chapter

8

Economic Modelling for LNG, Gas-to-Liquids, Coal-to Liquids and Sales Gas Plants

8.1 Introduction

As part of the Roundtable initiative DMITRE engaged Core Energy to prepare the dynamic financial analysis models relating to four gas commercialisation options for gas from basins in South Australia. The options include:

- Liquefied Natural Gas (LNG);
- Gas to Liquids (GTL);
- Natural and synthetic gas for power generation; and
- Natural gas for sale to traditional gas markets.

The intent of the initiative is for DMITRE to gain perspective on the volumes of gas and price required to underpin each option.

A simplified version of the model, that excludes access to certain assumptions, will be made available to the Roundtable to enable participants to undertake economic assessments of proposed projects. The models have been peer reviewed by both Santos Ltd and Beach Energy Ltd.

This chapter summarises the structure, capabilities and assumptions of the model. Results for model scenarios are also included to provide perspective on gas quantities and costs associated with unconventional resource development for LNG or GTL purposes.

8.2 Description

8.2.1 Commercialisation Plans

The model is Microsoft Excel based and allows the user to determine the key outputs, noted in Section 8.2.2, for each commercialisation plan. Figures 8.1 and 8.2 show the commercialisation plans for gas feed into an LNG export facility and a GTL facility respectively. Assumptions used in the development for each commercialisation plan are explained in Sections 8.2.3 and 8.2.4.

8.2.2 Key Outputs

The model allows the user to identify key variables that help determine the financial viability of the proposed project. The key outputs calculated by the model are:

- Gas price required to underpin field development, based on an assumed resource volume, on a no-profit and profit basis (based on an assumed rate of return);
- Resource volume required to underpin field development, based on an assumed gas price, on a no-profit and profit basis;
- Required project capital expenditure; and
- Project Net Present Value (NPV) based on assumed gas price.

