Appendix

Appendix 2-A: Price Forecasts

A.1 Natural Gas

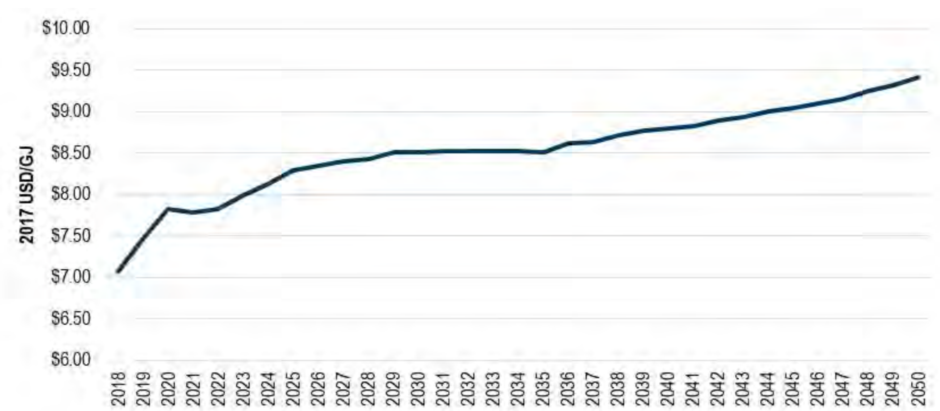
For the Base Case estimates, we use a typical price for a U.S. Gulf Coast supplier, with a typical fee schedule as follows. Other landed LNG costs can be examined as sensitivities.

Table 1: Natural Gas Cost Assumptions

Cost Source	
Henry Hub Natural Gas	See Henry Hub Forecast
Liquefaction Fee	$2.00/MMBtu
Fuel Gas Multiplier	15% of Henry Hub
Transportation Fee	$1.40/MMBtu
Landed LNG Cost	Sum of above components

This results in the landed LNG price forecast shown in Figure 1.

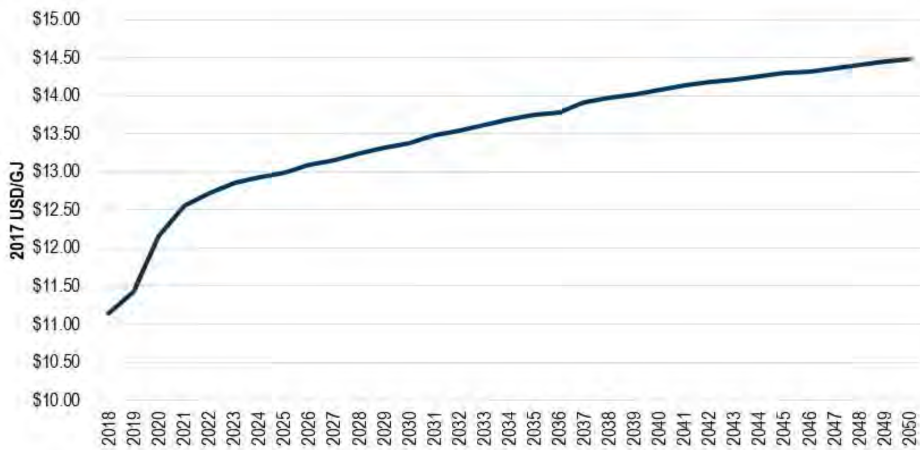
Figure 1: Landed LNG Price Forecast



A.2 LPG

The LPG forecast is calculated by utilizing the historical statistical relationship between the retail price of coastal LPG reported by the South Africa Department of Energy, the USD/ZAR exchange rate, as reported by the United States Federal Reserve, and the Brent crude oil price, as reported by the United States Energy Information Administration. Overall, these two factors explain more than 98% of the variation in historical South African LPG prices. This historical statistical relationship is applied to the Brent crude oil price forecast from the United States Energy Information Administration's Annual Energy Outlook 2018 forecast, and to a forecasted exchange rate, that is held at the average observed exchange rate from 2013-2018. This results in the forecast for coastal LPG prices shown in Figure 2.

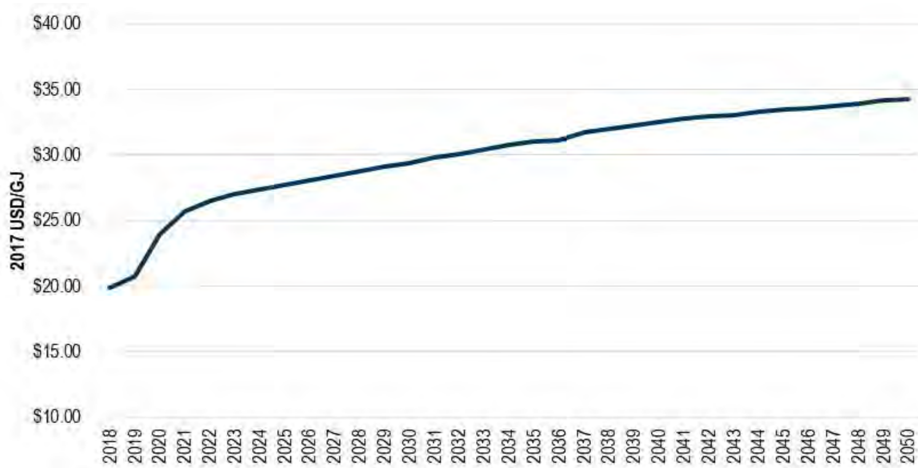
Figure 2: Coastal LPG Price Forecast



A.3 Diesel

Like LPG, the Diesel forecast is derived using the historical statistical relationships between coastal South African 0.05% Sulfur diesel and Brent crude oil prices. The variance in the Brent crude oil forecast explains over 95% of the variation in South African diesel prices historically. The relationship is then applied to the EIA's AEO 2018 Brent crude oil forecast, and results in the diesel price forecast shown in Figure 3.

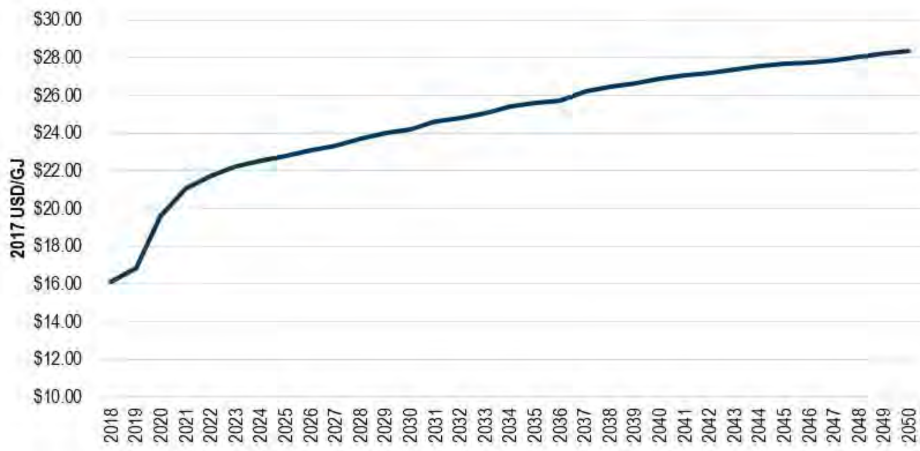
Figure 3: Diesel Price Forecast



A.4 Paraffin

Like Diesel and LPG prices, the historical statistical relationship between coastal South African LPG prices, Brent crude oil, and the USD/ZAR exchange rate. Historically, these two variables have explained over 94% of the variation in coastal paraffin prices. Applying this relationship to the Brent crude oil and exchange rate forecasts produces the paraffin price forecast shown in the figure below.

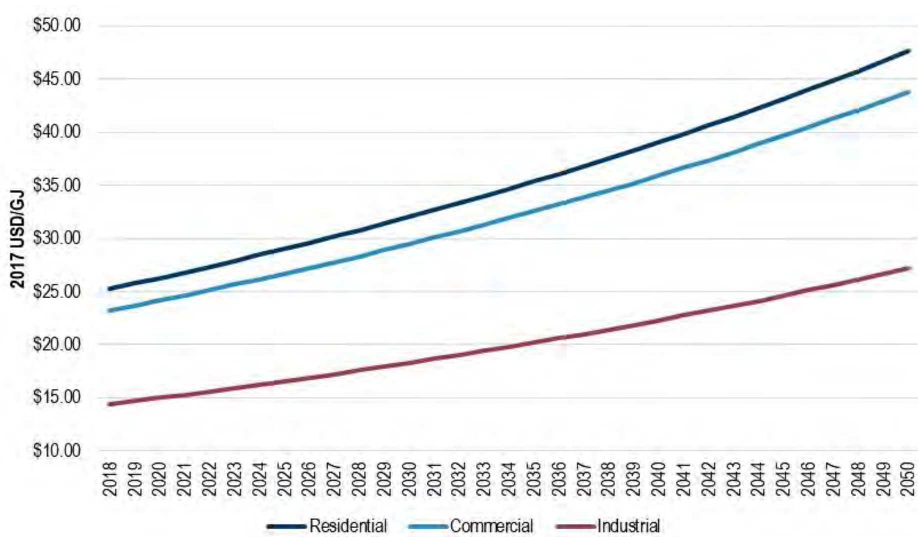
Figure 4: Coastal Paraffin Price Forecast



A.5 Electricity

Electricity prices are forecast separately for the residential, commercial, and industrial sectors using the same methodology. Electricity prices are escalated at a real rate of growth of 2% per year in the Base Case, like the NERSA award to Eskom for the 5-year multi-year price determination ("MYPD3") period of CPI +2%, and slightly higher than the CPI plus 1% awarded in the first two periods, and in the most recent 2018/2019 determination. This results in the sectoral electricity price forecasts displayed in Figure 5.

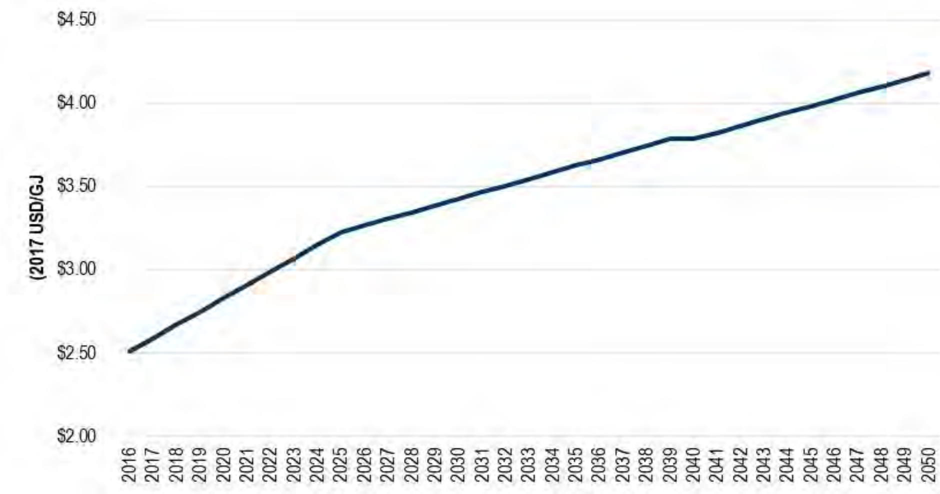
Figure 5: Electricity Price Forecasts



A.6 Coal

The coal price forecast comes from the International Energy Agency's World Energy Outlook 2017 report, which is displayed below in Figure 6.

Figure 6: Steam Coal Price Forecast



A.7 Combined

The combined view of all forecast energy prices is displayed below in Figure 7 and Figure 8.

Figure 7: Combined Price Forecasts

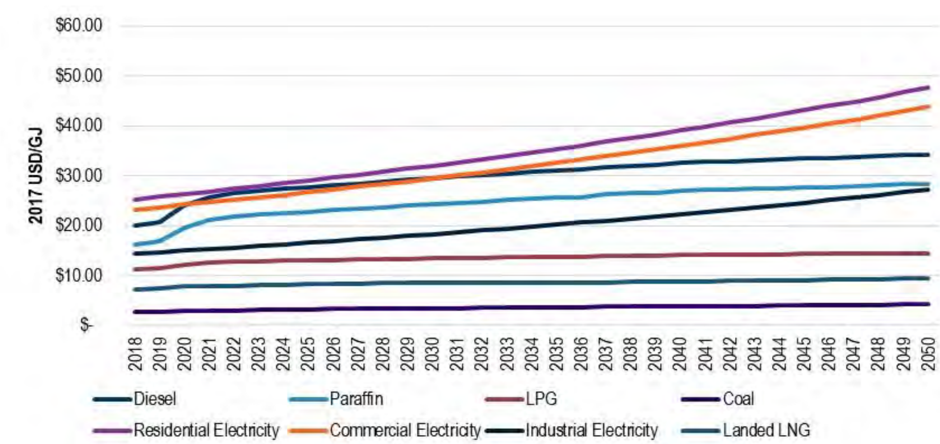
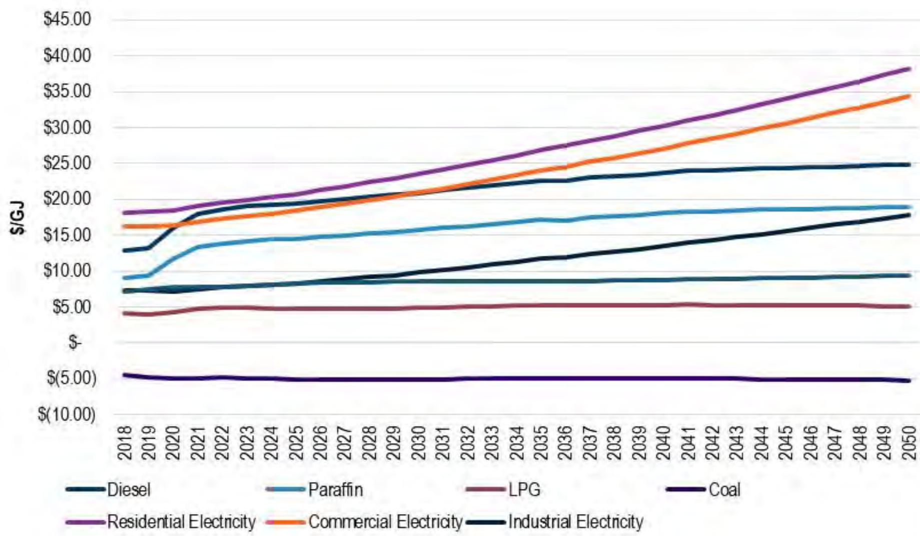


Figure 8: Combined Price Forecasts Differential to LNG Price Forecast



Appendix 2-B: Companies / Departments Contacted

The Team contacted the companies, organizations, and governmental agencies listed in the following table as part of its survey efforts.

Companies Contacted by the Team

1	ArcelorMittal	31	Langeberg & Ashton Foods (a division of Tiger Brands)
2	Afrox	32	Latex Threads
3	Air Liquide	33	Lucky Star-Hout Bay
4	Airports Company South Africa - CTIA	34	McMillan Bricks
5	Apollo Bricks	35	Mediclinic
6	Astral Foods (County Fair/National Chicks)	36	Naude Bakstene
7	Atlantis Diesel Engines (ADE)	37	Netcare
8	Atlantis Foundry	38	Novus Holdings Group
9	Atlantis Industrial Initiative (AII)	39	Oceana Group
10	Beukes Bricks	40	Oceana
11	Boland Bricks	41	Oranja Vis
12	Botriver Bricks	42	P&B Lime (Bontebok Limeworks)
13	Bredasdorp Steenwerke	43	Paarl Brick
14	Cabrico	44	PetroSA
15	Cape Peninsula University of Technology	45	PPC Regional Office (operations: Saldanha, Riebeeck West, De Hoek)
16	Cape Town Iron & Steel Works - HFO (CISCO)	46	RCL Foods
17	Chevron	47	Rheebok Stene
18	City of Cape Town (Energy/Electricity)	48	ROMPCO
19	City of Cape Town (Transport)	49	SA Breweries
20	Claybrick	50	Sea Harvest
21	Claytile (Pty) Ltd	51	South African Breweries
22	Coca-Cola Peninsula Beverages	52	South African National Energy Association (SANEA)
23	Consol	53	South African Oil and Gas Alliance (SAOGA)
24	Corobrik George	54	Spitskop Steenwerke
25	Corobrik Lansdowne	55	Stellenbosch University
26	Corobrik Phesantekraal	56	Sunbird

27	Corobrik Stellenbosch	57	Sunrise
28	Corobrik Vredenburg	58	Tiger Brands
29	Crammix Bricks	59	Transnet National Ports Authority (TNPA)
30	De Hoop Steenwerwe	60	Tronox
61	Distell	72	Tulbagh Bricks
62	Duferco Steel Processing	73	UCT Energy Research Centre
63	FFS-Vissershok	74	University of Cape Town
64	GigaJoule	75	University of Western Cape
65	Golden Era	76	Vantell
66	GRI	77	Victoria and Alfred Waterfront
67	Growthpoint Properties	78	Western Cape Government - Department of Environmental Affairs and Development Planning
68	Huhtamaki	79	Western Cape Government - Socio Economic data
69	i-Gas	80	Western Cape Government (Saldanha IDZ)
70	Kimberly-Clark	81	Winelands Textiles
71	Kurland bricks	82	Worcester Bakstene

Appendix 2-C: Survey Sample

Completed By:	*Please fill in below:
Name	
Title	
Email	

Data from:	*Please mark with X:		
	2018	2017	2016
Actual			
Estimated			

Table A - Fuel Consumption (see notes on page 3 for additional clarification)

Fuel	Quantity	Quantity Units	Average Price/unit	Natural Gas Switching Potential	Five Year Expansion Potential
(example) Coal	10,000	tonnes per annum	2300 rand / metric tonne	50%	25%
Biomass					
Coal (Bituminous)					
Coal (Anthracite)					
Coke					
Diesel					
Heavy Fuel Oil					
Kerosene					
LPG					
Paraffin					
Other					

Table B – Electricity Consumption (see notes on page 3 for additional clarification)

Quantity	Quantity Units	Tariff	Five Year Expansion Potential
(example) 1,700	MWh	Eskom Businessrate 1	25%

Appendix 2-D: Simulation Parameters

Table 1: Macroeconomic / Socioeconomic Input Variables

Input Variable	Sector	Distribution	Source	Low	Midpoint	High
Commercial Share of Western Cape GDP[1]	Comm/Ind	Normal	Historically Derived Variance (Stats SA)	N/A	72%	N/A
Industrial Share of Western Cape GDP[2]	Comm/Ind	Normal	Historically Derived Variance (Stats SA)	N/A	18%	N/A
Energy Intensity of Use	Comm/Ind/Res	Triangular	Forecast (EIA & IEP), Low/High Assumed	Base - 10%	Base Case Forecast	Base + 10%
GDP Growth Rate	Comm/Ind/Trans	Normal	Historically Derived Variance (Stats SA), Forecast (OECD)	N/A	OECD Base Case	N/A
Pipeline Route Share of Western Cape Population (net-migration)	Res/Trans	Triangular	Historically Derived (Stats SA)	65%	68%	71%
South Africa Population Growth Rate	Res/Trans	Normal	UN Probabilistic Forecast	N/A	UN Probabilistic Forecast	N/A
Western Cape Share of South Africa GDP	Comm/Ind	Normal	Historically Derived (Stats SA)	N/A	11.6%	N/A
Western Cape Share of South Africa Population (net-migration)	Res/Trans	Normal	Historically Derived (Stats SA)	N/A	13.7%	N/A

Table 2: Price Input Variables

Input Variable	Sector	Distribution	Source	Low	Midpoint	High
Brent Price	All	Normal	Historically Derived Variance (CME), Forecast (IEA)	N/A	IEA Forecast	N/A
Electricity Price Inflation Rate	All	Triangular	Assumed	CPI	CPI +2%	CPI + 5%
Carbon Tax (1)	All	Binomial	Assumed	None (75%)		Implemented (25%)
Carbon Tax (2)[3]	All	Triangular	World Bank	$3	$10/tCO2e	$22

[1] Related to Industrial Share of Western Cape GDP, Commercial Share = (1 – Industrial Share)

[2] Ibid.

