoring record. Also, the location of peak impact is likely to be variable in space and time. This maximum increase of 0.003 ppmv (3 ppbv) in a region where ozone design values currently range around 0.045 ppmv would not lead to non-attainment issues in the region.

For $PM_{2.5}$, the analysis presented in Appendix D indicates that emissions from the Liquefaction Facility would at most lead to nitrate increments of about 1 $\mu g/m^3$ and sulfate increments of less than 2 $\mu g/m^3$ for the 24-hour averaging period. These would be the estimated $PM_{2.5}$ impacts that are not expected to occur near the source, but downwind as the result of secondary formation. Just as with ozone, this increase is not additive and the location of peak impact likely to be variable in space and time. This maximum increase of less than 3 $\mu g/m^3$ in a region where $PM_{2.5}$ concentrations range around 10 $\mu g/m^3$ would not lead to nonattainment issues in the region. Furthermore, the formation of ammonium sulfate and nitrate would be significantly limited by the availability of ammonia.

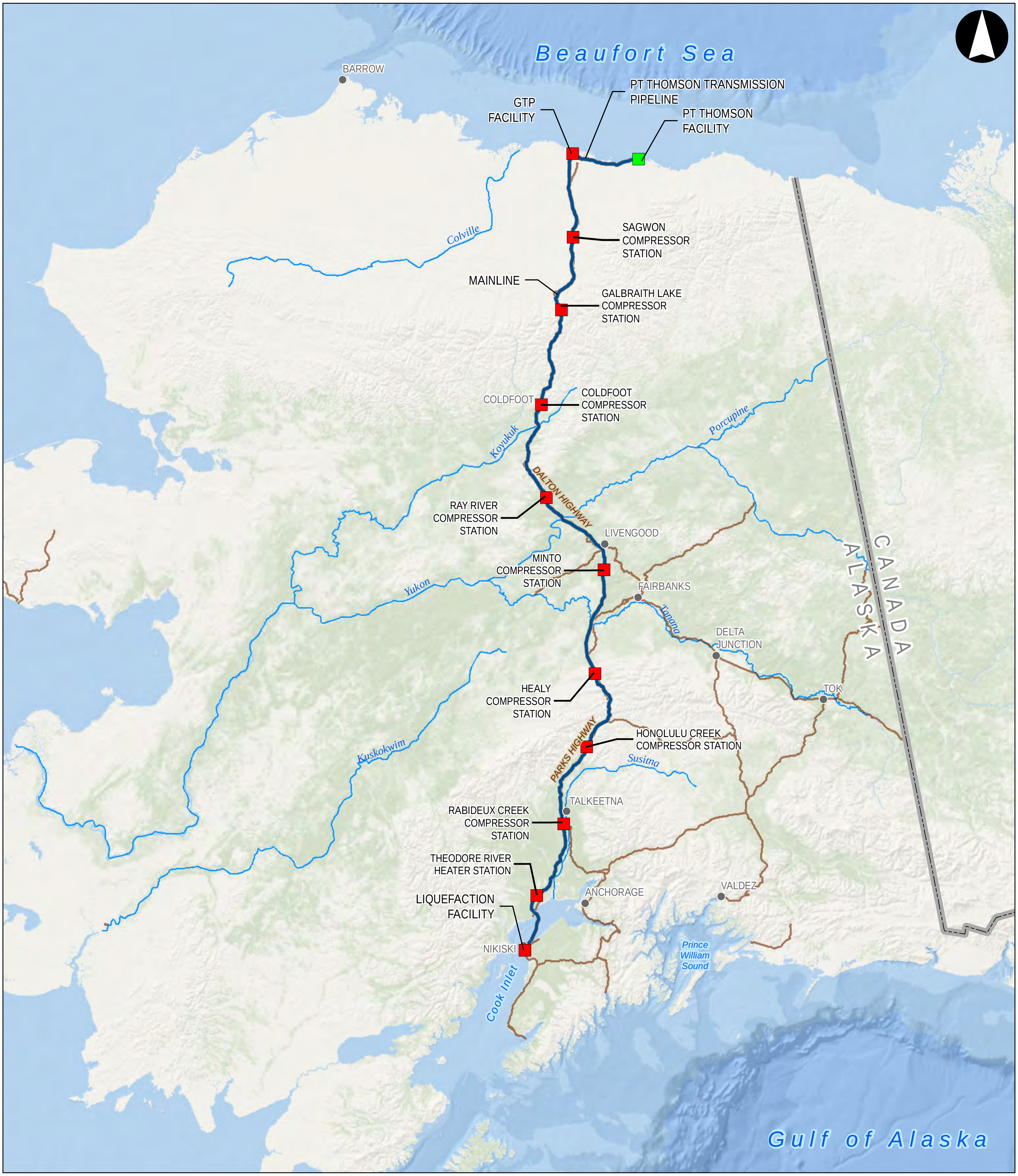
The assessment suggests there is little concern about formation of ozone and secondary $PM_{2.5}$ as a result of operation of the Liquefaction Facility.

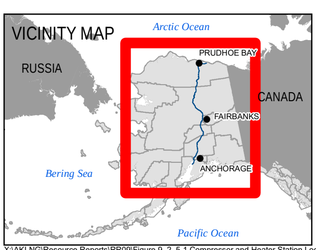
9.2.5.2 Interdependent Project Facilities

9.2.5.2.1 Mainline

The Mainline would be an approximately 806-mile, 42-inch natural gas pipeline transporting 3.3 billion cubic feet per day of treated gas at 2,075 pounds per square inch (psig) maximum allowable operating pressure from the GTP located at Prudhoe Bay to the Liquefaction Facility located near Nikiski, Alaska.

Once in operation, emission sources from the Mainline would include eight compressor stations, and one standalone heater station. Based on the proposed design, other aboveground pipeline facilities, such as metering stations, would not have permitted emission "point" sources, but would include fugitive emissions. Each compressor and heater stations, is anticipated to trigger the minor air quality control permit requirements under 18 AAC 50.502(c)(1). Compressor and heater station locations are shown in Figure 9.2.5-1.





LEGEND

- Project Facility
- Existing Facility
- Alaska Place Names
- Alaska LNG Rev C2 Route
- Major Highways
- Major Rivers

0 50 100 200 Miles

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COMPRESSOR AND HEATER STATION LOCATIONS

FIGURE 9.2.5-1

ALASKA LNG

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9.2.5.2.1.1 Compressor and Heater Stations Emissions

The design equipment for each of the compressor stations is shown in Table 9.2.5-14. The Sagwon Compressor Station would operate two turbine-driven compressors, with one available for standby; the other compressor stations have single-unit turbine-driven compressors. All sites would include power generators, auxiliary glycol heaters or indirect fired heaters, and waste incinerators. Operation of these units is described in Appendix E.

TABLE 9.2.5-14

Compressor Station Emission Unit Inventory

Station	Station Type (Nominal Horsepower [HP])	Major Equipment (Number of Units)
Sagwon	Multi-Unit with Cooling (~68,000 HP)	Turbine-driven Compressors (3) Power Generators (4) Auxiliary Utility Glycol Heaters (2) Waste Incinerator (1)
Galbraith Lake, Coldfoot, Ray River, Minto, Healy	Single-Unit with Cooling (~42,000 HP)	Turbine-driven Compressor (1) Power Generators (3) Auxiliary Utility Glycol Heaters (2) Waste Incinerator (1)
Honolulu Creek, Rabideux Creek	Single-Unit without Cooling (~33,000 HP)	Turbine-driven Compressor (1) Power Generators (3) Auxiliary Utility Glycol Heaters (2) Waste Incinerator (1)
Theodore River	Heater Station	Power Generators (3) Indirect Fired Gas Heaters (9) Waste Incinerator (1)

Total estimated annual emissions of criteria air pollutants from each type of compressor stations is shown in Table 9.2.5-15 with further details included Appendix F of Appendix E. Based on these data, each of the compressor and heater stations would require an air quality construction permit from ADEC prior to construction.

TABLE 9.2.5-15

Total Annual Emissions from Compressor and Heater Station Operations (tons/year)

Pollutant	Multiple Turbine Compressor Station with Cooling (Sagwon)	Single Turbine Compressor Station with Cooling (Galbraith Lake, Coldfoot, Ray River, Minto, Healy)	Single Turbine Compressor Station without Cooling (Honolulu Creek), Rabideux Creek	Heater Station (Theodore River)
NOx	185	161	131.2	49
CO	248	244	200	103
VOCs	34	21	13.9	16.2
$PM/PM_{10}/PM_{2.5}$ [a]	29	13.1	10.6	8.7
SO_2	4.8	4.3	3.5	2.6
Maximum HAP	7.9	6.3	5.0	2.1
Total HAPs	10.7	8.3	6.6	4.2
GHGs[b]	233,784	206,382	166,013	125,201

[a] Potential PM_{10} and $PM_{2.5}$ emissions are conservatively assumed to equal potential PM emissions.
[b] Annual emissions of GHGs are given in metric tons (tonnes) of CO_2e per year.

Fugitive emissions of organic compounds, including some HAPs, would be emitted from piping components and connectors throughout the compressor station. The total estimated fugitive emissions of GHGs, VOCs, and HAPs from normal operation of each compressor station are included in Table 9.2.5-15, along with the emission rate for the highest (maximum) emitted HAP, which is essential in determining the requirements for emissions of HAPs. Fugitive emissions for each of the compressor stations were calculated based on preliminary component counts and the EPA emission factors found in Table 2-4 of the EPA Protocol for Equipment Leak Emissions (EPA-453/R-95-017, November 1995) and subsequent procedures.

9.2.5.2.1.2 Compressor and Heater Station Ambient Air Quality Impact Analysis

To assess air quality impacts, dispersion modeling was conducted using the AERMOD and the AERMAP, AERSURFACE, AERMET, and BPIP pre-processors, in accordance with EPA's Guideline on Air Quality Models (40 C.F.R. 51 Appendix W) and ADEC's Modeling Review Procedures Manual (ADEC, 2016b).

Due to the sparse nature of meteorological stations through the rugged terrain of Alaska, virtual onsite meteorological tower data were produced for each of the compressor and heater stations (with the exception of Galbraith Lake) using prognostic meteorological data. Two different prognostic datasets have been developed to cover the state—the Weather Research and Forecasting Model, or WRF, data and the Fifth Generation Penn State/NCAR Mesoscale Model, or MM5, data. The WRF dataset is for three years (2007–2009) and covers the North Slope down to the south side of the Brooks Range, while the MM5 dataset is for the three years (2002–2004) and covers Southcentral Alaska into the Interior. WRF data was used to model the Sagwon, Coldfoot, Ray River, and Minto compressor stations; MM5 data was used to model the Healy, Honolulu Creek, and Rabideux Creek compressor stations plus the Theodore River heater station. For the Galbraith Lake compressor station, meteorological data for April 2002 through March 2003 collected nearby at Alyeska Pipeline Pump Station 4 (PS 4) was used for modeling. For further details on meteorological data used to model Mainline facilities, see Appendix E, Section 5.2.

Each compressor and heater station was modeled using the most recent site layout, local terrain features, and a receptor grid established at the facility fence line and beyond. As discussed in Section 9.2.2.1, ambient air quality data are sparse along much of the pipeline corridor. Available datasets were carefully reviewed, and background concentrations for each compressor station location were identified from the nearest available, representative monitoring site. Details of the modeling effort, including the background concentration locations, are included in Appendix E.

The proposed compressor and heater stations are generally located in remote areas away from other stationary sources. This analysis does not include modeled pollutant impacts from any offsite sources with the exception of the Galbraith Lake. The Galbraith Lake compressor station would be located approximately 1.5 kilometers southeast PS 4. Due to its proximity to the proposed Galbraith Lake compressor station, emissions from PS 4 were included in the modeling analyses for Galbraith Lake. PS 4 emission rates and source parameters used in the modeling are provided in Appendix E.

A formal modeling protocol would be submitted to ADEC for concurrence, then an ambient air quality impact analysis would be completed as part of the air permit application for the compressor and heater stations. In advance of the formal protocol, a "modeling approach" was circulated to EPA, FLMs, ADEC, and FERC. Subsequent dialogue and correspondence with these agencies has helped to guide the modeling impact analysis for this Resource Report.

A nested receptor grid was used to capture impacts. Receptor spacing of 25 meters was established along the ambient air boundary out to 100 meters, extending through additional grids of 100, 250, and 500 meters out to 10 kilometers from each facility. Predicted maximum air quality impacts for criteria air pollutants, including modeled results plus representative background concentrations, are summarized in Table 9.2.5-16. Supporting documentation is provided in Appendix E.

TABLE 9.2.5-16

Air Quality Impact Analysis for Compressor Stations – Normal Operations (μg/m³)

	NO_2		$PM_{2.5}$[a]		SO_2		CO	
Station	**Max. 1-hr**	**Annual**	**Max. 24-hr**	**Annual**	**Max 1-hr**[b]	**Annual**	**Max 1-hr**	**Max 8-hr**
Sagwon	133	7.9	19.5	3.2	19.4	1.0	944	754
Galbraith Lake	152	10.7	15.7	4.2	35.3	2.6	1,117	710
Coldfoot	117	9.2	22.7	5.3	21.0	3.6	984	857
Ray River	142	11.2	25.6	4.5	19.6	2.2	950	735
Minto	134	10.3	21.2	5.1	18.8	3.6	934	762
Healy	105	14.8	19.2	3.8	29.2	1.8	8,587	5,336
Honolulu Creek	104	19.6	19.0	4.3	19.8	2.4	8,343	5,302

TABLE 9.2.5-16

Air Quality Impact Analysis for Compressor Stations – Normal Operations (μg/m^3)

	NO_2		$PM_{2.5}$[a]		SO_2		CO	
Station	**Max. 1-hr**	**Annual**	**Max. 24-hr**	**Annual**	**Max 1-hr**[b]	**Annual**	**Max 1-hr**	**Max 8-hr**
Rabideux Creek	87	5.9	13.6	2.7	17.2	1.5	8,276	5,246
Theodore River	130	13.2	26.7	4.1	16.0	1.3	8,323	5,339
NAAQS/AAAQS	**188**	**100**	**35**	**12**	**196**	**80**	**40,000**	**10,000**

[a] PM_{10} concentration is conservatively assumed to equal $PM_{2.5}$. Only $PM_{2.5}$ is shown here because it is most stringent.
[b] Maximum 3-hour and 24-hour SO_2 concentrations are assumed to equal one-hour SO_2 concentration. Only 1-hour SO_2 is shown here since it is most stringent.

All results, modeled following the above-described conservative screening procedures, demonstrate compliance with the National and Alaska AAQS.

9.2.5.2.1.3 Compressor and Heater Station AQRV Analysis

The 806-mile long Mainline traverses a long corridor across Alaska near many Class I and Sensitive Class II areas. See Figure 9.2.2-7.

As a preliminary step in evaluating AQRVs at Class I and Sensitive Class II areas, the FLAG (2010) guidance for screening areas more than 50 kilometers from a compressor or heater station based on the Q/D method was applied. Using this method, all areas over 50 kilometers from any of the compressor or heater stations are below the FLAG de minimis for evaluation and no further analysis is warranted. See details in Appendix E, Section 3.2.4. That is, the impacts are so small that compressor and heater stations do not require any far-field (50 kilometers or further) analysis.

AQRVs at all Class I and Sensitive Class II areas within 50 kilometers of a compressor or heater station were evaluated following the FLAG near-field analysis methods. These areas are identified in Table 9.2.5-17. See, also, Appendix E, Figures 2 and 3.

TABLE 9.2.5-17

Class I and Sensitive Class II Areas Included in the AQRV Analysis for Compressor and Heater Stations

Compressor/Heater Station	Class I Areas (approx. distance from Compressor Station)	Sensitive Class II Areas Warranting AQRV Evaluation (approx. distance from Compressor Station)
Sagwon	None	Arctic NWR (30 km)
Galbraith Lake	None	Arctic NWR (3.3 km) Gates of the Arctic National Park and Preserve (11 km)
Coldfoot	None	Gates of the Arctic National Park and Preserve (8.8 km) Yukon Flats NWR (44 km)
Ray River	None	Yukon Flats NWR (17 km) Kanuti NWR (36 km)

TABLE 9.2.5-17

Class I and Sensitive Class II Areas Included in the AQRV Analysis for Compressor and Heater Stations

Compressor/Heater Station	Class I Areas (approx. distance from Compressor Station)	Sensitive Class II Areas Warranting AQRV Evaluation (approx. distance from Compressor Station)
Minto	None	None
Healy	DNPP (4.7 km)	None
Honolulu Creek	DNPP (14 km)	None
Rabideux Creek	None	None
Theodore River	None	Kenai NWR (46 km)

Complete details of the visibility and deposition AQRV analyses at these areas are provided in Appendix E.

The model used for all visibility analysis was VISCREEN using the Level 1 or 2 assessment methodology as appropriate. VISCREEN requires emission rates of NO_X and primary particulate, which were based on the compressor station and heater station emissions in Sections 9.2.5.3.1.1. For Level 2 assessments, meteorological conditions were based on the same WRF or MM5 prognostic datasets as described in Section 9.2.5.3.1.2. Background visual range was based on FLAG (2010) for the DNPP for the Healy and Honolulu compressor stations, and for Tuxedni NWR for the Theodore River Heater Station. Background visual range for all other compressor stations was assumed to be 258 kilometers, the default in the ADEC (2016b) modeling guidance. The conservative VISCREEN default parameters were assumed for other model inputs. See Appendix E for more details. Results are provided in Table 9.2.5-18.

TABLE 9.2.5-18

VISCREEN Results for Compressor and Heater Station Impacts at Class I and Sensitive Class II Areas

Source	Observer	Background	VISCREEN Mode	Contrast (Cp)		Perceptibility (ΔE)	
				Criteria	Modeled	Criteria	Modeled
Forward Scatter, Sky Background							
Healy	Inside Denali	SKY	Level 2	2.00	1.36	0.05	0.01
	Outside Denali	SKY	Level 2	2.00	3.19	0.05	-0.03
Honolulu Creek	Inside Denali	SKY	Level 2	2.00	0.30	0.05	0.00
	Outside Denali	SKY	Level 2	2.00	2.05	0.05	0.01
Sagwon	Arctic NWR	SKY	Level 2	2.00	1.46	0.05	0.02
Galbraith Lake	Arctic NWR	SKY	Level 2	2.00	1.83	0.05	0.01
	Gates of the Arctic National Park and Preserve	SKY	Level 2	2.00	0.83	0.05	0.01
Coldfoot	Gates of the Arctic National Park and Preserve	SKY	Level 2	2.00	0.87	0.05	0.01

TABLE 9.2.5-18

VISCREEN Results for Compressor and Heater Station Impacts at Class I and Sensitive Class II Areas

Source	Observer	Background	VISCREEN Mode	Contrast (Cp)		Perceptibility (ΔE)	
				Criteria	Modeled	Criteria	Modeled
	Yukon Flats	SKY	Level 1	2.00	1.87	0.05	0.01
Ray River	Kanuti	SKY	Level 1	2.00	1.87	0.05	0.01
	Yukon Flats	SKY	Level 2	2.00	0.17	0.05	0.00
Theodore River	Kenai NWR	SKY	Level 1	2.00	0.63	0.05	0.01
Backward Scatter, Sky Background							
Healy	Inside Denali	SKY	Level 2	2.00	0.92	0.05	-0.01
	Outside Denali	SKY	Level 2	2.00	1.86	0.05	-0.03
Honolulu Creek	Inside Denali	SKY	Level 2	2.00	0.23	0.05	-0.00
	Outside Denali	SKY	Level 2	2.00	1.31	0.05	-0.02
Sagwon	Arctic NWR	SKY	Level 2	2.00	0.76	0.05	-0.01
Galbraith Lake	Arctic NWR	SKY	Level 2	2.00	1.21	0.05	-0.02
Galbraith Lake	Gates of the Arctic National Park and Preserve	SKY	Level 2	2.00	0.61	0.05	-0.01
Coldfoot	Gates of the Arctic National Park and Preserve	SKY	Level 2	2.00	0.63	0.05	-0.01
	Yukon Flats	SKY	Level 1	2.00	1.27	0.05	-0.02
Ray River	Kanuti	SKY	Level 1	2.00	1.26	0.05	-0.02
	Yukon Flats	SKY	Level 2	2.00	0.11	0.05	-0.00
Theodore River	Kenai NWR	SKY	Level 1	2.00	0.33	0.05	-0.01
Forward Scatter, Terrain Background							
Healy	Inside Denali	TERRAIN	Level 2	2.00	1.91	0.05	0.02
	Outside Denali	TERRAIN	Level 2	2.00	4.94	0.05	0.05
Honolulu Creek	Inside Denali	TERRAIN	Level 2	2.00	0.50	0.05	0.00
	Outside Denali	TERRAIN	Level 2	2.00	2.80	0.05	0.03
Sagwon	Arctic NWR	TERRAIN	Level 2	2.00	1.66	0.05	0.01
Galbraith Lake	Arctic NWR	TERRAIN	Level 2	2.00	2.56	0.05	0.03
Galbraith Lake	Gates of the Arctic National Park and Preserve	TERRAIN	Level 2	2.00	1.29	0.05	0.01
Coldfoot	Gates of the Arctic National Park and Preserve	TERRAIN	Level 2	2.00	1.31	0.05	0.01

TABLE 9.2.5-18

VISCREEN Results for Compressor and Heater Station Impacts at Class I and Sensitive Class II Areas

Source	Observer	Background	VISCREEN Mode	Contrast (Cp)		Perceptibility (ΔE)	
				Criteria	Modeled	Criteria	Modeled
	Yukon Flats	TERRAIN	Level 1	2.00	0.19	0.05	0.00
Ray River	Kanuti	TERRAIN	Level 1	2.00	1.05	0.05	0.01
	Yukon Flats	TERRAIN	Level 2	2.00	0.29	0.05	0.00
Theodore River	Kenai NWR	TERRAIN	Level 1	2.00	0.23	0.05	0.00
Backward Scatter, Terrain Background							
Healy	Inside Denali	TERRAIN	Level 2	2.00	0.65	0.05	0.01
	Outside Denali	TERRAIN	Level 2	2.00	1.52	0.05	0.01
Honolulu Creek	Inside Denali	TERRAIN	Level 2	2.00	0.11	0.05	0.00
	Outside Denali	TERRAIN	Level 2	2.00	1.06	0.05	0.01
Sagwon	Arctic NWR	TERRAIN	Level 2	2.00	0.12	0.05	0.00
Galbraith Lake	Arctic NWR	TERRAIN	Level 2	2.00	0.90	0.05	0.01
	Gates of the Arctic National Park and Preserve	TERRAIN	Level 2	2.00	0.34	0.05	0.00
Coldfoot	Gates of the Arctic National Park and Preserve	TERRAIN	Level 2	2.00	0.38	0.05	0.00
	Yukon Flats	TERRAIN	Level 1	2.00	0.02	0.05	0.00
Ray River	Kanuti	TERRAIN	Level 1	2.00	0.13	0.05	0.00
	Yukon Flats	TERRAIN	Level 2	2.00	0.05	0.05	0.00
Theodore River	Kenai NWR	TERRAIN	Level 1	2.00	0.06	0.05	0.00

As shown in Table 9.2.5-18, results for almost all of the combinations of compressor and heater stations and Class I and Sensitive Class II areas are below the screening thresholds below which no concern exists. For three scenarios, the Healy and Honolulu Creek compressor stations outside the DNPP and the Galbraith Lake Compressor Station at Gates of the Arctic National Park, results are above the screening criteria.

Deposition modeling at the compressor and heater stations used the AERMOD model, Level 1 screening procedures in FLAG (2010), and the Federal Land Managers' Draft Interagency Guidance for Near Field Deposition Modeling (USDOI 2014). See Appendix E for further details. Extensive receptor grids were developed radially from each compressor/heater station out 50 kilometers in all directions to capture screening level impacts at each Class I and Sensitive Class II area. See Attachment D to Appendix E.

The results are provided in Table 9.2.5-19 and can be compared to the Class I screening deposition analysis thresholds (DATs) of 0.005 kg/ha/yr. As shown in Table 9.2.5-19, screening analyses are not able to demonstrate that nitrogen deposition would be below the DAT at any of the Class I and Sensitive Class II areas within 50 kilometers of a compressor or heater station. Sulfur deposition screening results are above the DAT at the Arctic NWR (ANWR) for the Galbraith Lake Compressor Station, but below the DAT for all other scenarios.

TABLE 9.2.5-19

Deposition Results for Compressor and Heater Station Impacts at Class I and Sensitive Class II Areas

Station	Class I/II Area (within 50 km)	Species	Maximum Modeled Deposition (kg/ha/yr)
Sagwon Compressor Station	Arctic National Wildlife Refuge (ANWR)	Nitrogen	***0.062***
		Sulfur	<0.005
Galbraith Lakes Compressor Station	ANWR	Nitrogen	***1.937***
		Sulfur	***0.030***
	Gates of the Arctic National Park and Preserve	Nitrogen	***0.147***
		Sulfur	<0.005
Coldfoot Compressor Station	Gates of the Arctic National Park and Preserve	Nitrogen	***0.395***
		Sulfur	<0.005
	Yukon Flats NWR	Nitrogen	***0.011***
		Sulfur	<0.005
Ray River Compressor Station	Kanuti NWR	Nitrogen	***0.102***
		Sulfur	<0.005
	Yukon Flats NWR	Nitrogen	***0.115***
		Sulfur	<0.005
Healy Compressor Station	DNPP	Nitrogen	***0.273***
		Sulfur	<0.005
Honolulu Creek Compressor Station	DNPP	Nitrogen	***0.084***
		Sulfur	<0.005
Theodore River Compressor Station	Kenai NWR	Nitrogen	***0.030***
		Sulfur	<0.005

9.2.5.2.1.4 Other Aboveground Pipeline Facilities

There are no proposed combustion sources emission units at other aboveground facilities along the Mainline.