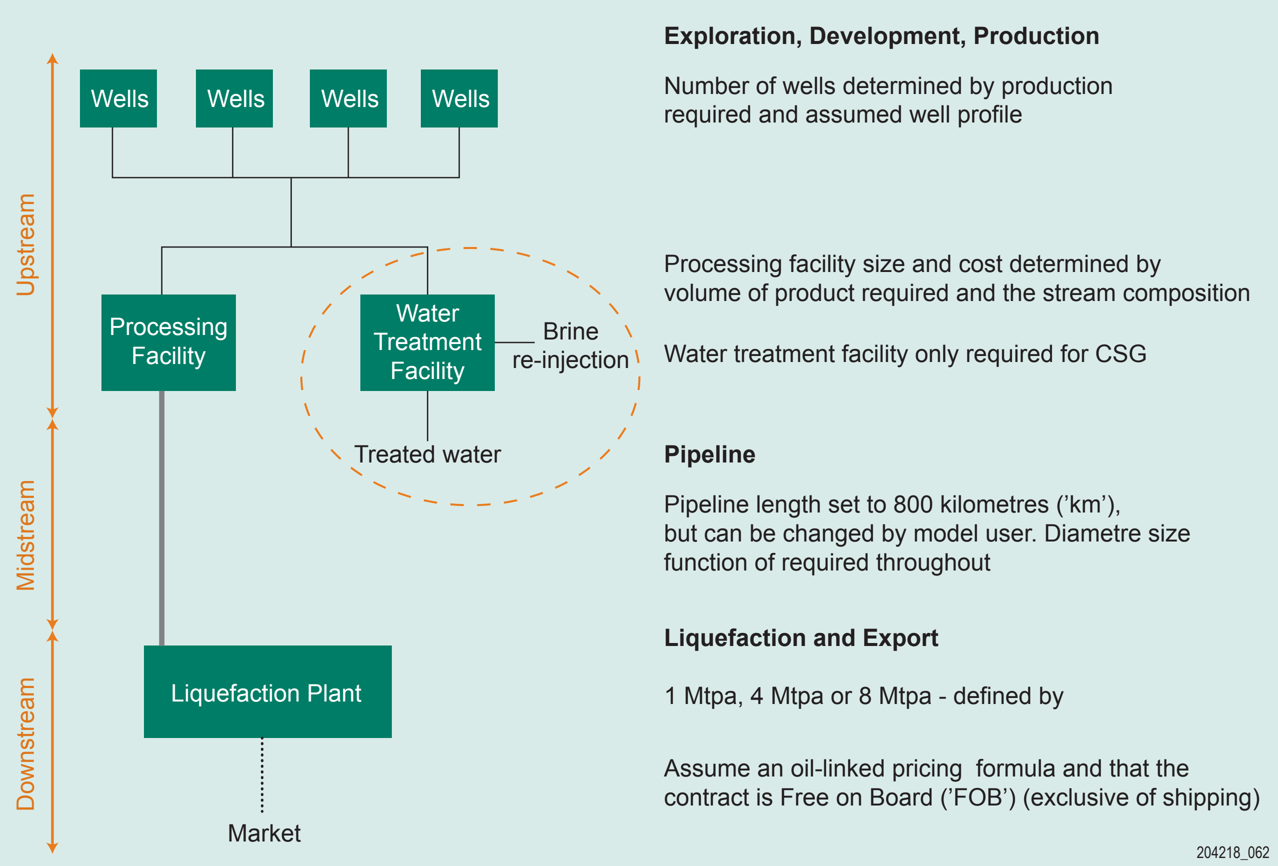

Figure 8.1 *Commercialisation Plan – LNG (source: Core Energy Group, 2011[1])*

8.2.3 Economic Assumptions

8.2.3.1 State Royalty Regime

Royalties in South Australia, similarly to other states, are determined under the wellhead royalty regime, based on a percentage of the wellhead value.

The wellhead value is derived by taking the gross value of petroleum recovered and deducting all costs incurred between a defined valve on the wellhead and the point of sale over a certain period.

There are three types of costs allowed to be deducted against the gross value to determine wellhead value:

- Post-wellhead operating costs;
- Depreciation on commissioned post-wellhead assets; and
- Cost of borrowing on commissioned post-wellhead assets (limited to a gearing allowance).

In South Australia, the royalty rate is 10 percent of wellhead value. The model assumes that this rate applies to the quantity of gas feed dedicated to the downstream process, at an assumed domestic gas price (rather than the ultimately realised price).

As discussed in Section 8.2.3.2, the Federal Government has proposed to change the current tax regime for onshore petroleum projects; however the proposed changes are additional to state royalties and thus will not affect net royalty.

8.2.3.2 Company Tax

The model assumes a 30 percent income tax rate on the taxable profits of production. This is in line with the Australian corporate tax rate. It should be noted that the Government has proposed to change the system by which petroleum projects are taxed, key points are summarised:

1 Core Energy Group Pty Ltd, (November 2011), Gas Commercialisation Options. Prepared for the Department of Primary Industries and Resources SA (unpublished).