[3] This is based upon the World Bank source cited in the Task #2 Demand Report and is based upon a range of actual implemented taxes.

Input Variable	Sector	Distribution	Source	Low	Midpoint	High
Carbon Tax Growth Rate	All	Triangular	Assumed	1%	2%	3%
Coal Price	Ind	Normal	Historically Derived Variance (CME), Forecast (IEA)	N/A	Base	N/A
Natural Gas Fuel Price	All	Normal	Historically Derived Variance (EIA), Forecast (EIA)		Base	

Table 3: Sectoral / Other Input Variables

Input Variable	Sector	Distribution	Source	Low	Midpoint	High
Cost of New Build Gas CCGT	Power	Triangular	Low/High Assumed, Base Case (EIA)	$914 (-25%)	$1,218/kw	$1,523 (+25%)
Cost of Conversion to CCGT	Power	Triangular	Low/High Assumed, Base Case (EIA)	$437 (-25%)	$583	$729 (+25%)
Ankerlig CCGT Capacity factor	Power	Triangular	Assumed	15%	35%	55%
Ankerlig Status Quo Capacity factor	Power	Triangular	Low/High Assumed, Historically Derived Base	7%	17%	27%
Discount Rate	Power	Triangular	Assumed	9.5%	10%	10.5%
Gas and Diesel Open Cycle Heat Rates	Power	Triangular	Assumed	11.4 (-5%)	12 MMBtu/MWh	12.6 (+5%)
Advanced-CC Heat Rate	Power	Triangular	Assumed	6.0 (-5%)	6.3 MMBtu/MWh	6.6 (+5%)
Technical Substitution Rate	Comm/Ind/Res/Trans	Triangular	Assumed	Base – 20%	Base	Base + 20%
Equipment Turnover Rate	Comm/Res	Triangular	Assumed	Base – 20%	Base	Base + 20%
Thermal Desalination (1)	Ind	Binomial	Assumed	None		Built
Thermal Desalination Output (2)	Ind	Triangular	Historically Derived (To Research)	1,600	2,000 kgal/day	7,000
Annual Vessel Calls to Port of Cape Town	Trans	Triangular	Low/High Assumed, Base Case (World Maritime University)	2,462 (-10%)	2,735/year	3,009 (+10%)

Input Variable	Sector	Distribution	Source	Low	Midpoint	High
Vessel Calls Requiring LNG Bunkering Fuel	Trans	Triangular	Low/High Assumed, Base Case (World Maritime University)	2.5%	5%	7.5%
Vessel Call Growth Rate	Trans	Triangular	Assumed	-1%	0%	1%
Annual Vessel Calls to Port of Durban	Trans	Triangular	Low/High Assumed, Base Case (World Maritime University)	3,582 (-10%)	3,980/year	4,378 (+10%)
Port of Durban Share of Potential Refueling at Port of Cape Town[4]	Trans	Triangular	Assumed	15%	25%	35%
Natural Gas Share of Transportation Demand	Trans	Triangular	Low/High Assumed, Forecast (EIA) – Rebased to Western Cape	Base – 5%	Base	Base + 5%

[4] Assumed that some ships calling to Durban may stop at Cape Town to fuel, given availability of fuel

Appendix 3-A: SAM Model

Table 1: Western Cape SAM Sectors and SIC Numbers

SIC Number and Sector in Western Cape SAM		
1 Cereal Farming	27 Sugar	52 Manufacturing of Transport Equipment
2 Table Grape Farming	28 Bakery Products	53 Furniture
3 Wine Grape Farming	29 Animal Feed Products	54 Other Manufacturing and Recycling
4 Other Deciduous	30 Other Food Products	55 Electricity
5 Citrus	31 Beverages and Tobacco	56 Water
6 Sub-Tropical Fruit	32 Textiles	57 Buildings and Other Construction
7 Sugar Cane	33 Clothing	58 Wholesale and retail trade
8 Vegetable Farming	34 Leather Products	59 Catering and accommodation services
10 Livestock Farming	35 Footwear	60 Transport and storage
11 Poultry (White Meat excl. Eggs)	36 Sawmilling and Planning of Wood	61 Communication
12 Game Farming	37 Wood products	62 Finance and insurance
13 Fishing	38 Paper and Paper Products	63 Business services
14 Forestry	39 Publishing and Printing	64 Business Process Management
15 Other Agriculture	40 Petroleum	65 Community, social and personal services
16 Coal	41 Basic chemicals	66 Other 1
17 Crude Oil	42 Other chemicals	67 Other 2
18 Precious Metal and Minerals	43 Rubber Products	68 Other 3
19 Metal Ores	44 Plastic Products	69 Other 4
20 Other Mining	45 Non-Metallic Mineral Products	70 Other 5
21 Meat	46 Basic Metal Products	71 Other 6
22 Fish	47 Machinery and Equipment	72 Other 7
23 Fruit and Vegetables	48 Electrical Machinery and Apparatus	73 Other 8
24 Oil and Fat Products	49 Renewable Energy Machinery	74 Other 9
25 Dairy Products	50 Communication and Medical Equipment	75 Other 10
26 Grain Mill Products	51 Electronic Equipment	

Table 2: SAM Sector Receiving Allocated Project Investment

Sector	SIC Code
Basic Metal Products	46
Machinery and Equipment	47
Electrical Machinery and Apparatus	48
Electronic Equipment	51
Buildings and Other Construction	57
Finance and insurance	62
Business services	63
Business Process Management	64

Appendix 3-B: Investment Allocations

Table 1: PRDW Component Costs to SAM Sectors

	PRDW CAPEX Line Item									
SAM Sector	Dredging and Reclamation	Revetment, Scour Protection	Pipe Protection	Quay Structure	Access Trestle	Aids to Navigation	General Facility Infrastructure	General Services	Gas Pipeline	Gas Off-loading
Basic Metal Products	0%	0%	0%	15%	15%	5%	2%	0%	20%	1%
Machinery and Equipment	0%	0%	0%	2%	0%	30%	2%	0%	5%	45%
Electrical Machinery and Apparatus	0%	0%	0%	0%	0%	0%	0%	25%	0%	0%
Electronic Equipment	0%	0%	0%	0%	0%	8%	1%	0%	0%	2%
Buildings and Other Construction	69%	70%	70%	54%	55%	21%	64%	40%	42%	18%
Finance and insurance	13%	13%	13%	13%	13%	18%	13%	17%	16%	17%
Business services	9%	10%	10%	10%	10%	10%	10%	10%	10%	10%
Business Process Management	9%	7%	7%	6%	7%	8%	8%	8%	7%	7%

Table 2: PRDW Investment Schedule for Option 3

Construction Year	Dredging and Reclamation	Revetment, Scour Protection	Pipe Protection	Quay Structure	Access Trestle	Aids to Navigation	General Facility Infrastructure	General Services	Gas Pipeline	Gas Off-loading
Year 1	0%	0%	0%	12%	0%	0%	35%	0%	10%	0%
Year 2	0%	0%	50%	58%	0%	0%	65%	100%	85%	80%
Year 3	0%	0%	50%	30%	0%	100%	0%	0%	5%	20%

Table 3: Granherne Investments to SAM Sectors

	Granherne Line Items								
SAM Sector	Total Equipment	Total Bulk Materials	Material-Related Costs	Subcontracts - Misc.	Buildings	Construction	Engineering, Design, Procurement Services	Miscellaneous Costs	Start-up and Commissioning
Basic Metal Products	0%	50%	0%	30%	0%	0%	0%	0%	0%
Machinery and Equipment	95%	0%	0%	30%	0%	0%	0%	0%	0%
Electrical Machinery and Apparatus	0%	10%	0%	5%	0%	0%	0%	0%	0%
Electronic Equipment	0%	20%	0%	10%	0%	0%	0%	0%	0%
Buildings and Other Construction	0%	15%	80%	20%	95%	95%	95%	0%	0%
Finance and insurance	1%	1%	1%	1%	1%	1%	1%	1%	1%
Business services	0%	0%	15%	0%	0%	0%	0%	95%	95%
Business Process Management	4%	4%	4%	4%	4%	4%	4%	4%	4%

Table 4: Granherne Operating Costs to SAM Sectors

SAM Sector	Staff / Fixed Operating Costs	Maintenance Costs	Insurance	LNG Carrier
Basic Metal Products	0%	0%	0%	0%
Machinery and Equipment	0%	0%	0%	0%
Electrical Machinery and Apparatus	0%	0%	0%	0%
Electronic Equipment	0%	0%	0%	0%
Buildings and Other Construction	0%	0%	0%	0%
Finance and insurance	1%	1%	100%	0%
Business services	95%	95%	0%	0%
Business Process Management	4%	4%	0%	0%

Table 5: Granherne Pipeline Investment Timeline

	Granherne Pipelines								
Construction Year	Total Equipment	Total Bulk Materials	Material-Related Costs	Subcontracts - Misc.	Buildings	Construction	Engineering, Design, Procurement Services	Miscellaneous Costs	Start-up and Commissioning
Year 1	0%	0%	0%	0%	0%	0%	0%	0%	0%
Year 2	0%	0%	0%	0%	0%	0%	50%	0%	0%
Year 3	0%	50%	50%	0%	0%	50%	50%	50%	0%
Year 4	0%	50%	50%	0%	0%	50%	0%	50%	100%

Appendix 4-A: Financial Model Structure

A.1 Financial Model Structure

The Model is fully interactive, flexible, and transparent. It consists of inputs (assumptions) tabs, calculation tabs, and output tabs, and an introduction page. The Model's calculations are generally constructed to flow from left to right (both columns and tabs) and top to bottom. The Model is built with consistent formulas across time with no hard coding (except in assumption cells) and is fully functional, i.e., changes in assumptions drive the Model automatically. The source data for inputs is noted in the comments in each of the individual cells. If no source is noted, the input is an internal estimate prepared by the Team.

The Model is designed to allow for the user to evaluate each component of the Project individually. This is valuable for review purposes to understand the viability of each component of the Project, but also critical in case certain investors are interested to see the economics of a single or several components of the Project. As such, separate financial statements are provided for the (i) import terminal ("GasCo"), (ii) regasification ("RegasCo"), (iii) transmission and distribution pipeline ("TransCo") and (iv) the anchor power plant ("PowerCo"). Consolidated financial statements are also provided for reference purposes (as described further below). Such a structure assumes that each Project component is developed as its own special purpose company (which is expected to be the case even if a single investor were to own the various assets, which they could then hold via a holding company dedicated to the Project). The calculation tabs have clearly demarcated sections for each component of the Project starting with the import terminal calculations in the top rows and running through to the anchor power plant calculations in the bottom rows of the respective tab.

The structure of the Model is described in detail in this section along with a brief narrative of the content in each tab.

A.1.1 Introduction Page ("Intro")

The Intro tab contains an outline of the Model structure by listing the various tabs along with abbreviations of the tab names. It also details the cell and font color coding used throughout the Model. Please refer to the figure below for further details.

Figure 1: Financial Model Table of Contents and Legend

TABLE OF CONTENTS:

1	Sum	Project Summary & Key Metrics
2	InpC	Constant Inputs
3	InpS	Time Series Inputs
4	S&U	Project Sources & Uses
5	LCCA	Life Cycle Cost Analysis
6	Draw	Drawdown Schedules
7	Debt	Debt Schedules
8	Equity	Equity Schedules
9	Ops	Operations
10	Dep	Depreciation & Amortization
11	Div	Dividend Policy & Payout
12	Tax	Taxation
13	Ret	Project Valuation & Returns
14	T	Timing Schedules
15	GasCo FS	Marine Import Terminal Proforma Financial Statements
16	RegasCo FS	Regasification & Storage Unit Proforma Financial Statements
17	TransCo FS	Pipeline & Distribution Proforma Financial Statements
18	PowerCo FS	Anchor Power Plant Proforma Financial Statements
19	Consol FS	Consolidated Project Proforma Financial Statements
20	Sens 4.1	Sensitivity Analysis as per Task 4.1
21	Sens 4.2	Sensitivity Analysis as per Task 4.2

LEGEND | CELL & FONT COLOR:

0.00	Hard-Coded Adjustable Inputs
0.00	Formulas
0.00	Offsheet Imports
0.00	Technical Input / Do Not Delete
	Empty Cell / Do Not Delete
OK	Checks Inactive
Warning	Checks Active
-	Flag
1	Active Selection Indicator

LEGEND | WORKSHEET TAB COLOR:

- Inputs
- Calculations
- Outputs
- Sensitivities
- Dormant

A.1.2 Summary ("Sum")

The Sum tab provides an overview of the Project's key financial and economic results. The tab contains a summary of the sources of financing and uses of funds as well as key project metrics such as net present value ("NPV"), weighted average cost of capital ("WACC"), internal rate of return ("IRR"), debt service coverage ratios ("DSCRs"), and levelized cost of electricity ("LCOE").

The following table outlines the summary sources and uses of funds related to the Project (note: given the base case assumes a leased FSRU approach, there are no separate sources and uses of funds for a regasification unit as there would be in the case of either (i) an onshore regasification unit) or (ii) a purchased FSRU).

Figure 2: Summary of Project Sources and Uses of Funds

		GASCO	REGASCO	TRANSCO	POWERCO	CONSOLIDATED
USES OF FUNDS						
Capital Expenditure	ZAR 000s	1,682,839	0	3,145,184	13,158,264	17,986,287
Financing Fees	ZAR 000s	62,415	0	107,636	546,887	716,938
Interest During Construction	ZAR 000s	115,602	0	299,507	1,683,069	2,098,178
Debt Service Reserve Account	ZAR 000s	108,709	0	207,523	827,789	1,144,021
Total Uses of Funds	ZAR 000s	1,969,566	0	3,759,850	16,216,008	21,945,424
SOURCES OF FUNDS						
Debt	ZAR 000s	1,378,696	0	2,631,895	11,351,206	15,361,797
Equity	ZAR 000s	590,870	0	1,127,955	4,864,803	6,583,627
Total Sources of Funds	ZAR 000s	1,969,566	0	3,759,850	16,216,008	21,945,424

The key results summarized in this tab are described further in Section 3.2.

A.1.3 Constant Inputs (“InpC”)

The InpC tab contains all constant inputs (assumptions) that do not necessarily change over time. All cells containing inputs are marked light yellow with blue font and can be modified by users. Time constant inputs include project component selections, capital expenditures and operating expenses associated with each project component, operating performance, financing terms, and macroeconomic assumptions, among others. For example, the figure below includes a snapshot of capital expenditures associated with the import terminal and marine infrastructure.

The timing assumptions contain inputs that relate to key dates for the Project’s financing, construction and operations. The Model assumes that the Project will commence in January 2021 with the construction activities associated with the Project component requiring the longest timeline to achieve completion, which is the Ankerlig conversion. The Ankerlig conversion requires approximately three years of construction activities until reaching its commercial operations date (“COD”) in January 2024. The Team assumed that Project components are aligned to commence with operations at the same time, as such the timelines for each Project component have been back-ended from the Ankerlig conversion COD using their respective CAPEX spending profiles to calculate each component’s financial close and start of construction. As such, each component will achieve financial close and commence with construction activities at different dates, but they will all reach project completion within the same quarter. Please see the figure below for a snapshot of the timing and capital expenditures associated with the import terminal.

