

Enemalta Natural Gas Supply Project



Gas Supply Report

to

Enemalta Corporation

31st October 2009



IPA Energy + Water Economics



Penspen

Gas Supply Report
to
Enemalta Corporation



IPA Energy + Water Economics
Gas Economics Division
PO Box 46562
Floor 11
Al Yasat Tower
6th Street
Abu Dhabi
United Arab Emirates

Email: Douglas.Caskie@ipaeconomics.com
web: www.ipaeconomics.com

TABLE OF CONTENTS

ABBREVIATIONS		V
1	EXECUTIVE SUMMARY	1
1.1	Natural Gas Delivery Options	1
1.2	Cost Savings to Enemalta	2
1.3	Conclusions and Recommendations	1
2	INTRODUCTION	2
2.1	Preliminary Assessment of LNG & CNG bidders	2
2.2	Technical, Commercial and Legal Clarifications	2
2.3	Assessment of Alternative (Pipeline) Gas Delivery Options	3
2.4	This Document	3
3	EVALUATION METHODOLOGY	4
3.1	Technical Evaluation	4
3.2	Commercial Evaluation	5
3.3	Legal Evaluation	14
4	BIDDER 1: BB ENERGY BV	15
4.1	General	15
4.2	Company Overview	15
4.3	Technical Evaluation	16
4.4	Commercial Evaluation	20
4.5	Legal Issues	23
5	BIDDER 2: ENERGY WORLD CORPORATION	27
5.1	General	27
5.2	Company Overview	27
5.3	Technical Evaluation	28
5.4	Commercial Evaluation	30
5.5	Legal Issues	35
6	BIDDER 3: SEANG CONSORTIUM	38
6.1	General	38
6.2	Company Overview	38
6.3	Technical Evaluation	39
6.4	Commercial Issues	42
6.5	Legal Issues	49
6.6	Conclusions	52
7	POTENTIAL PIPELINE DELIVERIES	54
7.1	Hydraulic Analysis	55
7.2	Cost Estimates	56
7.3	Financial Analysis & Tariff Calculation	58
7.4	Fuel Cost Savings Calculations	61
7.5	Conclusions and Recommendations	62
8	IMPACT OF AN ENHANCED HVAC CABLE INTERCONNECTIONS BETWEEN MALTA AND SICILY	63

TABLE OF CONTENTS

8.1	Introduction	63
8.2	Changed Demand for Gas and other Fuels	64
8.3	Fuel Price Changes	67
8.4	Impact on BBE Bid	67
8.5	Impact on EWC Bid	69
8.6	Impact on SeaNG	70
8.7	Impact on the Pipeline Options	73
8.8	Conclusions	76
APPENDIX 1: COMPARISON OF LNG AND CNG BIDS		79
8.9	General	79
8.10	Comparison of Technical Aspects	79
8.11	Comparison of Commercial Aspects	82
8.12	Overall Evaluation: Commercial/Technical Weighting	84
8.13	Recommendations	85

TABLE OF EXHIBITS

Exhibit 1: Discounted Fuel Cost Savings by Oil Price	2
Exhibit 2: Discounted Fuel Cost Savings associated with different gas supply options when the 200MW interconnector is 100% utilized.	1
Exhibit 3: Discounted Fuel Cost Savings associated with different gas supply options where the 1 x 200MW interconnector is utilised at 50% capacity.....	2
Exhibit 4: Commercial Evaluation Criteria.....	5
Exhibit 5: Base Case Fuel Prices.....	6
Exhibit 6: Exchange Rate Assumptions	8
Exhibit 7: Take or Pay Volumes vs Gas Demand	8
Exhibit 8: Enemalta Fuel Demand - With Gas project.....	9
Exhibit 9: Enemalta Fuel Demand - Without Gas Project	10
Exhibit 10: Additional CAPEX cost	10
Exhibit 11: Enemalta Plants	11
Exhibit 12: Fuel Carbon Intensity	12
Exhibit 13: CO2 Emissions –Gas Project vs. No-Gas Project	13
Exhibit 14: Capacity Charge-BBE	20
Exhibit 15: Regression against Oil Price Showing BB Energy pricing.	21
Exhibit 16: Impact of BBE Bid on Fuel Cost - Base Case.....	22
Exhibit 17: BB Energy: Commercial Scoring	23
Exhibit 18: Average Fuel Cost Comparison	32
Exhibit 19 Impact of EWC Bid on Fuel Cost – High Oil Price Case.....	33
Exhibit 20: EWC Bid: Discounted fuel cost savings by	34
Exhibit 21: EWC Bid: Discounted fuel and carbon cost savings.....	34
Exhibit 22: EWC Commercial Scoring.....	35
Exhibit 23: Credit Rating Marubeni.....	38
Exhibit 24: Credit rating Teekay	39
Exhibit 25: Capacity Charges SeaNG	45
Exhibit 26: Impact of SeaNG Bid on Total Cost – Base Case.....	46
Exhibit 27: Impact of SeaNG Bid on Fuel Cost – Low Oil Price Case.....	46
Exhibit 28: Impact of SeaNG Bid on Fuel Cost – High Oil Price Case.....	47
Exhibit 29: SeaNG Bid: Discounted fuel and carbon cost savings	48
Exhibit 30 : SeaNG Commercial Scoring	49
Exhibit 31: Summary of Studied Pipeline Options	54
Exhibit 32: Gela- Delimara Offshore Pipeline Summary Hydraulic Analysis.....	55
Exhibit 33: Capital Expenditure Summary - \$US’000s (2008)	56
Exhibit 34: ENI Capital Expenditure Estimates - (2008 prices)	57
Exhibit 35: Operating Expenditure Summary - (2008 prices).....	57
Exhibit 36: ENI Total Operating Expenditure Estimates - (2008 prices)	58
Exhibit 37: Pipeline Tariff per unit of Capacity.....	60
Exhibit 38: Pipeline Tariff per unit Consumed (\$/MMBtu 2008).....	60
Exhibit 39: NPV ₁₀ of Fuel Cost Savings (Base Fuel Price Scenario).....	61
Exhibit 40: NPV ₁₀ of Fuel Cost Savings by Fuel Price Scenario	61
Exhibit 41: NPV ₁₀ of Fuel and Carbon Cost Savings by Fuel Price Scenario.....	62
Exhibit 42: Gas Demand Scenarios.....	64
Exhibit 43: Enemalta Fuel Demand- With Gas Project (No Gas Supply Disruptions and 1x200MW 50% Interconnector).....	65
Exhibit 44: Take or Pay Volumes vs Gas Demand with 1x200MW 50% Interconnector	65
Exhibit 45: Enemalta Fuel Demand- Without Gas Project (1x200MW 50% Interconnector)....	66
Exhibit 46: Enemalta Fuel Demand – Without Gas Project (2x200MW 75% Interconnector) ..	66
Exhibit 47: Base Case Fuel Price Assumptions	67

Exhibit 48: BBE Average Fuel Cost Comparison Gas vs No Gas (Base prices and 1 x 200 MW 50% interconnector) 68

Exhibit 49: NPV of Fuel Cost Savings - BBE 68

Exhibit 50: EWC Average Fuel Cost Comparison - Gas vs No Gas (Base Fuel Price Scenario) 1x200MW 50% Interconnector 69

Exhibit 51: EWC Average Fuel Cost Comparison - Gas vs No Gas (Base Fuel Price Scenario) 1x200MW 100% Interconnector 69

Exhibit 52: EWC Average Fuel Cost Comparison - Gas vs No Gas (High Fuel Price Scenario) with Capital Costs 2x200MW 75% Interconnector 70

Exhibit 53: NPV of EWC fuel cost savings under different fuel price and interconnector scenarios 70

Exhibit 54: SeaNG Average Fuel Cost Comparison - Gas vs No Gas (Base Fuel Price Scenario) with Capital Costs 1x200MW 50% Interconnector 71

Exhibit 55: SeaNG Average Fuel Cost Comparison - Gas vs No Gas (Base Fuel Price Scenario) with Capital Costs 1x200MW 100% Interconnector 71

Exhibit 56: SeaNG Average Fuel Cost Comparison - Gas vs No Gas (High Fuel Price Scenario) with Capital Costs 1x200MW 50% Interconnector 72

Exhibit 57: SeaNG Average Fuel Cost Comparison - Gas vs No Gas (High Fuel Price Scenario) with Capital Costs 1x200MW 100% Interconnector 72

Exhibit 58: NPV of SeaNG Fuel Cost Savings under different fuel price and interconnector scenarios 73

Exhibit 59: NPV of Fuel Cost Savings by Fuel Price Scenario (1x200MW 50% Interconnector) 74

Exhibit 60: NPV of Fuel Cost Savings by Fuel Price Scenario (1x200MW 100% Interconnector) 75

Exhibit 61: NPV of Fuel Cost Savings by Fuel Price Scenario (2x200MW 75% Interconnector) 75

Exhibit 62: Discounted Fuel Cost Savings by Oil Price (1x200MW 100% Interconnector) 76

Exhibit 63: Discounted Fuel Cost Savings by Oil Price (1x200MW 50% Interconnector) 77

Exhibit 64: Discounted Fuel Cost Savings by Oil Price (2x200MW 75% Interconnector) 78

Exhibit 65: Technical Evaluation 81

Exhibit 66: Discounted Fuel Cost Savings by Oil 82

Exhibit 67: Discounted Fuel Cost Savings by Oil 83

Exhibit 68: Discounted Fuel and Carbon Cost Savings by 83

Exhibit 69: Summary Commercial Criteria 84

Exhibit 70: Commercial/Technical Bid Weightings 85

ABBREVIATIONS

Abbreviation	Expansion
bcm	billion (10 ⁹) cubic metres
CCGT	combined cycle gas turbine
cm/d	cubic metres per day
CNG	compressed natural gas
FSRU	Floating Storage and Regasification Unit
IOC	International Oil Company
LNG	Liquefied Natural Gas
JCC	Japanese Crude Cocktail
MCM	Thousand Cubic metres
mcm/d	thousand cubic metres per day
MMBTU	one million BTU
MMCM and mmcm	Million Cubic Metres
mtpa	million tonnes per annum
MW	Megawatts
MWh	Megawatt hours
NOC	National Oil Company, Libya
TPES	Total Primary Energy Supply

1 EXECUTIVE SUMMARY

Enemalta hired IPA Energy + Water Economics and Penspen (“the Consultant”) to assist Enemalta to choose a natural gas supplier. In 2007, Enemalta solicited for offers of gas supply and received three bids. This report:

- summarises the Consultant’s technical, commercial and legal evaluations of the bids from these three suppliers;
- sets out certain alternative options for pipeline supplies from Gela in Sicily to Delimara in Malta;
- quantifies and ranks the fuel cost savings from all the options; and
- recommends Enemalta’s next course of action.

1.1 Natural Gas Delivery Options

A range of natural gas delivery options have been considered:

LNG Two bidders provided gas supply solutions based on small scale LNG:

- **Bid 1** was from a consortium lead by BB Energy (“BBE”), primarily an oil trading company. The consortium also includes shipping company Anthony Veder BV and TGE, an engineering group with expertise in the construction and operation of LNG regasification terminals.
- **Bid 2** was offered by Energy World Corporation (“EWC”), a Hong Kong based LNG project development company with upstream gas assets in Indonesia. Like Bid 1, EWC offered a solution based around small-scale supply of LNG.

CNG One bidder suggested a CNG based solution:

- **Bid 3** was made by a consortium led by SeaNG, a CNG development company, and Teekay and Marubeni, respectively a large shipping company and a diversified industrial conglomerate.

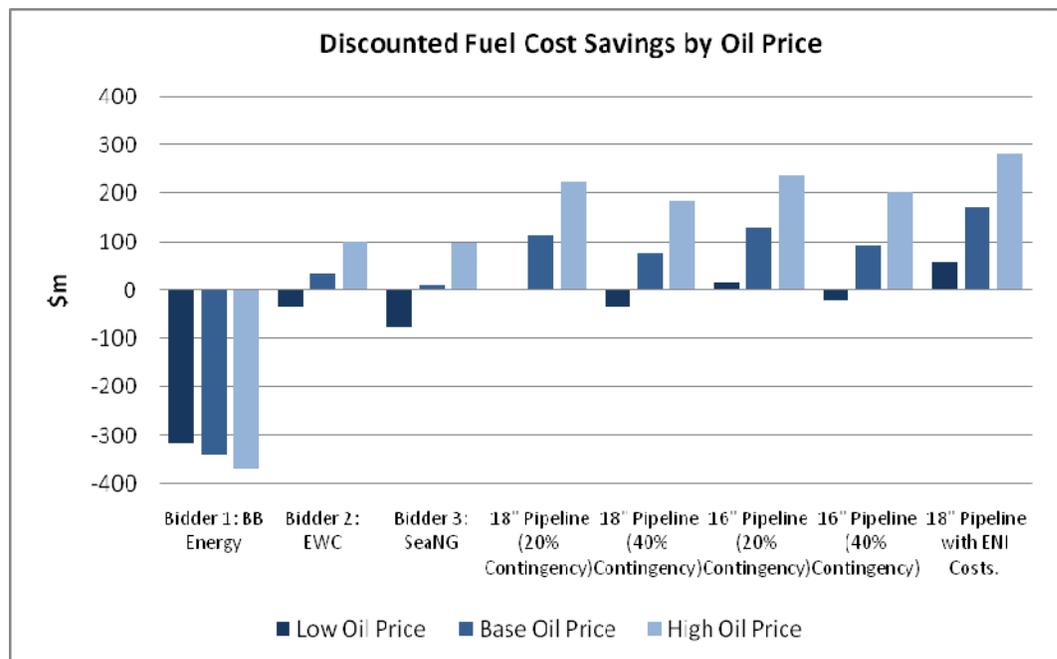
Pipeline The Consultant has analysed several options including:

- 16” and 18” pipelines for Gela in Sicily to Delimara in Malta using the Consultant’s cost estimates
- 18” pipeline as above using ENI’s cost estimates.

1.2 Cost Savings to Enemalta

The graph below compares the fuel cost savings under three fuel price scenarios for the three bidders and the pipeline options. The graph shows the relative robustness of the pipeline options against the LNG/CNG options.

Exhibit 1: Discounted Fuel Cost Savings by Oil Price



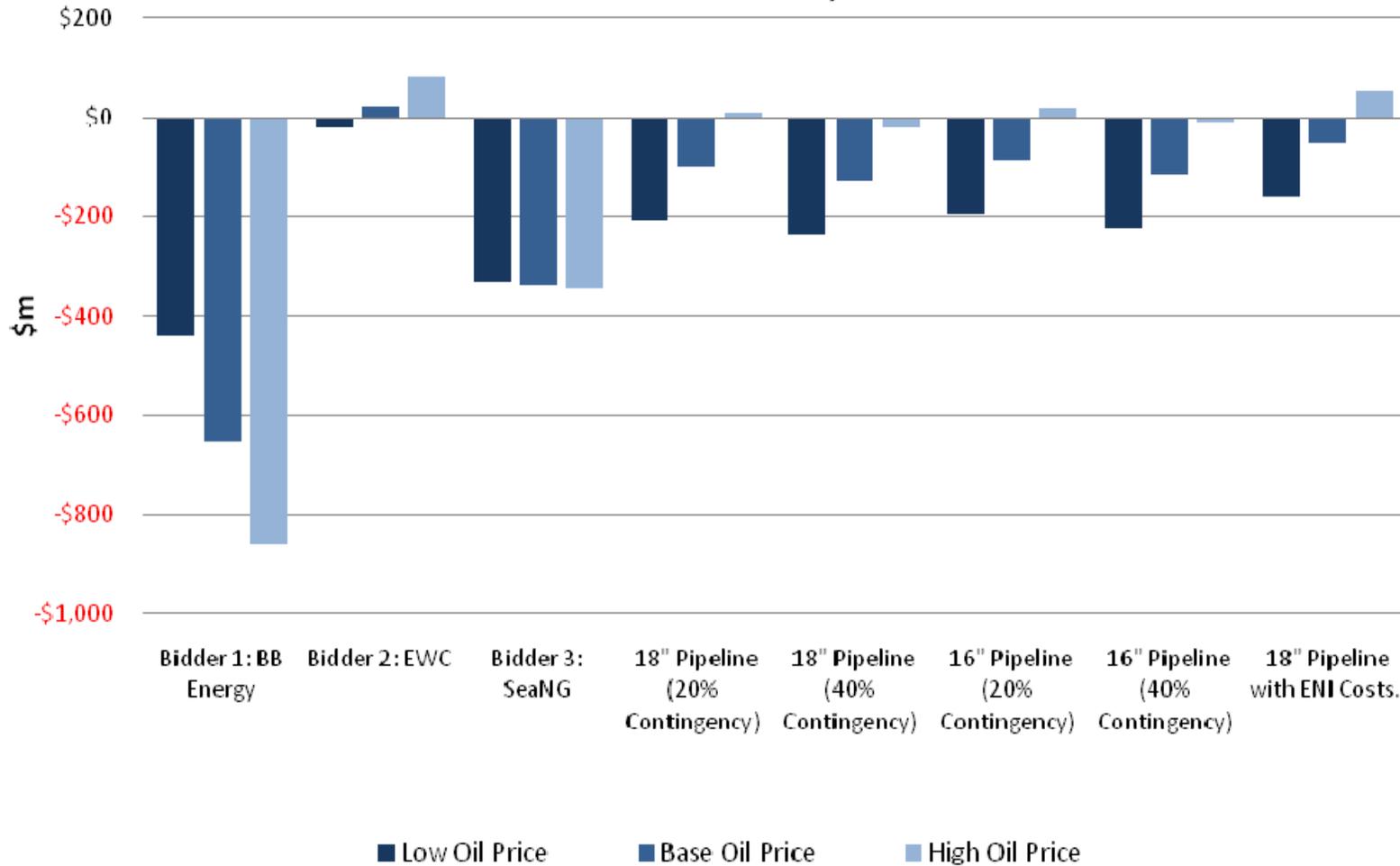
Source: IPA

The most robust option evaluated is the 18" pipeline from Gela – Delimara, assuming ENI's costs and a gas commodity price that is related to fuel oil and diesel, and against the gas volumes originally specified to bidders.

Enemalta subsequently decided to enhance the High Voltage Alternating Current ("HVAC") cable interconnections between Malta and Sicily. This revised the volume and timing of Enemalta's requirements for natural gas and other fuels. In addition to increasing the capacity of the interconnector, Enemalta also informed the Consultant that timings of gas availability would change and that Net Present Values of ("NPV") fuel cost savings should be calculated from 2015 to 2030 rather than from 2012 to 2030 as was previously requested.

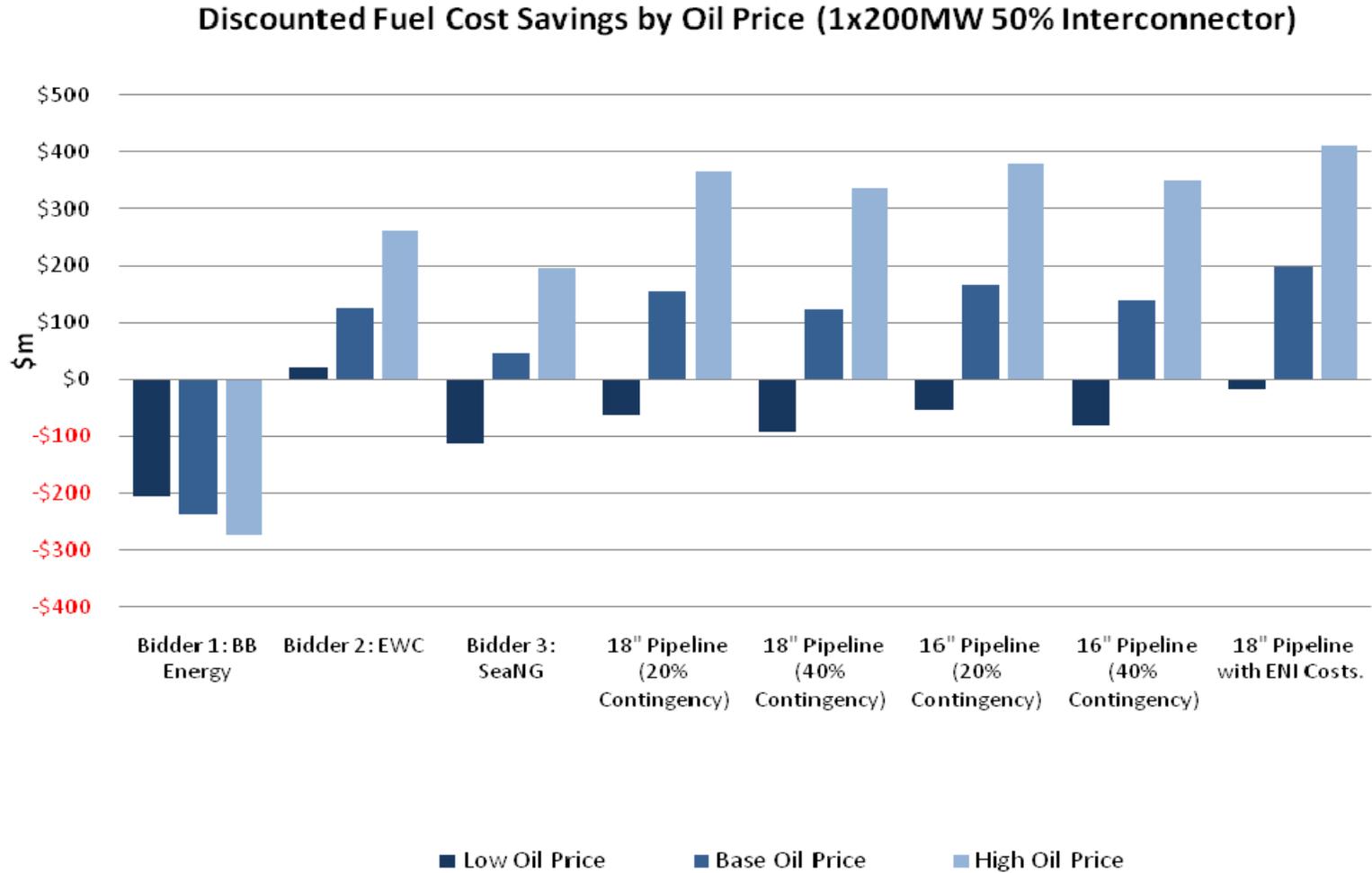
IPA therefore analysed how these changes would affect the economics of each of the potential gas supply options. A summary of this analysis is presented in the following two charts.

Exhibit 2: Discounted Fuel Cost Savings associated with different gas supply options when the 200MW interconnector is 100% utilized.



Source: IPA

Exhibit 3: Discounted Fuel Cost Savings associated with different gas supply options where the 1 x 200MW interconnector is utilised at 50% - 85%



Source: IPA



When the interconnector is 100% utilised, selected gas import options render fuel cost savings at high oil prices. In the base oil price scenario, an 18” pipeline renders fuel cost savings when interconnector utilisation is less than approximately 86%.

When the interconnector is 50% utilised, significant fuel cost savings are possible for all but one of the gas supply options. At these medium levels of interconnector utilisation, the pipeline options offer the largest potential for fuel cost savings, followed by the EWC option. At higher levels of interconnector utilisation, only the EWC option offers any chance of fuel cost savings and even this is only possible if fuel prices are high. This should not, however, be interpreted to mean that the interconnection option is the optimal investment; this has to be established by independent analysis.

1.3 Conclusions and Recommendations

IPA’s analysis shows that the pipeline from Gela - Delimara is the most cost-effective method for delivering gas to Malta. When compared with the bidder’s offers for LNG and CNG deliveries, the 18” pipeline from Gela to Delimara delivers significantly better project economics.

With enhanced interconnector uptake (following the construction of a 1 x 200 MW interconnector) fuel cost savings are still possible against HFO and diesel. The economics are favourable:

- In the high oil price scenario, for selected pipeline options, with 100% interconnector utilisation;
- In the base oil price scenario, for the 18” (ENI) pipeline option, when interconnector utilisation is less than approximately 86%;
- In the base and high oil price scenario, for all but one gas supply option, with 50%¹ interconnector utilisation.

The PSV, Italy’s virtual gas hub, remains thinly traded and used occasionally as a balancing market. Its relative immaturity means that a traditional long-term contract remains the most likely form of contracting for gas for Enemalta. If any non-recourse project financing is sought for investment in the Gela - Delimara pipeline, the transaction is also likely to require a suite of long term contracts to underpin the investment.

If the Gela – Delimara pipeline project is pursued, several gas suppliers including ENI and NOC of Libya could be potential counterparties for Enemalta. Continued engagement with ENI and initial approaches to the other suppliers is recommended.

¹ For the gas demand forecast for the 1x200MW scenario at 50%, it was assumed that the cable will be operated at 50% until 2021, increasing thereafter to 85% utilization in 2035

2 INTRODUCTION

Malta has no access to natural gas and produces all the electricity for the island from oil products. Substituting existing oil-fired generation to natural gas became a financial and environmental priority.

Enemalta Corporation (“Enemalta” or “the Client”) therefore sought bids from companies to supply natural gas to Malta, primarily to supplement and replace liquid petroleum fuels used at its electricity generating facility at Delimara on Malta’s south-east coast. The Request for Proposals (“RFP”), published by Enemalta in April 2007, gave bidders full scope to deliver gas to the power plant over a 15 year period, by whatever means they choose. Proposals were received from three bidders, two of which proposed imports via a small-scale liquefied natural gas (“LNG”) importation facility, whilst the third bidder proposed importing gas as compressed natural gas (“CNG”).

Enemalta subsequently hired IPA Energy + Water Economics and Penspen (“IPA”, “Penspen” or “the Consultant”) to assist in the choice of a natural gas supplier, by carrying out, *inter alia*, the following tasks:-

- Assess the technical feasibility and commercial viability of the proposals received thus far;
- Advise Enemalta on issues requiring further clarification from the bidders;
- Assist Enemalta in developing project requirements and specifications in support of project development, contractor selection, contract negotiation, and project financing.

2.1 Preliminary Assessment of LNG & CNG bidders

The Consultant carried out a preliminary assessment of the LNG and CNG bidders in the second quarter of 2008. The results and the methodology employed in carrying out the initial review were set out in a brief report entitled “*Evaluation of Proposals for the Supply of Natural Gas for Power Generation: Preliminary Evaluation.*” Initial findings were also discussed with Enemalta at meetings held on 6th and 7th May 2008 in Malta.

It was agreed that none of the bids had been presented in sufficient detail to enable the selection of a single contractor to be made, and it was therefore agreed that the Consultant should prepare a set of questions to which the bidders should respond providing necessary clarifications to their original proposals.

2.2 Technical, Commercial and Legal Clarifications

Technical and commercial clarifications were identified and raised and two gas sales contract term sheets were tabled. These in turn were issued by Enemalta to the bidders. Term sheet clarification meetings were held in Abu Dhabi and London with two of the bidders, and the responses to the technical clarifications and other issues were reviewed with each bidder during a Technical Review meetings and presentations held in London on the 10th - 11th of July 2008.

After the Technical Review meetings it was agreed that the Consultant would compose a summary review of the evaluations and review meetings and overall

assessments of the adequacy of each bidder in order to permit Enemalta to make a decision on whether or not to proceed with one of the bidders.

2.3 Assessment of Alternative (Pipeline) Gas Delivery Options

Following the initial assessment of bids, Enemalta asked the Consultant to advise on potential pipeline deliveries of Natural Gas from Italy or Libya. The Consultant delivered the report entitled *2397 Malta Gas Supply Report 2009-02-02* in February 2009. This report established that, relative to the LNG and CNG bidder's offers, pipeline deliveries of natural gas would be the least-cost option for Enemalta.

Enemalta also engaged with ENI to update a previous feasibility study for the supply of gas (in similar volumes as the bidders above) from Gela in Sicily to Delimara in Malta. This report confirmed the conclusions above, although ENI dismissed the Consultant's preferred (and the least-cost) option of a "hot tap" from the Greenstream pipeline.

Enemalta subsequently decided to enhance the High Voltage Alternating Current ("HVAC") cable interconnections between Malta and Sicily. This revised the volume and timing of Enemalta's requirements for natural gas. Although some uncertainty surrounds the potential utilisation of the HVAC interconnector (and hence the residual gas demand requirements), IPA was asked to advise Enemalta on the economic viability of the pipeline from Sicily to Malta under the new scenarios of HVAC cable utilisation.

2.4 This Document

This document summarises all the technical, economic and legal work done by the Consultant to date. It re-presents the summary assessment of LNG and CNG bids. Where possible it compares the gas pipeline options against these bids, drawing conclusions and recommendations for Enemalta's review.

