DATA REQUEST REFERENCE INFORMATION

Agency	Data Request Date	Letter Request No.
ADEC	06-18-2020 (via e-mail)	RFI-683

REQUEST:

E-mail from David Jones (ADEC) on 6/18/2020 indicated:

The Department is requesting a more detailed evaluation of the potential for carbon capture and sequestration (CCS) performed at the Liquefaction Facility. In the initial BACT analysis (CCS section attached) on PDF page 4 AGDC notes:

> *The United States 2012 Carbon Utilization and Storage Atlas (Fourth Edition published by the U.S. Department of Energy, Office of Fossil Energy) identifies an extensive saline aquifer directly below Nikiski as being "screened, high sequestration potential."* ***However, this area has not had detailed evaluation for CO_2 sequestration and lies in a fault zone. Thus, this saline aquifer is not deemed to be suitable for CCS at this time by the Project.***

The Department identified the area under the Liquefaction Plant as having a high sequestration potential as identified in the *Alaska Geologic Carbon Sequestration Potential Estimate: Screening Saline Basins and Refining Coal Estimates* (attached). Note that the executive summary on PDF page 9 states, "This report presents refined saline basin screening and improved coal storage capacity estimates **which take into account** data coverage, **geologic and tectonic environments** and gross measures of economic feasibility." PDF pages 10 and 11 of the report show maps with the highest sequestration potential where the planned Liquefaction Facility will be located in Nikiski.

In Table 24 of the attached BACT analysis, AGDC performs an economic analysis for CCS at the Liquefaction Facility. In this analysis, AGDC uses costs on a per ton basis from the Golden Pass Products Gas Emissions application for a PSD permit from June 2014, and assumes that 25 miles of pipeline will be required to transport the CO_2 for sequestration at an off-site location. Additionally, AGDC assumes that 1.2 million tons of CO_2 will be removed per year. However, the PTE spreadsheet submitted with the application (attached) shows 3.8 million tonnes (4.2 million tons) of CO_2 emissions from the turbine EUs 1 – 10.

Please provide the following information:

1. Justification as to why AGDC believes that the property on which the Liquefaction Facility is planned to be constructed is not suitable for injection of CO_2 and 25 miles of pipeline are required for off-site injection.
2. Site specific information for the cost of installing CCS on the ten turbines at the Liquefaction Facility, which includes a cost for total capital investment.

3. Please provide a justification as to why AGDC is assuming a roughly 29% capture of CO_2 emissions from the turbines at the Liquefaction Facility; or use a more representative control efficiency for CCS.

Please provide the requested information by July 2, 2020 or let us know if you need additional time or if you have any questions.

ALASKA LNG RESPONSE:

1. <u>Justification as to why AGDC believes that the property on which the Liquefaction Facility is planned to be constructed is not suitable for injection of CO2 and 25 miles of pipeline are required for off-site injection</u>

The facility design and technical challenges of concentrating large and very dilute streams of carbon dioxide from turbine exhaust are significant and largely unproven. Furthermore, the feasibility of injecting large volumes of greenhouse gases at the Liquefaction Facility location in underground aquifers is not known. While AGDC conducted detailed geotechnical and seismic studies and engineering analysis of the conditions at the site and the surrounding area as part of the Liquefaction Facility design, detailed geotechnical and safety evaluations for injection at the site were not included.

The results of available engineering evaluations were included in AGDC's FERC Application in Resource Report No.13, Appendix I Seismic Hazard Analysis. The appendix included two detailed reports: *LNG Facilities Probabilistic Seismic Hazard Analysis (PSHA) Report (USAL-FG-GRHAZ-00-002015-001)* and *LNG Facilities Seismic Engineering Report (USAL-FG-GRHAZ-00-002016-008*). The purpose of those analyses was to determine the seismic hazards and design criteria for the Liquefaction Facility. The information in those reports was also utilized in evaluating the potential for on-site carbon dioxide injecting and sequestration. Attachment 1 provides selected figures from each report that illustrate the multiple faults in the immediate area of the site. This information supports our conclusion in the BACT analysis that site conditions are not suitable for carbon dioxide injection and sequestration.

The installation costs for a pipeline of up to 25 miles were included in the BACT cost-effectiveness analysis to estimate costs for transportation of compressed carbon dioxide to a more suitable site for sequestration and storage. These transportation costs were estimates that assumed the technical challenges with implementing CCS could be overcome and that an acceptable location could be found for sequestration in the overall Cook Inlet regional area. Potential sites could include depleted oil and gas reservoirs that are indicated in the ADNR map figure (Plate 5) in Attachment 1.

2. <u>Site specific information for the cost of installing CCS on the ten turbines at the Liquefaction Facility, which includes a cost for total capital investment</u>

AGDC updated its cost-effectiveness analysis for CCS in response to ADEC's comments, as described below and detailed in Attachment 2.