Figure 3: Timing and Capital Expenditures for Import Terminal

IMPORT TERMINAL

TIMING ASSUMPTIONS

Construction Start Date	01-Oct-21	date
Construction End Date	31-Dec-23	date
Commercial Operations Date	01-Jan-24	date

CAPITAL EXPENDITURES

Terminal Location	Shallow Water		Deep Water	
Storage Type	Onshore	FSRU	FSRU	Active
Expenditures	Option 1	Option 2	Option 3	Option 3
Dredging and Reclaimation	82,800,000	82,800,000	0	0
Revetment, Scour Protection	23,400,000	23,400,000	0	0
Pipe Protection	0	0	2,100,000	2,100,000
Quay Structure	44,500,000	44,500,000	47,500,000	47,500,000
Access Trestle	26,900,000	0	0	0
Aids to Navigation	2,400,000	2,400,000	2,400,000	2,400,000
General Facility Infrastructure	4,500,000	4,500,000	4,500,000	4,500,000
General Services	1,400,000	1,400,000	1,400,000	1,400,000
Gas Pipeline & Distribution Hub	0	11,600,000	39,600,000	39,600,000
Gas Off-Loading	0	6,400,000	6,400,000	6,400,000
Total	185,900,000	177,000,000	103,900,000	103,900,000

As mentioned above, each Project component features its own adjustable spending profile to accommodate up to four years of expenditures. Please refer to the spend profile snapshot for the import terminal project component as an example (a similar spend profile has been prepared for each component of the Project and each of these can be found in the InpC tab of the Model):

Figure 4: Snapshot of Spend Profile for Import Terminal

Terminal Location			Shallow Water		Deep Water	
Storage Type			Onshore	FSRU	FSRU	Active
Expenditures			Option 1	Option 2	Option 3	Option 3
31-Dec-21	2021	Q1	3%	3%	4%	3,646,736
31-Mar-22	2022	Q2	3%	3%	4%	3,646,736
30-Jun-22	2022	Q3	14%	15%	4%	4,401,675
30-Sep-22	2022	Q4	19%	20%	8%	8,509,052
31-Dec-22	2022	Q5	23%	22%	10%	10,441,182
31-Mar-23	2023	Q6	27%	29%	13%	13,307,389
30-Jun-23	2023	Q7	9%	10%	18%	19,103,781
30-Sep-23	2023	Q8	2%		22%	22,405,037
31-Dec-23	2023	Q9			18%	18,438,411
31-Mar-24	2024	Q10				0
30-Jun-24	2024	Q11				0
30-Sep-24	2024	Q12				0
31-Dec-24	2024	Q13				0
31-Mar-25	2025	Q14				0
30-Jun-25	2025	Q15				0
30-Sep-25	2025	Q16				0
Total			100%	100%	100%	103,900,000

Constant financing inputs for the Project include assumptions for capital structure, debt and equity financing, and dividend distributions. The financing assumptions are based on the Team's discussions with potential financiers, industry research, and prior experience advising on oil and gas and power projects in the global emerging markets. The Model assumes that each Project component will be financed through a combination of debt and equity. The capital structure for each Project component is based on an adjustable equity-to-value (i.e., equity % of the total Project costs) assumption for each respective financing. An embedded macro goal seeks the debt drawn to equal the target debt required to meet CAPEX requirements and soft costs associated with the financing to eliminate any circularity upon calculation. Please note that debt drawn for the regasification unit component of the Project is equal to zero as the Base Case assumes a leased FSRU option (however, an option to evaluate the purchase of the FSRU can be examined by selecting "Purchase" under the "FSRU Option Selection" input).

Figure 5: Capital Structure

CAPITAL STRUCTURE

Project Component	Equity / Value	
Import Terminal	30%	% of equity-to-value
Regasification Unit	30%	% of equity-to-value
Transmission Pipeline	30%	% of equity-to-value
Anchor Power Plant	30%	% of equity-to-value

Project Component	Debt Drawn	Target Debt	Check	
Import Terminal	1,378,696,407	1,378,696,407	OK	ZAR
Regasification Unit	0	0	OK	ZAR
Transmission Pipeline	2,631,894,855	2,631,894,855	OK	ZAR
Anchor Power Plant	11,351,205,838	11,351,205,838	OK	ZAR

The debt financing terms are adjustable for each project component and include loan tenor, loan amortization schedule selections of either straight-line principal payments (“Straight-Line”) or mortgage style payments (“Mortgage”), pricing components, and fees.

Figure 6: Debt Financing Terms

Debt Financing	Terminal	Regas Unit	Pipeline	Ankerlig	Greenfield IPP	
Tenor	17.00	15.00	17.00	17.75	17.75	years
Principal Payment Moratorium	2.00	0.00	2.00	2.75	2.75	years
Payments per Year	4	4	4	4	4	payments / year
Principal Amortization	Mortgage	Mortgage	Mortgage	Mortgage	Mortgage	type
Base Rate	9.67%	9.67%	9.67%	9.67%	9.67%	% p.a.
Spread	4.00%	4.00%	4.00%	2.50%	4.00%	% p.a.
Interest Rate	13.67%	13.67%	13.67%	12.17%	13.67%	% p.a.
Commitment Fee	0.50%	0.50%	0.50%	0.50%	0.50%	% p.a.
Facility / Exposure Fee	1.25%	1.25%	1.25%	1.25%	1.25%	% of loan amount
Maintenance Fee	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	ZAR p.a.
Closing Fees	0.50%	0.50%	0.50%	0.50%	0.50%	% of loan amount
Debt Service Reserve Account	2	2	2	2	2	P+I payments
Initial Funding of DSRA	108,709,070	0	207,522,729	827,788,987	895,033,177	ZAR

The tenor listed above is door-to-door (i.e. inclusive of the principal payment moratorium or grace period). The interest rate spread for the Ankerlig conversion is assumed to be lower given the lower risk profile of a conversion project as opposed to a greenfield project. In addition, it is important to note that the Ankerlig conversion will likely be financed by Eskom on a corporate basis as opposed to on a project finance basis (which would also typically result in a lower interest margin than the other Project components given the limited recourse nature of the project financing structure assumed for the other components of the Project). However, we believe these assumptions allow for a reasonable comparison of the Ankerlig Conversion vs. the Greenfield IPP.

Further, the financing assumptions also include target equity internal rates of return (“IRR”), or costs of equity, for each Project component to calculate the gas tariff required for that component to deliver a target rate of return to the equity holders based off dividend distribution covenants that are generally acceptable to lenders. As such, the target equity input is a key driver of the tariff that the Model produces. Note that the IRR’s calculated in the Model are a ZAR IRR as opposed to a USD IRR and therefore the target Equity IRR is a ZAR IRR. The Model also includes component specific costs of equity using the capital asset pricing model (“CAPM”) and assumptions from publicly available data sources and reports.[1, 2] The Model provides the option for switching between a hard-coded target equity IRR or by using the cost of equity buildup.

While the Base Case currently targets a hard-coded equity IRR of 20% for the import terminal, regasification unit, and transmission pipeline and 10% for Ankerlig as the anchor power plant, to build up the gas tariff required at each Project component to achieve such returns, the Model can also accommodate user-defined incremental gas tariffs along the value chain and assess asset returns and equity returns.

[1] Aswath Damodoran. Stern School of Business, New York University. Data portal. Jan 8, 2018. http://pages.stern.nyu.edu/~adamodar/

[2] KPMG. Equity Market Risk Premium - Research Summary. Sep 30, 2018. https://assets.kpmg.com/content/dam/kpmg/nl/pdf/2018/advisory/equity-market-risk-premium-research-summary-september-2018.pdf.

Figure 7: Equity Financing and Dividend Policy

Equity Financing	Terminal	Regas Unit	Pipeline	Ankerlig	Greenfield IPP	
Unlevered Industry Beta	0.94x	0.94x	1.23x	0.63x	0.63x	beta
Levered Project Beta	2.52x	2.52x	3.30x	2.10x	2.10x	beta
Equity Risk Premium	5.50%	5.50%	5.50%	5.50%	5.50%	% p.a.
Closing Cost of Equity	23.53%	23.53%	27.80%	21.22%	21.22%	% p.a.
Target Equity IRR	20.00%	20.00%	20.00%	10.00%	20.00%	% p.a.
Target Equity IRR Selected	20.00%	0.00%	20.00%	10.00%	0.00%	% p.a.
Actual Equity IRR	20.26%	0.00%	20.38%	9.97%	0.00%	% p.a.
Equity IRR Check	OK	OK	OK	OK	OK	check

Dividend Policy	Terminal	Regas Unit	Pipeline	Ankerlig	Greenfield IPP	
Min Cash Balance	13,786,964	0	26,318,949	113,512,058	113,512,058	ZAR
Min Debt Service Coverage	1.20x	1.20x	1.20x	1.20x	1.20x	ratio
Max Debt / Equity	2.50x	2.50x	2.50x	2.50x	2.50x	ratio

The taxation assumptions related to the Project are shown in the figure below. The Team has assumed a corporate income tax rate of 28%. However, the Team has also included a Special Economic Zone ("SEZ") tax rate scenario switch and assumed that the Import Terminal and Regasification components of the Project will be located within the Saldanha Bay SEZ.[3] As such, we have assumed these components will be subject to the SEZ income tax rate of 15%. Furthermore, the Team has also separated out an income tax rate for Eskom with regards to its taxes related to the Ankerlig conversion. Given that Eskom is operating at net losses before taxes, we have assumed for the sake of the Model that the incremental income tax rate related to the Ankerlig plant conversion will be 0% (i.e., any incremental taxable benefit from the Ankerlig conversion will be offset by Eskom's net overall losses). Net operating losses are carried forward indefinitely as per current regulatory guidance and offset future taxation liabilities until accrued losses are depleted.[4]

Figure 8: Taxation

Taxation	Rates	
Corporate Tax Rate	28.0%	% of taxable income
SEZ Corporate Tax Rate	15.0%	% of taxable income
Eskom Tax Rate	0.0%	% of taxable income
Import & Regas located in SEZ?	0	1 = Yes || 0 = No
Import Terminal & Regas Tax Ra	28%	% of taxable income

Additional notable time constant inputs include depreciation schedules, LNG pricing assumptions, and market demand scenario selections. The InpC worksheet also includes annual inflation forecasts that drive the time series assumptions for domestic and international inflation and the USD-ZAR exchange rate forecast on the time series inputs worksheet.

[3] The Team understands that in Saldanha Bay there is presently an IDZ, which is transitioning to an SEZ. As such, the details remain subject to confirmation. We further understand that even if the Project components are sited with the SEZ, they may not be subject to all the benefits the SEZ has to offer including the lower tax rate. While the Team has assumed that the Project components sited in the SEZ will receive the benefit of the lower tax rate, this input can be easily adjusted by the user.

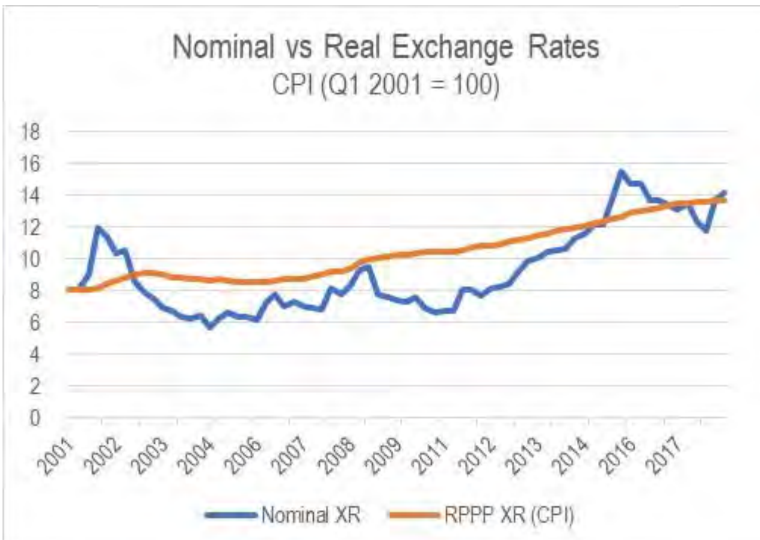
[4] Deloitte. International Tax: South Africa Highlights 2018. https://www2.deloitte.com/content/dam/Deloitte/global/Documents/Tax/dttl-tax-southafricahighlights-2018.pdf.

A.1.4 Time Series Inputs ("InpS")

Time series assumptions are included in the InpS tab for inputs that change over the Project's timeline. Items included on a time series basis are ZAR-USD exchange rate, ZAR consumer price index (inflation), and tariff escalation. As in the case of the InpC tab, assumptions in the InpS can also be changed and will impact the Model's results dynamically.

Projections of annual inflation were sourced from the International Monetary Fund ("IMF") through 2023 and located on the InpC worksheet. For periods beyond 2023, the Model assumes the inflation rate remains constant using the prior year's inflation rate. The forecasted exchange rate assumes that the U.S. Dollar and South African Rand are currently in equilibrium, as suggested by comparing their historical nominal and real exchange rates, and forward rates are calculated using the theory of relative purchasing power parity ("RPPP"), wherein the exchange rate adjusts over time to compensate for the inflation differentials between the two countries.[5]

Figure 9: Nominal vs. Real Exchange Rate (USD-ZAR)



The InpS tab also includes the base, low, and high market demand curves for residential, commercial, industrial, transportation, and power sector users as previously shared in the Task 2: Market Demand Analysis Report. The InpS tab also includes the same price forecasts for Brent oil, diesel, Henry Hub, and the buildup for the price of landed LNG that were included in the Task 2 analysis to ensure consistency across the various tasks

[5] U.S. Federal Reserve Economic Data. Economic Research Division. Federal Reserve Bank of St. Louis. Data sets: DEXSFUS, ZAFCPIALLMINMEI_NBD19800101, CPIAUCNS_NBD19800101. https://fred.stlouisfed.org.

Figure 10: Base Case LNG Market Demand

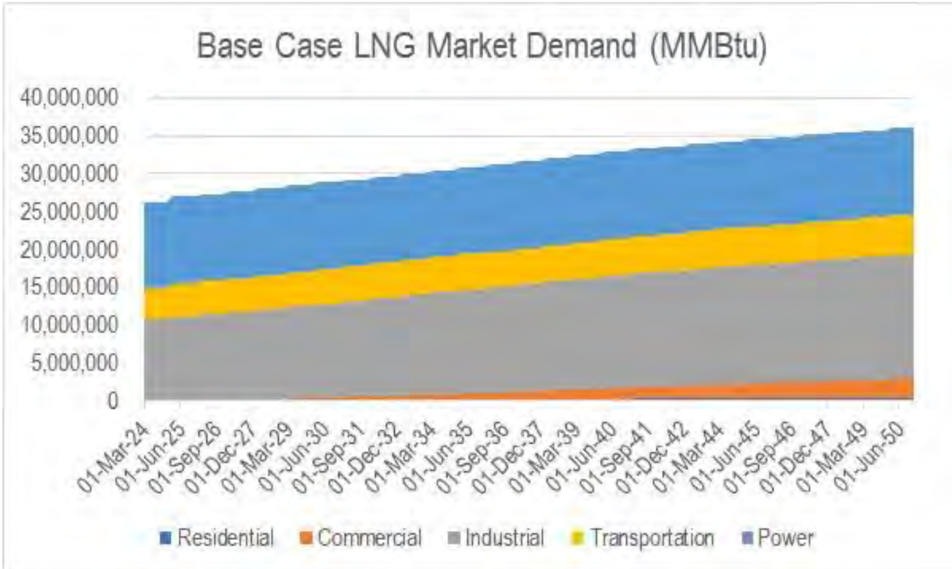
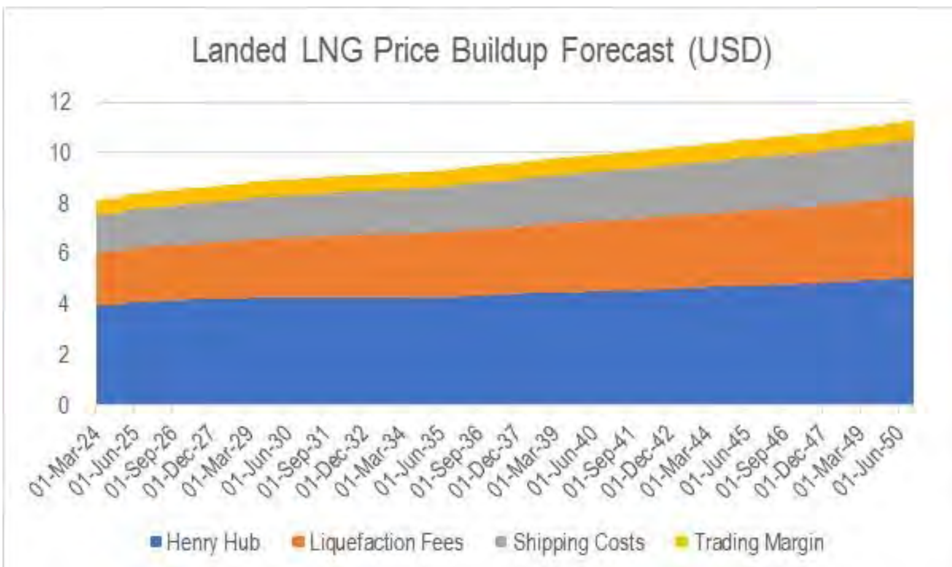


Figure 11: Landed LNG Price Buildup Forecast



A.1.5 Sources and Uses of Funds ("S&U")

This tab summarizes the Project's capital cost requirements (uses of funds) for each component of the Project. The tab also presents how such costs are funded through senior debt and equity (sources of funds).

A.1.6 Draw Schedule ("Draw")

This tab contains drawdown schedules for each of the Project components based on the CAPEX spend profiles assumed in the InpC tab as well as the associated soft costs (e.g., financing costs). This tab also shows the sources of funds used to fund these Project costs.