It is presented in four main parts:

- | | |
|-----------------------|---|
| Section 3 | Presents the methodology used to evaluate the original LNG/CNG bidders' offers; |
| Sections 4 – 6 | Presents the evaluations of each of the bidders' offers; |
| Section 7 | Summarises the pipeline delivery options; |
| Section 8 | Assesses the impact of enhanced HVAC connections; |
| Section 9 | Presents the Conclusions and Recommendations; |
| Appendix 1 | Compares the original LNG and CNG bids; |

3 EVALUATION METHODOLOGY

This section sets out the evaluation methodology employed for the assessment of the original LNG and CNG bids.

Enemalta received the following three bids:

- **Bid 1** was from a consortium lead by BB Energy, primarily an oil trading company. The consortium also includes shipping company Anthony Veder BV and TGE, an engineering group with expertise in the construction and operation of LNG regasification terminals.
- **Bid 2** was offered by Energy World Corporation, a Hong Kong based LNG project development company with upstream gas assets in Indonesia. Like Bid 1, EWC offered a solution based around small-scale supply of LNG.
- **Bid 3** was made by a consortium led by SeaNG, a CNG development company, and Teekay and Marubeni, respectively a large shipping company and a diversified industrial conglomerate.

3.1 Technical Evaluation

In carrying out a technical evaluation of proposals from the three bidders, the Consultant has attempted to structure the evaluation process in line with conventional risk management procedures, whereby initial perceived risks associated with each of the bids are identified, risk mitigation measures already identified or proposed by the bidders, and submitted in response to a set of technical queries (TQs), are further evaluated, and as a result of this evaluation, residual risks are identified and evaluated.

Following initial review of the bids, the Consultant set out a list of activities for each the components of the supply chain, where it considered that project technical risks potentially exist.

The activities considered in the evaluation are listed below.

- Gas Supply
- Gas Processing
- Shipping
- Re-gasification Terminal
- Permits and Licences
- Quality and HSE Systems
- Construction
- Operations

On the basis of preliminary review of the bids, a set of questionnaires was prepared containing a number of technical queries. The three bidders submitted written responses to these queries, and attended technical clarification meetings at Penspen’s Richmond offices on 10th and 11th July 2008.

Enemalta prepared a summary of the written clarification responses of the three bidders prior to the meeting.

In general, the quality of the technical responses was high, and the amount of work undertaken in preparing their responses and the willingness of the bidders to commit both time and cost to preparing clarifications and attending the meetings, confirms the genuine interest of all three bidders in pursuing the Project.

The following sections outline for each of the bidders a review of the technical issues under the supply chain headings, together with a weighted score derived from the product of the weighting ascribed to each component in the supply chain (same for all bidders) and a comparative score (out of 10) reflecting an assessment of the relative strength of each bidder’s treatment of issues.

The weightings ascribed to each group of activities in the summary below are:-

- Gas Supply 25%
- Gas Processing 7.5%
- Shipping 15%
- Re-gasification Terminal 45%
- Operations 7.5%

3.2 Commercial Evaluation

The Commercial Evaluation was carried out using the following evaluation criteria:

Exhibit 4: Commercial Evaluation Criteria

	Weighting
Sponsor Quality	15%
Concept	10%
Gas Pricing	60%
Take or Pay Conditions	15%
	100%

Source: IPA

Cost savings on the purchase of fuel for the generation of electricity is a key objective of the potential project to import natural gas, and is duly ascribed the highest weighting in the commercial evaluation.

The project for conversion will require capital expenditure by Enemalta to convert the existing plant to dual firing. The conversion will change the heat rate of the plant and improve the efficiency of energy conversion while the plant is using natural gas. All this changes must be taken into account in evaluating the bids to supply natural gas.

IPA has constructed a financial model to estimate costs and savings to Enemalta Corporation, implied by each of the bids above. The key variables and the methodology underpinning the financial model are described below.

3.2.1 Commodity Price Forecasts

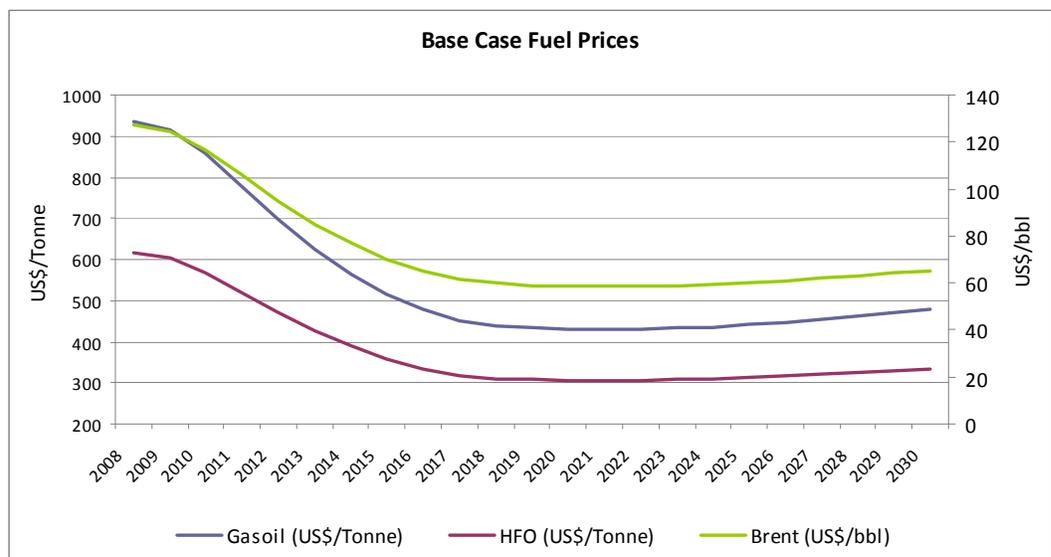
Brent, Low Sulphur Heavy Fuel Oil (“HFO”) and Gasoil reference price forecasts under three scenarios (Base, Low, and High) are based on PowerView, IPA’s in-house quarterly report. This forecast considers fundamental drivers of commodity prices as well as the most recent forecasts provided by well established institutions such as the International Energy Agency and US Department of Energy.

Gasoil and HFO prices under the Base scenario were calibrated to mimic the delivered prices of those commodities in Malta in 2nd Quarter 2008. The percentage difference between the PowerView forecast and delivered prices in Malta in 2nd Quarter 2008 has been applied to IPA forecasts over the period 2009-2030.

The Low and High scenarios are based on the ratio between commodity prices in the original IPA forecasts. These ratios are applied to the adjusted Base scenario to produce calibrated Low and High scenarios.

Base Scenario projections are shown in Exhibit 5: Base Case Fuel Prices. This chart shows the expectation that oil prices will decline from the very high price levels experienced in the oil market in mid-2008 but then increase in real terms towards the end of the forecast period. The prices shown are in US\$ 2008 terms.

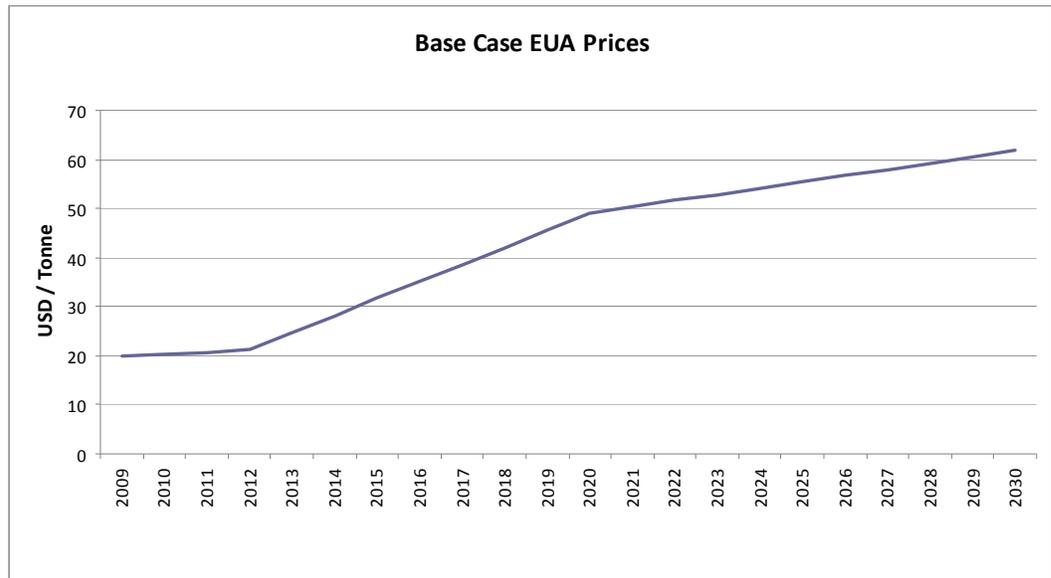
Exhibit 5: Base Case Fuel Prices



Source: IPA

Similarly, our EUA price forecast consistent with the Base Case fuel price forecasts is shown in Exhibit 6: Base Case EUA Prices. This chart shows the expectation that EUA prices will continue to rise aggressively during the 2012-2030 period with the acceleration declining during the post-2020 period. The prices shown are in USD 2008 per metric tonne.

Exhibit 6: Base Case EUA Prices



Source: IPA

3.2.2 Inflation Rate

An average long-term inflation rate of 2% per annum for Malta was used in the model. The analysis is based on real figures rather than nominal and an inflation index is required to calculate escalation in the capacity price contained in the BBE offer.

3.2.3 Discount Rate

A real discount rate of 10% is used to calculate a Net Present Value from the fuel costs and savings implied by each bidder's offer. This is a reasonable discount rate for an investment in fuel conversion. Lower discounts rates would favour higher gains in fuel cost savings while a higher discount rate would favour a project that gives quick returns.

The discount rate should reflect both the cost of capital to Enemalta and the ability to invest in other projects that might give a better return.

3.2.4 Exchange Rates

With prices for the fuels being quoted in US dollars and some of the operating costs being in Euros, the model needs to convert currencies to US dollars which is the currency used in the model to compare options.

Exhibit 6: Exchange Rate Assumptions

Real Exchange Rates	
USD/GBP	2.00
EUR/USD	0.74

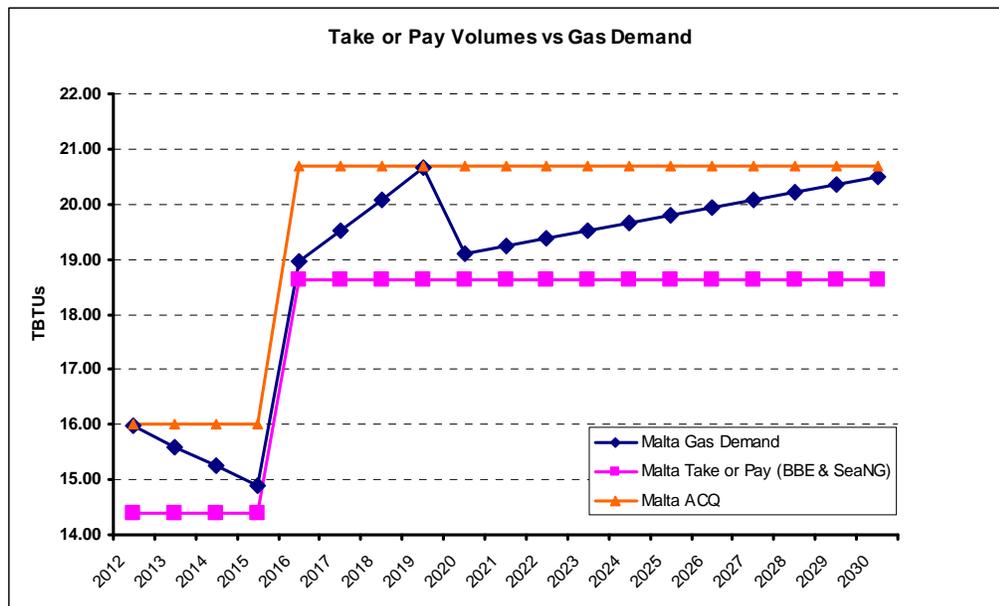
Source: IPA

Real exchanges rates are fixed through the modelling period.

3.2.5 Gas Volumes and Fuel Demand

Enemalta have provided the forecasts for gas demand and annual contract quantity used in the modelling. BBE and SeaNG have included minimum volumes in the take-or-pay terms offered. The Take or Pay volumes are compared to forecast gas consumption Exhibit 7 below.

Exhibit 7: Take or Pay Volumes vs Gas Demand



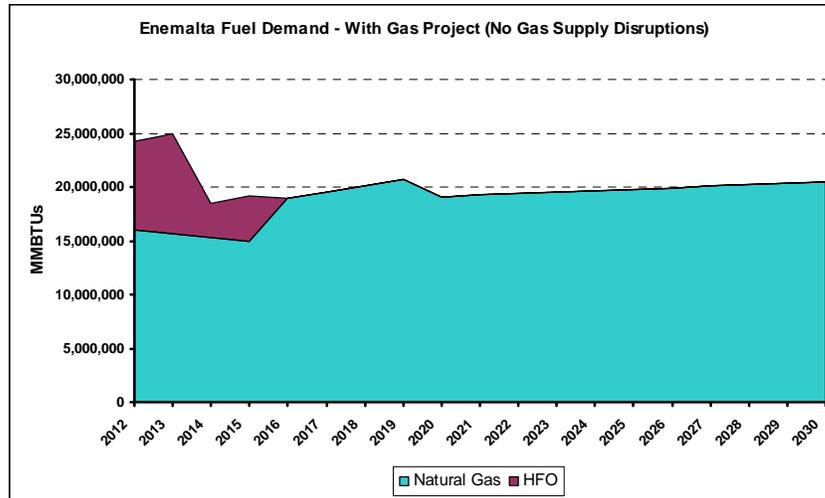
Source: IPA

With natural gas in Enemalta’s fuel mix, electricity will typically be generated using HFO and natural gas and Gasoil will only be used in case

of disruptions to natural gas supply. The model will provide sensitivity analysis to show the impact of any supply disruptions.

The projected fuel demand in the model is shown in Exhibit 8. HFO is used only in the early years when there is higher generation demand and natural gas provides all generation fuel from 2016.

Exhibit 8: Enemalta Fuel Demand - With Gas project

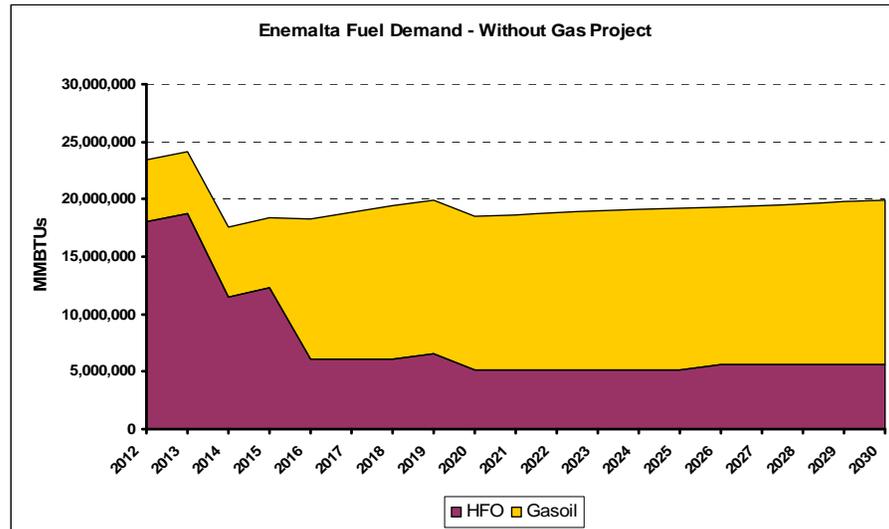


Source: Enemalta

3.2.6 No Gas Supply

If the natural gas supply bids are not competitive Enemalta could continue to generate electricity from its existing fuel supplies. If natural gas is not in Enemalta’s fuel mix, electricity would continue to be generated with HFO and Gasoil. Total fuel consumption forecast is shown in Exhibit 9 below.

Exhibit 9: Enemalta Fuel Demand - Without Gas Project



Source: Enemalta

This analysis shows the fall in HFO use as older plant is retired and the increase in gas oil used in the CCGT plant planned to be built. This fuel mix, based on data supplied by Enemalta, forms the basis of the comparison against which the natural gas bids are compared.

3.2.7 CAPEX Costs for the Project

Under the gas project, **additional** CAPEX costs will be incurred to adapt certain existing generating units to burn natural gas as below:

Exhibit 10: Additional CAPEX cost

Convert existing DPS - HFO Steam Plant to Gas Burning and comply with LCPD	Real 2008 \$290/KW
Convert existing CCGT to Gas Burning	Real 2008 \$60/KW

Source: Enemalta

These conversion costs will apply to the following plants:

Exhibit 11: Enemalta Plants²

Plant	Capacity (MW)	CAPEX
DPS - Phase 1 Steam Plant (2 x 60MW) – HFO	120	\$290/KW
DPS - Phase 2A OCGT (2 X 37MW)	70	\$60/KW
DPS - Phase 2B CCGT	101	\$60/KW
DPS - 120MW Diesel Engines (From 2014)	120	\$60/KW

Source: Enemalta

The CAPEX costs are levelised assuming an investment recovery rate of 6% within 18 years (2012 to 2030). The resulting levelised annual capital charge rate comes to 9.24% per year. The annual total CAPEX charges are calculated by multiplying the CAPEX cost per KW by the installed capacity in KWs and the capital charge rate of 9.24% over the model horizon from the starting year that the CAPEX is incurred. Note that, this implies that the gas burning conversion CAPEX costs for DPS - 120MW Diesel Engines (From 2014) will not be fully amortised over the time horizon modelled, i.e. 2008-2030. Note also that the \$290/KW charge rate for the DPS HFO plant contains the LCPD compliance costs which would be incurred despite of whether the gas project goes ahead. Although this introduces a slight inaccuracy, the impact is negligible.

3.2.8 Total Costs and Levelised Costs – Project vs. No Project

Under the assumption that the gas project goes ahead, total costs for each bidder are calculated by adding the total capacity costs, capex costs, and commodity costs, considering the annual gas demand as well as take-or-pay terms. We consider three different formulations of costs:

1. Average Cost of Gas - calculated via adding the total capacity and commodity costs (for each bidder) divided by gas demand in MMBTUs. This is compared against the existing and future consumption volume weighted average cost of burning HFO and Gasoil with no Natural Gas in the Fuel Mix.
2. Average Cost of Fuel - calculated via adding the total capacity commodity, and capex costs of natural gas (for each bidder) as well as the costs of burning HFO and Gasoil divided by total fuel demand in MMBtu. This is compared against the existing and future consumption volume weighted average cost of burning HFO and Gasoil with no Natural Gas in the Fuel Mix.

² At the time of this writing Enemalta indicated that these numbers should be slightly different. In particular, Enemalta advised that conversion cost for the existing DPS plant should be circa \$145/KW instead of \$290/KW while the size of the Diesel Engines should increase to 144MW from 120MW. We have incorporated this new information into the latest set of assumptions as in section 8 of this report. Therefore the results in section 8 reflect the latest information provided.

3. Average Cost of Generating Power – Average Cost of fuel converted to \$/MWh units by dividing the total costs by the forecasted power demand in MWh instead of MMBTUs.

3.2.9 Impact of Supply Disruptions

The impact of the interruption of shipping, for example due to bad weather, has been modelled. For modelling purposes, we assumed that such events would be force-majeure events and any guarantees on liquidated damages would not apply.

For the LNG schemes, which have relatively infrequent delivery schedule, 10 day and 20 day supply disruptions have been modelled.

For the CNG scheme, which has almost daily deliveries, sensitivities of up to 50 days supply disruption have been modelled.

In the event that supplies of natural gas are disrupted it is assumed that Enemalta generates using Gasoil. In addition, capacity and commodity charges to the gas suppliers are not paid and the take or pay threshold (if applicable) are commensurately reduced.³

3.2.10 CO₂ Impacts

CO₂ impacts of project versus no-project were calculated by determining the CO₂ emissions based on the carbon intensity and quantity of consumption of the fuels that would be available under the two options as well as the efficiency of the plant burning those fuels.

For example, CO₂ emissions from a plant burning Natural Gas at 50% operational efficiency can be calculated by Natural Gas Carbon Intensity in tonnes per MWh divided by 50% and multiplied by the MWhs generated.

Fuel carbon intensity figures used are as below:

Exhibit 12: Fuel Carbon Intensity

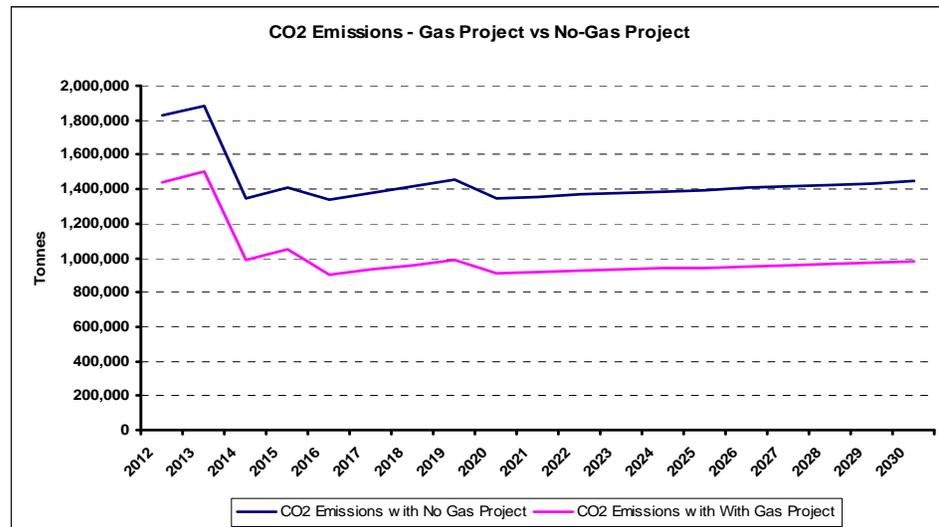
Natural Gas	<i>0.172 tonnes/MWh</i>
HFO	<i>0.263 tonnes/MWh</i>
Gasoil	<i>0.25 tonnes/MWh</i>

Source: IPA

CO₂ Emissions under the gas project option are calculated assuming that there are no disruptions to natural gas supply. We observe an annualised CO₂ saving of 434,288 tonnes over 2012-2030 if gas is in the fuel mix as forecasted.

³ This assumes that the gas supply contract is to a point at DPS, and the supplier takes the shipping/transport risk.

Exhibit 13: CO2 Emissions – Gas Project vs. No-Gas Project



Source: IPA

3.2.11 CER/VER generation potential for Malta

Under the Article 12 of the Kyoto Protocol, Malta is an eligible signatory to host and develop CDM projects as it is not an Annex I state.

Despite the complexity of CDM and Malta’s limited energy consumption, it is possible for one or more CDM projects in Malta during the 2nd Trading Period. Indeed a 100kt/year Landfill Flaring project is currently at validation stage.

However, Enemalta will not be getting CERs that can be used for compliance within 2008-2012 as it will not be funding CDM projects unless it purchases CERs from the emissions trading market as per Directive 2004/101/EC (Malta NAP 2008-2012).

The future of CDM projects beyond 2012 is still uncertain, however, it is highly likely that the EU will continue with a regime of similar underlying principles to the current one and implement a number of schemes to increase energy generation from renewable sources and energy efficiency. Therefore, we can expect the CER and similar carbon currencies such as voluntary emission reductions (VERs) to survive after 2012.

A number of projects to convert existing oil or coal burning plant into natural gas fired facilities for power generation have been already registered in various countries designated to host CDM projects. AM29 (Grid connected electricity generation plants using natural gas) and ACM11 (Fuel switching from coal and/or petroleum fuels to natural gas in existing power plants for electricity generation) are currently approved

methodologies that are relevant to the planned investments by Enemalta. In the light of this, the potential to adapt Enemalta's investment in natural gas for power generation into a CER or at least VER generating schemes after 2012 cannot be discounted, despite the numerous potential complexities that may arise.

Modelling the financial impact of emission reductions is difficult at this stage due to the uncertainty as to how they will be treated. For the sake of simplicity, we will assume that the emission reduction from bringing in natural gas will benefit Malta as a whole, since a significant chunk of cost will not have to be passed through into the power price.

In addition to this, if Enemalta funds part of the project directly and manages to register it as a credit generating scheme (a continuation of CER or VER into the post 2012 period), it can acquire additional proceeds. However, the potential proceeds from such a scenario needs to be investigated in more detail and we will not be modelling the financial impacts explicitly.

3.3 Legal Evaluation

The legal analysis planned to compare the significant deviations from the term sheets that were tabled by Enemalta. In fact, only one bidder returned the marked-up term sheet. While a formalised comparison of the legal terms between bidders is difficult, the legal aspects of bidder's submissions have been analysed to the extent possible.

4 BIDDER 1: BB ENERGY BV

4.1 General

BBE produced a comprehensive proposal which was well presented at the meeting. For a project at this stage of development, they have put a lot of effort into their bid and their response to the additional questions was very good.

BBE claim to have evaluated a number of supply options, including pipeline and CNG, and have considered and rejected off-shore re-gasification and LNG delivery options.

TGE were able to demonstrate that they have undertaken similar projects, and were the only bidders able to 'provide reference data from a similar plant' as requested in the original RFP.

4.2 Company Overview

The consortium presenting the BB energy bid includes:

- **BB Energy** – a trading company
- **TGE** – a construction company with substantial experience in building LNG terminals.
- **Anthony Veder Group N.V.** a shipping company that will supply the LNG carriers.

4.2.1 BBE Financial Position

BBE has a balance sheet that reflects the nature of its business as a trader of oil products. There is a high turnover around \$3.2bn in 2006 with a small gross margin. There are around \$376m of debtors on the balance sheet at 2006 with \$255m of trade creditors. The company uses short term bank lending secured against the cargoes to finance trading as well as managing the terms of trade to create cash flow. Their reports state that credit risk is managed by each subsidiary to company wide policies. There is clearly financial risk to the company from its large debtor balance.

As most of oil product trading is in US\$ there is a limited exposure to foreign exchange risks.

There is a potential risk from the sharp swings in oil product pricing and BBE will need to have in place measures to control these risks. It will be done using contract prices related to oil price benchmarks. The company manages price risk by entering into swap contracts.

The company is not rated by any of the major rating agencies.

4.2.2 TGE Financial Accounts

The consortium has provided brief accounts to December 2007 for TGE. These show that the company made a loss of Euro 13.m on a turnover of Euro 22m. The company has assets of \$47m of which \$38m is receivables mainly from a shareholder.

TGE is not rated by the major rating agencies.

4.2.3 TGE Ownership

In 2006 Suez Tractebel SA reduced its Shareholding to 25 %, allowing TGE Holding a 75 % ownership. The shareholders named the company TGE Gas Engineering GmbH.

Detailed TGE Holding ownership is now:

49.9 % Caledonia Investment plc
10.1 % Glenalta Capital LLP
40 % TGE Management

In 2008 TGE management decided to split the business into two lines Offshore and Onshore. Therefore TGE Gas Engineering GmbH demerged from TGE representing the onshore business, developing terminals and storage facilities, gas processing and package plants. TGE Marine Gas Engineering concentrates on its core business of carriers and offshore units.

The proposal includes financial information on the main shareholder Caledonia Investment PLC, which is an investment trust.

4.2.4 Anthony Vader Group NV

Anthony Vader Group NV is a Rotterdam based shipping company which at the end of 2007 operated 17 gas tankers and had two vessels under construction. Anthony Vader has 350 employees, with net sales of \$55 million. In 2007 operating income was \$20 million with higher freight charges and changes to the composition of the fleet being given as the reason for the \$2m increase over the previous year.

The shares of the company are largely in the control of HAL investments.

4.3 Technical Evaluation

BBE have proposed a LNG solution for the supply of natural gas to Malta. This section looks at the main aspects of the project including gas supply, shipping, regasification and operations.

4.3.1 Gas Supply

BBE has concluded a prospective contract for LNG from Sonatrach with delivery from Algeria. Algeria has a large gas resource and Sonatrach controls all LNG exports from Algeria. Gas availability in Algeria is well documented and should not be a concern for Enemalta.

Delivery of LNG from Algeria is reliable and with the short sea transport distances a reasonable choice for supply to Malta. BBE propose that Sonatrach will produce and ship LNG from its Skikda plant in Algeria, delivering the LNG to a SPC in Malta on a CIF basis. The corporate structure and the ability of an SPC to provide Enemalta with the necessary guarantees needs further review.