- The revised cost evaluation is based on the capture and sequestration carbon dioxide emissions from all ten turbines proposed for operation at the site. The evaluation presented in the 2018 BACT analysis only included a representative subset of turbine emissions to confirm economic feasibility.
- A 90% capture and control efficiency is assumed in the updated analysis. This level of control is consistent with the design and operating assumptions of other proposed CCS installations throughout the United States. Higher capture and control efficiencies are potentially possible, but to achieve such capture and control efficiencies would come at a significantly higher cost.
- The updated analysis leverages cost data from the Gas Treatment Plant (GTP) CO2 Capture Study (Document No. USAG-WD-PRTEC-000045), which was provided to ADEC on April 28, 2020 (See RFI-679). The cost-effectiveness evaluation is supplemented with cost data from the Golden Pass LNG Project PSD Permit Application. Both of these analyses include detailed cost information for the construction and operation of carbon dioxide capture and control, transportation, and storage facilities. AGDC believes that these cost data are relevant because the facilities contemplated in the GTP CO2 Capture Study and Golden Pass PSD Permit Application are approximately the same size and capacity as the facilities needed to capture and sequester carbon dioxide from the Liquefaction facility turbine operations.
- The above referenced cost data have been adjusted based on the total uncontrolled carbon dioxide emissions from the Liquefaction facility. All costs are re-stated in 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI). Finally, the Golden Pass cost data have been adjusted to reflect Alaska pricing using the DOD Area Cost Factors (Reference provided in the cost-effectiveness worksheet). Other than adjusting costs to 2019 dollars, no adjustment of costs from the GTP CO2 Capture Study were required since they consider Alaska-specific pricing.
- The analysis conservatively assumes a plant life of 25 years and does not include extensive upgrades and equipment replacements expected during the life of the facility. This assumption would make the analysis conservative in that life-cycle costs associated with CCS facilities would be underestimated.

The updated analysis confirms that CCS is not cost-effective, with an overall cost-effectiveness of $165/ton/year. If the transportation of compressed carbon dioxide to an offsite location is not needed, there is no significant difference in cost-effectiveness as the value is only marginally reduced to $157/ton/year.

In addition to not being cost-effective on an average dollars per ton, per year basis, CCS is not economically viable given its overall cost relative to the facility cost. As noted in the attached evaluation, CCS would cost on the order of $5.1 billion dollars to construct at the Liquefaction Facility. Operating costs would be on the order of $192 million per year. The magnitude of this expenditure eliminates CCS as a viable BACT alternative for the project.

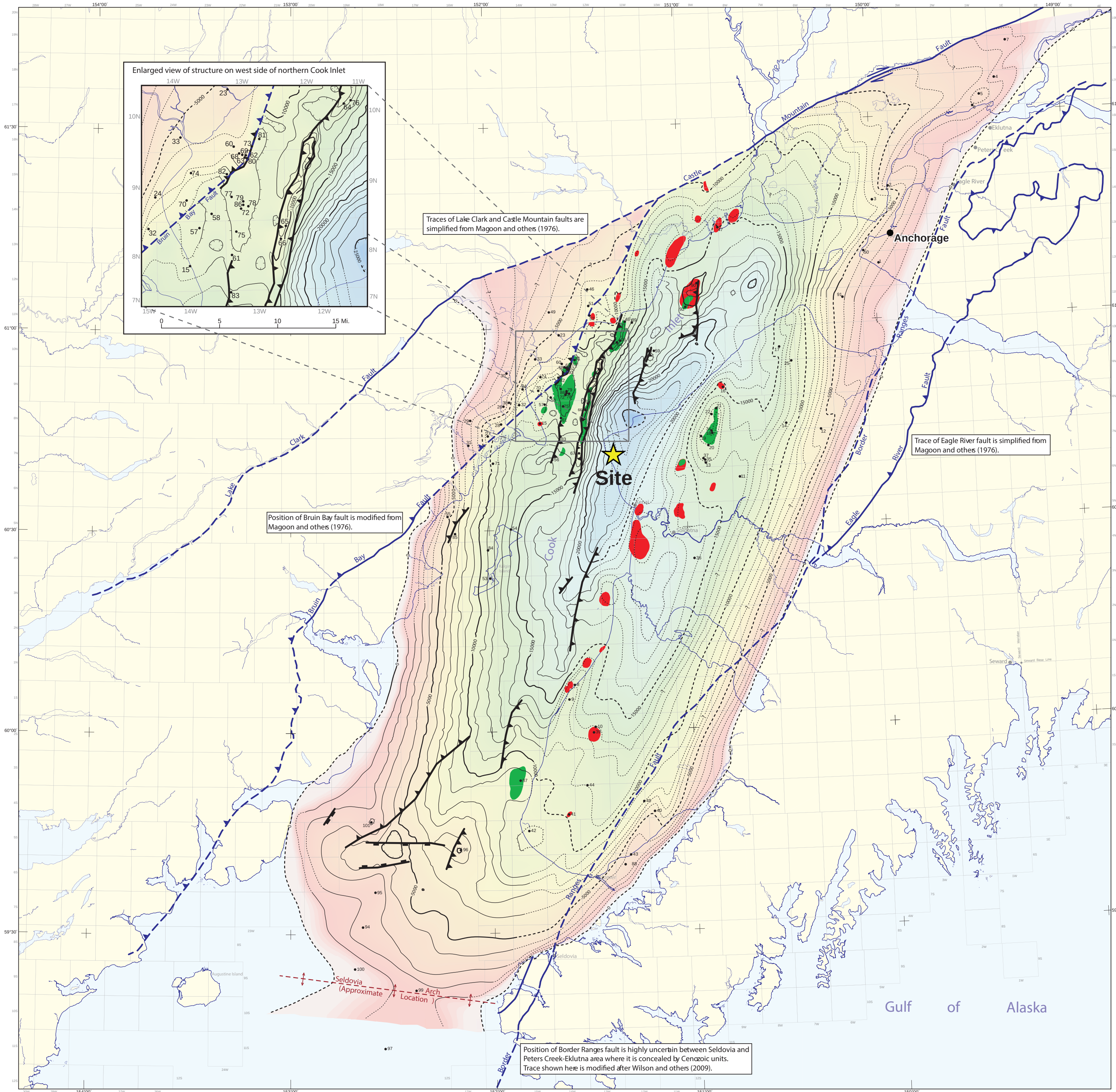
3. Please provide a justification as to why AGDC is assuming a roughly 29% capture of CO_2 emissions from the turbines at the Liquefaction Facility; or use a more representative control efficiency for CCS