Fugitive emissions of organic compounds, including the GHGs methane and CO_2, would be emitted from piping components and connectors along the pipelines (Mainline, PTTL, and PBTL). The Interstate Natural Gas Association of America has created guidance for calculating CH_4 and CO_2 leak emissions from a natural gas pipeline. The methodology uses the length of the aboveground pipeline, based on the assumption of cathodic protection, and the number of meter stations to determine an estimate of the annual fugitive emissions. There are four metering stations planned—three in the vicinity of the GTP and one at the inlet to the Liquefaction Facility. There are 30 mainline block valves (MLBVs) in the proposed design.

Table 9.2.5-20 provides the estimated annual fugitive GHG emissions for these pipeline operations (excluding the GTP and compressor station fugitives, which are included in those facilities).

TABLE 9.2.5-20

Estimated Pipeline Fugitive Greenhouse (GHG) Gas Emissions

Pollutant	Segment	No. of stations or miles	Emission Factor [a,b]	Emissions (tonnes per year)
MAINLINE				
Methane (CH_4)	Meter/Regulator	2	2,533 lb CH_4/station-yr	2.30
	Pipeline Length	806	23.08 lb CH_4/mile-yr	8.44
Carbon Dioxide (CO_2)	Meter/Regulator	2	146.34 lb CO_2/station-yr	0.13
	Pipeline Length	806	1.52 lb CO_2/mile-yr	0.56
CO_2 from CH_4 Oxidation	Pipeline Length	806	7.59 lb CO_2/mile-yr	2.77
			Mainline Total GHG Emissions (CO_2e)[c]	271.86
PTTL				
Methane (CH_4)	Meter/Regulator	1	2,533 lb CH_4/station-yr	1.15
	Pipeline Length	63	23.08 lb CH_4/mile-yr	0.66
Carbon Dioxide (CO_2)	Meter/Regulator	1	146.34 lb CO_2/station-yr	0.07
	Pipeline Length	63	1.52 lb CO_2/mile-yr	0.04
CO_2 from CH_4 Oxidation	Pipeline Length	63	7.59 lb CO_2/mile-yr	0.22
			PTTL Total GHG Emissions (CO_2e)[c]	45.54
PBTL				
Methane (CH_4)	Meter/Regulator	1	2,533 lb CH_4/station-yr	1.15
	Pipeline Length	1	23.08 lb CH_4/mile-yr	0.01
Carbon Dioxide (CO_2)	Meter/Regulator	1	146.34 lb CO_2/station-yr	0.07
	Pipeline Length	1	1.52 lb CO_2/mile-yr	0.001
CO_2 from CH_4 Oxidation	Pipeline Length	1	7.59 lb CO_2/mile-yr	0.003
			PBTL Total GHG Emissions (CO_2e)[c]	29.06
			Total Pipeline Fugitive GHG Emissions (CO_2e)[c]	346.46

[a] The meter/regulator emission factor is in units of pounds per station per year.
[b] The pipeline length emission factor is in units of pounds per mile per year.
[c] The total GHG emissions are calculated as CO_2e emissions, i.e., the sum of individual GHGs with the annual tons of each gas multiplied by its GWP relative to CO_2.
.
Source: Interstate Natural Gas Association of America 2005, Table 4-3.

9.2.5.2.2 Point Thomson and Prudhoe Bay Gas Transmission Lines

There are no combustion emission sources required for operation of either the PTTL or PBTL. Estimates of fugitive GHG emissions from operation of these pipelines are provided in Table 9.2.5-20.

9.2.5.2.3 Gas Treatment Plant Emissions

The design of the GTP consists of three identical gas processing trains that receive gas from the PTU and PBU, clean the gas by removing CO_2 and H_2S and send this Byproduct stream back to Prudhoe Bay, remove any water and inject it down a Class I well, then ship the remaining natural gas down the Mainline to the LNG Plant in Nikiski. See Resource Report No. 1 for a complete description of the GTP.

A number of air emission units are required to operate the GTP:

- Approximately 298,000 International Organization for Standardization (ISO) horsepower of mechanical drive natural gas turbine capacity to support treated gas compression;
- Approximately 205,000 ISO horsepower of mechanical drive natural gas turbine capacity to support Byproduct gas (CO_2) compression;
- Approximately 230 ISO MW of natural gas turbine capacity to support power generation;
- Supplemental firing of waste heat recovery units associated with mechanical drive;
- Natural gas-fired common utility heaters (two primary, one reserve);
- Diesel-fired essential generator;
- Diesel-fired firewater pumps;
- A dormitory emergency diesel generator;
- A communications tower diesel generator;
- Buyback gas bath heaters;
- Camp heaters;
- Low pressure CO_2 flares;
- High pressure CO_2 flares;
- Low pressure hydrocarbon flares; and
- High pressure hydrocarbon flares.

Emissions estimates are based on preliminary Project design data for equipment and operations. Key input data are the total firing rate for turbines and heaters, hours of operation, projected load, the projected gas heat content, and projected use of diesel fired engines. Emission factors are derived from standard databases or vendor data from typical sources such as turbines, heaters, and engines. Vendor data that are used are considered representative of emissions, but are not implied as the data for the final design equipment. Details of the equipment design, fuel use, hours of operation, emission factors, projected load factors, and other operational considerations are provided in Appendix F.

Fugitive emissions of organic compounds would be emitted from piping components and connectors throughout the GTP. Emissions are estimated from component counts (valves, flanges, pumps, compressors, etc.) and EPA and industry emission factors.

Based on the proposed design, short-term and annual emissions from operation of this equipment, including fugitive emissions and potential HAPs, are provided in Table 9.2.5-21. Emission calculations are included in Appendix F. Hourly and short-term emissions are based on worst-case assumptions regarding performance and maximum facility design capabilities, using vendor-supplied emission data, where available, or standard emission factors that are cited in the Appendix. Emissions are for normal operation of the GTP. Sulfur dioxide emissions reflect the use of "raw" fuel gas, which is expected to be used on initial facility commissioning. Use of "treated" fuel gas after commissioning is expected to reduce sulfur dioxide emissions by approximately 80 percent.

TABLE 9.2.5-21

Total Emissions from GTP Operations

Pollutant	GTP Potential to Emit (pounds per hour)	GTP Potential to Emit (tons per year)
Nitrogen Oxides (NO_X)	682	2,242
Carbon Monoxide (CO)	767	2,080
Volatile Organic Compounds (VOCs)	97	354
Particulate Matter (PM_{10})	69	264
Particulate Matter ($PM_{2.5}$)	69	264
Sulfur Dioxide (SO_2)[c]	157	593
Largest Individual Hazardous Air Pollutant (Formaldehyde)	5.9	25.8
Total Hazardous Air Pollutants (HAPs)	9.8	42
Total GHG Emissions (CO_2e)[a,b]	Not Applicable	4,201,860

[a] Annual emissions of GHGs are given in metric tons (tonnes) per year.

[b] The total GHG emissions are calculated as CO_2 equivalent (CO_2e) emissions.

[c] SO_2 emissions based on commissioning when part of the facility will combust raw gas with 90 ppmv H_2S. This severely overstates PTE for normal GTP operations which will likely be based on 16 ppmv H2S. Normal operations PTE can be estimated by multiplying listed values by 16/90

GTP Near-Field Analyses – Ambient Air Quality Impacts

Air quality impacts from GTP operations would result from the emissions units identified above—primarily natural gas-fired compression turbines, power generation turbines, and utility heaters. Additionally, the GTP would include auxiliary and emergency RICEs, auxiliary and camp heaters, and emergency CO_2 and hydrocarbon flares, which may also have small emission rates from pilot and purge gas.

To assess air quality impacts, dispersion modeling was conducted using the AERMOD model Version 15181, with AERMET and BPIP pre-processors, in accordance with EPA's Guideline on Air Quality Models (40 C.F.R. 51 Appendix W) and ADEC's Modeling Review Procedures Manual (ADEC, 2016b). The proposed GTP site is located approximately 6 miles northeast of the A Pad meteorological and air quality monitoring station. A Pad meteorological data are considered representative of dispersion conditions in the near-field of the GTP due to its close proximity and lack of significant terrain features between the two. Thus, five years of recent (2010–2014) PSD-quality A Pad data were used in this modeling in accordance with EPA and ADEC modeling guidance. Concurrent upper air data from Barrow, Alaska, located approximately 325 kilometers northwest of the GTP, were used in this modeling effort.

A nested receptor grid was used to predict impacts. Receptor spacing of 82 feet (25 meters) was established along the pad edge out to 328 feet (100 meters), extending through additional grids of 164 feet (50 meters), 328 feet (100 meters), 820 feet (250 meters), and 1,640 feet (500 meters) out to 6.2 miles (10 kilometers) from the GTP. Background air quality data in the vicinity of GTP were calculated from the A Pad and Prudhoe Bay Central Compression Plant PSD-quality monitoring sites for calendar years 2009–2013. Data collected at these ambient air stations are considered conservatively representative of the GTP site and non-modeled sources since the monitoring stations are located downwind of existing large stationary sources, well site activities, and mobile sources typical of the Prudhoe Bay oilfield development. Details of this modeling effort are included in Appendix F.

A formal modeling protocol would be submitted to ADEC for concurrence, then an ambient air quality impact analysis would be completed as part of the air permit application for the GTP. In advance of the protocol, a "modeling approach" and draft modeling protocol were circulated to the EPA, FLMs, ADEC, and FERC. Subsequent dialogue and correspondence with these agencies has helped to guide the modeling impact analysis, including AQRV analysis, for this Resource Report.

The analysis herein is focused on characterizing GTP standalone and cumulative impacts utilizing the modeling approach outlined above and in Appendix F. Predicted impacts are summarized in Table 9.2.5-22, along with the NAAQS and Alaska AAQS, and in Table 9.2.5-23 for the PSD Increments. The modeling results, when added to representative background air quality concentrations, demonstrate compliance with the NAAQS and Alaska AAQS, as well as the PSD Increments.

TABLE 9.2.5-22

Air Quality Impact NAAQS/AAAQS Analysis at the Gas Treatment Plant – Normal Operations

Air Pollutant	Averaging Period	Model-Predicted (Project-only) Concentration (μg/m^3)	Ambient Background Concentration (μg/m^3)	Total Concentration(μg/m^3)	NAAQS (μg/m^3)	AAAQS (μg/m^3)
Sulfur Dioxide	1-Hour[a]	11.2	9.39	20.6	196	196
	3-Hour[b]	37.7	21.0	58.7	1,300	1,300
	24-Hour[b]	11.2	8.12	19.3	---	365
	Annual[d]	0.54	1.80	2.34	---	80

TABLE 9.2.5-22

Air Quality Impact NAAQS/AAAQS Analysis at the Gas Treatment Plant – Normal Operations

Air Pollutant	Averaging Period	Model-Predicted (Project-only) Concentration (μg/m³)	Ambient Background Concentration (μg/m³)	Total Concentration(μg/m³)	NAAQS (μg/m³)	AAAQS (μg/m³)
Carbon Monoxide	1-Hour[b]	366	1,150	1,516	40,000	40,000
	8-Hour[b]	139	1,150	1,289	10,000	10,000
Nitrogen Dioxide	1-Hour[c]	65.0	NA [g]	65.0	188	188
	Annual[d]	2.62	6.00	8.62	100	100
Particulate Matter less than 10 Microns	24-Hour[f]	3.77	50.0	53.8	150	150
Particulate Matter less than 2.5 Microns	24-Hour[e]	3.29	15.0	18.3	35	35
	Annual[h]	0.22	3.70	3.92	12	12

Notes:
μg/m³ = micrograms per cubic meter
[a] Value is the 99th percentile of the distribution of daily maximum values.
[b] Value is the highest, second highest concentration of the values determined for each of the five modeled years.
[c] Value is the 98th percentile of the distribution of daily maximum values.
[d] Value is the maximum annual average concentration for the five -year period.
[e] Value is the 98th percentile averaged over the five -year period.
[f] Value is the highest, 5th highest concentration over the five -year period.
[g] The 1-hour NO2 modeling was conducted with wind speed-varying background values applied by hour in AERMOD. Therefore, the AERMOD-predicted 1-hour NO2 concentration includes the background.
[h] Value is the annual mean concentration averaged over the five -year period.

TABLE 9.2.5-23

Increment Analysis for the Gas Treatment Plant – Normal Operations

Air Pollutant	Averaging Period	Model-Predicted Concentration (μg/m³)	Class II Increments (μg/m³)
Sulfur Dioxide	1-Hour [a]	NA	NA
	3-Hour [b]	37.7	512
	24-Hour [b]	11.2	91
	Annual [c]	0.5	20
Nitrogen Dioxide	Annual [c]	2.6	25
Particulate Matter less than 10 Microns	24-Hour [b]	4.8	30
	Annual [c]	0.3	17
Particulate Matter less than 2.5 Microns	24-Hour [b]	4.8	9
	Annual [c]	0.3	4

TABLE 9.2.5-23

Increment Analysis for the Gas Treatment Plant – Normal Operations

Air Pollutant	Averaging Period	Model-Predicted Concentration (μg/m³)	Class II Increments (μg/m³)

Abbreviations:
NA = not applicable
μg/m³ = micrograms per cubic meter

Notes:
[a] Neither USEPA nor ADEC have established increment thresholds for 1-hr NO_2, 1-hr SO_2, 1-hr CO, or 8-hr CO.
[b] Value reported is the maximum of the highest-second-high values from each of the five modeled years.
[c] Value reported is the maximum annual average concentration for the five-year period.

In addition to modeling Project emission sources, the Appendix F dispersion analysis also addressed cumulative ambient air quality impacts from the proposed Project and nearby offsite sources. For the GTP cumulative air quality impact analysis, the following offsite sources were considered:

- PBU Central Compression Plant (CCP), and
- PBU Central Gas Facility (CGF).

No other sources were explicitly modeled because they were either not expected to produce a significant concentration gradient in the vicinity of the GTP or were included as part of the background concentration.

Modeled emissions and stack parameters for the CCP and CGF facilities were developed from the respective facility's most recent Title V operating permits and a review of historical dispersion modeling information submitted to ADEC supporting these permit applications. See Appendix F for further details.

Cumulative model-predicted concentrations from the GTP and offsite sources are compared to the NAAQS and AAAQS in Table 9.2.5-24 and to the PSD Increments in Table 9.2.5-25. All model-predicted impacts are below the applicable standards.

TABLE 9.2.5-24

Cumulative NAAQS/AAAQS Analysis for the Gas Treatment Plant – Normal Operations

Air Pollutant	Averaging Period	AERMOD-Predicted Concentration (μg/m³)	Ambient Background Concentration (μg/m³)	Total Concentration (μg/m³)	NAAQS (μg/m³)	AAAQS (μg/m³)
Sulfur Dioxide	1-Hour [a]	39.2	9.39	48.6	196	196
	3-Hour [b]	57	21.0	78	1,300	1,300
	24-Hour [b]	30.1	8.12	38.3	NA	365
	Annual [d]	2.84	1.80	4.64	NA	80
Carbon Monoxide	1-Hour [b]	423	1,150	1,573	40,000	40,000
	8-Hour [b]	302	1,150	1,452	10,000	10,000
Nitrogen Dioxide	1-Hour [c]	158	NA [g]	158	188	188

TABLE 9.2.5-24

Cumulative NAAQS/AAAQS Analysis for the Gas Treatment Plant – Normal Operations

Air Pollutant	Averaging Period	AERMOD-Predicted Concentration (μg/m³)	Ambient Background Concentration (μg/m³)	Total Concentration (μg/m³)	NAAQS (μg/m³)	AAAQS (μg/m³)
	Annual [d]	13.97	6.00	20.0	100	100
Particulate Matter less than 10 Microns	24-Hour [f]	18.4	50.0	68.4	150	150
Particulate Matter less than 2.5 Microns	24-Hour [e]	14.5	15.0	29.5	35	35
	Annual [h]	3.30	3.70	7.00	12	12

Abbreviations:

NA = not applicable

μg/m³ = micrograms per cubic meter

Notes:

[a] Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the modeled period.

[b] Value reported is the highest, second highest concentration of the values determined for each of the modeled years.

[c] Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the modeled period.

[d] Value reported is the maximum annual average concentration for the modeled period.

[e] Value reported is the 98th percentile averaged over the modeled period.

[f] Value reported is the highest, 6th highest concentration over the modeled period.

[g] The 1-hour NO_2 modeling was conducted with wind speed-varying background values applied by hour in AERMOD. Therefore, the AERMOD-predicted 1-hour NO_2 concentration includes the background.

[h] Value reported is the annual mean concentration, averaged over the 5-year period.

TABLE 9.2.5-25

Cumulative Increment Analysis for the Gas Treatment Plant – Normal Operations

Air Pollutant	Averaging Period	Model-Predicted Concentration (μg/m³)	Class II Increments (μg/m³)
Sulfur Dioxide	1-Hour [a]	NA	NA
	3-Hour [b]	53	512
	24-Hour [b]	27	91
	Annual [c]	2.0	20
Nitrogen Dioxide	Annual [c]	6.6	25
Particulate Matter less than 10 Microns	24-Hour [b]	12.8	30
	Annual [c]	1.2	17
Particulate Matter less than 2.5 Microns	24-Hour [b]	4.79	9
	Annual [c]	0.3	4

TABLE 9.2.5-25

Cumulative Increment Analysis for the Gas Treatment Plant – Normal Operations

Air Pollutant	Averaging Period	Model-Predicted Concentration ($\mu g/m^3$)	Class II Increments ($\mu g/m^3$)

Abbreviations:
NA = not applicable
$\mu g/m^3$ = micrograms per cubic meter
Notes:
[a] Neither USEPA nor ADEC have established increment thresholds for 1-hr NO_2, 1-hr SO_2, 1-hr CO, or 8-hr CO.
[b] Value reported is the maximum of the highest-second-high values from each of the five modeled years.
[c] Value reported is the maximum annual average concentration for the 5-year period.

GTP Near-Field Analyses – AQRVs

There are no Class I or Sensitive Class II areas within 50 kilometers of the GTP. See Appendix F, Figure 2-1.

GTP Far-Field Analyses – Ambient Air Quality and AQRVs

Generally ambient air quality impacts decrease with distance from an emission source due to mixing and dilution in the atmosphere. The results for ambient air quality in Section 9.2.5.3.3 demonstrate that there are no issues for the GTP complying with NAAQS, AAAQS, or increments in the near field, and therefore by extension there are no issues in the far field. Thus, the far-field analyses focuses on impacts at Class I and Sensitive Class II areas.

There are no Class I areas within 300 kilometers of the GTP. Sensitive Class II areas in the range of 50–300 kilometers of the GTP, with the distances away, are (see Appendix F, Figure 2-1):

- ANWR – Sensitive Class II Area (93 kilometers); and
- Gates of the Arctic National Park and Preserve – Sensitive Class II Area (214 kilometers).

Complete details of the ambient air quality, visibility, and deposition analyses at each of the areas is provided in Appendix F.

EPA's CALPUFF model was used to assess impacts at each of these areas. CALPUFF uses a prognostic meteorological input dataset. The most recent available dataset for the domain around the GTP is the three-year (2007–2009) WRF dataset developed for the Alaska North Slope by the Bureau of Ocean Energy Management. This dataset has been used for previous CALPUFF modeling on the North Slope and has been approved by the Bureau of Land Management for this region. The WRF modeling domain is a 620-kilometer by 450-kilometer grid centered on North Slope oilfields and pipeline corridor and encompassing each of the Sensitive Class II areas above. See Appendix F, Figure 6-1, for a location map.

For cumulative impact analyses, the far-field modeling included existing sources and reasonably foreseeable development not close enough to the GTP to cause a significant concentration gradient. A total of 19 other facilities were included in the far-field modeling to account for these impacts. See Appendix F, Figure 4-1, for the locations of these facilities.

The NAAQS, AAAQS, and increment modeling results for ANWR and Gates of the Arctic National Park and Preserve are all well below the applicable standards. The most sensitive of these are the Class II increment analyses at these two areas. These results are provided in Tables 9.2.5-26 and 9.2.5-27, respectively, demonstrating that the GTP would not cause or contribute to a violation of the increments at Alaska Sensitive Class II areas. The remainder of the results are provided in Appendix F.

TABLE 9.2.5-26

Increment Analysis for the Gas Treatment Plant – ANWR

Air Pollutant	Averaging Period	GTP Only Model-Predicted Concentration (μg/m³)	Cumulative Analysis Model-Predicted Concentration (μg/m³)	Class II Increments (μg/m³)
Sulfur Dioxide	1-Hour [a]	NA	NA	NA
	3-Hour [b]	0.07	4.06	512
	24-Hour [b]	0.03	1.20	91
	Annual [c]	0.002	0.05	20
Nitrogen Dioxide	Annual [c]	0.02	0.36	25
Particulate Matter less than 10 Microns	24-Hour [b]	0.26	4.27	30
	Annual [c]	0.02	0.29	17
Particulate Matter less than 2.5 Microns	24-Hour [b]	0.27	4.49	9
	Annual [c]	0.02	0.29	4

Abbreviations:
NA = not applicable
μg/m³ = micrograms per cubic meter

Notes:

[a] Neither USEPA nor ADEC have established increment thresholds for 1-hr NO_2, 1-hr SO_2, 1-hr CO, or 8-hr CO.

[b] Value reported is the maximum of the highest-second-high values from each of the five modeled years.

[c] Value reported is the maximum annual average concentration for the 5-year period.

TABLE 9.2.5-27

Increment Analysis for the Gas Treatment Plant – Gates of the Arctic National Park and Preserve

Air Pollutant	Averaging Period	GTP Only Model-Predicted Concentration (μg/m³)	Cumulative Analysis Model-Predicted Concentration (μg/m³)	Class II Increments (μg/m³)
Sulfur Dioxide	1-Hour [a]	NA	NA	NA
	3-Hour [b]	0.03	0.20	512

TABLE 9.2.5-27

Increment Analysis for the Gas Treatment Plant – Gates of the Arctic National Park and Preserve

Air Pollutant	Averaging Period	GTP Only Model-Predicted Concentration (μg/m³)	Cumulative Analysis Model-Predicted Concentration (μg/m³)	Class II Increments (μg/m³)
	24-Hour [b]	0.01	0.10	91
	Annual [c]	0.0004	0.003	20
Nitrogen Dioxide	Annual [c]	0.003	0.04	25
Particulate Matter less than 10 Microns	24-Hour [b]	0.19	1.58	30
	Annual [c]	0.01	0.08	17
Particulate Matter less than 2.5 Microns	24-Hour [b]	0.20	1.55	9
	Annual [c]	0.01	0.08	4

Abbreviations:
NA = not applicable
μg/m³ = micrograms per cubic meter
Notes:
[a] Neither USEPA nor ADEC have established increment thresholds for 1-hr NO_2, 1-hr SO_2, 1-hr CO, or 8-hr CO.
[b] Value reported is the maximum of the highest-second-high values from each of the five modeled years.
[c] Value reported is the maximum annual average concentration for the 5-year period.

For far-field AQRV analysis, regional haze impacts were modeled at ANWR and Gates of the Arctic National Park and Preserve using the CALPUFF model and the same domain and modeling inputs as the ambient air quality impact analyses. See Appendix F for complete details.

Regional haze impacts are estimated based on the change in light extinction. If the predicted change in light extinction due to Project sources is less than 5 percent, there is no concern. Furthermore, if the predicted change in light extinction due to Project and offsite sources is less than 10 percent, there is no concern. If modeled impacts are above either of these thresholds, further investigation may be warranted on a case-by-case basis in consultation with the relevant FLM.

TABLE 9.2.5-28

Regional Haze Results for the GTP Only

Class II Area	Year	Number of Days with Extinction Above		8th Highest Change in Extinction (%)	Visibility Extinction Threshold for a Project (%)
		5%	10%		
ANWR	2007	4	1	3.0	5.0
	2008	15	0	5.5	5.0
	2009	4	1	4.5	5.0
Gates of the Arctic National Park and Preserve	2007	1	1	1.6	5.0
	2008	2	0	2.8	5.0
	2009	5	1	2.8	5.0

TABLE 9.2.5-29

Cumulative Regional Haze Results for the Gas Treatment Plant and Offsite Sources

Class II Area	Year	Number of Days with Extinction Above		8th Highest Change in Extinction (%)	Visibility Extinction Threshold for a Project (%)
		5%	10%		
ANWR	2007	142	88	38.7	10.0
	2008	197	131	71.3	10.0
	2009	162	122	49.3	10.0
Gates of the Arctic National Park and Preserve	2007	76	36	23.0	10.0
	2008	94	55	35.9	10.0
	2009	69	44	32.5	10.0

Table 9.2.5-28 demonstrates the GTP generally would not contribute to visibility impairments Sensitive Class II areas within 300 kilometers. Results for one year at ANWR are slightly above the screening threshold.

For the cumulative impact results presented in Table 9.2.5-29, modeled visibility impacts are above the screening criteria at ANWR and the Gates of the Arctic National Park and Preserve.

Deposition modeling at ANWR and Gates of the Arctic National Park and Preserve used the CALPUFF model, which is consistent with FLAG (2010) for far-field deposition analyses. CALPUFF deposition modeling is both complex and conservative— see Appendix F for details. The results compared to the Class I screening DATs are provided in Table 9.2.5-30. As shown in Table 9.2.5-30, sulfur deposition from the GTP has negligible effects on ANWR and the Gates of the Arctic National Park and Preserve and therefore cumulative sulfur deposition modeling was not conducted. GTP-only and cumulative nitrogen deposition is below the applicable DATs at Gates of the Arctic National Park and Preserve demonstrating there is no concern at this Sensitive Class II area. At ANWR, while cumulative nitrogen deposition is below the DAT, GTP-only N deposition is slightly above the DAT.

