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Independent Assessment of Hydrocarbon Volumes for the Equus Project, Western Australia

Prepared for

Hess Exploration Australia Pty. Ltd.

May 2017

www.gaffney-cline.com

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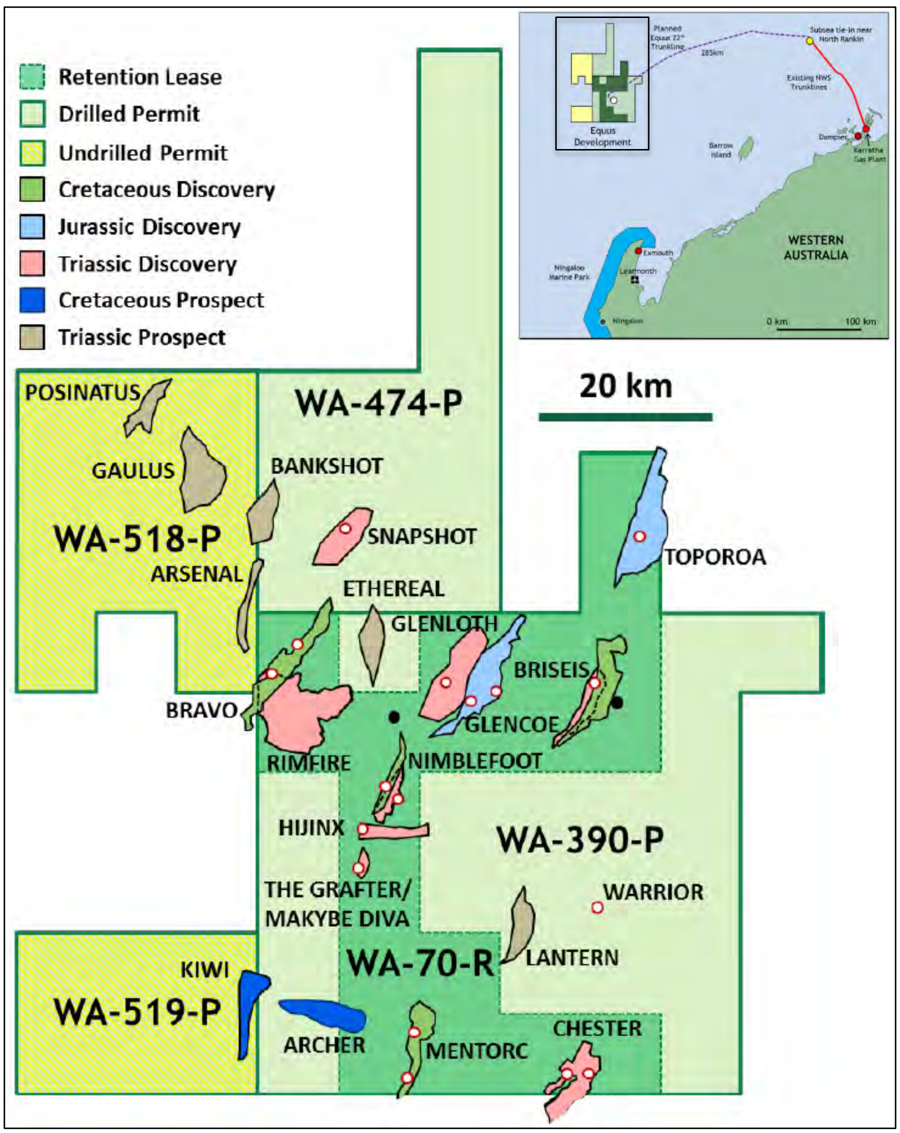
Introduction

At the request of Hess Exploration Australia Pty. Ltd. (Hess), Gaffney, Cline & Associates (GCA) has performed an Independent Assessment of Hydrocarbon Volumes for the recently deferred Equus Project (Hess Corporation Q4 2016 Earnings Release), offshore Western Australia as of 31 March 2017 (**Figure 1**). This request was in accordance with the GCA Proposal for Services reference **ZGK/jbi/PY-16-2009/L0177** dated 25 August 2016. The scope of this study as defined in the Hess Short Form Services Agreement: Schedule 1- Scope of Work **(AU-EQ1-SCM-TND-0008-SOW**), comprises the volumetric assessment of the 9 fields in WA-70-R plus the Snapshot discovery in WA-474-P and the undrilled Gaulus Prospect in WA-518-P. It is understood that the Independent Assessment is required for external purposes for attracting potential partners and investors.

Figure 1: Equus Project Location Map



Source: Modified from Hess

Hess is a subsidiary of US-based independent energy company Hess Corporation and has been operating in offshore Western Australia since 2007 when it was awarded an Exploration Licence for Permit area WA-390-P in the northern Carnarvon Basin. In 2007-8, Hess acquired the Glencoe 3D seismic survey which covered the entire permit. Sixteen (16) exploration wells were subsequently drilled from 2008-10 resulting in 14 gas/condensate discoveries. This was followed by an appraisal drilling program in 2011-14 which comprised the drilling of 4 wells and 5 drill-stem tests (DST's) in the Cretaceous/Jurassic/Triassic age reservoir intervals. Pre stack depth migration (PrSDM) seismic reprocessing was subsequently carried out with improved imaging of the deep Triassic reservoirs. In 2011, an area covering the discovered pools was declared and in March, 2016 the retention lease WA-70-R was awarded. Hess has a 100% working interest (WI) in both WA-390-P and WA-70-R.

In 2012, Hess was awarded an Exploration Licence for the Permit area WA-474-P, which is adjacent WA-390-P. Hess currently holds a 100% WI in WA-474-P. The Snapshot-1 exploration well was drilled in WA-474-P in early 2016 and was recently suspended for future production. In addition, Hess holds a 100% WI in two additional Exploration Permits; WA-518-P and WA-519-P which are adjacent to WA-390-P.

The deferred Equus Development is located approximately 200 km northwest of Onslow in water depths ranging from 1,000 - 1,200 m and comprises 9 separate fields within WA-70-R (Mentorc, Nimblefoot, Glencoe, Glenloth, Bravo, Rimfire, Brisies, Chester, Hijinx) spread over multiple horizons, plus the Snapshot Triassic discovery in WA-474-P. Also envisaged as an extension of the development was the tie-in of the undrilled Gaulus Prospect in WA-518-P following the drilling of a commitment well in 2018.

Development plan for the fields, as proposed before deferment, utilised subsea facilities tied back to a floating semi-submersible production facility. Produced gas was to be dehydrated and the remaining wet gas and condensate piped to the existing North-West Shelf onshore processing facility (NWS). A non-binding Letter of Intent was signed between Hess and the NWS Joint Venture participants in December 2014 to process resources from Hess' permits which included proposed terms for the tolling of resources through the Karratha Gas Plant.

Hess has made available to GCA a data set of technical information including geological, geophysical, and engineering data and reports applicable to the assets. In carrying out this assessment GCA has relied on the accuracy and completeness of this information. GCA has no reason to believe that any data is inaccurate or has been withheld.

Industry Standard terms and abbreviations are contained in the attached Glossary (**Appendix I**), not all of which have necessarily been used in this report.

This report relates specifically and solely to the subject matter as defined in the SFSA, as set out herein, and is conditional upon the specified assumptions. The report must be considered in its entirety and must only be used for the purpose for which it is intended.

Basis of Opinion

This document reflects GCA's informed professional judgment based on accepted standards of professional investigation and, as applicable, the data and information provided by Hess, the limited scope of engagement, and the time permitted to conduct the evaluation.

In line with those accepted standards, this document does not in any way constitute or make a guarantee or prediction of results, and no warranty is implied or expressed that actual outcome will conform to the outcomes presented herein. GCA has not independently verified any information provided by, or at the direction of, Hess, and has accepted the accuracy and completeness of this data. GCA has no reason to believe that any material facts have been withheld, but does not warrant that its inquiries have revealed all of the matters that a more extensive examination might otherwise disclose.

The opinions expressed herein are subject to and fully qualified by the generally accepted uncertainties associated with the interpretation of geological, geophysical, petrophysical and engineering data and do not reflect the totality of circumstances, scenarios and information that could potentially affect decisions made by the report's recipients and/or actual results. The opinions and statements contained in this report are made in good faith and in the belief that such opinions and statements are representative of prevailing physical and economic circumstances.

In the preparation of this report, GCA has used definitions contained within the Petroleum Resources Management System (PRMS), which was approved by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists and the Society of Petroleum Evaluation Engineers in March 2007 (**Appendix II**).

There are numerous uncertainties inherent in estimating reserves and resources, and in projecting future production, development expenditures, operating expenses and cash flows. Oil and gas resource assessments must be recognized as a subjective process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact way. Estimates of oil and gas resources prepared by other parties may differ, perhaps materially, from those contained within this report.

The accuracy of any resource estimate is a function of the quality of the available data and of engineering and geological interpretation. Results of drilling, testing and production that post-date the preparation of the estimates may justify revisions, some or all of which may be material. Accordingly, resource estimates are often different from the quantities of oil and gas that are ultimately recovered, and the timing and cost of those volumes that are recovered may vary from that assumed.

Oil and Condensate volumes are reported in millions (10^6) of barrels at stock tank conditions (MMBbl). Natural gas volumes have been quoted in billions (10^9) of standard cubic feet (Bscf) and are volumes of sales gas, after an allocation has been made for fuel and process shrinkage

GCA has prepared an independent assessment of resources based on data and interpretations provided by Hess.

Definition of Contingent Resources

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development because of one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no evident viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

It must be appreciated that the Contingent Resources reported herein are unrisked in terms of economic uncertainty and commerciality. There is no certainty that it will be commercially viable to produce any portion of the Contingent Resources. Once discovered, the chance that the accumulation will be commercially developed is referred to as the "chance of development" (per PRMS).

Definition of Prospective Resources

Prospective Resources are those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated "chance of discovery" and a "chance of development" (per PRMS). Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates, assuming their discovery and development, and may be sub-classified based on project maturity.

There is no certainty that any portion of the Prospective Resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. Prospective Resource volumes are presented as unrisked.

This report has been prepared based on GCA's understanding of the effects of petroleum legislation and other regulations that currently apply to these properties. However, GCA is not in a position to attest to property title or rights, conditions of these rights (including environmental and abandonment obligations), or any necessary licenses and consents (including planning permission, financial interest relationships, or encumbrances thereon for any part of the appraised properties).

Use of Net Present Values

It should be clearly understood that the NPVs contained herein do not represent a GCA opinion as to the market value of the subject property, nor any interest in it.

In assessing a likely market value, it would be necessary to take into account a number of additional factors including reserves risk (i.e., that Proved and/or Probable and/or Possible reserves may not be realized within the anticipated timeframe for their exploitation); perceptions of economic and sovereign risk, including potential change in regulations; potential upside; other benefits, encumbrances or charges that may pertain to a particular interest; and, the competitive state of the market at the time. GCA has explicitly not taken such factors into account in deriving the NPVs presented herein.

Qualifications

In performing this study, GCA is not aware that any conflict of interest has existed. As an independent consultancy, GCA is providing impartial technical, commercial, and strategic advice within the energy sector. GCA's remuneration was not in any way contingent on the contents of this report.

In the preparation of this document, GCA has maintained, and continues to maintain, a strict independent consultant-client relationship with Hess. Furthermore, the management and employees of GCA have no interest in any of the assets evaluated or related with the analysis performed, as part of this report.

Staff members who prepared this report hold appropriate professional and educational qualifications and have the necessary levels of experience and expertise to perform the work.

Executive Summary

The deferred Equus Development comprises 9 separate fields within WA-70-R; Mentorc, Nimblefoot, Glencoe, Glenloth, Bravo, Rimfire, Brisies, Chester, Hijinx, plus the un-drilled Glenloth North and Briseis Deep prospects, spread over multiple horizons. In addition, it includes the Snapshot Triassic discovery in WA-474-P and also envisages tie-in of the undrilled Gaulus prospect in WA-518-P which is scheduled as a commitment well in 2018. Potential Development of the fields is proposed using subsea facilities tied back to a floating semi-submersible production facility. Produced gas will be dehydrated and the remaining wet gas and condensate piped to the existing NWS onshore processing facility. A non-binding Letter of Intent was signed between Hess and the NWS Joint Venture participants in December 2014 to process resources from Hess' permits which included proposed terms for the tolling of resources through the Karratha Gas Plant. This letter of Intent has been considered by GCA in the preliminary review of the project economics where a Contingent Resources only scenario was reviewed along with a Contingent and Risked Prospective Resources volume scenario.

GCA has reviewed data and interpretations provided by Hess to carry out an independent probabilistic assessment of the hydrocarbon volumes of the various fields and un-drilled prospects associated with the Equus Development. This included independent seismic well ties, interpretation quality control and depth conversions, petrophysical reservoir property calculations and engineering analysis to determine recoverable volumes on an individual field basis and defined project basis through a Network Modelling review of the proposed development.

GCA ran its own Low, Best and High network modelling cases to account for differences to Hess in GIIP and EUR volumes for a number of fields. GCA's total project resource volumes were derived by calculating the average between a full arithmetic and probabilistic addition of the individual field volumes to account for unknown dependencies between the fields. The average Low, Best and High Network case profiles were allocated to each field by proportionally scaling each individual field 1C, 2C and 3C case to the respective average Network case profile. GCA also ran cases without including the undiscovered volumes, to generate production profiles to estimate Contingent Resources. Adjustments were made to timing of the different development phases to ensure the profile was able to meet the required sales volumes.

It is GCA's opinion that the estimates of recoverable hydrocarbon liquid and gas volumes, as of 31 March 2017, are (in the aggregate) reasonable, and the Contingent Resources and Prospective Resources classifications and categorisations are appropriate and consistent with the definitions and guidelines for Contingent and Prospective Resources.

Contingent Resources and Prospective Resources for the Equus Project Fields have been estimated utilising a combination of probabilistic and deterministic estimates and surface network modelling cases using the GAP software. Estimates have followed the SPE-PRMS definitions and guidelines. The Contingent Resources are assigned the sub-class "Development On Hold " as plans for commercial development have been deferred as announced in the Hess Corporations Q4 2016 Earnings Release: *"An after-tax charge of $US 693 million ($US938 million pre-tax) in Exploration and Production to fully impair the carrying value of our interests in blocks WA-390-P and WA-474-P (Hess 100 percent) offshore the North West Shelf of Australia following the decision to defer further development of the Equus natural gas fields".*

The proposed Equus Development Project is a combined surface and subsea production system connecting 11 potential fields with multiple reservoirs to a single Floating Production System (FPS) facility via three 12 inch interfield flowlines. Gas and condensate export is planned via a 22 inch trunkline to the NWS JV LNG facility at Karratha. The original development was planned and staged over 5 Phases from 2021 to 2039. The Operator's schedule shows first year production startup for the original planned development at the end of Q3 2021. In order to meet this timing, Phase 1 drilling operations will need to commence 24 months earlier. Phase 1 facilities design expenditure would start 60 months earlier, with major construction expenditure commencing 48 months in advance of first production. Offshore construction activities would start some 20 months prior to first production. GCA has maintained the original schedule prior to the Equus project deferment as an indicative timeline. The example lead times mentioned above can guide the reader on any possible future scheduling of the project.

GCA's Estimates of Gas Contingent Resources associated with the deferred Equus development as at 31 March 2017 are summarised in **Table 1** with estimates of associated Condensate Contingent resources summarised in **Table 2**. Three fields; Bravo, Chester, and Rimfire have closures which at some reservoir intervals extend beyond the WA-70-R block boundary and into adjacent blocks. **Table 1** and **Table 2** indicate on block volumes only. **Table 3** and **Table 4** include Prospective Resource volumes with their respective Geological Chance of Success (GCoS).

An economic limit test (ELT) has been carried out by considering two scenarios that include production profiles constructed utilising the discovered gas volumes to estimate Contingent Resources volumes and also a combination of the discovered and undiscovered gas volumes (Risked by GCoS) to assess Prospective Resources for the Equus project. This preliminary analysis has been based on the production (sales) and cost profiles presented in various sections of this report, together with the fiscal terms potentially applicable to WA-70-R. In addition the following factors have been considered for the preliminary economic analysis:

- Effective date of the economic analysis is as of 31 March 2017
- Costs are escalated at 2.0% p.a. from 1 January 2018
- GCA's 1Q 2017 price scenario for Brent crude oil
- The scenario analysis assumes that the Production License will be secured in year 2017/2018 as the basis to carry out the economic analysis

The economic cut-off is defined as the production rate beyond which the field's net operating cash flows are negative. The purpose of the analyses is to demonstrate preliminary cases of commercial viability for the Equus Project and hence justification for project volume outputs to be classified as Contingent/Prospective Resources in all resource reporting categories. Using the undiscounted cash flow result from the ELT analysis discussed in this report, the Equus Project would be commercially produced until year 2034, 2040 and 2052 based on the Low, Best and High case discovered resource profiles respectively. Taking into account discounted cash flow analysis with different discount rates produces Net Present Values (NPVs) and Internal Rates of Return (IRR) as per **Table 5.**

A Risked Prospective Resource scenario is also considered, and results are also included in **Table 5** demonstrating project viability in both cases. It should be clearly understood that the NPVs contained herein do not represent a GCA opinion as to the market value of the subject property, nor any interest in it.