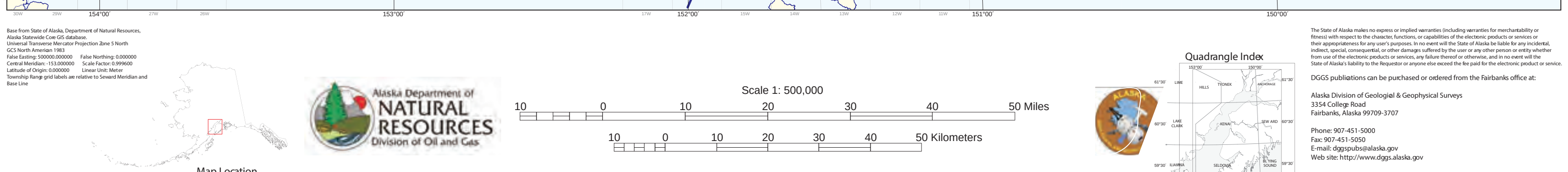
The original BACT analysis did not include all project turbines in the cost analysis. The original evaluation only included a subset of turbines to benchmark potential feasibility as a BACT measure. The updated analysis, which is attached to this response, has been corrected to include all ten turbines represented in the project emissions calculations. A representative capture and control efficiency of 90% has been used in the updated analysis to reflect the cost per ton of carbon dioxide emissions avoided. Ninety percent capture and control is a typical value used in CCS evaluations, including the GTP CO2 Capture Study, and the Golden Pass PSD Permit Application.

The updated cost-effectiveness does not change the conclusion of the BACT evaluation. CCS is not a cost-effective measure to identify as BACT for the project.

ATTACHMENTS:

1. Resource Report No. 13 Appendix I Seismic Reports Figures
2. GHG CCS Cost Effectiveness





Modified from Shellenbaum et al. (2010)

Legend

Fault - dashed where approximately located

- Strike-slip fault
- Thrust fault - sawteeth on upper plate
- Thrust fault - sawteeth on upper plate (seismic derived)
- Normal fault (seismic derived)

Fold axis - dashed where approximately located

- Anticline
- Syncline
- Anticline
- Syncline

Depth contours - dashed outside of seismic control; queried where inferred or doubtful

- Red line on location map above denotes area of seismic reflection data used in this study
- -5000 Index contour (depth in feet relative to sea level datum)
- Intermediate contour
- ●36 Well with base Tertiary penetrations
- Oil accumulation
- Gas accumulation

*Oil and gas accumulations are displayed for reference only. They are typically located within the shallower Tertiary section, not at the mapped surface.