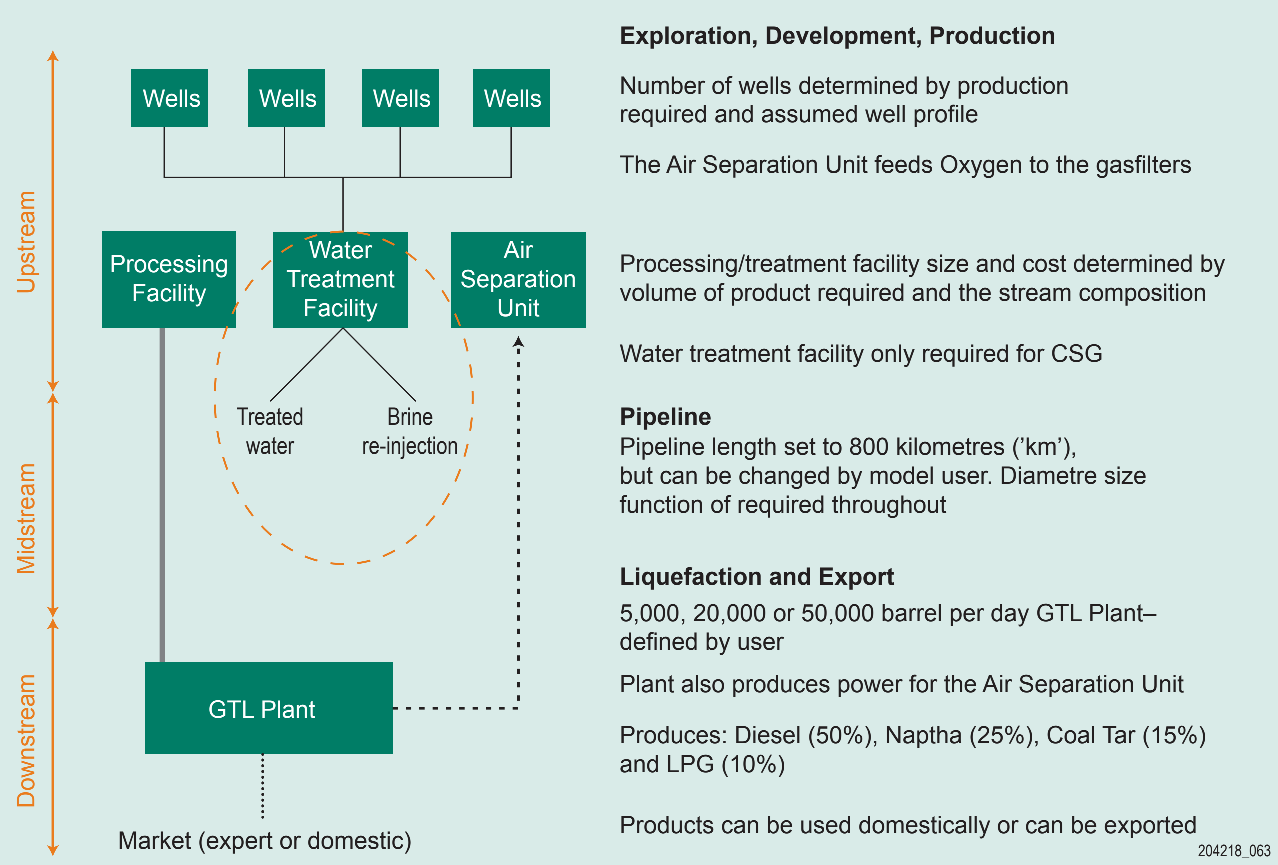

Figure 8.2 *Commercialisation Plan – GTL (source: Core Energy Group, 2011[1])*

- The report on Australia's Future Tax System, the Henry Review, was released on 2 May 2010.
- One of the most significant recommendations adopted by the Government was a change to the taxation of resource projects. Initially the government introduced the Resources Super Profit Tax (RSPT) which was to be introduced from 1 July 2012 at a rate of 40 percent on Australia's non-renewable resources.
- The change of leadership in the Labor Party in June 2010 resulted in a change to the proposed tax, now known as the Minerals Resource Rent Tax (MRRT).
- The MRRT proposal includes the extension of Petroleum Resource Rent Tax (PRRT) to cover all oil, gas and coal seam methane projects, offshore and onshore, including the North West Shelf, which was previously exempt.
- Iron ore and coal would be subject to the MRRT which would be at a rate of 30 percent.
- The government has proposed that the new tax system be implemented from 1 July 2012.

The model includes the options of both onshore PRRT and MRRT within the model. At present all models are set with an opening PRRT and MRRT value of zero. This will be a consideration for the user of the model.

The model assumes that the PRRT regime applies from 1 July 2012 with the onshore PRRT regime set at a rate of 40 percent with features consistent with the offshore PRRT regime. Some general features of the onshore PRRT provisions are:

- Carried forward general project expenditure is augmented at the Long Term Bond Rate (LTBR) plus 5 percent;
- Carried Forward Exploration expenditure is augmented at LTBR plus 15 percent;
- PRRT is deductible for income tax purposes;
- Companies will receive a credit for state royalties paid with unused credits

for royalties paid being uplifted at PRRT augmentation rates (refer above);

- Project operators may elect to use market value, book value or a look-back method to determine the starting base for a project at 1 May 2010; and
- Eligible capital expenditure between May 2010 and July 2012 is added to the starting base and deducted accordingly.

Additionally, the model assumes the economic life of assets for tax depreciation purposes based on Australian Tax Office determinations.

8.2.3.3 Inflation

The model uses inflation targets and historical inflation rate data published by the Reserve Bank of Australia as the basis for the determination of inflation rate assumptions. Over the past two years, average annualised Consumer Price Index (CPI) has been approximately 2.5 percent. Additionally, the Governor of the Reserve Bank and the Federal Treasurer have agreed that the appropriate target for monetary policy in Australia is to achieve an inflation rate of 2–3 percent, on average, over the cycle. Accordingly, a forward inflation rate of 2.5 percent per annum has been used within the assumptions.

8.2.3.4 Australian Dollar Exchange Rate

The assumed forward exchange rate is based on the forward curve as sourced from Bloomberg in October 2011. The long-term rate is assumed to be equal to the rate in 2020.

8.2.3.5 Commodity Prices

- In the model, commodity prices are used to give rise to project revenue (depending on the stream composition assumptions). Crude oil, LPG and condensate forward pricing is based on forward curve for Brent as at 20 October 2011. Domestic gas price is based on Core's analysis of the Australian domestic gas market. The LNG price is linked to the Brent price as noted below.

