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BEFORE THE GUAM PUBLIC UTILITIES COMMISSION

IN THE MATTER OF:

LIQUIFIED NATURAL GAS (LNG)

GPA DOCKET NO. 23-17

**GUAM POWER AUTHORITY'S
SUBMISSION OF FINAL PHASE 1
LIQUIFIED NATURAL GAS REPORT**

In accordance with paragraph 1 of the ordering provisions of the Guam Public Utilities Commission's Order of November 30, 2023, in the above-referenced docket, the Guam Power Authority (GPA) hereby submits the Engineering, Procurement, and Construction Management – LNG Pre-Development Phase, Phase I – Final Report from Stanley Consultants and K&M Advisors.

Respectfully submitted this 16th day of July, 2025.

Attorney for Guam Power Authority

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July 14, 2025

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Engineering, Procurement, and Construction Management – LNG Pre-Development Phase – Final Report

Dear Stanley Team,

I am pleased to submit K&M's final report for the LNG Pre-Development Phase. Please do not hesitate to contact me with any questions or clarifications.

Yours sincerely,



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Engineering, Procurement, and Construction Management – LNG Pre-Development Phase

Phase 1 – Final Report

July 2025



Table of Contents

1	Abbreviations	xii
2	Executive Summary	2
3	Introduction	8
4	Task 1 – LNG Demand Analysis	11
4.1	LNG Demand Estimate Methodology	11
4.2	Modeling Assumptions	13
4.2.1	Peak Load Growth and Load Curve Assumptions	14
4.2.2	Generation Sources Assumptions	15
4.2.3	System Operating Reserve Assumptions	20
4.2.4	Renewable Generation Scenarios	20
4.3	Results of the LNG Demand Analysis	24
4.3.1	LNG Demand Results – GPA Target	24
4.3.2	LNG Demand Results – Renewable Generation Scenarios	27
4.4	Conclusions	31
5	Task 2 – LNG Sourcing and Shipping Options	33
5.1	LNG Sourcing and Shipping Options	33
5.1.1	LNG Sourcing	33
5.1.2	Consultation with Potential LNG Suppliers	35
5.1.3	LNG Shipping Options	36
5.2	Estimated LNG Prices	37
5.2.1	Estimated Unit Freight Costs (UFC)	37
5.2.2	Estimated Freight on Board (FOB) Prices	41
5.2.3	Estimated Delivered Ex-Ship (DES) Prices	44
5.3	LNG Storage Tank Capacity	46
5.4	Conclusions	47
6	Task 3 – Least-Cost LNG Terminal Site and Configurations	49
6.1	Methodology	49
6.1.1	Modeling Assumptions	51
6.2	Site Descriptions	53
6.2.1	Tanguisson	54
6.2.2	Hotel Wharf	55
6.2.3	Dry Dock Island	55
6.3	LNG Terminal Functional Requirements	56
6.3.1	Minimum Storage	56
6.3.2	Floating Storage Solutions	56
6.3.3	LNG Carriers	56
6.3.4	Support Vessels	56

6.3.5	LNG Deliveries Per Month	57
6.3.6	Exclusion and Safety Zones	58
6.3.7	LNG Bunkering	58
6.4	LNG Terminal Configurations	59
6.4.1	Tanguisson Site Options	59
6.4.2	Hotel Wharf Options	61
6.4.3	Dry Dock Island	66
6.5	Results of Least-Cost Terminal Configuration Analysis	71
6.5.1	Class V Cost Estimation Results	71
6.5.2	Class V Levelized Cost of Gas (LCOG) Results	71
6.5.3	Class V Levelized Cost of Bunkering	72
6.5.4	Cost and Non-Cost Evaluation of the Options	73
6.5.5	Analysis of Comparison Results	74
6.6	Analysis of Shortlisted Options	74
6.6.1	Analysis of the Tanguisson LNG Terminal Option	74
6.6.2	Analysis of the Hotel Wharf LNG Terminal Option	80
6.7	Conclusions	82
7	Task 4.1 – Economic Cost-Benefit Analysis	86
7.1	Methodology	86
7.2	Modeling Assumptions	87
7.2.1	Model Period	87
7.2.2	Macroeconomic Assumptions	87
7.2.3	Discount Rate	88
7.2.4	Import Terminal	88
7.2.5	Gas Demand	88
7.2.6	Fuel Prices	89
7.2.7	GUPP Fixed Charges	92
7.2.8	Emissions Accounting	92
7.2.9	Model Sensitivities	95
7.3	Economic Cost Benefit Analysis	96
7.3.1	Direct Benefits	97
7.3.2	Indirect Benefits	97
7.3.3	Direct Costs	98
7.3.4	Indirect Costs	98
7.4	Results	99
7.4.1	Results with Sensitivities	100
7.5	Conclusions	102
8	Task 4.2 – Ratepayer Impact Analysis	103
8.1	Methodology	103
8.1.1	End-User Rate Composition	103

8.1.2	Fuel Recovery Charge Calculation	104
8.2	Model Assumptions and Sensitivities	106
8.2.1	Model Period	106
8.2.2	Demand Scenarios	106
8.2.3	Thermal Generation	106
8.2.4	Renewable Energy Price	106
8.2.5	Fuel Prices	106
8.2.6	Rate Schedule Assumptions	107
8.2.7	Fixed O&M Charges	107
8.2.8	Civilian Portion	108
8.2.9	Transmission Portion	108
8.2.10	Sensitivities	108
8.3	Results	109
8.3.1	Forecasted Generation Expense	109
8.3.2	Forecasted Fuel Recovery Charge	110
8.3.3	Sample Customer Monthly Bills	111
8.3.4	Cost Savings	113
8.3.5	Sensitivity Analysis	114
8.4	Conclusions	115
9	Task 5.1 & 5.2 – Legal Analysis & Business Model Comparison	118
9.1	Legal Analysis	118
9.1.1	Background	118
9.1.2	Issues Addressed by the Legal Opinion	119
9.1.3	Legal Opinion Conclusions	119
9.1.4	Impact of the Legal Opinion on the Business Model Options	119
9.2	Business Model Options	120
9.2.1	Business Model Option 1 (with Resale)	121
9.2.2	Business Model Option 1a (without Resale)	122
9.2.3	Business Model Option 2 (with Resale)	123
9.2.4	Business Model Option 3 (with Resale)	124
9.2.5	Business Model Option 3a (without Resale)	125
9.2.6	Business Model Option 4 (with Resale)	126
9.2.7	Business Model Option 5 (without Resale)	127
9.2.8	Business Model Option 6 (without Resale)	128
9.3	Evaluation of Business Model Options	128
9.3.1	Methodology for Option Comparison	128
9.3.2	Evaluation Results	130
9.4	Risk Allocation of the Preferred Business Model	132
9.4.1	Risk Allocation and Mitigation Strategy	132
9.4.2	Risk Identification	132
9.4.3	Risk Analysis	132

9.4.4	Risk Allocation and Structuring	133
9.4.5	Risk Mitigation and Management	133
9.4.6	Risk Matrix	135
9.5	Conclusions	142
10	Task 5.3 – Financial Analysis of the Gas Supply Company	143
10.1	Methodology	143
10.2	Modeling Assumptions	144
10.2.1	Model Period	144
10.2.2	Macroeconomic Assumptions	145
10.2.3	Required Equity Return	145
10.2.4	Project Revenues	146
10.2.5	Gas Demand	146
10.2.6	DES LNG Price	147
10.2.7	Project CAPEX & OPEX	147
10.2.8	Depreciation	147
10.2.9	Taxes	147
10.2.10	Inventory	147
10.2.11	Days Receivable / Payable	148
10.2.12	Financing Terms	148
10.2.13	Debt Repayment Terms	148
10.2.14	Sensitivities	148
10.3	Results of the Financial Analysis	149
10.3.1	Results	149
10.3.2	Results with Sensitivities	150
10.3.3	CAPEX	150
10.3.4	Brent	151
10.3.5	Debt Amortization Period	151
10.3.6	Debt-to-Equity Ratio	153
10.4	Conclusions	153
11	Task 6 – Consultations with Industry, Guam Stakeholders, and Guam and Federal Regulatory Authorities	156
11.1	Methodology & Approach	156
11.2	Stakeholder Mapping	157
11.3	Results of Stakeholder Consultations	158
11.3.1	Expansion of LNG Volumes	158
11.3.2	LNG Terminal Site: Security & Technical Considerations	159
11.3.3	Business Model / Commercial Arrangement	160
11.3.4	Permitting and Regulation	161
11.4	Conclusions	162
12	Task 7 – Environmental, Cultural, and Construction Permits Survey	164

12.1	Methodology & Approach	164
12.2	Summary of Major Permits, Approvals, and Consultations	164
12.3	Federal and Local Guam Agencies	167
12.3.1	Federal Agencies	168
12.3.2	Local Guam Agencies	171
12.4	National Environmental Policy Act (NEPA) Process	174
12.4.1	NEPA - LNG Terminal	175
12.4.2	NEPA - Natural Gas Pipeline	176
12.4.3	NEPA – Natural Gas Sendout Pipeline	177
12.5	Conclusion	177
13	Conclusions and Recommendation: Go – No Go Decision	180
13.1	Conclusions	180
13.2	Recommendations	181

Appendices

Appendix A : Brent Curve & Levelized Cost Calculation	183	
Appendix B : Battery Duration Analysis	184	
Appendix C : Feedback from Potential LNG Suppliers and Service Providers	186	
Appendix D : Market Summary Issued to Potential LNG Suppliers	192	
Appendix E : Vessel Particulars for Small-Scale LNG Carriers	196	
Appendix F : Feasibility of Using Cold Natural Gas for Gas Turbine Inlet Air Cooling	200	
Appendix G : Safety & Exclusion Zones	202	
G.1	Regulatory Background	202
G.2	Exclusion Zone Determination	202
G.3	Thermal Radiation Modeling Results	203
G.3.1	Dry Dock Island	203
G.3.2	Hotel Wharf	204
G.3.3	Tanguisson	205
Appendix H : Metocean, Mooring, and Wave Height Analysis at Tanguisson	207	
H.1	Metocean Assessment	207
H.2	Mooring and Wave Height Analysis	207
H.3	Accuracy	209
H.4	Results Summary	209
H.5	Conclusions	210
Appendix I : LNG Transfer Mechanisms at Tanguisson	211	
I.1	LNG Transfer Mechanisms	211
I.1.1	Semisubmersible Vessel	211

I.1.2	Permanent Transfer Tower	212
I.2	Horizontal Directional Drill	213
Appendix J : Bunkering Consultation Results		214
Appendix K : Legal Opinion		216
Appendix L : Market Summary Issued to Guam Stakeholders		225
Appendix M : Feedback from Stakeholders		230
Appendix N : Permitting Matrix		235
Appendix O : Implementation Schedule		241

List of Tables

Table 4.1:	Existing Thermal Units	15
Table 4.2:	Merit Order Adjustments	16
Table 4.3:	Gas Units	17
Table 4.4:	Renewable Capacity Additions – GPA Target	18
Table 4.5:	BESS Capacity Additions – GPA Target	19
Table 4.6:	Renewable Capacity Additions – Guam Public Law	21
Table 4.7:	BESS Capacity Additions – Guam Public Law	21
Table 4.8:	Renewable Capacity Additions – Delayed Renewable Generation Expansion	23
Table 4.9:	BESS Capacity Additions – Delayed Renewable Generation Expansion	23
Table 5.1:	LNG Terminals Capable of Loading Small-Scale LNG Carriers	33
Table 5.2:	Estimated UFCs (\$/MMBtu, HHV Basis)	38
Table 5.3:	Estimated Number of LNG Carriers Required	39
Table 5.4:	Estimated Number of Cargo Deliveries per Annum	40
Table 5.5:	Estimated Frequency of Cargo Deliveries (Days)	40
Table 5.6:	Estimated Days (Go-Return) for One Voyage	40
Table 5.7:	Estimated Alpha Fixed Element for 'In-Tank' LNG Prices	43
Table 5.8:	Estimated 'In-Tank' LNG Prices	43
Table 5.9:	Estimated Storage, Handling, and Reloading Fees	43
Table 5.10:	FOB Prices at \$75 Brent	44
Table 5.11:	Estimated DES LNG Price at \$75 Brent	45
Table 5.12:	Estimated Required Tank Capacity	47
Table 6.1:	Non-Cost Evaluation Matrix	49
Table 6.2:	DES Price of LNG - 174,000 m ³ (Gladstone)	53
Table 6.3:	FSU Specifications	56
Table 6.4:	Support Vessels	56

Table 6.5:	LNG Deliveries Per Month	57
Table 6.6:	Configurations Summary	59
Table 6.7:	Class V CAPEX and OPEX Estimates	71
Table 6.8:	Class V Levelized Cost of Bunkering (USD / MMBtu)	72
Table 6.9:	Cost and Non-Cost Evaluation of the Options	73
Table 6.10:	Tanguisson - Class IV Cost Estimation Results	77
Table 6.11:	LNG Delivery Windows	79
Table 6.12:	Hotel Wharf - Class IV Cost Estimation Results	81
Table 6.13:	Selected LNG Terminal Sites and Configurations	82
Table 7.1:	LNG Supply Solution Assumptions	91
Table 7.2:	Carbon Dioxide Equivalents	92
Table 7.3:	Increase in Health Outcomes from Baseline Incidences in Guam	94
Table 7.4:	Summary of Baseline Health Incidence	95
Table 7.5:	Summary of Health Costs	95
Table 7.6:	Overview of the Project's Economic Costs and Benefits	96
Table 7.7:	CBR Sensitivity to Brent Price and Supply Solution	101
Table 7.8:	Results of the Combined Sensitivities	101
Table 8.1:	LNG Terminal Recovery Charge and LCOG by Demand Scenario	107
Table 8.2:	Rate Schedules by Customer Class	107
Table 8.3:	Average Reduction in FRC	109
Table 8.4:	Average Cost Savings by Demand Scenario	114
Table 9.1:	Risk Matrix for the Preferred Business Model	135
Table 10.1:	CAPM Inputs	145
Table 10.2:	Required Storage Capacity and Related Volumes	147
Table 10.3:	Financing Terms for Terminal Loan	148
Table 10.4:	Summary of Key Inputs	149
Table 10.5:	Results	150
Table 10.6:	Results with CAPEX Sensitivity	151
Table 10.7:	Results with Brent Sensitivity	151
Table 10.8:	Results with Debt Amortization Sensitivity	152
Table 10.9:	Results with Debt-to-Equity Sensitivity	153
Table 12.1:	Major Permits, Approvals, and Consultations	164
Table E.1:	Vessel Particulars for Small-Scale LNG Carriers	196
Table E.2:	Vessel Particulars for Floating Storage Units	199
Table G.1:	Inputs for Thermal Radiation Modeling	203

List of Figures

Figure 4.1:	LNG Demand Model Diagram	12
Figure 4.2:	GPA Historical and Projected Peak Load	14
Figure 4.3:	LNG Demand – GPA Target	25
Figure 4.4:	Annual Generation by Technology – GPA Target	26
Figure 4.5:	Weekly LNG Demand	27
Figure 4.6:	LNG Demand – Renewable Generation Scenarios	29
Figure 4.7:	Annual Generation by Technology – Guam Public Law	30
Figure 4.8:	Annual Generation by Technology – Delayed Renewables Generation Expansion	30
Figure 4.9:	LNG Demand Range for Subsequent Tasks	31
Figure 5.1:	Map of LNG Terminals Capable of Loading Small-Scale LNG Carriers	34
Figure 5.2:	Estimated UFCs (\$/MMBtu, HHV Basis)	39
Figure 5.3:	Estimated DES LNG Price at \$75 Brent	45
Figure 6.1:	Model Diagram	50
Figure 6.2:	Three Potential Sites	54
Figure 6.3:	Tanguisson Site Location	54
Figure 6.4:	Hotel Wharf Site Location	55
Figure 6.5:	Dry Dock Island	55
Figure 6.6:	Tanguisson Marine and Onshore Infrastructure	60
Figure 6.7:	Tanguisson Onshore Infrastructure and Pipeline Diagram	61
Figure 6.8:	Configuration 3 - Marine and Onshore Infrastructure	62
Figure 6.9:	Configuration 3 - Onshore Infrastructure	62
Figure 6.10:	Hotel Wharf – Pipeline to Interface	62
Figure 6.11:	Configuration 4 - Marine and Onshore Infrastructure	63
Figure 6.12:	Configuration 4 - Onshore Infrastructure	64
Figure 6.13:	Configuration 5 - Marine and Onshore Infrastructure	65
Figure 6.14:	Configuration 5 - Onshore Infrastructure	66
Figure 6.15:	Configuration 6 - Marine and Onshore Infrastructure	67
Figure 6.16:	Configuration 6 - Onshore Infrastructure	67
Figure 6.17:	Dry Dock Island – Pipeline to Interface	68
Figure 6.18:	Configuration 7 – Marine and Onshore Infrastructure	68
Figure 6.19:	Configuration 7 – Onshore Infrastructure	69
Figure 6.20:	Configuration 8 – Marine and Onshore Infrastructure	70
Figure 6.21:	Configuration 8 – Onshore Infrastructure	70
Figure 6.22:	Class V Levelized Cost of Gas (LGOG) to GUPP by Component	72

Figure 6.23:	Class V Levelized Cost of Gas (LCOG) by Demand Scenario	72
Figure 6.24:	Tanguisson Layout – Marine and Onshore Infrastructure	75
Figure 6.25:	Tanguisson – Onshore Infrastructure	76
Figure 6.26:	Onshore Pipeline – Tanguisson to GUPP	76
Figure 6.27:	Tanguisson - LCOG by Demand Scenario	77
Figure 6.28:	Tanguisson – Breakdown of LCOG for GPA Target Scenario	77
Figure 6.29:	Hotel Wharf – Marine and Onshore Infrastructure	80
Figure 6.30:	Hotel Wharf – Onshore Infrastructure	81
Figure 6.31:	Hotel Wharf - LCOG by Demand Scenario	82
Figure 6.32:	Hotel Wharf – Breakdown of LCOG for GPA Target Scenario	82
Figure 6.33:	Implementation Schedule – Tanguisson	84
Figure 7.1:	ECBA Model Diagram	87
Figure 7.2:	Gas Demand by RE Scenario	89
Figure 7.3:	Unit Freight Cost – GPA Target – West Papua (10,000 m ³ Vessel)	91
Figure 7.4:	Unit Freight Cost – Guam Law – West Papua (10,000 m ³)	91
Figure 7.5:	Unit Freight Cost – Delayed RE – West Papua (10,000 m ³)	92
Figure 7.6:	Greenhouse Gas Emissions at GUPP: ULSD vs. Natural Gas	93
Figure 7.7:	Shadow Carbon Pricing	93
Figure 7.8:	Percentage Increase in Health Outcomes from Local Emissions	94
Figure 7.9:	Brent Price Projections (2031 – 2050)	95
Figure 7.10:	Results of the ECBA by Demand Scenario	100
Figure 7.11:	Results with LCODG	102
Figure 8.1:	Rate Schedule Composition	104
Figure 8.2:	Fuel Recovery Charge Calculation Diagram	105
Figure 8.3:	Brent Price Sensitivity (2031 – 2050)	108
Figure 8.4:	Total Generation Expense – GPA Target	109
Figure 8.5:	Total Generation Expense – Guam Law	110
Figure 8.6:	Total Generation Expense – Delayed RE	110
Figure 8.7:	Fuel Recovery Charge – GPA Target	111
Figure 8.8:	Fuel Recovery Charge – Guam Law	111
Figure 8.9:	Fuel Recovery Charge – Delayed RE	111
Figure 8.10:	Residential Bill Calculation – GPA Target	112
Figure 8.11:	General Service Bill Calculation – GPA Target	112
Figure 8.12:	Residential Bill for 1000 kWh Consumption – GPA Target	113
Figure 8.13:	Residential Bill for 1000 kWh Consumption – Guam Law	113
Figure 8.14:	Residential Bill for 1000 kWh Consumption – Delayed RE	113

Figure 8.15:	FRC Reduction due to LNG Import in 2031	114
Figure 8.16:	Fuel Recovery Charge by Commodity Price in 2031	115
Figure 9.1:	Business Model Options with Resale	120
Figure 9.2:	Business Model Options without Resale	121
Figure 9.3:	Diagram of Business Model Option 1 (with Resale)	121
Figure 9.4:	Diagram of Business Model Option 1a (without Resale)	122
Figure 9.5:	Diagram of Business Model Option 2 (with Resale)	123
Figure 9.6:	Diagram of Business Model Option 3 (with Resale)	124
Figure 9.7:	Diagram of Business Model Option 3a (without Resale)	125
Figure 9.8:	Diagram of Business Model Option 4 (with Resale)	126
Figure 9.9:	Diagram of Business Model Option 5 (without Resale)	127
Figure 9.10:	Diagram of Business Model Option 6 (without Resale)	128
Figure 9.11:	Evaluation Matrix of Options with Resale	130
Figure 9.12:	Evaluation Matrix of Options without Resale	131
Figure 9.13:	Risk Allocation and Structuring Process Diagram	133
Figure 10.1:	Gas Supply Company Financial Structure	144
Figure 10.2:	Brent Price Sensitivity (2031 – 2050)	149
Figure 10.3:	Operating Revenues and Costs – GPA Target	152
Figure 10.4:	Operating Revenues and Costs – Guam Law	152
Figure 10.5:	Operating Revenues and Costs – Delayed RE	153
Figure 11.1:	Timeline of Consultations	157
Figure 11.2:	Stakeholder Mapping	158
Figure 12.1:	NEPA Process	175
Figure A.1:	Brent Curve (2031 – 2050)	183
Figure B.1:	LNG Demand – Battery Duration Sensitivities	185
Figure E.1:	Avenir Ascension	197
Figure E.2:	Coral Favia	197
Figure E.3:	Coral Energy	198
Figure E.4:	Coral Energy	199
Figure E.5:	Alto Acruz	199
Figure F.1:	Inlet Air Cooling Arrangement Option 1	200
Figure F.2:	Inlet Air Cooling Arrangement Option 2	200
Figure G.1:	Dry Dock Island Thermal Radiation Exclusion Zone (Tank Top Fire)	204
Figure G.2:	Hotel Wharf Thermal Radiation Exclusion Zone (Tank Top Fire)	205
Figure G.3:	Tanguisson Thermal Radiation Exclusion Zone (Tank Top Fire)	206
Figure I.1:	EConnect Platform attached to an LNGC during a Transfer Operation	211

Figure I.2:	EConnect IQuay C-Class Configuration at Tanguisson	212
Figure I.3:	Conceptual Sketch of Transfer Tower Solution at Tanguisson	213
Figure P.1:	Full Implementation Schedule – Tanguisson	242

List of Boxes

Box 7.1: ULSD Price Forecast	90
Box 7.2: Alternative Revenue StructureBox 7.3: ULSD Price Forecast	90
Box 10.1: Alternative Revenue Structure	146

1 **Abbreviations**

BESS – Battery Energy Storage Systems
CAPEX – Capital Expenditures
CBR – Cost-Benefit Ratio
CCPP – Combined Cycle Power Plant
DES – Delivered Ex-Ship
DOD – U.S. Department of Defense
DOE – U.S. Department of Energy
DOT – U.S. Department of Transportation
ECBA – Economic Cost-Benefit Analysis
FAA – Federal Aviation Administration
FERC – Federal Energy Regulatory Commission
FOB – Freight on Board
FRC – Fuel Recovery Charge
FSU – Floating Storage Unit
GHG – Greenhouse Gas
GPA – Guam Power Authority
GSA – Gas Supply Agreement
GUPP – Guam Ukudu Power Plant
HDD – Horizontal Directional Drilling
HHV – Higher Heating Value
IRP – Integrated Resource Plan
LCOG – Levelized Cost of Gas
LNG – Liquefied Natural Gas
LHV – Lower Heating Value
MMBtu – Million British Thermal Units
NEPA – National Environmental Policy Act
NFPA – National Fire Protection Association
O&M – Operations and Maintenance
OPEX – Operational Expenditures
PHMSA – Pipeline and Hazardous Materials Safety Administration
PUC – Public Utilities Commission

RE – Renewable Energy

SOFR – Secured Overnight Financing Rate

tpa – Tonnes per Annum

UFC – Unit Freight Cost

ULSD – Ultra Low Sulfur Diesel

USD – United States Dollar

USACE – U.S. Army Corps of Engineers



Executive Summary

2 Executive Summary

Guam Power Authority (GPA) engaged Stanley Consultants and a K&M Advisors-led team¹ in April 2024, to conduct Phase I of an LNG infrastructure development study, following the scope outlined in the Public Utilities Commission's (PUC) approved order in November 2023. The primary objective of Phase I is to assess whether transitioning to LNG for power generation in Guam is technically feasible, economically viable, and in the ratepayers' interest. This assessment includes LNG demand forecasting, LNG sourcing and shipping analysis, terminal configuration and costing, economic cost-benefit analysis (ECBA), ratepayer impact assessment, business model evaluation, financial viability analysis of the gas supply company, stakeholder consultations, and permitting review.

➔ **The conclusions of Phase I culminate in a recommendation to proceed with LNG infrastructure development.**

The following sections summarize the key findings of each task presented in the body of this report.

Task 1: LNG Demand Forecasting

Accurately estimating LNG demand for the Guam Ukudu Power Plant (GUPP) over the next 25 years is central to the study, as this informs supply sourcing, shipping, terminal configuration, and project economics. Using a 20-year hourly dispatch model, K&M estimated gas demand under varying renewable energy (RE) deployment scenarios, acknowledging the uncertainty in the pace and scale of RE adoption in Guam. The scenarios include achieving the highest practicable RE penetration by 2040 (GPA Target scenario), achieving the highest practicable RE penetration by 2045 (Guam Law scenario), and a scenario with delayed RE penetration (Delayed RE scenario). The main results are as follows:

- LNG demand peaks at approximately 124,000 tonnes per annum (tpa) in 2035 and falls to 33,000 tpa by 2050 under the GPA Target scenario.
- The Guam Law and Delayed RE scenarios also follow a similar declining trend: Guam Law (152,000 tpa in 2035 and 33,000 tpa in 2050), Delayed RE (168,000 tpa in 2032 and 89,000 tpa in 2050).

Task 2: LNG Sourcing and Shipping Evaluation

K&M identified LNG sourcing and shipping options to determine the least-cost and most practical supply solution for Guam. The preferred approach involves importing LNG from West Papua (Tangguh LNG) using a 10,000 m³ small-scale LNG carrier. This solution balances cost, logistics, and demand variability.

- LNG sourced from West Papua and shipped in 10,000 m³ LNG carriers would result in an LNG delivered ex-ship (DES) cost between \$11.50–17.40 per MMBtu, depending on the LNG annual throughput (assuming Brent at \$75/bbl)
- On average, 3 to 4 10,000 m³ LNG cargo deliveries per month will be required during the peak demand years

¹ The K&M Advisors-led team includes GHD (covering marine studies and infrastructure) and CH-IV International (covering LNG handling, storage, and regasification facilities)

- A second 10,000 m³ vessel would be required in years when LNG demand exceeds 170,000 tpa, which only happens in the Delayed RE scenario.
- Further supplier engagement is recommended during procurement to optimize pricing and logistics.

Task 3: LNG Import Terminal Configuration and Costing

K&M assessed technically viable LNG import terminal configurations and siting options. The preferred terminal configuration includes marine infrastructure to moor or berth a 10,000 m³ LNG carrier, unloading arms and cryogenic lines to transfer LNG from the vessel to the 15,000 m³ full-containment LNG storage tank, ambient vaporizers, and a send-out gas pipeline.

Two sites were identified as technically viable alternatives: Tanguisson and Hotel Wharf in Apra Harbor.

- An LNG terminal at the Tanguisson site will require a CAPEX of approximately \$210 million, including the cost of the pipeline to connect the terminal to GUPP. The Levelized Cost of Delivered Gas for the Tanguisson site is \$20.59/MMBtu—for the delayed RE scenario, assuming Brent at \$119/bbl.² Dismantling the power plant currently at Tanguisson could require a CAPEX between \$10 and 20 million.³ The Tanguisson site is exposed to high wave events that could limit LNG unloading operations; however, the K&M team's analysis concluded that this risk is low.⁴ The land at the Tanguisson site is owned by the U.S. Navy and leased to GPA.
- An LNG terminal in Hotel Wharf would have a CAPEX of \$187 million, including the cost of the gas pipeline to connect to the existing gas pipeline to GUPP. The Hotel Wharf site is inside Apra Harbor and therefore benefits from the breakwater that protects the site from exposure to waves. The Guam Port Authority controls the Hotel Wharf site, which has an existing concrete platform that could be upgraded and repurposed for an LNG terminal. It is unclear whether the Guam Port Authority could commit Hotel Wharf to an LNG terminal.
- The higher CAPEX option—Tanguisson was used for the subsequent financial, economic, and ratepayer analyses. If the transition to LNG is financially and economically viable and in the ratepayers' interest for the Tanguisson site, it would also be for Hotel Wharf because the latter has a lower CAPEX.
- The development (procurement, permitting, design, construction, and commissioning) of an LNG terminal at Tanguisson or Hotel Wharf could take approximately 5 years.

Task 4.1: Economic Cost-Benefit Analysis

² All the levelized cost, economic cost benefit, financial, and ratepayer calculations in this report used the U.S. Energy Information Agency's (EIA) Brent price long-term forecast. This forecast is presented in Appendix A and shows that Brent starts at \$92 in 2031 and increases to \$153 in 2050—the annualized Brent during this period is \$119—using a 5% discount rate. Currently, Brent is at \$64/bbl

³ The dismantling capex has not been included in the analysis of the Tanguisson LNG terminal site because this is a cost that GPA would need to incur independently of the development of an LNG terminal in that site.

⁴ GHD conducted a metocean and mooring analysis with an estimated accuracy of 70%, concluding that the average availability of a 14-hour operational window at Tanguisson is 86.1%.

The ECBA evaluates the economic justification for transitioning GPA's generation from ultra-low sulfur diesel (ULSD) to LNG.⁵

- Switching to LNG in 2031 is economically justified across all gas demand scenarios—the cost-benefit ratio is below 0.87 for all three gas demand scenarios, and is below 1.0 for a Brent price as low as \$35/bbl and a social discount rate as high as 31% for the Delayed RE gas demand scenario.
- The economic benefits are largely driven by the lower per-unit cost of LNG relative to ULSD, with cost savings amplified under higher fuel prices.
- The transition from ULSD to LNG is economically justified insofar as the LNG terminal's CAPEX is less than \$291 million, approximately 1.4 times the \$210 million estimate for Tanguisson.

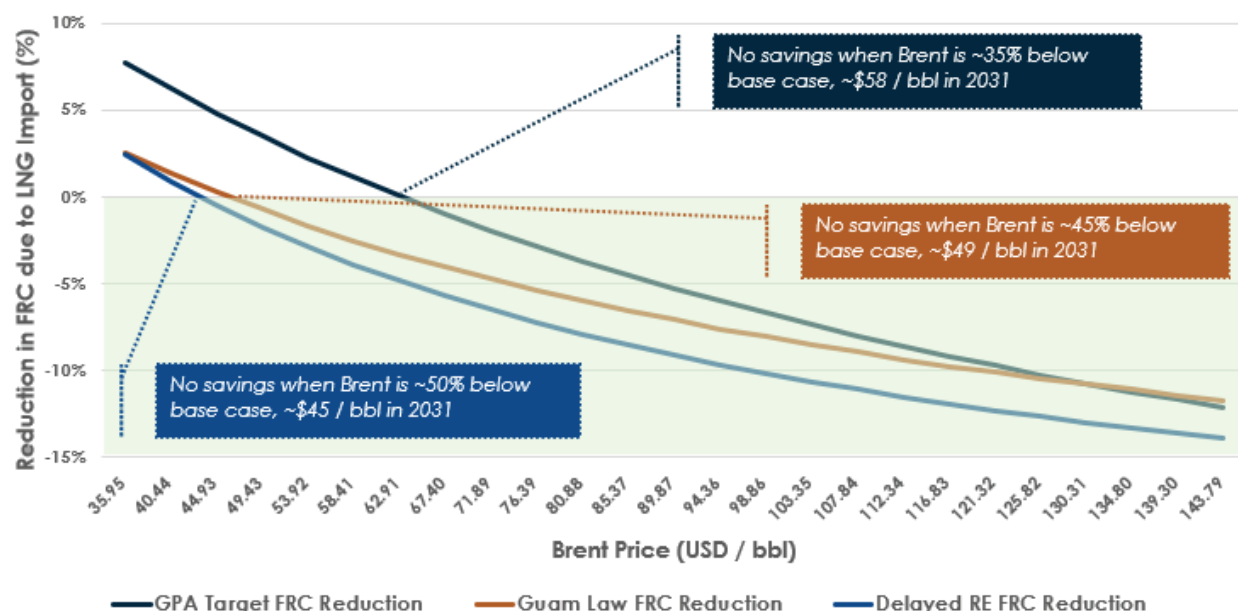
Task 4.2: Ratepayer Impact Analysis

This analysis estimates how the transition to LNG would impact end-user electricity rates.

Item	GPA Target	Guam Law	Delayed RE
Average Reduction in Fuel Recovery Charge	3.8%	7.7%	11.6%
Average Reduction in Total Bill (Residential)	1.2%	3.2%	6.6%
Average Reduction in Total Bill (General Service)	1.0%	2.9%	6.0%

- End-user electricity bills are estimated to decline by 1.0 – 6.6% when GUPP transitions from ULSD to LNG, with greater savings at lower RE penetration levels.
- The Fuel Recovery Charge (FRC)—covering fuel and renewable energy costs is between 4 and 12% lower with LNG use at GUPP than with continued ULSD use.
- Higher Brent prices increase the savings when GUPP uses LNG rather than ULSD. For the most aggressive renewable energy penetration scenario (GPA Target), Brent would need to be consistently below \$58/bbl over the projection period to offset the savings from switching to LNG. For the more realistic renewable energy penetration scenarios (Guam law and Delayed Renewable), Brent would need to be below \$50/bbl to erode savings from switching to LNG. For reference, the average Brent price between 2005 and 2025 was approximately \$74/bbl.

⁵ A project is economically cost-benefit justified if the net economic benefits and economic internal rate of return are greater than zero; or when the cost-benefit ratio is less than one. Economic analysis is different than financial analysis because it includes the benefits and costs of externalities such as CO₂, NO_x, SO_x, and particulate matter emissions.



Task 5.1 & 5.2: Legal Opinion & Business Model Evaluation

The K&M team evaluated various business models for LNG infrastructure development, concluding that a private Gas Supply Company operating under a long-term Gas Supply Agreement (GSA)⁶ offers the best balance of risk and efficiency.

- This model shifts LNG supply and terminal development risks to the private sector, while maintaining legal viability and market flexibility.
- Although private financing results in a higher cost of capital than public financing, competitive procurement can mitigate this impact.
- Under current regulations, the resale of LNG or gas to third parties is not permitted if GPA holds an ownership interest in the supply structure.

Task 5.3: Financial Viability of the Gas Supply Company

K&M estimated the delivered gas price that will make an investment in the LNG terminal bankable. Bankability requires achieving a 1.2 minimum debt-service-cover ratio and a return on equity consistent with the project's risk profile (at or above 8.1%).

- The Levelized Cost of Delivered Gas (LCODG) to GPA will need to be between \$21.43 and \$25.24 per MMBtu (depending on the gas demand scenarios) to make an investment in the LNG terminal bankable.
- The DES cost of LNG and terminal costs (CAPEX and OPEX) are the primary cost drivers.
- The LCODG is sensitive to debt-to-equity ratios and repayment periods, which can be refined in future phases.

Task 6: Stakeholder Consultations

⁶ This report uses the terms Gas Supply Agreement and Gas Sales and Purchase Agreement (SPA) interchangeably

Consultations with LNG developers, Guam stakeholders, and regulatory authorities provided critical insights into project feasibility, site selection, commercial structuring, and permitting risks.

- Apra Harbor (Hotel Wharf) is technically preferred, but the U.S. Navy opposes building an LNG terminal there because of security concerns.
- The U.S. Navy favors the Tanguisson site. Some of the developers consulted expressed concerns about this site's exposure and indicated that they might not bid if it were selected.
- Market appetite for expanding LNG demand (e.g., bunkering) remains limited, constraining project scale. Matson indicated that they would not be interested in bunkering LNG in Guam because they could bunker at a lower cost in other ports.
- Developers broadly supported the preferred business model but highlighted the need for a long-term contract (20–25 years) to reduce the cost of gas and ensure project bankability.
- Due to the project's scale and complexity, regulatory engagement, especially with FERC, will be a key challenge.

Task 7: Permitting Survey

The permitting review assessed key environmental, cultural, and construction permit requirements.

- No major differences were found between the Tanguisson and Hotel Wharf sites regarding federal permitting needs.
- Additional environmental and cultural resource surveys are recommended to identify permitting risks fully.
- Key permitting agencies include FERC, the U.S. Department of Transportation, U.S. EPA, the Army Corps of Engineers, Guam EPA, and the Bureau of Statistics and Plans.

Conclusion

Based on the results of Phase I, transitioning GPA's generation from ULSD to LNG is technically viable, economically justified, and in the ratepayers' interest. These findings support a **“Go”** recommendation to Phase II.

Despite having a slightly higher cost and operational risk, the Tanguisson site and configuration are recommended as the preferred option because they have the Navy's support. Based on the feedback received from the Navy, an LNG import terminal anywhere in Apra Harbor would create a security risk that the Navy cannot accept.

To ensure GUPP can transition to LNG as soon as possible and minimize the penalties in the form of higher fixed O&M charges under the Energy Conversion Agreement (ECA) between GPA and GUPP, Phase II should start with two parallel activities: developing the Request for Proposal (RFP) and performing the site studies required for the Tanguisson site and configuration.



Introduction

3 Introduction

Guam Power Authority engaged Stanley Consultants and a K&M-led team in April 2024 to proceed with Phase 1 of the LNG infrastructure development scope outlined in the PUC-approved order in November 2023. The objective of Phase 1 is to analyze whether the LNG infrastructure is technically feasible, economically justified, and in the ratepayers' interest. To this end, the scope of Phase 1 includes estimating LNG demand for Guam for the next 25 years, identifying the least-cost LNG terminal and infrastructure configuration, estimating the cost of natural gas delivered to the Ukudu Combined Cycle Power Plant (CCPP), and evaluating the economic and financial viability of the LNG infrastructure.

This report presents the findings of Phase 1 and the results in a recommendation for a 'Go' decision regarding the transition to LNG in Guam. The report is organized in thirteen sections, including this introduction and appendices.

- Section 4 presents the results of Task 1 – *LNG Demand Analysis*
- Section 5 presents the results of Task 2 – *LNG Sourcing and Shipping Options*
- Section 6 presents the results of Task 3 – *Least-Cost LNG Terminal Site and Configurations*
- Section 7 presents the results of Task 4.1 – *Economic Cost-Benefit Analysis*
- Section 8 presents the results of task 4.2 – *Ratepayer Impact Analysis*
- Section 9 presents the results of Task 5.1 & 5.2 – *Legal & Business Model Analysis*
- Section 10 presents the results of Task 5.3 – *Financial Analysis of the Gas Supply Company*
- Section 11 presents the results of Task 6 – *Consultation with Industry & Stakeholders*
- Section 12 presents the results of Task 7 – *Permitting Survey*
- Section 13 presents the final recommendation for Phase 1 of this Study
- Appendix A includes assumptions on Brent prices used throughout the study.
- Appendix B includes Battery Duration Analysis as part of Task 1.
- Appendix C includes Feedback from Potential LNG Suppliers as part of Task 2.
- Appendix D includes Market Summary Issued to Potential LNG Suppliers as part of Task 2.
- Appendix E includes Vessel Particulars for Small-Scale LNG Carriers as part of Task 2.
- Appendix F includes information on the use of cold natural gas for cooling as part of Task 3.
- Appendix G includes the full analysis of safety and exclusion zones as part of Task 3.
- Appendix H includes the results of the metocean analysis at Tanguisson as part of Task 3.
- Appendix I includes a discussion of marine infrastructure at Tanguisson as part of Task 3.
- Appendix J includes feedback on bunkering as part of Task 3.
- Appendix K includes Legal Opinion as part of Task 5.1.
- Appendix L includes the Market Summary issued to stakeholders as part of Task 6.
- Appendix M includes feedback on terminal development from stakeholders as part of Task 6.

- Appendix N includes the full permitting matrix as part of Task 7.
- Appendix O includes the full implementation schedule at the terminal sites as part of Task 3.



Task 1

LNG Demand Analysis

4 Task 1 – LNG Demand Analysis

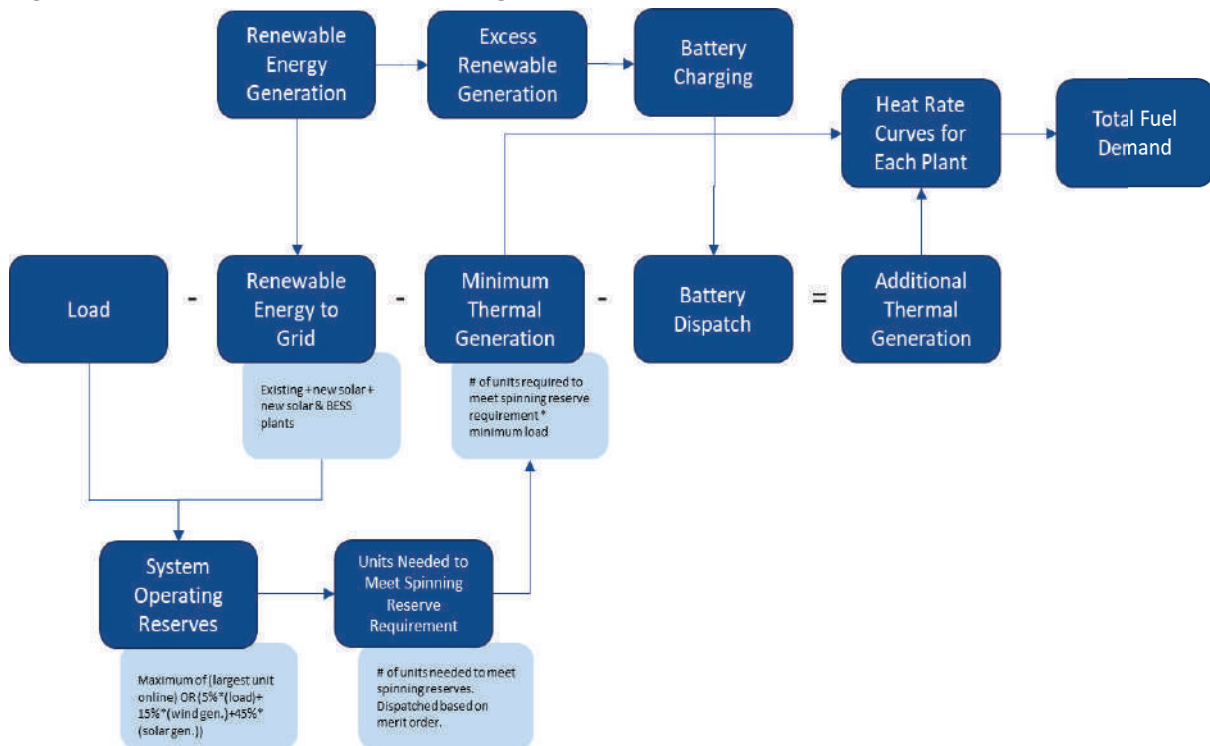
The objective of Task 1 is to estimate a realistic LNG demand for the Guam Ukudu Power Plant (GUPP). This is the most critical input in establishing the feasibility of the LNG infrastructure. The LNG demand estimate drives the selection of the optimal LNG source, shipping, and terminal solution, all of which have a direct impact on the cost of gas delivered at the GUPP. However, estimating LNG in Guam is particularly difficult given the island's ambitious goal of increasing renewable energy generation. Although clear renewable penetration goals have been established by law or by GPA, there is considerable uncertainty around the number, capacity, and timing of new solar and battery energy storage system (BESS) installations. No feasibility studies have been performed yet to demonstrate that there are technical, financial, and economically feasible projects that can realistically be implemented to achieve the goals. This uncertainty is of critical importance in developing the LNG demand estimate. K&M estimated LNG demand using a 20-year hourly dispatch model that K&M built for this purpose, which considers various renewable energy penetration scenarios.

This section presents the LNG demand results for Task 1 of the study. Section 4.1 describes the LNG demand estimate methodology and Section 4.2 presents the modeling assumptions. Section 4.3 presents the LNG demand analysis results. Section 4.4 provides conclusions and recommendations. Appendix B describes how K&M developed the BESS size assumptions.

4.1 LNG Demand Estimate Methodology

To estimate the LNG demand, K&M developed an Excel-based model that calculates the annual LNG demand for the period between 2031 and 2050. The model calculates the GUPP hourly dispatch by subtracting the renewable generation available at that hour from the load. The model also considers the role that BESS would have in providing system operating reserves and minimizing curtailed solar PV generation, both of which could impact the GUPP dispatch. The model estimates LNG demand using the GUPP hourly dispatch and the heat rate guarantee curve in the Energy Conversion Agreement (ECA). The modeling methodology is presented in Figure 4.1.

Figure 4.1: LNG Demand Model Diagram



The detailed sequence of calculations in the model is as follows:

For each hour of the year (totaling 8,760 hours):

- 1 Start with the total system load for the hour.
- 2 Calculate the renewable energy generation available during that hour using the NREL PVWatts software and the expected renewable energy generation from GPA's adjusted 2022 IRP Generation Expansion Plan.
- 3 Calculate the required Operating Reserve for that hour using the following formula:
 - a) Operating Reserve = Maximum of: (capacity of the largest unit online) OR (5% (load) + 15% (wind generation) + 45% (solar generation))⁷
- 4 If there is a thermal spinning reserve requirement, the model will calculate the number of thermal units needed to meet the reserve requirements and associated minimum thermal capacity. For this analysis, the system Operating Reserve is assumed to be covered by the Battery Energy Storage System (BESS)—that is, no thermal spinning reserves are required. As such, the thermal units are not considered part of the Operating Reserve, and the minimum thermal unit capacity equals zero. The model can calculate the minimum thermal capacity if the spinning reserve requirement were to change.
- 5 Calculate the renewable power injected into the grid by comparing the total renewable energy generation available during that hour to the system load. If the renewable energy

⁷ See a detailed description of the formula in Section 4.2.3.

generation available is lower than the load, all renewable energy is injected into the grid; otherwise, the excess renewable energy will charge the BESS. The excess renewable energy value is multiplied by the BESS roundtrip efficiency to calculate the amount of excess renewable energy available to charge the BESS. If the excess renewable energy generation is higher than the load and the BESS is fully charged, the excess generation is curtailed.

- 6 Calculate the energy injected into the grid from the BESS. The BESS is dispatched when solar is not available or when additional power is needed to meet peak load—as described below:
 - a) If the BESS charge at the beginning of the hour minus the minimum between
 - i) BESS capacity in MW,
 - ii) BESS maximum allowable depth of discharge,
 - iii) system load minus renewable injection to the grid and minus the capacity of the thermal operating reserve,
 is above the required annual maximum hourly Operating Reserve, then the BESS power injection to the grid is equal to the minimum between (i), (ii), and (iii) listed above or the BESS charge at the beginning of the hour.
 - b) If the BESS charge at the beginning of the hour minus the minimum of items (i), (ii), and (iii) listed above is less than the required annual maximum hourly Operating Reserve, and the battery charge at the beginning of the hour is more than the required annual maximum hourly Operating Reserve, then the BESS system injection to the grid will be equal to the BESS charge minus the required annual maximum hourly Operating Reserve.
 - c) If the BESS charge at the beginning of the hour is less than the required annual maximum hourly Operating Reserve, then the BESS system injection to the grid for that hour is equal to zero.
- 7 The additional thermal generation required by the GUPP and the existing diesel units (thermal generation other than the Operating Reserve) is calculated as the load minus renewable injection to the grid minus thermal operating reserve minus battery injection to the grid.
- 8 The additional thermal generation is distributed between the thermal units that are operational during that year based on their marginal cost (merit order).
- 9 Fuel (LNG and ULSD) demand is then calculated based on the GUPP load determined during Step 7. The GUPP fuel demand is calculated using the combined cycle plant's capacity, guaranteed heat rates, and guaranteed availability, as specified in the ECA.

These calculation steps are performed on an hourly basis for each year starting in 2028 to the year 2050 with the load increase based on load growth assumptions given in Section 4.2.

4.2 Modeling Assumptions

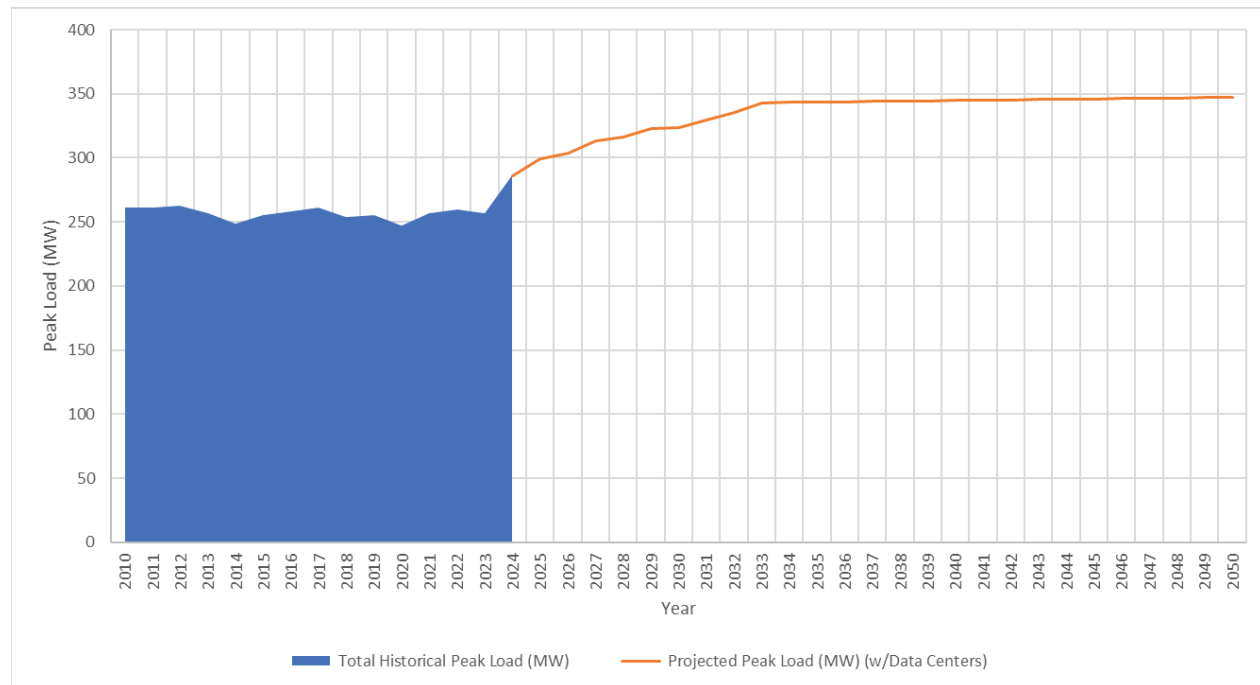
The LNG demand model is built using information provided by GPA as part of the Request for Information (RFI) and discussions between relevant stakeholders during the kickoff meeting. This section outlines the inputs and assumptions made to build the model, along with different scenarios considered for LNG demand estimation.

4.2.1 Peak Load Growth and Load Curve Assumptions

The LNG demand model is built for a period of operation between the years 2031 and 2050. The hourly demand profile for the modeled period is based on actual hourly load curves from 2021-2022 provided by GPA. The hourly load curve from year 2023 was provided as part of the RFI; however, the data was removed from the system load curve analysis due to Typhoon Mawar's impact on the dataset.

The peak load growth forecast for 2031 – 2050 is based on the Utility Financial Solutions (UFS) projected peak loads from 2025-2040 provided by GPA in March 2025, with additional projected data center loads⁸. The peak load growth curve is presented in Figure 4.2.

Figure 4.2: GPA Historical and Projected Peak Load



Source: UFS Load Growth Projections + GPA Data Center Capacity Additions

The peak load grows at an average rate of 1.74% from 2025-2032, primarily due to the expansion of the Navy facilities and installation of data center loads, and 0.08% each year after 2032 through 2050. UFS provided peak load growth projections to the year 2040. K&M used the same load growth of 0.08% for the peak load projection for years 2040-2050. The data center capacity installations are assumed to operate at 95% capacity factor and are added to the overall peak load given in the UFS provided data. The projected peak hourly demand in 2031 is 330 MW, and 347 MW in 2050. This results in a 5% peak load growth from 2031 levels by the year 2050.

⁸ UFS Load Growth Rates provided via email from GPA on 31-Mar-25 – Excel File: Phase 2 Adjustments.xlsx. Data Center installation projections provided by GPA via email on 2-Apr-25.

4.2.2 Generation Sources Assumptions

A critical piece of the LNG demand analysis is how the existing thermal generation and newly installed renewable generation impact the operation of the GUPP on natural gas. The main assumption for this analysis is that the GUPP is the only plant in GPA's system burning natural gas.

4.2.2.1 Diesel Fuel Operation

The primary power generation utilized by GPA is diesel-powered generation. This technology includes boilers with Steam Turbine Generators (STGs), combustion turbines (CTs), and reciprocating engines. The new GUPP and the existing diesel units are presented in Table 4.1. Temporary power from Aggreko is not included in this analysis, as, according to GPA, this facility would be decommissioned in 2026, five years before the start date of the analysis.

Table 4.1: Existing Thermal Units

Unit ID	Merit Order (Rank)	Unit Nameplate Capacity (MW)	Maximum Unit Capacity (MW)	Average Hourly Availability per Year (%)	Available Unit Capacity (MW)	Min Load (MW)	Engines Online (Date)	First Retirement (Date)
GUPP	2	198.0	198.0	96%	190.0	32.5	10/1/2025	10/1/2053
Cabras Unit #1	20	66.0	42.0	52%	22.0	20.0	1/1/2023	3/1/2026
Cabras Unit #2	21	66.0	43.0	30%	13.0	20.0	1/1/2023	3/1/2026
Piti #8	3	44.2	43.0	89%	38.2	18.0	1/1/2023	10/1/2053
Piti #9	4	44.2	43.0	91%	39.1	18.0	1/1/2023	10/1/2053
Dededo CT #1	8	22.0	18.0	90%	16.1	8.0	1/1/2023	10/1/2053
Dededo CT #2	9	23.0	18.0	93%	16.7	8.0	1/1/2023	10/1/2053
Macheche CT	6	22.0	20.0	88%	17.7	8.0	1/1/2023	10/1/2053
Piti #7 CT	7	40.0	23.0	67%	15.5	8.0	1/1/2023	10/1/2053
Yigo CT	5	22.0	20.0	39%	7.8	8.0	1/1/2023	10/1/2053
Manenggon Diesel #1	10	5.3	4.0	96%	3.8	1.0	1/1/2023	10/1/2053
Manenggon Diesel #2	11	5.3	0.0	57%	0.0	1.0	1/1/2023	10/1/2053
Talofofo Diesel #1	12	4.4	4.0	83%	3.3	1.0	1/1/2023	10/1/2053
Talofofo Diesel #2	13	4.4	4.0	22%	0.9	1.0	1/1/2023	10/1/2053
Tenjo Unit #1	14	4.4	3.0	83%	2.5	1.0	1/1/2023	10/1/2025
Tenjo Unit #2	15	4.4	3.0	75%	2.2	1.0	1/1/2023	10/1/2025
Tenjo Unit #3	16	4.4	3.0	65%	2.0	1.0	1/1/2023	10/1/2025
Tenjo Unit #4	17	4.4	0.0	8%	0.0	1.0	1/1/2023	10/1/2025
Tenjo Unit #5	18	4.4	0.0	8%	0.0	1.0	1/1/2023	10/1/2025
Tenjo Unit #6	19	4.4	0.0	8%	0.0	1.0	1/1/2023	10/1/2025

Source: GPA provided information as part of RFI

The source of inputs and assumptions used for the analysis of the diesel units is presented below:

- 1 The merit order presented above is based on the current dispatch of the units as provided by GPA and revised to reflect the projected availability of existing units once GUPP is online and the plan for rehabilitation of the existing units. Table 4.2 highlights the main merit order adjustments made for this analysis, that is reflected in Table 4.1.

Table 4.2: Merit Order Adjustments

Unit ID	Current GPA Merit Order	Revised Merit Order	Reason for Revision
Cabras Unit #1	4	20	Unit planned retirement 6 months after GUPP comes online (GPA IRP)
Cabras Unit #2	5	21	Unit planned retirement 6 months after GUPP comes online (GPA IRP)
Tenjo Unit #4	11	17	Unit planned retired when GUPP comes online due to the capacity and the current operations and maintenance status.
Tenjo Unit #5	12	18	Unit planned retired when GUPP comes online due to the capacity and the current operations and maintenance status.
Tenjo Unit #6	13	19	Unit planned retired when GUPP comes online due to the capacity and the current operations and maintenance status.
Manenggong Diesel #1	17	10	Unit is assumed to be on the rehabilitation schedule for GPA to lower O&M cost.
Manenggong Diesel #2	18	11	Unit is assumed to be on the rehabilitation schedule for GPA to lower O&M cost.
Talofofo Diesel #1	19	12	Unit is assumed to be on the rehabilitation schedule for GPA to lower O&M cost.
Talofofo Diesel #2	20	13	Unit is assumed to be on the rehabilitation schedule for GPA to lower O&M cost.

The remaining diesel units either had no change in their merit order or only shifted one spot lower due to the addition of GUPP operating on gas as the top merit order plant.

- 2 GPA provided the actual maximum unit capacity of the diesel units.
- 3 The unit average hourly availabilities used in the model are the unit availabilities for 2023 provided by GPA.
- 4 The available unit capacity for the existing units is calculated by multiplying the installed unit capacity by the average hourly availability.
- 5 GUPP's available unit capacity for a specific model year is calculated by multiplying installed unit capacity by the guaranteed contractual availability for that year specified in the ECA.
- 6 GPA provided minimum loads for the existing engines.
- 7 GUPP, in coordination with Siemens, provided the minimum load for the GUPP. The minimum load would be approximately 32.5 MW, with one combustion turbine (CT) operating at 50% load (22.5 MW) and a steam turbine (ST) operating at 15% load (10 MW).
- 8 The heat rate coefficients and heat rate exponents for the heat rate curves for existing diesel units are calculated using heat input curves provided by GPA. GUPP heat rate curves for diesel operation are developed based on guaranteed contractual heat rates in the ECA.

- 9 Engine retirements are estimated to ensure adequate diesel unit capacity will remain available to cover peak load during an outage of the entire GUPP for steam turbine maintenance.

4.2.2.2 Gas Operation

Gas generation is assumed to start in April 2031 based on the estimated LNG implementation schedule. This estimate is based on previous LNG terminal implementation work K&M has performed for projects of similar size. All units running on gas are assumed to be available to run at least through the end of the model period (2050), as shown in Table 4.3.

Table 4.3: Gas Units

Unit ID	Merit Order (Rank)	Unit Capacity (MW)	Average Hourly Availability in a Year (%)	Available Unit Capacity (MW)	Min Load %	Min Load (MW)	Engines Online	First Retirement
GUPP Gas	1	198.0	96%	190.0	16%	32.5	4/1/31	10/1/2053

Source: GPA provided information as part of RFI

The source of inputs and assumptions used for the analysis of the gas units is presented below:

- 1 GUPP operating on natural gas is assumed to be dispatched first before diesel generation once gas is available.
- 2 GUPP, in coordination with Siemens, provided the minimum load for the GUPP. The minimum load would be approximately 32.5 MW, with one combustion turbine (CT) operating at 50% load (22.5 MW) and steam turbine (ST) operating at 15% load (10 MW).
- 3 GUPP's available unit capacity for a specific year is calculated by multiplying installed unit capacity by the guaranteed contractual availability for that year, as specified in the ECA.
- 4 GUPP heat rate curve for gas operation is based on guaranteed contractual heat rates specified in the ECA.

4.2.2.3 Renewable Sources and Battery Energy Storage Systems (BESS)

Renewable Energy Generation – GPA Target

The GPA Target renewable energy capacity additions assumptions are based on the GPA's 2022 IRP Generation Expansion Plan, clarifications and revisions made by K&M based on inputs received from GPA during the kickoff and in response to the RFI, and K&M's analysis. These assumptions are:

- 1 All renewable energy additions are assumed to be Solar PV plants with BESS. Wind or other alternative energy generation sources are not considered part of this analysis. Wind generation was specifically not considered based on feedback received from GPA during the kickoff meeting that locations with high wind resources have severe transmission limitations.
- 2 The solar PV capacity additions are calculated by dividing the renewable energy production increase specified in the adjusted IRP generation expansion plan by the estimated annual

solar PV plant yield of 1,628 MWh/MWp. The solar yield of 1,628 MWh/MWp is based on historical data as provided by NREL's PVWatts⁹.

- a) Solar resource data is solar irradiance and meteorological data that describe the conditions at the system's location. PVWatts uses a set of weather data prepared from the NREL National Solar Radiation Database (NSRDB) and a collection of data from other sources for the rest of the world. PVWatts uses hourly typical meteorological year (TMY) data, which is one year's worth of data that represents the solar resource over a multi-year period.
- b) K&M chose to use this database in lieu of the information provided by GPA on the existing solar plant generation as there is only one year of data (2023) where both Dandan and Mangilao solar were operating. PVWatts uses information from 30 years of historical weather data and solar irradiation, which K&M believes gives a more representative data set for Guam.

3 The base case renewable capacity installation schedule is seen in Table 4.4.

Table 4.4: Renewable Capacity Additions – GPA Target

Year	Capacity Added (MW)	Capacity Cumulative (MW)	Assumption
2024	85	85	Existing operational solar plant capacities in Mangilao and DanDan provided by GPA.
2028	334	419	Phase IV proposed solar projects (334 MW) are assumed to be implemented by 2028. The sizing information for the Phase IV projects was provided as a set of bids by GPA.
2030	184	603	GPA will implement an additional 184 MW of solar capacity to achieve 50% renewable generation by 2030.
2036	266	869	432,303 MWh of solar PV generation will be added in 2036 per GPA inputs received during the kickoff meeting and RFI response. The 2036 increase specified in the IRP is adjusted downward to compensate for the higher solar PV capacity installed during previous periods.
2040	369	1,238	600,000 MWh of solar PV generation will be added in 2040 per GPA inputs received during the kickoff meeting.
2045	150	1,388	An additional 150 MW of solar PV capacity will be added in 2045 to cover load growth while maintaining the renewable generation percentage achieved during previous periods. K&M calculated this capacity addition.

4 Gas will not be available until April 2031, and generation will come from renewables, existing diesel units, and GUPP running on ULSD.

The size of the renewable energy generation system resulting from the above assumptions is ~1,400 MW of solar PV. This system requires a substantial amount of land (~6,800 hectares¹⁰) and a

⁹ <https://pvwatts.nrel.gov/>

¹⁰ Required land area is calculated using data from article: <https://doi.org/10.1371/journal.pone.0270155>

significant investment. It is unclear if there is enough land available in Guam that could be permitted for this purpose.

Furthermore, the renewable capacity additions assumed in this report will require updates after GPA completes a detailed least-cost generation expansion plan that finds the optimal amount and timing of renewable energy additions that meet renewable generation requirements and supply reliability targets at least-cost.

Battery Energy Storage Systems (BESS) – GPA Target

The BESS base case capacity addition assumptions are as follows:

- BESS systems at the existing solar PV plants and GUPP are assumed to be for grid stability and are not considered part of the analysis for load shifting.
- BESS technical parameters:
 - Maximum depth of discharge: 100%
 - Roundtrip efficiency: 85%
- BESS Capacity (MW)
 - BESS capacity additions are assumed to happen in the same year as the renewable capacity additions. BESS installed storage capacity (in MW) for each renewable capacity addition year is equal to the increase in the peak load since the last renewable capacity addition. BESS capacity additions for the base case are shown in Table 4.5.

Table 4.5: BESS Capacity Additions – GPA Target

Year	Capacity - Added (MW)	Capacity - Cumulative (MW)	Assumption
2024	0	0	Existing battery systems are not considered for load shifting.
2028	174	174	Phase IV proposed BESS projects (174 MW) are assumed to be implemented by 2028. The sizing information for the Phase IV projects was provided as a set of bids by GPA.
2030	170	344	Battery addition required to meet peak load.
2036	1	345	Battery addition required to meet peak load.
2040	1	346	Battery addition required to meet peak load.
2045	1	347	Battery addition required to meet peak load.

- BESS Duration (hours)
 - 2028 and 2029: 4.48 hours. This assumption is based on the Phase IV bids received from GPA. The battery sizes are different for each bid, so the storage hours were calculated using the total Energy Storage (MWh) of all bids divided by the total installed BESS capacity (MW) of all bids.
 - 2030 – 2050: 10 hours. K&M ran the LNG demand model for different battery durations to find the duration that minimizes curtailment and cost. The battery duration cases were for 4-hour, 8-hour, 10-hour, and 12-hour, as well as a battery duration that resulted in zero

curtailment. K&M found that a 10-hour battery duration minimizes curtailment. The results of this analysis are discussed in further detail in Appendix A.

The BESS capacity and duration assumptions were based on 'rule-of-thumb' estimates that were deemed appropriate and useful for the LNG demand estimate. However, these estimates should be properly done as part of a system-wide detailed least-cost expansion plan, and the LNG demand estimate should be updated accordingly.

4.2.3 System Operating Reserve Assumptions

The system's operating reserve requirement was estimated based on expected load and renewable energy fluctuations throughout the year using the following formula:

Operating Reserve Required at hour n = Maximum of:

- Capacity of the largest thermal unit online at hour n OR
- 5% (load at hour n) + 45% (solar generation at hour n)

K&M developed this formula based on hourly dispatch modeling for other similar island grids with a substantial amount of renewable energy generation. As GPA's generation portfolio shifts to consist of predominantly solar, the amount of solar generation will determine the operating reserves required at any given hour. This is different from the conventional practice of setting operating reserves based on the size of the largest thermal unit online. The components and parameters of this formula would need to be analyzed in detail as part of a study that analyzes the impact of adding variable renewable generation to GPA's system and how this affects operating reserves. The LNG demand estimates could be updated once the results of this study are available.

A point to note on the solar generation input for this calculation: if the solar generation at a given hour is greater than the peak load at that hour, the peak load is used as the input of the calculation; otherwise, the actual solar generation is used. This ensures the system's Operating Reserve is not higher than the peak load at any given hour.

The thermal units that are not retired at the start of the model are available to meet the load in cases where the renewables and batteries cannot; however, they are not kept at a minimum running load to meet the system's operating reserve requirement.

4.2.4 Renewable Generation Scenarios

K&M considered three scenarios for renewable energy and BESS capacity additions.

- 1 Base case: An adjusted version of the 2022 IRP Generation Expansion Plan, as explained in Section 4.2.2.3 and presented in Table 4.4 and Table 4.5.
- 2 Guam Public Law No. 35-46: target of 100% renewable generation by 2045.
- 3 Delayed Renewable Generation Expansion: This scenario is based on gradually adding renewable power sources and limiting the total renewable penetration to a value lower than the adjusted IRP and the Guam Public Law targets.

The assumptions behind the last two scenarios are explained below.

4.2.4.1 Guam Public Law No. 35-46

The Guam Public Law states GPA shall establish a preliminary renewables portfolio goal of:

- 5% Net Electricity Sales by December 2015
- 50% Net Electricity Sales by December 2035
- 100% Net Electricity Sales by December 2045

The adjusted IRP target of 50% renewable by 2030 and 100% renewable by 2040 is five years earlier than established by Guam Public Law. As such, the second scenario for renewable installation per the Guam Public Law is the adjusted 2022 IRP Generation Expansion Plan delayed by five years to meet the Guam Public Law. The renewable capacity and BESS additions are presented in Table 4.6 and Table 4.7.

Table 4.6: Renewable Capacity Additions – Guam Public Law

Year	Capacity Added (MW)	Capacity Cumulative (MW)	Assumption
2024	85	85	Existing operational solar plant capacities in Mangilao and DanDan provided by GPA.
2028	334	419	Phase IV proposed solar projects (334 MW) are assumed to be implemented by 2028. The sizing information for the Phase IV projects was provided as a set of bids by GPA.
2036	184	603	GPA will implement an additional 184 MW of solar capacity to achieve 50% renewable generation by 2036.
2040	266	869	432,303 MWh of solar PV generation will be added in 2040 per GPA inputs received during kickoff meeting and RFI response. The 2040 increase specified in the IRP is adjusted downward to compensate for the higher solar PV capacity installed during previous periods.
2045	369	1,238	600,000 MWh of solar PV generation will be added in 2045 per GPA inputs received during kickoff meeting.
2050	150	1,388	An additional 150 MW of solar PV capacity is added in 2050 to cover load growth while maintaining the renewable generation percentage achieved during previous periods. This capacity addition was calculated by K&M.

Table 4.7: BESS Capacity Additions – Guam Public Law

Year	Capacity -Added (MW)	Capacity - Cumulative (MW)	Assumption
2024	0	0	Existing battery systems are not considered for load shifting.
2028	174	174	Phase IV proposed BESS projects (174 MW) are assumed to be implemented by 2028. The sizing information for the Phase IV projects was provided as a set of bids by GPA.
2036	171	345	Battery addition required to meet peak load.
2040	1	346	Battery addition required to meet peak load.
2045	1	347	Battery addition required to meet peak load.
2050	1	348	Battery addition required to meet peak load.

The BESS duration for this scenario is:

- 2028 – 2035: 4.48 hours
 - This assumes all Phase IV BESS projects are the only battery energy storage capacity installed until the year 2036. These projects did not undergo the K&M battery size optimization analysis.
- 2036 – 2050: 10 hours

4.2.4.2 Delayed Renewable Generation Expansion

The amount of renewable generation capacity installed in Guam and the timing of these installations could be significantly delayed relative to the GPA Target and the Guam Public Law scenario. The experience of other island power systems shows that renewable targets set by IRPs or government policies are often not achieved because implementing the solar PV and BESS projects required to achieve these targets is a lot more complex than expected. Some of the reasons why renewable energy projects are delayed or not implemented include:

- Limited land availability. The 1,400 MW of new solar PV installations required to meet the adjusted IRP targets will need close to 6,800 hectares of land (~13% of Guam's land area). Land suitable for a solar PV plant will need to meet specific requirements, including being in an area with good irradiation and not subject to flooding or in a protected area, being owned by the government or sellers willing to sell, and being acquired at a price that is in line with the assumptions used in the IRP LCOE calculations. It is reasonable to expect that finding 6,800 ha of land in Guam that meets these characteristics will be difficult—causing delays or even capping the amount of viable solar PV installations in Guam below 1,400 MW.
- Delays in permitting, procurement, construction, and commissioning. The experience with the permitting process of the GUPP showed the complexity of Guam's permitting process and how much the implementation of a power plant could be delayed. It is reasonable to expect that part of the 1,400 MW of new solar installations will experience permit delays. Furthermore, lead times for purchasing solar PV and BESS equipment have increased because of increased global demand.
- Increase in tariffs. A 100% renewable generation system in Guam will require a substantial amount of solar PV and BESS capacity to meet the island's load 100% of the time. This system will require a massive investment—billions of dollars, that will require significant tariff increases. It is reasonable to expect that once regulators and policymakers understand the cost and tariff increase associated with pursuing a 100% renewable target, these targets will decrease to levels that are well below 100% renewable generation.

Based on these and other lessons observed from the implementation of renewable energy programs in other islands, K&M believes that it is important for Guam to seriously consider a scenario in which renewable generation installations are delayed. It is important for at least two reasons:

- Suppose the LNG supply project is designed to supply the volumes estimated for the GPA Target or Guam Law scenarios, but renewable projects are delayed, and Guam needs substantially more gas volume. In that case, Guam might not be able to source this additional gas from the LNG project (because of its design capacity and contractual penalties for adjusting supply volumes) and will be forced to run ULSD and incur higher generation costs.

- The amount of LNG demanded by Guam will influence the price that GPA will pay for this gas—a higher gas volume will have a lower price. If the LNG project is designed and procured to supply a lower amount of gas than what Guam would actually need, Guam could miss the opportunity to secure a lower price at the outset by designing and procuring an LNG project capable of supplying a larger volume.

K&M developed a delayed renewable generation expansion scenario based on its observation of how similar renewable generation programs in other islands have evolved. The solar PV and BESS capacity additions for a delayed renewable generation expansion scenario are presented in Table 4.8 and Table 4.9. The total capacity installed in 2050 for this scenario is approximately 60% of the total capacity of the GPA Target and Guam Public Law scenarios. This scenario is included in the analysis to establish the upper boundaries for LNG demand and estimate associated LNG prices.

Table 4.8: Renewable Capacity Additions – Delayed Renewable Generation Expansion

Year	Capacity Added (MW)	Capacity Cumulative (MW)	Assumption
2024	85	85	Existing operational solar plant capacities in Mangilao and DanDan provided by GPA.
2028	117	202	Assumed only 35% of Phase IV proposed solar projects will be implemented by 2028.
2030	60	262	Assumed an addition of 180 MW spread out over 4 years (2030 – 2034).
2032	60	322	
2034	60	382	
2036	76	458	Assumed an addition of 304 MW spread out over 6 years (2036 – 2042).
2038	76	534	
2040	76	610	
2042	76	686	
2045	61	747	Assumed an addition of 183 MW spread out over 4 years (2045 – 2049).
2047	61	808	
2049	61	869	

Table 4.9: BESS Capacity Additions – Delayed Renewable Generation Expansion

Year	Capacity - Added (MW)	Capacity - Cumulative (MW)	Assumption
2024	0	0	Existing battery systems are not considered for load shifting.
2028	104	104	Assumed 60% of BESS Phase IV projects will be implemented by 2028.
2030	40	144	Assumed an addition of 240 MW spread out over 10 years (2030 – 2040).
2032	40	184	

2034	40	224	
2036	40	264	
2038	40	304	
2040	40	344	
2042	1	345	Battery addition required to meet peak load.
2045	1	346	Battery addition required to meet peak load.
2047	1	347	Battery addition required to meet peak load.

The BESS duration for this scenario is:

- 2028 – 2030: 4.48 hours
- 2030 – 2050: 10 hours

4.3 Results of the LNG Demand Analysis

This section presents the results of the LNG demand analysis, including different scenarios and sensitivities considered for LNG demand estimation.

4.3.1 LNG Demand Results – GPA Target

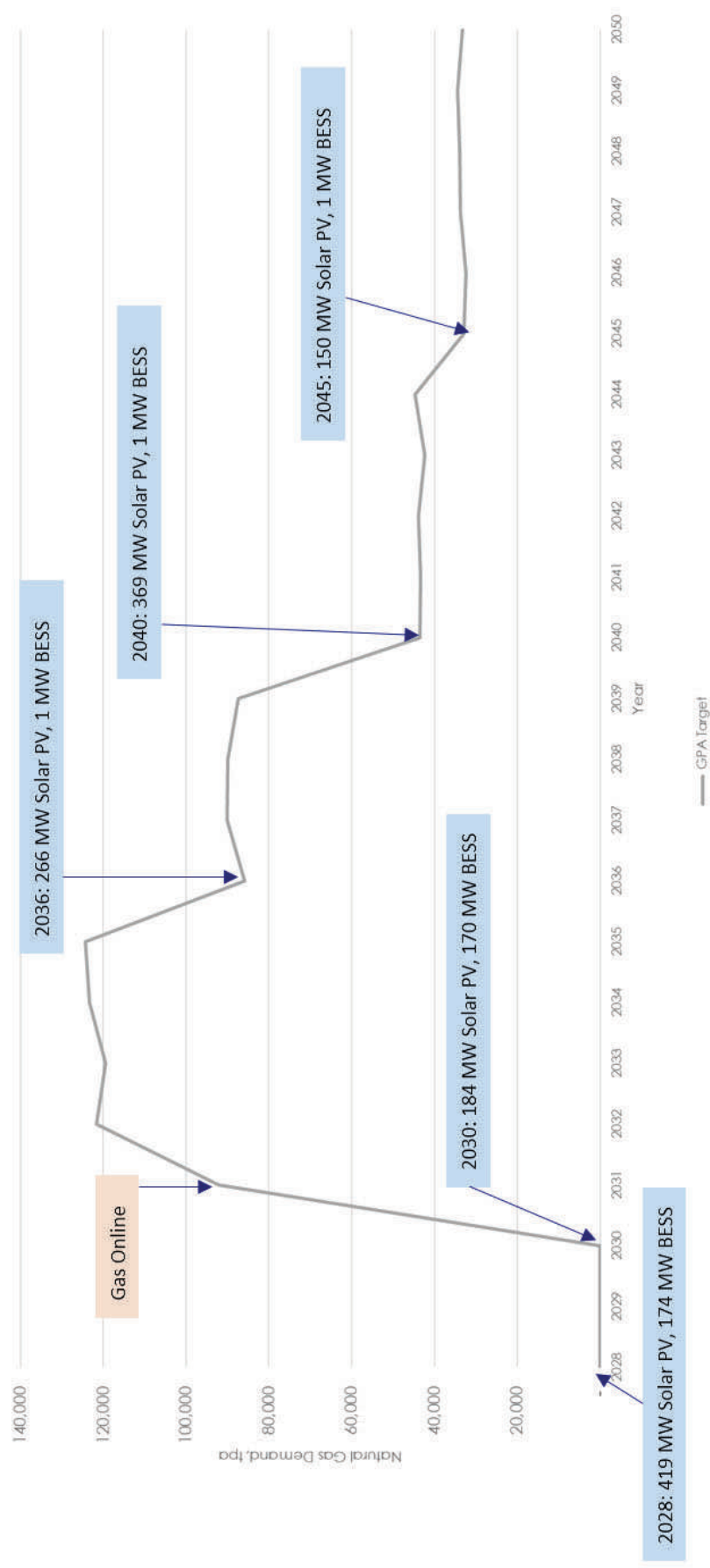
4.3.1.1 GPA Target Results

The LNG demand for the GPA Target scenario is presented in Figure 4.3. The LNG demand from 2028 to 2030 is zero, as the earliest natural gas will be available for the GUPP in 2031.