TABLE 9.2.5-30

Deposition Results for the Gas Treatment Plant Only

Class II Area		Year	Sulfur Predicted Impact (kg/ha/yr)	Nitrogen Predicted Impact (kg/ha/yr)	Class I Deposition Analysis Thresholds (kg/ha/yr)
Arctic NWR	GTP Only	3-Year Max	0.0009	0.007	0.005
	Cumulative	3-Year Max	NA	0.107	0.125
Gates of the Arctic National Park and Preserve	GTP Only	3-Year Max	0.0003	0.002	0.005
	Cumulative	3-Year Max	NA	0.031	0.125

Ozone and Secondary Particulate Matter Assessment

The Project reviewed the processes involved in the formation and loss of ozone and secondary $PM_{2.5}$ to provide a qualitative assessment of the level of concern. The intent is to help with the understanding of the formation and loss processes in general, but also in relation to the specific characteristics of the Arctic atmosphere. A complete analysis is provided in Appendix F.

A review of available monitoring data near the Project area showed that neither ozone nor $PM_{2.5}$ current concentrations are or have been in exceedance of the NAAQS/AAAQS despite continual development on the North Slope. Furthermore, back trajectory analysis for selected episodes identified from the monitoring data suggest that observed concentrations could be, at least in part, the result of pollution transported from mid-latitude regions.

Using available tools, a conservative quantification of the potential regional impact of the GTP in both ozone and $PM_{2.5}$ was developed. The information provided in this analysis is very conservative as it relies on photochemical modeling performed for the continental United States, which does not account for the chemical complexities (halogen chemistry), the seasonal pattern (photochemical shutdown in the winter) and the global boundary influences (long-range transport contribution to pollution from Asia and Europe) that is known to occur in Alaska.

The analysis in Appendix F indicates that emissions from the GTP would at most lead to ozone increments of about 7 ppbv. This increase is not additive, otherwise the cumulative effect of existing sources would have already affected the monitoring record. Also, the location of peak impact is likely to be variable in space and time. This maximum increase of 0.007 ppmv (7 ppbv) in a region where ozone design values currently range around 0.045 ppmv would not lead to non-attainment issues in the region.

For $PM_{2.5}$, the Appendix F analysis indicates that emissions from GTP would at most lead to nitrate increments of about 1 $\mu g/m^3$ and sulfate increments of less than 8 $\mu g/m^3$ for the 24-hour concentrations. Such $PM_{2.5}$ impacts would not be expected to occur near the source, but downwind as the result of secondary formation. Just as with ozone this increase is not additive and the location of peak impact likely to be variable in space and time. This maximum increase of less than 10 $\mu g/m^3$ in a region where $PM_{2.5}$ concentrations range around 10 $\mu g/m^3$ would not lead to non-attainment issues in the region. Furthermore, formation of ammonium sulfate and nitrate would be significantly limited by ammonia availability.

The assessment suggests there is little concern about formation of ozone and secondary $PM_{2.5}$ as a result of operation of the GTP.

9.2.5.3 Non-jurisdictional Facilities

Operations emissions from PBU MGS project and new facilities are anticipated to be limited to insignificant sources associated with new valve module heating and fugitive emissions of organic compounds emitted from piping components and connectors. Rather, net PBU emissions would actually decrease once the PBU MGS project begins because PBU turbine capacity currently needed for gas re-injection would be reduced. Future PBU emissions from CGF and CCP under the PBU MGS project are summarized in Table 9.2.5-31. These emissions are the net change from baseline (i.e., the no action alternative) for the MGS build alternative. See Appendix G for more details.

Operations emissions from the PTU Expansion project and new facilities are anticipated to be similar to current operating emission for the PTU Initial Production System (IPS) including natural gas production, and gas transportation. Like the PBU MGS project, PTU expansion emissions for the build alternative have been estimated and summarized in Table 9.2.5-31 as the net change in emissions from baseline (i.e., IPS with no gas expansion).

Kenai Spur Highway relocation project operation emissions are limited to assorted vehicle emissions that use the highway. However, relocation of the Kenai Spur Highway is not expected to have a material change in traffic emissions.

TABLE 9.2.5-31

Total Annual Operations Emissions for Non-Jurisdictional Facilities[a]

Project Construction Year	tons/year						tonnes/year[b]
	VOC	NOx	CO	PM_{10}	$PM_{2.5}$	SO_2	CO_2e
Year 10	-17	-3,038	-415	-51	-51	-39	-784,058
Year 15	-35	-6,020	-811	-110	-110	-84	-1,740,665
Year 20	-51	-10,427	-1,236	-174	-174	-98	-2,661,040
Year 25	-62	-13,021	-1,420	-211	-211	-128	-3,260,432

[a] Operations emissions are the net change from the baseline, which is the build alternative emissions less the no action alternative.
[b] Annual emissions of GHGs are reported in metric tons (tonnes) per year.

9.2.6 Applicable Air Quality Regulatory Requirements – Operations

9.2.6.1 Summary of Federal and State Regulatory Requirements

This section provides an overview of applicable regulations and expected compliance requirements. Some of the more significant provisions are discussed in more detail in the subsequent sections.

The federal programs discussed below are implemented by ADEC, which is the regulatory agency for state-only programs. A summary of applicable regulations is provided for federal rules in Table 9.2.6-1 and for Alaska state regulations that are implemented by ADEC in Table 9.2.6-2.[7]

Note that the regulations identified in Tables 9.2.6-1 and 9.2.6-2 may apply at one Project site, but not another. For example, based on design information, the PSD rules would apply to permitting the LNG Plant and the GTP, but not other stationary sources.

[7] This summary reflects the United States Supreme Court decision in UARG v. EPA, 573 U.S. __ (2014) and the July 24, 2014, EPA Guidance indicating that EPA will no longer treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a PSD or Title V permit. However, GHG emissions would trigger a BACT review under PSD if total annual emissions are 75,000 tons or more.

TABLE 9.2.6-1

Federal Air Quality Regulations Potentially Applying to the Project – Operation

Citation/Part of 40 C.F.R.	Title	Description
50	NAAQS	Modeling and any monitoring must comply with NAAQS.
51 Appendix W	Guideline on Air Quality Modeling	Dispersion modeling in support of permit applications must comply with this regulation.
§ 52.21	PSD Regulations	Applies to major stationary sources and modifications; see Section 9.2.6.2
58 Appendix E	Air Quality Monitoring	Applies for stationary sources that submit ambient air monitoring data in support of applications
60 Subpart A	General Provisions for NSPS	Includes general notifications, recordkeeping, reporting, and sampling requirements for affected units
§ 60.18	Flare compliance requirements	Includes flare design standards and monitoring requirements for flares used as NSPS emission control devices
60 Subpart Db	NSPS for boilers and heaters > 100 MMBtu/hr	Regulates NOx, SO_2, PM emissions from boilers and heaters
60 Subpart Dc	NSPS for boilers and heaters > 10 MMBtu/hr	Standards for small boilers, generally regulating SO_2 and PM emissions from oil (and solid fuel) fired units
60 Subpart Kb	NSPS for Tanks < 75 m^3	Can apply to tanks storing volatile organic liquids
60 Subpart IIII	NSPS for Compression Ignition Engines	Emissions limits, monitoring, testing requirements for diesel-fired engines based on use, horsepower, and engine sizes
60 Subpart JJJJ	NSPS for Spark Ignition Engines	Emissions limits, monitoring, testing requirements for spark-ignition natural gas-fired engines based on use, horsepower, and engine sizes.
60 Subpart KKKK	NSPS for Combustion Turbines including Supplemental Firing	Includes NOx and SO_2 limits for turbines > 10 MMBtu/hour heat rate, monitoring, testing, recordkeeping and reporting requirements
60 Subpart OOOOa	NSPS for Natural Gas Production and Transmission	Applies to onshore operations, including processing, transmission, and storage facilities. Contains monitoring, notification, recordkeeping and reporting requirements.
63 Subpart A	NESHAPs General Provisions	General compliance for listed sources of hazardous air pollutants, includes permitting requirements, monitoring, recordkeeping, reporting, and includes standards for flares used as NESHAPs emission control devices.
63 Subpart HH	NESHAP for oil and gas production facilities	Applies to VOC/HAP emission from major and area sources including glycol dehydration units, tanks and compressors. May be exempt based on liquid hydrocarbon production rates (<39,700 liter/day), (10,500 gal) and other factors.
63 Subpart HHH	NESHAP for natural gas transmission and storage	Applies to natural gas transmission and storage facilities, but only at sites with a glycol dehydration unit.
63 Subpart YYYY	NESHAPs for combustion turbines	Applies at major HAP sources, but not on the North Slope, except for notifications
63 Subpart ZZZZ	NESHAPs for stationary engines	Applies to RICE, including generator engines, emergency generator engines, firewater pump engines, etc. Compliance generally demonstrated by complying with NSPS Subparts IIII or JJJJ.
63 Subpart DDDDD	NESHAPs for Boilers and heaters at major sources	Applies to boilers and process heaters at major HAP sources. Natural gas fired units must conduct five-year tune-ups.
63 subpart CCCCCC	NESHAPs for Gasoline Dispensing Facilities	Applies to an onsite gasoline dispensing facility, with requirements based on monthly throughput.
68	Chemical Accident Prevention	Applies to stationary sources that have more than the threshold quantity of a regulated toxic or flammable substance.
71	Title V operating Permits	Major sources > 100 ton/year and certain NSPS and NESHAP

TABLE 9.2.6-1

Federal Air Quality Regulations Potentially Applying to the Project – Operation

Citation/Part of 40 C.F.R.	Title	Description
		sources must obtain an operating permit from ADEC.
80 Subpart I	ECA Marine Fuel Standards	May apply to end-users of marine fuel.
82	Stratospheric Ozone Protection	Applies to facilities with listed refrigerants, to manage and control emissions or releases from those units.
89	Non-road compression ignition engines	Applies to pre-2014 non-road compression-ignition engines, including portable units
91	Marine spark-ignition engines	May apply to specific marine spark-ignition engines
94	Marine compression-ignition engines	May apply to specific marine compression-ignition engines
98 Subparts A, C, and W	Mandatory GHG reporting rule	Sources with > 25,000 metric tons/year of CO_2e emissions must calculate and submit annual reports of GHG emissions.
1042	Marine compression-ignition engines	May apply to certain end-users of marine compression-ignition engines
1043	Control of Emissions under MARPOL	Controls NOx, SO_2, and PM emissions from marine vessels subject to MARPOL Protocol.

TABLE 9.2.6-2

Alaska Air Quality Regulations Potentially Applying to the Project – Operation

Citation to 18 AAC 50	Title	Description
50.010	Ambient air quality	Facility must be designed and permitted to operate in compliance with ambient air quality standards.
50.020	PSD Baseline dates and maximum allowable increases	Facility must be designed and permitted to operate in compliance with the PSD increments. PSD increments will be evaluated for LNG and GTP operation.
50.025	Visibility and other special protection areas	Establishes visibility protections for three areas, including (1) Mt. Deborah and the Alaska Range East, as viewed from approximately the Savage River Campground area, (2) Mt. McKinley, Alaska range, and Interior Lowlands as viewed from the vicinity of wonder Lake, and (3) geographic areas classified as Class I under 18 AAC 50.15(c). This last group is also an area with federally enforceable visibility protection, but this provision allows ADEC to interpret and regulate visibility impacts under its own rules.
50.035 (a) (2)	Documents adopted by reference	Adopts the *Workbook for Plume Visual Impact Screening and Analysis (Revised)* EPA 454/R-92-023, October 1992 as a means of addressing visibility impacts.
50.040 (a)	New Source Performance Standards	Adopts the Federal New Source Performance Standards, including Subpart A general provisions, Subpart IIII for compression ignition reciprocating internal combustion engines, Subpart JJJJ for spark ignition reciprocating internal combustion engines, Subpart KKKK for stationary combustion turbines, and Subpart OOOO for natural gas production and transmission.
50.040(c)	National Emission Standards for Hazardous Air Pollutants	Adopts the Federal National Emission Standards for Hazardous Air Pollutants, including the Subpart A for general provisions, Subpart YYYY for stationary combustion turbines, Subpart ZZZZ for stationary reciprocating internal combustion engines, and Subpart DDDDD for industrial, commercial, and institutional boilers and process heaters located at major HAP sources.
50.045 (d)	Prohibitions	A person who causes or permits bulk materials to be handled,

TABLE 9.2.6-2

Alaska Air Quality Regulations Potentially Applying to the Project – Operation

Citation to 18 AAC 50	Title	Description
		transported, or stored, or who engages in any industrial activity or construction project shall take reasonable precautions to prevent particulate matter from being emitted into the ambient air. No specific permitting or approval for compliance is required; however, the agency may take action if this provision is violated, particularly in response to a complaint by the general public.
50.050	Incinerator emission standards	Requires opacity to be 20 percent or less averaged over any six consecutive minutes. No limit exists for particulate matter emissions for incinerators that have a rated capacity less than 1,000 pounds per hour. Project design indicates that no incinerators will exceed that design threshold, but if rated capacity is above that level, the PM emission standards would apply.
50.055	Industrial Processes and fuel burning equipment	This rule limits visible emissions from industrial process or fuel-burning equipment to 20 percent or less for any consecutive six-minute period. Particulate matter emissions from fuel-burning equipment also must comply with grain loading standards in § (b) of the regulation. Sulfur compound emissions from an industrial process or fuel-burning equipment may not exceed 500 ppm averaged over three hours.
50.070	Marine Vessel visible emission standards	Establishes marine vessel visible emission standards and would apply to marine vessels that are used in support of construction both of the pipeline across Cook Inlet and of the LNG terminal facilities. Specific visibility standards apply to these vessels.
50.080	Ice fog standards	Allows ADEC to require a permit to reduce water vapor emissions for fuel burning equipment or an incinerator in areas of potential ice fog
50.100	Non-road engines	Specifies that the emissions from non-road engines (heavy equipment, portable generators, and any engines that are temporary) are not included when determining the classification of a stationary source or modification for a permit.
50.110	Air pollution prohibited	ADEC can restrict emissions which may be injurious to health, welfare, property or unreasonably interfere with the enjoyment of life or property. Construction activities that may cause excessive dust, particularly near residences or sensitive receptors, may be curtailed under this regulation if a complaint is received and ADEC considers the impacts to be within these adverse determinations.
50.215	Ambient air quality analysis methods	Provides methods for analyzing (or modeling) ambient air quality impacts for permitting.
50.220	Test methods	References test methods for demonstrating compliance with emission limits.
50.225	Owner requested limits	Operators and owners can request emission limits that limit applicability of other air quality regulations.
50.235	Unavoidable emergencies	Establishes rules for reporting and responding to emergencies related to air pollution
50.240	Excess emissions	Provides requirements for reporting excess emissions including startup and shutdown.
50.245 and 50.246	Air Quality episodes	Allows ADEC to declare an air quality episode based on actual or potential impacts, and subsequently request voluntary reductions in emissions from stationary sources.
50.306	Prevention of Significant	Applies to major stationary sources for construction. Applies to

TABLE 9.2.6-2

Alaska Air Quality Regulations Potentially Applying to the Project – Operation

Citation to 18 AAC 50	Title	Description
	Deterioration (PSD) Permits	LNG at GTP based on preliminary data.
50.316	Preconstruction review for major source of HAPs	Provides ADEC review of federal standards under 40 C.F.R. Part 63 (Maximum Achievable Control Technology Standards). Includes obtaining a permit from ADEC.
50.326	Title V operating permits	Sources with emissions of 100 tons/year or greater of any regulated criteria pollutant (not GHG) must obtain an operating permit, renewable on a five-year basis, and when new applicable requirements affect the source.
50.345 50.346	Construction minor and operating permits standard permit conditions	Compliance requirements (standard conditions) for PSD, Title V operating, and minor sources permits and for modifications to existing stationary sources. Includes requirements for notifications, document submittals, and inventory reporting.
50.400 - 50.499	User Fees	Establishes fee schedules for permits and permit renewals
50.502	Minor construction permits	Specifies provisions for requiring a minor source construction permit for certain activity, based on the potential emissions from a stationary source or modification. Certain components of the construction activity may qualify as a stationary source depending on the duration of activity at a specific location. Minor permits must be obtained for the following potential activities under §(b) of this regulation: (1) An asphalt plant with a rated capacity of at least 5 tons/hour of product (2) A rock crusher with a rated capacity of 5 tons/hour (3) One or more incinerators with a cumulative rated capacity of 1,000 lbs./hour or more
50.508	Minor permits requested by owner or operator	Owner or operator can establish enforceable emission limits in a permit to avoid applicability of specific regulations
50.540	Minor Permits	A minor source construction permit is required based on potential emissions.
50.544	Minor permits: content	Requires permit conditions for minor sources
50.990	Definitions	Provides regulatory definitions for air quality regulations. Should be consulted in reviewing permit and compliance requirements, including any changes or modifications.

9.2.6.2 New Source Review (NSR) and Prevention of Significant Deterioration (PSD)

Ambient air quality is protected in part by an air quality permitting program for new stationary sources and modifications to existing stationary sources. This program is implemented by ADEC and addresses the federal NSR regulations, as well as state regulations. Separate programs are in place to issue permits for major and minor stationary sources. The federal NSR program for major sources consists of rules for issuing preconstruction permits for attainment area pollutants (known as the PSD rules) and non-attainment area pollutants (known as the non-attainment NSR rules). The Project would be located in areas that are in attainment with, or unclassified with respect to, the ambient standards for all pollutants. As a result, only PSD would apply for permitting major stationary sources within the Project. EPA has approved the Alaska PSD rules as an element of the SIP allowing ADEC to implement PSD (see 18 AAC 50.306 and 40 C.F.R. § 52.21).

A stationary source is a "major source" if the source's potential to emit, which is its capability at maximum design capacity to emit a pollutant, except as constrained by federally enforceable permit conditions, exceeds certain emission thresholds. Under the PSD rules, a major stationary source is one that emits or has the potential to emit:

- For a categorical list of 28 sources (40 C.F.R. § 52.21[b][1][i][a]), 100 tons per year or more of any regulated air contaminant (other than GHGs) in an area designated attainment for that air contaminant; or

- For other sources, 250 tons per year or more of any regulated air contaminant (other than GHGs) in an area designated attainment for that air contaminant.

The stationary sources proposed as part of the Project are not included on the categorical list and so 250 tons per year is the threshold for determining major source status under PSD for all criteria pollutants for new sources installed as part of the Project.

If a new source or modification is "major," PSD review and permitting is required for associated regulated pollutants emitted in amounts equal to or greater than the applicable "significance levels." The PSD significance levels are specified in 40 C.F.R. § 52.21(b) (23) (i) as follows: 40 tons per year for NO_X, SO_2, and VOCs; 100 tons per year for CO; 15 tons per year for PM_{10}; 10 tons per year for $PM_{2.5}$; and 0.6 tons per year for lead. PSD applicability for some pollutants can also be triggered by other pollutant emissions. For instance, $PM_{2.5}$ PSD applicability can be triggered by significant emissions of NO_X or SO_2, and ozone PSD applicability can be triggered by significant emissions of NOx. Formation of ozone and secondary particulate matter ($PM_{2.5}$) can be addressed qualitatively.

GHG emissions may be regulated if the stationary source triggers PSD applicability through other pollutants and the total CO_2e emissions (or increase) are above 75,000 tons per year[8]. CO_2e emissions are defined as the sum of the mass emissions of each individual GHG adjusted using the applicable GWP for the following six gases:

- CO_2;
- Nitrous oxide (N_2O);
- Methane (CH_4);
- Hydrofluorocarbons;
- Perfluorocarbons; and
- Sulfur hexafluoride.

Based on the information provided in Section 9.2.5, both the LNG Plant and the GTP would be major sources subject to PSD review. An applicability summary is provided in Table 9.2.6-3 based on Project information. Compressor stations are not included in the list of 28 sources provided in 40 C.F.R. §

[8] EPA is undertaking rulemaking regarding the threshold for applying PSD to GHGs; however, any changes would not be expected to impact permitting for the Project.

52.21[b][1][i][a]), so are not considered major sources subject to PSD review for the Project because their total annual potential emissions of any criteria air pollutant are below 250 tons per year.

TABLE 9.2.6-3

y PSD Applicability for the Liquefaction Facility and GTP – Operation

Pollutant	Liquefaction Facility Potential to Emit (tons per year)	LF PSD	GTP Potential to Emit (tons per year)	GTP PSD
Nitrogen Oxides (NO_X)	1,170	Yes	2,231	Yes
Carbon Monoxide (CO)	1,728	Yes	2,073	Yes
Volatile Organic Compounds (VOCs)	195	Yes	304	Yes
Particulate Matter (PM_{10})	259	Yes	263	Yes
Particulate Matter ($PM_{2.5}$)	259	Yes	263	Yes
Sulfur Dioxide (SO_2)	90	Yes	99[b]	Yes
Lead (Pb)	TBD	TBD	TBD	TBD
Total GHG Emissions (CO_2e)[a]	3,846,143	Yes	4,196,914	Yes

[a] GHG are reported in metric tons (tonnes) per year.

[b] Value based on 15 ppmv sulfur in the fuel gas which is representative of permitted long-term, normal operations. For a short-period of time during facility commissioning, the sulfur content of the fuel gas will be 90 ppmv sulfur in the fuel gas which is not expected to become an enforceable permit limit applicable to long-term, normal operations.

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If PSD review applies, a PSD permit application must address the following requirements:

- Apply Best Available Control Technology (BACT) for each regulated pollutant for which the new stationary source or major modification would result in a significant net emissions increase (40 C.F.R. § 52.21[j][3]);
- Conduct an air quality impact analysis that establishes the maximum modeled impact and demonstrates emissions associated with the proposed new source or modification, in conjunction with all other emission increases and decreases, will not cause or contribute to violations of any NAAQS or allowable PSD increment (40 C.F.R. § 52.21[k]);
- Provide an ambient air analysis based on current data collected in the vicinity of the Project (§ 52.21[m]);
- Provide an analysis of the impairment to visibility, soils, and vegetation that would occur as a result of the stationary source and general commercial, industrial, residential, and other growth associated with the stationary source (40 C.F.R. § 52.21[o][1]);
- Provide an analysis of the projected additional air quality impact as a result of general commercial, industrial, residential, and other growth associated with the stationary source (40 C.F.R. § 52.21[o][2]); and

- Provide an analysis of the impacts to air quality and air quality-related values at nearby Class I areas (40 C.F.R. § 52.21[p]), if applicable.

9.2.6.3 Preconstruction Review of Major Sources of Hazardous Air Pollutants

Stationary sources that emit more than 10 tons per year of a single HAP or 25 tons per year of all HAPs combined are classified as major sources under 40 C.F.R. 63.2. Major HAP sources are required by 40 C.F.R. 63.5 to obtain a permit prior to construction. The construction permit required by major HAP sources is administered by ADEC under a SIP-approved program through 18 AAC 50.316.

Based on the information provided in Section 9.2.5 above, both the LNG Plant and the GTP would be major HAP sources subject to preconstruction review. An applicability summary is provided in Table 9.2.6-4, based on preliminary Project information. Based on the information provided in Section 9.2.5, the compressor stations would not be major HAP sources. As a result, a preconstruction review is not required for those facilities.

TABLE 9.2.6-4

Preliminary HAP-Major Applicability for the Liquefaction Facility and GTP – Operation

Pollutant	Liquefaction Facility Potential to Emit (tons per year)	LF HAP Major	GTP Potential to Emit (tons per year)	GTP HAP Major
Largest Individual Hazardous Air Pollutant (Formaldehyde)	25.8	Yes	25.8	Yes
Total Hazardous Air Pollutants (HAPs)	37.7	Yes	42.4	Yes

Under the HAP-major preconstruction review rules, a major HAP source must implement the maximum achievable control technology (MACT) as determined in the applicable subparts of 40 C.F.R. 63. Further information about applicable NESHAPs subparts (40 C.F.R. 63) is provided in Section 9.2.6.7.

9.2.6.4 Minor New Source Review Permits

For new stationary sources, a minor permit is required under 18 AAC 50.502(c) (1) if (1) the source is not a major source, and (2) the potential to emit one or more criteria pollutants exceeds the following:

- 15 tons per year of PM_{10};
- 40 tons per year NO_X;
- 40 tons per year of SO_2;
- 0.6 tons per year of Pb;
- 100 tons per year of CO within 10 kilometers of a CO non-attainment area; or
- 10 tons per year of direct $PM_{2.5}$.

Based on the information provided in Section 9.2.5, none of the compressor or heater stations would be major stationary sources subject to PSD, but all compressor and heater stations would be subject to minor NSR permitting. Therefore, these sources require minor source permits from ADEC prior to beginning construction.

At this time, no minor NSR permits have been identified for construction sources. A final determination would be made after construction contractors are selected.

9.2.6.5 Title V Operating Permits

Title V of the CAA requires that sources that either emit more than 100 tons per year of any criteria air pollutant or are subject to certain NSPS or NESHAP subparts obtain an operating permit under this rule. ADEC is responsible for issuing operating permits in Alaska pursuant to 18 AAC 50.326. A new source must submit a complete application for an operating permit within 12 months after the start of operation.

Based on information available at this time, the Liquefaction Facility, GTP, and all compressor and heater stations would each be required to obtain a Title V permit.