LNG pricing under long-term contracts in Asian markets has historically taken the form of an "S-curve" based on a formula:

P(LNG) = ax + b, (USD per MMBtu), where

a =	the slope of the price curve (includes the unit conversion rate of USD per barrel to USD to MMBtu)
x =	Japanese Customs Cleared Crude / Japanese Crude Cocktail (JCC) oil price, which is the average cost value of all oil imported to Japan in a specified trading period, based on statistics maintained by the Japanese Ministry of Finance (units given as USD per bbl)
b =	constant

The values of "a" and "b" are negotiated individually in each contract.

Analysis of recent contracts has seen a movement towards a price of 0.14 x JCC (or 11.20 per MMBtu at a JCC price of USD80 per barrel). Assumptions for LNG pricing have been included summarised in Table 8.1.

Important to note that both the USA and Canada are now planning export of substantially lower cost LNG into Asia, Australia's major market. If gas prices for LNG in the USA are linked to New York Mercantile Exchange (NYMEX) Henry Hub gas futures rather than crude oil prices, competition from the USA in Australian LNG markets would increase even further.

8.2.3.6 Carbon price

With the passing of Australia's Carbon legislation through both the House of Representatives (October 2011) and the Senate (November 2011) as of 1 July 2012 Australia's 500 worst polluting companies will be required to pay a cost for their carbon emissions. Consequently the model includes both the upstream and downstream impacts of this legislation on each of the commercialisation options. The carbon rate assumptions are based on:

Table 8.1 *LNG pricing assumptions (source: Core Energy Group, 2011[1])*

Assumption	Data	Source
Formula	P(LNG) = ax + b	▪ Core analysis of LNG pricing formulas.
		▪ Industry accepted formula.
		▪ Public source document: Eng, G; A Formula for LNG Pricing – A Report Prepared for the Ministry of Economic Development; 16 June 2006.
Slope (“a”)	0.14	▪ Based on Core analysis of recent pricing trends.
Constant (“b”)	0	▪ Based on Core analysis of recent pricing trends.
JCC Price (“x”)	Calculated	▪ The JCC price has been calculated based on a 1 percent discount to the Brent price (see Tables 4.2 and 4.3 for further information on Brent price assumptions.
		▪ The 1 percent discount is based on Core analysis of recent historical average of JCC pricing as a function of JCC pricing per Barrel

- An initial fixed period at AUD 23 per tonne Carbon Price fixed for the first 3 years with escalation; and
- A stepped changed to the assumed long term carbon price of AUD 35 per tonne.

8.2.3.7 Weighted Average Cost of Capital (WACC)

Each of the model scenarios works on either a Profit or No-Profit basis. Under a profit basis, the discount rate (WACC) is used to equate the future cash flows to their present value reflecting the risk-adjusted rate of return demanded by a hypothetical investor for the asset being valued. Under a No-Profit basis the breakeven gas price is calculated.

For ungeared cash flows, discount rates are determined based on the cost of an entity’s debt and equity weighted by the proportion of debt and equity used. This is commonly referred to as the WACC.

WACC=(E/V * Ke)+(D/V * Kd(1-tc)), where

Ke = cost of equity

Kd = cost of debt

tc = corporate tax rate

E/V = proportion of enterprise funded by equity

D/V = proportion of enterprise funded by debt

“Ke” is the rate of return that investors require to make an equity investment. The Capital Asset Pricing Model (CAPM) is used to estimate Ke for a hypothetical investor. CAPM calculates the minimum rate of return that the company must earn on the equity-financed portion of its capital to leave the market price of its shares unchanged. The CAPM is the most widely accepted and used methodology for determining the cost of equity capital.

Under the CAPM, Ke is determined using the following formula:

Ke = R f+ β(Rm−Rf) + a, where

Rf = the risk-free rate of return

Rm = the expected return on the market portfolio

Rf - Rm = equity market risk premium (EMRP)

a = the specific company risk premium

β = the systematic risk of a stock

The risk free rate (Rf) compensates the investor for the time value of money and the expected inflation rate over the investment period. The frequently adopted proxy for Rf is the long-term (10 year) government bond rate which is widely used and accepted benchmark for the risk-free rate in Australia.