BBE appear to have a long-term business relationship with Sonatrach, through its fuel trading business, but although BBE claim to be LNG traders, they appear not to have yet secured a LNG project, and have not produced any documentation from Sonatrach confirming their agreement in principle to supply LNG to Malta.

BBE propose to base its gas supply contract with Enemalta on Sonatrach's standard LNG supply contract, under which Sonatrach seeks a 90% TOP provision and limits options for re-directing or on-selling LNG cargoes. Since Enemalta would be dependent on a single gas supplier, such lack of flexibility poses considerable problems (e.g. with such high TOP, Enemalta could not use any gas carried forward under the contract to subsequent years in the event of not meeting its TOP obligations). The BBE Take or Pay conditions are outlined below.

BBE state that in the event of any difficulties with gas supply from Sonatrach, LNG could be sourced from other LNG producers in the Mediterranean, or indeed from re-gasification terminals in the region. Whereas this is clearly possible from a theoretical point of view, there are a number of potential obstacles to this, not least of which is the shipping arrangements proposed by BBE (see below).

Algeria's proven reserves, existing infrastructure and delivery track record support the view that, subject to securing firm commitment from Sonatrach through HOA or draft GSPA, gas supply risk is low.

A score of 8 has been ascribed (weighted score of 2)

4.3.2 Gas Processing

BBE stated that Sonatrach intend to expand their LNG processing facilities, but provided no detail as to how supplies to Malta would be handled. Gas quality should not be a problem.

The liquefaction plant would be owned and operated by Sonatrach, who are experienced operators, thus reducing risk in this area.

A score of 8 has been ascribed (weighted score of 0.6)

4.3.3 Shipping

Although LNG is to be delivered by Sonatrach on a CIF basis, Sonatrach does not have suitable shipping capacity to enable delivery to Delimara.

It is proposed that as part of the project package, the Anthony Veder Group N.V. will build and operate a purpose-built LNG vessel, with a second as back-up of appropriate size and suitable for port conditions in Malta. One (or both) of the vessels could be multi-purpose vessels, suitable for LNG and LPG transportation. The ships would be provided under a time charter to Sonatrach. Such an arrangement might limit flexibility in arranging alternative supplies. One ship is currently contemplated for this project of 7500m³ size.

BBE contemplate use of the existing berth facilities for a 5 day period in every month as a maximum. The use of existing berth benefits the project by reducing new construction costs but must be examined in relation to existing fuel deliveries. EneMalta have confirmed that HFO deliveries are every 3 weeks and Gas Oil every 6 weeks, hence the use of the facilities would appear prima facie possible.

Sonatrach's experience in managing maritime transportation coupled with the provision of new purpose-built vessels operated under charter by a relatively small but reputable and experienced shipper suggest that shipping presents relatively low risk.

A score of 8 has been ascribed (weighted score of 1.2)

4.3.4 Re-Gasification Terminal

TGE obviously have experience of constructing a similar installation in Spain and demonstrated knowledge and experience of all issues concerning codes and permitting requirements relating to the design, construction, commissioning and operation of the terminal and re-gasification facility.

BBE confirmed that although they have not yet carried out detailed marine studies, initial review of the bay and discussions with port authorities suggest that operating the ship within the bay should not present problems.

TGE propose to design the plant and sub-contract construction, and claim that their prominent position in the industry gives them advantages in material and equipment procurement. A single tank of 50,000 m³ and approximate size 40m diameter x 34m high was considered appropriate; this would fit the existing available area noting the need for detailed site location studies to reduce risks and hazards. Hazardous area classification would be to API 505.

With an estimated round trip duration of 5 days and unloading requiring 10 – 15hrs, it is considered that the existing quayside could be used by the proposed ships, which are able to berth at the quayside due to shallow draught of around 8m, without interference to fuel oil and gas oil deliveries. The details concerning the LNG offloading design and possible impact on HFO loading arms will need to be investigated.

TGE had considered using sea water heating for the LNG evaporators, with the benefit of reducing the inlet temperature of cooling water to the power plant, but discounted this option due to the small benefits gained and high capital cost.

TGE confirmed that the current design involved clear separation between power plant and LNG terminal operation.

Enemalta asked BBE to examine plant integration options and incorporate energy efficiency measures in its revised financial proposal, even if the economic benefits appear weak. One option might be to chill the inlet air to the gas turbine units, improving mass flow rate and efficiency.

Duration for EIA activity is currently shown as just 7 months and it is believed that this should be extended to 12 and will have an effect on project duration.

The receipt facilities cost is estimated at €6M.

The combination of TGE's experience in designing and constructing a similar plant together with the advantages of low berth occupancy rate and use of existing berthing facilities, results in the assessment that BBE's proposal represents relatively low risk in this area.

Scores in the range 7 to 8, have been ascribed resulting in an overall weighted score of 3.3 being ascribed

4.3.5 Operation

TGE propose to train plant operators and provide initial support in operations management. TGE can arrange operator training on existing plants within Europe or the USA.

A score of 8 has been ascribed (weighted score of 0.6)

4.3.6 Overall Technical Score

BBE' selection of proven process technology, gas supply from a reliable source and TGE's experience in designing and building similar facilities results in a high overall weighted score of 7.7

4.4 Commercial Evaluation

4.4.1 Gas Pricing

In the BBE proposal, gas is charged in two parts:

- A capacity charge
- A commodity charge

The BBE commodity cost is calculated on the basis of the formula provided in their offer, and this is Gas price in \$/mmbtu = 0.1585*Brent Price in \$/bbl +0.37. In the clarification there was a suggestion of an “S” curve formula to limit the upside risk on oil prices with a consequent support at low oil prices. Details of this are subject to negotiation and with no firm commitment IPA has used the basic price formula in all the analysis.

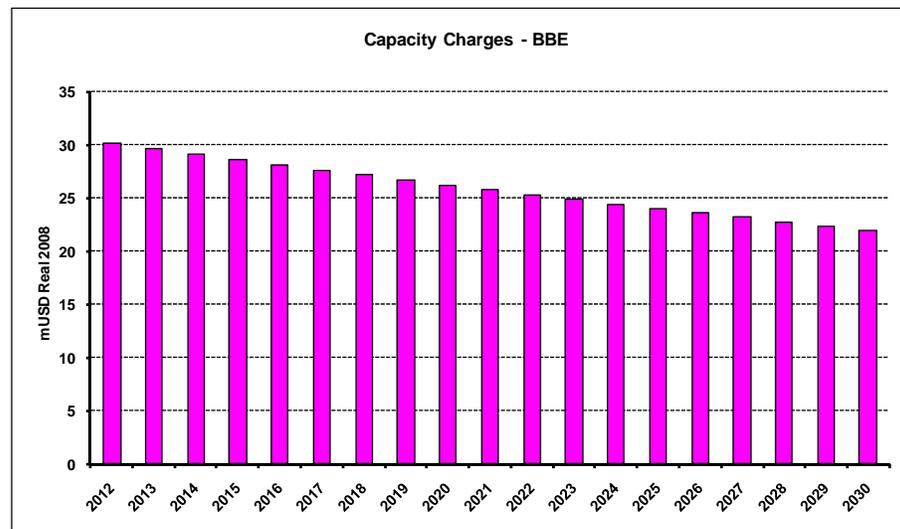
The capacity charge is based on the Euro, and is charged on the basis of the DCQ. There is an adjustment for inflation using the rate of inflation as defined by the Malta National Statistics Office. 40% of the charge will be adjusted for inflation.

At the early DCQ of 119000mmbtu/day the capacity charge is Euro 0.56/mmbtu reducing to Euro 0.46/mmbtu when the DCQ increases to 142800 mmbtu/day. These rates depend on the exchange.

Capacity Costs

Based on the BBE offer as described above, the annual capacity charge is shown in the Graph below. This shows that the capacity charge declines over the contract in real terms.

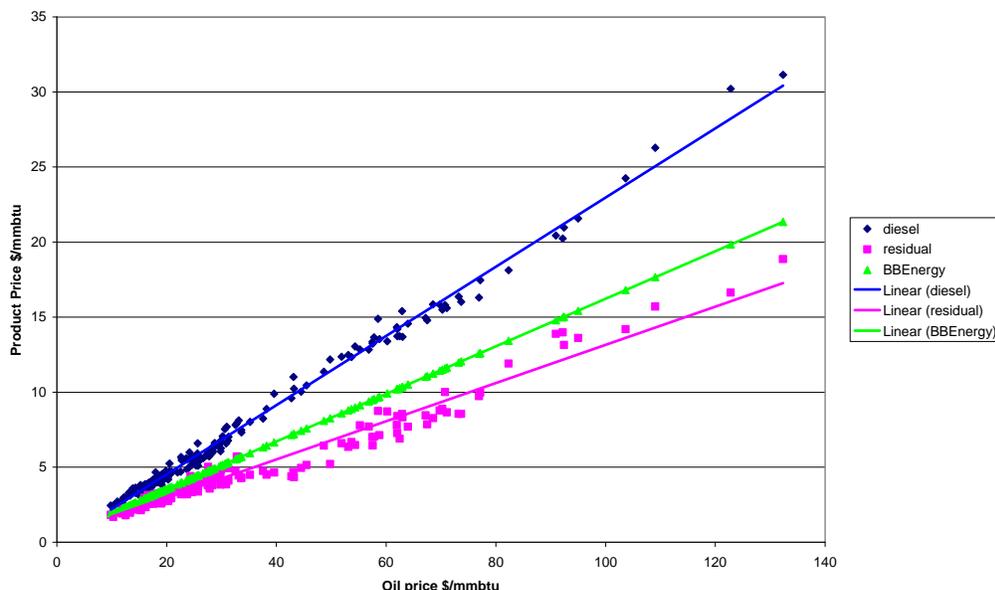
Exhibit 14: Capacity Charge-BBE



Source: BBE

To show how the commodity price of natural gas relates to oil product prices shows the BBE bid against oil product prices. Once the capacity charge is added the pricing becomes uncompetitive as shown in the analysis of the bid later in the report.

Exhibit 15: Regression against Oil Price Showing BB Energy pricing.



Source: IPA

Take or Pay Conditions

The minimum annual contractual quantity (MACQ) is defined as 90% of the annual contract quantity (ACQ). Enemalta would have to pay for any shortfall in any year from the MACQ at the average contract price for the year.

The ACQ is 16 million mmbtu in years 1 to 4, increasing to 20.7 million mmbtu in years 5 to 20.

These conditions make this the most restrictive of the three bids and provide very limited flexibility in the supply of natural gas making it difficult to maximise use of gas in the generation of electricity.

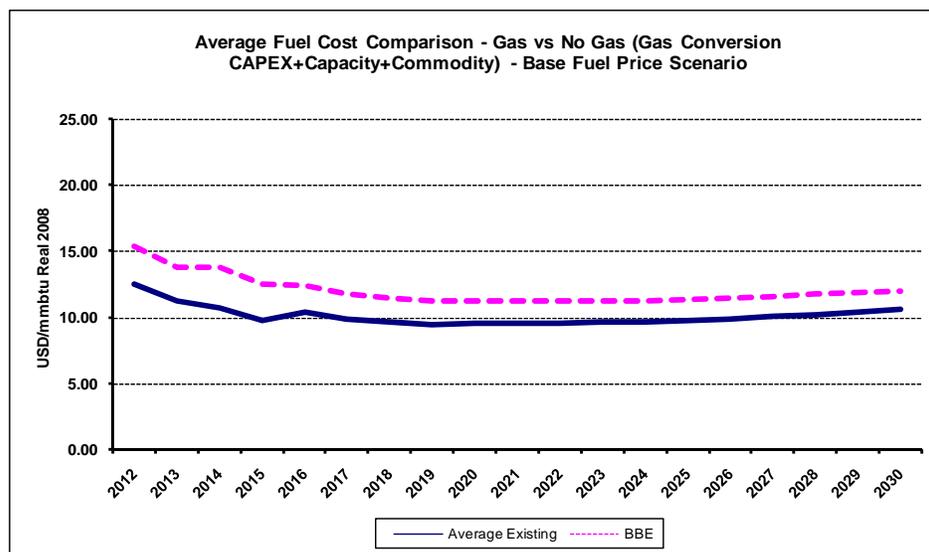
These constraints have been included in the financial model.

4.4.2 Impact on Enemalta Operating Costs

At all fuel price scenarios used in the modelling the fuel price offer from BBE are higher than using the HFO and gasoil for generation. Exhibit 16 shows that the fuel costs remains above the cost of using existing fuels

throughout the forecast period. As the costs in the BBE formula for natural gas delivered to Enemalta is closely related to the price of oil there is no gain at high oil prices as there is with the other bids.

Exhibit 16: Impact of BBE Bid on Fuel Cost - Base Case



Source: IPA

Including the costs of conversion that must be paid by Enemalta to enable the dual firing of the generation plant increases the disadvantage of the pricing in the BBE bid. In the analysis the BBE bid is not competitive with oil products at any oil price scenario.

4.4.3 Commercial Scoring

The bid is via a project company. The sponsor is a trading company, BBE that does not have a track record of managing long term contracts. We have given sponsor quality a score of 6.

The concept is an LNG system delivering from Algeria. This is a tested system. One weakness is the indirect nature of the contracting through Sonatrach which limits Enemalta's contact with the LNG producer.

Gas pricing scores 0 as the delivered natural gas price does not compete with the existing fuel mix at any forecast oil price.

There are tight Take or Pay conditions that do not give flexibility to Enemalta's generating programme. This criterion attracts a low score of 4.

Exhibit 17: BB Energy: Commercial Scoring

	Weighting	Score
Sponsor Quality	15%	6
Concept	10%	8
Gas Pricing	60%	0
Take or Pay Conditions	15%	4
	100%	
Average Score		2.3

Source: IPA

The table above summarises the scoring and gives a weighted score of 2.3, which is too low for consideration as a viable bid. The pricing score of zero should rule out the bid.

4.5 Legal Issues

The following legal matters arise from the BB Energy proposal.

4.5.1 General

BB Energy has adopted the preferred Capacity Charge / Commodity Charge approach.

BB Energy has not provided a revised term sheet, but instead has set out some terms (which are different from those proposed in the draft term sheet provided by Enemalta for bidding purposes) in its proposal letter. At the end of the letter, it proposes that “Other terms and conditions of this agreement shall be finalized according to the indications of the drafts and the relevant clarifications discussed during the above mentioned meeting...”. We therefore assume that, except where it has otherwise been indicated, BB Energy accepts in principle the draft terms set out in the commodity Charge / Capacity Charge term sheet provided by Enemalta.

4.5.2 Significant Changes

The following are the changes to the term sheet mentioned by BB Energy which are significant from a legal perspective.

- **Quantities**

BB Energy accepts the Annual Contract Quantities proposed by Enemalta (16 million MMBtu in years 1 to 4, and 20.7 million MMBtu thereafter). However it then introduces a new concept, “Minimum Annual Contract Quantity”. This is equal to 90% of the applicable ACQ, and seems to be equivalent to the “Adjusted ACQ” concept in Enemalta’s term sheet.

- The first issue is that the Take or Pay threshold is 90%.

- The second issue with this is that this Minimum Annual Contract Quantity is not adjusted in the normal way (as is the Adjusted ACQ proposed by Enemalta), for shortfall in deliveries, non-delivery because of force majeure, off-specification gas, maintenance, etc.
- The third issue is that the Make-up entitlements are almost non-existent, i.e. if gas is paid for under this clause but not taken, it will be very difficult if not impossible to take that gas at a later time. The Make-up period is only 1 year (the Enemalta term sheet allowed for 3 years), and no more than 5% of the ACQ can be taken in that year. Thus if Enemalta takes any less than 85% of the ACQ in a year, that amount is irrevocably lost, and even the difference between 85% and 90% can only be taken in the following year if Enemalta has already taken 90% of the ACQ in that following year.

If the Take or Pay clause applies, the shortfall quantity must be paid for at the average price prevailing during that year. This is reasonable.

- ***Commodity Charge Pricing***

BB Energy says in its proposal that it is negotiating an alternative supply arrangement (from Libya), and that it would pass on the relevant savings. This could be very beneficial, but there is no more detail than this.

The use of liquefied natural gas, rather than compressed natural gas, also helps diversify sources of possible supply, so this provision could be of some value.

- ***Contract Price Revision***

The proposal includes a provision providing for a review every 3 years of the contract price. It isn't clear whether this is intended to apply to the Capacity Charge, the Commodity Charge, or both.

We have a number of issues with this. First, there is no apparent justification for there ever to be an adjustment to the Capacity Charge. The Capacity Charge compensates the Seller for the sunk cost of the infrastructure it has procured (an LNG reception facility in Malta, and ships), which at the Commencement date is all sunk cost. This is then purely a financing issue, akin to a loan repayment. It makes no sense for it to be adjusted.

The Commodity Charge may be different, but the only justification for a change to the terms of the Commodity Charge would be if there was a change to the calculation of the price under which BB Energy acquired LNG. If any change clause is agreed to, it should only be on the basis of a change to the pricing under BB Energy's LNG purchase contract. This would mean that Enemalta has a vested

interest in being involved in negotiating the terms of that contract. This creates a difficult situation for Enemalta, as the others would resist this but if Enemalta is not involved then they have no incentive not to agree a provision or a change which is very disadvantageous to Enemalta.

The second issue is that this concept doesn't work under English or Malta law, unless there are provisions for an expert to declare a new price. The proposal by BB Energy is more reflective of a civil law agreement. This is likely to be very difficult to negotiate.

Finally, this pricing clause introduces significant uncertainty into the assumed price for the BB Energy proposal, and gives Enemalta much greater risk.

- ***Hardship Clause***

BB Energy also proposes including a “hardship” clause.

This also is a concept which is common in civil law contracts, but doesn't easily work under English or Malta law contracts. Nor is it clear how this propose clause relates to the proposed pricing revision clause.

- ***Invoicing and Payment***

One significant change sought by BB Energy is that if an invoice is disputed by Enemalta, it should still be paid in full pending determination of the dispute. This is not normal. There is no provision proposed for interest on repayment if Enemalta wins the dispute.

Their proposal also raises the possible need for the provision of a letter of credit by Enemalta. It is unclear if this is just a short term L/C as a payment mechanism, or a long term security for payment. If the latter, this is a significant change and would be a significant extra cost for Enemalta.

In the course of discussions with BB Energy, they suggested that they would provide credit support from an entity “rated by Dun & Bradstreet”. Dun & Bradstreet is not a rating agency, it is a debt collection and credit advisory firm. It provides credit reports, but cannot be relied on in the same way as Standard & Poors, Moody's and Fitch. It is therefore unclear what BB Energy is really proposing for credit support.

4.5.3 Other Matters

Because BB Energy has not provided a revised term sheet, it is very difficult to judge what legal issues really exist with their proposal. In

particular, there is no comment on the force majeure, termination or termination payment provisions proposed by Enemalta, which is surprising.

Our view is that there is considerable legal uncertainty in their position, and extensive negotiation would be required with them.

If Enemalta nevertheless prefers their bid, we recommend first agreeing a detailed term sheet with them.

5 BIDDER 2: ENERGY WORLD CORPORATION

5.1 General

EWC is an Australian listed / Hong Kong based Energy Company, with gas production and LNG production and distribution and power generation operations in Australia. The company has a production sharing agreement for a gas field in South Sulawesi in Indonesia which is supplying gas to the Sengkang power station. EWC claim that the potential gas reserves, at perhaps 5 – 7 tcf, are large enough to support LNG export projects and are currently developing a LNG liquefaction facility at Sengkang, using low-cost, scalable modular production methods, based on proven process technology employing electrically driven compressors. The plant will initially supply LNG to the Philippines.

EWC claim to have a strategic alliance with Chart Industries (producers of cryogenic plant), Tokyo Gas and Siemens for the development of LNG projects, and claim to have strong support from major banks.

The quality of their initial proposal was the lowest of the three submissions, and whereas EWC provided much additional information in response to the request for clarifications, and demonstrated entrepreneurial flair during the clarification meeting, their proposal lacks clarity regarding gas supply, the configuration of the plant and shipping arrangements, and fails to convince Penspen of their ability to meet Enemalta's requirement regarding long term security of gas supply.

Clearly if EWC's revised commercial offer is particularly attractive, this situation could be reviewed in greater detail.

5.2 Company Overview

Energy World Corporation (EWC) is a company listed on the Australian and New Zealand Stock Exchanges. It is financing all the costs of providing the infrastructure for the supply of natural gas to Malta from its own resources.

EWC has several subsidiaries through which it is active in exploration, development, and production of oil and gas. It also operates and maintains gas processing plants and gas pipelines. In addition, the company engages in the development, design, construction, operation, and maintenance of power stations; development and production of liquefied natural gas; design, construction, operation, and maintenance of liquefied natural gas (LNG) plants; and road transportation of LNG. The company primarily operates in Australia, Indonesia, India, and the Philippines. Energy World Corporation is based in Sydney, Australia.

EWC has a concession on the Sengkang gas field in South Sulawesi, Indonesia. The gas is used to supply a power station at Sengkang. EWC has a PPA to supply electricity from the plant until 2022. In August 2008, EWC raised \$104m through a project financing for the gas supply and power plant. The financing was closed by Standard Chartered Bank and Mizuho and included expansion of the power plant.

EWC has experience of developing and operating an LNG road tanker business to deliver supplies to isolated rural communities.

5.3 Technical Evaluation

EWC have proposed a LNG solution for the supply of natural gas to Malta. This section looks at the main aspects of the project including gas supply, shipping, regasification and operations.

5.3.1 Gas Supply Solution

Gas will initially be supplied from the Sulawesi LNG plant in Indonesia. PT South Sulawesi LNG (PTSSLNG) is a 100% owned subsidiary of EWC.

EWC's reserve estimates and the quoted LNG export capacities are slightly contradictory. The EWC website says that gas reserves at the Sengkang gas field are sufficient to produce 1 million tons of LNG per annum, whereas, in reply to Enemalta questions about gas supply EWC said that the Sulawesi plant is under construction and will have a capacity of 2-5 million tons per annum.

What is known is that the plant will be built as 500,000 ton trains, with the initial two trains being targeted at South East Asia. There is an existing MOU with Indonesia Power to supply LNG signed in June 2008.

They also said that a secondary supply will be made available from North Africa or the Middle East. In the discussions it was reported that EWC had been talking to Libya about gas supplies using LNG.

The distance from Sulawesi to Malta will introduce schedule risk to the gas supply. This will be partially protected by the gas storage available at Malta

EWC propose to supply LNG to Malta from a new liquefaction plant in Indonesia, at least for an initial period of around 4 years. Their intention is to substitute supply from a new plant, which they will build in Libya, and claim that they are in negotiation with NOC to develop the project. They claim that NOC is supportive of EWC's approach, in that it bypasses the necessary involvement of the major IOCs.

EWC claim that they are the owners of the gas in Indonesia, and as such, can avoid time delays in project implementation normally associated with NOCs and IOCs. The proposed source of LNG supplies for Enemalta will derive from the existing Indonesian facilities.

NB. Since the field development is under a PSC, the gas would presumably belong to the Indonesian State, which would probably insist on some involvement in the development process.

Although claiming that gas reserves in their Sengkang concession may lie in the range 5–7Tcf, reserves are currently uncertified, and EWC’s ability from a technical and financial standpoint to carry out the necessary field development to support gas supply is not known. EWC proposes to switch supply to North Africa at some time in the future, but plans are at an early stage. In consequence this proposal is seen to represent a higher risk regarding security.

A score of 4 has been ascribed (weighted score of 1)

5.3.2 Gas Processing

EWC has provided an outline description of its modular liquefaction process, but has provided little information concerning gas quality. Their proprietary technology involves small LNG modules of 0.5MT/year capability which permits the gradual accumulation of capacity at a site in line with supply requirements. EWC believe that this modular system is particular to their company.

EWC’s first liquefaction trains are under construction, and although the trains employ basic proven technology, the plant has not yet displayed a proven track record, and therefore presents medium technical risk.

A score of 6 has been ascribed (weighted score of 0.45)

5.3.3 Shipping

EWC has proposed using vessels with capacities ranging from 20,000cu.m to 80,000cu.m, and claims to be in discussion with Teekay regarding shipping.

Since EWC would be the sole supplier of LNG, the distance between the LNG production facility in Indonesia and Malta, and the risk of shipping delays gives cause for concern.

1 ship per month for LNG delivery is envisaged by EWC; shipping time approximately 2-3 weeks. Unloading time estimated at one day.

EWC’s proposal regarding shipping was the least developed of the three bids, containing a wide range of options concerning vessel size, ownership and operation, resulting in the view that residual risk is high.

A score of 3 has been ascribed (weighted score of 0.45)

5.3.4 Re-Gasification Terminal

The draught of the largest vessel dictates that a new jetty will be required. The facility will store 80,000cu.m. of LNG, sufficient to meet around

60days demand. EWC proposes to construct the facilities using affiliate companies.

EWC have a relationship with Siemens for compressor technology and Siemens were highlighted as world leaders in LNG gas boil off compressor technology. Boil off rate estimated at 0.05%

The cost of the regasification facilities were estimated by EWC at €88M. Proposed LNG tanks would be full containment concrete tanks with internal membranes. This design is consistent with standard good LNG practice.

Although EWC claim to have the support of experienced players in the LNG business to complement their own experience in small-scale LNG, their proposal lacked clarity concerning project management structure and the participation of the sponsors, resulting in the view that there remains moderate to high risk in this area.

Scores in the range 3 to 5, have been ascribed resulting in an overall weighted score of 2.025 being ascribed

5.3.5 Operation

EWC propose that Central Energy (Australia) Pty Ltd., who have experience in operating small-scale satellite LNG facilities, will operate the re-gasification plant, with technical and training support from Tokyo Gas, thus representing medium risk.

A score of 5 has been ascribed (weighted score of 0.375)

5.3.6 Overall Score

The general lack of clarity in EWC's proposal in a number of key areas increases perceived risk and results in allocation of a low overall weighted score of 4.3.

5.4 Commercial Evaluation

EWC have said that they can structure a contract around any contract length and that the contract length could be 7.5 years or 10, or 15, 20 years subject to Enemalta's requirements.

Pricing would be dependent on the length of the contract and pricing proposals reflect the longer contract terms.

5.4.1 Natural Gas Pricing

The price charged by EWC will be in two parts. There will be a commodity charge for the natural gas and services charges for the terminal and regasification and operators costs.

The pricing formula for the LNG is show in the box below. It is based on a recent contract that EWC have been discussing for a supply in Asia. It is therefore based on the Japanese Crude Cocktail (JCC), which has a good correlation with Brent.

In the May 2007 proposal to Enemalta, the price for natural gas to be delivered under the 15 (fifteen) years contract was fixed for the first 3 (three) years, and thereafter subject to annual fluctuation, based upon a formula (to be agreed) linked to the published average prices of LNG delivered to Europe. The fixed base contract price for the first 3 (three) years (fixed price) was Euro 0.188 per cubic metre, delivered by pipeline to the meter point at the power station.

EWC currently offers LNG for sale based upon a formula which uses the JCC (Japanese Crude Cocktail) as an index, to calculate LNG price, in addition to a Terminal operating and regasification fee, and an operator's fee.

The typical JCC Formula is as follows:

Price: The contract price (in United States dollars) for LNG shall be based on the following formula:

$P_n = 11 \times JCC + 120$ (when JCC is more than US\$40 per barrel and less than or equal to US\$100 per Barrel).

$P_n = 7 \times JCC + 280$ (when JCC is less than or equal to US\$40 per barrel).

$P_n = 7 \times JCC + 520$ (when JCC is more than US\$100 per barrel).

For the above price formulas:

P_n = price of LNG sold and delivered in a month (month "n"), expressed in US cents per MMBtu.

JCC = the weighted average landed price of all crude oils imported into Japan ("JCC"), expressed in US Dollars per barrel, based on published statistics, in the third month prior to the month during which unloading of the cargo commenced (month "n-3").

Discounts or other formulas can be the subject of negotiation with Enemalta.

The Terminal and Regasification fee is calculated at the rate of ten percent (10%) of the gas cost, as computed from the JCC or European formula from time to time of delivery.

The Operator's fee is calculated at the rate of five percent (5%) of the gas cost, of which the same formula of calculation as stated above shall apply. This fee covers the cost of Plant administration insurance, ship berthing, labour, water and power (at wholesale price). The costs of labour, water and power are subject to inflation. All prices are exclusive of local taxes and duties.