When GUPP is operating on gas in 2031, LNG demand will be significant as the renewable generation and BESS capacity installed up to 2031 is not enough to meet the system's peak load. The GPA Target LNG demand in 2031 is 92,208 tonnes per annum (tpa).

Table 4.4 provides the inputs to the base case renewable energy capacity additions. For the GPA Target scenario, no renewables are added in the interim years; however, the system peak load is still growing based on the load growth rates. As a result, the LNG demand increases during the period between the renewable capacity addition years and then drops when additional renewable generation and BESS begin operation. The peak LNG demand for the GPA Target occurs in the year 2035, with an estimated demand of 124,342 tpa. Based on this graph, LNG demand will decrease substantially to approximately 43,485 tpa by 2040, approximately nine years from the start of the GUPP operation on natural gas.

Figure 4.3: LNG Demand – GPA Target

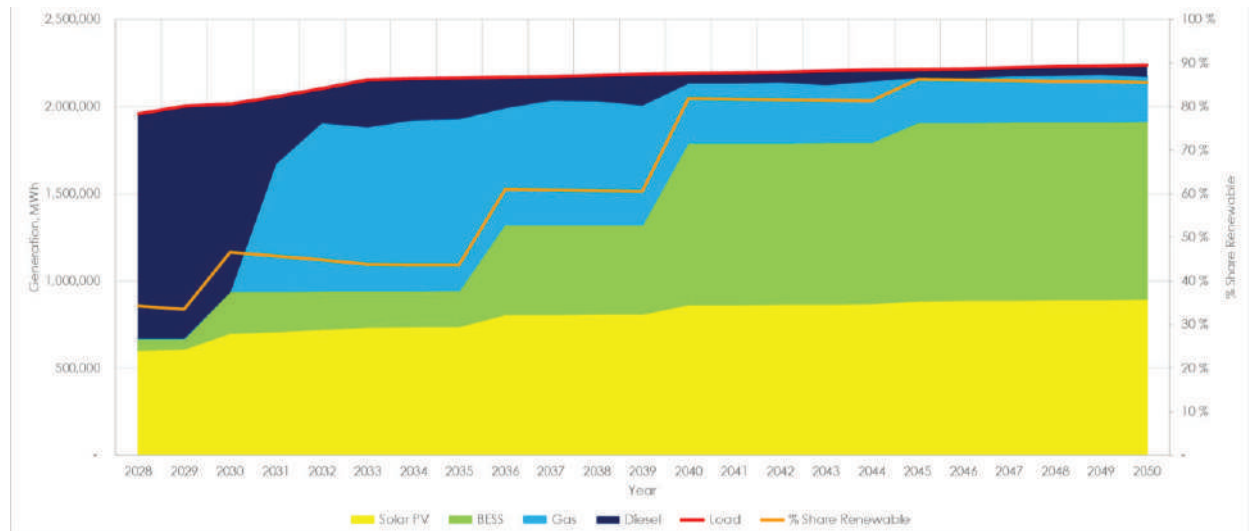


Annual Gas Demand (tpa)		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Year		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
GPA Target		-	-	-	92,208	121,686	119,467	123,399	124,342	85,849	90,144	89,906	87,498	43,485	43,339	43,926	42,345	44,732	32,947	32,357	33,775	34,031	34,459	33,348

4.3.1.2 Annual Generation by Technology

As part of the LNG demand analysis, the annual generation by each generation technology was calculated to determine if the renewable generation targets will be met with the GPA Target renewable and BESS capacity additions. The result for the GPA Target generation by technology is shown in Figure 4.4.

Figure 4.4: Annual Generation by Technology – GPA Target



% Share Renewables																								
	Year	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
GPA Target		34%	33%	47%	46%	45%	44%	44%	44%	61%	61%	61%	61%	82%	82%	82%	81%	81%	86%	86%	86%	86%	86%	86%

The graph and table show a similar result to the LNG demand chart in Figure 4.3. Throughout the modeling period, renewable generation (solar PV and BESS) increases based on the renewable generation assumptions of the GPA Target scenario. During the period between 2031 and 2035, natural gas generation increases due to system load growth coupled with constant renewable generation. Natural gas demand decreases with each addition of renewable generation capacity. However, renewable generation does not eliminate the need for natural gas. Sizing the solar PV and BESS system to cover the load 100% of the time (including rainy season periods with low radiation) would require a solar PV and BESS installed capacity with unreasonably high cost. The GUPP operating on gas will be used to cover the electricity demand during such periods.

Diesel generation drastically decreases once gas is available, as GUPP, which runs on natural gas, will be dispatched before the diesel units because it will have a lower marginal cost. The diesel generation then steadies out for the remaining years of the model; however, it is not eliminated. Diesel generation will be required throughout the projection period because:

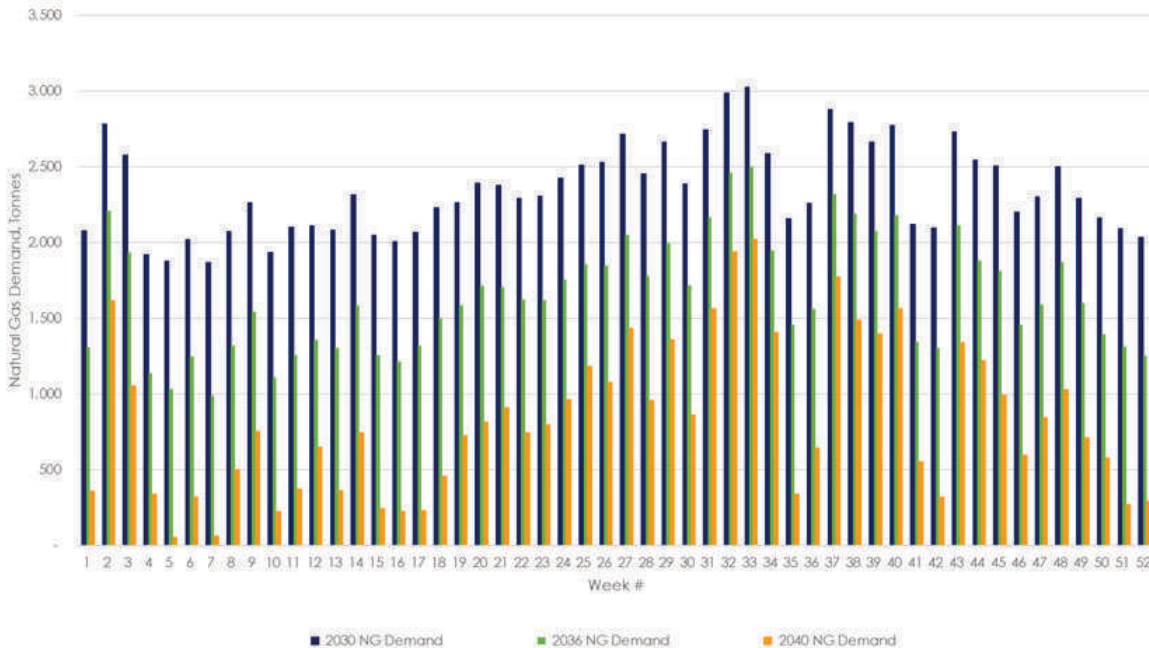
- The model considers the availability of GUPP per the ECA. During GUPP outages, the remaining diesel engines will be required to pick up the load that the renewable generation and BESS cannot meet.
- The system Operating Reserve requirement only allows the BESS to discharge to the maximum reserve requirement for any given hour in the year. As such, there are periods during the year when the system load/demand is higher than the remaining charge in the battery available to discharge to maintain this reserve AND the maximum capacity of GUPP. In this case, additional diesel units must be brought online to meet the remaining load.

The key takeaway from Figure 4.4 is the percentage share of renewable generation that the system can meet with the renewable and BESS capacity additions presented in Table 4.4 and Table 4.5. The maximum percent share of renewable generation will be 86% in 2045 and will not reach 100% at any point in the modeling period.

4.3.1.3 Weekly LNG Demand

The weekly demand for natural gas for three of the renewable generation capacity addition years is seen in Figure 4.5.

Figure 4.5: Weekly LNG Demand



The chart shows that natural gas demand is primarily a function of the seasonal variation of solar irradiance. The gas demand follows solar generation throughout the year. In the early months of the year, solar irradiation is the highest, resulting in lower gas demand; however, gas demand increases during July and August, when solar irradiation is the lowest. As the renewable penetration increases in the later indicative years, natural gas demand decreases for each week of the year.

The seasonality of the gas demand is important to consider for decisions related to gas storage sizing and delivery schedule, as it may impact the gas cost.

4.3.2 LNG Demand Results – Renewable Generation Scenarios

The LNG demand for the base case scenario, including the two additional renewable generation scenarios, can be seen in Figure 4.6.

A few key observations are:

- The GPA Target's peak LNG demand will occur in 2035, with an estimated value of 124,342 tpa.

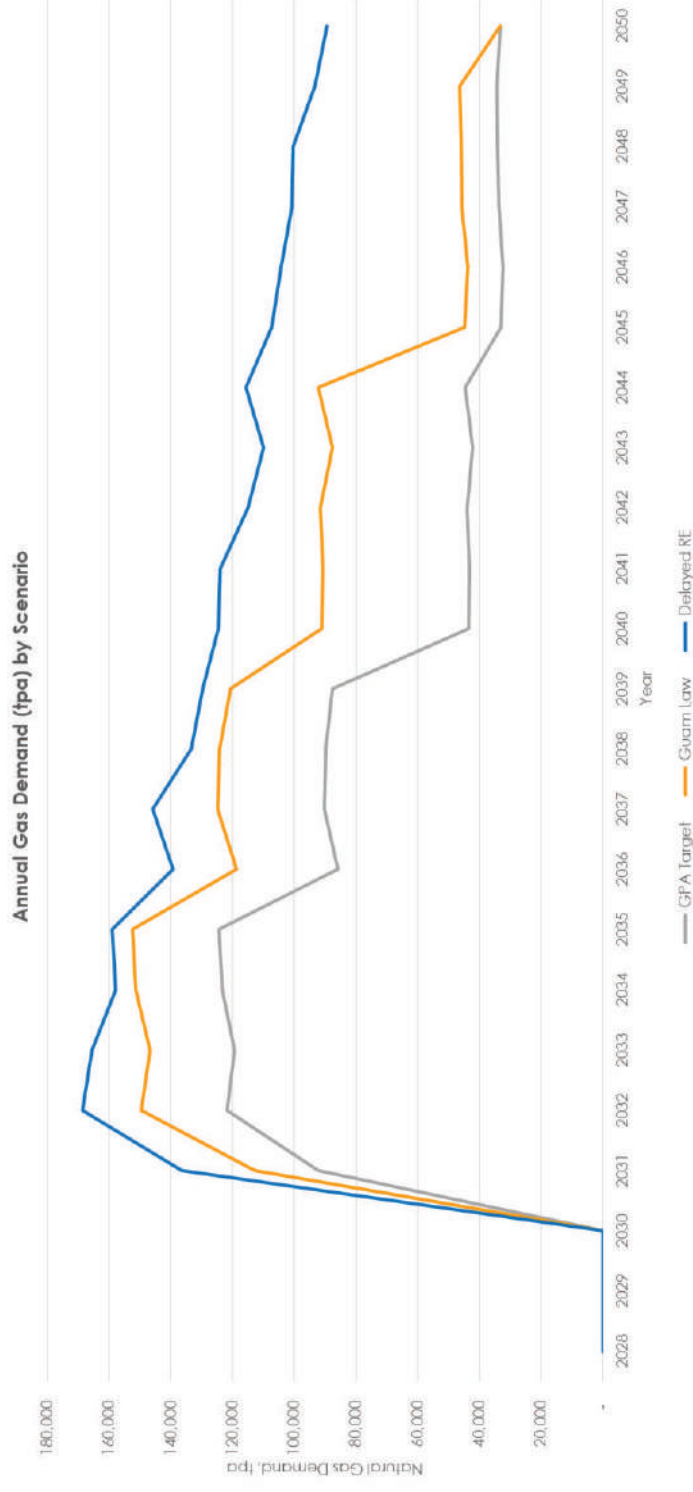
- The Guam Public Law scenario peak LNG demand also occurs in 2035 but is higher than the GPA Target at 152,372 tpa.
- The Delayed Renewable Generation Expansion scenario has a peak LNG that occurs in 2032 with an estimated value of 168,652 tpa.

The GPA Target and Guam Public Law scenarios have large renewable capacity additions in 2036, 2040, and 2045, resulting in a large and sustained drop in LNG demand. The delayed renewables scenario not only delays the renewable installations but also reduces the total installed capacities, resulting in higher gas demand for more extended periods.

The renewable capacity additions specified in the GPA Target, Guam Public Law, and the delayed renewable generation expansion case do not result in achieving 100% of electricity generation from renewable sources by 2045.

- Electricity generation from renewable sources achieve 86% in 2045 for the GPA Target Case.
- Electricity generation from renewable sources achieve 81% in 2045 for the Guam Public Law.
- Electricity generation from renewable sources achieve 52% in 2045 for Delayed Renewable Generation Expansion.

Figure 4.6: LNG Demand – Renewable Generation Scenarios



Annual Gas Demand (tpa)		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
GPA Target	Year	-	-	-	92,208	121,686	119,467	123,399	124,342	85,849	90,144	89,906	87,498	43,485	43,339	43,926	42,345	44,732	32,947	32,357	33,775	34,031	34,459	33,348
	Guam Law	-	-	-	112,794	149,715	146,788	151,317	152,372	118,815	124,758	124,192	120,607	91,075	90,716	91,505	87,549	92,125	44,822	43,779	45,670	45,882	46,401	33,350
	Delayed RE	-	-	-	136,472	168,652	165,618	157,951	159,032	139,321	145,994	133,501	129,727	124,539	123,926	115,107	109,970	115,580	107,356	104,285	100,694	100,414	93,318	89,286

% Share Renewables		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
GPA Target	Year	34%	33%	47%	46%	45%	44%	44%	44%	61%	61%	61%	61%	82%	82%	82%	81%	81%	86%	86%	86%	86%	86%	86%
	Guam Law	34%	33%	33%	33%	32%	31%	31%	31%	44%	43%	43%	43%	60%	60%	60%	60%	60%	81%	81%	81%	81%	81%	86%
	Delayed RE	17%	16%	21%	21%	25%	24%	29%	29%	34%	34%	39%	39%	44%	44%	48%	48%	48%	52%	52%	56%	59%	59%	59%

4.3.2.1 Annual Generation by Technology

The following charts for the Guam Public Law scenario and the Delayed Renewable Generation Expansion scenario show the annual generation per generation technology. The graphs in Figure 4.7 and Figure 4.8 show results similar to those presented in Figure 4.4.

Figure 4.7: Annual Generation by Technology – Guam Public Law

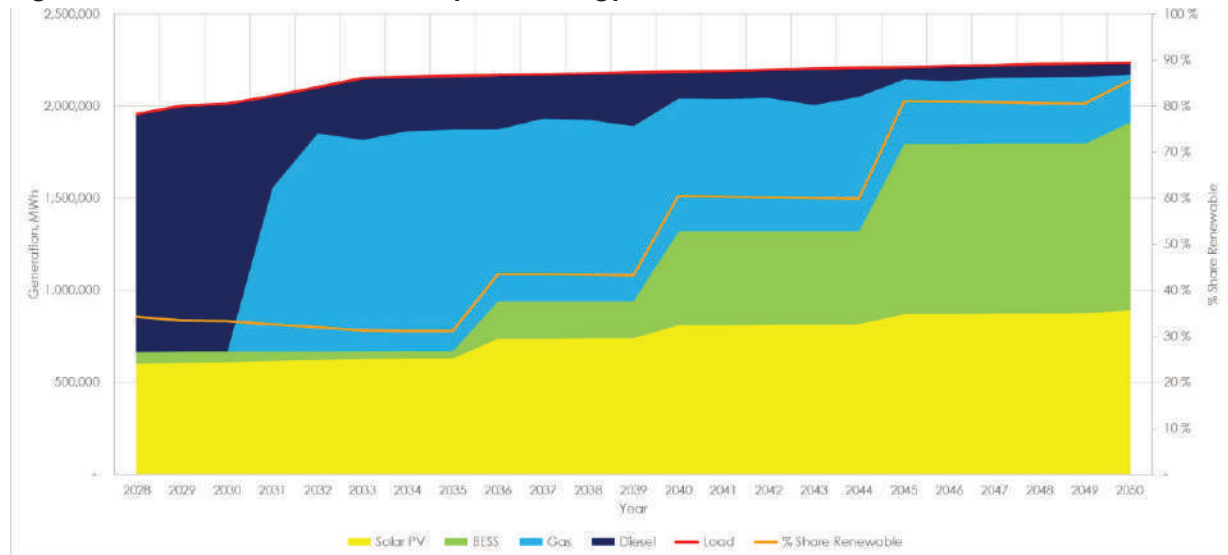
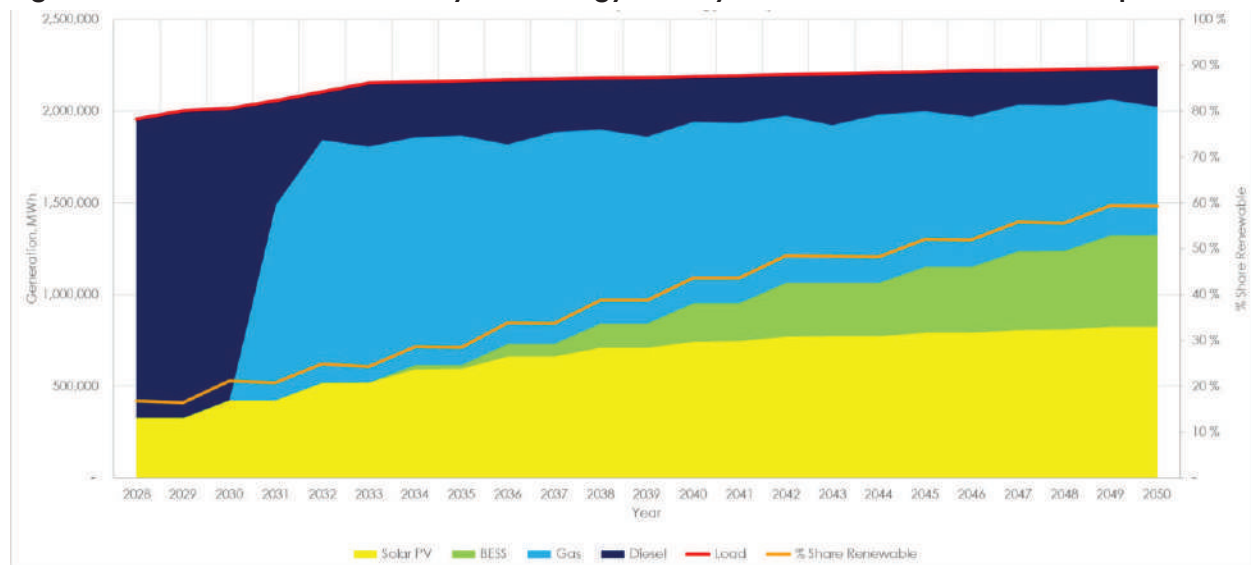


Figure 4.8: Annual Generation by Technology – Delayed Renewables Generation Expansion

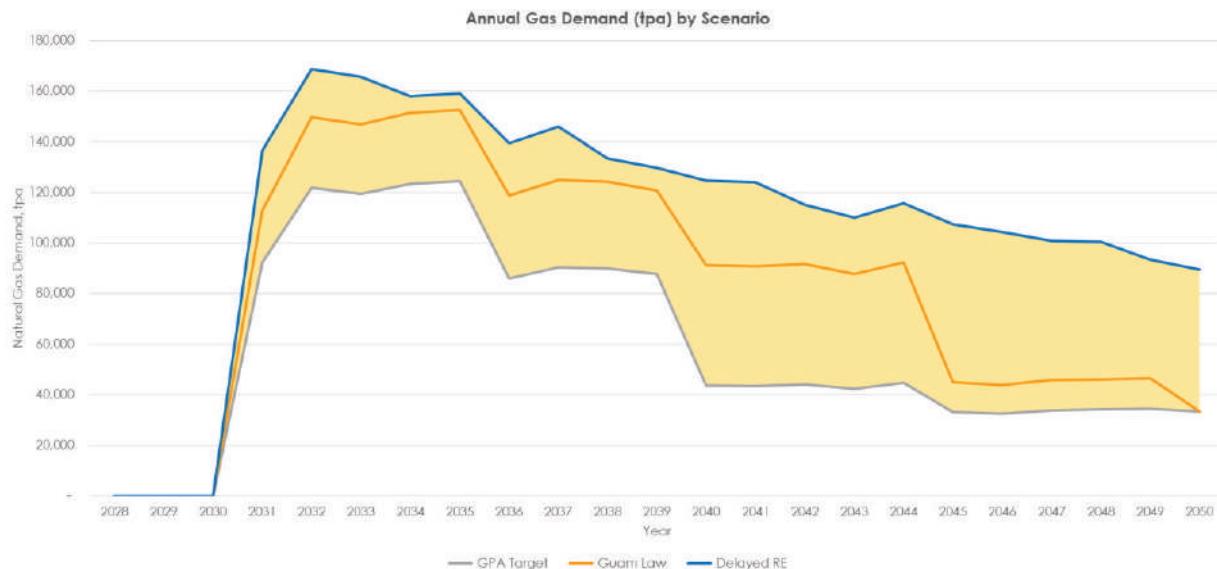


4.4 Conclusions

Based on the results and observations presented in Section 4.3, the following conclusions can be drawn from the LNG demand analysis at this stage.

- The maximum demand for the GPA Target demand scenario is 124,342 tonnes per annum (tpa), which occurs in 2035, and its minimum is 32,357 tonnes per annum in 2046. The GPA Target scenario shows relatively high LNG demand for approximately ten years of GUPP operations on natural gas.
- The analysis indicates that with the total installed capacity of solar PV (~1,400 MW) and batteries (~400 MW with 10-hour storage), which generally meets the plan outlined in the adjusted 2022 IRP, the system's maximum share of renewable generation in 2045 is 86% of the total demand, not 100% as targeted by GPA and Guam Public Law. The total investment cost in such solar PV and BESS systems is estimated at approximately \$3 billion.
- The range of LNG demand throughout the model across all sensitivities and scenarios is between 32,357 tpa and 168,652 tpa. The wide range of operation of the GUPP on natural gas creates a similarly wide range of LNG sourcing and gas production from the LNG terminal. As such, it is imperative to base the LNG demand projections on the most realistic scenario that is expected to occur regarding the renewable installation expansion plan. Tasks 2 and 3 of our study use an LNG demand band with a lower value equal to the base case LNG demand, and an upper value equal to the delayed renewable generation expansion case. The yellow highlighted area in Figure 4.9 reflects this LNG demand range.

Figure 4.9: LNG Demand Range for Subsequent Tasks



The current results of the LNG demand analysis are considered a realistic estimate of the range of natural gas that could be required and will be used for further tasks within the study.



Task 2

LNG Sourcing and Shipping Options

5 Task 2 – LNG Sourcing and Shipping Options

The main objective of Task 2 - Evaluation of LNG Sourcing & Shipping Options analysis is to identify potential sources of LNG, gauge interest from potential LNG suppliers, determine how LNG could be transported via sea to Guam, estimate the cost of LNG delivered ex-ship (DES) to Guam, and identify preliminary LNG terminal configurations and requirements. The analysis evaluates a range of supply solutions from potential regional suppliers to determine the most practical, least-cost LNG supply solution for Guam. The outputs of this analysis, such as the DES price of LNG, are critical to understanding the economic feasibility of transitioning to LNG and are used as inputs for other tasks under this assignment.

This section presents the results of the LNG sourcing and shipping options analysis. Section 5.1 presents LNG sourcing and shipping options. Section 5.2 estimates the LNG DES price. Section 5.3 describes LNG terminal storage and logistics requirements. Section 5.4 presents the conclusions. Appendix C presents feedback from consultations with potential LNG suppliers. Appendix D presents the market summary issued to potential LNG suppliers. Appendix E describes small-scale LNG carriers and specifications.

5.1 LNG Sourcing and Shipping Options

This section presents LNG sourcing and shipping options. Section 5.1.1 identifies potential LNG supply sources, including regional import and export terminals and partial delivery solutions. Section 5.1.2 describes feedback from K&M's outreach and consultation with potential LNG suppliers in the region. Section 5.1.3 describes LNG carrier options based on feedback on commercial considerations from LNG suppliers.

5.1.1 LNG Sourcing

Given Guam's relatively low expected annual quantities, K&M explored the following potential supply sources of LNG for Guam, which are explained in more detail in Sections 5.1.1.1 and 5.1.1.2:

- Regional LNG production and export terminals capable of loading small-scale LNG carriers
- Regional LNG import terminals capable of reloading small-scale LNG carriers
- Partial ex-ship deliveries from large-scale LNG ships transiting the Pacific Ocean

5.1.1.1 Regional LNG Export or Import Terminals Capable of Loading Small-Scale LNG Carriers

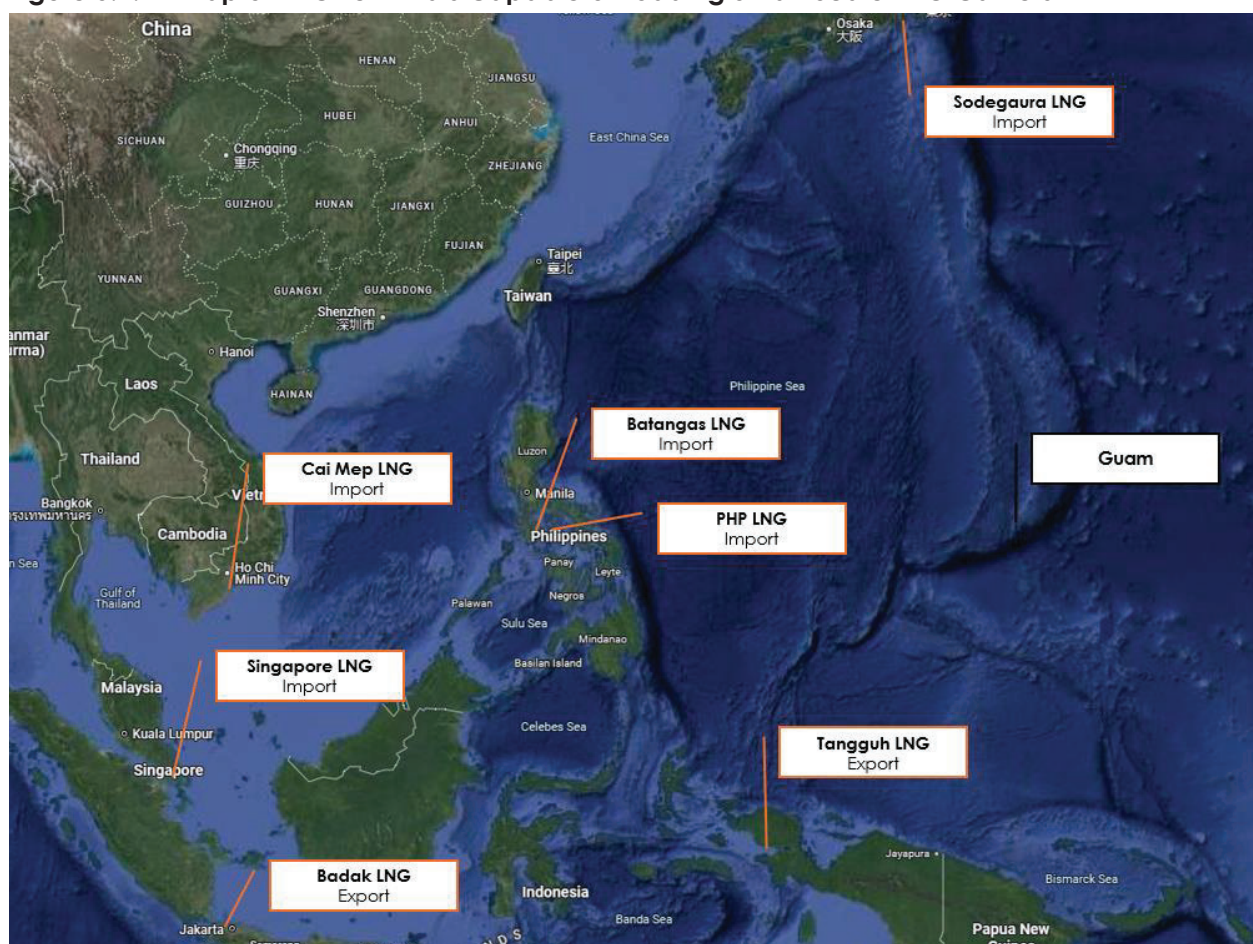
K&M identified seven regional LNG export and import terminals capable of loading small-scale LNG carriers, listed in Table 5.1 below and organized by distance to Guam. Figure 5.1 maps the locations of these facilities in relation to Guam. The shipping distance from the loading source to Guam is a key consideration in this analysis, since longer shipping distances will result in higher shipping costs, and consequently, higher LNG prices in Guam.

Table 5.1: LNG Terminals Capable of Loading Small-Scale LNG Carriers

	Indonesia	Japan	Philippines	Philippines	Indonesia	Vietnam	Singapore
Terminal	Tangguh	Sodegaura	Batangas	PHP	Bontang	Cai Mep	Singapore
Type	Export	Import	Import	Import	Export	Import	Import

	Indonesia	Japan	Philippines	Philippines	Indonesia	Vietnam	Singapore
Terminal Owner	Tangguh LNG	Tokyo Gas	First Gen	AG&P	PT Badak	AG&P / Hai Linh	Singapore LNG
LNG Seller	Tangguh LNG / BP	Tokyo Gas	First Gen	AG&P	Pertamina	AG&P	Shell, etc.
Location	West Papua	Tokyo Bay	Batangas	Iligan	Bontang, Kalimantan	Cai Mep	Jurong
Load Port	Manado	Chiba	Batangas	Batangas	Balikpapan	Nha Be	Jurong
Load Port Abbreviation	Tan	Sod	Bat	Bat	Bon	Cai	Sin
Shipping Distance to Guam (NM)	1,368	1,373	1,426	1,426	1,886	2,305	2,589

Figure 5.1: Map of LNG Terminals Capable of Loading Small-Scale LNG Carriers



In the region, only two LNG export terminals – Tangguh LNG and Badak LNG, both located in Indonesia – are currently capable of loading small-scale LNG carriers. K&M is not aware of any other LNG export projects in the area that plan to add this capability. Large-scale LNG exporters have little incentive to upgrade their facilities for small-scale carrier loading, as these smaller carriers require the same berth occupancy time as conventional large-scale carriers. Moreover, large-scale LNG producers are focused on delivering large quantities of LNG, and the smaller volumes carried by small-scale carriers are not material enough to be of interest. Consequently, there are very few LNG export terminals in the region that can accommodate small-scale LNG loading.

There are five LNG import terminals in the region – Sodegaura LNG, Batangas LNG, PHP LNG, Cai Mep LNG, and Singapore LNG – equipped to reload small-scale LNG carriers. K&M anticipates that additional LNG import terminal projects with this capability will be developed in the future.

5.1.1.2 Partial Cargo Deliveries from Large-Scale LNG Carriers

A conventional large-scale LNG carrier transiting the Asia Pacific to North Asia could potentially divert its voyage to Guam and deliver a partial cargo, e.g., 15,000 m³ or 30,000 m³, and then continue its voyage to its destination and deliver the remaining cargo.

The cost of such a diversion would include additional charter days, fuel, LNG boil-off, and Guam port costs. Guam's port cost for a large-scale LNG carrier could be significant, given the requirements for multiple large tugs and other services.

Technical considerations for this option include maintaining the LNG carrier membrane cargo containment systems within their sloshing limits, having a suitable berth, jetty, or mooring arrangement to accommodate the large-scale vessels safely, and achieving a workable vessel LNG unloading rate.

5.1.2 Consultation with Potential LNG Suppliers

After identifying potential LNG sourcing options, K&M consulted a selection of LNG suppliers and service providers, including Arabian Holdings, BP, First Gen, Shell, JERA, Karpowership, Pertamina, AG&P LNG, and Tokyo Gas, to understand:

- Potential interest in supplying LNG to Guam
- Relevant regional LNG activities
- Capability to handle small-scale LNG deliveries
- Feasibility of partial cargo deliveries on conventional large-scale LNG carriers
- Interest in developing Guam LNG import terminal development.

Appendix C presents a summary of feedback generated from these consultations. Appendix D includes the market summary issued to potential suppliers.

K&M recommends that the LNG procurement process include consultation with a larger group of potential LNG suppliers and service providers.

5.1.2.1 Feedback Regarding Partial Delivery Solutions

After consulting potential LNG suppliers and service providers, K&M identified the following commercial considerations related to partial deliveries from large-scale LNG carriers:

- The "tram line" nature of many LNG supply chains would make partial deliveries unworkable

- The contractual requirements in most existing ex-ship Supply & Purchase Agreements (SPAs) typically state that deliveries are required to be in full cargo lots, making partial deliveries in transit contractually impossible
- The scheduling of partial cargo deliveries to Guam would need to align with the scheduling of cargo deliveries to their final destination, i.e., GPA would not be able to dictate the dates of partial cargo deliveries
- By committing to partial cargo deliveries to Guam, LNG suppliers would lose the option to substitute another cargo to meet their supply commitment at the final destination. This loss of optimality would come at a cost to the LNG supplier
- Any partial cargo delivery supply arrangements would likely require wide flexibility in both delivered cargo quantities and cargo delivery dates to Guam, which would require the Guam LNG terminal to have significantly more LNG storage capacity than otherwise
- A partial cargo delivery supply arrangement is unlikely to be feasible for a firm long-term LNG contract and is more likely suited for ad hoc transactions
- With an ad hoc partial cargo delivery supply arrangement, oil-indexed LNG pricing would also not be feasible, and pricing would need to be based on the LNG spot price (JKM indexed)
- A partial cargo delivery supply arrangement wouldn't provide GPA with adequate security of supply

Considering the above, K&M believes that partial deliveries from large-scale LNG carriers are not a viable LNG supply solution for Guam, especially because GPA requires LNG security on a long-term basis, with firm quantities and cargo delivery windows, and with an oil-indexed LNG price. Therefore, this LNG supply solution is not assessed further in this study.

5.1.3 LNG Shipping Options

A key aspect of the study is understanding how LNG could be transported via sea from an LNG supply source to an LNG import terminal in Guam. Given Guam's relatively low expected annual quantities and feedback from potential suppliers regarding the feasibility of partial deliveries, only small-scale LNG carrier options are considered hereafter.

Small-scale LNG shipping (capacity < 40,000 m³) is in its infancy, with fewer than 50 vessels in operation globally. However, significant expansion of the global small-scale fleet has occurred in the last few years. LNG containment systems for small-scale LNG carriers are typically Type-C cylindrical or bilobed tanks that can handle tank pressures up to ~4.5 BarG without the need for boil-off gas management. By comparison, modern conventional large-scale carriers typically use membrane-type LNG containment systems, which operate close to atmospheric pressure and require boil-off gas management.

Three small-scale LNG carrier sizes have been used for estimating LNG prices in Section 5.2:

- **7,500 m³** – representing the smallest Type-C small-scale LNG carriers in the global fleet. Avenir LNG is currently the most active carrier owner of this vessel size. The proxy LNG vessel used is the recently built *Avenir Ascension*, owned/operated by Avenir LNG.
- **10,000 m³** - representing the slightly larger Type-C small-scale LNG carrier. Anthony Veder is the world's largest owner of small-scale vessels. The proxy LNG vessel used is the *Coral Favia*, owned/operated by Anthony Veder.

- **15,600 m³** – representing a large small-scale Type-C carrier in the global fleet. The proxy LNG vessel used is *Coral Energy*, which is owned/operated by Anthony Veder.

Specifications of these LNG vessels are detailed in Appendix E.

5.2 Estimated LNG Prices

Based on the potential LNG sourcing and shipping options identified in Section 5.1, K&M estimated the delivered ex-ship (DES) price of LNG in Guam for each location and a range of LNG carrier sizes to identify the most practical and cost-effective supply solution. The DES price is composed of the Unit Freight Cost (UFC), described in Section 5.2.1, and the Free on Board (FOB) price at each source location, described in Section 5.2.2.

5.2.1 Estimated Unit Freight Costs (UFC)

Estimated UFCs have been calculated from each identified potential LNG supply source to Guam and for each of the three small-scale LNG carrier cases described in Section 5.1.3. The UFC is the price (USD) per MMBtu of LNG, calculated as the estimated total voyage costs divided by the estimated quantity of LNG delivered.

5.2.1.1 Estimated Voyage Costs

Total voyage costs are based on vessel charter costs, vessel fuel costs, and vessel port costs. They are calculated on a round-trip basis and include both the cost of the laden leg and ballast leg, i.e., the vessel returning empty to the load port.

The analysis assumes that the vessel(s) are dedicated 100% of the time (353 days/year on-hire) to supplying LNG to Guam and includes the cost of idle days when the vessel is not utilized. These idle days can also be considered buffer days in the shipping schedule. Additional buffer days create a more robust schedule capable of accommodating anticipated delays; however, too many buffer days result in poor vessel utilization and consequently higher UFCs.

Vessel Time Charter Costs

Vessel time charter costs are based on the days used in the round-trip voyage and a time charter (TC) day rate, in \$/day. TC day rates are based on K&M's market intelligence for long-term charters (10-15+) years for similar-sized small-scale LNG carriers and have been calibrated based on discussions with reputable ship brokers.

Vessel Fuel Costs

Vessel fuel costs are calculated based on the bunker fuel price, the vessel's bunker fuel consumption in each operational mode, i.e., loading, sailing laden, unloading, sailing ballast, and stationary, and the number of days the vessel is in each operational mode. In the calculation of estimated UFCs, bunker fuel is assumed to be Very Low Sulfur Fuel Oil ("VLSFO") at a price of \$600/Tonne.

Vessel Port Costs

Vessel port costs represent the fees or tariffs charged by the loading and unloading port authorities or companies for using pilots, tugs, escort/security vessels, navigational aids, and so on. K&M assumed loading port and unloading port costs between \$30,000 to \$50,000, depending on the location and size of the small-scale LNG carrier.

5.2.1.2 LNG Quantity Delivered

LNG deliveries are assumed to be full cargo lots, and the gross storage capacity (m³) for each small-scale carrier size, maximum fill limits, and requirements for retained LNG heel are taken into consideration to ensure cargo tanks are kept cold during the ballast voyage. K&M assumed that LNG has a density of 0.45 Tonnes/m³ and a Higher Heating Value of 52 MMBtu/Tonne.

5.2.1.3 UFC Results

Table 5.2 below shows the estimated UFCs for each combination of small-scale LNG carrier and potential LNG supply source, for LNG demand ranging from 25,000 to 185,000 tpa.

Table 5.2: Estimated UFCs (\$/MMBtu, HHV Basis)

LNG Carrier Size & Supply Source	tpa								
	25,000	45,000	65,000	85,000	105,000	125,000	145,000	165,000	185,000
7,500 - West Papua	\$6.60	\$4.00	\$3.05	\$2.50	\$ 2.20	\$ 2.00	\$ 2.80	\$ 2.55	\$ 2.40
7,500 - Japan	\$6.60	\$4.00	\$3.05	\$2.50	\$ 2.20	\$ 2.00	\$ 2.80	\$ 2.55	\$ 2.40
7,500 - Philippines	\$6.60	\$4.05	\$3.05	\$2.55	\$ 2.20	\$ 2.00	\$ 2.85	\$ 2.60	\$ 2.40
7,500 - Kalimantan	\$6.75	\$4.15	\$3.20	\$2.65	\$ 3.70	\$ 3.30	\$ 2.95	\$ 2.70	\$ 2.55
7,500- Vietnam	\$6.85	\$4.30	\$3.30	\$2.80	\$ 3.85	\$ 3.40	\$ 3.10	\$ 2.85	\$ 3.45
7,500 - Singapore	\$6.95	\$4.40	\$3.40	\$4.55	\$ 3.90	\$ 3.50	\$ 3.15	\$ 3.80	\$ 3.50
10,000 - West Papua	\$7.70	\$4.60	\$3.45	\$2.80	\$ 2.40	\$ 2.15	\$ 1.95	\$ 1.80	\$ 2.70
10,000 - Japan	\$7.70	\$4.60	\$3.45	\$2.80	\$ 2.40	\$ 2.15	\$ 1.95	\$ 1.80	\$ 2.65
10,000 - Philippines	\$7.70	\$4.65	\$3.45	\$2.80	\$ 2.45	\$ 2.15	\$ 2.00	\$ 1.90	\$ 2.65
10,000 - Kalimantan	\$7.85	\$4.75	\$3.55	\$2.95	\$ 2.55	\$ 2.30	\$ 3.30	\$ 3.00	\$ 2.75
10,000- Vietnam	\$7.95	\$4.85	\$3.65	\$3.05	\$ 2.65	\$ 3.80	\$ 3.40	\$ 3.10	\$ 2.90
10,000 - Singapore	\$8.00	\$4.95	\$3.75	\$3.10	\$ 4.40	\$ 3.85	\$ 3.45	\$ 3.20	\$ 2.95
15,600 - West Papua	\$9.00	\$5.25	\$3.85	\$3.10	\$ 2.60	\$ 2.30	\$ 2.05	\$ 1.90	\$ 1.75
15,600 - Japan	\$9.00	\$5.25	\$3.85	\$3.10	\$ 2.60	\$ 2.30	\$ 2.05	\$ 1.90	\$ 1.75
15,600 - Philippines	\$9.00	\$5.30	\$3.85	\$3.10	\$ 2.65	\$ 2.30	\$ 2.10	\$ 1.90	\$ 1.75
15,600 - Kalimantan	\$9.10	\$5.40	\$3.95	\$3.20	\$ 2.75	\$ 2.40	\$ 2.20	\$ 2.00	\$ 1.85
15,600- Vietnam	\$9.20	\$5.50	\$4.05	\$3.30	\$ 2.80	\$ 2.50	\$ 2.25	\$ 2.10	\$ 3.10
15,600 - Singapore	\$9.25	\$5.55	\$4.10	\$3.35	\$ 2.90	\$ 2.55	\$ 2.35	\$ 3.45	\$ 3.15

Figure 5.2 shows the estimated UFCs for each combination of small-scale LNG carrier and potential LNG supply source, for LNG demand ranging from 25,000 to 185,000 tpa.

Figure 5.2: Estimated UFCs (\$/MMBtu, HHV Basis)

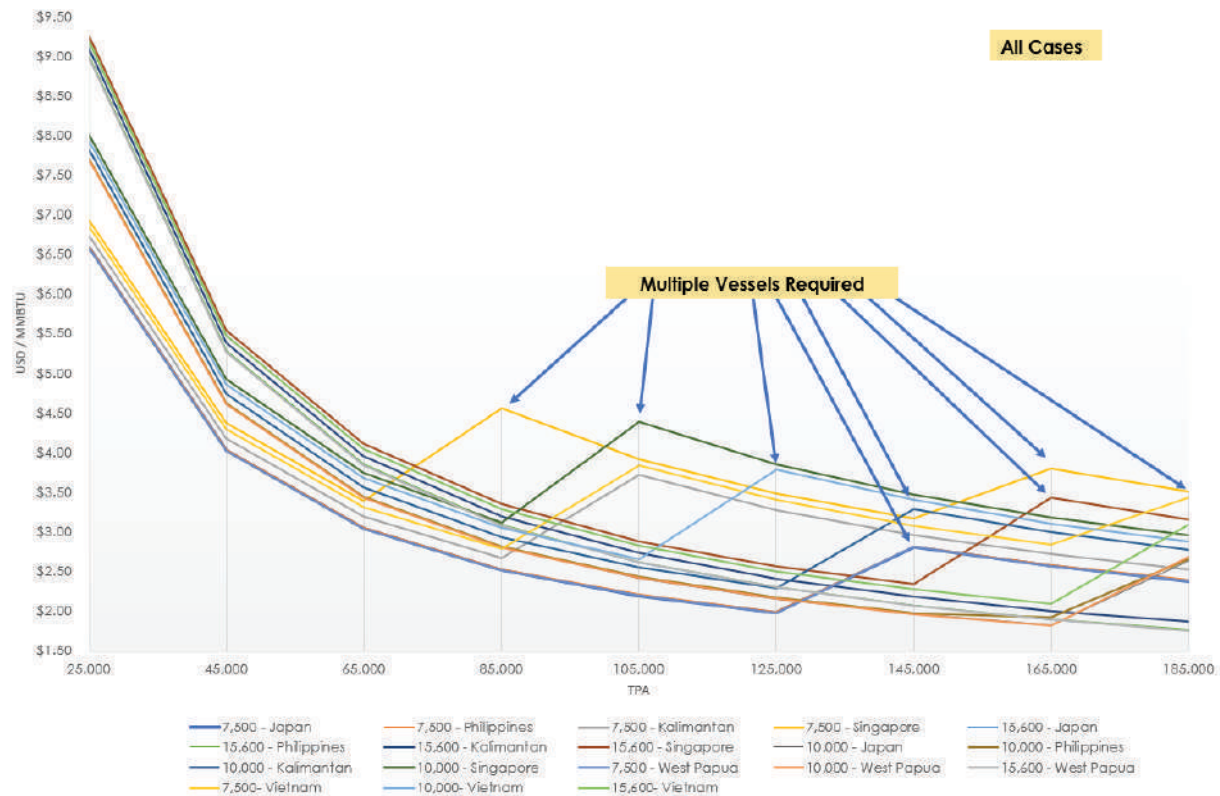


Table 5.3 below shows the estimated number of small-scale LNG carriers required for each combination of small-scale LNG carrier and LNG supply source for LNG demand ranging from 25,000 to 185,000 tpa. Combinations highlighted in green could be completed with just one LNG carrier across the entire expected annual quantity range, assuming regularly spaced deliveries.

Table 5.3: Estimated Number of LNG Carriers Required

LNG Carrier Size & Supply Source	tpa								
	25,000	45,000	65,000	85,000	105,000	125,000	145,000	165,000	185,000
7,500 - West Papua	1	1	1	1	1	1	2	2	2
7,500 - Japan	1	1	1	1	1	1	2	2	2
7,500 - Philippines	1	1	1	1	1	1	2	2	2
7,500 - Kalimantan	1	1	1	1	2	2	2	2	2
7,500 - Vietnam	1	1	1	1	2	2	2	2	3
7,500 - Singapore	1	1	1	2	2	2	2	3	3
10,000 - West Papua	1	1	1	1	1	1	1	1	2
10,000 - Japan	1	1	1	1	1	1	1	1	2
10,000 - Philippines	1	1	1	1	1	1	1	1	2
10,000 - Kalimantan	1	1	1	1	1	1	2	2	2
10,000 - Vietnam	1	1	1	1	1	2	2	2	2
10,000 - Singapore	1	1	1	1	2	2	2	2	2
15,600 - West Papua	1	1	1	1	1	1	1	1	1
15,600 - Japan	1	1	1	1	1	1	1	1	1
15,600 - Philippines	1	1	1	1	1	1	1	1	1
15,600 - Kalimantan	1	1	1	1	1	1	1	1	1
15,600 - Vietnam	1	1	1	1	1	1	1	1	2
15,600 - Singapore	1	1	1	1	1	1	1	2	2

Table 5.4 below shows the estimated number of cargo deliveries per annum required for each small-scale LNG carrier size for LNG demand ranging from 25,000 to 185,000 tpa.

Table 5.4: Estimated Number of Cargo Deliveries per Annum

Small-Scale LNG Carrier Size	tpa								
	25,000	45,000	65,000	85,000	105,000	125,000	145,000	165,000	185,000
7,500 m ³	8	14	20	26	32	39	45	51	57
10,000 m ³	6	10	15	20	24	29	34	38	42
15,600 m ³	4	7	10	13	15	18	21	24	27

Table 5.5 below shows the estimated frequency (days) of cargo deliveries for each small-scale LNG carrier size, for LNG demand ranging from 25,000 to 185,000 tpa.

Table 5.5: Estimated Frequency of Cargo Deliveries (Days)

Small-Scale LNG Carrier Size	tpa								
	25,000	45,000	65,000	85,000	105,000	125,000	145,000	165,000	185,000
7,500 m ³	47	26	18	14	11	9	8	7	6
10,000 m ³	63	35	24	19	15	13	11	10	9
15,600 m ³	99	55	38	29	24	20	17	15	13

Table 5.6 below presents the round-trip voyage duration (in days) from each LNG supply source by vessel size, along with the maximum number of annual trips a single vessel can complete. In years or seasons with higher demand, these factors may present operational constraints and should be considered when selecting the optimal supply solution. In some scenarios, deploying two vessels may provide additional operational flexibility.

Table 5.6: Estimated Days (Go-Return) for One Voyage

LNG Supply Source	Go-Return Days			Max Annual Trips (One Vessel)		
	7,500	10,000	15,600	7,500	10,000	15,600
West Papua	8.4	8.9	9.0	43	40	40
Japan	8.4	9.0	9.1	43	40	40
Philippines	8.7	9.3	9.3	41	39	39
Kalimantan	11.1	11.8	11.9	32	30	30
Vietnam	13.3	14.1	14.1	27	25	25
Singapore	14.8	15.7	15.8	24	23	23

5.2.1.4 Key Observations about UFC Results

K&M has the following observations based on the above UFC results.

- UFCs are sensitive to estimated annual LNG demand. The lowest UFCs are achieved when the annual quantities result in full utilization of a single vessel. This is the so-called "sweet spot". When

annual LNG quantities exceed the capacity of a single vessel, another vessel is required. This results in the "saw tooth" variations in UFCs with increasing annual quantities, seen in Figure 5.2.

- UFCs for a 7,500 m³ small-scale LNG carrier from West Papua, Japan, and The Philippines are the lowest, up to ~135,000 tpa. However, above ~135,000 tpa, two LNG carriers would be required, which increases these UFCs.
- Between ~135,000 tpa and ~170,000 tpa, UFCs for a 10,000 m³ small-scale carrier from West Papua, Japan, and the Philippines are relatively the lowest. At these volumes, one LNG carrier can accommodate the entire expected annual quantity range. However, below ~135,000 tpa, the UFCs for a 10,000 m³ LNG carrier from these locations are slightly higher than UFCs for a 7,500 m³ small-scale LNG carrier.
- At above ~170,000 tpa, UFCs for a 15,600 m³ small-scale LNG carrier from West Papua, Japan, and the Philippines are the lowest, and just one LNG carrier can accommodate the entire expected annual quantity range. However, below ~65,000 tpa, the UFCs for a 15,600 m³ small-scale LNG carrier from these locations are amongst the highest.
- UFCs for all small-scale carrier sizes from Singapore are the highest, reflecting the long shipping distance from Singapore to Guam.
- The frequency of LNG cargo deliveries is an important consideration:
 - With an annual quantity of 185,000 tpa, a 15,600 m³ vessel would require a cargo delivery every ~13 days, assuming uniformly spaced demand, which would be relatively easy to manage operationally. However, if deliveries were required more frequently than every 9 days during high-demand months, a second vessel would be required.
 - With an annual quantity of 185,000 tpa, using a 10,000 m³ vessel would require a cargo delivery every ~9 days, which would require two vessels.
- The operational feasibility of deliveries depends on the timing of the required shipments (including demand seasonality and available weather windows), the duration of the journey (based on the supply source location), and the vessel size.

5.2.2 Estimated Freight on Board (FOB) Prices

The FOB price is the price of LNG loaded in the vessel at the LNG loading facility. It is composed of the 'In-Tank' LNG price, which is oil-indexed, plus the reload fees and seller's margin. Each of these components is discussed in more detail below.

5.2.2.1 Oil Indexed LNG Price Formula

In the Asia Pacific region, LNG pricing in the long term (10 - 15+ years) and for SPAs, is almost exclusively based on oil-indexed price formulas. Historically, the Japan Custom-cleared crude oil price (JCC) has been used as the oil price marker in Asia Pacific LNG SPAs; however, using the Brent crude oil price is now common practice.

The analysis uses the following straight-line oil-indexed LNG price formula:

LNG Price = A x Oil Price + Alpha, where:

- LNG Price (US\$/MMBtu, Higher Heating Value basis).
- Oil price marker = Brent crude oil price (US\$/bbl).
- A = Slope (%).

- Alpha = Fixed Element (US\$/MMBtu), generally representing LNG shipping costs and any fixed costs.

Oil Price Marker

Historically, the monthly average of Platt's published "dated Brent" daily assessment was used as the Brent oil price marker. In modern contracts, it's now the norm to use the monthly average of the daily settlement prices of the ICE Brent Crude Futures Contract (BRICE). Use of BRICE allows buyers and sellers to hedge LNG prices without any basis risk. Also, BRICE has significant liquidity in forward pricing, which allows buyers to hedge effectively forward for at least 1-2 years.

5.2.2.2 Slope and Alpha

The achievable slope (%) in long-term LNG SPAs depends on the LNG market conditions at the time the LNG SPA is tendered, negotiated, and signed. When the LNG market is 'long', it is a buyer's market, and slopes are generally lower. When the LNG market is 'short', it is a seller's market, and slopes are generally higher.

Slope Element

A slope of ~17.5% is full oil price parity. Historical long-term LNG pricing, for example, Indonesia to Japan in the 1970's, used a slope of 14.85% (85% oil parity). Over the last 25 years, slopes have varied from as high as 17% in the late 2000s to lower than 8% in the early 2000s.

Over the last ten years, slopes for long-term LNG SPAs have trended downwards from ~13.5% to less than ~11%. Slopes have trended upward in recent years, up to ~12.5% in the current market. Notable recent deals are:

- Qatar Energy with Sinopec at a reported¹¹ Slope of 12.7%
- Qatar Energy with Petronet at a reported¹² Slope of 12.67%, with an Alpha of 0.52

K&M's market view is that an achievable slope for a long-term conventional (not necessarily small-scale) LNG SPA negotiated in 2024 would be ~12.5%. This view is supported by feedback from several potential LNG suppliers (refer to Appendix C). Based on current market conditions, K&M assumed a 12.5% slope for Guam.

Alpha Fixed Element

Historical long-term LNG pricing in Asia, for example, from Indonesia to Japan in the 1970s, used an Alpha Fixed Element in the range of \$0.40 to \$1.00, depending on shipping distance and cost.

Table 5.7 shows the K&M estimated Alpha Fixed Element for 'In-Tank' price formulas for each LNG supply source to Guam. The Alpha Fixed Element for both West Papua (Tangguh LNG) and Kalimantan (Babak LNG) is zero, as these are both LNG production and export projects. The Alpha Fixed Element for other LNG supply sources increases with distance to the original LNG production source (assumed to be the Middle East or Australia), reflecting the higher shipping costs to the source.

¹¹ <https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/lng/110923-qatarenergy-sinopecs-long-term-lng-contract-likely-priced-around-127-slope-to-oil>

¹² <https://www.reuters.com/business/energy/indias-petronet-sign-lng-deal-with-qatar-supplies-beyond-2028-sources-2024-02-06/>

Table 5.7: Estimated Alpha Fixed Element for 'In-Tank' LNG Prices

	\$ / MMBtu
West Papua	\$ --
Japan	\$0.80
The Philippines	\$0.40
Kalimantan	\$ --
Vietnam	\$0.40
Singapore	\$0.40

5.2.2.3 Estimated FOB Prices

K&M estimated the FOB prices for each identified potential LNG supply source using the following formula:

FOB Price = 'In-Tank' LNG Price + C + D, where:

- FOB Price is expressed in \$/MMBtu (Higher Heating Value)
- 'In-Tank' LNG Price = % * Brent + Alpha
- C = Storage, handling, and reloading fee
- D = Seller's trading margin

'In-Tank' LNG Prices

Table 5.8 shows the estimated 'In-Tank' LNG prices for each of the potential LNG supply sources, assuming a Brent oil price of \$75/bbl.

Table 5.8: Estimated 'In-Tank' LNG Prices

	% Brent	Alpha (\$ / MMBtu)	'In-Tank' Price @ \$75 Brent
West Papua	12.5%	\$ --	\$9.40
Japan	12.5%	\$0.80	\$10.20
The Philippines	12.5%	\$0.40	\$9.80
Kalimantan	12.5%	\$ --	\$9.40
Vietnam	12.5%	\$0.40	\$9.80
Singapore	12.5%	\$0.40	\$9.80

Storage, Handling, and Reloading Fees

Table 5.9 shows the estimated storage, handling, and reloading fees for a small-scale LNG carrier loading and reloading from each of the potential LNG supply sources to Guam.

Table 5.9: Estimated Storage, Handling, and Reloading Fees

	\$ / MMBtu
Small-Scale LNG Carrier Loading from West Papua	\$ --
Small-Scale LNG Carrier Reloading from Japan	\$1.00

	\$ / MMBtu
Small-Scale LNG Carrier Reloading from The Philippines	\$0.50
Small-Scale LNG Carrier Loading from Kalimantan	\$ --
Small-Scale LNG Carrier Reloading from Vietnam	\$0.50
Small-Scale LNG Carrier Reloading from Singapore	\$1.00

West Papua and Kalimantan have no storage, handling, and reload fee because these are LNG production and export facilities. The storage, handling, and reloading fee for The Philippines and Vietnam is estimated at \$0.50/MMBtu. This is consistent with published equivalent reload fees for terminals in Spain, Portugal, and the Baltics. Japan and Singapore have relatively high storage, handling, and reloading fees. K&M estimated this fee to be \$1.00/MMBtu based on K&M's market intelligence and feedback from prospective LNG suppliers.

Estimated Seller's Trading Margin

K&M estimates the seller's trading margin at a typical industry figure of \$0.35/MMBtu. This figure is a gross margin and covers the seller's working capital costs, trading desk overheads, contractual risk, and others, leaving a relatively small net trading margin.

5.2.2.4 FOB Price Results

Table 5.10 presents the estimated FOB prices assuming a Brent oil price of \$75/bbl.

Table 5.10: FOB Prices at \$75 Brent

	% Brent	Alpha + C + D	FOB Price @ \$75 Brent
Small-Scale LNG Carrier Loading from West Papua	12.5%	\$0.35	\$9.70
Small-Scale LNG Carrier Reloading from Japan	12.5%	\$2.15	\$11.55
Small-Scale LNG Carrier Reloading from The Philippines	12.5%	\$1.25	\$10.65
Small-Scale LNG Carrier Loading from Kalimantan	12.5%	\$0.35	\$9.70
Small-Scale LNG Carrier Reloading from Vietnam	12.5%	\$1.25	\$10.65
Small-Scale LNG Carrier Reloading from Singapore	12.5%	\$1.75	\$11.15

5.2.3 Estimated Delivered Ex-Ship (DES) Prices

K&M estimated the DES price for each identified potential LNG supply source using the following formula:

DES Price = FOB Price + UFC, where:

- DES price is expressed in \$/MMBtu (Higher Heating Value)
- FOB price = the estimated FOB price formulas for each potential LNG supply source
- UFC = the estimated UFC for each combination of small-scale LNG carrier size and potential LNG supply source

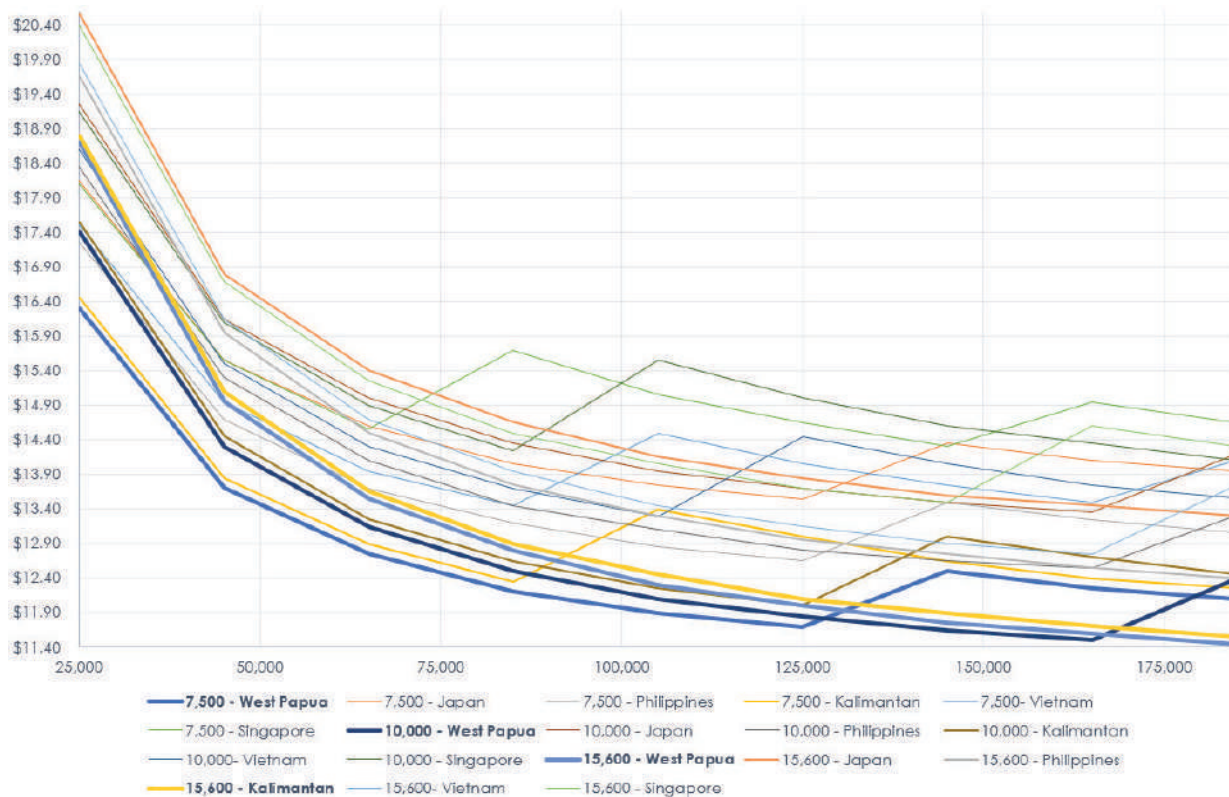
Table 5.11 below shows the estimated DES prices for each combination of small-scale LNG carrier size and potential LNG supply sources assuming a Brent oil price of \$75/bbl, over an LNG demand range of 25,000 to 185,000 tpa. The four combinations with the lowest average ex-ship LNG prices are highlighted in green.

Table 5.11: Estimated DES LNG Price at \$75 Brent

LNG Carrier Size & Supply Source	tpa								
	25,000	45,000	65,000	85,000	105,000	125,000	145,000	165,000	185,000
7,500 - West Papua	\$ 16.30	\$ 13.70	\$ 12.75	\$ 12.20	\$ 11.90	\$ 11.70	\$ 12.50	\$ 12.25	\$ 12.10
7,500 - Japan	\$ 18.15	\$ 15.55	\$ 14.60	\$ 14.05	\$ 13.75	\$ 13.55	\$ 14.35	\$ 14.10	\$ 13.95
7,500 - Philippines	\$ 17.25	\$ 14.70	\$ 13.70	\$ 13.20	\$ 12.85	\$ 12.65	\$ 13.50	\$ 13.25	\$ 13.05
7,500 - Kalimantan	\$ 16.45	\$ 13.85	\$ 12.90	\$ 12.35	\$ 13.40	\$ 13.00	\$ 12.65	\$ 12.40	\$ 12.25
7,500 - Vietnam	\$ 17.50	\$ 14.95	\$ 13.95	\$ 13.45	\$ 14.50	\$ 14.05	\$ 13.75	\$ 13.50	\$ 14.10
7,500 - Singapore	\$ 18.10	\$ 15.55	\$ 14.55	\$ 15.70	\$ 15.05	\$ 14.65	\$ 14.30	\$ 14.95	\$ 14.65
10,000 - West Papua	\$ 17.40	\$ 14.30	\$ 13.15	\$ 12.50	\$ 12.10	\$ 11.85	\$ 11.65	\$ 11.50	\$ 12.40
10,000 - Japan	\$ 19.25	\$ 16.15	\$ 15.00	\$ 14.35	\$ 13.95	\$ 13.70	\$ 13.50	\$ 13.35	\$ 14.20
10,000 - Philippines	\$ 18.35	\$ 15.30	\$ 14.10	\$ 13.45	\$ 13.10	\$ 12.80	\$ 12.65	\$ 12.55	\$ 13.30
10,000 - Kalimantan	\$ 17.55	\$ 14.45	\$ 13.25	\$ 12.65	\$ 12.25	\$ 12.00	\$ 13.00	\$ 12.70	\$ 12.45
10,000 - Vietnam	\$ 18.60	\$ 15.50	\$ 14.30	\$ 13.70	\$ 13.30	\$ 14.45	\$ 14.05	\$ 13.75	\$ 13.55
10,000 - Singapore	\$ 19.15	\$ 16.10	\$ 14.90	\$ 14.25	\$ 15.55	\$ 15.00	\$ 14.60	\$ 14.35	\$ 14.10
15,600 - West Papua	\$ 18.70	\$ 14.95	\$ 13.55	\$ 12.80	\$ 12.30	\$ 12.00	\$ 11.75	\$ 11.60	\$ 11.45
15,600 - Japan	\$ 20.55	\$ 16.80	\$ 15.40	\$ 14.65	\$ 14.15	\$ 13.85	\$ 13.60	\$ 13.45	\$ 13.30
15,600 - Philippines	\$ 19.65	\$ 15.95	\$ 14.50	\$ 13.75	\$ 13.30	\$ 12.95	\$ 12.75	\$ 12.55	\$ 12.40
15,600 - Kalimantan	\$ 18.80	\$ 15.10	\$ 13.65	\$ 12.90	\$ 12.45	\$ 12.10	\$ 11.90	\$ 11.70	\$ 11.55
15,600 - Vietnam	\$ 19.85	\$ 16.15	\$ 14.70	\$ 13.95	\$ 13.45	\$ 13.15	\$ 12.90	\$ 12.75	\$ 13.75
15,600 - Singapore	\$ 20.40	\$ 16.70	\$ 15.25	\$ 14.50	\$ 14.05	\$ 13.70	\$ 13.50	\$ 14.60	\$ 14.30

Figure 5.3 below shows the estimated DES prices for each combination of small-scale LNG carrier size and potential LNG supply sources, assuming a Brent oil price of \$75/bbl, over an LNG demand range of 25,000 to 185,000 tpa.

Figure 5.3: Estimated DES LNG Price at \$75 Brent



5.2.3.1 Key Observations about DES Prices

Key observations about DES prices in Guam are generally consistent with the key observations about the estimated UFCs.

- Estimated DES LNG prices are sensitive to estimated annual LNG demand. The lowest DES price is achieved when the annual quantities result in full utilization of a single vessel. This is the so-called “sweet spot”. When annual LNG quantities exceed the capacity of a single vessel, another vessel is required. This results in the “saw tooth” variations in ex-ship LNG prices with increasing annual quantities.
- A 7,500 m³ small-scale LNG carrier from West Papua (Tangguh LNG) results in the lowest estimated DES price up to ~135,000 tpa. However, above ~135,000 tpa, the estimated DES price increases because two small-scale LNG carriers would then be required.
- A 10,000 m³ small-scale LNG carrier from West Papua (Tangguh LNG) results in the relatively lowest estimated DES price for volumes between ~135,000 and ~170,000 tpa. At these volumes, one carrier can accommodate the entire expected annual quantity range. However, below ~135,000 tpa, the UFCs for a 10,000 m³ small-scale LNG carrier from West Papua are slightly higher than the estimated DES price for a 7,500 m³ small-scale LNG carrier.
- A 15,600 m³ small-scale LNG carrier from West Papua (Tangguh LNG) results in the lowest estimated DES price from volumes above ~170,000 tpa. At these volumes, one carrier can accommodate the entire expected annual quantity range. However, below ~65,000 tpa, the DES price for a 15,600 m³ small-scale LNG carrier from West Papua is much higher than a 7,500 m³ or 10,000 m³ LNG carrier.
- The estimated DES price from Singapore is the highest across all small-scale LNG carrier sizes. This is due to the relatively longer shipping distance to Guam and the higher estimated LNG reload fee.
- The maximum annual quantities for the three demand scenarios are ~124,000 tpa (GPA target), ~152,000 tpa (Guam Law), ~178,000 tpa (Delayed Renewables). K&M analyzed the required delivery frequency, considering both seasonal demand and weather windows, to determine the necessary delivery schedule throughout the year (described in Section 6.3.5). In years with higher demand volumes (>170,000 tpa), deliveries during peak months would need to occur at intervals shorter than the ~9-day round-trip voyage of a single vessel. In such cases, two vessels would be required - regardless of whether the supply solution uses a 10,000 m³ or 15,600 m³ LNG carrier - to meet the necessary volume and frequency.

Even at lower demand volumes, seasonal variations impact the delivery schedule and necessitate additional buffer storage. The 10,000 m³ LNG carrier provides greater storage flexibility compared to the 7,500 m³ option, helping to manage these seasonal fluctuations more effectively. Based on this analysis and the conclusion that the lowest-cost supply source is West Papua, K&M considered the 10,000 m³ LNG carrier from West Papua (loaded from Tangguh LNG) as the optimal solution across all three demand scenarios and used it for subsequent analysis in this study.

5.3 LNG Storage Tank Capacity

The type and size of the LNG carrier delivering LNG to Guam will influence the technical specifications of the LNG import terminal, including LNG storage capacity. The required capacity of the Guam terminal LNG storage tank depends on the maximum size of the LNG cargo lot delivered and the required buffer storage. Buffer storage will be required to manage foreseeable delays in cargo deliveries and variations in GPA’s LNG demand (against the annual forecast). For this study, K&M assumed an industry rule-of-thumb for buffer storage equivalent to five days of

demand. Table 5.12 below presents the estimated net tank capacity required for the Guam LNG import terminal. A 15,000 m³ storage tank is assumed for all three demand scenarios to ensure sufficient storage.

Table 5.12: Estimated Required Tank Capacity

Small-Scale LNG Carrier Size	tpa								
	25,000	45,000	65,000	85,000	105,000	125,000	145,000	165,000	185,000
10,000 m ³	10,300	10,800	11,400	11,900	12,500	13,000	13,600	14,100	14,600

5.4 Conclusions

Based on the results of the Evaluation of Sourcing and Shipping Options, the following conclusions can be drawn at this stage:

- The most practical and least-cost LNG supply solution for Guam, across all three demand scenarios, involves deliveries from West Papua (Tangguh LNG) using 10,000 m³ small-scale LNG carriers. This conclusion is based on both cost and operational feasibility. In years or months when LNG deliveries are needed more frequently than approximately every nine days, a second vessel would be required to meet demand and maintain operational flexibility. Even in these instances, the 10,000 m³ vessel remains more cost-effective than the 15,600 m³ option. This analysis assumes that a second vessel can be contracted on a short-term basis if demand exceeds 170,000 tonnes per annum (tpa) for any reason.
- Further consultation with potential LNG suppliers and service providers is advisable during the LNG procurement process.



Task 3

Least-Cost LNG Terminal Site and Configurations

6 Task 3 – Least-Cost LNG Terminal Site and Configurations

The primary objective of Task 3 is to identify the least-cost option for siting and configuring the terminal that will receive and handle LNG in Guam. To this end, this task includes an initial analysis of all technically viable sites and terminal configuration options, developing Class V¹³ cost estimates for this subset of technically feasible options, evaluating the pros and cons of each, selecting a shortlist of options, and developing Class IV cost estimates for the shortlisted option(s). The output of this analysis is an estimate of the CAPEX and OPEX for the least-cost LNG terminal and infrastructure, which is used as a primary input for Task 4.1 – Economic Cost Benefit Analysis, Task 4.2 – Ratepayer Impact Analysis, and Task 5.3 – Financial Analysis of the Gas Supply Company.

This section is organized into six sections. Section 6.1 presents the methodology used to estimate the cost of each configuration and the basis for comparison. Section 6.2 describes the three potential sites for the LNG import terminal and infrastructure. Section 6.3 presents the assumptions and functional requirements of the LNG import terminal. Section 6.4 describes the long list of LNG terminal configurations. Section 6.5 presents the results of the options comparison, including the least-cost terminal options. Section 6.6 describes the shortlisted options in detail. Section 6.7 presents the conclusions. Appendix F includes additional information about the feasibility of using cold natural gas for gas turbine inlet air cooling. Appendix G includes the full analysis of safety and exclusion zones for the three sites. Appendix H includes the results of the metocean, mooring, and wave height analysis at Tanguisson. Appendix I includes additional discussion of marine infrastructure at Tanguisson. Appendix J includes information about bunkering options in Guam. Appendix O includes the full implementation schedule for the two terminal sites.

6.1 Methodology

This section presents the methodology for costing and comparing the LNG terminal options. The comparison considers the cost of each option by determining the price per MMBtu (USD / MMBtu), to identify the least-cost LNG terminal configuration. Additionally, the analysis evaluates non-cost considerations such as acceptability to the Navy, gas pipeline utilization, permitting risk, and operational risks. The non-cost evaluation matrix is presented in Table 6.1. Both the cost and non-cost considerations were used to compare options and determine the preferred configuration.

Table 6.1: Non-Cost Evaluation Matrix

Acceptability to the Navy
<i>Navy's Security Risk Perception (1=High/5=Low)</i> The Navy is concerned that an LNG terminal near its facilities could limit its ability to operate freely during critical war events, and that the terminal could be a target
<i>Improves Navy's Fuel Supply Security (5=Significantly/1=Not at All)</i> The location of the LNG/fuel import terminal could provide the Navy with an additional facility to import fuel to Guam - increasing fuel security
Gas Pipeline Utilization

¹³ Class V and IV refers to the Association of Advancement of Cost Engineering (AACE International) cost estimate classification. Class V (or 5) refers to a project with 0% to 1% definition and a cost estimate accuracy of -50% to +100%. Class IV (or 4) refers to a project with 1% to 15% definition and a cost estimate accuracy of -30% to +50%.

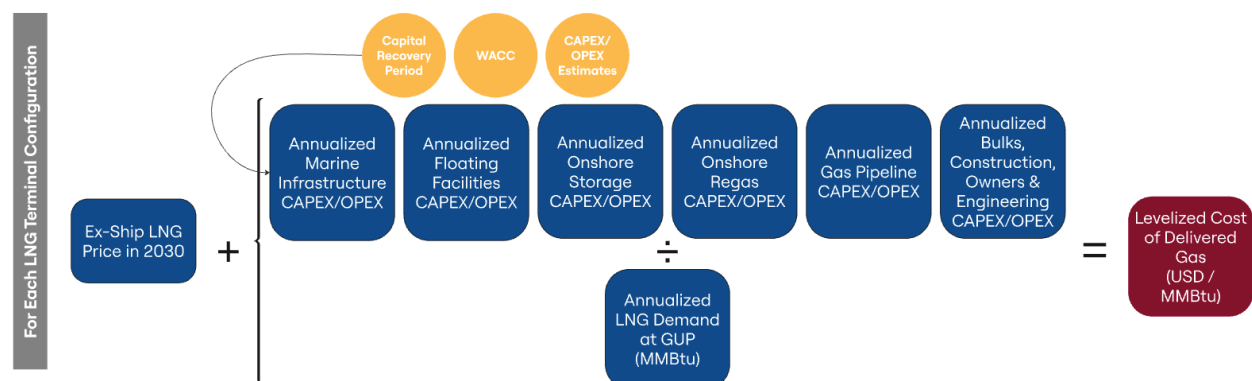
Utilization of Existing Gas Pipeline (5=Used/1=Not Used)
Some options use the gas pipeline to supply gas to Ukudu, or to transport gas to the port for bunkering
Permitting Risk
LNG Terminal Permitting Risk (5=Low/1=High)
Permitting options with a subsea pipeline makes permitting more complex and riskier
Gas Pipeline Permitting Risk (5=Low/1=High)
Some options may require a pipeline with new rights of way, which is more complex and riskier
Operational Risk
Extreme Metocean Condition Risk (5=Low/1=High)
Some options have greater exposure to extreme wave conditions that could affect LNG delivery windows

The LNG terminal options used in the analysis were identified based on an iterative selection process. Initially, only Apra Harbor sites were considered, but stakeholder feedback from the Navy led to an expansion of siting options. Ultimately, three feasible sites were selected, detailed in Section 6.2. Each site includes a configuration option with onshore storage and regas. Two sites include configurations with floating storage solutions. Additionally, each configuration included infrastructure related to bunkering LNG vessels.