The EMRP represents the risk associated with holding a market portfolio of investments, that is, the excess return a shareholder can expect to receive for the uncertainty of investing in equities as opposed to investing in a risk-free alternative. The EMRP is not readily observable in the market and therefore represents an estimate based on available data. Australian studies on the historical risk premium approach generally indicate that the EMRP would be in the range of 5 percent to 8 percent. In recent years it has been common market practice in Australia in expert's reports and regulatory decisions to adopt an EMRP of 6 percent.

8.2.3.8 Sunk costs

Sunk costs refer to costs associated with the project that have already been incurred prior to the valuation start date. The model assumes sunk cots to be zero as the model considers hypothetical large scale projects may occur in the future.

8.2.4 Upstream and Downstream Assumptions

The model considers the following upstream and downstream costing assumptions, which are based on data published by industry. The model does contain the ability to override these assumptions for manual input. Due to the intellectual property associated with these assumptions, values used within the models have not been published in this report, however, sections 8.2.4.1 to 8.2.4.3 provide a list of the assumptions.

8.2.4.1 Upstream

The assumptions for the upstream portion of the model are noted below. The values for conventional and tight reservoirs were based on historical data sourced from the Cooper Basin; CSG and shale development was based on national and international experience. Upstream variables considered for the purposes of model development are listed below.

- Well decline rate
- Initial well production rate
- Gas composition
- Well hyperbolic exponent
- Well costs
- Facility and gathering systems operating and capital expenditure
- Carbon emissions and water treatment
- For GTL projects underpinned by syngas feedstock, the model only considers syngas production through the UCG process.

8.2.4.2 Mid-stream and Downstream

Downstream assumptions, listed in Table 8.2, consider LNG and GTL plant capital and operating costs and performance parameters. Values used for these assumptions are based on publically available information provided for upcoming and existing developments in Australia and overseas. Downstream variables considered for the purposes of LNG development are noted below. For the purposes of displaying results in Section 8.3, the midstream (transmission) portion of the project is included within the "downstream" costs.

8.3 Results

Based on the development plan and assumptions outlined in Section 8.2 the model was used to produce breakeven gas price and volume of gas reserves required to underpin development for projects outlined below. A sensitivity analysis was also performed to show effect of key variables on project feasibility.

8.3.1 LNG Export

Assumptions used in the analysis are shown below in Table 8.3, Tables 8.4 and 8.5 summarise breakeven and profit based results respectively.

8.3.1.1 Price Impacts

Using results shown in Section 8.3.1, Table 8.6 summarises the price effects associated with LNG export development underpinned by unconventional gas feedstock. The table shows that the LNG netback price is approximately AUD 8.50 per GJ, which will put upwards pressure on domestic eastern Australian gas prices, which is currently approximately AUD 4 to AUD 6 per GJ.

Increasing supply side competition through appropriate policy implementation, as discussed in Chapter 7 (Key Investment Settings), is the most effective government tool to ease price domestic price pressures.

Table 8.2 Midstream and Downstream Assumptions (source: Core Energy Group, 2011[1]).

LNG	GTL	Transmission (Mid-stream)
Plant capacity	Plant Capacity	Fixed Operating Expenditure
Production year commencement	Production Commencement Year	Variable Operating Expenditure
Project economic life	Project Economic Life	Midstream Abandonment Costs
Construction period	Construction Period	Pipeline SIB Capital Expenditure
Plant gas losses	Plant Gas Losses	Pipeline Diameter
Capital expenditure	Capital Expenditure	Pipeline Capital Expenditure
Operating expenditure	Operating Expenditure	Pipeline Length
Abandonment costs	Abandonment Cost	Transmission Losses
Carbon emissions	Carbon Emissions	
Phasing – capital expenditure across years of construction	Phasing – capital expenditure across years of construction	
Contract period		

Table 8.3 Assumptions used in LNG analysis (source: Core Energy Group, 2011[1]).

Category	Assumption
Valuation Start Date	01/01/2012
Scenario Selection	4 Mtpa
Production Commencement	31/12/2020
Project Economic life	30 years
Plateau / contract period	20 years
Costing Basis	Profit Basis
Rate of Return	10 percent
Dry Gas Content	100 percent
LNG sales price	AUD14 per GJ

Table 8.4: Results for breakeven analysis – LNG (source: Core Energy Group, 2011[1]).

