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East Coast North Island

Oil Resource Play - Development Scenario Models

Final Report

Version with Confidential and Commercially Sensitive Material Removed

Report prepared by Michael Adams of Michael Adams Reservoir Engineering Ltd for the Ministry of Business Innovation and Employment.

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1. Summary & Conclusions

The main conclusions and results of this work are:

a. A series of Development Scenario models have been constructed and used to assess the potential production and associated cash-flows. These include expenditures, revenues, royalties and taxes associated with the notional development of currently undiscovered oil volumes that may be present within the Resource Play type Waipawa and Whangaii formations in the East Coast region of the North Island of New Zealand.

b. These Development Scenario models have to be used to:

   i. Identify approximate commercial oil resource play thresholds for recoveries per well in the East Coast region.
   ii. Estimate project cash-flows and revenues, including to the field owners and taxes and royalties to the Crown.

c. The Development Scenario models constructed for each scenario include forecasts of all product streams (i.e. oil, gas, and water), exploration and development capital expenditure (CAPEX), fixed and variable operating costs (OPEX), project administration, abandonment, royalties and taxes. The technical basis for these forecasts is documented.

d. Exploration and appraisal wells may successfully test oil from the target Waipawa and Whangai Formations. But this is unlikely to be commercially viable unless recoveries per well can exceed 0.45 million BOE (barrels of oil equivalent), which is the recovery per well estimated using models based on the Whangai/Waipawa formation parameters. This means that the commercial threshold for the onshore East Coast oil resource play requires per well recoveries in the order of 0.45 million barrels of oil equivalent and sufficient play area to allow per unit development costs to be reduced by application to a substantial area.

e. The smallest commercially viable scenario (i.e. Scenario 3) modelled covers an area of 95 km^2 with 30 wells distributed over 5 well sites of 6 wells each. This particular scenario recovers 14 mmstb of oil over 11 years and spends approximately NZ$150 to 200 million per annum in capital and operating costs.

   This scenario only just passes the oil industry's typical investment hurdle of a VIR (Value Investment Ratio) better than 0.5, having a VIR of 0.53, despite generating approximately NZ$165 million in NPV (Net-Present-Value at 20% Discount rate) profit. This low VIR is due to the high capital investment required, peaking at a cumulative capital investment (depreciated) of NZ$340 million.

f. A number of additional scenarios have been modelled to investigate the effect of a greater degree of both well recoveries and of success in multiple permits and areas. These scenarios can be considered of lower probability, and in the case of the largest development model made (Scenario 5B), as a very low probability end-member in the case of an extreme level of success. The following table summarises the development scenarios modelled.

Table 1 Summary of the Development Scenarios as Modelled

#	Scenario	Area (km2)	Description
1	Exploration not Successful	NA	Planned 4 well Apache/Tag campaign is unsuccessful and discourage further exploration by any party. 4 Expl. Wells. **Not modelled further.**
2	Limited Exploration success but sub-commercial results	NA	Planned 4 well Apache/Tag campaign is partially successful and further exploration (including other parties) continues but no commercial production results. 12 Expl. Wells**. Not modelled further.**
3	Limited success and commercially viable production.	100	Recovery of 0.45 million BOE per well. 6 Expl. & Appraisal & 30 production wells drilled 2015 through 2020 from
3A	3 of Scenario 3 with maximum of NZ$1 billion CAPEX spend per annum.	300	Assumes limited success in 3 different areas of the East Coast. Development proceeds in the first area the others follow at 5 year intervals at a maximum spend rate of NZ$1 billion per annum. 6 Expl. & Appraisal & 3 x 30 production wells drilled 2015 through 2025.
4	Intermediate exploration success and average N. American shale oil yields.	260	Recovery of 0.55 million BOE per well. 10 Expl. & Appraisal & 600 production wells drilled 2017 through 2030 from 50 sites.
4A	3 of Scenario 4 with maximum of NZ$1 billion CAPEX spend per annum.	780	Assumes intermediate success in 3 different areas of the East Coast. Development proceeds in the first area the others follow at 5 year intervals at a maximum spend rate of NZ$1 billion per annum.
5	Exploration success analogous with N. American Bakken Shale. Provided by Apache.	260	Recovery of 1.0 million BOE per well. 10 Expl. & Appraisal & 600 production wells drilled 2017 through 2030 from 50 sites.
5A	3 of Scenario 5 with maximum of NZ$1 billion CAPEX spend per annum, i.e. 3 of the Apache Scenario.	780	Assumes Scenario 5 high success in 3 different areas of the East Coast. Development proceeds in the first area then the others follow at 5 year intervals at a maximum spend rate of NZ$1 billion per annum.
5B	6 of Scenario 5 distributed over 50 years, i.e 6 of the Apache scenario.	1560	Assumes two of Scenario 5A, i.e. extreme success across the entire region in 6 different areas of the East Coast. Development proceeds in the first area then others follow at 3 to 5 year intervals at a maximum spend rate of approximately NZ$2 billion per annum.

g. A number of overseas oil resource play developments have been reviewed to determine the most suitable analogy for application to the East Coast. Industry participants, including permit holders Apache/Tag have suggested the North American Bakken Shale forms an analogous scenario.

A comparison of the substantial publically available data from North America with the area in this study confirms that the Bakken and Eagleford shales are in some degree analogous. This is primarily in the application of production technologies, i.e. should the Waipawa and Whangai formations be proven productive by testing, then the production technologies successfully employed in the North American analogies would likely be deployed to make these formations commercially viable here.

The lowering of costs with time and activity volume observed in the US would also be expected to occur here, assuming substantial exploration success. In addition, the application of development technologies includes drilling up to 12 horizontal wells of

1000 to 2000 m horizontal reach from individual sites, where each of these wells would be fracture stimulated at up to 10 intervals, can be anticipated here in the event of exploration success.

h. It is the view of the author, and of GNS Science (GNS, Sep. 2012), that the East Coast Waipawa and Whangai Formations which are the primary target of the current East Coast exploration phase, are not truly analogous to "Resource Plays" such as the Bakken or Eagle Ford Shales. The Waipawa and Whangai formations are not true shales in the manner of the North American analogues, instead being sequences of interbedded sands, silts and carbonaceous clay/silt stones. Oil and gas generated in the carbonaceous units will migrate into the adjacent silts and sands, and these will be the permeable sources of oil or gas. In addition the high degree of faulting present in the East Coast formations makes migration of hydrocarbons from these formations more likely. This is supported by the observations of oil (and gas) seeps at surface in the region. A better analogy for these formations is likely to be one based on conventional tight oil or gas plays, i.e. where the wells do not require the same intensity of production stimulation, e.g. fracturing, and the productivities are slightly better than in a shale "resource" play.

   That the Waipawa and Whangai Formations are viable oil source rocks is supported by the oil seeps in the region. Geochemical analyses of these oils confirm their probable genesis in these formations. While the current depth of burial pressure and temperature places these formations either outside or just in the oil generating window, they have been buried substantially deeper in very recent history. This view is supported by regional structural geology and by the high degree of observed over-pressure in these formations when drilled in the region. The implication of these observations is that the Waipawa and Whangai Formations are almost certain to contain some hydrocarbons. The risk is how much of these will be present and what volume can be mobilised for production by the application of the relevant technologies, and at what rate?

2. Study Objectives & Scope

2.1. Objectives

This study was requested by the Energy and Communication unit of the Ministry of Business, Innovation and Employment with the following objectives;

1. To provide a detailed review of the (East Coast Oil Development) scenario(s) provided by Apache & TAG
2. To benchmark/compare the Apache/Tag scenarios against known developments in other countries, especially those that are now producing unconventional "tight oil" resources.
3. To provide alternative development scenarios (if warranted) based on information that is publically available, and from discussions with and documents from GNS Science.

The overall aim of this study is to assist MBIE and the participating East Coast Regional councils in assessing the potential impacts and the potential rewards should the exploration testing of the Waipawa and Whangai formations in these regions prove commercially viable oil production.

2.2. Scope

The study objectives were met by conducting data reviews, comparison analyses, and analytical forecasting and modelling of the geological and testing data from these formations on the East Coast, and by reviewing potentially analogous oil exploration/development plays, and by detailed study of the geology and development scenarios supplied by Apache and their partner Tag Oil.

As part of assessing the impact and contribution of potential discoveries in the region a series of Oil Development Scenario Models were made that encompass the range of potential development sizes. These models included forecasts for all product streams, of exploration and development CAPEX, fixed and variable OPEX, administration, abandonment and of royalties, with the technical basis for these forecasts documented.

2.3. Deliverables

The deliverables agreed for this study were;

i. A report detailing the findings and conclusions relating to the study objectives.
ii. Recommendations for further work if applicable.
iii. A formal presentation of the key findings of the study to the Ministry (MBIE) at a time to be agreed but no later than 10 business days after the submission of the report. The format of the presentation will be agreed between MARE and the Ministry.
iv. Following the submission and presentation of the Report by MARE, the Ministry shall provide feedback and comments to MARE for inclusion in a revised Report, if required.

2.4. Disclaimer

The statements, analyses, recommendations, and conclusions presented in this work are based on the application of oil and gas industry best practice and standard analysis techniques, diverse international and domestic experience, on the information made available to MARE by the client and its representatives, and on that available in the public domain. MARE, therefore, states that whilst making best endeavours to ensure the accuracy of the work presented herein, MARE cannot guarantee the accuracy of these interpretations and analyses.

3. Data Sources

The following section details the sources of the technical and financial data used in the compilation of the Development Scenario Models. The data itself is summarized in the relevant tables in subsequent sections rather than repeated here.

3.1. Public Domain

The following sources were consulted, particularly when considering analogue reservoirs:

i. "Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays", U.S. Energy Information Administration (EIA), July 2011.
ii. "Diagenesis and Fracture Development in the Bakken Formation, Williston Basin: Implications for Reservoir Quality in the Middle Member" By Janet K. Pitman, Leigh C. Price, and Julie A. LeFever. US. Geological Survey Professional Paper 1653. From Web location http://pubs.usgs.gov/pp/p1653/
iii. "Characterization of the Bakken System of the Williston Basin from Pores to Production; The Power of a Source Rock/Unconventional Reservoir Couplet" by Anne Grau1 and Robert H. Sterling. AAPG Search and Discovery Article #40847, Dec, 2011.
iv. "Statistical Handbook for Canada's Upstream Petroleum Industry" by Canadian Association of Petroleum Producers, November 2010.
v. "Production Forecasting in Low-Permeability Oil and Gas Reservoirs", by John Lee, University of Houston. SPE Presentation, 17 May 2012.

3.2. Provided by MBIE

The data supplied by MBIE and NZ Petroleum and Minerals (NZPAM) included:

a. Trans-Orient Petroleum Ltd – Resource Estimation & Economic Evaluation Report (Sept 2008)
b. "Technical Assessment of the Undiscovered Hydrocarbon Resource Potential of PEP 38348 and 38349, Onshore, East Coast Basin, New Zealand, as of September 30, 2007" by Sproule Petroleum Consultants, Calgary, for Trans-Orient Petroleum Ltd.
c. Apache/TAG Powerpoint presentation – Resource Development Scenarios (July 2012)
d. Apache/TAG Powerpoint presentation – Resource Parameter Explanations (July 2012)

Well Completion Reports and Associated Data was obtained (via NZPAM database) for the following wells;

- Rere-1
- Opoutama-1
- Hukarere-1 (offshore)

3.3. Provided by GNS Science

Discussions were held with GNS personnel on September 11, 2012. A series of maps and notes were taken and GNS subsequently produced a summary of the relevant geological input as report “Geological Input into the Evaluation of a Potential East Coast Resources Play”, GNS report 2012/250 by Bland, K.J and Quinn, R. (GNS, Sept 2012).

In addition, an earlier GNS Report 2009/13 “Geochemical database and interpretation of 10 oils from several New Zealand basins” by Zink, K.G. and Sykes, R (GNS, Nov 2010) was consulted for the oil densities, and hence oil properties, to be used in the modelling. The oil densities are based on those measured at seeps on the East Coast.

3.4. Capital Expenditure Data

Development Capital Expenditure was derived from both public domain and private sources, the public domain sources include development expenditure for similar onshore developments in North America and Australia.

Drilling and fracturing costs for current/recent onshore Taranaki developments also generally available from public domain sources or from proprietary cost databases used by MARE. Initial drilling, stimulation, and testing costs for the East Coast were loaded with an additional 25% over the equivalent Taranaki based activity to compensate for the distance from existing support infrastructure and services. In addition, Apache have supplied their own estimates for the drilling, completion and stimulation of exploration and production wells within their permits. These are generally lower than those estimated by the author of this report but are possibly achievable if the exploration and testing is very successful and activity levels are high. Apache’s development costs are used in Scenario families 4 and 5.

Item by item CAPEX Tables are included in the spreadsheet models compiled as part of this study and are summarised below in Table 2.

Table 2 East Coast Oil Development CAPEX Assumptions

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3.5. Operating Expenditure Data

Operating Costs have been extrapolated from those of current NZ onshore Operators as reported to Crown Minerals in the Half Yearly returns. For the East Coast areas these costs have been loaded an additional 20% to cover the lack of supporting oil and gas infrastructure in these areas.

Item by item OPEX Tables are included in the spreadsheet models compiled as part of this study and are summarised below in Table 3.

Table 3 East Coast Oil Development OPEX Assumptions

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3.6. Financial Data

The financial parameters/assumptions used in the development modelling scenarios are listed below in Table 4.

Table 4 Financial Assumptions (Table Truncated at 2020 for Display purposes)

	Units	Comments	2012	2013	2014	2015	2016	2017	2018	2019	2020
NZ/US $ Exchange	**na**	MBIE supplied. Flat assumption from 2017 on.	0.79	0.79	0.76	0.71	0.66	0.65	0.60	0.60	0.60
USD Oil Price (Brent)	**US$ /stb**	MBIE supplied.	110.2	107.8	102.4	106.3	108.7	111.0	113.4	115.7	118.1
NZ Oil Price	**NZ$ /stb**	Calc from MBIE Price & Exchange	121.2	122.8	126.9	132.9	138.9	141.2	147.2	148.5	149.8
Gas Price - < 1.92 PJ pa	**NZ$ /GJ**	No Market Condition	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas Price - Q < 10 PJ pa	**NZ$ /GJ**	Flat for local market uses	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Gas Price - Q < 30 PJ pa	**NZ$ /GJ**	Export in greater NZ	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Gas Price - For Power Gen	**NZ$ /GJ**	Needs >5 years at >10PJ pa	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Gas Price - For GTL	**NZ$ /GJ**	**Needs >10 years at >30PJ pa**	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Carbon Price	**NZ/GJ**	Flat from NZPAM	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5	-1.5
NZ Inflation Rate	**fraction**	2012 rate to RBNZ upper target of 3%	2.7	2.8	2.9	3	3	3	3	3	3

4. Discussion

4.1. East Coast Regional Geology (GNS, Sep. 2012)

The regional geology with respect to the resource play Waipawa and Whangai Formations has recently been reviewed and summarised by GNS Science (GNS, Sep 2012). This report includes the following key observations:

i. The Whangai and Waipawa formations do not represent “shale oil” or “shale gas” plays; rather, we consider them to be tight, conventional oil or gas plays, reservoired within silts and minor sands.
ii. Waipawa and Whangai maturity estimates based on present-day depths of burial will underestimate any potential resource. There is a need to take account of uplift history.
iii. The Gross Rock Volume (GRV) of Whangai and Waipawa Formation source rock within the present-day oil window is estimated to be 144 km3

The Whangai and Waipawa formations are regarded as being the two most important petroleum source rocks in the East Coast region. On the basis of geological mapping and a few drill-hole penetrations, the formations are known to occur in northern and eastern Wairarapa, central and coastal Hawke’s Bay, and the Gisborne-Raukumara areas. Outcrops are reasonably common in most of these areas (Figure 2).

Although the Waipawa Formation is considered the best source rock in the region, it has a patchy distribution and is generally fairly thin (2–50 m thick, average 17 m). Because the Waipawa Formation is so thin, it cannot be readily mapped as a separate geological unit at a regional scale; therefore, it has traditionally been incorporated within the Whangai Formation mapping unit. Both units have been considered seperately in the 2012 GNS work which has produced GRV estimates for the Waipawa Formation as well as the Whangai, based on the few data available, as well as estimates of average thicknesses. These are shown in Table 5 which is based on the GNS report Tables 3 and 4 combined. Figure 1 following illustrates the various structural blocks referred to in Table 5 (Both based on reference GNS, Sep 2012).

Table 5 GNS Estimates of Waipawa & Whangai Area and Gross-Rock Volume (GRV) in the East Coast.

Structural Blocks (North to South)	Est. Area Waipawa & Whangai Fms (km2)	Whangai Thk (m)	Whangai GRV (km3)	Waipawa Thk (m)	Waipawa GRV (km3)	Total Source GRV (km3)
E.Coast Allocthon	3635	600	2181	10	36	2217
Eastern Sub-Belt Nth	1320	600	792	10	13	805
Motu North	1175	375	441	15	18	458
Motu South	3940	70	276	15	59	335
Pongoroa North	1895	300	569	40	76	644
Pongoroa South	2160	470	1015	5	11	1026
Coastal North	656	200	131	5	3	134
Coastal South	1030	355	366	25	26	391

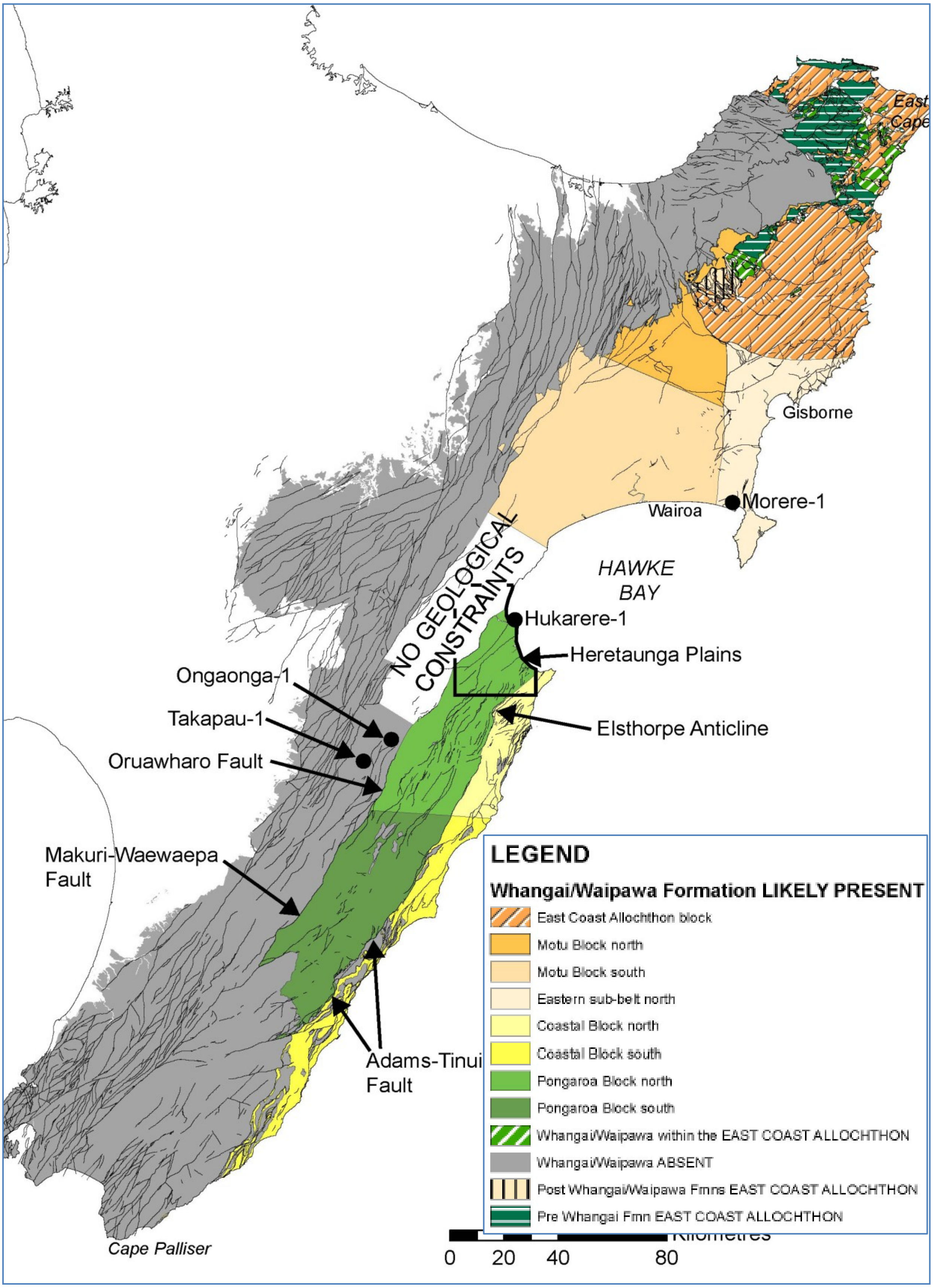
The GNS report (Sep, 2012) also discusses the carbon content of the Waipawa and Whangai Formations and while these are variable, with the Waipawa generally richer than the Whangai, the TOC (Total Organic Carbon) content for the Whangai is on average relatively low at 0.56 weight % (these values are useful in comparison to analogue rocks) and that for the Waipawa 3.6 weight %. . However, the areas covered and the volume of rock in the Whangai in particular, as shown in Table 4, is substantial and the opportunity for large volumes of hydrocarbon to be generated from these rocks does exist.

Table 5 is a summary of typical reservoir properties for the Waipawa and Whangai Formations.