A.1.7 Debt Schedule ("Debt")

The Debt tab presents calculations of debt financing including disbursement of debt, interest payment, and debt amortization for each component of the Project. There are two options for debt amortization: (i) mortgage style (i.e., level (annuity) debt service), and (ii) straight-line (i.e., level repayment of principal). The options can be chosen in the InC tab. Level principal method has equal principal payments over the life of the loan, whereas level debt service style has fixed debt service payments (mortgage or annuity style) with the share of interest in each payment reducing (and share of principal increasing) over time. Finally, the Debt tab contains calculations of the various financing fees typically charged by lenders.

A.1.8 Equity Schedule ("Equity")

This tab contains the cash flows to and from the Project's equity investors including equity drawdowns (outlays) during project development and construction phases and equity distributions (inflows) during Project operations. Equity distributions include dividends to the Project's equity investors, which are calculated in the Div tab.

A.1.9 Operations ("Ops")

This tab provides calculations of the Project's projected revenues and expenses that are used in the proforma financial statements (i.e. the income statement, cash flow statement and balance sheet for each Project component).

A.1.10 Depreciation and Amortization ("Dep")

The Dep tab contains supporting calculations for non-cash, pre-tax depreciation expense for the Project's fixed assets. This tab also contains amortization of capitalized "soft" (financing and development) costs.

A.1.11 Dividends ("Div")

This tab incudes the calculations related to the dividends to the Project's equity investors. Dividends are made in each period subject to meeting certain requirements including a minimum cash balance of USD and a DSCR covenant, which are assumptions in the InpC tab.

A.1.12 Taxes ("Tax")

The Tax tab contains the Project's income tax calculations based on the assumed tax rates in the InpC tab.

A.1.13 Returns ("Ret")

This tab calculates the Project returns including the Project IRR and the equity IRR.

A.1.14 Timing ("T")

This tab calculates the various construction and operations timing flags that flow throughout the Model.

A.1.15 Financial Statements – Import Terminal ("GasCo FS")

This tab builds on the underlying calculations tabs described above, to present pro-forma quarterly financial statements for the LNG import terminal and marine infrastructure including: Income Statement, Balance Sheet, and Cash Flow Statement. All amounts are presented in ZAR thousands.

A.1.16 Financial Statements – Regasification Unit ("RegasCo FS")

This tab builds on the underlying calculations tabs described above, to present pro-forma quarterly financial statements for the storage and regasification unit including: Income Statement, Balance Sheet, and Cash Flow Statement. All amounts are presented in ZAR thousands.

A.1.17 Financial Statements – Transmission Pipeline ("TransCo FS")

This tab builds on the underlying calculations tabs described above, to present pro-forma quarterly financial statements for the transmission and distribution pipeline including: Income Statement, Balance Sheet, and Cash Flow Statement. All amounts are presented in ZAR thousands.

A.1.18 Financial Statements – Anchor Power Plant ("PowerCo FS")

This tab builds on the underlying calculations tabs described above, to present pro-forma quarterly financial statements for the anchor power plant including: Income Statement, Balance Sheet, and Cash Flow Statement. The anchor power plant will be either the Ankerlig conversion or the new greenfield IPP depending on the scenario selected in the InpC tab. All amounts are presented in ZAR thousands.

A.1.19 Financial Statements – Consolidated ("Consol FS")

This tab builds on the FS tab for each of the four phases of the Project to present consolidated pro-forma quarterly financial statements including: Income Statement, Balance Sheet, and Cash Flow Statement. This consolidation is simply for summary purposes. All amounts are presented in ZAR thousands.

A.1.20 Sensitivity Analyses ("Sens 4.1")

This tab contains sensitivity analysis as per Task 4.1 of key drivers of the Model such as tariff, capex, interest rate, etc. analyzing how a change in each of these inputs impacts the Project's financial viability. The sensitivity analysis is presented in detail in Section 3.2

A.1.21 Sensitivity Analyses ("Sens 4.2")

This tab contains sensitivity analysis as per Task 4.2 of key drivers of the Model such as tariff, capex, interest rate, etc. analyzing how a change in each of these inputs impacts key metrics of the Project. The sensitivity analysis is presented in detail in Section 3.2.

A.2 User Instructions

This section contains detailed instructions on how to operate the Model. Intentionally, the Model contains limited circularity, e.g., in calculating interest and financing fees during construction. This circularity is minimized by a macro designed by the Team to calculate the appropriate debt amount. As such, the user must click "Enable Content" next to the notification "Security Warning: Macros have been disabled" on the Excel task bar after opening the Model to ensure that the Macro functions once an input is adjusted.

The Intro tab contains a table of contents of the different tabs in the Model as well as instructions and descriptions of what the different cell and font colors mean. The most important item of note is that cells colored light yellow in the input tabs contain assumptions that users can adjust. Upon changing any assumption, users must recalculate the Model by pushing the "F9" key on their keyboard. White cells with black text contain formulas that should not be changed.

The following table shows a snapshot of the InpC tab of the model and notes where users may adjust inputs.

Figure 12: Model Snapshot

WESTERN CAPE INTEGRATED LNG IMPORTATION & GAS-TO-POWER PROJECT						Scenario	Scenario Builder			
CONSTANT INPUTS						Base	Base	[Case 1]	[Case 2]	< insert additional columns here
TIMING										
PROJECT TIMING										
Construction Start Date	01-Jan-21	date								
Construction Duration	3.00	years								
Commercial Operations Date	01-Jan-24	date								
Project Operation Duration	20	years					20			years
IMPORT TERMINAL										
TIMING ASSUMPTIONS										
Construction Start Date	01-Oct-21	date								
Construction End Date	31-Dec-23	date					31-Dec-23			quarter-end date
Commercial Operations Date	01-Jan-24	date								

CAPITAL EXPENDITURES										
Terminal Location	Shallow Water		Deep Water							
Storage Type	Onshore	FSRU	FSRU	Active						
Expenditures	Option 1	Option 2	Option 3	Option 3	selection		Option 3			import terminal selection
Dredging and Reclaimation	82,800,000	82,800,000	0	0	USD		0%			% change
Revetment, Scour Protection	23,400,000	23,400,000	0	0	USD		0%			% change
Pipe Protection	0	0	2,100,000	2,100,000	USD		0%			% change
Quay Structure	44,500,000	44,500,000	47,500,000	47,500,000	USD		0%			% change
Access Trestle	26,900,000	0	0	0	USD		0%			% change
Aids to Navigation	2,400,000	2,400,000	2,400,000	2,400,000	USD		0%			% change
General Facility Infrastructure	4,500,000	4,500,000	4,500,000	4,500,000	USD		0%			% change
General Services	1,400,000	1,400,000	1,400,000	1,400,000	USD		0%			% change
Gas Pipeline & Distribution Hub	0	11,600,000	39,600,000	39,600,000	USD		0%			% change
Gas Off-Loading	0	6,400,000	6,400,000	6,400,000	USD	Sensitivity	0%			% change
Total	185,900,000	177,000,000	103,900,000	103,900,000	USD	0%				

The InpC tab also includes functionality to create specific scenarios in the Scenario Builder columns. Currently, the Base Case is the only scenario fully built out. However, the Model allows for additional cases to be created and saved for ease of comparison amongst possible Project scenarios by selecting such scenarios using the selection field at the top of the worksheet (Cell L2). This allows for testing changes to multiple inputs at the same time. The Model can accommodate additional scenarios by inserting columns to the right of the most recently built out scenario as indicated in the worksheet.

The "Sum" tab has a model checks section, which displays select technical and commercial errors in the Model. The Model has no errors in the base case version delivered, but it is possible errors will arise if certain inputs being tested are not viable. If an error occurs when adjusting inputs, it is recommended to reverse the adjustment or restart with the previously saved version of the Model.

Figure 13: Model Checks

		IMPORT TERMINAL	REGAS UNIT	T&D PIPELINE	POWER PLANT	CONSOLIDATED
MODEL CHECKS						
Balance Sheet	check	OK	OK	OK	OK	OK
Negative Cash	check	OK	OK	OK	OK	OK
Debt Repayment	check	OK	OK	OK	OK	OK
Target Debt Amount	check	OK	OK	OK	OK	OK

Appendix 4-B: Financing Sources

The Team evaluated various financing sources relevant to the Project and conducted discussions with financial institutions and investors to gauge their interest in the Project. The financing sources evaluated by Delphos can be categorized into development finance institutions ("DFIs"), export credit agencies ("ECAs"), private market financiers (i.e., commercial banks), and equity investors. The financial institutions that Delphos met or held conference calls with includes all of the sources identified in the ToR as well additional sources selected by the Team based on its knowledge of institutions that are active in financing oil and gas infrastructure projects in emerging markets and would be the most likely financing sources for the Project.

B.1 Development Finance Institutions

DFIs are specialized financial institutions set up to support economic development by unlocking access to capital and private investment in developing countries. The universe of DFIs consists of both national (sponsored by specific governments) and international (sponsored by multilateral agencies) organizations. DFIs' mission is to play a catalytic role in markets where commercial lenders are unwilling to lend at viable terms. A benefit of DFI financing is that the DFI "stamp of approval" may pave the way for a syndicate of commercial banks to provide financing for projects. In addition, projects may obtain additional leverage or extended tenor under a DFI financing scenario when compared with strictly commercial lending. Furthermore, projects typically benefit from the political support that these quasi-government and government-backed institutions can bring.

B.1.1 The World Bank Group

B.1.1.1 International Finance Corporation

The International Finance Corporation ("IFC") is the private sector branch of the World Bank Group and promotes sustainable economic growth in developing countries by financing private sector investment, mobilizing capital in the international financial markets, and providing advisory services to businesses and governments. IFC has 184-member countries, including South Africa.

Since 1957, South Africa has been a member country of IFC, and the IFC office in Johannesburg serves Botswana, Lesotho, Namibia, Swaziland, and Zimbabwe in addition to South Africa. One of the IFC's main priorities in Sub-Saharan African is the expansion and promotion of infrastructure projects, particularly in the power sector. In South Africa, the IFC has traditionally worked in solar and wind power sectors; however, the IFC has extensive experience with gas power projects throughout southern Africa and Sub-Saharan Africa. In 2016, IFC approved a USD 235 million loan to help finance an integrated oil and gas development project, utilizing a shared, new conversion, double-hulled floating production, storage, and offloading unit ("FPSO"), offshore in the Western Region of Ghana. The World Bank's International Development Association ("IDA") and Multilateral Investment Guarantee Agency ("MIGA") also provided guarantees and risk management products in support of the USD 8 billion project. In addition, in 2015, IFC approved a USD 58 million loan and an additional USD 2 million of funding for risk management for a 175 MW gas-fired power plant in Mozambique. This independent power producer ("IPP") project was the first of its kind in Mozambique, which lacked extensive public-private partnership ("PPP") experience previously. In 2011, approved a USD 85 million loan for a 216 MW gas-fired power plant in Cameroon to increase fuel supply diversity and security.

Relevant Products

- Loans: IFC offers fixed and variable rate loans for its own accounts ("A-loans") and arranges syndicated loan ("B-loans") to private sector projects in developing countries. Most loans are issued in leading currencies, but local currency loans can also be provided. Grace periods and repayment schedules are determined on a case-by-case basis in accordance with the borrower's cash flow needs. Loan tenors depend on due diligence and the needs of the project where IPP projects get repayment terms of up to the PPA term minus a "tail" of at least 2 years. To ensure the participation of other private investors, A-loans are usually limited to 25% of the total estimated project cost. For expansion projects, IFC may provide up to 50% of the project cost, provided its investments do not exceed 25% of the total capitalization of the project company. Generally, A-loans range from USD 1 million to USD 100 million.

- Partial Credit Guarantee: IFC's partial credit guarantee ("PCG") is a credit enhancement for debt instruments (bonds and loans) consisting of an irrevocable promise by IFC to pay principal and/or interest up to a pre-determined amount. Typically, a PCG covers 100% of each debt service payment, subject to a maximum cumulative amount and amortizes in proportion to the guaranteed debt instrument. IFC tailors PCGs to meet the needs of both borrower and creditors with an intention to reduce the probability of default and increase the recovery if default occurs. PCGs are offered in foreign or local currencies.

- Equity: IFC can take minority (usually up to 25%) equity stakes in private enterprises in developing countries. Equity investments may also be structured as profit-participating loans, convertible loans, and preferred shares IFC is a long-term investor and usually maintains equity investments for a period of 8 to 15 years.

Requirements

Projects must be in a developing country that is a member of IFC, be in the private sector, be technically sound, have good prospects of being profitable, benefit the local economy, and satisfy IFC's environmental and social standards as well as those of the host country.

Pricing

Interest rates are based on an underlying cost of capital (comparable to the London Interbank Offered Rate ("LIBOR") plus a risk premium (credit spread), depending on IFC's assessment of the commercial and political risks involved. IFC also charges per annum commitment fees on undrawn amount and one-time facility fees, typically about 1% and 2.5%, respectively.

B.1.1.2 Multilateral Investment Guarantee Agency

MIGA is a member of The World Bank Group. It was created in 1988 to complement public and private sources of investment insurance against non-commercial risks in developing countries. MIGA's mission is to promote foreign direct investment into developing countries to support economic growth and reduce poverty and improve people's lives. Since its inception in 1988, MIGA has issued more than USD 28 billion in risk mitigation solutions to projects in a wide variety of sectors, covering all regions of the world. During financial year ending in June 2017, it issued USD 4.8 billion in guarantees which is expected to catalyze an additional USD 15.9 billion in public and private co-investment.

Relevant Products

- Political Risk Insurance: MIGA's PRIs are provided to private sector investors and lenders to protect against four non-commercial risks which include: (i) currency inconvertibility and transfer restrictions, (ii) expropriation, (iii) war, terrorism, and civil disturbance, and (iv) breach of contract by a government (or state-owned enterprises ("SOEs") in certain circumstances). MIGA may insure up to USD 250 million per project, and if necessary more can be arranged through syndication of insurance. Coverage can be provided for 15-20 years depending on the project.

- Credit Enhancements: Credit enhancement is provided to protect commercial investors against non-honoring of financial obligations by sovereign, sub-sovereign, and SOEs. MIGA covers losses resulting from a failure to make a payment when due should arise under an unconditional financial payment obligation or guarantee, and MIGA's coverage does not require the investor to obtain an arbitral award. Credit enhancements help projects attract commercial debt financing and improve ratings for capital market transactions.

Requirements

MIGA only supports investments that are developmentally sound. It applies a comprehensive set of social and environmental performance standards to all projects and offers expertise in working with investors to ensure compliance to these standards. All loans and loan guarantees, including those issued by shareholders of the project, must have a minimum maturity of more than one year provided that MIGA determines the project represents a long-term commitment by the investors. Availability of credit enhancement is limited to governments and SOEs with satisfactory credit ratings.

Pricing

MIGA uses risk-based pricing based on both country and project risks. Fees average approximately one percent of the insured amount per year but can be significantly lower or higher. An application fee of USD 5,000 for cover of less than USD 25 million and USD 10,000 for larger amounts is charged. The application fee is applied toward the initial premium. If the project is rejected for any reason, this fee is refunded. A processing fee may also be charged on a case by case basis depending on the complexity of the project. A syndication fee is charged if MIGA arranges a project's total insurance requirements through reinsurance.

B.1.2 African Development Bank

Founded in 1964, the African Development Bank Group ("AfDB") is a multilateral development finance agency that seeks to further the social and economic well-being of its member countries in Africa by using its AAA rating to lend to its borrower countries at favorable terms.

Relevant Products

The AfDB provides standard loans to its clients on non-concessional terms and are categorized as either sovereign-guaranteed loans ("SGLs") or non-sovereign-guaranteed loans ("NGSLs"). SGLs are loans made to regional member countries ("RMCs") or public-sector enterprises from RMCs supported by the full faith and credit of the RMC in whose territory the borrower is domiciled. NGSLs are either loans made to public sector enterprises, without the sovereign guarantee from the host country government, or to private sector enterprises in all RMCs provided that they meet specific eligibility criteria. For non-sovereign-guaranteed clients and private sector, the loan product offered is the fixed spread loan ("FSL").

AfDB's product offerings have evolved over time as the agency tries to be more responsive to the varied and evolving requirements of its borrowers. Some of the more innovative offerings include risk management products that allow clients to hedge against financial risks associated with their AfDB-related loans, as well as equity and quasi-equity financial products.

- Loans: AfDB can offer FSLs in major leading currencies, including the U.S. Dollar, Euro, Japanese Yen, and South African Rand, as well as other select local African currencies. Typical maturities are up to 15 years, inclusive of a five-year grace period. Although semi-annual equal principal repayment terms are standard after expiration of the grace period, other repayment terms may be considered. Fees include front-end and appraisal fees determined upon appraisal, a minimum commitment fee of 0.5%, and other fees associated with the underwriting of the debt instrument.

- Guarantees: AfDB can leverage its preferred creditor status to help eligible borrowers to obtain financing from third party lenders, including the capital markets, through its guarantee products:

partial credit guarantees ("PCGs") and partial risk guarantees ("PRGs"). PCGs cover a portion of scheduled repayments of private sector loans or bonds against the risk of default. The PCG can be utilized to support mobilization of private funds for project finance, financial intermediation and policy-based finance. PRGs on the other hand, cover private lenders against the risk of a government, or a government-owned agency, failing to perform its obligations vis-à-vis a private sector project. Such risks could include political force majeure, currency inconvertibility, regulatory risks (adverse changes in law), and various forms of breach of contract.

- Equity and Quasi-Equity: On a select basis, AfDB offers equity and quasi-equity products, including redeemable preference shares, preferred stock, subordinated loans, and convertible loans, to eligible borrowers. The bank typically will participate in such investments to promote the efficient use of resources, promote African participation, attract other investors and lenders to financially viable projects, and to promote new activities and investment ideas.