Table 1: GCA's Estimate of Gross Gas Contingent Resources as of 31 March 2017

Block	Field	Reservoir	1C (Bscf)	2C (Bscf)	3C (Bscf)
WA-70-R	Mentorc	LBG	352	378	450
	Nimblefoot	LBG	88	168	257
	Glencoe	Jurassic	143	226	381
	Bravo	LBG	76	128	186
	Chester	Norian 700	34	71	117
		Norian 800 C1	61	102	184
		Norian 800 C2	21	27	44
		Total	**117**	**200**	**345**
	Briseis	LBG	14	33	107
		Norian 600	87	92	103
		Total	**101**	**125**	**210**
	Glenloth	Carnian 300	184	298	562
		Norian 600	24	30	38
		Norian 100	10	94	172
		Norian 400 SA3	30	35	43
		Norian 100 SA1	13	16	20
		Norian 300 SA6	9	14	19
		Norian 300 SA4	14	20	30
		Total	**284**	**505**	**884**
	Rimfire	Norian 100	33	79	115
		Carnian 400	51	94	227
		Total	**84**	**173**	**343**
	Hijinx	Norian 400 SA3	29	35	46
		Norian 400 SA4	14	21	34
		Total	**43**	**56**	**79**
WA-474-P	Snapshot	Carnian 300	37	49	63
		Norian 700	19	21	25
		Total	**56**	**70**	**88**
Total			**1,343**	**2,028**	**3,223**

Notes:

1. GCA's total project resource volumes were derived by calculating the average between a full arithmetic and probabilistic addition of the individual field volumes to account for unknown dependencies between the fields. The average Low, Best and High Network case profiles were allocated to each field by proportionally scaling each individual field 1C, 2C and 3C case to the respective average Network case profile.
2. "Gross Contingent Resources" are 100% of the volumes estimated to be recoverable from the field/reservoir without any economic cut-off being applied.
3. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that the project may not be developed in the form envisaged or may not go ahead at all (i.e. no "Chance of Development" factor has been applied).
4. Contingent Resources should not be aggregated with Prospective Resources because of the different levels of risk involved and the different basis on which the volumes are determined.
5. All volumes are reported as gross on block volumes.
6. Resource categories adhere to the required CO_2 and N_2 limitations for the Karratha Gas Plant (2.8% and 4% respectively). Production constraints used in the Network GAP model for resource estimates were based on those from the scoping design of the Equus development.

Table 2: GCA's Estimate of Gross Condensate Contingent Resources as of 31 March 2017

Block	Field	Reservoir	1C (MMBbl)	2C (MMBbl)	3C (MMBbl)
WA-70-R	Mentorc	LBG	12.4	16.4	23.4
	Nimblefoot	LBG	1.2	2.7	4.9
	Glencoe	Jurassic	2.7	4.2	8.3
	Bravo	LBG	2.4	4.9	6.7
	Chester	Norian 700	0.3	0.6	0.9
		Norian 800 C1	0.5	0.9	1.6
		Norian 800 C2	0.2	0.2	0.6
		Total	0.9	1.7	3.2
	Briseis	LBG	0.3	0.7	2.4
		Norian 600	1.4	1.5	1.8
		Total	1.8	2.2	4.2
	Glenloth	Carnian 300	0.6	1.4	2.9
		Norian 600	0.5	0.7	0.9
		Norian 100	0.2	2.1	3.8
		Norian 400 SA3	0.3	0.5	0.6
		Norian 100 SA1	0.2	0.2	0.3
		Norian 300 SA6	0.2	0.3	0.4
		Norian 300 SA4	0.3	0.5	0.7
		Total	2.2	5.6	9.5
	Rimfire	Norian 100	0.9	1.7	3.5
		Carnian 400	0.3	0.4	1.6
		Total	1.2	2.2	5.1
	Hijinx	Norian 400 SA3	1.1	1.1	1.7
		Norian 400 SA4	0.4	0.4	0.8
		Total	1.5	1.4	2.5
WA-474-P	Snapshot	Carnian 300	0.2	0.2	0.5
		Norian 700	0.0	0.1	0.1
		Total	0.2	0.4	0.6
Total			**26.6**	**41.5**	**68.4**

Notes:

1. GCA's total project resource volumes were derived by calculating the average between a full arithmetic and probabilistic addition of the individual field volumes to account for unknown dependencies between the fields. The average Low, Best and High Network case profiles were allocated to each field by proportionally scaling each individual field 1C, 2C and 3C case to the respective average Network case profile.
2. "Gross Contingent Resources" are 100% of the volumes estimated to be recoverable from the field/reservoir without any economic cut-off being applied.
3. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that the project may not be developed in the form envisaged or may not go ahead at all (i.e. no "Chance of Development" factor has been applied).
4. Contingent Resources should not be aggregated with Prospective Resources because of the different levels of risk involved and the different basis on which the volumes are determined.
5. All volumes are reported as gross on block volumes.

GCA's Estimates of Unrisked Gas Prospective Resources associated with the Equus Development as at 31 March 2017 are summarised in **Table 3** with estimates of associated Unrisked Condensate Prospective resources summarised in **Table 4** together with the associated geological chance of success (GCoS) for each prospect.

Table 3: GCA's Estimate of Unrisked Gas Prospective Resources as of 31 March 2017

Block	Prospect	Reservoir	Low (Bscf)	Best (Bscf)	High (Bscf)	GCoS
WA518-P	Gaulus	Norian 200	110	227	345	0.38
		Norian 800	78	135	277	0.50
		Carnian 300	16	73	379	0.38
WA-70-P	Glenloth North	Carnian 400	160	382	1,136	0.38
	Briseis Deep	Carnian 300	65	118	239	0.30
		Carnian 400	57	143	427	0.38

Notes:
1. Gross Prospective Resources are 100% of the volumes estimated to be recoverable from the Prospect in the event that a discovery is made and subsequently developed.
2. The estimates of Prospective Resources are based initially on a probabilistic methodology with project totals calculated as an average of the probabilistic and arithmetic sum. Individual field volumes for the Low, Best and High categories were input into the Gap Network cases for each field via a scaling process so the arithmetic total was equivalent to the average between a full arithmetic and probabilistic addition of the individual field volumes.
3. The GCoS reported here represents an indicative estimate of the probability that drilling this Prospect/Lead would result in a discovery. This does not include any assessment of the risk that the discovery, if made, may not be developed.
4. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk, that no discovery will be made, or that any discovery would not be developed.
5. Identification of Prospective Resources associated with a Prospect is not indicative of any certainty that the Prospect will be drilled, or will be drilled in a timely manner.
6. Prospective Resources should not be aggregated with each other because of the different levels of risk involved.
7. Resource categories adhere to the required CO_2 and N_2 limitations for the Karratha Gas Plant (2.8% and 4% respectively). Production constraints used in the Network GAP model for resource estimates were based on those from the scoping design of the Equus development.

Table 4: GCA's Estimate of Unrisked Condensate Prospective Resources as of 31 March 2017

Block	Prospect	Reservoir	Low (MMBbl)	Best (MMBbl)	High (MMBbl)	GCoS
WA518-P	Gaulus	Norian 200	0.5	1.0	1.7	0.38
		Norian 800	0.3	0.5	1.0	0.50
		Carnian 300	0.0	1.8	6.8	0.38
WA-70-P	Glenloth North	Carnian 400	0.5	1.3	6.1	0.38
	Briseis Deep	Carnian 300	0.4	0.7	1.5	0.30
		Carnian 400	0.2	0.7	2.1	0.38

Notes:
1. Gross Prospective Resources are 100% of the volumes estimated to be recoverable from the Prospect in the event that a discovery is made and subsequently developed.
2. The estimates of Prospective Resources are based initially on a probabilistic methodology with project totals calculated as an average of the probabilistic and arithmetic sum. Individual field volumes for the Low, Best and High categories o the Gap Network cases for each field via a scaling process so the arithmetic total was equivalent to the average between a full arithmetic and probabilistic addition of the individual field volumes.
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5. Identification of Prospective Resources associated with a Prospect is not indicative of any certainty that the Prospect will be drilled, or will be drilled in a timely manner.
6. Prospective Resources should not be aggregated with each other because of the different levels of risk involved.

Table 5: Project Equus Scenario Analysis NPVs Attributable to a 100% Working Interest as of 31 March 2017

Discount Rates	Contingent Resources			Contingent Resources + Risked Prospective Resources		
	1C NPV Scenario (US$ MM)	2C NPV Scenario (US$ MM)	3C NPV Scenario (US$ MM)	1C + Risked Low Case NPV Scenario (US$ MM)	2C+ Risked Best Case NPV Scenario (US$ MM)	3C+Risked High Case NPV Scenario (US$ MM)
0%	928	3,997	8,610	1,187	4,560	11,325
5%	71	1,596	3,246	183	1,828	3,618
8%	-260	780	1,723	-196	923	1,786
10%	-425	394	1,063	-382	500	1,050
12%	-556	97	584	-528	179	542
IRR	**6%**	**13%**	**16%**	**6%**	**13%**	**15%**

Notes:
1. Using the undiscounted cash flow as the basis, the total gas to be sold commercially for 1C, 2C and 3C are 1,315 Bscf, 2,006 Bscf and 3,127 Bscf, respectively. Total condensate to be sold commercially for 1C, 2C and 3C are 26.4 MMstb, 41.4 MMstb and 66.9 MMstb, respectively.
2. Using the undiscounted cash flow as the basis, the last commercial production year for 1C, 2C and 3C are year 2034, 2040 and 2052, respectively.
3. Using the undiscounted cash flow as the basis, the additional commercial risked volumes due to the discovery of the Prospective Resources for the Low, Best and High cases for gas are 194 Bscf, 347 Bscf and 1,014 Bscf, respectively. The additional commercial condensate volumes related to the Low, Best and High cases are 0.8 MMstb, 1.7 MMstb and 7.3 MMstb, respectively.
4. Should the Prospective Resources be discovered and developed, the additional risked volumes on the Low, Best and High case will extend the proje ct life until year 2036, 2044 and 2061, respectively.
5. GCA's 1Q 2017 price scenario for Brent crude oil is utilised for the economic analysis along with GCA's vetted/adjusted Capex and Opex forecasts

Discussion

1 Equus Project Overview

In 2012, Hess was awarded an Exploration Licence for the Permit area WA-474-P, which is adjacent WA-390-P. Hess currently holds a 100% WI in WA-474-P. The Snapshot-1 exploration well was drilled in WA-474-P in early 2016 and was recently suspended for future production. In addition, Hess holds a 100% WI in two additional Exploration Permits; WA-518-P and WA-519-P which are adjacent to WA-390-P.

The Equus Development is located offshore Western Australia, approximately 200 km northwest of Onslow in water depths ranging from 1,000 - 1,200 m and comprises 9 separate fields within WA-70-R (Mentorc, Nimblefoot, Glencoe, Glenloth, Bravo, Rimfire, Brisies, Chester, Hijinx) spread over multiple horizons, plus the Snapshot Triassic discovery in WA-474-P. It also envisages tie-in of the undrilled Gaulus Prospect in WA-518-P following the drilling of a commitment well in 2018.

Development of the fields is proposed using subsea facilities tied back to a floating semi-submersible production facility. Produced gas will be dehydrated and remaining wet gas and condensate piped to the existing North-West Shelf onshore processing facility (NWS). A non-binding Letter of Intent was signed between Hess and the NWS Joint Venture participants in December, 2014 to process resources from Hess' permits which included proposed terms for the tolling of resources through the Karratha Gas Plant.

1.1 Data Set

Hess provided GCA with full data set of geological, geophysical, petrophysical, engineering, facilities and economic data. These data included 3D PSDM seismic surveys over the entire Equus Development area, seismic inversion cubes, electronic well data, Petrel models, Eclipse and GAP models.

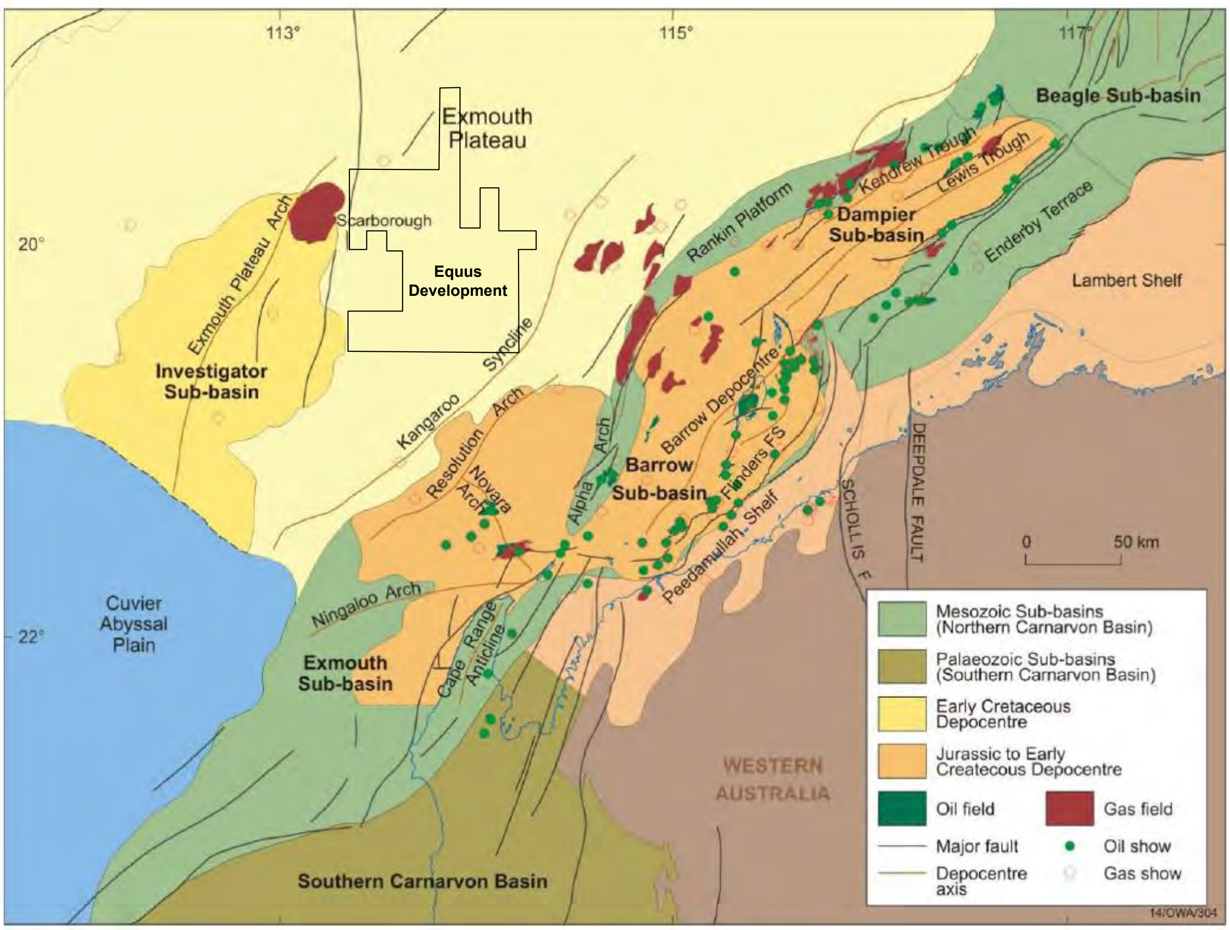
These data were accompanied by supporting reports and presentations. In particular, GCA's analysis of the regional geology has been summarised from various Well Completion Reports.

2 Geology

2.1 Regional Overview

The fields of the Equus Project lie on the Exmouth Plateau, a continental platform within the North Carnarvon Basin, 150- 500 km off the northwest coast of Australia (**Figure 2**). The platform is bound to the southwest, northwest and northeast by abyssal plains of Jurassic – Cretaceous oceanic crust and to the south by the Exmouth and Barrow Sub-Basins and Rankin Trend. The Exmouth Plateau formed by Upper Jurassic rifting due to the break-up of Australia and India which resulted in a series of northeast – southwest trending tilted fault blocks.

Figure 2: Exmouth Plateau



Source: Modified from Hess

2.2 Tectonic Evolution of the NW Australian Margin

In the late Carboniferous-early Permian, rifting of the Sibamasu block is thought to have formed the northeast – southwest striking Westalian Superbasin (WASB) as a relatively unrifted intracratonic sag basin which accumulated a thick Permian and Triassic sedimentary sequence. Layer cake geometry of the Permo – Triassic shallow marine and terrestrial basin fill suggests accommodation space was created by widespread thermal subsidence.