Table 6 Waipawa and Whangai Formations – Typical Reservoir Properties

Parameter	Waipawa	Whangai
Depth (m)	1950	2000
Average Thickness (m)	20	300
Porosity (%)	4 - 8	4 - 8
Initial Oil Saturation (%)	40 - 75	40 - 75
Total Organic Content (TOC) (% wt)	3.6	0.56

Figure 1 EC Structural Blocks & Interp. Outcrop/Subsurface Whangai/Waipawa Fm (GNS, Sep 2012)



4.2. Analogous Plays

The following is an editted excerpt from the Jul 2011 U.S. EIA review of Emerging Resources (U.S. EIA, July 2011).

Resource, or shale, plays in the U.S and elsewhere didn't become commercially viable until experimental testing of technologies by Mitchell Energy and Development Corporation during the 1980s and 1990s made deep shale gas production a commercial reality in the Barnett Shale in North-Central Texas (U.S. EIA, July 2011). As the success of Mitchell Energy and Development became apparent, other companies aggressively entered the play, so that by 2005, the Barnett Shale alone was producing nearly 0.5 trillion cubic feet of natural gas per year. As producers gained confidence in the ability to produce natural gas profitably in the Barnett Shale, with confirmation provided by results from the Fayetteville Shale in Arkansas, they began pursuing other shale plays, including Haynesville, Marcellus, Woodford, Eagle Ford, and others. These plays are now being actively pursued globally.

The technologies that have been successfully applied to make these shale plays viable are primarily the use of horizontal drilling in conjunction with multi-stage (i.e. multiple fractures placed along the horizontal wells) hydraulic fracturing has greatly expanded the ability of producers to profitably recover natural gas and oil from low-permeability plays, such as shale plays.

The application of fracturing techniques to stimulate oil and gas production began to grow rapidly in the 1950s, although experimentation dates back to the 19th century. Starting in the mid-1970s, a partnership of private operators, the U.S. Department of Energy (DOE) and predecessor agencies, and the Gas Research Institute (GRI) endeavoured to develop technologies for the commercial production of natural gas from the relatively shallow Devonian (Huron) shale in the eastern United States. This partnership helped foster technologies that eventually became crucial to the production of natural gas from shale rock, including horizontal wells, multi-stage fracturing, and slick-water fracturing. The practical application of horizontal drilling to oil production began in the early 1980s, by which time the advent of improved down-hole drilling motors and the invention of other necessary supporting equipment, materials, and technologies had brought some applications within the realm of commercial viability.

With respect to the reserves and recovery from shales, the EIA report (page 6) includes the following;

There is considerable uncertainty regarding the ultimate size of technically recoverable shale gas and shale oil resources, including but are not limited to the following:

- *Because most shale gas and shale oil wells are only a few years old, their long-term productivity is untested. Consequently, the long-term production profiles of shale wells and their estimated ultimate recovery of oil and natural gas are uncertain.*
- *In emerging shale plays, production has been confined largely to those areas known as "sweet spots" that have the highest known production rates for the play. If the production rates for the sweet spots are used to infer the productive potential of entire plays, their productive potential probably will be overstated.*
- *Many shale plays are so large (e.g., the Marcellus shale) that only portions have been extensively production tested.*

- *Technical advancements could lead to more productive and less costly well drilling and completion.*
- *Currently untested shale plays, such as thin-seam plays or untested portions of existing plays, could prove to be highly productive.*

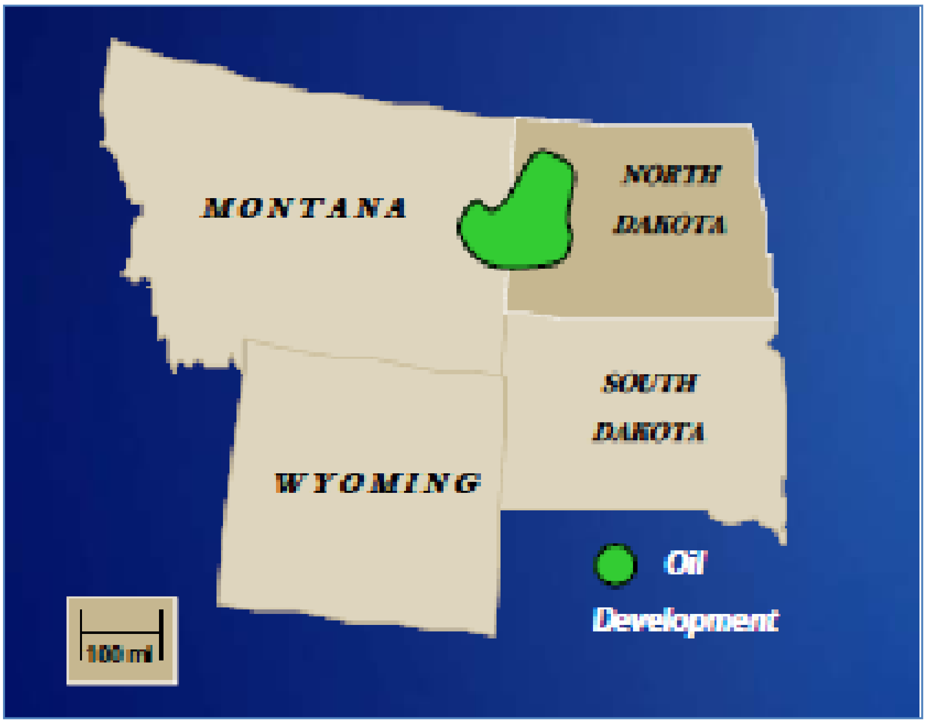
The EIA Review provides a detailed over-view of the shale gas and oil production in the U.S. and includes summaries of the key parameters of the oil producing Bakken and Eagleford shales, amongst others. Hence the recovery statistics that are quoted in the following section should be treated as indicative, and not as absolutes.

4.2.1. The Bakken Shale

The Baaken Shale has been indicated (Ferguson/Apache, 2012) to be a useful analogy to the Waipawa and Whangai Formations and a summary of the Bakken Shale Oil Play based on U.S. EIA, 2011, is included below.

The Bakken shale oil play is located within the Williston Basin in Montana and North Dakota as shown in Figure 2. The oil shale extends into the Canadian provinces of Manitoba and Saskatchewan. The U.S. portion of the Bakken shale has been estimated to contain 3.65 billion barrels of oil.

Figure 2 Location of the Bakken Oil Shale Play (Onshore U.S.) (EIA, 2011)



Based on the combined net leased acreage for Bakken shale, the area is approximately 6,522 square miles within the United States. And the shale oil play has an average EUR of 550 MBO per well (i.e. 0.5 million barrels of oil) and approximately 3.59 Billion bbl of technically recoverable oil.

The Bakken shale ranges from 4,500 to 7,500 feet deep (i.e. 1370 to 2290 m) with a mean of 6,000 feet (i.e. 1830 m) and an average thickness of 22 feet (6.7 m). According to Kodiak Oil and Gas Corporation and other companies, the typical development well spacing ranges from 320 to 1,280 acres per well with a mean of 640 acres per well (i.e. 1 well per square mile). The typical reservoir properties for the Bakken from the EIA Review (July 2011) are shown in Table 7.

Table 7 Bakken Oil Shale – Typical Reservoir Properties

Parameter	Value
Depth (m)	1830
Thickness (m)	7
Porosity (%)	8
Initial Oil Saturation (%)	68
Total Organic Content (TOC) (% wt)*	11 - 20

** from Grau and Sterling (Dec 2011)*

The well costs for the Bakken have trended down with time and in 2011 the costs ranged from US$5.5 to 8.5 million per well, i.e. NZ$7 to 10.8 million per well. In addition the operating costs are reported at less than US$5 per barrel (EIA, July 2011).

4.2.2. The Eagle Ford Shale

The Eagle Ford shale gas and oil play is located within the Texas Maverick Basin. This play contains a high liquid component and this has led to the definition of three zones: an oil zone, a gas-condensate zone, and a dry gas zone within the shale fairway.

The July 2011 EIA Review reports that the Eagle Ford has an average EUR of 5.0 Bcf per well (gas well) and 300 MBO per well (oil well). The shale gas and shale oil plays have approximately 20.81 Tcf of technically recoverable gas and 3.35 Bbbl of technically recoverable oil. In the Eagle Ford oil play, the well densities are typically 5 wells per square mile, up from 1 in the Bakken.

Typical reservoir properties for the Eagle Ford from the EIA Review (July 2011) are shown in Table 8.

Table 8 Eagle Ford Oil Shale – Typical Reservoir Properties

Parameter	Value
Depth (m)	2180
Thickness (m)	62
Porosity (%)	9
Initial Oil Saturation (%)	-
Total Organic Content (TOC) (% wt)	4.25

The well costs for the Eagle Ford are lower than the Bakken at US$4 to 6.5 million per horizontal well (i.e. NZ$5.1 to 8.3 million per well).

4.3. Comparison of Analogies

In comparing the analogous plays with the East Coast, it is important to bear in mind that the regional structural framework is completely different. The Bakken, and Eagle Ford shales are in stable mid-continental locations where the degree of faulting and deformation has been minor in recent geological time. By contrast, the East Coast of the North Island is immediately west of an active subducting continental plate boundary and is the site of large allocthonous geological sections and of extensive recent faulting and deformation. This means that the East Coast area is extensively broken up and faulting has made all of the regional geology essentially made up of small geological blocks which increases the likelihood that any hydrocarbons that may have been generated within the Waipawa or Whangai formations have already migrated up through section either into shallower formations and/or to seeps and substantial volumes are unlikely to remain trapped within the source rocks or the adjacent silt and sandstones.

At face value, the similar depths and porosity values of the Bakkan, Eagle Ford and Waipawa/Whangai formations indicate that the analogy may be useful. However, the highest East Coast TOC values are in the thin Waipawa shale (3%) whereas the lowest analogous TOC is that in the Eagle Ford at 4.5% and in a substantially thicker unit (17m average c.f. 62m). This implies that the Waipawa has oil potential but that the volumes may not be substantial. The Whangai has a very low TOC at 0.56% but is much thicker at an average of 300m, than either the Bakken or Eagle Ford, so despite its lower carbon content, hydrocarbons generated from this formation may be substantial, and if they remain trapped within the Whangai then they may be producible using the application of Bakken style technologies.

Note that the Bakken and Eagleford Formations are predominantly gas-prone shales, but specific areas are oil-prone rather than gas and these analogies are the ones that have been considered in this assessment report.

5. Modelling Basis and Assumptions

For each development scenario, a model encapsulating the development size and types were made as spreadsheet models. These models were used to identify commercial thresholds for hydrocarbon accumulations on the basis of well yields and development costs, resource size and location (e.g. distance from infrastructure).

Screening level economics were conducted when making the development model for each field size in order to optimise the development scenario economics for a number of wells and production capacities and plateau lengths. These were also used in determining the appropriate commercial thresholds for field developments and for the application of incremental development technologies, e.g. when gas sales become viable.

1. Production forecasts were developed using the GNS and analogue data for some scenarios and from the those combined with data and forecast assumptions provided by Apache/Tag for the Scenario 5 based cases
2. The initial well deliverability was forecast using analytical inflow models of tight oil multi-stage fractured horizontal wells. These models were based on expected reservoir fluid properties, pressures, permeabilities and recoveries by well, predominantly derived from the GNS data.

3. Production forecasts for the full field scenarios were built up by adding wells in the drilling sequence(s) until the available well deliverability fills the available production plateau. The production plateau rates required iterations after the first pass through the economics model to optimise the NPV and VIR.
4. The financial assumptions are discussed in a subsequent section.
5. The Screening Economics are based on a conventional discounted cash-flow model with inputs of forecasts of expenditures (capital and fixed and variable operating), and of product streams.
6. After the first pass through the economics models an iterative step is taken to optimise the capital expenditure versus production rate plateau length. This typically involves changing well numbers and facilities costs to match the changed well numbers. This iteration stops when further gains in NPV & VIR are hard to make.
7. Output forecast streams including royalty and tax revenues, and project/scenario NPV & VIR. In addition some basin commercial thresholds and unit costs with respect to field size are determined.

5.1. Reservoir Conditions

The Waipawa and Whangai Formations have been both mapped at surface (GNS, Sep 2012) and intersected sub-surface in a number of the East Coast wells. The depths to the Whangai, which is immediately overlaid by the Waipawa Formation (2 to 50 m – average 17m in thickness) when it is present, are summarized in Table 9.

Table 9 Pressure Estimates Based on key Wells

Well	Depth to Top Whangai Fm (mAH)	Whangai Fm Thickness (m)	Mud. Grad. at Whangai (ppg)	Pressure at 2000m TV (psia)
Opoutama-1 (1967)	1469	734	na	na
Rere-1 (1985)	1990	392	12	4100
Hakarere-1 (2001)	2764	323	>14	4800
Normal Pressure	na	na	8.34	2840

Based on the existing drilled well results, it has been assumed that the average mid-depth of the Waipawa/Whangai Formation packages in the more prospective parts of the East Coast region is 2000 mTV and that the formations at that depth are substantially over-pressured, i.e. an average formation reservoir pressure of 4100 psia has been assumed for both fluid properties and production rate estimates

The geothermal temperature gradients in the East Coast are marginally depressed, i.e. lower temperatures than normal, when compared to those in Taranaki where the normal temperature gradient is approximately 3 deg.C per 100m of burial (Adams, Oct 2009). For this study a temperature gradient of 2.7 deg.C per 100m, i.e. 75 deg.C or 167 deg.F, has been assumed when calculating the oil fluid properties.

5.2. Rock Properties

The Waipawa and Whangai Formations have been intersected in a number of East coast wells and a review of the wireline log data from the Hukarere-1, Opuotama-1 and Rere-1 shows the inter-bedded nature of these formations and that the porosities are in the range of 4 to 8% and the water saturations in the range of 40% to more than 75%.

Permeabilities are not normally directly measured by wireline logs but can be inferred from porosity-permeability relationships for the fine grained sands and silts and have been assumed to be in the order of 0.025 mD. These estimates are significantly higher than the permeabilities typically seen in the North American Bakken Fm which are typically 0.001 mD or less through to 0.01 mD (Grau & Sterling, 2011).

5.3. Recovery By Well

The analogy data, summarized in section 4 indicates that a typical Bakken well will recover 0.55 million barrels of oil equivalent and the Eagle Ford wells slightly less at 0.3 million BOE.

Apache (Ferguson 2012) has suggested that the thicker formations on the East coast may see up to 1 million BOE per well and they have used this number in deriving their development scenarios.

For this study, three different recovery cases were made;

i. A single well model was made using the analytical well modeling software Saphir (from Kappa Engineering) and forecasts were made using this to give the shape of the production declines and a well recovery of 0.45 million barrels.
ii. The Bakken well EUR of 0.55 million BOE with the production decline by well scaled from case i.
iii. The Apache provided well EUR of 1 million BOE with the production decline by well scaled from case i.

These well recoveries were used for Scenarios 3, 4, and 5 respectively.

5.4. Screening Level Financial Models

In creating the development scenario models, a simplified NPV based economic model has been built (as a MS Excel spreadsheet). This optimises the development production rates and associated CAPEX and OPEX. The modelled NPV is based on forecasts of variable price(s), NPV discount rate, exchange rates, and inflation assumptions. An example of the spreadsheet inputs and calculations is shown in Table 10 below.

Table 10 Example Financial Model Inputs

Case Description	O3 PS for 2500 stb/d											
	Assumes Gas Re-injection via 2 Dedicated Wells											
	Current											
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Inputs												
Ann. New Exploration Well Count			1	1								
Ann. New Production Well Count					1							
Ann. New Injection Well Count												
Capital												
Exploration G&G	2	2	2	2								
Exploration Seismic												
Exploration & Appraisal Wells			12	12	0	0	0					
Development Seismic				1.3								
Development Wells					10	0	0					
Subsea Equipment & Flowlines												
Platform/FPSO												
Process Plant				7.50	9.50							
Export Pipelines				1.13	3.38							
Onshore Power Generation (50 PJ pa)												
Abandonment										5		
Abandonment Platform/Installation												
Other												
Operating (Fixed)												
G&A					2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
OPEX Baseline (incl well re-entries etc)					5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
Operating (Variable)												
Gas Processing (per GJ)	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
LNG Cooling and Liq/Storage (NZ$ per GJ)												
Liquids Treatment (NZ$ per bbl)	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50
Water Treatment (NZ$ per bbl)	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Other												
Production Forecasts												
Producing Year					1	2	3	4	5	6	7	8
Gas Rate (mmscf per day)					1.00	1.00	0.99	0.98	0.63	0.36	0.20	0.12
Gas Fuel & Flare (mmscf per day)					0.05	0.05	0.05	0.05	0.03	0.02	0.01	0.01
Cum. Gas incl Fuel (Bscf)		0.0	0.0	0.0	0.2	0.5	0.7	1.1	1.3	1.4	1.5	1.6
Cum Sales Gas, i.e less Fuel (Bscf)			0.0	0.0	0.3	0.5	0.9	1.2	1.4	1.5	1.6	1.7
Sales Gas, i.e less Fuel etc (PJ pa)		0	0	0	0	0	0	0	0	0	0	0
LNG Sales Gas (PJ pa)		0	0	0	0							
LNG Sales Gas Cumulative (PJ)		0	0	0	0							
Oil/Condensate (stb per day)		0	0	0	2000	2000	2000	2000	1306	751	432	248
Cum. Oil/Condensate (mmstb)		0.0	0.0	0.0	0.7	1.5	2.2	2.9	3.4	3.7	3.8	3.9
LPG (t/day)												
Produced Water (stb per day)		0	0	0	5	5	60	120	121	95	71	50
Cum. Prod. Water (mmstb)		0	0	0	0	0	0	0	0	0	0	0
Injected Water (stb per day)					2405	2405	2460	2520	1687	996	588	348
Cum. Inj. Water (mmstb)		0	0	0	1	2	3	4	4	5	5	5

Well Count

Capital Expenditure by year.

Fixed Operating Expenditure by year.

Variable Operating Expenditure unit by by year.

Production Forecasts for all product streams

The calculations and model outputs are illustrated in Table 11 below for an example model taken from a prior report using the same methodology (Adams, 2009) carried out for the Ministry in 2009. Note that the economic cut-off is determined by the year in which the Net Cash-flows become negative after the start-up of production.

Table 11 Example Financial Model Calculations & Outputs

	Current 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Outputs												
Capital (NZ$ mm) (inflation adj.)	**2.00**	**2.10**	**15.44**	**27.64**	**27.80**	**0.00**	**0.00**	**0.00**	**0.00**	**7.76**	**0.00**	**0.00**
Operating (Fixed NZ$ mm) (inflation adj.)	**0.00**	**0.00**	**0.00**	**0.00**	**8.51**	**8.93**	**9.38**	**9.85**	**10.34**	**10.86**	**11.40**	**11.97**
Operating (Variable NZ$ mm)	**0.00**	**0.00**	**0.00**	**0.00**	**3.74**	**3.60**	**4.13**	**4.35**	**2.98**	**1.81**	**1.09**	**0.66**
Gas Processing NZ$ mm (inflation adj.)	0	0	0	0	1	0	1	1	0	0	0	0
Liquids Trans./Treatment NZ$ mm (inflation adj.)		0	0	0	3	3	3	4	2	1	1	1
Water Treatment NZ$ mm (inflation adj.)	0	0	0	0	0	0	0	0	0	0	0	0
Revenues	**0.00**	**0.00**	**0.00**	**0.00**	**69.41**	**72.28**	**78.20**	**82.92**	**57.64**	**35.43**	**21.85**	**13.44**
Gas (NZ$ mm pa) - inflation adjusted	0.00	0.00	0.00	0.00	2.54	1.42	3.14	3.40	2.66	1.95	1.46	1.03
Oil/Condensate (NZ$ mm pa) - inflation adj.	0.00	0.00	0.00	0.00	66.87	70.85	75.06	79.52	54.98	33.48	20.39	12.41
Oil (NZ$ mm pa) - inflation adj.												
DCF Analysis												
Net Revenue	**0.00**	**0.00**	**0.00**	**0.00**	**57.16**	**59.74**	**64.69**	**68.72**	**44.31**	**22.77**	**9.36**	**0.81**
AVR 5%	0.00	0.00	0.00	0.00	2.86	2.99	3.23	3.44	2.22	1.14	0.47	0.04
APR 20%	0.00	0.00	0.00	0.00	8.10	7.92	10.12	11.77	7.48	3.46	0.64	0.00
Depreciation Scale	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Cum. Capital	2.00	3.50	17.89	40.16	55.92	39.14	27.40	19.18	13.43	17.15	12.01	8.41
Capital Depreciation	0.00	0.60	1.05	5.37	12.05	16.77	11.74	8.22	5.75	4.03	5.15	3.60
Capital Cost	0	0	1	3	5	3	2	2	1	1	1	1
Net Revenue less Cap.Cost		-0.88	-2.49	-8.65	40.48	39.61	50.58	58.85	37.40	17.31	3.18	-3.52
Cum Net. Revenue less Cap. Cost	0.0	-0.9	-3.4	-12.0	28.5	68.1	118.6	177.5	214.9	232.2	235.4	231.9
Net Rev+Depr.+Cap.Cost+Royalty	0.00	-0.88	-2.49	-8.65	32.38	31.69	40.47	47.08	29.92	13.85	2.54	-3.52
Net Rev+Depr.+Cap.Cost+Royalty+Tax	0.0	-0.9	-2.5	-8.7	22.7	22.2	28.3	33.0	20.9	9.7	1.8	-2.5
NPV Calc (Ex.Royalty)	**$88**	**mm**										
NPV Calc (Incl.Royalty)	**$50**	**mm**										
NPV Calc (Incl.Royalty and Taxes)	**$33**	**mm**										
VIR Calc (Inc.Royalty and Taxes)	**$38**	**PV Future Cashflows**										
	$45	**PV Investment**										
	0.83	**VIR**										

Capital spend
Fixed Opex Spend
Variable Opex Spend
Revenues
Discounted Cashflow Analyses
Net Revenues
Taxes and Royalties
Final NPV and VIR

6. Development Model Descriptions

Following on from the geology and geophysics, plus the data from prior wells and the preliminary financial modelling to screen outcomes, 5 discrete Exploration/Appraisal/ Development scenarios were modelled taking into some duplication of commercially viable scenarios to account for multiple permit/larger area successes. The scenarios are shown in Table 12.