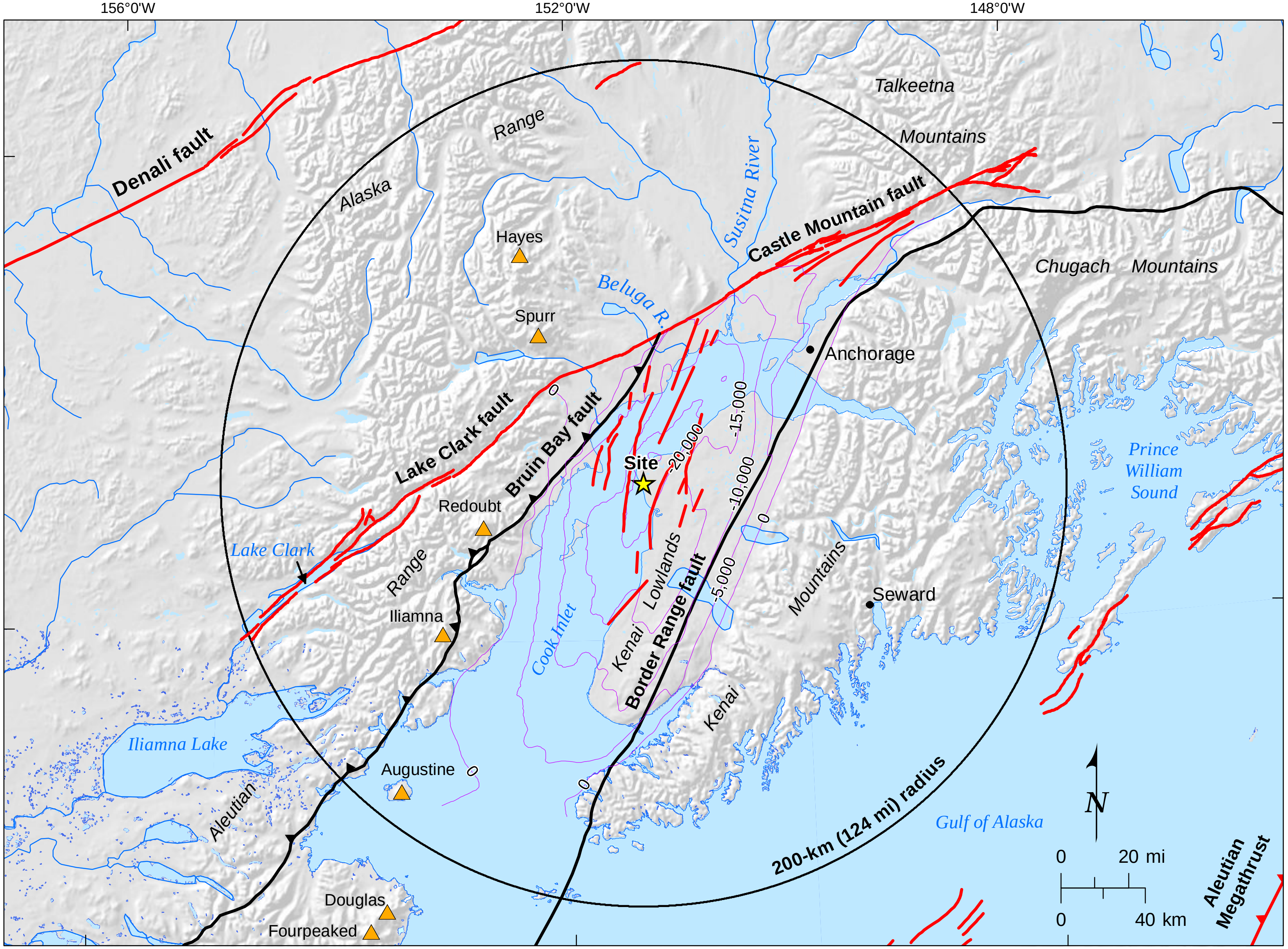
-25000 -19000 -13000 -6500 0

Vertical depth in feet
Datum: Sea Level

TOP MESOZOIC UNCONFORMITY
DEPTH MAP OF THE COOK INLET BASIN
LNG FACILITIES
ALASKA LNG PROJECT
NIKISKI, ALASKA

PLATE 5

fwla-wc-file1/project/Projects/10_0000/10_140334_AKLNG_PreFEED_Phase2/05_Graphics/10_140334 PSHA