The major tectonic features of the North Carnarvon Basin were formed by early Jurassic northeast – southwest rifting. The Pliensbachian unconformity, seen as unconformable downlap in the basin suggests rapid subsidence due to the initiation of faulting. A second period of rifting in the Callovian marked the start of an intense phase of extensional tectonism that continued until the Late Jurassic. During this time the north-west shelf moved between tropical and more southerly latitudes.

The Cretaceous tectonic history of the north-west shelf is dominated by the separation of Australia from Greater India and Antarctica and saw three stages of thermal subsidence linked to extension and two stages of inversion linked to stresses caused by plate reorganization. The separation was associated with marine transgression and as spreading rates between Australia and Antartica increased in the Eocene and Oligocene, open ocean between the two continents lead to the initiation of the Antartic Circum-polar Current (ACC) and the onset of Antartic glaciation. During the Miocene, the north-west shelf underwent punctuated periods of inversion related to the convergence of Australia and Asia with the subduction of the Timor Trench causing flexural uplift and collision with New Guinea causing compressional inversion.

2.3 Stratigraphy of the North Carnarvon Basin

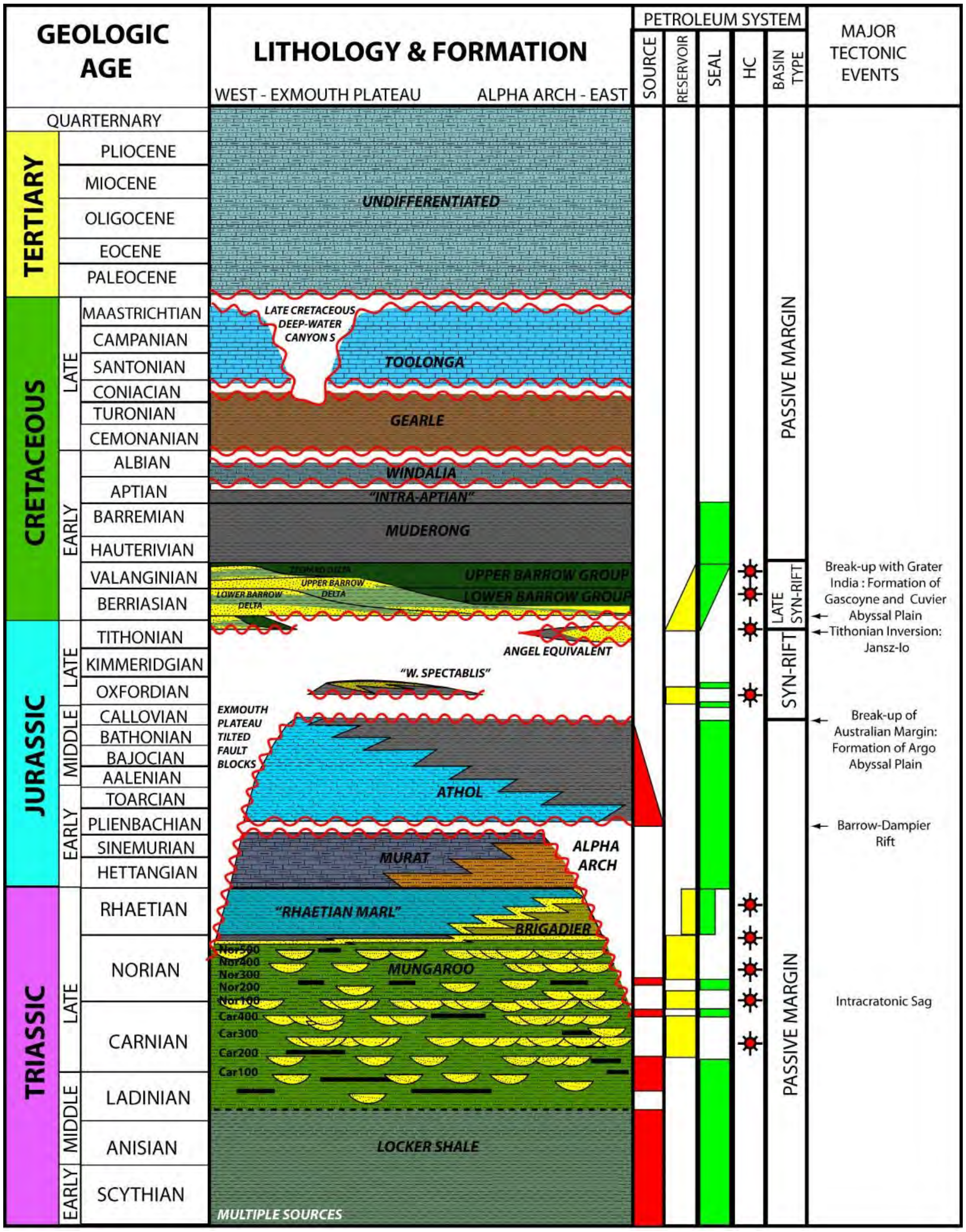
Paleozoic stratigraphy is dominated by glacial sediments passing into a Permian delta complex which was sourced from the Central Australian Highlands. The Base of the Triassic is marked by a marine transgression related to tectonic subsidence and a global eustatic sea level rise which resulted in the deposition of the Locker Shale in the North Carnarvon Basin. During this period, the north-west shelf was part of an extensive intracratonic basin connected to a northern seaway. As the sea-level fell during the mid-Triassic, the fluviodeltaic Mungaroo Formation, sourced via a large river network which flowed westward across Australia prograded over the western shelf. The Mungaroo Formation forms the main source and reservoir sands of the Exmouth Plateau gas fields.

A marine transgression at the end of the Triassic led to the deposition of the coastal and shallow marine Brigadier formation which is capped by a maximum flooding surface. During the deposition of the Triassic – Early Jurassic sequences, there was no syn-depositional faulting and the sediments filled an elongate basin parallel to the current Australian coastline.

This episode is followed by a syn-rift megasequence which begins with the Pliensbachian Unconformity which marks a rapid deepening of the margin. The Callovian Unconformity marks the onset of rifting and an acceleration in subsidence. A second rifting phase initiated the separation of India from Australia resulting in sub-aerial erosion of uplifted fault blocks and the deposition of reworked Triassic sediments as forced regressive sands during the Oxforian, followed by Mungaroo and Brigadier Formations as Tithonian transgressive deposits.

During the Cretaceous, rifting resulted in the formation of the Barrow Delta which prograded to the north-northeast across the Exmouth Plateau. A Further marine transgression in the Lower Cretaceous Valanginian led to the deposition of the Munderong Shale which acts as a regional seal for the north-west shelf. Marine transgression continued into the late Createaceous depositing the Gearle Formation. By the Tertiary, Australia had begun to drift northwards and the decreasing latitudes together with decreasing sediment supply led to the formation of large carbonate shelf deposits. (*Source: various Well Completion Reports*). **Figure 3** shows the stratigraphic column of the Exmouth Basin.

Figure 3: Stratigraphic Column of the Exmouth Basin



Source: Hess

2.4 Petroleum System

The Exmouth Plateau contains 10-15 km of sediment and contains three main reservoirs; the Cretaceous Lower Barrow Group, the Jurassic Oxfordian and the Triassic Mungaroo Formation.

The Lower Barrow Group is formed of delta top and basin floor sands. The delta top facies, which have been penetrated at Mentorc have very good reservoir properties with high porosities and net to gross and are analogous to the reservoirs at the Scarborough Field. The basin floor sands have good reservoir properties and have been penetrated at Briseis, Bravo and Numblefoot.

The Jurassic Oxfordian reservoirs, penetrated at Glencoe are formed of shallow marine sand deposited unconformably on underlying Triassic sediments and are characterised by moderate reservoir properties.

The Triassic Mungaroo Formation which includes both Norian and Carnian aged reservoir targets is formed of fluvial-deltaic sediments charecterised by stacked channels which are often identified by amplitude anomaly. Mungaroo targets are generally have a combined structural and stratigraphical trapping mechanism and depositional fairways are mapable by amplitude anomalies. Sediments become more distal with greater marine influence to the northwest.

The main kitchen for the area lies to the east in the Exmouth Sub-basin. The source is composed of Mungaroo and Ladinian to Norian age and consists of predominantly terrestrial carbonaceous shales and coals. Generation from the source began in the Late Cretaceous and continued through the Tertiary to present times.

2.5 Exploration History

Modern petroleum exploration began in the Carnarvon Basin in 1951 with the drilling of the onshore Rough Range-1 well which penetrated an oil accumulation in the Early Cretaceous Barrow Group. Significant offshore exploration began in 1963 in shallow water blocks with deeper water exploration beginning from 1970.

In 1979 the first deepwater drilling phase began in North West Australia and 10 wells were drilled on the Exmouth Plateau targeting known onshore plays and included the Scarborough-1 well which discovered a large gas accumulation in a Barrow Group reservoir. Lack of a local market for gas and available technology to transport the gas resulted in the field not being developed.

A second phase of exploration on the Exmouth Plateau began in 1992 initiated by the introduction of 3D seismic surveys and advances in deepwater drilling. Since the mid-1990's exploration focused on the Triassic Locker Shale (source) – Mungaroo (reservoir) play with a number of large discoveries being made on the Eastern Plateau between 1999 and 2001.

Hess was awarded the WA-390-P permit, which comprises 39 graticular blocks in 2007 for a first term license commitment that included 3,135 km^2 new 3D seismic and 16 exploration wells. The exploration campaign was completed in October 2010 with 14 of the 16 wells being gas discoveries.

3 Geophysics

3.1 Data Set

Hess provided GCA with a set of geophysical and well data loaded into both regional and individual field Petrel Projects. The data included:

- Various 3D seismic data sets of different vintages over WA-390-P and surrounding area and which included the Glencoe 3D seismic survey acquired by Hess in 2007-8 and which covers the entire permit
- Pre stack depth migration (PSDM) seismic reprocessed cube of the Glencoe 3D seismic survey carried out by CGG Services (Australia) in 2013/2014
- Simultaneous Elastic Inversion and Litho-Classification 3D seismic cubes prepared by Hampson Russel, a CGG Veritas company in 2012
- Electronic log and geological data for 21 wells; Bravo-1, Bravo-2, Brisies-1, Chester-1ST1, Chester-2, Dunlop-1, Glencoe-1, Glencoe-2, Glenloth-1, Hijinx-1, Juene-1, lightfinger-1, Makybe Diva-1, Mentorc-1, Mentorc-2, Nimblefoot-1, Rimfire-1, Snapshot-1, The Grafter-1, Topora-1 and Warrior-1
- Hess's geophysical interpretations
- Petrel models for the nine fields plus the Gaulus Prospect

3.2 Seismic Interpretation Depth Conversion

Hess' geophysical interpretations of the discovered and prospective gas accumulations were based on the PSDM Depth cube data. To evaluate the depth uncertainty inherent in the provided PSDM interpretations GCA utilised the PSDM velocity cube to construct an initial 3D velocity model to convert the depth structure surfaces back to time. The PSDM velocity cube converted time surfaces were subsequently correlated to the time-stretched PSDM data for well and synthetic seismogram character ties. The time surfaces were finally re-converted to depth utilising GCA constructed velocity models (after integrating and reviewing well and seismic velocity data and discussed below) to investigate the GRV uncertainty derived from the depth conversion process.

GCA carried out three different depth conversions utilizing the data contained within the regional Petrel Project to investigate the uncertainty for GRV ranges: after converting the PSDM interpretations to time

1. A multiple surface 3D velocity model utilizing: An average velocity surface calculated for the water layer and for each of Hess' regionally mapped intervals, interval velocity well based surfaces were created utilising point data at the well intersections (these points were gridded utilizing the convergent algorithm to produce an interval velocity map for each interval which was then used in the Petrel velocity modeling module). The convergent gridding algorithm was consistently utilized for gridding time, velocity and depth surfaces.
2. A second multiple surface 3D velocity model utilizing an average velocity surface calculated for the water layer and for each of Hess' regionally mapped intervals, constant interval velocities were applied which were averaged from interval velocities calculated from check shot data for penetrating wells.

3. A simple 3D velocity model created by applying a velocity function in the form "$V = V_0 + K*(Z-Z_0)$" within the Petrel software module. V_0 and K are determined by the Time-Depth relationship and the intersection of the regionally interpreted surfaces with the well data.

For each of the velocity models, GCA utilized a checkshot data set which excluded any anomalous points or wells after reviewing well time depth pair plots for consistent trend analysis. To test the accuracy of each depth conversion, GCA incorporated well markers as calibration points. A cross-section of GCA's three depth conversions is given in **Figure 4**. GCA considered Velocity Model 1 to be its Best Case as it resulted in the smallest average well residuals across the reservoir intervals. A comparison of GCA's three depth conversions together with Hess' PSDM interpretation (dotted lines) is given in **Figure 5**.

Figure 4: GCA Depth Surfaces

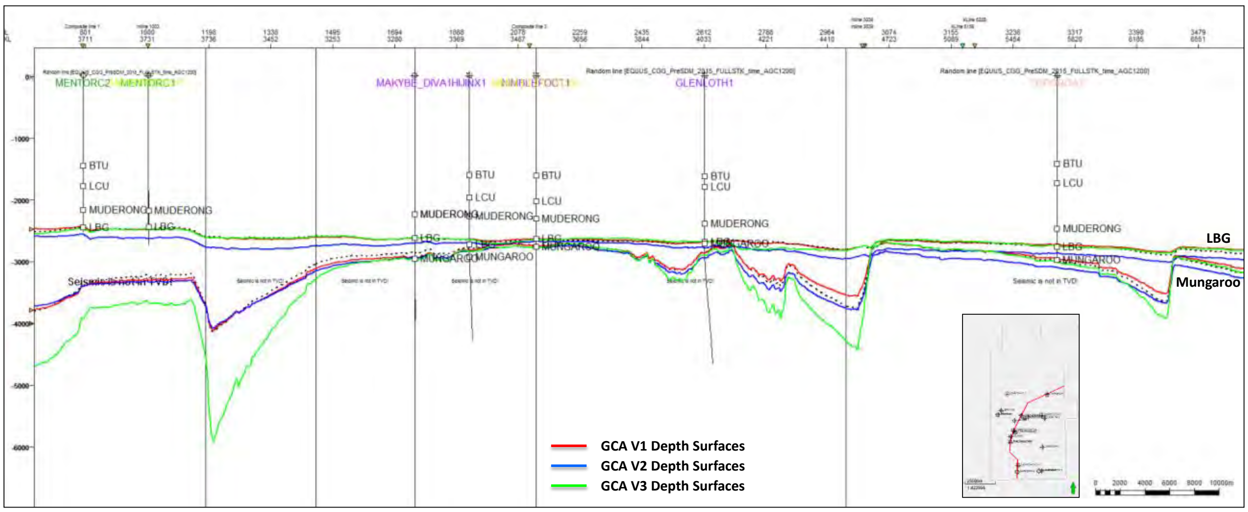
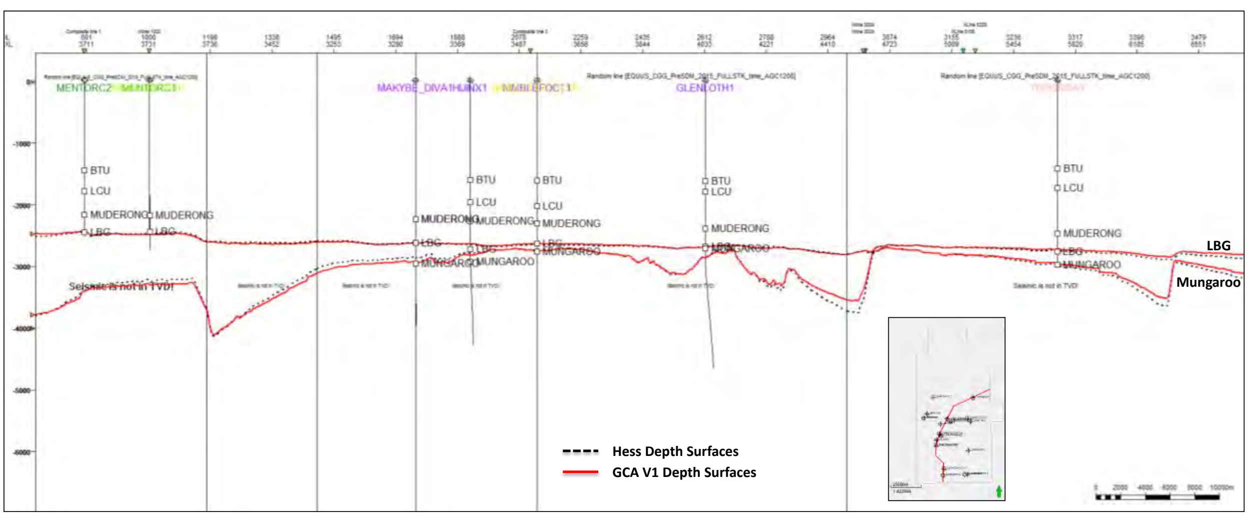
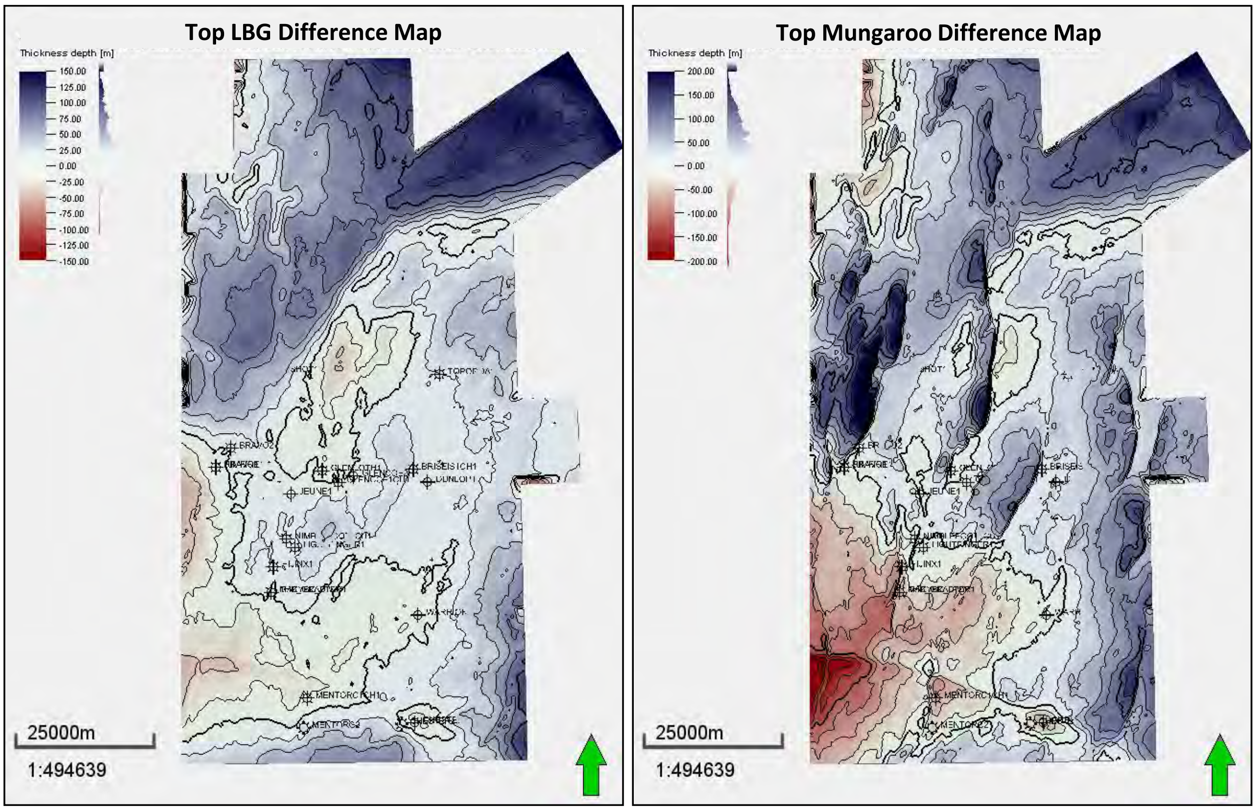