Requirements

AfDB supports public sector and private sector companies in RMCs.

Pricing

AfDB interest rates are the sum of two components: a base rate and a lending margin specific to the different categories of loans. AfDB provides three base rate options: a floating base rate, which fluctuates based on the six-month reference rate of the selected currency market (i.e., USD LIBOR, EURIBOR, JPY LIBOR, and JIBAR); a fixed base rate, which is determined based on the interest rate swap prevailing for the loan's maturity and currency; and a variable base rate, which adjusts semi-annually using AfDB's historical average cost of funding of a designated pool of borrowings in each currency as its reference. The lending margin is a rate premium expressed as a nominal interest, determined by AfDB independently of the base rate chosen and remains unchanged throughout the life of the loan.

B.1.3 Development Bank of Southern Africa

The Development Bank of Southern Africa ("DBSA"), established in 1983, is a South African state-owned enterprise that works in development finance across the African continent. Its primary purpose is to promote economic development and growth as well as regional integration through infrastructure finance and development. The Bank's primary focuses lie in the energy, water, transport and telecommunications sectors, with secondary focuses in healthcare and education. The DBSA is actively involved in all phases of the infrastructure development and contributes to project preparation and funding as well as infrastructure implementation and delivery.

As a South African state-owned entity, DBSA aims to support the South African infrastructure development agenda through financing and non-financing support services for the municipal sector and project financing of large-scale infrastructure projects and programs. In 2017, DBSA achieved 83% growth in disbursements to secondary and under-resourced municipalities and completed 17 infrastructure projects in secondary and under-resourced municipalities. DBSA also issued EUR 7.2 billion in disbursements for energy projects in 2017 with a total project impact of 860 MW.

DBSA also offers three funding programs to aid in the preparation and development of infrastructure projects in Southern Africa, two of which are relevant to the Project:

- DBSA Project Preparation Fund: The DBSA Project Preparation Fund was created to provide project preparation funds for developing infrastructure projects in DBSA's financing pipeline. The funds are intended to be used to help create an enabling environment for infrastructure projects to be implemented, conduct pre-feasibility studies, conduct bankable feasibility studies, and assist with costs associated with financial close.

- Infrastructure Investment Programme for South Africa ("IIPSA"): IIPSA is a grant facility created through the joint efforts of the European Union ("EU") and the Government of South Africa ("GoSA") to support South Africa's National Development Plan and the Regional Infrastructure Development Master Plan of the Southern Africa Development Community ("SADC") to address constraints to infrastructure development. Grant funding is awarded in support of project preparation activities and/or in support of the overall financing of infrastructure projects, including lump-sum grants to reduce the interest rate of long-term debt financing and loan guarantee premiums. IIPSA aims to involve blending grants together with loans from participating development finance institutions ("DFIs"), including DBSA, the German development bank ("KfW"), European Investment Bank ("EIB"), and the French development agency ("AFD"). Although the initial request for proposals closed in 2014, the IIPSA Secretariat, DBSA, has reopened the application window and invites eligible project proposals for consideration.

Relevant Products

DBSA offers both financing and non-financing support services through both DBSA's capital and reserves as well as third party funds.

- Balance sheet loans
- Mezzanine finance
- Limited non-recourse project finance
- Grants

B.1.4 Industrial Development Corporation

Founded in 1940, the Industrial Development Corporation ("IDC") is South Africa's largest development finance institution and has helped to build the industrial capacity that fuels the country's economic growth, by funding viable businesses. IDC focuses on priority economic sectors which the institution deems to have the greatest potential to increase employment and economic prosperity in the region.

IDC's industrial infrastructure subdivision aims to unlock infrastructure development to create an environment that helps grow South Africa's economy. To that end, IDC makes investments in energy and logistics infrastructure. With a focus on energy projects that boost the country's energy security while maintaining ESG standards, IDC considers funding for fixed assets and working capital, projects that exhibit sustainable economic merit, and projects with significant developmental impact, particularly sustainable job creation, value addition, empowerment and local content. Additionally, the director of IDC's Western Cape regional office has given public statements emphasizing the institution's desire to become involve in energy development and conservation initiatives in the region.

In 2017, IDC approved ZAR 15.3 billion for eligible projects, up 5% from 2016 approvals and up 39% from 2015, of which approximately 10% of total approvals were dedicated to projects in the Western Cape. The value of funding approved for infrastructure development, before cancellations, reached ZAR 2.1 billion in 2017, similar to the year prior. The bulk of the funding was dedicated to the electricity generation sector, with financing approved for two coal-fired independent power producers ("IPPs"), one in the Waterberg area of Limpopo and the other in Mpumalanga. IDC expects funding for this sector will grow in 2018 and target ZAR 2.5 billion in commitments for the year.

Relevant Products

- Debt
- Equity and quasi-equity
- Guarantees
- Trade finance

- Venture capital

Requirements

Eligible projects must demonstrate compliance with international environmental standards. Shareholders/owners are also required to make a financial contribution to the development of the project. Additionally, the project must reach requirements for projected profitability and sustainability. The IDC also favors projects which promote the economic empowerment of underserved populations.

B.1.5 Overseas Private Investment Corporation

The Overseas Private Investment Corporation ("OPIC") was established as an agency of the U.S. Government in 1971. OPIC helps U.S. businesses invest overseas, fosters economic development in new and emerging markets, complements the private sector in managing risks associated with foreign direct investment, and supports U.S. foreign policy. Because OPIC charges market-based fees for its products, it operates on a self-sustaining basis at no net cost to U.S. taxpayers. OPIC supports projects in a variety of industries from critical infrastructure to electricity, financial services, healthcare and technology, and is authorized to do business in more than 160 countries around the world.

Sub-Saharan Africa has long been a priority region for OPIC, and the region makes up more than 20% of OPIC's portfolio. OPIC committed a total of USD 369 million in financing and insurance through the ACEF program, and these projects have raised an additional USD 443 million in capital from other sources. While most OPIC-funded energy projects in South Africa have been in solar and hydropower sectors – including the approval of a USD 400 million loan for a 100 MW solar power plant in the Northern Cape region in 2015 – there is notable precedent for OPIC support of thermal power projects, and power projects generally, in Sub-Saharan Africa. In 2017, OPIC approved a loan of up to USD 100 million for a 50 MW thermal power plant in Guinea. Previously, in 2014, OPIC approved a 10-year USD 75 million loan to the Africa Finance Corporation ("AFC") Nigeria branch to support AFC's ability to finance infrastructure development.

Relevant Products

- Project/Structured Finance: OPIC provides financing either through direct loans or loan guarantees. OPIC's financings range from USD 500,000 up to USD 250 million, with an average loan size of USD 5 million to USD 50 million. Financing tenor is usually between 5 and 20 years, with a maximum of 30 years, depending on project type and debt servicing capability. OPIC typically lends on a senior secured basis and works with co-lenders in case of larger projects.

- Political Risk Insurance ("PRI"): OPIC's PRI covers local currency inconvertibility and earnings transfer restrictions; losses due to expropriation, nationalization or confiscation; loses due to political violence; losses of business income due to interruption by political violence; and contract repudiation through direct government action or changed regulation.

Requirements

To be eligible for financing, OPIC expects a U.S. equity or debt investor to assume at least 25% ownership of a project. However, OPIC can also support projects below this threshold if U.S. parties are involved as long-term operators. Projects with government shareholding are required to have at least 50% of the venture held by firms or persons in the private sector, but OPIC can support projects blow this threshold if it is contractually agreed that management will remain in private sector hands and U.S. involvement is strongly present in other respects. OPIC will not support projects that could result in the loss of U.S. jobs, adversely affect the U.S. economy or the host country's development or environment or contribute to violations of internationally recognized worker rights.

Pricing

Interest rates are based on an underlying cost of capital (comparable to U.S. Treasury notes or other U.S. Government-guaranteed issues of similar maturity) plus a risk premium of between 2% and 6%, depending on OPIC's assessment of the commercial and political risks involved. OPIC therefore lends on a fixed-rate basis.

OPIC also charges up front retainer fee to cover costs of its credit due diligence, and facility and commitment fees that are typically 1% and 0.5%, respectively. OPIC also charges a nominal annual loan maintenance fee.

B.1.6 European Development Finance Institutions

European Development Finance Institutions ("EDFIs") consist of institutions established in a member state of the European Union ("EU") or the European Free Trade Association ("EFTA") which are undertaking development finance activities in the private sector of countries outside the EU. Collectively, these member institutions consist of 15 bilateral DFIs, including DEG, the Netherlands Development Finance Company ("FMO"), and Proparco, the private sector financing arm of the French Development Agency ("AFD"), among others.

EDFIs share similar mandates and operate in comparable markets, sometimes on their own and often together. In addition, the EDFIs share common policies, one of which is a common commitment to achieving sustainable environmental, economic and social development, including reducing greenhouse gas emissions and developing renewable energy and energy efficiencies. Such common-bound policies likely considerably limit the involvement and support of EDFIs in a fossil fuel-based project.

B.2 Export Credit Agencies

Export credit agencies ("ECAs") are typically government-owned entities that offer financing solutions in support of domestic exporters. ECAs can offer loans, insurance, or guarantees to protect against political and commercial risks of the foreign entity that the local exporter is doing business with. Most developed nations have an ECA, with approximately 100 existing throughout the world. ECAs are governed by the Organization for Economic Co-Operation and Development's Arrangement of Officially Supported Export Credits that results in largely similar products and terms among the various ECAs. Thus, for the purposes of this Report, the Team focused solely on the Export-Import Bank of the United States.

B.2.1 Export-Import Bank of the United States

The Export-Import Bank of the United States ("USEXIM") is the country's official ECA whose stated mission is to assist in financing the export of U.S. goods and services to international markets. To support U.S. jobs, USEXIM maximizes U.S. companies' participation in international markets by providing tools like buyer financing, export credit insurance, and access to working capital. In 2017, USEXIM authorized over USD 3.4 billion of loan guarantees, insurance, and direct loans in support of an estimated USD 7.4 billion of U.S. export sales. USEXIM's portfolio was almost USD 72.5 billion as of 30 September 2017, with USD 4.4 billion (6.1%) supporting U.S. exports to Sub-Saharan Africa, of which total exposure to South Africa was over USD 1.3 billion.

In 2011, USEXIM approved a USD 805 million direct loan to Eskom to support the purchase of EPC services from Black & Veatch International to develop and construct the Kusile coal-fired power plant located in the Emalahleni area of the Mpumulanga Province. The Kusile plant is to consist of six 800 MW units, for a total capacity of 4,800 MW, and is the second of two plants being constructed by the state-owned electric power utility to meet the country's increasing demand for power and minimize particulate emissions by including highly efficient supercritical boilers. Beginning in 2011 through 2013, USEXIM provided USD 230 million equivalence in financing and support to support the purchase of 100 GE locomotives by Transet SOC

Limited. EXIM guaranteed the local currency denominated loan, with Barclays Bank PLC of London serving as the guaranteed loan agent and arranger. Nedbank of Johannesburg was the funding bank.

Relevant Products

- Loan Guarantees: USEXIM's lender loan guarantees can cover commercial banks that extend export credit to a buyer of U.S. goods and/or services, generally up to 10 years. The guarantee to the lender is unconditional, transferable and can cover local costs up to 30% and ancillary services such as financial, legal, or bank fees associated with the eligible financing. There is no limit to the minimum or maximum size of the U.S. export sale that may be financed with USEXIM's loan guarantee, although internal country-specific terms do apply.
- Direct Loans in the Form of Buyer Financing: USEXIM provides fixed-rate financing, up to 12 years in general and up to 18 years for renewable energy projects, to creditworthy international buyers in both the private and public sectors and can finance up to 30% of local costs. The total level of USEXIM support will be the lesser of 85% of the value of all eligible goods and services in the U.S. supply contract or 100% of the U.S. content in all eligible goods and services supply contract.
- Project Finance Loans: Limited recourse (project) and structured financing are offered for credit worthy projects of U.S. project sponsors and/or suppliers. USEXIM allows repayment terms of up to 18 years for properly structured transactions plus a grace period on principal payments during construction. There are no project dollar limits; however, financing for different countries is decided as per the USEXIM's Country Limitation Schedule, of which South Africa does not have any limitations.

It must be noted that USEXIM currently cannot process transactions over USD 10 million since it is without a quorum for its Board of Directors. When the quorum for the Board of Directors is satisfied, which is expected in the near future, USEXIM will be able to process transactions over USD 10 million.

Requirements

Eligibility is determined by the project's economic impact on U.S. jobs and the environment, foreign content, and other criteria. Eligible project finance candidates include greenfield projects or production expansions. USEXIM limits its support to the less of 85% of the value of all eligible goods and services in the U.S. supply contract or 100% of the U.S. content in all eligible goods and services in the U.S. supply contract.

Pricing

USEXIM currently rates South Africa as a Category 4 country, which is medium-risk country on its proprietary scale of 1 to 7 and is considered one level removed from what is considered investment grade credit. The cost of funds for direct loans consists of the Commercial Interest Reference Rate ("CIRR") and an exposure fee. The CIRR is based on current U.S. Treasury rates plus a spread of 1.0% and serves as the base rate. The exposure fee is a one-time, upfront payment that differs from project-to-project based on the country and project risks. Additionally, USEXIM charges an initial facility fee typically about 1.5% and nominal commitment fee on undrawn principal amounts during the disbursement period.

CIRR for a 12-year repayment direct loan as of the date of the Report is 3.96% and exposure fee for a project in South Africa with good credit quality is 12.96%. Based on the current CIRR, exposure fee, and facility fee of 1.5%, the all-in cost of a USEXIM direct loan would be approximately 6.4%.

B.3 Private Sector Financing

B.3.1 Commercial Lenders

Commercial banks can serve as sources of financings for IPPs as co-lenders with DFIs and/or lending against ECA guarantees or PRI and can offer a range of products including long-term loans, bridge loans, letters of credit, and revolving credit. Depending on the size of financing requested, commercial banks can also finance a project alone or form a syndicate with numerous other banks. In the case of the Project, it expected that commercial banks would form a syndicate given the size of the Project. In evaluating commercial banks, the Team chose to focus on large international and South African banks active in the regional power sector with the capacity to provide a meaningful level of financing for the Project. This is not meant to be an exhaustive list of commercial banks, but rather a representative sample of likely commercial funding sources, which would have the ability to bring in other commercial banks as necessary.

B.3.1.1 Absa Group Limited

Absa Group Limited ("Absa"), formerly Barclays Africa Group Limited, is a South African financial services company delivering an integrated set of products and services including corporate and investment banking. At the end of 2017, Absa reported a loan book of ZAR 666 billion (USD 54 billion) in South Africa, representing almost 90% of its entire lending practice, and held ZAR 335 billion (USD 27 billion) in assets under management, a 16% increase over the prior year. Absa's Resource and Project Finance team is a leading provider of project financing solutions in a variety of sectors, including resources, power, infrastructure, and the industrial sectors.

B.3.1.2 Citigroup

Citigroup ("Citi") is a leading global financial services company headquartered in New York City with approximately 200 million customer accounts with business in over 160 countries and jurisdictions. Citi provides consumers, corporations, governments and institutions with a broad range of financial products and services, including commercial banking and credit, corporate and investment banking, securities brokerage, transaction services and wealth management. At the end of fiscal year 2017, Citi's credit exposure consisted of USD 4.3 billion in South Africa, about 0.3% of Citi's total loan portfolio. Citigroup participated as a joint-lead arranger in the structuring of USD 6.4 billion in credit facilities for Cheniere Corpus Christi Holdings, LLC, which reached financial close in May 2018. The credit facilities will be used to fund a portion of the costs of developing, constructing, and placing into service three trains, an associated pipeline, and other infrastructure near Cheniere's Corpus Christi liquefaction project.

B.3.1.3 Nedbank Group

Established in 1969, the Nedbank Group is a South African banking and financial services institution with a presence in six countries in the SADC and East Africa region, including South Africa, Namibia, Swaziland, Malawi, Mozambique, Lesotho, Zimbabwe, Angola and Kenya. In addition to providing retail and commercial banking services, Nedbank has a dedicated oil and gas finance team that provides funding to independent and emerging upstream oil and gas companies, as well as specialists in the financing of large infrastructure and energy-related projects. Nedbank can provide financing in the form of senior, mezzanine and consumer price index debt, corporate debt and bonds. As of June 30, 2018, Nedbank had a market capitalization of ZAR 1 trillion (USD 73 billion) and ZAR 314 billion (USD 23 billion) in assets under management. Nedbank received Euromoney *Project Finance Magazine's* "Africa Power Deal of the Year" award for 2013, acting as the mandated lead arranger and a financier of the ZAR 9.7 billion open-cycle gas turbine Avon and Dedisa Peaking Power Projects. With commercial operations commencing in July 2016, the 670 MW Avon facility located in Shakaskraal, and together with its sister power plant the 335 MW Dedisa facility in Port Elizabeth, is South Africa's first large IPP initiated by the DoE.

B.3.1.4 Societe Generale

Societe Generale is a French multinational banking and financial services company, headquartered in Paris. As one of the leading European financial services groups, Societe Generale offers services in retail banking, corporate and investment banking and private banking, among others. Within Corporate & Investment Banking, the bank provides a full range of finance and advisory services for producers, traders, processors and end-users of energy, metals and soft commodities through their Energy, Metals & Mining

Finance, and Traders, Commodity Finance & Agribusiness groups. In Sub-Saharan Africa, SG has a historic presence in 14 countries. In 2016, the region's outstanding loans totaled EUR 4.7 billion (USD 4.96 billion) and deposits stood at EUR 6.2 billion (USD 6.5 billion).