Component	Units	Type Curve B Range	
Required Reserves	PJ	5120	5742
Breakeven Gas Price	AUD per GJ - 2011	9.82	13.2
Downstream	AUD per GJ - 2011	5.3	5.51
Upstream	AUD per GJ - 2011	4.93	7.84
Operating Expenditure and Abandonment	AUD per GJ - 2011	-2.28	-2.45
Downstream	AUD per GJ - 2011	-0.8	-0.8
Upstream	AUD per GJ - 2011	-1.48	-1.86
Capital Expenditure	AUD per GJ - 2011	-5.96	-8.47
Downstream	AUD per GJ - 2011	-3.7	-3.85
Upstream	AUD per GJ - 2011	-2.26	-4.62
Royalties	AUD per GJ - 2011	-0.33	-0.68
Tax	AUD per GJ - 2011	-1.25	-1.61
Downstream	AUD per GJ - 2011	-0.81	-0.84
Upstream	AUD per GJ - 2011	-0.44	-0.79

Table 8.5 *Results for profit based analysis – LNG (source: Core Energy Group, 2011[1]).*

Component	Units	Type Curve B Range	
IRR - Nominal	%	10.10	13.60
Downstream	%	10	13.20
Upstream	%	10.40	14.70
Total Project Profile			
NPV	AUDm	186	3276
NPV of projected royalties	AUDm	674	695

Table 8.6 *Price impact summary.*

	Gas price (AUD/GJ)
Existing long term domestic contracts (including transmission tariffs)	4.50
Recent domestic contracts (including transmission tariffs)	6.50 – 7.00
LNG breakeven price for unconventional development (downstream and upstream)	9.82 to 13.20
LNG sales price	14
Upstream unconventional development	4.93 to 7.84
Downstream development	5.30 to 5.50

8.3.1.2 Sensitivities

Figures 8.3 – 8.5 display the sensitivities for the four different gas supply plays to LNG scenarios.

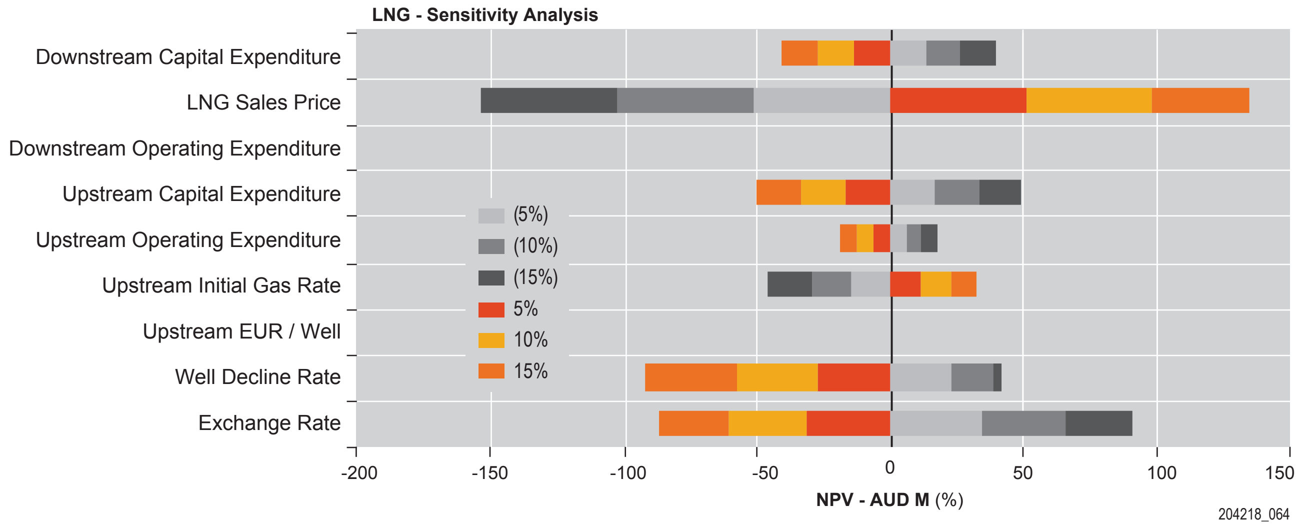

Figure 8.3 *Shale gas to LNG development - tornado chart (source: Core Energy Group, 2011[1]).*