Figure 5: Comparison of GCA and Hess Depth Surfaces



The maps in **Figure 6** are difference maps between the GCA and Hess depth surfaces at the Lower Barrow Group (LBG) and Mungaroo reservoir intervals. While GCA's Best Case depth conversion and Hess' PSDM interpretation show only small differences in areas of good well control, further from well control the depth surfaces show that there is enough depth uncertainty and consequently gross rock volume (GRV) uncertainty to justify incorporating other depth conversion results into the analysis of GRV uncertainty.

Figure 6: Difference Maps at Lower Barrow Group and Mungaroo Reservoir Intervals between GCA Velocity Model 1 Surfaces and Hess' PSDM Surfaces where Blue = GCA Surfaces are shallower and Red = Hess Surfaces are Shallower



4 Petrophysics

An independent petrophysical interpretation of key wells was performed to study the validity of the models and assumptions applied in the petrophysical analysis performed by HESS. The GCA interpretation results were compared with available core data and the HESS interpretation results to assess the reasonableness of the HESS reservoir property averages used for volumetric calculations. The output curves from the GCA interpretation and the results curves provided by HESS were averaged and compared to analyze their impact on the in-place volumetric estimates.

The resulting averages were used to provide an uncertainty range in key reservoir parameters (net to gross, porosity, water saturation) associated with the petrophysical analysis, which have been used as a basis for validating the range of property values applied in the HESS geological models and as input to HESS probabilistic volumetric calculations.

4.1 Petrophysical Database

A comprehensive set of QC'd raw and interpreted log data was provided in LAS format for each well in the Equus Project area. A standardized set of log curve mnemonics was used in the dataset; these are shown in **Table 6**. Deviation survey data was also available for each well.

Table 6: Standardized Log Curve Mnemonics

Curve Name	Units	Description
BVW	V/V	Bulk volume water
CALI	IN	Caliper
COAL	V/V	Coal
DRHO	G/CC	Density correction
DTC_E	US/F	Compressional sonic slowness
DTS_E	US/F	Shear sonic slowness
GR	GAPI	Gamma ray
NEUTRON	V/V	Thermal neutron porosity
PEF	B/E	Photoelectric factor
PHIT	V/V	Total porosity excluding coals and zones of bad hole
POTA	%	Potassium
RDEEP	OHMM	Deep resistivity
RHO_E	G/CC	Density
RMED	OHMM	Medium resistivity
RSHAL	OHMM	Shallow resistivity
SFILTO	V/V	Synthetic based mud filtrate saturation.
SW	V/V	Total water saturation
SW_SAND	V/V	Total water saturation in SAND intervals (Coals excluded and generally shale volume <0.5). 1 in non-net and interpreted water zones.
TENS	LBF	Line tension
THOR	PPM	Thorium
URAN	PPM	Uranium
VOLCANIC	V/V	Most likely basalt, but other volcanics possible.
VSHALE	V/V	Shale volume

Routine (RCA) and Special (SCAL) Core Analysis reports and associated core analysis data were provided in spreadsheet format for wells where whole core or sidewall cores were available.

Reservoir pressure measurements (RCI/MDT) and fluid study reports were available for all wells analyzed.

4.2 Interpretation Methodology

Shale volume analysis in all the Equus Project reservoirs was estimated by HESS from a combination of the GR and density/neutron logs. GR clean and shale readings and the density and neutron clay points were estimated directly from logs in shale intervals. Shale volume estimated from the density/neutron crossplot method was corrected for light hydrocarbons. The final shale volume curve was computed as an average of the results from the two methods.

The GCA analysis followed a similar methodology and the resulting shale volume curves were found to be very similar. The resulting shale volume analyses were used as input for the calculation of total and effective porosity.

The HESS porosity interpretation was based on the density log using an iterative calculation in combination with water saturation calculation to correct for light hydrocarbons. The HESS results were verified by independently calculating porosity using the density/neutron cross-plot method and the density-porosity method, both of which were corrected for the presence of light hydrocarbons and shale content. Based on the available core data, a constant grain density of 2.65 g/cc was used by GCA. Whenever available, core data was used for the calibration of log-derived porosity.

Water saturation (Sw) was calculated by HESS using the Archie equation, but with sensitivity tests performed with shaley-sand (Waxman-Smits) models. The Archie saturation (*m*) and cementation (*n*) exponents were derived from the core analysis performed on a reservoir level. A summary of the *m* and *n* values used in the HESS interpretation is provided in **Table 7** below. GCA reviewed the petrophysical report describing the derivation of these exponents from core data and found it to be reasonable. No attempt to independently estimate the *m* and *n* exponents from the core data was made in this study.

Table 7: Summary of cementation and saturation exponents

Reservoir	Cementation exponent, *m*	Saturation exponent, *n*
Lower Barrow Group	1.84	1.90
Oxfordian	1.94	2.05
Mungaroo	1.90	1.95

Hess reported a number of water samples that were acquired to assist in the determination of water salinity values for Sw calculations. A list of salinity values for each of the reservoir units is provided in **Table 8**. For the LBG and Oxfordian units, no obvious salinity-depth trend was observed, but for the Mungaroo reservoir, a large range in water salinity measurements was recorded. For GCA's analysis, the salinity values were cross-checked against estimates derived using a Pickett plot (whenever a clean, water-bearing interval was available) and were found to be consistent with the measured samples.

Table 8: Summary Water Salinity Values

Reservoir	Sampled well	Water salinity range (ppm)
Lower Barrow Group	Nimblefoot-1 Lightfinger-1 Bravo-1 Mentorc-1	23,000 to 30,000 (higher in Mentorc-1)
Oxfordian	Dunlop-1 Glencoe-2	20,000 (Dunlop-1) to 25,000 (Glencoe-2)
Mungaroo	Glencoe-1 Briseis-1 Nimblefoot-1 Rimfire-1 Hijinx-1 Glenloth-1 Chester-1ST1 Makybe Diva-1	10,000 (deepest well, Chester-1ST1) to 24,000 (Glencoe-1)

Given the relatively high clay content observed on the logs, GCA adopted the shaley-sand models in its interpretation. Sw calculation was tested using the Indonesian and Simandoux equations and compared with the Archie model (and the Waxman-Smits model, whenever available) calculated by HESS. In a number of key wells, the core-derived Sw using the lambda equation was regenerated using GCA permeability curves (core-derived) and then compared with the GCA Sw interpretation.

The HESS fluid contacts in each field were determined by integrating data from the well logs, RCI/MDT pressures, while taking into consideration the structural limit of the reservoirs. A similar approach was adopted by GCA with ranges applied based on the available data.

4.3 Petrophysical Analysis Results

4.3.1 Cretaceous - Lower Barrow Group Reservoirs

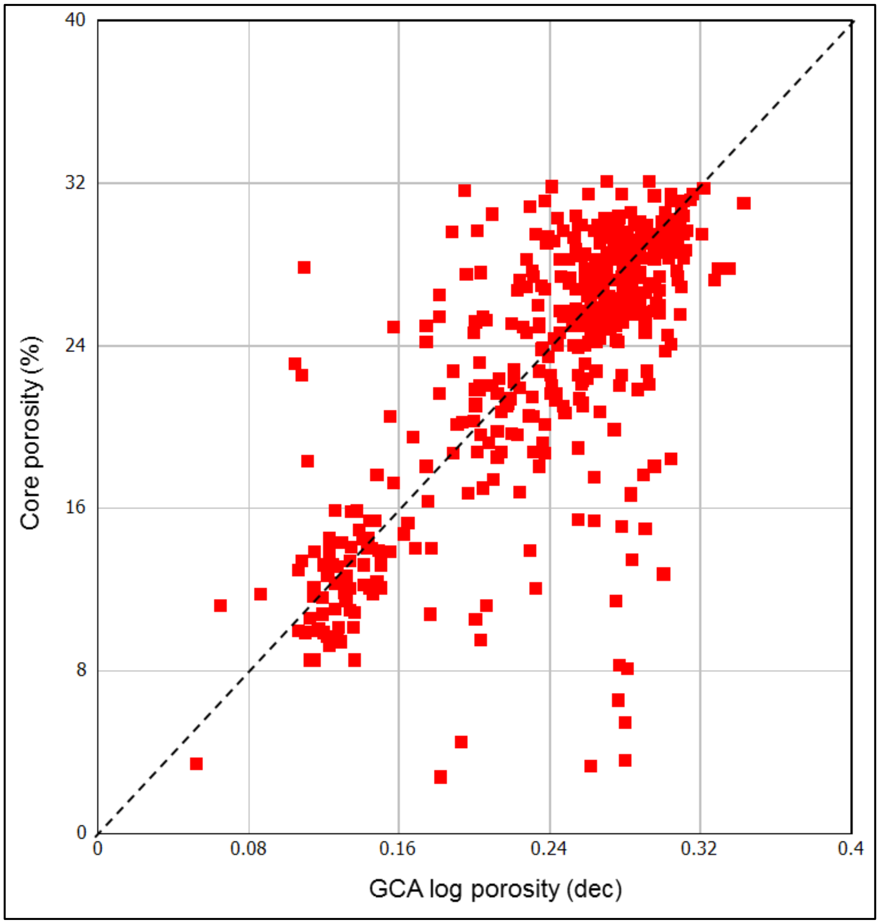
Significant gas discoveries in the Lower Barrow Group (LBG) reservoirs have been made in 4 fields (Mentorc, Nimblefoot, Bravo and Briseis) included within the Equus Project. With the exception of the Briseis field, each of these discoveries has been confirmed by one or more appraisal wells. All wells penetrating the LBG reservoirs were analysed for this review; the wells analysed are listed by field below.

- Mentorc – Mentorc-1, Mentorc-2
- Nimblefoot – Nimblefoot-1, Lightfinger-1
- Bravo – Bravo-1, Bravo-2, Rimfire-1
- Briseis – Briseis-1

Whenever available, core data was used to calibrate log interpretation. In the four fields analyzed, core data within the LBG reservoir was available in seven out of eight wells, allowing a comparison between core- and log-derived porosity to be made. The results are shown in **Figure 7**. The match provides confidence in the use of log-derived porosity for this petrophysical interpretation.

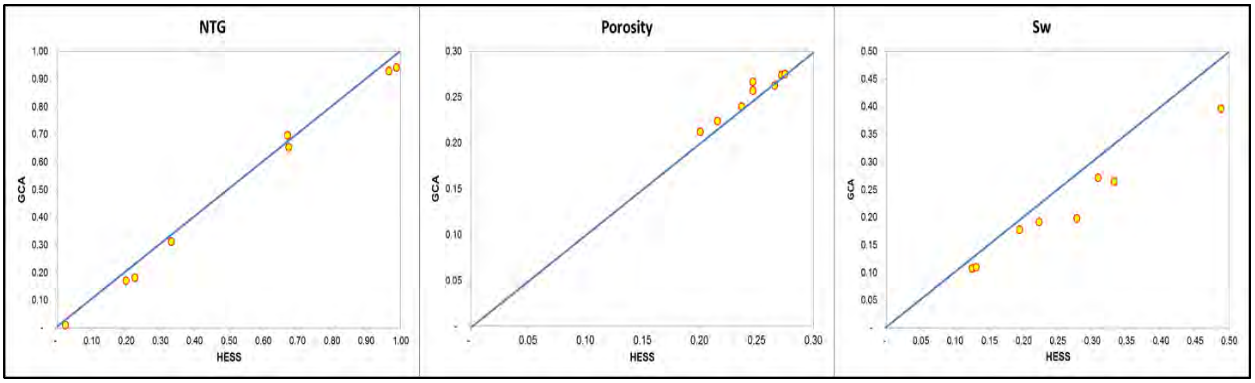
Although a large scatter in core porosity is observed, there is generally good agreement between core- and log-derived estimations. The cloud of data in the crossplot can be explained by the difference between core and log scales where the logs were not able to resolve the thin variations in porosity as well as core measurements. An upscaling of the core data is required to provide similar scales in measurement and thus a better match between the two sets of data.

Figure 7: LBG Reservoirs – Core vs. GCA Log Porosity



Overall, the GCA analysis has broadly confirmed the interpretations provided by HESS. Crossplots comparing the reservoir property averages (net to gross (NTG), porosity and Sw) over the reservoir interval from all the LBG wells are presented in **Figure 8** and shows the results to be very similar. The lower Sw calculated by GCA is most probably due to the use of shaley-sand models that compensate for the lower resistivity readings in the presence of clay minerals compared to the Archie equation.

Figure 8: LBG Reservoirs – HESS vs. GCA Reservoir Property Averages Comparison Cross-Plot



The fluid contacts for the fields analyzed by GCA are summarized in **Table 9** below, with a comparison of the contact levels generated by HESS. A range of depths were then selected based on the depths below to define the Low, Best and High volumetric cases.