In May 2018, Societe Generale provided USD 205 million as part of a USD 2.4 billion debt financing used by Freeport LNG Development to fund an expansion of its Freeport LNG Import and Export facility through investment in its floating LNG Liquefaction 3 project, refinancing project debt and repayment of interest during construction. It acted as underwriter, bookrunner, MLA, lender, facility agent and security agent for CVC Capital Partners in the EUR 2 billion acquisition financing of 20% stake in Gas Natural. The financing was underwritten by five banks and was successfully syndicated among 21 banks, with Societe Generale involved in every aspect of the transaction. In January 2018, Societe Generale joined SEA/LNG, a multi-sector coalition with the objective of increasing the global adoption of LNG as a marine fuel, aiming for cleaner maritime shipping by 2020. The coalition includes Shell LNG, Total, Mitsubishi, Carnival, and Clean Marine Energy.

B.3.1.5 Standard Bank

The Standard Bank Group ("Standard Bank") is a South African financial services group headquartered in Johannesburg, South Africa and is Africa's largest lender by assets. Standard Bank has two main business units: Personal & Business Banking and Corporate & Investment Banking ("CIB"). Within CIB, the bank offers a full spectrum of project and export finance products and services, with capacity to act as financial advisor, arranger and underwriter of senior debt, mezzanine debt, and equity for all large capital projects. Standard Bank specializes in the natural resources sector and works to assist local and national governments with their funding requirements and infrastructure projects. The bank has USD 2.3 billion in project finance invested in energy infrastructure since 2012, enabling a total energy generation capacity of more than 2,500 MW.

In June 2018, Standard Bank issued USD 30 million in a syndicated loan to Zimbabwe Power Company ("ZPC") for the 300 MW expansion of the Kariba South hydro power plant, rehabilitation of the existing 750 MW Kariba South hydro power plant and rehabilitation of Units 1-6 of the existing 920 MW Hwange coal-fired power plant. The debt financing is backed by 15-year power purchase agreement between ZPC and off-taker Namibia Power Corporation for 80 MW of the capacity at Kariba. In November 2017, Standard Bank was part of a syndicate of lenders that agreed to provide USD 4.7 billion financing for the development of the Coral South FLNG facility offshore along the coast of Mozambique. The project targets production and monetization of the gas contained in the southern part of the Coral gas reservoir, by means of a floating LNG plant with a capacity of 3.4 million tons per year. Also, in 2017, Standard Bank acted as sole mandated structurer, arranger, and lender for one of Africa's first independent storage terminal project financings. The group reached Financial Close in December for the Burgan Cape Terminal 118,000 m3 Fuel Storage Terminal Project located in the Cape Town Harbor.

B.3.2 Equity Investors

Developers may be able to bring financial partners for a portion of the Project costs. However, this capital would only share in the developer risk and is unlikely to lower the need for debt financing. Examples of viable potential equity providers include the following:

B.3.2.1 African Infrastructure Investment Managers

African Infrastructure Investment Managers ("AIIM") is based out of Cape Town and was founded in 2000. It is a principal investment firm specializing in infrastructure investments. AIIM was established as a 50/50 joint venture between Old Mutual and Macquarie in 2000. The Funds managed and advised by the AIIM team focus on equity investments into core infrastructure projects in Africa that provide essential services to communities, have a strategic competitive advantage, require significant capital expenditure and are expected to generate strong risk-adjusted returns for investors.

In June 2017, AIIM acquired a 44% ownership stake in Albatros Energy Mali by investing USD 18.7 million through its AIIF3 fund to help finance the development of a 90 MW heavy fuel oil-fired power station located in western Mali. The Kayes thermal power station will be Mali's first IPP to feed into the national grid and is structured under a build, own, operate, and transfer model. Lenders to the USD 121.9 million project include the West African Development Bank, Islamic Development Bank, the Islamic Corporation for the Development of the Private Sector, the OPEC Fund for International Development, the Emerging Africa Infrastructure Fund, and GuarantCo.

B.3.2.2 Cheniere Energy, Inc.

Cheniere Energy, Inc. ("Cheniere") is an international energy company headquartered in Houston, Texas, and is the leading producer of liquefied natural gas in the United States. As a global importer/exporter of LNG, Cheniere has expressed interest in potentially developing gas importation infrastructure in the Western Cape. The Team spoke with Darryl Hunt, Cheniere's representative in South Africa. Cheniere believes that LNG poses less risk for the buyer when compared to pipeline gas (e.g., via the Rompco line) given that pipeline CNG is on a take-or-pay basis whereas LNG has lower termination payments (given that LNG could be rerouted to other buyers) resulting in a lower contingent liability for the buyer.

B.3.2.3 Helios Investment Partners

Helios Investment Partners ("Helios") was founded in 2004 and is headquartered out of London. It is a private investment firm that focuses on Africa. The firm manages funds that total USD 3.6 billion. It focuses its infrastructure investments on: telecom, media and technology, financial institutions and services, power and energy, transportation, logistics and distribution.

In September 2018, Helios Investment Partners reached a deal with China Harbour Engineering Company to build a $350 million LNG terminal in Ghana's Tema port. To be completed in 18 months, the LNG terminal is set to become Sub-Saharan Africa's first regasification terminal and, once completed, the project is estimated to deliver approximately two million tonnes of LNG annually.

B.3.2.4 EIG Global Energy Partners

B.3.2.4 EIG Global Energy Partners ("EIG") specializes in private investments in energy and energy-related infrastructure on a global basis and had more than $17 billion under management as of the end of 2017. Founded in 1982, EIG is one of the leading providers of institutional capital to the global energy industry, providing financing solutions across the balance sheet for companies and projects in the oil and gas, midstream, infrastructure, power and renewables sectors globally. EIG has invested over $25 billion in more than 320 portfolio investments in 36 countries. EIG is headquartered in Washington, D.C., with offices in Houston, London, Sydney, Rio de Janeiro, Hong Kong and Seoul.

B.3.2.5 Azura Power Holdings Ltd.

Azura Power Holdings Ltd. ("Azura") is an independent power and renewable producer based in South Africa. With experience in project development, industry expertise and financing skills, the company develops, finances, acquires, and operates independent power plants. It has a strong presence in West Africa and is the founder and majority owner of Nigeria's first privately project financed IPP, a 450MW IPP currently under construction near Benin City in Edo State. Azura also owns one of the country's largest solar projects, a 100MW IPP located in Katsina State which is expected to reach financial close by the end of 2017. As part of its plan to expand and diversify its portfolio, Azura is expecting to have invested $500 million of equity in power assets that will add over 2GW of power across the African continent in the near term.

B.3.2.6 Vitol Group

Vitol Group ("Vitol") is a privately held global energy and commodities company with over 40 offices worldwide and its largest operations in Bahrain, Geneva, Houston, London, Rotterdam, and Singapore. Vitol is the largest independent energy trader in the world, trading over 7 million barrels of crude products per day with a turnover of USD 181 billion in 2017. These operations are complimented by refining, shipping, exploration and production, power generation, mining and retail businesses. The company extracts, produces, and markets liquefied petroleum gas and natural gas products and offers trading services throughout the supply chain. Vitol leverages its energy-industry expertise to participate in projects as an equity investor by buying, restructuring and revitalizing energy assets. Vitol retains investments in African fuel and lubricant retail businesses through partial ownership of Vivo Energy and OVH Energy, providing over 2,500 service stations across Africa. Through Vivo Energy, Vitol holds a presence in Namibia, Botswana, Ghana and the Ivory Coast, among other countries.

B.3.2.7 Sempra Energy

Sempra Energy is an energy infrastructure company headquartered in San Diego, California with operations located throughout North and South America and 40 million electric and natural gas consumers worldwide. Sempra LNG & Midstream, a subsidiary of Sempra Energy, leads their efforts to develop and build LNG facilities, midstream natural gas infrastructure, and natural gas storage in North America. Their joint-venture LNG facility under construction in Louisiana, USA is expected to be one of the first U.S. liquefaction-export projects to commence operations in 2019. Sempra LNG & Midstream is also developing an additional liquefaction project in Texas, USA and another liquefaction-export facility in Ensenada, Mexico.

B.3.3 Supplier Credits

In some instances, suppliers may be able to offer and help to arrange for export credit insurance as provided by ECAs and referenced in the above relevant section. Exporters in the engineering, procurement and construction ("EPC") and shipbuilding industries that involve large transactions with long repayment periods may benefit from this product as it extends credit terms to a foreign customer and insures against the nonpayment from such buyer, covering both commercial and political risks. However, given the tenor and amount of financing required for the Project, the Team does not view this as a viable financing solution, but perhaps rather could be considered as a smaller, complementing piece of a much larger financing need.

Appendix 4-C: Task 4 Model

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WESTERN CAPE INTEGRATED LNG IMPORTATION & GAS-TO-POWER PROJECT
INTRODUCTION

PREPARED BY:	DELPHOS INTERNATIONAL
ON BEHALF OF:	Green Cape Sector Development Agency
PROJECT:	Feasibility Study for the Western Cape Integrated LNG Import and Gas-to-Power Project
MODEL TYPE:	Financial Model

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LEGEND | CELL & FONT COLOR:

0.00	Hard-Coded Adjustable Inputs
0.00	Formulas
0.00	Offsheet Imports
0.00	Technical Input / Do Not Delete
	Empty Cell / Do Not Delete
OK	Checks Inactive
Warning	Checks Active
-	Flag
1	Active Selection Indicator

LEGEND | WORKSHEET TAB COLOR:

	Inputs
	Calculations
	Outputs
	Sensitivities
	Dormant

NOTE: Workbook is set to manual calculations. Please select [F9] to calculate and/or refresh the entire workbook and wait until the processing indicator in the status bar below completes its run.

Appendix 7-A: Details of U.S. Export Potential

The following tables in this section present a further breakdown of U.S. export potential, as well as the expected likelihood of U.S. participation, across cost categories for each Project component to arrive at an expected potential value of such U.S. participation. Sections are organized by Project component including the marine import terminal, the onshore storage and regasification facility, and the anchor power plant. Details for the potential value of U.S. exports related to the FSRU are presented in **Error! Reference source not found.** in the main body of the Report.

A.1 Import Terminal

Based on the Team's understanding and knowledge of the Port of Saldanha infrastructure and regulations, two locations were identified for the marine infrastructure and import terminal, one being in the shallow waters adjacent to the existing LPG terminal, which would require capital dredging and the other in the naturally deep waters near Donkergat Peninsula. The Base Case scenario assumes deep water import infrastructure and feature an FSRU (Option 3 in the table below).

Cost Item (USD MM)	Option 1: Shallow Water & Onshore Regas Unit	Option 2: Shallow Water & FSRU	Option 3: Deep Water & FSRU
Dredging & Reclamation	82.80	82.80	0.00
Revetment, Scour Protection	23.40	23.40	0.00
Pipe Projection	0.00	0.00	2.10
Quay Structure	44.50	44.50	47.50
Access Trestle	26.90	0.00	0.00
Aids to Navigation	2.40	2.40	2.40
General Facility Infrastructure	4.50	4.50	4.50
General Services	1.40	1.40	1.40
Gas Pipeline/Distribution Hub	0.00	11.60	39.60
Gas Off-Loading	0.00	6.40	6.40
Total	185.90	177.00	103.90

A.1.1 Base Case Import Terminal: Option 3

Cost Item (USD MM)	Option 3: Deep Water Facility & FSRU	Potential for U.S. Participation	Probability of U.S. Participation	Expected Potential Value of U.S. Participation
Dredging & Reclamation	0.00	100.0%	0.0%	0.00
Revetment, Scour Protection	0.00	100.0%	0.0%	0.00
Pipe Projection	2.10	100.0%	0.0%	0.00
Quay Structure	47.50	100.0%	0.0%	0.00
Access Trestle	0.00	100.0%	0.0%	0.00
Aids to Navigation	2.40	100.0%	0.0%	0.00
General Facility Infrastructure	4.50	100.0%	0.0%	0.00
General Services	1.40	100.0%	0.0%	0.00
Gas Pipeline/Distribution Hub	39.60	100.0%	10.0%	3.96
Gas Off-Loading	6.40	100.0%	0.0%	0.00
Total	103.90			3.96

A.2 Onshore Storage and Regasification Unit

Although not part of the Base Case scenario, the costing for an onshore storage and regasification unit was developed as part of the Study. There would be one onshore LNG storage tank with a 165,000-cubic meter capacity.

Cost Item (USD MM)	Regasification Plant	LNG Storage Tanks	LNG Unloading Arms	Total
Equipment	81.22	20.80	5.00	107.02
Bulk Materials	95.17	52.00	26.29	173.46
Material-Related Costs	13.01	0.00	3.76	16.76
Subcontracts	59.61	0.00	0.00	59.61
Buildings	8.16	0.00	0.00	8.16
Construction Costs	92.98	124.80	32.45	250.23
EPC Services	35.56	10.40	3.38	49.34
Miscellaneous Costs	6.58	0.00	1.06	7.64
Start-Up & Commissioning	18.20	0.00	0.00	18.20
Total	410.49	208.00	71.94	690.42

A.2.1 Regasification Plant

Cost Item (USD MM)	Regasification Plant	Potential for U.S. Participation	Probability of U.S. Participation	Expected Potential Value of U.S. Participation
Equipment	81.22	100.0%	50.0%	40.61
Bulk Materials	95.17	100.0%	10.0%	9.52
Material-Related Costs	13.01	50.0%	25.0%	1.63
Subcontracts	59.61	100.0%	10.0%	5.96
Buildings	8.16	0.0%	0.0%	0.00
Construction Costs	92.98	100.0%	50.0%	46.49
EPC Services	35.56	100.0%	50.0%	17.78
Miscellaneous Costs	6.58	100.0%	50.0%	3.29
Start-Up & Commissioning	18.20	100.0%	50.0%	9.10
Total	410.49			134.37

A.2.2 LNG Storage Tanks

Cost Item (USD MM)	LNG Storage Tanks	Potential for U.S. Participation	Probability of U.S. Participation	Expected Potential Value of U.S. Participation
Equipment	20.80	100.0%	50.0%	10.40
Bulk Materials	52.00	100.0%	25.0%	13.00
Construction Costs	124.80	100.0%	25.0%	31.20
EPC Services	10.40	100.0%	50.0%	5.20
Total	208.00			59.80

A.2.3 LNG Unloading Arms

Cost Item (USD MM)	LNG Unloading Arms	Potential for U.S. Participation	Probability of U.S. Participation	Expected Potential Value of U.S. Participation
Equipment	5.00	100.0%	50.0%	2.50
Bulk Materials	26.29	100.0%	25.0%	6.57
Material-Related Costs	3.76	50.0%	10.0%	0.19
Construction Costs	32.45	100.0%	10.0%	3.25
EPC Services	3.38	100.0%	10.0%	0.34
Miscellaneous Costs	1.06	100.0%	10.0%	0.11
Total	71.94			12.95

A.3 Transmission Pipeline

The gas transmission pipeline from Saldanha Bay to Cape Town was sized for the Base Case market demand as discussed in the Task 2 Report: Market Demand Analysis and will feature two segments, a high-pressure segment and a medium pressure segment. The high-pressure gas transmission pipeline will run from Saldanha Bay to the area where the branches to the Ankerlig Power Plant and the Atlantis industrial area are located, and a pressure reduction station will reduce the pipeline's operating pressure for the two medium-pressure gas transmission pipelines running onward to Ankerlig and Atlantis. A local pressure reduction station will further reduce the operating pressure to provide gas to the Atlantis distribution network.

Cost Item (USD MM)	Total Cost	Potential for U.S. Participation	Probability of U.S. Participation	Expected Potential Value of U.S. Participation
Bulk Materials	84.60	100.0%	10.0%	8.46
Material-Related Costs	23.37	50.0%	5.0%	0.58
Construction Costs	66.25	100.0%	10.0%	6.62
EPC Services	8.86	100.0%	10.0%	0.89
Miscellaneous Costs	8.36	100.0%	10.0%	0.84
Start-Up & Commissioning	4.02	100.0%	10.0%	0.40
Total	195.45			17.79

A.4 Anchor Power Plant

The Project will also feature an anchor power plant, either the conversion and expansion of the existing Ankerlig power plant from 1,338 MW to a 2,038 MW natural gas combined cycle ("NGCC") facility or the buildout of a greenfield 1,000 MW independent power plant. The Base Case scenario assumes the Ankerlig conversion will serve as the anchor power plant for the Project.