After defining the configurations, the K&M team identified the required marine and onshore infrastructure and developed potential layouts. These layouts were the basis for Class V cost estimates, covering both capital expenditures (CAPEX) and operating expenses (OPEX) for key components, including marine infrastructure, floating facilities (if applicable), onshore storage, onshore regasification, gas pipelines, bulk materials, construction, and owner's engineering.

To enable cost comparison, these CAPEX and OPEX figures were annualized for the model period using the weighted average cost of capital (WACC). These annualized costs (USD) were then divided by the annualized LNG volume (MMBtu) to determine the price per MMBtu for each component. Figure 6.1 illustrates how these inputs were used to calculate the levelized cost of delivered gas to GUPP (USD / MMBtu), with further details provided in Section 6.1.1.

Figure 6.1: Model Diagram



Following the cost and non-cost comparison of the terminal configuration options, two configurations were selected to be refined further with Class IV cost estimations. These two configurations are described in greater detail in Section 6.6.

The CAPEX and OPEX for the preferred configuration option are used as inputs for subsequent tasks of this assignment, including for Task 4.1 – Economic Cost Benefit Analysis, Task 4.2 – Ratepayer Impact Analysis, and Task 5.3 – Financial Analysis of the Gas Supply Company.

6.1.1 Modeling Assumptions

6.1.1.1 CAPEX / OPEX Estimation

K&M's subcontractors, GHD and CH·IV, led the development of Class V and Class IV cost estimates for the marine and onshore infrastructure components, respectively. To develop these estimates, each firm followed standard industry methodologies appropriate for the level of design definition. GHD conducted preliminary engineering assessments for the marine infrastructure to determine the sizing and configuration of key components such as the berth, mooring structures, and transfer systems. GHD also engaged with specialized equipment vendors and marine contractors to obtain indicative pricing and technical specifications, which were used to inform Class V and IV estimates, a high-level, order-of-magnitude cost approximation based on conceptual designs.

Similarly, CH·IV developed the Class V and IV cost estimate for the onshore infrastructure, which included onshore storage, regasification systems, cryogenic piping, utilities, and civil works. CH·IV's process included the development of preliminary equipment layouts and system designs, supported by engagement with vendors and suppliers to request quotations for major equipment and construction services. For options involving floating storage units, the annual OPEX was estimated based on typical daily charter rates for comparable LNG carriers, as well as projected fuel and electricity consumption. These estimates provide a foundation for comparing alternative configurations and assessing the technical and financial feasibility of LNG supply solutions for Guam.

6.1.1.2 Guam Factor

As part of the CAPEX estimation process for the proposed LNG terminal in Guam, the project team applied a "Guam factor" to adjust certain CAPEX inputs to reflect Guam's specific cost environment. Some cost estimates were provided directly by contractors with experience in Guam and already incorporated local conditions, including transport and labor costs. However, for other CAPEX inputs sourced from U.S.-based estimates, escalation factors were applied to account for the additional costs associated with transporting equipment to Guam and, conversely, the relatively lower local construction labor costs.

For the Class V estimates, which represent order-of-magnitude approximations with limited design definition, a Guam factor of two (2.00) was applied to the base U.S. cost inputs. This conservative factor served as a rough estimation to account for the heightened uncertainty at the early stage of design and reflects expected cost premiums associated with Guam's remote location and logistical challenges.

The Guam factor was refined further using more detailed Class IV estimates, applied selectively depending on the nature of each cost item:

- Construction-related costs (e.g., bulk materials, labor, civil works) were escalated using a construction factor.
- Equipment-related costs (imported from the U.S.) were escalated using a transportation factor.

Construction Factor

The construction factor was derived from the RS Means Index for Guam, which provides localized construction cost indices relative to U.S. averages. RS Means is a widely recognized industry database that tracks construction material, labor, and equipment costs across regions. Based on data from 2021 to 2024, the construction cost index for Guam showed an increase, resulting in an escalation factor of 1.29 by the end of 2024 compared to the baseline. This factor was applied to construction-related line items such as bulk materials and site works.

Transportation Factor

The transportation factor accounts for the additional cost of shipping equipment from the U.S. mainland to Guam. Based on estimates provided by CH·IV, shipping costs were approximated at \$4 per kilogram.¹⁴ Using vendor price quotes and equipment weight data, K&M estimated that shipping represents approximately 24% of the total equipment cost, leading to a transportation factor of 1.24. This factor was applied to imported equipment line items requiring shipment to Guam.

These escalation factors help ensure the CAPEX estimates accurately reflect the logistical, economic, and geographic realities of constructing and operating an LNG terminal in Guam.

6.1.1.3 Capital Recovery Period

The capital recovery period used to annualize the inputs is 19 years.

6.1.1.4 Weighted Average Cost of Capital (WACC)

The weighted average cost of capital (WACC) is the discount rate used to annualize the inputs. The equation for calculating the WACC is:

$$\text{WACC} = (E/V * r_e) + (D/V * r_d), \text{ where:}$$

E / V = Proportion of Equity, assumed 30%

D / V = Proportion of Debt, assumed 70%

V = Total Capital (Equity + Debt)

r_e = Cost of equity, estimated by CAPM (see Section 10.2.3) at 8.12%

r_d = Cost of debt, assumed 6.95%

Based on these assumptions and inputs, the WACC used for the analysis is 7.30%.

6.1.1.5 Gas Demand and Annual Volumes

The volume of gas required at GUPP is a function of electricity demand and the level of renewable energy generation in Guam. K&M assumes that GPA will dispatch electricity generated from renewables first and meet the remaining load with electricity generated from natural gas and ULSD power plants. Given the uncertainty surrounding the timeline for renewable energy deployment in Guam, the analysis evaluates three scenarios, listed below, that determine gas demand at GUPP:

¹⁴ [https://www.freightos.com/freight-resources/ocean-freight-explained/#:~:text=Sea%20Freight%20Rates%20Per%20KG,-With%20the%20exception&text=Ocean%20freight%20is%20around%20\\$2,000%20days%20quicker%2C%20but%20more%20expensive.](https://www.freightos.com/freight-resources/ocean-freight-explained/#:~:text=Sea%20Freight%20Rates%20Per%20KG,-With%20the%20exception&text=Ocean%20freight%20is%20around%20$2,000%20days%20quicker%2C%20but%20more%20expensive.)

- **GPA Target:** Based on GPA's timeline for renewable energy deployment, which targets 50% renewable energy by 2030 and 100% renewable energy by 2040.
- **Guam Law:** Based on Guam Public Law No. 35 – 46, which targets 50% RE by 2035 and 100% RE by 2045.
- **Delayed Renewables:** Based on gradual additions of RE at a lower rate than either GPA's target or Guam law.

The gas demand under these three scenarios was derived from K&M's fuel demand model from Task 1, which is detailed in Section 4 of this report.

For each scenario, the present value of the total gas demand (MMBtu) over the period 2031 - 2050 is calculated using a discount rate of 7.30%, described in Section 6.1.1.4. This volume is then annualized using the same discount rate and capital recovery period of 20 years. This annualized volume is used to calculate the price per MMBtu for each of the infrastructure components described in Section 6.1.1.1 and illustrated in Figure 6.1.

6.1.1.6 LNG Bunkering Demand

The annual volumes of LNG required for LNG bunkering were determined to be just under 35,000 tpa, based on the potential bunkering demand of 1,500 m³ per week. This figure was estimated during a consultation with the shipping company Matson, described in Appendix J.

6.1.1.7 Ex-Ship LNG Prices

The methodology for calculating Ex-Ship LNG prices is described in Task 2 and detailed in Section 5.2.3. The DES price for the Commercial Operation Date (COD) 2031 is used for each gas demand scenario. LNG is assumed to be delivered via a 10,000 m³ LNG carrier from West Papua for all configurations with onshore storage or a small-scale Floating Storage Unit (FSU). For configurations with a large-scale Floating Storage Unit (FSU), the DES price is calculated following the same methodology but with the inputs described in Table 6.2.

Table 6.2: DES Price of LNG - 174,000 m³ (Gladstone)

Brent %	12.5%
Alpha	\$0.85
Storage, handling, Reload Fees	\$ --
Seller's Margin	\$0.35
Unit Freight Cost	\$0.11

6.2 Site Descriptions

Three sites were considered for the LNG import terminal in Guam. One site, Tanguisson, is in northwest Guam, while the others – Hotel Wharf and Dry Dock Island – are within Apra Harbor. Initially, only the Apra Harbor sites were considered, given the existence of the newly constructed LNG pipeline to transfer gas from Apra Harbor to GUPP; this pipeline was financed and constructed as part of the IPP project under the assumption that LNG would be imported at the harbor. However, subsequent consultation with key stakeholders in Guam, namely the US Navy, cited concerns over the safety and security of an LNG import terminal in the harbor and encouraged

K&M to investigate alternative sites that may be technically viable for LNG import. Figure 6.2 illustrates the locations of the three potential sites in relation to GUPP and the LNG pipeline.

Figure 6.2: Three Potential Sites



6.2.1 Tanguisson

Tanguisson is located in northwest Guam, approximately four kilometers from GUPP and outside the viewshed of Two Lovers Point (see Figure 6.3). This site was identified as an alternative to Apra Harbor. It is the location of a retired power plant owned by GPA and has vehicle access to the beach. Key advantages of this site include its acceptability to the Navy and its potential to support bunkering for U.S. Navy vessels and the importation of JP8 aviation fuel. However, a primary limitation is its lack of natural protection. Floating storage solutions are not viable at this location, requiring deliveries to be scheduled within acceptable weather windows. Given Guam's storm and seasonal weather patterns, these windows may be reduced during winter and summer months, increasing storage requirements. The technical feasibility of the site is assessed in greater detail in Section 6.6. Additionally, this site would not utilize the existing LNG pipeline.

Figure 6.3: Tanguisson Site Location



6.2.2 Hotel Wharf

Hotel Wharf is located within Apra Harbor, west of the Port Authority of Guam, along Hotel Wharf Access Road (Highway 11), approximately 2.3 kilometers from the existing LNG pipeline interface point (see Figure 6.4). The site is currently unused, and GPA is not aware of any confirmed projects planned for this location. Key advantages of this site include its protected position, which could support semi-permanently moored floating storage solutions, as well as its proximity to the existing LNG pipeline. However, the available onshore space is insufficient to accommodate all necessary infrastructure, requiring a small reclamation area for development. While the site's use would have a minimal impact on current port or Navy operations, the Navy has raised concerns regarding its acceptability due to safety and security considerations.

Figure 6.4: Hotel Wharf Site Location



6.2.3 Dry Dock Island

Dry Dock Island is located within Apra Harbor, south of the Port Authority of Guam, along Highway 18, approximately 6.5 kilometers from the existing LNG pipeline interface point (see Figure 6.5). The Navy occasionally uses the site for training exercises. Key advantages of this site include its protected position, which could support semi-permanently moored floating storage solutions, as well as its proximity to the existing LNG pipeline. Additionally, the site has sufficient onshore space to accommodate all necessary infrastructure. While the site's use would have a minimal impact on current Navy operations, use of this site may require change to navigation patterns from Inner Harbor to fuel piers. Additionally, the Navy has raised concerns regarding its acceptability due to safety and security considerations.

Figure 6.5: Dry Dock Island



6.3 LNG Terminal Functional Requirements

This section describes assumptions related to the LNG import terminal, including storage requirements, floating storage options, LNG carrier sizes and specifications, required support vessels, monthly deliveries, exclusion and safety zones, and a description of the LNG bunkering options.

6.3.1 Minimum Storage

Required storage is assumed to be 15,000 m³ at all three sites. This figure is based on the analysis completed under Task 2 and detailed in Section 5 of this report.

6.3.2 Floating Storage Solutions

While the Tanguisson site is too exposed to accommodate floating storage solutions, these solutions were considered for the two Apra Harbor sites. Floating Storage and Regasification Units (FSRUs) were excluded from consideration due to their higher capital and operating costs compared to Floating Storage Units (FSUs) and onshore regasification. Permanently moored FSUs were also deemed unfeasible due to typhoon exposure in Apra Harbor. However, semi-permanently moored FSUs were considered viable, as they could be relocated ahead of significant storm events.

Two FSU sizes were assessed for each of the Apra Harbor sites:

- A 15,000 m³ small-scale FSU, which could be filled by a 10,000 m³ small-scale LNG carrier
- A 147,000 m³ large-scale FSU, which could be filled by a 174,000 m³ large-scale LNG carrier

While the capital and operating expenses of the larger FSU are higher than those of the small-scale FSU, these costs may be offset by lower DES prices and reduced unit freight costs of the larger LNG carrier (see Table 6.3). Further details on these vessels are provided in Appendix E.

Table 6.3: FSU Specifications

	Moulded Hull 15k FSU	Moss-Type 147k FSU
Time Charter Rate (USD / day)	50,000	80,000
Fuel Consumption (tonnes / year)	730	1,460
Electricity Consumption (MWh / year)	13,600	17,600

6.3.3 LNG Carriers

Two sizes of LNG carriers were considered – a 10,000 m³ small-scale LNG carrier and a 174,000 m³ large-scale LNG carrier. Further details on these vessels are provided in Appendix E.

6.3.4 Support Vessels

Additional support vessels, including tugboats, line handling boats, and security and emergency response craft will be required at each of the sites. Table 6.4 estimates these requirements for each of the sites.

Table 6.4: Support Vessels

	Tanguisson	Apra Harbor
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Tugboats	3 – 4 Required	2 – 3 Required
Line Handling Boats	2 Required	N/A
Security and Emergency Response Craft	TBD	TBD

6.3.5 LNG Deliveries Per Month

Based on demand forecasting completed during Task 1, K&M estimated the monthly number of deliveries the LNG terminal will receive for each LNG demand scenario. The number of deliveries required was calculated using the weekly LNG demand for each scenario, utilizing a 10,000 m³ LNG carrier with a 15,000 m³ onshore LNG storage tank. The analysis assumes the LNG storage tank is filled to maximum volume at the beginning of the year. The calculation takes the tank volume at the start of the week and subtracts the LNG demand for that week. A delivery is required when the tank volume at the end of the previous week is below the projected LNG demand for the next week (i.e. there is not enough volume left in the tank to cover the next week's demand). The calculation was completed for the three LNG demand scenarios during each scenario's highest LNG demand year. The calculation was only done for the 10,000 m³ vessel because this vessel size would be more likely to reach its maximum number of deliveries in one year; therefore requiring a second vessel Table 6.5 below shows the results.

Table 6.5: LNG Deliveries Per Month

Demand Scenario	Highest LNG Demand Year	Total Deliveries Required during Highest LNG Demand Year	Average Deliveries per Month
GPA Target	2035	28	2.33
Guam Law	2035	34	2.83
Delayed Renewables	2032	38	3.16

The number of deliveries required per month for each scenario is not evenly distributed throughout the year, as there are certain periods of the year with higher LNG demand, primarily due to lower solar radiation during those times (see Figure 4.5 for the typical weekly distribution for LNG demand).

On average, the LNG terminal will require between 3 and 4 LNG deliveries per month during the peak demand years. Forty-one 10,000 m³ deliveries in 2031 for the delayed renewables scenario. This is one more delivery per year than the estimated maximum number of deliveries that a 10,000 m³ LNG carrier can make from West Papua in one year—as presented in Table 6.6. Therefore, in that year, two 10,000 m³ LNG carriers will be needed to meet the LNG demand for the delayed renewables scenario.

The number of required deliveries and vessels is used in conjunction with the metocean analysis to determine whether there will be periods when GUPP will have to operate on ULSD due to interruptions in LNG deliveries caused by metocean conditions. The results of this analysis are presented in Section 6.6.1.1.

6.3.6 Exclusion and Safety Zones

When siting LNG import terminals, the establishment of exclusion and safety zones is a critical factor in ensuring public safety and achieving regulatory approval. Exclusion zones are designated areas around LNG facilities that must remain under the legal control of the operator or a government entity to protect people and infrastructure from the effects of thermal radiation or vapor dispersion in the event of an incident. Federal regulations enforced by PHMSA under 49 CFR Part 193, together with industry standards outlined in NFPA 59A-2001, require applicants to model credible release scenarios—such as an LNG tank top fire—and demonstrate that exclusion zones comply with specific safety thresholds. PHMSA coordinates closely with FERC during the siting process to confirm that facilities meet these requirements, with PHMSA issuing a Letter of Determination to FERC as part of the permitting review. Establishing compliant exclusion zones early in the design process is crucial for minimizing permitting risks and ensuring that any land use conflicts are identified and resolved through acquisition, leasing, or agreements with government entities.

Site-specific evaluations conducted for Dry Dock Island, Hotel Wharf, and Tanguisson show that, while the thermal radiation exclusion zones for an LNG tank top fire can generally be accommodated within project boundaries, certain locations require targeted mitigation strategies. At Dry Dock Island, exclusion zones remain within the facility's boundaries but extend onto waterways and adjacent Navy-controlled land, requiring a legal agreement with the Navy. At Hotel Wharf, exclusion zones impact nearby government land and a roadway, necessitating agreements with both the Navy and local public works authorities. At Tanguisson, while the majority of the exclusion zone is contained, a portion extends onto private property, requiring either land acquisition or leasing to comply with regulatory requirements. In all cases, exclusion zones also extend over adjacent waterways, which do not present regulatory obstacles. A complete description of the thermal radiation modeling and detailed site-specific considerations is provided in Appendix G.

6.3.7 LNG Bunkering

GPA requested that K&M assess the possibility of LNG bunkering for vessels in the Guam port. For the Tanguisson site, two options for delivering LNG to the Port of Guam were evaluated: 1) trucking LNG in ISO containers, and 2) utilizing the existing pipeline from GUPP to the port with small-scale re-liquefaction and storage infrastructure at the port. For the Apra Harbor sites, only trucking of LNG in ISO containers was considered.

6.3.7.1 Bunkering Analysis

During the Class V cost estimate stage, LNG bunkering was included in all terminal configurations, and the cost of bunkered LNG at the Port of Guam was estimated for each option. The results are provided in Section 6.5.3. However, in a January 2025 discussion with a potential off-taker – Matson, a global shipping company – it was determined that Matson is unlikely to pursue LNG bunkering in Guam at the prices that could be offered to them in Guam (see Appendix J). This decision is based on their recent tenders and long-term supply agreements. For Guam's LNG pricing to be viable for Matson, it would need to have a significantly lower cost, and even then, it would serve only as a tertiary backup option. As a result, bunkering was excluded from the final Class IV cost estimates and the final analysis of the least-cost terminal configuration.

6.4 LNG Terminal Configurations

Eight LNG terminal configurations were identified, which are summarized below in Table 6.6, and detailed in the sections below. These configurations include the marine and onshore infrastructure related to gas delivery to GUPP and the option for LNG bunkering at the port of Guam.

Table 6.6: Configurations Summary

#	Site	Gas Delivery to GUPP	LNG Bunkering
1	Tanguisson	Mooring / Subsea Pipeline with Onshore Storage & Regas	ISO Containers by Truck
2	Tanguisson	Mooring / Subsea Pipeline with Onshore Storage & Regas	Pipelined Gas and Reliquefaction
3	Hotel Wharf	At-Shore Berth with Onshore Storage & Regas	ISO Containers by Truck
4	Hotel Wharf	Jetty for 15,000 m ³ FSU with Onshore Regas	ISO Containers by Truck
5	Hotel Wharf	Jetty for 140,000 m ³ FSU with Onshore Regas	ISO Containers by Truck
6	Dry Dock Island	At-Shore Berth (South Side) with Onshore Storage & Regas	ISO Containers by Truck
7	Dry Dock Island	Jetty for 15,000 m ³ FSU with Onshore Regas	ISO Containers by Truck
8	Dry Dock Island	Jetty for 140,000 m ³ FSU with Onshore Regas	ISO Containers by Truck

6.4.1 Tanguisson Site Options

6.4.1.1 Configuration 1 & 2

The Tanguisson site was evaluated for two bunkering options: (1) LNG transport via ISO containers on trucks and (2) pipelined natural gas utilizing the existing pipeline infrastructure with regasification at the port. While these options have different operational and cost implications, the marine and onshore infrastructure required to support LNG import and storage remains consistent for both and is therefore presented together in this section. The marine infrastructure consists of a multi-buoy mooring system and a permanently installed transfer tower, connected to shore via a subsea cryogenic pipeline installed within a horizontal directional drilling (HDD) casing. Onshore, LNG is stored in a full containment storage tank, regasified on-site, and transported via a dedicated pipeline approximately 2.45 miles to the Ukudu power plant. The onshore facility also includes a flood protection wall/levee, an LNG impoundment area, and a truck loading station, which supports Option 1 (bunkering via ISO containers). Figure 6.6 and Figure 6.7 include the diagrams of the marine and onshore infrastructure and pipeline path to Ukudu.

The Tanguisson site presents several environmental and technical considerations that influence the selection of LNG transfer infrastructure. The project team evaluated two primary alternatives for transferring LNG from the LNG carrier to shore: the use of a semisubmersible vessel and a permanent offshore transfer tower. The semisubmersible option, based on EConnect's IQuay C-Class system, offers mechanical connection capabilities and would be moored offshore, linking to the onshore facility via flexible cryogenic hoses. However, due to the site's exposed metocean conditions, including wave climate and shallow approach angles, this alternative raised uncertainties regarding operational reliability and potential downtime associated with LNG carrier interactions.

As a result, the project team identified the permanent transfer tower as the preferred concept for Phase I analysis. This fixed structure would be located offshore at a position that satisfies draft requirements and vessel motion parameters, enabling LNG transfers via flexible hoses while maintaining safety clearances. Given the presence of shallow waters and coral outcrops nearshore, the design also incorporates horizontal directional drilling (HDD) to install a subsea casing for the LNG pipeline, connecting the offshore transfer point to the proposed onshore regasification facilities. HDD has been successfully applied in Guam for similar utility projects and was selected to minimize impacts on the seafloor. Additional information on the alternatives considered and supporting technical analyses is provided in Appendix I.

Figure 6.6: Tanguisson Marine and Onshore Infrastructure

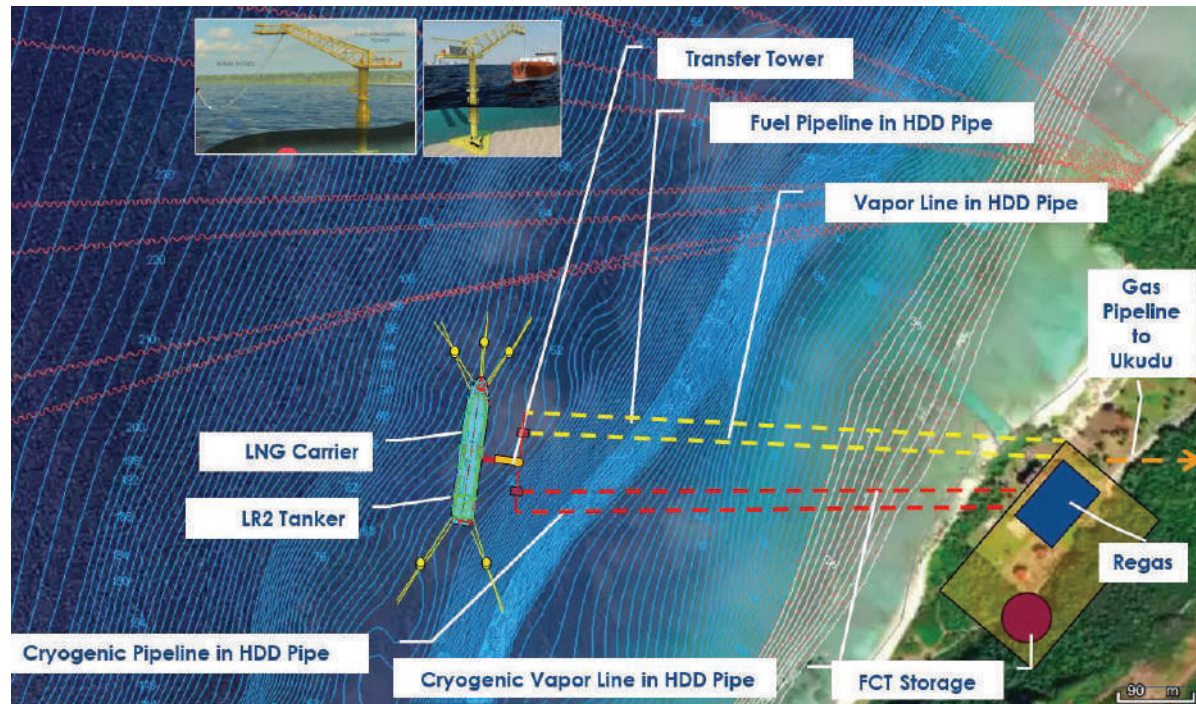


Figure 6.7: Tanguisson Onshore Infrastructure and Pipeline Diagram



Bunkering

Configuration 1 includes the trucking bunkering solution, which involves transporting ISO containers of LNG (approximately 20 containers supported by 5 trucks) over roughly 20.5 miles from the Tanguisson site to Apra Harbor. Each round trip is estimated to take 49 minutes, enabling the bunkering operation to meet the weekly demand of 2,000 m³ of LNG within a 22-hour bunkering window.

Configuration 2 includes the pipeline bunkering solution, which would utilize the existing natural gas pipeline to deliver gas to the port. This option would require the construction of an additional pipeline segment to connect the existing pipeline interface point to the port, where the gas would be reliquefied and stored for subsequent bunkering operations.

6.4.2 Hotel Wharf Options

6.4.2.1 Configuration 3

The first configuration option for the Hotel Wharf site involves an at-shore berth designed for transient LNG deliveries, incorporating a small land reclamation area to support marine infrastructure. The configuration includes an onshore full-containment LNG storage tank and an associated regasification facility. A new pipeline connection will be required to link the site to the existing pipeline interface point. The onshore facility also includes a flood protection wall or levee, an LNG impoundment area, and a truck loading station to support the bunkering solution involving the transport of LNG in ISO containers. For this option, LNG would be trucked approximately 1.4 miles (about 4 minutes travel time) to Apra Harbor, requiring 5 ISO containers and 5 trucks to deliver the weekly demand of 2,000 m³ within a 22-hour bunkering window. Figure 6.8, Figure 6.9, and Figure 6.10 include the diagrams of the marine and onshore infrastructure and pipeline path to the interface point.

Figure 6.8: Configuration 3 - Marine and Onshore Infrastructure

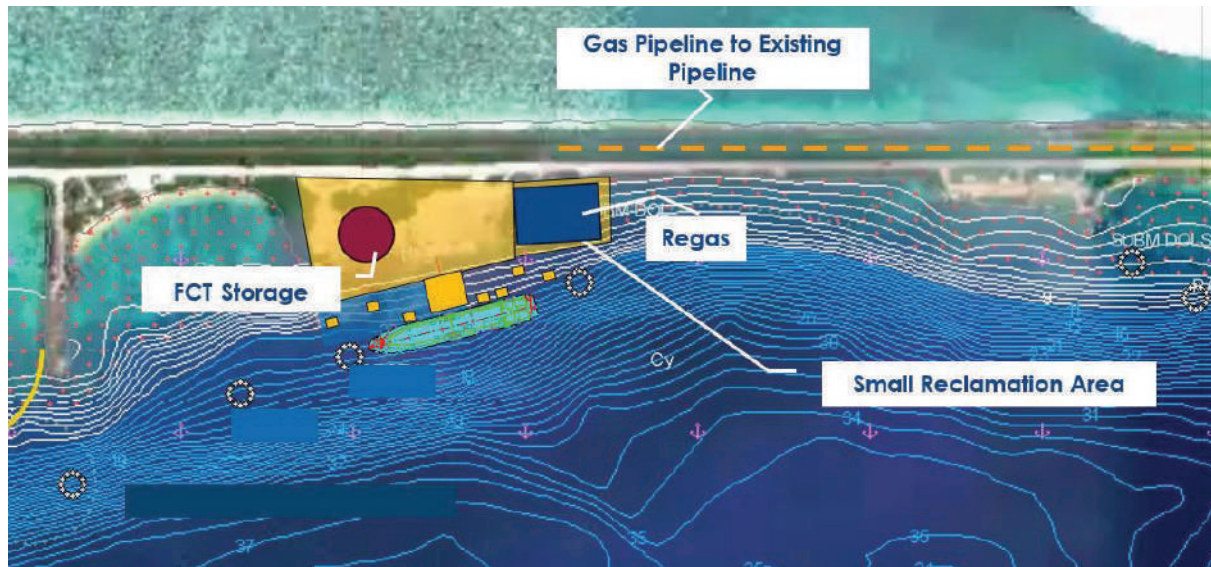


Figure 6.9: Configuration 3 - Onshore Infrastructure



Figure 6.10: Hotel Wharf – Pipeline to Interface



6.4.2.2 Configuration 4

The second configuration option at Hotel Wharf features a 15,000 m³ floating storage unit (FSU) that is filled by the LNG carrier and semi-permanently moored at the site. The FSU is accessed via a pile-supported jetty with an unloading platform. Because this configuration utilizes floating storage, only an onshore regasification system is required, eliminating the need for land reclamation at the site. Regasified natural gas is then transported via pipeline to the existing pipeline interface point (see Figure 6.10). Figure 6.11 and Figure 6.12 below provide detailed diagrams of the marine and onshore infrastructure as well as the pipeline route to the interface point. The associated bunkering solution is identical to that described under Configuration 3 in the previous section.

Figure 6.11: Configuration 4 - Marine and Onshore Infrastructure

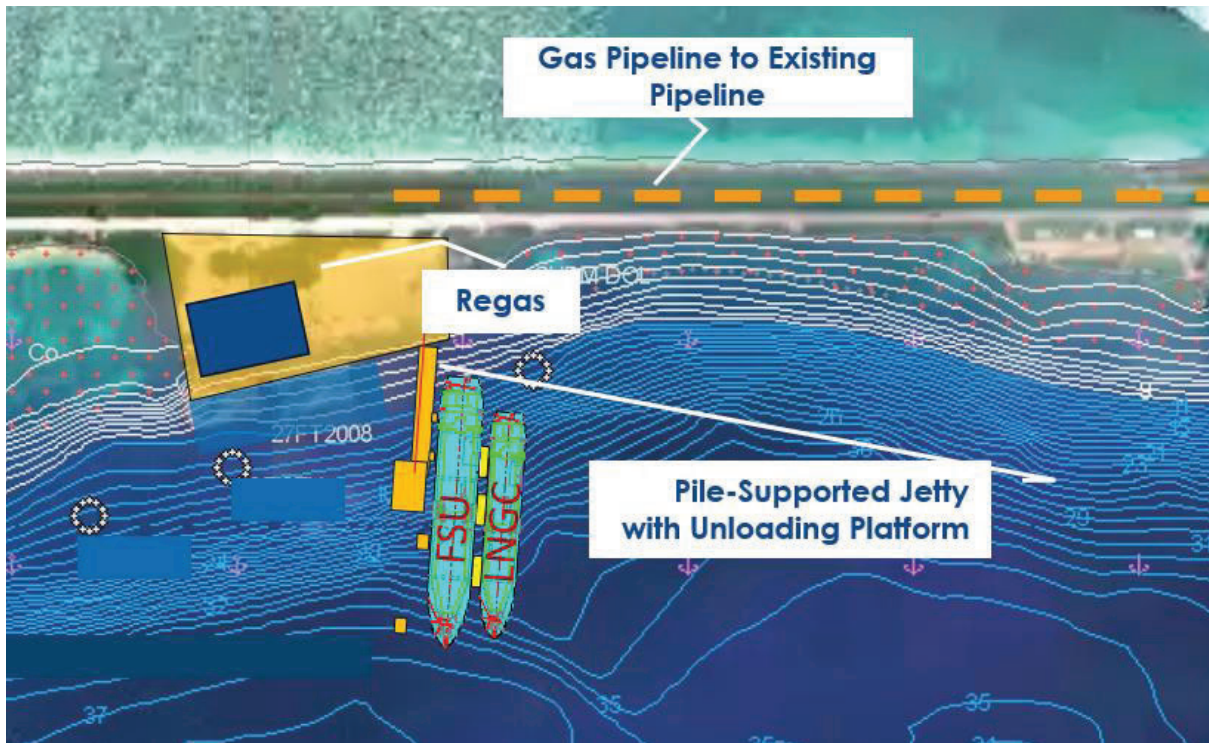


Figure 6.12: Configuration 4 - Onshore Infrastructure



6.4.2.3 Configuration 5

The third configuration option at Hotel Wharf includes a 140,000 m³ floating storage unit (FSU), which is filled by a large-scale LNG carrier and semi-permanently moored at the site. The FSU is accessed via a pile-supported jetty with an unloading platform. As with the other floating storage configurations, this option requires only an onshore regasification system, eliminating the need for any land reclamation at the site. This configuration was evaluated to assess whether the potentially lower delivered cost of LNG from a large-scale LNG carrier could offset the relatively higher OPEX associated with operating a larger FSU. The regasified natural gas is transported via pipeline to the existing pipeline interface point. Figure 6.13 and Figure 6.14 below illustrate the marine and onshore infrastructure as well as the pipeline route to the interface point. The associated bunkering solution is the same as that described under configuration three.

Figure 6.13: Configuration 5 - Marine and Onshore Infrastructure

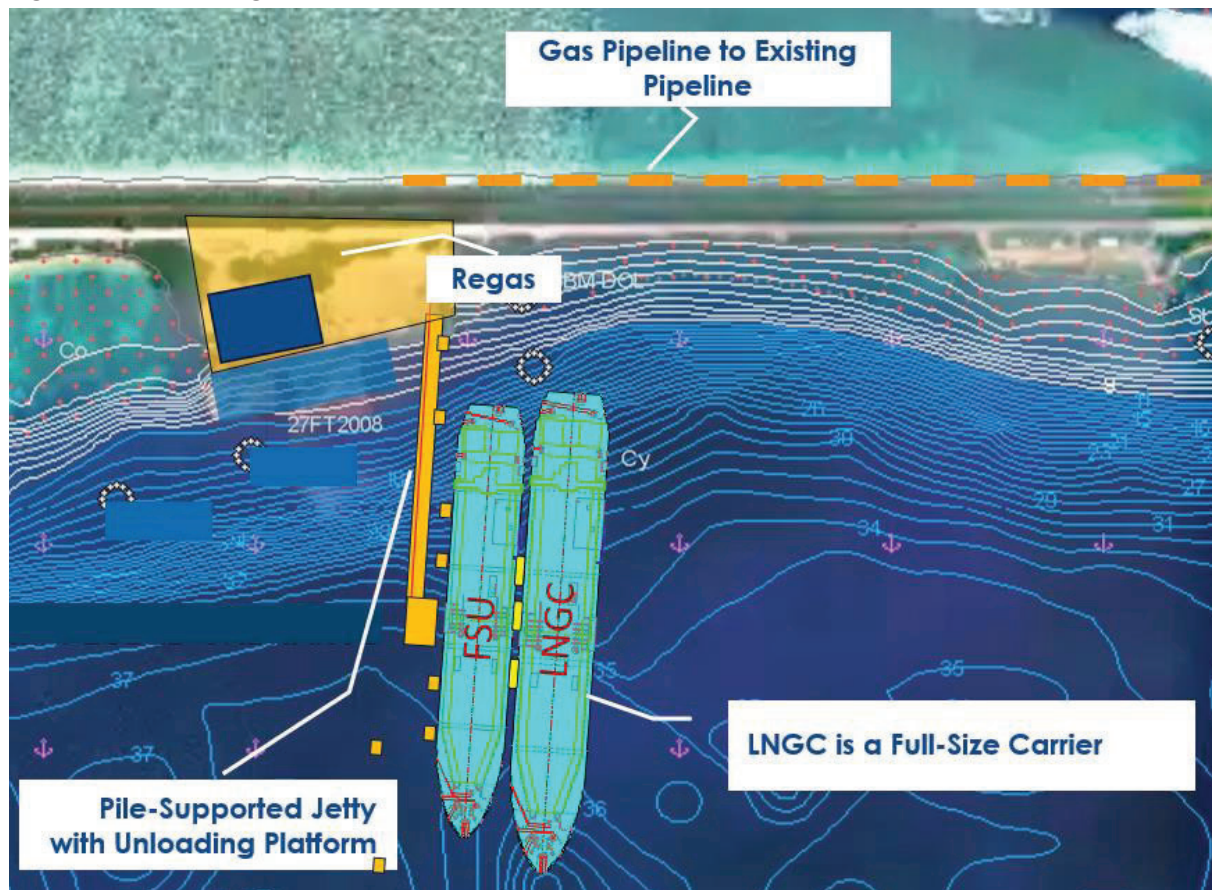


Figure 6.14: Configuration 5 - Onshore Infrastructure



6.4.3 Dry Dock Island

6.4.3.1 Configuration 6

The first configuration option for the Dry Dock Island site involves an at-shore berth designed for transient LNG deliveries. The configuration includes an onshore full-containment LNG storage tank and an associated regasification facility. A new pipeline connection will be required to link the site to the existing pipeline interface point. The onshore facility also includes a flood protection wall or levee, an LNG impoundment area, and a truck loading station to support the bunkering solution involving the transport of LNG in ISO containers. For this option, LNG would be trucked approximately 3.9 miles (about 10 minutes travel time) to Apra Harbor, requiring 6 ISO containers and 5 trucks to deliver the weekly demand of 2,000 m³ within a 22-hour bunkering window. Figure 6.15, Figure 6.16, and Figure 6.17 include the diagrams of the marine and onshore infrastructure and pipeline path to the interface point.

Figure 6.15: Configuration 6 - Marine and Onshore Infrastructure

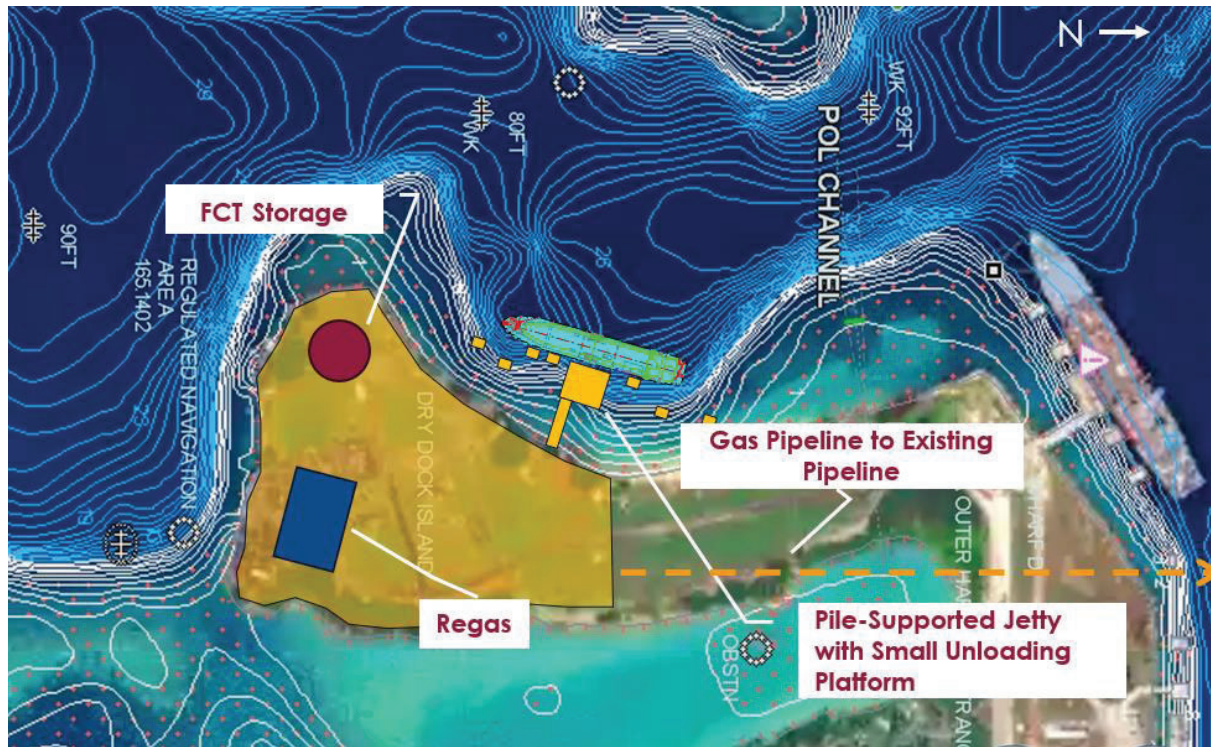


Figure 6.16: Configuration 6 - Onshore Infrastructure

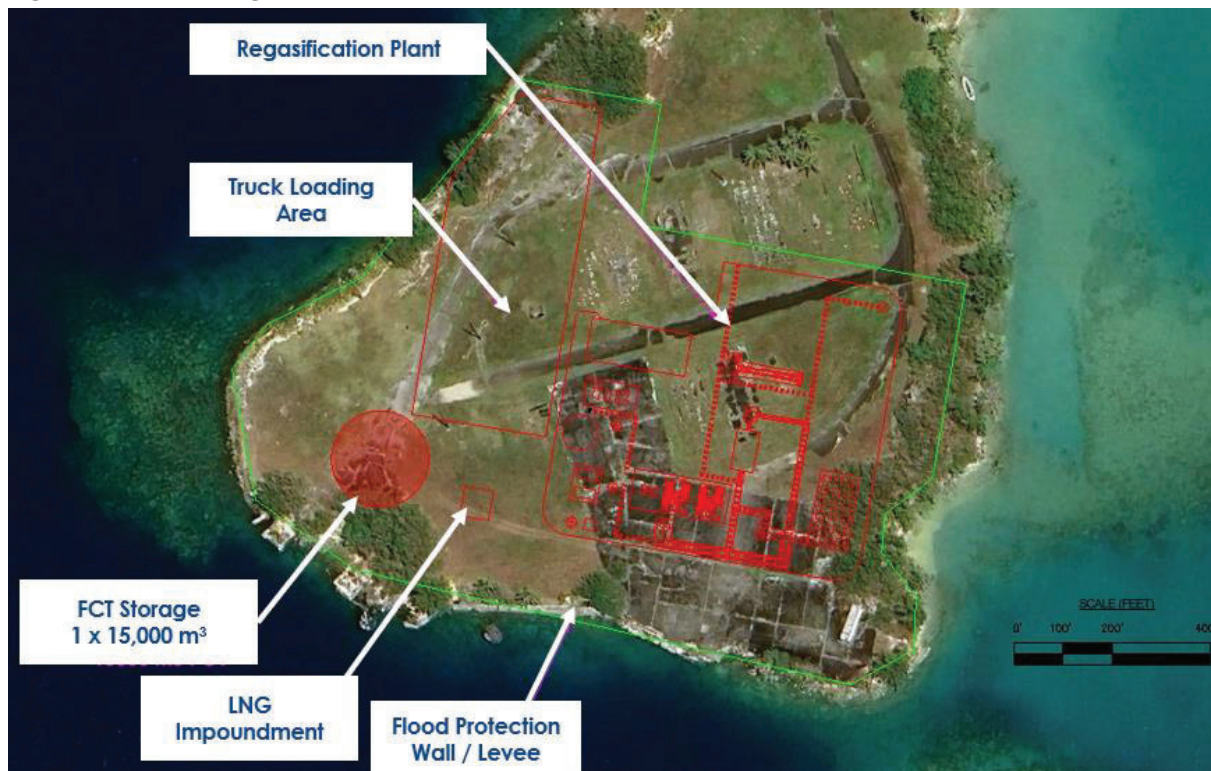


Figure 6.17: Dry Dock Island – Pipeline to Interface



6.4.3.2 Configuration 7

The second configuration option at Dry Dock Island features a 15,000 m³ floating storage unit (FSU) that is filled by the LNG carrier and semi-permanently moored at the site. The FSU is accessed via a pile-supported jetty with an unloading platform. Because this configuration utilizes floating storage, only an onshore regasification system is required. Regasified natural gas is then transported via pipeline to the existing pipeline interface point (see Figure 6.17). Figure 6.18 and Figure 6.19 below provide detailed diagrams of the marine and onshore infrastructure as well as the pipeline route to the interface point. The associated bunkering solution is identical to that described under Configuration 6 in the previous section.

Figure 6.18: Configuration 7 – Marine and Onshore Infrastructure

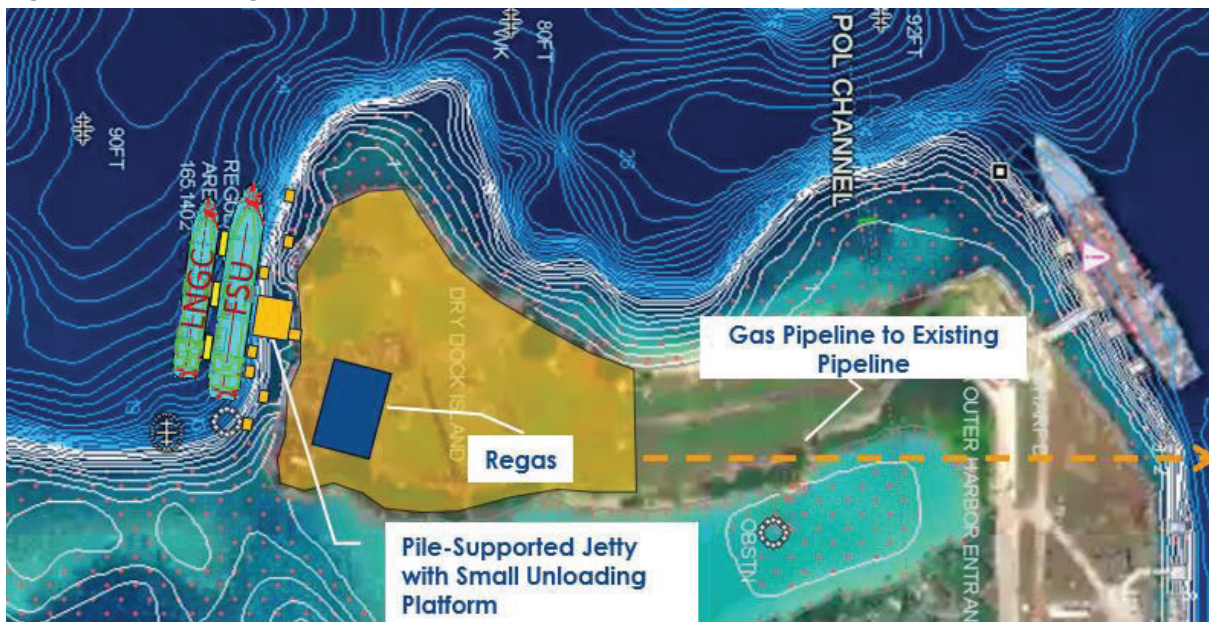


Figure 6.19: Configuration 7 – Onshore Infrastructure



6.4.3.3 Configuration 8

The third configuration option at Dry Dock Island includes a 140,000 m³ floating storage unit (FSU), which is filled by a large-scale LNG carrier and semi-permanently moored at the site. The FSU is accessed via a pile-supported jetty with an unloading platform. As with the other floating storage configurations, this option requires only an onshore regasification system. This configuration was evaluated to assess whether the potentially lower delivered cost of LNG from a large-scale LNG carrier could offset the relatively higher OPEX associated with operating a larger FSU. The regasified natural gas is transported via pipeline to the existing pipeline interface point (see Figure 6.17). Figure 6.20 and Figure 6.21 below illustrate the marine and onshore infrastructure as well as the pipeline route to the interface point. The associated bunkering solution is the same as that described under Configuration 6.

Figure 6.20 Configuration 8 – Marine and Onshore Infrastructure

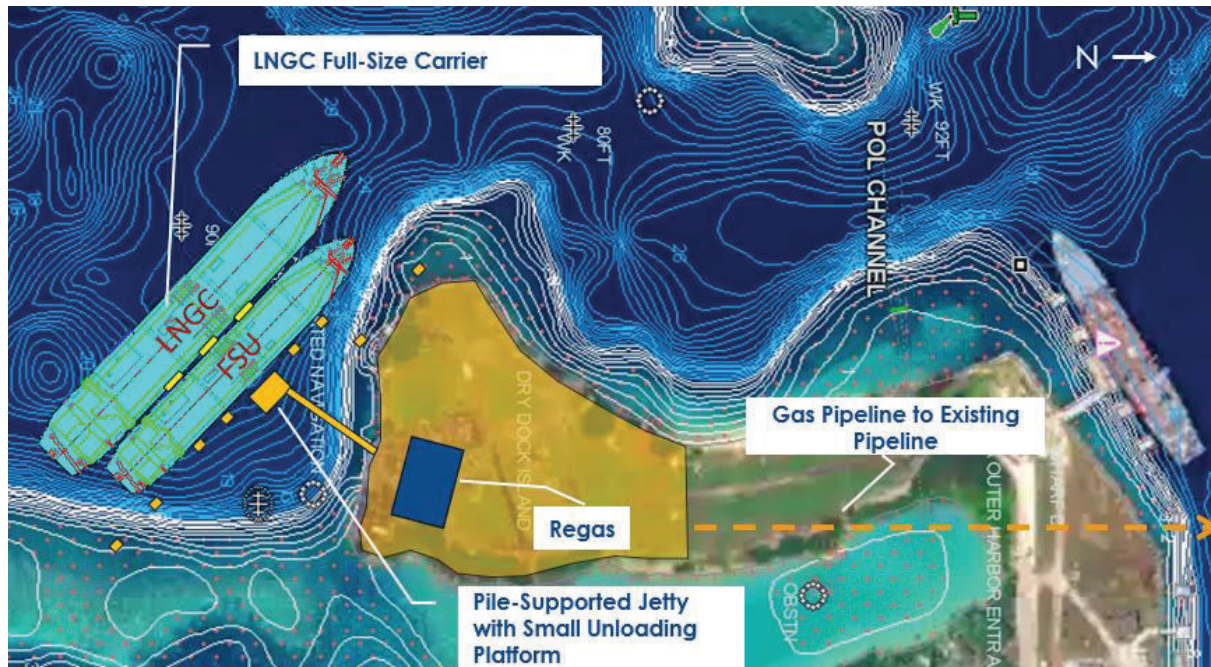


Figure 6.21: Configuration 8 – Onshore Infrastructure



6.5 Results of Least-Cost Terminal Configuration Analysis

6.5.1 Class V Cost Estimation Results

The Class V CAPEX and OPEX estimations are presented below in Table 6.7. The configurations with an FSU have lower CAPEX given the exclusion of onshore storage; however, the annual OPEX is significantly higher than other options due to the time charter rate and fuel and electricity consumption.¹⁵

Table 6.7: Class V CAPEX and OPEX Estimates

Option	1	2	3	4	5	6	7	8
Total CAPEX (USD Million)	396.6	396.6	386.4	261.1	310.3	321.9	225.4	276.5
Marine	173.1	173.1	156.7	129.5	178.8	95.9	98.8	148.9
Regas / Storage	131.6	131.6	133.8	38.0	38.0	133.8	38.0	38.0
Gas Pipeline / Other	92.0	92.0	95.9	93.5	93.5	92.1	88.6	89.6
Total OPEX (USD Million / year)	10.8	10.6	7.8	24.3	35.8	7.2	24.0	35.5
FSU OPEX	--	--	--	18.3	29.2	--	18.3	29.2
Other OPEX	10.8	10.6	7.8	6.0	6.6	7.2	5.7	6.3

6.5.2 Class V Levelized Cost of Gas (LCOG) Results

The Class V cost estimates were used to calculate the LCOG delivered at GUPP. The LCOG is composed of the DES price of LNG (USD / MMBtu) plus a portion (USD / MMBtu) related to the CAPEX and OPEX of the option. Further information regarding the DES price can be found in Section 5.2.2. The DES price for each scenario is indexed to a Brent curve with a levelized price per bbl of \$116, which is described in Appendix A. The results presented in Figure 6.22 are for the Delayed RE scenario. The configurations resulting in the lowest LCOG to Ukudu are the options with onshore storage and regas across all three potential sites.

¹⁵ These CAPEX estimates were derived using a Guam Factor of 2.0. The lower Guam Factor described in section 6.1.1.2 was used for the Class IV estimates presented in section 6.6.2.1

Figure 6.22: Class V Levelized Cost of Gas (LGOG) to GUPP by Component

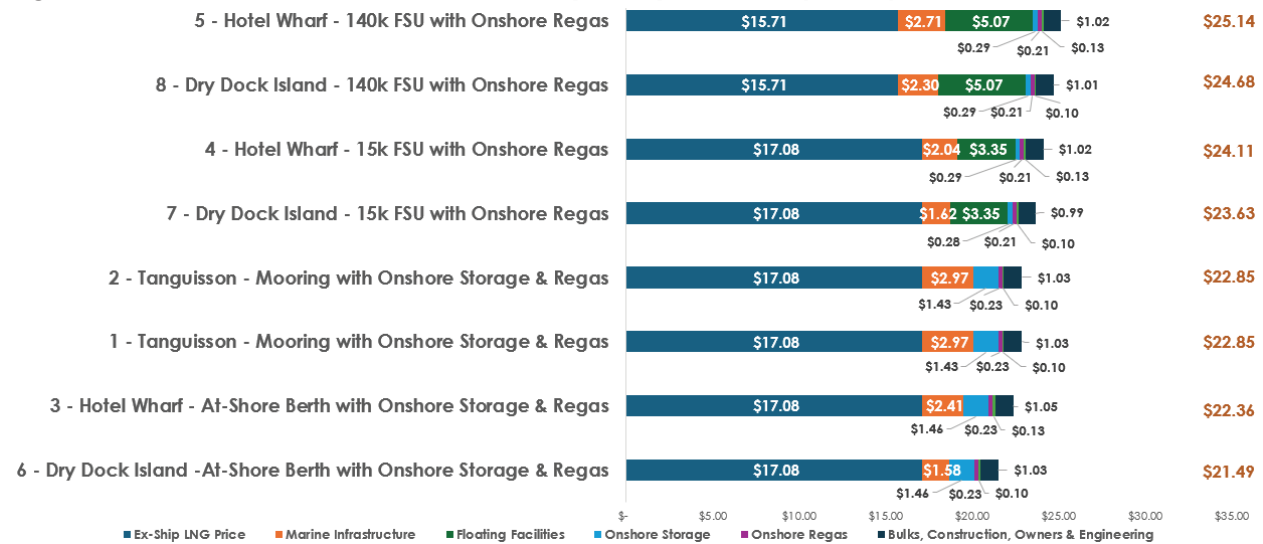
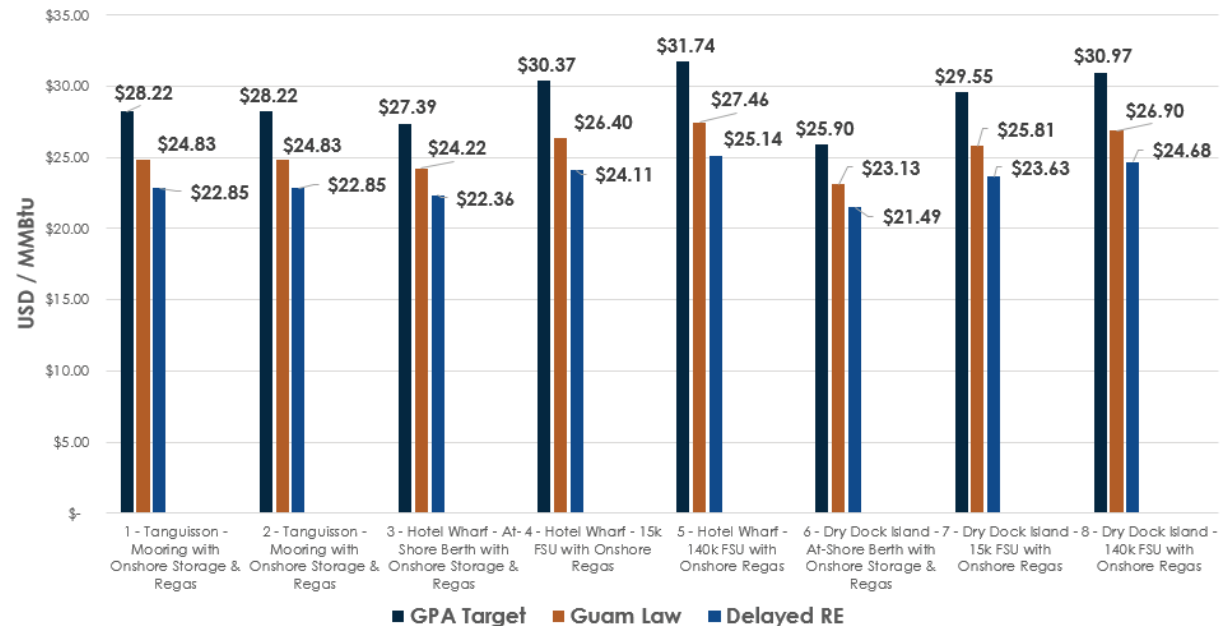


Figure 6.23 illustrates the LCOG for all three scenarios; the Delayed RE scenarios result in the lowest LCOG across all configuration options.

Figure 6.23: Class V Levelized Cost of Gas (LCOG) by Demand Scenario



6.5.3 Class V Levelized Cost of Bunkering

Table 6.8 presents the levelized cost of bunkering (USD / MMBtu) for each of the configuration options. The least-cost options are the onshore storage with LNG bunkering via ISO by truck at each of the three sites.

Table 6.8: Class V Levelized Cost of Bunkering (USD / MMBtu)

Option	1	2	3	4	5	6	7	8
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Levelized Cost of Bunkering	23.37	24.37	22.48	24.28	25.30	21.68	23.90	24.93
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6.5.4 Cost and Non-Cost Evaluation of the Options

Table 6.9 below presents the results of the least-cost analysis combined with the non-cost evaluation and scoring.

Table 6.9: Cost and Non-Cost Evaluation of the Options

Option	1	2	3	4	5	6	7	8
Cost Evaluation								
LCOG at GUPP	22.85	22.85	22.36	24.11	25.14	21.49	23.63	24.68
Non-Cost Evaluation								
Acceptability to Navy, (5=High/1=Low)								
Navy's Security Risk Perception <i>The Navy is concerned that an LNG terminal in Apra Harbor could limit their ability to operate freely during critical war events and that the terminal could be a target.</i>	5	5	1	1	1	1	1	1
Navy's Fuel Supply Security <i>A new LNG/fuel import terminal in Tanguisson could provide the Navy with the additional facility to import fuel to Guam – increasing fuel security.</i>	5	5	1	1	1	1	1	1
Gas Pipeline Utilization, (5=High/1=Low)								
Utilization of Existing Gas Pipeline <i>All Apra Harbor options use the gas pipeline to supply gas to GUPP. Option 2 uses the pipeline to transport gas to the port for bunkering, but only a small amount of gas.</i>	1	3	5	5	5	5	5	5
Permitting Risk, (1=High/5=Low)								
LNG Terminal Permitting Risk <i>Permitting the subsea pipeline for Options 1 and 2 makes permitting more complex and riskier than the Apra Harbor options.</i>	3	3	3	3	3	3	3	3

Gas Pipeline Permitting Risk <i>Options 1 and 2 require a pipeline with new rights of way. It could be riskier to permit than the shorter gas pipelines required by the Apra Harbor options.</i>	3	3	3	3	3	3	3	3
Operational Risk, (1=High/5=Low)								
Extreme Metocean Conditions Risk <i>Options 1 and 2 have a higher exposure to extreme wave conditions that could affect LNG delivery windows.</i>	2	2	4	4	4	4	4	4

6.5.5 Analysis of Comparison Results

The analysis shows that the Apra Harbor options with onshore storage offer the lowest levelized cost of gas delivered to GUPP. Specifically, Option 3 (Hotel Wharf) and Option 6 (Dry Dock Island) are the least-cost configurations. Both options include onshore LNG storage. Whilst the Dry Dock Island option has a slightly lower cost than Hotel Wharf, the K&M team was not granted access to that site and is unable to conclude that it is a technically viable site. If an Apra Harbor site is shortlisted, the K&M team would recommend considering Hotel Wharf.

The Tanguisson site options (Options 1 and 2) have a cost within 10% of the least-cost Apra Harbor options. While slightly more expensive, these options offer a significant advantage in terms of Navy acceptability, as the Navy perceives fewer security risks at Tanguisson and sees potential value in using the site as an alternative fuel import facility.

However, the Tanguisson site options also present slightly higher operational risks and do not utilize the existing gas pipeline between Apra Harbor and GUPP.

Given the results of the options comparison, Options 1 (Tanguisson) and 3 (Hotel Wharf) were shortlisted for further evaluation. Section 6.6 present the results of Class IV cost estimates for these options and a further assessment of the non-cost criteria. Given stakeholder feedback, LNG bunkering services were excluded from further analysis.

6.6 Analysis of Shortlisted Options

The two shortlisted options were analyzed in more detail to assess their CAPEX, OPEX, permitting requirements, implementation schedule, and, more generally, their advantages and disadvantages. The permitting requirements are covered in Section 12, but the timing required to obtain these permits is included in the implementation schedule for each site.

6.6.1 Analysis of the Tanguisson LNG Terminal Option

Further analysis of the Tanguisson option included updating the layout (section 6.6.1.1), developing Class IV CAPEX and OPEX estimates (section 6.6.1.1), and detailed analysis of the operational risk related to the sites exposure to high waves (section 6.6.1.3).

6.6.1.1 Updated Layout

A few refinements were made to the marine and onshore layout at Tanguisson. Based on consultation with stakeholders and equipment suppliers, the cryogenic vapor line was deemed unnecessary. Minor adjustments to the positioning of the storage and regasification facilities were also made to better align with the exclusion and safety zone analysis, illustrated in Figure 6.24, Figure 6.25, and Figure 6.26.

Figure 6.24: Tanguisson Layout – Marine and Onshore Infrastructure

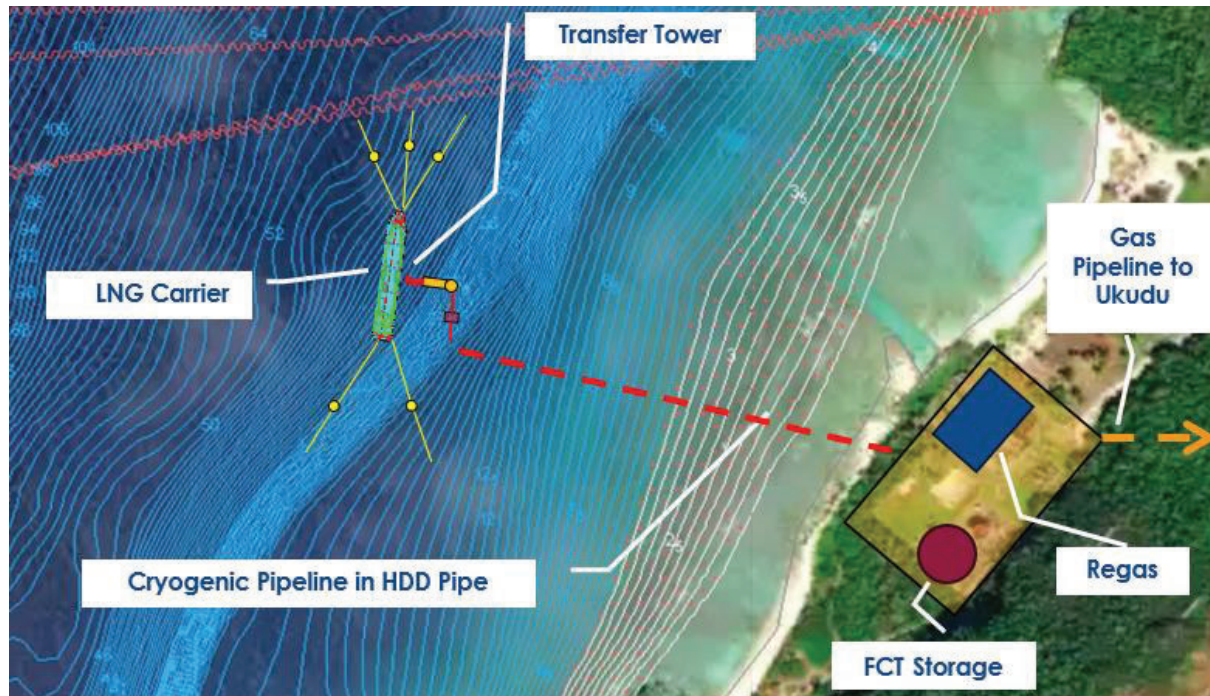


Figure 6.25: Tanguisson – Onshore Infrastructure

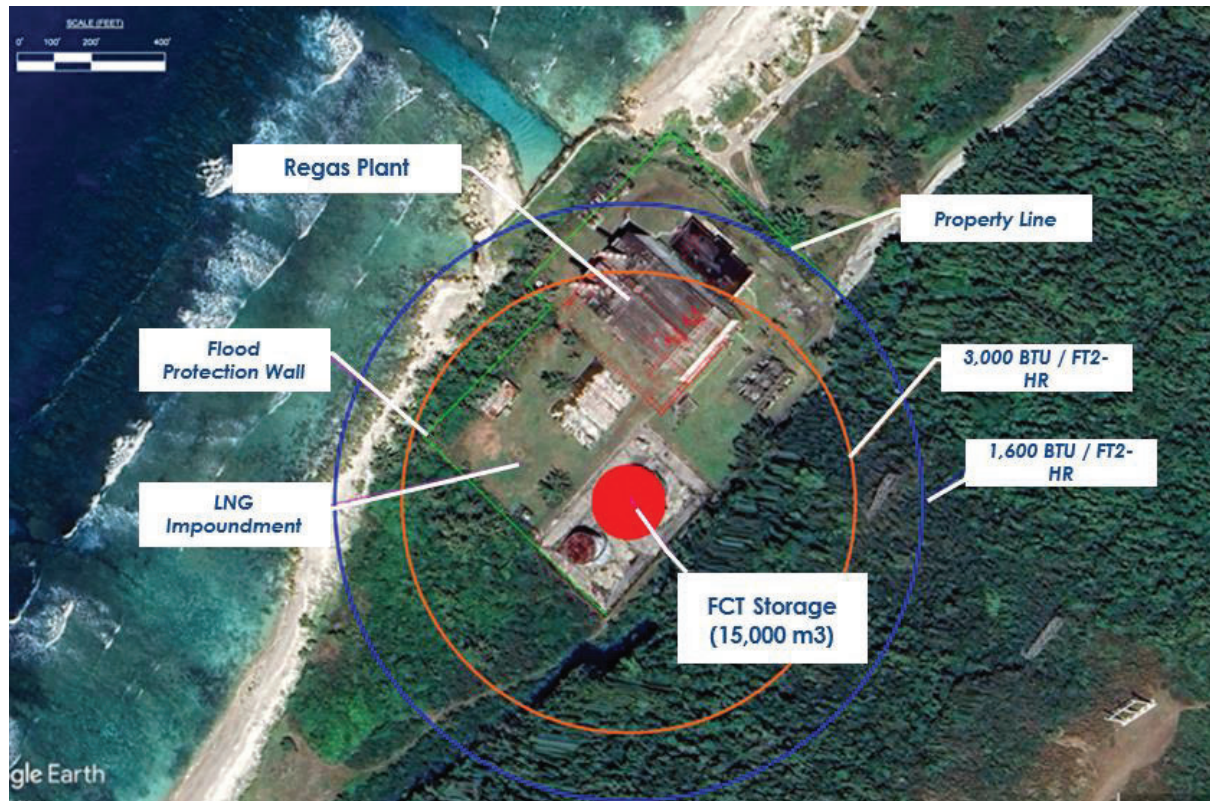


Figure 6.26: Onshore Pipeline – Tanguisson to GUPP



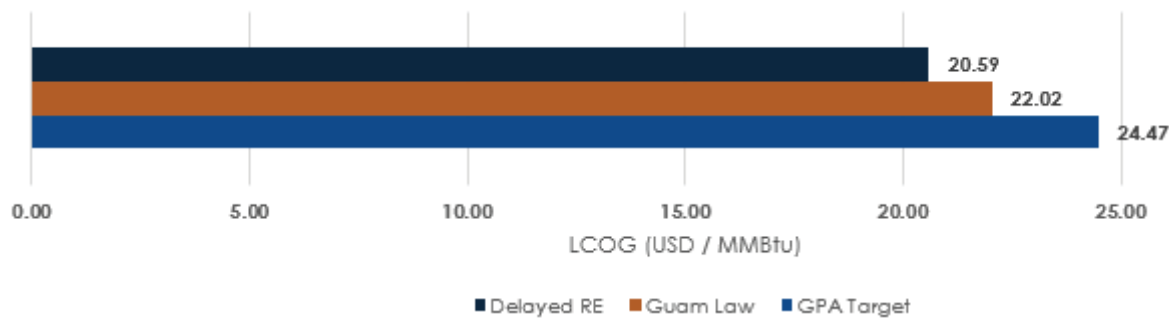
6.6.1.2 Class IV Cost Estimation Results - Tanguisson

Class V cost estimates were further refined to the Class IV level. Table 6.10 below summarizes the results of the Class IV cost estimation for the Tanguisson site.

Table 6.10: Tanguisson - Class IV Cost Estimation Results

Total CAPEX	210,620,753 USD
Marine Infrastructure	80,000,000 USD
Onshore Storage & Equipment	53,967,388 USD
Onshore Regas	6,436,089 USD
Onshore Pipeline	13,622,500 USD
Bulks, Construction, Owner's, and Engineering Costs	56,594,826 USD
Total OPEX	9,386,820 USD
Marine Infrastructure OPEX	6,060,000 USD
Other OPEX	3,326,820 USD
Land Acquisition Cost	2,000,000 USD

These CAPEX and OPEX figures result in an LCOG ranging \$20.59 – \$24.47, depending on the LNG demand scenario (see Figure 6.27). The breakdown of the LCOG by component for the GPA Target scenario is presented in Figure 6.28 below.

Figure 6.27: Tanguisson - LCOG by Demand Scenario**Figure 6.28: Tanguisson – Breakdown of LCOG for GPA Target Scenario¹⁶**

Levelized Cost of Delivered Gas at Ukudu	\$ / MMBtu	
Ex-Ship LNG Price	\$ / MMBtu	18.41
Marine Infrastructure	\$ / MMBtu	3.09
Onshore Storage	\$ / MMBtu	1.25
Onshore Regas	\$ / MMBtu	0.14
Gas Pipeline	\$ / MMBtu	0.30
Bulks, Construction, Owners & Engineering	\$ / MMBtu	1.24
Land Acquisition	\$ / MMBtu	0.04
Total		24.47

These CAPEX and OPEX results are used as inputs for the remainder of the analysis, as they represent the higher values among the two shortlisted options and reflect the potential selection

¹⁶ The LNG ex-ship price presented in this table is higher than the ex-ship price presented in section 5.2.3 because these prices are calculated using the Energy Information Agency (EIA) Brent price forecast (which starts at \$92/bbl in 2031 and increases to \$153/bbl in 2050) and those presented in section 5.2.3 were derived with a single Brent price of \$75/bbl.

of the Tanguisson site, which may be the only viable option for Navy consideration. However, this site poses several technical challenges, and considerations are described in the following section.

6.6.1.3 Operational Risk Assessment

The Tanguisson site presents several challenges that could affect the viability of ensuring reliable LNG deliveries, primarily due to its exposed metocean conditions. If selected for Phase II of the study, additional metocean data will need to be collected and analyzed to confirm the site's suitability. Additionally, other considerations such as the transfer mechanism and the feasibility of horizontal drilling will need to be explored. The following sections outline these key issues.

Metocean, Mooring and Wave Height Conditions

The feasibility of LNG carrier (LNGC) operations at the Tanguisson site requires a thorough assessment of environmental and operational constraints. GHD conducted an assessment focusing on three primary areas: metocean conditions, mooring system performance, and wave climate impacts on marine and onshore operations and infrastructure. The metocean analysis characterizes the meteorological and oceanographic factors influencing marine operations, including wind, atmospheric pressure, air and sea temperature, wave heights, currents, tides, and salinity. These environmental parameters form the foundation for evaluating the LNG terminal's ability to support berthing and unloading operations safely.

Building on the metocean assessment, a hydrodynamic mooring analysis was conducted using MIKE 21 Mooring Analysis and Ansys AQWA software to simulate how the LNGC mooring system responds to environmental forces. This analysis included both static and dynamic simulations of mooring line tensions, vessel motions (displacements and rotations), and fender loads under operational and extreme conditions. The hydrodynamic modeling also calculated Response Amplitude Operators (RAOs) to quantify vessel responses to varying wave scenarios. The analysis further evaluated breaking tensions of mooring lines to ensure system stability and assessed operational flexibility, identifying potential downtime when metocean conditions exceed safe limits for LNG unloading.

In parallel, a wave modeling analysis estimated maximum anticipated wave heights to guide the design of protective measures for onshore infrastructure, given the site's exposure to open ocean conditions. This modeling integrates historical wave records, storm event data (e.g., Typhoon Mawar, tsunamis), bathymetry, coastal topology, and climate change projections. The analysis simulated wave transformation processes, accounting for local seafloor topography and coastal features that affect wave reflection, refraction, and amplification. The complete results, including metocean conditions, mooring system performance, vessel motion responses, and wave height estimates, are provided in Appendix H.

The results of the metocean and mooring analyses indicate that LNG transfers at Tanguisson are technically feasible, with an estimated annual terminal availability of 84.20%. This estimate is based on six years of historical metocean data and reflects seasonal variations, with the lowest availability occurring during the summer months of July through September. While the assessed availability is somewhat lower than that typically achieved at sheltered harbor facilities, it remains sufficient to support LNG operations with appropriate operational planning. Sensitivity analyses suggest that modest design adjustments, such as optimizing vessel orientation, could further improve annual availability to approximately 90%. GHD estimates the accuracy of these results to be around 70%, which is sufficient for this level of feasibility assessment. To enhance the accuracy of these

assessments and better characterize site-specific conditions, continued data collection and coordination with equipment manufacturers will be necessary.

Analysis of Monthly LNG Deliveries and Possible Interruptions

The results of the monthly LNG delivery analysis completed in Section 6.3.5 are utilized with the metocean and mooring analysis results to determine whether there will be periods when GUPP will have to operate on ULSD due to interruptions in LNG deliveries, due to ocean conditions. On average, during the peak years, the LNG terminal will require 3 to 4 LNG deliveries per month to ensure Ukudu maintains operation on natural gas. The GHD metocean and mooring analysis provides the total monthly windows available for the LNG carrier to offload the LNG, based on the metocean conditions, mooring system performance, vessel motion responses, and wave height estimates. GHD models the LNG carrier unloading period as 14 hours (3 hours for vessel hook-up, 8 hours for vessel unloading, and 3 hours for departure).

Table 6.11: LNG Delivery Windows

Month	Days in Month	Number of 14-Hour Windows in Month	Availability of Delivery Windows (%) ¹⁷	Number of 14-Hour Windows with Metocean Availability
January	31	53	86.47%	46
February	28	48	90.59%	43
March	31	53	86.40%	46
April	30	51	92.73%	47
May	31	53	93.64%	50
June	30	51	80.19%	41
July	31	53	63.10%	33
August	31	53	68.01%	36
September	30	51	76.39%	39
October	31	53	95.77%	51
November	30	51	93.18%	48
December	31	53	84.68%	45
		Average	84.20%	

The results presented in Table 6.11 indicate that the total number of available 14-hour delivery windows per month, when considering the metocean analysis results, greatly exceeds the total number of deliveries required for continued GUPP operation on gas for all LNG demand scenarios. The lowest number of available windows is during July, with 33; however, the maximum number of deliveries required for that month is 4, highlighting that there is minimal potential risk or impact from the metocean analysis on the projected deliveries of LNG. In the unlikely event that the required delivery window is unavailable, there are a few options to consider:

¹⁷ Based on GHD Metocean Analysis.

- The LNG carrier can wait for a window to deliver the LNG, during which time, GUPP can switch to ULSD operation, or
- A second LNG carrier can be utilized for operational flexibility to fill the onshore LNG storage tank in advance of potential poor ocean conditions or a storm.

6.6.2 Analysis of the Hotel Wharf LNG Terminal Option

Further analysis of the Hotel Wharf option included updating the layout (section 6.6.2.1), refining CAPEX and OPEX estimates (section 6.6.2.2).

6.6.2.1 Updated Layout

Refinements were made to the marine and onshore layout at Hotel Wharf. Specifically the positioning and location of the storage and regasification facilities were altered to better align with the exclusion and safety zone analysis, illustrated in Figure 6.29 and Figure 6.30.