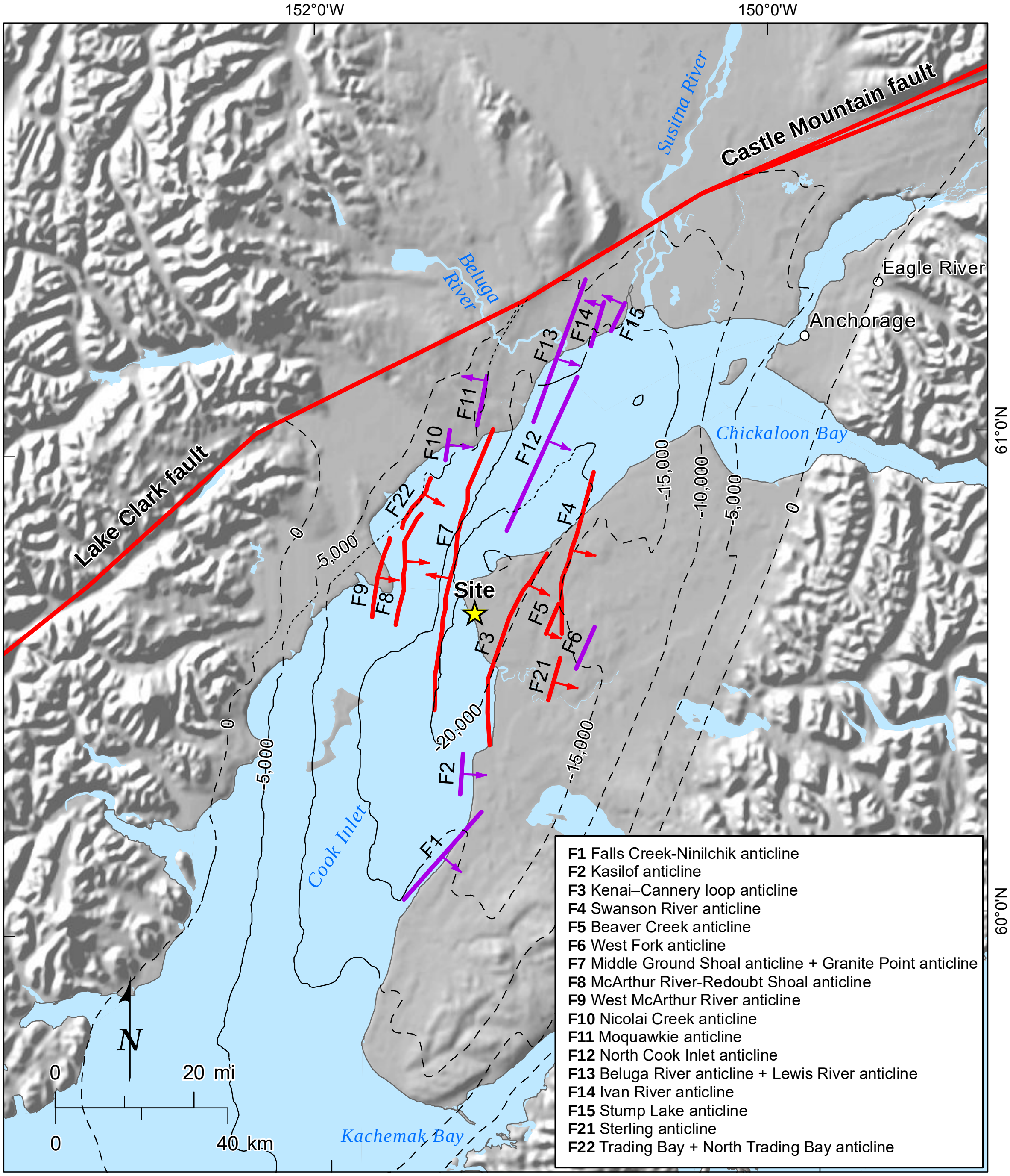
Legend

- Pre-Quaternary fault (Plafker et al., 1994)
- Quaternary-active fault, Koehler et al. (2012), and this study
- Volcanoes
- 15,000 — Depth of Cook Inlet Basin, 5,000-foot contours (modified from Schellenbaum et al., 2010)

REGIONAL FAULT MAP
LNG FACILITIES
ALASKA LNG PROJECT
NIKISKI, ALASKA

PLATE 5

 P:\Projects\10_0000\10_160001_AKLNG_2016\05_Graphics\04.10160001_Seismic_Engineering_Update\Tsunami_Report\05_D-18_Tectonic_Overview.mxd; j.holmberg; 10/26/2016