9.2.6.6 New Source Performance Standards (NSPS)

Pursuant to Section 111 of the CAA, EPA promulgates NSPS, codified in 40 C.F.R. Part 60, for certain newly constructed, modified, or reconstructed sources of emissions of criteria pollutants. These standards are based on best demonstrated technology for air pollution control of specified equipment and may be expressed as numerical emission limits, performance standards, or work practices. Subpart A of Part 60 establishes general provisions for sources subject to the various NSPS subparts, including general performance testing, monitoring, notification, reporting, and recordkeeping requirements.

Table 9.2.6-5 provides a summary of the NSPS categories under 40 C.F.R. 60 that are potentially applicable to emission units included in the Project. Further details regarding applicability and requirements are provided in Appendix H. Final NSPS applicability determinations would be made after construction contractors are selected.

TABLE 9.2.6-5

Preliminary NSPS Applicability Summary for Operations

NSPS Subpart	Applicability		
	Liquefaction Facility	Compressor and Heater Stations	GTP
Subpart A – General Provisions	Yes	Yes	Yes
Subpart Da – Electric Utility Steam Generation Units	No	No	No
Subpart Db – Industrial, Commercial, and Institutional Steam Generating Units	No	No	Yes
Subpart Dc – Small Industrial, Commercial, and Institutional Steam Generating Units	No	Yes	No
Subpart Kb – Volatile Organic Liquid Storage Vessels	TBD	No	TBD
Subpart CCCC – Commercial and Industrial Solid Waste Incineration Units	No	Yes	No
Subpart IIII – Stationary Compression Ignition Internal Combustion Engines	Yes	No	Yes
Subpart JJJJ – Stationary Spark Ignition Internal Combustion Engines	No	Yes	No
Subpart KKKK – Stationary Combustion Turbines	Yes	Yes	Yes

TABLE 9.2.6-5

Preliminary NSPS Applicability Summary for Operations

NSPS Subpart	Applicability		
	Liquefaction Facility	Compressor and Heater Stations	GTP
Subpart OOOOa – Crude Oil and Natural Gas Production, Transmission and Distribution	Yes	Yes	Yes

9.2.6.7 National Emission Standards for Hazardous Air Pollutants (NESHAPs)

The 1970 CAA required that the EPA develop health risk-based standards for regulating HAP emissions. These regulations are codified in 40 C.F.R. Part 61, National Emission Standards for Hazardous Air Pollutants (NESHAPs) and apply to specific pollutants and source categories. The Project is not one of the source categories regulated under 40 C.F.R. Part 61 and, as such, the requirements of 40 C.F.R. 61 do not apply to the Project.

The 1990 CAA Amendments expanded EPA obligation to regulate HAPs and required EPA to set technology-based standards for a larger list of HAPs and for many more source categories. These NESHAPs are codified in 40 C.F.R. Part 63, also referred to as MACT standards, and regulate HAP emissions from major sources of HAPs and area sources of HAPs within specific source categories. Part 63 defines a major source of HAPs as any stationary source or group of stationary sources located within a contiguous area and under common control that has the potential to emit more than 10 tons per year of any single HAP or more than 25 tons per year of all HAPs combined. Part 63 defines an area source of HAPs as any stationary source of HAPs that is not a major source of HAPs. Preliminary HAPs emission calculations indicate that the Liquefaction Facility and the GTP are each anticipated to have the potential to emit a single HAP, formaldehyde (which is formed by chemical reaction of the products of combustion), at a rate greater than 10 tons per year. As a result, these facilities are expected to be major sources of HAPs. The compressor stations, heater stations, and metering station potential to emit total HAPs and any single HAP would be below the 25 tons per year and 10 tons per year thresholds, respectively, and would be classified as area sources of HAPs.

Subpart A of Part 63 provides the general provisions of the MACT standards, which includes monitoring, notification, and reporting requirements for sources subject to certain subparts within 40 C.F.R. Part 63. Each subpart provides a table identifying which general provisions apply to that subpart. Table 9.2.6-6 provides a summary of the MACT standards in 40 C.F.R. Part 63 that may apply to the proposed Project facilities. Further details regarding applicability and requirements are provided in Appendix H. Final NESHAPs applicability determinations would be made after construction contractors are selected.

TABLE 9.2.6-6

Preliminary NESHAPs Applicability Summary for Operations

NESHAPs Subpart	Applicability		
	LNG Plant	Compressor and Heater Stations	GTP
Subpart A – General Provisions	Yes	Yes	Yes

Subpart Y – National Emission Standards for Marine Tank Vessel Loading Operations	No	No	No
Subpart EEE – NESHAPs from Hazardous Waste Combustors	No	TBD	No
Subpart EEEE – NESHAPs for Organic Liquids Distribution (Non-Gasoline)	TBD	No	TBD
Subpart H – Organic HAPs for Equipment Leaks	TBD	TBD	TBD
Subpart HH – NESHAPs for Oil and Natural Gas Production Facilities	TBD	No	TBD
Subpart HHH – NESHAPs for Natural Gas Transmission and Storage Facilities	No	No	Yes
Subpart YYYY – NESHAPs for Stationary Combustion Turbines	Yes	No	Yes
Subpart ZZZZ – NESHAPs for Stationary Reciprocating Internal Combustion Engines	Yes	Yes	Yes
Subpart DDDDD – NESHAPs for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters	No	No	Yes
Subpart JJJJJJ – NESHAPs for Industrial, Commercial, and Institutional Boilers Area Sources	No	No	No

9.2.6.8 Chemical Accident Prevention (40 C.F.R. 68)

Section 112(r) of the 1990 CAA Amendments requires the EPA to publish regulations and guidance for chemical accident prevention at facilities for substances that pose the greatest risk of harm from accidental releases. The chemical accident prevention provisions, also referred to as the Risk Management Program (RMP), are codified in 40 C.F.R. Part 68. The regulations include a list of regulated substances that include methane, propane, and ethylene. The regulation also includes threshold quantities (TQs) for determining applicability to stationary sources. If a stationary source stores, handles, or processes one or more regulated substances in a quantity equal to or greater than the TQ as determined per 40 C.F.R. 68.115, the facility must prepare and submit a risk management plan to the EPA.

A preliminary RMP applicability analysis that may apply to the proposed Project facilities is summarized in Table 9.2.6-7. See Appendix H for further details. Final applicability determinations would be made based on final facility design.

TABLE 9.2.6-7

Preliminary RMP Applicability Summary

40 C.F.R. Part 68 - Chemical Accident Prevention Provisions	Applicability		
	Liquefaction Facility	Compressor and Heater Stations	GTP
Subpart F – Regulated Substances for Accidental Release Prevention	No	No	Yes

9.2.6.9 The Federal Greenhouse Gas Reporting Rule

EPA's Greenhouse Gas Monitoring Recordkeeping and Reporting Rule (40 C.F.R. Part 98) requires reporting of GHG emissions from suppliers of fossil fuels or industrial GHGs, manufacturers of vehicles and engines, and facilities that emit greater than or equal to 25,000 metric tons of GHG (as CO_2e) per year. As set forth in Section 9.2.5, the potential CO_2e emissions from operation of the Liquefaction Facility, GTP, compressor stations, and heater station would all exceed 25,000 tonnes per year; therefore, they would all be subject to the GHG reporting rule. Additionally, construction of the Liquefaction Facility, GTP, and possibly Mainline could also exceed 25,000 tonnes per year, triggering GHG reporting requirements.

Reporting would be required for the first year of operation or construction that exceeds 25,000 tonnes per year. A report needs to be submitted on EPA's electronic database by March 31 of each year for the previous calendar year's emissions. Reporting is not required for construction activities from portable equipment unless stationary sources (e.g., heaters, compressors, engines) have combined emissions above 25,000 tons per year and are at the same location for 12 consecutive months.

9.2.6.10 General Conformity with Non-Attainment SIPs

Promulgated under 40 C.F.R. Part 51 Subpart W and 40 C.F.R. Part 93 Subpart B, the General Conformity Rule is used to determine if non-transportation-related federal actions meet the requirements of the CAA and the applicable SIP by ensuring that air emissions related to the action do not cause or contribute to new violations of a NAAQS or increase the frequency or severity of any existing violation of a NAAQS or interim emission reduction. A General Conformity Determination is required for federally sponsored or federally approved actions in non-attainment areas, or in certain maintenance areas, when the total direct and indirect net emissions of non-attainment pollutants (or their precursors) exceed specified thresholds (40 C.F.R. § 93.153). This regulation ensures federal actions conform to the SIP and state attainment plans.

A complete analysis of general conformity is provided in Appendix M. To summarize, Project representatives reviewed air pollutant emissions associated with Project activities that would be emitted within air quality non-attainment areas or maintenance areas identified in Table 9.2.6-8.

TABLE 9.2.6-8

Non-Attainment and Maintenance Areas in the Project Vicinity

Area	Relevant Emissions Type
Fairbanks North Star Borough 2006 $PM_{2.5}$ Non-attainment Area	$PM_{2.5}$ emissions and $PM_{2.5}$ precursors (SO_2 and NOx)
Fairbanks Area CO Maintenance Area (including the Fairbanks and Fort Wainwright portion and the North Pole portion of the Maintenance Area)	Carbon Monoxide
Municipality of Anchorage CO Maintenance Area	Carbon Monoxide
Eagle River PM_{10} Maintenance Area	PM_{10}

Relevant emissions would result from Project transportation/logistics activities that occur within specific non-attainment or maintenance areas and from a pipeline construction support facility that may be located in Fairbanks during Project construction. Neither Project physical construction activities nor facility operations would occur within any of the areas listed in Table 9.2.6-8.

Under Section 93.153(b) of the General Conformity rule, a conformity determination is required for each criteria pollutant or precursor where the total of direct and indirect emissions of the pollutant or precursor would equal or exceed specified "de minimis" emissions levels. For $PM_{2.5}$ nonattainment areas, CO maintenance areas, and PM_{10} maintenance areas, Section 93.153(b)(1) and (2) specifies that the de minimis emissions level for the relevant pollutants is 100 tons per year.

Table 9.2.6-9 summarizes the peak annual emissions for relevant pollutants or precursors expected to occur within each nonattainment or maintenance area within Alaska that potentially could be affected by the proposed Project.

TABLE 9.2.6-9

Applicability of General Conformity to Project Emissions

Area	Relevant Emissions Type	Direct/Indirect Project Emissions (tons per year)	Does General Conformity Apply?
Fairbanks North Star Borough 2006 $PM_{2.5}$ Nonattainment Area	$PM_{2.5}$ emissions and $PM_{2.5}$ precursors (SO_2 and NOx)	3.55 tons $PM_{2.5}$/year 5.46 tons NOx/year 0.014 tons SO_2/year	No No No
Fairbanks Area CO Maintenance Area (including the Fairbanks and Fort Wainwright portion and the North Pole portion of the Maintenance Area)	Carbon Monoxide	1.90 tons CO/year	No
Municipality of Anchorage CO Maintenance Area	Carbon Monoxide	0.37 tons CO/year	No
Eagle River PM_{10} Maintenance Area	PM_{10}	0.01 tons PM_{10}/year	No

As can be seen in Table 9.2.6-9, emissions for each pollutant or precursor is far below the 100 tons per year de minimis emissions threshold. Therefore, as specified in 40 C.F.R. 93.153(c)(1), the General Conformity provisions of 40 C.F.R. 93, Subpart B do not apply to federal approvals required for the Project. See Appendix M for complete details.

9.2.6.11 Federal Marine Vessel Regulations

Several regulations could potentially apply to marine vessel emissions ranging from small service vessels to oceangoing vessels. Emission standards and certification requirements are provided in 40 C.F.R. Parts 89, 94, and 1042, based on engine size and date of manufacture. Emissions from Project-operated vessels and carriers are based on assumptions about fleet engine sizes and dates of manufacture. General compliance provisions are provided in 40 C.F.R. Part 1068 with further regulations in 40 C.F.R. Part 1043 related to implementing MARPOL Protocol for in-use fuels.

9.2.6.12 Regional Haze Rule

The federally mandated Regional Haze Rule (40 C.F.R. 51 Subpart P) establishes regulations to improve and protect visibility in designated Class I areas (see Section 9.2.2.2). For new sources, the program is implemented through 40 C.F.R. Subpart P §53.307 as part of the existing NSR Program for major stationary sources and major modifications.

The EPA adopted the Regional Haze Rule to protect visibility in Class I areas. The rule lays out the specific requirements to ensure improvements in visibility in the DNPP and other large national parks and wilderness areas across the country through the mitigation of human-caused air pollution impacts. The Regional Haze Plan describes how the State of Alaska will meet federal requirements to measure and monitor visibility, aerosols, and air pollution at Alaska's four Class I areas, how Alaska will evaluate the factors reducing visibility at each site, and how Alaska plans to identify and implement air pollution control measures on a case-by-case basis to reach natural visibility conditions by the 2064 Regional Haze Rule target date. There are no applicable requirements for the proposed facilities beyond the AQRV analyses that may be required for the PSD sources in the Project.

ADEC is required to notify the appropriate FLM of any proposed PSD major project that has the potential to impact a Class I area (generally within 62 miles [100 kilometers] of the Class I area). This notification must include an analysis of the project's impact on visibility in the Class I area. Impacts are assessed to ensure continued "reasonable further progress" toward attaining visibility goals in the Class I areas. Compliance can require visibility monitoring as well as the imposition of control technologies based on cost and other factors. Analyses would generally be completed as part of the PSD application.

9.2.7 Construction Regulatory Compliance and Mitigation Measures

Air quality impacts would be minimized through the use of construction equipment that is compliant with applicable NSPS, NESHAPs, and other emission standards. Impacts may also be minimized through such means as best management practices (BMPs) for construction, optimization of site layouts, and efficiency assessments of electric power and process heat uses.

The Project *Construction Emissions Control Plan* would discuss BMPs for how construction practices would comply with applicable requirements. A template is provided in Appendix I. Other construction mitigation plans are the Project *Fugitive Dust Control Plan* (Appendix J) and the Project *Open Burning Plan* (Appendix K). Each of these plans would be used to identify controls and BMPs for applicable construction equipment and construction activities. Site/activity-specific plans won't be able to be developed until construction contractors are appointed, and completed versions the referenced appendix plans would be provided at that time.

9.2.8 Operational Regulatory Compliance and Mitigation Measures

As set forth in Section 9.2.5, modeling analyses of the Liquefaction Facility, compressor stations, and GTP have not identified any instances where facility operations would not comply with applicable ambient air quality standards.

Air quality impacts would be minimized through the use of turbines and generators that are compliant with applicable NSPS, NESHAPs, and BACT determinations. Facilities impacts may also be minimized through such means as optimization of Project design parameters such as stack heights, building heights (which affect downwash), and efficiency assessments of electric power and process heat uses.

A Project *Operations Emission Control Plan* would be developed that sets forth how facilities would ensure compliance with applicable requirements. The Table of Contents provided in Appendix L reflects annotated sections to be addressed in the full Plan developed during the Project permitting phase

9.2.9 Greenhouse Gas (GHG) Impacts and Mitigation Measures

Observations of climate trends in Alaska and the Arctic region have been well documented in recent years. There are many causes of global climate change, and the nature of climate change is affected by complex interactions within the earth-atmosphere-ocean system. Many of these causes are undergoing extensive research, and the results of these studies may play a role in developing a deeper understanding of global climate change and its relation to local emissions.

9.2.9.1 GHG Emissions Quantification

The GHG emissions associated with the Project are calculated and summarized in Sections 9.2.3 and 9.2.5, along with other air quality emissions, and the analysis includes both construction and operating activities. The information in Tables 9.2.9-1 and 9.2.9-2 includes emissions from construction and operation of jurisdictional facilities and non-jurisdictional connected actions.

TABLE 9.2.9-1

Total GHG Emissions from Construction (CO_2e, tonnes)

Year	Liquefaction Facility	Pipeline Spread 1	Pipeline Spread 2	Pipeline Spread 3	Pipeline Spread 4	PTTL	GTP & PBTL	NJF [a]	Totals
1							6,897	1,384	**8,281**
2	28,534	12,212	26,782	21,664	15,327		50,110	7,490	**162,119**
3	46,077	37,971	43,885	53,448	21,130	15,279	49,861	73,827	**341,478**
4	158,307	38,658	26,041	33,030	74,543	21,877	45,462	139,301	**537,219**
5	170,477	68,321	69,744	68,158	261,141	0	58,961	310,684	**1,007,486**
6	83,941	57,717	46,861	31,419	36,487	352	61,684	358,659	**676,768**
7	64,595	8,994	3,201	2,958	1,463		55,536	355,720	**492,467**
8	42,951						32,979	137,732	**213,662**
9	27,043						11,475	50,859	**89,377**
Total	**621,925**	**223,873**	**216,514**	**210,677**	**410,091**	**37,508**	**372,965**	**1,435,654**	**3,528,855**

[a] NJF = non-jurisdictional facilities

TABLE 9.2.9-2

Annual GHG Emissions from Operations

Facility	CO_2e (tonnes per year)
LNG Plant and Marine Terminal	3,850,732
LNG Carriers and Support Tugs	81,248
Compressor and Heater Stations	1,722,921
Gas Treatment Plant	4,201,860
Pipeline Fugitives	346

TABLE 9.2.9-2

Annual GHG Emissions from Operations

Facility	CO_2e (tonnes per year)
Non-Jurisdictional Facilities (Year 10)	-784,058
Total GHG Emissions (CO_2e)[a]	**9,073,049**

[a] The total GHG emissions are calculated as CO_2 equivalent (CO_2e) emissions, i.e., the sum of individual GHGs with the annual tons of each gas multiplied by its Global Warming Potential (GWP) relative to CO_2.

9.2.9.2 Potential Impacts

While the GHG emissions from a single project can be estimated with an acceptable level of confidence, the potential influence of those GHG emissions on global climate change is not measurable with an acceptable level of confidence and, therefore, is not addressed in this Resource Report. The increased availability of natural gas in the world market (and potentially within Alaska) is likely to replace current use or displace future use of some higher-carbon fossil fuels, thereby resulting in an overall reduction in global GHG emissions. However, the extent to which air quality, GHG emissions, and climate might be improved through this replacement cannot be quantified at this time[9]. Estimates for GHG emissions from jurisdictional and non-jurisdictional connected actions are provided in Table 9.2.9-1.

9.2.9.3 Mitigation Measures

Generally, mitigation measures include unit fuel combustion efficiency, management of flaring and venting, protocols for reducing and minimizing fugitive leaks of methane from the pipeline system, and management of construction and maintenance operations to minimize overall GHG emissions.

9.3 NOISE

This section describes the existing baseline noise environment of the Project area and assesses potential noise impacts from Project construction and operation. The information provided relates to the human environment. Potential noise impacts on fish, wildlife, and marine mammals are addressed in Resource Report No. 3.

[9] For comparison, EPA emission factors for CO_2 are 53.06 kg/mmBtu of natural gas, 73.96 kg/mmBtu of #2 fuel oil, and 95.52 kg/mmBtu for thermal coal. See 40 CFR 98, Subpart C, Table C-1. Thus, #2 fuel oil produces about 40% more CO_2 than natural gas and coal produces about 80 percent more CO_2 than natural gas. (EPA, 2009b).

9.3.1 Existing (Baseline) Noise Levels

The majority of the Project area is located in undeveloped, sparsely populated areas; therefore, existing ambient noise levels are anticipated to generally be low. However, portions of the Project are located in residential or commercial areas or near highways, where ambient noise levels are expected to be higher.

9.3.1.1 Noise-Sensitive Areas

The FERC National Environmental Policy Act (NEPA) review generally evaluates noise generated by a project at noise-sensitive areas (NSAs), which include such receptors as residences, schools, hospitals, churches, playgrounds, farms, and camping facilities. The evaluation includes description of existing noise levels at the nearest NSAs and estimated impacts associated with Project construction and operations noise. Existing noise levels can be developed using either an estimate of the noise levels for land use types or a field survey measurement of existing noise levels. Field surveys determine existing ambient outdoor sound level measurements and document observed or measured factors, including meteorological conditions and witnessed or perceived sources of natural and manmade sounds, which describe the preexisting outdoor ambient sound environment at NSAs prior to Project construction and operation. Impact assessment of projected noise using an environmental sound level assessment for Project facilities includes developing a model to estimate the sound level contribution level from the facility at the nearest existing NSAs, assessing the far-field community sound levels at the identified NSAs for Facility construction and normal full load operation, and identifying the noise mitigation measures required to comply with the environmental sound level criterion stipulated by FERC of an Ldn of 55 dBA (see Section 9.3.5). This sound level is based on EPA's published Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety. The EPA determined that an Ldn of 55 dBA protects the public from indoor and outdoor activity noise interference.

A survey of NSAs was conducted in vicinity of the Project. Table 9.3.1-1 provides a summary of the proximity of NSAs to various primary long-term noise generating facilities and possible buried trenchless locations during construction along with an analysis of NSA proximity to the Project.

TABLE 9.3.1-1

Identified NSAs Near Project Facilities and Buried Trenchless Locations

Noise Source	MP	Identified NSAs within 1 Mile	Nearest NSA (miles)	Field Noise Survey?	Modeling Impact Analysis?
GTP	0.00	0	128.20	No	No
Sagwon Compressor Station	75.97	0	60.26	No	No
Galbraith Lake Compressor Station	148.51	0	4.83	No	No
Middle Fork Koyukuk River Horizontal Directional Drill (HDD)	210.99	0	22.34	No	No
Coldfoot Compressor Station	240.11	1	0.92	Yes	Yes
Ray River Compressor Station	332.65	0	16.22	No	No
Yukon River HDD	356.25	4	0.09	Yes	Yes
Minto Compressor Station	421.58	0	15.82	No	No
Tanana River HDD	472.66	246	0.17	Yes	Yes
Healy Compressor Station	517.63	1	0.52	Yes	Yes

TABLE 9.3.1-1

Identified NSAs Near Project Facilities and Buried Trenchless Locations

Noise Source	MP	Identified NSAs within 1 Mile	Nearest NSA (miles)	Field Noise Survey?	Modeling Impact Analysis?
Honolulu Creek Compressor Station	597.58	0	1.20	No	No
Chulitna River HDD	641.72	0	1.02	Yes	Yes
Rabideux Creek Compressor Station	675.38	0	1.08	Yes	No
Deshka River HDD	704.73	0	1.62	No	No
Theodore River Heater Station	749.26	0	12.30	No	No
Liquefaction Facility	806.72	371	0.00	Yes	Yes

As noted in Table 9.3.1-1, site-specific 24-hour baseline noise surveys were conducted near NSAs for several of the planned facilities or buried trenchless locations. The baseline noise level report is provided in Appendix N for the Liquefaction Facility and Appendix O for the Mainline. A summary of the respective results follows.

9.3.1.2 Liquefaction Facility

Approximately 440 residential receptors and one recreational campground are located within 1 mile of the Liquefaction Facility. Further analysis was conducted to NSAs closest to the facility. Refer to Appendix N for more information on representative NSA parameters. Baseline outdoor ambient sound level data were collected at selected representative NSAs nearest the proposed Liquefaction Facility during the weeks of March 10, 2015, and June 3, 2015, to represent winter and summer conditions, respectively. Sound level measurements include the 24-hour equivalent sound level (Leq) and day-night sound level (Ldn). The Leq is the level of steady sound with the same total (equivalent) energy as the time-varying sound of interest, averaged over a 24-hour period. The Ldn is the Leq plus 10 decibels on the A-weighted scale (dBA) added to account for people's greater sensitivity to nighttime sound levels (between the hours of 10 p.m. and 7 a.m.). The A-weighted scale is used because human hearing is less sensitive to low and high frequencies than mid-range frequencies. The human ear's threshold of perception for noise change is considered to be 3 dBA; 6 dBA is clearly noticeable to the human ear, and 10 dBA is perceived as a doubling of noise. Measured day-night average sound level (L_{dn}) values ranged from 43 to 60 A-weighted decibels (dBA). Table 9.3.1-2 and Table 9.3.1-3 show the distances and directions to the NSAs and the measured daytime, nighttime, and L_{dn} values for NSAs near the Liquefaction Facility during winter and summer conditions, respectively. Baseline ambient noise levels are generally higher in the summer. Figure 9.3.1-1 shows the Liquefaction Facility and identified NSA measurement locations. Baseline noise survey details are provided in Appendix N.