Figure 6.29: Hotel Wharf – Maring and Onshore Infrastructure

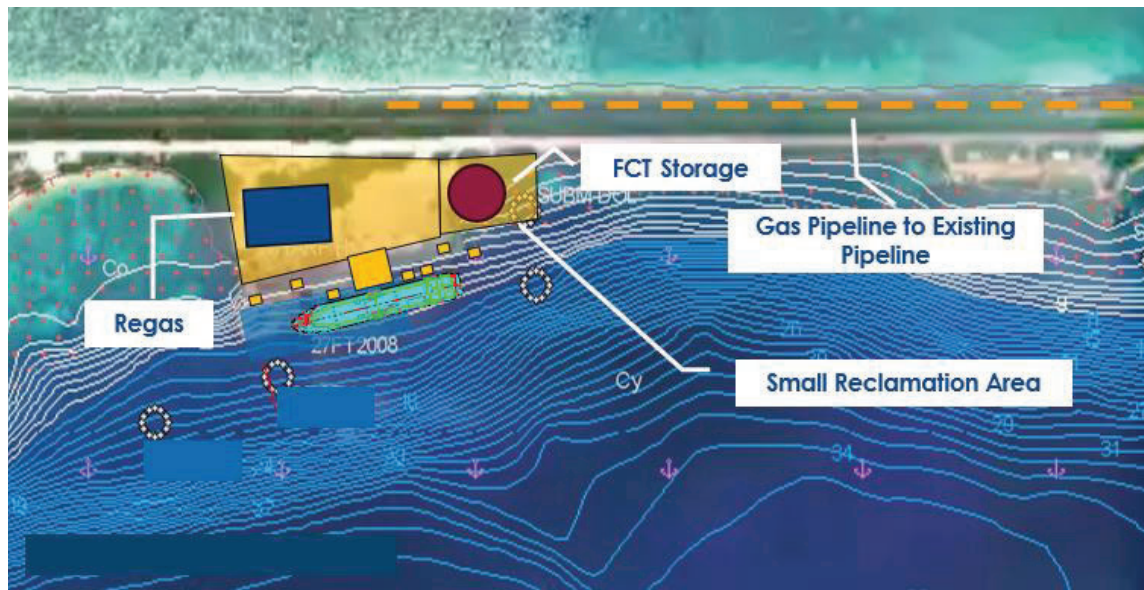
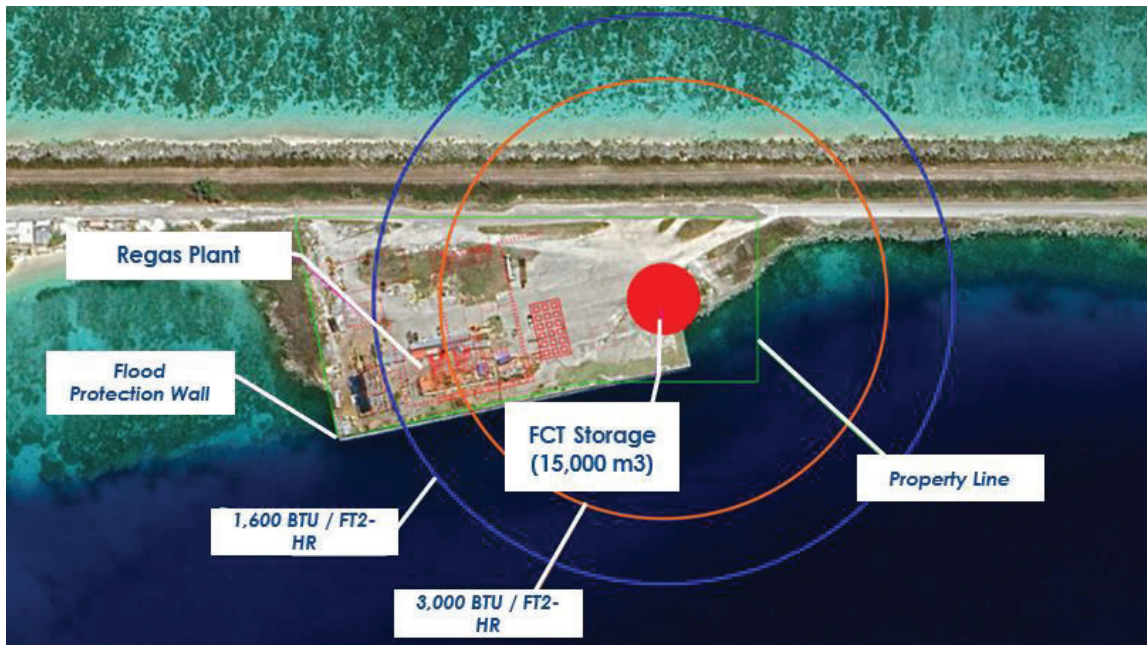


Figure 6.30: Hotel Wharf – Onshore Infrastructure



6.6.2.2 Class IV Cost Estimation Results

Class V cost estimates were further refined to the Class IV level. Table 6.12 below summarizes the results of the Class IV cost estimation for the Hotel Wharf site.

Table 6.12: Hotel Wharf - Class IV Cost Estimation Results

Total CAPEX	187,333,390 USD
Marine Infrastructure	61,411,710 USD
Onshore Storage & Equipment	54,952,831 USD
Onshore Regas	6,436,089 USD
Onshore Pipeline	4,607,164 USD
Bulks, Construction, Owner's, and Engineering Costs	59,925,596 USD
Total OPEX	6,232,868 USD
Marine Infrastructure OPEX	3,081,176 USD
Other OPEX	3,151,693 USD
Land Acquisition Cost	-- USD

These CAPEX and OPEX figures result in an LCOG ranging \$19.88 – \$23.25, depending on the demand scenario(see Figure 6.31). The breakdown of the LCOG by component for the GPA Target scenario is presented in Figure 6.32 below.

Figure 6.31: Hotel Wharf - LCOG by Demand Scenario

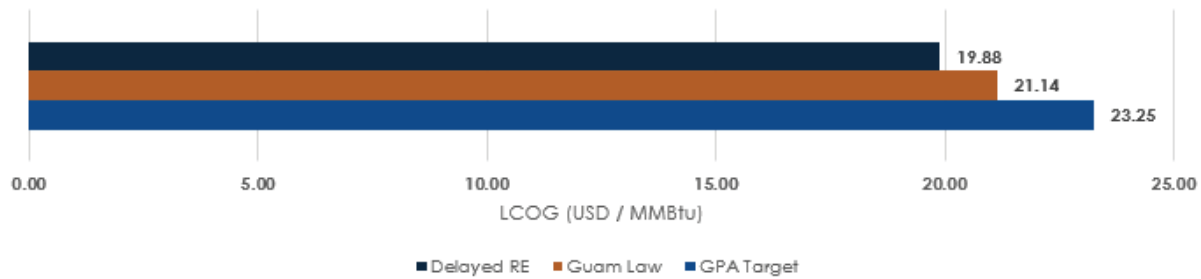


Figure 6.32: Hotel Wharf – Breakdown of LCOG for GPA Target Scenario¹⁸

Levelized Cost of Delivered Gas at Ukudu		\$ / MMBtu
Ex-Ship LNG Price	\$ / MMBtu	18.41
Marine Infrastructure	\$ / MMBtu	2.02
Onshore Storage	\$ / MMBtu	1.27
Onshore Regas	\$ / MMBtu	0.14
Gas Pipeline	\$ / MMBtu	0.10
Bulks, Construction, Owners & Engineering	\$ / MMBtu	1.31
Land Acquisition	\$ / MMBtu	-
		23.25

The CAPEX and OPEX results are included in the analysis to compare with the Tanguisson option. While the Hotel Wharf site may be more technically and economically viable, uncertainties remain regarding Navy approval.

6.7 Conclusions

The study's results show that two sites and configurations are technically viable, and they are the lowest cost options for developing an LNG import terminal to supply gas to GUPP. The main characteristics of these two options are summarized in Table 6.13 below.

Table 6.13: Selected LNG Terminal Sites and Configurations

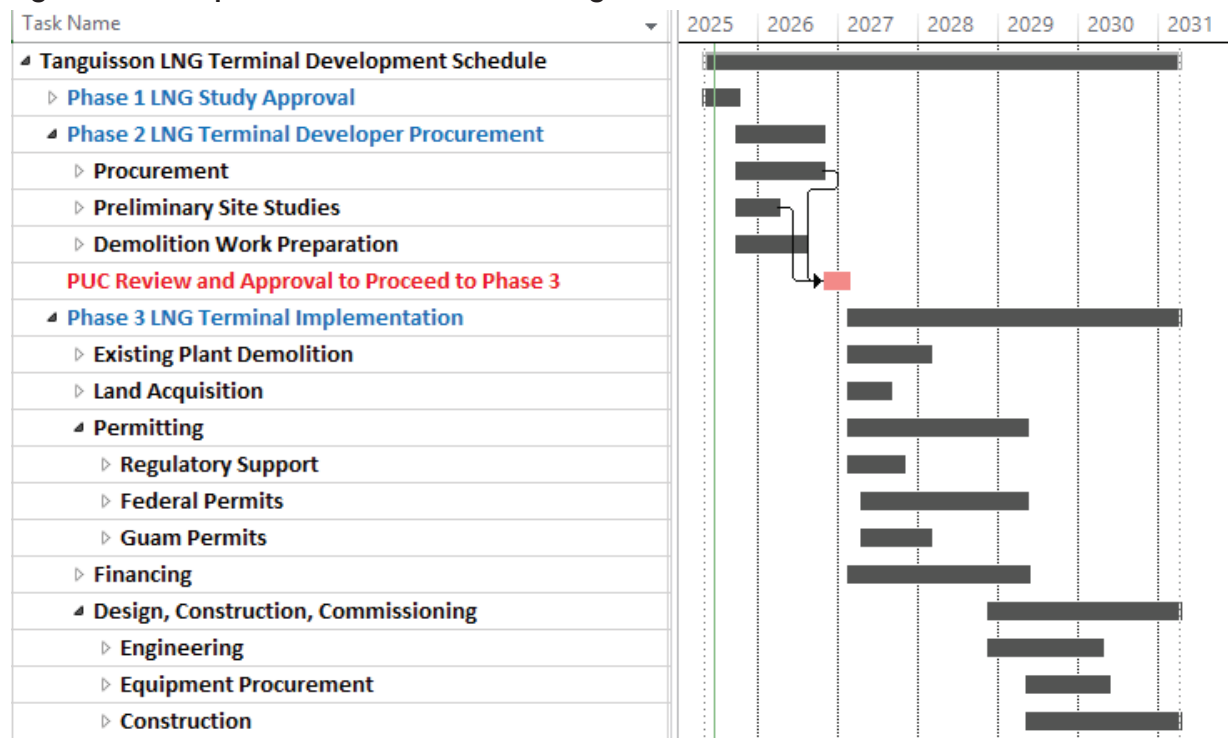
	Tanguisson	Hotel Wharf
LNG Carrier Size	10,000 m ³	10,000 m ³

¹⁸ The LNG ex-ship price presented in this table is higher than the ex-ship price presented in section 5.2.3 because these prices are calculated using the Energy Information Agency (EIA) Brent price forecast (which starts at \$92/bbl in 2031 and increases to \$153/bbl in 2050) and those presented in section 5.2.3 were derived with a single Brent price of \$75/bbl.

Configuration	• Multi-buoy mooring system • Permanently installed transfer tower • Subsea cryogenic pipeline installed within a horizontal directional drilling (HDD) casing • Onshore full containment 15,000 m3 LNG storage tank • Ambient vaporizes and sendout pumps • Flood protection wall/levee • 2.45 mile gas pipeline to GUPP	• Unloading platform with breasting and mooring dolphins • Land reclamation and retaining wall • LNG offloading arms and cryogenic line • Onshore full containment 15,000 m3 LNG storage tank • Ambient vaporizes and sendout pumps • Flood protection wall/levee • Gas pipeline to connect to the existing gas pipeline
CAPEX (Class IV)	US\$ 210,620,753	US\$ 187,333,390
OPEX	US\$ 9,386,820 / year	US\$ 6,232,868 / year
Levelized Cost of Delivered Gas	• Delayed RE = US\$ 20.59/MMBtu • Guam Law = US\$ 22.02/MMBtu • GPA Target = US\$ 24.47/MMBtu	• Delayed RE = US\$ 19.88/MMBtu • Guam Law = US\$ 21.14/MMBtu • GPA Target = US\$ 23.25/MMBtu
Implementation Schedule	~5 years	~5 years
Pros	• Strong support from the U.S. Navy • Could offer an alternative fuel import facility to the U.S. Navy • Land owned by the U.S. Navy and leased to GPA	• Located in a protected harbor • Lower CAPEX than Tanguisson option • Slight lower LCOG (3.4%) than Tanguisson option
Cons	• Higher operational risk than Hotel Wharf, but low risk • Higher CAPEX than Hotel Wharf – 12% more • Requires dismantling the existing power plant	• Rejected by the U.S. Navy due to security concerns • Unclear if the Guam Port Authority could make the site available for an LNG terminal

As described in the above table, both sites have advantages and disadvantages that should be considered when selecting one. Based exclusively on technical and cost criteria, Hotel Wharf is a better choice than Tanguisson. However, given the U.S. Navy's strong opposition to using this site, or any other site in Apra Harbor for an LNG terminal, Tanguisson is the only site that would receive their support. This report therefore recommends that Tanguisson be selected as the preferred site. Implementing and LNG import terminal at Tanguisson could require approximately 5 to 6 years as illustrated in Figure 6.33 and presented in more detail in Appendix O.

Figure 6.33: Implementation Schedule – Tanguisson



The overall duration of the project implementation from the conclusion of the Phase 1 study to LNG terminal operation with LNG in-tank is approximately 6 years. The durations of different activities included in the schedule are based on the K&M Team's experience in the development of similar-sized terminals.



Task 4

Economic Cost-Benefit Analysis and Ratepayer Impact Assessment

7 Task 4.1 – Economic Cost-Benefit Analysis

This section presents the results of Subtask 4.1 – Economic Cost-Benefit Analysis (ECBA), which draws on the results of Tasks 1, 2, 3, and 5. The conclusions presented in this section are the final results of the analyses, which have been updated following the conclusion of all other tasks within this study.

The main objective of the ECBA is to determine if the transition to LNG is economically cost-benefit justified. The ECBA calculates the cost-benefit ratio by dividing the present value of the Project's economic cost by the present value of the Project's economic benefits. The Project is economically cost-benefit justified if the ratio is below one, in other words, if the Project's economic benefits are higher than its economic costs.

This section is organized into five sections. Section 7.1 describes the methodology used in the ECBA. Section 7.2 presents the modeling assumptions and inputs to the ECBA and describes model sensitivities. Section 7.3 provides a description of each section of the ECBA, including direct and indirect benefits and costs. Section 7.4 provides the results of the ECBA and sensitivity runs. Section 7.4.1.4 concludes.

7.1 Methodology

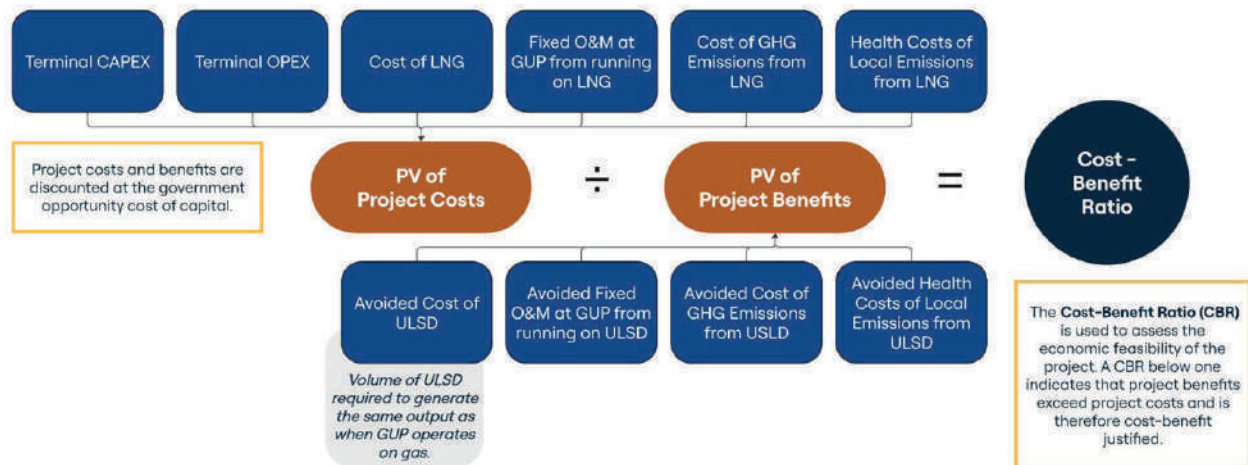
Economic analysis differs from financial analysis in that it aims to comprehensively evaluate the impact of a proposed project, including externalities (i.e., indirect costs or benefits to uninvolved third parties) and the incremental costs and benefits of the project relative to a counterfactual in which the project does not occur. Where data allows, economic analysis uses economic prices (prices without any market distortions) to quantify direct and indirect costs and benefits. Economic analysis is used to assist in decision-making for projects in a wide range of sectors, including energy and infrastructure projects. The World Bank has developed comprehensive guidelines on how to perform economic analysis—which K&M has followed for this analysis.¹⁹

Specifically, the ECBA for the Project estimates the direct costs and benefits of transitioning GUPP from ULSD to natural gas. Figure 7.1 below illustrates the ECBA methodology used for the Project. The Project's direct costs include terminal CAPEX and OPEX, the cost of LNG, and contracted operating and maintenance (O&M) charges described in the Energy Conversion Agreement (ECA). The Project's direct benefits include the avoided cost of ULSD and O&M charges that would otherwise be incurred if GUPP continued to operate on ULSD.

The ECBA also considers externalities, including the costs of greenhouse gas (GHG) emissions and health costs of chronic exposure to emissions in Guam. Shadow prices are used in the absence of formal carbon prices.

¹⁹ <https://documents1.worldbank.org/curated/es/277051467993159767/99506-WP-v1-PUBLIC-Box393204B-Guidelines-Economic-Analysis-Power-Projects-Volume-1-Final.docx>,
<https://documents1.worldbank.org/curated/fr/267971468000014869/pdf/99506-WP-v2-PUBLIC-Box393204B-Guidelines-Economic-Analysis-Power-Projects-Volume-2-Final.pdf>

Figure 7.1: ECBA Model Diagram



The Cost-Benefit Ratio (CBR) and Net Present Value (NPV) are the two metrics used to assess if a project is cost-benefit justified. The ECBA calculates the cost-benefit ratio by dividing the present value of the Project's economic cost by the present value of the Project's economic benefits. The Project is economic cost-benefit justified if the ratio is below one - in other words, if the Project's economic benefits are higher than its economic costs. A CBR closer to zero indicates greater benefits compared to costs. A positive NPV indicates that the Project will generate economic value exceeding the expected returns from alternative investments.

ECBAs use the economic opportunity cost of capital to discount benefits and costs. In the absence of country-specific studies determining the economic opportunity cost of capital, The World Bank recommends using the government's opportunity cost of capital. This cost is estimated as the cost of government borrowing, which can be proxied by the coupon rate on government-issued bonds.

7.2 Modeling Assumptions

The data and inputs used in the ECBA come from GPA, publicly available sources, or are derived from related models developed by K&M for this assignment.

7.2.1 Model Period

The ECBA covers the period 2029 to 2050, which includes a two-year construction period for the LNG import terminal (2029 – 2031), fuel switching at GUPP starting in 2031, and a nineteen-year operational period (2031 – 2050).

7.2.2 Macroeconomic Assumptions

The model uses the IMF's long-term inflation assumption for the United States of America of 2% to escalate relevant model inputs; the Project's base year is 2029. The model uses nominal prices to quantify forecasted benefits and costs.

7.2.3 Discount Rate

The discount rate used in the ECBA represents the opportunity cost of capital for the government of Guam. This is estimated to be 5.0%, which is the coupon rate of the Government of Guam's 12-year general obligations bonds series 2019.²⁰

7.2.4 Import Terminal

K&M's CAPEX estimate for the LNG import terminal is USD 210 million. The model assumes that 50% of the CAPEX will be expensed in the first year of construction and the other 50% expensed in year two. The terminal OPEX is assumed to be 4.5% of total CAPEX, paid during the terminal's operational life (2031 – 2050). These CAPEX and OPEX estimates are the result of Task 3, which is detailed in Section 6 of this report.

7.2.5 Gas Demand

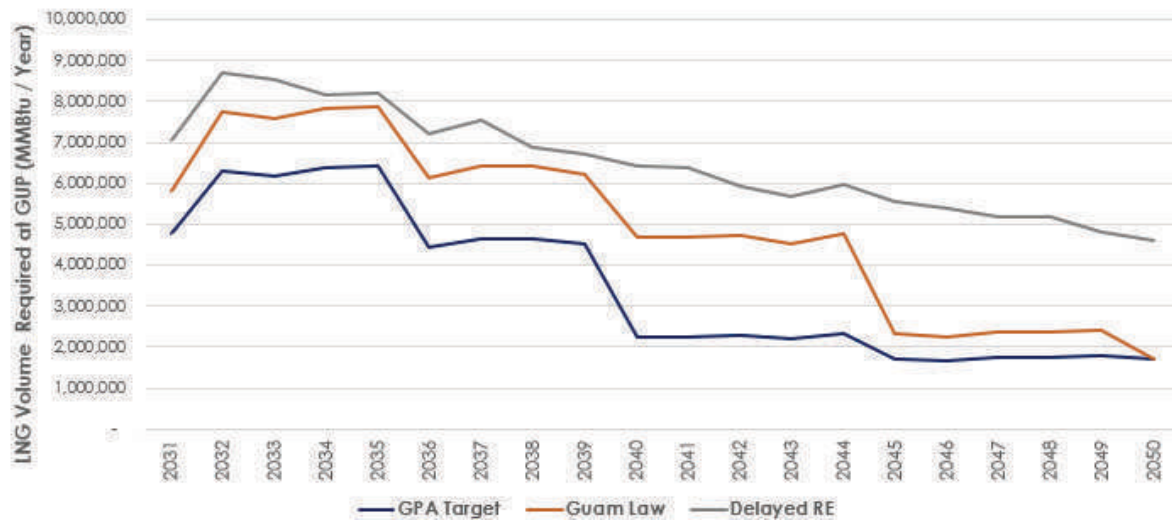
The volume of gas required at GUPP is a function of electricity demand and the level of renewable energy generation in Guam. K&M assumes that GPA will dispatch electricity generated from renewables first and will meet the remaining load with electricity generated from natural gas and ULSD power plants. Given the uncertainty surrounding the timeline for renewable energy deployment in Guam, the analysis evaluates three scenarios, listed below, that determine gas demand at GUPP:

- 1 **GPA Target:** Based on GPA's timeline for renewable energy deployment, which targets 50% renewable energy by 2030 and 100% renewable energy by 2040.
- 2 **Guam Law:** Based on Guam Public Law No. 35 – 46, which targets 50% RE by 2035 and 100% RE by 2045.
- 3 **Delayed Renewables:** Based on gradual additions of RE at a lower rate than either GPA's target or Guam law.

The gas demand under these three scenarios was derived from K&M's fuel demand model from Task 1, which is detailed in Section 4 of this report. Figure 7.2 presents gas demand for the model period for the three RE scenarios.

²⁰ <https://emma.msrb.org/IssueView/Details/ES395378>

Figure 7.2: Gas Demand by RE Scenario



7.2.6 Fuel Prices

The price of landed ULSD and natural gas are both indexed to the forecasted Brent price, using EIA's long-term Brent forecast. The methodology for estimating these prices is described below.

7.2.6.1 Landed ULSD Prices

K&M used historic Brent prices from January 2021 to June 2023 and historic ULSD commodity prices (Singapore FOB gasoil 10ppm) provided by GPA for the same period to calculate the price ratio of Brent to ULSD prices. This ratio was applied to EIA's Brent forecasted prices to derive ULSD commodity prices for 2031 to 2050. The landed ULSD price equals the ULSD commodity price plus a premium fee.

- $\text{ULSD Commodity Price}_{(\text{USD} / \text{bbl})} = \text{Price Ratio (Brent : ULSD)} \times \text{Forecasted Brent Price}_{(\text{USD} / \text{bbl})}$
- $\text{Landed ULSD Price}_{(\text{USD} / \text{MMBtu})} = (\text{ULSD Commodity Price}_{(\text{USD} / \text{bbl})} + \text{Premium Fee}_{(\text{USD} / \text{bbl})}) / \text{Heating Value}_{(\text{MMBtu} / \text{bbl})}$

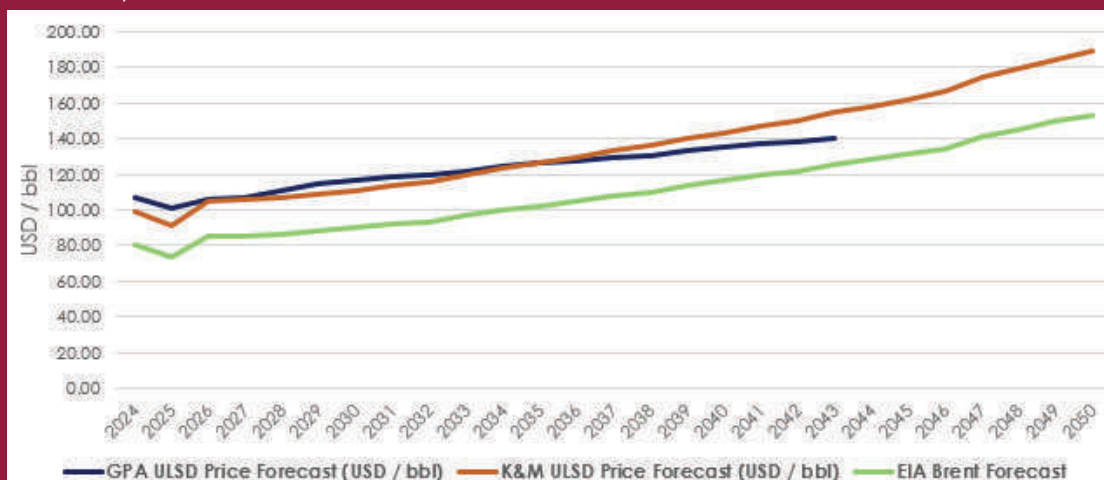
The premium fee, provided by GPA, is USD 8.08 in 2024; GPA assumes a 10% increase every fifth year and a heating value of 5.82 (MMBtu / bbl).

Box 7.1: ULSD Price Forecast

GPA provided, in September 2024, the commodity price forecast shown in the figure below (GPA ULSD Price Forecast). This forecast differs slightly from K&M's forecast (K&M ULSD Price Forecast). K&M's and GPA's estimates are relatively similar through 2035 and then diverge thereafter.

K&M decided to use its own forecast for two main reasons:

- The price of LNG in Asia-Pacific is typically indexed to Brent. Aligning the basis for LNG and ULSD price projections allows for more consistent comparison of how these prices evolve over time. K&M determined that linking both ULSD and natural gas to Brent ensures a coherent framework for the entire analysis.
- As ULSD is a derivative product of crude oil, it is reasonable to expect its price to be higher than the Brent forecast. However, as illustrated in the figure below, GPA's forecast begins to converge with the Brent forecast towards 2045. This suggests that GPA's ULSD price forecast is based on a crude oil price forecast below the EIA forecast. K&M therefore opted to use its forecast to maintain consistency with EIA's Brent forecast.



7.2.6.2 LNG Prices

Forecasting the ex-ship price of LNG is subject to more uncertainty; it is a function of the volume demanded, LNG source, and the LNG shipping solution. The methodology for calculating the ex-ship price is described below.

- Freight on Board (FOB) Price (USD/ MMBtu) = (Forecasted Brent Price (USD / bbl) × Brent Percentage) + Alpha (USD/ MMBtu)
- Delivered Ex-Ship (DES) Price (USD/ MMBtu) = FOB Price (USD/ MMBtu) + Reload Fee (USD/ MMBtu) + Seller's Margin (USD/ MMBtu) + Unit Freight Cost (UFC) (USD/ MMBtu)

Where:

- FOB Price is the price of LNG loaded in the vessel at the LNG export facility.
- Alpha is a fixed number that represents the cost of shipping LNG from the export facility to the reloading terminal.
- Reload Fee is the price that an LNG terminal will charge for unloading LNG from a large vessel, storing it, and reloading it into a small vessel.

- Seller's Margin is the markup that the LNG seller applies to the delivered LNG price to remunerate itself for arranging the sale.
- Unit Freight Cost is the cost of shipping the LNG from the reloading LNG terminal facility to a receiving terminal in Guam.

The inputs for these calculations are derived from Task 2 and detailed in Section 5 of this report. In all three demand scenarios, the optimal LNG supply solution is a 10,000 m³ small-scale LNG carrier loading in West Papua. The inputs used to derive DES LNG prices for all scenarios are summarized in Table 7.1 below.

Table 7.1: LNG Supply Solution Assumptions

Supply Solution	Small-Scale LNG Carrier (10,000 m ³) from West Papua
Brent Percentage	12.5%
Alpha (USD / MMBtu)	\$ --
Reload Fees (USD / MMBtu)	\$ --
Seller's Margin (USD / MMBtu)	\$0.35
Unit Freight Cost (USD / MMBtu)	Varies based on volume (Figure 7.3, Figure 7.4 and Figure 7.5)

The UFC is a function of the volume of gas demanded; at higher volumes, the cost of chartering an LNG vessel is spread across more units, resulting in a relatively lower UFC per MMBtu. This relationship is depicted in Figure 7.3, Figure 7.4, and Figure 7.5 below.

Figure 7.3: Unit Freight Cost – GPA Target – West Papua (10,000 m³ Vessel)

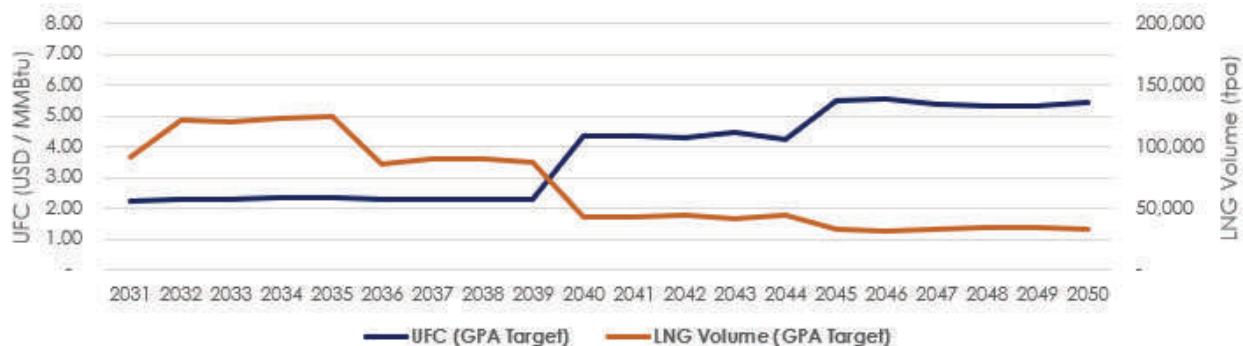


Figure 7.4: Unit Freight Cost – Guam Law – West Papua (10,000 m³)

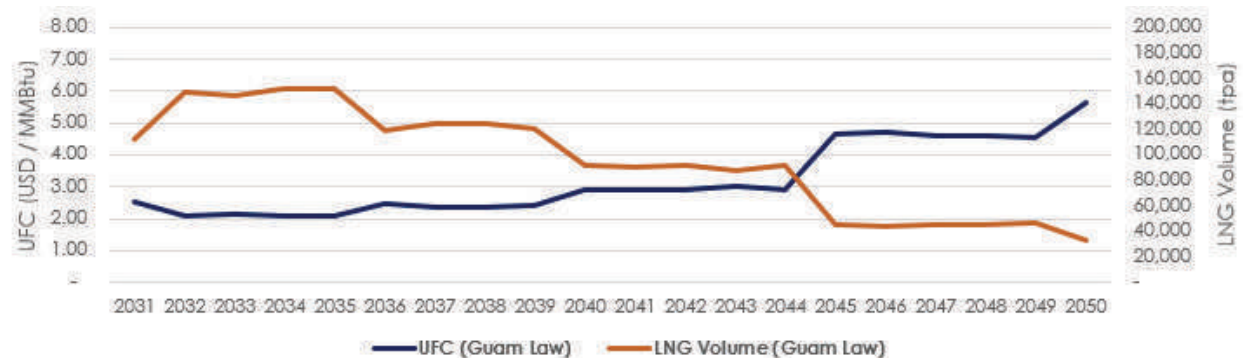
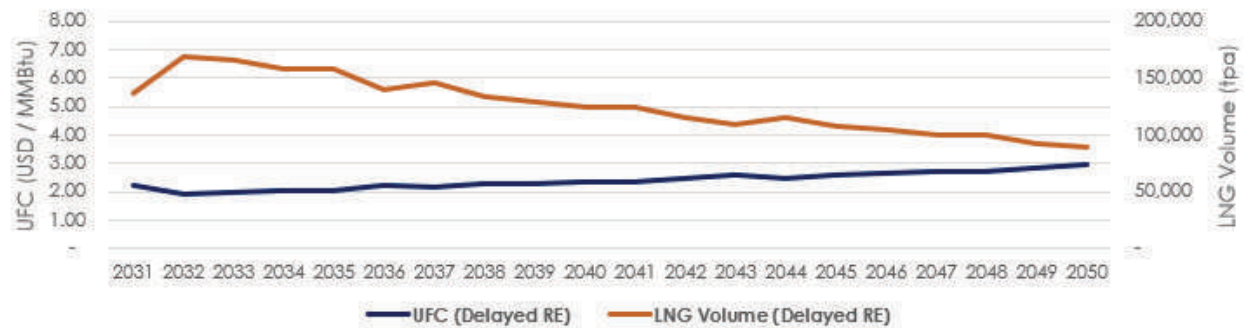


Figure 7.5: Unit Freight Cost – Delayed RE – West Papua (10,000 m³)



7.2.7 GUPP Fixed Charges

Under the ECA signed between GPA and GUPP, GPA pays GUPP a fixed O&M charge. This charge is greater when GUPP operates on ULSD than natural gas. Specifically, it is 11.5246 USD / KW / month for ULSD and 7.5735 USD / KW / month for natural gas, escalated yearly based on the reference year, defined as April 2019, and adjusted based on a correction load factor. The correction load factor is assumed to be 1.03 for the first ten years of the plant's operational life, based on GUPP's units operating at 90 – 95% capacity, and is adjusted to 1.00 for the remaining years of the plant's operational life, when GUPP's units are assumed to operate below 90% capacity. These assumptions are based on the gradual integration of renewables, which lowers generation requirements for Guam's thermal units.

7.2.8 Emissions Accounting

7.2.8.1 Greenhouse Gas Emissions

The United States Environmental Protection Agency publishes data on GHG emissions levels for different fuel types, as well as conversion factors, called Global Warming Potential (GWP), to convert all greenhouse gases to their carbon dioxide equivalents (CO₂e).²¹ Table 7.2 summarizes the kilograms of CO₂e per MMBtu for both fuels.

Table 7.2: Carbon Dioxide Equivalents

Greenhouse Gas	GWP	ULSD (kg / MMBtu)	ULSD (kg CO ₂ e / MMBtu)	NG (kg / MMBtu)	NG (kg CO ₂ e / MMBtu)
Carbon Dioxide (CO ₂)	1	73.960	73.960	53.060	53.060
Methane (CH ₄)	28	0.003	0.084	0.001	0.028
Nitrous Oxide (N ₂ O)	265	0.0006	0.159	0.0001	0.027
Total			74.203		53.115

Figure 7.6 shows the forecasted GHG emissions when GUPP is operating on ULSD versus LNG.

²¹ <https://www.epa.gov/system/files/documents/2024-02/ghg-emission-factors-hub-2024.pdf>

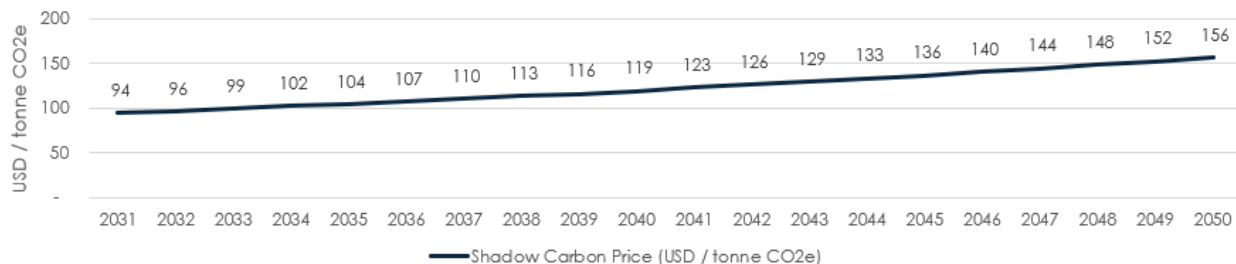
Figure 7.6: Greenhouse Gas Emissions at GUPP: ULSD vs. Natural Gas



7.2.8.2 Shadow Carbon Pricing

Guam has no formal carbon pricing mechanism. In the absence of a formal carbon price, shadow carbon pricing is used to account for the expected damage cost of GHG emissions from GUPP operating on both fuels. This cost is estimated by the High-Level Commission on Carbon Pricing for high-middle income countries and aims to capture the global impact on net agricultural productivity, damage to built environments, and ecosystems from carbon emissions.²² The prices used for the model period 2031 – 2050 are depicted in Figure 7.7.

Figure 7.7: Shadow Carbon Pricing



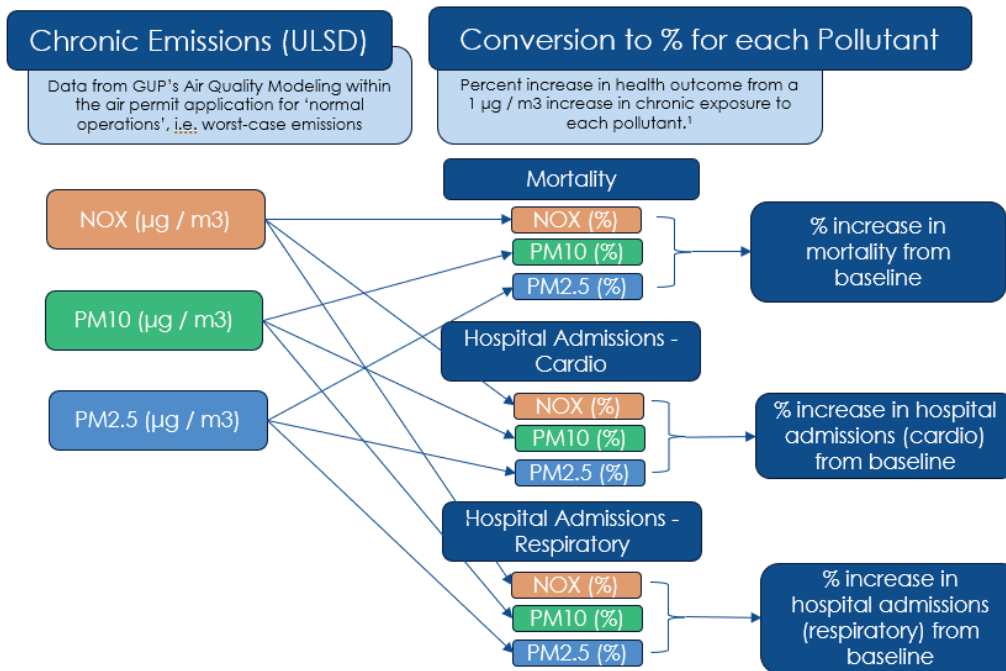
7.2.8.3 Local Emissions

The ECBA estimates chronic emissions from other pollutants, including nitrous oxide (NOX) and particulate matter (PM2.5, PM10), and converts these emissions into a percentage increase in health outcomes in Guam, specifically increases in mortality and hospital admissions from respiratory and cardio-related illnesses. Inputs for these estimates, measured in micrograms per cubic meter of air ($\mu\text{g} / \text{m}^3$), come from GUPP's air permit application and air quality modeling for normal operations on ULSD. Normal operations are the level of operations that produce the worst-case chronic emissions. Economic analyses on air pollution provide the percentage increases in

²²https://static1.squarespace.com/static/54ff9c5ce4b0a53decccfb4c/t/59b7f2409f8dce5316811916/1505227332748/CarbonPricing_FullReport.pdf

health outcomes for a $1 \mu\text{g} / \text{m}^3$ increase in chronic exposure for each of the pollutants.²³ Figure 7.8 summarizes the methodology used to determine the overall percentage increase in health outcomes from baseline incidence.

Figure 7.8: Percentage Increase in Health Outcomes from Local Emissions



The air permit model did not conduct Air Quality Modeling for GUPP running on natural gas. K&M calculated chronic emissions from LNG by taking the proportion of emissions (kg / MMBtu) for NOX, PM10 and PM2.5 from ULSD and LNG (provided in the appendix of GUPP's air permit application) and used this ratio to adjust chronic emissions (ULSD) to find chronic emissions (LNG). Results are summarized in Table 7.3 below.

Table 7.3: Increase in Health Outcomes from Baseline Incidences in Guam

Health Outcome	ULSD	Natural Gas
Mortality	4.86%	1.61%
Hospital Admissions (Cardio)	0.60%	0.15%
Hospital Admissions (Respiratory)	0.75%	0.19%

7.2.8.4 Baseline Health Incidence

Data on baseline mortality rates and hospital admissions from cardio and respiratory-related illnesses in Guam are publicly available.²⁴ These numbers were used to derive the baseline percentage of mortality and hospital admissions within the population summarized in Table 7.4. The population of Guam in 2024 is 174,000, and the growth rate is assumed to be 0.67%.

²³ www.nice.org.uk/guidance/ng70/evidence/economic-report-pdf-4595574493

²⁴ https://www.ahd.com/free_profile/650003/Guam_Regional_Medical_City/Dededo/Guam/
https://www.ahd.com/free_profile/650001/Guam_Memorial_Hospital_Authority/Oka_Tamuning/Guam/

Table 7.4: Summary of Baseline Health Incidence

Baseline Mortality (% of Population)	0.216%
Baseline Hospital Admissions (Cardio)	0.336%
Baseline Hospital Admissions (Respiratory)	0.335%

7.2.8.5 Health Costs

Related costs for each health category are also publicly available.²⁵ The cost of mortality is conservatively estimated as the average hospital cost plus lost income due to premature mortality using average annual salaries in Guam. Figures used in the ECBA are summarized in Table 7.5 below.

Table 7.5: Summary of Health Costs

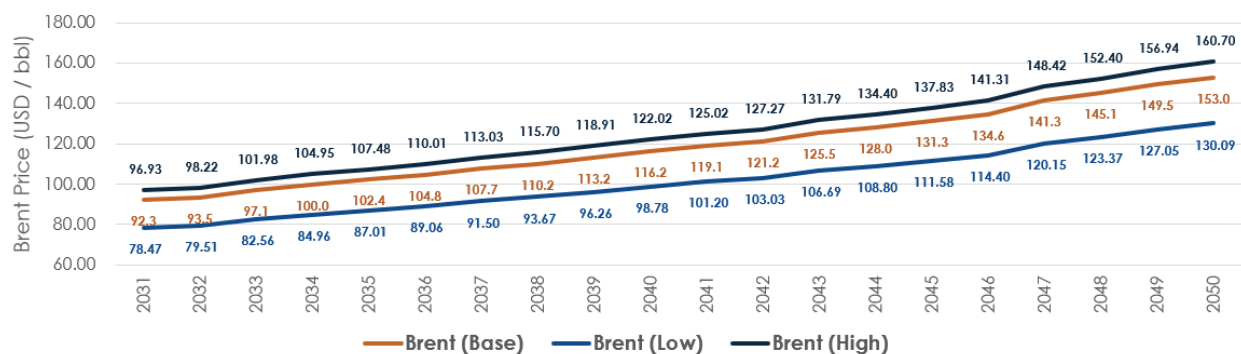
	23 USD / Patient
Average Cost of Mortality	\$661,379
Average Cost of Hospital Admissions (Cardio)	\$50,225
Average Cost of Hospital Admissions (Respiratory)	\$29,146

7.2.9 Model Sensitivities

While the ECBA aims to quantify the Project's direct and indirect benefits and costs, several uncertainties remain for various inputs. To analyze this uncertainty, K&M includes sensitivity runs for the Brent forecast and discount rates, both of which impact fuel prices.

7.2.9.1 Brent

The price of fuel, both ULSD and LNG, is indexed to the price of Brent crude oil and forecasted for the Project lifetime (2031 – 2050) (see Appendix A). In addition to the base case forecast based on EIA's long-term Brent forecast, the ECBA includes a high Brent scenario (+5% from base case) and a low Brent scenario (-15% from the base case), depicted in Figure 7.9.

Figure 7.9: Brent Price Projections (2031 – 2050)

²⁵<https://gbhwc.guam.gov/sites/default/files/2018%20Guam%20State%20Epidemiological%20Profile.pdf>
https://www.ahd.com/free_profile/650003/Guam_Regional_Medical_City/Dededo/Guam/
https://www.ahd.com/free_profile/650001/Guam_Memorial_Hospital_Authority/Oka_Tamuning/Guam/

7.2.9.2 Discount Rate

The discount rate used in the CBA represents the opportunity cost of capital for the government of Guam. The base case uses a discount rate of 5% based on the coupon rate of the 2019 bonds issued by the government of Guam. However, the analysis includes a sensitivity of +/- 1% around that discount rate.

7.3 Economic Cost Benefit Analysis

The ECBA includes both direct and indirect benefits and costs of the Project. Direct benefits and costs are directly attributed to the Project. The primary benefit of the Project is the avoided costs of operating on ULSD when GUPP operates on natural gas. The primary costs of the Project are the costs incurred when GUPP operates on natural gas. Indirect benefits and costs refer to the externalities imposed on uninvolved third parties. Indirect benefits include the avoided cost of emissions from ULSD, and indirect costs include emissions from LNG. These economic benefits and costs are summarized in Table 7.6.

Table 7.6: Overview of the Project's Economic Costs and Benefits

			Description
Project Benefits	Direct Benefits	7.3.1.1 Avoided Cost of Fuel (ULSD)	Refers to the avoided cost of ULSD fuel that would otherwise be required to generate the same amount of electricity (MWh) as when GUPP operates on natural gas.
		7.3.1.2 Avoided Fixed O&M Payments (ULSD)	Refers to the avoided cost of fixed O&M charges that would otherwise be owed to GUPP when operating on ULSD. Under the ECA, the fixed O&M charge when operating on ULSD is greater than the charge when operating on natural gas.
	Indirect Benefits	7.3.2.1 Avoided Cost of GHG Emissions (ULSD)	Refers to the avoided economic cost of GHG emissions that would otherwise be generated from operating GUPP on ULSD. GHG emissions are priced at the shadow price of carbon for high-middle-income countries.
		7.3.2.2 Avoided Health Cost of Local Emissions (ULSD)	Refers to the avoided health cost of local emissions that would otherwise be generated from operating GUPP on ULSD. Higher emissions translate to higher health care / societal costs from mortality and hospital admissions due to cardio and respiratory illnesses.
Project Costs	Direct Costs	7.3.3.1 LNG Terminal CAPEX	Refers to the capital expenditure required to construct the LNG terminal for LNG imports.
		7.3.3.2 LNG Terminal OPEX	Refers to the operational expenditures required to operate the LNG terminal for LNG imports.
		7.3.3.3 Cost of Fuel (LNG)	Refers to the cost of natural gas required to operate GUPP and generate electricity (MWh) according to the three demand scenarios.
		7.3.3.4 Cost of Fixed O&M Payments (LNG)	Refers to the cost of fixed O&M charges owed to GUPP when operating on natural gas. Under the ECA, the fixed O&M charge when operating on natural gas is less than the charge when operating on ULSD.

			Description
	Indirect Costs	7.3.4.1 Cost of GHG Emissions (LNG)	Refers to the economic cost of GHG emissions generated from operating GUPP on natural gas. GHG emissions are priced at the shadow price of carbon for high-middle income countries.
		7.3.4.2 Health Cost of Local Emissions (LNG)	Refers to the health cost of local emissions generated from operating GUPP on natural gas. Higher emissions translate to higher health care / societal costs from mortality and hospital admissions due to cardio and respiratory illnesses.

7.3.1 Direct Benefits

7.3.1.1 Avoided Cost of Fuel (ULSD)

The Project avoids the cost of ULSD fuel that would otherwise be required to generate the same amount of electricity (MWh) as when GUPP operates on natural gas. The avoided fuel cost is the product of the delivered ULSD price (USD / MMBtu) and the ULSD fuel requirement (MMBtu). The calculation of the ULSD delivered price is described in Section 7.2.6.1.

The ULSD fuel requirement is derived from K&M's fuel demand model under Task 1. It accounts for the differing heat rates, availability schedules, and maintenance schedules at GUPP when it operates on ULSD rather than natural gas. To generate the same amount of electricity (MWh) as when GUPP operates with natural gas, some additional ULSD fuel is required. This additional quantity of ULSD is included in the analysis. In years where GUPP's availability on ULSD is greater than GUPP's availability on natural gas due to mismatched maintenance schedules, no additional ULSD fuel is required. In years where this is the case, the analysis only considers the required ULSD fuel at GUPP to match the output (MWh) in that year if GUPP were operating on natural gas instead.

7.3.1.2 Avoided Fixed O&M Payments (ULSD)

The Project avoids the cost of fixed O&M charges that would otherwise be owed to GUPP when operating on ULSD. Under the ECA, the fixed O&M charge when operating on ULSD rather than natural gas is \$3.95 higher per KW / month. The charge is escalated yearly based on the reference date and adjusted based on the correction load factor described in Section 7.2.7.

7.3.2 Indirect Benefits

7.3.2.1 Avoided Cost of GHG Emissions (ULSD)

The Project avoids the economic cost of GHG emissions that would otherwise be generated from operating GUPP on ULSD. GHG emissions included in the analysis are CO₂, CH₄, and N₂O, which are converted to their CO₂ equivalent as described in Section 7.2.8.1.

The total cost of avoided GHG emissions is determined by multiplying the metric tons of CO₂e emitted from operating GUPP on ULSD by the shadow carbon price. Shadow pricing, discussed in Section 7.2.8.2, is commonly used in projects that aim to account for GHG emissions on a voluntary basis. This cost aims to capture the global impact on net agricultural productivity and damage to built environments and ecosystems from carbon emissions. Climate change impacts in Guam include depletion of its aquifers due to hotter weather and droughts, food insecurity, greater frequency and severity of typhoons and storms impacting infrastructure, degradation of ecosystems due to coral bleaching and wildfires, and sea level rise impacting cultural and historical resources along its coast.

7.3.2.2 Avoided Health Cost of Local Emissions (ULSD)

The Project avoids the health cost of local emissions that would otherwise be generated from operating GUPP on ULSD. The emissions included in the ECBA are NOX, PM₁₀, and PM_{2.5}; chronic exposure to these emissions is linked to increased instances of mortality and hospital admissions from cardiovascular and respiratory-related illnesses. The ECBA uses emissions data from air quality modeling at GUPP and data on the percentage increase in mortality and hospital admissions from cardiovascular and respiratory-related illnesses due to a 1 µm / m³ increase in chronic exposure for these emissions to estimate the increase above baseline incidences in Guam. These calculations are described in Section 7.2.8.3 and Section 7.2.8.4. The increase in mortality and hospital admissions is quantified using the average cost of hospital admission and mortality in Guam, described in Section 7.2.8.5.

The estimated health costs for normal operations of GUPP operating on ULSD were then adjusted for fuel demand at GUPP, using a health cost adjustment factor calculated by comparing fuel consumption (MMBtu) in each scenario to the MMBtu required for normal operations.

7.3.3 Direct Costs

7.3.3.1 LNG Terminal CAPEX

The Project incurs the direct cost of the terminal infrastructure required to import and re-gasify LNG in Guam. This CAPEX is assumed to be USD 210 M, with 50% of the cost borne in the first year and 50% in the second year.

7.3.3.2 LNG Terminal OPEX

The Project incurs the direct cost of operational expenditures each year the terminal is operating. The OPEX is assumed to be 4.5% of total CAPEX for each year of operations (2031 – 2050).

7.3.3.3 Cost of Fuel (LNG)

The Project incurs the direct fuel cost of natural gas required to operate GUPP and generate electricity (MWh). The fuel cost is the product of the ex-ship price, described in Section 7.2.6.2, and the fuel requirement (MMBtu), described in Section 7.2.5.

7.3.3.4 Cost of Fixed O&M Payments (LNG)

The Project incurs the direct cost of fixed O&M charges owed to GUPP when operating on natural gas. Under the ECA, the fixed O&M charge when operating on natural gas is \$3.95 per KW / month lower than when operating on ULSD. The charge is escalated yearly based on the reference date and adjusted based on the correction load factor, described in Section 7.2.7.

7.3.4 Indirect Costs

7.3.4.1 Cost of GHG Emissions (LNG)

The Project generates externalities from GHG emissions generated from operating GUPP on natural gas. GHG emissions included in the analysis are CO₂, CH₄ and N₂O, which are converted to their CO₂ equivalent as described in Section 7.2.8.1.

The total cost of GHG emissions is determined by multiplying the metric tons of CO₂e emitted from operating GUPP on natural gas by the shadow carbon price. Shadow pricing, discussed in Section 7.2.8.2, is commonly used in projects that aim to account for GHG emissions on a voluntary basis. This cost aims to capture the global impact on net agricultural productivity, damage to built environments, and ecosystems from carbon emissions. Climate change impacts in Guam include

depletion of its aquifers due to hotter weather and droughts, food insecurity, greater frequency and severity of typhoons and storms impacting infrastructure, degradation of ecosystems due to coral bleaching and wildfires, and sea level rise impacting cultural and historical resources along its coast.

7.3.4.2 Health Cost of Local Emissions (LNG)

The Project generates externalities measured by the health cost of local emissions from operating GUPP on natural gas. The emissions included in the ECBA are NO_x, PM₁₀ and PM_{2.5}; chronic exposure to these emissions is linked to increased instances of mortality and hospital admissions from cardiovascular and respiratory-related illnesses. The ECBA uses emissions data from air quality modeling at GUPP and data on the percentage increase in mortality and hospital admissions from cardiovascular and respiratory-related illnesses due to a 1 µm / m³ increase in chronic exposure for these emissions to estimate the increase above baseline incidences in Guam. These calculations are described in Section 7.2.8.3 and Section 7.2.8.4. The increase in mortality and hospital admissions is quantified using the average cost of hospital admissions and mortality in Guam, described in Section 7.2.8.5.

The estimated health costs for normal operations of GUPP operating on natural gas were then adjusted for fuel demand at GUPP, using a health cost adjustment factor calculated by comparing fuel consumption (MMBtu) in each scenario to the MMBtu required for normal operations.

7.4 Results

The results of the ECBA are presented for each of the demand scenarios in Figure 7.10 below. The positive NPV and Cost-Benefit Ratio (CBR) below one indicates that the Project is cost-benefit justified. That is, the benefits of the Project outweigh the costs while exceeding expected returns from alternative investments. This is true for both the direct benefits and costs (without externalities), as well as when indirect benefits and costs are considered (with externalities). The CBR is lowest in the Delayed RE scenario when annual fuel demand is greatest. In this case, the Project's avoided cost of fuel (ULSD) is much greater than the cost of fuel (LNG) given the per-unit price differential between the two fuels. The net economic benefits of the project are greater with higher fuel requirements.

Figure 7.10: Results of the ECBA by Demand Scenario

Economic Cost Benefit Analysis	GPA Target	Guam Law	Delayed Renewables
Benefits	PV (000)	PV (000)	PV (000)
Avoided Fuel Cost (ULSD)	1,155,380	1,611,512	2,067,751
Avoided Fixed O&M Cost (ULSD)	477,849	477,849	477,849
Benefits (Without Externalities)	1,633,230	2,089,361	2,545,601
Avoided Cost of GHG Emissions (ULSD)	385,267	537,917	690,853
Avoided Health Cost of Local Emissions (ULSD)	74,240	103,701	133,042
Benefits (With Externalities)	2,092,737	2,730,979	3,369,495
Costs	PV (000)	PV (000)	PV (000)
LNG Terminal CAPEX	200,711	200,711	200,711
LNG Terminal OPEX	133,155	133,155	133,155
Fuel Cost (LNG)	770,610	1,045,358	1,310,404
Fixed O&M Cost (LNG)	314,023	314,023	314,023
Costs (Without Externalities)	1,418,499	1,693,247	1,958,293
Avoided Cost of GHG Emissions (LNG)	266,865	373,693	479,951
Avoided Health Cost of Local Emissions (LNG)	24,191	33,868	43,484
Costs (With Externalities)	1,709,555	2,100,807	2,481,727
NPV of Costs & Benefits (Without Externalities)	214,730	396,114	587,308
NPV of Costs & Benefits (With Externalities)	383,183	630,172	887,768
Cost - Benefit Ratio (Without Externalities)	0.8685	0.8104	0.7693
Cost - Benefit Ratio (With Externalities)	0.8169	0.7693	0.7365

7.4.1 Results with Sensitivities

7.4.1.1 Discount Rates

With higher discount rates, the Project becomes less Cost-Benefit justified. This is because higher discount rates reduce the value of future cashflows compared to near-term cash flows. For the Project, near-term outflows for the terminal CAPEX and more significant fuel expense due to higher quantities demanded are valued more than future cash inflows. Using the Goal Seek What-If Analysis in Excel, K&M found that depending on the demand scenario, a discount rate of 18.88% - 30.67% is required to make the Project not cost-benefit justified, i.e., when NPV is zero and the CBR is 1. However, a discount rate this high is unlikely.

7.4.1.2 Brent Prices

Since the price of both ULSD and LNG are indexed to Brent, the underlying price of Brent will impact fuel prices. The analysis includes sensitivity for base, low, and high Brent prices, described in Section 7.2.9.1. Given the pricing structure for both fuels, lower Brent prices mean a lower price differential between ULSD and LNG, while higher Brent prices mean a greater price differential between ULSD and LNG per unit. The CBR for the three fuel demand scenarios are presented in Table 7.7 below for the three Brent scenarios, which are all still below one. K&M utilized a Brent curve with a levelized cost of ~\$119 / bbl in the base case. Using the Goal Seek What-if Analysis in Excel, K&M found that, depending on the demand scenario, the levelized Brent prices would have to decrease to ~\$34 – \$64 to make the Project not cost-benefit justified, i.e., when NPV is zero and CBR is 1. Brent prices this low are unlikely.

Table 7.7: CBR Sensitivity to Brent Price and Supply Solution

CBR (Without Externalities)			GPA Target	Guam Law	Delayed Renewables
Brent:	Low		0.9013	0.8393	0.7946
Brent:	Base		0.8685	0.8104	0.7693
Brent:	High		0.8590	0.8021	0.7621

7.4.1.3 Combined Sensitivities

Based on these results, the following table combines several sensitivities to generate a scenario that is least-cost-benefit justified (highest CBR) and most cost-benefit justified (lowest CBR). In both these cases, summarized in Table 7.8, the CBR remains below one.

To estimate the impact of CAPEX on these results, K&M ran a Goal-Seek What-If Analysis to determine the CAPEX figure that would make these scenarios not cost-benefit justified, i.e., NPV = 0 and CBR = 1. These CAPEX thresholds are higher than the USD 210M assumption, indicating that even if CAPEX is greater than the current estimate, the Project is still cost-benefit justified.

Table 7.8: Results of the Combined Sensitivities

Combined Inputs	Least Cost-Benefit Justified	Most Cost-Benefit Justified
Demand Scenario	GPA Target	Delayed Renewables
Discount Rate	6.00%	4.00%
Brent	Low	High
NPV of Costs & Benefits (Without Externalities)	122,198	710,793
NPV of Costs & Benefits (With Externalities)	278,038	1,041,520
Cost - Benefit Ratio (Without Externalities)	0.9094	0.7565
Cost - Benefit Ratio (With Externalities)	0.8432	0.7279
CAPEX Limit (Without Externalities)	291,306,590	637,382,580

7.4.1.4 Delivered Cost of Gas

Although not typically part of a standard ECBA methodology, K&M also evaluated the results of the ECBA using the Levelized Cost of Delivered Gas (LCODG) to test the robustness of the findings. The LCODG is inclusive of the DES price of LNG plus the estimated LNG Terminal Capital Recovery Charge (see Section 10 detailing Task 5.3). The LNG Terminal Capital Recovery Charge is the additional charge on top of the DES price that is required to make the gas supply company's investment in the LNG terminal and related infrastructure bankable. In other words, it enables investors to recover the CAPEX and OPEX while achieving a target internal rate of return and maintaining a specified debt-service coverage ratio. In effect, the LNG Terminal Capital Recovery Charge represents the additional cost above the DES price needed to make the terminal investment financially viable. When this LCODG is used in the ECBA instead of the DES price, CAPEX, and OPEX, the analysis still shows that the project is cost-benefit justified across all three scenarios (see Figure 7.11).

Figure 7.11: Results with LCODG

Economic Cost Benefit Analysis	GPA Target	Guam Law	Delayed Renewables
Benefits	PV (000)	PV (000)	PV (000)
Avoided Fuel Cost (ULSD)	1,155,380	1,611,512	2,067,751
Avoided Fixed O&M Cost (ULSD)	477,849	477,849	477,849
Benefits (Without Externalities)	1,633,230	2,089,361	2,545,601
Avoided Cost of GHG Emissions (ULSD)	385,267	537,917	690,853
Avoided Health Cost of Local Emissions (ULSD)	74,240	103,701	133,042
Benefits (With Externalities)	2,092,737	2,730,979	3,369,495
Costs	PV (000)	PV (000)	PV (000)
Fuel Cost (Including CAPEX / OPEX Recovery)	1,154,866	1,430,573	1,695,542
-	-	-	-
Fixed O&M Cost (LNG)	314,023	314,023	314,023
Costs (Without Externalities)	1,468,889	1,744,596	2,009,565
Avoided Cost of GHG Emissions (LNG)	266,865	373,693	479,951
Avoided Health Cost of Local Emissions (LNG)	24,191	33,868	43,484
Costs (With Externalities)	1,759,945	2,152,156	2,533,000
NPV of Costs & Benefits (Without Externalities)	164,340	344,765	536,035
NPV of Costs & Benefits (With Externalities)	332,793	578,823	836,495
Cost - Benefit Ratio (Without Externalities)	0.8994	0.8350	0.7894
Cost - Benefit Ratio (With Externalities)	0.8410	0.7881	0.7517

7.5 Conclusions

The Project's ECBA analyzes the economic impact of switching GUPP from ULSD to LNG. The results are summarized below:

- 1 Switching from ULSD to LNG at GUPP in 2031 is cost-benefit justified in all three demand scenarios, as well as under all sensitivities examined: Brent scenarios impacting fuel prices and discount rates.
- 2 These results are largely driven by the difference in per-unit fuel costs of ULSD and LNG. The per-unit cost of ULSD is higher than LNG in all scenarios, meaning that the avoided cost of ULSD, a benefit to the Project, will always be greater than the direct cost of LNG, a cost to the Project. This result is more pronounced with greater fuel demand and/or higher Brent prices.
- 3 These results are only impacted when CAPEX is significantly higher than K&M's assumption. For the least cost-benefit justified scenario, the CAPEX threshold that would make the Project not cost-benefit justified is USD 290 M, which is approximately 1.4x the USD 210M estimate.

8 Task 4.2 – Ratepayer Impact Analysis

This section presents the results of Subtask 4.2 – Ratepayer Impact Analysis, which draws on the results of Tasks 1, 2, 3 and 5. These conclusions presented in this section are the final results of the analyses, which have been updated following the conclusion of all other tasks within this study.

The main objective of the Ratepayer Impact Analysis is to determine how the end-user rates will change after GUPP switches from ULSD to LNG and how rates will change with international fuel price fluctuations. End-user rates include a Fuel Recovery Charge (FRC), which is readjusted periodically under the Levelized Energy Adjustment Clause (LEAC). The analysis estimates the FRC for a scenario in which GPA imports LNG (LNG Import) and the counterfactual scenario in which ULSD remains the primary fuel (no LNG) at thermal generation plants in Guam. The impact of switching GUPP to LNG on end-user rates is the difference between LNG Import and No LNG end-user rates.

This section is organized into five sections. Section 8.1 describes the methodology used in the Ratepayer Impact Analysis. Section 8.2 presents the modeling assumptions. Section 8.3 provides the results of the Ratepayer Impact Analysis, as well as the results of the sensitivity runs. Section 8.4 concludes.

8.1 Methodology

The Ratepayer Impact Analysis examines the effect of transitioning from ULSD fuel to natural gas at GUPP and its impact on end-user rates for residential and general service customers during the period 2031 – 2050. This analysis estimates the end-user rate for both the LNG Import and No LNG scenarios and compares these rates to determine the cost savings from fuel switching. Cost savings refer to the average reduction in total end-user bills and the average reduction in the variable energy charge, called the FRC.

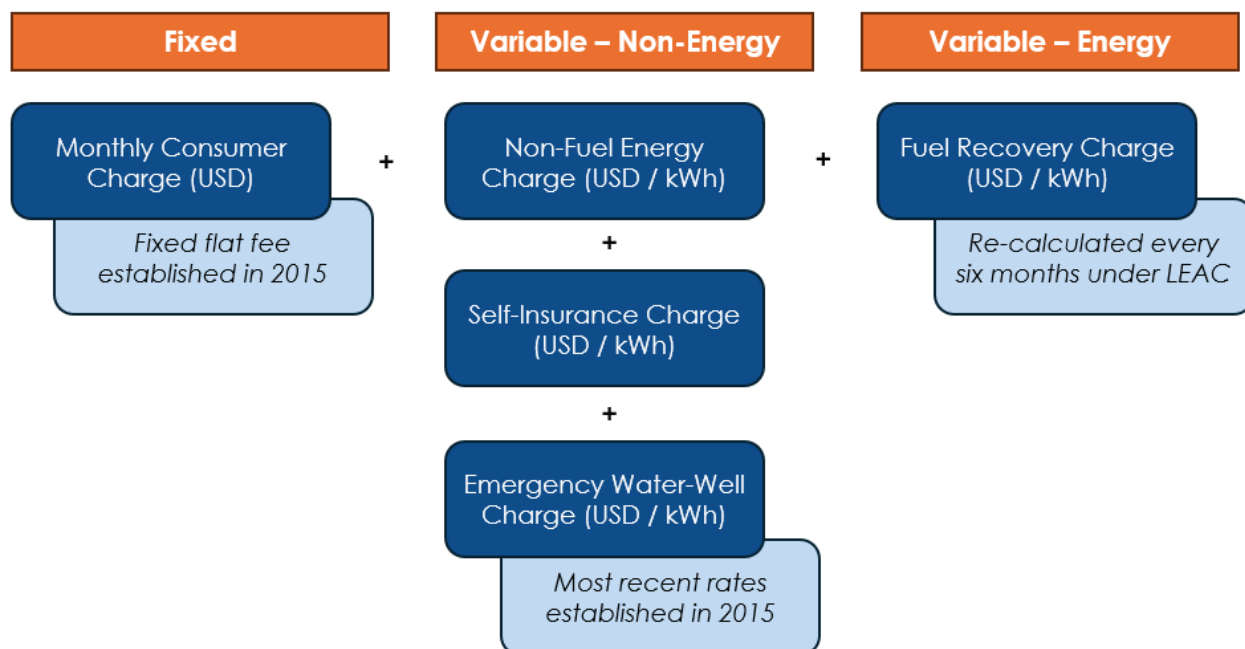
The composition of end-user rate schedules is discussed in Section 8.1.1, which explains that the primary driver of variations in end-user rates is the FRC, a variable charge that allows GPA to recover variable electricity generation costs. The FRC, therefore, includes the fuel cost at thermal power plants and the tariff paid to renewable energy (RE) Independent Power Producers (IPPs). The amount of RE generation impacts the amount of fuel required by thermal power plants and the fuel expense. As RE generation gradually replaces thermal generation, payments to RE IPPs will make up a more significant portion of the FRC. The methodology for calculating the FRC is discussed in Section 8.1.2.

8.1.1 End-User Rate Composition

GPA's rate schedules comprise a fixed component, which is a monthly flat fee determined by the customer class, and a variable component, based on electricity consumption. The variable component includes a non-fuel energy charge with rates established in 2015, a demand charge for certain customer classes, and the FRC, which is readjusted every six months as described by LEAC. The FRC broadly refers to the variable cost of generation, which is primarily fuel, but also includes the per kilowatt-hour (kWh) payments to IPPs under Power Purchase Agreements (PPAs) for RE. While the lower fixed O&M costs incurred by the Guam Ukudu Plant (GUPP) when operating on natural gas instead of ULSD would typically be reflected in the variable non-fuel energy charge, K&M lacks sufficient information to estimate this rate, which has remained fixed since 2015. As a

result, K&M assumes that the reduction in generation costs from using natural gas is accounted for in the FRC (refer to Section 8.2.7). The rate schedule composition is depicted in Figure 8.1 below.

Figure 8.1: Rate Schedule Composition



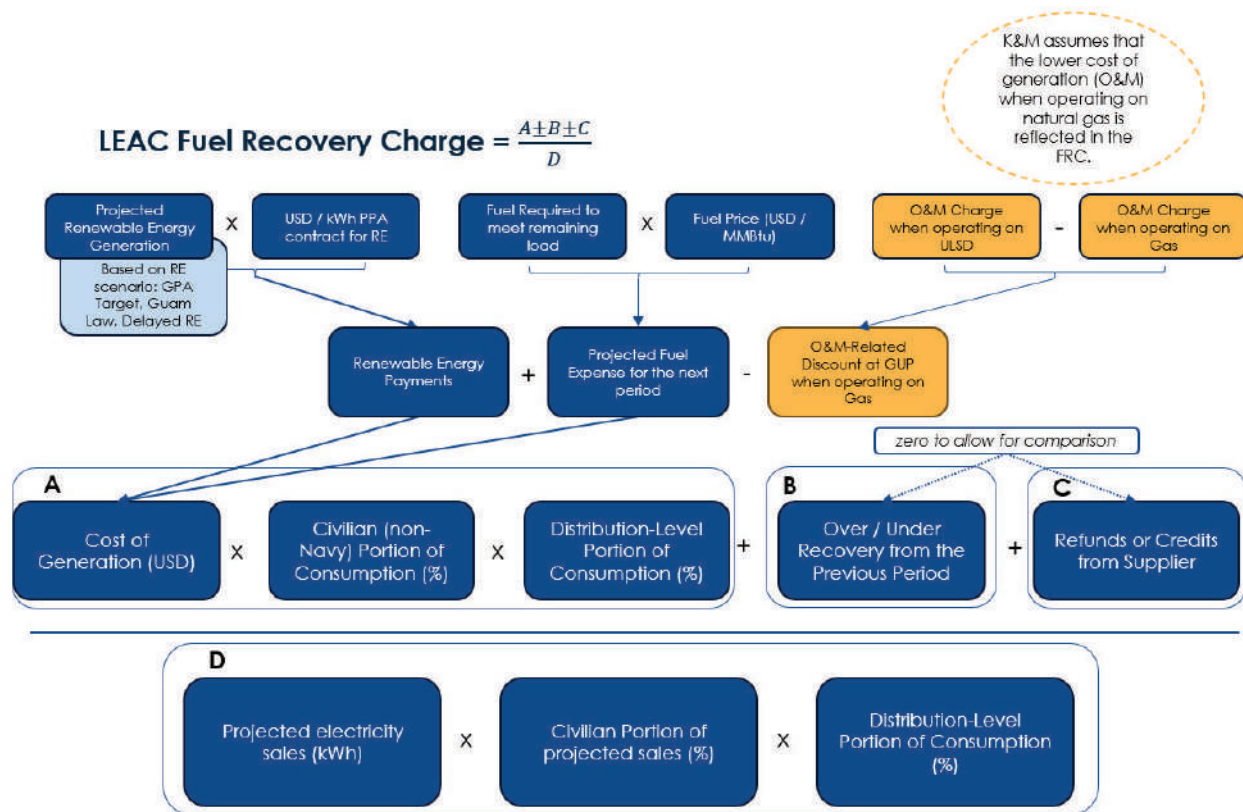
8.1.2 Fuel Recovery Charge Calculation

K&M calculated the FRC using the mechanism described in Schedule Z of GPA's rate schedule documents.²⁶ Conceptually, the FRC equals the cost of generation divided by kWh of generation, with some adjustments to exclude the Navy and transmission-related costs and generation.

Therefore, the FRC is the projected cost of generation (fuel and RE) in the next LEAC period for distribution-level, civilian (non-Navy) ratepayers, divided by the projected distribution-level retail kWh sales for the next LEAC period. Though the FRC is typically also adjusted for the rebate management program, any over/under recovery of expenses from the previous period, and for refunds or credits from suppliers, these adjustments have been left out of the analysis due to insufficient data and to allow comparison across time. Additionally, the lower fixed O&M costs incurred by GUPP when operating on natural gas instead of ULSD, as dictated by GPA's Energy Conversion Agreement, is reflected in the FRC as an O&M-related discount in the LNG Import scenario. The FRC has been estimated for one year rather than six months based on available data. Figure 8.2 illustrates the FRC calculation model.

²⁶ https://admin.guampowerauthority.com/uploads/Z_Levelized_Energy_Adjustment_Clause_LEAC_95394a2965.PDF

Figure 8.2: Fuel Recovery Charge Calculation Diagram



The detailed sequence of calculations is as follows:

- 1 Calculate the annual RE Payment by multiplying the forecasted total system RE generation by the RE Contract Price (determined by PPAs).
- 2 Calculate the annual fuel expense by multiplying the forecasted total system fuel requirement (MMBtu) by the forecasted price (USD / MMBtu). For the LNG Import scenario, the fuel expense includes the cost of natural gas at GUPP and the cost of ULSD at other thermal units. For the No LNG scenario, the fuel expense includes the cost of ULSD for all thermal units.
- 3 Calculate the annual O&M-related discount at GUPP when operating on natural gas (if applicable) by subtracting the O&M charge when operating on gas from the O&M charge when operating on ULSD.
- 4 Calculate the cost of generation by adding the forecasted RE payment and projected fuel expenditure and subtracting the O&M-related discount (if applicable)
- 5 Adjust the cost of generation by multiplying the total cost by the percentage of civilian consumption and by the percentage of distribution-level consumption.
- 6 Adjust the forecasted electricity sales in the next period by multiplying the total kWh by the percentage of civilian sales and by the percentage of distribution-level sales.
- 7 Divide the adjusted cost of generation by the adjusted forecasted sales to derive the FRC (USD / kWh).

8.2 Model Assumptions and Sensitivities

The data and inputs used in the Ratepayer Impact Analysis come from GPA, publicly available sources, or are derived from related models developed by K&M for this assignment. The model shares many of the same inputs and assumptions as Task 4.1 – Economic Cost Benefit Analysis, which is presented in Section 7 of this report. Notably, the Ratepayer Impact Analysis considers generation and output (kWh) for the entire island rather than just GUPP.

8.2.1 Model Period

The Ratepayer Impact Analysis covers the period 2031 – 2050, which includes fuel switching at GUPP starting in 2031 and a nineteen-year operational period.

8.2.2 Demand Scenarios

The fuel required at GUPP is a function of electricity demand and the level of renewable energy generation in Guam. GPA dispatches electricity generated from renewables first and meets the remaining load with electricity generated from natural gas and ULSD power plants. Given the uncertainty surrounding the timeline for renewable energy deployment in Guam, the analysis evaluates three scenarios for renewable energy deployment, described below, that determine gas demand for Guam:

- 1 **GPA Target:** Based on GPA's timeline for renewable energy deployment, which targets 50% renewable energy by 2030 and 100% renewable energy by 2040.
- 2 **Guam Law:** Based on Guam Public Law No. 35 – 46, which targets 50% RE by 2035 and 100% RE by 2045.
- 3 **Delayed Renewables:** Based on gradual additions of RE at a lower rate than either GPA's target or Guam law.

Under these assumptions for renewable energy generation, GUPP's fuel requirement for natural gas will be much higher in 2031 and decrease as renewables replace thermal generation. The annual volumes (MMBtu) are derived from K&M's fuel demand modeling work done as part of Task 1 and detailed in Section 4 of this report.

8.2.3 Thermal Generation

Based on the RE generation profile, K&M's Fuel Demand Model under Task 1 of this assignment calculates the estimated fuel requirement (MMBtu) at each of Guam's thermal generation units. The LNG Import scenario includes natural gas required at GUPP and ULSD required by other thermal units to meet the total system load. The No LNG scenario includes ULSD required by all thermal units to meet the total system load.

8.2.4 Renewable Energy Price

The model uses the contract price per kilowatt hour from the most recent PPA signed between GPA and an RE IPP, which is USD 0.1700 / kWh. This cost is escalated by 1% per year to match the contract agreement.

8.2.5 Fuel Prices

ULSD and natural gas prices are indexed to the forecasted Brent price, using EIA's long-term Brent forecast. The Ratepayer Impact Analysis shares the methodology for estimating the prices of ULSD

and LNG with the Economic Cost Benefit Analysis (Task 4.1). ULSD price forecasts are detailed in Section 7.2.6.1. The DES LNG price forecasts are detailed in Section 7.2.6.2.

8.2.5.1 Price of Delivered Gas

The price of delivered gas to GUPP consists of the DES LNG price, described in Section 7.2.6.2, plus the LNG Terminal Capital Recovery Charge. The LNG Terminal Capital Recovery Charge is an annual fixed charge that is estimated in Task 5.3 – Financial Analysis of the Gas Supply Company and detailed in Section 10. This recovery charge (USD / year) ensures the terminal investment is financially viable. Table 8.1 summarizes the levelized cost of delivered gas per MMBtu across the analysis period for each demand scenario.