Legend

Modeled Surface Projection of Blind Fault Tip-Line

F3 — Based on mapping of seismic reflection data; arrow shows direction of dip

F1 — Based on Koehler (2012); arrow shows direction of dip

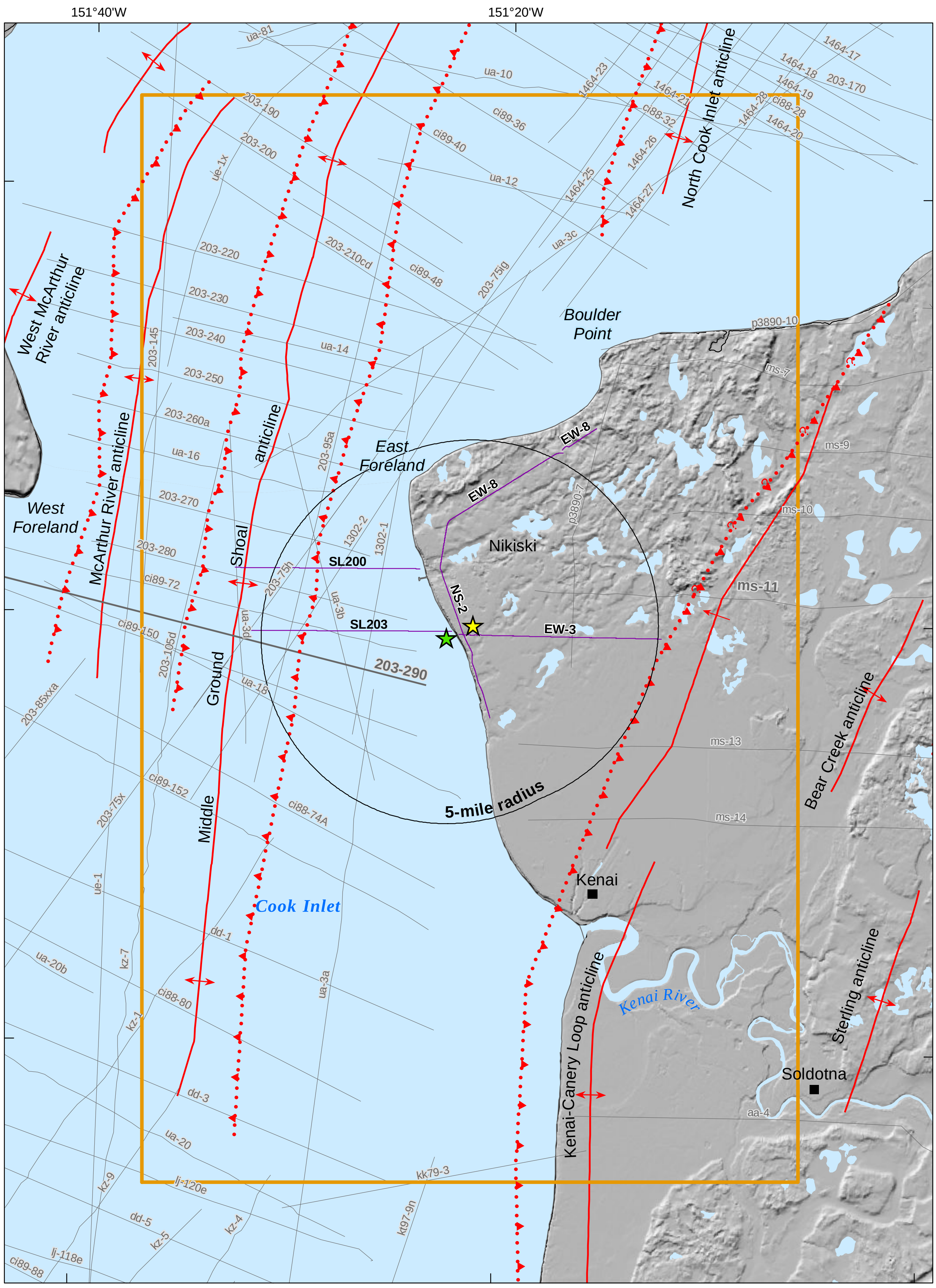
Depth of Cook Inlet Basin, 5,000-foot Contours (modified from Schellenbaum et al., 2010)