TABLE 9.3.1-2

Baseline Ambient Sound Levels – Liquefaction Facility (Winter)

Noise-Sensitive Area	Distance to NSA (feet)	Direction to NSA	Measured Baseline Ambient $L_{eq(day)}$, dBA	Measured Baseline Ambient $L_{eq(night)}$, dBA	Calculated Baseline Ambient L_{dn}, dBA
NSA 01215	10,500	N	49,55	43,48	51,56
NSA 01533	3,700	E	40,46	36,38	43,47

TABLE 9.3.1-2

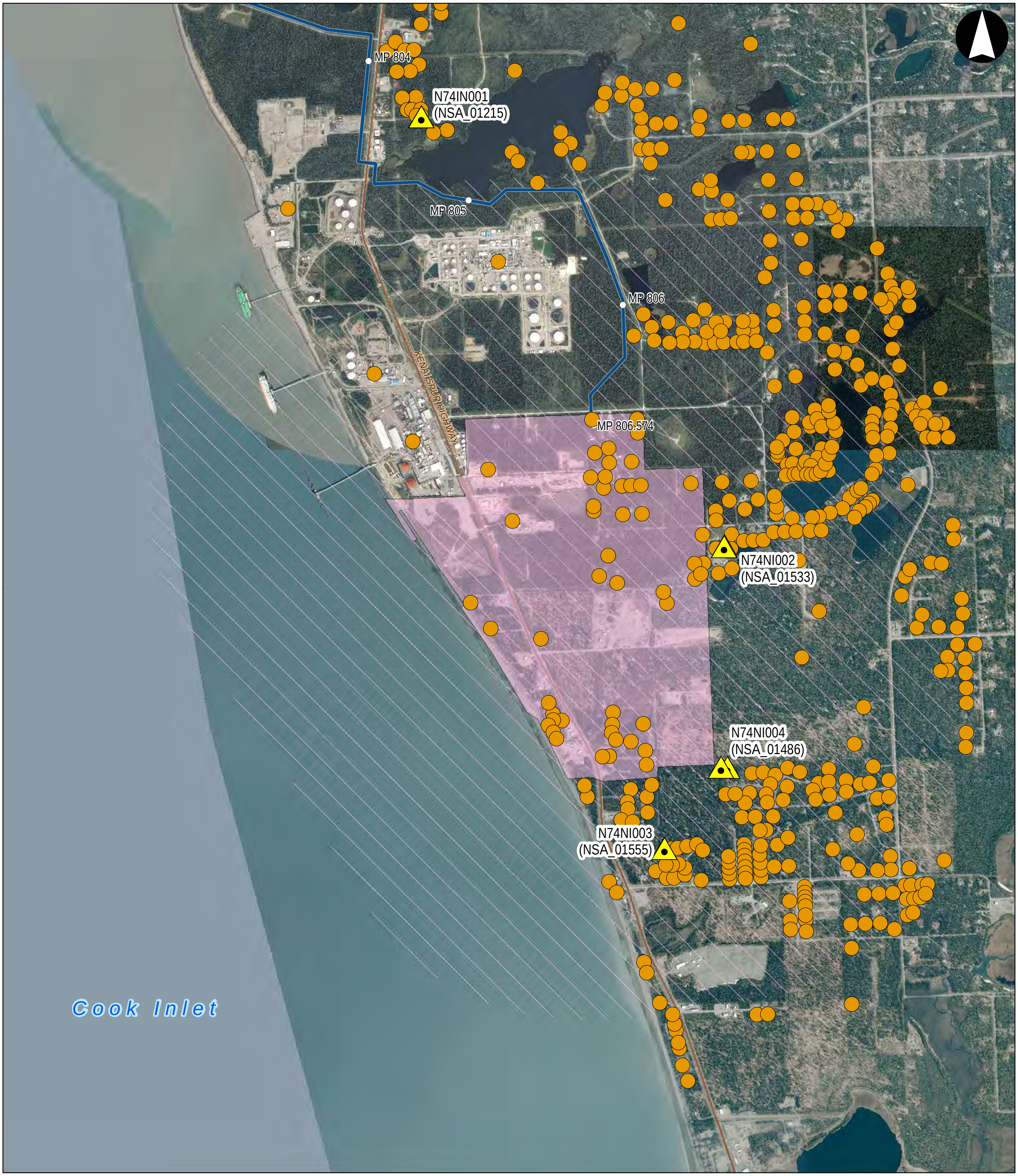
Baseline Ambient Sound Levels – Liquefaction Facility (Winter)

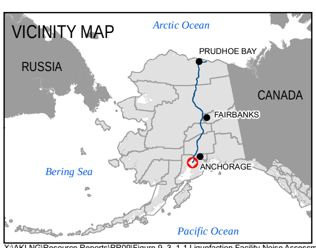
Noise-Sensitive Area	Distance to NSA (feet)	Direction to NSA	Measured Baseline Ambient $L_{eq(day)}$, dBA	Measured Baseline Ambient $L_{eq(night)}$, dBA	Calculated Baseline Ambient L_{dn}, dBA
NSA 01555	6,600	S	47,56	39,39	48,54
NSA 01486	5,700	SE	36,43	32,32	39,43

TABLE 9.3.1-3

Baseline Ambient Sound Levels – Liquefaction Facility (Summer)

Noise-Sensitive Area	Distance to NSA (feet)	Direction to NSA	Measured Baseline Ambient $L_{eq(day)}$, dBA	Measured Baseline Ambient $L_{eq(night)}$, dBA	Calculated Baseline Ambient L_{dn}, dBA
NSA 01215	10,500	N	53,54	48,53	55,59
NSA 01533	3,700	E	45,52	44,49	50,56
NSA 01555	6,600	S	48,54	41,54	49,60
NSA 01486	5,700	SE	45,49	42,45	49,52





LEGEND

- Noise Study Location
- Noise Sensitive Area (NSA)
- Milepost
- Alaska LNG Rev C2 Route
- Major Highways
- LNG Facility
- 1 mile zone

0 0.25 0.5 1 Miles

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LIQUEFACTION FACILITY NOISE ASSESSMENT LOCATIONS

FIGURE 9.3.1-1

ALASKA LNG

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9.3.1.3 Interdependent Project Facilities

Baseline outdoor ambient sound data were collected at 14 selected NSAs in the vicinity of proposed Project compressor stations, heater stations, and buried trenchless sites along the Mainline route during the weeks of May 22–29, 2015, and August 16–28, 2015. These were the only locations where NSAs were found to be within 1 mile of the facilities, unless noted in the following tables. The two locations with existing L_{dn} values above the FERC threshold of 55 dBA (see Section 9.3.5.1) are in proximity to major roadways. See Appendix O for further details of the Mainline ambient noise survey.

9.3.1.3.1 Pipelines

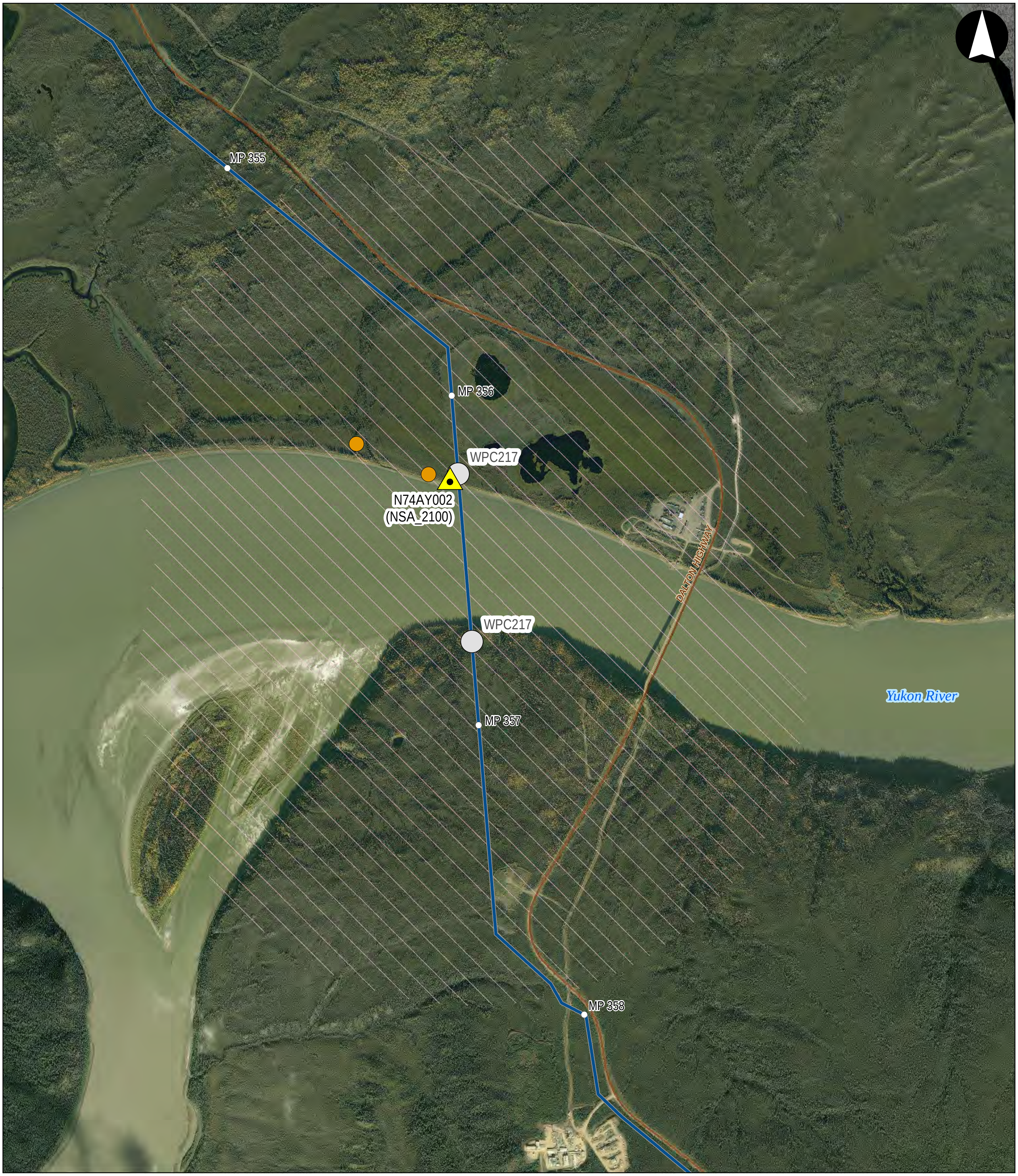
Table 9.3.1-4 shows the distances, directions, and measured daytime, nighttime, and L_{dn} values for NSAs near planned buried trenchless locations. Figures 9.3.1-2 through 9.3.1-4 show the respective buried trenchless sites and identified NSA measurement locations.

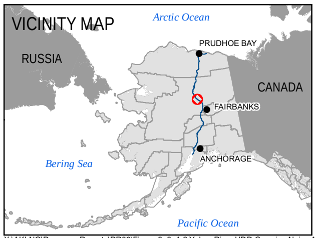
TABLE 9.3.1-4

Baseline Ambient Sound Levels – Buried Trenchless Sites

Buried Trenchless Site	Noise-Sensitive Area	Distance to NSA (feet)	Direction to NSA	Measured Baseline Ambient $L_{eq(day)}$, dBA	Measured Baseline Ambient $L_{eq(night)}$, dBA	Calculated Baseline Ambient L_{dn}, dBA
Yukon River	NSA_2100	150	W	42,42	29,39	41, 46
Tanana River	NSA_02116	1,600	NW	49,50,50	48,48,49	55
Tanana River	NSA_2101 NSA 02336	3,390	E	54,52	52,53	58, 60
Chulitna River	NSA_2102	5,200	SE	59,59	52,57	61, 64

There are no NSAs within 1 mile of either the PBTL or PTTL.





LEGEND

- Noise Study Location
- Noise Sensitive Area (NSA)
- Proposed Horizontal Directional Drilling (HDD) Location
- Milepost
- Alaska Place Name
- Major Highways
- Alaska LNG Rev C2 Route
- 1 mile zone

0 0.1 0.2 0.4 Miles

X:\AKLNG\Resource Reports\RR09\Figure 9_3_1-2 Yukon River HDD Crossing Noise Assessment Locations.mxd

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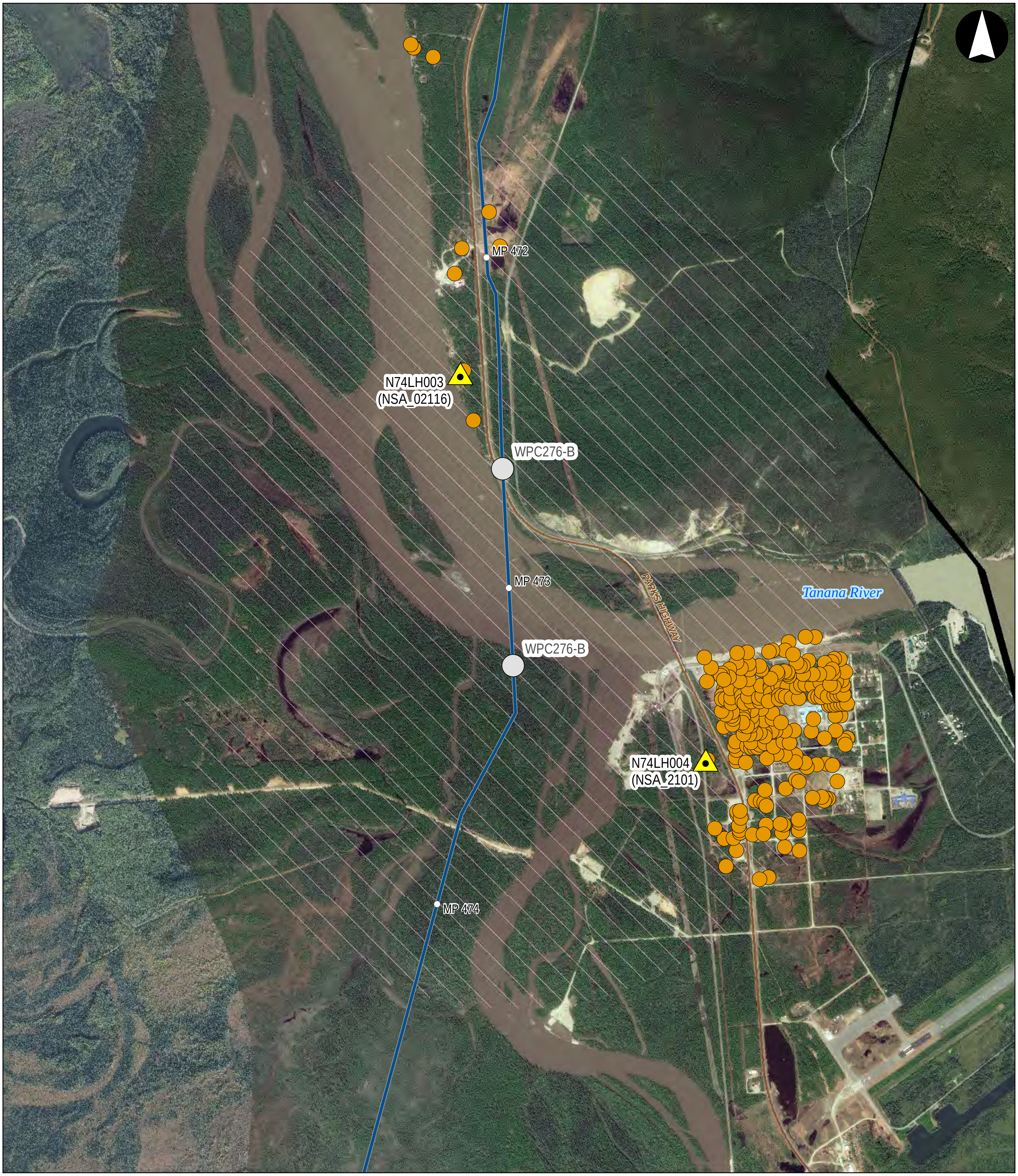
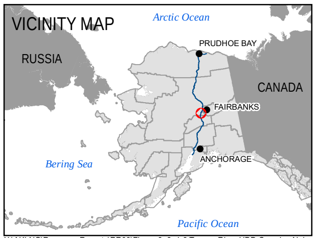
YUKON RIVER HDD CROSSING
NOISE ASSESSMENT LOCATION

FIGURE 9.3.1-2

ALASKA LNG





LEGEND

- Noise Study Location
- Noise Sensitive Area
- Proposed Horizontal Directional Drilling (HDD) Location
- Milepost
- Alaska LNG Rev C2 Route
- Major Highways
- 1 mile zone

0 0.1 0.2 0.4 Miles

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TANANA RIVER HDD CROSSING NOISE ASSESSMENT LOCATIONS

FIGURE 9.3.1-3

ALASKA LNG

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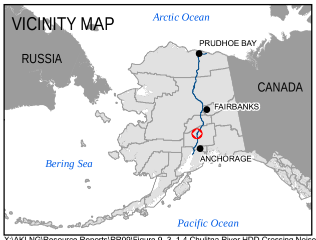
VICINITY MAP



LEGEND

- Noise Study Location
- Noise Sensitive Area
- Milepost
- Proposed Horizontal Directional Drilling (HDD) Location
- Alaska LNG Rev C2 Route
- Major Highways
- Buffer Distances

0 0.1 0.2 0.4 Miles

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CHULITNA RIVER HDD CROSSING NOISE ASSESSMENT LOCATIONS

FIGURE 9.3.1-4

ALASKA LNG

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9.3.1.3.2 Pipeline Aboveground Facilities

9.3.1.3.2.1 Compressor Stations

NSAs were only found within 1 mile of the proposed Coldfoot and Rabideux compressor station locations. Table 9.3.1-5 shows the distance, direction and measured daytime, nighttime, and L_{dn} values for NSAs near these two compressor stations. Figures 9.3.1-5 and 9.3.1-6, respectively, show the Coldfoot and Healy compressor stations and identified NSA measurement locations.

TABLE 9.3.1-5

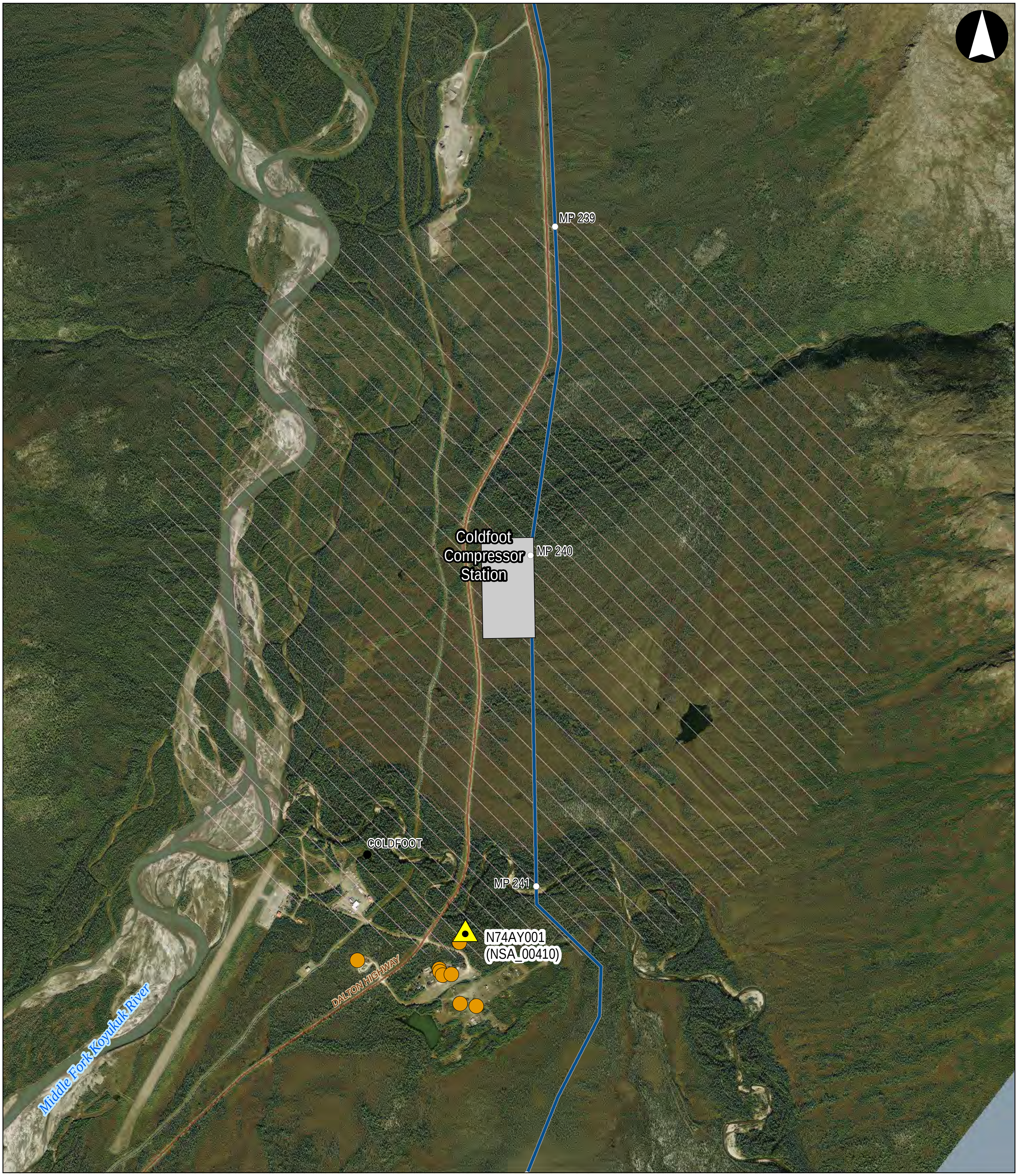
Baseline Ambient Sound Levels – Compressor Stations

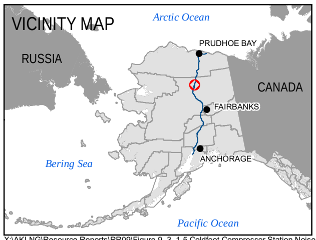
Location	Noise-Sensitive Area	Distance to NSA (feet)	Direction to NSA	Measured Baseline Ambient $L_{eq(day)}$, dBA	Measured Baseline Ambient $L_{eq(night)}$, dBA	Calculated Baseline Ambient L_{dn}, dBA
Coldfoot	NSA_00410	5,770	SSW	42,43	40,41	47,48
Healy	NSA_02337	2,850	NE	48,48	44,46	51,52

Given the general undeveloped, sparsely populated nature of the entire Mainline corridor, the existing ambient noise levels at Coldfoot and Healy are likely comparable to baseline noise levels at other proposed compressor station sites based on land use and proximity to major roadways. The Mainline would follow highways over most of the section where compressor stations would be located. Coldfoot would be located at MP 240.1 near the Dalton Highway with traffic levels typical of the northern compressor stations; Healy would be located at MP 517.6 near the Parks Highway with traffic levels typical of the southern compressor stations.

9.3.1.3.2.2 Heater Stations

As shown in Table 9.3.1-1, there are no NSAs identified within 1 mile of the proposed Theodore River heater station location.





LEGEND

- Noise Study Location
- Noise Sensitive Area (NSA)
- Milepost
- Alaska LNG Rev C2 Route
- Major Highways
- Compressor Station
- 1 mile zone

0 0.1 0.2 0.4 Miles

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COLDFOOT COMPRESSOR STATION NOISE ASSESSMENT LOCATIONS

FIGURE 9.3.1-5

ALASKA LNG

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VICINITY MAP

LEGEND

- Noise Study Location
- Noise Sensitive Area (NSA)
- Milepost
- Alaska LNG Rev C2 Route
- Major Highways
- Compressor Station
- 1 mile zone

0 0.1 0.2 0.4 Miles

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HEALY COMPRESSOR STATION
NOISE ASSESSMENT LOCATION

FIGURE 9.3.1-6

ALASKA LNG

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9.3.1.3.2.3 Metering Stations and Mainline Valves

Table 9.3.1-6 provides a summary of the proximity of NSAs to the two Project meter stations and 30 MLBVs along with an analysis of NSA proximity. The baseline noise survey conducted for the Liquefaction Facility discussed in Section 9.3.1.2 included the associate meter station and MLBV 30 given it is located at the facility. Likewise, the baseline surveys conducted for Galbraith Lake, Coldfoot, and Healy compressor stations included the associated MLBVs, located at each station. No baseline surveys were conducted at the remaining MLBVs and GTP meter stations. The GTP meter station and 25 MLBVs do not have NSAs within 0.5 miles. Two MLBVs collocated at compressor stations that have a NSA within 1 mile are included in the baseline survey results discussed in Section 9.3.1.3.2.1. Three MLBVs have NSAs within 0.5 mile.

TABLE 9.3.1-6

Identified NSAs Near Project Meter Stations and MLBV Locations

Noise Source	**MP**	**Identified NSAs within 0.5 Mile**	**Nearest NSA (miles)**
GTP Mainline Meter Station	0.00	0	131.12
MLBV 2	36.74	0	95.91
MLBV 3 (Sagwon Compressor Station)	75.97	0	60.26
MLBV 4	112.04	0	28.41
MLBV 5 (Galbraith Lake Compressor Station)	148.51	0	4.83
MLBV 6	194.10	0	36.85
MLBV 7 (Coldfoot Compressor Station)	240.11	1	0.92
MLBV 8	286.06	0	21.47
MLBV 9 (Ray River Compressor Station)	332.65	0	16.22
MLBV 10	377.96	0	20.39

MLBV 11 (Minto Compressor Station)	421.58	0	15.82
MLBV 12	444.90	0	4.25
MLBV 13	467.12	0	0.62
NSA_00410	NSA_00410	NSA_00410	NSA_00410
MLBV 14	492.96	0	4.55
MLBV 15 (Healy Compressor Station)	517.63	1	0.52
MLBV 16	534.79	0	1.44
MLBV 17	538.79	0	1.38
MLBV 18	546.50	0	2.01
MLBV 19	57222.23	0	1.31
MLBV 20 (Honolulu Creek Compressor Station)	597.58	0	1.20
MLBV 21	625.83	0	3.74
MLBV 22	648.16	0	0.86
MLBV 23 (Rabideux Creek Compressor Station)	675.38	0	1.08
MLBV 24	703.67	0	2.29
MLBV 25	725.93	0	1.70
MLBV 26 (Theodore River Heater Station)	749.26	0	12.30
MLBV 27	766.01	2	0.13
MLBV 28	793.34	5	0.17
MLBV 29	799.85	11	0.06
Nikiski Meter Station and MLBV 30	806.72	25	0.03

9.3.1.3.3 GTP

As shown in Table 9.3.1-1, no NSAs have been identified within 1 mile of the GTP. As a result, a baseline survey was not conducted.

9.3.2 Construction Noise Levels and Impacts

Noise level considerations for impacts related to Project construction generally include the following:

- Type of construction equipment used;
- Construction duration;
- Time of day; and
- Distance to NSAs.

Construction noise levels are analyzed for the some of the sites identified in Table 9.3.1-1. Supporting documentation is provided in appendices P through U.