Table 8.1: LNG Terminal Recovery Charge and LCOG by Demand Scenario

	GPA Target	Guam Law	Delayed Renewables
Levelized Cost of Gas (LCOG), USD / MMBtu	\$25.24	\$22.61	\$21.43

8.2.6 Rate Schedule Assumptions

GPA publishes existing rates on its website; the fixed and variable rates used in the analysis for residential and general service customers are in Table 8.2 below. While GPA has over ten different customer classifications, the analysis focuses on the impact on residential and general service ratepayers rather than government or larger industrial customer classes.

Since the monthly flat fee, non-fuel energy charge, and other non-energy charges have been in effect since 2015 and have remained constant, the model assumes these figures to remain constant over the analysis period. This also isolates the impact of the FRC on ratepayers, which typically makes up over half of the total bill and changes every LEAC period.

Table 8.2: Rate Schedules by Customer Class

Customer Class	Consumer Charge (USD / Month)	Non-Fuel Energy Charge (USD / kWh)	Self-Insurance Charge (USD / kWh)	Emergency Water-Well Charge (USD / kWh)	Fuel Recovery Charge (USD / kWh)
Residential	15 USD / month	0 – 500 kWh: 0.06955 500+ kWh: 0.08687	0.00279	0 – 500 kWh: 0.000 500+ kWh: 0.00290	Changes every LEAC period
General Service	14.16 USD / month	0 – 350 kWh: 0.20086 350+ kWh: 0.10861	0.00279	0.00290	Changes every LEAC period

8.2.7 Fixed O&M Charges

Under the ECA signed between GPA and GUPP, GPA pays GUPP a fixed O&M charge. This charge is greater when GUPP operates on ULSD than natural gas. Specifically, it is 11.5246 USD / KW / month for ULSD and 7.5735 USD / KW / month for natural gas, escalated yearly based on the reference year, defined as April 2019, and adjusted based on a correction load factor. The correction load factor is assumed to be 1.03 for the first ten years of the plant's operational life, based on GUPP's units operating at 90 – 95% capacity, and is adjusted to 1.00 for the remaining years of the plant's

operational life, when GUPP's units are assumed to operate below 90% capacity. These assumptions are based on the gradual integration of renewables, which lowers generation requirements for Guam's thermal units.

The difference in the Fixed O&M charge is applied as a discount to the cost of generation when GUPP operates on natural gas instead of ULSD.

8.2.8 Civilian Portion

K&M determined that the portion of consumption and sales generally attributed to the Navy is 20.05%.²⁷ This is based on publicly available data from 2021 and confirmed in GPA's documentation of LEAC calculations in recent years.²⁸ The civilian (non-Navy) portion of consumption and sales is therefore estimated to be 79.95% for the model period.

8.2.9 Transmission Portion

K&M determined that the portion of civilian consumption and sales generally attributed to transmission level customers (e.g., large industrial customers capable of accepting higher-voltage electricity supply), is around 6%.²⁹ This is based on GPA documentation of LEAC calculations in recent years. The distribution-level portion of civilian consumption and sales is, therefore, estimated to be 94% for the model period.

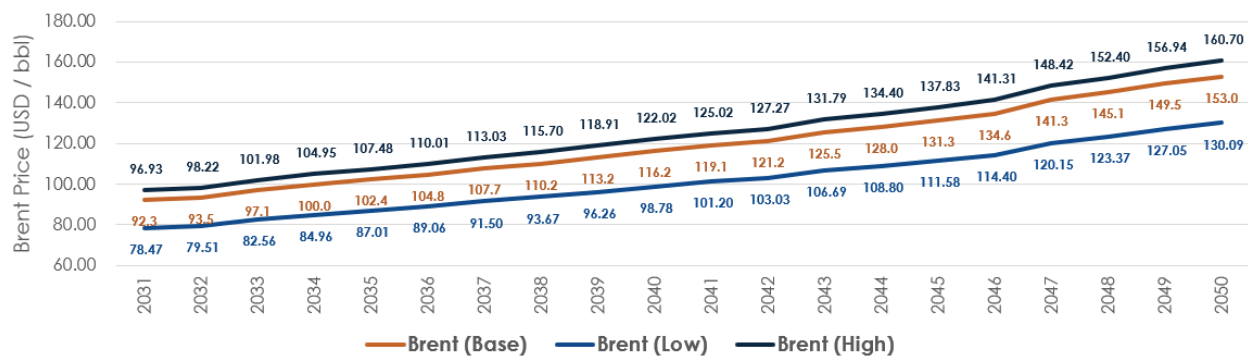
8.2.10 Sensitivities

To account for uncertainties surrounding fuel demand and fuel prices, K&M includes a sensitivity for the Brent forecast, which impact fuel prices.

8.2.10.1 Brent

The price of fuel, both ULSD and LNG, is indexed to the price of Brent crude oil and forecasted for the Project lifetime (2031 – 2050). In addition to the base case forecast based on EIA's long-term Brent forecast, the analysis includes a high Brent scenario (+5% from the base case) and a low Brent scenario (-15% from the base case), depicted in Figure 8.3.

Figure 8.3: Brent Price Sensitivity (2031 – 2050)



²⁷ www.nrel.gov/docs/fy24osti/88454.pdf

²⁸ <https://guampuc.com/wp-content/uploads/2024/07/GPA-24-20-PETITION-060724.pdf>

²⁹ <https://guampuc.com/wp-content/uploads/2024/07/GPA-24-20-PETITION-060724.pdf>

8.3 Results

The results of the Ratepayer Impact Analysis demonstrate cost savings to ratepayers as a result of a lower FRC in all three demand scenarios, summarized in Table 8.3.

Table 8.3: Average Reduction in FRC

Ratepayer Impact Analysis	GPA Target	Guam Law	Delayed RE
Fuel Recovery Cost	USD / kWh	USD / kWh	USD / kWh
Avg. Fuel Recovery Cost 2031 - 2050 (No LNG Import)	0.1293	0.1484	0.1713
Avg. Fuel Recovery Cost 2031 - 2050 (LNG Import)	0.1244	0.1368	0.1514
Percent Difference	-3.75%	-7.79%	-11.60%

The detailed results are presented in subsequent sections. Section 8.3.1 presents the estimation of the total generation cost for all demand scenarios across the period 2031 – 2050. Section 8.3.2 presents the estimation of the FRC. The FRC is used as the primary input in the calculation of the monthly customer bill, which is done for a typical residential customer and a typical commercial customer in Section 8.3.3. Section 8.3.4 summarizes the cost savings to end consumers. Section 8.3.5 includes the sensitivity analysis.

8.3.1 Forecasted Generation Expense

Figure 8.4, Figure 8.5, and Figure 8.6 illustrate that the total cost of generation is lower with LNG Import than with No LNG across all three demand scenarios. The difference in generation expense is the greatest in the Delayed RE scenario.

Figure 8.4: Total Generation Expense – GPA Target

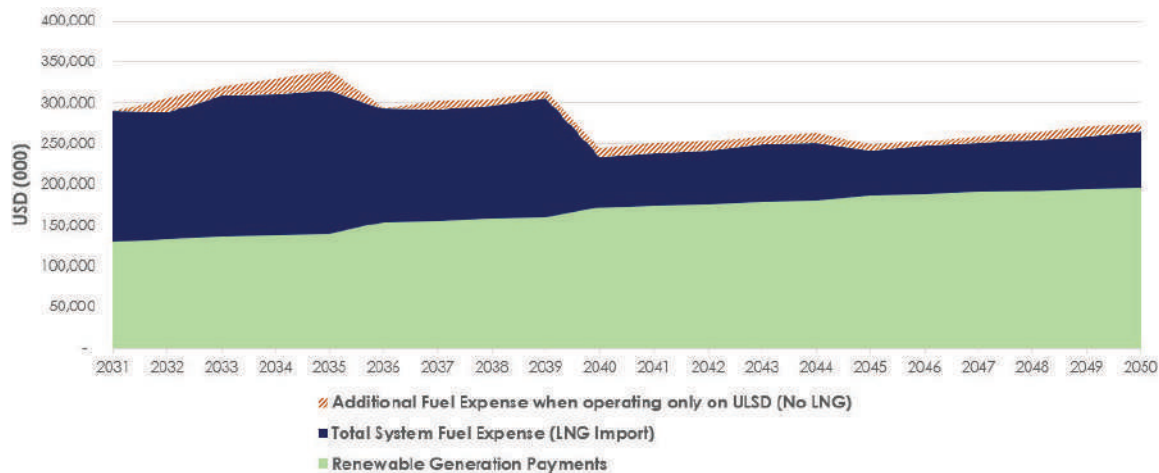


Figure 8.5: Total Generation Expense – Guam Law

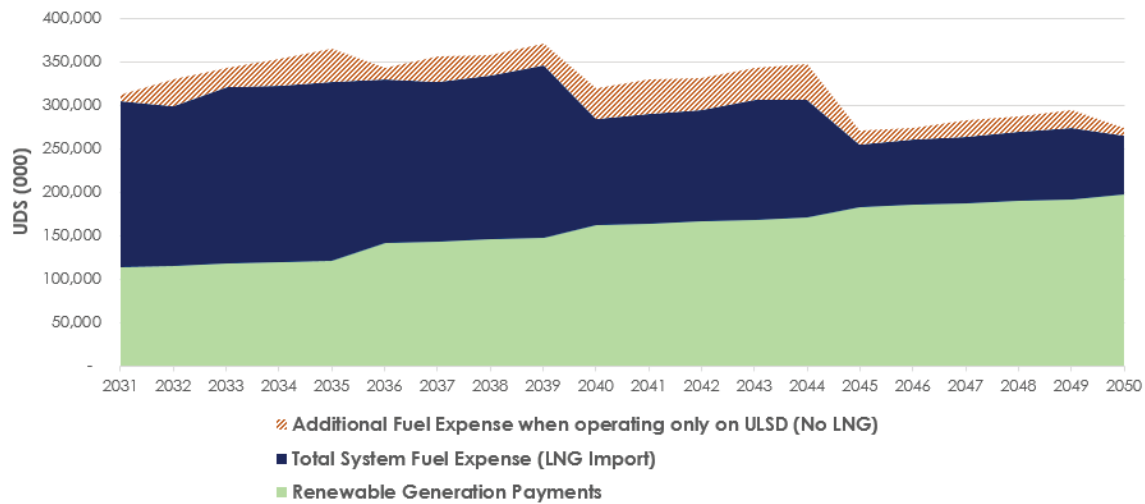
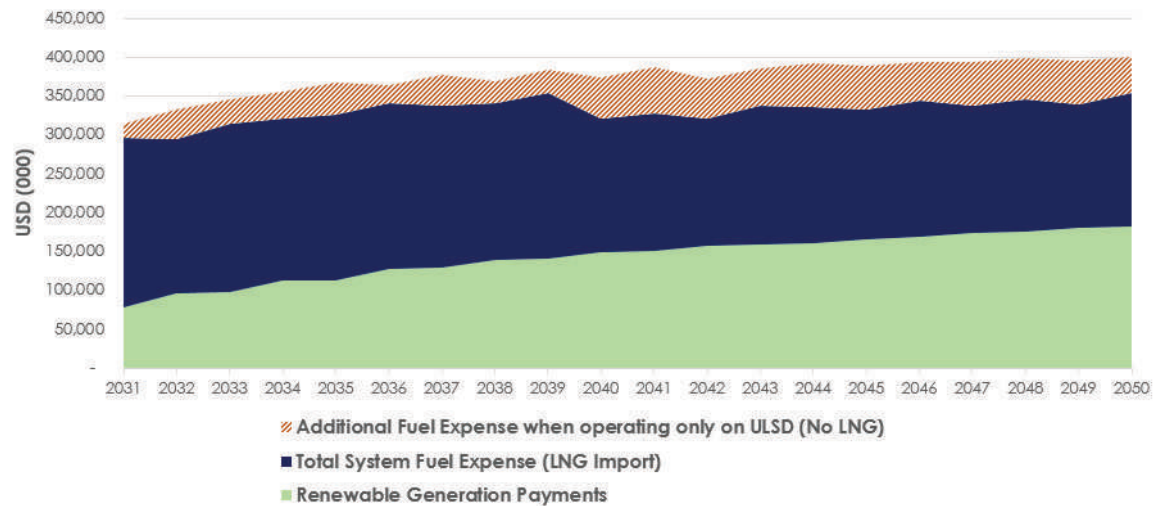


Figure 8.6: Total Generation Expense – Delayed RE



8.3.2 Forecasted Fuel Recovery Charge

Figure 8.7, Figure 8.8, and Figure 8.9 illustrate that the FRC is lower with LNG Import than with No LNG across all three demand scenarios. The difference in the FRC is greatest in the Delayed RE scenario.

Figure 8.7: Fuel Recovery Charge – GPA Target

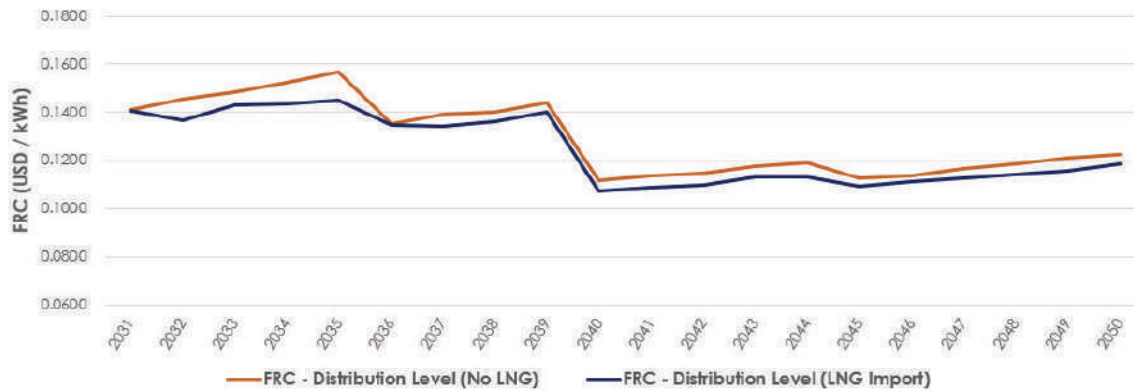


Figure 8.8: Fuel Recovery Charge – Guam Law

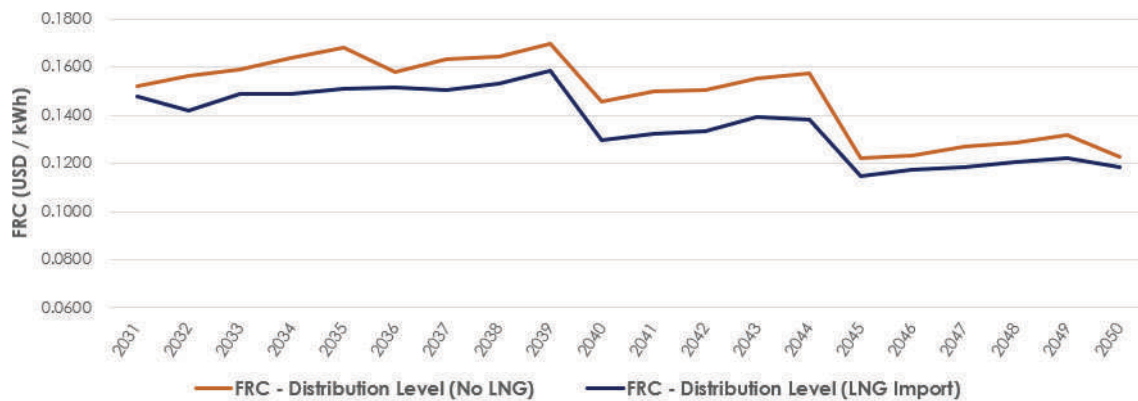
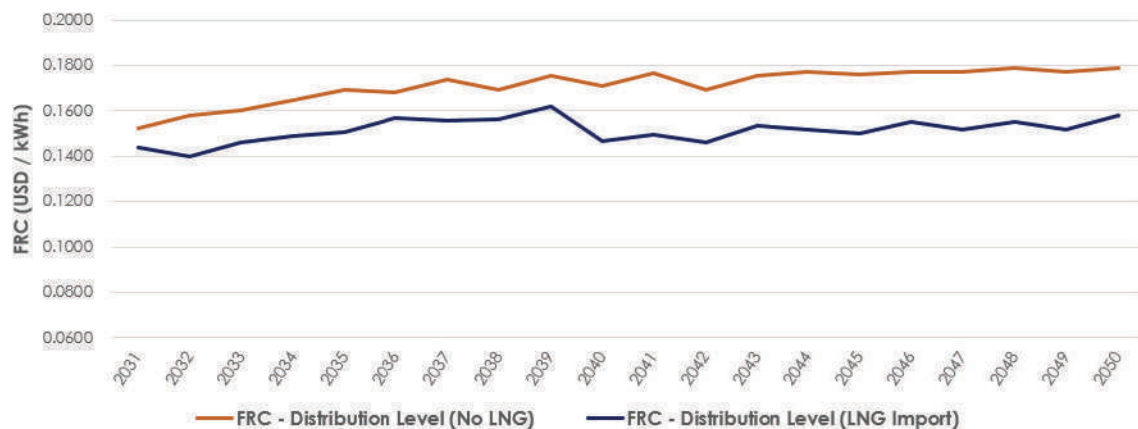


Figure 8.9: Fuel Recovery Charge – Delayed RE



8.3.3 Sample Customer Monthly Bills

Using the rate schedule inputs described in Section 8.2.6 and the forecasted FRC described in Section 8.3.2, K&M calculated sample customer monthly bills for residential and general service ratepayers consuming 1000 kWh and 5000 kWh, respectively. The total electricity monthly bill for these customers in 2031, 2040, and 2050 under the GPA Target scenario is shown in Figure 8.10 and Figure 8.11.

Figure 8.10: Residential Bill Calculation – GPA Target

		Residential Service Rate Schedule - Sample Bill									
		2031		2036		2041		2046		2050	
No LNG	R	1,000		1,000		1,000		1,000		1,000	
kWh											
Monthly Charge		\$ 15.00	\$ 15.00	\$ 15.00	\$ 15.00	\$ 15.00	\$ 15.00	\$ 15.00	\$ 15.00	\$ 15.00	\$ 15.00
Non-Fuel Energy Charge											
First 500 kWh		0.06955	\$ 34.78	0.0696	\$ 34.78	0.0696	\$ 34.78	0.0696	\$ 34.78	0.0696	\$ 34.78
Over 500 kWh		0.08687	\$ 43.44	0.08687	\$ 43.44	0.08687	\$ 43.44	0.08687	\$ 43.44	0.08687	\$ 43.44
Demand Charge		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Emergency water-well charge		0.00279	\$ 1.40	0.00279	\$ 1.40	0.00279	\$ 1.40	0.00279	\$ 1.40	0.00279	\$ 1.40
Self-insurance charge		0.00290	\$ 2.90	0.00290	\$ 2.90	0.00290	\$ 2.90	0.00290	\$ 2.90	0.00290	\$ 2.90
Total Electric Charge before Fuel Recovery Charge		\$ 97.51		\$ 97.51		\$ 97.51		\$ 97.51		\$ 97.51	
Fuel Recovery Charge (LEAC Rate)		0.14088	\$ 140.88	0.13513	\$ 135.13	0.11391	\$ 113.91	0.11389	\$ 113.89	0.12252	\$ 122.52
Total Electric Charge		\$ 238.39		\$ 232.63		\$ 211.42		\$ 211.39		\$ 220.02	

		Residential Service Rate Schedule - Sample Bill									
		2031		2036		2041		2046		2050	
LNG Import	R	1,000		1,000		1,000		1,000		1,000	
kWh											
Monthly Charge		\$ 15.00	\$ 15.00	\$ 15.00	\$ 15.00	\$ 15.00	\$ 15.00	\$ 15.00	\$ 15.00	\$ 15.00	\$ 15.00
Non-Fuel Energy Charge											
First 500 kWh		0.06955	\$ 34.78	0.0696	\$ 34.78	0.0696	\$ 34.78	0.0696	\$ 34.78	0.0696	\$ 34.78
Over 500 kWh		0.08687	\$ 43.44	0.08687	\$ 43.44	0.08687	\$ 43.44	0.08687	\$ 43.44	0.08687	\$ 43.44
Demand Charge		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Emergency water-well charge		0.00279	\$ 1.40	0.00279	\$ 1.40	0.00279	\$ 1.40	0.00279	\$ 1.40	0.00279	\$ 1.40
Self-insurance charge		0.00290	\$ 2.90	0.00290	\$ 2.90	0.00290	\$ 2.90	0.00290	\$ 2.90	0.00290	\$ 2.90
Total Electric Charge before Fuel Recovery Charge		\$ 97.51		\$ 97.51		\$ 97.51		\$ 97.51		\$ 97.51	
Fuel Recovery Charge (LEAC Rate)		0.14049	\$ 140.49	0.13463	\$ 134.63	0.10875	\$ 108.75	0.11141	\$ 111.41	0.11859	\$ 118.59
Total Electric Charge		\$ 237.99		\$ 232.14		\$ 206.26		\$ 208.91		\$ 216.09	

% Increase / (Decrease) of Total Bill	-0.17%	-0.21%	-2.44%	-1.17%	-1.79%
% Increase / (Decrease) of LEAC FRC Portion	-0.28%	-0.37%	-4.53%	-2.18%	-3.21%

Figure 8.11: General Service Bill Calculation – GPA Target

		General Service Non-Demand Rate Schedule - Sample Bill									
		2031		2036		2041		2046		2050	
No LNG	R	5,000		5,000		5,000		5,000		5,000	
kWh											
Monthly Charge		\$ 14.16	\$ 14.16	\$ 14.16	\$ 14.16	\$ 14.16	\$ 14.16	\$ 14.16	\$ 14.16	\$ 14.16	\$ 14.16
Non-Fuel Energy Charge											
First 350 kWh		0.20086	\$ 70.30	0.2009	\$ 70.30	0.2009	\$ 70.30	0.2009	\$ 70.30	0.2009	\$ 70.30
Over 350 kWh		0.10861	\$ 505.04	0.10861	\$ 505.04	0.10861	\$ 505.04	0.10861	\$ 505.04	0.10861	\$ 505.04
Demand Charge		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Emergency water-well charge		0.00279	\$ 12.97	0.00279	\$ 12.97	0.00279	\$ 12.97	0.00279	\$ 12.97	0.00279	\$ 12.97
Self-insurance charge		0.00290	\$ 14.50	0.00290	\$ 14.50	0.00290	\$ 14.50	0.00290	\$ 14.50	0.00290	\$ 14.50
Total Electric Charge before Fuel Recovery Charge		\$ 616.97		\$ 616.97		\$ 616.97		\$ 616.97		\$ 616.97	
Fuel Recovery Charge (LEAC Rate)		0.14088	\$ 704.42	0.13513	\$ 675.63	0.11391	\$ 569.57	0.11389	\$ 569.44	0.12252	\$ 612.58
Total Electric Charge		\$ 1,321.39		\$ 1,292.60		\$ 1,186.54		\$ 1,186.41		\$ 1,229.55	

		General Service Non-Demand Rate Schedule - Sample Bill									
		2031		2036		2041		2046		2050	
LNG Import	R	5,000		5,000		5,000		5,000		5,000	
kWh											
Monthly Charge		\$ 14.16	\$ 14.16	\$ 14.16	\$ 14.16	\$ 14.16	\$ 14.16	\$ 14.16	\$ 14.16	\$ 14.16	\$ 14.16
Non-Fuel Energy Charge											
First 350 kWh		0.20086	\$ 70.30	0.2009	\$ 70.30	0.2009	\$ 70.30	0.2009	\$ 70.30	0.2009	\$ 70.30
Over 350 kWh		0.10861	\$ 505.04	0.10861	\$ 505.04	0.10861	\$ 505.04	0.10861	\$ 505.04	0.10861	\$ 505.04
Demand Charge		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Emergency water-well charge		0.00279	\$ 12.97	0.00279	\$ 12.97	0.00279	\$ 12.97	0.00279	\$ 12.97	0.00279	\$ 12.97
Self-insurance charge		0.00290	\$ 14.50	0.00290	\$ 14.50	0.00290	\$ 14.50	0.00290	\$ 14.50	0.00290	\$ 14.50
Total Electric Charge before Fuel Recovery Charge		\$ 616.97		\$ 616.97		\$ 616.97		\$ 616.97		\$ 616.97	
Fuel Recovery Charge (LEAC Rate)		0.14049	\$ 702.45	0.13463	\$ 673.16	0.10875	\$ 543.76	0.11141	\$ 557.03	0.11859	\$ 592.93
Total Electric Charge		\$ 1,319.42		\$ 1,290.13		\$ 1,160.73		\$ 1,174.00		\$ 1,209.90	

% Increase / (Decrease) of Total Bill	-0.15%	-0.19%	-2.18%	-1.05%	-1.40%
% Increase / (Decrease) of LEAC FRC Portion	-0.28%	-0.37%	-4.53%	-2.18%	-3.21%

The Ratepayer Impact Analysis calculates total customer bills for both customer classes over the model period to allow comparison of the LNG Import and No LNG scenarios. The results of the residential bill are depicted for all three demand scenarios in Figure 8.12, Figure 8.13, and Figure 8.14.

Figure 8.12: Residential Bill for 1000 kWh Consumption – GPA Target

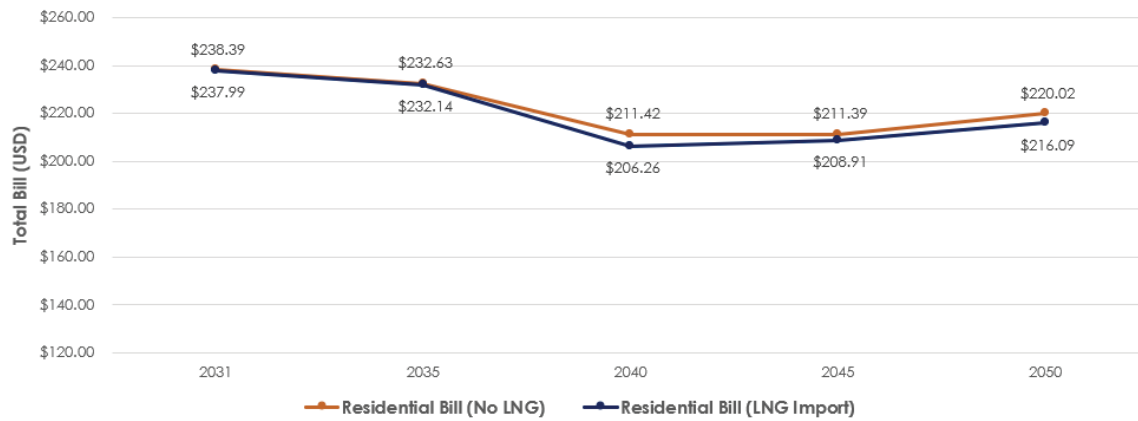


Figure 8.13: Residential Bill for 1000 kWh Consumption – Guam Law

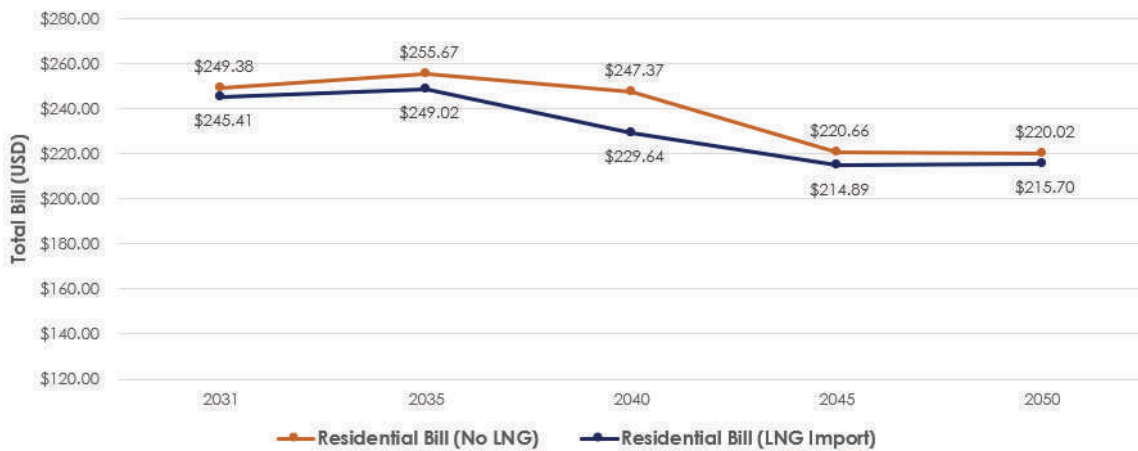
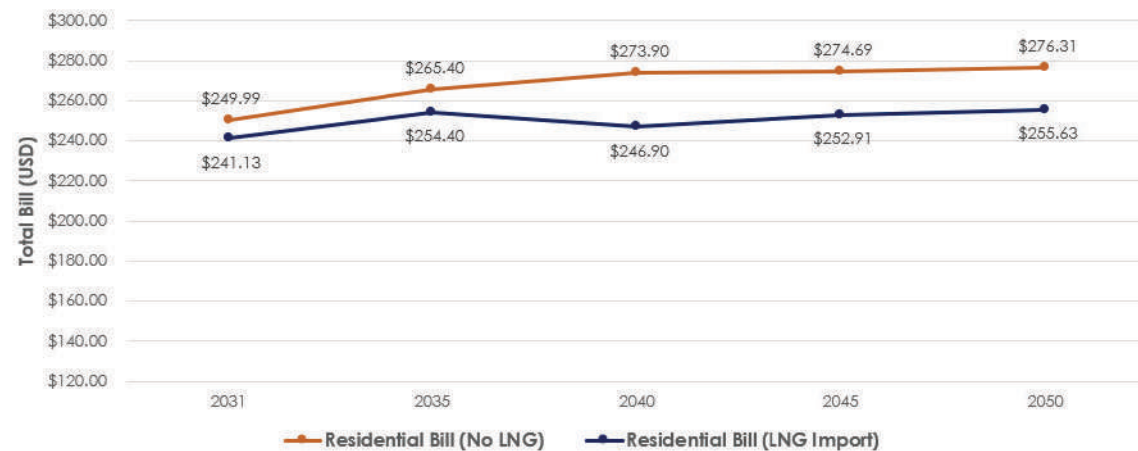


Figure 8.14: Residential Bill for 1000 kWh Consumption – Delayed RE



8.3.4 Cost Savings

Across the analysis period, switching from ULSD to LNG reduces both the FRC and the total bill for residential and general service customers, detailed in Table 8.4 below. Fuel switching results in an

average reduction in the FRC from 3.9 – 11.6% depending on the demand scenario and an average reduction in the overall residential and general service bill by 1.0 – 6.6%.

Table 8.4: Average Cost Savings by Demand Scenario

	GPA Target	Guam Law	Delayed RE
Average Reduction in Fuel Recovery Charge	3.9%	7.8%	11.6%
Average Reduction in Total Bill (Residential)	1.2%	3.2%	6.6%
Average Reduction in Total Bill (General Service)	1.0%	2.9%	6.0%

8.3.5 Sensitivity Analysis

The forecasted ULSD and LNG prices are indexed to the long-term EIA forecast for Brent crude oil. The model includes sensitivities for increases (+5%) and decreases (-15%) in the underlying commodity price of Brent crude oil. K&M analyzed the Brent crude price thresholds at which the benefits of LNG imports to ratepayers would be eliminated, using 2031 as a representative year (see Figure 8.15). In the GPA Target scenario, importing LNG results in a lower FRC unless Brent prices fall below approximately \$58 per barrel. In the Guam Law scenario, the breakeven Brent price is approximately \$49 per barrel, while in the Delayed RE scenario, it is approximately \$45 per barrel. Brent prices at or below these levels are considered highly unlikely and are not expected to be sustained over the analysis period.

Figure 8.15: FRC Reduction due to LNG Import in 2031

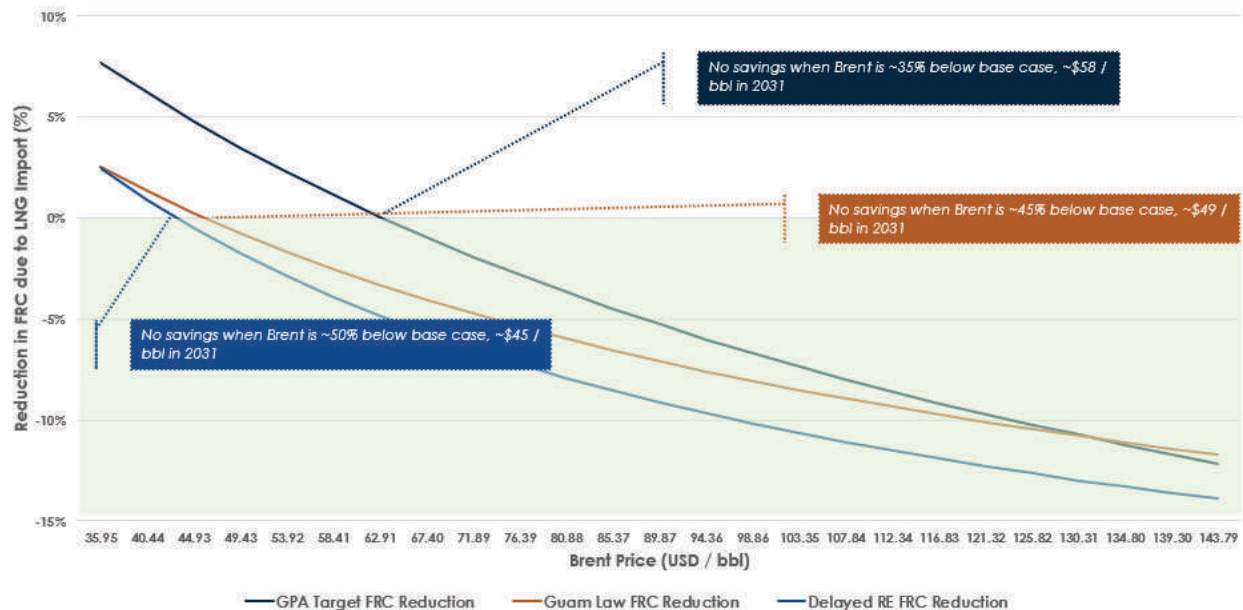
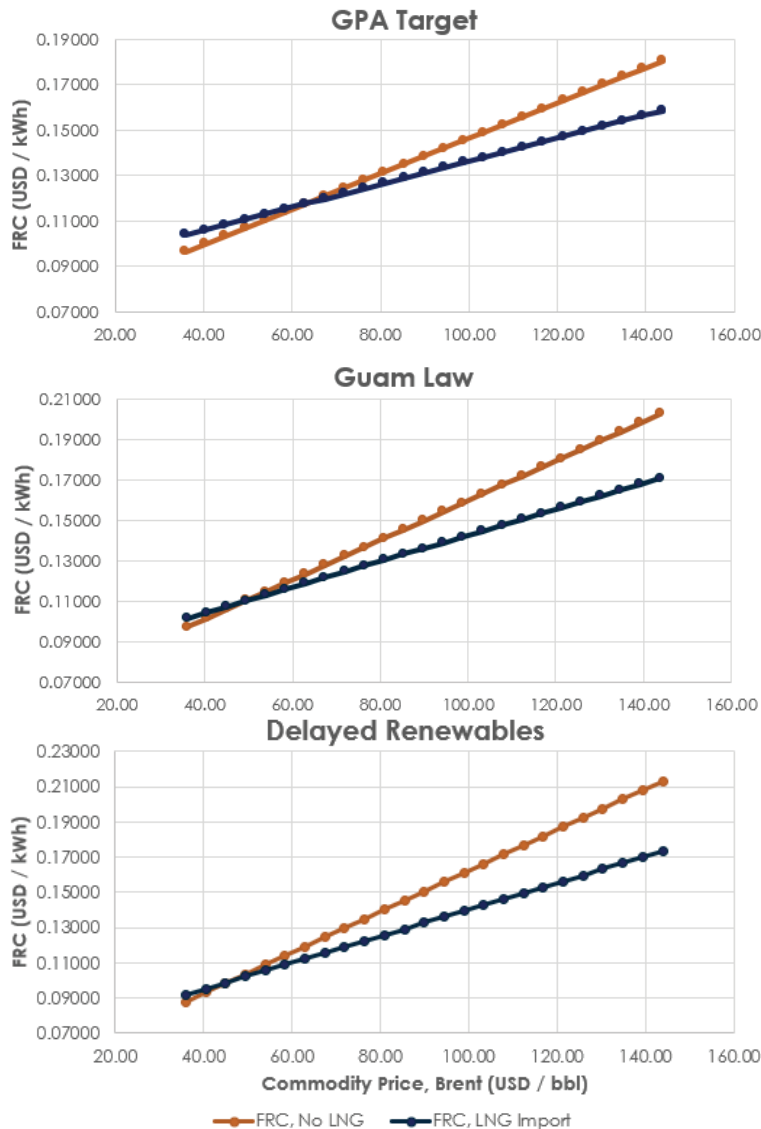


Figure 8.16 presents the same analysis but plots the FRC on the y-axis instead of percentage savings. It shows that, across all scenarios, the FRC under the LNG Import case remains below that of the No LNG case at Brent prices above approximately \$45 to \$58 per barrel, depending on the scenario. The figure also highlights that the FRC differential widens at higher Brent prices -

particularly in the Delayed RE scenario, where greater gas demand amplifies the price advantage of LNG over ULSD. Nonetheless, the overall FRC remains lowest in the GPA Target scenario, averaging \$0.1244 across the analysis period, compared to \$0.1514 in the Delayed RE scenario.

Figure 8.16: Fuel Recovery Charge by Commodity Price in 2031



8.4 Conclusions

Based on the results of the Ratepayer Impact Analysis, the following conclusions can be drawn at this stage:

- 1 The variable Fuel Recovery Charge, which captures both RE payments and fuel expenditures, is consistently lower when LNG is used at GUPP than when no LNG is imported. This result exists in all RE generation scenarios (GPA Target, Guam Law, and Delayed RE) and for all variations in the underlying commodity prices.

- 2 Because the Fuel Recovery Charge is lower when GUPP uses LNG rather than ULSD, the transition to LNG lowers customer bills overall. The average reduction in a residential and general service bill is 1.0 – 6.6%, depending on the RE deployment scenario. The savings to ratepayers are greater at lower levels of RE penetration.
- 4 When the price of the underlying commodity, Brent, increases, the fuel price differential between ULSD and LNG increases, and consequently the cost savings to consumers represented by the lower Fuel Recovery Charge is greater when GUPP operates on LNG.



Task 5

Legal Analysis, Business Model Comparison, and Financial Analysis

9 Task 5.1 & 5.2 – Legal Analysis & Business Model Comparison

The main objective of Task 5.1 – Legal Analysis and Task 5.2 – Business Model Comparison, is to evaluate potential business models for the implementation of the LNG infrastructure that satisfy Guam's legal and regulatory requirements, minimize GPA risks during project development, construction, and operation, and ensure a reliable supply of natural gas to GUPP at a competitive price. The analysis also considers business models that allow the resale of LNG or natural gas to third-party customers, especially given that increased LNG demand reduces the price of gas supplied to GUPP and improves the economic viability of the LNG infrastructure development project.

This section is organized into four sections. Section 9.1 presents the legal analysis of business model options. Section 9.2 describes all identified business model options. Section 9.3 provides the criteria and results of the business model evaluation. Section 9.4 includes an assessment of the risk allocation for the preferred business model. Section 9.5 concludes. Appendix K includes a copy of the independent legal opinion prepared by the Guam attorney, Mr. Arthur Clark.

9.1 Legal Analysis

9.1.1 Background

In their petition to Guam PUC asking to approve the EPCM Phase 1, LNG Pre-development Study, Scope and Costs, GPA described the overall scope of the EPCM work on the LNG project implementation, which included Phase 4, LNG/CNG Transshipment. The LNG/CNG Transshipment phase would explore the possibility of supplying LNG to other users and potential business arrangements for such an undertaking. The possible arrangements described in the petition included the following:

- GPA selling LNG or gas ex-terminal to third parties who could then distribute to end-users
- GPA allowing third parties to use the LNG terminal to import LNG and charging these third parties a fee for using the terminal (equivalent to a franchise fee)
- GPA entering into a joint venture with a third party that will distribute and sell LNG or natural gas to end-users.

In a June 26, 2023 report, the Administrative Law Judge (ALJ) expressed a concern that under the GPA Act of 1968 (see Guam Code 12, Chapter 8), GPA has no legal authority to engage in any activities listed above. In the November 22, 2023 report, ALJ requested that "In its Phase 1 Study, Stanley /GPA should arrange for a comprehensive legal opinion as to whether the intra-island sale of LNG and regional transshipment are activities that GPA can legally enter". This requirement was included in the Guam Public Utility Commission (PUC) Order dated November 30, 2023, authorizing GPA to proceed with the Phase 1 Study.

K&M, serving as a subcontractor to Stanley and the lead advisor for the LNG infrastructure implementation, engaged the Law Office of Arthur Clark to address this requirement. Mr. Clark is an attorney who works in Guam and has extensive knowledge and experience in Guam commercial law and regulations. This section of the report presents the legal questions that K&M asked Mr. Clark (section 9.1.2), summarizes his legal opinion (section 9.1.3), and explains the impact of this opinion on the business model options (section 9.1.4).

9.1.2 Issues Addressed by the Legal Opinion

K&M requested the Legal Opinion to:

- Address the issues concerning Phase IV raised in the ALJ Reports dated June 26, 2023, and November 22, 2023, and the PUC Order dated November 30, 2023, concerning the legality of GPA's proposal to sell LNG to third parties, franchise the distribution of LNG to customers in Guam, or transship LNG to other islands.
- To the extent possible, assess the attitude of private fuel suppliers in Guam (i.e., IP&E/Mobil, etc.) regarding the potential development of an LNG monopoly should be assessed.
- To assess whether under the laws of Guam:
 - A private entity can develop and own the LNG infrastructure, supply gas to GPA, and sell LNG to third parties or
 - GPA can own the LNG infrastructure, which supplies gas to the Ukudu plant as a sole owner or as part of a joint venture and get paid for providing LNG storage and processing services to a private LNG reseller, who would purchase LNG under a separate contract with a private company supplying LNG to Guam and sell it to third parties on Guam or transship to nearby islands.

9.1.3 Legal Opinion Conclusions

Mr. Clark reviewed the applicable laws and regulations and similar court cases adjudicated in Guam and prepared a memo presenting his legal opinion. The complete document is included in Appendix K. The summary of the legal opinion is as follows:

- There are no limitations on the LNG-related activities a private entity can undertake. A private developer can develop and own the LNG infrastructure, supply gas to GPA, and sell LNG to third parties.
- Under the current legislature and court precedents, GPA cannot own or be a part-owner of the LNG terminal, which is not used solely to provide gas for the GUPP but also to provide storage and/or regasification services to other customers and derive revenue from these activities.
- Under the current legislature and court precedents, GPA does not have the authority to sell LNG to third parties, franchise the distribution of LNG to customers in Guam, or transship LNG to other islands.
- GPA can own or be a part-owner of the LNG terminal if the terminal is used solely to supply gas to the Ukudu plant.

Regarding assessing the attitude of private fuel suppliers in Guam to the possible creation of an LNG monopoly, the legal opinion recommended not to pursue such an assessment, as the question appears to be specific to a “monopoly” controlled by GPA for the sale and transshipment of LNG, and it does not appear that GPA has any legislative authorization to engage in such an activity.

9.1.4 Impact of the Legal Opinion on the Business Model Options

All business models deemed unviable based on the legal opinion have been excluded from the analysis. For instance, a business model in which GPA is directly involved in LNG or natural gas

resale was excluded. However, K&M understands that GPA may propose changes to the laws that could enable GPA to consider business models currently deemed legally unviable. K&M will update the business model options analysis once GPA has a more precise idea of the scope of these legal changes and their likelihood of being enacted.

According to the legal opinion, the inclusion of resale of LNG or gas in the scope of the LNG infrastructure development project has a material impact on the legal viability of the business models and, especially, on GPA's ability to own the whole or a part of the LNG infrastructure — that is why the options are presented with and without resale.

9.2 Business Model Options

K&M identified eight business model options. As described above, the inclusion of resale LNG or gas has a material impact on the legal viability of the business models. Therefore, four business model options are presented with resale and four options without resale, summarized in Figure 9.1 and Figure 9.2 respectively. The eight subsequent sections describe each option in more detail.

The business model is broken down into four different supply chain components: (1) LNG delivery to Guam ex-ship, (2) LNG purchase, (3) LNG storage and regasification at the terminal, and (4) LNG or natural gas resale. Each function can be performed by a private entity and/or GPA, which determines the business model and LNG terminal ownership structure.

Figure 9.1: Business Model Options with Resale

Option	Activity			
	LNG Delivery ex-Ship	LNG Purchaser	LNG Terminal	LNG Resale
1	Gas Supplier and Reseller			
2	Gas Supplier			Reseller
3	LNG Supplier	GPA	Terminal Owner/Reseller	
		Terminal Owner/ Reseller		
4	LNG Supplier	GPA	Terminal Owner	Reseller
		Reseller		

Figure 9.2: Business Model Options without Resale

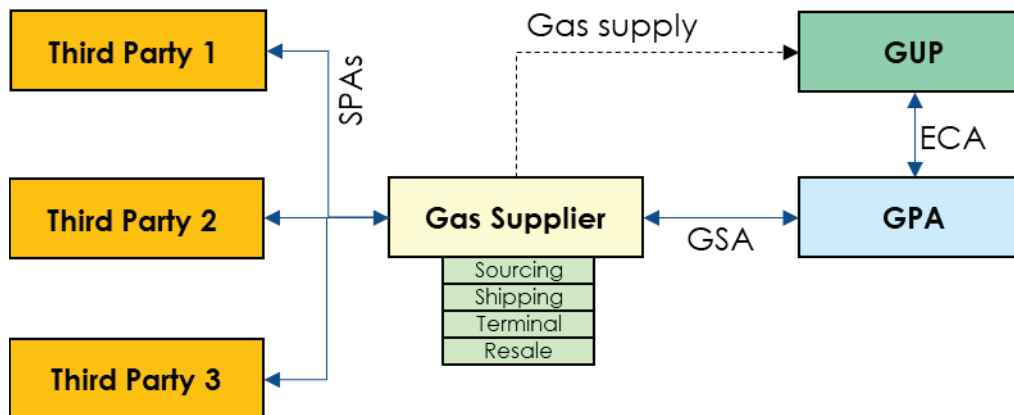
Option	Activity		
	LNG Delivery ex-Ship	LNG Purchaser	LNG Terminal
1a	Gas Supplier		
3a	LNG Supplier	GPA	Terminal Owner
5	LNG Supplier	GPA	
6	LNG Supplier	JV	

Yellow	Private
Blue	GPA/Gov of Guam
Dark Blue	Joint Venture between Company and GPA/Gov of Guam

As illustrated in Figure 9.1, business models with resale do not include options with GPA or JV terminal ownership, as such options are not legally viable. Additionally, to meet the legal and regulatory requirements, GPA may only purchase LNG quantities required for GUPP, and the reseller must purchase the LNG quantities to be sold to third parties under a separate LNG or gas Sale and Purchase Agreement (SPA).

9.2.1 Business Model Option 1 (with Resale)

Figure 9.3: Diagram of Business Model Option 1 (with Resale)



Business Model Option 1 (with resale), illustrated in Figure 9.3, consists of a single private entity (Gas Supplier) that performs all the supply chain functions and supplies natural gas to GPA under a Gas Supply Agreement (GSA). The main features and division of responsibilities for this option are:

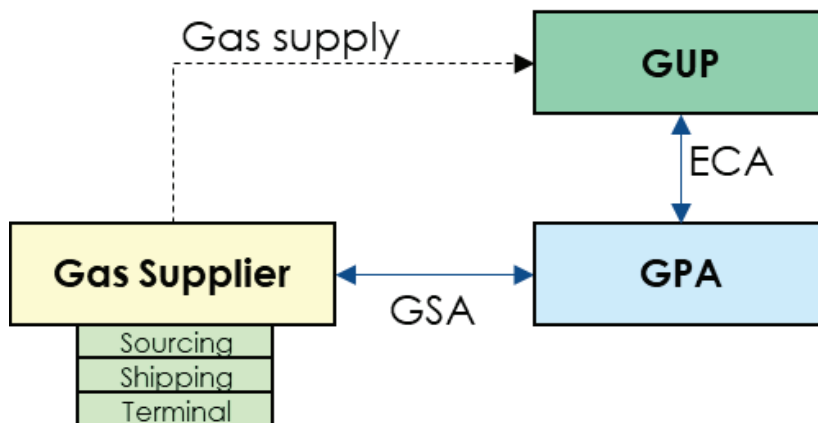
- The Gas Supplier is responsible for sourcing, shipping, importing, storing, and regasifying LNG, delivering gas to the interface point of the existing gas pipeline built for the Ukudu IPP, and resale of LNG and, possibly compressed natural gas (CNG) to third parties under Sales and Purchase Agreements (SPAs)
- GPA purchases gas from the Gas Supplier under a GSA

- The Gas Supplier designs, permits, finances, builds, owns, and operates all the equipment and infrastructure required to unload, store, and regasify LNG and transport gas to the interface point (the gas pipeline built as part of the Ukudu power plant project)
- The Gas Supplier selects an LNG terminal size and configuration that meets the functional specifications set by GPA and the Ukudu Energy Conversion Agreement (ECA) requirement
- Supplied gas meets quality specifications, delivery conditions, and quantity requirements set by GPA in GSA
- GPA provides reasonable assistance to the Gas Supplier on land acquisition, permitting, etc.

Under this option, most project risks are borne by the Gas Supplier, who takes responsibility for the terminal development and the entire LNG/gas supply chain. There is some risk related to the Gas Supplier's monopoly on LNG/gas supply in Guam, which may result in GPA competing for the LNG supply with third parties. In addition, a monopoly on LNG/gas supply in Guam can also have a negative impact on other potential LNG/gas users in Guam who could be charged a higher-than-market price for gas. However, this risk can be addressed contractually by including appropriate provisions in the GSA that prioritize gas supply to GPA over LNG/gas supply to third parties. The interface risk for this option is minimized, as one entity covers the entire LNG/gas supply chain.

9.2.2 Business Model Option 1a (without Resale)

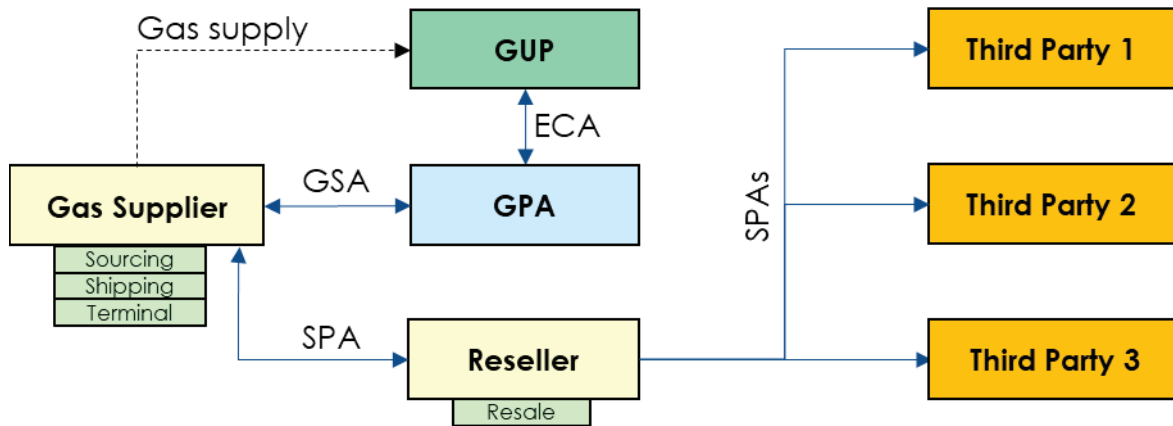
Figure 9.4: Diagram of Business Model Option 1a (without Resale)



Business Model Option 1a (without Resale), illustrated in Figure 9.4, consists of the same division of responsibilities and risk allocation as Option 1, but with no LNG/natural gas resale to third parties.

9.2.3 Business Model Option 2 (with Resale)

Figure 9.5: Diagram of Business Model Option 2 (with Resale)



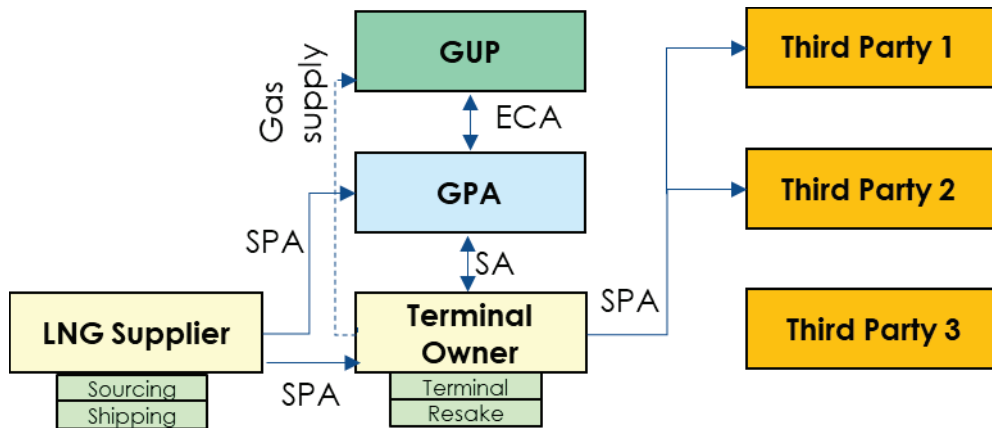
Business Model Option 2 (with resale), illustrated in Figure 9.5, differs from Option 1 by separating the resale business into a separate business operated by a separate private entity (reseller). The main features and division of responsibilities between the parties are as follows:

- The Gas Supplier is responsible for sourcing, shipping, importing, storing, and regasifying LNG, delivering gas to the interface point of the existing gas pipeline built for the Ukudu IPP, and supplying LNG and, possibly, CNG to a Reseller
- GPA purchases gas from the Gas Supplier under a Gas Supply Agreement (GSA)
- The Gas Supplier designs, permits, finances, builds, owns, and operates all the equipment and infrastructure required to unload, store, and regasify LNG and transport gas and LNG to the interface points
- The Gas Supplier selects LNG terminal size and configuration to meet functional specifications set by GPA, Ukudu ECA, and LGN/natural gas reseller requirements
- Supplied gas meets quality specifications, delivery conditions, and quantity requirements set by GPA in GSA
- GPA provides reasonable assistance to Gas Supplier on land acquisition, permitting, etc.
- The Reseller purchases LNG and, possibly, CNG from Gas Supplier and resells it to third parties under SPAs

Most project risks are borne by the Gas Supplier, who takes responsibility for the terminal development and the entire LNG/gas supply chain to GPA and the Reseller. Similarly to Option 1, this option presents some risk related to the Gas Supplier having a monopoly for LNG/gas supply on Guam, which may result in GPA competing for the LNG supply with the Reseller. However, this risk can be addressed contractually by including appropriate provisions in the GSA, prioritizing gas supply to GPA over LNG/gas supply to the Reseller.

9.2.4 Business Model Option 3 (with Resale)

Figure 9.6: Diagram of Business Model Option 3 (with Resale)



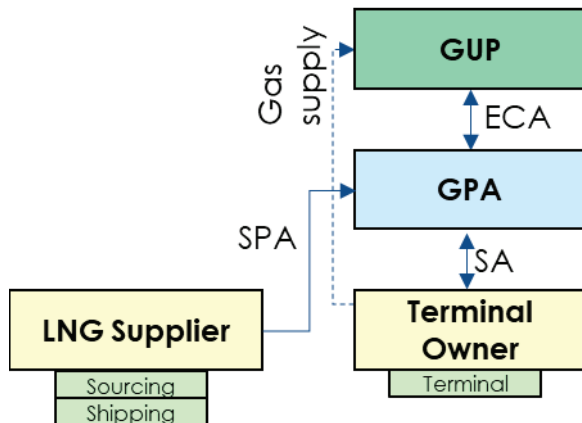
Business Model Option 3 (with resale), illustrated in Figure 9.6, separates the LNG supply from terminal development and resale, as well as separates the LNG purchase by GPA for the Ukudu plant and by the terminal developer for resale to third parties. The main features of this option are:

- The LNG Supplier is responsible for LNG sourcing, shipping, and importation
- GPA enters into a SPA with the LNG Supplier for LNG supply and a Service Agreement (SA) with the private entity, which develops and owns the LNG terminal for unloading, storage, regasification, and transporting gas to the interface points of the LNG purchase by GPA for the Ukudu plant
- The Terminal Owner enters into a SPA with the LNG Supplier to purchase additional quantities of LNG for resale
- The Terminal Owner designs, permits, finances, builds and operates all the equipment and infrastructure required to unload, store, and regasify LNG and transport gas and LNG to the interface points
- The Terminal Owner resells LNG and/or regasified natural gas to third parties
- The Terminal Owner selects the LNG terminal size and configuration to meet functional specifications set by GPA and Ukudu ECA and to satisfy the resale requirements
- Supplied gas meets quality specifications, delivery conditions, and quantity requirements set in ECA
- GPA provides reasonable assistance to Terminal Owner on land acquisition, permitting, etc.

The risk allocation for this option is similar to Options 1 and 2. There is some additional interface risk due to the increased number of agreements between the parties (SPA between the LNG Supplier and the Terminal Owner and SA between GPA and the Terminal Owner).

9.2.5 Business Model Option 3a (without Resale)

Figure 9.7: Diagram of Business Model Option 3a (without Resale)



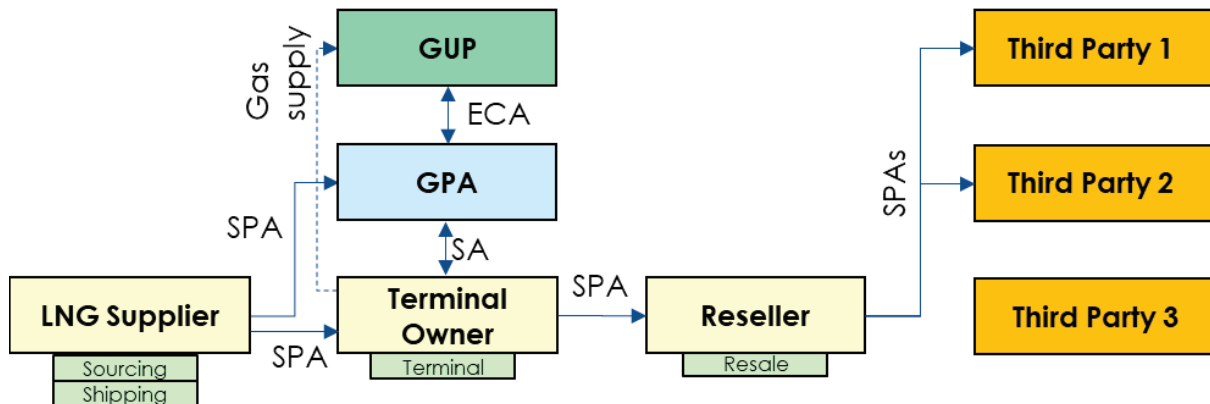
Business Model Option 3a (without Resale), illustrated in Figure 9.7, excludes resale and separates LNG sourcing and shipping from terminal development. The main features of this business model option are:

- The LNG Supplier is responsible for LNG sourcing, shipping, and importation
- GPA enters into a SPA with the LNG Supplier for LNG supply ex-ship and a Service Agreement (SA) with the Terminal Owner for LNG unloading, storage, regasification, and transporting gas to the interface point of the existing gas pipeline built for the Ukudu IPP
- The Terminal Owner designs, permits, finances, builds and operates all the equipment and infrastructure required to unload, store, and regasify LNG and transport gas and LNG to the interface points
- The Terminal Owner selects LNG terminal size and configuration to meet functional specifications set by GPA and Ukudu ECA
- Supplied gas meets quality specifications, delivery conditions, and quantity requirements set in GSA
- GPA provides reasonable assistance to the Terminal Owner on land acquisition, permitting, etc.

There is no risk of competition from any third party, as this option does not include resale, as GPA is the only gas purchaser in Guam. The interface risk is similar to the interface risk for Option 3.

9.2.6 Business Model Option 4 (with Resale)

Figure 9.8: Diagram of Business Model Option 4 (with Resale)



Business Model Option 4 (with Resale), illustrated in Figure 9.8, further separates different supply chain components, with separate entities responsible for gas sourcing and shipping, terminal development, and resale. The main features of this option are as follows:

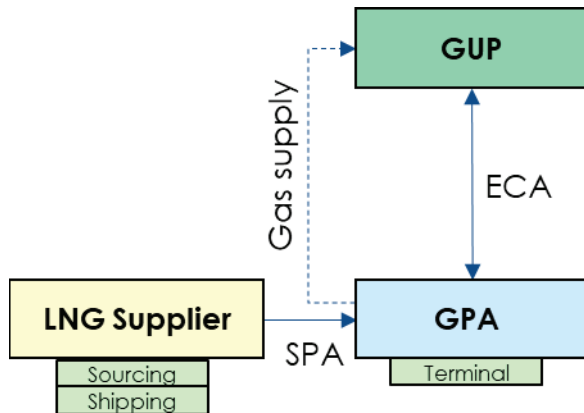
- GPA enters into a SPA with the LNG Supplier for LNG supply ex-ship and a Service Agreement (SA) with the Terminal Owner for LNG unloading, storage, regasification, and transporting gas to the interface points
- The Terminal Owner enters into a SPA with the LNG Supplier to purchase additional quantities of LNG and with the Reseller to sell these additional quantities of LNG or CNG to third parties
- The LNG Supplier is responsible for LNG sourcing, shipping, and importation
- The Terminal Owner is responsible for LNG storing, regasifying, and delivering gas to the interface point of the existing gas pipeline built for the Ukudu IPP and for delivering LNG and CNG to the Reseller
- The Terminal Owner designs, permits, finances, builds and operates all the equipment and infrastructure required to unload, store, and regasify LNG and transport gas and LNG to the interface points
- The Terminal Owner selects LNG terminal size and configuration insofar as it meets functional specifications set by GPA and Ukudu ECA and Reseller's requirements
- Supplied gas meets quality specifications, delivery conditions, and quantity requirements set in GSA

GPA provides reasonable assistance to the Gas Supplier on land acquisition, permitting, etc.

The risk allocation for this option is similar to that for Option 3, but compared to Option 3, the interface risk is slightly increased due to an additional contract between the Terminal Owner and Reseller.

9.2.7 Business Model Option 5 (without Resale)

Figure 9.9: Diagram of Business Model Option 5 (without Resale)



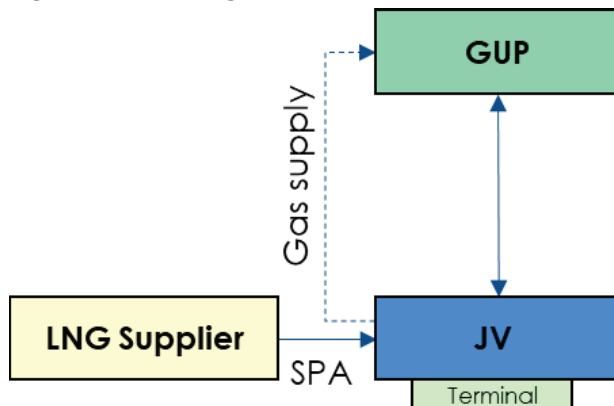
Business Model Option 5 (without Resale), illustrated in Figure 9.9, features GPA as the LNG Terminal Owner. The main features of this model are as follows:

- The LNG Supplier is responsible for LNG sourcing, shipping, and importation
- GPA is responsible for LNG storing, regasifying, and delivering gas to the interface point of the existing gas pipeline built for the Ukudu
- GPA designs, permits, finances, builds, and operates all the equipment and infrastructure required to unload, store, and regasify LNG and transport gas and LNG to the interface points
- GPA selects LNG terminal size and configuration insofar as it meets functional specifications set by Ukudu ECA
- Supplied gas meets quality specifications, delivery conditions, and quantity requirements set in ECA
- GPA is responsible for land acquisition, permitting, etc.

Since GPA will be responsible for terminal development, construction, and ownership, this option is associated with the highest risk to GPA. At the same time, GPA will have more control over the LNG supply chain, thus eliminating any risk associated with a possible private company's monopoly over gas supply.

9.2.8 Business Model Option 6 (without Resale)

Figure 9.10: Diagram of Business Model Option 6 (without Resale)



Business Model Option 6 (without Resale), illustrated in Figure 9.10, is similar to Option 5 with the primary difference being that the terminal is developed and owned by a joint venture between GPA and a private entity. In such an arrangement, GPA will likely only be an equity investor, not a managing partner, and will have limited responsibilities related to the terminal's development and construction.

The main features of this option are:

- The LNG Supplier is responsible for LNG sourcing, shipping, and importation
- A JV between GPA and a private company is responsible for LNG storing, regasifying, and delivering gas to the interface point of the existing gas pipeline built for the Ukudu
- The JV designs, permits, finances, builds, and operates all the equipment and infrastructure required to unload, store, and regasify LNG and transport gas and LNG to the interface points
- The JV selects LNG terminal size and configuration insofar as it meets functional specifications set by GPA and Ukudu ECA
- Supplied gas meets quality specifications, delivery conditions, and quantity requirements set in ECA
- The JV is responsible for land acquisition, permitting, etc.

The risk to GPA for this option will be reduced compared to Option 5, as most of the terminal development, construction, and operation risk will be allocated to the private JV partner. At the same time, as a JV member, GPA may have some additional control over the terminal development and operation.

9.3 Evaluation of Business Model Options

9.3.1 Methodology for Option Comparison

The criteria used to compare the business model options include the expected gas price, the risk to GPA and/or Guam, the schedule, market precedents, and GPA control of gas in Guam. Each of these criteria is discussed further below.

Expected Gas Price

The gas price is influenced by 1) economies of scope – a larger scope allocated to one party would result in a lower gas price, and 2) the expected cost of capital for terminal financing – terminals financed by private companies are expected to have a higher cost of capital than terminals financed by GPA or the Guam government. The evaluation gives a higher score to options that result in a lower expected gas price.

Risk to GPA / Guam

Business models that feature a private entity as the terminal developer more effectively shift project risks away from GPA, which is viewed favorably in the evaluation.

Schedule

A shorter project implementation schedule improves the project's economic viability. Given the uncertainty of the time required for project development, this evaluation assumes the same schedule for all the business model options, with a private company taking responsibility for the terminal development and construction. For options where GPA is the full or partial owner of the LNG terminal, it is assumed that the implementation schedule is longer.

Market Precedents at a Similar Scale and in Commercial Operation

Business model options that have been utilized for similar-scale operating projects reduce the overall project risk and improve the project's chances of success.

GPA Control of Gas in Guam

Business model options that provide GPA with greater control over the gas supply in Guam reduce the risk associated with a gas supplier monopolizing control of the gas supply on the island and are viewed favorably.

Scoring

The evaluation uses a scoring system for each criterion. Options that are most responsive to a criterion were assigned a score of 3 on that criterion. The results of the evaluation of options with and without resale are presented in Figure 9.11 and Figure 9.12.

9.3.2 Evaluation Results

Figure 9.11: Evaluation Matrix of Options with Resale

Ranking											
Option	Expected Gas Price		Risk to GPA / Guam		Schedule		Market Precedents at Similar Scale and Operating		GPA Control of Gas in Guam		Total Score
Scope	Score	Evaluation	Score	Evaluation	Score	Evaluation	Score	Evaluation	Score	Evaluation	
1	2.50	- Highest economies of scope - Lowest interface management cost - Higher value than #2 to 4 by including LNG resale business in supply business - Higher cost of capital relative to GPA financing in case GPA Terminal ownership becomes legally viable	3.00	- Majority of risks transferred to Gas Supplier	3.00	- Shortest timeline to achieve financial closure and procure terminal EPC contractor - Permitting and construction timeline assumed equal across options	3.00	- Jamaica (NFE) - Sardinia, Italy (Avenir)	1.50	- Low GPA control because LNG imports and resale are controlled by a private company (Gas Supplier). GPA can exert some control via the contract that gives Gas Supplier the right to develop/operate the terminal and resale LNG or gas	13.00
2	1.00	- Lower economies of scope than # 1. - Higher interface management cost than # 1 - Lower perceived value relative to # 1 by separating LNG resale - Higher cost of capital relative to GPA/GoG financing (in case GPA ownership of the terminal and participating in resale become legally viable)	2.75	- Majority of risks transferred to Gas Supplier and Reseller, but some interface risk remains with GPA	3.00	- Shortest timeline to achieve financial closure and procure terminal EPC contractor - Permitting and construction timeline assumed equal across options	2.50	- LNG ex-ship + Terminal - Jamaica (NFE) - Sardinia, Italy (Avenir) - Antigua & Barbuda (Eagle) - LNG Resale (No precedents of separate company reselling LNG)	1.50	- Low GPA control because LNG imports and resale are controlled by private companies, each. GPA can exert some control via the contracts that gives Gas Supplier and Reseller the right to develop/operate the terminal and resale LNG or gas	10.75
3	1.25	- Lower economies of scope than # 1 - Higher interface management cost than # 1 - Lower perceived value relative to # 1 by separating LNG supply business - Higher cost of capital relative to GPA/GoG financing (in case GPA ownership of the terminal and participating in resale become legally viable)	2.75	- Majority of risks transferred to LGN Supplier and the Terminal Owner/Reseller, but some interface risk remains with GPA	3.00	- Shortest timeline to achieve financial closure and procure terminal EPC contractor - Permitting and construction timeline assumed equal across options	3.00	- Cartagena, Colombia (Calamar) - Andres, Dominican Republic (BP)	1.50	- Low GPA control because LNG imports, terminal infrastructure, and resale are controlled by two separate private companies. GPA can exert some control via the contract that gives the Terminal Owner/Reseller the right to develop/operate the terminal and resale LNG or gas	11.50
4	1.00	- Lower economies of scope than # 1 through 3 - Highest interface management cost - Lower perceived value relative to # 1 through 3 by separating LNG supply and resale businesses - Higher cost of capital relative to GPA/GoG financing (in case GPA ownership of the terminal and participating in resale become legally viable)	2.50	- Majority of risks transferred to LNG Supplier, Terminal Owner, and Reseller, but interface risk remains with GPA	3.00	- Shortest timeline to achieve financial closure and procure terminal EPC contractor - Permitting and construction timeline assumed equal across options	1.00	- No precedents of three separate companies involved in each stage	1.50	- Low GPA control because LNG imports, terminal infrastructure, and resale are controlled by three separate private companies. GPA can exert some control via the contracts that gives the Terminal Owner and the Reseller the right to develop/operate the terminal and resale LNG or gas	9.00

Figure 9.12: Evaluation Matrix of Options without Resale

Ranking									
Option	Expected Gas Price		Risk to GPA / Guam		Schedule		Market Precedents at Similar Scale and Operating		Government Control of Gas in Guam
Score	Score	Evaluation	Score	Evaluation	Score	Evaluation	Score	Evaluation	Score
1a	2.50	Highest economies of scope, and lowest interface management cost, but higher cost of capital relative to GPA/GoG financing (#5 & 6)	3.00	- Majority of risks transferred to Gas Supplier	3.00	- Shortest timeline to achieve financial closure and procure terminal EPC contractor - Permitting and construction timeline assumed equal across options	3.00	LNG ex-ship + Terminal - Jamaica (NFE) - Sardinia, Italy (Aventi) - Antigua & Barbuda (Eagle)	1.50 Lowest Government control because LNG imports and resale are controlled by a private company (Company A). The Government can exert some control via the contract that gives Company A the right to develop/operate the terminal and resale
3a	1.25	- Lower economies of scope than # 1, 5 & 6 - Higher interface management cost than # 1, 5 & 6 - Lower perceived value relative to # 1 by separating LNG supply business - Higher cost of capital relative to GPA/GoG financing (#5 & 6)	2.75	- Majority of risks transferred to LNG Supplier and Terminal Owner, but some interface risk remains with GPA	3.00	- Shortest timeline to achieve financial closure and procure terminal EPC contractor - Permitting and construction timeline assumed equal across options	3.00	- Cartagena, Colombia (Calamar) - Andres, Dominican Republic (BP)	1.50 Lowest Government control because LNG imports and resale are controlled by private companies, each. The Government can exert some control via the contracts that gives Company A & B the right to develop/operate the terminal and resale
5	2.50	- Lower economies of scope than # 1 - Higher interface management cost than # 1 - Lower perceived value relative to # 1 due to separating the LNG supply business - Lower cost of capital relative private financing (#1 and 3a)	1.00	- LNG supply risks transferred to LNG Supplier - GPA retains LNG terminal and resale business risk	1.00	- GPA procurement and financing of LNG terminal would be longer than a private company - Permitting and construction time assumed equal across options	3.00	- Klaipeda, Lithuania (KN)	3.00 Highest Government control because Government (GPA) owns and controls the LNG import terminal and therefore the supply of gas on the island
6	2.00	- Lower economies of scope than # 1 - Highest interface management cost than # 1 - Lower perceived value relative to # 1 by separating LNG supply business - Higher cost of capital relative to GPA/GoG financing (#1 and 3a)	1.25	- LNG supply risks transferred to LNG Supplier - GPA retains LNG terminal and resale business risk	2.50	- Shorter timeline than # 5 to achieve financial closure and procure terminal EPC contractor-- assuming JV doesn't need to follow GPA procurement rules - Permitting and construction timeline assumed equal across options	2.50	- Bali, Indonesia (JSK/PT Pelindo)	2.50 Intermediate Government control because Government (GPA) has some control on the LNG import terminal and resale via its ownership on the JV that owns and controls the terminal and resale
									10.75
									10.50
									11.50
									13.00

9.4 Risk Allocation of the Preferred Business Model

This section presents the risk matrix applicable to the preferred gas supply business model. It includes a list of all material LNG supply project risks. For each risk, the matrix explains the key driver and recommends an allocation and mitigation strategy.

9.4.1 Risk Allocation and Mitigation Strategy

Every infrastructure project involves material risks that expose the project to damage or loss due to uncertain events or variables. Therefore, developing a robust risk allocation and mitigation strategy in advance becomes crucial for the project to become bankable, reach financial close, and achieve successful development and operation. The primary components of risk allocation and mitigation strategy include identification, analysis, allocation, structuring, and mitigation and management of risks. This section explains an approach towards each component and application to the Guam LNG supply project.

9.4.2 Risk Identification

Risk identification is a process of identifying all material risks relevant to the project and is the first step in the risk allocation and mitigation process. When identifying the risks associated with a project, risk classification becomes important as it can drive its optimal allocation and form of mitigation or management. Risks for the LNG supply project can be classified by source (i.e., supply chain segment) and stage of the project life cycle (i.e., development, construction, operation).

It is important to highlight that risk identification does not stop when the feasibility study phase is concluded. Risk identification should be conducted beyond the feasibility study phase, as new risks and challenges may emerge as the project progresses, and project stakeholders may need to reallocate the risk and develop a new mitigation strategy as applicable.

9.4.3 Risk Analysis

Risk analysis is largely a process of determining the likelihood of the occurrence of the identified risks and the magnitude of their consequences if they do materialize. The risk analysis process enables stakeholders to decide the areas of project management that require focused attention and risk mitigation and/or management to ensure successful results. As such, it is necessary to approach the risks holistically, practically, and objectively with the involvement of experts who understand distinct risk categories and how the risks impact each stage of the project. It is also important to integrate international and regional expertise to arrive at a complete understanding of the risks and their ramifications to both the project and its stakeholders. The following factors were considered when assessing the identified risks for the Guam LNG supply project:

- Categorization of the risk (i.e., technical, commercial, financial, environmental, and social);
- Probability of the occurrence of the risk
- Triggers and causes of the risk; and
- Parties with a material impact if the risks were to materialize.

9.4.4 Risk Allocation and Structuring

The primary purpose of risk allocation is to diversify the risk exposure and management across multiple parties and ensure that risks are allocated to the parties that are best equipped, able, and willing to mitigate the risk. Risk allocation aims to create incentives for the parties to manage risk well, thereby improving project benefits and reducing costs. It also seeks to reduce the overall cost of project risk by insulating parties from risks that they are not willing or capable of bearing. Therefore, they get inefficiently priced into the project. As such, reasonable and appropriate allocation of risks among participants enables the project to achieve better value for money and overall project success.