- Dashed where approximate
- Solid where well located
- Interpolated

COOK INLET FAULT-CORED FOLD SOURCE MODEL

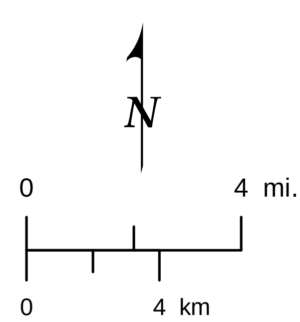
LNG FACILITIES
ALASKA LNG PROJECT
NIKISKI, ALASKA

PLATE 6



Legend

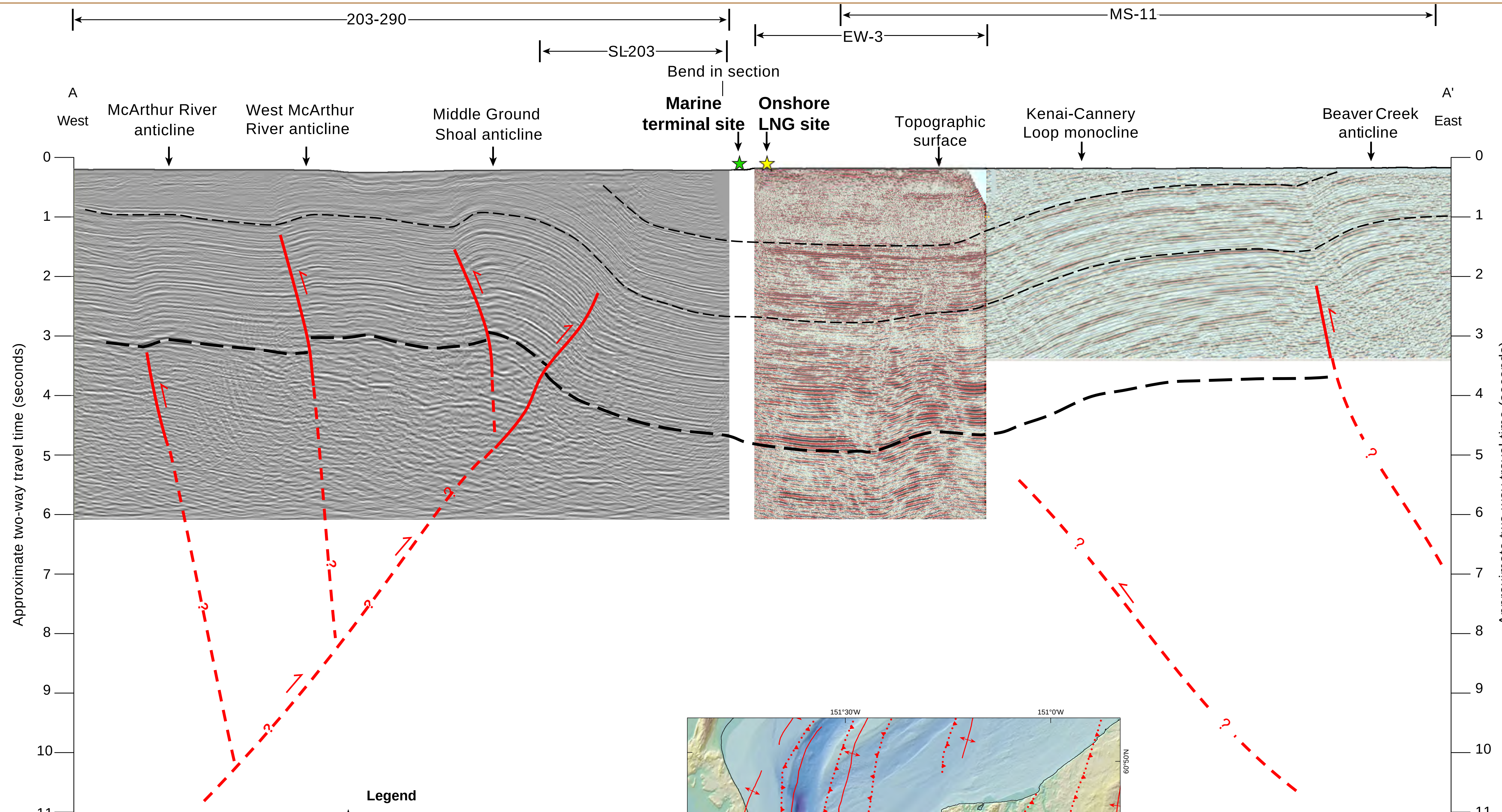
- Onshore LNG site center
- Marine terminal site center
- Extent of structural mapping
- Blind thrust fault, teeth on upper plate, queried where uncertain
- Monocline axis
- Anticline axis
- Industry seismic reflection line (bold profile line IDs shown in report)
- Fugro 2015 seismic reflection line (bold profile line IDs shown in report)



FOLDS AND FAULTS MAPPED FROM SEISMIC REFLECTION DATA

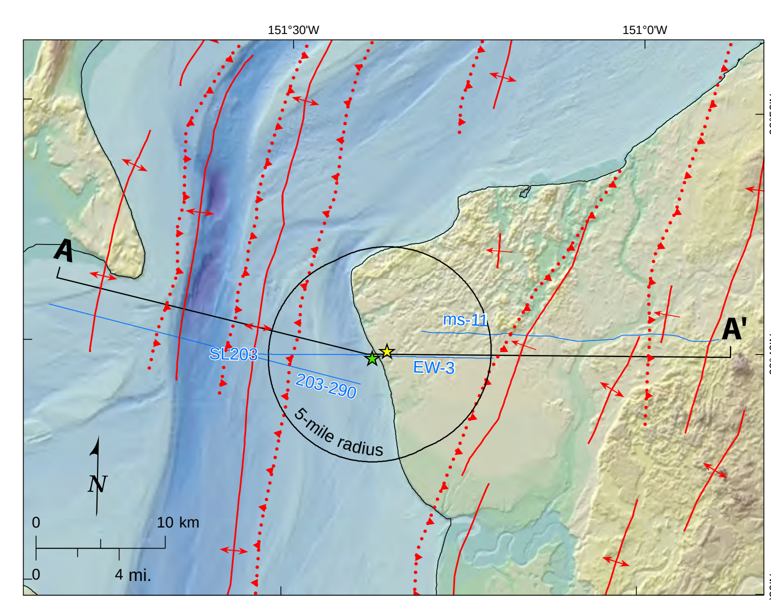
LNG FACILITIES
ALASKA LNG PROJECT
NIKISKI, ALASKA

PLATE 7



Legend

- Marine terminal site
- Site center
- Structural form line within undifferentiated Tertiary units
- Top of Mesozoic basement
- Faults; dashed where inferred