9.3.2.1 Liquefaction Facility

Construction of the Liquefaction Facility would take place in phases across the facility site. Construction noise impacts were estimated assuming construction activity at different phases for different locations on the site. Typical types and numbers of construction equipment for each phase, along with the maximum sound level at 50 feet for each item, were used to calculate the maximum equipment sound power level. Those sound levels were used to determine predicted composite construction noise levels at the previously identified NSAs around the Liquefaction Facility. Most of the construction equipment operate at the maximum sound level for only a percentage of the entire 24-hour period. This is identified as the utilization time. The duration of equipment operation and the time of day the equipment operates are factors included in the calculation of the estimated Ldn sound levels at the NSAs. Details of the Liquefaction Facility construction noise impact analysis, including a list of construction equipment and sound levels, are provided in Appendix P. The estimated construction sound levels are shown in Table 9.3.2-1.

TABLE 9.3.2-1

Predicted Sound Levels at NSAs from Construction – Liquefaction Facility

Construction Activity	Noise-Sensitive Area	Distance to NSA (feet)	Direction to NSA	Calculated Baseline Ambient L_{dn}, dBA	Predicted Sound Levels L_{dn}, dBA	Construction L_{dn} + Ambient L_{dn} dBA	Potential Increase Above Baseline Ambient dBA
Composite	NSA 01215	10,500	N	51	53.5	55.4	1.4
Composite	NSA 01533	3,700	E	43	67.1	67.1	24.1
Composite	NSA 01555	6,600	S	48	63.6	63.7	15.7
Composite	NSA 01486	5,700	SE	39	65.5	65.5	26.5

Blasting plans, if any, for Liquefaction Facility construction are not yet defined and any associated noise impacts.

9.3.2.2 Interdependent Project Facilities

9.3.2.2.1 Pipeline

9.3.2.2.1.1 Mainline

Five river crossings have been identified as possible buried trenchless locations. Three have NSAs within 1 mile, as shown in Table 9.3.1-1. Noise modeling impact assessments were conducted for NSAs at the Yukon, Tanana, and Chulitna rivers. Details of the buried trenchless noise impact analyses are provided in Appendix U.

Total sound power levels of 115 dBA at entry sites and 103 dBA at exit sites were used to calculate the total sound level at nearby NSAs, assuming simultaneous operation of entry and exit site. The assessment assumes a worst-case condition that all of the equipment would be in non-stop operation through the nighttime hours of 10:00 p.m. to 7:00 a.m. Once trenchless construction has begun it is not practicable to stop until completed, otherwise the likelihood for failure is increased. Predicted sound levels for the buried trenchless sites are shown in Table 9.3.2-2.

TABLE 9.3.2-2

Predicted Sound Levels at NSAs from Construction – Potential Buried Trenchless Locations

Buried Trenchless Crossing	MP	Noise-Sensitive Areas	Distance to NSA (feet)	Direction to NSA	Calculated Baseline Ambient L_{dn}, dBA	Predicted Sound Levels L_n, dBA
Yukon River	356.25	NSA_2100	716	W	41	47.9
Tanana River	472.66	NSA_02116	1,400	NW	55	35.9
Tanana River	473.26	NSA_2101 NSA 02336	3,000	E	58	37.7
Chulitna River	642.43	NSA_2102 NSA 02007	4,950	SE	61	31.8

Blasting plans for Mainline construction are not yet defined and any associated noise impacts will be addressed prior to construction.

9.3.2.2.2 Pipeline Aboveground Facilities

9.3.2.2.2.1 Compressor Stations

Noise modeling impact assessments methodology and results are provided in appendices Q and R for the Coldfoot, and Healy compressor stations, respectively. With a 24-hour construction schedule, the maximum predicted level at the closest NSAs is less than 55 dBA L_{dn} for the Coldfoot station and greater than 55 dBA Ldn for and Healy compressor station. The estimated construction sound levels are shown in Table 9.3.2-3

TABLE 9.3.2-3

Predicted Sound Levels at NSAs from Construction – Compressor Stations

Compressor Station	Noise-Sensitive Area	Distance to NSA (feet)	Direction to NSA	Calculated Baseline Ambient L_{dn}, dBA	Predicted Sound Levels L_{dn}, dBA	Construction L_{dn} + Ambient L_{dn} dBA	Potential Increase Above Baseline Ambient dBA
Coldfoot	NSA_00410	5,770	SSW	47	50.3	52.0	5.0
Healy	NSA_02337	2,850	NE	52	61.5	62.0	11.0

9.3.2.2.2.2 Heater Station

As shown in Table 9.3.1-1, there are no NSAs identified within 1 mile of the proposed Theodore River heater station location.

9.3.2.2.2.3 Metering Stations and Mainline Block Valves (MLBVs)

Construction noise impact analyses for metering stations and mainline valve sites collocated at the Liquefaction Facility and compressor stations were included in the analysis discussed in Sections 9.3.1.3.2.1 and 9.3.2.2.2.1 respectively.

9.3.2.2.3 Pipeline Associated Infrastructure

Noise impact analyses for pipeline associated infrastructure (such as granular material mine-site operations) have not yet been conducted. These will be provided prior to construction.

9.3.2.2.4 GTP

As shown in Table 9.3.1-1, no NSAs have been identified within 1 mile of the GTP, therefore, a noise modeling analysis has not been conducted.

9.3.2.3 Non-jurisdictional Facilities

The PBU MGS project is within proximity to the GTP and is not within 1 mile of any NSAs. The PTU Expansion project is within the existing developed PTU areas that are not within 1 mile of any NSAs.

Kenai Spur Highway relocation project construction would occur within 1 mile of several NSAs. Potential impacts and mitigation will be evaluated after completion of the selection of the preferred route and available design and construction information.

9.3.3 Regulatory Requirements for Noise – Construction

For construction, the applicable noise limit is 55 dBA L_n, which means that between the hours of 10:00 p.m. and 7:00 a.m. local time, the equivalent sound level (L_{eq}t) must not exceed 55 dBA. See 18 C.F.R. 157.206(b)(5)(iii). There are no other identified numeric regulatory requirements specific to project construction noise for any of the Project components.

9.3.4 Operations Noise Levels and Impacts

9.3.4.1 Liquefaction Facility

Details of the Liquefaction Facility noise impact and mitigation analysis are provided in Appendix P. Major noise producing equipment includes turbine compressors, process compressors, connected piping, fans, motors, and pumps. Other sound sources include power generation, heat recovery steam generators, and steam turbine and utility equipment such as air compressors and air dryers.

A computer noise model of the proposed Liquefaction Facility was created using SoundPLAN version 7.4, as distributed by Braunstein + Berndt GmbH. Sound levels at NSAs were calculated based on octave band sound power emission levels of equipment, taking into account terrain effects using a topological digital ground model created from the Project Geographic Information System (GIS) library. Predicted sound levels for the Liquefaction Facility at nearby NSAs are shown in Table 9.3.4-1.

TABLE 9.3.4-1

Predicted Sound Levels at NSAs from Normal Operations – Liquefaction Facility

Noise-Sensitive Area	Distance to NSA (feet)	Direction to NSA	Calculated Baseline Ambient L_{dn}, dBA[a]	Predicted Sound Level L_{dn}, dBA	Total Predicted L_{dn}, dBA	Potential Increase Above Baseline Ambient
NSA 01215	10,500	NW	51	39.0	51.3	0.3
NSA 01533	3,700	E	43	54.8	55.1	12.1
NSA 01555	6,600	S	48	47.6	50.8	2.8
NSA 01486	5,700	SE	39	53.5	53.7	14.7

[a] This column includes the lower of the 24-hour noise samples measured in the baseline survey to characterize the worst-case potential increase above ambient.

9.3.4.1.1.1 Marine Vessels

LNGC routes traversing Cook Inlet have not yet been finalized. However, it is anticipated that they would be located more than a mile from shore. Thus, any onshore NSAs along the Cook Inlet shipping routes would not be adversely affected by LNGC noise.

9.3.4.2 Interdependent Project Facilities

9.3.4.2.1 Pipeline

9.3.4.2.1.1 Compressor Stations

Compressor station noise impact analyses are provided in appendices Q, and R, for Coldfoot, , and Healy compressor stations, respectively. Predicted sound levels are shown in Table 9.3.4-2.

TABLE 9.3.4-2

Predicted Sound Levels at NSAs from Normal Operations – Compressor Stations

Station	Noise-Sensitive Area	Distance to NSA (feet)	Direction to NSA	Calculated Baseline Ambient L_{dn}, dBA[a]	Predicted Sound Level L_{dn}, dBA	Total Predicted L_{dn}, dBA	Potential Increase Above Baseline Ambient
Coldfoot	NSA_00410	5,770	SSW	47	40.7	47.9	0.9
Healy	NSA_02337	2,850	NE	52	53.0	55.5	3.5

[a] This column includes the lower of the 24-hour noise samples measured in the baseline survey to characterize the worst-case potential increase above ambient.

Compressor stations occasionally require a "blowdown" event, wherein an upset would require high pressure gas to be rapidly vented to decrease line pressure. Typically, sound levels would start high and rapidly decrease as the line depressurizes. Silencers are proposed for blowdown stacks to limit the maximum sound levels. Thus, the modeled maximum initial sound level at the nearest NSAs for Coldfoot, and Healy are 45 and -48 dBA respectively. See Appendices Q and R. Potential vibrations effects on NSAs related to compressor station operations sound levels are not anticipated but will be further evaluated prior to the draft EIS.

9.3.4.2.1.2 Heater Stations

As shown in Table 9.3.1-1, there are no NSAs identified within 1 mile of the proposed Theodore River heater station location.

9.3.4.2.1.3 Metering Stations and MLBVs

The Liquefaction Facility meter station noise impacts were considered as part of the overall facility noise assessment discussed in Section 9.3.4.1 and Appendix P. The following is the noise impact assessment of the sound level for MLBV normal operational (i.e., planned) blowdown at the currently identified NSAs and the mitigation that would be required to meet a Day-Night Level (L_{dn}) of 55 dBA or less at the identified NSAs. The assessment was based on sound power level for an unmitigated blowdown in Table 9.3.5-3. The normal operating scenario is that the blowdown will be conducted during the daytime hours of 07:00 to 22:00 and the maximum duration of the blowdown will be three hours. This scenario allows comparison of the Ldn of 55 at the NSA if the measured or predicted sound level is 64 or less at the NSA during a blowdown operation.

TABLE 9.3.4-3

Sound Power for an Un-Mitigated Blowdown Vent Operation

	Octave Band Center Frequency - Hz									Awt
	31.5	63	125	250	500	1000	2000	4000	8000	
Sound Power Level – L_w in dB	155	158	160	167	170	168	165	159	153	172

A large majority of the MLBVs have existing NSAs that are a distance greater than 1 mile from MLBV location. In that case a vent muffler with a minimal sound level reduction would be sufficient to limit the sound level of the vent operation to 64 dBA or less at any NSA at a distance of 1 mile or greater. The performance of this vent muffler is given in Table 9.3.4-4.

TABLE 9.3.4-4

Vent Silencer Dynamic Insertion Loss (DIL) in dB – Minimal Design

	Octave Band Center Frequency - Hz								
	31.5	63	125	250	500	1000	2000	4000	8000
DIL – L_w in dB	0	0	6	25	35	35	30	20	10

The minimal design muffler alone would be insufficient to limit onsite personnel noise exposure to permissible safety limits because the estimated sound level with this silencer at a distance of 100 feet would be approximately 109 dBA. Therefore, additional in-plant personnel noise mitigation would be required (e.g., local barriers).

There are three MLBVs listed in Table 9.3.4-5 that have NSAs within a 0.5-mile radius of the valve location that would be potentially impacted by normal blowdown operating noise.

TABLE 9.3.4-5

MLBV Locations with Nearby NSAs

Facility Name	Facility Type	Milepost	NSAs within 0.5 mile	Distance to Nearest NSA (mi)	Nearest NSA ID
MLBV 27	MLBV Pad	766.01	2	0.13	NSA_01769
MLBV 28	MLBV Pad	793.34	5	0.17	NSA_01078
MLBV 29	MLBV Pad	799.85	11	0.06	NSA_00846

One noise mitigation option is to increase the performance of the vent silencer. Table 9.3.4-6 provides the sound attenuation performance for a premium silencer, which represents the maximum performance that can be achieved for this type of operation.

TABLE 9.3.4-6

Vent Silencer Dynamic Insertion Loss (DIL) in dB-Premium Design

	Octave Band Center Frequency - Hz								
	31.5	**63**	**125**	**250**	**500**	**1000**	**2000**	**4000**	**8000**
DIL – L_w in dB	5	20	35	45	55	55	45	35	25

With a premium muffler, the estimated sound level would be equal to or less than 64 dBA at all of the MLBV installations of Table 9.3.5-5 with the exception of MLBV 27 and MLBV 28. At these two locations additional mitigation would be required, which can include noise barriers near the NSAs or relocation of the MLBV.

Operational noise impact for MLBV blowdown vents can be mitigated with a vent muffler to attenuate the sound levels to an Ldn of 55 dBA or less where the distance between the vent and the NSA is greater than 0.17 mile. Where an NSA is located less than 0.17 mile, additional mitigation including local sound barrier(s) to limit the Ldn to 55 dBA or less.

9.3.4.2.2 GTP

As shown in Table 9.3.1-1, no NSAs have been identified within 1 mile of the GTP. Therefore, a noise modeling analysis has not been conducted at the facility. Mitigation measures that address opportunities to minimize noise from the facility during operations would be incorporated into the Project design. Typical mitigation measures would be based on noise control equipment, enclosure design, and noise absorption capabilities.

9.3.4.3 Non-jurisdictional Facilities

The PBU MGS project is in proximity to the GTP and are not within 1 mile of any NSAs. The PTU Expansion project is within the existing developed PTU areas that are not within 1 mile of any NSAs.

Potential impacts and mitigation from the Kenai Spur Highway relocation project will be evaluated after the selection of the preferred route based on proximity to NSAs, and available design information.

9.3.5 Regulatory Requirements for Noise – Operations

9.3.5.1 Federal

At any location, both the magnitude and frequency of environmental noise may vary considerably over the course of the day and throughout the week. This variation is caused in part by changing weather conditions, but also by the effects of seasonal groundcover and other activity. Two measures used by federal agencies to relate the time-varying quality of environmental noise to its known effect on people are the 24-hour equivalent sound level (L_{eq} (24)) and the L_{dn}. The L_{eq} (24) is the level of steady sound with the same total (equivalent) energy as the time-varying sound of interest, averaged over a 24-hour period. The L_{dn} is the L_{eq} (24) with 10 decibels added to the nighttime sound levels between the hours of 10:00 pm and 7:00 am to account for people's greater sensitivity to sound during nighttime hours.

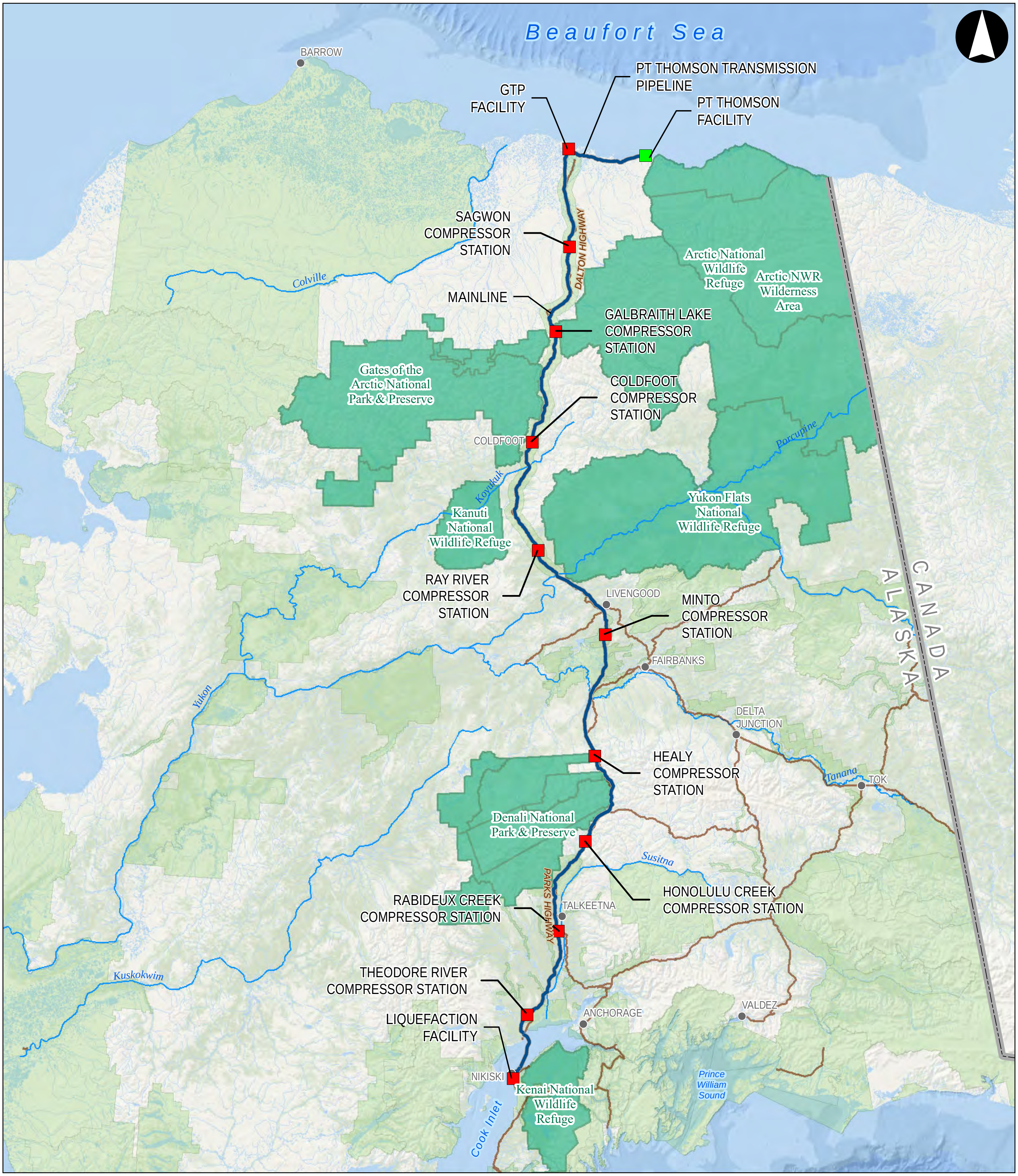
In 1974, EPA published "Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety." This publication evaluated the effects of environmental noise with respect to human health and safety. EPA identified an L_{dn} of 55 dBA as a threshold for outdoor noise in residential areas (EPA, 1974). This noise level is often used by federal and state agencies to establish noise limitations for cumulative noise exposure. With a 10 decibel nighttime weighting penalty, a 55 dBA L_{dn} noise level equates to a 24-hour continuous noise level of 48.6 dBA L_{eq}(24). FERC limits the noise attributable to stationary energy facilities (such as compressor stations) to 55 dBA L_{dn} at noise-sensitive areas such as schools, hospitals, or residences.

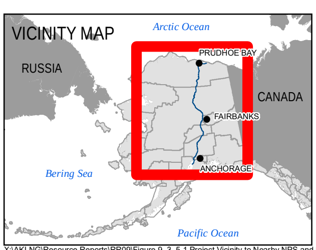
The NPS and USFWS manage lands near the Project and may have an interest in potential noise impacts (Figure 9.3.5-1). A discussion and mapping of federal lands in the vicinity of the Project are provided in Resource Report No. 8. The NPS does not have a numeric noise criterion for human exposure applicable to the Project. However, the NPS has a Soundscape Management Policy that states, "Using appropriate management planning, superintendents will identify what levels and types of unnatural sound constitute acceptable impacts on park natural soundscape. In and adjacent to parks, the NPS will monitor human activities that generate noise that adversely affects park soundscapes, including noise caused by mechanical or electronic devices" (NPS, 2006). As shown in Figure 9.3.5-2, the DNPP and Gates of the Arctic National Park and Preserve, both managed by the NPS, are adjacent to the Mainline corridor.

The USFWS does not have a numeric noise criterion for human exposure applicable to the Project. The USFWS does preserve "natural soundscapes" as an "aspect of wilderness character" to "prevent or minimize…unnatural sounds that adversely affect wilderness resources or values or visitors' enjoyment of them" (USFWS, 2008). Four NWRs managed by the USFWS are near the Mainline corridor: ANWR, Yukon Flats NWR, Kanuti NWR, and Kenai NWR.

9.3.5.2 State

The State of Alaska has not adopted noise regulations applicable to the Project. In the absence of an applicable state noise level limit, the FERC noise criterion of 55 dBA L_{dn} would be used to ensure the Project's compliance with noise regulatory requirements.





LEGEND

Project Facility	Major Highways
Existing Facility	Major Rivers
Alaska Place Names	State and Federal Conservation Lands
Alaska LNG Rev C2 Route	NPS and USFWS Conservation Units Nearby the Project

0 25 50 100 Miles

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PROJECT VICINITY TO NEARBY NPS AND USFWS CONSERVATION UNITS

FIGURE 9.3.5-1

ALASKA LNG

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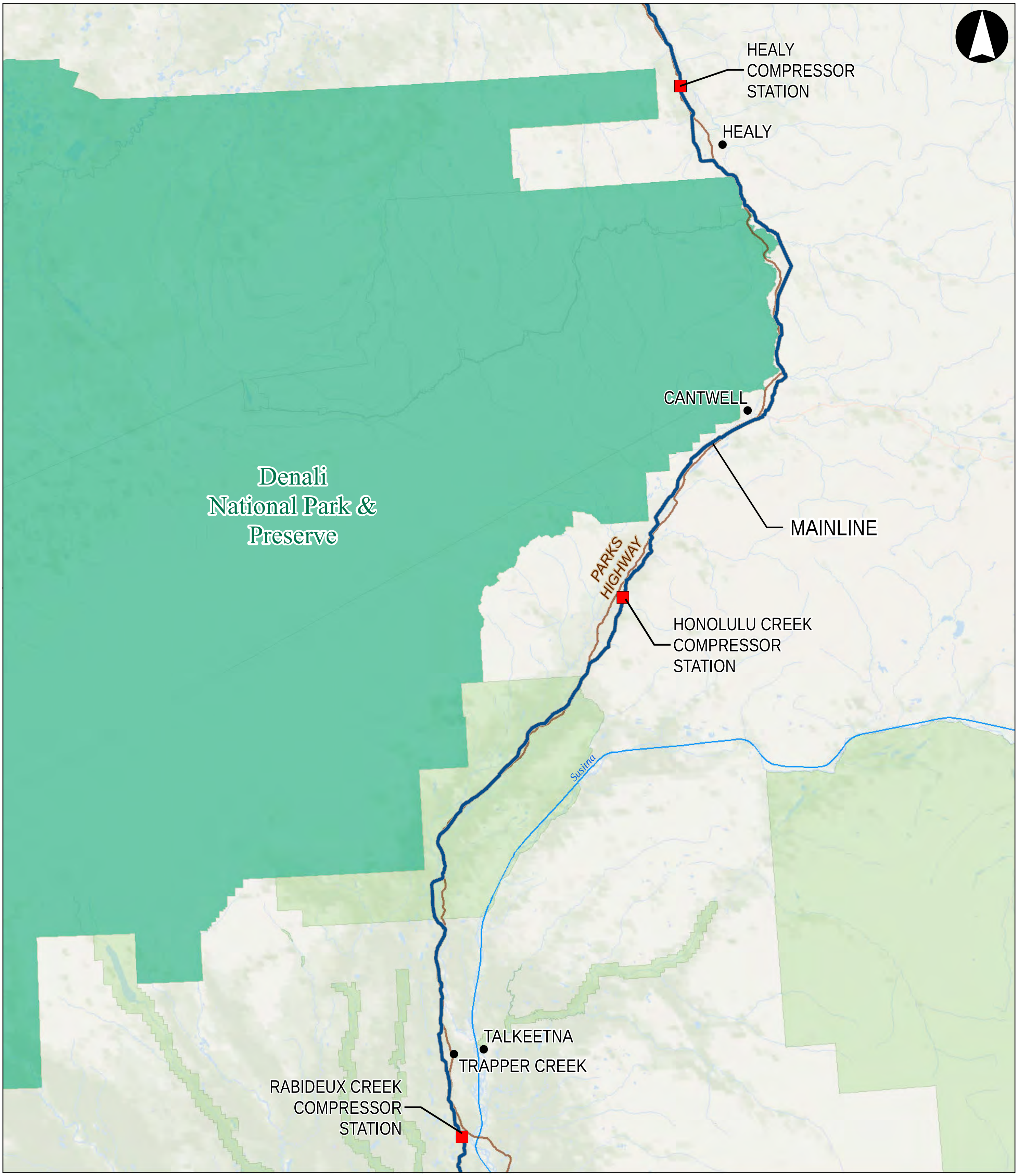
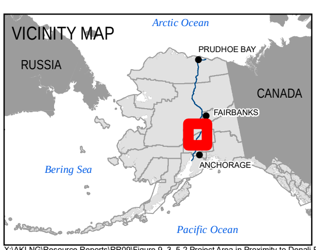


VICINITY MAP



LEGEND

- Project Facility
- Alaska Place Names
- Alaska LNG Rev C2 Route
- Major Highways
- Major Rivers
- Denali National Park & Preserve
- State and Federal Conservation Lands

0 5 10 20 Miles

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PROJECT AREA IN PROXIMITY TO DENALI NATIONAL PARK AND PRESERVE

FIGURE 9.3.5-2

ALASKA LNG

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9.3.5.3 Local

Except for the Matanuska-Susitna Borough (MSB), none of the local jurisdictions have adopted noise regulations applicable to the Project.