JCC index projections are obtained using the following approximation formula (source: IPA Research):

$$\text{JCC} = \text{Brent Benchmark Oil Price (\$/\text{bbl})} * 0.9568 + 1.238$$

The resulting commodity cost is inflated by 10% as a regasification terminal fee and then by a further 5% as an OPEX fee, according to the terms in the EWC offer.

5.4.2 Take or Pay Obligation

EWC do not see this as a “take or pay” contract. EWC will be flexible in this regard and this will be confirmed in further discussions with Enemalta. This is the most flexible of the suggested contracts.

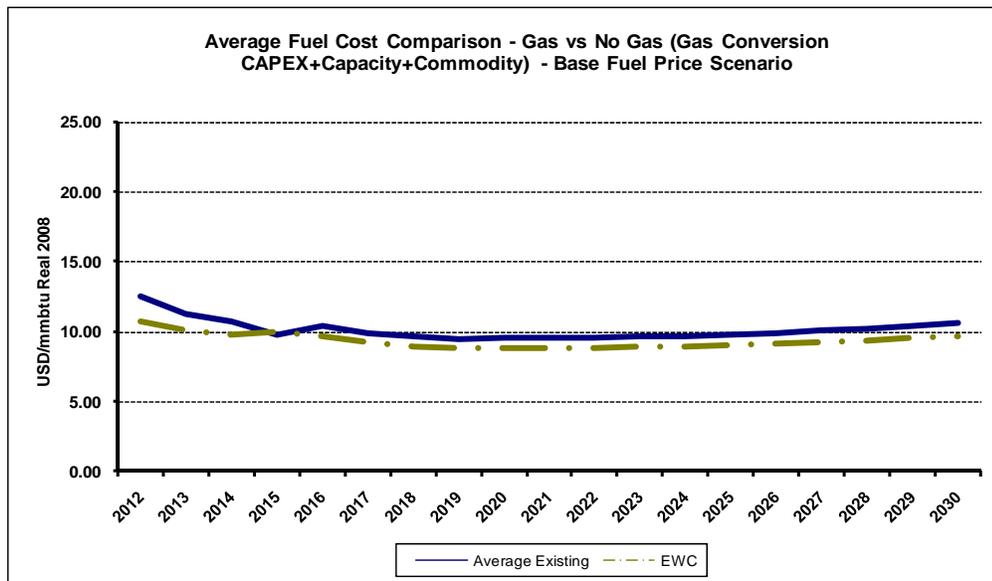
In principle there would be no restrictions on the onward sale of the natural gas and EWC wish to offer maximum flexibility to Enemalta. Should any adjustments be necessary, this can be adjusted on a 2 year basis.

The annual contracted value of LNG would be as flexible as necessary to suit and support Enemalta’s generation requirements.

5.4.3 Impact on Enemalta Operating Costs

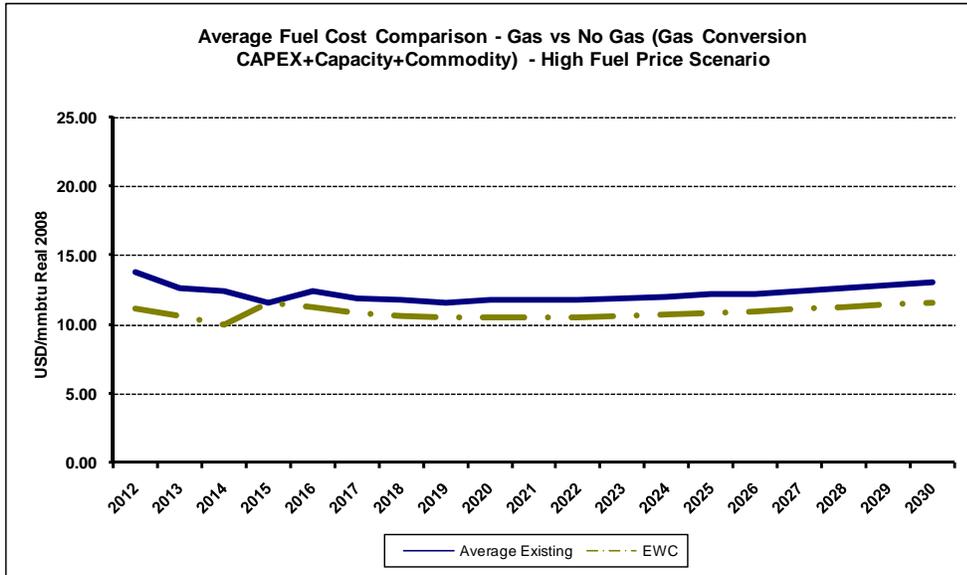
The EWC bid shows a reduction in fuel costs when compared to the current mix of fuels in the Base and High fuel price scenarios. The results for the Base Case fuel price scenario are shown in Exhibit 18

Exhibit 18: Average Fuel Cost Comparison



The High Fuel Price scenario is shown in Exhibit 19 below. There is a consistent gain over all the periods from the start of the project.

Exhibit 19 Impact of EWC Bid on Fuel Cost – High Oil Price Case



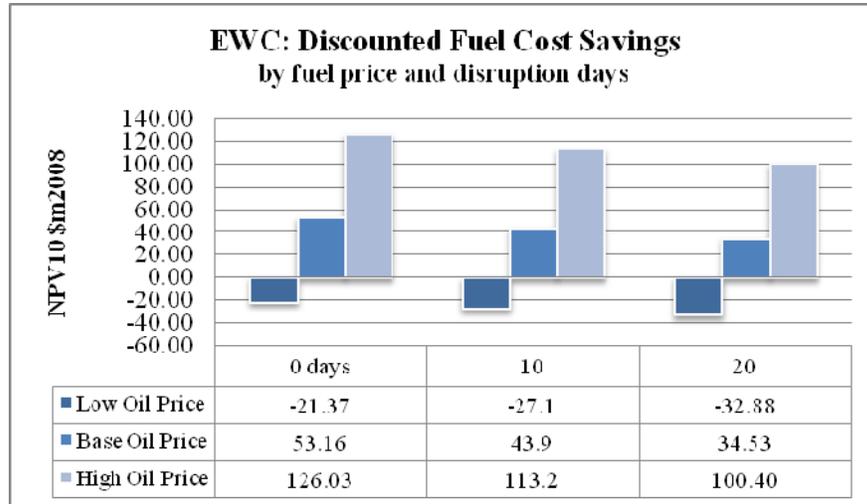
Source: IPA

In the Low Oil Price case there is no overall cost reduction for the EWC bid.

Introducing the impact of weather-related disruption lessens the attractiveness of the EWC bid. The graph overleaf shows the total discounted fuel cost switching benefit by oil price scenario and by the number of days disruption, ranging from 0 to 20. Since the LNG solution relies on relatively infrequent deliveries, bad weather would cause less disruption to deliveries than would be the case for more frequent CNG shipments.

In the base case, if supplies were disrupted for 20 days per annum, the NPV of fuel switching to gas is reduced by \$19m, from \$56m to \$37m. In the high case, the NPV reduces from \$129m to \$103m, but still remains strongly positive overall. In the low case, the marginally negative NPV worsens to -\$31m overall.

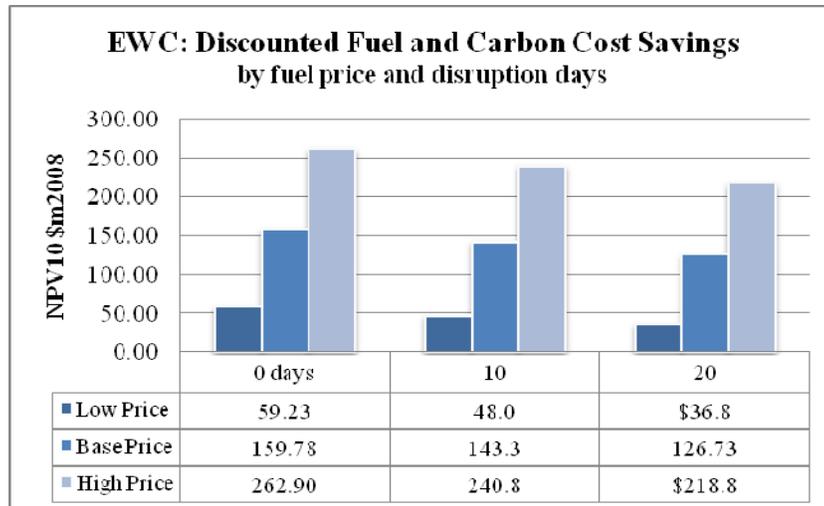
Exhibit 20: EWC Bid: Discounted fuel cost savings by fuel price scenario and number of disruption days



Source: IPA

Introducing the benefit of reduced carbon costs makes the benefits of fuel switching more pronounced, and mitigates against the negative impact of delivery disruption. Even with the maximum foreseeable disruption days (20) and the low carbon & oil price scenarios, the avoided fuel and carbon costs remain positive throughout the forecast horizon.

Exhibit 21: EWC Bid: Discounted fuel and carbon cost savings by oil price scenario and number of disruption days.



Source: IPA

5.4.4 Commercial Scoring

The EWC bid is based on the balance sheet of the main sponsor. This company has limited experience of small scale LNG in Australia and is building an LNG plant in Sulawesi which will be the initial supply point for deliveries to Malta. However, the sponsor lacks experience in long term international LNG trading and has limited staff and resources. The sponsor quality is ascribed a score of 4.

The concept is of LNG delivery to Malta which is a well tried system. There is a weakness in that the source gas is initially Indonesia introducing long distance transport. The concept of small LNG delivery is usually from local sources. The score for the concept is 7.

Gas pricing: EWC's offer leads to moderate fuel cost savings at higher and base case fuel prices. The score for natural gas price is 5.

There are no take or pay constraints on the bid. The score is reduced by the long distance that will increase uncertainty in scheduling supply to match Enemalta's generating programme.

Exhibit 22: EWC Commercial Scoring

	Weighting	Score
Sponsor Quality	15%	4
Concept	10%	7
Gas Pricing	60%	5
Take or Pay Conditions	15%	8
	100%	
Average Score		5.5

Source: IPA

The overall score of 5.6 is a weak score derived from the weaknesses in the location and pricing of the natural gas.

5.5 Legal Issues

The following legal matters arise from the Energy World Corporation ("EWC") proposal.

EWC states that is prepared to adopt the Capacity Charge / Commodity Charge approach.

EWC has not provided a revised term sheet, but instead has set out a very few terms (which are different from those proposed in the draft term sheet provided by Enemalta for bidding purposes) in its proposal letter. In many instances, on major issues, it basically says "to be agreed". This makes a legal analysis of their proposal extremely difficult.

5.5.1 Significant Changes

The following are changes from the Enemalta position which can be ascertained from the EWC proposal.

- ***Acceptable Credit Rating***

EWC relies solely on its stock exchange listing and current market capitalization (approximately US\$1.7 billion), and is not, apparently, proposing to have or provide acceptable credit support.

This is a major issue, particularly given concerns about their ability to reliably deliver over a 20 year contract period.

- ***Commissioning Date***

The Enemalta term sheet contemplated a specific mechanism for determining the Commissioning Date, and a commitment to “not before” and “not after” dates or periods. EWC’s response is “to be determined through negotiation with Enemalta”.

- ***Maintenance***

This also is “to be determined in negotiations”. There is no specific proposal.

- ***Termination Payments***

This also is “to be determined in negotiations”. There is no specific proposal.

The EWC proposal says that “Credit for Terminal infrastructure will have to be discussed and agreed to the satisfaction of both parties, and evaluated according to an agreed formula”. We do not know what this means, but it certainly seems inconsistent with Enemalta’s proposal that Sellers would rely on Enemalta’s credit rating.

- ***Price***

There is no firm price proposal, just an “indicative” price of €6.50 per MMBtu, “to be discussed”.

The EWC proposal also says that there will be an “agreed adjustment formula for annual deliveries”. This may be a reference to some kind of Take or Pay mechanism, but it is very unclear.

- ***Liquidated Damages***

This also is “to be determined in negotiations”. There is no specific proposal.

- *Other Matters*

Because EWC has not provided a revised term sheet, it is very difficult to judge what legal issues really exist with their proposal.

Our view is basically that EWC has not provided a proposal which is capable of legal evaluation, or which complies with the requests for clarifications given to the Bidders.

If Enemalta nevertheless prefers the EWC bid, we recommend that the starting point should be to get EWC to commit to a comprehensive term sheet.

6 BIDDER 3: SEANG CONSORTIUM

6.1 General

SeaNG provided the most comprehensive initial proposal, from a technical point of view, and followed up with detailed responses to the request for clarification. Their presentation on the 10th July 2008 was very competent and professional, and their ability to answer questions raised was impressive.

Aspects of the proposal are attractive, particularly the composition of the JV, the simplicity and small footprint of plant, and the demonstrated commitment by the gas supplier. The technology, though basically simple, remains commercially unproven, and despite gaining the approval of ABS, there remain a number of residual technical issues / risks which require resolution, particularly concerning the lack of proven standards covering port operations, the frequency of cargo discharge and the long-term integrity of the coselles in an operating environment.

The novelty of the CNG design means that there is no recognized design standard at present in contrast to those for LNG which are tried and tested. This must mean a more significant theoretical risk during the design phase.

6.2 Company Overview

SeaNG has selected partners with significant experience and financial strength. They have also identified a large international bank, Mizuho Corporate Bank, experienced in financing oil and gas projects to help with the financing of the project.

Marubeni is rated by both Moodys and Standard and Poors (S&P) with an investment grade rating.

Exhibit 23: Credit Rating Marubeni

Rating Agency	Rating
S&P	BBB
Moodys	Baa2

Source: IPA

The rating is constrained by the concentration of risk in resource project including a recent decision to invest in copper mining in Chile. The company is substantial and is well able to provide financial support to the Sea NG bid.

Teekay is a shipping company rated by both Moodys and Standard and Poors (S&P) with sub investment grade ratings.

Exhibit 24: Credit rating Teekay

Rating Agency	Rating
S&P	BB+
Moodys	Ba2

Source: IPA

These ratings show that the company is subject to some uncertainty. Moodys comments that the rating is underpinned by substantial liquidity in its assets.

The Sea NG proposal includes annual reports for both Teekay and Marubeni.

This is the bid with the strongest sponsors but the project will be managed by a project company and this will create some risk for the supply to Enemalta. The sponsors may wish to ensure that the project company does not fail but there is no guarantee that they would step in if there was a problem.

6.3 Technical Evaluation

SeaNG have proposed a compressed natural gas solution for the supply of natural gas to Malta. This section looks at the main aspects of the project including gas supply, shipping, regasification and operations.

6.3.1 Gas Supply

SeaNG have demonstrated NOC's willingness to supply gas to the project from Mellitah. This may need to be further explored by Enemalta at an appropriate time. Although the required quantities are relatively modest there is a potential issue of gas supply from Libya where with rising national domestic demands, greater exports by pipeline and to LNG facilities, it is not inconceivable for short term constrictions in supply to occur in the medium term. In such circumstances, the priority of supplying gas for SeaNG / EneMalta is obviously unknown. This potential risk can probably be best mitigated by examination of the supply contract and ensuring that alternative provisions of gas supplies are adequately covered. Sea NG highlighted the fact that their facility would receive gas from the much larger Mellitah plant.

Upset conditions affecting gas supply were discussed with SeaNG and in a case of gas supplied off specification with H₂S a shut-in would occur. The gas is specified to be very dry (H₂O 1lb/mmscfd) to avoid internal corrosion issues in the coselles. liquids are predicted not to exist in the dense phase for the likely gas specification.

Libya's large proven reserves and on-going development plan, the location of the source on the outlet of the Mellitah gas processing plant and NOC's demonstrated support for the project, results in a low level of perceived gas supply risk.

A score of 8 has been ascribed (weighted score of 2)

6.3.2 Gas Processing

The gas processing and compression facility is relatively simple, but is a single facility, providing sole supply of CNG, and as such should be subjected to a more detailed reliability study, before final commitment.

3 x 50% compressor arrangement is proposed at Mellitah; the cooling of the gas in compression is proposed to be reused to cool input air to the compressors to aid energy conservation.

The proposal represents relatively low technical risk.

A score of 8 has been ascribed (weighted score of 0.6)

6.3.3 Shipping

SeaNG propose to supply a number of purpose-built ships to deliver the CNG, with ships arriving in Malta to discharge cargoes every 1-2days. Gas transported per ship was estimated at 2000T/ship representing 75 mmscfd.

Despite having gained ABS approval of the concept, there is still concern regarding the long-term integrity of the coselle storage units. SeaNG offered to make available test data from pressure cycling tests, which they claim to be equivalent to 300years. They also claim that improvements to welding procedures and pipe metallurgy since the tests were carried out suggest that performance should be further increased. The gas will be at 220barg pressure in the ship. Individual coselles can be isolated.

The HAZID / HAZOP carried out by ABS identified potential problems associated with pipe cooling during pressure reduction, and in consequence, changes in design and procedures were identified. A similar situation could arise in the event of leakage from the coselle, when rapid expansion could lead to potentially dangerous cooling of pipe-work. SeaNG claim that high gas velocity at the point of leakage leads to frictional heating. Evidence supporting this thesis needs to be checked.

Although the carbon steel pipes are encased in the coselle and will be maintained in a nitrogen atmosphere, corrosion of the carbon steel pipes in a marine atmosphere should be considered.

The procedure for handling possible hydrocarbon deposition in the coselle if the supplier's treatment plant fails also needs further review noting that SeaNG stated that the coselles are piggable. On integrity grounds this will be an important design feature. Other integrity issues relate to the material choice for the coselles; SeaNG stated that material toughness would be chosen for the lowest possible temperature likely to be -15/20 deg C.

The key component of this novel concept is the coselle ship, which comprises both the storage and transportation elements in the gas supply chain. Having the participation of Teekay as member of the JV, and having obtained ABS classification for the vessel design and process, provides a

measure of confidence, balanced in part by the underlying concern relating to the commercially un-proven concept.

A score of 8 has been ascribed (weighted score of 1.2)

6.3.4 Re-Gasification Terminal

The terminal comprises pressure control and metering facilities, and does not include any shore-based storage facility. Gas storage solely comprises the ship-borne coselles, operating at high pressure. In consequence, the plant footprint is small.

Clearly SeaNG are aware of the lack of flexibility in this arrangement, and have suggested that consideration be given to on-shore storage including small-scale LNG. The most practical solution appears to be switching to the use of gas oil in the event of gas supply disruption. SeaNG also suggest that peak electricity demand may be most economically met by supplementing gas supply with gas oil in early years of the project. Enemalta intends to retain stocks of gas oil and fuel oil on site in any case.

The jetty will be occupied continuously by one ship, and for periods of change-over (around 5hrs.) by two ships. The frequency of deliveries means that the existing jetty cannot be used for discharging CNG, without possible disruption of liquid fuel delivery, and in consequence, SeaNG must construct a new jetty. The 'semi permanent' presence of a gas ship at the jetty cannot be good in the long term. The other harbour requirements and future development will be affected and the regular connect and disconnect procedures will eventually increase the risk of an incident in the harbour area. This issue needs to be explored further and a risk analysis should be presented to cover this aspect.

The technical issues will centre around whether the ship will be classed as a permanent 'on shore' storage or considered to be a 'marine storage vessel'. Recognised LNG codes may not apply and SeaNG have made no suggestion as to what would be the correct codes and standards to use in this instance and what would be the restricted areas around the berths where 'odourless' gas is constantly present.

It is suggested that this matter is discussed with Sigitto to seek information regarding any similar arrangements that are presently in use around the world.

SeaNG have outlined the option to install a turbo expander or other energy recovery equipment at the Delimara terminal, and should detail these options in their revised proposal.

The probable need for a year long environmental data collection window for the World Bank standard EIA that is likely to be required was discussed with SeaNG and their schedule will need to reflect this activity duration.

Whereas the proposed facility is simple and occupies a small footprint, the scheme's main drawbacks are the need to permanently have one ship berthed at the facility, with two vessels being regularly moored at the jetty, resulting in the need for the construction of a new jetty, and the high level of ship movements and gas hook-up which result from the high frequency of gas delivery. In addition the scheme provides no on-shore storage, which might require Enemalta to switch to liquid fuels in the event of disruption to delivery.

It is considered that these factors increase technical risk to a medium level.

Scores in the range 5 to 8, have been ascribed resulting in an overall weighted score of 2.775 being ascribed

6.3.5 Operation

SeaNG propose that the simple shore-based facilities at the terminal are operated by Enemalta. The ship and on-board process facilities would be operated by Teekay.

SeaNG propose to develop appropriate training plans with assistance from SIGGTO. Apart from the issues relating to berthing and hook-up dealt with under 5.5 above, the operation of the on-shore facility presents relatively low technical risk.

A score of 6 has been ascribed (weighted score of 0.45)

6.3.6 Overall Score

The thoroughness of the proposal, professionalism and competence displayed in the technical presentation, and the structure of the JV, incorporating major international players, give reasonable confidence in the JV's ability to deliver the project.

This view must be tempered somewhat by the risks associated with adopting an unproven concept, and the inherent disadvantages regarding berthing arrangements.

In consequence the proposal receives a reasonably high overall weighted score of 7.03, slightly lower than that gained by its main LNG competitor.

6.4 Commercial Issues

6.4.1 Gas Pricing

The pricing of the gas is based on two parameters, a fixed cost for transporting the gas using the Coselle system and a commodity price for the natural gas. The fixed price is high and at the quoted base prices is 25% of the total delivered price.

Transportation Demand Charge = DCQ times the applicable CNG Transportation Tariff times the number of days in the month.

In this formula CNG Transportation Tariff shall mean

For the period 2012 to 2015 US \$4.18 per MMBtu;

For the period 2016 to 2032 US \$3.98 per MMBtu

Gas Commodity Charge = Actual gas volume converted to MMBtu's delivered during the month times the Monthly Index Price

Monthly Index Price (expressed in US\$/MMBtu) = $PO * [.50 \times (G/GO) + .30 \times (F/FO) + .20 \times (B/BO)] * 1.05^1$

in this formula:

- all prices are taken from Platt's Oilgram Price Report
- G is an average of "CIF Med Basis of gasoil .2" expressed in \$/metric ton and converted in US\$/MMBtu
- F is an average of "CIF Med Basis of combustible oil at low sulphur content" expressed in \$/metric ton and converted in US\$/MMBtu
- B is an average of "spot average of Brent" expressed in \$/barrel and converted in US\$/MMBtu

P0 = Baseline reference price is adjusted based on the resultant movement in the indices each month.

GO, FO, and BO are reference prices that will remain fixed over the term of the contract. Whereas, G, F, and B can represent average price settlements over 3, 6, and 9 month periods as published by Platts.

The proposal from SeaNG makes the following estimate of the total price of the natural gas supply.

Applying this formula to current market references, the Monthly Index Price FOB Libya is in the range of \$9.00 per MMBtu. The all-in "Bundled Service" price for gas supply delivered to Delimara using the proposed Sea NG price structure is \$13.18.

The high fixed cost of the natural gas transportation will make this option more cost effective at high international energy prices but should prices fall the fixed cost could become a burden.

On top of the gas pricing formula there is a further charge called the “gas arrangement fee” which SeaNG will charge Enemalta for servicing the contract.

Gas Arrangement Fee: As is common with the provision of a “bundled service” by gas distribution companies to industrial customers, this arrangement fee is required to compensate Sea NG for the upfront expenses, credit support, and ongoing risk and operational expenses it will incur in arranging continuous supply of natural gas for Enemalta. For the fee Sea NG will provide: ongoing credit support to the National Oil Corporation of Libya for the gas supply contract; daily scheduling and nomination services; daily, monthly, and year end accounting and invoicing services; regulatory reporting services; ensuring all required gas import/export authorizations are obtained and kept in good standing; financial responsibility for off-spec gas deliveries; responsibility for unaccounted shipping losses other than fuel; and assumption of the risk of non-payment for gas delivered. The fee is a percentage of the value of the gas sold as the liabilities assumed by Sea NG will vary according to such value of the gas sold.

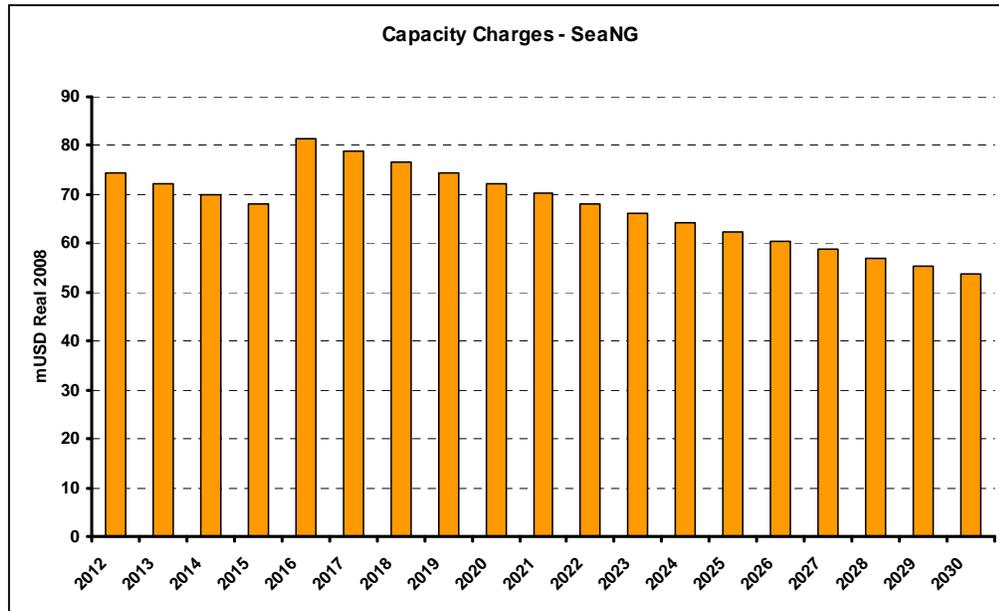
SeaNG commodity cost is calculated in the financial model based on the formula provided in their offer. 2008 forecasts for Gasoil, HFO, and Brent are used as reference prices while the constant \$9/mmbtu is used as the reference gas price. Long-term commodity price forecasts are used to calculate the final commodity cost, which is then inflated by 5% of OPEX and “transaction costs” that would be incurred by the bidder under their respective bundled offer.

The commodity charge needs further clarification and definition to be part of a contract. This can only be done in conjunction with the Libya NOC.

- **Capacity Charge**

Based on the SeaNG offer described above, the annual capacity charge is shown in Exhibit 25 below. In general, the capacity charge declines with time with one increase in 2016.

Exhibit 25: Capacity Charges SeaNG



6.4.2 Liquidated Damages

The draft term sheet from the SeaNG consortium gives a method by which Enemalta would be compensated for the non-delivery of natural gas.

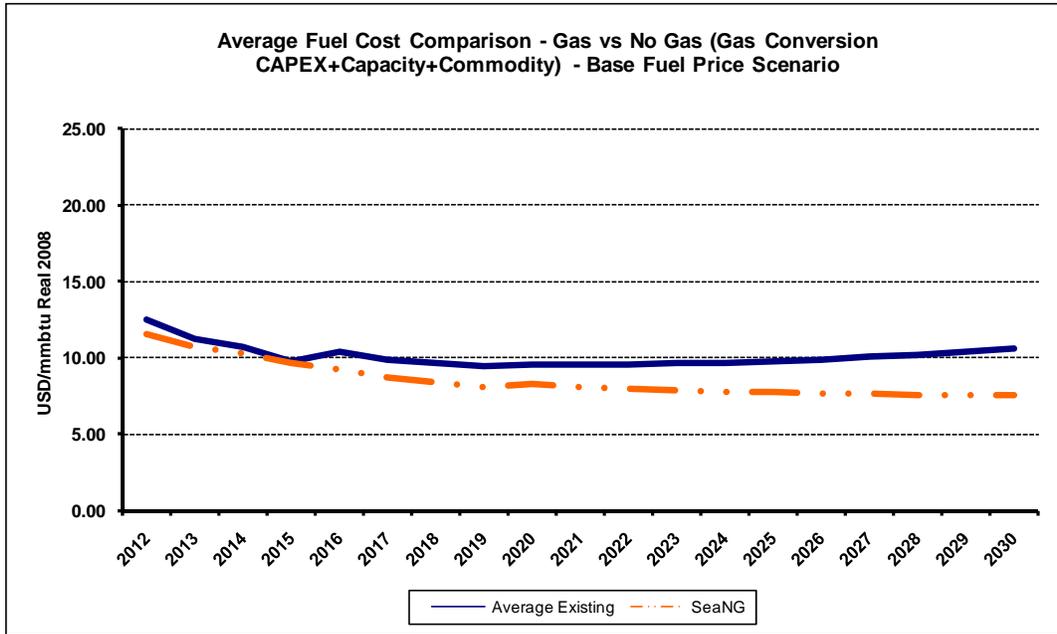
In the event the Seller is the defaulting party then the Seller shall pay the Buyer Liquidated Damages calculated as follows:

Default Quantity times the positive difference between the Buyer’s actual liquid fuel replacement costs converted to US\$/MMBtu minus the Monthly Index Price converted to US\$/MMBtu plus actual cost incurred by Enemalta for switching to alternate fuels.