Table 9: LBG Reservoirs – Fluid Contacts

Field	HESS (m TVDss)			GCA (m TVDss)
	Low	Best	High	
Mentorc	2,472.0	2,472.0	2,472.0	GWC = FWL = 2,472.0
Nimblefoot	2,676.0	2,676.0	2,676.0	GWC = FWL = 2,677.0
Bravo	2,542.0	2,542.0	2,542.0	FWL = 2,540.0; GWC = 2,544.0
Briseis	2,845.0	2,875.0	2,890.0	GDT = 2,837.0

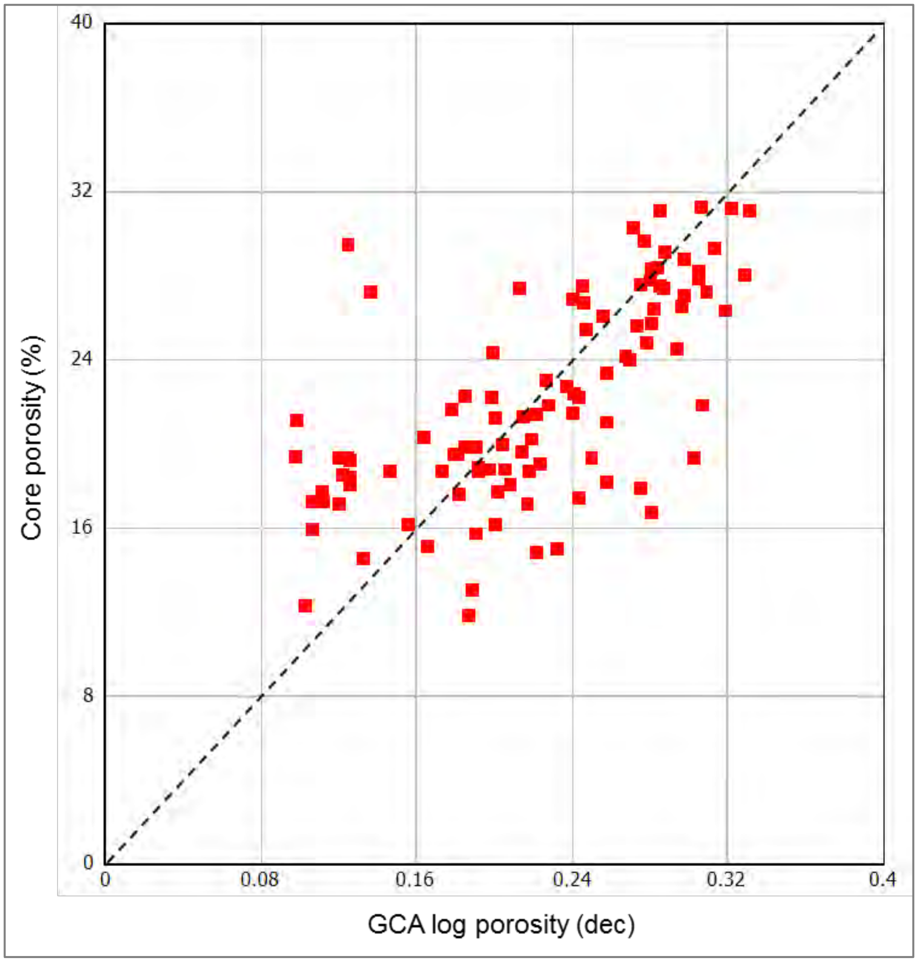
4.3.2 Jurassic - Oxfordian Reservoirs

The Glencoe discovery is the only Oxfordian age gas reservoir included in the Equus Project. Two wells; Glencoe-1 and Glencoe-2 have penetrated the accumulation and both have been analyzed.

In the Glencoe Field, core data was available in the two wells and was used to calibrate log interpretation. The results are shown in **Figure 9**. The match provides confidence in the use of log-derived porosity for this petrophysical interpretation.

Although a large scatter in core porosity is observed, there is generally good agreement between core- and log-derived estimations. The cloud of data in the crossplot can be explained by the difference between core and log scales where the logs were not able to resolve the thin variations in porosity as well as core measurements. An upscaling of the core data is required to provide similar scales in measurement and thus a better match between the two sets of data.

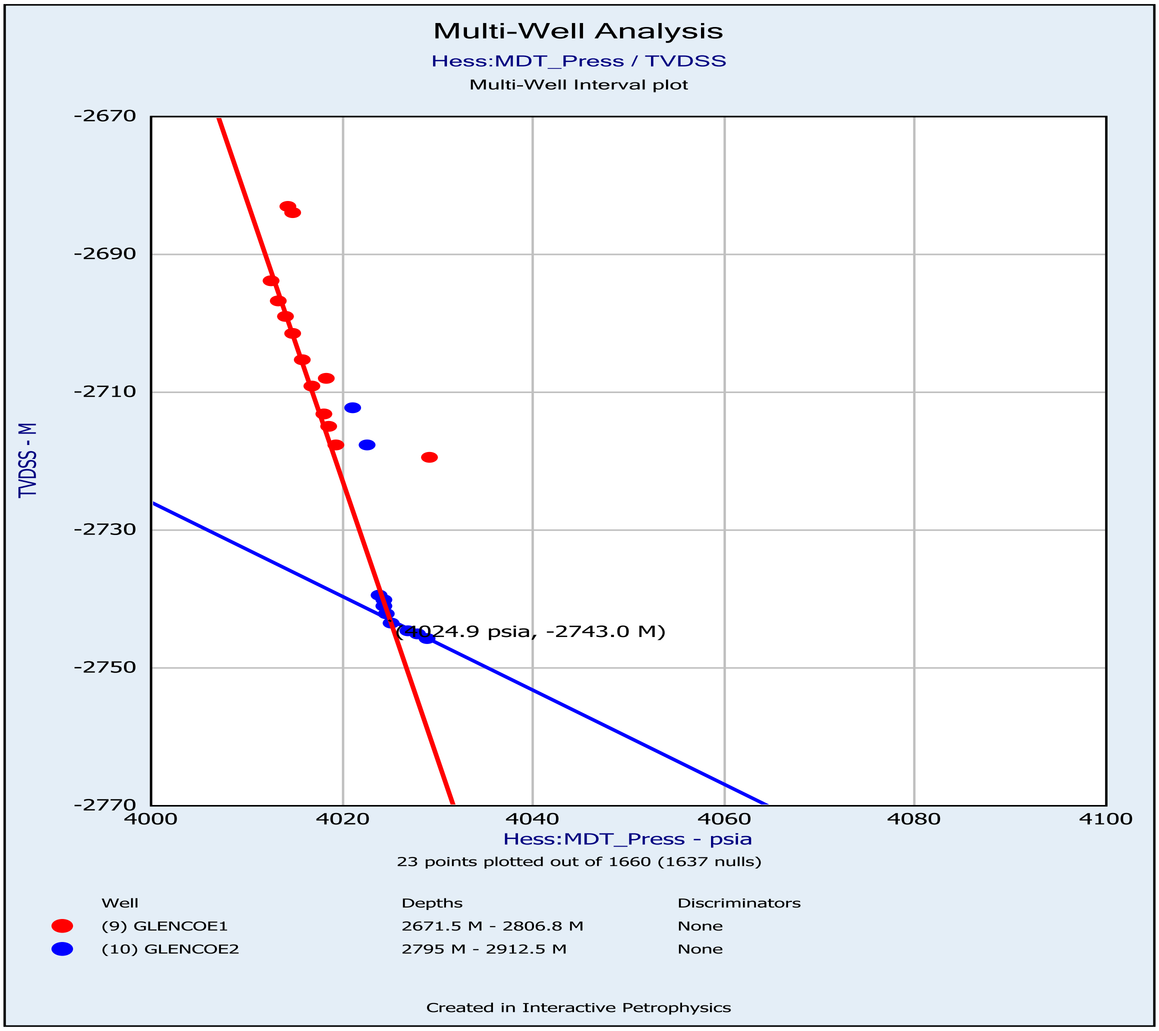
Figure 9: Oxfordian Reservoirs – Core vs. GCA Log Porosity



Overall, the GCA analysis has broadly confirmed the interpretations provided by HESS. Net pay thickness in both wells is identical to the HESS results; reservoir property averages are very similar.

There is a small uncertainty in the definition of the FWL in the field due to the small offset in gas pressure gradients between the two wells. Depending upon the intercept used, the FWL depth ranges from -2,743 to -2,744.7 m TVDss. A GWC was penetrated in the Glencoe-2 well and pressure measurements from both wells were used to define the FWL at -2,743 m TVDss. A plot of the MDT pressure data in both wells is shown in **Figure 10**. The gas pressure gradients in the two wells are offset by about 2 psi; the reason for the difference is unclear, however, if the FWL is picked on the basis of the intersection between the gas gradient from the Glencoe-1 well and the water gradient defined in the Glencoe-2 well the FWL is estimated at -2,744.7 m TVDss. An alternative interpretation based solely on the Glencoe-2 well measurements would result in a FWL depth approximately 2m shallower, also at -2,743 m TVDss. HESS has based its analyses on an FWL of -2,744 m TVDss. This is within the range of uncertainty in the measurements and is considered reasonable.

Figure 10: Glencoe Field – MDT Pressure Data & Definition of FWL



4.3.3 Triassic – Mungaroo Reservoirs

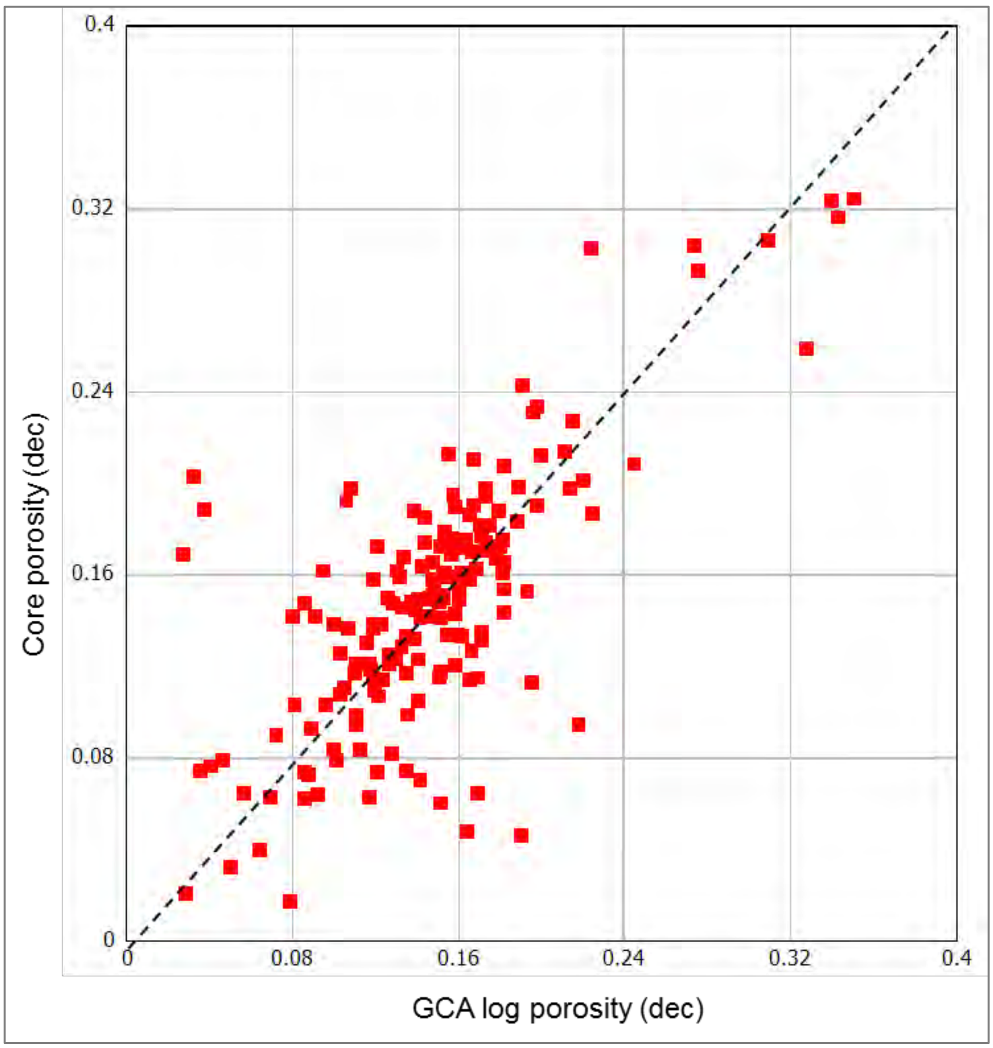
Significant gas discoveries in the Mungaroo (Norian and Carnian sequences) reservoirs have been made through 12 penetrations and included within the Equus Project. The wells analyzed for the Mungaroo reservoirs are listed by field below.

- Briseis – Briseis-1
- Chester – Chester-1ST1 and Chester-2
- Glenloth – Glenloth-1
- Hijinx – Hijinx-1
- Rimfire – Rimfire-1
- Snapshot – Snapshot-1

Whenever available, core data was used to calibrate log interpretation. In the six fields analyzed, core data within the Mungaroo reservoir was available in six out of seven wells, allowing a comparison between core- and log-derived porosity to be made. The results are shown in **Figure 11**. The match provides confidence in the use of log-derived porosity for this petrophysical interpretation.

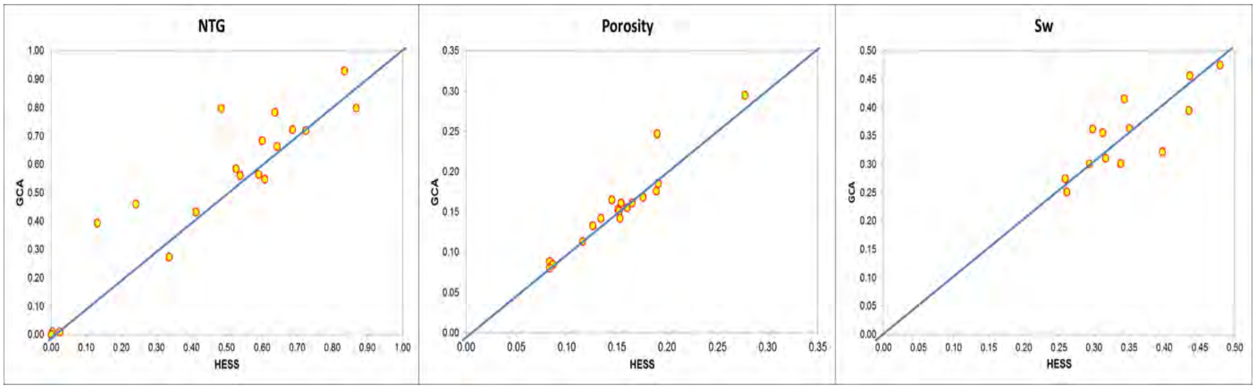
Although a large scatter in core porosity is observed, there is generally good agreement between core- and log-derived estimations. The cloud of data in the crossplot can be explained by the difference between core and log scales where the logs were not able to resolve the thin variations in porosity as well as core measurements. An upscaling of the core data is required to provide similar scales in measurement and thus a better match between the two sets of data.

Figure 11: Mungaroo reservoirs – core vs. GCA log porosity



Overall, the GCA analysis has broadly confirmed the interpretations provided by HESS. Crossplots comparing the reservoir property averages (NTG, porosity and Sw) over the reservoir interval from all the Mungaroo wells are presented in **Figure 12** and shows the results to be very similar.

Figure 12: Mungaroo Reservoirs – HESS vs. GCA Reservoir Property Averages Comparison Cross-plot



The fluid contacts for the fields analyzed by GCA are summarized in **Table 10** below, with a comparison of the contact levels generated by HESS. A range of depths were then selected based on the depths below to define the Low, Best and High volumetric cases.

Table 10: Mungaroo Reservoirs – Fluid Contacts

Field	Reservoir	HESS (m TVDss)			GCA (m TVDss)
		Low	Best	High	
Briseis	N600_SA1	3,202.0	3,210.0	3,216.0	GDT = 3,202
Chester	N800_C1 N800_C2	3,605.0	3,640.0	3,650.0	GDT = 3,589.0
	N700_SA2	3,605.0	3,650.0	3,654.0	FWL = 3,609.0; Possible GWC = 3,659.0
Glenloth	N600_SA2	-	2,708.0	-	FWL = 2,708.0; GWC = 2,710.0
	N400_SA3	-	3,442.0	-	GDT = 3,439.0
	N400_SA1	-	3,473.0	-	GWC = FWL= 3,473.0
	N300_SA6	3,609.0	3,620.0	3,630.0	GDT = 3,612.0
	N300_SA4	-	3,674.0	-	FWL = 3,674.0; GWC = 3,677.0
	N100_SA2	4,098.0	4,150.0	4,185.0	GDT = 4,098.0
	C300	4,617.0	4,640.0	4,740.0	GDT = 4,617.0
Rimfire	N100_SA6	3,905.0	3,950.0	3,991.0	GDT = 3,890.0
	C400_SA1	4,425.0	4,475.0	4,741.0	GDT = 4,410.0
Hijinx	N400_SA4	3,307.0	3,310.0	3,318.0	GDT = 3,302.0
	N400_SA3	3,360.0	3,375.0	3,381.0	GDT = 3,346.0
Snapshot	N700	2,366.0	2,366.0	2,366.0	GWC = 2,366.0; WUT = 2,369.0
	C300	4,427.0	4.427.0	4,427.0	GWC = 4,427.0

4.4 Reservoir Property Averages

The curves generated from the petrophysical analysis were used to estimate the reservoir property averages for the field. The cut-offs used by HESS to define Net Pay were checked against the available log and core data and were found to be reasonable in generating reservoir parameters for volumetric estimation. The results were compared with those of HESS and their impact on volumetric estimates was analyzed (see **In-Place Volumetric Estimation Section**).