Table 12 Summary of the Development Scenarios as Modelled

#	Scenario	Area (km2)	Description
1	Exploration not Successful	NA	Planned 4 well Apache/Tag campaign is unsuccessful and discourage further exploration by any party. 4 Expl. Wells. **Not modelled further.**
2	Limited Exploration success but sub-commercial results	NA	Planned 4 well Apache/Tag campaign is partially successful and further exploration (including other parties) continues but no commercial production results. 12 Expl. Wells**. Not modelled further.**
3	Limited success and commercially viable production.	100	Recovery of 0.45 million BOE per well. 6 Expl. & Appraisal & 30 production wells drilled 2015 through 2020
3A	3 of Scenario 3 with maximum of NZ$1 billion CAPEX spend per annum.	300	Assumes limited success in 3 different areas of the East Coast. Development proceeds in the first area the others follow at 5 year intervals at a maximum spend rate of NZ$1 billion per annum. 6 Expl. & Appraisal & 3 x 30 production wells drilled 2015 through 2025.
4	Intermediate exploration success and average N.American shale oil yields.	260	Recovery of 0.55 million BOE per well. 10 Expl. & Appraisal & 600 production wells drilled 2017 through 2030 from 50 sites.
4A	3 of Scenario 4 with maximum of NZ$1 billion CAPEX spend per annum.	780	Assumes intermediate success in 3 different areas of the East Coast. Development proceeds in the first area the others follow at 5 year intervals at a maximum spend rate of NZ$1 billion per annum.
5	Exploration success analogous with N.American Bakken Shale. Provided by Apache.	260	Recovery of 1.0 million BOE per well. 10 Expl. & Appraisal & 600 production wells drilled 2017 through 2030 from 50 sites.
5A	3 of Scenario 5 with maximum of NZ$1 billion CAPEX spend per annum, i.e. 3 of the Apache Scenario.	780	Assumes Scenario 5 high success in 3 different areas of the East Coast. Development proceeds in the first area then the others follow at 5 year intervals at a maximum spend rate of NZ$1 billion per annum.
5B	6 of Scenario 5 distributed over 50 years, i.e 6 of the Apache scenario.	1560	Assumes two of Scenario 5A, i.e. extreme success across the entire region in 6 different areas of the East Coast. Development proceeds in the first area then others follow at 3 to 5 year intervals at a maximum spend rate of approximately NZ$2 billion per annum.

6.1. Scenario 1 Unsuccessful Exploration

Assumes that Apache/TAG execute the currently planned 4 well campaign on the East Coast. Results are negative and discourage any further exploration by any party.

No development models were made of this scenario.

6.2. Scenario 2 Exploration Success But Not Commercial

Assumes the same initial campaign as Scenario-1, but with sufficiently encouraging results to inspire additional exploration work along the East Coast basins. It has been assumed that this will involve some 12 wells and that on completion of the exploration activity development is not commercially viable. At this point all the well sites are remediated and permits handed back.

No development models were made of this scenario.

6.3. Scenario 3 Limited Success & Commercially Viable

This scenario is based on the GNS supported estimates of rock properties and the associated tight-oil derived production forecasts for individual wells rolled up into a 6 exploration and 30 production well development. The development has been scheduled on the assumption of using 1 (one) rig continuously for 6 years, i.e. 30 development wells covering approximately 95 km2 at a density of approximately 1 development well per 2.6 km2 (1 sq mile).

The individual wells using the assumed reservoir properties will flow at an oil rate initially of approx. 1000 bopd declining at approximately 50% per annum initially. For simplicity in estimating the development costing, it has been assumed that this development is in the geographically (relatively) benign blocks to the SW of Napier, i.e. Pongoroa Blocks North and South (see Figure 1). Activity to the north, i.e. towards Gisborne or further north, will be even more remote and the terrain significantly more difficult and costs would be substantially (say 10 to 20%) higher to develop in this area.

The oil recovery per well used in this scenario is 0.45 million barrels of oil equivalent (mmboe) which is around 25% less than a typical Bakken oil shale well (U.S. EIA, 2011).

Oil and gas production would be consolidated at a central production station via buried pipelines. The stabilised crude oil would initially be trucked to New Plymouth for export,. However, it is likely that following an early stage of testing, port facilities would be set up locally, reducing the need for long distance trucking. Any associated gas production will be flared during initial exploration testing but once being produced via the pipeline system, the gas would be used to fuel the oil processing and any excess would be sold locally at a relatively low price.

The associated production forecasts, capital, operating costs, along with the screening level economics for this scenario are shown in Appendix 1 as Table 20. The forecast and economic parameters for this scenario are summarised in Table 13.

Table 13 Scenario 3 Development Modelling Results

Parameter	Value	Comments
Developed Area (km2)	95	
Number of sites	9	4 Exploration sites
Number of Wells	6 + 30	6 Exploration wells
Years Production	11	
Plateau Oil Production Rate (stb/d)	5000	
Oil Recovery (mmstb)	14.3	
Gas Recovery (Bscf)	11.2	
Post Royalty & Tax NPV@20% (NZ$ mil.)	165	
VIR	0.53	
Capital Invest. (2012 NZ$ mill.)	791	Undepreciated cumulative

6.4. Scenario 3A Limited Success x 3

This scenario assumes that the success seen in Scenario-3 is replicated in two other permits/areas in the region, following on from the success of the first development. The subsequent developments are phased with 3-4 year delays and the number of working rigs is limited to 2. In this scenario, it is also envisaged that oil would be piped to new port facilities at Napier and/or Gisborne for export and that gas would also be piped to the local spurs of the North Island network.

The associated production forecasts, capital, operating costs, along with the screening level economics for this scenario are shown in Appendix 1 as Table 21. The forecast and economic parameters for this scenario are summarised in Table 14.

Table 14 Scenario 3A Development Modelling Results

Parameter	Value	Comments
Developed Area (km2)	300	
Number of sites	19	4 Exploration sites
Number of Wells	6 + 90	6 Exploration wells
Years Production	21	
Plateau Oil Production Rate (stb/d)	15000	
Oil Recovery (mmstb)	41.8	
Gas Recovery (Bscf)	41.1	
Post Royalty & Tax NPV@20% (NZ$ mil.)	267	
VIR	0.47	
Capital Invest. (2012 NZ$ mill.)	2457	Undepreciated cumulative

6.5. Scenario 4 Intermediate Success

This is identical to the Apache derived Scenario 5 with the exception of the well recoveries being the same as a typical Bakken shale oil well at 0.55 mmboe (instead of the 1 mmboe in Scenario-5) Hence the details of this scenario are discussed in that section.

The associated production forecasts, capital, operating costs, along with the screening level economics for this scenario are shown in Appendix 1 as Table 22. The forecast and economic parameters for this scenario are summarised in Table 15.

Table 15 Scenario 4 Development Modelling Results

Parameter	Value	Comments
Developed Area (km2)	260	
Number of sites	56	6 Expl. Sites. 12 prod well/site
Number of Wells	10 + 600	10 Exploration wells
Years Production	29	
Plateau Oil Production Rate (stb/d)	70000	
Oil Recovery (mmstb)	303	
Gas Recovery (Bscf)	280	
Post Royalty & Tax NPV@20% (NZ$ mil.)	1316	
VIR	0.75	
Capital Invest. (2012 NZ$ mill.)	10642	Undepreciated cumulative

6.6. *Scenario 4A Intermediate Success x 3*

This scenario assumes that the success seen in Scenario-4 is replicated in two other permits/areas in the region, following on from the success of the first development. The subsequent developments are phased with 3-4 year delays and the number of wells drilled per annum is limited ensure that no more than NZ$1 billion Capital is spent in any one year.

The associated production forecasts, capital, operating costs, along with the screening level economics for this scenario are shown in Appendix 1 as Tables 23 and 24. The forecast and economic parameters for this scenario are summarised in Table 16.

Table 16 Scenario 4A Development Modelling Results

Parameter	Value	Comments
Developed Area (km2)	780	
Number of sites	156	6 Expl. Sites. 12 prod well/site
Number of Wells	10 + 1800	10 Exploration wells
Years Production	41	
Plateau Oil Production Rate (stb/d)	150000	
Oil Recovery (mmstb)	838	
Gas Recovery (Bscf)	916	
Post Royalty & Tax NPV@20% (NZ$ mil.)	3023	
VIR	1.3	
Capital Invest. (2012 NZ$ mill.)	39115	Undepreciated cumulative

6.7. Scenario 5 Large Exploration Success

This scenario is very closely derived from that supplied by Apache (Ferguson, Jul 2012) and uses Apache's proposed costs, where available. This is based on the concept of developing 260 km2 of permit area in a pattern where there are 50 production well sites with 12 horizontal, multi-stage fracture stimulated wells per site. The The oil recovery per well used in this scenario is 1.0 million barrels of oil equivalent (mmboe), as described by Apache, which is around the upper end of the range observed in the Bakken oil shale (U.S. EIA, 2011).

As for the Scenario 3 model, oil and gas production would be consolidated at a central production station via buried pipelines. The stabilised crude oil during exploration testing would initially be trucked to New Plymouth for export. However, once development proceeds, notionally in 2017, pipelines and port facilities would be set up locally, removing the need for trucking. Any associated gas production will be flared during initial exploration testing but once being produced via the pipeline system, the gas would be used to fuel the oil processing and any excess would be sold, probably at a relatively low price.

The associated production forecasts, capital, operating costs, along with the screening level economics for this scenario are shown in Appendix 1 as Tables 25 and 26. The forecast and economic parameters for this scenario are summarised in Table 17.

Table 17 Scenario 5 Development Modelling Results

Parameter	Value	Comments
Developed Area (km2)	260	
Number of sites	56	6 Expl. Sites. 12 prod well/site
Number of Wells	10 + 600	10 Exploration wells
Years Production	33	
Plateau Oil Production Rate (stb/d)	100000	
Oil Recovery (mmstb)	506	
Gas Recovery (Bscf)	547	
Post Royalty & Tax NPV@20% (NZ$ mil.)	3245	
VIR	1.85	
Capital Invest. (2012 NZ$ mill.)	10642	Undepreciated cumulative

6.8. Scenario 5A Large Success x 3

This scenario assumes that the success seen in Scenario-5 is replicated in two other permits/areas in the region, following on from the success of the first development. The subsequent developments are phased with 3-4 year delays and the number of wells drilled per annum is limited ensure that no more than NZ$1 billion Capital is spent in any one year.

The associated production forecasts, capital, operating costs, along with the screening level economics for this scenario are shown in Appendix 1 as Tables 27 and 28. The forecast and economic parameters for this scenario are summarised in Table 18.

Table 18 Scenario 5A Development Modelling Results

Parameter	Value	Comments
Developed Area (km2)	780	
Number of sites	156	6 Expl. Sites. 12 prod well/site
Number of Wells	10 + 1800	10 Exploration wells
Years Production	41	
Plateau Oil Production Rate (stb/d)	225000	
Oil Recovery (mmstb)	1522	
Gas Recovery (Bscf)	1665	
Post Royalty & Tax NPV@20% (NZ$ mil.)	6381	
VIR	2.73	
Capital Invest. (2012 NZ$ mill.)	39115	Undepreciated cumulative

6.9. *Scenario 5B Large Success x 6*

This scenario assumes that the success seen in Scenario-5 is replicated in five other permits/areas in the region, following on from the success of the first development. The subsequent developments are phased with 3-4 year delays and the number of wells drilled per annum is limited ensure that no more than NZ$2 billion Capital is spent in any one year.

The associated production forecasts, capital, operating costs, along with the screening level economics for this scenario are shown in Appendix 1 as Tables 29, 30, and 31. The forecast and economic parameters for this scenario are summarised in Table 19.

Table 19 Scenario 5A Development Modelling Results

Parameter	Value	Comments
Developed Area (km2)	1560	
Number of sites	306	6 Expl. Sites. 12 prod well/site
Number of Wells	10 + 3600	10 Exploration wells
Years Production	64	
Plateau Oil Production Rate (stb/d)	225000	
Oil Recovery (mmstb)	3043	
Gas Recovery (Bscf)	3338	
Post Royalty & Tax NPV@20% (NZ$ mil.)	6861	
VIR	2.86	
Capital Invest. (2012 NZ$ mill.)	114127	Undepreciated cumulative

7. References

Author	Title	Date	Publisher
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Ferguson, A et al.	Resource Development Scenarios - East Coast New Zealand Onshore, Unconventional Petroleum Resources	July 2012	Apache MS PowerPoint presentation given to NZPAM. Apache Calgary.
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U.S. EIA	Review of Energing Resources: U.S. Shale Gas and Shale Oil Plays	July 2011	U.S. Energy Information Administration (EIA)
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Zink, K.G. & Sykes, R	Geochemical database and interpretation of 10 oils from several New Zealand basins	Nov 2010	GNS Science Consultancy Report 2009/13, Lower Hutt

8. Appendix 1 – Development Scenarios Forecast Sheets

Table 20 Scenario 3

Development Economics Model																		
MRA 25 Oct 2012																		
NPV (NZ$mm 2012 Dollars)	*$418*	*Gross NPV Pre Royalty & Tax*																
NPV (NZ$mm 2012 Dollars)	*$165*	*Post Royalty & Taxes*																
Case Description	**SC03**	**PS for 5000 stb/d**																
	Assumes Central 5000 bopd Production Station and 5 Development wells per year for 6 years. 100 km2 of producing area developed.																	
	Current 2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Inputs																		
Ann. New Exploration Well Count		3	3															
Ann. New Production Well Count				5	5	5	5	5	5									
Ann. New Injection Well Count																		
Capital																		
Exploration G&G	2	2	2	2	2	2	2	2	2									
Exploration Seismic	5.6		10															
Exploration & Appraisal Wells		36	36	0														
Development Seismic																		
Development Wells				85	85	85	85	85	85									
Subsea Equipment & Flowlines																		
Platform/FPSO																		
Process Plant				27.50	27.50													
Intra-field Pipelines				2.50	2.50	2.50	2.50	2.50	2.50									
Onshore Power Generation (50 PJ pa)																		
Abandonment											72							
Abandonment Platform/Installation																		
Other																		
Operating (Fixed)																		
G&A		2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
OPEX Baseline (incl well re-entries etc)		3.00	3.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00
Operating (Variable)																		
Gas Processing (per GJ)				1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
LNG Cooling and Liq/Storage (NZ$ per GJ)																		
Liquids Treat incl. Transport & Port etc (NZ$ per bbl)		17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
Water Treatment (NZ$ per bbl)		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Other - Gas F&F Carbon Cost (NZD/mscf)		1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43
Production Forecasts									0.642995									
Producing Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Gas Rate (mmscf per day)		3.36	5.05	5.47	5.50	5.50	5.50	5.50	3.54	2.27	1.46	0.94	0.60	0.39	0.25	0.16	0.10	0.07
Gas Fuel & Flare (mmscf per day)		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.94	0.60	0.39	0.25	0.16	0.10	0.07
Cum. Gas incl Fuel (Bscf)		0.6	1.5	2.5	3.5	5.5	6.6	8.6	9.9	10.7	11.2	11.6	11.8	11.9	12.0	12.1	12.1	12.1
Cum Sales Gas, i.e less Fuel (Bscf)		0.4	1.2	2.0	2.8	3.6	4.5	5.3	5.7	6.0	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Sales Gas, i.e less Fuel etc (PJ pa)		0.4	0.7	0.8	0.8	0.8	0.8	0.8	0.5	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LNG Sales Gas (PJ pa)																		
LNG Sales Gas Cumulative (PJ)																		
BOE Cum		**1.22**	**3.05**	**5.03**	**7.03**	**9.19**	**11.18**	**13.34**	**14.73**	**15.62**	**16.20**	**16.57**	**16.81**	**16.96**	**17.06**	**17.12**	**17.16**	**17.19**
Oil/Condensate (stb per day)		3059	4588	4977	5000	4997	5000	5000	3215	2067	1329	855	550	353	227	146	94	60
Cum. Oil/Condensate (mmstb)		1.1	2.8	4.6	6.4	8.3	10.1	11.9	13.1	13.8	14.3	14.6	14.8	15.0	15.1	15.1	15.1	15.2
LPG (t/day)																		
Produced Water (stb per day)		3	229	249	250	250	250	250	161	103	66	43	27	18	11	7	5	3
Cum. Prod. Water (mmstb)		0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1
Injected Water (stb per day)																		
Cum. Inj. Water (mmstb)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
																		Information Bel
Sales Price (NZ$)																		
Gas ($ per GJ)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Condensate ($ per bbl)	110.19	107.80	102.39	106.30	108.66	111.02	113.38	115.74	118.10	119.94	121.78	123.62	125.46	127.30	128.74	130.18	131.62	133.06
Oil ($ per bbl)	110.19	107.80	102.39	106.30	108.66	111.02	113.38	115.74	118.10	119.94	121.78	123.62	125.46	127.30	128.74	130.18	131.62	133.06
Other (LPG etc)																		
Financial Model Assumptions																		
Capital Cost (% pa)	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
Discount Rate (% pa)	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Inflation Rate (% pa)	2.70	2.80	2.90	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Tax Rate (% pa)	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Outputs																		
Capital (NZ$ mm) (inflation adj.)	**7.60**	**39.06**	**50.82**	**127.85**	**131.68**	**103.76**	**106.87**	**110.07**	**113.38**	**0.00**	**96.76**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Operating (Fixed NZ$ mm) (inflation adj.)	**0.00**	**5.14**	**5.29**	**15.30**	**15.76**	**16.23**	**16.72**	**17.22**	**17.73**	**18.27**	**18.81**	**19.38**	**19.96**	**20.56**	**21.18**	**21.81**	**22.47**	**23.14**
Operating (Variable NZ$ mm)	**0.00**	**20.06**	**30.81**	**35.34**	**36.56**	**37.64**	**38.79**	**39.95**	**26.61**	**17.78**	**11.94**	**8.05**	**5.33**	**3.53**	**2.34**	**1.55**	**1.03**	**0.68**
Gas Processing & Carbon NZ$ mm (inflation adj.)	0	1	1	1	2	2	2	2	1	1	1	1	0	0	0	0	0	0
Liquids Trans./Treatment NZ$ mm (inflation adj.)		20	30	34	35	36	37	38	25	17	11	7	5	3	2	1	1	1
Water Treatment NZ$ mm (inflation adj.)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Revenues	**0.00**	**123.80**	**181.68**	**211.16**	**223.35**	**234.92**	**247.24**	**259.96**	**175.68**	**118.16**	**79.46**	**53.42**	**35.90**	**24.13**	**16.16**	**10.82**	**7.25**	**4.85**
Gas (NZ$ mm pa) - inflation adjusted	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil/Condensate (NZ$ mm pa) - inflation adj.	0.00	123.80	181.68	211.16	223.35	234.92	247.24	259.96	175.68	118.16	79.46	53.42	35.90	24.13	16.16	10.82	7.25	4.85
Oil (NZ$ mm pa) - inflation adj.																		
DCF Analysis																		
Net Revenue	**0.00**	**98.60**	**145.58**	**160.53**	**171.03**	**181.05**	**191.74**	**202.79**	**131.33**	**82.11**	**48.70**	**25.99**	**10.62**	**0.04**	**-7.35**	**-12.54**	**-16.24**	**-18.97**
AVR 5%	0.00	4.93	7.28	8.03	8.55	9.05	9.59	10.14	6.57	4.11	2.44	1.30	0.53	0.00	0.00	0.00	0.00	0.00
APR 20%	0.00	18.55	25.12	24.19	18.82	15.82	16.09	16.75	1.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Depreciation Scale	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Cum. Capital	7.60	44.38	81.89	185.17	261.31	286.67	307.54	325.35	341.12	238.78	263.91	184.74	129.32	90.52	63.37	44.36	31.05	21.73
Capital Depreciation	0.00	2.28	13.32	24.57	55.55	78.39	86.00	92.26	97.60	102.34	71.64	79.17	55.42	38.79	27.16	19.01	13.31	9.31
Capital Cost	0	4	7	15	21	24	25	27	28	20	22	15	11	8	5	4	3	2
Net Revenue less Cap.Cost		92.77	125.61	120.95	94.12	79.08	80.43	83.74	5.63	-40.17	-44.64	-68.61	-55.61	-46.32	-39.81	-35.25	-32.15	-30.10
Cum Net. Revenue less Cap. Cost	0.0	92.8	218.4	339.3	433.4	512.5	593.0	676.7	682.3	642.2	597.5	528.9	473.3	427.0	387.2	351.9	320	290
Net Rev+Depr.+Cap.Cost+Royalty	0.00	74.22	100.49	96.76	75.30	63.27	64.34	66.99	4.51	-40.17	-44.64	-68.61	-55.61	-46.32	-39.81	-35.25	-32.15	-30.10
Net Rev+Depr.+Cap.Cost+Royalty+Tax	0.0	52.0	70.3	67.7	52.7	44.3	45.0	46.9	3.2	-28.1	-31.3	-48.0	-38.9	-32	-28	-25	-23	-21
NPV Calc (Ex.Royalty)	**$418**	**mm**																
NPV Calc (Incl.Royalty)	**$236**	**mm**																
NPV Calc (Incl.Royalty and Taxes)	**$165**	**mm**																
VIR Calc (Inc.Royalty and Taxes)	**$193**	**PV Future Cashflows**																
	$363	**PV Investment**																
	0.53	**VIR**																