6.4.3 Impact on Enemalta Operating Costs

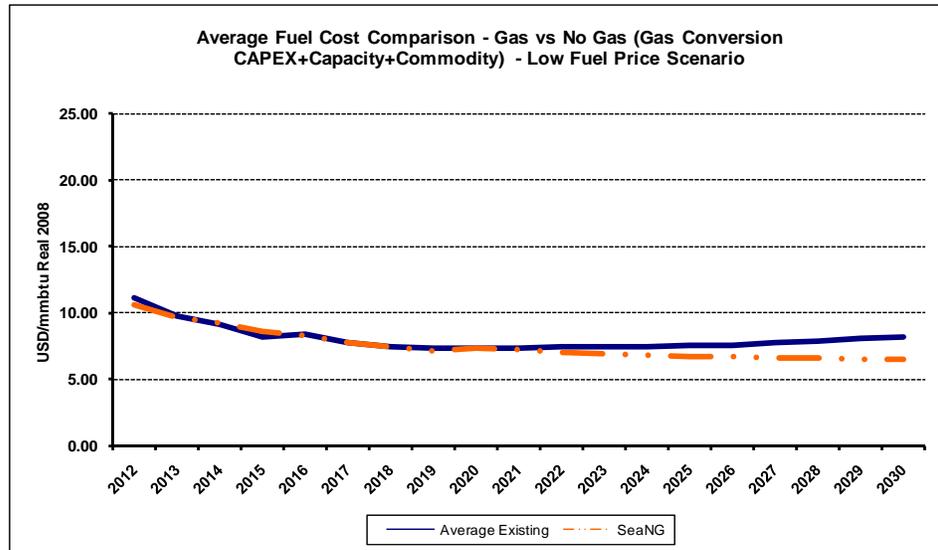
The offer from SeaNG reduces costs to Enemalta under the base case oil price. Exhibit 26 shows that there is a consistently positive benefit to the fuel costs compared to existing fuels.

Exhibit 26: Impact of SeaNG Bid on Total Cost – Base Case



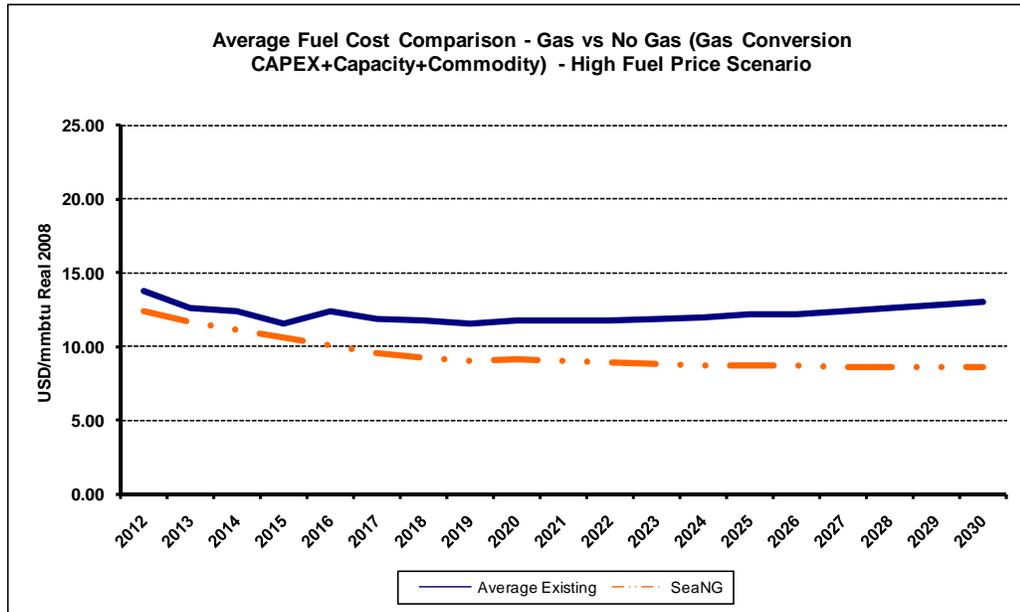
This bid has a high fixed cost element and if oil prices are low the benefit of the bid is much reduced and fuel costs for most of the time would be slightly higher than the current fuel mix. This is shown in Exhibit 27 where the cost of the gas option remains above the current fuel mix until 2022.

Exhibit 27: Impact of SeaNG Bid on Fuel Cost – Low Oil Price Case



With a high oil price scenario the benefits of conversion to natural gas firing show. The graph below shows that the benefit starts immediately and increases over time. While the commodity gas price increases in line with oil prices the fixed cost becomes less of a burden and the price gain becomes substantial later in the forecast.

Exhibit 28: Impact of SeaNG Bid on Fuel Cost – High Oil Price Case



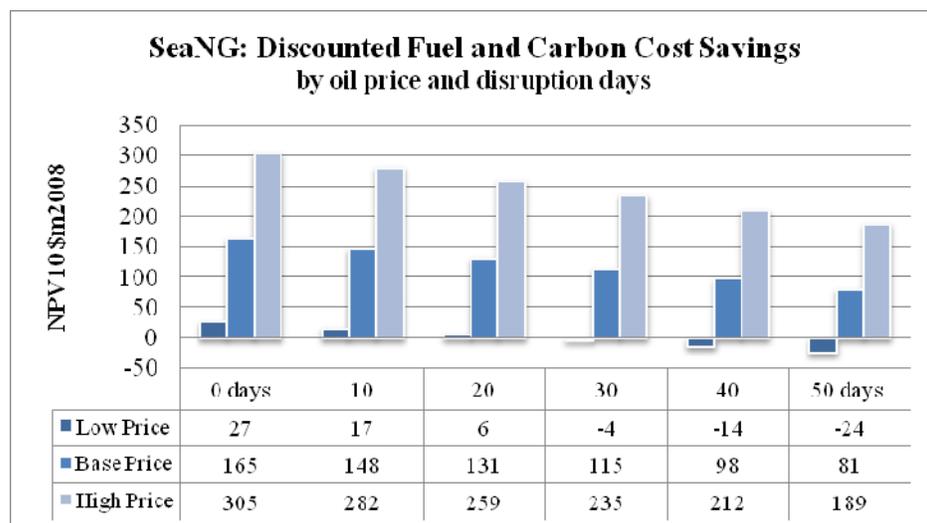
Source: IPA

Introducing the impact of weather-related disruption lessens the attractiveness of the SeaNG bid, both in absolute terms and relative to the other bidders. The graph overleaf shows the total discounted fuel cost switching benefit by oil price scenario and by the number of days disruption, ranging from 0 to 50. Note that since the CNG solution relies on very frequent deliveries, bad weather would cause more disruption to deliveries than would be the case for more infrequent LNG shipments.

In the base case, if supplies were disrupted for 50 days per annum, the NPV of fuel switching to gas is reduced by \$54m, from \$104m to \$50m. In the high case, the NPV reduces from \$214m to \$138m, but still remains strongly positive overall. In the low case, the marginally negative NPV worsens to -\$38m overall.

Introducing the benefit of reduced carbon costs makes the benefits of fuel switching more pronounced, and mitigates against the negative impact of delivery disruption. Even with the maximum foreseeable disruption days (50) and the low carbon & oil price scenarios, the avoided fuel and carbon costs remain positive throughout the forecast horizon.

Exhibit 29: SeaNG Bid: Discounted fuel and carbon cost savings by oil price scenario and number of disruption days.



Source: IPA

In the base and high cases, the NPV of fuel and carbon costs avoided remains strongly positive throughout the period.

6.4.4 Commercial Scoring

The commercial scoring is based on their being a project company supported by strong sponsors. The project company would be financially dependent on the sponsors should there be a failure of the project company and the project company would have little strength and reserves to weather major financial problems. We give a score of 7 to the financial strength of the project.

The concept of gas supply from Libya is good but there is no contract in place for the gas so the concept cannot score high marks. We are applied a score of 6 to the concept.

Gas pricing is the best of the three bids but still gives an improvement to energy input prices only at high and base oil price scenarios. This is a result of the high fixed cost in the bid. The susceptibility of the frequent CNG deliveries to weather related supply disruption is disadvantageous relative to LNG. However, if one includes the avoided carbon costs generating with gas, the fuel switching benefits remain positive in all scenarios. Overall, we apply a score of 6 to the gas pricing offer.

There are strong take or pay conditions that restrict flexible operation of Enemalta's generating capacity. Therefore the take or pay criteria will be scored at 4.

Exhibit 30 : SeaNG Commercial Scoring

	Weighting	Score
Sponsor Quality	15%	7
Concept	10%	6
Gas Pricing	60%	6
Take or Pay		
Conditions	15%	4
	100%	
Average Score		5.85

Source: IPA

The average score for Bid 3 from SeaNG is 5.85, as shown in the table above.

6.5 Legal Issues

The term sheet provided by SeaNG uses the Take-or-Pay approach to a Gas Sales Agreement for a bundled service, rather than the preferred Capacity Charge / Commodity Charge Approach.

SeaNG clearly is prepared to switch to a contractual structure under which it acts only as shipper, and Enemalta buys gas directly from NOC. This would mean Enemalta taking some greater risks, including an obligation to pay SeaNG’s transportation charge if NOC defaults on delivery. Because SeaNG’s term sheet is based on the take or pay / bundled service approach, it is not clear what different terms would apply, however at the very least it would be likely that the 5% “Gas Arrangement Fee” would be saved.

If it prefers the SeaNG bid, Enemalta should give consideration to dealing directly with NOC as gas buyer.

6.5.1 Significant Changes to Term Sheet

The following are the significant changes proposed by SeaNG in its term sheet, compared to the draft term sheet provided by Enemalta. As mentioned above, this is based on the Take or Pay / bundled service approach rather than the separate Capacity Charge Commodity Charge approach.

Definition of “Daily Contract Quantity” – The DCQ is only 54,794 MMBtu per Day, which is 25% greater than the ACQ divided by 365, thus allowing for a limited swing during peak demand periods. The term sheet permits Buyer to increase the rate of delivery to 119,000 MMBtu per Day, provided there is sufficient gas in the ship.

This is NOT the same as a DCQ of 119,000 per Day. It just allows for a higher offtake if gas is available dock side in the ship. There is no obligation to provide more than 54,794 MMBtu per Day, i.e. if a higher rate is drawn from the ship, there is no obligation to bring the next ship sooner than would otherwise have been the case.

The problem is compounded by the Delivery Obligation, which falls away once the ACQ is reached. This makes sense if the ACQ was equal to the DCQ times 365, or thereabouts, but with such a low DCQ it may cause problems.

Conditions Precedent – SeaNG has included Conditions Precedent of completion of a FEED study, term sheet agreement with the ship yard, and finalization of a gas supply contract with NOC. This is not unreasonable.

Completion Test – the Bidder has modified the right to terminate if the completion test is not passed, where the problem can be rectified within a reasonable time or was caused by the Buyer’s facilities. This is not unreasonable, although it will require careful definition in the SPA and may be difficult to negotiate.

The Nomination Procedure has been modified to remove a minimum flow requirement. This favours the Buyer (as a low flow rate may not register as gas delivered) but seems puzzling.

The Take or Pay threshold is 90% throughout the contract. This, together with the short proposed Makeup Period (see below) is onerous.

The Make-up Period has been changed from 3 years to 1 year, and the contract extension after 20 years to permit the Buyer to take any gas paid for but not taken in the previous 3 years has been removed. This renders the Make-up entitlement almost worthless, as if an entitlement arises in one year, it can only be taken in the following year and 90% of the ACQ must be taken before any Make-up gas can be taken.

The Excess Gas capacity obligation is 10% above DCQ. This is inconsistent with the 119,000 MMBtu per Day entitlement in the DCQ clause. It is now not clear how this inter-relates with the DCQ, ACQ and Delivery Obligation provisions.

Force Majeure – see separate section below.

There is a significant change to the Maintenance clause. They accept the concept of major maintenance (once every 5 years or so), however they have added the words: “Major scheduled maintenance does not affect the Take or Pay quantity”. This is inconsistent with the (unchanged) definition of “Adjusted ACQ”, but they clearly intend that they will continue to be paid for gas during major maintenance. This will be wasted money, and if they maintain this position needs to be factored in as a major additional cost, because it will not be possible to take that paid-for gas later via Make-up.

There are also significant changes to the Termination provisions – see below.

Applicable law – Seller requests English law. We have no issue with this, however this may be a policy matter for the Government of Malta.

- **Force Majeure**

SeaNG has made a major change to the force majeure provisions in the Enemalta draft term sheet. The amendment is badly worded (it basically reads “The Seller shall be relieved of its obligation to deliver Natural Gas if its failure is due to an Event of Force Majeure affecting by the gas supplier in the source country to supply gas to Seller”, however the intent seems to be that if a force majeure event affects the Producer (i.e. NOC in Libya) that constitutes a force majeure under this contract.

This is a significant change, although not surprising.

Importantly, it does NOT say that *default* by NOC constitutes force majeure under this contract. However it isn’t clear if that is really their intent.

The result of this change is not unreasonable, and is a position commonly arrived at in gas sales agreements, but it means an increased risk to Enemalta.

Oddly, their change does not, on its face, mean that an event affecting the SeaNG compression facility in Libya is force majeure under this contract. However we expect that this is a matter of drafting, and hasn’t yet been thought through by SeaNG.

SeaNG accepts a reasonable endeavours obligation to find alternative sources of gas if there is a force majeure problem in Libya. However this is really meaningless, because probably no other source would have the SeaNG compression facilities available. They also propose sharing with Buyer any damages that Seller may obtain from the gas supplier. This doesn’t make sense, because if there is a force majeure event affecting the supplier then no damages would be payable.

Unfortunately this raises a doubt about the true intent of the Bidder. Although the term sheet clearly only says a “force majeure event affecting the gas supplier”, it is possible that they intend that a producer default would be force majeure. Our analysis presumes that they mean what they say, and producer default is not intended to be force majeure under this contract.

The definition of “Event of Force Majeure” is unchanged, but now doesn’t make sense because SeaNG intends that events affecting other persons (e.g. the producer) would constitute force majeure under this contract. Nevertheless their intent seems clear.

- **Termination Provisions**

There are significant changes to the termination and termination payment provisions.

- Termination for force majeure is suggested for 6 months, but only if it is force majeure affecting the other party's facilities (presumably, in the case of termination by the Buyer, force majeure affecting the producer's facilities). There is no right of termination by a party for force majeure affecting that party's facilities. This is not a major issue, but is unusual.
- Termination for Seller default is now restricted to "material" default. This isn't unreasonable, but would need to be defined.
- If the contract is terminated by the Seller for Buyer default (i.e. default of payment), the Bidder wants, as liquidated damages, all remaining amounts payable under the contract, plus whatever the Seller owes to NOC under the gas supply contract. This is not reasonable. The payments to NOC are reasonable, provided Enemalta is involved in their negotiation and they are of the order indicated (lost revenues for 1 year). However at best the payment to the Bidder should be a discounted calculation of lost future cash flow (their proposal is undiscounted), without the profit component. This potentially is a major issue.
- If the contract is terminated by Buyer for Seller default on delivery, the Seller proposes paying only 12 months of liquidated damages (based on a reasonable calculation, of incremental cost of liquid fuels). It is unlikely that Enemalta could replace the contract in that time.

- **Price**

The price proposed by SeaNG includes a "Gas Arrangement Fee" of 5%. This is stated to be a fee for providing a bundled service, including credit support for NOC and the obligation to provide a continuous service.

This isn't unusual, however it does have relevance to the force majeure provisions. If they are receiving a fee then they should also be taking risks commensurate with that fee. There is a good argument that if they receive this fee then they should also be taking supplier force majeure risk.

6.6 Conclusions

The SeaNG Bid could provide Enemalta with a cheaper source of primary energy at high and base oil prices. The bid is reasonably well structured as a project with strong sponsors. The novel method of natural gas delivery will introduce some uncertainty to the reliability of natural gas supply a major requirement for the project.

There is no contract in place for the gas supply in Libya introducing further uncertainty into this bid.

Scoring commercial aspects of the bid from SeaNG gives a score of 6.5.

7 POTENTIAL PIPELINE DELIVERIES

This section presents the results of a high level analysis into the options of supplying piped gas to Malta for power generation. The following options were investigated:

Exhibit 31: Summary of Studied Pipeline Options

Pipeline Option	Source of Costs	Source of Demand Forecasts	Comment
Greenstream Tap – Delimara	Consultant, 20% and 40% contingency variants	Enemalta	Dismissed as an option by ENI, not considered further
Gela - Delimara	Consultant, 20% and 40% contingency variants	Enemalta	16” and 18” options examined with first gas in late 2011
Gela - Delimara	ENI	Enemalta	18” option examined with first gas in late 2011
Gela – Delimara	ENI	Enemalta; altered gas demand due to enhanced HVAC trades.	18” option, with altered demand due to enhanced HVAC cable option and first gas in 2016 Evaluation for notional 25/50/75% cable utilization

IPA investigated two different gas pipeline route options. The first was from a tapping point on the existing Greenstream pipeline west of Gozo to Delimara in Malta, while the second was a 153km pipeline from Gela in Sicily to Delimara.

The Gela – Delimara option was then studied with several variants:

- With Enemalta’s estimates of future gas demand (consistent with the demand profiles sent out to prospective LNG and CNG bidders) and the Consultant’s cost estimates;
- With Enemalta’s estimates of future gas demand and ENI’s pipeline cost estimates;
- With Enemalta’s revised estimates of future gas demand, deferring first gas until 2016 taking into account an expanded role for HVAC power imports. This option also used ENI’s cost estimates.

Although the Consultant’s initial analysis of the Greenfield pipeline option showed the option to be both technically viable and economically the most desirable, the option was dismissed by ENI, part of the NOC/ENI Joint Venture which operates the Greenstream pipeline. For this reason, we have not included our analysis of this option here.

The remainder of this chapter sets out the analysis of the various Gela – Delimara pipeline options.

7.1 Hydraulic Analysis

IPA initially carried out a hydraulic analysis of the possible pipeline from Gela to Delimara to confirm the sizing options for the pipeline.

A simple steady state analysis conducted by IPA largely confirmed the results of a study carried out by ENI in 2003⁴. IPA's analysis suggesting that an 18" pipeline would have a corresponding delivery pressure of 43 bar, while a 16" pipeline would have a delivery pressure of 29 bar. Given the broad consistency of these and ENI's results, it was decided that a simple steady state analysis would provide the degree of accuracy required for the current high-level study of the pipeline sizing options.

As well as the sizing of the pipes, hydraulics analysis was also carried out to check the maximum capacity of both the 18" and 16" pipelines for a delivery pressure of 25 bar. These results indicated that an additional capacity of 46 MMscf/d for the 18" pipeline and 8 MMscf/d for the 16" pipeline. Thus if there is potential to supply gas to **other markets** in Malta then serious consideration would have to be given to the 18" pipeline.

An overview of the Hydraulic analysis results are provided in the table below.

Exhibit 32: Gela- Delimara Offshore Pipeline Summary Hydraulic Analysis.

Item	Units	Gela to Delimara - 153 Km Offshore			
		18" Pipeline		16" Pipeline	
		20%	40%	20%	40%
Length	Km	153.0	153.0	153.0	153.0
Outside Diameter	mm	457.0	457.0	406.4	406.4
Wall Thickness	mm	10.3	10.3	9.5	9.5
Specific Gravity		0.65	0.65	0.65	0.65
Inlet Pressure	bar	55.0	55.0	55.0	55.0
Flow Rate	mmscf/d	99.5	142.0	99.5	104.2
Outlet Pressure	bar	43.0	25.0	29.0	25.0

Source: IPA

⁴ ENI's 2003 study considered what the optimal pipe size for the pipeline should be based on a flow rate of approximately 99.5 MMscf/d and an available source pressure of 55 bar at Gela. They found that the 18" pipe would deliver a (free flow) pressure of 42.5 bar at Delimara while a 16" pipe would deliver a pressure of 30 bar. Since the power plant is understood to operate with a minimum pressure of 25 bar, it would thus appear feasible to build a 16" pipeline. However, ENI assumed that there would have to be a minimum (free flow) pressure of 35bar and so concluded that the 18" pipe size would be the most appropriate. ENI also looked at the possibility of a 12" and 14" pipe line but concluded that pipelines of this size would require compression to provide a feasible outlet pressure.

7.2 Cost Estimates

As a result of the Hydraulic analysis, when estimating the costs of the pipeline, IPA considered two potential pipeline sizes (18" and 16") and two different levels of contingency allowance (20% and 40%). All the cost estimates IPA made for each of these pipe types are shown in the table below alongside the subsequent cost estimates ENI made on developing an 18 inch pipeline between Gela and Delimara.

Exhibit 33: Capital Expenditure Summary - \$US'000s (2008)

Cost Element	Gela to Delimara - 153 Km Offshore				
	18" Pipeline		ENI's Estimate	16" Pipeline	
	20% Cont.	40% Cont.		20% Cont.	40% Cont.
<i>Offshore</i>	366,852	427,994	276,366	345,526	403,113
Material Procurement - Pipeline	136,710	136,710	71,431	118,938	118,938
Construction - Mobilisation/Demob	20,400	20,400	24,349	20,400	20,400
Construction - Pipe Lay	115,600	115,600	137,979	115,600	115,600
Engineering/Management/Sup.	14,000	14,000	19,929	14,000	14,000
Trenching	19,000	19,000	22,678	19,000	19,000
Contingency	61,142	122,284	-	57,588	115,175
<i>Onshore</i>	1,945	1,945	2,112	1,716	1,716
Material Procurement - Pipeline	80	80	42	66	66
Material Procurement - Piping	285	285	149	250	250
Construction - Pipeline	730	730	871	650	650
Construction - Plant & Facilities	510	510	609	450	450
Engineering/Management/Sup.	240	240	342	210	210
Land Acquisition/ROW	100	100	100	90	90
Total	364,655	422,655	278,478	347,242	404,829

Source: IPA, Penspen, ENI

ENI's cost estimates for an eighteen inch pipeline were not broken down in the manner shown above but rather were divided into just three broad categories as shown in the table below (Exhibit 34). The more detailed breakdown shown above was done by IPA so that ENI's estimates could be analysed on a comparative basis.

The main reason for the discrepancy in the total costs between IPA's estimate and ENI's estimate of an eighteen inch pipeline is due to ENI not including a contingency cost in their calculation. Putting contingency costs aside, IPA's total capital expenditure cost estimate (\$305.7m) is broadly consistent with ENI's estimated cost (\$276.3m).

Exhibit 34: ENI Capital Expenditure Estimates - (2008 prices)

Capital Cost Estimates for an 18" Pipeline		
	Million Euro	Million \$
Management and Design	15	20
Materials	53	72
Construction	138	186
Total	206	278

Source: ENI

The estimated costs for the 16 inch options were derived by adjusting the material costs of the 18 inch pipe, with the assumption that the material costs for the 16 inch pipeline were 13% less than the material costs for the 18 inch pipeline (\$63m). It was hence assumed that the construction and all other costs of laying a 16 inch would be approximately the same as that for an 18 inch pipe.

It is assumed that the earliest that a Final Investment Decision can be taken is July 2010. It is estimated that construction duration would be approx 18 months with gas being available by October 2011. All cost have been phased over the construction period based on the nature of the cost and have also been aggregated by year to provide a discounted cash flow analysis. An estimate has also been made of the proportion of offshore lay costs associated with mobilisation and demobilisation.

With regards to operating expenses, IPA assumed the costs shown in the following table.

Exhibit 35: Operating Expenditure Summary - (2008 prices)

Operating Costs	Annual Cost US\$(000)	Annual Cost Euro(000)	Total Cost US\$(000)	Total Cost Euro (000)
Offshore Survey	2,500	1850	20,000	14800
Shore Approach	1,000	740	8,000	5920
Intervention Works Std				
Maintenance	3,700	2738	29,600	21904
Intervention Works	3,700	2,738	7,400	5,476
Insurance	1,000	740	20,000	14,800
Telecoms License	800	592	16,000	11,840
Tech Assistance	400	296	8,000	5,920
Others	129	95	2,580	1,909
Management	800	592	16,000	11,840

Source: IPA

IPA assumed that offshore surveys, shore approaches and standard maintenance would occur every year for the first five years and then every five years after that. Insurance, telecoms license, technical assistance, management and other costs are expected to occur every year, while major intervention works have been assumed to occur only every ten years.

ENI also estimated how much operating costs were likely to be and their results are presented in the following table.

Exhibit 36: ENI Total Operating Expenditure Estimates - (2008 prices)

ENI Operating Cost Estimates	Euro (000)	US\$ (000)
Total Cost for pipeline and shore approach surveys	22,000	29,730
Total cost for internal line inspection	5,600	7,568

Source: ENI

ENI have assumed that pipeline and shore approach surveys will take place every couple of years at a cost of 2.2 million Euros each year and that internal line inspection will each cost 1.4 million Euros each year it is done. ENI estimated that such inspections were expected to occur once every seven years. Following a consultation with Enemalta, we assume that once every five years is more realistic frequency; this is what we assumed when using ENI's estimates in our modeling.

Since ENI did not specifically estimate insurance, telecoms license, technical assistance, management and other costs that are expected to occur every year, IPA used their own estimates of these costs when using ENI's operational expenses' estimates in our modeling. Similarly, IPA used their own estimates of exceptional intervention costs when using ENI's operating expense estimates.

All of these costs except intervention works are expected to occur annually. Intervention costs are expected to occur only every 10 years at an expected cost each time of \$3.7 million.

The operating costs have been summarized and phased by operation and calendar year based on the planned frequency of each activity. The calendar year phasing has been used in the discount cash flow analysis.

7.3 Financial Analysis & Tariff Calculation

A financial analysis was carried out to determine a pipeline daily capacity charge for the various options examined. This charge is expressed as a daily reserved capacity tariff per MMBtu (\$US 2008) based on a daily capacity of 99,500 MMBtu, which is required to satisfy a peak hour of 120 000 MMBtu. It should be noted that the various pipeline options can deliver in excess of 99,500 MMBtu/d and if this capacity can be utilized the tariff will be proportionally reduced.

The analysis is based on 100% equity financing and does not consider any debt funding. The capex estimates (which are in \$US 2008) have been phased across the 15-month construction period (July 2010 to September 2011). The monthly costs have been aggregated for the fiscal years 2010/2011 and inflated to nominal values using compound inflation of 2% per annum.

It is assumed that the Operational start date is 1 October 2011. Cost estimates for the various activities involved during the project term were developed based on 2008 Dollars. Operating Expenses have been compiled for the 20 year operating period based on the planned frequency and occurrence of the various activities. The cost for each year of operation were apportioned to each Fiscal year

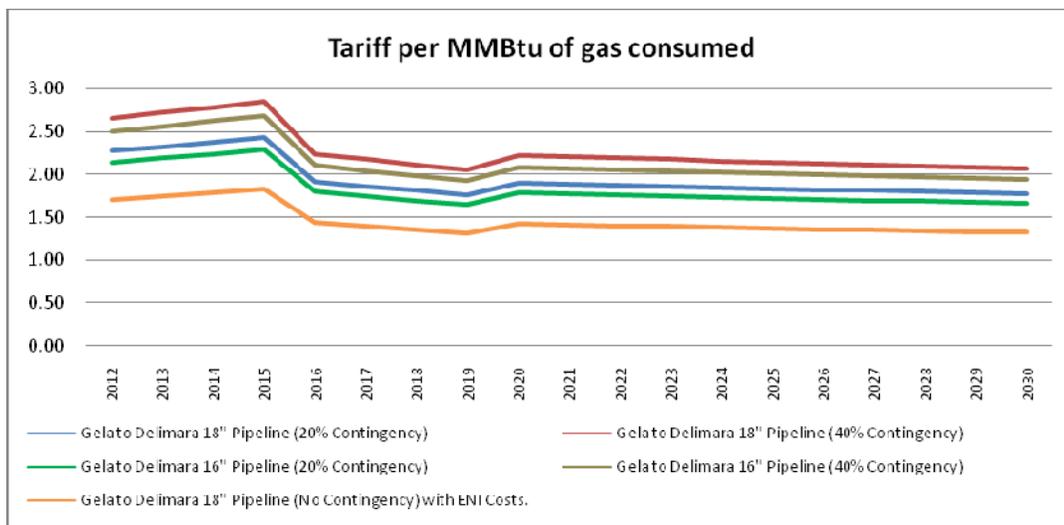
**Exhibit 37: Pipeline Tariff per unit of Capacity
(\$/MMBtu and Euro/MMBtu, 2008)**

No	Scenario	Capacity Tariff \$/MMBtu of Capacity	Capacity Tariff Euro/MMBtu of Capacity
1	Gela to Delimara - 18" Pipeline (20% Contingency)	1.00	0.74
2	Gela to Delimara - 18" Pipeline (40% Contingency)	1.17	0.86
3	Gela to Delimara - 16" Pipeline (20% Contingency)	0.94	0.69
4	Gela to Delimara - 16" Pipeline (40% Contingency)	1.10	0.81
5	Gela to Delimara - 18" Pipeline (ENI Cost Estimates)	0.75	0.55

Source: IPA

The tariffs in the above table represent the tariff per unit of pipeline capacity (assumed to be 99,500 MMBtu per day). It is not expected that Malta will utilize all of this gas but rather that gas demand will be around 44,000 MMBtu per day in 2012 and will rise to around 56 MMBtu per day by 2030. With this in mind the tariffs per unit of gas consumed are expected to be somewhat higher than the tariffs displayed above but will show a declining trend similar to that given in the chart below.