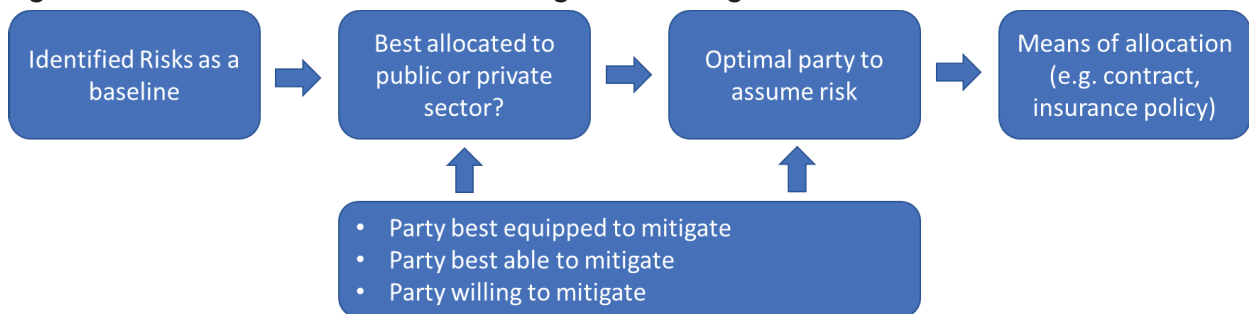
The risk allocation process began with an identification of whether the public or private sector should assume the risk, followed by the identification of the optimal party to assume the risk within the public or private sector participants (as applicable). The following factors were considered when identifying the optimal risk allocation for the parties involved in the Guam LNG supply project:

- Technical and financial capability of the party;
- Insurability of the risk for the party;
- Regulatory or legal constraints for the party to assume the risk;
- Party's willingness to assume the risk; and
- Expected cost of risk transfer.

Once the party is best capable and willing to assume the risk, the relevant document through which the applicable risk could be allocated to such party is identified.

Figure 9.13 below is an illustration of the Consultant's risk allocation and structuring process.

Figure 9.13: Risk Allocation and Structuring Process Diagram



9.4.5 Risk Mitigation and Management

The purpose of risk mitigation and management is to minimize (if not eliminate) the negative impacts of risks to the project and project stakeholders by reducing the likelihood of the risk occurrence or the degree of its consequences in case it materializes. The parties, assuming the risks, can mitigate and/or manage the risks through the following tools:

- Establishing a comprehensive management plan and effective execution of the plan;
- Assigning experienced internal personnel and external advisors to establish and implement the plan;

- Proactively interfacing with project stakeholders and allowing access to information for effective risk sharing and coordination procedures;
- Ensuring sufficient bankable contract terms and including reasonable penalty clauses in contracts to properly incentivize parties to follow the contract and its risk mitigation/management characteristics;
- Early issue identification and continuous robust monitoring during the life cycle of the project, as risks may change as the project progresses; and
- Risk training among the project stakeholders.

In addition, it is important to understand that there are material risks that cannot be fully mitigated. These gaps must be identified, and the risk management plans must be tailored to account for them.

9.4.6 Risk Matrix

The risk matrix applicable to the preferred business model is presented Table 9.1 below.

Table 9.1: Risk Matrix for the Preferred Business Model

#	Risk Category	Impact and Driver	Allocation and Mitigation
1	Unavailability of LNG Unavailability of LNG shipping Shipping delays Loss of cargo Contamination of cargo	<u>Impact</u> Reduced operations and revenue for the Gas Supplier Reduced LNG operations will lead to burning ULSD as backup fuel, resulting in an overall increase in the cost of electricity supply. <u>Key Drivers</u> LNG becomes unavailable at the source due to force majeure or fault of the Gas supplier	<u>Allocation</u> The Project should transfer LNG supply risk and responsibility to an experienced private Gas Supplier through the Gas Sale and Purchase Agreement ("Gas SPA"), as they are best positioned to mitigate, manage, and streamline. <u>Mitigation</u> Strong SPA allocating all appropriate work scope and associated risks to the Gas Supplier (including LDs for shortfall quantities). Selection of a proven/capable Gas Supplier Comprehensive Gas Supplier insurance policy to cover insurable events
2	Demand Volume / Throughput	<u>Impact</u> Reduced operations and revenue for the Gas Supplier Reduced LNG operations will lead to burning ULSD as backup fuel, resulting in an overall increase in the cost of electricity supply. <u>Key Drivers</u> Lower than expected gas demand, caused by: - Higher penetration of renewables, battery storage, and other low-cost technologies - Grid congestion - Higher solar capacity factors - Availability of GUPP plant	<u>Allocation</u> Volume risk should be passed downstream via the Gas SPA (as appropriate, depending on the root cause of the lower demand) The precise allocation will be linked to the cause of the demand reduction as follows: Allocate to GPA if: - Higher penetration of renewables, battery storage, and other low-cost technologies - Grid congestion - Higher solar capacity factors Allocate to GUPP the unavailability of the GUPP plant. <u>Mitigation</u>

#	Risk Category	Impact and Driver	Allocation and Mitigation
			Sound generation capacity expansion and flexibility planning (including frequent updates and supply/demand scenario analyses) Sound transmission capacity expansion planning (including frequent updates and scenario analyses) Robust operation and maintenance of gas-consuming facilities to ensure industry-standard availability factors Structure/Negotiate termination, price mechanism revision, and other clauses that can provide greater flexibility in cases where dispatch dynamics have changed dramatically
3	Payment risk	<u>Impact</u> Reduced or delayed revenue/cash flow for the Gas Supplier Gas Supplier unable to serve debt and pay for operating expenses <u>Key Drivers</u> Failure of GPA to meet its LNG/Gas payment obligations caused by financial stress or bankruptcy by the downstream project participants	<u>Allocation</u> GPA should assume the payment risk via the Gas SPA <u>Mitigation</u> Ensure the GPA's rate includes the cost of paying the Gas Supplier Include appropriate performance security (Letter of Credit) in downstream contracts to cover periods of cash flow shortfalls Inclusion of credit enhancement mechanisms from the Government of Guam, if necessary, when the project goes to market Inclusion of appropriate risk allocation and damage provisions in the Gas SPA
4	Regulatory risk	<u>Impact</u> Additional Gas supply costs Delays in LNG imports Reduced operations and revenue for the Gas Supplier Reduced operations can lead to an overall increase in the cost of electricity. <u>Key Drivers</u>	<u>Allocation</u> GPA should assume the regulatory risk via Gas SPA and/or a special government support instrument (for example, Implementation Agreement). <u>Mitigation</u> Ensure well-designed, fair, and transparent regulations are in place early in the project's development and maintained throughout its life.

#	Risk Category	Impact and Driver	Allocation and Mitigation
		Additional LNG supply costs or delays due to Guam or Federal regulatory gaps, constraints, or changes	Allocation Include a change in law mitigation obligations in a Gas SPA Establish political force majeure and change in law, monitoring, and mitigation plans
5	Market price risk	Impact Higher electricity tariffs Higher risk of financial stress for GPA Key Drivers Relevant LNG price indices are increasing substantially, caused by: • Global or regional supply/demand dynamics • War or political turmoil • Macroeconomic factors	Allocation GPA should assume the market price risk via the Gas SPA Mitigation Use of a Gas SPA contract with LNG price indexed to Brent at a set slope Well-designed hedging on reliable indices and price review or adjustment clauses in the SPA that pass through to the regulated tariff Purchase of future contracts to manage volatility
6	Development - Permitting	Impact Significant delay in project implementation Cancellation of the project Reduced operations and revenue for the Gas Supplier Delays or cancellations of the project can lead to an overall increase in the cost of electricity supply. Key Drivers Failure or delay in obtaining required permits to build, own, and operate the new LNG terminal and other relevant Gas Supplier infrastructure due to force majeure or fault of Gas Supplier, including but not limited to: • Failure or delays in the assessment or issuance of approvals by FERC and/or other relevant governmental authorities • Errors or omissions in the process attributable to either the Gas Supplier or the relevant authorities • Failure or delays due to community / social interests	Allocation The Project should transfer permitting risk to an experienced Gas Supplier Optimal structures and procurement should include a highly experienced Gas Supplier/Gas Supplier. The Gas SPA should have clauses that transfer permitting risk that is beyond the reasonable control of the developer to the public sector. Mitigation Include appropriate damage and relief provisions in the Gas SPA to properly allocate permitting risks due to the Gas Supplier's fault and force majeure Selection of proven/capable Gas Supplier/Gas Supplier/owner Establish a comprehensive project permitting plan and an effective permitting plan execution Comprehensive Gas Supplier insurance policy to cover insurable events

#	Risk Category	Impact and Driver	Allocation and Mitigation
7	Development – Site and LNG terminal area	Impact Significant delay in project implementation Cancellation of the project Reduced operations and revenue for the Gas Supplier Delays or cancellations of the project can lead to an overall increase in the cost of electricity supply. Key Drivers Failure or delay in obtaining land, wayleaves, and access rights required to build, own, and operate the new terminal and other relevant Gas Supplier infrastructure due to force majeure or fault of Gas Supplier, including but not limited to: • Failure or delays in the assessment or issuance of approvals by FERC, GPA, and/or other relevant governmental authorities • Errors or omissions in the process attributable to either the Gas Supplier or the relevant authorities • Failure or delays due to community / social interests	Allocation The Project should transfer land use and access rights risk to an experienced Gas Supplier. Optimal structures and procurement should include a highly experienced Gas Supplier. A Gas SPA should have clauses that transfer land use and access rights risk that is beyond the reasonable control of the developer to the public sector. Mitigation Include appropriate damage and relief provisions in the Gas SPA to properly allocate land use and access rights risks due to Gas Supplier fault and force majeure Selection of a proven/capable Gas Supplier/owner Comprehensive Gas Supplier insurance policy to cover insurable events
8	Financing	Impact Significant delay in project implementation Cancellation of the project Reduced operations and revenue for the Gas Supplier Delay or cancellation of the project can lead to an overall increase in the cost of electricity supply Key Drivers Failure or delay in securing commercially reasonable financing to construct the terminal and other infrastructure to be owned by Gas Supplier due to force majeure or fault of Gas Supplier, including but not limited to:	Allocation Optimal structures should include a Gas Supplier developer with proven project finance experience for projects of this kind and public sector participation, which is critical to supporting bankability. The Gas SPA should be designed to ensure bankability. Mitigation Include appropriate damage and relief provisions in the Gas SPA to properly allocate financing risk due to Gas Supplier fault and force majeure Selection of a proven/capable Gas Supplier/owner

#	Risk Category	Impact and Driver	Allocation and Mitigation
		- Unavailability of viable commercial debt terms (e.g., tenor, interest rates) - Failure or significant delay in procuring governmental approvals	Allocation Comprehensive Gas Supplier insurance policy to cover insurable events Monitoring market or project changes that could negatively impact expected terms for debt financing Using realistic debt financing assumptions in the project analysis
9	Construction	Impact Delay in the project schedule Reduced operations and revenue for the Gas Supplier Reduced operations can lead to an overall increase in the cost of electricity supply and a decrease in the availability of electricity. Key Drivers Delays or cost overruns in the construction of the terminal or other infrastructure owned by Gas Supplier caused by force majeure or fault of Gas Supplier, including but not limited to: - Unrealistic, flawed, and over-optimistic construction execution schedule by the Gas Supplier - Failure to select a Gas Supplier with sufficient experience and capability - Poor construction planning or management by the Gas Supplier - Flawed/incomplete project scope and/or design by the Gas Supplier - Inadequate procurement and/or contract management by the Gas Supplier	Allocation Optimal structures will transfer terminal construction risk and responsibility to an experienced private sector Gas Supplier, as they are best positioned to mitigate, manage, and streamline. Mitigation Include appropriate damage and relief provisions in the Gas SPA to properly allocate construction risk due to Gas Supplier fault and force majeure Pass through the appropriate Gas SPA cover from the Gas Supplier downstream through the applicable agreements. Selection of a proven/capable Gas Supplier Comprehensive Gas Supplier insurance policy to cover insurable events
10	Operation and maintenance cost overruns	Impact Reduced profitability for Gas Supplier Key Drivers	Allocation The Gas Supplier should be responsible for managing and mitigating terminal O&M cost overruns, as it is best positioned to minimize, manage, and streamline. Mitigation

#	Risk Category	Impact and Driver	Allocation and Mitigation
		O&M cost overruns or errors due to force majeure or fault of the Gas Supplier, including but not limited to: • Failure to budget effectively by the terminal owner/operator • Terminal operator error or inefficiency • Failure to select a terminal operator with sufficient experience and capabilities	Develop a well-defined O&M budget and monitoring system O&M contract with a comprehensive scope allocation to the terminal operator Selection of a proven/capable Gas Supplier Build in appropriate contingency levels in the budgeting process Comprehensive Gas Supplier insurance policy to cover insurable events
11	Property damage	<u>Impact</u> Reduced operations and revenue for the Gas Supplier Reduced operations can lead to an overall increase in the cost of electricity supply. <u>Key Drivers</u> Potential for damage to any Gas Supplier infrastructure due to force majeure or fault of the Gas Supplier	<u>Allocation</u> The Gas Supplier should be responsible for managing and mitigating terminal property damage, as it is best positioned to minimize, manage, and streamline. <u>Mitigation</u> Selection of a proven/capable Gas Supplier Comprehensive Gas Supplier insurance policy to cover insurable events
12	Demand Volume / Throughput	<u>Impact</u> Reduced operations and revenue for the Gas Supplier Reduced operations can lead to an overall increase in the cost of electricity supply. <u>Key Drivers</u> Lower than expected gas demand, including but not limited to: • Higher penetration of renewables, battery storage, and other low-cost technologies • Grid congestion • Changes to merit order dispatch mechanism (including adjustments to favor certain technologies over others) • Higher solar capacity factors	<u>Risk Allocation</u> Refer to risk #2 <u>Mitigation</u> Refer to risk #2

#	Risk Category	Impact and Driver	Allocation and Mitigation
13	E&S risks	Impact Extra costs (remedial costs, lawsuits, and fines) for the Gas Supplier Key Drivers Potential for additional project costs or delays due to environmental or social issues applicable to the new terminal and any of the other infrastructure owned by Gas Supplier, such as a pipeline to Ukudu, including but not limited to: • Insufficient Environmental and Social Impact Assessment ("ESIA") • Complications with environmental permitting that are associated with the existing plant and facilities • Delays in assessment or issuance of approvals by FERC, EPA, and/or other relevant governmental authorities • Errors or omissions in the permitting process attributable to either Gas Supplier or the relevant authorities • Insufficient communication with the community and/or failure to effectively engage and address community concerns	Allocation Gas Supplier to manage/mitigate E&S risk from the point of LNG arrival to the delivery point Optimal structures should include a highly experienced developer with a strong track record of managing E&S issues. Mitigation The Gas SPA should have clauses that transfer E&S risk beyond the reasonable control of the developer to the public sector. Comprehensive environmental compliance plan applicable to the Gas Supplier Compliance plans and procedures to include or be based on the Project ESIA, ancillary documents, and agreements
14	Availability of storage and regasification capacity	Impact Reduced operations and revenue for the Gas Supplier Reduced operations can lead to an overall increase in the cost of electricity supply Key Driver Unavailability of the LNG storage and regasification capacity when needed to meet the plant's dispatch profile operating on Gas caused by force majeure or fault of power plant owner/developer	Allocation This risk should be allocated to Gas Supplier via the Gas SPA. Mitigation Include appropriate liability provisions (including LDs or similar mechanism) in the Gas SPA for failure to achieve minimum availability thresholds for both force majeure and operator fault Comprehensive Gas Supplier insurance policy to cover insurable events

9.5 Conclusions

Business Model Option 1 (with or without Resale) is the preferred option given:

- It has the highest economy of scope and the lowest interface cost.
- The LNG supply risk and terminal development risk are shifted to a private company, thereby minimizing the risk to GPA.
- It is legally viable as there are no legal limitations for a private entity to be involved in the LNG supply, terminal development, and LNG/natural gas resale activities

The primary drawbacks of this preferred option include:

- The cost of capital for a privately financed project is expected to be higher than for a project financed by GPA, which will result in a higher gas price. This risk can be mitigated by running a competitive LNG and LNG infrastructure procurement process and selecting an experienced and cost-competitive gas supplier/LNG terminal developer.
- GPA will have less control over gas supply and terminal operation. This risk can be mitigated by developing a GSA that protects GPA from gas supply interruptions and other risks.

Based on this analysis and conclusion, all tasks under this assignment assume an ownership structure that aligns with Business Model Option 1.

10 Task 5.3 – Financial Analysis of the Gas Supply Company

This section presents the results of Task 5.3 – Financial Analysis of the Gas Supply Company, which is based on the results of Task 5.2 – Comparison of Business Models (detailed in Section 9). The preferred business model was determined to be a private Gas Supply Company (the “Company”) that is responsible for sourcing, shipping, importing, storing, and regasifying LNG, delivering gas to the interface point at GUPP, and operating the LNG terminal.

The primary objective of the financial analysis is to assess the financial viability of the Company's investment in the LNG terminal and infrastructure. Accordingly, the financial analysis models the Company's construction and operating cash flows to estimate the natural gas price (USD per MMBtu) delivered to GUPP that would allow the Company to be bankable, i.e., achieve a certain debt-service-cover ratio and a target internal rate of return to equity investors. The resulting gas price is used in Task 4.2 – Ratepayer Impact Analysis (detailed in Section 8) to assess potential cost savings for end consumers in Guam.

This section is organized into four sections. Section 10.1 describes the methodology used in the financial analysis. Section 10.2 presents the modeling assumptions and inputs for the financial analysis. Section 10.3 provides the results of the financial analysis and sensitivity runs. Section 10.4 concludes.

10.1 Methodology

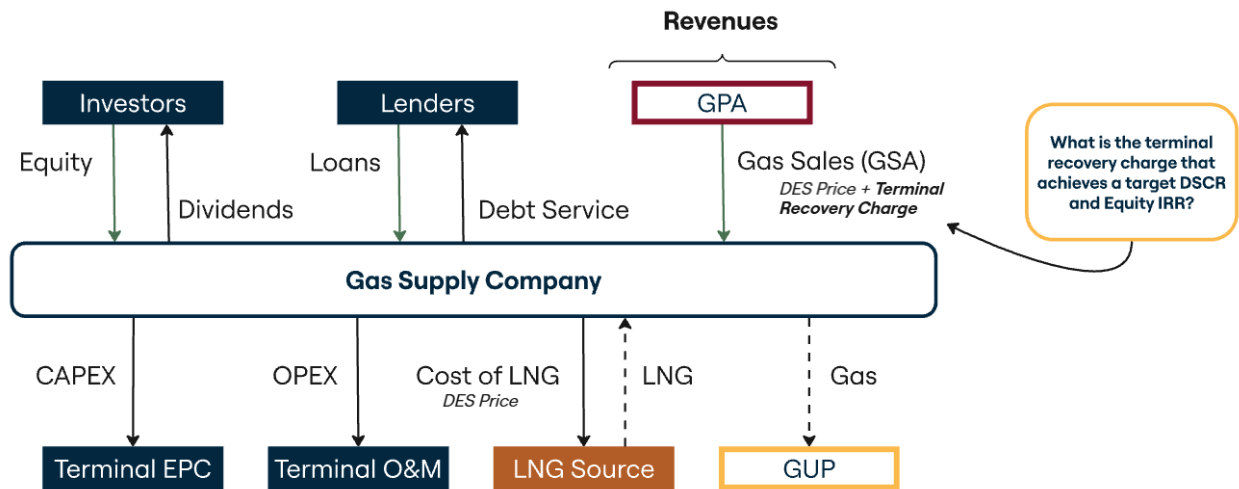
The financial analysis aims to assess the financial viability of the Company's investment in the LNG terminal and related infrastructure based on the business model outlined in Task 5.2 – Comparison of Business Models. This analysis relies on market prices, rather than economic or shadow prices, to estimate project revenues and costs. These estimates serve as the basis for developing the Company's pro forma financial statements, which include the income statement, balance sheet, and cash flow statement.

The income statement provides insight into profitability by detailing projected revenues, operating costs, depreciation, and net income over the Project's lifecycle. The balance sheet captures the Company's financial position by tracking assets, liabilities, and equity, helping to assess the Project's leverage and liquidity. The cash flow statement analyzes the timing and magnitude of cash inflows and outflows, which is critical for understanding the Project's ability to generate sufficient cash to cover operating expenses and debt obligations. These financial statements are used to calculate specific metrics essential for determining the Project's viability and bankability, including the Debt Service Cover Ratio (DSCR) and the Project and Equity Internal Rate of Return (IRR). The DSCR measures the Company's ability to meet debt obligations, while the IRR provides a rate of return on the Project and for equity investors.

Figure 10.1 illustrates the financial flows of the Company's business model. Under this model, the Gas Supply Company is responsible for sourcing, shipping, importing, storing, regasifying, and delivering natural gas to the interface point at GUPP. The Company's primary expense is the Delivered Ex-Ship (DES) cost of LNG, representing the cost of LNG delivered to the Gas Supply Company from the LNG source. The Company generates revenues from the sale and delivery of gas to GUPP, which is assumed to be based on two charges: 1) the LNG DES Charge and 2) the LNG Terminal Capital Recovery Charge. The latter covers the LNG terminal's capital investment,

cost of capital, and operating expenses. Using Goal-Seek, the model estimates the LNG Terminal Capital Recovery Charge that achieves the target DSCR and Equity IRR.

Figure 10.1: Gas Supply Company Financial Structure



These inflows and outflows populate the financial model, allowing for the calculation of the DSCR and the Equity IRR. K&M has identified the minimum DSCR and required Equity IRR, which serve as thresholds for assessing project bankability. The DSCR is calculated by dividing the Project's cash flow available for debt service by the total debt service (principal payment and interest) in that period. Lenders typically require a DSCR of 1.2 to ensure that the Project can meet its debt obligations. The Equity IRR measures the return to equity investors. If the Equity IRR exceeds the required rate of return, the investment is generally considered attractive. K&M estimated the required equity rate of return for an LNG supply project in Guam using the Capital Asset Pricing Model (CAPM) - this estimate is described in more detail in Section 10.2.3.

The model calculates the LNG Terminal Capital Recovery Charge that achieves a DSCR above 1.2 and an Equity IRR above the value estimated by K&M. This charge is then used to estimate the Levelized Cost of Delivered Gas to GUPP, which is calculated as the present value of total project revenues divided by the present value of total project gas demand using GPA's discount rate of 5%.

10.2 Modeling Assumptions

The data and inputs used in the financial analysis come from GPA, publicly available sources, or are derived from related models developed by K&M for this assignment.

10.2.1 Model Period

The financial analysis covers the period of the Gas Supply Agreement (GSA), equivalent to the Energy Conversion Agreement (ECA) signed between GPA and GUPP. The model assumes a two-year construction period for the LNG import terminal (2029 – 2031), operations starting in 2031, and a nineteen-year operational period (2031 – 2050).

10.2.2 Macroeconomic Assumptions

The model uses the IMF's long-term inflation assumption for the United States of America of 2% to escalate relevant model inputs; the Project's base year is 2029. The Company's financial statements are forecasted in nominal prices. The required return on equity is also a nominal rate.

10.2.3 Required Equity Return

The required equity return is calculated using the CAPM model. CAPM provides a theoretical required rate of return that corresponds to an investment in a certain asset class. The rate of return is calculated using the formula below—where beta (β) represents the correlation of the asset's returns to equity market risk premium.

$$\text{Required Equity Return} = \text{Risk-Free Rate} + \beta \times \text{Risk Premium}$$

Table 10.1 includes the assumptions used in calculating this figure.

Table 10.1: CAPM Inputs

	Rate
Risk Free Rate ³⁰	4.62%
Levered Beta for oil/gas, Global Average ³¹	0.85
Risk Premium ³²	4.12%
Required Return on Equity for an LNG Project in Guam	8.12%

The price of gas delivered to GUPP must therefore generate an expected Equity IRR of 8.12% or higher to be attractive to equity investors.

³⁰ US Government Treasury Constant Maturities, 20-Year, retrieved November 1, 2024.

<https://www.federalreserve.gov/releases/h15/>

³¹ Levered Beta for oil/gas distribution. <https://pages.stern.nyu.edu/~adamodar/pc/datasets/betaGlobal.xls>

³² Total equity risk premium based on US risk premium as of July 2024.

<https://pages.stern.nyu.edu/~adamodar/pc/datasets/ctrypremJuly24.xlsx>

10.2.4 Project Revenues

The Gas Supply Company generates revenues from GPA for the delivery of gas to GUPP. The price of this gas encompasses both a volumetric charge and a fixed annual charge that enables the company to recover the investment in the terminal infrastructure and operating charges. The volumetric charge is determined by the quantity of gas delivered multiplied by the DES LNG price. The fixed charges are split into two separate annual charges: the LNG Terminal O&M Charge and the LNG Terminal Capital Recovery Charge. Under this structure, the LNG Terminal Capital Recovery Charge remains constant throughout the debt amortization period but decreases to approximately a quarter of its initial value throughout the remainder of the GSA term. This reduced Capital Recovery Charge is intended to cover the equity investor's initial investment and a return on this investment, after the debt service obligations are fulfilled. The resulting revenue profile concentrates project revenues during the debt repayment period, with a decline thereafter.

Box 10.1: Alternative Revenue Structure

K&M analyzed alternative revenue structures for the Gas Supply Company that could optimize key financial metrics such as the DSCR and Equity IRR while minimizing the costs to GPA and subsequently ratepayers in Guam. One such alternative replaces the fixed annual recovery charges with a volume-based terminal recovery charge (USD/MMBtu).

Under this structure, this recovery charge would cover the LNG terminal's capital investment, cost of capital, and operating costs. It is composed of a fixed portion and a variable portion that is indexed to inflation. Based on Gas Supply Agreements (GSAs) with similar off-takers, the fixed portion was assumed to be 35% of the recovery charge in the base year and to remain constant throughout the GSA term. The indexed portion was assumed to be 65% of the recovery charge in the base year and adjusted for inflation in each subsequent period. The base year for the escalation is 2028, the year construction starts.

Using GPA's discount rate of 5% to determine the present value of project revenues under both structures, K&M found that the levelized cost of delivered gas is marginally higher when using the LNG Terminal Recovery Charge. Consequently, K&M decided not to use the volume-based revenue structure for its analysis. However, this alternative revenue structure warrants further exploration should GPA move forward with the project, as it may offer benefits in scenarios not covered in the current analysis. Additionally, the choice in revenue structure will have implications for GPA's tariff structure.

10.2.5 Gas Demand

The volume of gas required at GUPP is a function of electricity demand and the level of renewable energy generation in Guam. K&M assumes that GPA will dispatch electricity generated from renewables first and will meet the remaining load with electricity generated from natural gas and ULSD power plants. Given the uncertainty surrounding the timeline for renewable energy deployment in Guam, the analysis evaluates three scenarios, listed below, that determine gas demand at GUPP:

- 1 **GPA Target:** Based on GPA's timeline for renewable energy deployment, which targets 50% renewable energy by 2030 and 100% renewable energy by 2040.
- 2 **Guam Law:** Based on Guam Public Law No. 35 – 46, which targets 50% RE by 2035 and 100% RE by 2045.
- 3 **Delayed Renewables:** Based on gradual additions of RE at a lower rate than either GPA's target or Guam law.

The gas demand under these three scenarios was derived from K&M's fuel demand model from Task 1, which is detailed in Section 4 of this report.

10.2.6 DES LNG Price

The Financial Analysis of the Gas Supply Company shares the methodology for estimating the DES LNG price with Task 4.1 and Task 4.2. DES LNG prices are indexed to the forecasted Brent price, using EIA's long-term Brent forecast. Furthermore, DES LNG prices are a function of the volume demanded, LNG source, and the LNG shipping solution. The methodology for calculating the ex-ship price is described in detail in Section 7.2.6.2.

10.2.7 Project CAPEX & OPEX

K&M's CAPEX estimate for the LNG import terminal is USD 210 million. The model assumes that 50% of the CAPEX will be expensed in the first year of construction and 50% expensed in year two. The terminal OPEX is assumed to be 4.5% of total CAPEX, paid during the terminal's operational life (2031 – 2050). These CAPEX and OPEX estimates are the result of Task 3, which is detailed in Section 6 of this report.

10.2.8 Depreciation

The Gas Supply Company's depreciable basis consists of marine infrastructure, onshore facilities, storage tanks, and regasification equipment. The marine infrastructure, storage tanks, and onshore facilities are depreciated according to straight-line depreciation based on their estimated useful life (35, 40 and 40 years, respectively). The regasification equipment has a 20-year useful life and is fully depreciated by the end of the GSA term.

10.2.9 Taxes

The model assumes that LNG imports, similar to ULSD imports, are exempt from Guam's import duties.

10.2.10 Inventory

10.2.10.1 Gas Inventory

The inventory required at the start of operations includes LNG to fill the storage tank at the terminal, as well as materials and spare parts. The required LNG storage capacity is estimated in Task 2 to be 15,000 m³ for all demand scenarios. Table 10.2 includes estimates the volume of LNG required to fill the tank based on a calorific value (LHV) of 23.10 MMBtu / m³.

Table 10.2: Required Storage Capacity and Related Volumes

LNG Carrier Size	Required Storage Capacity	Volume to Fill Tank
10,000 m ³	15,000 m ³	346,500 MMBtu

10.2.10.2 Materials and Spare Parts Inventory

Upfront inventories also include materials and spare parts. This requirement is equivalent to three months of operating costs, or around 25%. This inventory is also required during each operating period.

10.2.11 Days Receivable / Payable

The model assumes that accounts receivable are equal to 45 days of annual revenues ($45 / 365 \times 100 = 12.3\%$) and accounts payable are equal to 45 days of annual operating expenses (LNG + terminal O&M).

10.2.12 Financing Terms

The interest during construction, underwriting fee, and annual commitment fee are capitalized during the construction period. K&M estimates that the interest rate on the loan is 195 basis points above the Secured Overnight Financing Rate (SOFR) which is ~5% at the time of the analysis. All financing terms are presented in Table 10.3, which are similar to the financing terms offered to GUPP.

Table 10.3: Financing Terms for Terminal Loan

	Percent (%)
Interest on Terminal Loan	6.95%
Underwriting Fee	1.00%
Annual Commitment Fee	0.50%

10.2.13 Debt Repayment Terms

10.2.13.1 Debt Amortization Period

The model assumes a nine-year amortization period for all three scenarios.

10.2.13.2 Debt-to-Equity Ratio

The model assumes that the Company's debt-to-equity ratio is 70%.

10.2.13.3 Debt Structure

The model employs a mortgage-style debt structure, where total debt service remains constant in each period, with an increasing portion of each successive payment applied to the principal.

10.2.14 Sensitivities

The Financial Analysis of the Gas Supply Company runs sensitivities on several assumptions to evaluate the impact of different inputs on the price of gas delivered to GUPP. K&M includes sensitivities for capital expenditures, Brent scenarios, the debt amortization period, and debt-to-equity ratios.

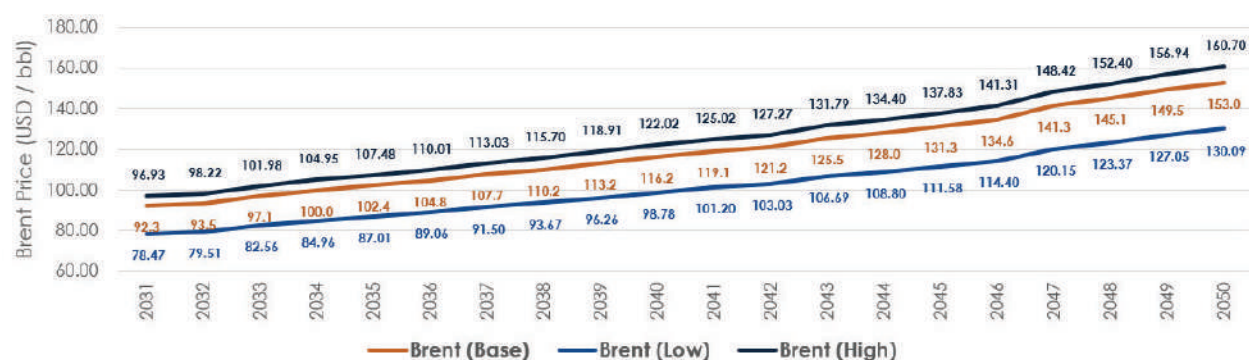
10.2.14.1 CAPEX

The base case assumes that the CAPEX for the Gas Supply Company is \$210M. However, there is uncertainty surrounding this figure. To assess the impact of CAPEX on the price of gas delivered to GUPP, the model assesses a range of CAPEX figures, ranging from \$100M to \$300M.

10.2.14.2 Brent

The price of LNG is indexed to the price of Brent crude oil and forecasted for the Project lifetime (2031 – 2050). In addition to the base case forecast based on EIA's long-term Brent forecast, the Financial Analysis includes a high Brent scenario (+5% from the base case) and a low Brent scenario (-15% from the base case), depicted in Figure 10.2.

Figure 10.2: Brent Price Sensitivity (2031 – 2050)



10.2.14.3 Debt Amortization Period

The base case debt amortization period is nine years. The analysis includes this sensitivity to understand the impact of a longer tenor (fifteen years), a medium tenor (10 years), and a shorter tenor (eight years).

10.2.14.4 Debt-to-Equity Ratio

The base case uses a 70% debt-to-equity ratio. The analysis includes a sensitivity for different debt ratios (50%, 60%, 75%, and 80%) to evaluate their impact on the price of gas delivered to GUPP.

10.3 Results of the Financial Analysis

10.3.1 Results

The key inputs and results are summarized in Table 10.4 and Table 10.5 below. The main results of this financial analysis are the LNG Terminal Recovery Charge and corresponding Levelized Cost of Delivered Gas (LCODG) required to achieve a DSCR and Equity IRR equal to or higher than 1.2 and 8.12%, respectively.

Table 10.4: Summary of Key Inputs

	Key Inputs
CAPEX	USD 210 Million
Debt Amortization	9 Years
Debt Structure	Mortgage Style
Debt Ratio	70%
GSA Term Duration	20 Years

Table 10.5: Results

Financial Analysis of Gas Supply Company	GPA Target	Guam Law	Delayed RE
Debt Facility	USD	USD	USD
Debt Facility: Estimate	158,292,935	158,262,323	158,188,892
Debt Drawdown	158,292,935	158,262,323	158,188,892
Difference	-	-	-
Valuations	%	%	%
Equity IRR	8.21%	8.21%	8.15%
Project IRR	8.70%	8.81%	8.88%
Debt Service Ratios	DSCR	DSCR	DSCR
Average DSCR	1.32	1.33	1.33
Minimum DSCR	1.32	1.32	1.32
Sources	USD % of Total	USD % of Total	USD % of Total
Debt	158,292,935 70%	158,262,323 70%	158,188,892 70%
Equity	67,839,829 30%	67,826,710 30%	67,795,240 30%
Total Sources	226,132,765	226,089,033	225,984,132
Uses	USD % of Total	USD % of Total	USD % of Total
Total CAPEX	210,620,753 93.1%	210,620,753 93.2%	210,620,753 93.2%
Interest During Construction	5,238,864 2.3%	5,238,842 2.3%	5,238,788 2.3%
Underwriting Fee	1,582,929 0.7%	1,582,623 0.7%	1,581,889 0.7%
Annual Commitment Fee	1,206,033 0.5%	1,205,728 0.5%	1,204,998 0.5%
Initial Working Capital	7,484,186 3.3%	7,441,087 3.3%	7,337,704 3.2%
Total Uses	226,132,765	226,089,033	225,984,132
Revenue Structure			
LNG Terminal Capital Recovery Charge ☒			
Charge (USD / year)	\$ 31,976,419	\$ 32,098,511	\$ 32,088,799
Levelized Cost of Delivered Gas (USD / MMBtu)	\$ 25.24	\$ 22.61	\$ 21.43

The above results show that the LNG Terminal Recovery Charge changes substantially with the LNG demand scenario. The LNG Terminal Capital Recovery Charge ranges from \$32.0 - \$32.1 million in the base year, depending on the demand scenario. This translates into a lower LCODG in the Delayed Renewable scenario since this fixed annual charge is spread across more units, as gas demand is the highest in this scenario.

10.3.2 Results with Sensitivities

10.3.3 CAPEX

The model assesses a range of CAPEX estimates, ranging from \$100M to \$300M in \$50M increments, to assess the impact of CAPEX on the price of gas delivered to GUPP. Table 10.6 shows the results of the CAPEX sensitivity analysis. The Terminal Capital Recovery Charge is sensitive to the CAPEX assumption, ranging from \$15.2 to \$45.7 million per year across all scenarios. Changing the CAPEX by about 50% also changes the LNG Terminal Recovery Charge by around 50%, but the LCODG by only 10 to 15%—depending on the scenario—which impacts cost savings from fuel switching.

Table 10.6: Results with CAPEX Sensitivity

	GPA Target		Guam Law		Delayed RE	
	LNG Terminal Capital Recovery Charge	Levelized Cost of Delivered Gas	LNG Terminal Capital Recovery Charge	Levelized Cost of Delivered Gas	LNG Terminal Capital Recovery Charge	Levelized Cost of Delivered Gas
CAPEX:	USD/Year	USD/MMBtu	USD/Year	USD/MMBtu	USD/Year	USD/MMBtu
\$ 100,000,000	\$ 15,288,270	\$ 20.84	\$ 15,312,066	\$ 19.42	\$ 15,282,370	\$ 18.88
\$ 150,000,000	\$ 22,830,163	\$ 22.83	\$ 22,929,640	\$ 20.87	\$ 22,924,609	\$ 20.04
\$ 200,000,000	\$ 30,369,257	\$ 24.81	\$ 30,484,828	\$ 22.31	\$ 30,475,798	\$ 21.19
\$ 250,000,000	\$ 37,953,270	\$ 26.81	\$ 38,098,144	\$ 23.75	\$ 38,087,015	\$ 22.34
\$ 300,000,000	\$ 45,510,100	\$ 28.79	\$ 45,682,514	\$ 25.19	\$ 45,667,422	\$ 23.49

10.3.4 Brent

Since the price of LNG is indexed to Brent, the underlying price of Brent will impact DES LNG prices in Guam. The analysis includes sensitivity for base, low, and high Brent prices. Table 10.7 shows the result of Brent sensitivity, which has an insignificant impact on the Terminal Capital Recovery Charge; however, it does directly impact the DES price of LNG, which explains why the Levelized Cost of Delivered Gas is highest in the High Brent scenario. Changes in Brent are unlikely to have a material impact on the Ratepayer Impact Analysis because the price of ULSD is also indexed to a Brent-correlated index.

Table 10.7: Results with Brent Sensitivity

	GPA Target		Guam Law		Delayed RE	
	LNG Terminal Capital Recovery Charge	Levelized Cost of Delivered Gas	LNG Terminal Capital Recovery Charge	Levelized Cost of Delivered Gas	LNG Terminal Capital Recovery Charge	Levelized Cost of Delivered Gas
Brent Scenario:	USD/Year	USD/MMBtu	USD/Year	USD/MMBtu	USD/Year	USD/MMBtu
Low	\$ 31,971,772	\$ 23.22	\$ 32,093,857	\$ 20.58	\$ 32,084,059	\$ 19.34
Base	\$ 31,976,419	\$ 25.24	\$ 32,098,511	\$ 22.61	\$ 32,088,798	\$ 21.43
High	\$ 31,977,968	\$ 25.91	\$ 32,100,063	\$ 23.29	\$ 32,090,377	\$ 22.13

10.3.5 Debt Amortization Period

The model runs sensitivities for the debt amortization period to understand its impact on the price of gas delivered to GUPP. The sensitivity analysis in Table 10.8 shows that a 10-year amortization produces the lowest price of gas for Guam Law and Delayed RE scenarios. However, the 9-year amortization produces the lowest price of gas for the GPA Target scenario. This is due to the structure of the fixed charge, which drops to 25% of the initial charge after the amortization period ends. This is optimal for prices since forecasted demand drops in 2040 (nine years after operations start), when renewable capacity additions are expected to replace thermal generation. The forecasted operating revenues and costs for each scenario are depicted in Figure 10.3, Figure 10.4, and Figure 10.5 below.

Table 10.8: Results with Debt Amortization Sensitivity

	GPA Target		Guam Law		Delayed RE	
	LNG Terminal Capital Recovery Charge	Levelized Cost of Delivered Gas	LNG Terminal Capital Recovery Charge	Levelized Cost of Delivered Gas	LNG Terminal Capital Recovery Charge	Levelized Cost of Delivered Gas
Debt Amortization:	USD/Year	USD/MMBtu	USD/Year	USD/MMBtu	USD/Year	USD/MMBtu
8	\$ 34,200,000	\$ 25.28	\$ 34,386,598	\$ 22.65	\$ 34,333,437	\$ 21.46
10	\$ 30,137,630	\$ 25.20	\$ 30,212,379	\$ 22.58	\$ 30,198,701	\$ 21.41
15	\$ 25,529,347	\$ 25.40	\$ 25,253,741	\$ 22.67	\$ 24,947,182	\$ 21.44

Figure 10.3: Operating Revenues and Costs – GPA Target

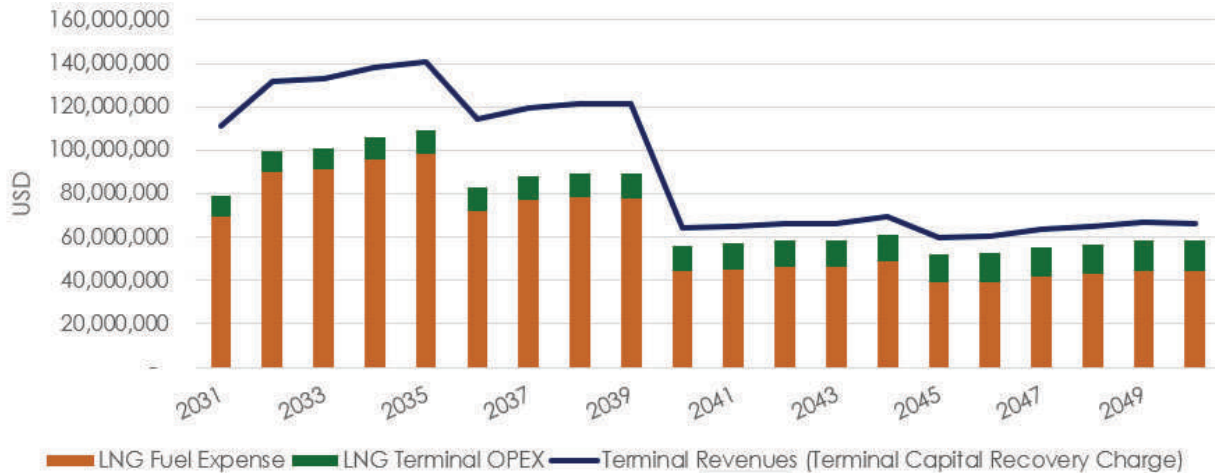


Figure 10.4: Operating Revenues and Costs – Guam Law

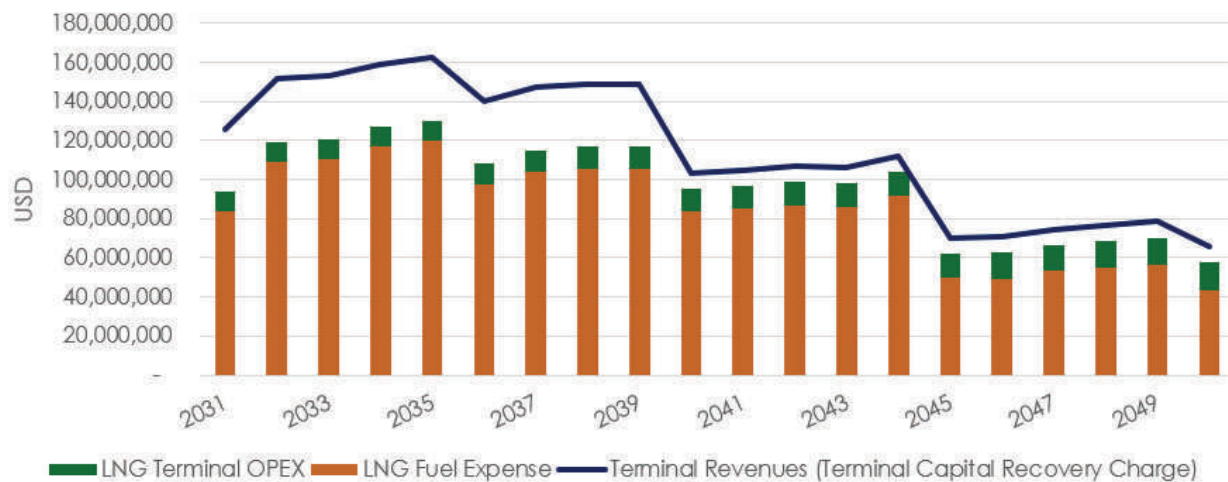
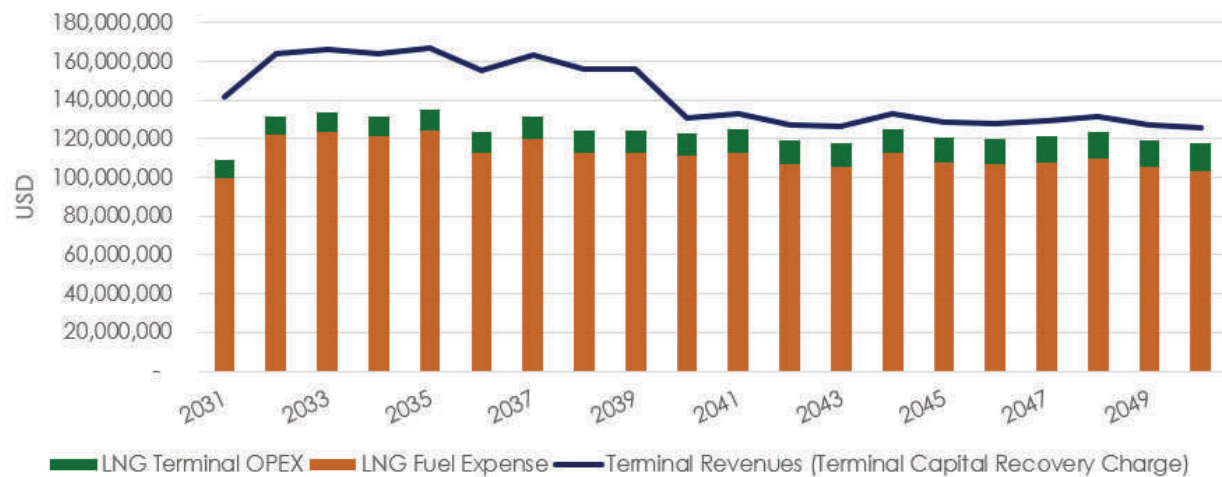


Figure 10.5: Operating Revenues and Costs – Delayed RE



10.3.6 Debt-to-Equity Ratio

The analysis also evaluates the impact of leverage on the price of gas delivered to GUPP by running sensitivities for five different debt-to-equity ratios. As seen in Table 10.9 below, a 70-75% debt ratio produces the lowest price of gas delivered to GUPP in all scenarios.

Table 10.9: Results with Debt-to-Equity Sensitivity

	GPA Target		Guam Law		Delayed RE	
	LNG Terminal Capital Recovery Charge	Levelized Cost of Delivered Gas	LNG Terminal Capital Recovery Charge	Levelized Cost of Delivered Gas	LNG Terminal Capital Recovery Charge	Levelized Cost of Delivered Gas
Debt-to-Equity Ratio:	USD/Year	USD/MMBtu	USD/Year	USD/MMBtu	USD/Year	USD/MMBtu
50%	\$ 32,216,326	\$ 25.28	\$ 32,331,591	\$ 22.64	\$ 32,301,483	\$ 21.45
60%	\$ 32,055,035	\$ 25.25	\$ 32,168,849	\$ 22.62	\$ 32,146,871	\$ 21.44
70%	\$ 31,976,419	\$ 25.24	\$ 32,098,511	\$ 22.61	\$ 32,088,798	\$ 21.43
75%	\$ 31,906,511	\$ 25.22	\$ 32,028,782	\$ 22.60	\$ 32,023,535	\$ 21.42
80%	\$ 33,488,434	\$ 25.50	\$ 33,481,988	\$ 22.79	\$ 33,466,525	\$ 21.57

10.4 Conclusions

The Financial Analysis of the Gas Supply Company estimates the Levelized Cost of Delivered Gas (USD / MMBtu) to GUPP that will make the Gas Supply Company bankable and an attractive investment for equity investors. The results of the analysis are summarized below:

- 1 The Gas Supply Company is bankable and a viable equity investment if the Levelized Cost of Delivered Gas (LCODG) that GPA pays is between \$21.43 to \$25.24 per MMBtu - depending on the LNG demand scenario. This price will cover the cost of LNG delivered ex-ship to Guam (which is between \$14 and 15 per MMBtu for 2031) and the LNG terminal's CAPEX, cost of capital, and operation and maintenance costs. The Ratepayer Impact Analysis considers these cost estimates to determine if the transition from ULSD to natural gas will reduce the rates for end-customers.
- 2 The largest determinant of the LCODG is the cost of LNG delivered ex-ship. This cost is treated in this Financial Analysis as a "pass-through"—that is, 100% of the cost incurred by the Gas

Supply Company to deliver LNG ex-ship Guam is charged to GPA as an LNG DES charge. This cost, therefore, does not affect the Gas Supply Company's bankability or return on investment.

- 3 The second largest determinant of the price of gas delivered to GUPP is the cost of building the LNG terminal, as well as the cost of the capital (debt and equity) used to finance the terminal and the terminal's operating and maintenance costs. This CAPEX has been estimated to be \$210 Million based on the results of Task 3.
- 4 The LCODG is also sensitive to changes in the Gas Supply Company's debt-to-equity ratio and debt repayment period. These two parameters can be updated as more accurate information on financing is received.



Task 6

Consultations with Industry and Guam Stakeholders

11 Task 6 – Consultations with Industry, Guam Stakeholders, and Guam and Federal Regulatory Authorities

The main objective of the consultations with LNG terminal developers, Guam stakeholders, and regulatory authorities is to receive feedback on key parts of the LNG pre-development phase. This outreach sought input on several key elements: terminal configurations and site locations, proposed commercial arrangements and business model, permitting and regulatory considerations, and any potential challenges or red flags associated with the project as currently envisioned. Consultations were held with industry stakeholders, namely LNG suppliers, terminal developers, and equipment suppliers, Guam stakeholders, including the US Navy, the Guam Port Authority, and other government agencies, and other local stakeholders with experience navigating permitting and regulatory processes for LNG terminal development. The feedback received during these consultations is critical to understanding challenges and opportunities for the project and the potential market response and participation in the development of an LNG import terminal in Guam. Additional consultations with LNG suppliers were held as part of Task 2 – LNG Shipping and Sourcing Options and can be viewed in Section 5.1.2.

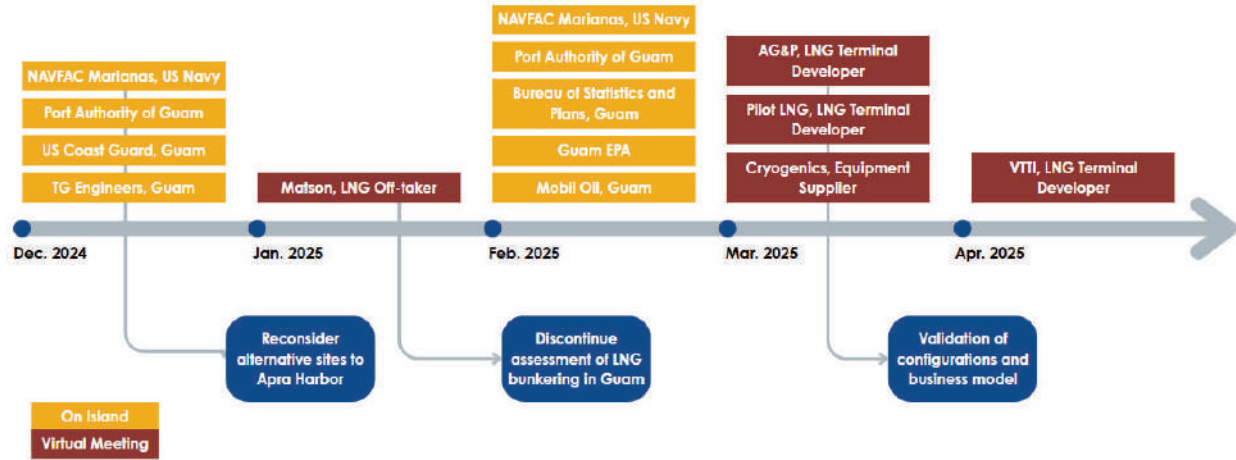
This section presents the results of these consultations. Section 11.1 presents the methodology and approach. Section 11.2 presents the stakeholder mapping and outreach plan. Section 11.3 presents the results and feedback from the stakeholder consultations. Section 11.4 presents the main findings from these consultations. Appendix L presents the market summary that was shared with stakeholders during outreach efforts. Appendix M presents a summary of the feedback from stakeholders.

11.1 Methodology & Approach

The stakeholder consultation process was conducted iteratively from December 2024 to April 2025. It included both in-person and virtual engagements with a range of relevant stakeholders. In-person meetings with Guam-based stakeholders, such as representatives of the U.S. Navy, Guam Port Authority, and Guam EPA, among others, were conducted during site visits facilitated by the Guam Power Authority (GPA). Additional outreach was conducted virtually with pre-identified industry participants, including LNG terminal developers, equipment suppliers, and other market participants with relevant technical and regulatory experience.

The consultation process informed several aspects of the study. For example, feedback from stakeholders prompted reconsideration of initial site options, leading to the evaluation of alternative locations. Similarly, discussions with potential bunkering clients led to the conclusion that bunkering demand is not feasible in the near term, and this element was excluded from further analysis. These insights are illustrated in Figure 11.1 below.

Figure 11.1: Timeline of Consultations



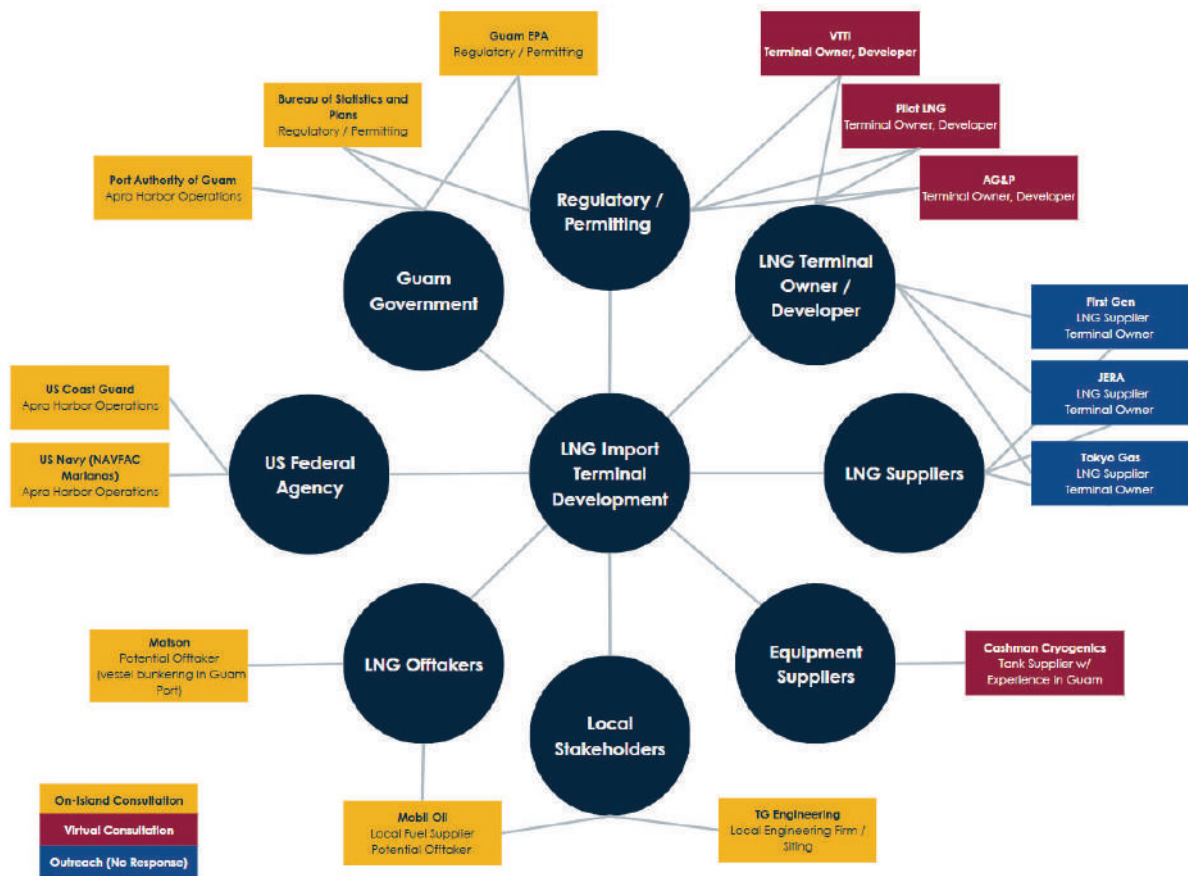
Following the completion of Task 3 – Least-Cost LNG Terminal Site and Configurations, and Task 5.2 – Business Model Comparisons, additional consultations in March and April 2025 were initiated to obtain feedback on the preliminary findings of those tasks. This process began with stakeholder mapping to identify relevant parties for outreach. This included LNG terminal developers previously engaged during Task 2 – LNG Sourcing and Supply Analysis, as well as additional stakeholders identified by K&M Advisors and its subcontractors based on their market knowledge and networks.

Selected stakeholders were contacted and provided with a market summary outlining the project scope and consultation objectives (see Appendix L). Virtual consultations were conducted between March and April 2025. The feedback received is summarized in the subsequent sections (and presented in Appendix M) and has been incorporated into the study's analysis and recommendations.

11.2 Stakeholder Mapping

Figure 11.2 below provides a visual representation of the stakeholders contacted for consultations. This list was developed based on the market knowledge and networks of K&M Advisors and its subcontractors, as well as local contacts identified by the Guam Power Authority (GPA). The purpose of this stakeholder mapping is to ensure comprehensive coverage across key groups, including industry and market participants, local government entities and the U.S. Navy, and individuals with experience in permitting and regulatory processes. Some stakeholders who were contacted did not express interest in consultations. Not all stakeholders contacted opted to participate in the consultations.

Figure 11.2: Stakeholder Mapping



11.3 Results of Stakeholder Consultations

The sections below summarize the key feedback gathered during stakeholder consultations for the LNG import terminal project in Guam. The feedback primarily addressed four themes: the potential for expanding LNG volumes, technical and non-technical considerations for the terminal site, the proposed business model and commercial arrangements, and permitting and regulatory considerations.

11.3.1 Expansion of LNG Volumes

Many stakeholders, including GPA, emphasized that the economic viability of LNG in Guam improves as total volumes increase. Several developers and suppliers inquired about opportunities to expand demand by identifying additional off-takers. In response, K&M evaluated potential synergies with other LNG users on the island, including the potential for LNG bunkering operations at the Port of Guam.

11.3.1.1 Increased Volumes from Bunkering

In a January 2025 consultation with a potential off-taker – Matson, a global shipping company – it was determined that Matson is unlikely to pursue LNG bunkering in Guam (see Appendix J). This decision is based on their recent tenders and long-term supply agreements. For Guam's LNG pricing to be viable for Matson, it would need to be highly competitive, and even then, it would

serve only as a tertiary backup option. As a result, bunkering was excluded from subsequent assessments.

11.3.2 LNG Terminal Site: Security & Technical Considerations

The original site for the LNG import terminal was envisioned in Apra Harbor, where four potential locations were initially evaluated. However, consultations with key stakeholders - including the U.S. Navy and the Port Authority of Guam (PAG), conducted between December 2024 and February 2025 - prompted the team to evaluate alternative siting options. Feedback from these and other stakeholders, including industry participants, is summarized below for the two primary options considered: Hotel Wharf (Apra Harbor) and Tanguisson. While developers strongly prefer Apra Harbor from a technical and operational standpoint, the Navy's opposition presents a significant barrier to its feasibility.

11.3.2.1 Hotel Wharf

The U.S. Navy expressed serious concerns about the potential for a catastrophic event at the LNG facility disrupting Pacific Fleet operations in Apra Harbor. Specific concerns included obstruction caused by LNG carriers and the risk of the facility becoming a strategic target during regional conflict. This opposition and risk perception is likely difficult to mitigate or address.

While some stakeholders have expressed interest in developing the Hotel Wharf site, no firm commitments have been made. For example, the Navy has mid-term plans to use the site as a staging area for bulk materials related to storm damage repairs to its glass breakwater. Similarly, PAG has expressed interest in expanding Hotel Wharf to potentially accommodate aircraft carriers.

Despite these constraints, developers consistently indicated that Hotel Wharf is the more technically viable and operationally favorable option. One developer described Apra Harbor as the “far and away” more logical site, while others cited its safety and ease of execution as key advantages. Land reclamation was not considered a barrier. However, Navy approval remains a critical requirement for any developer to pursue this site.

11.3.2.2 Tanguisson

The Navy responded favorably to the consideration of the Tanguisson site, highlighting potential synergies with other fuel imports such as diesel and JP-8. The Navy owns land in the area and has indicated openness to collaboration, which could support the project's feasibility.

The U.S. Coast Guard advised the team to investigate a Fire Exclusion Zone north of the Tanguisson site that may pose siting restrictions, and to verify whether the U.S. Air Force or Navy conduct munitions dumping or other activities in the vicinity. They also raised operational concerns, including the ability to move vessels in adverse weather.

From a developer's standpoint, the Tanguisson site requires further validation. While no immediate technical red flags have been identified, its exposed location presents significant engineering and operational challenges. One developer stated clearly that the site is not attractive to the market, while another cited weather-related constraints that could drive up both engineering costs and the need for additional onshore storage.

11.3.2.3 Summary

The Tanguisson site may represent the only acceptable option to the U.S. Navy. However, market interest in participating in terminal development at this location is limited due to perceived technical, operational, and cost-related risks. Developers remain strongly in favor of the Apra Harbor site, pending resolution of Navy opposition.

11.3.3 Business Model / Commercial Arrangement

Industry stakeholders were consulted on the proposed business model, under which a private Gas Supplier develops the LNG import terminal under a Gas Supply Agreement with GPA. The Gas Supplier is responsible for sourcing, transporting, importing, storing, and regasifying LNG, and for delivering gas to the Guam Utilities Power (GUPP) interface point. GPA, in turn, pays for the gas supplied and assists with permitting. The Gas Supplier finances, designs, builds, owns, and operates all infrastructure and equipment required for the terminal. GPA selects the terminal site and acquires or leases the land, while the Gas Supplier proposes the terminal's configuration and size based on GPA's functional requirements and the Energy Conversion Agreement (ECA).

11.3.3.1 Business Model

The proposed business model was presented to the Navy for input. The Navy was unfamiliar with the Build-Own-Operate-Transfer (BOOT) structure and indicated that their involvement could delay project development. As a result, incorporating the Navy into the business structure at Tanguisson is not being actively pursued.

Industry developers responded positively to the model. One integrated LNG supplier favored the turnkey structure, which allows them to manage sourcing, EPC, and O&M, enabling efficiencies across the value chain. Another developer suggested that a consortium approach—combining a large player with smaller partners—may be more realistic, given the project's complexity and limited scale.

11.3.3.2 Renumeration Structure

All stakeholders agreed that the commercial structure must provide a stable and bankable revenue stream. One developer proposed a fixed capacity charge to recover capital costs, paired with a variable pass-through charge based on volumes. Another emphasized the importance of Guam's credit rating in supporting project finance. A third stakeholder recommended a fixed day-rate structure over 15 years, combined with a variable operating fee that would also cover tug and anchor handler services.

Contract Term

Stakeholders noted that shorter contract terms increase pricing. While five-year terms have been offered, they often carry a cost premium. More typical contracts range from 10 to 15 years, with longer terms of 20 to 25 years preferred for spreading capital recovery and reducing financial risk.

11.3.3.3 Summary

Stakeholders did not raise any major concerns regarding the feasibility of the proposed business model. Several viable remuneration models were suggested, typically involving a fixed capacity or day-rate paired with a variable operating fee. Longer-term contracts are preferred by developers to improve project bankability and reduce pricing pressure.

11.3.4 Permitting and Regulation

Consultations with relevant stakeholders provided valuable insight into the permitting and regulatory considerations for the proposed LNG import terminal in Guam. These discussions covered local environmental regulations, coordination with federal agencies, and the significant implications of the federal permitting process under the jurisdiction of the Federal Energy Regulatory Commission (FERC).

11.3.4.1 Local Permitting and Regulation

The Bureau of Statistics and Plans (BSP) oversees implementation of the Coastal Zone Management Act (CZMA) in Guam, which generally necessitates compliance with the National Environmental Policy Act (NEPA). Under CZMA, Section 106 provides the framework for Consistency Determinations, which BSP will use to assess the project's alignment with coastal management objectives. While the project is unlikely to require a Nationwide Permit, it may fall under Nationwide Permit 12, which applies to utility line activities. All relevant permits and environmental documentation will be processed through Guam's Environmental Clearinghouse, a centralized body for interagency review and public comment. A specific consideration for this project is the potential presence of Department of Defense (DoD) rights-of-way over submerged lands off the coast of Tanguisson, which could influence plans to use horizontal directional drilling (HDD). Jurisdictional responsibilities between BSP and other agencies remain somewhat unclear in nearshore and offshore areas. BSP's seashore clearance zone extends from 30 feet inland to 10 fathoms (approximately 60 feet) offshore. Although BSP requires a more developed project scope to engage formally, early coordination is recommended, and public outreach should begin as soon as the project is sufficiently defined.

The Guam Environmental Protection Agency (Guam EPA), in coordination with the U.S. EPA Region 9, has jurisdiction over environmental issues related to air, land, and water. During consultations, no significant concerns were raised by Guam EPA regarding either of the proposed sites. The agency's review is expected to focus primarily on land-side infrastructure and equipment, such as backup generators, which are anticipated to have minimal air emissions. The air permitting requirements for converting the Ukudu power plant from ultra-low sulfur diesel (ULSD) to natural gas remain to be clarified. However, Guam EPA is expected to provide review and comment once design details are submitted. Overall, their involvement is projected to be limited in scope and generally supportive.

11.3.4.2 Federal Permitting

In contrast, industry stakeholders raised considerable concerns regarding the federal permitting process under FERC. Multiple developers noted that the scale and location of the Guam project make FERC permitting particularly challenging. One stakeholder emphasized that securing a developer willing to take on the FERC process for a small-volume, remote project would require an entity with deep experience and a highly capable permitting team. The lack of certainty in FERC outcomes, combined with the disproportionate burden of navigating the process for a smaller project, poses a significant barrier. Another stakeholder underscored the timeline challenges, noting that even if FERC permitting were initiated in 2025, approval may not be granted until 2030, with construction potentially extending the timeline by another two to three years before the terminal could become operational.

11.3.4.3 Summary

Local permitting authorities, such as BSP and Guam EPA, appear generally supportive and foresee minimal barriers at this stage; engagement will become more critical as the project scope is refined. The most significant permitting challenge identified by stakeholders is at the federal level, where the complexity, duration, and uncertainty of FERC approval present a potential obstacle to project feasibility and developer participation.

11.4 Conclusions

The following observations are the conclusions from the consultations with industry, Guam stakeholders, and Guam and Federal Regulatory Agencies.

- **Apra Harbor is the technically preferred site, but politically infeasible.** Developers unanimously favored the Apra Harbor site—specifically Hotel Wharf—for its operational simplicity, engineering viability, and overall safety. However, strong opposition from the U.S. Navy, combined with competing interests from the Port Authority of Guam and Navy infrastructure plans, make development at this location unlikely. Without Navy approval, the site is not considered viable for private investment.
- **Tanguisson is the only viable site from a political perspective, but it has slighter higher cost and operational risk.** The Tanguisson site received support from the Navy and presents potential for collaboration, including shared use with other fuel imports. Some stakeholders flagged concerns around its exposed location, weather-related risks, and higher development and operational costs.
- **Expansion of LNG demand is limited in the near term.** Increasing LNG volumes would improve the project's economics, and stakeholders were broadly interested in identifying additional demand. However, efforts to pursue bunkering, specifically with Matson, were unsuccessful. Without significant new off-takers, demand will remain limited to power sector use.
- **The proposed business model is generally accepted by the industry, but requires flexibility.** The Build-Own-Operate-Transfer (BOOT) structure was well-received by developers, particularly those with integrated capabilities. However, some stakeholders indicated that a consortium model may be necessary to manage project complexity and risk. The financial structure must offer secure, long-term revenue through fixed and variable components to attract investment.
- **Longer contract terms improve project bankability.** Developers emphasized that contract terms in the 20–25 year range are preferable, as they reduce capital recovery pressure and improve project economics. Shorter-term contracts are possible but would increase pricing and reduce market interest.
- **Regulatory engagement will become more critical as the project advances.** Local regulatory bodies, including the Guam EPA and BSP, currently see no major red flags, though further input will depend on a more defined project scope. Guam EPA's role will likely be limited to land-side equipment review. The most significant regulatory challenge lies with the Federal Energy Regulatory Commission (FERC), whose lengthy and complex permitting process represents a major barrier, especially given the small scale and remote location of the project.



Task 7

Permitting Survey

12 Task 7 – Environmental, Cultural, and Construction Permits Survey

The primary objective of the environmental, cultural, and construction permits survey is to assess and outline the key permitting requirements for the construction and operation of the LNG terminal and associated facilities. This survey provides an overview of the permitting process, identifies the key agencies involved, highlights potential permitting challenges, and serves as a resource for Phase II of the study.

This section presents the results of the permitting analysis. Section 12.1 describes the methodology and approach. Section 12.2 summarizes the major permits, approvals, and consultations anticipated for the project. Section 12.3 provides an overview of the relevant agencies and their jurisdictions, including applicable legislation and local permitting requirements in Guam. Section 12.4 outlines the National Environmental Policy Act (NEPA) process and its application to the LNG terminal, natural gas pipeline, and sendout pipeline. Section 12.5 presents the conclusions of the permitting task. Appendix N includes the full permitting matrix.

12.1 Methodology & Approach

Based on their expertise with both federal and local Guam permitting requirements and processes, CH·IV and GHD identified the major permits, approvals, and consultations anticipated for the construction and operation of the LNG terminal and natural gas pipeline facilities at both the Tanguisson and Hotel Wharf sites. For the purposes of this study, it is assumed that any required federal land use, whether for construction, operational facilities, or exclusion zones, will be secured through a lease or license agreement with the U.S. Navy, as applicable to each site and pipeline route. Relevant information on each federal agency and its regulatory oversight is provided in the sections below, while the major permits, approvals, and consultations are summarized in the table included in Section 12.2.

12.2 Summary of Major Permits, Approvals, and Consultations

Table 12.1 below provides a high-level view of the major permits, approvals, and consultations anticipated for the construction and operation of the LNG terminal and natural gas pipeline facilities at the Tanguisson and Hotel Wharf sites. Appendix N provides a detailed permitting matrix for all expected permits, approvals, and consultations with additional details to the table below.

Table 12.1: Major Permits, Approvals, and Consultations

Agency	Jurisdiction	Permit, Approval, or Consultation	Permit Type	Typical Agency Review Period
Federal Energy Regulatory Commission (FERC)	Federal	Natural Gas Act Section 3 Authorization	Authorization	18-24 months
U.S. Department of Energy (DOE)	Federal	Natural Gas Act Section 3, Free Trade Agreement (FTA) and Non-FTA Authorizations	Authorization	1-12 months

Agency	Jurisdiction	Permit, Approval, or Consultation	Permit Type	Typical Agency Review Period
U.S. Army Corps of Engineers (USACE)	Federal	Clean Water Act Section 404 / Rivers & Harbors Act Section 10 Permit	Permit	12-18 months
U.S. Department of Defense (DoD) Department of the Navy	Federal	License/Lease	License/ Lease	24 months
U.S. Department of Defense (DoD)	Federal	Energy Policy Act of 2005 FERC/DoD Consultation	Consultation	1-18 months
U.S. Department of Transportation (USDOT) Pipeline and Hazardous Materials Safety Administration (PHMSA)	Federal	49 CFR Part 192 Compliance	Compliance	N/A
U.S. Department of Transportation (USDOT) Pipeline and Hazardous Materials Safety Administration (PHMSA)	Federal	49 CFR Part 193 Compliance (including Letter of Determination)	Compliance	N/A
U.S. Coast Guard	Federal	33 CFR Part 127 Compliance (including Letter of Intent, Waterway Suitability Assessment, and Letter of Recommendation); 33 CFR Part 105 Compliance	Compliance	N/A
U.S. Fish & Wildlife Service	Federal	Section 7 of Endangered Species Act; Migratory Bird Treaty Act; Bald and Golden Eagle Protection Act; Marine Mammal Protection Act; Fish and Wildlife Coordination Act	Consultation	18-24 months

Agency	Jurisdiction	Permit, Approval, or Consultation	Permit Type	Typical Agency Review Period
National Oceanic and Atmospheric Administration (NOAA)	Federal	Section 7 of Endangered Species Act; Magnuson-Stevens Fishery Conservation and Management Act; Marine Mammal Protection Act; Fish and Wildlife Coordination Act; Coral Reef Conservation Act as amended	Consultation	18-24 months
U.S. Department of Transportation (USDOT) Federal Aviation Administration (FAA)	Federal	Title 14 Part 77 Notification of Proposed Construction or Alteration	Notification followed by FAA Determination	45 business days
Guam Environmental Protection Agency (GEPA)	Local	General Permit Application: Earthmoving Work (Optional) Full Construction (Required)	Clearance	3 months
Guam Environmental Protection Agency (GEPA)	Local	Section 401 Water Quality Certification	Certification	Unknown
Guam Environmental Protection Agency (GEPA)/US EPA	Local	National Pollution Discharge Elimination System (NPDES)	Permit	1-2 years
Guam Environmental Protection Agency (GEPA)	Local	Pollution Discharge Permit	Permit	6 months - 1 year
Guam Environmental Protection Agency (GEPA)	Local	Hazardous Waste Permits: Notification of Hazardous Waste Activity, RCRA Part A, Underground Storage Tank (UST)	Permit	Unknown
Guam Environmental Protection Agency (GEPA)	Local	Well Operating Permit, Underground Injection Control Permit, Well Drilling	Permit	Unknown
Guam Environmental Protection Agency (GEPA)	Local	Air Permits: Air Pollution Source Construction Permit, Emission Unit Permit, Compliance Certification, Air Pollution Permit to Construct in Non-Attainment Areas	Permit	Unknown

Agency	Jurisdiction	Permit, Approval, or Consultation	Permit Type	Typical Agency Review Period
Guam Department of Public Works (DPW)	Local	Right-of-Way Permit	Permit	Unknown
Guam Department of Public Works (DPW)	Local	Building Inspection and Permit	Permit	4 months if no land ownership issues
Department of Land Management, Guam Seashore Protection Commission	Local	Seashore Clearance	Permit	84 days
Department of Land Management, Land Planning Division	Local	Wetland Permit	Permit	Unknown
Department of Land Management, Land Planning Division	Local	Flood Hazard Area Permit	Permit	Unknown
Guam Coastal Management Program (GCMP), Bureau of Statistics and Plans (BSP)	Local	Federal Consistency Review / Application for Consistency Certification	Certification	14 days
Department of Agriculture (DoAg), Division of Aquatic and Wildlife Resources (DAWR)	Local	Special Use Permit	Permit	Unknown

12.3 Federal and Local Guam Agencies

This section describes the federal and local Guam agencies anticipated to be involved in the major permits, approvals, and consultations required to construct and operate the LNG terminal and natural gas pipeline facilities.

The federal agencies include the Federal Energy Regulatory Commission (FERC), U.S. Department of Energy (DOE), U.S. Department of Defense (DoD), U.S. Army Corps of Engineers (USACE), U.S. Department of Transportation (USDOT) and its sub-agencies Pipeline and Hazardous Materials Safety Administration (PHMSA) and Federal Aviation Administration (FAA), U.S. Coast Guard (USCG), U.S. Fish & Wildlife Service (USFWS), and the National Oceanic and Atmospheric Administration (NOAA). These agencies oversee permitting and regulatory compliance at the

national level, including LNG terminal siting, marine safety, environmental protection, pipeline safety, and species protection.

The local Guam agencies include the Guam Department of Public Works (DPW), Guam Department of Land Management (DLM) including the Land Planning Division, Guam Seashore Protection Commission, and Chamorro Land Trust Commission (CLTC), Guam Environmental Protection Agency (GEPA), Guam Department of Agriculture Division of Aquatic and Wildlife Resources (DAWR), Guam Parks and Recreation State Historic Preservation Office (GSHPO), and the Guam Coastal Management Program (GCMP) under the Bureau of Statistics and Plans (BSP). These agencies manage permitting processes related to land use, building codes, environmental protection, cultural resources, and coastal zone management within Guam's jurisdiction.

The sections below provide relevant details about each agency's authority, permitting processes, and applicable legislation.