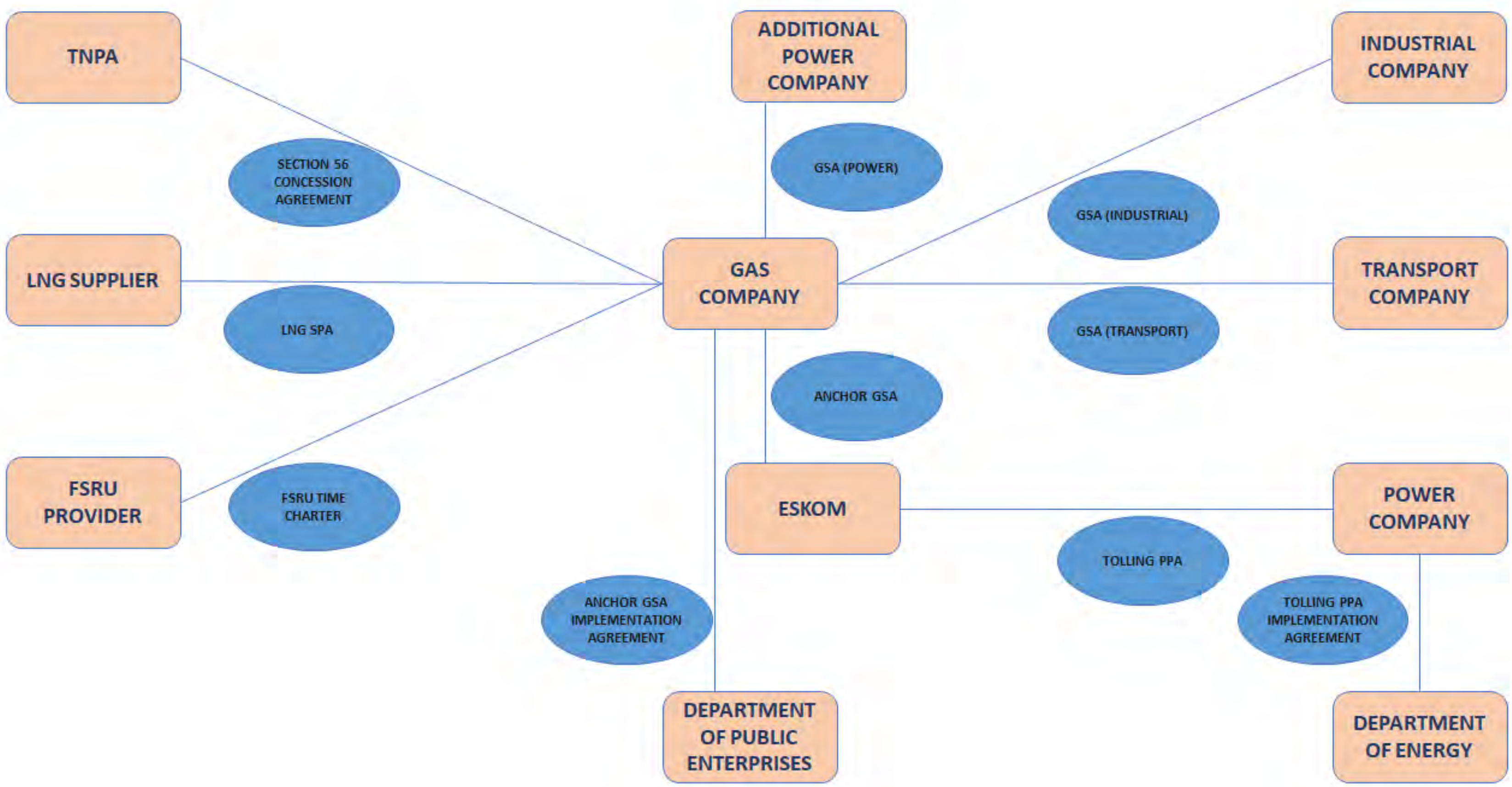
A.4.1 Base Case Anchor: Ankerlig Power Plant Conversion

Cost Item (USD MM)	Ankerlig Conversion	Potential for U.S. Participation	Probability of U.S. Participation	Expected Potential Value of U.S. Participation
Equipment	397.5	100.0%	50.0%	198.75
Bulk Materials	128.00	100.0%	10.0%	12.80
Material-Related Costs	19.88	50.0%	10.0%	0.99
Subcontracts	56.45	100.0%	25.0%	14.11
Construction Costs	137.54	100.0%	25.0%	34.38
EPC Services	62.01	100.0%	25.0%	15.50
Miscellaneous Costs	11.93	100.0%	25.0%	2.98
Start-Up & Commissioning	13.52	100.0%	25.0%	3.38
Total	826.80			282.90

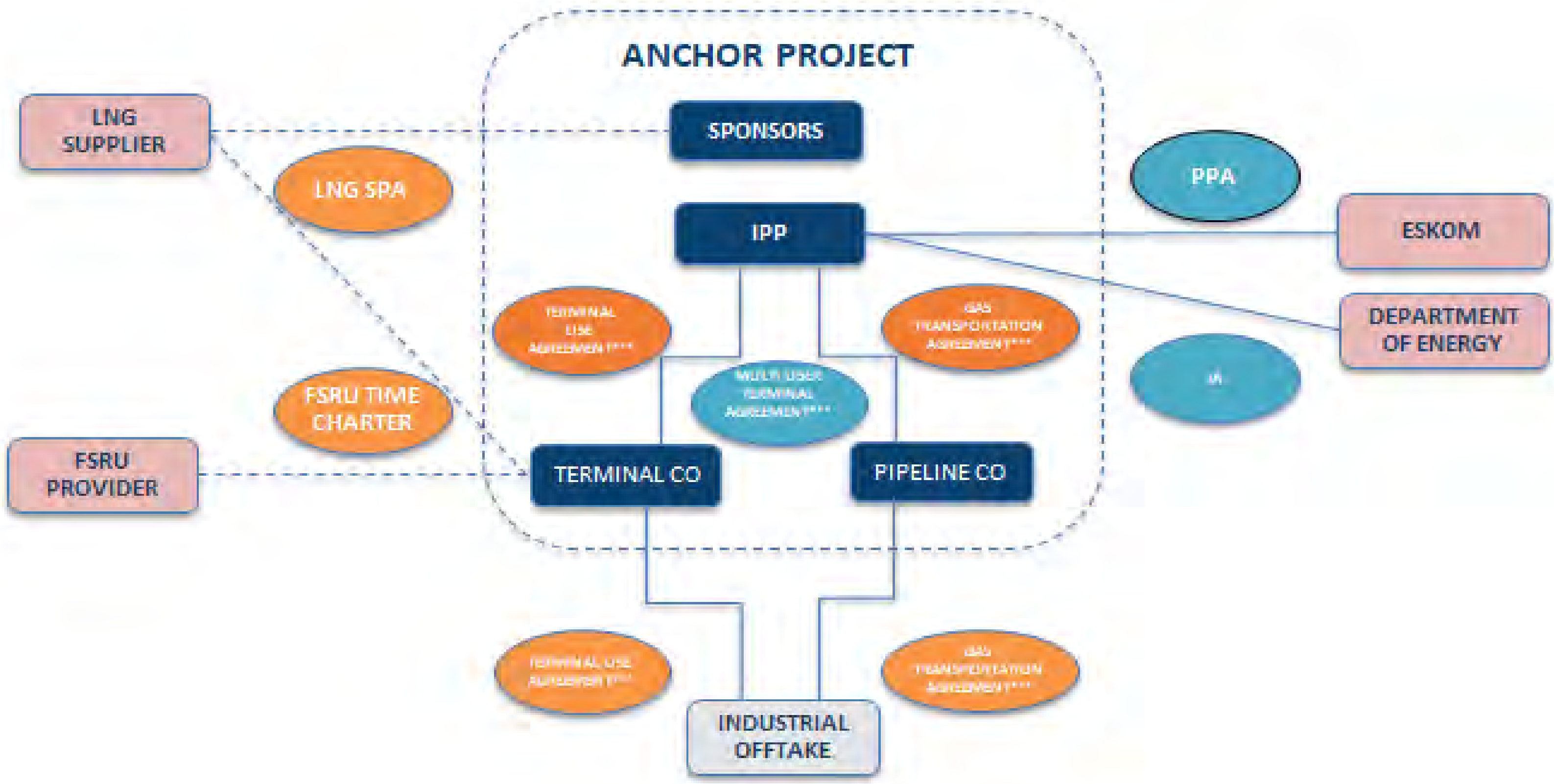
A.4.2 Alternate Anchor: Greenfield IPP

Cost Item (USD MM)	Greenfield IPP	Potential for U.S. Participation	Probability of U.S. Participation	Expected Potential Value of U.S. Participation
Equipment	624.83	100.0%	50.0%	312.42
Bulk Materials	164.43	100.0%	10.0%	16.44
Material-Related Costs	30.45	50.0%	10.0%	1.52
Subcontracts	85.26	100.0%	25.0%	21.32
Buildings	6.09	0.0%	0.0%	0.00
Construction Costs	182.70	100.0%	25.0%	45.68
EPC Services	85.26	100.0%	25.0%	21.32
Miscellaneous Costs	18.27	100.0%	25.0%	4.57
Start-Up & Commissioning	20.71	100.0%	25.0%	5.18
Total	1,218.00			428.43

Appendix 8-A: Selected Contractual Model



Appendix 8-B: Alternative Contractual Model



Appendix 8-C: Task 8 Outreach Plan

APPLICABLE APPROVAL	RELEVANT REGULATORY BODY	RESPONSIBLE PARTY	STEPS TO OBTAIN APPROVAL
GAS			
Registration for importation of LNG	NERSA[1]	GasCo, IPPCo or third-party gas users	Application to NERSA (see page 15 of Report)
Operation licence for the regasification of LNG	NERSA	FSRUCo, GasCo or TermCo	Application to NERSA followed by public comment process (see pages 15-16)
Storage licence	NERSA	FSRUCo, GasCo or TermCo	Same as above
Construction licence for gas transmission pipelines	NERSA	PipeCo[2]	Same as above
Operation licence for gas transmission pipelines	NERSA	PipeCo	Same as above (can apply for operation licence at same time as application for construction licence)
Trading licence for sale of gas to Eskom, additional PowerCo, TransCo and IndCo	NERSA	GasCo	Same as above
PORTS			
Section 56 agreement or section 57 licence in terms of the Ports Act	The Authority[3]	FSRUCo, TermCo or GasCo[4]	Section 56 agreement: public, competitive process (normally involving feasibility study, expressions of interest, RFQ, RFP and negotiations) Section 57 licence: competitive invitation issued by the Authority (see pages 33-4)
Section 56 agreement or section 57 licence	The Authority	PipeCo	Same as above

[1] National Energy Regulator of South Africa.

[2] PipeCo may require licences to construct and operate gas distribution facilities in the event that it engages in pipeline transportation "*at a general operation pressure of more than 2 bar gauge and less than 15 bar gauge*" and constructs pipelines for this purpose.

[3] Transnet National Ports Authority.

[4] To the extent that GasCo (or any other person other than the Authority) engages in the construction, development or maintenance of "*port infrastructure*" including capital dredging, GasCo/other person would require an agreement with the Authority in terms of section 68(2) of the Ports Act.

APPLICABLE APPROVAL	RELEVANT REGULATORY BODY	RESPONSIBLE PARTY	STEPS TO OBTAIN APPROVAL
ENVIRONMENT			
Environmental authorisations for regasification facility	Western Cape Department of Environmental Affairs and Development Planning	FSRUCo, GasCo or TermCo	Environmental impact assessment process and public participation, as stipulated by the NEMA EIA Regulations (see pages 41-43)
Environmental authorisations for gas transportation	Western Cape Department of Environmental Affairs and Development Planning	PipeCo	Same as above (see pages 41, 43-44)
Environmental authorisations for electricity generation	Western Cape Department of Environmental Affairs and Development Planning	PowerCo or IPPCo	Same as above (see pages 41, 44-45)
Environmental authorisations for electricity transmission / distribution	Western Cape Department of Environmental Affairs and Development Planning, provided the lines do not cross over to another Province, in which case it will be the National Department of Environmental Affairs	IPPCo or third party	Same as above (see page 41 and 45)
Atmospheric emission licence	Metropolitan / district municipality	PowerCo of IPPCo	As per Metropolitan / District municipality requirements (see pages 41-42)
Water use licence	Local Catchment Management Agency will facilitate licence application, but final approval will be made by the National Department of Water and Sanitation	PipeCo	As governed by the Regulations Regarding the Procedural Requirements for Water Use Licence Applications and Appeals, 2017
ELECTRICITY			
Generation licence	NERSA	PowerCo or IPPCo	Inclusion of MW capacity in IRP[5] or deviation approved by Minister;[6] licence application to NERSA followed by public comment process (see pages 49-56)[7]
Transmission licence (where privately-constructed transmission lines are involved)	NERSA	IPPCo or third party	Licence application to NERSA followed by public comment process (see pages 52-6)

5 Integrated Resource Plan.

6 NERSA currently also requires a ministerial determination in terms of ERA.

7 If the Ankerlig Plan is to be converted to a gas-fired power station, a licence amendment (rather than a new licence) is probably required.

APPLICABLE APPROVAL	RELEVANT REGULATORY BODY	RESPONSIBLE PARTY	STEPS TO OBTAIN APPROVAL
Distribution licence (where there privately-constructed distribution lines are involved)	NERSA	IPPCo or third party	Same as above

Appendix 8-D: Brief Comparative Analysis

The purpose of this Appendix D is to briefly analyse the key features of the regulatory frameworks that apply to LNG-to-power projects in three foreign jurisdictions – the United States of America (the "US"), the United Kingdom (the "UK") and Japan[1] – in order that they might be compared to the South African regulatory framework described in this Task 8 Report.

For purposes of this appendix, we confine our analysis to the most important regulatory aspects, namely (i) the applicable licensing or authorisation regime for the construction and operation of gas and electricity infrastructure in the context of LNG projects; and (ii) tariff or price regulation in respect of such projects.

1. The United States of America

Regulatory instruments and authorisations

The main statutory instruments through which LNG-to-power projects are regulated at the federal level in the US include the Energy Policy Act, 2005 ("EPA") and the Natural Gas Act, 1938 ("NGA"). Together with the Interstate Commerce Act of 1887, the Federal Power Act of 1920 ("FPA"), and the Public Utility Regulatory Policies Act of 1978, these statutory instruments regulate the gas and electricity industries in the US, and vest regulatory authority in the Federal Energy Regulatory Commission (the "FERC" or the "Commission"). The FERC primarily regulates the gas and electricity industries through making orders and issuing authorisations in terms of various regulatory instruments and, where appropriate, imposing penalties for contraventions.

(a) gas regulation

The NGA prohibits the importation of natural gas from a foreign country without first having secured an order from the FERC authorising such person to import the gas.[2] The FERC is required to issue such order upon application, unless it finds that the proposed importation will not be consistent with the public interest.

With regard to the establishment of LNG infrastructure, section 311(c) of the EPA, read with section 3 of the NGA (15 U.S.C. 717b(e)), provides that the FERC has "*exclusive authority to approve or deny an application for the siting, construction, expansion, or operation of an LNG terminal*". An LNG terminal includes "*all natural gas facilities located onshore or in State waters that are used to receive, unload, load, store, transport, gasify, liquefy, or process natural gas that is imported to the United States from a foreign country, exported to a foreign country from the United States, or transported in interstate commerce by waterborne vessel…*".[3] All the facilities needed to receive, load and unload, store and regasify LNG as part of an LNG project are therefore encompassed in the definition of "LNG terminal", and are regulated as such.

In relation to the transportation and sale of gas, the NGA prohibits a natural-gas company (or a person which will be a natural-gas company) from engaging in the transportation or sale of natural gas, or the construction or extension of any facilities therefor, unless a certificate of public convenience and necessity

[1] This appendix has been prepared by Webber Wentzel, who are South African lawyers. They are not experts in the law of these three jurisdictions. This appendix is intended purely to compare the South African regulatory regime to that which applies in these other jurisdictions, and should not be construed as legal advice.

[2] 15 U.S.C. 717b(a).

[3] Section 311(b) of the EPA, read with section 2 of the NGA (15 U.S.C. 717a).

issued by the FERC authorises those acts or operations.[4] Such a certificate is only issued if: (i) the proposed service, sale, operation, construction or extension "*is or will be required by the present or future public convenience and necessity*"; and (ii) "*if it is found that the applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of [the NGA] and the requirements, rules, and regulations of the Commission thereunder*".[5]

The following elements of the gas portion of an LNG project that is akin to the Project would thus be regulated in the US:

- the importation of the LNG, through an FERC order;

- the gas loading pipelines required to offload the LNG from the Gas Tanker to an FSRU, the storage tanks in the FSRU, and the regasification plant within the FSRU would all constitute an "LNG terminal" and would require approval from the FERC in order to be constructed and operated. It is our understanding that only a single application and authorisation would be needed for the siting, construction and operation of the various parts of the LNG terminal; and

- the transmission and sale of the regasified gas, and the construction of any facilities therefor, would require a certificate of public convenience and necessity from the FERC.

(b) electricity regulation

With regard to the electricity portion of LNG projects like the Project, the Frequently Asked Questions About FERC published on the FERC's website (the "FERC FAQs") indicate that "*[t]he only electric generating projects that require FERC approval are hydropower projects*". The FERC thus does not regulate the electricity generation portion of gas-to-power projects. Nor does the FERC, according to the FERC FAQs, generally regulate the construction and operation of electricity transmission lines. The authority to do this rests with the individual states or the various state public utility commissions.

Under certain circumstances, section 1221 of the EPA, read with Part II of the FPA,[6] gives the FERC limited authority to site interstate electric transmission facilities if certain conditions have been met. These conditions mainly relate to the public interest and or to circumstances where the relevant state or the state public utility commission does not have authority to, or cannot or refuses to, grant the necessary authorisation required for the construction or modification of electric transmission facilities.[7]

The FPA contains open-access provisions, and provides for interconnection and or wheeling.[8]

Price or tariff regulation

In respect of gas prices, the FERC FAQs state that the FERC does not regulate the price of natural gas, and stopped doing so "*at the well head during the 1980s*".[9] According to the FERC FAQs, the FERC "*only regulates the price to transport natural gas*".[10] We understand this to mean that the FERC does not determine or approve gas prices upfront, other than for the transportation of natural gas. The FERC is, however, empowered to determine that the price for natural gas or the transport thereof is unreasonable and to intervene in this regard. In particular, the NGA stipulates that: *"[a]ll rates and charges made,*

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[4] 15 U.S.C. 717f(c).

[5] 15 U.S.C. 717f(e).

[6] See 16 U.S.C. 824.

[7] See 16 U.S.C. 824p(b).

[8] See 16 U.S.C. 824j-k.

[9] See the Natural Gas Wellhead Decontrol Act, 1989 and Order No. 490 Final Rule re abandonment of sales/purchases of natural gas.