Exhibit 38: Pipeline Tariff per unit Consumed (\$/MMBtu 2008)



Source: IPA

7.4 Fuel Cost Savings Calculations

Fuel cost savings relative to status quo, and in comparison with the LNG and CNG bidders, were calculated for the pipeline option. The gas commodity price was assumed to be identical to the price offered by NOC to SeaNG. The NPV₁₀ of the fuel cost and carbon cost savings are shown below.

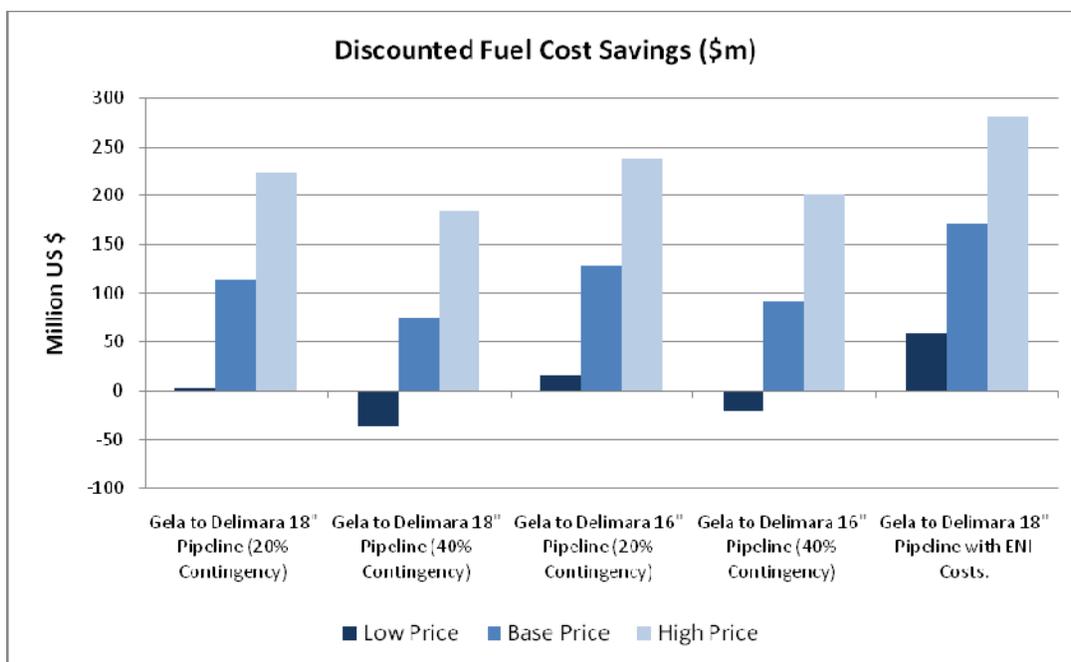
Exhibit 39: NPV₁₀ of Fuel Cost Savings (Base Fuel Price Scenario)

NPV Cost Savings			Without CO2 Effects	With CO2 Effects
Bidder 1 – BB Energy	<i>mUSD</i>	<i>Real 2008</i>	-\$341.73	-\$249.53
Bidder 2 - EWC	<i>mUSD</i>	<i>Real 2008</i>	\$34.53	\$126.73
Bidder 3 - SeaNG	<i>mUSD</i>	<i>Real 2008</i>	\$10.81	\$81.38
Gela Pipeline (Option 1)	<i>mUSD</i>	<i>Real 2008</i>	\$113.44	\$220.06
Gela Pipeline (Option 5)	<i>mUSD</i>	<i>Real 2008</i>	\$170.50	\$277.12

Source: IPA

In the High Fuel Price Scenario, the fuel and carbon cost savings rise to \$223 million dollars for Gela Pipeline option 1 and \$281 million dollars for option 5. In the Low Fuel Price Scenario they drop to \$2m and \$59m respectively. These fuel price scenarios are illustrated in Exhibit 40 below.

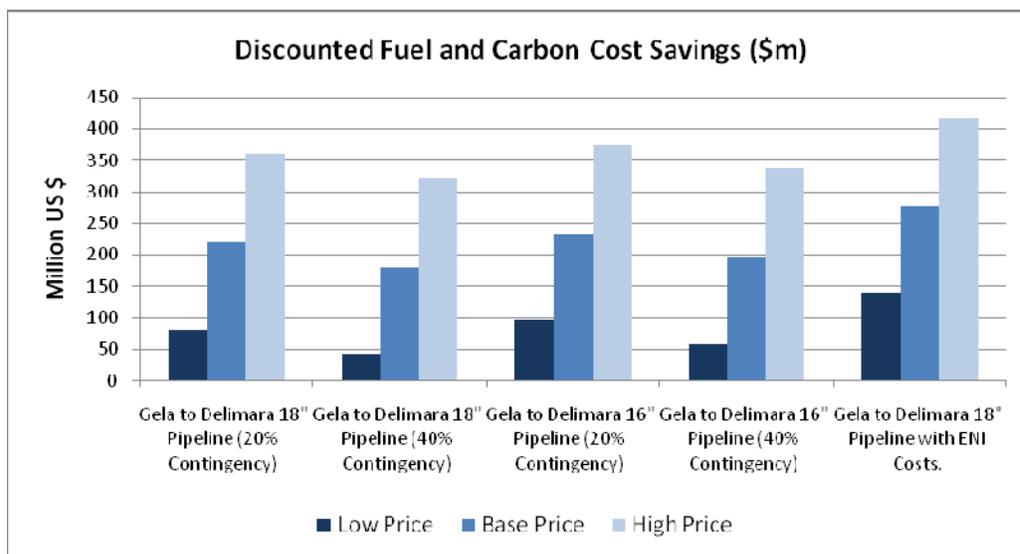
Exhibit 40: NPV₁₀ of Fuel Cost Savings by Fuel Price Scenario



Source: IPA

Introducing the CO₂ cost savings increases the net present value of the savings uniformly across these options as illustrated in the figure below.

Exhibit 41: NPV₁₀ of Fuel and Carbon Cost Savings by Fuel Price Scenario



Source: IPA

7.5 Conclusions and Recommendations

IPA’s analysis indicates that the pipeline from Gela - Delimara is the most cost-effective method for delivering gas to Malta. When compared with the bidder’s offers for LNG and CNG deliveries, the 18” pipeline from Gela to Delimara delivers significantly better project economics.

Additional analysis is required to optimise power interconnector/pipeline requirements. EneMalta’s total energy requirements should be analysed in a coherent and unified fashion to determine the best energy import strategy.

The PSV, Italy’s virtual gas hub, remains thinly traded and used occasionally as a balancing market. Its relative immaturity means that a traditional long-term contract remains the most likely form of contracting for gas for EneMalta. If any non-recourse project financing is sought for investment in the Gela - Delimara pipeline, the transaction is also likely to require a suite of long term contracts to underpin the investment.

If the Gela – Delimara pipeline project is pursued, there are several gas suppliers including ENI, Sonatrach, Gazprom and NOC of Libya that could be potential gas supply counterparties for EneMalta. Continued engagement with ENI and initial approaches to the other suppliers is strongly recommended.

8 IMPACT OF AN ENHANCED HVAC CABLE INTERCONNECTIONS BETWEEN MALTA AND SICILY

8.1 Introduction

Enemalta has recently decided to plan for a larger electricity interconnector between Italy (Sicily) and Malta than that originally considered. The original plan was the construction of two 100MW interconnectors which were expected to be operated at about 50% load factor to accommodate the intermittency of a potential <100MW off shore wind-farm, and to enhance reliability, using an n-1 criteria.

Since then the plan has shifted towards a single 200MW interconnector, an investment which has been approved, and an option for an additional 200MW interconnector. The interconnectors will have redundancy at the terminal ends rather than the cables themselves. This will render possible a greater utilisation of the interconnector, which is viewed as necessary in the light of the CO₂ emissions reduction targets expected post-2020.

Nevertheless, Enemalta will retain local generation plant to make up for the difference in demand and possibly exploit the differential in electricity costs. There will also be standby plant in case of a long-term outage of a cable. The ENI gas pipeline sizing considered only the supply necessary to meet the peak daily/hourly gas demand under normal circumstances and hence operation of standby plant will likely be through use of liquid fuel.

This resulted in a revision of the forecasted volume and timing of Enemalta requirements for natural gas and other fuels which of course resulted in changes to all the net present values of fuel cost savings for all of the different gas supply options. This section sets out how the enhancement of the interconnector and other changed assumptions⁵ are likely to affect the relative economics of the different gas supply options. The section starts by setting out what the gas and fuel demands are projected to be under three different levels of interconnector capacity utilisation, i.e:

- 1X200MW Interconnector at 50% (to 85%)⁶
- 1X200MW Interconnector at 100%
- 2X200MW Interconnectors at 75%

⁵ Enemalta asked IPA to provide NPV for the years 2015-2030 rather than 2012-2030 as previous requested. Similarly there was also a further change to the gas demand and subsequently the projected demand for other fuels and finally NPV were discounted to 2009 rather than 2008. Our latest results incorporate the revised HFO and Gasoil consumption projections provided by Enemalta in October 2009.

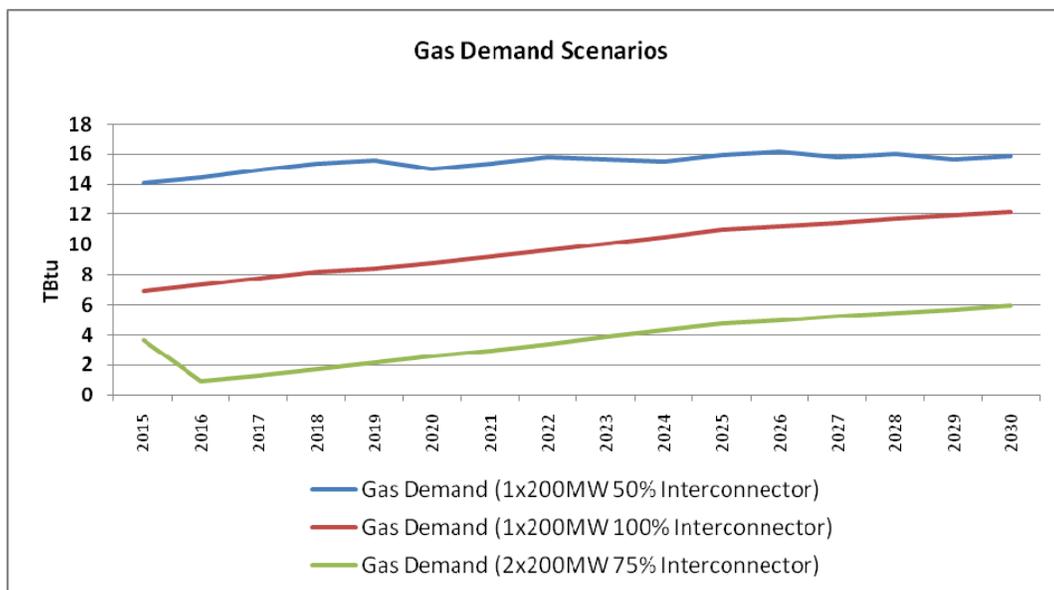
⁶ For the gas demand forecast for the 1x200MW scenario at 50%, it was assumed that the cable will be operated at 50% until 2021, increasing thereafter to 85% utilization in 2035

The following section sets out some changes to the fuel price projections that have been made, while the remaining sections look at impact that these new assumptions and projections have on each of the gas supply options.

8.2 Changed Demand for Gas and other Fuels

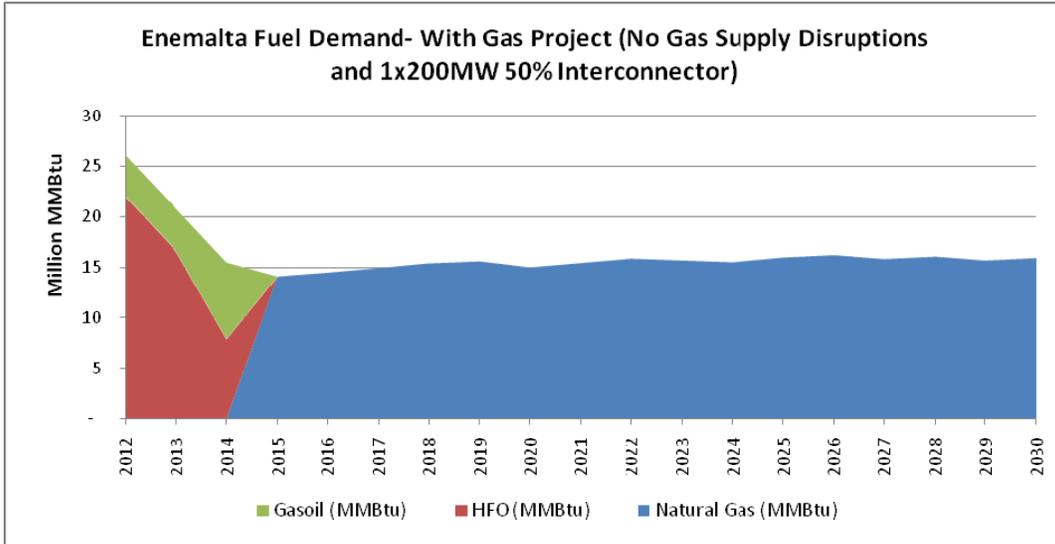
The more power that Enemalta receives through the Malta-Sicily interconnector, the less power that will need to be generated in Malta. Consequently, the amount of fuel required to generate power will be lower the higher is utilisation of the interconnector. The chart below shows how the projected demand for gas is altered by the level of interconnector utilisation. These gas demands are considerably lower than those presented in section 3.2.5.

Exhibit 42: Gas Demand Scenarios



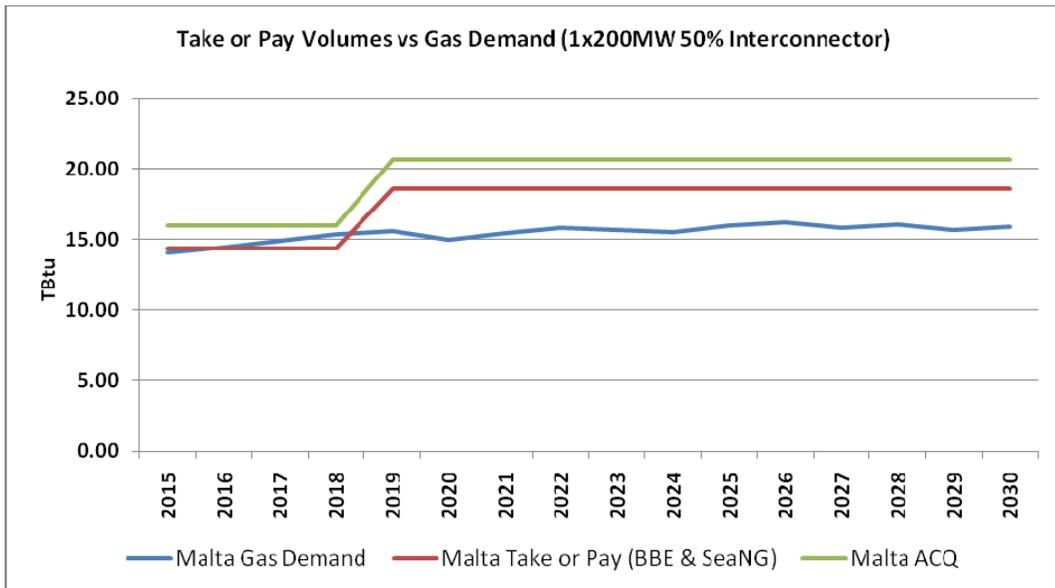
If the project to introduce gas-fired power generation goes ahead, then it was assumed that HFO and gasoil will cease being used and that gas will be the only fuel used to generate electricity, as shown in the chart below. In this chart it is assumed that 50% of the 200MW interconnector capacity would be used. Note it is assumed that gas will be made available in 2015, not 2012 and thus in the financial analysis of the gas supply options presented later, the net present values of the fuel cost savings of the options are all calculated from the period 2015 to 2030, and not 2012 to 2030 as was case in the previous analysis.

Exhibit 43: Enemalta Fuel Demand- With Gas Project (No Gas Supply Disruptions and 1x200MW 50% Interconnector)



The reduced gas demand projections have implications for the Take or Pay (TOP) conditions put forward by BBE and SeaNG. Even if the 200MW interconnector is only used at 50%, the TOP gas levels from 2018 will be higher than the volume of gas projected to be demanded, as shown in the chart below. If a higher proportion of the interconnector’s capacity is used (100% of 200MW or greater) then the difference between the TOP levels and the demand levels will be even greater.

Exhibit 44: Take or Pay Volumes vs Gas Demand with 1x200MW 50% Interconnector



We have assumed that if gas-fired power plants were not introduced in Malta, HFO and gasoil would continue to be used to generate electricity. The projected demand for other fuels are shown in the charts below for the case where the 200MW interconnector is 50% utilised and two 200MW interconnectors are 75% used.

Exhibit 45: Enemalta Fuel Demand- Without Gas Project (1x200MW 50% Interconnector)

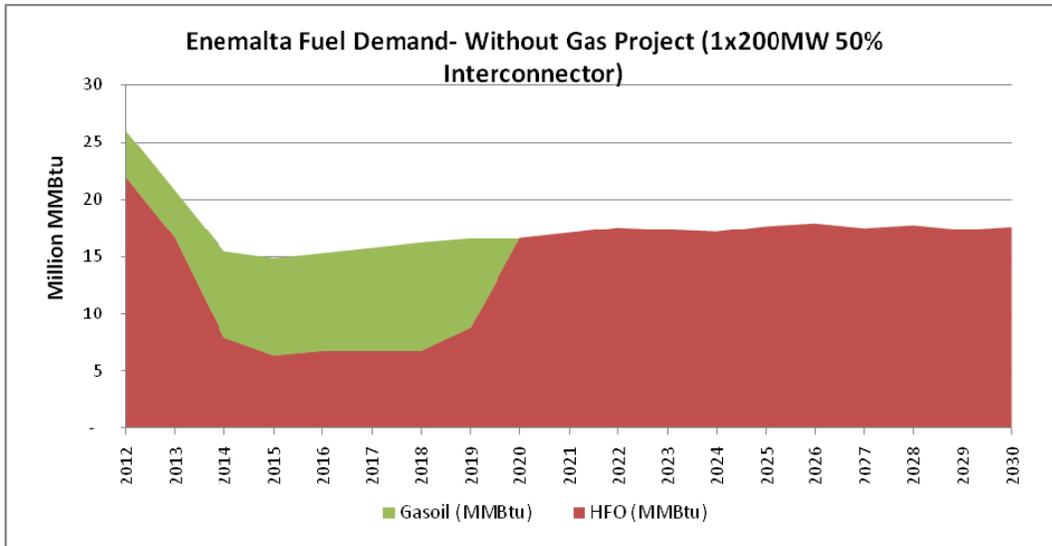
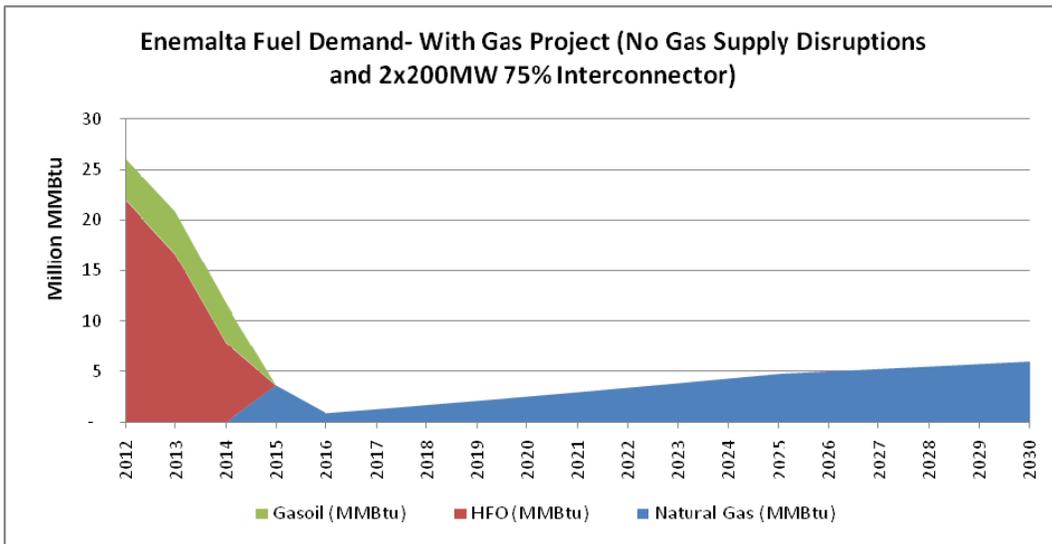


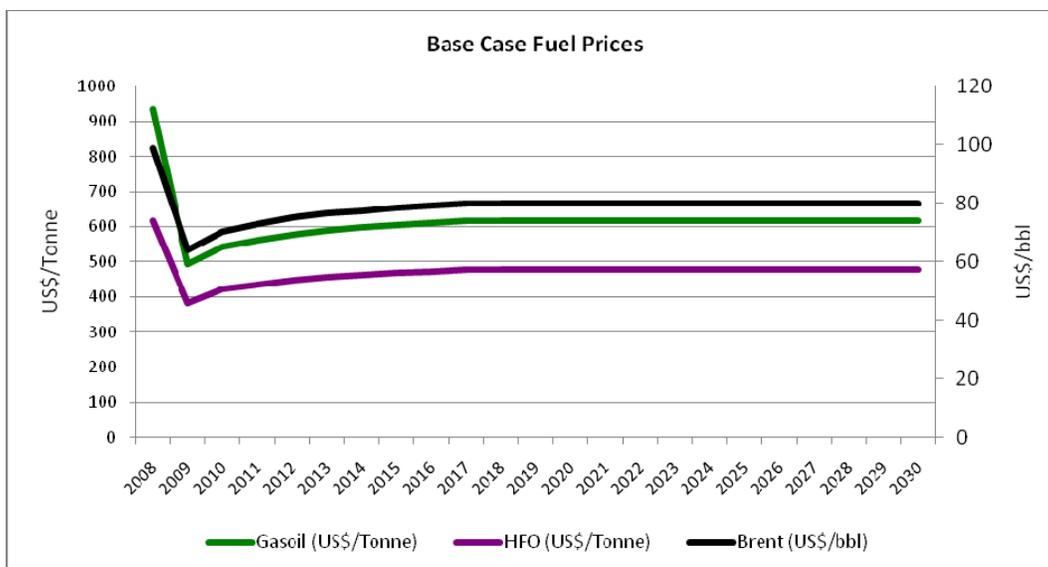
Exhibit 46: Enemalta Fuel Demand – Without Gas Project (2x200MW 75% Interconnector)



8.3 Fuel Price Changes

In addition to the introduction of the interconnector and consequent changes to the volumes of gas and fuel demand, a number of changes were also made to fuel prices. The chart below shows these new fuel price assumptions.

Exhibit 47: Base Case Fuel Price Assumptions



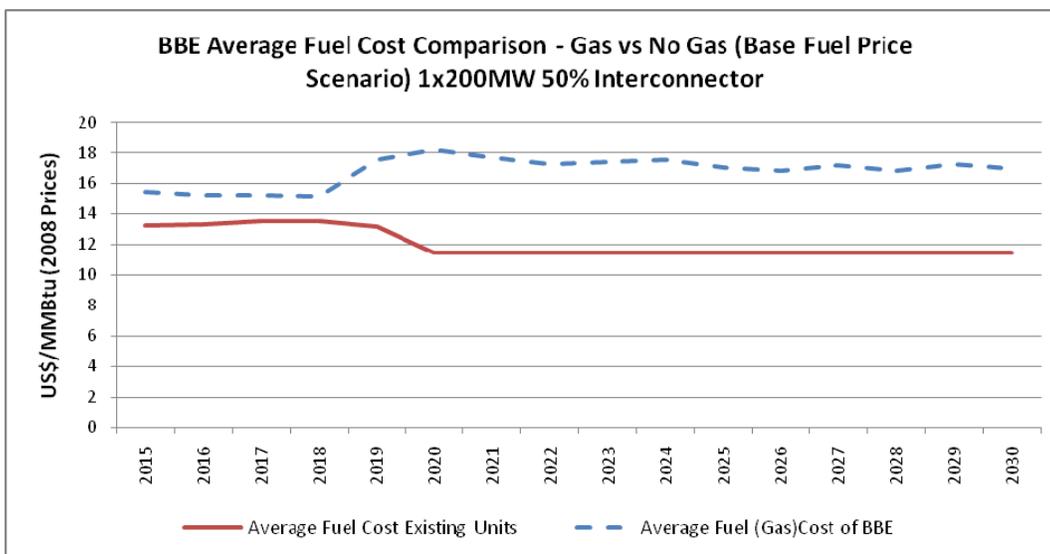
Prior to 2014, these prices are lower than the ones reported previously but thereafter the projected fuel prices are all expected to be higher than previously reported.

8.4 Impact on BBE Bid

The changes to the projections and assumptions described above do not alter the fundamental commercial position of the BBE Bid. Under all three interconnector assumptions and three fuel price assumptions, the BBE offer fails to offer any fuel cost savings. Instead, the option would increase fuel costs as shown in the following chart where the 200MW interconnector is assumed to only be 50% utilised.

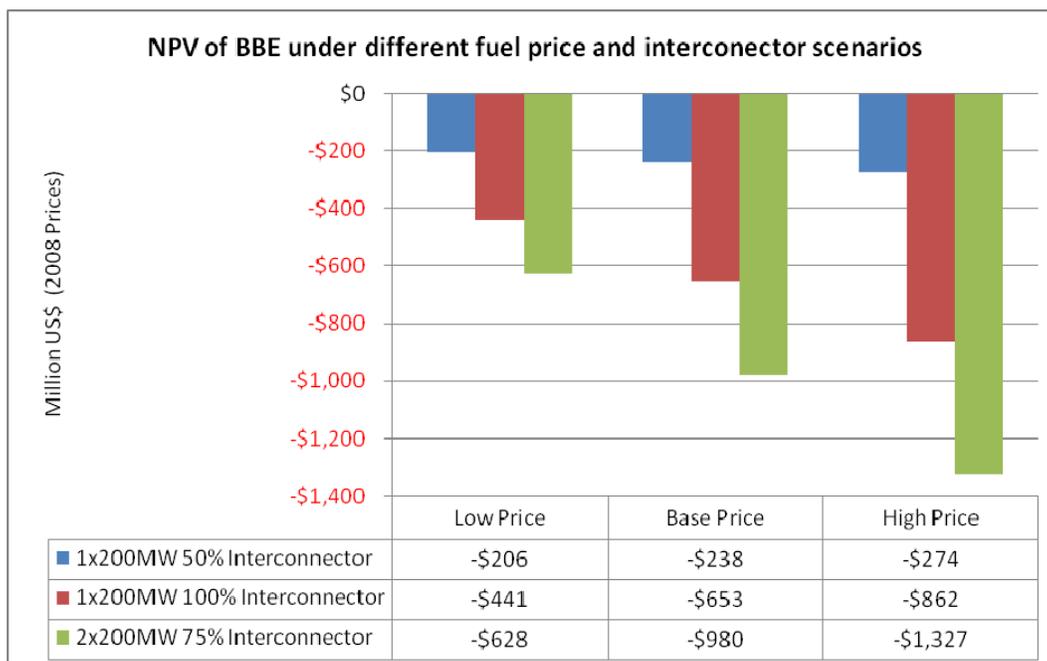
At higher levels of interconnector utilisation, the additional fuel costs associated with this option become even larger, this is largely because of the Take of Pay conditions: although as the interconnector usage increases and less gas is demanded, the payment for gas will remain the same, causing the average cost to increase.