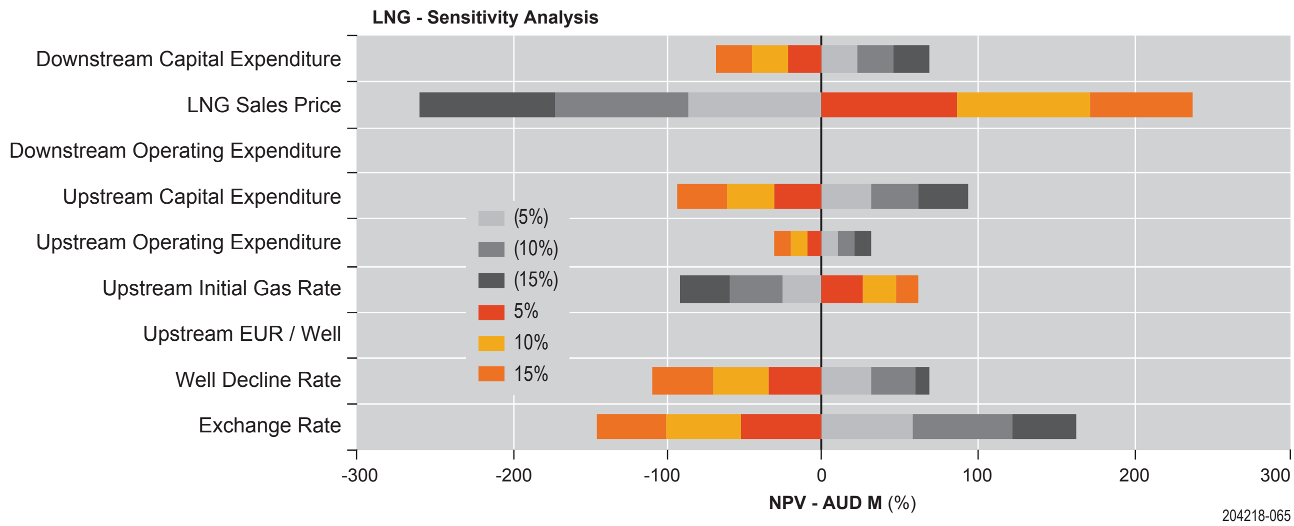

Figure 8.4 *Tight gas to LNG development - tornado chart (source: Core Energy Group, 2011[1]).*

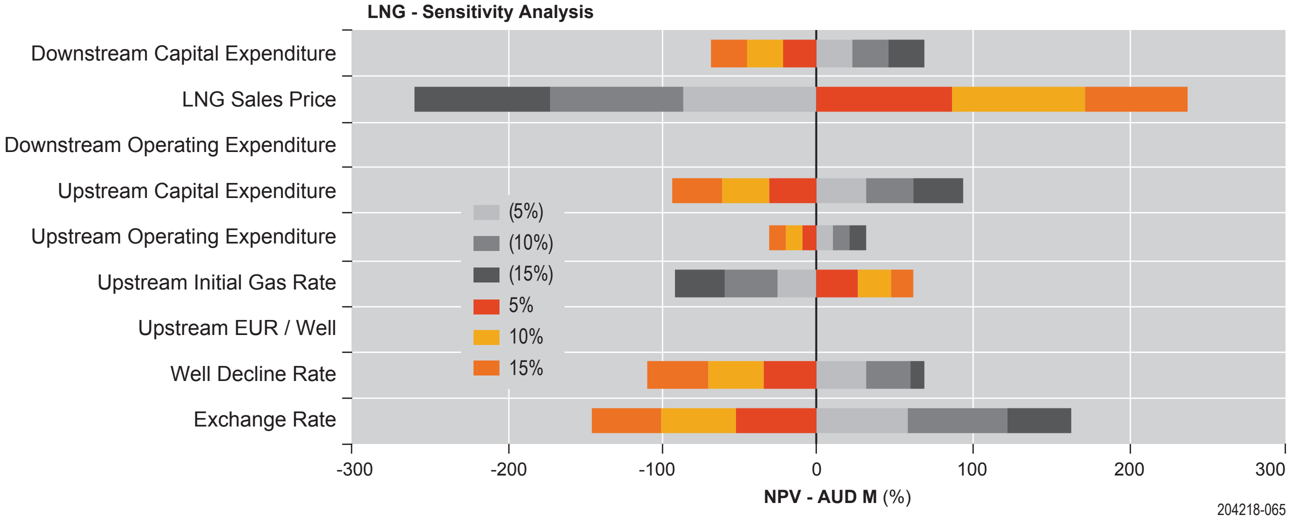

Figure 8.5 *CSG to LNG development - tornado chart (Source: Core Energy Group, 2011[1]).*

On the basis of the "tornado" figures displayed above, the following conclusions can be determined:

- LNG sales price and the exchange rate are the most sensitive variables.
- The well decline rate is a highly sensitive variable for shale plays due to the steep decline rates encountered in the United States.
- Downstream expenditure as well as the liquids content of the gas can make substantial difference to the feasibility of the project. This is discussed further below.
- In relation to shale development, the uncertainty associated with the upstream assumptions is considerable due to the infancy of the shale industry in Australia, project NPV for shale development can vary considerably with upstream capital expenditure, predominantly associated with well costs.