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Table 21 Scenario 3A

Development Economics Model																					
MRA 10 Oct 2012																					
NPV (NZ$mm 2012 Dollars)	*$688*	*Gross NPV Pre Royalty & Tax*																			
NPV (NZ$mm 2012 Dollars)	*$267*	*Post Royalty & Taxes*																			
Case Description	SC03A	PS for 5k bopd and gas processing sales with 3 seperate developments, i.e. 15,000 bopd. Well drilling rates limited by amaximum of 2 rigs working simultaneously.																			
	Assumes 3 of the SC03 Central 5000 bopd Production Station with 3 x 5 Development wells per year per Station for 6 years phased 2-3 years apart (limited by 2 ri																				
	Current 2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Inputs																					
Ann. New Exploration Well Count		3	3																		
Ann. New Production Well Count				5	5	5	10	10	10	10	10	10	10	5							
Ann. New Injection Well Count																					
Capital																					
Exploration G&G	2	2	2	2	2	2	2	2	4	4	4	4	4	2							
Exploration Seismic	5.6		10			10			10												
Exploration & Appraisal Wells		36	36	0																	
Development Seismic																					
Development Wells				85	85	85	170	170	170	170	170	170	170	85							
Subsea Equipment & Flowlines				20				20		20											
Platform/FPSO																					
Process Plant				27.50	27.50			27.50	27.50	27.50	27.5										
Intra-field Pipelines				2.50	2.50	2.50	2.50	2.50	5.00	5.00	5.00	5.00	5.00	2.50							
Onshore Power Generation (50 PJ pa)																					
Abandonment																					192
Abandonment Platform/Installation																					
Other																					
Operating (Fixed)																					
G&A		2.00	2.00	2.00	2.00	2.00	2.00	4.00	8.00	8.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00
OPEX Baseline (incl well re-entries etc)		3.00	3.00	12.00	12.00	12.00	12.00	12.00	24.00	48.00	48.00	72.00	72.00	72.00	72.00	72.00	72.00	72.00	72.00	72.00	72.00
Operating (Variable)																					
Gas Processing (per GJ)				1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
LNG Cooling and Liq/Storage (NZ$ per GJ)																					
Liquids Treat incl. Transport & Port etc (NZ$ per bbl)		17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
Water Treatment (NZ$ per bbl)		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Other - Gas F&F Carbon Cost (NZD/mscf)		1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43
Production Forecasts														0.701207							
Producing Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Gas Rate (mmscf per day)		3.36	5.05	5.47	5.50	5.50	7.15	9.90	13.20	16.50	16.50	11.57	8.11	5.69	3.99	2.80	1.96	1.38	0.96	0.68	0.47
Gas Fuel & Flare (mmscf per day)		3.36	5.05	5.47	5.50	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Cum. Gas incl Fuel (Bscf)		0.6	1.5	2.5	3.5	5.5	6.9	10.5	15.3	21.3	27.3	31.6	34.5	36.6	38.1	39.1	39.8	40.3	40.7	40.9	41.1
Cum Sales Gas, i.e less Fuel (Bscf)		0.0	0.0	0.0	0.0	0.6	1.6	3.0	5.1	7.7	10.4	12.1	13.2	13.9	14.3	14.4	14.4	14.3	14.1	13.9	13.6
Sales Gas, i.e less Fuel etc (PJ pa)		0.0	0.0	0.0	0.0	0.6	0.9	1.4	2.1	2.7	2.7	1.8	1.1	0.7	0.4	0.1	0.0	-0.1	-0.2	-0.2	-0.3
LNG Sales Gas (PJ pa)																					
LNG Sales Gas Cumulative (PJ)																					
BOE Cum		**1.2**	**3.0**	**5.0**	**7.0**	**9.2**	**11.8**	**15.7**	**20.9**	**27.3**	**33.8**	**38.4**	**41.6**	**43.8**	**45.4**	**46.5**	**47.2**	**47.8**	**48.1**	**48.4**	**48.6**
Oil/Condensate (stb per day)		3059	4588	4977	5000	5000	6500	9000	12000	15000	15000	10518	7375	5172	3626	2543	1783	1250	877	615	431
Cum. Oil/Condensate (mmstb)		1.1	2.8	4.6	6.4	8.3	10.6	13.9	18.3	23.8	29.3	33.1	35.8	37.7	39.0	39.9	40.6	41.1	41.4	41.6	41.8
LPG (t/day)																					
Produced Water (stb per day)		3	229	249	250	250	325	450	600	750	750	526	369	259	181	127	89	63	44	31	22
Cum. Prod. Water (mmstb)		0	0	0	0	0	0	1	1	1	1	2	2	2	2	2	2	2	2	2	2
Injected Water (stb per day)																					
Cum. Inj. Water (mmstb)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
																					Information Below this Line is Basic I
Sales Price (NZ$)																					
Gas ($ per GJ)	0.00	0.00	0.00	0.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
Condensate ($ per bbl)	110.19	107.80	102.39	106.30	108.66	111.02	113.38	115.74	118.10	119.94	121.78	123.62	125.46	127.30	128.74	130.18	131.62	133.06	134.50	135.60	136.70
Oil ($ per bbl)	110.19	107.80	102.39	106.30	108.66	111.02	113.38	115.74	118.10	119.94	121.78	123.62	125.46	127.30	128.74	130.18	131.62	133.06	134.50	135.60	136.70
Other (LPG etc)																					
Financial Model Assumptions																					
Capital Cost (% pa)	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
Discount Rate (% pa)	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Inflation Rate (% pa)	2.70	2.80	2.90	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Tax Rate (% pa)	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Outputs																					
Capital (NZ$ mm) (inflation adj.)	**7.60**	**39.06**	**50.82**	**149.70**	**131.68**	**115.35**	**208.36**	**273.03**	**274.26**	**295.53**	**277.52**	**247.78**	**255.21**	**131.43**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**346.77**
Operating (Fixed NZ$ mm) (inflation adj.)	**0.00**	**5.14**	**5.29**	**15.30**	**15.76**	**16.23**	**16.72**	**19.68**	**40.54**	**73.07**	**80.63**	**116.28**	**119.76**	**123.36**	**127.06**	**130.87**	**134.80**	**138.84**	**143.00**	**147.29**	**151.71**
Operating (Variable NZ$ mm)	**0.00**	**21.33**	**33.04**	**36.99**	**38.27**	**38.05**	**50.71**	**71.99**	**98.59**	**126.71**	**130.51**	**94.54**	**68.57**	**49.82**	**36.29**	**26.52**	**19.48**	**14.40**	**10.75**	**8.12**	**6.23**
Gas Processing & Carbon NZ$ mm (inflation adj.)	0	2	3	3	3	2	2	3	4	5	5	4	3	3	2	2	2	2	1	1	1
Liquids Trans./Treatment NZ$ mm (inflation adj.)		20	30	34	35	36	48	69	94	122	125	90	65	47	34	25	18	13	9	7	5
Water Treatment NZ$ mm (inflation adj.)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Revenues	**0.00**	**123.80**	**181.68**	**211.16**	**223.35**	**238.02**	**325.92**	**475.05**	**666.12**	**871.26**	**910.95**	**667.10**	**488.25**	**357.10**	**260.13**	**189.28**	**137.51**	**99.68**	**72.03**	**51.69**	**36.85**
Gas (NZ$ mm pa) - inflation adjusted	0.00	0.00	0.00	0.00	0.00	2.97	4.51	7.12	10.40	13.87	14.28	9.71	6.39	3.97	2.21	0.91	-0.05	-0.76	-1.29	-1.70	-2.02
Oil/Condensate (NZ$ mm pa) - inflation adj.	0.00	123.80	181.68	211.16	223.35	235.04	321.41	467.93	655.72	857.39	896.66	657.39	481.87	353.13	257.93	188.37	137.55	100.43	73.32	53.39	38.87
Oil (NZ$ mm pa) - inflation adj.																					
DCF Analysis																					
Net Revenue	**0.00**	**97.3**	**143.3**	**158.9**	**169.3**	**183.7**	**258.5**	**383.4**	**527.0**	**671.5**	**699.8**	**456.3**	**299.9**	**183.9**	**96.8**	**31.9**	**-16.8**	**-53.6**	**-81.7**	**-103.7**	**-121.1**
AVR 5%	0.00	4.9	7.2	7.9	8.5	9.2	12.9	19.2	26.3	33.6	35.0	22.8	15.0	9.2	4.8	1.6	0.0	0.0	0.0	0.0	0.0
APR 20%	0.00	18.3	24.7	23.5	16.9	15.1	26.2	41.9	60.1	81.3	80.5	28.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Depreciation Scale	0.70	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Cum. Capital	7.60	44.4	81.9	207.0	276.6	309.0	424.6	570.3	673.5	766.9	814.4	817.8	827.7	710.8	497.6	348.3	243.8	170.7	119.5	83.6	405.3
Capital Depreciation	0.00	2.3	13.3	24.6	62.1	83.0	92.7	127.4	171.1	202.0	230.1	244.3	245.4	248.3	213.2	149.3	104.5	73.1	51.2	35.8	25.1
Capital Cost	0	3.6	6.7	16.8	22.6	25.4	34.7	46.7	55.3	63.0	67.0	67.4	68.2	58.9	41.6	29.1	20.4	14.3	10.0	7.0	32.6
Net Revenue less Cap.Cost		91.5	123.4	117.5	84.6	75.4	131.1	209.3	300.6	406.4	402.7	144.5	-13.7	-123.3	-158.0	-146.5	-141.6	-141.0	-142.9	-146.6	-178.8
Cum Net. Revenue less Cap. Cost	0.0	91.5	214.9	332.4	417.0	492.4	623.4	832.7	1133.4	1539.8	1942.5	2087.0	2073.4	1950.1	1792.0	1645.5	1503.9	1362.9	1220.0	1073.5	894.6
Net Rev+Depr.+Cap.Cost+Royalty	0.00	73.2	98.7	94.0	67.7	60.3	104.9	167.5	240.5	325.1	322.1	115.6	-13.7	-123.3	-158.0	-146.5	-141.6	-141.0	-142.9	-146.6	-178.8
Net Rev+Depr.+Cap.Cost+Royalty+Tax	0.0	51.2	69.1	65.8	47.4	42.2	73.4	117.2	168.4	227.6	225.5	80.9	-9.6	-86	-111	-103	-99	-99	-100	-103	-125
NPV Calc (Ex.Royalty)	**$688**	**mm**																			
NPV Calc (Incl.Royalty)	**$381**	**mm**																			
NPV Calc (Incl.Royalty and Taxes)	**$267**	**mm**																			
VIR Calc (Inc.Royalty and Taxes)	**$312**	**PV Future Cashflows**																			
	$667	**PV Investment**																			
	0.47	**VIR**																			

Table 22 Scenario 4

Development Economics Model

MRA 11 Oct 2012 CAPEX Check 1437.5

NPV (NZ$mm 2012 Dollars) ***$3,398*** *Gross NPV Pre Royalty & Tax*

NPV (NZ$mm 2012 Dollars) ***$1,316*** *Post Royalty & Taxes*

Case Description SC04 PS for 100k bopd and gas processing sales. SC05 but 0.55 MMBOE per well instead of 1.0 MMBOE per well. Costs the same. Capped Annual CAPEX of NZ$1 Billion per annum. Reduce well count to control.

Assumes Central 100,000 bopd Production Station and 3 or 4 x 12 wells per site per year until 600 wells drilled . 260 km2 of producing area developed.

	Current 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Inputs															
Ann. New Exploration Well Count		4	2	4											
Ann. New Production Well Count						45	50	50	50	50	50	50	45	45	40
Ann. New Injection Well Count															
Capital															
Exploration G&G	2.0	2.0	2.0	2.0											
Exploration Seismic	5.6		10.0												
Exploration & Appraisal Wells		45.0	22.5	45.0											
Development Seismic															
Development Wells						506.3	562.5	562.5	562.5	562.5	562.5	562.5	506.3	506.3	450.0
Production Site Equipment & Flowlines					25.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
Platform/FPSO															
Process Plant & Export Lines				133.3	291.5	258.3									
Intra-field Pipelines					12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Onshore Power Generation (50 PJ pa)															
Abandonment															
Abandonment Platform/Installation															
Other															
Operating (Fixed)															
G&A					3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
OPEX Baseline (incl well re-entries etc)					70.00	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20
Operating (Variable)															
Gas Processing (per GJ)					1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
LNG Cooling and Liq/Storage (NZ$ per GJ)															
Liquids Treat incl. Transport & Port etc (NZ$ per bbl)		17.00	17.00	17.00	17.00	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80
Water Treatment (NZ$ per bbl)		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Other - Gas F&F Carbon Cost (NZD/mscf)		1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43
Production Forecasts															
Producing Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14
Gas Rate (mmscf per day)		1.16	0.87	1.52	0.37	8.70	21.76	28.34	40.44	46.59	49.80	63.70	71.61	79.10	82.50
Gas Fuel & Flare (mmscf per day)		1.16	0.87	1.52	0.37	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Cum. Gas incl Fuel (Bscf)		0.2	0.4	0.6	0.7	3.9	7.9	18.2	33.0	50.0	68.2	91.5	117.6	146.5	176.6
Cum Sales Gas, i.e less Fuel (Bscf)		0.0	0.0	0.0	0.0	2.0	4.1	7.5	13.1	19.7	27.0	36.8	48.1	60.7	73.9
Sales Gas, i.e less Fuel etc (PJ pa)		0.0	0.0	0.0	0.0	2.0	2.2	3.4	5.6	6.7	7.3	9.8	11.3	12.7	13.3
LNG Sales Gas (PJ pa)															
LNG Sales Gas Cumulative (PJ)															
BOE Cum		**0.4**	**0.7**	**1.3**	**1.4**	**5**	**13**	**24**	**40**	**58**	**78**	**103**	**131**	**162**	**194**
Oil/Condensate (stb per day)		1055	791	1386	335	7911	19778	25761	36765	42359	45276	57912	65097	71908	75000
Cum. Oil/Condensate (mmstb)		0.4	0.7	1.2	1.3	4.2	11.4	20.8	34.3	49.7	66.3	87.4	111.2	137.5	164.8
LPG (t/day)															
Produced Water (stb per day)		1.05	0.79	5.38	16.74	396	989	1288	1838	2118	2264	2896	3255	3595	3750
Cum. Prod. Water (mmstb)		0.0	0.0	0.0	0.0	0.2	0.5	1.0	1.7	2.4	3.3	4	6	7	8
Injected Water (stb per day)															
Cum. Inj. Water (mmstb)		0	0	0	0	0	0	0	0	0	0	0	0	0	0
Information Below this Line is Basic Financial Model Only - i.e. OUTPUTS															
Sales Price (NZ$)															
Gas ($ per GJ)	0.00	0.00	0.00	0.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
Condensate ($ per bbl)	110.19	107.80	102.39	106.30	108.66	111.02	113.38	115.74	118.10	119.94	121.78	123.62	125.46	127.30	128.74
Oil ($ per bbl)	110.19	107.80	102.39	106.30	108.66	111.02	113.38	115.74	118.10	119.94	121.78	123.62	125.46	127.30	128.74
Other (LPG etc)															
Financial Model Assumptions															
Capital Cost (% pa)	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
Discount Rate (% pa)	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Inflation Rate (% pa)	2.70	2.80	2.90	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Tax Rate (% pa)	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Outputs															
Capital (NZ$ mm) (inflation adj.)	**7.60**	**48.32**	**36.53**	**197.04**	**371.25**	**907.56**	**693.51**	**714.31**	**735.74**	**757.81**	**780.55**	**803.96**	**747.88**	**770.32**	**708.35**
Operating (Fixed NZ$ mm) (inflation adj.)	**0.00**	**0.00**	**0.00**	**0.00**	**82.16**	**125.43**	**129.20**	**133.07**	**137.06**	**141.18**	**145.41**	**149.77**	**154.27**	**158.90**	**163.66**
Operating (Variable NZ$ mm)	**0.00**	**7.36**	**5.68**	**10.28**	**2.56**	**34.67**	**76.51**	**101.39**	**147.20**	**174.02**	**191.27**	**250.69**	**289.64**	**329.03**	**353.25**
Gas Processing & Carbon NZ$ mm (inflation adj.)	0	1	0	1	0	8	9	11	14	16	17	21	24	26	28
Liquids Trans./Treatment NZ$ mm (inflation adj.)		7	5	9	2	26	67	90	133	157	173	228	264	301	323
Water Treatment NZ$ mm (inflation adj.)	0	0	0	0	0	0	0	1	1	1	1	1	2	2	2
Revenues	**0.00**	**42.69**	**31.33**	**58.81**	**14.95**	**381.20**	**988.28**	**1355.89**	**2037.20**	**2456.19**	**2745.68**	**3674.05**	**4317.46**	**4984.36**	**5414.78**
Gas (NZ$ mm pa) - inflation adjusted	0.00	0.00	0.00	0.00	0.00	9.31	10.29	16.53	28.26	35.00	39.21	54.49	64.38	74.38	80.38
Oil/Condensate (NZ$ mm pa) - inflation adj.	0.00	42.69	31.33	58.81	14.95	371.90	977.99	1339.36	2008.94	2421.20	2706.47	3619.56	4253.08	4909.99	5334.41
Oil (NZ$ mm pa) - inflation adj.															
DCF Analysis															
Net Revenue	**0.00**	**35.34**	**25.64**	**48.53**	**-69.77**	**221.10**	**782.57**	**1121.43**	**1752.93**	**2141.00**	**2409.00**	**3273.59**	**3873.55**	**4496.44**	**4897.87**
AVR 5%	0.00	1.77	1.28	2.43	0.00	11.06	39.13	56.07	87.65	107.05	120.45	163.68	193.68	224.82	244.89
APR 20%	0.00	5.75	0.70	1.24	0.00	0.00	52.99	98.43	207.50	271.41	313.71	476.98	589.69	712.20	790.68
Depreciation Scale	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Cum. Capital	7.60	53.64	74.08	248.89	545.47	1289.39	1596.08	1831.57	2017.84	2170.30	2299.76	2413.79	2437.54	2476.60	2441.96
Capital Depreciation	0.00	2.28	16.09	22.22	74.67	163.64	386.82	478.82	549.47	605.35	651.09	689.93	724.14	731.26	742.98
Capital Cost	0	4	6	20	44	104	131	150	166	179	189	199	201	204	201
Net Revenue less Cap.Cost		28.77	3.50	6.22	-188.68	-47.02	264.94	492.16	1037.52	1357.04	1568.57	2384.88	2948.45	3561.02	3953.41
Cum Net. Revenue less Cap. Cost	0.0	28.8	32.3	38.5	-150.2	-197.2	67.7	559.9	1597.4	2954.4	4523.0	6907.9	9856.3	13417.4	17370.8
Net Rev+Depr.+Cap.Cost+Royalty	0.00	23.01	2.80	4.97	-188.68	-47.02	211.95	393.73	830.02	1085.64	1254.85	1907.90	2358.76	2848.82	3162.73
Net Rev+Depr.+Cap.Cost+Royalty+Tax	0.0	16.1	2.0	3.5	-188.7	-47.0	148.4	275.6	581.0	759.9	878.4	1335.5	1651.1	1994	2214