Exhibit 48: BBE Average Fuel Cost Comparison Gas vs No Gas (Base prices and 1 x 200 MW 50% interconnector)



Fuel costs combined with the cost of converting or building plants to gas-fire results in significantly negative fuel cost savings for this option on a net present value basis. The higher the price level and the higher the usage of the interconnector the lower the fuel cost savings for this option, as shown in the chart below.

Exhibit 49: NPV of Fuel Cost Savings - BBE



8.5 Impact on EWC Bid

The changed gas demand and price projections affected the average fuel cost savings of the EWC option. Under the 1 x 200 MW 50% interconnection scenario, the average fuel cost of the EWC option would be lower than if just HFO and gasoil were used. If on the other hand, the 1 x 200 MW interconnector was used at 100% of capacity and base prices prevailed, then the average fuel cost savings would be marginal. This situation is shown in the following charts.

Exhibit 50: EWC Average Fuel Cost Comparison - Gas vs No Gas (Base Fuel Price Scenario) 1x200MW 50% Interconnector

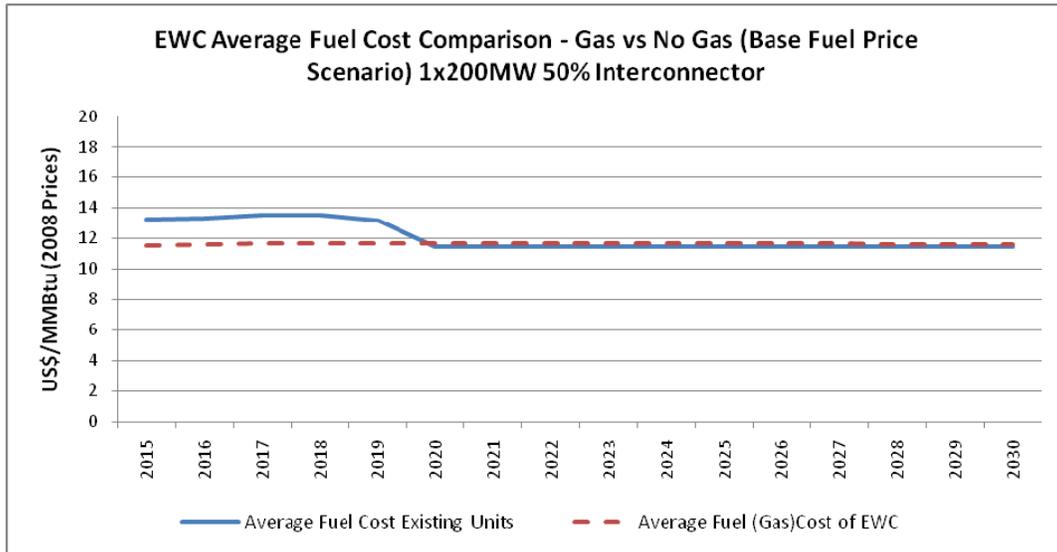
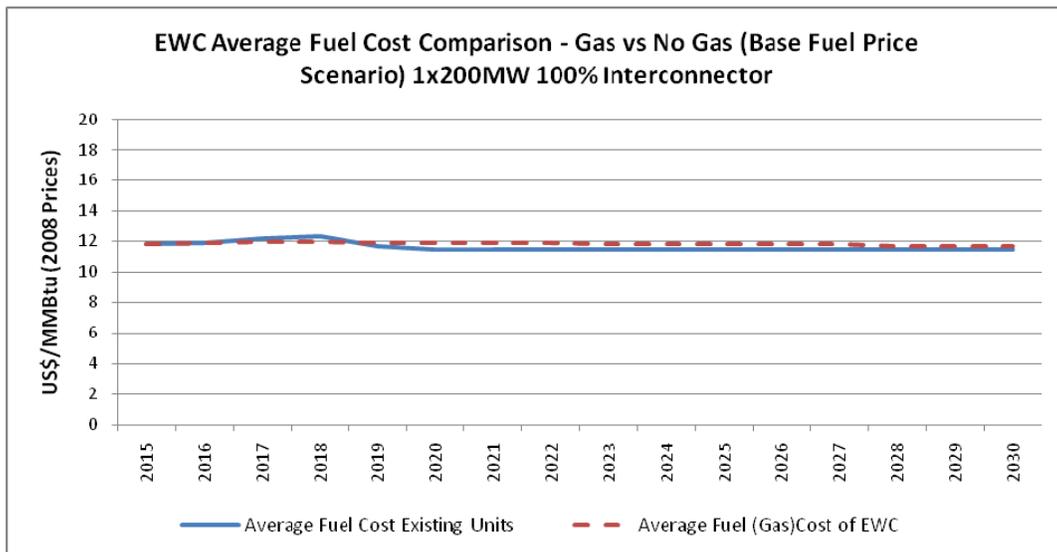
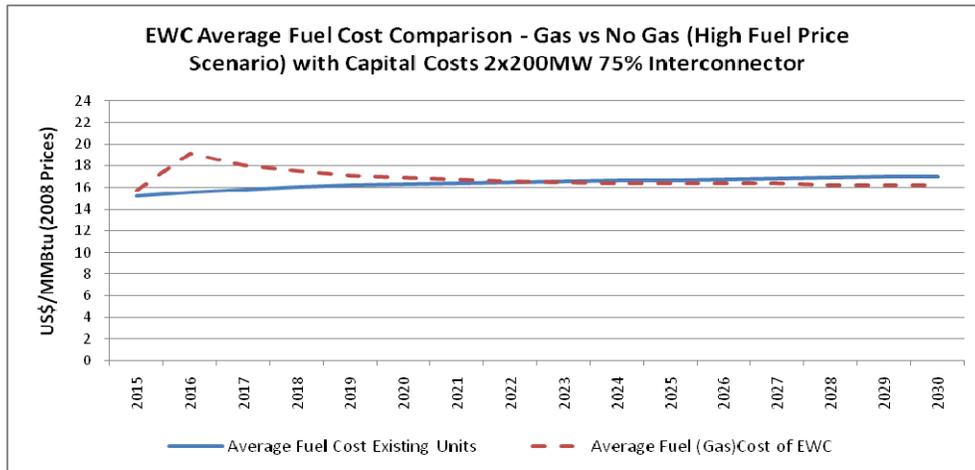


Exhibit 51: EWC Average Fuel Cost Comparison - Gas vs No Gas (Base Fuel Price Scenario) 1x200MW 100% Interconnector



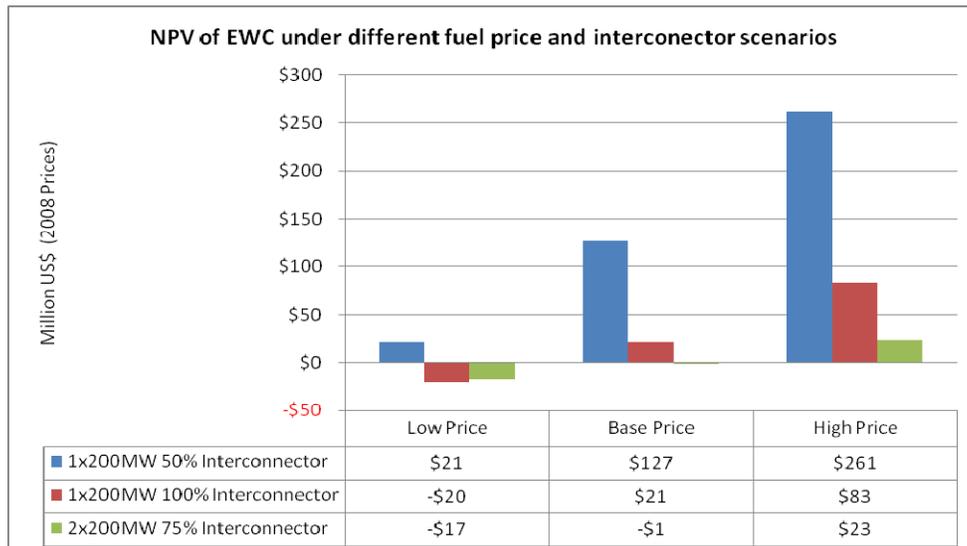
With high oil prices, fuel cost savings in the EWC option are positive in all cases, including the 75% of the 2x200MW interconnector capacity case, as shown in the chart below.

Exhibit 52: EWC Average Fuel Cost Comparison - Gas vs No Gas (High Fuel Price Scenario) with Capital Costs 2x200MW 75% Interconnector



The net present value of the cost savings are positive in most cases. The exceptions are in base and low oil price scenarios with 75% of the 2 x 200 MW utilisation and in the low oil price 100% of 200MW interconnector case. These results are summarised in the chart below.

Exhibit 53: NPV of EWC fuel cost savings under different fuel price and interconnector scenarios



8.6 Impact on SeaNG

As with the previous results, the net present value of the fuel cost savings are expected to be negative if prices are low. The capacity usage of the interconnector does not change this.

At base prices, average fuel cost savings of the SeaNG option are generally expected to be negative regardless of the interconnection usage. The interconnection usage affects the extent of the negative cost savings as can be seen in the following two charts.

Exhibit 54: SeaNG Average Fuel Cost Comparison - Gas vs No Gas (Base Fuel Price Scenario) with Capital Costs 1x200MW 50% Interconnector

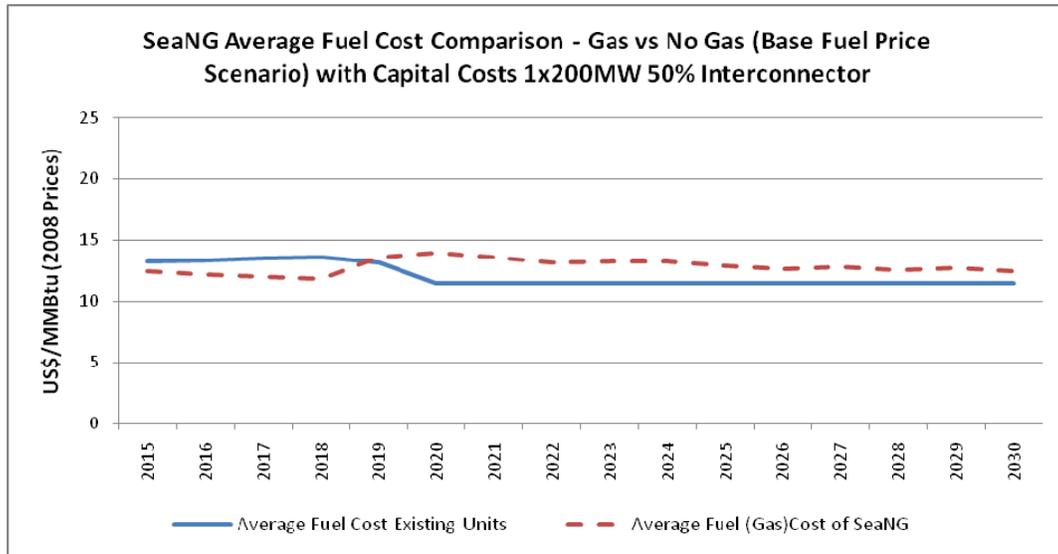
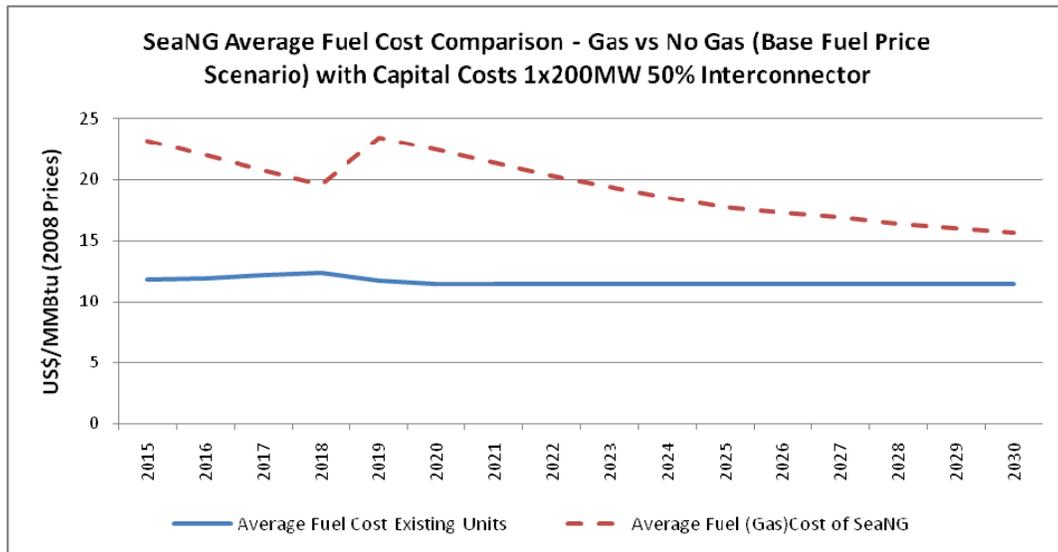


Exhibit 55: SeaNG Average Fuel Cost Comparison - Gas vs No Gas (Base Fuel Price Scenario) with Capital Costs 1x200MW 100% Interconnector



At high level fuel prices, the extent of interconnector usage affects whether average fuel cost savings are made and thus also whether total fuel cost savings are made too. Under the assumptions that the single 200MW interconnector is used to 50% of capacity, average (and total) fuel cost savings will be positive in all but the low price scenario. At interconnection usage of greater than 200 MW

at 100%, the average fuel cost savings become negative and so do the total fuel cost savings. These effects are shown in the following charts.

Exhibit 56: SeaNG Average Fuel Cost Comparison - Gas vs No Gas (High Fuel Price Scenario) with Capital Costs 1x200MW 50% Interconnector

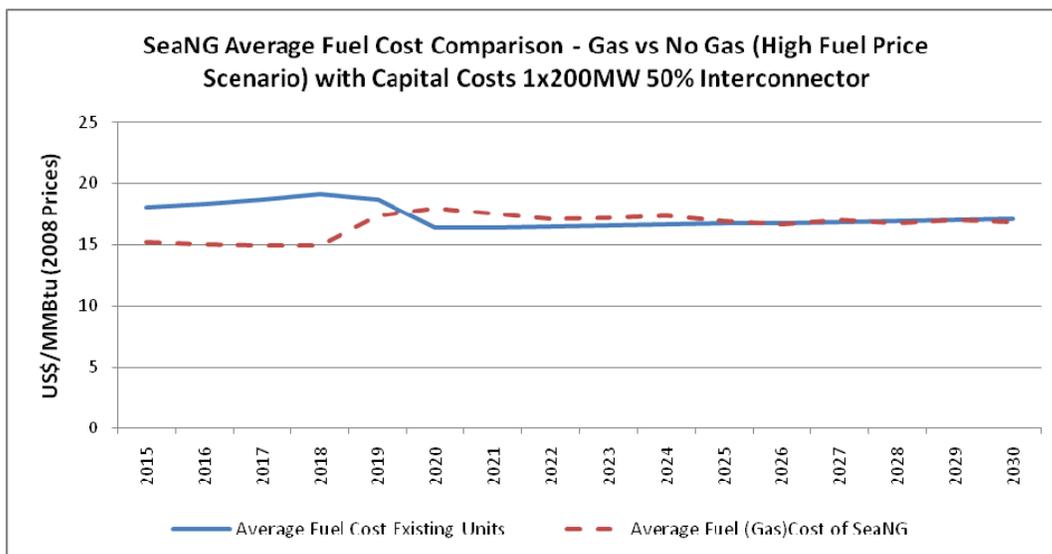
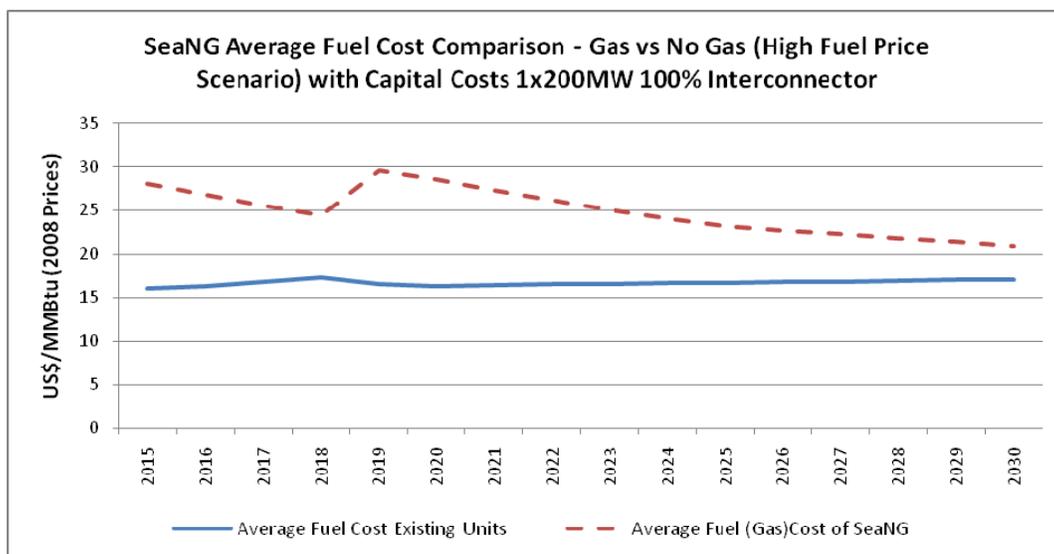
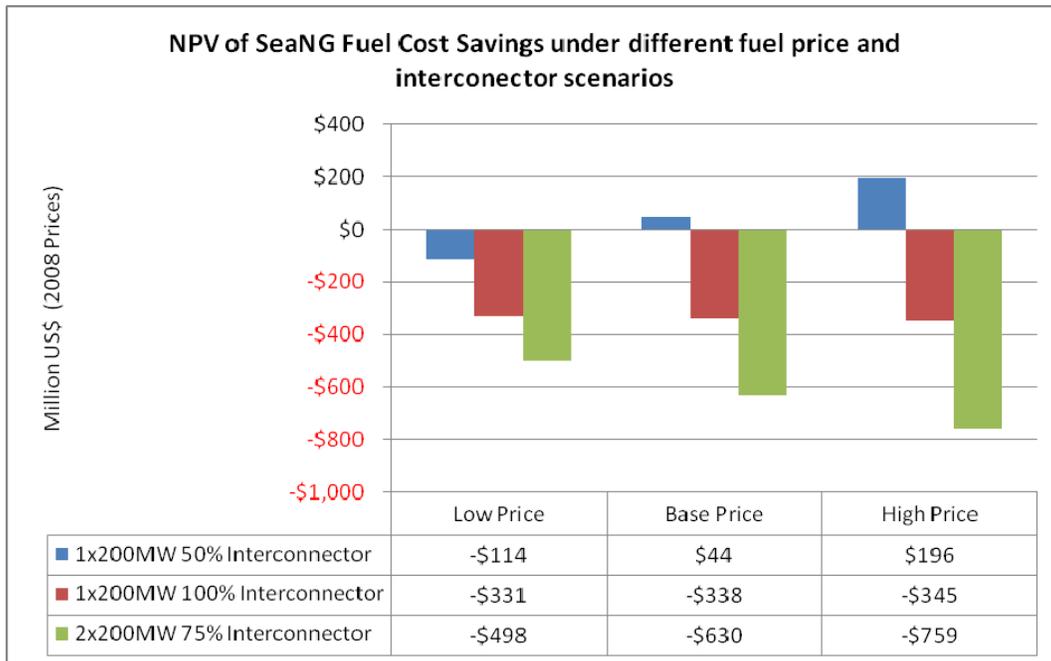


Exhibit 57: SeaNG Average Fuel Cost Comparison - Gas vs No Gas (High Fuel Price Scenario) with Capital Costs 1x200MW 100% Interconnector



Overall, the results suggest that positive fuel cost savings can be made provided that one 200 MW interconnector is only used up to c. 50% of the time and that prices are as projected in the base case or high case. A summary of the net present value of the fuel cost savings of the SeaNG option under different price and interconnection scenarios are shown below.

Exhibit 58: NPV of SeaNG Fuel Cost Savings under different fuel price and interconnector scenarios



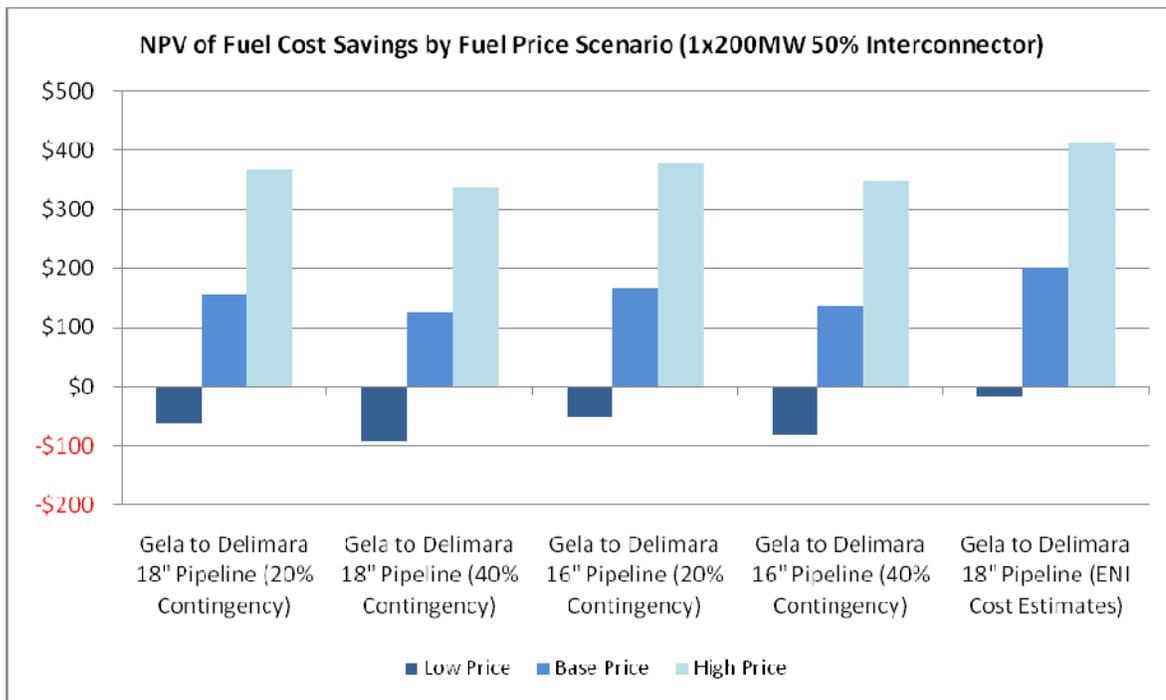
8.7 Impact on the Pipeline Options

The previous chapter set out how the increased capacity of the interconnector may affect the pipeline options. However, since that analysis was done, a number of other changes were made to some of the underlying assumptions and so this section reports the impact that the interconnector will have on the pipeline options, taking all other recent changes also into account.⁷

At interconnector utilisation levels of 50%, all of the pipeline options will continue to offer positive fuel cost savings over not having a gas project, provided prices are in line with baseline figures or higher. At low oil prices, none offer positive fuel cost savings. This result is summarised in the following chart.

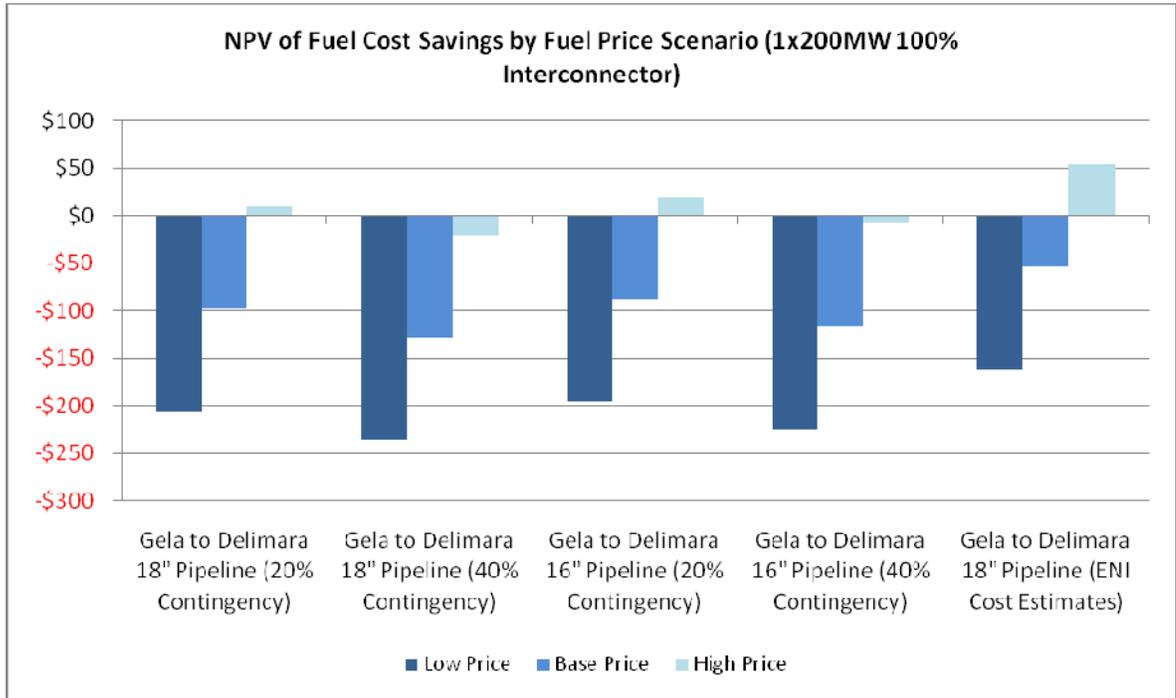
⁷ These changes included: changes to gas demand and other fuel demand projections; changed net present value period from 2012-2030 to 2015-2030 ; and changing the year of discount from 2008 to 2009.

Exhibit 59: NPV of Fuel Cost Savings by Fuel Price Scenario (1x200MW 50% Interconnector)



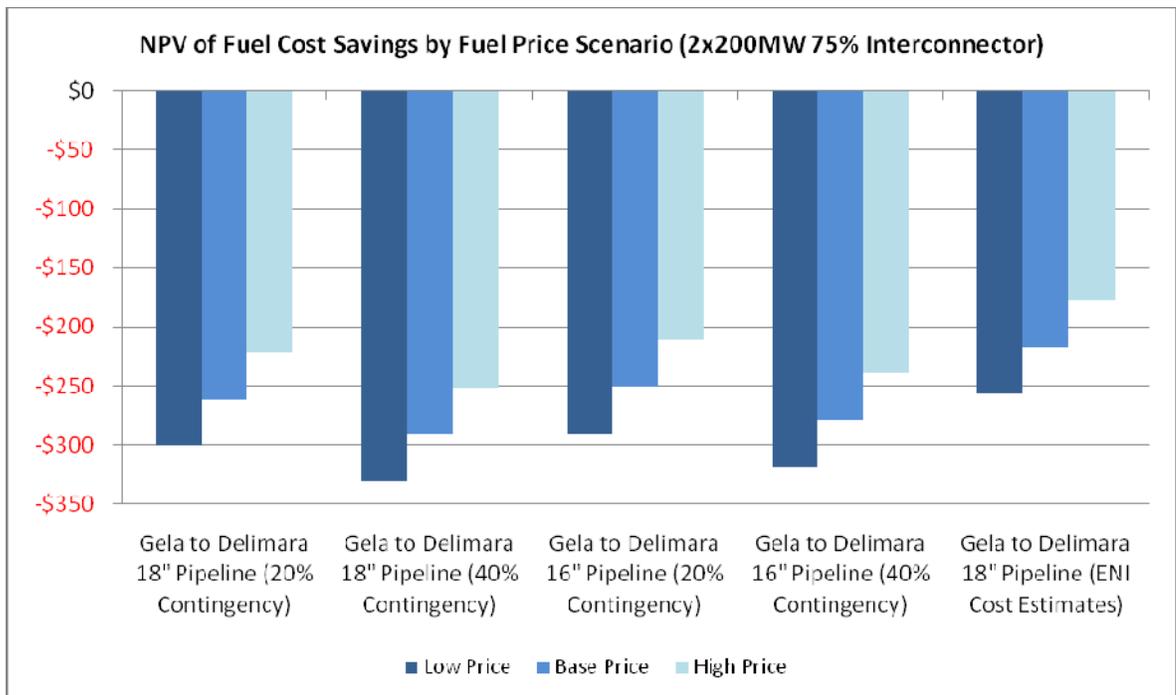
At higher levels of interconnector utilisation, the NPV of the fuel cost savings start to turn negative. At 100% utilisation of the 1 x 200 MW interconnector, the pipeline options would offer cost savings over existing generation methods only in certain circumstances. At low prices, all pipeline options will fail to offer costs savings. These results are summarised in the following chart.