Further to above, NPV is sensitive to gas composition (hydrocarbon liquids content), where incremental changes in liquids content will have considerable impact on project NPV.

Table 8.7 shows the effects of sharing infrastructure on the NPV of a shale to LNG project. The table shows that downstream costs are reduced from AUD 5.35 per GJ to AUD 4.29 per GJ for an 8Mtpa project over 4MPta project. This example demonstrates that two parties engaging in a downstream Joint Venture (JV) arrangement for one single 8Mtpa LNG plant stand to gain significant benefits in comparison to investment in two separate 4 Mtpa LNG Plants.

8.3.2 Gas to Liquids

Assumptions used in the analysis are shown below in Table 8.8; Tables 8.9 and 8.10 summarise breakeven and profit based results respectively.

Table 8.7 *Impact of sharing infrastructure.*

	Breakeven price (AUD per GJ)	**Project NPV** (AUD m)
4Mtpa Plant and feed in transmission	13.20 (downstream 5.36)	186
8Mtpa Plant and feed in transmission	12.13 (downstream 4.29)	2,522

Table 8.8 *Assumptions used in analysis – GTL (Source: Core Energy Group, 2011[1]).*

Category	Assumption
Valuation Start Date	01/01/2012
Scenario Selection	50,000 barrels per day
Production Commencement	31/12/2020
Project Economic life	20 years
Gas type	Natural/synthetic
Costing Basis	Profit Basis
Rate of Return	10 percent
Dry Gas Content	100 percent

Table 8.9 *Results for breakeven analysis – GTL (Source: Core Energy Group, 2011[1])*

Component	Units	Type Curve B Natural Gas (unconventional – range)		Syngas
Required Reserves	PJ	4159	4165	4083
Breakeven Gas Price	**AUD per GJ - 2011**	**15.43**	**20.97**	**13.80**
Downstream	AUD per GJ - 2011	7.35	6.37	5.35
Upstream	AUD per GJ - 2011	5.08	14.60	8.45
Operating Expenditure and Abandonment	AUD per GJ - 2011	-3.32	-3.32	-3.46
Downstream	AUD per GJ - 2011	-1.28	-1.28	-1.28
Upstream	AUD per GJ - 2011	-2.04	-2.04	-2.18
Capital Expenditure	AUD per GJ - 2011	-8.81	--13.79	-8.58
Downstream	AUD per GJ - 2011	-4.24	-4.23	-3.38
Upstream	AUD per GJ - 2011	-4.57	-9.55	-5.19
Royalties	AUD per GJ - 2011	-.61	-1.31	-0.20
Tax	AUD per GJ - 2011	-2.0	-2.40	-1.56
Downstream	AUD per GJ - 2011	-1.14	-0.86	-0.69
Upstream	AUD per GJ - 2011	-.86	-1.54	-0.87

Table 8.10 *Results - profit based analysis – GTL (Source: Core Energy Group, 2011[1])*

Component	Units	Type Curve B		
		Natural Gas (Unconventional - Range)		Syngas
IRR - Nominal	**%**	**12.6**	**6.4**	**13.1**
Downstream	%	15.8	4.1	13.1
Upstream	%	7.5	8.5	13.1
Total Project Profile				
NPV	**AUDm**	**1135**	**-1,374**	**1,195**
NPV of projected royalties	AUDm	247	277	73

8.3.2.1 Discussion

Tables 8.8 through to 8.10 above show that natural gas to liquids projects are less profitable than equivalent LNG projects. The key reason for this is the relatively high parasitic losses and low energy efficiency of the Fischer Tropsch (F-T) Process, which leads to increased upstream CAPEX due to the increased raw gas feed requirement.

Tables 8.9 and 8.10 also outline results for coal to synthetic fuel (synfuel) development, where synthetic gas or syngas (mixture of carbon monoxide and hydrogen) is converted into methane and then synfuel through the F-T process. The example noted above demonstrates that synfuel production yields a positive project NPV at predicted oil prices.

Whilst the results noted above are a useful example to demonstrate costs and reserves associated with GTL production, it is important to note that these results are based on costing assumptions sourced from international projects and may not necessarily accurately reflect cash flows associated with project currently proposed in South Australia.