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Inputs															
Ann. New Exploration Well Count															
Ann. New Production Well Count	40	35	30	20											
Ann. New Injection Well Count															
Capital															
Exploration G&G															
Exploration Seismic															
Exploration & Appraisal Wells															
Development Seismic															
Development Wells	450.0	393.8	337.5	225.0											
Production Site Equipment & Flowlines	5.8	5.8	5.8												
Platform/FPSO															
Process Plant & Export Lines															
Intra-field Pipelines	12.5	12.5	12.5												
Onshore Power Generation (50 PJ pa)															
Abandonment															610.00
Abandonment Platform/Installation															
Other															
Operating (Fixed)															
G&A	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
OPEX Baseline (incl well re-entries etc)	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20
Operating (Variable)															
Gas Processing (per GJ)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
LNG Cooling and Liq/Storage (NZ$ per GJ)															
Liquids Treat incl. Transport & Port etc (NZ$ per bbl)	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80
Water Treatment (NZ$ per bbl)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Other - Gas F&F Carbon Cost (NZD/mscf)	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43
Production Forecasts	0.814415														
Producing Year	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
Gas Rate (mmscf per day)	67.19	54.72	44.56	36.29	29.56	24.07	19.61	15.97	13.00	10.59	8.63	7.02	5.72	4.66	3.79
Gas Fuel & Flare (mmscf per day)	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	5.72	4.66	3.79
Cum. Gas incl Fuel (Bscf)	201.2	221.2	237.4	250.7	261.5	270.3	277.5	283.29	288.04	291.91	295.06	297.62	299.71	301.41	302.80
Cum Sales Gas, i.e less Fuel (Bscf)	84.4	92.5	98.8	103.7	107.2	109.8	111.5	112.6	113.2	113.3	113.0	112.5	112.5	112.5	112.5
Sales Gas, i.e less Fuel etc (PJ pa)	10.5	8.2	6.3	4.8	3.6	2.6	1.8	1.1	0.6	0.1	-0.3	-0.5	0.0	0.0	0.0
LNG Sales Gas (PJ pa)															
LNG Sales Gas Cumulative (PJ)															
BOE Cum	**221**	**242**	**260**	**274**	**286**	**295**	**303**	**309**	**314**	**318**	**322**	**324**	**327**	**329**	**330**
Oil/Condensate (stb per day)	61081	49745	40513	32995	26871	21885	17823	14515	11822	9628	7841	6386	5201	4236	3449
Cum. Oil/Condensate (mmstb)	187.2	205.3	220.1	232.2	242.0	250.0	256.5	261.8	266.1	269.6	272.5	274.8	276.7	278.3	279.5
LPG (t/day)															
Produced Water (stb per day)	3054	2487	2026	1650	1344	1094	891	726	591	481	392	319	260	212	172
Cum. Prod. Water (mmstb)	9	10	11	12	12	12	13	13	13	13	14	14	14	14	14
Injected Water (stb per day)															
Cum. Inj. Water (mmstb)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Information Below this Line is Basic Financial Model Only - i.e. OUTPUTS															
Sales Price (NZ$)															
Gas ($ per GJ)	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
Condensate ($ per bbl)	130.18	131.62	133.06	134.50	135.60	136.70	137.80	138.90	140.00	140.60	141.20	141.80	142.40	143.00	143.60
Oil ($ per bbl)	130.18	131.62	133.06	134.50	135.60	136.70	137.80	138.90	140.00	140.60	141.20	141.80	142.40	143.00	143.60
Other (LPG etc)															
Financial Model Assumptions															
Capital Cost (% pa)	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
Discount Rate (% pa)	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Inflation Rate (% pa)	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Tax Rate (% pa)	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Outputs															
Capital (NZ$ mm) (inflation adj.)	**729.60**	**661.22**	**588.08**	**383.05**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**1437.50**
Operating (Fixed NZ$ mm) (inflation adj.)	**168.57**	**173.63**	**178.84**	**184.20**	**189.73**	**195.42**	**201.28**	**207.32**	**213.54**	**219.95**	**226.55**	**233.34**	**240.34**	**247.55**	**254.98**
Operating (Variable NZ$ mm)	**297.30**	**250.40**	**211.08**	**178.13**	**150.53**	**127.40**	**108.04**	**91.83**	**78.27**	**66.93**	**57.46**	**49.55**	**39.75**	**33.34**	**27.97**
Gas Processing & Carbon NZ$ mm (inflation adj.)	24	22	19	17	15	14	13	12	11	11	10	10	7	6	5
Liquids Trans./Treatment NZ$ mm (inflation adj.)	271	227	191	160	134	113	94	79	66	56	47	39	33	28	23
Water Treatment NZ$ mm (inflation adj.)	2	1	1	1	1	1	1	1	0	0	0	0	0	0	0
Revenues	**4590.11**	**3890.21**	**3296.26**	**2792.29**	**2358.85**	**1992.14**	**1681.90**	**1419.42**	**1197.37**	**1005.93**	**844.58**	**708.56**	**600.85**	**506.14**	**426.36**
Gas (NZ$ mm pa) - inflation adjusted	65.31	52.60	41.87	32.81	25.14	18.63	13.10	8.38	4.35	0.88	-2.11	-4.70	0.00	0.00	0.00
Oil/Condensate (NZ$ mm pa) - inflation adj.	4524.81	3837.61	3254.39	2759.48	2333.72	1973.51	1668.80	1411.04	1193.02	1005.06	846.69	713.26	600.85	506.14	426.36
Oil (NZ$ mm pa) - inflation adj.															
DCF Analysis															
Net Revenue	**4124.24**	**3466.18**	**2906.34**	**2429.95**	**2018.60**	**1669.32**	**1372.57**	**1120.27**	**905.56**	**719.05**	**560.57**	**425.66**	**320.76**	**225.25**	**143.41**
AVR 5%	206.21	173.31	145.32	121.50	100.93	83.47	68.63	56.01	45.28	35.95	28.03	21.28	16.04	11.26	7.17
APR 20%	638.10	507.80	402.05	318.83	263.53	235.73	205.82	175.97	147.45	120.25	95.62	73.59	56.07	39.39	1.72
Depreciation Scale	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Cum. Capital	2438.97	2368.50	2246.03	1955.27	1368.69	958.08	670.66	469.46	328.62	230.04	161.02	112.72	78.90	55.23	1476.17
Capital Depreciation	732.59	731.69	710.55	673.81	586.58	410.61	287.42	201.20	140.84	98.59	69.01	48.31	33.82	23.67	16.57
Capital Cost	201	196	186	162	114	80	56	39	27	19	13	9	7	5	118
Net Revenue less Cap.Cost	3190.49	2538.98	2010.25	1594.16	1317.66	1178.63	1029.09	879.83	737.25	601.24	478.10	367.93	280.35	196.96	8.61
Cum Net. Revenue less Cap. Cost	20561.3	23100	25110	26705	28022	29201	30230	31110	31847	32448	32926	33294	33575	33772	33780
Net Rev+Depr.+Cap.Cost+Royalty	2552.39	2031.18	1608.20	1275.33	1054.13	942.91	823.27	703.87	589.80	480.99	382.48	294.34	224.28	157.57	6.89
Net Rev+Depr.+Cap.Cost+Royalty+Tax	1787	1422	1126	893	738	660	576	493	413	337	268	206	157	110	5

NPV Calc (Ex.Royalty)	**$3,398**	**mm**
NPV Calc (Incl.Royalty)	**$1,920**	**mm**
NPV Calc (Incl.Royalty and Taxes)	**$1,316**	**mm**
VIR Calc (Inc.Royalty and Taxes)	**$1,537**	**PV Future Cashflows**
	$2,057	**PV Investment**
	0.75	**VIR**

Table 23 Scenario 4A (page 1 of 2)

Development Economics Model																					
MRA 10 Oct 2012					CAPEX Check																
										1038.338	1069.49	1101.57	1134.62	1021.81	1203.72	1247.62	1646.11	1695.49	1576.11	1623.4	1672.1
NPV (NZ$mm 2012 Dollars)	*$7,625*	*Gross NPV Pre Royalty & Tax*																			
NPV (NZ$mm 2012 Dollars)	*$3,023*	*Post Royalty & Taxes*																			
Case Description	SC04A	PS for 100k bopd and gas processing sales with 3 different developments. SC05A but 0.55 MMBOE per well instead of 1.0 MMBOE per well. Costs kept the same as Sc05A.																			
	Assumes 3 x 100,000 bopd Production Station and wells drilled at 12 wells per site at a rate capped initially by NZ$1 billion CAPEX pa and increasing slowly fron																				
	Current																				
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Inputs																					
Ann. New Exploration Well Count		4	2	4																	
Ann. New Production Well Count						45	50	50	50	60	60	60	60	60	60	60	80	80	80	80	80
Ann. New Injection Well Count																					
Capital																					
Exploration G&G	2	2	2	2																	
Exploration Seismic	5.6		10																		
Exploration & Appraisal Wells		45.0	22.5	45.0																	
Development Seismic																					
Development Wells						506.25	562.5	562.5	562.5	675	675	675	675	675	675	675	900	900	900	900	900
Production Site Equipment & Flowlines					5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80
Platform/FPSO																					
Process Plant & Export Lines					258	225	100	100		100	100	100	100		100	100	100	100			
Intra-field Pipelines					11.25	12.50	12.50	12.50	15.00	15.00	15.00	15.00	15.00	15.00	15.00	20.00	20.00	20.00	20.00	20.00	20.00
Onshore Power Generation (50 PJ pa)																					
Abandonment																					
Abandonment Platform/Installation																					
Other																					
Operating (Fixed)																					
G&A					3.00	3.00	3.00	3.00	3.00	6.00	6.00	6.00	6.00	6.00	6.00	9.00	9.00	9.00	9.00	9.00	9.00
OPEX Baseline (incl well re-entries etc)					70.00	85.20	85.20	85.20	85.20	170.40	170.40	170.40	170.40	170.40	170.40	255.60	255.60	255.60	255.60	255.60	255.60
Operating (Variable)																					
Gas Processing (per GJ)					1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
LNG Cooling and Liq/Storage (NZ$ per GJ)																					
Liquids Treat incl. Transport & Port etc (NZ$ per bbl)		17.00	17.00	17.00	17.00	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80
Water Treatment (NZ$ per bbl)		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Other - Gas F&F Carbon Cost (NZD/mscf)		1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43
Production Forecasts																					
Producing Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Gas Rate (mmscf per day)		1.16	0.87	1.52	0.37	8.70	21.76	28.34	40.44	55.30	71.56	92.04	112.05	134.40	154.06	165.00	165.00	165.00	165.00	165.00	165.00
Gas Fuel & Flare (mmscf per day)		1.16	0.87	1.52	0.37	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Cum. Gas incl Fuel (Bscf)		0.2	0.4	0.6	0.7	3.9	7.9	18.2	33.0	53.2	79.3	112.9	153.9	203.0	259.2	319.5	379.8	440.0	500.3	560.6	620.8
Cum Sales Gas, i.e less Fuel (Bscf)		0.0	0.0	0.0	0.0	-0.2	1.9	5.3	10.8	19.1	30.3	45.3	64.0	86.7	113.0	141.3	169.6	197.9	226.2	254.5	282.8
Sales Gas, i.e less Fuel etc (PJ pa)		0.0	0.0	0.0	0.0	-0.2	2.2	3.4	5.6	8.3	11.3	15.0	18.7	22.8	26.4	28.4	28.4	28.4	28.4	28.4	28.4
LNG Sales Gas (PJ pa)																					
LNG Sales Gas Cumulative (PJ)																					
BOE Cum		**0.4**	**0.7**	**1.3**	**1.4**	**5**	**13**	**24**	**40**	**61**	**90**	**126**	**170**	**223**	**283**	**348**	**413**	**478**	**542**	**607**	**672**
Oil/Condensate (stb per day)		1055	791	1386	335	7911	19778	25761	36765	50270	65054	83673	101862	122178	140054	150000	150000	150000	150000	150000	150000
Cum. Oil/Condensate (mmstb)		0.4	0.7	1.2	1.3	4.2	11.4	20.8	34.3	52.6	76.4	106.9	144.1	188.8	239.9	294.7	349.5	404.3	459.1	513.9	568.6
LPG (t/day)																					
Produced Water (stb per day)		1	1	5	17	396	989	1288	1838	2513	3253	4184	5093	6109	7003	7500	7500	7500	7500	7500	7500
Cum. Prod. Water (mmstb)		0	0	0	0	0	1	1	2	3	4	5	7	9	12	15	17	20	23	26	28
Injected Water (stb per day)																					
Cum. Inj. Water (mmstb)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
																					Information Below this Line is Basic
Sales Price (NZ$)																					
Gas ($ per GJ)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
Condensate ($ per bbl)	110.19	107.80	102.39	106.30	108.66	111.02	113.38	115.74	118.10	119.94	121.78	123.62	125.46	127.30	128.74	130.18	131.62	133.06	134.50	135.60	136.70
Oil ($ per bbl)	110.19	107.80	102.39	106.30	108.66	111.02	113.38	115.74	118.10	119.94	121.78	123.62	125.46	127.30	128.74	130.18	131.62	133.06	134.50	135.60	136.70
Other (LPG etc)																					
Financial Model Assumptions																					
Capital Cost (% pa)	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
Discount Rate (% pa)	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Inflation Rate (% pa)	2.70	2.80	2.90	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Tax Rate (% pa)	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Outputs																					
Capital (NZ$ mm) (inflation adj.)	**8**	**48**	**37**	**51**	**310**	**869**	**813**	**837**	**739**	**1038**	**1069**	**1102**	**1135**	**1022**	**1204**	**1248**	**1646**	**1695**	**1576**	**1623**	**1672**
Operating (Fixed NZ$ mm) (inflation adj.)	**0**	**0**	**0**	**0**	**82**	**102**	**105**	**108**	**112**	**230**	**237**	**244**	**252**	**259**	**267**	**412**	**425**	**437**	**450**	**464**	**478**
Operating (Variable NZ$ mm)	**0**	**7**	**6**	**10**	**3**	**32**	**77**	**101**	**147**	**206**	**273**	**360**	**451**	**556**	**655**	**722**	**744**	**766**	**789**	**813**	**837**
Gas Processing & Carbon NZ$ mm (inflation adj.)	0	1	0	1	0	6	9	11	14	18	22	28	34	41	48	52	54	56	57	59	61
Liquids Trans./Treatment NZ$ mm (inflation adj.)		7	5	9	2	26	67	90	133	187	249	330	414	511	604	666	686	706	728	749	772
Water Treatment NZ$ mm (inflation adj.)	0	0	0	0	0	0	0	1	1	1	2	2	3	3	4	4	4	5	5	5	5
Revenues	**0**	**43**	**31**	**59**	**15**	**372**	**978**	**1339**	**2037**	**2917**	**3949**	**5313**	**6762**	**8476**	**10121**	**11289**	**11754**	**12237**	**12739**	**13226**	**13732**
Gas (NZ$ mm pa) - inflation adjusted	0	0	0	0	0	0	0	0	28	43	61	83	107	134	160	177	182	188	193	199	205
Oil/Condensate (NZ$ mm pa) - inflation adj.	0	43	31	59	15	372	978	1339	2009	2873	3889	5230	6655	8342	9961	11112	11572	12049	12545	13027	13527
Oil (NZ$ mm pa) - inflation adj.																					
DCF Analysis																					
Net Revenue	**0**	**35**	**26**	**49**	**-70**	**238**	**796**	**1129**	**1778**	**2481**	**3439**	**4709**	**6060**	**7662**	**9199**	**10154**	**10585**	**11033**	**11499**	**11949**	**12417**
AVR 5%	0	2	1	2	0	12	40	56	89	124	172	235	303	383	460	508	529	552	575	597	621
APR 20%	0	6	1	4	0	6	65	97	203	328	490	721	973	1280	1582	1758	1824	1875	1940	2016	2097
Depreciation Scale	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Cum. Capital	8	54	74	103	382	1136	1608	1963	2113	2518	2832	3084	3293	3327	3533	3721	4250	4671	4846	5015	5183
Capital Depreciation	0	2	16	22	31	115	341	483	589	634	755	850	925	988	998	1060	1116	1275	1401	1454	1505
Capital Cost	0	4	6	8	31	92	131	161	174	207	233	254	271	274	291	306	349	384	399	413	427
Net Revenue less Cap.Cost		29	3	18	-132	31	324	486	1015	1640	2451	3605	4863	6399	7910	8788	9120	9374	9698	10082	10485
Cum Net. Revenue less Cap. Cost	0	29	32	50	-81	-50	274	760	1775	3415	5867	9472	14336	20735	28645	37433	46553	55927	65625	75708	86193
Net Rev+Depr.+Cap.Cost+Royalty	0	23	3	14	-132	25	259	389	812	1312	1961	2884	3891	5120	6328	7030	7296	7499	7759	8066	8388
Net Rev+Depr.+Cap.Cost+Royalty+Tax	0	16	2	10	-132	25	181	272	569	919	1373	2019	2724	3584	4430	4921	5107	5249	5431	5646	5872
NPV Calc (Ex.Royalty)	**$7,625**	**mm**																			
NPV Calc (Incl.Royalty)	**$4,338**	**mm**																			
NPV Calc (Incl.Royalty and Taxes)	**$3,023**	**mm**																			
VIR Calc (Inc.Royalty and Taxes)	**$3,532**	**PV Future Cashflows**																			
	$2,727	**PV Investment**																			
	1.30	**VIR**																			

Table 24 Scenario 4A (page 2 of 2)

1722.26	1773.93	1827.15	1881.96	1938.42	1996.57	2056.47	2106.72	1627.92	1124.55								1844.87	1900.22	1989.84
m 2021. Overall around 780 km2 of producing area developed.																			
2033	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**
80	80	80	80	80	80	80	80	60	40	30	15								
900	900	900	900	900	900	900	900	675	450	337.5	168.75								
5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80								
20.00	20.00	20.00	20.00	20.00	20.00	20.00	15.00	10.00	7.50	3.75									
																	600.00	600.00	610.00
9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
255.60	255.60	255.60	255.60	255.60	255.60	255.60	255.60	255.60	255.60	255.60	255.60	255.60	255.60	255.60	255.60	255.60	255.60	255.60	255.60
1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
7.80	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43
0.83438																			
21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
137.67	114.87	95.85	79.97	66.73	55.68	46.45	38.76	32.34	26.99	22.52	18.79	15.68	13.08	10.91	9.11	7.60	6.34	5.29	4.41
10.00	10.00	10.00	10.00	10.00	10.00	46.45	38.76	32.34	26.99	22.52	18.79	15.68	13.08	10.91	9.11	7.60	6.34	5.29	4.41
671.1	713.06	748.07	777.28	801.65	821.99	838.96	853.12	864.93	874.78	883.01	889.87	895.60	900.37	904.36	907.68	910.46	912.77	914.71	916.32
306.1	325.3	341.0	353.7	364.1	372.4	372.4	372.4	372.4	372.4	372.4	372.4	372.4	372.4	372.4	372.4	372.4	372.4	372.4	372.4
23.4	19.2	15.7	12.8	10.4	8.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
726	**771**	**809**	**840**	**867**	**889**	**907**	**922**	**935**	**945**	**954**	**962**	**968**	**973**	**977**	**981**	**984**	**986**	**988**	**990**
125157	104429	87133	72702	60661	50615	42232	35237	29401	24532	20469	17079	14250	11890	9921	8278	6907	5763	4808	4012
614.4	652.5	684.3	710.9	733.0	751.5	767.0	779.8	790.6	799.5	807.0	813.2	818.4	822.8	826.4	829.4	832.0	834.1	835.8	837.3
6258	5221	4357	3635	3033	2531	2112	1762	1470	1227	1023	854	713	595	496	414	345	288	240	201
31	33	34	35	37	38	38	39	39	40	40	41	41	41	41	41	42	42	42	42
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Financial Model Only - i.e. OUTPUTS																			
4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
137.80	138.90	140.00	140.60	141.20	141.80	142.40	143.00	143.60	144.20	144.80	145.40	146.00	146.60	147.20	147.20	147.20	147.20	147.20	147.20
137.80	138.90	140.00	140.60	141.20	141.80	142.40	143.00	143.60	144.20	144.80	145.40	146.00	146.60	147.20	147.20	147.20	147.20	147.20	147.20
8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
1722	**1774**	**1827**	**1882**	**1938**	**1997**	**2056**	**2107**	**1628**	**1125**	**868**	**449**	**0**	**0**	**0**	**0**	**0**	**1845**	**1900**	**1990**
492	**507**	**522**	**538**	**554**	**571**	**588**	**605**	**624**	**642**	**662**	**681**	**702**	**723**	**745**	**767**	**790**	**814**	**838**	**863**
721	**1293**	**1112**	**957**	**824**	**709**	**638**	**548**	**471**	**405**	**348**	**299**	**257**	**221**	**190**	**163**	**140**	**121**	**104**	**89**
53	47	41	37	33	29	54	46	40	34	29	25	22	19	16	14	12	10	9	8
663	1242	1068	918	789	678	582	501	430	370	318	273	235	202	173	149	128	110	95	81
4	4	3	3	2	2	2	1	1	1	1	1	1	1	1	0	0	0	0	0
11893	**10299**	**8918**	**7694**	**6637**	**5726**	**4879**	**4211**	**3634**	**3136**	**2707**	**2336**	**2016**	**1739**	**1501**	**1290**	**1109**	**953**	**819**	**704**
174	147	124	104	87	72	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11719	10152	8793	7590	6550	5653	4879	4211	3634	3136	2707	2336	2016	1739	1501	1290	1109	953	819	704
10680	**8499**	**7283**	**6199**	**5260**	**4446**	**3653**	**3057**	**2539**	**2089**	**1697**	**1355**	**1057**	**796**	**566**	**360**	**178**	**19**	**-123**	**-248**
534	425	364	310	263	222	183	153	127	104	85	68	53	40	28	18	9	1	0	0
1737	1288	1032	802	600	424	251	118	9	0	0	0	0	0	0	0	0	0	0	0
1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
5350	5519	5691	5865	6044	6227	6416	6598	6246	5497	4716	3750	2625	1838	1286	900	630	2286	3500	4440
1555	1605	1656	1707	1760	1813	1868	1925	1979	1874	1649	1415	1125	788	551	386	270	189	686	1050
441	455	469	483	498	513	529	544	516	455	391	312	219	154	108	75	53	184	286	364
8684	6439	5159	4008	3002	2120	1257	589	44	-240	-343	-371	-288	-146	-92	-101	-144	-355	-1094	-1662
94877	101316	106474	110483	113485	115604	116861	117450	117494	117253	116910	116539	116251	116106	116013	115912	115768	115413	114319	112656
6947	5151	4127	3207	2402	1696	1005	471	35	-240	-343	-371	-288	-146	-92	-101	-144	-355	-1094	-1662
4863	3606	2889	2245	1681	1187	704	330	25	-168	-240	-260	-201	-102	-65	-71	-101	-248	-766	-1164

Table 25 Scenario 5 (page 1 of 2)