Exhibit 60: NPV of Fuel Cost Savings by Fuel Price Scenario (1x200MW 100% Interconnector)



If the 2 X 200MW interconnector was to be used at a rate of 75% or higher, under no circumstances would the pipeline options offer cost savings, as can be seen in the following chart.

Exhibit 61: NPV of Fuel Cost Savings by Fuel Price Scenario (2x200MW 75% Interconnector)



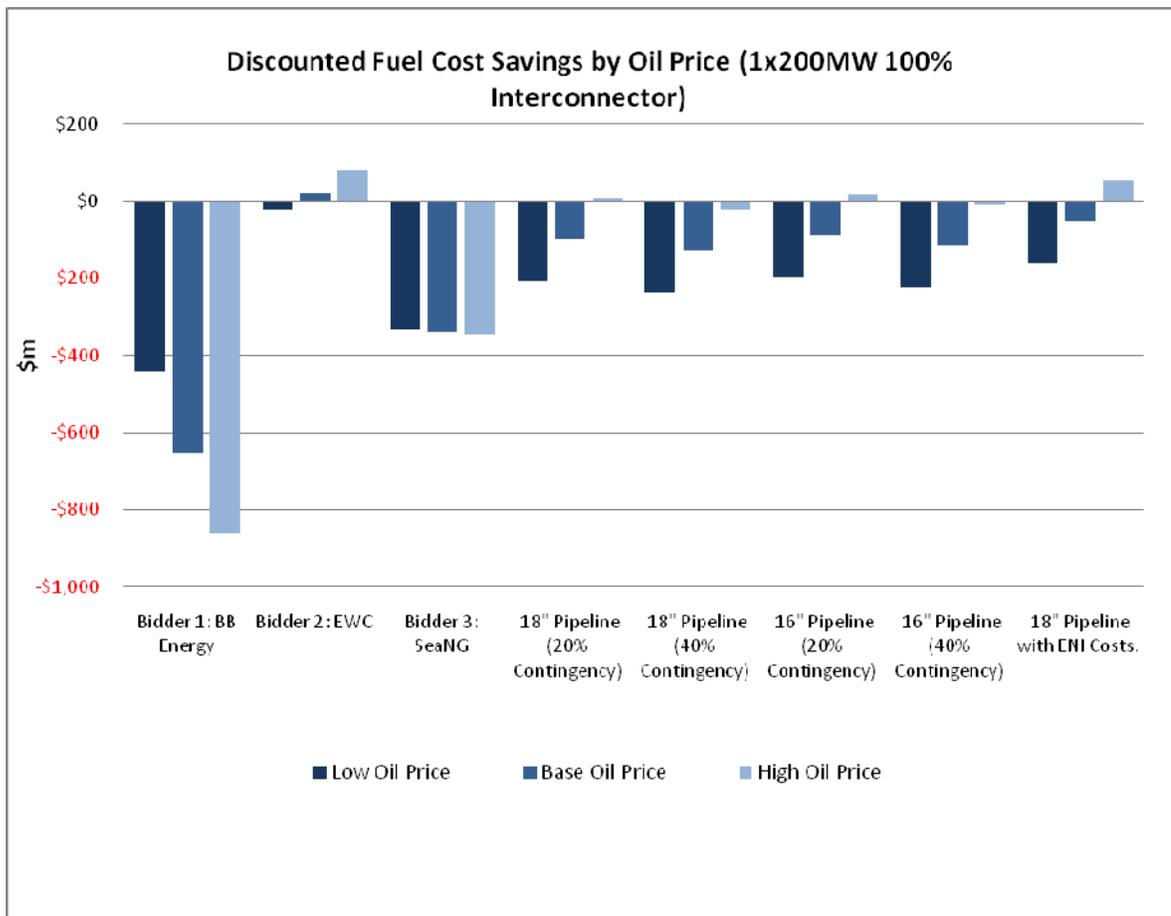
However, this does not imply, nor should it be interpreted to mean, that the most economic option energy delivery option is to construct a second 200MW interconnector. This should be the subject of separate analysis.

8.8 Conclusions

With enhanced interconnector uptake (following the construction of a 1 x 200 MW interconnector) fuel cost savings are still possible against HFO and diesel. The economics are favourable:

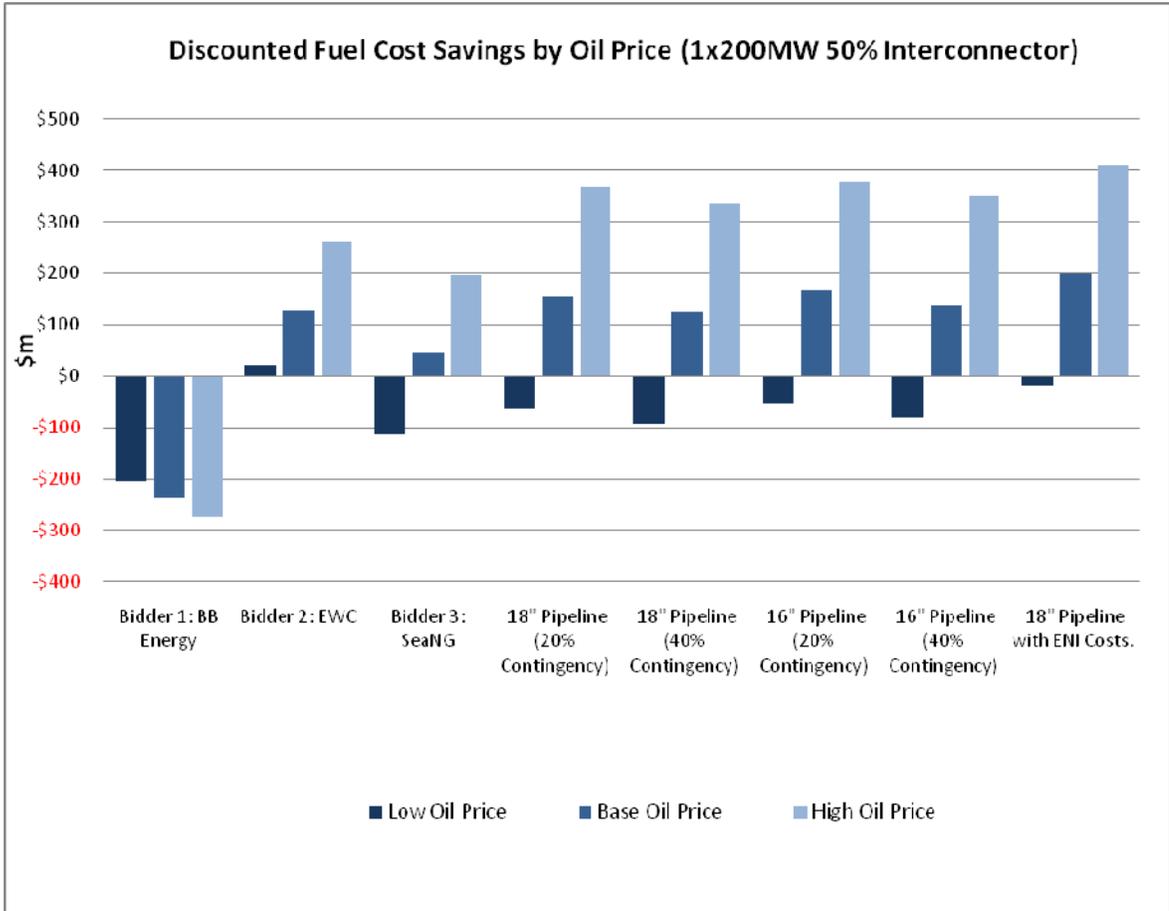
- In the high oil price scenario, for selected pipeline options, with 100% interconnector utilisation;
- In the base oil price scenario, for the 18" (ENI) pipeline option, when interconnector utilisation is less than approximately 86%;
- In the base and high oil price scenario, for all but one gas supply option, with 50%⁸ interconnector utilisation.

Exhibit 62: Discounted Fuel Cost Savings by Oil Price (1x200MW 100% Interconnector)



⁸ For the gas demand forecast for the 1x200MW scenario at 50%, it was assumed that the cable will be operated at 50% until 2021, increasing thereafter to 85% utilization in 2035

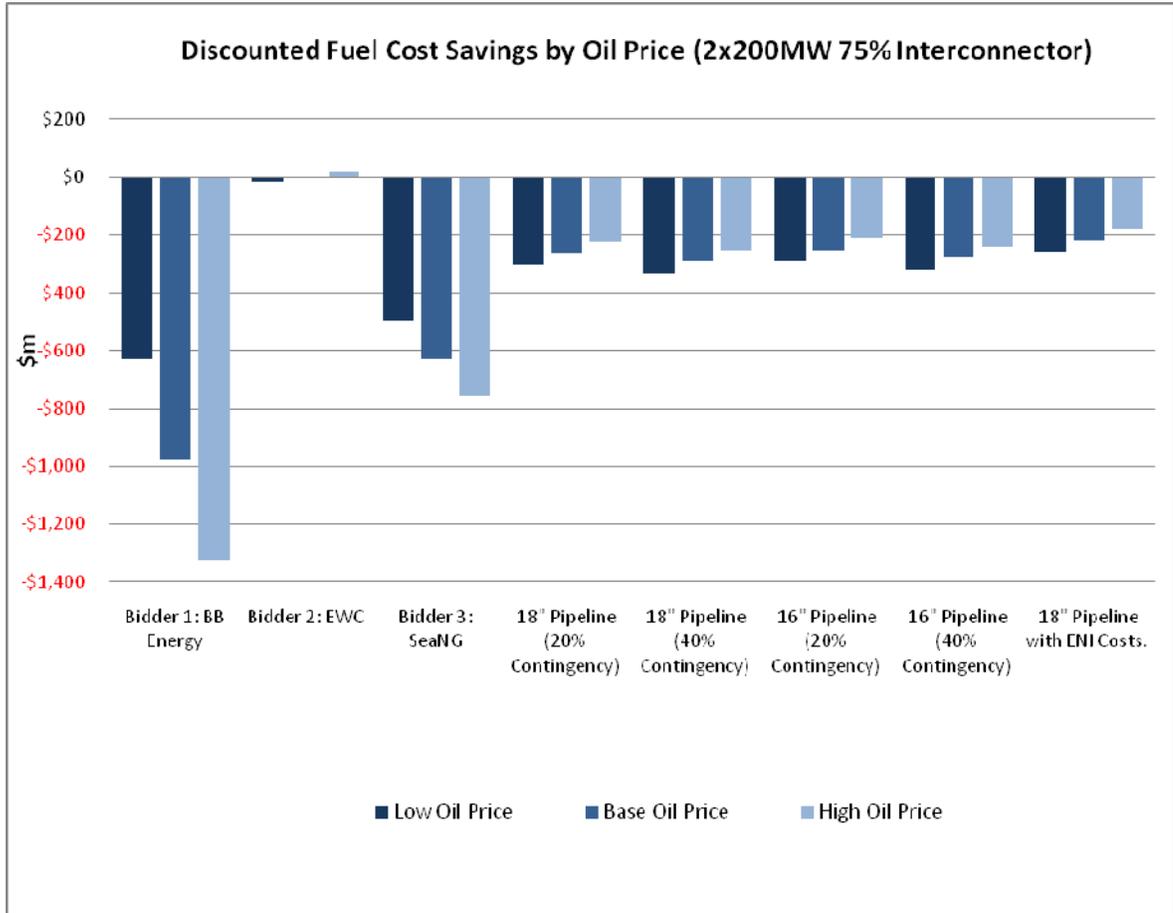
Exhibit 63: Discounted Fuel Cost Savings by Oil Price (1x200MW 50% Interconnector)



At 50% utilisation of the 1 x 200MW interconnector, all of the gas options except the BBE option offer fuel cost savings provided oil prices fall within the baseline range or higher. The best option in terms of fuel cost savings, when the interconnector operates at 200 MW 50% is the pipeline options, as was the case before the interconnector scenarios were introduced. The pipeline option will however only be better than the EWC option provided that the costs of construction are relatively low: either contingency left at 20% or ENI’s cost estimates used.

If the 2 x 200MW interconnector is to operate at 75% of capacity or more, then it is unlikely that any of the gas options would offer many fuel cost saving advantages. However, this does not imply, nor should it be interpreted to mean, that the most economic option is to construct a second 200MW interconnector. This should be the subject of separate analysis.

Exhibit 64: Discounted Fuel Cost Savings by Oil Price (2x200MW 75% Interconnector)



APPENDIX 1: COMPARISON OF LNG AND CNG BIDS

8.9 General

In making an assessment of the bidders at this stage of the process of evaluation it is apposite to take account of the following factors which impinge on the evaluation process, assessment and judgment offered to Enemalta:

- The technical evaluation, clarifications and presentations by bidders are related to conceptual submissions. This means that the level of detail is coarse and not conducive to deep probing wherein many issues may arise from examination of precise details. Hence what may appear a strong preference at this stage of evaluation may still bring a swathe of problems at a later stage of the projects development, although this may occur with any of the bidders.
- Early stage assessments include considerable amounts of uncertainty and ‘fuzziness’ in the evaluations.
- Macro issues from the wider world impinging on the project can soon erode an apparent advantage of one bidder; this includes issues concerning the type of gas (LNG versus CNG) and price/mcm as well as general security of supply issues.

8.10 Comparison of Technical Aspects

8.10.1 BB Energy and Sea NG

Bidders 1 & 3 (BB Energy and SeaNG) have devoted considerable effort to producing well-developed written technical proposals and presentations. Both bidders exhibit strengths in process engineering and marine gas transportation.

Both bidders propose to source gas from the national oil companies of neighbouring North African countries, Sonatrach in Algeria in the case of BB Energy, and NOC in Libya in the case of SeaNG, both of which control huge gas resources. Whereas both bidders claim to have support from their prospective suppliers, this fundamental issue needs further examination to confirm the level of commitment by the gas suppliers to support this project.

It is considered that Bid 1, which proposes supply of LNG, has a number of technical advantages over Bid 3, which proposes to supply CNG. Advantages include the use of commercially proven technology, and in consequence the ability to use internationally recognised design and operating codes covering the ships, gas transfer, plant design and operation. Other advantages include the ability to use the existing berth for unloading, reduced shipping movements and berth occupancy, and the

provision of sufficient on-shore gas storage to ensure continued gas supply over peak periods of demand and to overcome delays in gas delivery. In addition LNG theoretically offers increased security and flexibility in supply, in that there are a number of LNG producers and consumers in the region which could supply or accept gas in the event that supply or demand problems are encountered.

8.10.2 EWC

By comparison, the technical proposal submitted by Bidder 2 (Energy World Corporation) lacked the detail and clarity of the other two bids, and whereas EWC claim to have the technical support of Chart Industries and Tokyo Gas – both respected participants in the LNG business – their proposal lacked input by these partners, and was fairly generic in nature, particularly in the areas of shipping, terminal design and operation.

EWC claim to control substantial, but currently uncertified gas reserves in Sengkang, South Sulawesi, Indonesia, and propose to supply Enemalta from additional liquefaction trains to those currently under construction in Sengkang, at least over the initial years of operation, during which time they have aspirations to develop a similar new modular liquefaction plant in Libya. Development of this new plant in Libya might not proceed, and in view of the distance between supply and destination and uncertainty concerning the corporate structure and financial strength of EWC, Penspen has concerns regarding the long-term security of gas supply.

8.10.3 Summary Spreadsheet

An attempt has been made to rank the bids by considering a number of components in the gas supply chain and how each bid addresses issues relating to a number of perceived areas of potential risk. Appendix A contains a spreadsheet which summarises the technical aspects of the three bids. The consultant has allocated both weightings and scores against each of the main technical analysis headings on the basis of technical experience and the understanding gained of the overall project and Enemalta's requirements and objectives.

Weightings have been assessed in accordance with a split between the groupings of gas supply, transport and re-gasification, with each of these elements being critical to the security of supply. Within these groups engineering experience has been used to allocate final weightings.

Scores have been allocated in a 1-10 range to each of the technical analysis headings, where 1 is least and 10 maximum when the bid is compared to a theoretically fully technically compliant bid. The Technical Evaluation is summarised below:

Exhibit 65: Technical Evaluation

		Bidder 1: BBE	Bidder 2: EWC	Bidder 3: SeaNG
	Weighting	Score	Score	Score
Gas Supply	25%	8	4	8
Gas Processing	7.5%	8	6	8
Shipping	15%	8	3	8
Re-gasification Terminal	45%	7	4	6
Operations	7.5%	8	5	6
Average Score	100%	7.7	4.3	7.0

Source: IPA

It is considered that none of the three bids contain proposals that, from a technical perspective, are totally unacceptable, but instead each presents a different level of project technical risk.

The fundamental questions in carrying out the evaluation are:-

Does the bidder give confidence in his ability to:

- Deliver the project?
- Secure and maintain gas supplies over the long term?
- Mitigate / manage any residual project technical risks?

It is considered that Bid 2, by virtue of its lack of detail and clarity over aspects of the implementation of the project and the bidder's structure, provides least confidence.

Bids 1 and 3 displayed the bidders' high level of technical competence. In addition the bidders have assembled competent project teams.

It is considered that although Bid 3 presents additional project technical risk, the joint venture has the ability to manage those risks.

However Bid 1 (BBE) has security of supply advantages in using proven technology that permits LNG in theory to be sourced from the world market rather than being tied to a single unique supplier of a novel technology as is the case with Bidder 3 (Sea NG).

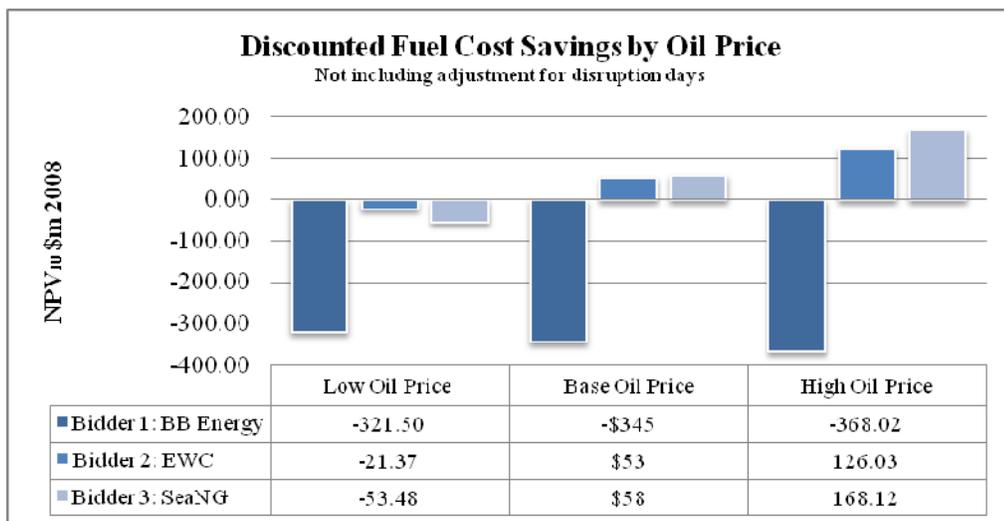
8.11 Comparison of Commercial Aspects

The commercial evaluation is heavily weighted towards securing the maximum possible fuel cost savings for Enemalta, consistent with the original instructions to bidders.

Bidder 1, the BBE consortium, was not competitive with existing fuel generation sources under any oil price scenario. BBE therefore scored very poorly under this criterion.

Bidders 2 and 3, EWC and the SeaNG Consortium, offered delivered gas prices that gave appreciable cost savings for Enemalta under base and high oil price scenarios. These are summarised in the graph below.

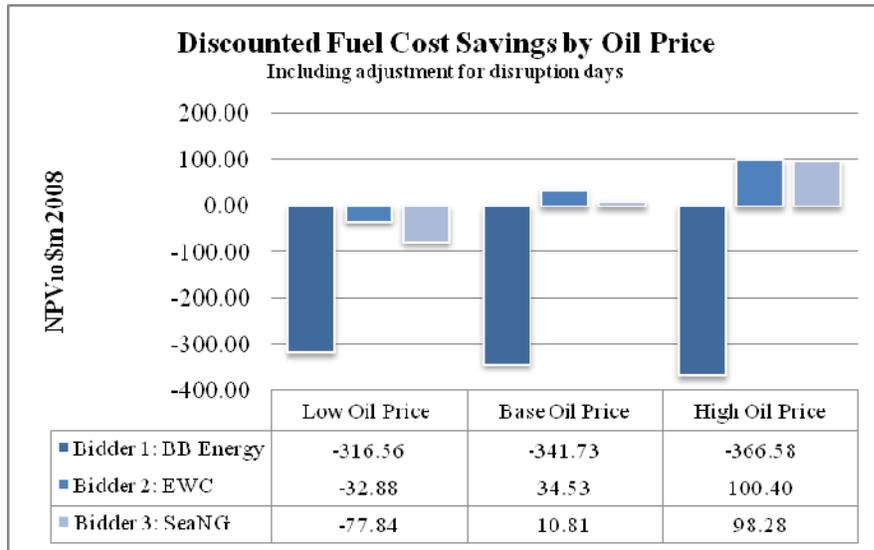
Exhibit 66: Discounted Fuel Cost Savings by Oil Price, not including adjustment for disruption days



Source: IPA

When adjusted for potential weather related supply disruptions (20 days for LNG suppliers and 50 days for CNG supplier), the relative attractiveness of the SeaNG bid reduces, although there are still fuel cost savings in the base and high oil price scenarios.

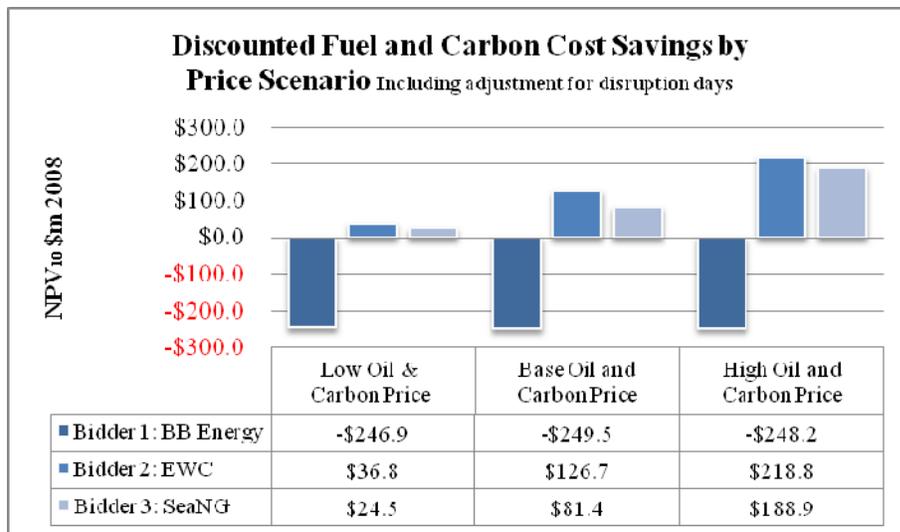
Exhibit 67: Discounted Fuel Cost Savings by Oil Price, inc. adjustment for disruption days



Source: IPA

Factoring in the carbon cost savings from fuel switching to gas, the EWC and SeaNG bids both become cost positive in all price scenarios, but the BB Energy bid remains strongly negative. The EWC bid becomes more attractive than the SeaNG bid in the base scenario, since the SeaNG bid is implicitly incurring 50 days of exposure to gasoil and carbon costs, against 20 days under the LNG based bids.

Exhibit 68: Discounted Fuel and Carbon Cost Savings by price scenario, inc. adjustment for disruption days



Source: IPA

The summary of the other commercial criteria suggested in the evaluation are shown below. Overall, the SeaNG Consortium's bid is the most commercially attractive, despite some weaknesses, including high fixed (transportation) costs and a relatively inflexible Take or Pay (ToP) threshold.

Exhibit 69: Summary Commercial Criteria

		Bidder 1: BBE	Bidder 2: EWC	Bidder 3: Sea NG
	Weights	Score	Score	Score
Sponsor Quality	15%	6	4	7
Concept	10%	8	7	6
Gas Pricing	60%	0	5	6
ToP Conditions	15%	4	8	4
	100%			
Average Score		2.3	5.5	5.9

Source: IPA

The results of this analysis of the NPV for the project show that in the High and the Base oil price scenarios the EWC and SeaNG bid showing a positive return for Enemalta. The BBE bid shows no benefit at all oil price scenarios. With low oil prices conversion to natural gas with these bids is not viable.

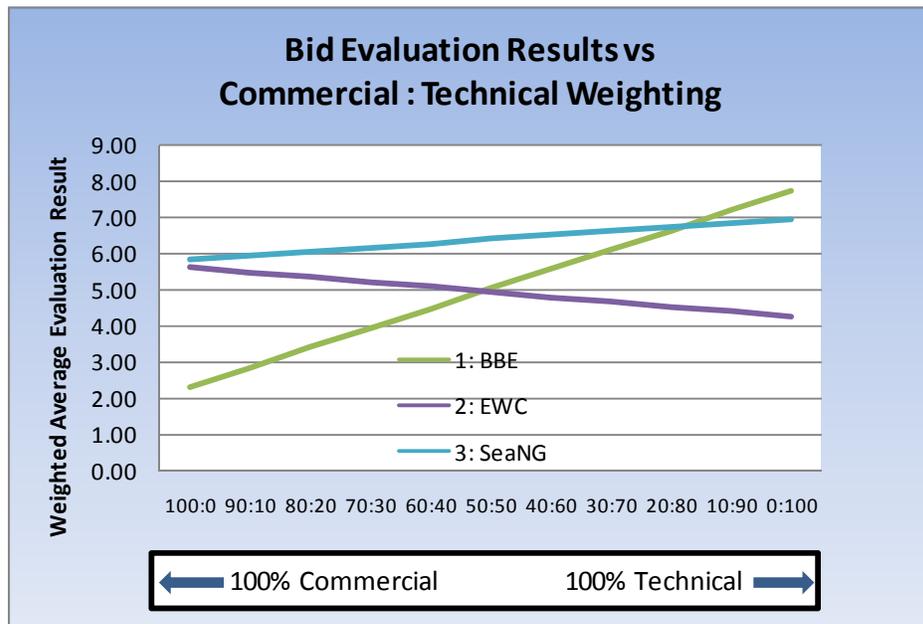
8.12 Overall Evaluation: Commercial/Technical Weighting

Due to bidders 1 and 2's incomplete responses to the Draft Gas Sales Term Sheet, the published evaluation criteria (which allocated 20% of available marks to the materiality of bidder's responses to the Term Sheet) can not be followed as written.

A preferred bidder could instead be chosen on the basis of a weighted average commercial and technical score.

In all but an extreme preference for the technical evaluation over the commercial evaluation would SeaNG fail to be the highest scoring bidder.

Exhibit 70: Commercial/Technical Bid Weightings



Source: IPA

8.13 Recommendations

From a technical point of view it is considered that Bids 1 and 3 are superior to Bid 2. Should EWC's commercial proposal be viewed as particularly attractive, then additional effort could be profitably expended in gaining further clarification, but should this not be the case, then evaluation should focus on the two technically stronger proposals, and Bid 2 should be rejected. Note that introduction of an enhanced Sicily – Malta Interconnector (as described and examined in Section 8 above) reveals that EWC's commercial proposal can be quite attractive in cases where interconnector is utilised at or under 50%.

Bids 1 and 3 are considered to be competent from a technical point of view, with Bid 1 considered to present a lower level of project technical risk, by virtue of using conventional, proven technology.

However, from a commercial perspective, Bid 1 is not attractive. The BBE bid shows no fuel cost saving at any oil price or interconnector utilisation scenarios.

On the basis of the combined commercial and technical scores, it is recommended that the SeaNG Corporation is considered the most favoured of the LNG and CNG bidders.