The MSB has a noise standard that limits noise for Core Area Conditional Use Permits according to the applicable zoning district classification (e.g., residential, commercial, industrial) of the noise source and the NSAs (MSB, 2013). A portion of the Mainline corridor is located in the MSB area and would be considered an industrial entity, but it is more than 20 miles from the designated Core Area. Regardless, the FERC criterion of 55 dBA L_{dn} is equivalent to a 24-hour continuous noise level of 48.6 dBA L_{eq} (24), which is less than the 60 dBA daytime and 50 dBA nighttime limits of the MSB. Thus, the more-stringent FERC noise criterion of 55 dBA L_{dn} will be applicable to the Project.

9.3.6 Regulatory Compliance and Mitigation Measures – Construction

Noise mitigation plans are not yet available for any of the Project components. The template for a Project *Construction Noise Abatement Plan* is attached as Appendix V.

9.3.6.1 Liquefaction Facility

As noted in Section 9.3.3, the generally applicable noise limit is 55 dBA Ln because there are no other specific component noise requirements for construction of the Liquefaction Facility. Predicted noise levels are as high as 67 dBA at nearby NSAs. Noise mitigation measures will be included in Appendix T that will be completed prior to the issuance of the DEIS and a vegetative buffer would be left in place along the eastern and southern boundaries of the site, which was not included in the modeling. The presence of the buffer would reduce noise levels during construction and operations.

9.3.6.2 Interdependent Project Facilities

9.3.6.2.1 Pipeline

Predicted noise levels at the two buried trenchless sites modeled would be within the applicable regulatory requirement of 55 dBA L_n at nearby NSAs. Noise modeling of construction of Coldfoot compressor stations predicts that noise levels at the nearest NSAs would be less than 55 dBA L_{dn}. Modeling of the Healy Compressor Station resulted in a prediction of maximum noise levels at nearby NSAs 61.5 dBA L_{dn}. Noise mitigation measures for compressor and heater station construction will be described in Appendix T that will be completed prior to the issuance of the DEIS.

9.3.6.2.2 GTP

The GTP would be constructed in a heavily industrialized area. Because adjacent land uses are compatible, noise from construction of the GTP is of low concern.

9.3.7 Regulatory Compliance and Mitigation Measures - Operations

9.3.7.1 Liquefaction Facility

All significant noise sources at the Liquefaction Facility would have noise mitigation measures applied to them, as detailed in Appendix P. The mitigation measures include noise specifications, acoustical duct or pipe lagging, combustion turbine exhaust silencers, acoustical enclosures, inline piping silencers, and enclosing noisy skids inside buildings. With the identified mitigation measures applied, predicted noise levels for the Liquefaction Facility demonstrate compliance with the 55 dBA L_{dn} regulatory limit at nearby NSAs.

9.3.7.2 Interdependent Project Facilities

9.3.7.2.1 Pipeline Aboveground Facilities

All significant noise sources at compressor and heater stations would have noise mitigation applied to them as indicated in the sound level assessments results provided in appendices Q through T. The mitigation measures include noise specifications, acoustical duct or pipe lagging, combustion turbine exhaust silencers, acoustical enclosures, inline piping silencers, blowdown silencers, and enclosing noisy skids inside buildings. With the identified mitigation measures applied, predicted noise levels for the modeled compressor and heater stations demonstrate compliance with the 55 dBA L_{dn} regulatory limit at nearby NSAs.

9.3.7.2.2 GTP

The GTP would be located in a heavily industrialized area, therefore, would be a compatible land use. Mitigation measures that address opportunities to minimize noise from the facility during operations would be incorporated into the Project design.

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APPENDIX H PROJECT NSPS, NESHAPs, and RMP APPLICABILITY ANALYSIS

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1.0 NEW SOURCE PERFORMANCE STANDARDS (NSPS)

Pursuant to Section 111 of the CAA, EPA promulgates NSPS, codified in 40 C.F.R. Part 60, for certain newly constructed, modified, or reconstructed sources of emissions of criteria pollutants. These standards are based on best demonstrated technology for air pollution control of specified equipment and may be expressed as numerical emission limits, performance standards, or work practices. Subpart A of Part 60 establishes general provisions for sources subject to the various NSPS subparts, including general performance testing, monitoring, notification, reporting, and recordkeeping requirements.

A preliminary analysis of NSPS that may apply to the proposed Project facilities is provided below. Final applicability determinations would be made based on final facility design. Table 1 provides a summary of the NSPS categories under 40 C.F.R. 60 that are potentially applicable to emission units included in the Project.

TABLE 1

Preliminary NSPS Applicability Summary

NSPS Subpart	Applicability		
	Liquefaction Facility	**Compressor and Heater Stations**	**GTP**
Subpart A – General Provisions	Yes	Yes	Yes
Subpart Da – Electric Utility Steam Generation Units	No	No	No
Subpart Db – Industrial, Commercial, and Institutional Steam Generating Units	No	No	Yes
Subpart Dc – Small Industrial, Commercial, and Institutional Steam Generating Units	No	Yes	No
Subpart Kb – Volatile Organic Liquid Storage Vessels	TBD	No	TBD
Subpart CCCC – Commercial and Industrial Solid Waste Incineration Units	No	Yes	No
Subpart IIII – Stationary Compression Ignition Internal Combustion Engines	Yes	No	Yes
Subpart JJJJ – Stationary Spark Ignition Internal Combustion Engines	No	Yes	No
Subpart KKKK – Stationary Combustion Turbines	Yes	Yes	Yes
Subpart OOOOa – Standards for Performance for Crude Oil and Natural Gas Facilities	Yes	Yes	Yes

1.1 LIQUEFACTION FACILITY

The Liquefaction Facility would be subject to the flare design and operating requirements of Subpart A for any flares that serve as a control device to comply with the applicable requirements of other NSPS-regulated units. Subpart A restricts visible emissions from flares and requires the documentation of design data to ensure proper flare operation. Final applicability determinations for the flares would be made based on final facility design.

NSPS Subpart Da, Standards of Performance for Electric Utility Steam Generating Units, applies to electric utility steam generating units with a heat input capacity greater than 250 MMBtu/hr and for which construction, reconstruction, or modification commenced after September 18, 1978. The Liquefaction Facility would not include any steam generating units constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net electrical output to any utility power distribution for sale and, as such, would not be subject to the requirements of Subpart Da.

NSPS Subparts Db and Dc regulate emissions from industrial, commercial, and institutional steam generating units, and may apply to the emission units at the facility if gas-fired steam generating units (or units that heat other liquids such as oil or glycol for process operations) are included in the facility design.

NSPS Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, applies to stationary source steam generating units with a heat input capacity greater than 100 MMBtu/hr and for which construction, reconstruction, or modification commenced after June 19, 1984. A steam generating unit is defined in Subpart Db as a device that combusts any fuel or byproduct/waste and produces steam or heats water or heats any heat transfer medium. Subpart Db does not apply to process heaters, which are devices primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst. The current facility design plan does not include any steam generating units with a heat input capacity greater than 100 MMBtu/hr and, as such, would not be subject to the requirements of Subpart Db.NSPS Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, applies to stationary steam generating units, as defined in 40 C.FR. 60.41c, with a heat input capacity less than 100 MMBtu/hr and greater than 10 MMBtu/hr and for which construction, reconstruction, or modification commenced after June 9, 1989. The current facility design plan does not include any steam generating units with a heat input capacity greater than 10 MMBtu/hr and less than 100 MMBtu/hr, each.

NSPS Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels for which Construction, Reconstruction, or Modification Commenced After July 23, 1984, applies to owners and operators of storage vessels constructed, reconstructed, or modified after July 23, 1984 with a capacity greater than or equal to 75 cubic meters (m^3) (19,813 U.S. gallons) and used to store a volatile organic liquid, which is any organic liquid that can emit VOCs, as defined in 40 C.F.R. 51.100, into the atmosphere. Subpart Kb does not apply to storage vessels with a capacity greater than or equal to 75 m^3 (19,813 U.S. gallons) but less than 151 m^3 (39,890 U.S. gallons) and used to store a liquid with a maximum true vapor pressure less than 15.0 kilopascals (kPa) (2.2 pounds per square inch [absolute] (psia)). Subpart Kb also does not apply to storage vessels with a capacity greater than or equal to 151 m^3 (39,890 U.S. gallons) used to store a volatile organic liquid with a maximum true vapor pressure less than 3.5 kPa (0.51 psia). Additionally, the following storage vessels are exempt from Subpart Kb per 40 C.F.R. 60.110b(d):

- Pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere;
- Storage vessels permanently attached to mobile vehicles such as trucks, railcars, barges, or ships; and
- Storage vessels with a design capacity less than or equal to 1,589.874 m^3 (420,000 U.S. gallons) used for petroleum or condensate stored, processed or treated prior to custody transfer. Custody transfer is defined in 40 C.F.R. 60.111b as the transfer of produced petroleum and/or condensate,

after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation.

The Liquefaction Facility is anticipated to include various storage tanks including:

- LNG storage tanks;
- Hydrocarbon condensate storage tanks;
- Diesel fuel oil tanks;
- Propane refrigerant tanks; and
- Ethane storage tanks.

The current facility design plan includes two LNG storage tanks with a capacity of approximately 240,000 m^3 (63,000,000 U.S. gallons), each, but because the true vapor pressure of the VOC components of LNG when maintained at storage temperature (-260 °F) would be less than 3.5 kPa, the LNG storage tanks would be exempt from Subpart Kb.

Approximately 175 m^3 (46,230 gallons) per day of condensate would be removed from the natural gas stream by the liquefaction process and stored in a condensation storage tank. This tank would be used to store condensate processed or treated prior to custody transfer, as defined in 40 C.F.R. 60.111b, and as such, would be exempt from Subpart Kb if the capacity of the condensate storage tank is less than 1,589.875 m^3 (420,000 gallons).

Diesel fuel storage tanks at the Liquefaction facility would range in size from 200 to 280 m^3 (55,000 to 75,000 gallons), each, but because the maximum true vapor pressure of diesel is much less than 3.5 kPa, the diesel storage tanks would be exempt from Subpart Kb.

The propane and ethane storage tanks planned for the Liquefaction Facility would be pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere. As a result, these storage vessels would be exempt from Subpart Kb.

The capacities of other storage tanks and the expected composition of the volatile organic liquid contents that would be stored at the Liquefaction Facility have not yet been determined. Final applicability determinations would be made for all storage tanks at the Liquefaction Facility based on the final facility design.

NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, applies to owners and operators of stationary compression ignition internal combustion engines (CI ICE) that commence construction after July 11, 2005 where the stationary CI ICE are either manufactured after April 1, 2006 and are not fire pump engines or manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006. Subpart IIII emission standards for stationary CI ICE are based on the engine rating, cylinder displacement, model year, and whether or not the CI ICE is an emergency engine, as defined under 40 C.F.R. 60.4211(f). All stationary CI ICE installed and operated at the Liquefaction Facility that are subject to Subpart IIII would be required to burn ultra-low sulfur diesel (ULSD).

The preliminary design plan for the Liquefaction Facility includes the following potentially affected engines:

- One non-emergency engine air compressor drive rated for a maximum power output of approximately 300 horsepower, and

- One firewater pump engine rated for a maximum power output of approximately 575 horsepower (429 kW), each.

Each of these units must be designed to meet the applicable Subpart IIII emission limits. Under 40 C.F.R. 60.4209(a), the fire pump CI ICE would require the installation of a non-resettable hour meter prior to startup if the engine does not meet the emission standards in Subpart IIII that are applicable to non-emergency engines. Additionally, the fire pump CI ICE would be required to be in compliance with the non-vacated portions of the operating and maintenance procedures specified in 40 C.F.R. 60.4211(f).

NSPS Subpart JJJJ, Standards of Performance for Stationary Spark Injection Internal Combustion Engines, applies to stationary spark ignition internal combustion engines (SI ICE) for which construction, modification, or reconstruction commenced after June 12, 2006. Currently, the Project plan does not include SI ICE at the Liquefaction Facility. If any stationary SI ICE are installed at the Liquefaction Facility and subject to Subpart JJJJ, then the stationary SI ICE would be required to meet the NO_X, CO, and VOC emission limits in Table 1 of Subpart JJJJ per 40 C.F.R. 60.4233(e).

NSPS Subpart KKKK, Standards of Performance for Stationary Combustion Turbines, applies to stationary combustion turbines, including any associated duct burners, with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour and for which construction, modification, or reconstruction commenced after February 18, 2005. As a result, Subpart KKKK applies to all of the combustion turbines proposed for the Liquefaction Facility. The preliminary Project plan includes six gas-fired simple cycle combustion turbines for compressor mechanical drives and four gas-fired combined cycle turbines for power generation at the Liquefaction Facility. The associated emissions from a combined turbine and heat recovery steam generator are subject to the Subpart KKKK NO_X and SO_2 emission requirements. Each new gas-fired turbine is expected to be equipped with DLN/DLE emission controls and would be capable of achieving the applicable Subpart KKKK NO_X emission limits. Additionally, the new combustion turbines at the Liquefaction Facility would burn fuel gas with a sulfur content no greater than 3 ppmv S, resulting in SO_2 emissions well below the SO_2 limits in Subpart KKKK.

- NSPS Subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced after September 18, 2015, establishes emission standards and compliance schedules for the control of SO_2, VOC, and greenhouse gases (GHG) in the form of a limitation on emissions of methane from affected facilities in the crude oil and natural gas source category. Subpart OOOOa would apply to certain components of the Liquefaction Facility that include:

- Each centrifugal compressor using wet seals;

- Each single continuous bleed natural gas-driven pneumatic controller;
- Storage vessels, as defined in 40 C.F.R. 60.4530a, with potential VOC emissions equal to or greater than 6 tons per year;
- Each pneumatic pump that is a natural gas-driven diaphragm pump; and
- The group of all equipment, except compressors, within a process unit. The definition of a process unit in 40 C.F.R. 60.5430a includes components assembled for the fractionation of liquids into natural gas products, or other operations associated with the processing of natural gas products.

Owners and operators of centrifugal compressors using wet seals subject to Subpart OOOOa must reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent. If a control device, such as a flare or thermal oxidizer, is used to reduce emissions, then the wet seal fluid degassing system must be equipped with a cover and closed vent system that meet the operating and design requirements in Subpart OOOOa and must be routed to a control device meeting the specifications in Subpart OOOOa. The closed vent system can be routed to a process as an alternative to routing the closed vent system to a control device.

Under Subpart OOOOa, each continuous bleed natural gas-driven pneumatic controller at a natural gas processing plant must have a bleed rate of zero. Subpart OOOOa requires that such pneumatic controllers at a natural gas processing plant be tagged with the month and year of installation, reconstruction, or modification and identification information that allows traceability to the records for that pneumatic controller.

Under Subpart OOOOa, each pneumatic pump that is a natural gas-driven diaphragm pump operating at the Liquefaction Facility must have a natural gas emission rate equal to zero.

Certain monitoring, recordkeeping and reporting requirements and VOC emission standards are applicable to storage vessels subject to Subpart OOOOa. Exceptions to Subpart OOOOa applicability exist for storage vessels subject to and controlled in accordance with the requirements for storage vessels in Subpart Kb or 40 C.F.R. Part 63 Subparts G, CC, HH, or WW. The following vessels are not storage vessels subject to regulation under Subpart OOOOa:

- Storage vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days.
- Process vessels such as surge control vessels, bottoms receivers or knockout vessels; and
- Pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere.

The Liquefaction Facility processing equipment, except compressors, subject to Subpart OOOOa must meet the equipment leak GHG and VOC standards in 40 C.F.R. 60.5400, which cross-reference equipment leak standards in Subpart VVa, Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic

Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After November 7, 2006.

Subpart OOOOa notification, reporting, and recordkeeping requirements are outlined in 40 C.F.R. 60.5420. In addition, 40 C.F.R. 60.5421a and 40 C.F.R. 60.5422a contain recordkeeping requirements and reporting requirements, respectively, for equipment at onshore natural gas processing plants subject to the equipment leak standards in Subpart OOOOa, which include semiannual reporting requirements.

1.2 INTERDEPENDENT PROJECT FACILITIES

1.2.2 Compressor and Heater Stations

NSPS Subpart Da, Standards of Performance for Electric Utility Steam Generating Units, applies to electric utility steam generating units with a heat input capacity greater than 250 MMBtu/hr and for which construction, reconstruction, or modification commenced after September 18, 1978. The compressor stations and heater stations would not include any steam generating units constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net electrical output to any utility power distribution for sale. As a result, the compressor stations and heater stations would not include any equipment subject to the requirements of Subpart Da.NSPS Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, applies to stationary source boilers with a heat input capacity greater than 100 MMBtu/hr and for which construction, reconstruction, or modification commenced after June 19, 1984. At this time, the compressor stations and heater stations would not include any steam generating units with a heat input capacity greater than 100 MMBtu/hr and, as such, would not be subject to the requirements of Subpart Db.

NSPS Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, applies to stationary source boilers with a heat input capacity less than 100 MMBtu/hr and greater than 10 MMBtu/hr and for which construction, reconstruction, or modification commenced after June 9, 1989. All of the compressor stations are planned to include a number of natural gas-fired auxiliary glycol heaters rated for a maximum heat input capacity of approximately 3 MMBtu/hr, each. Because each of these units would have a maximum heat input capacity less than 10 MMBtu/hr, these units would not be subject to the requirements of Subpart Dc.

One compressor station and the heater stations are planned to include a set of five and nine indirect-fired gas heaters, respectively, each heater rated for a maximum heat input capacity of approximately 28 MMBtu/hr. Each unit is expected to meet the definition of a steam generating device, per 40 C.F.R. 60.41c, and would be subject to monitoring, recordkeeping, and notification requirements but not the SO_2 and PM emission standards specified in Subpart Dc.

NSPS Subpart CCCC, Standards of Performance for Commercial and Industrial Solid Waste Incineration (CISWI) Units, applies to owners and operators of CISWI units that are constructed after June 4, 2010 or reconstructed or modified after August 7, 2013, and which meet all of the requirements specified in 40 C.F.R. 60.2010. The compressor stations and heater station would include a CISWI unit that is expected to meet the definition of a CISWI unit subject to Subpart CCCC in 40 C.F.R. 60.2265 and would not be exempt under 40 C.F.R. 60.2020. Per Subpart CCCC, a preconstruction siting analysis and waste management plan would be submitted to EPA prior to commencing construction of each CISWI unit. Commencing construction is defined by EPA as entering into an agreement to purchase a CISWI unit, among other actions. Subpart CCCC also requires proper operating training and qualification, emission and operating limits, performance testing and compliance monitoring, and recordkeeping and reporting requirements upon startup of each CISWI unit.

NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, applies to owners and operators of stationary CI ICE that commence construction after July 11, 2005 where the stationary CI ICE are either manufactured after April 1, 2006 and are not fire pump engines or manufactured as a certified NFPA fire pump engine after July 1, 2006. At this time, the Project plan does not include stationary CI ICE at any of the compressor stations and heater stations.

NSPS Subpart JJJJ, Standards of Performance for Stationary Spark Injection Internal Combustion Engines, applies to stationary SI ICE for which construction, modification, or reconstruction commenced after June 12, 2006. The compressor stations and heater station are planned to include SI ICE,which would be required to meet the NO_X, CO, and VOC emission limits in Table 1 of Subpart JJJJ.

NSPS Subpart KKKK, Standards of Performance for Stationary Combustion Turbines, applies to stationary combustion turbines, including any associated duct burners, with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour and for which construction, modification, or reconstruction after February 18, 2005. Each compressor station is planned to include gas-fired combustion turbines for compressor mechanical drives, each of which would have a maximum heat input at peak load (HHV) greater than 50 MMBtu/hr and less than 850 MMBtu/hr and, as such, Subpart KKKK applies to all of the combustion turbines proposed for the compressor stations. Each new gas-fired turbine is expected to be equipped with DLN/DLE emission controls and would be capable of achieving the applicable Subpart KKKK NO_X emission limits. Additionally, the new combustion turbines at the compressor stations would burn fuel gas with a sulfur content no greater than or equal to 3 ppmv S, resulting in SO_2 emissions well below the SO_2 limits in Subpart KKKK.

Subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced after September 18, 2015 would apply to;

- Each centrifugal compressor using wet seals;
- Each single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 standard cubic feet per hour (scfh);
- Storage vessels, as defined in 40 C.F.R. 60.4530a, with potential VOC emissions equal to or greater than 6 tons per year; and
- The collection of fugitive emissions components, as defined in 40 C.F.R. 60.5430a, at the compressor station.

The equipment and collection of fugitive emissions components at the compressor stations and heater stations would be subject to the monitoring, recordkeeping, and reporting requirements in Subpart OOOOa.

1.2.3 Meter Stations

Information needed to make an adequate regulatory applicability determination for equipment that would be installed and operated at the meter stations is not yet available. Final applicability determinations would be made for the meter stations based on final facility design.

1.2.4 GTP

The GTP would be subject to the flare design and operating requirements of Subpart A for any flare that serves as a control device to comply with the applicable requirements for NSPS-regulated units. Subpart A restricts visible emissions from flares and requires the documentation of design data to ensure proper flare operation.

NSPS Subpart Da, Standards of Performance for Electric Utility Steam Generating Units, applies to electric utility steam generating units with a heat input capacity greater than 250 MMBtu/hr and for which construction, reconstruction, or modification commenced after September 18, 1978. The GTP would not include any steam generating units constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net electrical output to any utility power distribution for sale and as such would not be subject to the requirements of Subpart Da.

NSPS Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, applies to stationary source steam generating units with a heat input capacity greater than 100 MMBtu/hr and for which construction, reconstruction, or modification commenced after June 19, 1984. The preliminary design plan for the GTP includes three natural gas-fired utility heaters with a heat input of approximately 225 MMBtu/hr, each. These heaters are anticipated to be subject to the monitoring, recordkeeping, and reporting requirements and NO_X emission limits in Subpart Db. Because the planned units would fire only natural gas, each unit would be exempt from the SO_2 and PM emission limits specified in Subpart Db.

NSPS Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, applies to stationary steam generating units, as defined in 40 C.FR. 60.41c, with a heat input capacity less than 100 MMBtu/hr and greater than 10 MMBtu/hr and for which construction, reconstruction, or modification commenced after June 9, 1989. The current GTP design plan does not include any steam generating units with a heat input capacity greater than 10 MMBtu/hr and less than 100 MMBtu/hr, each.

NSPS Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels for which Construction, Reconstruction, or Modification Commenced After July 23, 1984, applies to owners and operators of storage vessels constructed, reconstructed, or modified after July 23, 1984 with a capacity greater than or equal to 75 m^3 (19,813 U.S. gallons) and used to store a volatile organic liquid, which is any organic liquid that can emit VOCs, as defined in 40 C.F.R. 51.100, into the atmosphere. Subpart Kb does not apply to storage vessels with a capacity greater than or equal to 75 m^3 (19,813 U.S. gallons) but less than 151 m^3 (39,890 U.S. gallons) and used to store a liquid with a maximum true vapor pressure less than 15.0 kilopascals (kPa) (2.2 pounds per square inch [absolute] (psia)). Subpart Kb also does not apply to storage vessels with a capacity greater than or equal to 151 m^3 (39,890 U.S. gallons) used to store a volatile organic liquid with a maximum true vapor pressure less than 3.5 kPa (0.51 psia). Additionally, the following storage vessels are exempt from Subpart Kb per 40 C.F.R. 60.110b(d):

- Pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere;

- Storage vessels permanently attached to mobile vehicles such as trucks, railcars, barges, or ships; and

- Storage vessels with a design capacity less than or equal to 1,589.874 m^3 (420,000 U.S. gallons) used for petroleum or condensate stored, processed or treated prior to custody transfer. Custody transfer is defined in 40 C.F.R. 60.111b as the transfer of produced petroleum and/or condensate, after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation.

The current GTP design plan includes a number of fuel system storage tanks that would each have a capacity less than 75 m^3 (19,813 gallons) and, as such, would not be subject to Subpart Kb. The current GTP design plan also includes a triethylene glycol (TEG) storage tank with a design capacity of 100 m^3 (26,500 gallons). Because TEG has a vapor pressure much less than 15.0 kPa, the TEG storage tank would not be subject to Subpart Kb.

The capacities of other storage tanks and the expected composition of the volatile organic liquid contents that would be stored at the GTP have not yet been determined. Final applicability determinations would be made for all storage tanks based on final facility design.

NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, applies to owners and operators of stationary CI ICE that commence construction after July 11, 2005 where the stationary CI ICE are manufactured after April 1, 2006 and are not fire pump engines or manufactured as a certified NFPA fire pump engine after July 1, 2006. All stationary CI ICE installed and operated at the GTP that are subject to Subpart IIII would be required to burn ULSD.

The preliminary design plan for the GTP includes:

- One non-emergency stationary CI ICE power generator rated for a maximum power output of approximately 2,500 kW and a displacement less than 10 liters per cylinder,

- One non-emergency stationary CI ICE power generator rated for a maximum power output of approximately 150 kW and a displacement less than 10 liters per cylinder,

- Three fire water pumps CI ICE that would be rated for a maximum power output of approximately 250 horsepower each and have a displacement less than 10 liters per cylinder, and

- One emergency stationary CI ICE that would be rated for a maximum power output of approximately 250 kW and have a displacement less than 10 liters per cylinder.

Each of these units must be designed to meet the applicable Subpart IIII emission limits. The emergency CI ICE is expected to be required to be in compliance with the operating and maintenance procedures specified in 40 C.F.R. 60.4211(f) and the emission limits in 40 C.F.R. 60.4205(b). Under 40 C.F.R. 60.4209(a), the three fire pump CI ICE would require the installation of a non-resettable hour meter prior to startup for any unit that does not meet the emission standards in Subpart IIII that are applicable to non-emergency engines.