Development Economics Model																	
MRA 10 Oct 2012					CAPEX Check												
NPV (NZ$mm 2012 Dollars)	*$8,205*	*Gross NPV Pre Royalty & Tax*															
NPV (NZ$mm 2012 Dollars)	*$3,245*	*Post Royalty & Taxes*															
Case Description	SC05	PS for 100k bopd and gas processing sales. Capped Annual CAPEX of NZ$1 Billion per annum. Reduce well count to control.															
	Assumes Central 100,000 bopd Production Station and 3 or 4 x 12 wells per site per year until 600 wells drilled . 260 km2 of produ																
	Current 2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Inputs																	
Ann. New Exploration Well Count		4	2	4													
Ann. New Production Well Count						45	50	50	50	50	50	50	45	45	40	40	35
Ann. New Injection Well Count																	
Capital																	
Exploration G&G	2	2	2	2													
Exploration Seismic	5.6		10														
Exploration & Appraisal Wells		45.0	22.5	45.0													
Development Seismic																	
Development Wells						506.25	562.5	562.5	562.5	562.5	562.5	562.5	506.25	506.25	450	450	393.75
Production Site Equipment & Flowlines					25.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.8	5.8
Platform/FPSO																	
Process Plant & Export Lines				133.32	292	258											
Intra-field Pipelines					12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.5	12.5
Onshore Power Generation (50 PJ pa)																	
Abandonment																	
Abandonment Platform/Installation																	
Other																	
Operating (Fixed)																	
G&A					3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
OPEX Baseline (incl well re-entries etc)					70.00	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20
Operating (Variable)																	
Gas Processing (per GJ)					1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
LNG Cooling and Liq/Storage (NZ$ per GJ)																	
Liquids Treat incl. Transport & Port etc (NZ$ per bbl)		17.00	17.00	17.00	17.00	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80
Water Treatment (NZ$ per bbl)		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Other - Gas F&F Carbon Cost (NZD/mscf)		1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43
Production Forecasts																0.768954	
Producing Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Gas Rate (mmscf per day)		2.32	1.74	3.05	0.74	17.40	43.51	56.67	80.88	93.19	99.61	110.00	110.00	110.00	110.00	110.00	110.00
Gas Fuel & Flare (mmscf per day)		2.32	1.74	3.05	0.74	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Cum. Gas incl Fuel (Bscf)		0.4	0.7	1.3	1.4	7.8	15.7	36.4	66.0	100.0	136.4	176.6	216.8	256.9	297.1	337.3	377.5
Cum Sales Gas, i.e less Fuel (Bscf)		0.0	0.0	0.0	0.0	2.0	8.1	16.6	29.6	44.8	61.1	79.4	97.7	115.9	134.2	152.5	170.7
Sales Gas, i.e less Fuel etc (PJ pa)		0.0	0.0	0.0	0.0	2.0	6.1	8.6	13.0	15.2	16.4	18.3	18.3	18.3	18.3	18.3	18.3
LNG Sales Gas (PJ pa)																	
LNG Sales Gas Cumulative (PJ)																	
BOE Cum		**0.8**	**1.5**	**2.6**	**2.8**	**10**	**25**	**48**	**80**	**116**	**155**	**198**	**242**	**285**	**328**	**371**	**415**
Oil/Condensate (stb per day)		2110	1582	2772	669	15823	39556	51522	73529	84717	90551	100001	100000	100000	100000	100000	100000
Cum. Oil/Condensate (mmstb)		0.8	1.3	2.4	2.6	8.4	22.8	41.7	68.5	99.5	132.5	169.0	205.6	242.1	278.6	315.1	351.7
LPG (t/day)																	
Produced Water (stb per day)		2	13	139	33	791	1978	2576	3676	4236	4528	5000	5000	5000	5000	5000	5000
Cum. Prod. Water (mmstb)		0	0	0	0	0	1	2	3	5	7	8	10	12	14	16	18
Injected Water (stb per day)																	
Cum. Inj. Water (mmstb)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
																	Informati
Sales Price (NZ$)																	
Gas ($ per GJ)	0.00	0.00	0.00	0.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
Condensate ($ per bbl)	110.19	107.80	102.39	106.30	108.66	111.02	113.38	115.74	118.10	119.94	121.78	123.62	125.46	127.30	128.74	130.18	131.62
Oil ($ per bbl)	110.19	107.80	102.39	106.30	108.66	111.02	113.38	115.74	118.10	119.94	121.78	123.62	125.46	127.30	128.74	130.18	131.62
Other (LPG etc)																	
Financial Model Assumptions																	
Capital Cost (% pa)	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
Discount Rate (% pa)	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Inflation Rate (% pa)	2.70	2.80	2.90	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Tax Rate (% pa)	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Outputs																	
Capital (NZ$ mm) (inflation adj.)	**8**	**48**	**37**	**197**	**371**	**908**	**694**	**714**	**736**	**758**	**781**	**804**	**748**	**770**	**708**	**730**	**661**
Operating (Fixed NZ$ mm) (inflation adj.)	**0**	**0**	**0**	**0**	**82**	**125**	**129**	**133**	**137**	**141**	**145**	**150**	**154**	**159**	**164**	**169**	**174**
Operating (Variable NZ$ mm)	**0**	**15**	**11**	**21**	**5**	**61**	**149**	**199**	**290**	**344**	**378**	**429**	**442**	**456**	**469**	**483**	**498**
Gas Processing & Carbon NZ$ mm (inflation adj.)	0	1	1	2	0	8	14	17	23	27	29	33	34	35	36	37	38
Liquids Trans./Treatment NZ$ mm (inflation adj.)		13	10	19	5	52	135	181	265	315	347	394	406	418	431	444	457
Water Treatment NZ$ mm (inflation adj.)	0	0	0	0	0	0	1	1	2	2	2	3	3	3	3	3	3
Revenues	**0**	**85**	**63**	**118**	**30**	**753**	**1985**	**2721**	**4084**	**4922**	**5501**	**6352**	**6638**	**6936**	**7223**	**7522**	**7832**
Gas (NZ$ mm pa) - inflation adjusted	0	0	0	0	0	9	29	42	66	80	88	101	105	108	111	114	118
Oil/Condensate (NZ$ mm pa) - inflation adj.	0	85	63	118	30	744	1956	2679	4018	4842	5413	6250	6533	6828	7113	7408	7714
Oil (NZ$ mm pa) - inflation adj.																	
DCF Analysis																	
Net Revenue	**0**	**71**	**51**	**97**	**-57**	**567**	**1707**	**2389**	**3657**	**4437**	**4978**	**5772**	**6041**	**6321**	**6590**	**6870**	**7161**
AVR 5%	0	4	3	5	0	28	85	119	183	222	249	289	302	316	330	344	358
APR 20%	0	13	6	11	0	60	238	352	588	731	827	977	1023	1077	1129	1187	1247
Depreciation Scale	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Cum. Capital	8	54	74	249	545	1289	1596	1832	2018	2170	2300	2414	2438	2477	2442	2439	2368
Capital Depreciation	0	2	16	22	75	164	387	479	549	605	651	690	724	731	743	733	732
Capital Cost	0	4	6	20	44	104	131	150	166	179	189	199	201	204	201	201	196
Net Revenue less Cap.Cost		64	29	55	-176	299	1189	1760	2941	3653	4137	4884	5116	5386	5646	5936	6233
Cum Net. Revenue less Cap. Cost	0	64	93	148	-28	270	1460	3220	6161	9814	13951	18835	23951	29337	34983	40919	47153
Net Rev+Depr.+Cap.Cost+Royalty	0	51	23	44	-176	239	952	1408	2353	2923	3310	3907	4093	4309	4517	4749	4987
Net Rev+Depr.+Cap.Cost+Royalty+Tax	0.0	35.9	16.3	30.6	-176.3	167.2	666.1	985.5	1647.0	2045.8	2316.9	2734.9	2865.1	3016	3162	3324	3491
NPV Calc (Ex.Royalty)	**$8,205**	**mm**															
NPV Calc (Incl.Royalty)	**$4,667**	**mm**															
NPV Calc (Incl.Royalty and Taxes)	**$3,245**	**mm**															
VIR Calc (Inc.Royalty and Taxes)	**$3,791**	**PV Future Cashflows**															
	$2,054	**PV Investment**															
	1.85	**VIR**															

Table 26 Scenario 5 (page 2 of 2)

cing area developed.

2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
30	20															
337.5	225															
5.8																
12.5																
																610.00
3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20	105.20
1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80
1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43
17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33
110.00	84.58	65.04	50.01	38.46	29.57	22.74	17.49	13.45	10.34	7.95	6.11	4.70	3.61	2.78	2.14	1.64
10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	7.95	6.11	4.70	3.61	2.78	2.14	1.64
417.6	448.5	472.3	490.6	504.6	515.41	523.71	530.10	535.01	538.79	541.69	543.92	545.64	546.96	547.98	548.76	549.36
189.0	202.6	212.7	220.0	225.2	228.7	231.1	232.4	233.1	233.1	233.1	233.1	233.1	233.1	233.1	233.1	233.1
18.3	13.7	10.1	7.3	5.2	3.6	2.3	1.4	0.6	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
458	491	517	536	551	563	572	579	584	588	591	594	596	597	598	599	600
100000	76895	59129	45467	34962	26884	20673	15896	12224	9399	7228	5558	4274	3286	2527	1943	1494
388.2	416.3	437.9	454.5	467.3	477.1	484.6	490.4	494.9	498.3	501.0	503.0	504.6	505.8	506.7	507.4	507.9
5000	3845	2956	2273	1748	1344	1034	795	611	470	361	278	214	164	126	97	75
19	21	22	23	23	24	24	24	25	25	25	25	25	25	25	25	25
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ion Below this Line is Basic Financial Model Only - i.e. OUTPUTS																
4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
133.06	134.50	135.60	136.70	137.80	138.90	140.00	140.60	141.20	141.80	142.40	143.00	143.60	144.20	144.80	145.40	146.00
133.06	134.50	135.60	136.70	137.80	138.90	140.00	140.60	141.20	141.80	142.40	143.00	143.60	144.20	144.80	145.40	146.00
8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
588	383	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1618
179	184	190	195	201	207	214	220	227	233	240	248	255	263	271	279	287
513	407	324	258	206	165	132	106	86	69	55	44	35	27	22	17	14
39	32	27	23	19	17	15	13	12	11	9	7	6	5	4	3	2
471	373	295	234	185	147	116	92	73	58	46	36	29	23	18	14	11
3	2	2	1	1	1	1	1	0	0	0	0	0	0	0	0	0
8154	6524	5206	4153	3312	2641	2105	1671	1325	1050	835	664	528	420	334	266	211
121	93	71	53	39	27	18	11	5	1	0	0	0	0	0	0	0
8033	6431	5135	4100	3274	2613	2086	1659	1320	1050	835	664	528	420	334	266	211
7462	5932	4692	3700	2905	2269	1759	1345	1013	748	539	373	239	130	42	-30	-89
373	297	235	185	145	113	88	67	51	37	27	19	12	7	2	0	0
1313	1019	798	642	512	406	318	245	186	138	100	69	44	23	6	0	0
1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2246	1955	1369	958	671	469	329	230	161	113	79	55	39	27	19	13	1627
711	674	587	411	287	201	141	99	69	48	34	24	17	12	8	6	4
186	162	114	80	56	39	27	19	13	9	7	5	3	2	2	1	130
6566	5097	3991	3209	2562	2029	1591	1227	931	690	499	345	219	116	32	-37	-223
53719	58816	62807	66016	68577	70606	72197	73424	74355	75044	75543	75888	76107	76223	76255	76218	75995
5253	4077	3193	2567	2049	1623	1273	981	744	552	399	276	175	93	26	-37	-223
3677	2854	2235	1797	1435	1136	891	687	521	386	279	193	123	65	18	-26	-156

Table 27 Scenario 5A (page 1 of 2)

Development Economics Model																			
MRA 10 Oct 2012					CAPEX Check														
										1038.338	1069.49	1101.57	1134.62	1021.81	1203.72	1247.62	1646.11	1695.49	1576.11
NPV (NZ$mm 2012 Dollars)	*$15,989*	*Gross NPV Pre Royalty & Tax*																	
NPV (NZ$mm 2012 Dollars)	*$6,381*	*Post Royalty & Taxes*																	
Case Description	SC05A	PS for 100k bopd and gas processing sales with 3 different developments																	
	Assumes 3 x 100,000 bopd Production Station and wells drilled at 12 wells per site at a rate capped initially by NZ$1 billion CAPEX pa and increas																		
	Current 2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Inputs																			
Ann. New Exploration Well Count		4	2	4															
Ann. New Production Well Count						45	50	50	50	60	60	60	60	60	60	60	80	80	80
Ann. New Injection Well Count																			
Capital																			
Exploration G&G	2	2	2	2															
Exploration Seismic	5.6		10																
Exploration & Appraisal Wells		45.0	22.5	45.0															
Development Seismic																			
Development Wells						506.25	562.5	562.5	562.5	675	675	675	675	675	675	675	900	900	900
Production Site Equipment & Flowlines					5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.8	5.8	5.8	5.8
Platform/FPSO																			
Process Plant & Export Lines					258	225	100	100		100	100	100	100		100	100	100	100	
Intra-field Pipelines					11.25	12.50	12.50	12.50	15.00	15.00	15.00	15.00	15.00	15.00	15.00	20.00	20.00	20.00	20.00
Onshore Power Generation (50 PJ pa)																			
Abandonment																			
Abandonment Platform/Installation																			
Other																			
Operating (Fixed)																			
G&A					3.00	3.00	3.00	3.00	3.00	6.00	6.00	6.00	6.00	6.00	6.00	9.00	9.00	9.00	9.00
OPEX Baseline (incl well re-entries etc)					30.00	45.20	45.20	45.20	45.20	90.40	90.40	90.40	90.40	90.40	90.40	135.60	135.60	135.60	135.60
Operating (Variable)																			
Gas Processing (per GJ)					1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
LNG Cooling and Liq/Storage (NZ$ per GJ)																			
Liquids Treat incl. Transport & Port etc (NZ$ per bbl)		17.00	17.00	17.00	17.00	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80
Water Treatment (NZ$ per bbl)		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Other - Gas F&F Carbon Cost (NZD/mscf)		1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43
Production Forecasts																0.823196			
Producing Year		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Gas Rate (mmscf per day)		2.32	1.74	3.05	0.74	17.40	43.51	56.67	80.88	110.59	143.12	166.68	192.77	218.01	220.00	237.40	247.50	247.50	247.50
Gas Fuel & Flare (mmscf per day)		2.32	1.74	3.05	0.74	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.90	11.00	11.87	12.38	12.38	12.38
Cum. Gas incl Fuel (Bscf)		0.4	0.7	1.3	1.4	7.8	15.7	36.4	66.0	106.4	158.6	219.5	289.9	369.6	449.9	536.6	627.0	717.4	807.8
Cum Sales Gas, i.e less Fuel (Bscf)		0.0	0.0	0.0	0.0	1.4	7.5	16.0	28.9	47.3	71.6	100.2	133.6	171.4	209.6	250.8	293.7	336.7	379.6
Sales Gas, i.e less Fuel etc (PJ pa)		0.0	0.0	0.0	0.0	1.4	6.1	8.6	13.0	18.4	24.4	28.7	33.5	38.0	38.3	41.3	43.1	43.1	43.1
LNG Sales Gas (PJ pa)																			
LNG Sales Gas Cumulative (PJ)																			
BOE Cum		**0.8**	**1.5**	**2.6**	**2.8**	**10**	**25**	**48**	**80**	**123**	**179**	**245**	**320**	**406**	**493**	**586**	**683**	**780**	**878**
Oil/Condensate (stb per day)		2110	1582	2772	669	15823	39556	51522	73529	100540	130108	151523	175243	198190	200000	215823	225000	225000	225000
Cum. Oil/Condensate (mmstb)		0.8	1.3	2.4	2.6	8.4	22.8	41.7	68.5	105.2	152.8	208.1	272.1	344.5	417.5	496.4	578.6	660.7	742.9
LPG (t/day)																			
Produced Water (stb per day)		2	13	139	33	791	1978	2576	3676	5027	6505	7576	8762	9910	10000	10791	11250	11250	11250
Cum. Prod. Water (mmstb)		0	0	0	0	0	1	2	3	5	8	10	14	17	21	25	29	33	37
Injected Water (stb per day)																			
Cum. Inj. Water (mmstb)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
																			Information Below this
Sales Price (NZ$)																			
Gas ($ per GJ)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
Condensate ($ per bbl)	110.19	107.80	102.39	106.30	108.66	111.02	113.38	115.74	118.10	119.94	121.78	123.62	125.46	127.30	128.74	130.18	131.62	133.06	134.50
Oil ($ per bbl)	110.19	107.80	102.39	106.30	108.66	111.02	113.38	115.74	118.10	119.94	121.78	123.62	125.46	127.30	128.74	130.18	131.62	133.06	134.50
Other (LPG etc)																			
Financial Model Assumptions																			
Capital Cost (% pa)	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
Discount Rate (% pa)	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Inflation Rate (% pa)	2.70	2.80	2.90	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Tax Rate (% pa)	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Outputs																			
Capital (NZ$ mm) (inflation adj.)	**7.60**	**48**	**37**	**51**	**310**	**869**	**813**	**837**	**739**	**1038**	**1069**	**1102**	**1135**	**1022**	**1204**	**1248**	**1646**	**1695**	**1576**
Operating (Fixed NZ$ mm) (inflation adj.)	**0.00**	**0**	**0**	**0**	**37**	**56**	**58**	**59**	**61**	**126**	**130**	**133**	**137**	**142**	**146**	**225**	**232**	**239**	**246**
Operating (Variable NZ$ mm)	**0.00**	**15**	**11**	**21**	**5**	**60**	**149**	**199**	**290**	**407**	**541**	**648**	**772**	**899**	**934**	**1038**	**1115**	**1148**	**1183**
Gas Processing & Carbon NZ$ mm (inflation adj.)	0.00	1	1	2	0	8	14	17	23	31	40	47	55	64	67	74	79	82	84
Liquids Trans./Treatment NZ$ mm (inflation adj.)		13	10	19	5	52	135	181	265	374	498	598	712	829	862	958	1029	1059	1091
Water Treatment NZ$ mm (inflation adj.)	0	0	0	0	0	0	1	1	2	2	3	4	5	5	6	6	7	7	7
Revenues	**0.00**	**85**	**63**	**118**	**30**	**744**	**1956**	**2679**	**4084**	**5843**	**7909**	**9629**	**11640**	**13756**	**14457**	**16245**	**17634**	**18359**	**19111**
Gas (NZ$ mm pa) - inflation adjusted	0.00	0	0	0	0	0	0	0	66	96	131	159	191	223	232	258	277	285	293
Oil/Condensate (NZ$ mm pa) - inflation adj.	0.00	85	63	118	30	744	1956	2679	4018	5747	7778	9470	11449	13533	14225	15988	17358	18074	18818
Oil (NZ$ mm pa) - inflation adj.																			
DCF Analysis																			
Net Revenue	**0**	**71**	**51**	**97**	**-12**	**628**	**1749**	**2421**	**3733**	**5310**	**7238**	**8848**	**10731**	**12715**	**13377**	**14982**	**16287**	**16972**	**17682**
AVR 5%	0	4	3	5	0	31	87	121	187	266	362	442	537	636	669	749	814	849	884
APR 20%	0	13	6	13	0	84	255	355	594	894	1250	1549	1907	2291	2418	2723	2964	3062	3176
Depreciation Scale	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Cum. Capital	8	54	74	103	382	1136	1608	1963	2113	2518	2832	3084	3293	3327	3533	3721	4250	4671	4846
Capital Depreciation	0	2	16	22	31	115	341	483	589	634	755	850	925	988	998	1060	1116	1275	1401
Capital Cost	0	4	6	8	31	92	131	161	174	207	233	254	271	274	291	306	349	384	399
Net Revenue less Cap.Cost		64	29	66	-74	421	1277	1777	2970	4470	6250	7744	9535	11453	12088	13616	14822	15312	15882
Cum Net. Revenue less Cap. Cost	0	64	93	160	85	507	1784	3561	6531	11000	17250	24995	34530	45983	58071	71687	86509	101821	117703
Net Rev+Depr.+Cap.Cost+Royalty	0	51	23	53	-74	337	1022	1422	2376	3576	5000	6195	7628	9163	9670	10893	11858	12250	12705
Net Rev+Depr.+Cap.Cost+Royalty+Tax	0.0	35.9	16.3	37.2	-51.9	235.9	715.2	995.3	1663.0	2503.0	3500.0	4336.8	5339.7	6414	6769	7625	8300	8575	8894
NPV Calc (Ex.Royalty)	**$15,989**	**mm**																	
NPV Calc (Incl.Royalty)	**$9,116**	**mm**																	
NPV Calc (Incl.Royalty and Taxes)	**$6,381**	**mm**																	
VIR Calc (Inc.Royalty and Taxes)	**$7,456**	**PV Future Cashflows**																	
	$2,727	**PV Investment**																	
	2.73	**VIR**																	

Table 28 Scenario 5A (page 2 of 2)