12.3.1 Federal Agencies

12.3.1.1 Federal Energy Regulatory Commission (FERC)

The Federal Energy Regulatory Commission (FERC) holds jurisdiction over the siting, construction, and operation of LNG import terminals under Section 3 of the Natural Gas Act (NGA). The NGA stipulates that no entity may import natural gas from a foreign country without first obtaining an order from FERC authorizing such importation. FERC has exclusive authority to approve or deny applications for the siting, construction, expansion, or operation of LNG import terminals. The Commission is required to issue an authorization upon application unless, after an opportunity for hearing, it determines that the proposed importation is not consistent with the public interest. FERC's authorization under NGA Section 3 constitutes a federal action subject to the National Environmental Policy Act (NEPA) review process. The natural gas pipeline connecting the LNG terminal to the power plant, however, falls outside FERC's jurisdiction, as it is not classified as an interstate pipeline.

12.3.1.2 U.S. Department of Energy (DOE)

The Natural Gas Act (NGA) requires any person seeking to import or export natural gas, including liquefied natural gas (LNG), from or to a foreign country to obtain authorization from the U.S. Department of Energy (DOE). Section 3(c) of the NGA, as amended by the Energy Policy Act of 1992, mandates that applications to authorize: (a) the import or export of natural gas, including LNG, from or to a nation with which the United States has a free trade agreement requiring national treatment for trade in natural gas, and (b) the import of LNG from other international sources, be deemed consistent with the public interest and granted without modification or delay.

12.3.1.3 U.S. Department of Defense (DOD)

The Energy Policy Act of 2005 and Section 3 of the Natural Gas Act (NGA) require FERC to consult with the U.S. Department of Defense (DoD) to determine whether the proposed siting, construction, expansion, or operation of LNG facilities would impact an active military installation. In addition, FERC must obtain the concurrence of the Secretary of Defense before authorizing any LNG facility activities that could affect military training or operations. This consultation is conducted as part of FERC's National Environmental Policy Act (NEPA) review process and is outlined in a Memorandum of Understanding (MOU) between FERC and DoD.

U.S. Army Corps of Engineers (USACE)

The U.S. Army Corps of Engineers (USACE) has permitting authority under several statutes, including Section 404 of the Clean Water Act (CWA), Section 10 of the Rivers and Harbors Act (RHA) (33 USC 403), Section 408 of the RHA (33 USC 408), and Section 103 of the Marine Protection, Research, and Sanctuaries Act. Construction of the LNG terminal is expected to require Section 404 and Section 10 permits due to in-water construction activities. Similarly, construction of the natural gas pipeline may require these permits depending on final routing and the location of temporary construction facilities. For the purposes of this study, it is assumed that the pipeline would require USACE permits under CWA Section 404 and RHA Section 10, subject to confirmation through environmental surveys and USACE jurisdictional determinations. It is further assumed that no authorization would be required under RHA Section 408, as no alterations to USACE civil works projects are anticipated, and no permits would be required under Section 103 of the Marine Protection, Research, and Sanctuaries Act, as ocean disposal is not planned. The issuance of USACE permits constitutes a federal action under NEPA.

Department of the Navy (Navy)

The Department of the Navy (Navy) would be involved in the project due to the use of federal land. Construction and operation of the LNG terminal and natural gas pipeline under the Tanguisson site alternative would require access to federal land, while operation of the LNG terminal at the Hotel Wharf site would require federal land use for exclusion zones. Additionally, construction and operation of the natural gas pipeline at the Hotel Wharf site may also require federal land use, depending on final routing and temporary construction facilities. For this study, it is assumed that the use of federal land would be secured through a license or lease agreement with the Navy, though other mechanisms may also be available. The use of federal land for these purposes constitutes a federal action under NEPA.

12.3.1.4 U.S. Department of Transportation (DOT)

The project will interface with two administrations within the U.S. Department of Transportation (USDOT).

Pipeline and Hazardous Materials Safety Administration (PHMSA)

The Pipeline and Hazardous Materials Safety Administration (PHMSA) establishes the minimum federal safety standards for natural gas pipelines and LNG facilities under 49 USC 1671 et seq. (for pipelines) and 49 USC 60101 (for LNG facilities). These standards are codified in 49 CFR Parts 192 and 193, governing the design, construction, operation, maintenance, and security of these facilities. Specifically, 49 CFR Part 192 applies to natural gas pipelines, while 49 CFR Part 193 applies to LNG facilities. NFPA 59A (2001 edition), the industry standard for LNG production, storage, and handling, is incorporated by reference into Part 193. Under a Memorandum of Understanding (MOU) between FERC and PHMSA, PHMSA issues a Letter of Determination (LOD) confirming whether LNG facilities comply with the location criteria and design standards specified in Subpart B of Part 193. This LOD is considered during FERC's decision-making process.

For the natural gas pipeline facilities in Guam, compliance with 49 CFR Part 192 would be demonstrated directly to PHMSA, as there is currently no federal-state partnership for the oversight of pipeline safety regulations in Guam.

Federal Aviation Administration (FAA)

The Federal Aviation Administration (FAA) must be notified of any proposed construction or alterations related to the LNG terminal or natural gas pipeline that fall under the provisions of 14

CFR Part 77. This notification enables the FAA to evaluate potential aeronautical hazards before construction begins, helping to prevent or minimize impacts to the safe and efficient use of navigable airspace. Upon completing its review, the FAA will issue a determination outlining its findings.

12.3.1.5 U.S. Coast Guard (USCG)

The U.S. Coast Guard (USCG) is responsible for determining the suitability of waterways for LNG marine traffic and exercises regulatory authority over LNG facilities that impact the safety and security of port areas and navigable waterways. The USCG oversees matters related to navigation safety and the safety of facilities or equipment located in or adjacent to navigable waters. Additionally, the USCG has authority over LNG facility security under 33 CFR Part 105, which governs maritime facility security requirements.

USCG regulations under 33 CFR Part 127 specifically address waterfront facilities handling LNG, including the Letter of Intent (LOI), Waterway Suitability Assessment (WSA), and Letter of Recommendation (LOR) processes. These processes evaluate the risks and suitability of LNG marine operations within designated waterways. The USCG and FERC coordinate their respective review processes for LNG terminals under a Memorandum of Understanding (MOU) to ensure alignment of safety, security, and environmental oversight.

12.3.1.6 U.S. Fish & Wildlife Service (USFWS)

Consultation with the U.S. Fish and Wildlife Service (USFWS) may be required for the construction and operation of the LNG terminal and natural gas pipeline, depending on the presence of fish, wildlife, and habitats potentially impacted by the project. The extent of USFWS involvement will be determined following the completion of environmental surveys to identify any protected species or critical habitats within the project area. Until these surveys are conducted, it is assumed that no USFWS permits or authorizations will be required.

The USFWS is responsible for ensuring compliance with several key environmental statutes, including the Endangered Species Act (ESA), the Fish and Wildlife Coordination Act of 1934 (16 USC 661 et seq.), the Migratory Bird Treaty Act of 1918 (MBTA) (16 USC 703), the Bald and Golden Eagle Protection Act of 1940 (BGEPA) (16 USC 688), and the Marine Mammal Protection Act of 1972 (MMPA). The USFWS reviews project plans and provides recommendations to protect fish and wildlife resources. Typically, the USFWS participates in the project approval process as a cooperating agency under the NEPA.

12.3.1.7 National Oceanic and Atmospheric Administration (NOAA)

Consultation with the National Oceanic and Atmospheric Administration (NOAA) may be required for the construction and operation of the LNG terminal and natural gas pipeline where fishery and marine species could be affected. The extent of NOAA's involvement will depend on the presence of protected marine species, habitats, or resources that may be impacted by the project. Until environmental surveys are completed to identify any such resources, it is assumed that no NOAA permits or authorizations will be required.

NOAA is responsible for ensuring compliance with the Endangered Species Act (ESA) and also provides reviews and recommendations to protect fish and wildlife resources under the Fish and Wildlife Coordination Act of 1934 (16 USC 661 et seq.). In addition, NOAA has specific authority to conserve and manage U.S. fishery resources, including the requirement to consult with other federal agencies under the Magnuson-Stevens Fishery Conservation and Management Act of 1976 when proposed actions may adversely affect Essential Fish Habitat (EFH). NOAA also oversees

compliance with the Marine Mammal Protection Act (MMPA) and the Coral Reef Conservation Act. NOAA typically participates in the project approval process as a cooperating agency under the NEPA.

12.3.2 Local Guam Agencies

12.3.2.1 Guam Department of Public Works (DPW)

The Guam Department of Public Works (DPW) oversees the issuance of Right-of-Way Permits and Building Permits for construction activities within the territory. The Building Law, Title XXXII of the Government Code of Guam, provides the regulatory framework for ensuring that construction projects meet applicable safety standards, zoning regulations, and structural integrity requirements. A Right-of-Way Permit is required for any work within public roadways or easements to ensure public safety and maintain traffic flow, while a Building Permit is necessary for new construction, alterations, or demolition of structures.

For the LNG terminal project, the DPW permitting process will require submission of detailed design plans and specifications, which are reviewed for compliance with all relevant regulations. Once submitted, DPW circulates the application to various agencies, including the Department of Land Management, Guam EPA, Department of Agriculture, Guam Parks and Recreation, Guam Waterworks Authority, Guam Power Authority, Guam Fire Department, the Guam Contractors License Board, and the Guam PEALS Board, for review and approval. Due to the public land ownership at both proposed sites and the scale of the LNG terminal construction, both a Right-of-Way Permit and Building Permit will be required.

12.3.2.2 Department of Land Management, Land Planning Division

The Guam Department of Land Management (DLM), through its Land Planning Division, oversees the issuance of Wetland Permits and Flood Hazard Area Permits to ensure that land development activities comply with environmental and land use regulations.

- **Wetland Permit:** A Wetland Permit is required for any project that involves development, filling, dredging, or alterations within or adjacent to designated wetland areas. These areas are defined by the Guam Administrative Rules and Regulations, Title 18 - Land Management, Chapter 3, which outlines specific provisions for wetland management. The Land Planning Division reviews and approves maps, supports the Guam Land Use Commission and Guam Seashore Protection Commission, and oversees permit clearances.
- **Flood Hazard Area Permit:** A Flood Hazard Area Permit is required for any construction or land-disturbing activity within areas designated as Special Flood Hazard Areas (SFHAs), as identified by the Federal Emergency Management Agency (FEMA). Projects in these zones must comply with floodplain management regulations designed to reduce flood risks and ensure the safety and resilience of structures. The Guam Environmental Protection Agency (GEPA) provides additional guidelines, including prohibiting new septic systems in flood hazard areas and requiring that new buildings be connected to public sewer systems.

Both the Tanguisson and Hotel Wharf LNG facility sites are located within the Flood Hazard Area of Particular Concern and will require a Flood Hazard Area Permit. Wetland field surveys will also be required to determine whether a Wetland Permit is necessary at either site.

12.3.2.3 Department of Land Management, Guam Seashore Protection Commission

The Guam Seashore Protection Commission, operating within the Guam Department of Land Management, is responsible for ensuring that any development within the Seashore Reserve

complies with territorial regulations during the study and planning phases. The Commission's authority is established under 21 Guam Code Annotated (GCA), Chapter 63, known as the Guam Territorial Seashore Protection Act of 1974. The Seashore Reserve is defined as the waters surrounding Guam extending seaward to the ten-fathom contour, including all islands within the Government's jurisdiction (with the exception of Cabras Island and villages where residences were constructed along the shoreline prior to the act's effective date). Inland, the reserve extends to the nearer of the following points:

- Ten (10) meters from the mean high-water line on a horizontal plane, or
- From the mean high-water line to the inland edge of the nearest public right-of-way.

Any development within the Seashore Reserve—defined broadly to include the placement or construction of any solid material or structure—requires a Seashore Clearance Permit. The construction or placement of any components of the LNG terminal at either proposed location would meet this definition of development and, therefore, would trigger the requirement for a Seashore Clearance Permit.

12.3.2.4 Department of Land Management, Chamorro Land Trust Commission (CLTC)

The Chamorro Land Trust Commission (CLTC) is responsible for managing and regulating the use of public lands in Guam, including submerged lands. The regulatory authority for issuing commercial submerged lands license agreements is derived from Guam's Public Law 35-112, which governs the leasing and licensing of Chamorro Land Trust properties. A project requires a CLTC License when it involves commercial activities on submerged lands, such as marinas, docks, or other waterfront developments. The application process includes submitting detailed plans and specifications, demonstrating compliance with environmental and zoning regulations, and ensuring that the proposed use aligns with the best interests of the Chamorro people and the island's ecological sustainability. The CLTC reviews applications to ensure they meet all legal requirements and contribute positively to the community and environment. Consultation with the Chamorro Land Trust Commission to determine jurisdiction of submerged lands is likely necessary.

12.3.2.5 Guam Environmental Protection Agency (GEPA)

The Guam Environmental Protection Agency (GEPA) enforces multiple, locally mandated permits. As with Guam's environmental law, many of these permits were generated based on federal programs. The following permits will likely apply to the LNG Facility and will be coordinated through GEPA:

- Section 401 Water Quality Certification
- National Pollution Discharge Elimination System (NPDES), Pollution Discharge Permit
- Hazardous Waste Permits (Notification of Hazardous Waste Activity, RCRA Part A, Underground Storage Tank (UST))
- Well Operating Permit, Underground Injection Control Permit, Well Drilling
- Air Permits (Air Pollution Source Construction Permit, Emission Unit Permit, Compliance Certification, Air Pollution Permit to Construct in Non-Attainment Areas)

More specifically, under Section 401 of the Clean Water Act (CWA), a federal agency may not issue a permit or license for any activity that may result in a discharge into the Waters of the US unless a Section 401 water quality certification is issued or waived. States and authorized tribes where the discharge would originate are generally responsible for issuing water quality

certifications. For Guam, the Guam Environmental Protection Agency (GEPA) is the regulatory body under Section 401. The construction of the LNG terminal at either proposed location would impact Section 10 and Section 404 Waters requiring a Section 401 Water Quality Certification. Construction of the project would trigger the General Permit Application and may trigger others.

12.3.2.6 Department of Agriculture (DoAg), Division of Aquatic and Wildlife Resources (DAWR)

The Department of Agriculture's Division of Aquatic and Wildlife Resources (DAWR) oversees the issuance of Special Use Permits for activities that may impact Guam's natural resources. The regulatory authority for these permits is derived from Guam's environmental protection laws, which aim to safeguard the island's ecosystems. A Special Use Permit is required for activities that involve significant interaction with aquatic or wildlife areas. Consultation with the DoAG DAWR should inform the project applicant if a Special Use Permit or other type of approval will be required. The application process involves submitting detailed information about the proposed activities, including its purpose, location, potential environmental impacts, and mitigation efforts.

12.3.2.7 Guam Parks and Recreation State Historic Preservation Office (GSHPO)

Section 106 of the National Historic Preservation Act (NHPA) requires federal agencies to consider the effects of their actions on historic properties, which include districts, sites, buildings, structures, and objects listed in or eligible for listing in the National Register of Historic Places (National Register). The National Register is an official list of significant historic places across the United States, including Guam and the Commonwealth of the Northern Mariana Islands. Federal agencies comply with Section 106 through the Section 106 consultation process, which is conducted with the appropriate State and/or Tribal Historic Preservation Office (SHPO/THPO) and other relevant stakeholders.

For this project, any landward ground disturbance associated with the LNG facility at either location will require consultation with the Guam State Historic Preservation Office (GSHPO). Specifically, the Tanguisson site is located within 1,000 feet of a known historical site, which further underscores the need for consultation. No mapped historical features have been identified at the proposed Hotel Wharf site; however, consultation with GSHPO will still be required to ensure compliance with Section 106.

12.3.2.8 Guam Coastal Management Program (GCMP), Bureau of Statistics and Plans (BSP)

The Guam Coastal Management Program (GCMP), administered by the Bureau of Statistics and Plans (BSP), was established in 1979 under the authority of the Coastal Zone Management Act (CZMA) of 1972. BSP is responsible for conducting federal consistency reviews for activities requiring a federal license or permit that may affect land, water, or natural resource uses within Guam's coastal zone. The CZMA requires that federally conducted, supported, or licensed activities that directly affect the coastal zone be consistent, to the maximum extent practicable, with Guam's approved coastal management program.

The coastal zone of Guam includes all non-federal property on the island and extends 3 nautical miles seaward. Under certain circumstances, BSP may extend its jurisdiction up to 12 nautical miles seaward if an activity beyond the 3-mile limit could have direct or indirect effects on Guam's coastal uses or resources. Any project requiring a federal license or permit within the 3-nautical-mile zone must undergo a federal consistency review under the CZMA. The proposed LNG facility, at either the Tanguisson or Hotel Wharf site, falls within the jurisdictional limits of the GCMP. As part of the consistency review process, the project will be evaluated against GCMP's objectives and

policies, and a determination will be made regarding whether the project furthers or conflicts with these guidelines.

12.4 National Environmental Policy Act (NEPA) Process

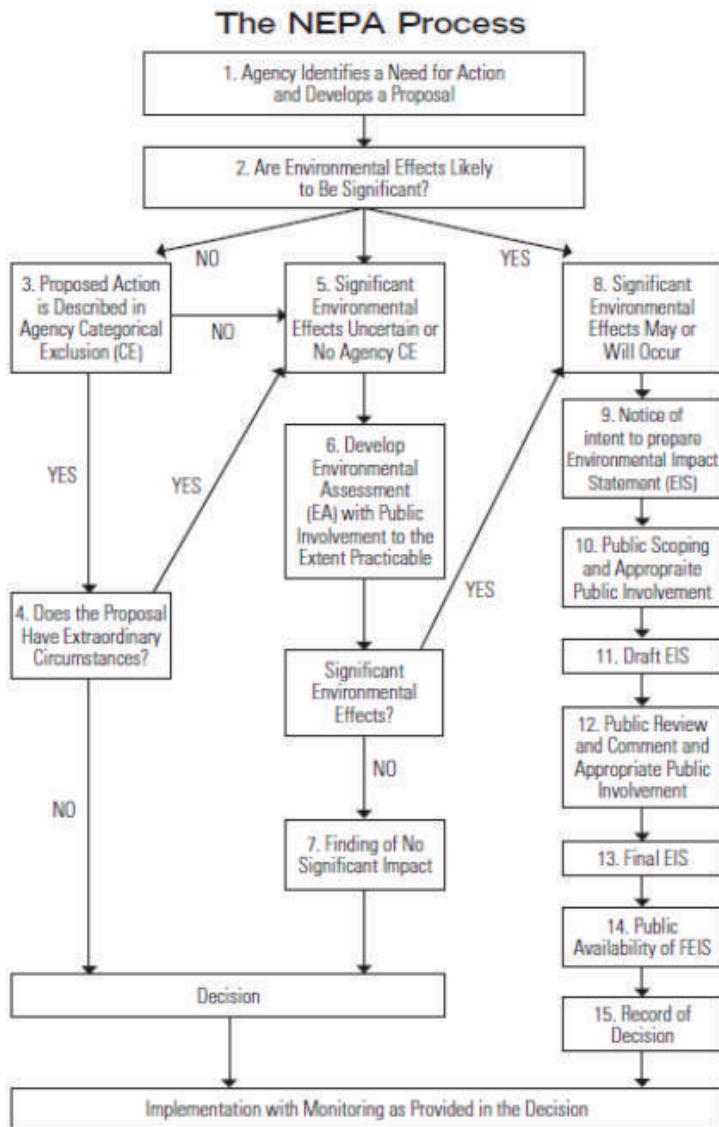
The National Environmental Policy Act (NEPA), enacted in 1970, establishes a framework for evaluating the potential environmental impacts of federal actions before decisions are made. NEPA is relevant to this project because multiple federal permits and approvals will be required for the construction and operation of the LNG terminal and associated natural gas pipeline. These permits constitute federal actions, triggering the NEPA review process. The analysis completed under NEPA ensures that environmental considerations, along with economic and technical factors, are integrated into the decision-making process for federally regulated projects.

NEPA requires federal agencies to assess the environmental effects of proposed federal actions before making final decisions. Each federal agency follows its own regulations and procedures for implementing NEPA, but the process is typically triggered by a federal action such as issuing a permit, allocating federal funds, constructing federal projects, or making land management decisions involving federal lands. The NEPA process must be completed prior to an agency's final decision and includes analyzing the potential impacts of the proposed action, considering alternatives, and engaging the public. The NEPA review may also serve as an umbrella framework that satisfies the environmental review requirements of other laws, such as the Endangered Species Act (ESA), the National Historic Preservation Act (NHPA), and other federal, territorial, tribal, or local regulations.

Under NEPA, a lead agency assumes primary responsibility for ensuring compliance with the NEPA process. For large or complex projects involving multiple federal agencies—as well as territorial, tribal, or local agencies—one or more agencies may serve as joint lead agencies. These agencies share responsibility for managing the NEPA process, including document preparation and public engagement. Other agencies with jurisdiction, regulatory authority, or special expertise may participate as cooperating agencies. A cooperating agency supports the lead agency by contributing to the analysis of environmental impacts within its area of expertise or jurisdiction.

The typical NEPA process is illustrated in Figure 12.1. The process begins with defining the proposed project and identifying reasonable alternatives. Based on the anticipated level of environmental impacts, the agency determines whether a Categorical Exclusion (CE), an Environmental Assessment (EA), or a more detailed Environmental Impact Statement (EIS) is required. Given the scale and potential environmental impacts associated with the proposed LNG terminal and natural gas pipeline, it is expected that either an EA or EIS will be necessary. Following the completion of an EA (and issuance of a Finding of No Significant Impact [FONSI]) or a Final EIS (with a Record of Decision [ROD]), the federal agencies involved will render their decisions on the proposed project.

Figure 12.1: NEPA Process



Source: A Citizen's Guide to NEPA by Council on Environmental Quality, December 2007

12.4.1 NEPA - LNG Terminal

The Federal Energy Regulatory Commission (FERC) authorization under Section 3 of the Natural Gas Act (NGA) for LNG import terminals constitutes a federal action subject to the National Environmental Policy Act (NEPA). The Energy Policy Act of 2005, as amended, designates FERC as the lead federal agency for coordinating all applicable federal authorizations related to jurisdictional natural gas facilities, including LNG import terminals, and for ensuring compliance with NEPA. As the lead agency, FERC is responsible for preparing the required NEPA documentation—either an Environmental Assessment (EA) or Environmental Impact Statement (EIS)—to evaluate the environmental impacts of the proposed LNG terminal.

FERC's definition of the project under NEPA is limited to those facilities over which it has jurisdiction under Section 3 of the NGA, namely the LNG import terminal itself. Other federal agencies with permitting or consultation responsibilities participate in the NEPA process as cooperating agencies. These typically include the U.S. Army Corps of Engineers (USACE), U.S. Coast Guard (USCG), U.S. Department of Energy (DOE), U.S. Department of Transportation (USDOT), U.S. Fish and Wildlife Service (USFWS), National Oceanic and Atmospheric Administration (NOAA), and U.S. Environmental Protection Agency (EPA). Through this coordinated process, cooperating agencies utilize the FERC NEPA documentation to satisfy their respective NEPA obligations and align their permitting, approval, and consultation processes (as summarized in Table 1.8) with FERC's NGA Section 3 authorization.

In addition to FERC's jurisdiction, the use of federal land for the LNG terminal or associated exclusion zones is also considered a federal action under NEPA. For this study, it is assumed that the required federal land use would be secured through a license or lease agreement with the U.S. Navy. However, alternative mechanisms for securing federal land use could also be considered. Under a Navy license or lease scenario, the Navy would have NEPA compliance responsibilities associated with the land use authorization. This compliance could be integrated into the FERC NEPA process, with the Navy participating either as a joint lead agency or a cooperating agency. Alternatively, the Navy could conduct an independent NEPA process to evaluate environmental impacts related to the land use authorization. In this case, the Navy would complete any required consultations and approvals in conjunction with executing the license or lease.

12.4.2 NEPA - Natural Gas Pipeline

The natural gas pipeline connecting the LNG terminal to the Ukudu power plant does not fall under FERC jurisdiction, as it is not classified as an interstate pipeline. Consequently, the pipeline does not require FERC authorization and is not considered part of the proposed action within FERC's NEPA process. Instead, the pipeline would be evaluated under the cumulative impacts assessment within the FERC NEPA document. Memoranda of Understanding (MOUs) between FERC and other federal agencies, including the U.S. Army Corps of Engineers (USACE), U.S. Fish and Wildlife Service (USFWS), National Oceanic and Atmospheric Administration (NOAA), and others, establish that environmental impacts associated with non-jurisdictional components—such as the pipeline—can be addressed within the FERC NEPA document to meet the informational needs of cooperating agencies for their respective permitting and consultation responsibilities.

For instance, the issuance of permits by USACE constitutes a federal action under NEPA. Construction of the pipeline may require Section 404 permits under the Clean Water Act (CWA) and Section 10 permits under the Rivers and Harbors Act (RHA), depending on the finalized routing and the location of temporary construction facilities. In such cases, USACE would typically adopt the FERC NEPA document under 40 CFR 1506.3(c) after conducting an independent review to ensure the document provides adequate information for decision-making under USACE's statutory authorities. While the FERC NEPA document may address environmental impacts relevant to USACE's permitting process, it does not replace the USACE public notice or formal permit review process. In addition to relying on the FERC NEPA document, USACE would issue its own Record of Decision (ROD) to formally document permit decisions, including any Section 404(b)(1) analyses and associated mitigation commitments.

The use of federal land for the pipeline also constitutes a federal action under NEPA. Under the Tanguisson site alternative, construction and operation of the pipeline would require access to

federal land, while under the Hotel Wharf site alternative, the need for federal land would depend on the final routing and associated construction facilities. For the purposes of this study, it is assumed that access to federal land would be secured through a license or lease agreement with the U.S. Navy, although other mechanisms could also be used. In the event of a Navy license or lease, the Navy would be responsible for NEPA compliance related to the land use authorization. This compliance could be achieved either by the Navy participating as a joint lead agency or cooperating agency under the FERC NEPA process, or by conducting an independent NEPA process. Under an independent process, the Navy would complete all required environmental reviews, consultations, and approvals associated with executing the license or lease.

12.4.3 NEPA – Natural Gas Sendout Pipeline

It is assumed that the natural gas pipeline connecting the LNG terminal to the power plant would be non-jurisdictional under the Natural Gas Act (NGA) and therefore not subject to FERC authorization. As a result, the pipeline would not be included in the proposed action for the purposes of FERC's NEPA process, but would instead be evaluated under the cumulative impacts assessment in the FERC NEPA document. However, it is also assumed that construction and operation of the pipeline would impact waters of the United States under the jurisdiction of the U.S. Army Corps of Engineers (USACE), pursuant to Section 404 of the Clean Water Act and Section 10 of the Rivers and Harbors Act. In accordance with Memoranda of Understanding (MOUs) between FERC, USACE, the U.S. Fish and Wildlife Service (USFWS), and other federal agencies, the environmental impacts of the pipeline may be addressed within the FERC NEPA document in a manner sufficient to support the permitting and consultation responsibilities of cooperating agencies.

The natural gas pipeline would be designed, constructed, operated, and maintained in compliance with 49 CFR Part 192, which outlines federal safety standards for natural gas pipelines. In Guam, compliance with Part 192 would be demonstrated directly to the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA), as no federal-territorial partnership exists for oversight in Guam. It should be noted that demonstration of compliance with PHMSA regulations under Part 192 does not constitute a federal action subject to NEPA.

Construction and operation of the pipeline may also require the use of federal land. For the purposes of this study, it is assumed that access to federal land would be secured through a license or lease agreement with the U.S. Navy, although other mechanisms could also be considered. Under a Navy license or lease scenario, the Navy would be responsible for NEPA compliance associated with the federal land use. This could be achieved either by participating as a cooperating agency in the FERC NEPA process or by conducting an independent NEPA review. If proceeding independently, the Navy would complete all necessary consultations and environmental approvals related to the land use authorization, including but not limited to compliance with the Coastal Zone Management Act (CZMA).

12.5 Conclusion

No significant differences were identified between the Tanguisson and Hotel Wharf sites with respect to federal major permits, approvals, and consultations required for the construction and operation of the LNG terminal and associated natural gas pipeline facilities.

While this evaluation addresses the primary permits, approvals, and consultations anticipated for both sites, additional permits may be required for project components that are yet to be fully defined, including but not limited to:

- Although the general footprint for the LNG terminal and governing exclusion zones has been identified in this study, all project-related land use requirements (for both construction and operations) will need to be clearly defined as the project design advances. Corresponding permits, approvals, and consultations should be incorporated into the permitting plan as these elements are finalized. The specific land use and conveyance mechanisms (e.g., lease or license for the LNG terminal and exclusion zones, right-of-way or easement for the pipeline) will determine the applicable approval processes, particularly where federal lands are involved.
- Temporary construction facilities such as laydown areas, construction trailers, and utilities have not yet been identified. As such, associated permits for these temporary facilities have not been included in the current analysis. The developer will need to identify the required temporary construction infrastructure and secure the necessary permits during the project's implementation phase.

To further refine the list of major permits, approvals, and consultations—and to better differentiate permitting risks between the Tanguisson and Hotel Wharf alternatives—it is recommended that environmental and cultural resource surveys be conducted for the proposed construction areas. These surveys should assess the presence of protected species and habitats, jurisdictional waters regulated by the U.S. Army Corps of Engineers (USACE), and any cultural resources that could be impacted by project activities. The findings from these surveys will help ensure comprehensive permitting and reduce the risk of unforeseen regulatory challenges.



Conclusion and Recommendations

13 Conclusions and Recommendation: Go – No Go Decision

The primary objective of Phase I was to assess whether transitioning to LNG for power generation in Guam is technically feasible, economically viable, and in the ratepayers' interest. This assessment includes LNG demand forecasting, LNG sourcing and shipping analysis, terminal configuration and costing, economic cost-benefit analysis (ECBA), ratepayer impact assessment, business model evaluation, financial viability analysis of the gas supply company, stakeholder consultations, and permitting review.

→ **The primary conclusions of Phase I culminate in a recommendation to proceed with LNG infrastructure development.**

The conclusions of Tasks 1 – 7 are summarized in Section 13.1 below. Section 13.2 presents the recommendations and next steps.

13.1 Conclusions

- 1 The LNG demand will decline over time with increases in renewable penetration. However, it remains relatively high (above 80,000 tpa) for approximately 9 years, even for the most aggressive GPA Target renewable penetration scenario, and for approximately 13 years for the Guam Law scenario.
- 2 The most practical and least-cost LNG supply solution appears to be using a 10,000 m³ small-scale LNG carrier to deliver LNG from West Papua (Tangguh LNG)n.
- 3 The least-cost terminal options include LNG delivery by a small-scale LNG carrier and onshore LNG storage and regasification.
- 4 Both the Tanguisson and Hotel Wharf sites are technically feasible for locating the LNG terminal.
- 5 The Hotel Wharf site is a better choice from a technical and cost perspective; however, this site faces strong opposition from the U.S. Navy.
- 6 The Tanguisson site has slightly higher cost and operational risk than Apra Harbor, but the cost difference is within the margin of error of the cost estimates, and the operational risk was deemed to be manageable.
- 7 The LNG infrastructure project is cost-benefit justified for all the renewable penetration scenarios.
- 8 Switching from ULSD to LNG reduces the Fuel Recovery Charge for all the renewable penetration scenarios. These savings increase with an increase in Brent prices.
- 9 LNG resale by GPA is not permitted under Guam laws and regulations.
- 10 The preferred business model involves a single private entity responsible for LNG supply, terminal delivery, and resale (if any).
- 11 Federal permitting is a complicated process that may significantly impact the project development and implementation schedule.
- 12 Project implementation schedule showing LNG infrastructure completion by 2031 is achievable, but aggressive.

- 1 It is in the best interest of the Guam ratepayers to switch to natural gas for power generation as soon as possible.

13.2 Recommendations

Based on the results of Phase I, transitioning GPA's generation from ULSD to LNG is technically viable, economically justified, and in the ratepayers' interest. These findings support a **"Go"** recommendation to Phase II.

Despite having a slightly higher cost and operational risk, the Tanguisson site and configuration are recommended as the preferred option because they have the Navy's support. Based on the feedback received from the Navy, an LNG import terminal anywhere in Apra Harbor would create a security risk that the Navy cannot accept.

To ensure GUPP can transition to LNG as soon as possible and minimize the penalties in the form of higher fixed O&M charges under the Energy Conversion Agreement (ECA) between GPA and GUPP, Phase II should start with two parallel activities: developing the Request for Proposal (RFP) and performing that site studies required for the Tanguisson site and configuration.



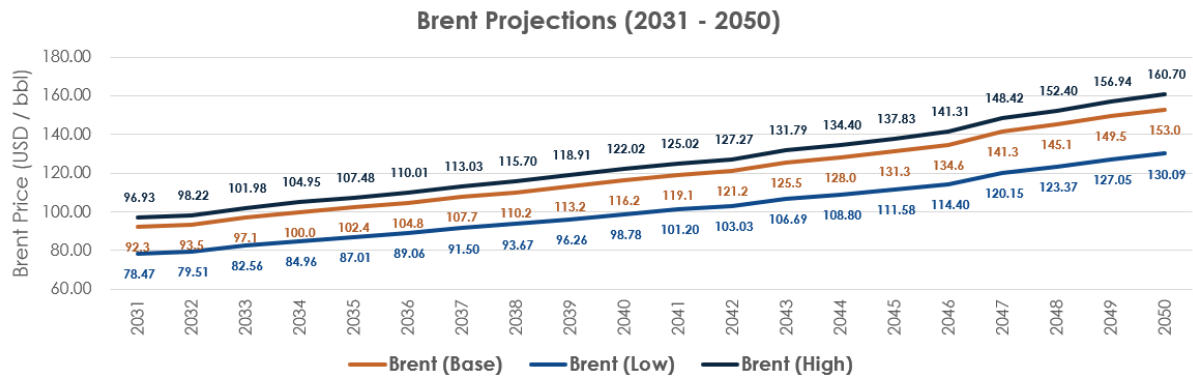
Appendices

Appendix A: Brent Curve & Levelized Cost Calculation

The levelized price of Brent crude oil provides a single reference point that allows for consistent comparison across different scenarios. The Brent price curve, shown in Figure A.1, is based on the latest U.S. Energy Information Administration's (EIA) long-term forecast for 2031 to 2050, published in April 2025.³³ Prices were provided in real terms based on \$USD 2024. A 2% inflation factor was applied to determine nominal prices.

To calculate the levelized Brent price, the net present value (NPV) of all future annual Brent prices was first determined using a 5% discount rate, which reflects the Government of Guam's assumed cost of capital to ensure consistency across the analysis. The NPV was then annualized using the same discount rate. Under the base case, the levelized Brent price is \$119.35 per barrel. In the low Brent scenario, which assumes prices 15% below the base case, the levelized Brent price is \$101.45 per barrel. In the high Brent scenario, with prices 5% above the base case, the levelized Brent price is \$125.32 per barrel.

Figure A.1: Brent Curve (2031 – 2050)



The Brent price is important because the prices of both ultra-low sulfur diesel (ULSD) and LNG, which drive the Project's fuel costs, are indexed to Brent crude oil prices throughout the project lifetime (2031–2050).

³³ U.S. Energy Information Administration (EIA). (2025). *Annual Energy Outlook 2025 – Data Browser*. Retrieved from <https://www.eia.gov/outlooks/aeo/data/browser/#/?id=1-AEO2025®ion=0-0&cases=ref2025~hm2025~lm2025~highprice~lowprice~highogs~lowogs~highZTC~lowZTC~nocaa111~alttrnp~aeo2023ref&start=2023&end=2050&f=A&sourcekey=0>

Appendix B: Battery Duration Analysis

The size of the battery impacts the amount of excess renewable energy that can be stored and subsequently sent to the grid to meet the peak load. As the IRP only provides renewable energy production in MWh and does not specify energy storage system sizing, K&M performed a preliminary estimate of the battery duration that minimizes curtailment at a reasonable cost.

The LNG demand model was run for 4-hour, 8-hour, 10-hour, and 12-hour batteries, as well as a battery duration that would ensure zero curtailment of renewable energy generation. The results of the analysis are presented in Figure B.1. The tables show the natural gas demand, and the percentage of renewable energy curtailed for each battery duration.

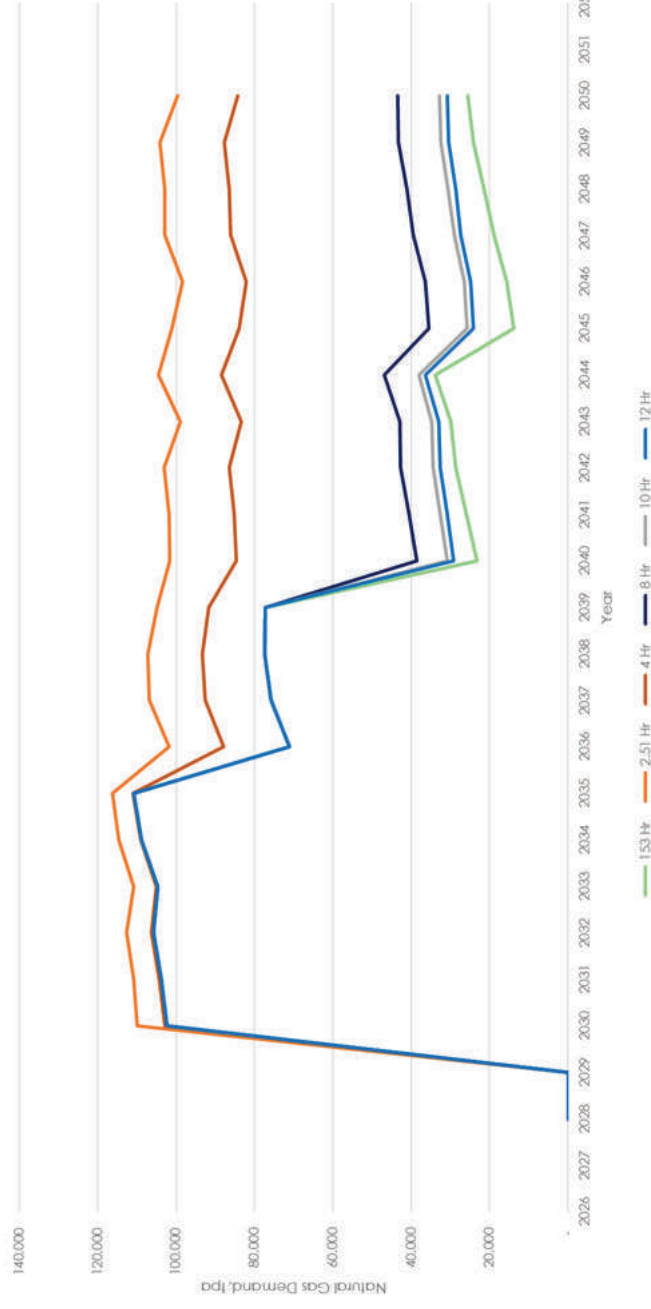
The 2.51-hour and 4-hour batteries are not large enough to store the excess solar generation as the amount of curtailed energy is 30-40% in the later years of the model. The natural gas demand for those battery sizes stays relatively constant at a higher demand due to the batteries not being large enough to store excess renewable energy and subsequently dispatched to the grid.

The 8-hour battery reduces the curtailment, and the 10-hour and 12-hour battery reduces it even further. The 10-hour battery was chosen as the base case battery size as there is minimal difference in the curtailment percentage (about 3-4%) between the 10-hour and 12-hour system, with the 10-hour battery estimated to be at a reduced cost to the 12-hour battery.

K&M also estimated the energy storage size required to meet zero curtailment of the renewable energy generated by Solar PV. This analysis found that a 153-hour battery will be required. There is a minimal difference in LNG demand for the first 10 years between the 10-hour battery and 153-hour battery, while a maximum reduction in curtailment is only 5% in the later years. The 153-hour battery is more than 15 times larger than the 10-hour battery but only covers a 5% marginal difference in curtailment. There will be a huge difference in cost to an order of magnitude of 15 times between those two systems, which makes the zero-curtailment battery option unviable.

The analysis for the base case assumes the total installed capacity of solar PV (~1400 MW) and batteries (~400 MW with 10-hour storage), which generally meets the plan outlined in the adjusted 2022 IRP, with a battery roundtrip efficiency of 85%. With this sizing, the system's maximum share of renewable generation in 2045 is 86% of the total demand, not 100% targeted by GPA and Guam Public Law.

Figure B.1: LNG Demand – Battery Duration Sensitivities



Annual Gas Demand (tpa)		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Storage Size - 2.51 Hr	-	-	-	109,932	110,865	112,564	110,876	114,639	116,342	101,830	106,957	107,301	104,960	101,699	101,891	103,157	98,915	104,530	101,036	98,439	102,955	102,939	104,170	99,615
Storage Size - 4 Hr	-	-	-	102,974	104,301	106,257	105,144	109,076	111,086	87,908	92,619	93,301	91,735	84,629	85,165	86,531	83,353	88,365	83,932	82,152	86,127	86,386	87,753	84,365
Storage Size - 8 Hr	-	-	-	102,302	103,744	105,805	104,781	108,784	110,869	71,138	75,829	77,442	77,173	38,587	40,578	42,766	42,942	46,886	35,458	36,454	39,568	41,167	43,381	43,505
Storage Size - 10 Hr	-	-	-	102,302	103,744	105,805	104,781	108,784	110,869	71,138	75,829	77,442	77,173	30,890	32,568	34,444	34,746	38,098	25,834	26,548	29,097	30,617	32,428	32,804
Storage Size - 12 Hr	-	-	-	102,302	103,744	105,805	104,781	108,784	110,869	71,138	75,829	77,442	77,173	29,270	30,870	32,724	33,075	36,464	24,234	24,935	27,333	28,752	30,443	30,841
Storage Size - 153 Hr	-	-	-	102,302	103,744	105,805	104,781	108,784	110,869	71,138	75,829	77,442	77,173	23,303	25,899	28,628	29,914	33,840	13,817	15,665	18,900	21,366	24,078	25,660
% Renewable Energy Curtailed																								
Year	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	
Storage Size - 2.51 Hr	-	-	7%	7%	7%	6%	6%	6%	22%	22%	22%	21%	21%	36%	36%	36%	35%	38%	38%	38%	37%	37%	37%	
Storage Size - 4 Hr	-	-	1%	-	-	-	-	-	11%	11%	11%	10%	10%	27%	27%	26%	26%	30%	29%	29%	29%	28%	28%	
Storage Size - 8 Hr	-	-	-	-	-	-	-	-	-	-	-	-	-	6%	6%	6%	6%	9%	8%	8%	8%	8%	7%	
Storage Size - 10 Hr	-	-	-	-	-	-	-	-	-	-	-	-	-	3%	3%	2%	2%	5%	5%	4%	4%	3%	3%	
Storage Size - 12 Hr	-	-	-	-	-	-	-	-	-	-	-	-	-	3%	2%	2%	1%	4%	4%	3%	3%	3%	2%	
Storage Size - 153 Hr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	

Appendix C: Feedback from Potential LNG Suppliers and Service Providers

Company		Strategic Fit	Guam Terminal	Pricing	Procurement
1	Arabian Holdings Role: LNG Broker / Supplier	Arabian Holding provides sourcing and procurement, logistics management, and deal structuring services.	No interest in Guam terminal development.	OK with pricing being indexed to Brent. Their view was that no supplier will give an indicative price until GPA is ready to sign an LNG SPA or MSA.	Quantities required by GPA are significantly smaller than Arabian Holding's typical clients. They are not familiar with small-scale LNG supply. Mentioned that there are very few export facilities that load small-scale carriers.
2	BP Role: IOC major, and portfolio LNG supplier. Participates in many LNG export and import projects globally.	BP delivers LNG on large-scale, conventional LNG carriers to buyers in to North Asia.	Having larger storage capacity at the Guam LNG terminal would increase supplier flexibility in the timing of any partial deliveries.	BP advised oil indexed pricing current market is ~12.5% (and Poten's view is ~12.7%). BP wouldn't add any price premium for small quantities that However, rigid buyer delivery requirements for partial cargo deliveries on large-scale LNG carrier would likely attract a premium (~\$1 + MMBtu?) due to logistical challenges and "deoptimization" of BP portfolio.	Guam's relatively low LNG quantities would be still material for BP, although they have little interest in small-scale LNG shipping. Conventional LNG export and import terminals are reluctant to accommodate small-scale vessels, and small volumes are insufficient to justify new builds. BP sees some potential in partial cargo deliveries, with no technical issues. However, buyer would need to be flexibility in terms of delivery timing and actual delivered quantities. This would be crucial to optimize supplier's logistics and reduce operational constraints. BP indicated it would be commercially challenging to have a long-term SPA, with firm ACQ, etc., for the partial delivery option.

	Company	Strategic Fit	Guam Terminal	Pricing	Procurement
	Tangguh LNG (BP) Tangguh LNG produces and exports LNG, and is located in West Papua, Indonesia	Through a JV, BP is the operator of the Tangguh LNG export terminal in West Papua, Indonesia		BP team had limited visibility on an LNG FOB price from Tangguh, but suggested it would be in line with the current market. BP suggested contacting Tangguh LNG directly regarding potential LNG purchase and provided contact details.	BP confirmed that the Tangguh export terminal is capable of loading small-scale LNG carriers.
3	First Gen Role: Regional LNG Import Terminal (Batangas, Philippines) with FSRU	First Gen owns/operate a number of gas-fired power plants in the Philippines. First Gen owns/operates LNG import terminal at Batangas, Philippines. It's based on an FSRU chartered from BW LNG. First Gen is utilizing a FSRU to regasify LNG and supply power plants in Philippines. Currently they have excess of LNG regasification capacity, but there is uncertainty about volumes in the future given declining gas fields in the Philippines. First Gen expressed interest in reloading small-scale LNG vessels for delivery to islands in the Philippines, which could have parallels to Guam's needs.	First Gen has interest in Guam LNG import terminal development.	First Gen purchases LNG on a spot basis, not a term basis. This would make it difficult to work with First Gen unless GPA is also willing to purchase on a spot basis with a JKM indexed LNG price. First Gen view that current oil indexed LNG pricing was ~12%*Brent (Qatar to China). First Gen encourages creative financing or government-to-government cooperation for small-scale solutions with strategic importance. First Gen's commercial model is flexible, with potential for FOB or DES basis, but clarity on exact commercial terms is needed to advance discussions.	First Gen confirmed that their Batangas FSRU can reload small-scale LNG carriers. Batangas FSRU has spare capacity now, but future availability is uncertain due to growing domestic demand. From a technical point of view, First Gen could load the small-scale vessel at its terminal and deliver it to Guam. It would be the matter of signing relevant contracts and reserving capacity. First Gen identified challenges related to unpredictable offtake levels in Guam and logistical complexities.

Company		Strategic Fit	Guam Terminal	Pricing	Procurement
4	Shell Role: IOC major, and portfolio LNG supplier. Participates in many LNG export and import projects globally.	Shell has a significant LNG position in the Asia Pacific and sells LNG to numerous buyers in North Asia and SE Asia. Shell utilizes the Singapore LNG import terminal to supply gas to the domestic Singapore market. Shell has small-scale LNG carrier reloading capabilities at Singapore LNG. It currently reloads LNG to bunker vessels.	Shell would have little interest in the Guam LNG import terminal development.	Reloading fees at Singapore LNG are not publicly disclosed but are relatively high (~\$1.00 per MMBtu.)	Shell typically works with large-scale buyers in Asia-Pacific While partial deliveries via diversions from large-scale LNG carriers is technically possible, costs would likely be high and it would pose many contractual difficulties. Diversions would lock in specific voyages and would be hard to optimize within the Shell portfolio. Ad-hoc opportunistic deliveries would be likely the only workable solution, but this wouldn't work for GPA. Shell's view was that partial deliveries on large-scale LNG carriers could not provide the security of supply that GPA would require.
5	JERA Role: JERA is a JV between Chubu Electric and TEPCO. They're a significant LNG importer in Japan	JERA has LNG offtake from Tangguh LNG (both FOB and ex-ship), Papua LNG and a number of Australian export projects/ JERA also has LNG offtake from the US Gulf Coast.	JERA is only interested Guam terminal development <u>plus</u> LNG supply. LNG supply only is not material enough for them.	N/A	JERA has no operational experience with small-scale LNG carriers and does not any such carriers capable of delivering LNG to Guam. Difficult to divert partial cargoes from the US to Tokyo. Given the "tram line" nature of their LNG supply chain, they do not think partial deliveries on large-scale LNG carriers would be a workable solution. Only interested if there is a terminal component.

Company		Strategic Fit	Guam Terminal		Pricing	Procurement
6	Karpowership 9 / 25 / 2024 Role: Fuel and tanker fleet manager based in Turkey and operations in New Caledonia (Australia). [Zackarie Fortin-Brazeau]	Karpowership operates powerplants in 20 countries and operates a fleet of 8 FSRUs and 4 LNG carriers to supply its floating power stations. Their latest FSRU (127,385 m³) will be operational within the next six months. (indicative charter rate = \$70k + \$24k; max regas rate = 84 mmscfd; send-out pressure = 10 bar; draught at summer freeboard: 10.45m; LAO: 272m)	Karpowership would have interest in owning/operating a FRSU at the Guam LNG import terminal.	LNG pricing would be based on spot market, and estimated to be around JKM + \$1.00-1.50 /MMBtu or equivalent oil price index 19% * Brent + \$1.00/MMBtu		

Company		Strategic Fit	Guam Terminal	Pricing	Procurement
7	Pertamina (PPT) Role: Indonesian national oil and gas company, with LNG export terminal in Indonesia OpelNG export terminal (PT Badak LNG, Bontang Indonesia)	PPT owns/operates the LNG export terminal at Bontang, Kalimantan (PT Badak LNG), and LNG storage terminal at Arun, Sumatra. PPT also has LNG offtake from the US Gulf Coast. PPT has an LNG trading company based in Singapore.	PPT could potentially offer a put option structure with a pre-agreed upon price (using oil index if necessary).		PPT confirmed that Badak LNG export terminal (Botang) can reload small-scale LNG carriers. PTT indicated that there may be volume available from Singapore LNG in the future, which also accommodates small-scale reloading. Partial deliveries on large-scale LNG carrier would require specific market conditions and logistics, making it commercially challenging and unlikely to be achievable for structural long-term supply. It might be workable if PPT had "put" option on GPA with ad hoc LNG deliveries, flexible quantities delivery dates and JKM pricing. Guam LNG storage capacity would determine limits for ad hoc deliveries

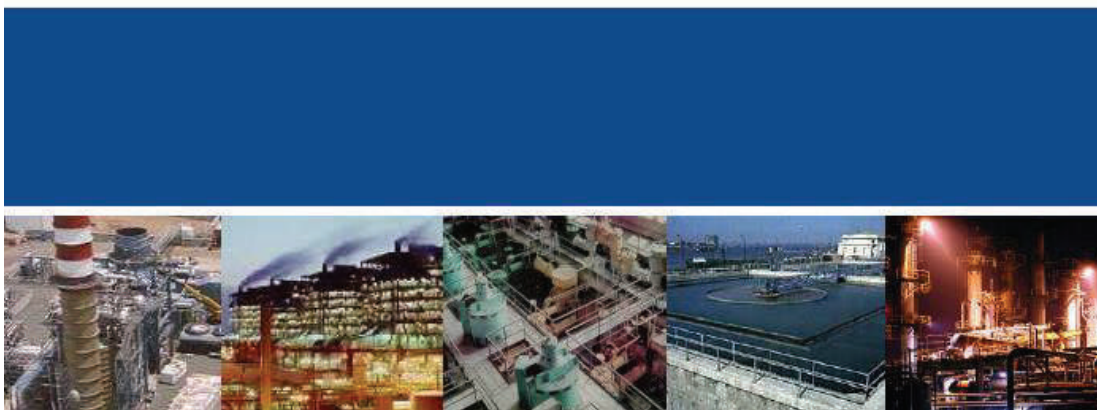
Company		Strategic Fit	Guam Terminal		Pricing	Procurement
8	AG&P LNG Role: LNG import terminal owner/operator, & LNG seller	Successfully developed PHP LNG import terminal in The Philippines. Has stake in Cai Mep LNG import terminal in Vietnam. Developing a FSRU LNG import project in Adelaide. Gas Entrec (AG&P affiliate) provided FRSU barge for Benoa, Indonesia (20,000 m³, 50 mmsfd, 24 months build time)	Strong interest in supplying LNG to Guam. Likely supplied from PHP LNG, but could be other source. Strong interest in developing Guam LNG import terminal. Likely supplied from PHP LNG, but could be other source.	Advised reload fee from Singapore LNG is high (~\$1/MMBtu). Expect reload fee from PHP LNG would be ~\$0.50/MMBtu	Confirmed that PHP LNG and Cai Mep LNG terminal can reload small-scale LNG carriers. Suggested LNG supply in ISO containers as an option, containers being loaded from an FSU close by.	
9	Tokyo Gas Role: Significant Japanese LNG buyer. Own/operate Sodegaura LNG import terminal (Tokyo Bay) which can load small-scale LNG carriers.	Declined call to discuss LNG supply, sourcing and shipping options. Willing to discuss in the future in conjunction with LNG terminal development.	Strong interest in supplying LNG to Guam, and also owning/operating the Guam LNG import terminal. Strategic interest in providing an integrated solution, not just LNG supply.		Confirmed that the Sodegaura LNG import terminal (Tokyo Bay) can load small-scale LNG carriers.	

Appendix D: Market Summary Issued to Potential LNG Suppliers



Guam Power Authority (GPA) LNG-to-Power Development Study Investigation into LNG Sourcing & Supply Options

August 2024





Project Information

Background

Guam Power Authority ("GPA") is a public corporation overseen by the Consolidated Commission on Utilities ("CCU") and regulated by the Guam Public Utilities Commission ("PUC").

To replace its retiring thermal power plants, GPA has executed an energy conversion (tolling) agreement with Guam Ukudu Power ("GUP"), a project company formed by the project sponsor, Korea Electric Power Corporation ("KEPCO") to construct, own and operate a 198 MW capacity combined cycle power plant. The GUP plant will be able to run on ultra-low sulfur diesel ("ULSD") or re-gasified Liquefied Natural Gas ("LNG") and is scheduled for commissioning by Q3 2025.

LNG-to-Power Development Study

K&M Advisors LLC ("K&M") has been engaged by GPA to undertake an LNG-to-Power Development Study to investigate the feasibility of transitioning from ULSD to LNG at the GUP plant by 2030. By converting to natural gas, GPA could lower emissions and reduce the cost of power generation. Based on initial analysis, it's envisaged that annual LNG demand could be up to 165,000 tons.

Evaluation of potential LNG Sourcing and Shipping Options

As part of the LNG-to-Power Development Study, K&M is investigating and evaluating potential LNG sourcing and shipping options and wishes to "sound" the market regarding such potential options and obtain LNG price indications from potential LNG suppliers. Having LNG price indications will be key in understanding the overall economic feasibility of importing LNG to Guam. It's important to note that at this stage GPA is not commencing an LNG procurement process or short-listing potential LNG suppliers; and that information provided by potential LNG suppliers at this stage will be solely used for the purpose of the LNG-to-Power Development Study and will not prejudice a potential LNG suppliers' involvement in any LNG procurement process at a later stage. If requested, information provided by a potential LNG supplier can be "anonymized" with the potential LNG suppliers identity being excluded in any reports, etc.

LNG Import Terminal Considerations

It's envisaged that the LNG import terminal will be developed, constructed, owned and operated by a third party, and that GPA will have a Terminal Use Agreement with such party.

Given the relatively low envisaged annual LNG quantities, it has been determined that an import terminal with large-scale LNG storage capacity, e.g. 200,000 m³, will not be economically viable. Therefore, for the purpose of the study, only an import terminal with small-scale LNG storage is being considered.

Two LNG import terminal configurations are currently being considered for the purpose of the study:

1. a small-scale LNG import terminal with berthing/mooring and LNG transfer facilities capable of berthing and receiving small-scale LNG carriers (~10,000 m³ capacity), together with LNG storage capacity being able to receive a full cargo lot, with some additional buffer storage (~15,000 m³ total storage capacity) ("Small-Scale Solution"); and
2. a small-scale LNG import terminal with berthing/mooring and LNG transfer facilities capable of berthing and receiving large-scale LNG carriers (~174,000 m³ capacity), together with LNG storage capacity being able to receive a partial cargo delivery (15,000 to 30,000 m³), with some additional buffer storage (~20,000 to 35,000 m³ total storage capacity) ("Partial Delivery Solution").

GPA and K&M wish to receive feedback from potential LNG regarding these two potential terminal configurations, and welcome suggestions regarding other potential configurations.

For the purposes of the study, it is assumed that the LNG import terminal will be located within the Apra harbor, a naturally deep-water location. See Figure 1 below.

Figure 1: Location of Apra Port & Ukudu Power Plant



LNG Sourcing & Shipping Considerations

For a Small-Scale Solution, it's envisaged that LNG would be sourced from either a regional LNG export facility with the capability to load to small-scale LNG carriers, or a regional LNG import facility (land-based or FSRU) with the capability to load/reload into small-scale LNG carriers. For the purpose of the study, potential LNG suppliers could provide either an indicative FOB price or an ex-ship LNG price.

For a Partial Delivery Solution, it's envisaged that LNG would be sourced from a regional LNG export facility. For the purpose of the study, potential LNG suppliers should provide an indicative ex-ship LNG price. Potential LNG suppliers should note that:

1. The diversion distance to Guam for voyages from regional LNG export facilities to North Asia (Japan, Korea, China, Taiwan) is relatively short, particularly those voyages originating from the Gladstone LNG export projects which sail through the Solman Sea and Bismark Sea (between Papua New Guinea and the Solomon Islands); and
2. Partial cargo deliveries of 15,000 to 30,000 m³ would result in a large-scale membrane LNG carriers still being within their "sloshing" limits.

Indicative Key Terms of LNG supply arrangement

GPA and K&M wish to receive feedback from potential LNG suppliers regarding indicative LNG pricing.

Indicative key terms of the LNG supply arrangement are summarized in Table 1 below.

Table 1: Indicative Key Terms of LNG Supply

LNG Buyer	GPA
Delivery Terms	Ex-ship for the Small-Scale Solution and Partial Delivery Solution
Start Date	Expected to ~Q4 2030
Term	Expected to be ~20 years
Annual Contract Quantity ("ACQ")	ACQ is expected to be ~8.6 TBtu (~165,000 Tons), with some flexibility in setting the ACQ annually.
Cargo Lot Size	Full cargo delivery (10,000 m ³) for the Small-Scale Solution; or a partial delivery (15,000 m ³ and/or 30,000 m ³) for the Partial-Delivery Solution
Indicative Price	$IP = A \cdot \text{Brent} + B$, where: • IP = Indicative Price, in USD/MMBtu (HHV basis) • A = a constant fixed over the Term, represented as a % • Brent = the final settlement price at expiration of the ICE Brent Crude futures contract for the month in which the cargo is delivered • B = a constant fixed over the Term, in USD/MMBtu

Appendix E: Vessel Particulars for Small-Scale LNG Carriers

Table E.1: Vessel Particulars for Small-Scale LNG Carriers

LNG Carrier Size	7,500 m ³	10,000 m ³	15,600 m ³
Vessel Name	Avenir Ascension	Coral Favia	Coral Energy
Owner	Avenir LNG	Anthony Veder	Anthony Veder
Year Built	2021	2010	2013
Gross Capacity (m ³)	7,500	10,000	15,600
Containment System	Type-C	Type-C	Type-C
LOA, m	116	137	155
LPP, m	111	129	146.7
Beam, m	19.0	19.8	22.7
Design Draft (Laden), m	6.0	6.2	7.4
Parallel Midbody (ballast), m			62.7
Gross Tonnage	8,293	10,105	13,501
Net Tonnage	2,488	3,032	4,051
Deadweight (tonnes)	~4,500	~10,446	~8,710
Unloading Rate (m ³ / hour)	1,000	1,200	1,620
Max. Cargo Tank Pressure (BarG)	4.5	5.0	4.2

Figure E.1: Avenir Ascension



Figure E.2: Coral Favia



Figure E.3: Coral Energy



Table E.2: Vessel Particulars for Floating Storage Units

FSU Carrier Size	15,000 m ³	147,000 m ³
Vessel Name	Coral Energy	Alto Acruz
Type	Moulded Hull with Full Propulsion	Moss Type with Full Propulsion
Year Built	2013	2008
Gross Capacity, m ³	15,600	147,000
LOA, m	155	288
Beam, m	22.7	49
Design Draft (Laden), m	7.4	12.3
Gross Tonnage	13,501	122,361
Summer DWT	-	80,229
Loading Rate (m ³ / hour)	1,620	10,000
Delivery Cargo Size, m ³	10,000	140,000

Figure E.4: Coral Energy



Figure E.5: Alto Acruz



Appendix F: Feasibility of Using Cold Natural Gas for Gas Turbine Inlet Air Cooling

At GPA's request, K&M evaluated the feasibility of using the cold stream of natural gas to cool the Ukudu plant's gas turbine inlet air.

Gas turbine inlet air cooling is a cost-effective way of producing additional power output at high ambient temperatures. It may also increase gas turbines and combined cycle plant efficiency. In case of using the stream of cold natural gas used as power plant fuel, the inlet air cooling could be achieved by either installing a gas-to-air heat exchanger in the gas turbine inlet or by providing a circuit with intermediate media, such as water with a pump and two heat exchangers. One gas-to-water heat exchanger could be installed in the natural gas stream, and the second in the gas turbine inlet, so that water is cooled by natural gas in the first heat exchanger and then cools the gas turbine inlet air in the second heat exchanger (see Figure F.1 and Figure F.2).

Figure F.1: Inlet Air Cooling Arrangement Option 1

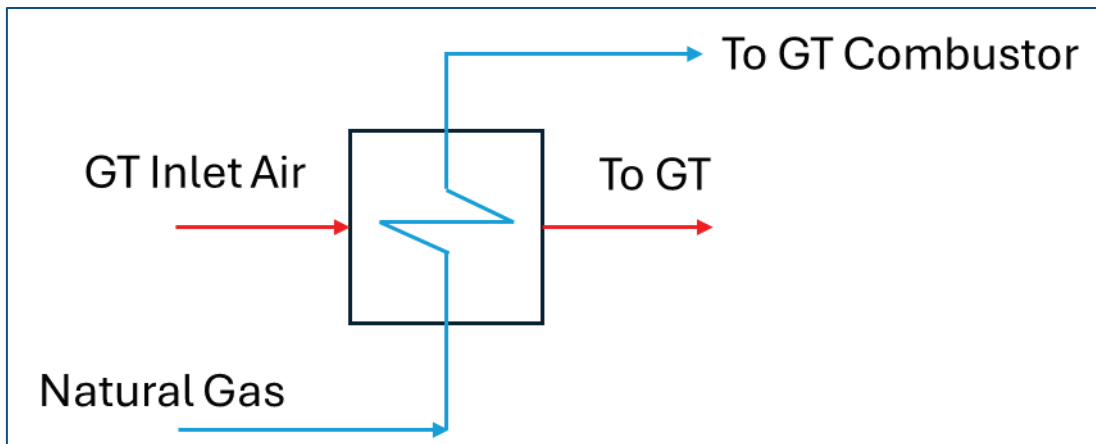
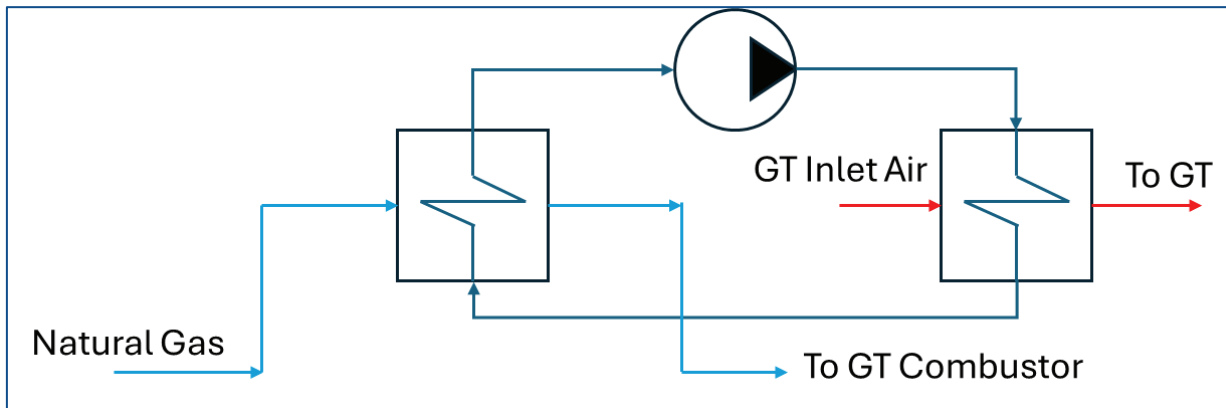


Figure F.2: Inlet Air Cooling Arrangement Option 2



To evaluate the technical feasibility of using cold natural gas supplied as fuel for the plant for inlet air cooling, K&M estimated the potential theoretical maximum inlet air temperature decrease, considering the natural gas and inlet air mass flow rates and specific heats.

Based on the heat and material balances for the Ukudu plant, K&M estimated the gas flow rate at approximately 27 metric tonnes per hour and the gas turbine inlet air flow rate at approximately 1,300 tonnes per hour, which means that the inlet air flow rate is approximately 48 times higher than the gas flow rate. Assuming a cold gas temperature of 5°C and an ambient air temperature of 30°C, the theoretical maximum gas turbine inlet air temperature decrease is approximately 1°C. The temperature decreases further because of heat transfer efficiency and pipeline heat losses.

Typically, gas turbine plant output increases by approximately 0.5% per 1°C of inlet air temperature decrease, so for the Ukudu plant using cold natural gas for GT inlet air cooling could, as the best case theoretical scenario, result in approximately 1 MW increase in plant output when the plant runs at full load and may not result in any output increase considering the efficiency of heat exchangers, heat losses, and plant's partial load operation.

Based on the above, K&M considers that using cold natural gas for gas turbine inlet air cooling for the Ukudu project is not viable.

Appendix G: Safety & Exclusion Zones

This section presents the full analysis of the safety and exclusion zones for the three potential sites.

G.1 Regulatory Background

The establishment of exclusion and safety zones for LNG import terminals in the United States is governed by federal safety standards enforced by the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) under 49 CFR Part 193, which incorporates the industry standard NFPA 59A-2001. These regulations outline the technical requirements for LNG facility siting, including the definition of safety and exclusion zones to protect surrounding populations and infrastructure. While PHMSA is responsible for enforcing these safety standards, the Federal Energy Regulatory Commission (FERC) retains jurisdiction over the siting and construction of onshore and near-shore LNG import facilities under Section 3 of the Natural Gas Act, conducting environmental assessments or impact statements in accordance with NEPA. A 2018 memorandum of understanding between FERC and PHMSA formalized the coordination process, designating PHMSA as the sole reviewer of safety zone compliance under Part 193's siting requirements, with PHMSA issuing a Letter of Determination to FERC confirming whether proposed facilities meet federal safety criteria. These regulatory processes ensure that exclusion and safety zones are thoroughly evaluated and established as part of LNG facility approvals.

G.2 Exclusion Zone Determination

As part of the permitting process for LNG import facilities, applicants must demonstrate compliance with federal siting requirements set forth in 49 CFR Part 193, NFPA 59A-2001, and additional guidance provided by the DOT PHMSA LNG FAQ webpage. Central to this process is the preparation of a Design Spill Package, which defines the exclusion zones and hazardous release footprints associated with the facility and demonstrates that these areas comply with safety standards, ensuring protection for surrounding communities and infrastructure. An exclusion zone is a legally controlled area around the facility, established to prevent harm from thermal radiation or vapor dispersion in the event of a design spill. These zones must remain under the operator's or government's control throughout the life of the facility, as mandated by 49 CFR 193.2057 (thermal radiation) and 49 CFR 193.2059 (vapor dispersion). The methodology for defining exclusion zones follows thermal radiation thresholds outlined in NFPA 59A-2001, which specify maximum allowable radiation levels at various distances, including critical limits of 1,600, 3,000, and 10,000 Btu/ft²-hr, depending on the surrounding use and occupancy.

For this study, CH2V conducted a preliminary evaluation of thermal radiation exclusion zones, specifically modeling the LNG tank top fire scenario, which is expected to govern the facility's thermal exclusion zone per NFPA 59A-2001. Given the significant thermal footprint of such scenarios, mitigation options to reduce exclusion zone size are limited, particularly for field-erected LNG storage tanks. Practical strategies include securing legal control of affected land areas through purchase or lease agreements or, less feasibly, adjusting tank height or location. Other scenarios, such as jet fires or process impoundment pool fires, may also generate thermal radiation exclusion zones, but these can often be mitigated through design modifications, such as altering impoundment sizes or installing pipe shrouds. Vapor dispersion exclusion zones, governed by 49 CFR 193.2059, were not evaluated in detail as they are unlikely to dictate facility siting, though they can similarly be mitigated through engineering controls like vapor barriers or pipe-in-pipe systems.

G.3 Thermal Radiation Modeling Results

The following inputs, described in Table G.1, were used to calculate the thermal radiation exclusion zones for an LNG tank top fire.

Table G.1: Inputs for Thermal Radiation Modeling

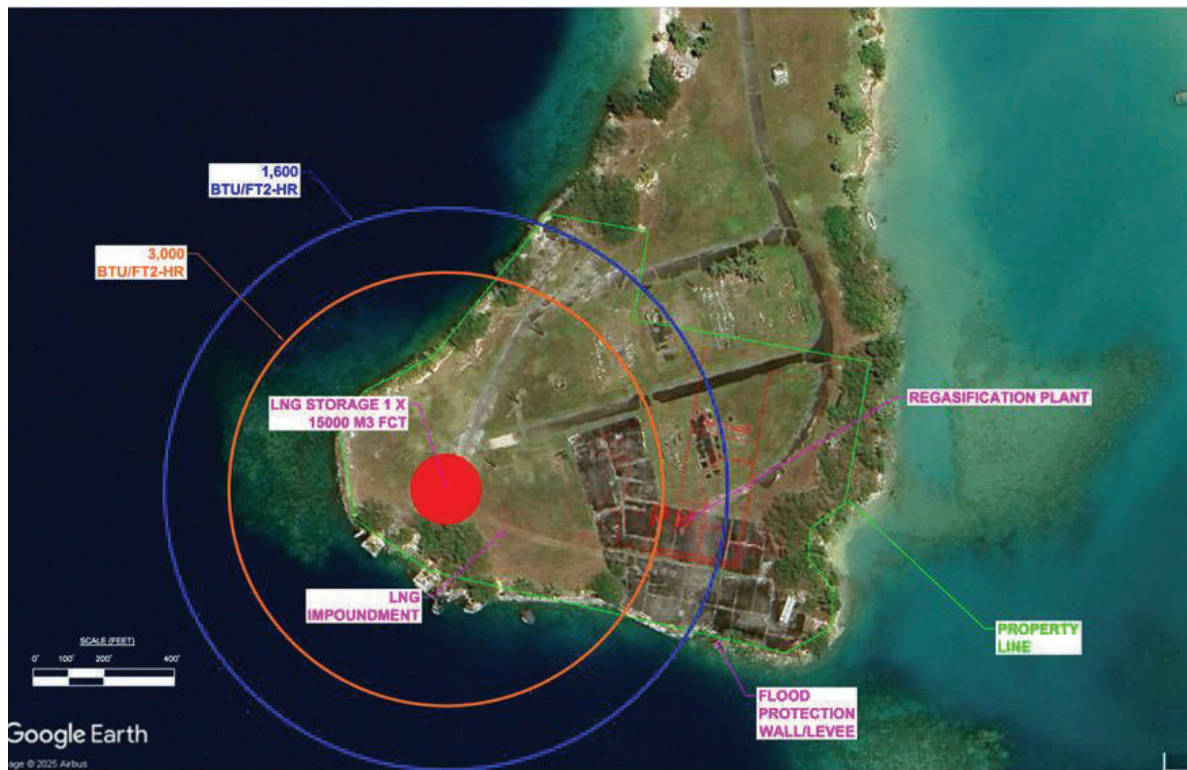
Tank Volume (m ³)	15,000 m ³
Tank Diameter (ft)	98.5 ft
Tank Height (ft)	98 ft
Target Height (ft)	0 ft
Temperature (F)	77 F
Relative Humidity (%)	63.1 %
10,000 Btu / ft ² - hr	Not Reached
3,000 Btu / ft ² - hr	307 ft
1,600 Btu / ft ² - hr	398 ft

Note that the 10,000 Btu/ft²-hr thermal isopleth is not reached at the target height (ground level). Therefore, this value is not recorded as an exclusion zone. The following sections include commentary and illustrations on the thermal radiation exclusion zones for each of the evaluated sites.

G.3.1 Dry Dock Island

The modeled thermal radiation exclusion zones for the proposed LNG import facility at Dry Dock Island remain within the estimated facility boundaries; however, this area falls under the legal control of the US Navy. As such, development at this location would require a formal legal agreement between the Navy and the facility operator to grant the operator legal control over all activities within the exclusion zones for the duration of the plant's operation. Importantly, the exclusion zones do not extend onto adjacent properties, avoiding any direct impact on neighboring landowners. While the zones do extend over nearby waterways, these areas are classified by DOT PHMSA as property that cannot be built upon and, therefore, do not pose a conflict with exclusion zone requirements. Figure G.1 illustrates the thermal radiation exclusion zones for the site.

Figure G.1: Dry Dock Island Thermal Radiation Exclusion Zone (Tank Top Fire)



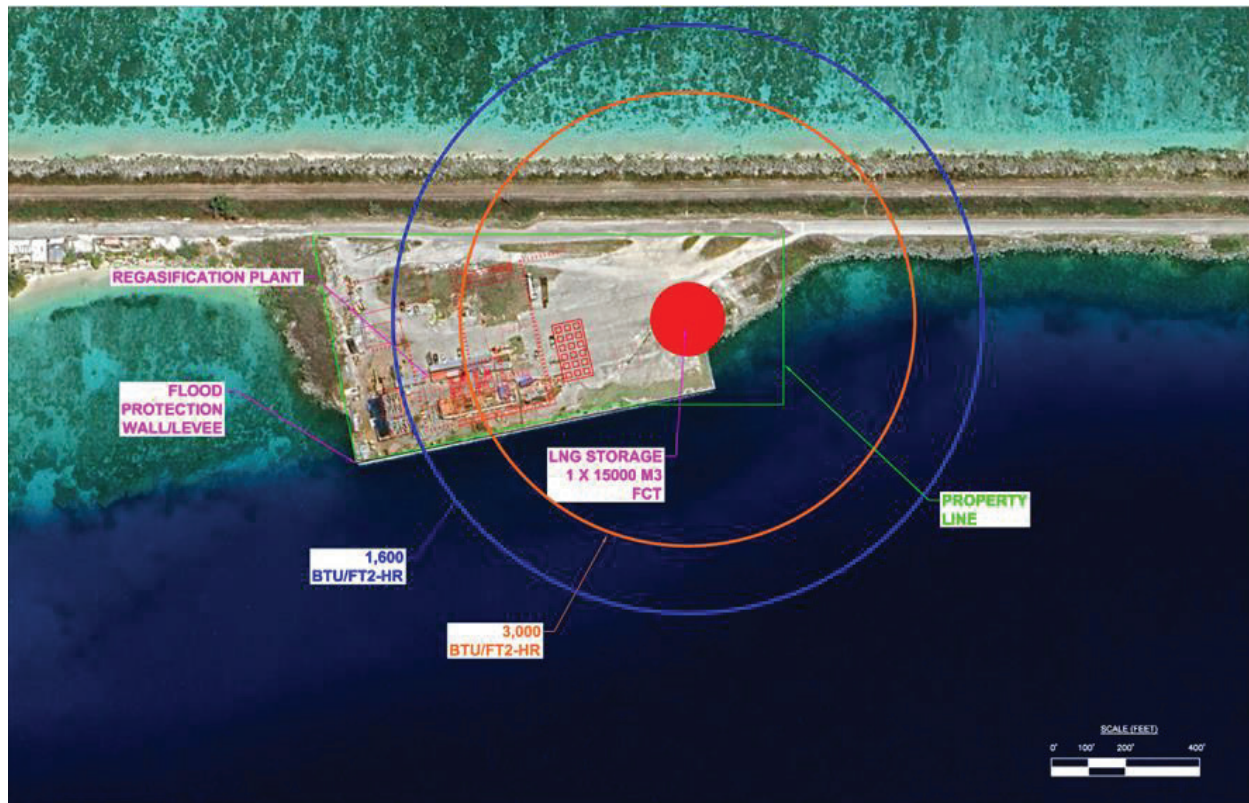
G.3.2 Hotel Wharf

For the Hotel Wharf site, the thermal radiation exclusion zones resulting from a potential tank top fire will dictate the placement of the LNG storage tank and associated process facilities at the proposed site. Specifically, the storage tank cannot be positioned on the west side of the property, as this would cause exclusion zones to extend onto adjacent land where the facility operator does not currently hold legal control. Mitigation options for this constraint include either acquiring the adjacent western property or securing a legal agreement with its owner to obtain control over activities within the exclusion zones. Toward the north, exclusion zones extend onto property controlled by the US Navy, specifically over a wave breaker. According to federal regulations under 49 CFR 193.2007, exclusion zones may extend onto government-controlled land provided the operator or agency maintains legal control of all activities within the zone. However, this would require a formal agreement with the US Navy to ensure compliance with NFPA 59A-2001 Section 2.2.3.2, which governs public access and activity restrictions in these zones. Given the nature of the wave breaker, where public gatherings or construction of occupied buildings are not anticipated, this does not present a fatal flaw for project siting.