[10] FERC FAQS.

demanded, or received by any natural-gas company for or in connection with the transportation or sale of natural gas", or any rules affecting or pertaining thereto, "*shall be just and reasonable, and any such rate or charge that is not just and reasonable is declared to be unlawful*".[11] Where the FERC finds that any rate or charge is unjust, unduly discriminatory, or preferential, the FERC is authorised to *determine* the just and reasonable rate or charge, and thereafter *fix* the same by order.[12]

Every natural-gas company is required to file with the FERC, and shall keep open for public inspection, schedules showing all rates and charges for any transportation or sale of natural gas.[13] No change to such schedules is possible except after thirty days' notice to the FERC and to the public.[14] There is a rule against undue preference or advantage in pricing and any unreasonable difference in rates and charges either as between localities or as between classes of service.[15]

The NGA also provides for the FERC to authorise a natural-gas company to provide storage and storage-related services at market-based rates for new storage capacity related to a specific facility placed in service after August 2005, if the FERC determines that market-based rates: (i) are in the public interest; (ii) are necessary to encourage the construction of the storage capacity in the area needing storage services; and (iii) customers are adequately protected.[16]

In respect of electricity prices, the FPA prescribes that any rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy must be just and reasonable (falling which, such rates or charges are unlawful).[17] The FPA's regulatory regime also provides for, amongst others: (i) filing schedules displaying all rates and charges;[18] (ii) notice requirements for changes to filed schedules;[19] (iii) the power of the FERC to determine and fix prices in certain circumstances;[20] and (iv) the rule against undue preference or advantage in pricing and any unreasonable difference in rates and charges.[21]

2. The United Kingdom

Regulatory instruments and authorisations

The main statutory instruments through which projects like the Project are regulated in the UK include the Gas Act, 1986 ("Gas Act"), the Electricity Act, 1989 ("Electricity Act") and the various Energy Acts. These instruments together confer regulatory authority on the Gas and Electricity Markets Authority ("GEMA"), which operates through the Office of Gas and Electricity Markets ("Ofgem") and the Secretary of State for Energy and Climate Change (the "Secretary of State").

(a) gas regulation[22]

There are no specific government authorisations required to construct and operate LNG facilities in the UK (although these facilities must comply with the relevant environmental, planning and health and safety

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[11] 15 U.S.C. 717c(a).
[12] 15 U.S.C. 717c(d).
[13] 15 U.S.C. 717c(c).
[14] 15 U.S.C. 717c(d).
[15] 15 U.S.C. 717c(b).
[16] 15 U.S.C. 717c(f).
[17] 16 U.S.C. 824d(a).
[18] 16 U.S.C. 824d(c).
[19] 16 U.S.C. 824d(d).
[20] 16 U.S.C. 824e(a).
[21] 16 U.S.C. 824d(b).
[22] This portion relies upon P Thomson and J Derrick 'United Kingdom' in *International Comparative Legal Guide: Oil & Gas Regulation* (2018).

requirements). LNG facilities are, however, subject to, among others, general gas storage regulatory requirements. Under the Energy Act, 2008, the storage of gas in offshore gas storage facilities requires a gas storage licence, and the unloading of gas to pipelines within the offshore area also requires a licence (an offshore unloading licence). In respect of onshore gas storage, section 4 of the Gas Act, 1965, which provides for licenced gas transporters to obtain storage authorisation from the Secretary of State, would apply.

The transmission, distribution and trading of the regasified LNG is subject to the normal regulatory regime applicable to the downstream gas industry in the UK, under a licencing system operated by Ofgem, as set out in the Gas Act. Three licences contemplated in the Gas Act could potentially apply depending on the manner in which an LNG project is structured:

- a gas transporter licence, which authorises the licensee to convey gas through pipelines to any premises within the area specified in the licence.[23] This licence encompasses both transmission and distribution, and no separate distribution licence is required in order to operate a distribution network. While regasified LNG would usually be piped into the (high-pressure) national transmission system, UK law does not prevent the construction and operation of separate private transmission and distribution pipelines. The Gas Act prohibits a person holding a gas transporter licence from holding any other gas licence.[24]

- a gas shipper licence, which authorises a gas wholesaler to contract with a gas transporter for gas to be conveyed through a pipeline system.

- a gas supplier licence, which authorises the licensee (a gas retailer) to supply gas to any domestic or non-domestic premises thorough pipelines.[25]

The Gas Act generally imposes a duty on gas transporters and owners of LNG and storage facilities to provide third-party access (subject to various exemptions provided for in the Act).[26] Non-discriminatory third-party access to LNG facilities, storage facilities as well as transmission and distribution pipeline systems is also required by the the European Gas Directive 2009/73/EC.

(b) ***electricity regulation***[27]

The electricity regulatory framework in the UK is mainly set out in the Electricity Act. The Act requires licences, granted by GEMA, in respect of all stages of the electricity value chain, including: (i) generation; (ii) participation in transmission (which is defined to cover both operation and ownership activities); (iii) distribution; and (iv) supply.[28] There is a separation of all the activities involved in the electricity value chain, and an entity within the common ownership is prohibited from carrying out other licenced activities.[29] This is usually enforced through licence conditions (e.g. a transmission licence may prohibit a licensee and its affiliated entities from owning electricity supply or generation interests). Licence conditions will also usually stipulate that the licensee must comply with the relevant industry codes.[30]

With regard to generation, the authorisations required to construct and operate generation facilities depend on the type and size of facility to be constructed or operated. If the generation capacity is more than 50MW onshore, and more than 100MW offshore, a development consent order (DCO) is to be applied for under

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[23] Section 7(2) of the Gas Act.

[24] Sections 7(3) and 7A(3).

[25] Section 7A of the Gas Act.

[26] Sections 19, 19B and 19D of the Gas Act.

[27] This portion relies upon M Hassan and D Majumder-Russell 'Electricity regulation in the UK: overview' *Thompson Reuters Practical Law* (2014).

[28] Section 6 of the Electricity Act.

[29] See sections 6(2) and 6(2A) of the Electricity Act. See Hassan and Majumder-Russell, para 2.

[30] On the conditions that may be imposed, see section 7 of the Electricity Act.

the Planning Act, 2008. This application is made to the Planning Inspectorate, which will make a recommendation to the Secretary of State. In addition, generating stations with a generating capacity of 50MW or more require consent under section 36 of the Electricity Act from the Secretary of State or an appropriate authority listed in section 36(10). Projects with a generating capacity of 50MW and less in England and Wales require consent under the Town and Country Planning Act, 1990.[31]

Subject to certain exceptions, an authorisation from the Secretary of State is required in order to construct overhead transmission lines.[32] The installation of overhead electric lines with a nominal voltage of 132kV or more would require a DCO. A transmission licence is required for the operation of a transmission network, while a distribution licence would be required for the operation and maintenance of a distribution network. Both transmission and distribution licensees are subject to the third-party access provisions of the Electricity Act.

The sale of electricity at the retail level requires a supply licence from Ofgem.[33]

Price or tariff regulation

Prices for the transmission of gas are regulated by the price control regime known as "RIIO-T1" (Revenue = Incentives + Innovation + Outputs) up to 31 March 2021, which sets out the outputs that the gas transmission network companies need to deliver for their customers, and the associated revenues they are allowed to collect, for an eight-year period.

Prices for gas distribution are regulated through the "RIIO-GD1" price control regime, which, in a manner similar to RIIO-T1, uses the RIIO model (Revenue = Incentives + Innovation + Outputs), and ensures that regional gas distribution networks can, through efficient operation, earn a fair return on their activities while controlling the end cost to consumers.

Turning to the electricity regime, wholesale electricity prices are not regulated and depend on the market prices of electricity supply. While the rates for electricity supply are not directly regulated, suppliers are regulated indirectly through licence conditions.[34]

The rates payable for connection to and use of the electricity transmission system are regulated and are set out in a suite of documents called the charging statements. Prices for the transmission of electricity are regulated by the price control regime "RIIO-T1".[35] With regard to electricity distribution, the rates charged are also regulated and distribution network operators (DNOs) must offer access to the distribution system based on published, approved tariffs and ensure priority access for renewable generators. The DNOs must have a use-of-system charging methodology for calculating their rates, which must be approved by Ofgem. Distribution prices are regulated by the price control regime "RIIO-ED1", which is in place until 31 March 2023, and which sets the outputs that the DNOs must deliver and the associated revenues they are allowed to collect over the eight-year price control period.[36]

[31] Hassan and Majumder-Russel, para 10.
[32] Section 37 of the Electricity Act.
[33] Section 6 of the Electricity Act.
[34] Hassan and Majumder-Russel, para 22.
[35] Hassan and Majumder-Russel, para 16.
[36] Hassan and Majumder-Russel, para 19.

3. Japan

Regulatory instruments and authorisations

The main statutory instruments through which projects like the Project are regulated in Japan include the Gas Business Act, 1954 (the "GBA"), the Electricity Business Act, 1964 (the "EBA") and various orders or ordinances passed by the Ministry of Economy, Trade and Industry ("METI").[37] Under these instruments, METI is conferred with regulatory authority over the gas and electricity industries. METI includes the Agency for Natural Resources and Energy and the Electricity and Gas Market Surveillance Commission, both of which assist with METI's regulation and monitoring of the gas and electricity industries (and the broader Japanese energy sector).

(a) gas regulation

Participants in the Japanese LNG value chain are regulated in terms of the GBA. Our understanding is that, while the importation of LNG is subject to general import laws, there is no specific regulation of the importation of LNG in Japan.

The construction and operation of LNG infrastructure is regulated. Such infrastructure falls within the GBA's definition of "Gas Facilities". According to the GBA, "Gas Facilities" include "*gas generating facilities, gas holders, gas purification plants, exhausters, feeding compressors, governors, pipelines, electric power receiving facilities and other facilities installed for the purpose of supplying gas as well as auxiliary facilities thereof, which are used for Gas Business*".[38] "Gas Business" is, in turn, defined to include businesses involved in all the stages of the LNG/gas value chain in Japan (gas manufacturers, gas retailers and gas pipeline service providers).[39] The GBA defines a "Gas Manufacturing Business" as "*the business of manufacturing gas using a Liquefied Gas Storage Facility*".[40] An FSRU and its related infrastructure would thus constitute "Gas Facilities" installed for the purpose of manufacturing gas (i.e. regasifying LNG) in a gas manufacturing business, and would need to adhere to the regulatory requirements of the GBA.

According to article 86 of the GBA, a person who intends to conduct a gas manufacturing business must notify METI, and in such notification include the prescribed particulars. The particulars that must be contained in the notification include details regarding "*liquefied gas storage facilities*"[41] (which would include the storage tanks part of the FSRU) and "*gas generating facilities*"[42] (which would presumably include the regasification plant component of the FSRU) to be used for the business, and "*the site where they are to be installed, the type, and number of them by capacity*".[43]

A gas manufacturer cannot refuse a third party's request for commissioned gas manufacturing without justifiable grounds, and must publicise the capacity of its liquefied gas storage facilities, the estimated quantity of the liquefied gas stored by the manufacturer, the type and capability of the gas generating facilities, and other particulars specified in an order of METI.[44]

With regard to transmission and distribution, a person who intends to provide a service of transporting gas via pipelines *in a service area* is regulated as a "General Gas Pipeline Service Provider" and must obtain a licence from METI under article 35 of the GBA. The licence application must contain, among other things,

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[37] Our discussion of the instruments in this portion is based on the English translations of the legislative instruments, as published on METI's website.

[38] Article 2(13) of the GBA.

[39] Article 2(11) of the GBA.

[40] Article 2(9) of the GBA.

[41] Article 86(1)(iii)(a) of the GBA.

[42] Article 86(1)(iii)(b) of the GBA.

[43] Articles 86(1)(iii)(a) and 86(1)(iii)(b) of the GBA.

[44] Article 90 of the GBA.

particulars regarding the gas facilities to be used for the proposed general gas pipeline service business, the site where they are to be installed, the inside diameter and the gas pressure within the pipelines.[45] A general gas pipeline service provider may not refuse to provide a transportation service in its service area without justifiable grounds.[46]

A specific gas pipeline provider, which intends to supply gas to *a specified service point* must notify METI of this activity.[47]

With regard to the sale of gas, a person who intends to provide a gas retail service must be registered by METI as a gas retailer under article 3 of the GBA.

Finally, there are certain restrictions prohibiting licensees authorised to participate in certain activities in the gas value chain from engaging in other activities in the value chain (e.g. a general gas pipeline service provider generally cannot engage in a gas retail business or a gas manufacturing business).[48]

(b) electricity regulation

The various stages of the electricity value chain are regulated in Japan by the EBA. In particular, the construction of generation, transmission and distribution infrastructure is regulated by the rules set out in Chapter III of the EBA, which apply to "Electric Facilities", which are defined as *"[m]achines, apparatuses, dams, waterways, reservoirs, electric lines, and other facilities installed for the purpose of generating, transforming, transmitting, distributing or using electricity*".

A person who intends to implement a construction project to install or modify electric facilities that are specified as being particularly important for assuring public safety must obtain METI's approval of the construction plan.[49] In relation to other construction projects to install or modify electric facilities, and which are specified by order of METI, the project implementer must notify METI of such construction plan.[50] In order to ensure the safety of the construction, maintenance and operation of electric facilities, a person who installs such facilities must establish safety regulations and notify METI of the regulations before using the facilities.[51] In addition to the regulation of the construction of electric facilities, the generation, sale, transmission and distribution activities are regulated by the EBA.

Subject to certain exceptions (e.g. the total generating capacity of facilities owned by the producer being less than 20 000 kW), a person who intends to conduct an electricity generation business must notify METI and must stipulate, among other things, the site where the proposed generation facility is to be installed and the type of motive power, frequency, and output capacity involved.[52]

In respect of transmission and distribution, the EBA stipulates that a person who intends to conduct a "General Electricity Transmission and Distribution Business" (as defined in the EBA) must obtain a licence from METI.[53] A licenced General Electricity Transmission and Distribution Utility is required to provide a wheeling service as contemplated in article 17 of the EBA. Companies that operate transmission lines that connect generation facilities to the transmission grid require the approval of METI.[54]

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[45] Article 36(1)(iv)(b) of the GBA.
[46] Article 47 of the GBA.
[47] Article 72(1) of the GBA. K Kubo "Japan" in *Getting the Deal Through: Gas Regulation* (2018), para 8.
[48] Article 54-2 of the GBA.
[49] Article 47 of the EBA.
[50] Article 48 of the EBA.
[51] Article 42 of the EBA.
[52] Article 27-27 of the EBA. N Sato and S Matsudaira "Japan" in *Getting the Deal Through: Electricity Regulation 2019* at 104.
[53] Article 3 of the EBA.
[54] Sato and Matsudaira at 103.

With regard to the sale of electricity, the EBA stipulates that a person who intends to do business in the retail electricity space must be registered by METI[55] and must, in its application for registration, address "*matters concerning ensuring the supply capability expected to be required for meeting the electricity demand of the recipient of the [retail service]*".[56] The regulation of wholesaling of electricity in Japan was abandoned in April 2016.[57]

There are certain restrictions prohibiting licensees authorised to participate in certain activities in the electricity value chain from engaging in other activities in the value chain. A general electricity transmission and distribution utility is, for example, prohibited from engaging in a retail electricity business or an electricity generation business without approval from METI.[58] It appears that, from 2020, vertically integrated companies "*will be required to split [the] transmission and distribution business from [the] power generation and retail business*".[59]

Price or tariff regulation

The extent of gas price regulation depends on the activity which is performed in the gas value chain. A manufacturer which maintains and operates LNG storage facilities is required to formulate general provisions for gas manufacturing, and to therein set rates and other supply conditions for contract gas manufacturing. METI must be notified of the provisions, and has the power to order that they be revised.[60]

In respect of gas transmission and distribution prices, a general gas pipeline service provider must formulate general provisions for the transportation service to set rates and other supply conditions for its services, which must be approved by METI. The rates must, among other things: (i) consist of fair costs incurred as a result of efficient management and fair profits; (ii) be clearly set as fixed rates or fixed amounts; and (iii) not treat any specific person in an unfair and discriminatory manner.[61]

The price for gas sales is not regulated *per se* but a gas retailer must, when concluding retail service agreements with service recipients, explain the rates and other supply conditions for the services contemplated, and deliver a document stating the rates and other supply conditions in the manner stipulated in an order of METI.[62]

The extent of electricity price regulation similarly depends on the type of activity being performed. With regard to transmission and distribution prices, a general electricity transmission and distribution business must formulate general provisions for its wheeling service and an electricity quantity adjustment service on rates and other supply conditions for the relevant service, which must be approved by METI.[63] The rates must, among other things: (i) consist of fair costs incurred as a result of efficient management and fair profits; (ii) be calculated in terms of a method that is specified appropriately and clearly; (iii) not treat any specific person in an unfair and discriminatory manner; and (iv) not hinder the promotion of public interest.[64] METI is empowered to order that the rates be revised under certain conditions.[65]

[55] Article 2-2 of the EBA.
[56] Article 2-3 of the EBA.
[57] Sato and Matsudaira at 103.
[58] Article 22-2 of the EBA.
[59] Sato and Matsudaira at 103.
[60] See article 89 of the GBA.
[61] Articles 48 and 49 of the GBA.
[62] Article 14 of the GBA.
[63] Article 18(1) of the EBA.
[64] Article 18(3) of the EBA.
[65] Article 18(6) of the EBA.

Since the abolishment of wholesale regulation in 2016, power generators are generally able to sell electricity at conditions determined in their discretion.[66]

In respect of electricity sale prices, electricity retail companies must provide a power sales tariff and obtain approval for it from METI, and must supply electricity to low-voltage consumers in accordance with the tariff as long as such consumers desire. This arrangement will continue until 2020 or later when METI decides on an area-by-area basis that sufficient competition exists in a certain supply area.[67]

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66 Sato and Matsudaira at 106.

67 Ibid.