NSPS Subpart JJJJ, Standards of Performance for Stationary Spark Injection Internal Combustion Engines, applies to stationary spark ignition internal combustion engines (SI ICE) for which construction, modification, or reconstruction commenced after June 12, 2006. Currently, the Project plan does not include SI ICE at the GTP. If any stationary SI ICE are installed at the GTP and subject to Subpart JJJJ, then the stationary SI ICE would be required to meet the NO_X, CO, and VOC emission limits in Table 1 of Subpart JJJJ per 40 C.F.R. 60.4233(e).

NSPS Subpart KKKK, Standards of Performance for Stationary Combustion Turbines, applies to stationary combustion turbines, including any associated duct burners, with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour and for which construction, modification, or reconstruction after February 18, 2005. As a result, Subpart KKKK applies to all of the combustion turbines proposed for the GTP. The preliminary GTP design plan includes eighteen gas-fired turbines for power generation and for compressor mechanical drives. Each new gas-fired turbine is expected to be equipped with DLN emission controls and would be capable of achieving the applicable Subpart KKKK NO_X emission limits. The sulfur content of the fuel gas burned in the new combustion turbines at the GTP would be low, resulting in SO_2 emissions well below the SO_2 limits in Subpart KKKK.

NSPS Subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Facilities, applies to certain components of onshore natural gas processing plants that commence construction, modification, or reconstruction after September 18, 2015. The components of the GTP that may be subject to Subpart OOOOa include:

- Each centrifugal compressor using wet seals;
- Each single continuous bleed natural gas-driven pneumatic controller;
- Storage vessels, as defined in 40 C.F.R. 60.4530, with potential VOC emissions equal to or greater than 6 tons per year;
- Sweetening units;
- Each natural gas-driven diaphragm pump; and
- The group of all equipment, except compressors, within a process unit, which is defined as components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products.

Under Subpart OOOOa, each continuous bleed natural gas-driven pneumatic controller at a natural gas processing plant must have a bleed rate of zero. Subpart OOOOa requires that such pneumatic controllers be tagged with the year and month of installation, reconstruction, or modification and identification information that allows traceability to the records for that pneumatic controller.

Monitoring, recordkeeping and reporting requirements, and VOC emission standards for storage vessels subject to Subpart OOOOa are included at 40 C.R.F. 60.5395a. Subpart OOOOa does not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in Subpart Kb or 40 C.F.R. Part 63 Subparts G, CC, HH, or WW.

The GTP processing unit equipment, except compressors, subject to Subpart OOOOa must meet the equipment leak standards in 40 C.F.R. 60.5400a, which cross-reference equipment leak standards in Subpart VVa, Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After November 7, 2006.

Sweetening units installed and operated at the GTP would be subject to the SO_2 emission reduction efficiency standards under 40 C.F.R. 60.5405a, the performance test method standards under 40 C.F.R. 60.4506a, and monitoring requirements under 40 C.F.R. 60.5407a if the sweetening units have a design capacity greater than 2 long tons per day (LT/day) of hydrogen sulfide (H_2S) in the acid gas (expressed as sulfur), per 40 C.F.R. 60.5365(g)(3). Sweetening facilities producing acid gas that is completely re-injected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere are not subject to the SO_2 emission and monitoring standards, initial and continuous compliance standards, and recordkeeping and reporting requirements for sweetening units in Subpart OOOOa.

Subpart OOOOa notification, reporting, and recordkeeping requirements are outlined in 40 C.F.R. 60.5420a. Additional recordkeeping requirements and reporting requirements are included at 40 C.F.R. 60.5421a and 40 C.F.R. 60.5422a, respectively, for equipment at onshore natural gas processing plants subject to the equipment leak standards in Subpart OOOOa, which include semiannual reporting requirements.

2.0 NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAPS)

The 1970 CAA required that EPA develop health risk-based standards for regulating hazardous air pollutant (HAP) emissions. These regulations are codified in 40 C.F.R. Part 61, National Emission Standards for Hazardous Air Pollutants (NESHAPs) and apply to specific pollutants and source categories. The Project is not one of the source categories regulated under 40 C.F.R. Part 61 and, as such, the requirements of 40 C.F.R. 61 would not apply to the Project.

The 1990 CAA Amendments expanded the EPA obligation to regulate HAPs and required EPA to set technology-based standards for a larger list of HAPs and for many more source categories. These NESHAPs are codified in 40 C.F.R. Part 63, also referred to as maximum achievable control technology (MACT) standards, and regulate HAP emissions from major sources of HAPs and area sources of HAPs within specific source categories. Part 63 defines a major source of HAPs as any stationary source or group of stationary sources located within a contiguous area and under common control that has the potential to emit more than 10 tons per year (tpy) of any single HAP or more than 25 tpy of all HAPs combined. Part 63 defines an area source of HAPs as any stationary source of HAPs that is not a major source of HAPs. Preliminary HAPs emission calculations indicate that the Liquefaction Facility and the GTP are each anticipated to have the potential to emit a single HAP, formaldehyde, at a rate greater than 10 tpy. As a result, these facilities are expected to be major sources of HAPs. The compressor stations, heater stations, and metering station potential to emit total HAPs and any single HAP would be below the 25 tpy and 10 tpy thresholds, respectively, and would be classified as area sources of HAPs.

Subpart A of Part 63 provides the general provisions for sources subject to the various MACT standards, which includes monitoring, notification, and reporting requirements for sources subject to certain subparts within 40 C.F.R. Part 63. Each subpart provides a table identifying which general provisions apply to that subpart. A preliminary analysis of MACT standards in 40 C.F.R. Part 63 that may apply to the proposed Project facilities is provided below and summarized in Table 2. Final applicability determinations would be made based on final facility design.

TABLE 2

Preliminary NESHAPs Applicability Summary

NESHAPs Subpart	Applicability		
	Liquefaction Facility	Compressor and Heater Stations	GTP
Subpart A – General Provisions	Yes	Yes	Yes
Subpart Y – National Emission Standards for Marine Tank Vessel Loading Operations	No	No	No
Subpart EEE – NESHAPs from Hazardous Waste Combustors	No	TBD	No
Subpart EEEE – NESHAPs for Organic Liquids Distribution (Non-Gasoline)	TBD	No	TBD
Subpart H – Organic HAPs for Equipment Leaks	TBD	TBD	TBD
Subpart HH – NESHAPs for Oil and Natural Gas Production Facilities	TBD	No	TBD
Subpart HHH – NESHAPs for Natural Gas Transmission and Storage Facilities	No	No	Yes
Subpart YYYY – NESHAPs for Stationary Combustion Turbines	Yes	No	Yes
Subpart ZZZZ – NESHAPs for Stationary Reciprocating Internal Combustion Engines	Yes	Yes	Yes
Subpart DDDDD – NESHAPs for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters	No	No	Yes
Subpart JJJJJJ – NESHAPs for Industrial, Commercial, and Institutional Boilers Area Sources	No	No	No

2.1 LIQUEFACTION FACILITY

The Liquefaction Facility would be subject to the flare design and operating requirements of Subpart A for the flares if the flares serve as a control device to comply with the applicable requirements of other NESHAPs-regulated units. Subpart A restricts visible emissions from flares and requires the documentation of design data to ensure proper flare operation. Final applicability determinations for the flares would be made based on final facility design.

Subpart Y, National Emission Standards for Marine Tank Vessel Loading Operations, applies to new major sources of HAPs with marine tank vessel loading operations, which are defined in 40 C.F.R. 63.561 as any operation under which a commodity is bulk loaded onto a marine tank vessel from a terminal. The Liquefaction Facility marine terminal loading berths would be located more than 0.81 km (0.5 miles) from the shore and meet the criteria of an offshore loading terminal in Subpart Y. The marine terminal would not be a new major source offshore loading terminal because the potential HAP emissions exclusively from the marine terminal would be less than 10 tons per year (tpy) of any single HAP and less than 25 tpy of all HAPs combined. As a result, Subpart Y would not apply to the marine terminal.

Subpart EEEE, National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline), establishes emission limits, operating limits, and work practice standards for organic HAPs emitted from organic liquid distribution (OLD) operations at major sources of HAPs. Per 40 C.F.R. 63.2334(b), OLD operations at facilities subject to Subpart HH and Subpart HHH are not subject to Subpart EEEE. Subpart EEEE applies to the collection of activities and equipment used to distribute organic liquids, as defined in 40 C.F.R. 63.2406, including:

- Storage tanks storing organic liquids;
- Transfer racks at which organic liquids are loaded into or unloaded out of transport vehicles and/or containers;
- Equipment leak components in organic liquids service that are associated with storage tanks and equipment subject to Subpart EEEE;
- Transport vehicles while the vehicles are loading or unloading organic liquids at transfer racks subject to Subpart EEEE; and
- Containers while the containers are loading or unloading organic liquids at transfer racks subject to Subpart EEEE.

Storage tanks, transfer racks, transport vehicles, containers, and equipment leak components that are part of an affected source under another subpart of 40 C.F.R. 63 are exempt from Subpart EEEE. A final applicability determination for Subpart EEEE will be made based on final facility design.

Subpart H, National Emission Standards for Organic HAPs for Equipment Leaks, applies to certain equipment within a source subject to the provisions of a specific subpart in 40 C.F.R. 63 that references Subpart H. For affected equipment, Subpart H includes equipment design requirements as well as leak detection and repair for pumps, compressors, agitators, pressure-relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, instrumentation systems, and control devices or closed-vent systems required by Subpart H that are intended to operate in organic HAP service 300 hours or more during the calendar year.

Organic HAP service means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least five percent by weight of total organic HAPs on an annual basis (40 C.F.R. 63.161). This definition may apply to equipment that handles hydrocarbon condensates if the hydrocarbon condensates contain concentrated amounts of organic HAPs such as hexane. The possibility exists that no equipment at the Liquefaction Facility would trigger Subpart H applicability. A final applicability determination for Subpart H would be made once detailed information about the composition of the hydrocarbon condensates anticipated at the Liquefaction Facility becomes available.

Subpart HH, NESHAPs for Oil and Natural Gas Production Facilities, applies to facilities that process, upgrade, or store either natural gas or hydrocarbon liquids. At facilities that are major sources of HAPs, Subpart HH applies to glycol dehydration units, storage vessels with the potential for flash emissions, and the group of all ancillary equipment intended to operate in volatile HAP service at natural gas processing plants. Per 40 C.F.R. 63.761, in volatile HAP service means that a piece of ancillary equipment or compressor either contains or contacts a fluid (liquid or gas) which has a total volatile HAP concentration equal to or greater than 10 percent by weight. Ancillary equipment and compressors that are subject to Subpart H and Subpart HH would only be required to comply with the requirements of Subpart H.

The storage vessel standards in Subpart HH apply to any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio (GOR) equal to or greater than 0.31 m^3 per liter (L) and an API gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters (21,000 gallons) per day. The Subpart HH storage vessel standards do not apply to storage vessels subject to 40 C.F.R. 60 Subpart Kb. An applicability determination for Subpart HH would be made based on the final Liquefaction Facility design.

Subpart HHH, NESHAP for Natural Gas Transmission and Storage Facilities, applies to owners and operators of natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user (if there is no local distribution company), and that are major sources of HAPs. Equipment types subject to Subpart HHH are new and existing glycol dehydration units at the natural gas transmission and storage facility and any affected glycol dehydration unit would be subject to emission control requirements in 40 C.F.R. 63.1275 and monitoring, recordkeeping and reporting requirements specified in 40 C.F.R. 63.1283 through 1285. Per 40 C.F.R. 63.1270(c), a facility that does not include any glycol dehydration units specified in 40 C.F.R. 63.1270(b) is not subject to Subpart HHH. The current Liquefaction Facility design plan does not include any glycol dehydration units so Subpart HHH would not be applicable.

Subpart YYYY, NESHAPs for Stationary Combustion Turbines, applies to existing, new, or reconstructed stationary combustion turbines at major stationary sources of HAPs. The preliminary Project plan includes six gas-fired simple cycle combustion turbines for compressor mechanical drives and four gas-fired combined cycle turbines for power generation at the Liquefaction Facility. On August 18, 2004, EPA stayed the combustion turbine NESHAP for natural gas-fired turbines. As a result, the new combustion turbines at the Liquefaction Facility would be subject to the initial notification requirements in Subpart YYYY, but need not comply with any other requirement of Subpart YYYY until EPA takes final action to require compliance and publishes a document in the Federal Register (40 C.F.R. 63.6095(d)).

Subpart ZZZZ, NESHAPs for Stationary Reciprocating Internal Combustion Engines, applies to emissions from both spark-ignition and compression-ignition reciprocating internal combustion engines at area sources and major sources. The preliminary Liquefaction Facility plan includes the following potentially affected engines:

- One non-emergency engine air compressor drive rated for a maximum power output of approximately 300 horsepower, and
- One firewater pump engine rated for a maximum power output of approximately 575 horsepower (429 kW), each.

Under Subpart ZZZZ, a new compression ignition stationary reciprocating ICE with a site rating of less than or equal to 500 brake horsepower located at a major source of HAPs emissions can demonstrate compliance with Subpart ZZZZ by demonstrating compliance with 40 C.F.R. 60, Subpart IIII. Per 40 C.F.R. 63.6590(b(1), the firewater pump engine would not be required to meet the requirements in Subpart ZZZZ and of Subpart A, except for the information in the initial notification requirements outlined in 40 C.F.R. 63.6645(f). All stationary diesel-fired engines at the Liquefaction Facility would be required to burn ULSD.

Subpart DDDDD, NESHAPs for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, applies to boilers and process heaters at major sources of HAPs. The current facility design plan does not include any boilers and process heaters and, as such, would not be subject to the requirements of Subpart DDDDD.

2.2 INTERDEPENDENT PROJECT FACILITIES

2.2.2 Compressor Stations and Heater Stations

Subpart EEE, National Emission Standards for HAPs from Hazardous Waste Combustors, can apply to the incineration of hazardous waste, as defined under 40 C.F.R. 261.3. The rule at 40 C.F.R. 261.4(b)(1) specifically excludes household waste, which includes any material (including garbage, trash and sanitary wastes in septic tanks) derived from households including crew quarters. The compressor stations and heater stations may include incinerators capable of burning hazardous waste. A final applicability determination would be made based on final facility design.

Subpart H, National Emission Standards for Organic HAPs for Equipment Leaks, applies to certain equipment within a source subject to the provisions of a specific subpart in 40 C.F.R. 63 that references Subpart H. Subpart H includes equipment design requirements as well as leak detection and repair requirements. Final applicability determinations to Subpart H would be made based on the final design of the compressor stations and heater station.

Subpart HH, NESHAPs from Oil and Natural Gas Production Facilities, applies to facilities that process, upgrade, or store either natural gas or hydrocarbon liquids. At facilities that are area sources of HAPs, Subpart HH applies to each triethylene glycol (TEG) dehydration unit. None of the compressor and heater stations are anticipated to include TEG units. As a result, Subpart HH would not be applicable.

Subpart HHH, NESHAP for Natural Gas Transmission and Storage Facilities, applies to owners and operators of natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user (if there is no local distribution company), and that are major sources of HAPs. Because the compressor stations and heater stations would be area sources of HAPs, equipment in these facilities would not be subject to Subpart HHH.

Subpart YYYY, NESHAPs for Stationary Combustion Turbines, applies to existing, new, or reconstructed stationary combustion turbines at major stationary sources of HAPs. Subpart YYYY defines a major source of HAPs for oil and gas production facilities in terms of the HAPs emissions from each surface site, where the compressor stations would be considered individual surface sites. Pending further design specifications, the compressor stations are not likely to be major sources of HAPs, so Subpart YYYY would not apply to the turbines located at the compressor stations.

Subpart ZZZZ, NESHAPs for Stationary Reciprocating Internal Combustion Engines, applies to emissions from both spark-ignition and compression-ignition reciprocating internal combustion engines at area sources and major sources of HAPs. The preliminary plan for the compressor stations and heater stations include spark-ignition reciprocating internal combustion engines. Because the engines would be located at area sources of HAPs, these engines would demonstrate compliance with the requirements of Subpart ZZZZ by complying with 40 C.F.R. 60, Subpart JJJJ.

Subpart JJJJJJ, NESHAPs for Industrial, Commercial, and Institutional Boilers Area Sources, applies to industrial boilers located at an area source of HAPs. Gas-fired boilers are not subject to Subpart JJJJJJ and, as such, Subpart JJJJJJ would not apply to the boilers at any of the compressor stations and heater stations.

2.2.3 Meter Stations

Information needed to make an adequate regulatory applicability determination for equipment that would be installed and operated at the meter stations is not yet available and would be provided in a subsequent draft of this Resource Report.

2.2.4 GTP

The GTP would be subject to the flare design and operating requirements of Subpart A for the flares if the flares serve as a control device to comply with the applicable requirements of other NESHAPs-regulated units. Subpart A restricts visible emissions from flares and requires the documentation of design data to ensure proper flare operation.

Subpart EEEE, National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline), establishes emission limits, operating limits, and work practice standards for organic HAPs emitted from organic liquid distribution (OLD) operations at major sources of HAPs. Activities and equipment used to process, store or transfer organic liquids at facilities defined in Subpart HH and at facilities defined in Subpart HHH are exempt from Subpart EEEE. A final applicability determination for Subpart EEEE would be made based on final facility design.

Subpart H, National Emission Standards for Organic HAPs for Equipment Leaks, applies to certain equipment within a source, and in a service, subject to the provisions of a specific subpart in 40 C.F.R. 63 that references Subpart H. Subpart H includes equipment design requirements as well as leak detection and repair for equipment such as pumps, compressors, agitators, pressure-relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, instrumentation systems, and control devices or closed-vent systems required by Subpart H that are intended to operate in organic HAP service 300 hours or more during the calendar year. The possibility exists that no equipment at the GTP would be subject to Subpart H. A final applicability determination to Subpart H would be made once detailed information about the composition of the hydrocarbon condensates anticipated at the GTP becomes available.

Subpart HH, NESHAPs from Oil and Natural Gas Production Facilities, applies to facilities that process, upgrade, or store either natural gas or hydrocarbon liquids. At facilities that are major sources of HAPs, Subpart HH applies to glycol dehydration units, storage vessels with the potential for flash emissions, and ancillary equipment intended to operate in volatile HAP service at natural gas processing plants. Ancillary equipment and compressors that are subject to Subpart H and Subpart HH would only be required to comply with the requirements of Subpart H. An applicability determination for Subpart HH would be made based on the final GTP design.

Subpart HHH, NESHAP for Natural Gas Transmission and Storage Facilities, applies to owners and operators of natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user (if there is no local distribution company), and that are major sources of HAPs. The equipment subject to Subpart HHH is new and existing glycol dehydration units at the natural gas transmission and storage facility. The preliminary GTP design plan includes three parallel treatment trains, each of which would include a glycol dehydration unit that would be subject to emission control requirements specified in 40 C.F.R. 63.1275 and monitoring, recordkeeping and reporting requirements specified in 40 C.F.R. 63.1283 through 1285.

Subpart YYYY, NESHAPs for Stationary Combustion Turbines, applies to existing, new, or reconstructed stationary combustion turbines at major stationary sources of HAPs. Because the new combustion turbines at the GTP would be located on the Alaska North Slope, these combustion turbines would be exempt from the requirements of Subpart YYYY except for initial notification requirements.

Subpart ZZZZ, NESHAPs for Stationary Reciprocating Internal Combustion Engines, applies to emissions from both spark-ignition and compression-ignition reciprocating internal combustion engines at area sources and major sources. Under Subpart ZZZZ, a new compression ignition stationary reciprocating ICE with a site rating of less than or equal to 500 horsepower located at a major source of HAPs can demonstrate compliance with Subpart ZZZZ by complying with 40 C.F.R. 60, Subpart IIII. All of the stationary compression ignition reciprocating internal combustion engines at the GTP are anticipated to have a maximum power output less than 500 horsepower with the exception of one non-emergency stationary engine expected to have a maximum power output of 2,500 kW (3,353 horsepower). That larger engine would be subject to the emission limits under Subpart ZZZZ. All stationary diesel-fired engines at the GTP would be required to burn ULSD.

Subpart DDDDD, NESHAPs for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, applies to boilers and process heaters at major sources of HAPs. The preliminary design plan for the GTP includes three natural gas-fired utility heaters with a maximum heat input of approximately 250 MMBtu/hr, each, which would be affected units under Subpart DDDDD. Because these units would combust only natural gas, the units would be exempt from the emission limits specified in Table 1 of Subpart DDDDD, but would be subject to the initial notification requirements in 40 C.F.R. 63.7545 and the work practice standards in 40 C.F.R. 63.7540(a), as cross-referenced in 40 C.F.R. 63.7500.

3.0 CHEMICAL ACCIDENT PREVENTION

Section 112(r) of the 1990 CAA Amendments requires the EPA to publish regulations and guidance for chemical accident prevention at facilities for substances that pose the greatest risk of harm from accidental releases. The chemical accident prevention provisions, also referred to as the Risk Management Program (RMP), are codified in 40 C.F.R. Part 68. The regulations include a list of regulated substances that include methane, propane, and ethylene. The regulation also includes threshold quantities (TQ) for determining applicability to stationary sources. If a stationary source stores, handles, or processes one or more regulated substances in a quantity equal to or greater than the TQ specified in Table 1 of 40 C.F.R. 68.130, the facility must prepare and submit a risk management plan to EPA.

The RMP applies only to stationary sources and, as such, does not apply to transportation subject to oversight or regulation under 49 C.F.R. Parts 192 (Federal safety standards for transportation of natural and other gas by pipeline), 193 (Federal safety standards for liquefied natural gas facilities), or 195 (Federal safety standards for transportation of hazardous liquids by pipeline), or a state natural gas or hazardous liquid program for which the state has in effect a certification to the U.S. Department of Transportation under 49 U.S.C. 60105. Transportation containers used for storage not incident to transportation and transportation containers connected to equipment at a stationary source are part of the stationary source.

Per 40 C.F.R. Part 68.115(b)(2)(iii), prior to entry into a natural gas processing plant, regulated substances in naturally occurring hydrocarbon mixtures do not need to be considered when determining whether more than a TQ of a regulated substance is present at a stationary source. Naturally occurring hydrocarbon mixtures include any combination of the following: condensate, field gas, and produced water, each as defined in 40 C.F.R. 68.3. Per 40 C.F.R. 68.3, field gas is gas extracted from a production well before the gas enters a natural gas processing plant, which is any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both, classified as North American Industrial Classification System (NAICS) code 211112, previously Standard Industrial Classification (SIC) code 1321.

A preliminary RMP applicability analysis that may apply to the proposed Project facilities is provided below and summarized in Table 3. Final applicability determinations would be made based on final facility design.

TABLE 3

Preliminary RMP Applicability Summary

40 C.F.R. Part 68 - Chemical Accident Prevention Provisions	Applicability		
	Liquefaction Facility	**Compressor and Heater Stations**	**GTP**
Subpart F – Regulated Substances for Accidental Release Prevention	No	No	Yes

Regardless of the applicability of 40 C.F.R. Part 68 to the Project facilities, the general duty clause in Section 112(r)(1) of the CAA Amendments would still apply. That requirement reads:

> "The owners and operators of stationary sources producing, processing, handling or storing such substances have a general duty in the same manner and to the same extent as section 654, title 29 of United States Code [Occupational Safety and Health Act of 1970 (29 U.S.C. 654)] to identify hazards which may result from such releases using appropriate hazard assessment techniques, to design and maintain a safe facility taking such steps as are necessary to prevent releases, and to minimize the consequences of accidental releases which do occur."

The Project facilities would be designed and maintained to meet the general duty provisions.

3.1 LIQUEFACTION FACILITY

The hydrocarbon refrigerants and natural gas components undergoing liquefaction at the Liquefaction Facility would be subject to regulation under 49 C.F.R. Part 193, Federal Safety Standards for Liquefied

Natural Gas Facilities and, therefore, would not be considered for determining applicability to 40 C.F.R. Part 68. The Liquefaction Facility would not include the storage of any hazardous or flammable substances in excess of a TQ determined per 40 C.F.R. 68.115 and, as such, the Liquefaction Facility would not be subject to 40 C.F.R. Part 68.

3.2 INTERDEPENDENT PROJECT FACILITIES

3.2.2 Compressor Stations and Heater Stations

The compressor stations and heater stations would be subject to regulation under 49 C.F.R. Part 192, Federal Safety Standards for Transportation of Natural and Other Gas by Pipeline. No hazardous or flammable substances in excess of a TQ determined per 40 C.F.R. 68.115 would be stored at the compressor stations or heater stations. As a result, these facilities would not be subject to 40 C.F.R. Part 68.

3.2.3 Meter Stations

No hazardous or flammable substances in excess of a TQ determined per 40 C.F.R. 68.115 would be stored at the meter stations. The meter stations would be subject to regulation under 49 C.F.R. Part 192, Federal Safety Standards for Transportation of Natural and Other Gas by Pipeline. As such, the meter stations would not be subject to 40 C.F.R. Part 68.

3.2.4 GTP

The GTP would include the storage of propane refrigerant in an amount greater than 10,000 lbs., which exceeds a TQ determined per 40 C.F.R. 68.115. The propane refrigerant stored at the GTP and would not be subject to regulation under 49 C.F.R. 192, 193, or 195 and would not be considered a component of a naturally occurring hydrocarbon mixture, as defined in 40 C.F.R. 68.3. As a result, the GTP would be subject to the provisions of 40 C.F.R. Part 68 for the storage of propane refrigerant.

Methane, ethane and propane inventories in the natural gas that would be treated at the GTP would not be subject to the provisions of 40 C.F.R. Part 68 because these substances would be components of a naturally occurring hydrocarbon mixture, as defined in 40 C.F.R. 68.3, and would not be considered for determining RMP applicability per 40 C.F.R. 68.115(b)(2)(iii).