The results for net to gross (NTG), porosity and Sw generated using the HESS and GCA curves are tabulated in **Table 11** below.

Table 11: Comparison of Reservoir Averages

Field	Well	Depth (m MD)		HESS			GCA		
		Top	Base	NTG	Poro	Sw	NTG	Poro	Sw
Lower Barrow Group									
Mentorc	Mentorc-1	2,457.0	2,500.5	1.00	0.27	0.14	0.94	0.27	0.11
	Mentorc-2	2,475.0	2,499.6	0.97	0.28	0.19	0.93	0.28	0.18
Nimblefoot	Nimblefoot-1	2,662.7	2,705.6	0.67	0.25	0.22	0.70	0.26	0.19
	Lightfinger-1	2,689.0	2,703.7	0.67	0.27	0.13	0.65	0.26	0.11
Bravo	Bravo-1	2,482.9	2,573.1	0.23	0.24	0.28	0.18	0.24	0.20
	Bravo-2	2,487.9	2,573.1	0.02	0.22	0.49	0.01	0.22	0.40
	Rimfire-1	2,500.0	2,608.6	0.33	0.25	0.33	0.31	0.27	0.27
Briseis	Briseis-1	2,838.8	2,865.4	0.20	0.20	0.31	0.17	0.21	0.27
Oxfordian									
Glencoe	Glencoe-1	2,721.3	2,758.1	0.71	0.24	0.46	0.71	0.26	0.49
	Glencoe-2	2,848.0	2,854.5	0.75	0.29	0.55	0.75	0.32	0.55
Mungaroo									
Briseis	Briseis-1	3,197.5	3,231.3	0.84	0.19	0.26	0.93	0.18	0.28
Chester	Chester-1ST	3,579.2	3,591.9	0.59	0.19	0.26	0.56	0.19	0.25
		3,638.0	3,689.1	0.87	0.15	0.29	0.80	0.15	0.30
	Chester-2	3,601.0	3,611.7	0.60	0.15	0.51	0.68	0.17	0.45
Glenloth	Glenloth-1	2,730.1	2,800.9	0.02	0.19	0.54	0.01	0.25	0.55
		3,535.9	3,557.3	0.73	0.16	0.35	0.72	0.16	0.36
		3,580.6	3,598.1	0.64	0.17	0.44	0.66	0.16	0.46
		3,739.9	3,768.5	0.41	0.15	0.31	0.43	0.14	0.36
		3,826.1	3,848.3	0.24	0.13	0.53	0.46	0.14	0.51
		4,345.6	4,375.0	0.64	0.08	0.44	0.78	0.09	0.40
		4,864.6	4,972.8	0.53	0.09	0.32	0.59	0.09	0.31
Hijinx	Hijinx-1	3,376.5	3,407.1	0.69	0.18	0.34	0.72	0.17	0.30
		3,426.1	3,462.1	0.61	0.15	0.30	0.55	0.16	0.36
Rimfire	Rimfire-1	4,102.1	4,148.9	0.48	0.12	0.48	0.80	0.11	0.48
		4,637.9	4,678.6	0.13	0.08	0.53	0.39	0.08	0.52
Snapshot	Snaphot-1	2,348.6	2,387.6	0.34	0.28	0.34	0.27	0.30	0.42
		4,735.0	4,747.2	0.54	0.13	0.40	0.56	0.13	0.32

5 Hydrocarbon Volume Assessment Methodology

5.1 Volume Estimation

GCA has reviewed the dataset provided by Hess in order to undertake an independent assessment of the GIIP and Contingent Resources for each of the discovered fields and the GIIP and the Prospective Resources of the un-drilled prospects in the Equus Development. GIIP, Contingent Resources and Prospective Resources have been estimated probabilistically using a 1D Monte Carlo simulation run with 10,000 iterations.

For petrophysical input parameters, GCA utilised the Standard Error of the Mean approach documented by Murtha and Ross (JPT, September 2009). The Standard Error of the Mean is computed by calculating the Standard Deviation of the reservoir properties measured for similar depositional environments and dividing by the square root of the count of the sample number. The range was defined by considering 3 standard deviations or +/- 3*SEM based on the GCA petrophysical analysis.

Reservoir engineering (Bg, Recovery Factor) inputs were based on a review of Hess' inputs into its GeoX software Monte Carlo model runs. Where GCA considered these were reasonable, the Hess inputs were used and where GCA deemed it necessary, GCA utilised its independently vetted engineering inputs. Excel worksheets of GCA's analysis are provided to Hess in combination with this report. This includes parameters utilised in GCA's analysis for each reservoir and field.

GRV inputs into the Monte Carlo simulation were estimated on a field by field basis. GCA used its own depth conversion to test the structural uncertainty associated with the Hess depth surfaces which were interpreted on PSDM seismic data. GCA's alternative depth conversion showed that there was enough uncertainty to warrant including GRVs derived from GCA's depth conversion in the range of GRV inputs. In certain cases GCA was not always able to reconcile the GeoX inputs used by Hess with the surfaces provided in the Petrel Projects. In these circumstances, GRV estimates were based on the provided surfaces rather than the GeoX GRV numbers.

GCA's total project resource volumes were derived by calculating the average between a full arithmetic and probabilistic addition of the individual field volumes to account for unknown dependencies between the fields. The average Low, Best and High Network case profiles were allocated to each field by proportionally scaling each individual field 1C, 2C and 3C Contingent Resource cases and Low, Best and High Prospective Resource cases to the respective average Network case profile discussed in the subsequent sections.

5.2 Geological Chance of Success

For each un-drilled prospect, GCA has estimated a GCoS based on the chance of finding a hydrocarbon volume which can flow to surface. The objective of this is to communicate GCA's understanding of the GCoS numerically in a simple, reproducible and consistent framework. The calculation of the GCoS uses a matrix approach for each of four factors:

- Trap and Seal
- Reservoir presence and quality
- Hydrocarbon source (presence, quality, maturity and migration)
- Geological timing

The overall GCoS is estimated by the multiplication of the specific values from each of the four factors. The GCoS estimate helps to provide a numerical ranking system of the prospects and leads and highlights the most significant risk of each. In doing this it is possible to identify areas where more analysis or a better understanding may help to de-risk a structure.

6 Mentorc Discovery

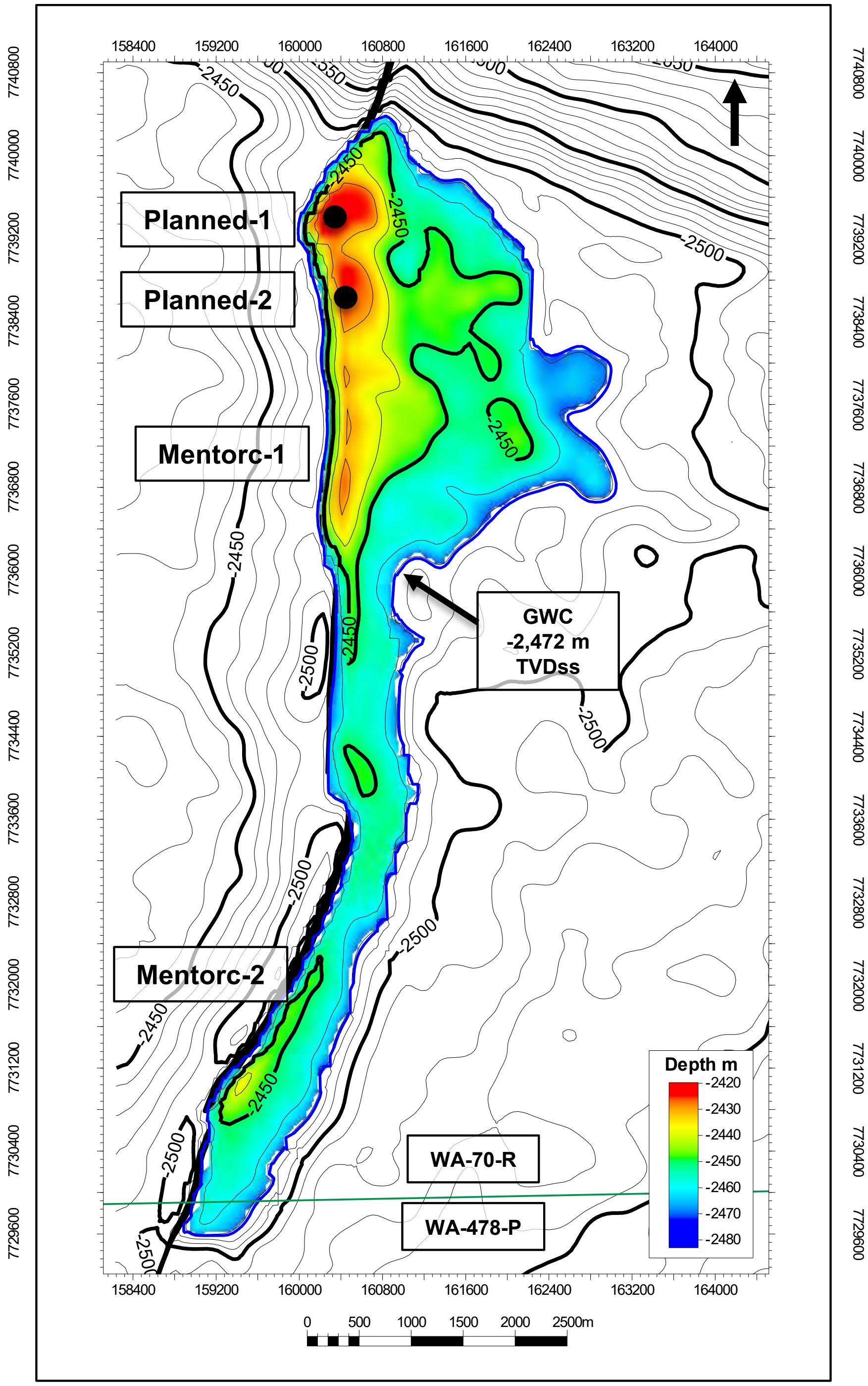
6.1 Field Summary

The Mentorc Field was discovered in 2010 with the drilling of the Mentorc-1 well. The field is a three-way dip closed, north northeast – south southwest trending structure which is fault closed to the west by a large westerly dipping north northeast – south southwest trending normal fault (**Figure 13**). The primary target of Mentorc-1 was a well-defined seismic amplitude anomaly in the Cretaceous aged Lower Barrow Group lying below the Valanginian disconformity. The well reached a total depth of 2,762 m MDRT within the Lower Barrow Group. The well intersected 42 m of net gas pay within the Lower Barrow Group. A core was acquired in a sidetrack; Mentorc-1 CH1 and the well was subsequently abandoned as a gas discovery.

The Mentorc-2 well was drilled in 2011 as a vertical well to appraise the Mentorc Discovery and is located approximately 5.3 km to the north of Mentorc-1. The Mentorc-2 well reached a total depth of 2,555 m MDRT and intersected 23 m net gas pay in the Lower Barrow Group.

The Lower Barrow Group reservoir exhibits a strong brightening of amplitude with offset (Class III AVO) and was deposited in a delta-top, nearshore to marginal marine setting. A shale section which developed along the main fault to the west of Mentorc-1 is also present at Mentorc-2 allowing the juxtaposition of the Lower Barrow Sands against a low permeability formation ensuring trap integrity. The main kitchen for the Mentorc structure lies to the east in the Exmouth Sub-basin. The source is composed of Mungaroo of Ladinian to Norian age and consists of predominantly terrestrial carbonaceous shales and coals. Generation from the source began in the Late Cretaceous and continued through the Tertiary to present times.

Figure 13: Hess' Lower Barrow Group Best Case Depth Map with Drilled and Planned Development Wells



6.2 Geology and Geophysics Review

GCA has reviewed the seismic interpretation of the Mentorc Field provided by Hess in the Mentorc Petrel Project and in general believes the interpretation is reasonable. A strong seismic response is seen in the strike direction between the two wells in the Gas Sand Probability seismic cube and which is concordant with the GWC penetrated by the two wells at -2,472 m TVDss. This response results in a clear flat-spot which is visible in the strike direction and can be correlated between the two wells.

In the dip direction, a clear response is seen in both the Gas Sand Probability cube and the Absolute P Impedance cube over the crest of the structure, however, as the reservoir thins to the east, near to the GWC, the seismic response dims suggesting some uncertainty in the interpretation and consequently the GRV of the structure (**Figure 14**). This uncertainty is also highlighted by the polarity of the seismic reflector defining the structure which reverses over the crest of the structure but which switches back before the interpretation meets the GWC (**Figure 15**). The structural uncertainty on the eastern flank of the structure means that GRV is the greatest uncertainty for the Mentorc Field.

To generate a range of GRV inputs, Hess has undertaken Low, Best and High Case seismic interpretations of the Mentorc structure. GCA has reviewed these interpretations and believes they are a reasonable representation of the range of possible interpretations given the structural uncertainty on the eastern flank of the closure. For volumetric calculations, these three interpretations have been used together with the established GWC.

GCA used its own depth conversion to further test the structural uncertainty. Each of Hess' three interpretations were converted to time utilising the PSDM seismic velocity cube, then back to depth using the GCA depth conversion. GRVs calculated using the GCA depth conversion for each of the three Lower Barrow Group Interpretations gave approximately 10-20 % increases in GRV.

Figure 14: Gas sand Probability and Absolute P-Impedance maps for the LBG Depth Surfaces