Additionally, exclusion zones extend over a roadway located on the northern boundary of the site. Since exclusion zones must remain within areas controlled by either the operator or a government agency, placing zones over the roadway would necessitate demonstrating that the road meets NFPA 59A-2001 Section 2.2.3.2 criteria - namely, that it prohibits gatherings of 50 or more people. In similar cases, DOT PHMSA has required operators to provide legal documentation confirming such restrictions. Consequently, the facility operator will need to collaborate with the Guam Department of Public Works to establish and document this designation. Lastly, while the modeled

exclusion zones extend over adjacent waterways, these areas are classified by DOT PHMSA as property that cannot be built upon and therefore do not conflict with exclusion zone requirements. Figure G.2 illustrates the thermal radiation exclusion zones for the site.

Figure G.2: Hotel Wharf Thermal Radiation Exclusion Zone (Tank Top Fire)



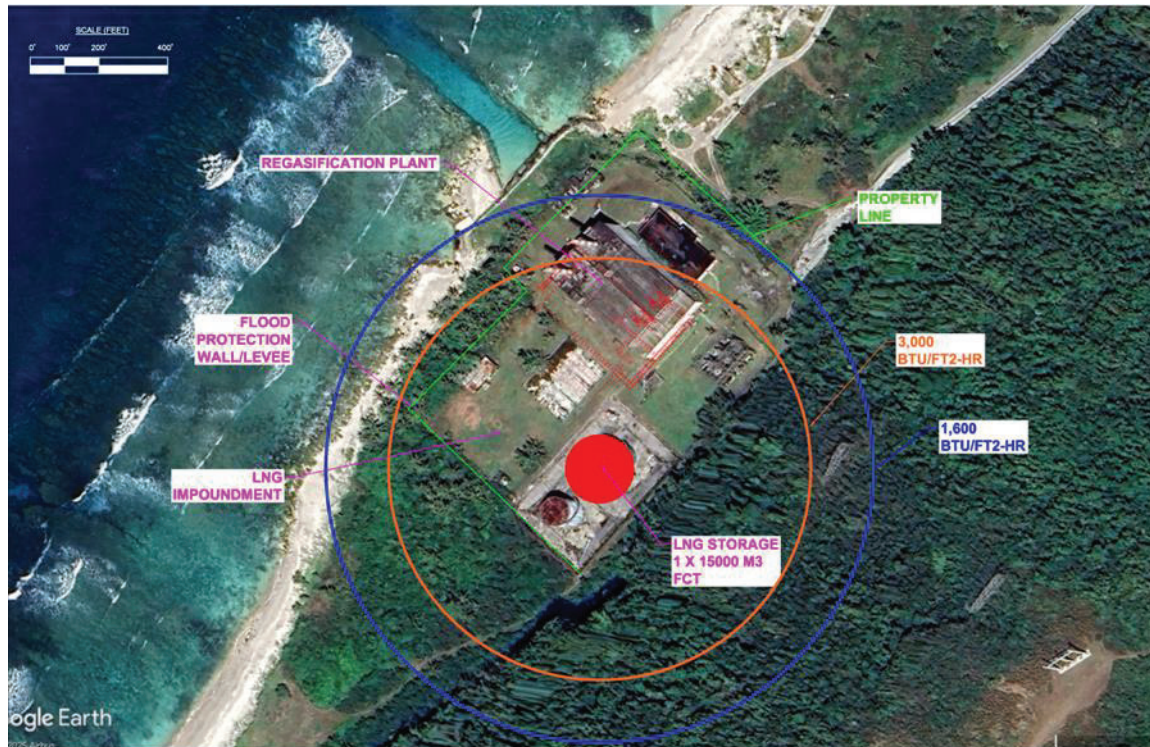
G.3.3 Tanguisson

At the Tanguisson site, thermal radiation exclusion zones from a potential LNG tank top fire will determine the placement of the LNG storage tank and associated process facilities. The storage tank cannot be sited on the east side of the property, as this would cause exclusion zones - particularly the 1,600 Btu/ft²-hr isopleth - to extend onto adjacent property to the northeast, where the facility operator does not currently have legal control. To avoid this, the tank has been positioned such that the exclusion zone remains within the project's boundaries, although the status of the adjacent northeastern property should be confirmed, as it is believed not to be under Navy control. Additionally, exclusion zones extend onto government-controlled properties to the east and south, where formal agreements would be required with the respective agencies to ensure compliance with NFPA 59A-2001 Section 2.2.3.2, which restricts public activities within these areas. Given that these zones overlap areas used for existing infrastructure supporting the former power plant, these encroachments are not considered a fatal flaw for siting the facility.

Further, the exclusion zones also extend onto private property to the east, which would necessitate securing legal control through either a lease agreement or land purchase for the life of the project. Lease agreements are typically structured to grant the facility operator control over all activities within the exclusion zone in exchange for compensation to the property owner. Lastly, as with other

sites, the exclusion zones extend over adjacent waterways, which are classified by DOT PHMSA as property that cannot be built upon and therefore do not conflict with exclusion zone regulations. Figure G.3 illustrates the thermal radiation exclusion zones for the site.

Figure G.3: Tanguisson Thermal Radiation Exclusion Zone (Tank Top Fire)



In general, siting the governing thermal radiation exclusion zones associated with an LNG tank fire at any of the proposed locations will require securing legal control of adjacent properties and/or establishing agreements with relevant government agencies to ensure compliance with the land use restrictions outlined in NFPA 59A-2001 for these areas. As discussed, additional exclusion zones - such as those for thermal radiation from jet fires, process impoundment fires, and vapor dispersion from spills or pressurized releases - will need to be modeled in future phases. However, these scenarios are not expected to drive siting decisions, as effective mitigation measures acceptable to DOT PHMSA are available to manage their impacts.

Appendix H: Metocean, Mooring, and Wave Height Analysis at Tanguisson

The objective of this analysis is to assess the suitability of the proposed LNG import terminal at the Tanguisson site by analyzing the environmental and operational constraints that may affect LNG carrier (LNGC) berthing, mooring, and unloading operations, as well as the resilience of associated onshore infrastructure. The assessment focuses on three core analyses - Metocean Assessment, Mooring Analysis, and Wave Modeling - each applying a structured methodology to provide the necessary environmental and operational context for the terminal's design and long-term viability. Together, these analyses evaluate the feasibility of LNGC operations under site-specific conditions and inform infrastructure requirements to ensure safe and reliable operations at the Tanguisson site.

H.1 Metocean Assessment

Metocean conditions refer to the combined meteorological and oceanographic factors that define the marine environment at a specific location. These conditions are critical inputs for the design, construction, and operation of marine infrastructure, including LNG import terminals, as they directly influence vessel safety, mooring system performance, and operational reliability.

Meteorological conditions encompass wind speed, direction, and variability, which affect vessel positioning and mooring loads; atmospheric pressure, which can alter sea levels and influence local weather patterns; and air temperature, which may impact marine operations and equipment performance.

Oceanographic conditions include waves - characterized by height, period, direction, and type (e.g., wind waves) - that exert dynamic forces on vessels and berthing structures; currents, defined by their speed, direction, and variability, which affect vessel drift and mooring tensions; and tides, which cause predictable fluctuations in sea levels due to gravitational forces. Additional oceanic factors such as sea temperature and salinity also play a role, influencing water density, buoyancy, and the overall marine environment. Together, these metocean conditions form the basis for assessing the feasibility of LNG carrier operations at the Tanguisson site, directly supporting the study's objective of ensuring safe and reliable berthing, mooring, and unloading under site-specific environmental conditions.

The metocean assessment involved the collection and statistical analysis of historical and hindcast data on wind, waves, currents, tides, atmospheric pressure, air temperature, sea temperature, and salinity. These parameters were used to define both operational and extreme environmental conditions at the site. The metocean data then served as the basis for the mooring analysis.

H.2 Mooring and Wave Height Analysis

The mooring and wave height analyses conducted for the Tanguisson LNG import terminal form critical components of the overall feasibility assessment, providing insight into the operational safety, stability, and resilience of the LNGC operations and associated infrastructure. The mooring analysis evaluates how the LNGC's mooring system performs under the environmental conditions identified in the metocean assessment, which includes wind, waves, currents, and tides. This

hydrodynamic mooring analysis delivers a comprehensive understanding of the vessel's response to these forces over time, ensuring safe berthing and unloading operations.

The mooring analysis was carried out using MIKE 21 Mooring Analysis and Ansys AQWA, specialized software tools for modeling vessel dynamics and mooring system performance. The model setup defined the specific mooring configuration, including the arrangement and mechanical properties of the mooring lines, and applied site-specific wave conditions derived from the metocean data. The simulation parameters incorporated the structural characteristics of the representative LNG vessel and the proposed terminal infrastructure.

The analysis proceeded in two stages: a hydrodynamic analysis, which modeled the interactions between waves and the LNGC, including calculations of Response Amplitude Operators (RAOs) to quantify vessel motions; and a mooring analysis, which included both static and dynamic simulations. The static analysis assessed the initial tension and configuration of mooring lines under steady-state conditions to ensure stability, while the dynamic analysis evaluated the mooring system's response to fluctuating environmental forces, capturing variations in mooring line tensions, fender loads, and vessel motions over time. Key vessel motions, such as horizontal and vertical displacements (surge, sway, heave) and rotational movements (pitch, roll, yaw), were quantified, as these are critical for maintaining vessel alignment during LNG transfer operations.

The analysis also included breaking tension checks to ensure mooring line integrity under extreme conditions. A key outcome of the mooring analysis was the estimation of operational flexibility, specifically determining the frequency and duration of downtime - periods when metocean conditions exceed operational limits, such as maximum vessel motions, minimum hose bending radii, or required clearances between the vessel and fixed infrastructure.

In parallel, the wave modeling analysis focused on estimating maximum anticipated wave heights at the Tanguisson site to inform the design of protective infrastructure (e.g., seawalls or barriers). Given the site's direct exposure to open ocean conditions and the absence of existing protective structures, understanding potential extreme wave events is essential for safeguarding terminal facilities.

The wave modeling incorporated historical wave records and storm event data, including typhoons (e.g., Typhoon Mawar) and tsunamis, to assess past maximum wave heights and long-term wave patterns. In addition, bathymetric data—detailing the seafloor topography and geotechnical conditions such as slopes and coral outcrops—was integrated, as these features significantly influence how waves transform as they approach the shore, potentially amplifying wave heights in shallow waters. The modeling used numerical simulations to predict wave conditions under various environmental scenarios, extending beyond historical observations to account for extreme events. This approach also included climate change considerations, recognizing that rising sea levels and intensifying storm patterns could alter future wave conditions. Furthermore, local coastal features, both natural and man-made, were evaluated for their effects on wave reflection, refraction, and dissipation, which can modify the wave energy reaching onshore infrastructure.

A risk assessment complemented the wave modeling, applying probability analysis to estimate the likelihood of extreme wave events and guide the design parameters for protective infrastructure. This integrated approach ensures that the Tanguisson LNG import terminal, including both offshore

mooring systems and onshore infrastructure, is designed to operate safely and reliably under both current and projected environmental conditions.

H.3 Accuracy

To assess the overall accuracy of the availability results at Tanguisson, it is essential to consider both the metocean analyses, which include significant wave height and peak wave period, and the definition of tolerable boundary conditions developed for the mooring analysis.

The metocean analysis and wave model performance primarily rely on extrapolated statistical data from the Ritidian Point offshore buoy, located approximately 20 kilometers north of the proposed project site at Tanguisson. The model's predictions for significant wave height align well with buoy observations, exhibiting minimal bias, meaning the model equally overestimates and underestimates peak wave periods. By applying a factor of 1.40 to the modeled wave heights, we can ensure that the corrected values will be equal to or greater than the actual wave heights 90% of the time. Using a factor of 1.2 achieves this 75% of the time. Although the model's predictions for peak wave periods show more variation compared to buoy observations, they are generally satisfactory, with minimal bias. Applying a factor of 1.30 to the modeled peak periods ensures that the corrected values will be equal to or greater than the actual peak wave periods 90% of the time, while a factor of 1.15 achieves this 80% of the time. Consequently, the metocean analysis and wave model performance can be conservatively estimated at an accuracy of 80%.

For the tolerable limits of vessel motion associated with the mooring analysis, standard design criteria for a representative LNGC, as prescribed by the World Association for Waterborne Transport Infrastructure (PIANC), were utilized to define maximum vessel rotations and excursions. Therefore, the mooring analysis accuracy can be estimated at 90%.

Combining the accuracy of the metocean and wave model accuracy of 80% with the tolerable vessel motion accuracy of 90%, the current assessment of LNGC terminal availability can be estimated at an accuracy of 70%.

To enhance the accuracy of these analyses and modeling efforts, site-specific data collection and continued engagement with vessel and equipment manufacturers will be necessary to further refine the boundary conditions associated with developing the long-term assessment of terminal availability.

H.4 Results Summary

The hydrodynamic mooring analysis estimates an annual availability of 86.1% for a 14-hour LNG transfer at Tanguisson. This evaluation is based on six years of data from 2018 to 2023, which represents a median range of historical metocean conditions, including significant weather events such as Typhoon Mawar. The assessment considered monthly variations in metocean conditions to develop an annual quantity of 14-hour windows for LNG transfers. Notably, availability tends to decrease from July through September, with July showing the lowest estimate at 68%.

The analysis also explored various sensitivities to optimize availability in response to variable metocean conditions throughout the year. For instance, rotating the vessel orientation counterclockwise by approximately 30 degrees could improve annual availability to around 90%. Future studies will need to consider orientation optimization in conjunction with offloading infrastructure selection and placement. Additionally, site-specific data collection will be critical to more accurately account for metocean conditions at the proposed LNGC berthing site.

An overall availability of 86.1%, although potentially lower than that of conventional harbor and port facilities, highlights the feasibility of LNG transfers at Tanguisson. Analyses indicate that the summer months of July through September present the fewest available transfer windows. Consequently, it is prudent for the project to consider the implementation of contingency plans for ULSD fuel operations to mitigate potential disruptions caused by adverse weather conditions.

Month	Days in Month	Number of 14-Hour Windows in Month	Availability of Delivery Windows (%) ³⁴	Number of 14-Hour Windows with Metocean Availability
January	31	53	86.90%	46
February	28	48	91.27%	44
March	31	53	87.99%	47
April	30	51	92.73%	47
May	31	53	94.87%	50
June	30	51	81.41%	42
July	31	53	68.01%	36
August	31	53	73.05%	39
September	30	51	80.42%	41
October	31	53	96.03%	51
November	30	51	94.58%	48
December	31	53	85.95%	46
		Average	86.10%	

H.5 Conclusions

The results of the metocean, mooring, and wave modeling analyses provide key insights into LNG offloading feasibility at Tanguisson, defining environmental limits, vessel motions, mooring loads, and potential downtime. These findings were compared against industry standards (e.g., OCIMF, PIANC) to ensure compliance with safety and operability criteria. The analysis informs berth design, mooring configurations, and potential coastal protection needs. Future work includes refining metocean data, optimizing mooring systems, enhancing wave modeling, and assessing infrastructure improvements to ensure safe and reliable operations.

³⁴ Based on GHD Metocean Analysis.

Appendix I: LNG Transfer Mechanisms at Tanguisson

I.1 LNG Transfer Mechanisms

The project team evaluated several options for transferring LNG from the LNG carrier while berthed offshore. The two primary alternatives considered were the use of a semisubmersible vessel and the installation of a permanent transfer tower, described below.

I.1.1 Semisubmersible Vessel

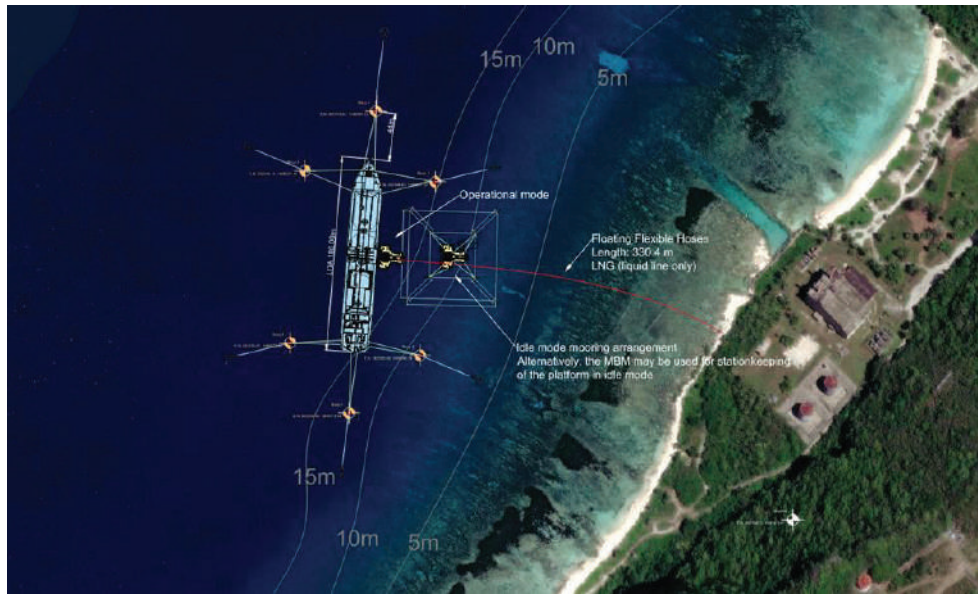
For the semisubmersible vessel option, the project team engaged EConnect, a Norway-based firm specializing in these solutions. EConnect's IQuay C-Class system offers the capability to mechanically connect to the side of a vessel using suction manifolds, while linking to the onshore facility through cryogenic floating hoses (see Figure I.1).

Figure I.1: EConnect Platform attached to an LNGC during a Transfer Operation



Given the exposed conditions at the Tanguisson site and the shallow approach angles to shore, EConnect proposed an offshore mooring configuration for their unit (see Figure I.2).

Figure I.2: EConnect IQuay C-Class Configuration at Tanguisson

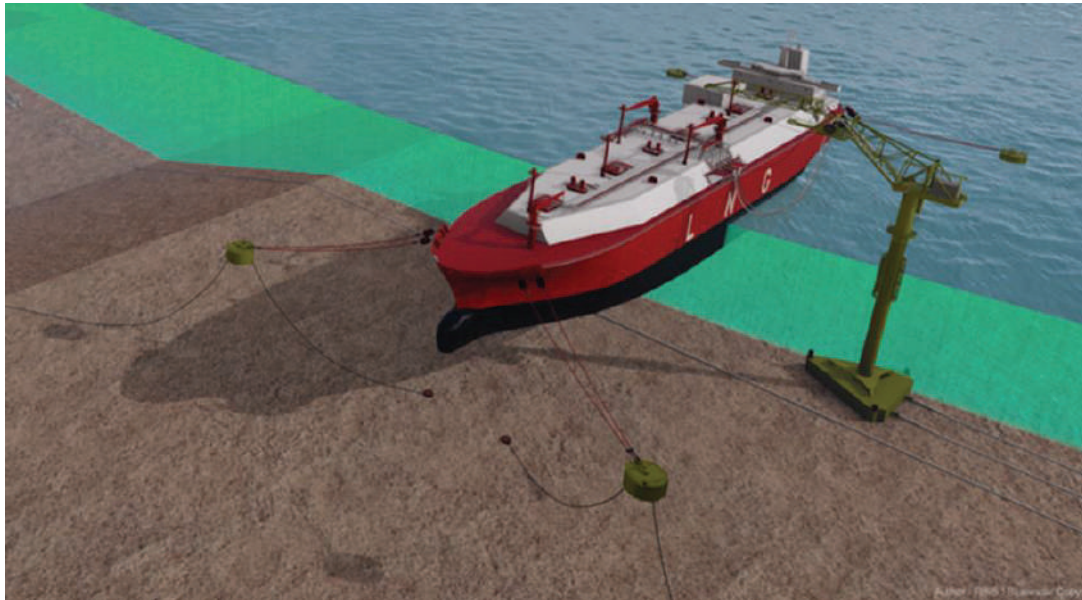


Despite the potential benefits of reduced construction costs and the innovative design of this alternative, the project team determined that the uncertainty surrounding metocean conditions and the likely operational challenges related to downtime during interactions between the LNGC and the IQuay system were too significant to consider this the preferred technology for the Phase I analysis. As a result, the project team developed the preferred concept for LNG transfers based on a permanently installed transfer tower, which would connect to the LNGC using flexible cryogenic hoses.

I.1.2 Permanent Transfer Tower

The transfer tower would be installed offshore at a location that ensures the berthed LNGC meets minimum draft requirements, maintains safe vessel motion parameters, and adheres to the necessary safety clearances between the LNG carrier and the transfer tower (see Figure I.3). Key technical challenges associated with this alternative include securing and protecting the flexible cryogenic hoses during extreme weather conditions, as well as managing hook-up procedures and ensuring operational safety.

Figure I.3: Conceptual Sketch of Transfer Tower Solution at Tanguisson



I.2 Horizontal Directional Drill

The current berthing location for the LNG carrier (LNGC) is approximately 1,000 feet (310 meters) from the proposed site for the onshore regasification and LNG storage infrastructure. Due to the offshore seafloor conditions, characterized by coral outcrops and shallow waters, the preferred method for LNG transfer is to construct a horizontal directional drilling (HDD) casing through which the cryogenic LNG pipeline would be routed. HDD is a widely used technique internationally and has been successfully implemented in Guam for similar-sized conduits in other utility projects, such as those undertaken by the Guam Water Authority. The project team has consulted with firms experienced in HDD operations in Guam, including Michels, to review the proposed approach, validate assumptions, and identify key next steps. Additionally, GHD's HDD team has developed a conceptual drill path and layout based on available bathymetric data provided by other sources.

Appendix J: Bunkering Consultation Results

The following memo describes the outcomes of a consultation with the shipping company, Matson, on the potential for bunkering out of Guam.

Memo

To Mario Jahn
From K&M Advisors
Date January 24, 2025
Subject LNG Bunkering Discussion – Matson

The K&M team and our Subcontractor CH-IV held a virtual meeting on January 24, 2025, with Matson to discuss the potential for LNG Bunkering of Matson vessels in Apra Harbor.

Table 1: List of Attendees

Name	Company
Jonathan Ogle	Matson - Director of Strategic Development
Archibald Morgan	Matson - VP of New Construction and Marine Engineering
Alfonso Guzman	K&M Advisors
Lenny Golbin	K&M Advisors
Nick LaBriola	K&M Advisors
Kate Miller	K&M Advisors
Brad Haley	CH-IV
Drew Jackson	CH-IV
Zack Dotson	CH-IV
Juan Carlos Rivadeneira	CH-IV

Below are the findings from the discussion with Matson.

- All Matson's ships sailing through Guam by 2030 will be able to use LNG.
- Matson recently signed long-term contracts with LNG bunkering facilities in Los Angeles (primary) and China (top-up ~ 2,000 m³).
- Guam could be an LNG bunkering backup option, but prices in Guam would need to be very competitive for Matson to consider this a viable option.
- The current prices for Matson's LNG bunkering in Los Angeles are between \$12-15/MMBtu but have been hovering around the low \$20s/MMBtu. The range of prices from Maton's recent LNG tender process was between \$17-30 / MMBtu.

- Matson indicated one vessel can bunker up to 3,100 m³ of LNG.
- The frequency of Matson ships to Guam is one delivery per week of ~300 containers.
- The ships are bunkered in Los Angeles before going to Guam. Matson estimates the vessels have approximately half the total storage capacity remaining for the trip from Guam to China.
- To estimate LNG bunkering costs in Guam, Matson suggested that K&M assume that one vessel will be bunkered once weekly and require 2,000 m³ each time in bunkers.
- The bunkering window is short, as ships spend an average of 22 hours in port. Matson stated during this time, the vessel and onshore crews are very busy unloading and loading cargo, which would make bunkering simultaneously a significant challenge.
- Current Matson ships are bunkering by barge (water side). They indicated there are physical challenges regarding the bunkering tie-ins on the ship and being able to lift cargo over the bunkering lines and equipment. Additionally, bunkering by ISO containers on the port side is logistically challenging, especially with Matson's primary function being loading/unloading activity at this port.

The primary takeaway from the discussion with Matson is that they are unlikely to be interested in bunkering their vessels in Guam. Due to their recent tenders and long-term supply agreements, the price of LNG in Guam would need to be extremely competitive for them to consider this a viable option. Even then, this would only be used as a tertiary backup option for them.

Appendix K: Legal Opinion

MEMORANDUM

CONFIDENTIAL

TO: K&M Advisors
FROM: Law Offices of Arthur Clark, P.C. ("Counsel")
DATE: August 16, 2024

RE: Guam Public Utilities Commission (PUC) GPA Docket No. 23-17; Guam Power Authority (GPA) Petition to Approve the EPMC, Phase I, Liquefied Natural Gas (LNG) Pre-Development Study, Scope and Costs (5/29/23); GPA's Updated Phase I Liquefied Natural Gas Pre-Development Study (11/14/23)

INTRODUCTION

In December 2022, Stanley Consultants was awarded the EPCM contract to support GPA's construction and commissioning of the Ukudu Power Plant and to support development and procurement of the LNG Infrastructure to supply natural gas to the power plant. Stanley assembled a highly qualified team of experts, led by K&M Advisors. In May 2023, GPA filed a petition with the PUC to approve its EPCM, Phase I, LNG Pre-Development Study, Scope and Costs. In November 2023, it filed an Updated Phase I LNG Pre-Development Study.

K&M retained counsel to:

- address the issues concerning Phase IV raised in the ALJ Reports dated June 26, 2023 and November 22, 2023, and the PUC Orders dated June 29, 2023 and November 30, 2023, concerning the legality of GPA's proposal to sell LNG to third parties, to franchise the distribution of LNG to customers in Guam, or to transship LNG to other islands;
- to the extent possible, assess what the attitude of private fuel suppliers in Guam (i.e., such as IP&E/Mobil etc.) might be to the possible creation of an LNG monopoly;
- • assess whether, under the laws of Guam:
 - A private entity can develop and own the LNG infrastructure, supply gas to GPA, and sell LNG to third parties.
 - GPA can own the LNG infrastructure, which supplies gas to the Ukudu plant as a sole owner or as part of a joint venture and get paid for providing LNG storage and processing services to a private LNG reseller, who would purchase LNG under a separate contract with a private company supplying LNG to Guam and sell it to third parties on Guam or transship to nearby islands.

Review Materials:

1. June 26, 2023 ALJ Report;
2. November 22, 2023 ALJ Report;
3. June 29, 2023 PUC Order;
4. November 30, 2023 PUC Order.

Executive Summary

GPA is a Guam public corporation. Title 12 Guam Code Annotated (GCA) § 8104 enumerates the powers granted to GPA by the Guam Legislature. Section 8104(a) identifies GPA’s main power as to: “Generate, transmit, distribute, sell and exchange electric power on Guam.” The powers enumerated in the other subsections are ancillary to GPA’s main power.

Regarding activities that may be conducted by public corporations, the Guam Supreme Court held, with respect to the Guam Telephone Authority (GTA) which was a public corporation at the time: “Because GTA is a creature of statute, GTA may only act within its powers as specifically granted by the legislature.” Carlson v. Guam Telephone Authority, 2002 Guam 15, ¶ 9.

Based on the ruling in Carlson, because the Guam Legislature has not specifically granted GPA the power to sell LNG to third parties, to franchise the distribution of LNG to customers in Guam, or to transship LNG to other islands, it does not have that authority.

Analysis

Legislatively created in 1968, GPA was classified as a public corporation and autonomous instrumentality of the Government of Guam. Guam Government Code §§ 21502 (repealed). In 2002, the Government of Guam enacted Public Law 26-76, “An Act to Create the Consolidated Commission on Utilities (“Commission”), To Reorganize and Consolidate Several Government of Guam Agencies and for Other Purposes.” The Act repealed and reenacted certain sections of GPA’s enabling act, 12 GCA Chapter 8, to give the elected Commission authority over GPA.

Reenacted § 8103 continued GPA’s existence as a public corporation, without reference to it as an autonomous agency. For purposes of this memo the removal of “autonomous agency” status does not appear relevant to the question of whether the Carlson decision, cited by the ALJ Report and Commission Orders above, controls.

GPA’s Proposal to Sell LNG to Third Parties, to Franchise the Distribution of LNG
To Customers in Guam, or to Transship LNG to Other Islands

In Bordallo v. Reyes, the District Court of Guam defined a “public corporation” as an instrumentality of the government. This definition was upheld by the Ninth Circuit Court of Appeals. Both the District Court and the Ninth Circuit Court, *in dictum*, identified the then-existing public corporations of Guam as including GPA. Bordallo v. Reyes, 763 F.2d 1098, 1103 (9th Cir. 1985) (“The district court found that in creating certain public corporations, such as the Guam Airport Authority, the Guam Telephone Authority, *the Guam Power Authority*, and the Port Authority of Guam, the Legislature had expressly designated each as a public corporation and as an instrumentality of the government.”) The Bordallo decision has been cited with approval in several cases by the Guam Supreme Court.¹

In Carlson, former Guam public corporation Guam Telephone Authority commenced operation of an internet service provider (ISP). The trial court issued a permanent injunction prohibiting GTA from continuing its ISP business. On appeal, the Guam Supreme Court affirmed the trial court decision. The Court held, “The central issue in this case is whether GTA has the statutory authority to provide internet access service. *Because GTA is a creature of statute, GTA may only act within its powers as specifically granted by the legislature.*” Carlson, ¶ 9.

The relevant analysis as it applies to GPA is whether there is statutory authorization for it to engage in the intra-island sale and regional transshipment of LNG. GPA’s specific grant of

¹ See Guam Economic Development Authority v. Island Equipment Co., Inc., 1998 Guam 7; Guam Radio Services, Inc. v. Guam Economic Development Authority, 2000 Guam 1; Wood v. Guam Power Authority, 2000 Guam 18; In re Request of Governor Felix P. Camacho, 2004 Guam 10; and Carlson v. Perez, 2007 Guam 6.

power is found in its enabling act. Section 8104 of the enabling act includes 15 specific grants of authority. The following are relevant for this analysis:

(a) Generate, transmit, distribute, sell and exchange electric power on Guam;

(b) Acquire, in accordance with Title 5 GCA, Chapter 5, and subject to the laws of Guam, by grant, purchase, gift, devise or lease, or by the exercise of the right of eminent domain in accordance with the provisions and subject to the limitations of 21 GCA, Chapter 15, and hold and use any real or personal property necessary or convenient or useful for the carrying on of any of the powers pursuant to the provisions of this Chapter;

(d) Establish and modify from time to time, with approval of the Public Utility Commission, reasonable rates and charges for electric service at least adequate to cover the full cost of such service, including the cost of debt service, and collect money from customers using such service, all subject to any contractual obligation of the Board to the holders of any bonds; and refund charges collected in error;

(f) Construct works along or across any street or public highway or watercourse or over any of the lands which are the property of Guam;

(k) Control, operate, improve, equip, maintain, repair, renew, replace, reconstruct, alter and insure the electric system subject to compliance with any applicable zoning, building and health regulations of Guam;

(l) Do any and all other things necessary to the full and convenient exercise of the above powers; and

(n) The Guam Power Authority may enter into long term contracts for a period up to and not exceeding thirty (30) years for renewable energy contracts, purchased power agreements, refurbish-operate-maintain contracts, and build-operate-transfer contracts that cost Thirty Million Dollars (\$30,000,000) or more.

Nothing contained in this Section or elsewhere in this Article shall be construed directly or by implication to be in any way in derogation or limitation of powers conferred upon or existing in the Authority or the Board by virtue of any provisions of the Organic Act of Guam or statutes of Guam or any other provisions of this Code.

The Carlson Court gave the following guidance: “terms should be defined in accordance with the legislature’s reasonable contemplation.” Carlson, ¶ 37. The Court also referred to a “plain reading” of the applicable legislation, alluding to the plain-meaning doctrine of statutory construction. “It is a cardinal rule of statutory construction that courts must look first to the language of the statute itself. Absent clear legislative intent to the contrary, the plain meaning

prevails.” Sumitomo Const., Co. v. Gov’t of Guam, 2001 Guam 23, ¶ 17.

Applying the plain-meaning standard to each of the above-listed powers, none of the powers granted to GPA include a specific legislative authorization to engage in the intra-island sale and regional transshipment of LNG. The main authority granted to GPA is in subsection (a): “Generate, transmit, distribute, sell and exchange electric power on Guam.” The other powers are ancillary to this main power. The 6/26/23 ALJ Report reached what appears to be an obvious conclusion based on the plain reading of GPA’s powers (at pp. 14-16):

[T]he claimed additional powers, such as transshipment to other islands, entry into the fuel market as a private competitor, the sales of LNG to other third-party purchasers, and monopolistic control as sole off-taker for all services and fuel supply, are not necessarily within the power of GPA to control and operate Guam’s electric power system.

GPA is acting like a private business in attempting to capitalize on a “negotiated franchise fee” for bunkering, and regional transshipment of LNG. GPA claims that customers should benefit since they are paying for ownership of the LNG facility. However, what is to ensure that GPA’s profits from the sale and transshipment of LNG will work to the benefit of GPA customers/ ratepayers?

Phase IV provides that GPA will be selling LNG or gas ex-terminal to third parties. How can GPA claim that it would not be an active LNG seller in the market? If the LNG Facility IPP would be the “seller”, why does GPA state in Phase IV that it would be selling LNG or gas to third parties? GPA also admits that “other fuel suppliers” are likely potentially interested in purchasing LNG supply from GPA. GPA will be competing with other fuel suppliers and trying to change customers from use of ULSD to LNG.

GPA has not made a convincing argument that selling fuel to third parties or transshipping fuels to other islands is within its powers under 12 GCA 8104(b) or (k). It states that it is authorized to use and hold its real or personal property and carrying out its other powers in the law. Nothing authorizes GPA to engage in private commercial business selling and transshipping oil. Its powers are to generate electric power in Guam, not to transship fuel to other islands or to sell fuel in the market. GPA’s claim that it will not be involved in active transshipment of LNG outside with Guam is again directly contrary to the language in its proposed “study.” GPA is directly involved in transshipment of “regional LNG” and “for a negotiated franchise fee.” In 2013, GPA raised the concern that GPA customers would be paying for virtually all the infrastructure capable of supporting transshipment and the ancillary markets.

GPA’s defense summarized in ALJ Report above appear to have been capably rebutted. Section 8104(b)’s grant of power to own or use personal or real property is not intended to be an independent grant of power such that GPA can engage in any business that utilizes personal or

real property. Subsection (b) clearly states GPA can “hold and use any real or personal property *necessary or convenient or useful for the carrying on of any of the powers pursuant to the provisions of this Chapter.*” Subsection (k) also refers to GPA’s authority to operate the “electric system.” It is not a broad grant of authority to engage in any business that is operations-based. The interpretations offered by GPA rely on general grants of authority; however, per Carlson, it is not a general grant of authority, but a specific one that is required. The proposed additional commercial activities are not specifically authorized, nor do they appear to be ancillary to GPA’s main mandate, which is to generate, transmit, distribute, sell and exchange electricity.

GPA’s claim that its customers should benefit since they are paying for ownership of the LNG facility, even if accurate, is also unavailing. As commercially desirable as it may be to reduce the cost of services to ratepayers by generating profits from other sales or operations, the Carlson decision summarizes the distinction between private and public corporations, broadly speaking, as: private corporations can engage in commercial activities not prohibited by law; public corporations can only engage in commercial activities permitted by law. In Carlson, GTA had already commenced operations and had already signed up customers. At the time of the decision, it had expended over \$5 million in start up costs. Neither the trial court nor the Supreme Court factored the commercial impact to GTA or to its customers in their decisions.

The ALJ Report has multiple references to the public policy ramifications of empowering the government to compete with private entities whose revenues contribute to the government’s tax base. Although public policy considerations may influence the enactment of legislation, they do not in and of themselves constitute binding legislation.

A review of GPA’s Petition and its Updated Study support the above conclusion. The following excerpts identify services other than providing electric power to parties other than electric power consumers (ratepayers):

- the LNG could be used to *provide natural gas to other end users on Guam* (GPA 5/29/23 Petition, p. EX A-07);
- contact some of Guam’s larger industrial and commercial consumers and the US Navy and military to identify the parties that may be interested in *receiving LNG or natural gas for their operations* (p. EX A-010);
- using the LNG infrastructure *for other than GPA’s needs* (p. EX A-023);

- *selling LNG or gas ex-terminal to third parties who could then distribute to end-users (id., p. EX A-024);*
- *allowing third parties to use the LNG terminal to import LNG and charging these parties a fee for using the terminal (id.);*
- *entering into a joint venture with a third party that will distribute and sell LNG or natural gas to end users (id.).*

Assess What the Attitude of Private Fuel Suppliers in Guam
Might Be to the Possible Creation of an LNG Monopoly

It is not recommended to pursue such an assessment of attitude at this time. The reference appears to be specific to a “monopoly” controlled by GPA for the sale and transshipment of LNG. Since it does not appear that GPA has any legislative authorization to engage in such an activity, it is inadvisable to stir up the private industry over this issue.

Can a Private Entity Develop and Own the LNG Infrastructure,
Supply Gas to GPA, and Sell LNG to Third Parties?

As Carlson has been summarized above, in part, private entities may engage in any business not otherwise prohibited by law. Counsel has been unable to find any Guam law prohibiting a private entity from developing and owning an LNG receiving terminal, LNG storage, and regasification facility. Thus, it does appear that a private entity may engage in this business on its own. There also does not appear to be any restriction prohibiting GPA from securing its LNG supply from an on-island provider. To the contrary, Guam’s law provides for a 15% bid preference for local procurements. 5 GCA § 5008.

Can GPA Own the LNG Infrastructure as a Sole Owner or as Part of a Joint Venture and Get
Paid for Providing LNG Storage and Processing Services to a Private LNG Reseller?

The legality of GPA’s ownership of the LNG Infrastructure is not raised in any of the ALJ Reports or PUC Orders. As the word “ownership” is used in the context of the above question, it appears correlated to GPA’s ability to generate extra revenue from the LNG

Infrastructure either on its own or as part of a joint venture. *See* Petition, pp. EX A-24-25, Task 20.

Under the holding in Carlson, to the extent that GPA's ownership of the LNG Infrastructure is ancillary to and supports its power to generate, transmit, distribute, sell and exchange electric power on Guam, such as for use in a dual-fuel capable power plant, it would be permitted. The arguments previously provided by GPA to the PUC support this conclusion. Section 8104(b) allows GPA to hold and use any real or personal property necessary or convenient or useful for the carrying on of any of its powers. Subsection (k) allows GPA to operate and, improve the electric system. In addition, subsection (l) allows GPA to "[d]o any and all other things necessary to the full and convenient exercise of the above powers."

However, although GPA may own the LNG Infrastructure, it may not get paid to provide LNG storage and processing services to a private LNG reseller. Based on Carlson, the relevant legal analysis is not who GPA's customer is, but whether the commercial activity is specifically authorized by legislation.

As for whether GPA may indirectly engage in such a business as part of a joint venture, for the reasons explained above the ownership structure of the LNG Infrastructure would not alter the conclusion on whether GPA is granted the power to sell LNG or gas ex-terminal. It isn't. Guam's Business License Law, 11 GCA § 70103(c), defines "Business" to mean and include:

any activity or conduct, whether proprietary, *partnership*, corporate, or whatever form, engaged in, transacted, conducted, continued, done or carried on, or caused to be engaged in, transacted, conducted, continued, done or carried on, with the object of gain or economic benefit, either direct or indirect, but shall not include casual sales, personal service contracts or fund raising activities by political candidates, committees, parties, corporations, associations, organizations or funds.

GPA would not be able to engage in a business as a joint venturer that it would not be able to conduct on its own.

Conclusion

In summary, GPA, as a public corporation, may only exercise powers specifically granted by legislation. GPA has been granted the power to generate, transmit, distribute, sell and

exchange electric power on Guam. It has been granted ancillary powers to support this main grant of power. It does not have any legislative authorization to sell LNG, gas ex-terminal, or the use a GPA-owned LNG terminal to any third-parties. This conclusion is not altered by the ownership structure of the LNG Infrastructure, regardless of whether GPA has full or partial ownership, so long as GPA is generating revenues through commercial activities not specifically authorized by law.

Appendix L: Market Summary Issued to Guam Stakeholders

Project: Guam LNG Import Study

March 25, 2025

Background

Guam Power Authority (GPA) is a public corporation overseen by the Consolidated Commission on Utilities (CCU) and regulated by the Guam Public Utilities Commission (PUC). To replace its retiring thermal power plants, GPA has executed an energy conversion (tolling) agreement with Guam Ukudu Power (GUPP), a project company formed by the project sponsor, Korea Electric Power Corporation (KEPCO) to construct, own and operate a 198 MW capacity combined cycle power plant. The GUPP plant will be able to run on ultra-low sulfur diesel (ULSD) or re-gasified Liquefied Natural Gas (LNG) and is scheduled for commissioning by Q3 2025.

LNG-to-Power Development Study

K&M Advisors LLC (K&M) has been engaged by GPA, through Stanley Consultants, to undertake an LNG-to-Power Development Study ("Study") to investigate the feasibility of transitioning the GUPP plant from ULSD to natural gas by 2031. By converting GUPP to natural gas, GPA could lower emissions and reduce the cost of power generation. Based on the initial analysis, it's envisaged that GUPP's annual LNG demand could start at around 165,000 tons, but it will decline over time to about 100,000 tpa as renewable energy generation increases. Preliminary LNG sourcing and shipping analysis suggests that LNG from Indonesia transported on a small-scale LNG carrier (7,500 or 10,000 m³) could be the most practical and least-cost LNG supply solution for Guam. However, GPA will not prescribe LNG sources or shipping solutions. LNG terminal site selection and preliminary configurations were based on small-scale LNG carrier deliveries.

Objective

As part of the Study, K&M is investigating and evaluating potential LNG terminal configurations and layouts and wishes to consult various market participants regarding such potential options. K&M is also interested in feedback regarding the business model for developing a gas supply solution for GPA.

Disclaimer

GPA is not currently commencing an LNG procurement process or shortlisting potential LNG suppliers or developers. Information provided at this stage will be solely used for the Study. It will not prevent any company participating in this consultation from being involved in any gas procurement process at a later stage. If requested, the information provided can be "anonymized," with the identity excluded in any reports, etc.

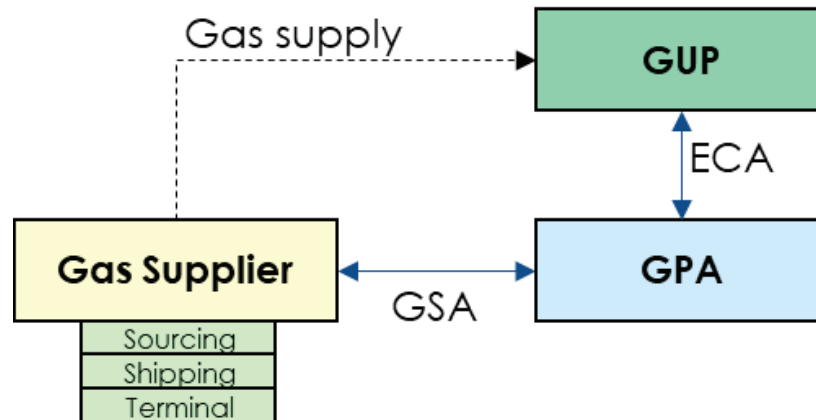
LNG Import Terminal Business Model

GPA and K&M wish to receive feedback from the potential LNG developers regarding the proposed business model and contracting arrangement:

GPA's current thinking is that the LNG import terminal will be developed under a Gas Supply Agreement between GPA and a private 'Gas Supplier'. The Gas Supplier is responsible for sourcing, shipping, importing, storing, and regasifying LNG, delivering gas to the interface point for GUPP. GPA will pay for the gas supplied by the Gas Supplier. The Gas Supplier designs, permits, finances,

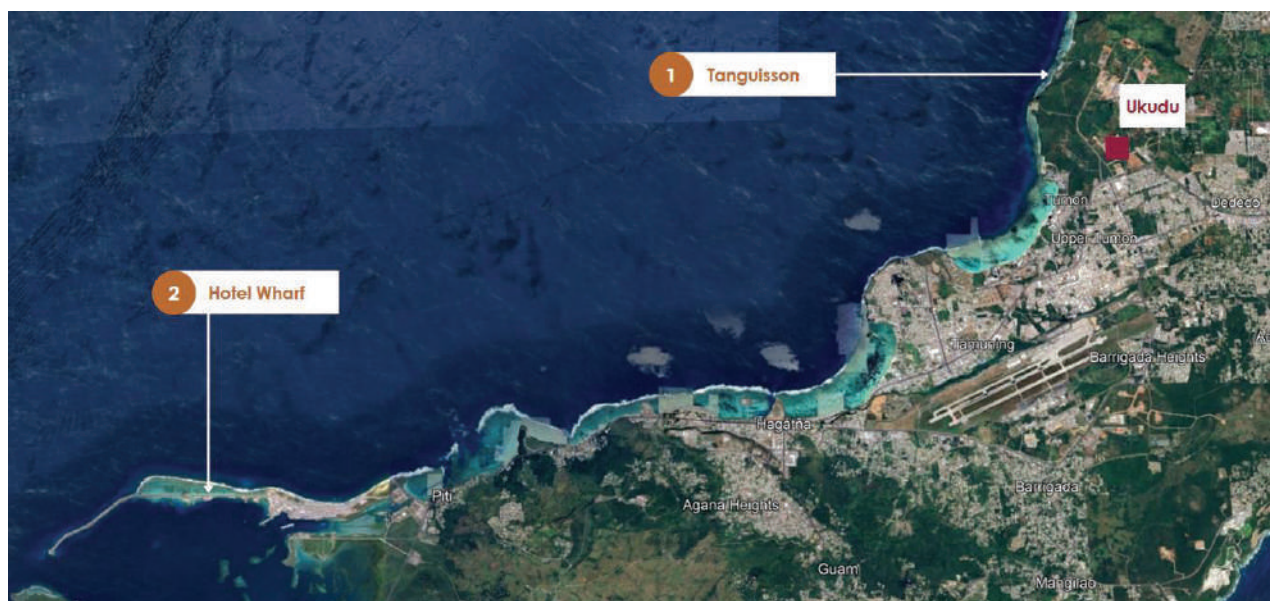
builds, owns, and operates all the equipment and infrastructure required to unload, store, and regasify LNG and transport gas to the GUPP interface point. GPA selects the site and acquires or leases the land where the LNG terminal will be located. The Gas Supplier selects an LNG terminal size and configuration that meets the functional specifications set by GPA and the GUPP Energy Conversion Agreement (ECA) requirement. GPA will reasonably assist the Gas Supplier with permitting, including applicable Federal Energy Regulatory Commission (FERC) and Guam-specific permits. This arrangement is illustrated in Figure 1 below. GPA will select the Gas Supplier through competitive procurement.

Figure 1: Diagram of the LNG Import Terminal Business Model



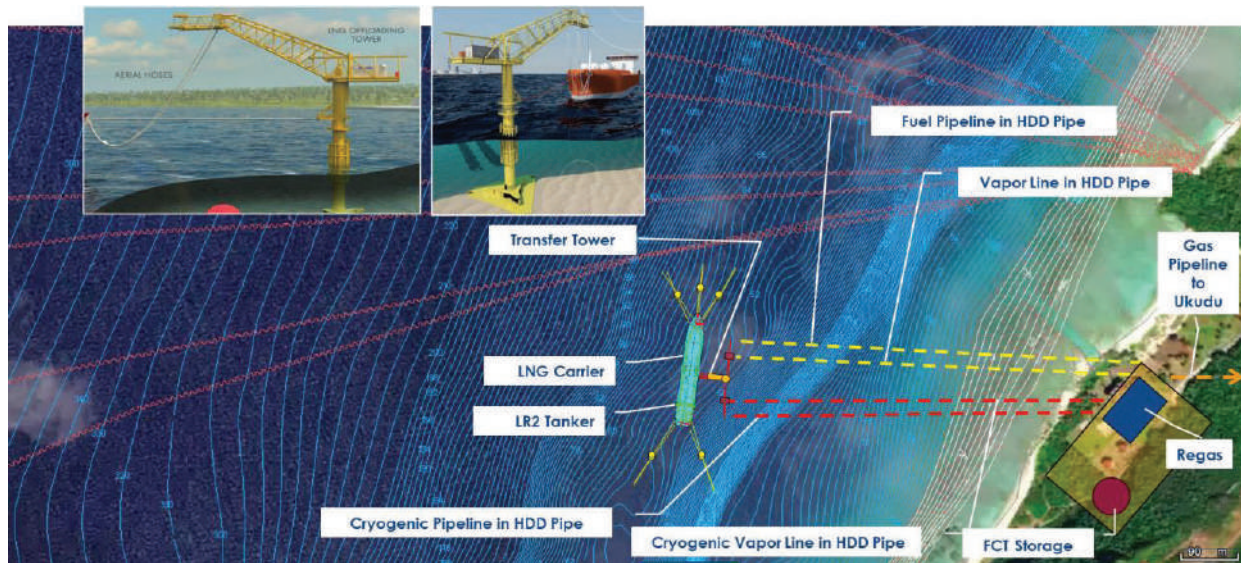
LNG Import Terminal Configurations

GPA and K&M wish to receive feedback from potential LNG developers regarding potential terminal configurations. Two sites and configurations have been short-listed for the LNG import terminal:



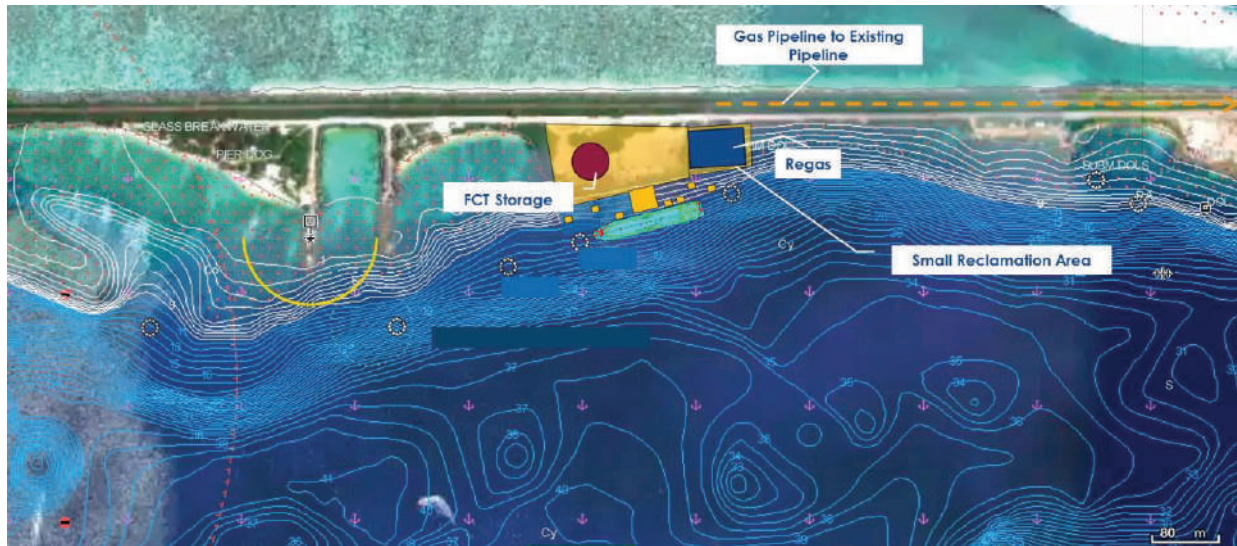
- 1 **Tanguisson**—Located to the northwest of Guam, this site is the location of a retired power plant and has vehicle access to the beach. Based on preliminary metocean conditions analysis, this site might be viable. The terminal configuration comprises a multi-buoy mooring system and transfer tower with a subsea cryogenic pipeline to shore, onshore storage and regas, and pipelined gas to GUPP.

Other Considerations: The Navy prefers this location because they could potentially use it as an alternative fuel import or bunkering facility. However, given the metocean conditions, it has more technical limitations.



- 2 **Hotel Wharf** - Located in Apra Harbor, the site is underutilized. A small reclamation area would need to be built to accommodate onshore infrastructure. The terminal configuration includes an at-shore berth for transient LNG deliveries, onshore storage and regas, and pipelined gas to GUPP.

Other Considerations: The Navy opposes this location, citing security and accessibility concerns related to having LNG storage and carriers in Apra Harbor.



Consultation Questions

1 Business Model

- a) Do you have any general views on the proposed business model?
- b) Would it be more or less attractive if the project were split into two parts:
 - i) Company # 1 - LNG delivery ex-ship
 - ii) Company # 2 - LNG terminal and gas supply to GUPP
- c) Understanding that permitting (including FERC and Guam permits) would be the developer's responsibility, do you have any views on how GPA could assist in mitigating permitting risk?
- d) Considering that LNG demand is likely to decrease significantly over time, do you have any views on how GPA could create a remuneration structure that: 1) ensures the gas supply project is bankable, 2) GPA maximizes the use of renewable energy in the island, and minimizes the system-wide cost of power generation?
- e) What would be the shortest viable GSA term for developers? 10, 15 years?

2 Terminal Site and Configuration

- a) Do any of these sites stand out to you as a better option?—Tanguisson or Hotel Wharf (Apra Harbor)
- b) Tanguisson
 - i) Do you perceive any fatal flaws with this site? Exposure, flooding potential, accessibility, etc.
 - ii) Do you have any preliminary views on the proposed configuration? Understanding that this is indicative, and developers would have the freedom to choose their own configuration
 - iii) Would you have any major concerns if some of the facilities at this site (e.g. transfer tower) are shared with a Navy operation for importing jet fuel or bunkering?

- c) Hotel Wharf
 - i) Do you perceive any fatal flaws or major concerns with this site?
 - ii) The Navy is concerned about an LNG terminal in Apra Harbor creating a security risk for the Navy's operations—any views on how to address this concern?

Appendix M: Feedback from Stakeholders

NAVFAC Marianas, Role: Navy	The goal of the meeting was to solicit feedback from the Navy and NAVFAC representatives for current siting options for an LNG import facility in Guam. An introduction to LNG and associated benefits was presented, providing technical and commercial information and data. Guam's opportunity to transition to LNG was presented, where energy costs and emissions would be reduced. Key emphasis was put on the current and existing mandates that are in place to reduce the island's greenhouse gas emissions. LNG import facilities with proximity to other Navy operations were presented. Guantánamo Bay's LNG terminal serving as the primary example. Four (4) sites in Apra Harbor were presented: Dry Dock Island, Hotel Wharf, Breakwater 1 and Breakwater 2. The Navy vocalized strong concerns regarding the potential risk of a catastrophic event associated with an LNG facility interrupting Apra Harbor operations specific to the Pacific Fleet. The K&M team offered to perform a qualitative risk assessment (QRA) to evaluate LNG terminal safety. However, given that the Navy is more concerned about possible obstructions that an LNG carrier entering the Apra harbor can present to the Navy operations and the LNG terminal becoming a target for US enemies in case of a war in the region, the K&M team, after internal discussion, concluded that the QRA, as per the NFPA 59 requirements, will not be beneficial. Navy showed interest in collaborating with alternative site locations for additional fuel import operations for diesel, JP-8, and potentially other fuels. Andersen AFB may have other demands. Dry Dock Island (peninsula) poses a significant concern for fueling the Pacific Fleet. Bunkering LNG may also interest a variety of stakeholders at Apra Harbor if the existing pipeline and storage infrastructure could facilitate this type of fuel transfer.
Port Authority of Guam, Role: Port Authority	Goal of the meeting was to solicit feedback from the Port Authority of Guam representatives for current siting options for an LNG import facility in Guam, specifically Apra Harbor. LNG bunkering for large container ships (e.g., Matson) and cruise ships is part of the PAG's Master Plan. PAG generates ~\$2M per year in fuel sales and wheeling. Fuel piers: only 1 of 2 are currently viable due to the damage caused by Typhoon Mawar. PAG has an interest in building out Hotel Wharf, potentially to serve aircraft carriers (~\$100M to rehabilitate). Port Readiness Plan will be distributed to the project partners for further understanding of potential synergies with fuel bunkering. Navy concerns with LNG inside Apra Harbor relayed to PAG. PAG mentioned during the meeting that an RFP for an LNG Bunkering Study was in progress. They stated Matson would be the only entity driving the demand for LNG at the port. The status of this LNG Bunkering study will be discussed with PAG during K&M's next visit to Guam.
US Coast Guard, Role: US Coast Guard	The goal of the meeting was to solicit feedback from the U.S. Coast Guard representatives for current siting options for an LNG import facility in Guam. The U.S. Coast Guard representatives asked various questions on operations in terms of duration and potential movement of vessels during weather events. The U.S. Coast Guard representatives also provided contacts at the Office for Coastal Management who could potentially provide site-specific data and issues to concern the project in regards to disturbances during construction. A "Fire Exclusion Zone" north of Tanguisson to be reviewed by the Stanley and K&M team to determine if the Air Force or Navy are using this area for dumping of munitions, or possibly, other activities. This should be located on a map for future reference.

NAVFAC Marianas, Role: Navy	Goal of the meeting was to revisit the Navy and NAVFAC representatives to discuss Tanguisson as a potential site for consideration and to solicit additional feedback from finding synergies at the shortlisted Apra Harbor sites (Hotel Wharf and Dry Dock Island). The Navy discussed their interest in developing a secondary import site for JP-8 and other fuels where Tanguisson would be of interest. The Navy owns land near Tanguisson and will provide a plot map and land use designations. The LNG Infrastructure Project will continue to debrief with the Navy to understand potential synergies with siting a facility that would benefit both GPA and the Navy.
TG Engineers, Role: Engineer	The goal of the meeting was to inquire about any AS-BUILT data that TG Engineers may have on record specific to Hotel Wharf and Apra Harbor at large. Tor used to work for GHD and has good relationships with GPA on the island. TG Engineers is also involved with some data centers, solar/BESS projects, and fiber optic line landings in Guam. Tor to provide any potential plan and or profile drawings of Hotel Wharf. This confirms and records GHD's interpretation of the discussions and our understanding reached during this meeting.
Matson, Role: LNG Offtaker	Matson is unlikely to be interested in bunkering their vessels in Guam. Due to their recent tenders and long-term supply agreements, the price of LNG in Guam would need to be extremely competitive for them to consider this a viable option. Even then, this would only be used as a tertiary backup option for them.
NAVFAC Marianas, Role: Navy	Navy would like to consider Tanguisson as a contingency-based logistical hub for all fueling operations, no limiting thoughts on the size of the vessel at this point. The Navy would only use Tanguisson in a contingent situation and not for normal operations. The Navy is unfamiliar with the BOOT model of development – this likely means that there would be an issue in coordinated operations between the Navy and the eventual Developer to take on the LNG terminal at Tanguisson. The Navy is OK with the project team continuing the analysis of project alternatives within Apra Harbor for completeness of the study and staying within the scope as outlined by GPA / PUC. Navy involvement will take significant time to coordinate and/or require an urgent need from external forces to make the logistics and configuration work. The team is to consider two vessels, small and large, to be used by Navy, and coordinate with Robert Ford out of Japan to understand which vessels would be considered for this project. Golf and Hotel Wharf are considered the same in terms of impacts to Apra Harbor. The Navy's work on glass breakwater likely to take ~5 years and plan to utilize Hotel Wharf for staging area of large bulk materials for amending the storm-damaged areas.
Port Authority of Guam, Role: Port Authority	Hwy 11 is a federal highway route to a family beach. There are existing easements for pipelines, both currently installed and upcoming (water) lines to be installed. Design for full replacement of Gulf Pier via public-private partnership. PAG is concerned that the cost-benefit ratio of ~\$300M CAPEX for ~\$2M/yr income is not worth it for PAG nor potential developers/investors. 200M of Shared PPA available between GPA and PAG? Need \$83M for Golf Pier, \$80M for F1, \$100M+ for F2(?). Project team to continue to update PAG on project status overtime.

Bureau of Statistics and Plans, Role: Guam Government	Coastal Zone Management Act typically requires NEPA. CZMA utilizes Section 106 which provides guidelines for Consistency Determination. Project would likely not require a Nation-wide Permit, would be under a "12". There is an Environmental Clearing House that all projects and permits would funnel into, where the distribution of comments is handled. DOD likely has submerged lands right of way off the coast of Tanguisson, need to consider with HDD. Jurisdiction between BPS / other slightly unclear. Seashore clearance is 30-ft from shore, and down to 10 fathoms (60 ft). Project team don't need to continue to closely engage with this group as they require more definition to allow for comments and their own internal process. Recommendation to commence public outreach as soon as possible and viable.
EPA Guam, Role: Guam Regulatory Agency	Guam EPA leverages US EPA (Region 9). GEPA covers air, land, and water. Unsure of air permit status with converting Ukudu from ULSD to natural gas. No significant concerns on the project at either site – require input and commentary on the design once submitted but jurisdiction would likely reside purely on land-side equipment and infrastructure which would be minimal impact to air emissions at the terminal site (backup generators, etc.)
Mobil Oil, Role: Fuel Supplier / Developer	Mobil's potential interest, albeit very low, may depend on timing and condition of F1 Pier
AG&P, Role: Terminal Developer	During the consultation, AG&P raised several key considerations regarding the proposed LNG project. They expressed concerns about the relatively small volumes, suggesting that identifying additional off-takers or increasing volumes could improve project economics. From a permitting perspective, AG&P acknowledged limited direct experience with FERC processes, noting that environmental impacts in sensitive areas could pose significant challenges that would require close scrutiny from EPC contractors, especially if liquidated damages are tied to third parties. Technically, AG&P did not identify major red flags but emphasized that site validation, particularly at Tanguisson, is necessary. While the exposed location might present some feasibility concerns, they consider the project technically viable, albeit potentially costly. On the business model, AG&P indicated that their integrated approach—combining fuel sourcing, EPC, and O&M services—enhances project attractiveness by capturing value across the supply chain. They prefer turnkey solutions where a single entity manages both infrastructure and fuel supply, finding split models (e.g., separate EPC/O&M and fuel ownership) less appealing. Regarding the payment structure, AG&P stressed the need for secure revenue commitments, recommending a fixed capacity charge to cover long-term CAPEX and OPEX, supplemented by a variable pass-through charge tied to volumes. They outlined scenarios where, as terminal operator, they would implement a daily tariff covering fixed costs with transparent, open-book variable charges. Finally, on contract terms, AG&P noted that shorter tenors significantly increase pricing; while flexible, they prefer longer terms (10-25 years) to spread capital recovery, with shorter agreements (e.g., five years) only feasible at higher costs.

	Pilot LNG highlighted that the most significant barrier is finding a party willing to take on FERC permitting for such a small and remote project, which would deter many potential participants. Larger players with sufficient LNG volumes are unlikely to engage in permitting, construction, and supply for a project of this scale. A potential solution could involve forming a consortium of stakeholders—such as infrastructure developers and major suppliers—to distribute risks and responsibilities, though economic viability remains a concern. The regulatory framework, particularly FERC, was described as the "hub of the wheel" around which the project must be structured. Regulatory risks and costs were a major focus, with Pilot LNG emphasizing that navigating FERC can involve tens of millions in permitting expenses, even for a lean team. Larger projects have seen permitting costs upwards of \$200 million to reach final investment decisions (FID). The high transaction costs relative to the project's size were noted as a significant deterrent. Attracting experienced FERC participants and establishing a competent permitting strategy will be crucial to managing these regulatory challenges. From a commercial standpoint, Pilot LNG suggested that broadening the project scope—such as adding a truck rack for LNG distribution or providing marine fuel to surrounding islands—could increase volumes and improve economics. The concept of positioning Guam as a fuel hub could enhance commercial attractiveness, though this might face resistance from existing diesel providers. For contract terms, Pilot LNG noted that longer agreements reduce pricing risk, with 10 years considered long for small-scale bunkering projects, while 15 to 25 years are more typical in the export market. On configuration, they expressed strong reservations about offshore sites like Tanguisson due to exposure to Pacific weather. In-harbor solutions were preferred, though concerns remain about issues such as unexploded munitions. Floating storage units (FSUs) or sea island platforms were suggested as alternative configurations, leveraging currently available older floating assets at potentially lower costs. However, rising shipping costs remain an overarching concern affecting project feasibility.
Pilot LNG, Role: Terminal Developer	
Cashman Cryogenics, Role: Equipment Supplier	Cashman Cryogenics is an equipment supplier specializing in LNG storage tanks. They have experience in shipping / delivering to Guam. They did not view FERC as constraint to project feasibility and were eager to participate in the project as a supplier.

VTI, Role: Terminal Developer	VTI raised significant concerns regarding the feasibility of offshore configurations, particularly at the Tanguisson site. They noted that while a 300–400 meter pipeline might be technically feasible, metocean conditions, including super typhoons and harsh Pacific weather, pose major risks. The Tanguisson location, in particular, is considered challenging due to exposure to storm conditions and logistical complexities, while in-harbor options like Hotel Wharf are viewed as safer and more executable, though still requiring Navy approvals. Floating storage units (FSUs) were ruled out due to insufficient storm protection, and VTI emphasized the need for robust design of transfer systems and subsea cryogenic pipelines, which would require significant engineering work relative to the project’s small and potentially declining demand. From a business model standpoint, VTI indicated a preference for longer-term contracts (20–30 years) to ensure revenue certainty, particularly in light of decreasing gas demand as renewable energy scales up. They referenced similar challenges in other markets like Australia and New Zealand. Shorter terms (10–15 years) would require high pricing to fully amortize capital investments, especially given the lack of available small LNG vessels. A fixed daily rate structure, supplemented by variable operating expenses, was suggested as a bankable approach, allowing capital recovery across terminal infrastructure, storage tanks, regasification, subsea pipelines, and support assets like tugs and anchor handlers. Estimated CAPEX for terminal infrastructure (excluding LNG carriers) was in the \$200–300 million range. On FERC permitting, VTI expressed skepticism about the timeline, estimating that even if permitting began in 2025, approvals would likely extend into 2030, with construction adding another 2–3 years. They noted that this timeline could delay operations into the mid-2030s if FERC jurisdiction applies. VTI also raised questions about Guam’s government creditworthiness, though they acknowledged no prior issues with government payments or financing related to infrastructure projects. Finally, demand uncertainty remains a key issue. VTI emphasized that decreasing volumes would increase unit costs, reinforcing the importance of structuring fixed-capacity payments to maintain financial viability over time, while also ensuring diesel backup capacity remains available as part of the island’s fuel inventory strategy.
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Appendix N: Permitting Matrix

Major Permits, Approvals, and Consultations Required									
Agency	Permit, Approval, or Consultation	Permit Type	Permit Responsibility	Typical Agency Review Period (months/days)	Location				Notes/Remarks
					Tangier	Wharf	Hotel	Wharf	
Federal									
Federal Energy Regulatory Commission (FERC)	Natural Gas Act Section 3 Authorization	Authorization	Developer/Operator	18-24 months	X		X		
U.S. Department of Energy (DOE)	Natural Gas Act Section 3, Free Trade Agreement (FTA) and Non-FTA	Authorization	Developer/Operator	1-12 months	X		X		
U.S. Army Corps of Engineers (USACE)	Clean Water Act Section 404 / Rivers & Harbors Act Section 10 Permit	Permit	Developer/Operator	12-18 months	X	X	X	X	Assumes no Rivers & Harbors Act Section 14 (33 United States Code Section 408) Authorization Needed (because no alteration to an authorized USACE Civil Works project is anticipated); assumes no permit needed pursuant to Section 103 of the Marine Protection Research and Sanctuaries Act (because no ocean disposal/dumping is contemplated)
U.S. Department of Defense (DoD) Department of the Navy	License/Lease	License/Lease	Developer/Operator	24 months	X	X	X	TBD	Assumes Navy lease/license for use of federal land (exclusion zones)
U.S. Department of Defense (DoD)	Energy Policy Act of 2005 FERC/DoD Consultation	Consultation	Developer/Operator	1-18 months	X		X		This consultation regarding effects of proposed LNG Terminal on activities undertaken by active military installations is specific to the FERC Natural Gas Act Section 3 Authorization process
U.S. Department of Transportation (USDOT) Pipeline and Hazardous Materials Safety Administration (PHMSA)	49 CFR Part 192 Compliance	Compliance	Developer/Operator	N/A		X		X	
U.S. Department of Transportation (USDOT) Pipeline and Hazardous Materials Safety Administration (PHMSA)	49 CFR Part 193 Compliance (including Letter of Determination)	Compliance	Developer/Operator	N/A	X		X		Letter of Determination precedes FERC Natural Gas Act Section 3 Authorization

Major Permits, Approvals, and Consultations Required									
Agency	Permit, Approval, or Consultation	Permit Type	Permit Responsibility	Typical Agency Review Period (months/days)	Location				Notes/Remarks
					Tanguisson	Hotel Wharf	NG Pipeline	NG Pipeline	
Federal									
U.S. Coast Guard	33 CFR Part 127 Compliance (including Letter of Intent, Waterway Suitability Assessment, and Letter of Recommendation); 33 CFR Part 105 Compliance	Compliance	Developer/Operator	N/A	X		X		Letter of Intent, Waterway Suitability Assessment, and Letter of Recommendation precedes FERC Natural Gas Act Section 3 Authorization
U.S. Fish & Wildlife Service	Section 7 of Endangered Species Act; Migratory Bird Treaty Act; Bald and Golden Eagle Protection Act; Marine Mammal Protection Act; Fish and Wildlife Coordination Act	Consultation	Developer/Operator	18-24 months	X		X	X	Performed as part of federal Authorization, Permitting, Licensing/Leasing processes; no USFWS permits/authorizations are assumed (pending environmental surveys and consultations)
National Oceanic and Atmospheric Administration (NOAA)	Section 7 of Endangered Species Act; Magnuson-Stevens Fishery Conservation and Management Act; Marine Mammal Protection Act; Fish and Wildlife Coordination Act; Coral Reef Conservation Act as amended	Consultation	Developer/Operator	18-24 months				X	Performed as part of federal Authorization, Permitting, Licensing/Leasing processes; no NOAA permits/authorizations are assumed (pending environmental surveys and consultations)
U.S. Department of Transportation (USDOT) Federal Aviation Administration (FAA)	Title 14 Part 77 Notification of Proposed Construction or Alteration	Notification followed by FAA Determination	Developer/Operator	45 business days	X		X	X	

Major Permits, Approvals, and Consultations Required									
Agency	Permit, Approval, or Consultation	Permit Type	Permit Responsibility	Typical Agency Review Period (months/days)	Location				Notes/Remarks
					Tanguisson	Hotel Wharf	LNG Pipeline	LNG Pipeline	
Guam									
Guam Environmental Protection Agency (GEPA)	General Permit Application: Earthmoving Work (Optional) Full Construction (Required)	Clearance	Developer/Operator	3 months	X		X	X	Engage Guam EPA at the 60% Design Phase. This is ultimately a component of the Guam DPW Building Permit
Guam Environmental Protection Agency (GEPA)	Section 401 Water Quality Certification	Certification	Developer/Operator	Unknown	X		X	X	All federal permits for work in marine waters, rivers, streams and wetlands require 401 WQC.
Guam Environmental Protection Agency (GEPA)/US EPA	National Pollution Discharge Elimination System (NPDES)	Permit	Developer/Operator	1-2 years	X		X	X	USEPA coordinates drafts and issues the permit facilities that require wastewater discharges such as sewage treatment plants, electrical power generation plants, industrial processing facilities, storm water outfalls, aquaculture facilities, aquariums, and similar operations must be permitted under this permit system.
Guam Environmental Protection Agency (GEPA)	Pollution Discharge Permit	Permit	Developer/Operator	6 months - 1 year	X		X	X	Pollution Discharge Permit. For discharges similar to those covered by the NPDES permit, GEPA may require a Government of Guam Pollution Discharge Permit for any number for liquid, gaseous, solid or thermal discharges into Territorial Waters that fall below the minimum criteria defined in the Federal Clean Water Act as Determined by the Administrator
Guam Environmental Protection Agency (GEPA)	Hazardous Waste Permits: Notification of Hazardous Waste Activity, RCRA Part A, Underground Storage Tank (UST)	Permit	Developer/Operator	Unknown	X		X	X	

Major Permits, Approvals, and Consultations Required								
Agency	Permit, Approval, or Consultation	Permit Type	Permit Responsibility	Typical Agency Review Period (months/days)	Location			Notes/Remarks
					Tanguisson	Hotel Wharf	NG Pipeline	
					NG Pipeline	LNG Terminal	NG Pipeline	
					LNG Terminal			
Guam								
Guam Environmental Protection Agency (GEPA)	Well Operating Permit, Underground Injection Control Permit, Well Drilling	Permit	Developer/Operator	Unknown				
Guam Environmental Protection Agency (GEPA)	Air Permits: Air Pollution Source Construction Permit, Emission Unit Permit, Compliance Certification, Air Pollution Permit to Construct in Non-Attainment Areas	Permit	Developer/Operator	Unknown	TBD	TBD	TBD	
Guam Department of Public Works (DPW)	Right-of-Way Permit	Permit		Unknown	X		X	Permit for construction in public right-of-way
Guam Department of Public Works (DPW)	Building Inspection and Permit	Permit	Developer/Operator	4 months if no land ownership issues				Following is required to obtain a building permit - Permit application (fully filled out with signatures) - Construction contract (must identify the contractor and construction cost). - Structural Calculations prepared by a licensed engineer. - Construction design plans, 1 each (original, 18" x 24" in size, stamped sealed and wet signed by a Guam PEALS licensed engineer) - Rewritable CD, 1 each, containing the above documents - Clearance letters from Regulatory Agencies
					X	X	X	Once DPW approves application submission, permit routed to following agencies for their signature; 1. Dept. of Land Management 2. Contractors Licensing Board 3. Guam Environmental Protection Agency 4. Guam PEALS Board 5. Department of Agriculture 6. Guam Parks and Recreation State Historic Preservation Office

Major Permits, Approvals, and Consultations Required							
Agency	Permit, Approval, or Consultation	Permit Type	Permit Responsibility	Typical Agency Review Period (months/days)	Location		
					Tanguisson	Hotel Wharf	Notes/Remarks
Guam Department of Land Management, Guam Seashore Protection Commission	Seashore Clearance	Permit	Developer/Operator	84 days	LNG Terminal	NG Pipeline	Needed if situated within ten meters inland from Mean High Water Mark or situated seaward to the ten (10) fathom contour: - Site Plan; Plans drawn to scale showing dimensions and shape of lot; lot size; size and location of existing building(s); location and dimensions of proposed building(s) or alterations; - 8 1/2" X 11" map, drawn to scale, showing all land zones within 1000 feet radius of subject lot's boundaries; - 8 1/2" X 11" map, drawn to scale, showing all building(s) or uses within 750 feet of the subject lot's boundaries. On the same map, applicant must also show any natural or topographic peculiarities of subject lot; - 8 1/2" X 11" map, drawn to scale, showing all parcels with correct lot number within 500 feet of subject's property boundaries; - Most recent recorded and certified Department of Land Management survey map showing subject's property; - Initial comprehensive Environmental Impact Assessment as required by Guam Chief Planner; - Erosion control plan; - If leased, lease assignment and covenant; and - Additional information as required by the Guam Chief Planner.
						LNG Terminal	
						NG Pipeline	
						Hotel Wharf	
Department of Land Management, Land Planning Division	Wetland Permit	Permit	Developer/Operator	Unknown	X	X	If wetlands on site
					X	X	

Major Permits, Approvals, and Consultations Required									
Agency	Permit, Approval, or Consultation	Permit Type	Permit Responsibility	Typical Agency Review Period (months/days)	Location				Notes/Remarks
					Tanguisson	Hotel Wharf	NG Pipeline	NG Pipeline	
Guam									
Department of Land Management, Land Planning Division	Flood Hazard Area Permit	Permit	Developer/Operator	Unknown	X	X	X	X	Tanguisson and Hotel Wharf sites are within the Flood Hazard Area of Particular Concern
Chamorro Land Trust Commission (CLTC)	License (commercial submerged lands license agreements)	License/Lease	Developer/Operator	Unknown	X	X	X	X	
Guam Coastal Management Program (GCMP), Bureau of Statistics and Plans (BSP)	Federal Consistency Review / Application for Consistency Certification	Certification	Developer/Operator	14 days	X	X	X	X	Determination of consistency of federal actions with Guam Coastal Management Plan
Department of Agriculture (DoAg), Division of Aquatic and Wildlife Resources (DAWR)	Special Use Permit	Permit	Developer/Operator	Unknown	X	X	X	X	
Guam Parks and Recreation State Historic Preservation Office (GHPO)	State Historic Preservation (SHPO) Consultation/Comment	Consultation/Comment	Developer/Operator	Unknown	X	X	X	X	Tanguisson Site is within 1000ft of Historical Site No concerns for Hotel Wharf

Appendix O: Implementation Schedule

Figure O.1 below includes the full implementation schedule for Tanguisson.

Figure O.1: Full Implementation Schedule – Tanguisson