1623.4	1672.1	1722.26	1773.93	1827.15	1881.96	1938.42	1996.57	2056.47	2106.72	1627.92	1124.55								1844.87	1900.22	1989.84
sing slowly from 2021. Overall around 780 km2 of producing area developed.																					
2031	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**
80	80	80	80	80	80	80	80	80	80	60	40	30	15								
900	900	900	900	900	900	900	900	900	900	675	450	337.5	168.75								
5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8								
20.00	20.00	20.00	20	20	20	20	20	20	15	10	7.5	3.75									
																			600.00	600.00	610.00
9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60
1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
7.80	7.80	7.80	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43
19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
247.50	247.50	247.50	247.50	247.50	203.74	167.72	138.07	113.65	93.56	77.02	63.40	52.19	42.96	35.37	29.11	23.97	19.73	16.24	13.37	11.01	9.06
12.38	12.38	12.38	12.38	12.38	10.19	10.00	10.00	113.65	93.56	77.02	63.40	52.19	42.96	35.37	29.11	23.97	19.73	16.24	13.37	11.01	9.06
898.2	988.6	1079.0	1169.42	1259.82	1334.24	1395.50	1445.93	1487.44	1521.61	1549.74	1572.90	1591.96	1607.66	1620.57	1631.21	1639.96	1647.17	1653.10	1657.98	1662.00	1665.31
422.6	465.5	508.4	551.4	594.3	629.7	658.5	681.9	681.9	681.9	681.9	681.9	681.9	681.9	681.9	681.9	681.9	681.9	681.9	681.9	681.9	681.9
43.1	43.1	43.1	43.1	43.1	35.5	28.9	23.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
975	**1072**	**1169**	**1267**	**1364**	**1444**	**1510**	**1564**	**1609**	**1645**	**1676**	**1701**	**1721**	**1738**	**1752**	**1763**	**1773**	**1780**	**1787**	**1792**	**1796**	**1800**
225000	225000	225000	225000	225000	185219	152472	125514	103323	85055	70017	57637	47447	39058	32152	26468	21788	17936	14765	12154	10005	8236
825.1	907.3	989.5	1071.6	1153.8	1221.5	1277.2	1323.0	1360.7	1391.8	1417.4	1438.4	1455.8	1470.0	1481.8	1491.4	1499.4	1506.0	1511.3	1515.8	1519.4	1522.4
11250	11250	11250	11250	11250	9261	7624	6276	5166	4253	3501	2882	2372	1953	1608	1323	1089	897	738	608	500	412
41	45	49	54	58	61	64	66	68	70	71	72	73	73	74	75	75	75	76	76	76	76
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
s Line is Basic Financial Model Only - i.e. OUTPUTS																					
4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
135.60	136.70	137.80	138.90	140.00	140.60	141.20	141.80	142.40	143.00	143.60	144.20	144.80	145.40	146.00	146.60	147.20	147.20	147.20	147.20	147.20	147.20
135.60	136.70	137.80	138.90	140.00	140.60	141.20	141.80	142.40	143.00	143.60	144.20	144.80	145.40	146.00	146.60	147.20	147.20	147.20	147.20	147.20	147.20
8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
1623	**1672**	**1722**	**1774**	**1827**	**1882**	**1938**	**1997**	**2056**	**2107**	**1628**	**1125**	**868**	**449**	**0**	**0**	**0**	**0**	**0**	**1845**	**1900**	**1990**
254	**261**	**269**	**277**	**285**	**294**	**303**	**312**	**321**	**331**	**341**	**351**	**362**	**372**	**384**	**395**	**407**	**419**	**432**	**445**	**458**	**472**
1218	**1255**	**1292**	**2780**	**2863**	**2428**	**2060**	**1748**	**1561**	**1323**	**1122**	**951**	**807**	**684**	**580**	**492**	**417**	**354**	**300**	**254**	**216**	**183**
87	89	92	95	98	83	71	62	132	112	95	80	68	58	49	41	35	30	25	21	18	15
1124	1158	1192	2677	2757	2338	1982	1681	1425	1208	1025	869	737	625	530	449	381	323	274	232	197	167
7	7	8	8	8	7	6	5	4	4	3	3	2	2	2	1	1	1	1	1	1	0
19843	**20601**	**21388**	**22202**	**23047**	**19624**	**16706**	**14222**	**11937**	**10164**	**8654**	**7368**	**6274**	**5341**	**4548**	**3872**	**3296**	**2795**	**2370**	**2009**	**1704**	**1445**
302	311	321	330	340	288	242	202	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19541	20290	21067	21872	22707	19335	16464	14019	11937	10164	8654	7368	6274	5341	4548	3872	3296	2795	2370	2009	1704	1445
18371	**19086**	**19826**	**19146**	**19898**	**16902**	**14344**	**12162**	**10055**	**8510**	**7191**	**6066**	**5105**	**4285**	**3584**	**2985**	**2472**	**2022**	**1638**	**1311**	**1030**	**790**
919	954	991	957	995	845	717	608	503	425	360	303	255	214	179	149	124	101	82	66	52	40
3301	3431	3566	3417	3555	2942	2417	1967	1532	1208	939	747	613	512	448	409	363	312	263	187	12	0
1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
5015	5183	5350	5519	5691	5865	6044	6227	6416	6598	6246	5497	4716	3750	2625	1838	1286	900	630	2286	3500	4440
1454	1505	1555	1605	1656	1707	1760	1813	1868	1925	1979	1874	1649	1415	1125	788	551	386	270	189	686	1050
413	427	441	455	469	483	498	513	529	544	516	455	391	312	219	154	108	75	53	184	286	364
16504	17154	17831	17086	17774	14712	12086	9836	7658	6041	4696	3737	3065	2559	2240	2044	1814	1561	1315	937	59	-624
134208	151362	169192	186278	204052	218764	230850	240686	248344	254386	259082	262818	265884	268442	270682	272726	274539	276101	277416	278353	278412	277788
13203	13723	14265	13669	14219	11769	9669	7869	6127	4833	3757	2989	2452	2047	1792	1635	1451	1249	1052	750	47	-624
9242	9606	9985	9568	9953	8239	6768	5508	4289	3383	2630	2093	1717	1433	1254	1145	1016	874	737	525	33	-437

Table 29 Scenario 5B (page 1 of 3)

Development Economics Model
MRA 10 Oct 2012

NPV (NZ$mm 2012 Dollars) *$17,189* *Gross NPV Pre Royalty & Tax*
NPV (NZ$mm 2012 Dollars) *$6,861* *Post Royalty & Taxes*
Case Description SC05Ax2 PS for 100k bopd and gas processing sales with 2 different developments. Do this in 2 separate developments to get MAX scale project. CAPEX Limits as SC05A mean projects are spread over a very long time frame.
Assumes 2 times the SC05A Scenario, i.e. 2 times 3 x 100,000 bopd Production Station and 3600 wells spread over approximately 50 years. 1600 km2 of producing area developed.

	Current 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Inputs												
Ann. New Exploration Well Count		4	2	4								
Ann. New Production Well Count						45	50	50	50	60	60	60
Ann. New Injection Well Count												
Capital												
Exploration G&G	2	2	2	2								
Exploration Seismic	5.6		10									
Exploration & Appraisal Wells		45.0	22.5	45.0								
Development Seismic												
Development Wells						506.25	562.5	562.5	562.5	675	675	675
Production Site Equipment & Flowlines					5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80
Platform/FPSO												
Process Plant & Export Lines					258	225	100	100		100	100	100
Intra-field Pipelines					11.25	12.50	12.50	12.50	15.00	15.00	15.00	15.00
Onshore Power Generation (50 PJ pa)												
Abandonment												
Abandonment Platform/Installation												
Other												
Operating (Fixed)												
G&A					3.00	3.00	3.00	3.00	3.00	6.00	6.00	6.00
OPEX Baseline (incl well re-entries etc)					30.00	45.20	45.20	45.20	45.20	90.40	90.40	90.40
Operating (Variable)												
Gas Processing (per GJ)					1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
LNG Cooling and Liq/Storage (NZ$ per GJ)												
Liquids Treat incl. Transport & Port etc (NZ$ per bbl)		17.00	17.00	17.00	17.00	7.80	7.80	7.80	7.80	7.80	7.80	7.80
Water Treatment (NZ$ per bbl)		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Other - Gas F&F Carbon Cost (NZD/mscf)		1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43
Production Forecasts												
Producing Year		1	2	3	4	5	6	7	8	9	10	11
Gas Rate (mmscf per day)		2.32	1.74	3.05	0.74	17.40	43.51	56.67	80.88	110.59	143.12	166.68
Gas Fuel & Flare (mmscf per day)		2.32	1.74	3.05	0.74	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Cum. Gas incl Fuel (Bscf)		0.4	0.7	1.3	1.4	7.8	15.7	36.4	66.0	106.4	158.6	219.5
Cum Sales Gas, i.e less Fuel (Bscf)		0.0	0.0	0.0	0.0	1.4	7.5	16.0	28.9	47.3	71.6	100.2
Sales Gas, i.e less Fuel etc (PJ pa)		0.0	0.0	0.0	0.0	1.4	6.1	8.6	13.0	18.4	24.4	28.7
LNG Sales Gas (PJ pa)												
LNG Sales Gas Cumulative (PJ)												
BOE Cum		**0.8**	**1.5**	**2.6**	**2.8**	**10**	**25**	**48**	**80**	**123**	**179**	**245**
Oil/Condensate (stb per day)		2110	1582	2772	669	15823	39556	51522	73529	100540	130108	151523
Cum. Oil/Condensate (mmstb)		0.8	1.3	2.4	2.6	8.4	22.8	41.7	68.5	105.2	152.8	208.1
LPG (t/day)												
Produced Water (stb per day)		2	13	139	33	791	1978	2576	3676	5027	6505	7576
Cum. Prod. Water (mmstb)		0	0	0	0	0	1	2	3	5	8	10
Injected Water (stb per day)												
Cum. Inj. Water (mmstb)		0	0	0	0	0	0	0	0	0	0	0
Sales Price (NZ$)												
Gas ($ per GJ)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	4.00	4.00	4.00
Condensate ($ per bbl)	110.19	107.80	102.39	106.30	108.66	111.02	113.38	115.74	118.10	119.94	121.78	123.62
Oil ($ per bbl)	110.19	107.80	102.39	106.30	108.66	111.02	113.38	115.74	118.10	119.94	121.78	123.62
Other (LPG etc)												
Financial Model Assumptions												
Capital Cost (% pa)	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
Discount Rate (% pa)	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Inflation Rate (% pa)	2.70	2.80	2.90	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Tax Rate (% pa)	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Outputs												
Capital (NZ$ mm) (inflation adj.)	**7.60**	**48.32**	**36.53**	**51.36**	**309.83**	**868.93**	**812.91**	**837.30**	**738.91**	**1038.34**	**1069.49**	**1101.57**
Operating (Fixed NZ$ mm) (inflation adj.)	**0.00**	**0.00**	**0.00**	**0.00**	**37.14**	**55.88**	**57.55**	**59.28**	**61.06**	**125.78**	**129.55**	**133.44**
Operating (Variable NZ$ mm)	**0.00**	**14.71**	**11.37**	**20.60**	**5.12**	**60.21**	**148.98**	**198.61**	**290.12**	**406.98**	**541.13**	**648.34**
Gas Processing & Carbon NZ$ mm (inflation adj.)	0.00	1.24	0.96	1.74	0.43	7.62	13.56	16.93	23.06	30.85	39.79	47.0
Liquids Trans./Treatment NZ$ mm (inflation adj.)		13	10	19	5	52	135	181	265	374	498	598
Water Treatment NZ$ mm (inflation adj.)	0	0	0	0	0	0	1	1	2	2	3	4
Revenues	**0.00**	**85.39**	**62.65**	**117.62**	**29.90**	**743.80**	**1955.99**	**2678.72**	**4083.69**	**5843.00**	**7908.64**	**9629.35**
Gas (NZ$ mm pa) - inflation adjusted	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	65.81	96.20	131.13	158.96
Oil/Condensate (NZ$ mm pa) - inflation adj.	0.00	85.39	62.65	117.62	29.90	743.80	1955.99	2678.72	4017.88	5746.80	7777.52	9470.39
Oil (NZ$ mm pa) - inflation adj.												
DCF Analysis												
Net Revenue	**0**	**71**	**51**	**97**	**-12**	**628**	**1749**	**2421**	**3733**	**5310**	**7238**	**8848**
AVR 5%	0	4	3	5	0	31	87	121	187	266	362	442
APR 20%	0	13	6	13	0	84	255	355	594	894	1250	1549
Depreciation Scale	1	1	1	1	1	1	1	1	1	1	1	1
Cum. Capital	8	54	74	103	382	1136	1608	1963	2113	2518	2832	3084
Capital Depreciation	0	2	16	22	31	115	341	483	589	634	755	850
Capital Cost	0	4	6	8	31	92	131	161	174	207	233	254
Net Revenue less Cap.Cost		64	29	66	-74	421	1277	1777	2970	4470	6250	7744
Cum Net. Revenue less Cap. Cost	0	64	93	160	85	507	1784	3561	6531	11000	17250	24995
Net Rev+Depr.+Cap.Cost+Royalty	0	51	23	53	-74	337	1022	1422	2376	3576	5000	6195
Net Rev+Depr.+Cap.Cost+Royalty+Tax	0	36	16	37	-52	236	715	995	1663	2503	3500	4337
NPV Calc (Ex.Royalty)	**$17,189**	**mm**										
NPV Calc (Incl.Royalty)	**$9,801**	**mm**										
NPV Calc (Incl.Royalty and Taxes)	**$6,861**	**mm**										
VIR Calc (Inc.Royalty and Taxes)	**$8,017**	**PV Future Cashflows**										
	$2,806	**PV Investment**										
	2.86	**VIR**										

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Inputs												
Ann. New Exploration Well Count												
Ann. New Production Well Count	60	60	60	60	80	80	80	80	80	80	80	80
Ann. New Injection Well Count												
Capital												
Exploration G&G												
Exploration Seismic												
Exploration & Appraisal Wells												
Development Seismic												
Development Wells	675	675	675	675	900	900	900	900	900	900	900	900
Production Site Equipment & Flowlines	5.80	5.80	5.80	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
Platform/FPSO												
Process Plant & Export Lines	100		100	100	100	100			100	100	100	100
Intra-field Pipelines	15.00	15.00	15.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20	20
Onshore Power Generation (50 PJ pa)												
Abandonment												
Abandonment Platform/Installation												
Other												
Operating (Fixed)												
G&A	6.00	6.00	6.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
OPEX Baseline (incl well re-entries etc)	90.40	90.40	90.40	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60
Operating (Variable)												
Gas Processing (per GJ)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
LNG Cooling and Liq/Storage (NZ$ per GJ)												
Liquids Treat incl. Transport & Port etc (NZ$ per bbl)	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	17.00	17.00
Water Treatment (NZ$ per bbl)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Other - Gas F&F Carbon Cost (NZD/mscf)	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43
Production Forecasts												
Producing Year	12	13	14	15	16	17	18	19	20	21	22	23
Gas Rate (mmscf per day)	192.77	218.01	220.00	237.40	247.50	247.50	247.50	247.50	247.50	247.50	247.50	247.50
Gas Fuel & Flare (mmscf per day)	10.00	10.90	11.00	11.87	12.38	12.38	12.38	12.38	12.38	12.38	12.38	12.38
Cum. Gas incl Fuel (Bscf)	289.9	369.6	449.9	536.6	627.0	717.4	807.8	898.2	988.6	1079.0	1169.42	1259.82
Cum Sales Gas, i.e less Fuel (Bscf)	133.6	171.4	209.6	250.8	293.7	336.7	379.6	422.6	465.5	508.4	551.4	594.3
Sales Gas, i.e less Fuel etc (PJ pa)	33.5	38.0	38.3	41.3	43.1	43.1	43.1	43.1	43.1	43.1	43.1	43.1
LNG Sales Gas (PJ pa)												
LNG Sales Gas Cumulative (PJ)												
BOE Cum	**320**	**406**	**493**	**586**	**683**	**780**	**878**	**975**	**1072**	**1169**	**1267**	**1364**
Oil/Condensate (stb per day)	175243	198190	200000	215823	225000	225000	225000	225000	225000	225000	225000	225000
Cum. Oil/Condensate (mmstb)	272.1	344.5	417.5	496.4	578.6	660.7	742.9	825.1	907.3	989.5	1071.6	1153.8
LPG (t/day)												
Produced Water (stb per day)	8762	9910	10000	10791	11250	11250	11250	11250	11250	11250	11250	11250
Cum. Prod. Water (mmstb)	14	17	21	25	29	33	37	41	45	49	54	58
Injected Water (stb per day)												
Cum. Inj. Water (mmstb)	0	0	0	0	0	0	0	0	0	0	0	0
Sales Price (NZ$)												
Gas ($ per GJ)	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
Condensate ($ per bbl)	125.46	127.30	128.74	130.18	131.62	133.06	134.50	135.60	136.70	137.80	138.90	140.00
Oil ($ per bbl)	125.46	127.30	128.74	130.18	131.62	133.06	134.50	135.60	136.70	137.80	138.90	140.00
Other (LPG etc)												
Financial Model Assumptions												
Capital Cost (% pa)	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
Discount Rate (% pa)	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Inflation Rate (% pa)	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Tax Rate (% pa)	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Outputs												
Capital (NZ$ mm) (inflation adj.)	**1134.62**	**1021.81**	**1203.72**	**1247.62**	**1646.11**	**1695.49**	**1576.11**	**1623.40**	**1852.71**	**1908.29**	**1965.54**	**2024.51**
Operating (Fixed NZ$ mm) (inflation adj.)	**137.44**	**141.57**	**145.81**	**225.28**	**232.04**	**239.00**	**246.17**	**253.56**	**261.16**	**269.00**	**277.07**	**285.38**
Operating (Variable NZ$ mm)	**771.57**	**898.58**	**933.99**	**1038.11**	**1114.72**	**1148.17**	**1182.61**	**1218.09**	**1254.63**	**1292.27**	**2779.74**	**2863.14**
Gas Processing & Carbon NZ$ mm (inflation adj.)	55.2	64.1	66.6	74.0	79.5	81.9	84.3	86.9	89.5	92.2	94.9	97.8
Liquids Trans./Treatment NZ$ mm (inflation adj.)	712	829	862	958	1029	1059	1091	1124	1158	1192	2677	2757
Water Treatment NZ$ mm (inflation adj.)	5	5	6	6	7	7	7	7	7	8	8	8
Revenues	**#######**	**#######**	**#######**	**#######**	**17634.17**	**18358.79**	**19111.03**	**19842.87**	**20601.43**	**21387.64**	**22202.49**	**23046.97**
Gas (NZ$ mm pa) - inflation adjusted	190.99	222.92	231.71	257.54	276.55	284.84	293.39	302.19	311.26	320.59	330.21	340.12
Oil/Condensate (NZ$ mm pa) - inflation adj.	11449.39	13532.71	14225.09	15987.83	17357.62	18073.95	18817.64	19540.68	20290.17	21067.05	21872.27	22706.85
Oil (NZ$ mm pa) - inflation adj.												
DCF Analysis												
Net Revenue	**10731**	**12715**	**13377**	**14982**	**16287**	**16972**	**17682**	**18371**	**19086**	**19826**	**19146**	**19898**
AVR 5%	537	636	669	749	814	849	884	919	954	991	957	995
APR 20%	1907	2291	2418	2723	2964	3062	3176	3301	3428	3550	3392	3522
Depreciation Scale	1	1	1	1	1	1	1	1	1	1	1	1
Cum. Capital	3293	3327	3533	3721	4250	4671	4846	5015	5363	5663	5929	6175
Capital Depreciation	925	988	998	1060	1116	1275	1401	1454	1505	1609	1699	1779
Capital Cost	271	274	291	306	349	384	399	413	441	466	488	509
Net Revenue less Cap.Cost	9535	11453	12088	13616	14822	15312	15882	16504	17140	17751	16959	17611
Cum Net. Revenue less Cap. Cost	34530	45983	58071	71687	86509	101821	117703	134208	151347	169098	186057	203668
Net Rev+Depr.+Cap.Cost+Royalty	7628	9163	9670	10893	11858	12250	12705	13203	13712	14201	13567	14089
Net Rev+Depr.+Cap.Cost+Royalty+Tax	5340	6414	6769	7625	8300	8575	8894	9242	9598	9941	9497	9862

Table 30 Scenario 5B (page 2 of 3)

2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
900	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900
5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
	100	100	100	100		100	100	100	100										
20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60
1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43
																			0.80101452
24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43
247.50	247.50	247.50	247.50	247.50	247.50	247.50	247.50	247.50	247.50	247.50	247.50	247.50	247.50	247.50	247.50	247.50	247.50	247.50	198.25
12.38	12.38	12.38	247.50	247.50	247.50	247.50	247.50	247.50	247.50	247.50	247.50	247.50	247.50	247.50	247.50	247.50	247.50	247.50	198.25
1350.22	1440.62	1531.02	1621.42	1711.82	1802.22	1892.62	1983.02	2073.42	2163.82	2254.22	2344.62	2435.02	2525.41	2615.81	2706.21	2796.61	2887.01	2977.41	3049.82
637.3	680.2	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1
43.1	43.1	43.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1461	**1558**	**1656**	**1753**	**1850**	**1947**	**2045**	**2142**	**2239**	**2336**	**2434**	**2531**	**2628**	**2725**	**2823**	**2920**	**3017**	**3114**	**3211**	**3289**
225000	225000	225000	225000	225000	225000	225000	225000	225000	225000	225000	225000	225000	225000	225000	225000	225000	225000	225000	180228
1236.0	1318.2	1400.4	1482.5	1564.7	1646.9	1729.1	1811.3	1893.5	1975.6	2057.8	2140.0	2222.2	2304.4	2386.5	2468.7	2550.9	2633.1	2715.3	2781.1
11250	11250	11250	11250	11250	11250	11250	11250	11250	11250	11250	11250	11250	11250	11250	11250	11250	11250	11250	9011
62	66	70	74	78	82	86	91	95	99	103	107	111	115	119	123	127	132	136	139
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Information Below this Line is Basic Financial Model Only - i.e. OUTPUTS																			
4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
140.60	141.20	141.80	142.40	143.00	143.60	144.20	144.80	145.40	146.00	146.60	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20
140.60	141.20	141.80	142.40	143.00	143.60	144.20	144.80	145.40	146.00	146.60	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20
8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
1881.96	**2147.80**	**2212.23**	**2278.60**	**2346.96**	**2181.71**	**2489.89**	**2564.58**	**2641.52**	**2720.77**	**2529.20**	**2605.07**	**2683.23**	**2763.72**	**2846.63**	**2932.03**	**3019.99**	**3110.59**	**3203.91**	**3300.03**
293.94	**302.76**	**311.84**	**321.20**	**330.83**	**340.76**	**350.98**	**361.51**	**372.36**	**383.53**	**395.03**	**406.88**	**419.09**	**431.66**	**444.61**	**457.95**	**471.69**	**485.84**	**500.42**	**515.43**
2949.03	**3037.50**	**3128.62**	**3399.11**	**3501.09**	**3606.12**	**3714.30**	**3825.73**	**3940.50**	**4058.72**	**4180.48**	**4305.90**	**4435.07**	**4568.12**	**4705.17**	**4846.32**	**4991.71**	**5141.46**	**5295.71**	**4369.20**
100.7	103.7	106.8	286.7	295.3	304.1	313.2	322.6	332.3	342.3	352.6	363.1	374.0	385.3	396.8	408.7	421.0	433.6	446.6	368.5
2840	2925	3013	3103	3196	3292	3391	3493	3598	3706	3817	3931	4049	4171	4296	4425	4557	4694	4835	3989
8	9	9	9	9	10	10	10	11	11	11	12	12	12	13	13	13	14	14	12
23838.62	**24657.02**	**25503.07**	**25994.88**	**26887.54**	**27810.37**	**28764.36**	**29750.57**	**30770.06**	**31823.94**	**32913.37**	**34039.52**	**35060.70**	**36112.53**	**37195.90**	**38311.78**	**39461.13**	**40644.97**	**41864.32**	**34539.94**
350.32	360.83	371.66	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23488.29	24296.18	25131.41	25994.88	26887.54	27810.37	28764.36	29750.57	30770.06	31823.94	32913.37	34039.52	35060.70	36112.53	37195.90	38311.78	39461.13	40644.97	41864.32	34539.94
20596	**21317**	**22063**	**22275**	**23056**	**23863**	**24699**	**25563**	**26457**	**27382**	**28338**	**29327**	**30207**	**31113**	**32046**	**33008**	**33998**	**35018**	**36068**	**29655**
1030	1066	1103	1114	1153	1193	1235	1278	1323	1369	1417	1466	1510	1556	1602	1650	1700	1751	1803	1483
3646	3784	3912	3934	4071	4218	4380	4529	4685	4849	5023	5220	5389	5559	5732	5908	6089	6273	6463	5159
1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
6205	6491	6756	7008	7252	7258	7571	7864	8146	8423	8425	8503	8635	8808	9013	9241	9489	9753	10031	10322
1853	1861	1947	2027	2102	2176	2178	2271	2359	2444	2527	2528	2551	2591	2643	2704	2772	2847	2926	3009
512	535	557	577	598	599	624	648	671	694	695	701	712	726	743	762	782	804	827	851
18231	18921	19559	19670	20356	21089	21898	22644	23427	24244	25116	26098	26944	27796	28661	29542	30444	31367	32316	25796
221899	240820	260379	280049	300405	321494	343392	366036	389463	413707	438823	464921	491865	519661	548322	577864	608307	639675	671991	697786
14585	15137	15647	15736	16285	16871	17518	18115	18741	19395	20093	20878	21555	22237	22929	23634	24355	25094	25853	20636
10210	10596	10953	11015	11399	11810	12263	12681	13119	13577	14065	14615	15089	15566	16050	16544	17048	17566	18097	14446