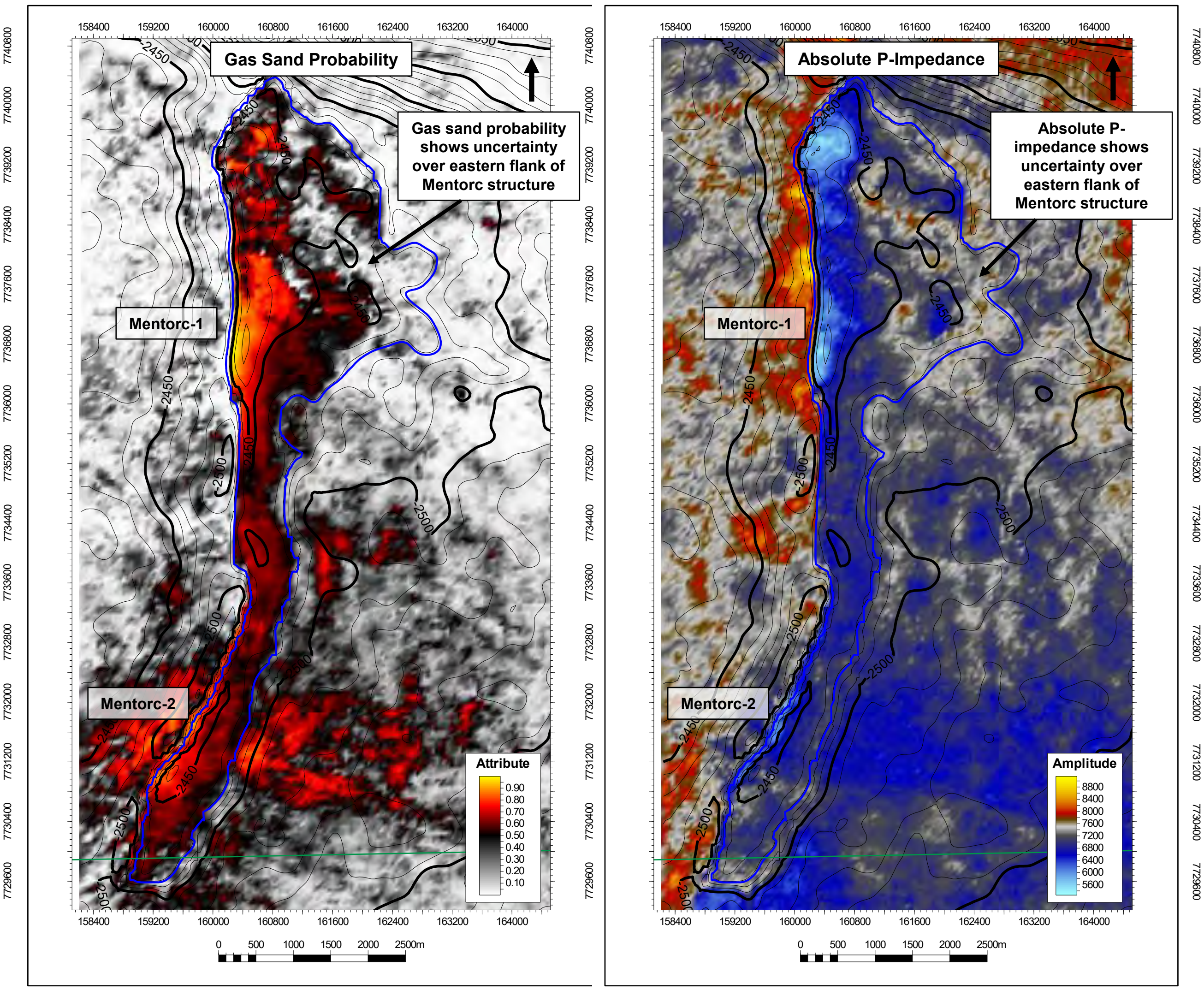
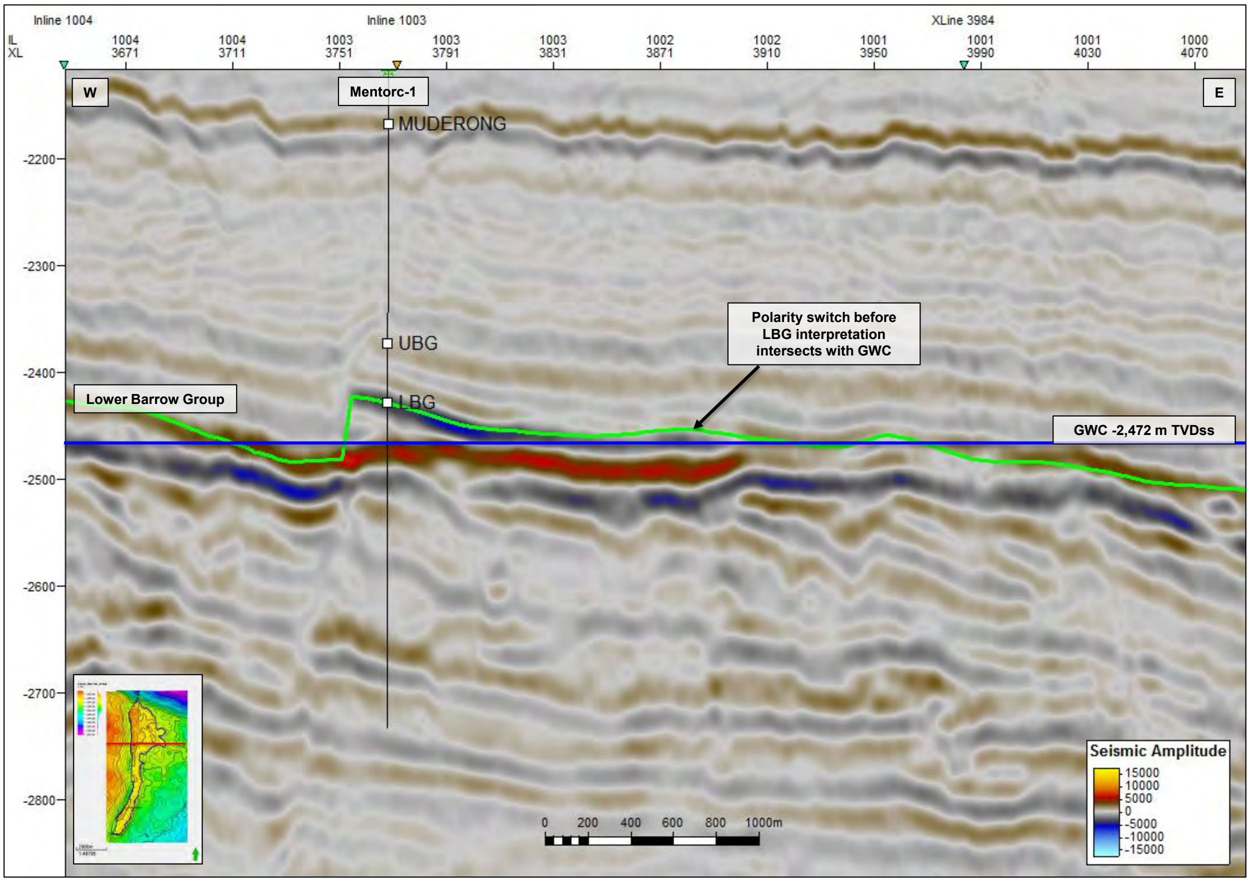


Figure 15: Seismic Section through the Mentorc-1 Well



6.3 Engineering Review

A total of 10 down-hole samples were collected from the Mentorc-1 and Mentorc-2 wells. The sampling tool used in the Mentorc-1 well was the RCI tool, and samples from this well all suffered 1% to 2% contamination from the oil-based mud (OBM) used during drilling. The Mentorc-2 well samples were collected using the MDT tool with a Quicksilver probe, which significantly reduced OBM contamination.

Reservoir conditions at Mentorc are at the dewpoint. Gas gravity has been measured at 0.8, with a gas expansion factor of 247 scf/rcf. The CO_2 concentration is low at 0.25% whilst the N_2 is the highest of the Equus fields at approximately 6%.

Condensate gas ratio (CGR) has been estimated from samples and recombination laboratory experiments. Due to contamination in some samples, Hess has captured a range of 41 to 51 bbl/MMscf with a Best Case of 49 bbl/MMscf. This is the highest CGR seen across the Equus fields. Laboratory testing has indicated a maximum liquid drop in the reservoir of 6% with production, which should present no issues with near-wellbore condensate banking from occurring.

6.3.1 Well Tests

No well tests were performed on the Mentorc-1 and Mentorc-2 wells. Two well tests were performed on the Barrow sands at the Rimfire-1 well on the Bravo field. The Bravo Field exhibits lower reservoir quality due to being a basin floor fan instead of the tidal-dominated delta-top environment seen at Mentorc. Well deliverability is expected to be extremely high with significant thicknesses of multi-darcy sands evident in the petrophysical logs.

6.3.2 Development Plan

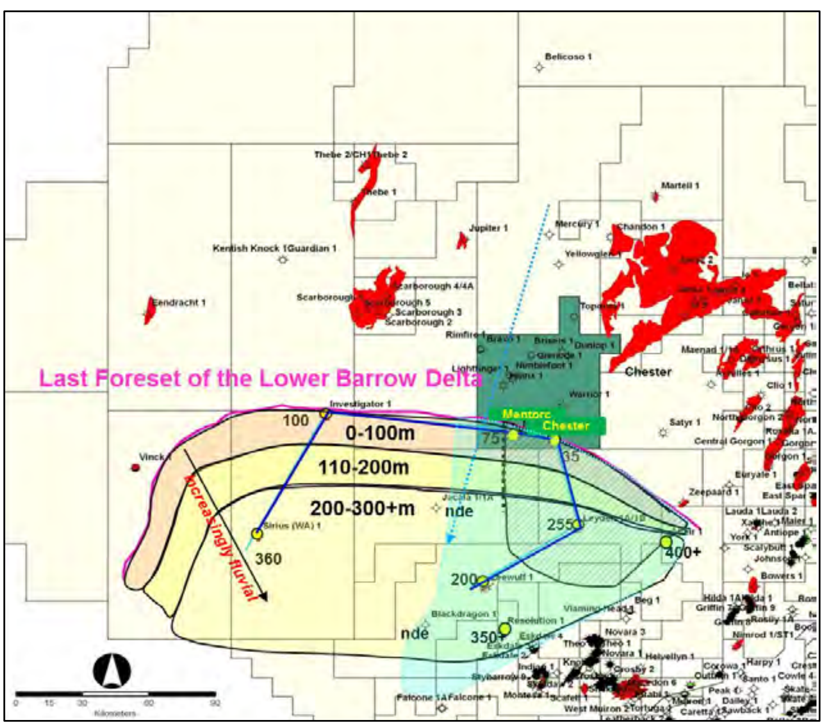
The Equus Project Phase 1 development plan considers that the Mentorc Field will be developed early to accelerate condensate production. Under this plan, the wells are scheduled to be drilled in 2020 and come online in 2021. The development plan includes 2 horizontal development wells in crestal locations to maximize the stand-off from the GWC. The wells will be placed in the north of the field where the majority of volumes are located as shown in **Figure 13**. The two wells will be tied back to the Equus Floating Production System (FPS) facility via a 10 inch flowline.

6.3.3 Recovery Factor

Hess assessed the deliverability and recovery of gas and condensate from the Mentorc Field using reservoir simulation and analogue data. GCA has deemed this approach as reasonable.

The Mentorc reservoir is high quality with continuous sands as part of the Barrow delta-top depositional environment. Based on the extent of the Barrow sands, a large regional aquifer has been mapped as part of the Kangaroo syncline (**Figure 16**).

Figure 16: Kangaroo Syncline Regional Aquifer



Source: Hess

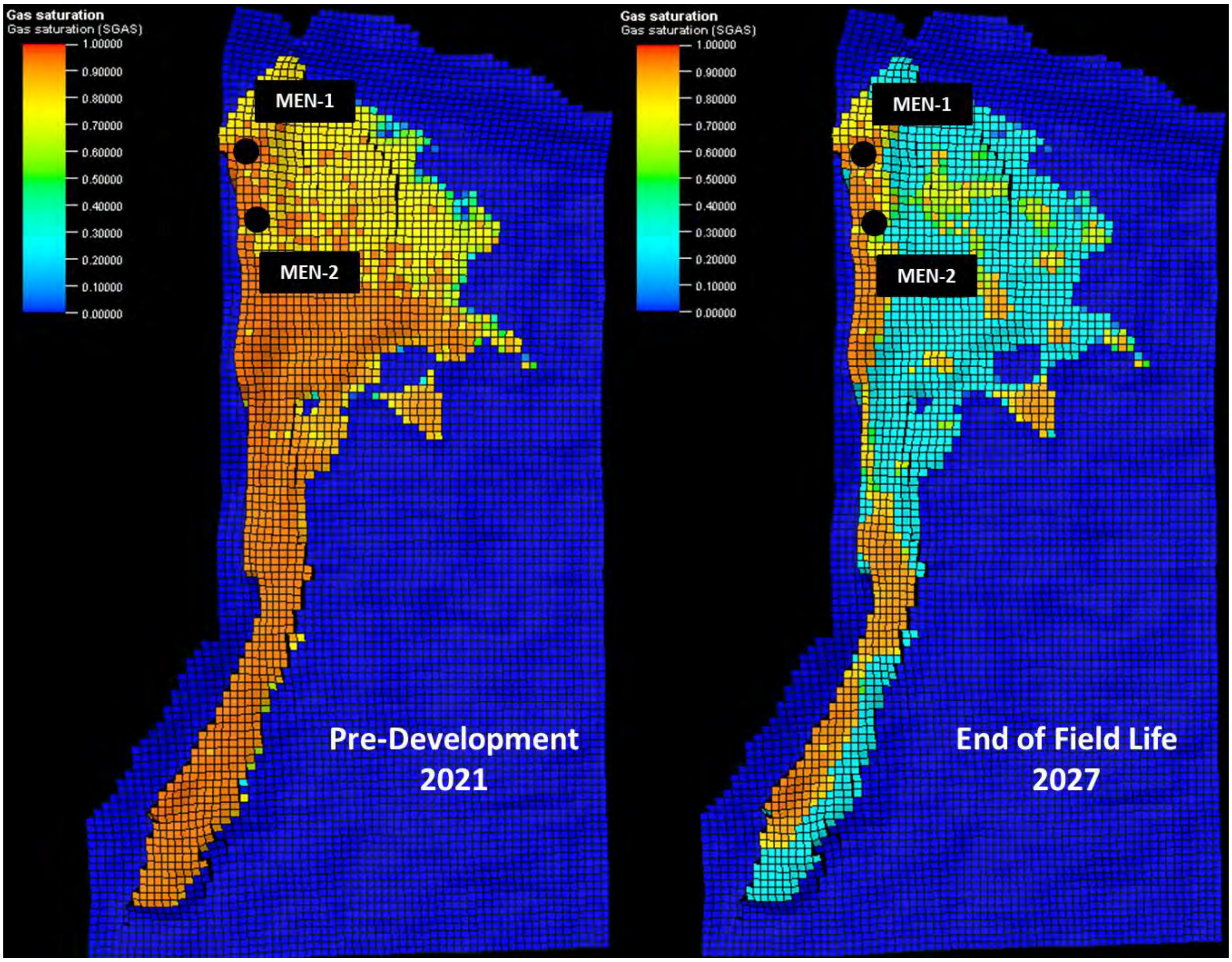
The large regional aquifer is expected to be in the order of hundreds of billions of barrels and therefore provide very strong pressure support to the Mentorc Field. For a gas reservoir with strong aquifer drive, recovery is typically determined by water breakthrough and subsequent water cut increase at the wells.

There are no Lower Barrow group delta-top analogues in the area for gas field developments. Hess has identified the Angel Field in the NWS JV development as an analogue for the Mentorc Field. The Angel Field is a Jurassic-age gas field but has similar reservoir quality and strong aquifer drive. The recovery factor for the Angel Field is expected to lie within 60% to 70%.

Hess ran a number of dynamic simulation cases in order to quantify the uncertainty contributing to gas recovery at the Mentorc Field. The methodology that Hess followed was to generate a number of models based on different subsurface realisations by varying static and dynamic model properties. By running the different simulation model realisations, Hess was able to generate an S-curve of estimated ultimate recovery (EUR) outcomes. As part of the process, Hess was able to identify the key uncertainties contributing to EUR, which are gross rock volume and residual gas saturation.

The recovery factor range derived from the simulation uncertainty modelling was 53% to 76%, with the proposed development case achieving a recovery factor of 63%. **Figure 17** below shows the deterministic model associated with the 63% recovery factor case. The map on the left shows the gas saturation prior to commencing production, whilst the map on the right shows gas saturation at the end of field life. It is clear that the water has moved from the water leg to the production wells as gas has been produced and the large aquifer has been activated.

Figure 17: Mentorc Field Deterministic Best Case Simulation Model



The Mentorc Field gas recovery factor range proposed by Hess is 53%, 63% and 73% for the Low, Best and High Cases, respectively. This recovery factor range is consistent with the ranges from simulation and analogue analysis, and also within the range GCA would expect from a high permeability, strong aquifer gas field subsea tieback development.

6.4 Resource Estimate

The GIIP and Contingent Resources for the Mentorc Field were estimated using a 1D Monte Carlo Model. Reservoir parameter inputs are based on the sums and averages calculated from GCA's petrophysical interpretation. For the GRV inputs into the calculation, GCA accepted the Hess Low and Best Case Petrel surfaces as being reasonable and so has calculated GRVs based on these and using the -2,472 m TVDss GWC for the P90 and P50 inputs. Because the GCA depth conversion suggested the possibility of potential upside, a GRV calculated using Hess' High Case interpretation depth converted using the GCA velocity model was used; resulting in a higher P10 GRV than used by Hess. The very southern tip of the field extends beyond the boundary of the WA-70-R block, into the adjacent WA-478-P block (**Figure 13**). GCA tested volumetric cases which excluded this area, however due to the very small nature of this extension and the fact that it only has a very small impact on the P10 GRV input, GCA found that it did not have an impact on volumes. GCA's input parameters into its 1D Monte Carlo Model, together with the resulting GIIP estimates, are given in **Table 12**.

GCA's estimates of GIIP for the Mentorc Field are given in **Table 13**. Gas Contingent Resources are given in **Table 14** and associated Condensate Contingent Resources are summarized in **Table 15**.

Table 12: GCA's Input Parameters for its Estimate of GIIP for the Mentorc Field

Reservoir	Parameter	Unit	P90	P50	P10
LBG	Contact	m TVDss	-2,742	-2,742	-2,742
	GRV	MM m^3	210	288	400
	NTG	Decimal	0.970	0.980	0.990
	Porosity	Decimal	0.225	0.275	0.295
	Sg	Decimal	0.785	0.875	0.965
	Gas Expansion Factor	1/Bg	242.0	247.0	252.0
	Condensate Yield	Stb/MM scf	41.00	46.00	51.00
	Recovery Factor	Decimal	0.530	0.630	0.700
	GIIP	**Bscf**	**416**	**585**	**832**

Note: This estimate of GIIP is based on a probabilistic methodology using GCA's 1D Monte Carlo Model.

Table 13: GCA's Estimate of GIIP for the Mentorc Field

Reservoir	Low (Bscf)	Best (Bscf)	High (Bscf)
LBG	582.8	614.3	714.2

Note: This estimate of GIIP is based on GCA's total project GIIP volumes which were derived by calculating the average between a full arithmetic and probabilistic addition of individual field volumes to account for unknown dependencies between the fields. The average Low, Best and High Network case profiles were allocated to each field by proportionally scaling each individual field P90, P50 and P10 case to the respective average Network case profile.

Table 14: GCA's Estimate of Gas Contingent Resources for the Mentorc Field

Reservoir	1C (Bscf)	2C (Bscf)	3C (Bscf)
LBG	352	378	450

Table 15: GCA's Estimate of Condensate Contingent Resources for the Mentorc Field

Reservoir	1C (MMBbl)	2C (MMBbl)	3C (MMBbl)
LBG	12.4	16.4	23.4

6.5 Production Forecasts

The Hess Best Case raw gas production forecast is a deterministic case from simulation modeling that matches the 63% recovery factor. The associated condensate production has been forecast based on a modeled CGR versus reservoir pressure relationship. There is only minor reservoir pressure decline due to the strong aquifer so the CGR shows little decline over field life.