The information contained herein is ConocoPhillips "independent information," as defined in the June 30 2014 Alaska LNG Project Pre-FEED Joint Venture Agreement ("Pre-FEED JVA"), and is provided to Lead Party subject to the Pre-FEED JVA solely for the purpose of geohazard analysis, including probabilistic seismic hazard analysis, to support the Alaska LNG project's FERC filings.

Notes:
1. For conceptual purposes only.
2. Horizontal and vertical are not to scale.

CONCEPTUAL CROSS SECTION OF UPPER COOK INLET BASIN AT THE LATITUDE OF THE SITE
LNG FACILITIES
ALASKA LNG PROJECT
NIKISKI, ALASKA

PLATE 8

ALASKA LNG

Alaska LNG Liquefaction Plant
Natural Gas Turbines
Carbon Capture and Sequestration Cost-Effectiveness

Cost Quantification:

Cost Category	Project Cost	Default Estimate	Default Applied	Estimate Basis	Reference
Direct Capital Costs					
Capture and Compression	$3,784,325,773		-	See Calculation Below	See References Below
Transport	$343,676,927				
Storage	$890,081,703				
Total Capital Investment	**$5,018,084,403**		-	**TCI**	
Direct and Indirect Annual Costs					
Total Direct and Indirect Annual Costs	**$192,665,300**		-	**DAC + IDAC**	
Capital Recovery Cost					
Equipment Life (years)		25	-	n	Golden Pass PSD Application. Reference below.
Interest Rate	7.00%	7.00%	-	i	7% per Agrium US Inc, Kenai Nitrogen Operations Facility Air Quality Control Construction Permit AQ0083CPT06
Capital Recovery Factor	0.0858		-	CRF = i/(1-(1+i)^-n)	-
Capital Recovery Cost (CRC)	**$430,604,418**		-	**CRC**	OAQPS Eqn 2.54 (Section 4.2, Ch. 2)
Total Annual Costs	**$623,269,718**		-	**TAC = DAC + IDAC + CRC**	OAQPS Eqn 2.56 (Section 4.2, Ch. 2)

Cost Effectiveness Analysis:

		Reference
Uncontrolled Turbine CO2 (tpy)	4,199,705	
Controlled Turbine CO2 (tpy)	419,970	90% Capture and Control Efficiency
CO2 Emissions Avoided (tpy)	3,779,734	= Uncontrolled - Controlled Emissions
Total Annual Costs	$623,269,718	TAC
Cost Effectiveness ($/ton/yr)	**$165**	OAQPS Eqn 2.58 (Section 4.2, Ch. 2)

Capital and Operation and Maintenance Cost Calculations

		Capital Costs			Annual Costs
	Uncontrolled CO2 (tons/day)	Capture and Control	Transport	Storage	Op. and Maint.
Liquefaction Plant Gas Turbines	11,506	$ 3,784,325,773	$ 343,676,927	$ 890,081,703	$ 192,665,300
Capture Study (Cost Data in 2010 dollars)	12,179	$ 3,631,800,000	[redacted]		$ 184,900,000
Golden Pass LNG Project (Cost Data in 2014 dollars, adjusted by DOD Alaska pricing factor of 2.2)	13,519	$ 3,809,216,899	$ 382,936,789	$ 991,760,000	[redacted]

1. CO2 Capture Study data are from "USAG-WD-PRTEC-000045, Alaska Pipeline Project Gas Treatment Plant CO2 Capture Study, March 18, 2010."
2. Golden Pass LNG Project data are from "Golden Pass Products LNG Export Project - Application for a Prevention of Significant Deterioration (PSD) for Greenhouse Gas Emissions, June 2014." Cost data have been adjusted to reflect Alaska conditions by the cost factor (2.2) in "DOD Area Cost Factors (ACF) PAX Newsletter No. 3.2.1, dated 25 MAR 2015 Table 4-1, UFC 3-701-01, Change 7, March 2015."
3. Liquefaction Plant Costs estimated based on the CO2 Capture Study (Capture and Control, and Op. and Maint.) or Golden Pass LNG Project (Transport, and Storage) costs. Costs adjusted by the uncontrolled turbine emission rate and converted to 2019 dollars.
4. Chemical Engineering Plant Cost Index (CEPCI) was used to adjust all cost data.