Table 31 Scenario 5B (page 3 of 3)

	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075	2076	Totals
																						10
0	80	80	80	80	80	80	80	80	60	45												3600
																						0
																						6.00
																						10.00
																						112.50
																						0.00
0	900	900	900	900	900	900	900	900	675	506												40500.00
8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8													284.20
																						0.00
																						2683.23
0	20	20	20	20	20	20	20	15	11.25													900.00
																						0.00
																			1200	1200	1210	3610.00
																						0.00
																						48105.93
0	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	501.00
0	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	135.60	7533.20
0	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	
0	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	
0	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	
3	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	
2																						
3	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60	61	62	63	64	
5	158.80	127.20	101.89	81.62	65.38	52.37	41.95	33.60	26.91	21.56	17.27	13.83	11.08	8.88	7.11	5.69	4.56	3.65	2.93	2.34	1.88	
5	158.80	127.20	101.89	81.62	65.38	52.37	41.95	33.60	26.91	21.56	17.27	13.83	11.08	8.88	7.11	5.69	4.56	3.65	2.93	2.34	1.88	
2	3107.83	3154.29	3191.50	3221.31	3245.19	3264.32	3279.64	3291.91	3301.74	3309.62	3315.92	3320.98	3325.02	3328.26	3330.86	3332.94	3334.61	3335.94	3337.01	3337.87	3338.55	3338.55
1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.1	723.13
0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	726
9	**3352**	**3402**	**3442**	**3474**	**3500**	**3520**	**3537**	**3550**	**3560**	**3569**	**3576**	**3581**	**3585**	**3589**	**3592**	**3594**	**3596**	**3597**	**3598**	**3599**	**3600**	
8	144365	115639	92628	74197	59433	47606	38133	30545	24467	19599	15699	12575	10073	8068	6463	5177	4147	3322	2661	2131	1707	
1	2833.8	2876.1	2909.9	2937.0	2958.7	2976.1	2990.0	3001.2	3010.1	3017.3	3023.0	3027.6	3031.3	3034.2	3036.6	3038.5	3040.0	3041.2	3042.2	3043.0	3043.6	3044
1	7218	5782	4631	3710	2972	2380	1907	1527	1223	980	785	629	504	403	323	259	207	166	133	107	85	
9	142	144	145	147	148	149	149	150	150	151	151	151	152	152	152	152	152	152	152	152	152	152
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	0.00	0.00	0.00	4.00	4.00	
0	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	
0	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	147.20	
0	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	
0	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	
0	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	
0	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	
3	**3399.03**	**3501.00**	**3606.03**	**3714.21**	**3825.64**	**3940.41**	**4058.62**	**4157.80**	**3218.65**	**2425.15**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**7500.48**	**7725.50**	**8023.57**	**137322**
3	**530.89**	**546.82**	**563.22**	**580.12**	**597.52**	**615.45**	**633.91**	**652.93**	**672.52**	**692.69**	**713.47**	**734.88**	**756.93**	**779.63**	**803.02**	**827.11**	**851.93**	**877.48**	**903.81**	**930.92**	**144.60**	**25681**
0	**3604.78**	**2974.11**	**2453.77**	**2024.47**	**1670.28**	**1378.06**	**1136.96**	**938.04**	**773.93**	**638.52**	**526.81**	**434.64**	**358.60**	**295.86**	**244.10**	**201.39**	**166.16**	**137.09**	**113.10**	**93.32**	**76.99**	**121068**
5	304.0	250.8	206.9	170.7	140.9	116.2	95.9	79.1	65.3	53.9	44.4	36.7	30.2	25.0	20.6	17.0	14.0	11.6	9.5	8	6	
9	3291	2715	2240	1848	1525	1258	1038	856	707	583	481	397	327	270	223	184	152	125	103	85	70	
2	10	8	7	5	4	4	3	3	2	2	1	1	1	1	1	1	0	0	0	0	0	
4	**28497.00**	**23511.31**	**19397.89**	**16004.13**	**13204.13**	**10894.00**	**8988.04**	**7415.54**	**6118.15**	**5047.75**	**4164.62**	**3436.00**	**2834.85**	**2338.88**	**1929.68**	**1592.07**	**1313.53**	**1083.72**	**894.12**	**737.69**	**608.63**	**1057293**
0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4897
4	28497.00	23511.31	19397.89	16004.13	13204.13	10894.00	8988.04	7415.54	6118.15	5047.75	4164.62	3436.00	2834.85	2338.88	1929.68	1592.07	1313.53	1083.72	894.12	737.69	608.63	1052396
																						0
5	**24361**	**19990**	**16381**	**13400**	**10936**	**8900**	**7217**	**5825**	**4672**	**3717**	**2924**	**2266**	**1719**	**1263**	**883**	**564**	**295**	**69**	**-123**	**-287**	**387**	**910544**
3	1218	1000	819	670	547	445	361	291	234	186	146	113	86	63	44	28	15	3	0	0	19	45548
9	4078	3180	2434	1813	1295	861	497	190	0	0	0	0	0	0	0	0	0	0	0	0	0	153907
1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	44
2	10624	10938	11263	11598	11944	12301	12670	13027	12337	11061	7743	5420	3794	2656	1859	1301	911	638	7947	13288	17325	
9	3096	3187	3281	3379	3479	3583	3690	3801	3908	3701	3318	2323	1626	1138	797	558	390	273	191	2384	3986	120050
1	875	901	928	956	984	1014	1044	1073	1019	915	647	453	317	222	155	109	76	53	637	1082	1386	34352
6	20389	15902	12171	9065	6473	4304	2483	950	-255	-900	-1041	-509	-224	-97	-70	-103	-171	-257	-951	-3753	-4985	756142
6	718176	734078	746249	755314	761787	766091	768573	769524	769268	768368	767327	766818	766594	766497	766428	766325	766154	765896	764945	761192	756206	
6	16312	12721	9737	7252	5178	3443	1986	760	-255	-900	-1041	-509	-224	-97	-70	-103	-171	-257	-951	-3753	-4985	602236
6	11418	8905	6816	5076	3625	2410	1390	532	-179	-630	-729	-357	-157	-68	-49	-72	-120	-180	-666	-2627	-3490	421565

9. Glossary

Abandon, Abandonment	To cease work on a well which is non-productive, to plug off the well with cement plugs and salvage all recoverable equipment Also used in the context of field abandonment.
Annulus	The space between the drillstring and the well wall, or between casing strings, or between the casing and the production tubing.
Appraisal Well	A well drilled as part of an appraisal drilling programme which is carried out to determine the physical extent, reserves and likely production rate of a field.
Associated Gas	Natural gas associated with oil accumulations, which may be dissolved in the oil at reservoir conditions or may form a cap of free gas above the oil.
AVR, APR	See Royalties
Barrel	A unit of volume measurement used for petroleum and its products (7.3 barrels = 1 ton: 6.29 barrels = 1 cubic metre).
Basin	Area of focussed sediment build-up within tectonically defined boundaries. Typically encompass multiple sub-basins.
bbl	One barrel of oil; 1 barrel = 35 Imperial gallons (approx.), or 159 litres (approx.); 7.5 barrels = 1 tonne (approx.); 6.29 barrels = 1 cubic metre.
bcf	Billion cubic feet; 1 bcf = 0.83 million tonnes of oil equivalent.
bcm	Billion cubic metres (1 cubic metre = 35.31 cubic feet).
Blow-out preventers (BOPs)	Are high pressure wellhead valves, designed to shut off the uncontrolled flow of hydrocarbons.
Blow-out	When well pressure exceeds the ability of the wellhead valves to control it. Oil and gas "blow wild" at the surface.
Borehole	The hole as drilled by the drill bit. Also know as a well.
Capex, CAPEX	Capital expenditure
Casing	The steel tubing that lines a well after it has been drilled. It is formed from sections of steel tube screwed together.
Christmas tree	The assembly of fittings and valves on the top of the casing which control the production rate of oil. Also known as a wellhead.
Commercial field	An oil and/or gas field judged to be capable of producing enough net income to make it worth developing.
Completion	The installation of permanent wellhead equipment for the production of oil and gas.
Compressor	An engine used to increase the pressure of natural gas so that it will flow more easily through a pipeline
Condensate	Hydrocarbons which are in the gaseous state under reservoir conditions and which become liquid when temperature or pressure is reduced. A mixture of pentanes and higher hydrocarbons.
Condensate-Gas-Ratio, CGR	Ratio of condensate produced per unit of the produced gas. Typical units are standard barrels (stb) of condensate per million standard cubic feet (mmmscf) gas or m3 condensate per million m3 (Mm3) gas.
Connate water	Water occurring within the rocks in the oil and gas in the reservoir.
Coring	Taking rock samples from a well by means of a special tool -- a "core barrel".
Creaming Curve	A statistical technique which recognises that in any exploration province after an initial period in which the largest fields are found, success rates and average field sizes decline as more exploration wells are drilled and knowledge of the area matures.
Cubic foot	A standard unit used to measure quantity of gas (at atmospheric pressure); 1 cubic foot = 0.0283 cubic metres.
Cuttings	Rock chippings cut from the formation by the drill bit, and brought to the surface with the mud. Used by geologists to obtain formation data.
Derrick	The tower-like structure that houses most of the drilling controls.
Development phase	The phase in which a proven oil or gas field is brought into production by drilling production (development) wells.
Development well	A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive; a well drilled in a proven

	field for the purpose of completing the desired spacing pattern of production.
Drilling rig	A drilling unit that is not permanently fixed to the seabed or ground, e.g. a drillship, a semi-submersible or a jack-up unit. Also means the derrick and its associated machinery.
Dry Gas	Natural gas composed mainly of methane with only minor amounts of ethane, propane and butane and little or no heavier hydrocarbons in the gasoline range.
Dry hole	A well, which has proved to contain no productive oil or gas.
E&A	Abbreviation for exploration and appraisal.
E&P	Abbreviation for exploration and production.
Enhanced oil recovery	A process whereby oil is recovered other than by the natural pressure in a reservoir.
Exploration drilling	Drilling carried out to determine whether hydrocarbons are present in a particular area or structure.
Exploration phase	The phase of operations which covers the search for oil or gas by carrying out detailed geological and geophysical surveys followed up where appropriate by exploratory drilling.
Exploration well	A well drilled in an unproven area. Also known as a "wildcat well".
Farm in	When a company acquires an interest in a block by taking over all or part of the financial commitment for drilling an exploration well.
Field	A geographical area under which an oil or gas reservoir lies.
Fishing	Retrieving objects from the borehole, such as a broken drillstring, or tools.
Formation damage	The reduction in permeability in reservoir rock due to the infiltration of drilling or treating fluids into the area adjacent to the wellbore.
Formation pressure	The pressure at the bottom of a well when it is shut in at the wellhead.
Formation water	Water, usually salty, underlying gas and oil in the rock formations.
FPSO	Floating Storage and Offloading facility. Typically a tanker or platform with oil/gas separation and treatment and oil storage tanks. Offloading to sales typically is via a floating hose or other arrangement which enables a tanker to pull in nearby and take the stored oil/condensate.
Fracture Stimulation	See Fracturing.
Fracturing	A method of breaking down a formation by pumping fluid at very high pressures and creating a vertically oriented fracture intersecting the wellbore in order to increase the area of formation open to flow or injection. The objective is to increase production or injection rates from/to a reservoir.
G	Gas.
G & A	General and Administration. Expenditure category for the overhead costs associated with running an exploration/development work programme.
G & G	Geology and Geophysics work and associated expenditure.
G/C	Gas Condensate.
Gas field	A field containing natural gas but no oil.
Gas injection	The process whereby separated associated gas is pumped back into a reservoir for conservation purposes or to maintain the reservoir pressure.
Gas/oil ratio, GOR	Also GOR. The volume of gas at atmospheric pressure produced per unit of oil produced.
Gas Rate	Gas flow rate is the volume of gas as measured at standard conditions that is produced in a unit of time. Typical units are: mmscf/d (millions of standard cubic feet per day) Mm3/d (millions of cubic metres per day) m3/s (cubic metres per second) TJ/d (Tera joules per day) - this is an energy based flow rate.
Gas-to-Liquids (GTL)	The conversion of natural gas to a liquid form so that it can be transported easily. Typically, the liquid is converted back to natural gas prior to consumption.
Gravity	A standard adopted by the American Petroleum Institute (API) for measuring the density of a liquid. Gravity is expressed in degrees with lower numbers indicating heavier liquids and higher numbers indicating lighter liquids.
Hydrocarbon	A compound containing only the elements hydrogen and carbon. May exist as

	a solid, a liquid or a gas. The term is mainly used in a catch-all sense for oil, gas and condensate.
Injection well	A well used for pumping water or gas into the reservoir.
Jacket	The lower section, or "legs", of an offshore platform.
Kick	A well is said to "kick" if the formation pressure exceeds the pressure exerted by the mud column.
Lay barge	A barge that is specially equipped to lay submarine pipelines.
Liquefied natural gas (LNG)	Naturally occurring gas, chiefly methane, liquefied for transportation.
Liquefied petroleum gas (LPG)	Light hydrocarbon material, gaseous at atmospheric temperature and pressure, held in the liquid state by pressure to facilitate storage, transport and handling. Commercial liquefied gas consists essentially of either propane or butane, or mixtures thereof. Also known as NGL.
Lifting costs	The cost of producing oil from a well, lease, property or field.
Log	To conduct a survey inside a borehole to gather information about the subsurface formations; the results of such a survey. Logs typically consist of several curves on a long grid that describe properties within the wellbore or surrounding formations that can be interpreted to provide information about the location of oil, gas, and water. Also called well logs, borehole logs, wireline logs.
MDT	Modular Dynamics Tester. A wireline logging tool designed to take pressures from the wall of the well and to take fluid samples from the rock wall. Updated version of the previous tool (RFT).
mmboe .	Million Barrels Oil Equivalent
MEG	Mono Ethylene Glycol. A chemical typically used in minor doses in water wet gas streams/pipelines to inhibit or break the formation of gas hydrates.
Metric tonne	Equivalent to 1000 kilos, 2204.61 lbs; 7.5 barrels.
mmcfd	Millions of cubic feet per day (of gas).
Mt	Million tonnes.
Mud	A mixture of base substance and additives used to lubricate the drill bit and to counteract the natural pressure of the formation.
Natural gas	Gas, occurring naturally and often found in association with crude petroleum.
NGLs	Natural gas liquids. Liquid hydrocarbons found in association with natural gas. Also known as LPG
Non-associated gas	natural gas produced from a reservoir that does not contain significant quantities of crude oil.
NPV, Net-Present-Value	The discounted value of future net revenues/expenditures in today's money. See VIR.
O	Oil.
O&G	Oil and Gas.
Oil	A mixture of liquid hydrocarbons of different molecular weights.
Oil field	A geographic area under which an oil reservoir lies.
Oil in place (OIP)	An estimated measure of the total amount of oil contained in a reservoir, and, as such, a higher figure than the estimated recoverable reserves of oil.
Oil initially in place (OIIP)	As for OIP but the volume of oil contained before any flow of hydrocarbons from the reservoir.
Oil Rate	Oil flow rate is the volume of oil as measured at standard conditions that is produced in a unit of time. Typical units are: stb/d (standard barrels per day) m3/d (cubic metres per day)
Operator	The company that has legal authority to drill wells and undertake production of hydrocarbons are found. The Operator is often part of a consortium and acts on behalf of this consortium.
Opex , OPEX	Operating expenditure.
Payzone	Rock in which oil and gas are found in exploitable quantities.
Permeability	The property of a formation which quantifies the flow of a fluid through the pore spaces and into the wellbore.
Petroleum	A generic name for hydrocarbons, including crude oil, natural gas liquids,

	natural gas and their products.
Platform	An offshore structure that is permanently fixed to the seabed.
Porosity	The percentage of void in a porous rock compared to the solid formation.
Possible reserves	Those reserves which at present cannot be regarded as 'probable' but are estimated to have a significant but less than 50% chance of being technically and economically producible.
Primary recovery	Recovery of oil or gas from a reservoir purely by using the natural pressure in the reservoir to force the oil or gas out.
Probable reserves	Those reserves which are not yet proven but which are estimated to have a better than 50% chance of being technically and economically producible.
Proven field	An oil and/or gas field whose physical extent and estimated reserves have been determined.
Proven reserves	Those reserves which on the available evidence are virtually certain to be technically and economically producible (i.e. having a better than 90% chance of being produced).
Recoverable reserves .	That proportion of the oil and/gas in a reservoir that can be removed using currently available techniques
Recovery factor , RF	The ratio of recoverable oil and/or gas reserves to the estimated oil and/or gas in place in the reservoir.
Reserves	Commercially producible hydrocarbons that are known to exist. See Proven, Probable and Possible Reserves.
Reservoir	The underground formation where oil and gas has accumulated It consists of a porous rock to hold the oil or gas, and a cap rock that prevents its escape.
Resources	Hydrocarbon accumulations that may or may not exist in the location or volumes specified.
	Repeat Formation Tester. A wireline logging tool designed to take multiple pressures from the wall of the well and to take fluid samples from the rock wall. Replaced by next generation tool (MDT).
Riser (drilling)	A pipe between a seabed BOP and a floating drilling rig.
Riser (production)	The section of pipework that joins a seabed wellhead to the Christmas tree.
Royalties, Royalty payment	The cash or kind paid to the owner of mineral rights. In New Zealand this takes the form of either 20% Accounting Profits Royalty (APR) or 5% Add Valorem Royalty (AVR) from 1 January 2010.
Saturation (1) Saturation (2)	The proportion of a rock pore space filled with a particular fluid, e.g. a pore with 70% gas and 30% water has a gas saturation of 70%. A hydrocarbon is said to be saturated when it has as much liquid or gas dissolved in it as it can at the prevailing temperature and pressure while still remaining as a single phase fluid. Example is a saturated oil has gas dissolved in it such that any drop in pressure or temperature will cause gas to bubble out of the oil. A saturated gas has liquid hydrocarbon (e.g. condensate) dissolved such that a drop in pressure or temperature will cause liquid hydrocarbon to start condensing out of the gas (hence condensate).
Secondary recovery	Recovery of oil or gas from a reservoir by artificially maintaining or enhancing the reservoir pressure by injecting gas, water or other substances into the reservoir rock.
Separation –	The process of separating liquid and gas hydrocarbons and water. This is typically accomplished in a pressure vessel at the surface, but newer technologies allow separation to occur in the wellbore under certain conditions.
Shutdown	A production hiatus during which the platform ceases to produce while essential maintenance work is undertaken.
Spud-in	The operation of drilling the first part of a new well.
Stimulation	The term used for several processes to enlarge old channels, or create new ones, in the producing formation of a well designed to enhance production. Examples include acidising and fracturing.
Suspended well	A well that has been capped off temporarily.
Tcf	Trillion Cubic Feet (of gas).
Topsides	The superstructure of a platform.

Upstream.	The exploration and production portions of the oil and gas industry
VIR, Value Investment Ratio	An economic investment assessment criterion. VIR is the Net-Present Value of a project/investment divided by the Net-Present-Value of the Capital Invested (to be invested)
Waterflooding	The injection of water into an oil reservoir to “push” additional oil out of the reservoir rock and into the wellbores of producing wells.
Well	A hole drilled into the ground to investigate and/or connect with sub-surface rocks and their contents. See Borehole.
Well log	A record of geological formation penetrated during drilling, including technical details of the operation.
Wet gas	Natural gas containing significant amounts of liquefiable hydrocarbons.
Wildcat well	A well drilled in an unproven area. Also known as a "exploration well".
Workover	Remedial work to the equipment within a well, the well pipe work, or relating to attempts to increase the rate of flow.

Glossary/Terms modified and expanded from those provided by the Society of Petroleum Engineering (SPE) and the United Kingdom Offshore Oil and Gas Industry Association (UKOOGIA) on their respective websites.