GCA has accepted the Hess Best Case forecasts for raw gas and condensate. GCA generated Low and High Cases based on the Best Case profile but scaled for the Low and High Case GIIP estimates. These Cases are similar to deterministic simulation cases generated by Hess in their simulation uncertainty analysis.

The GCA production forecasts for raw gas and condensate for the Mentorc Field are shown in **Figure 18** and **Figure 19**.

Figure 18: Mentorc Field Raw Gas Production Forecasts

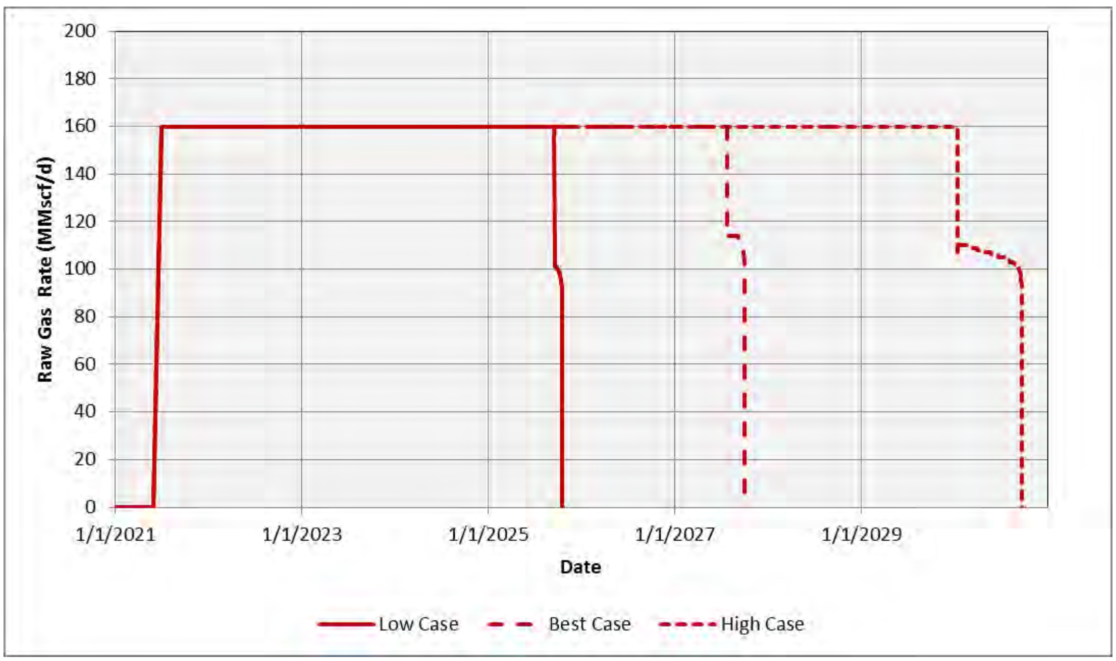
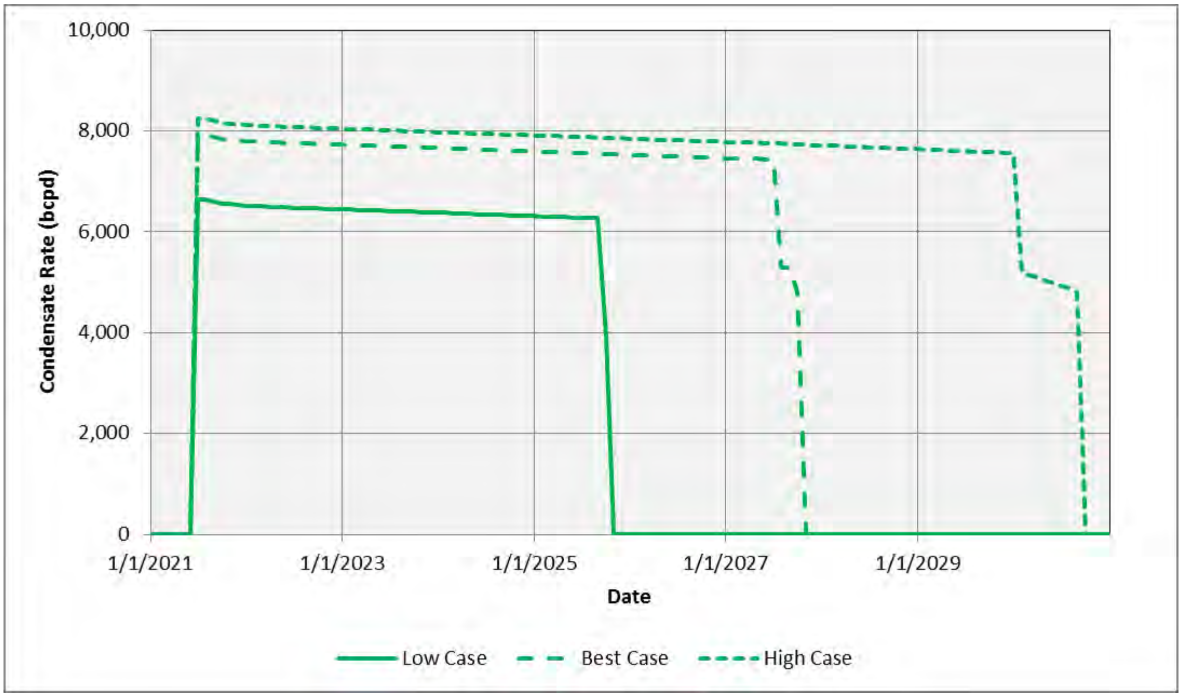


Figure 19: Mentorc Field Condensate Production Forecasts



7 Nimblefoot Discovery

7.1 Field Summary

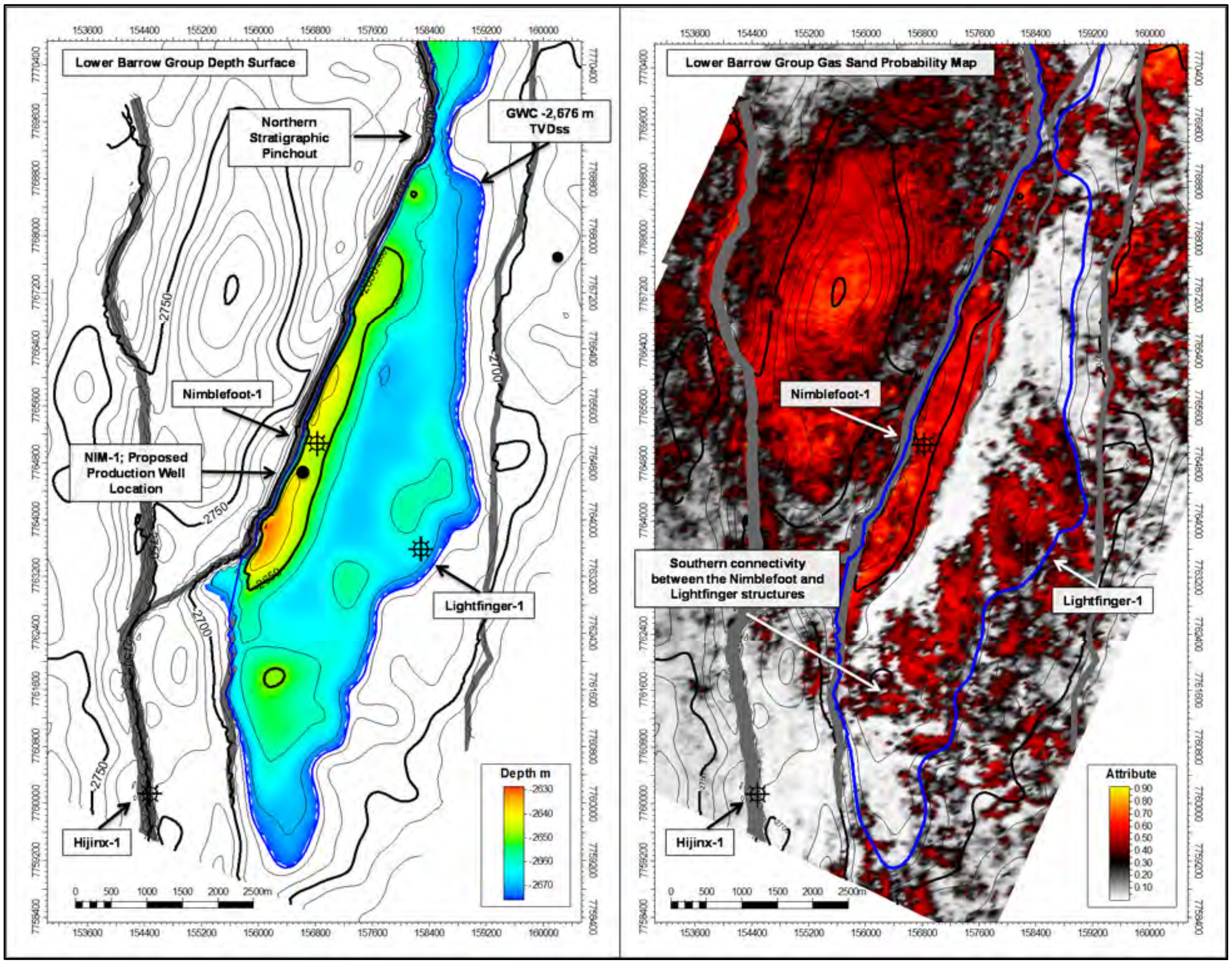
The Nimblefoot Field was discovered with the drilling of the Nimblefoot-1 deviated exploration well in 2008. The well was drilled to target a northeast – southwest trending three-way dip closure which dips to the east. The primary target was a well-defined seismic amplitude anomaly above the Callovian Unconformity and Mungaroo sandstones along the fault plane. The well intersected 28 m net gas pay in the Lower Cretaceous, Lower Barrow Group Sandstones. The well was plugged and abandoned as a gas discovery after cutting 41.5 m of core in a sidetrack (Nimblefoot-1 CH1).

The Lightfinger-1 well was drilled in 2009 to target a three way dip closed structure trending north-northeast by south-southwest dipping to the east. The reservoir target of the well was a well-defined seismic amplitude anomaly above the Callovian Unconformity mapped as a combination structural and stratigraphic trap. The well intersected 9.5 m net gas pay in the Lower Barrow Group Sandstones.

The Nimblefoot and Lightfinger structures are separated by a small structural high where the reservoir section has been eroded or the onlapping sediments have failed to cover the full extent of the paleo high. Amplitude maps including the Gas Sand Probability map confirm an area between the two structures which does not see the same amplitude response seen over the main structures. There is however an area in the south where seismic the interpretation suggests the presence of reservoir connecting the two closures and this is supported by an amplitude response (**Figure 20**). Consequently, the two structures are considered part of the same Nimblefoot closure.

The Nimblefoot accumulation is a combined structural and stratigraphic trap with closure to the east-west and north requiring stratigraphic pinchout. The original prospect was identified by a strong Type III AVO amplitude anomaly. The reservoir at Nimblefoot is interpreted to have been deposited on an erosional surface of a northeast – southwest tilted fault block as an elongate northeast – southwest trending, shallow marine sandbody. The reservoir is sealed by Barriassian through Valanginian marine shales of the Barrow Group. The main source kitchen for the Nimblefoot structure lies to the south in the Exmouth Sub-basin with the source formed of Mungaroo terrestrial carbonaceous shales and coals. Migration and charging began in the Upper Cretaceous and continued through the Tertiary until the present time.

Figure 20: Hess' Lower Barrow Group Best Case Depth Map and Gas Sand Probability Map with Drilled and Planned Production Wells



7.2 Geology and Geophysics Review

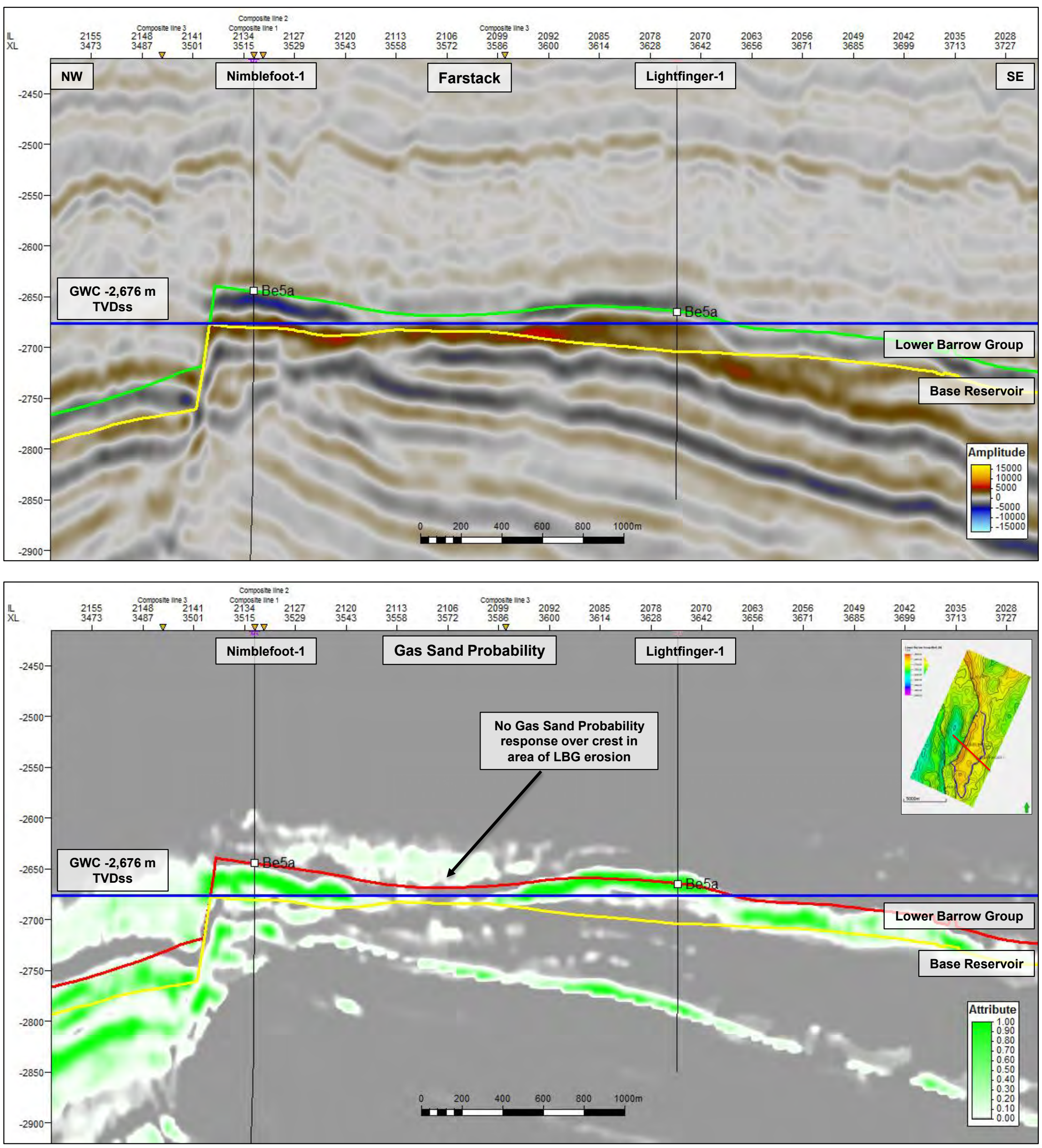
GCA has reviewed the seismic interpretation of the Nimblefoot Field provided by Hess in the Nimblefoot Petrel Project and in general considers the interpretation is reasonable. A strong seismic response, particularly in the Gas Sand Probability cube, is seen in the dip direction over both the Lightfinger and Nimblefoot structures but is seen to pinch out between the two wells (**Figure 21**). GCA's review of the seismic data confirms Hess' interpretation that it is likely there is connectivity between the two closures in an area where the LBG has not been eroded in the south of the structure, this is supported by the Gas sand Probability map in **Figure 20**. GCA has considered Nimblefoot and Lightfinger as a single structure.

Structural configuration is considered the greatest uncertainty of the Nimblefoot Discovery. While the interpretation of top reservoir is defined by a reasonably consistent trough horizon pick, the manner of closure in some areas and the degree of erosion in the center of the field remains uncertain. Amplitude anomalies extracted by GCA show a concordance with structure however there is no structural closure to the north meaning stratigraphic closure is required.

To generate a range of GRV inputs, Hess has undertaken Low and Base Case seismic interpretations of the Nimblefoot structure. GCA has reviewed these interpretations and considers they are a reasonable representation of the range of possible interpretations. For volumetric calculations, Hess has used these interpretations together with a GWC at -2,676 m TVDss established by pressure data from Nimblefoot-1.

GCA used its own depth conversion to further test the structural uncertainty. Each of Hess' interpretations was converted to time utilising the PSDM velocity cube, then back to depth using the GCA depth conversion. GRVs calculated using the GCA depth conversion for each of the Lower Barrow Group Interpretations gave approximately 20-40 % increases in GRV.

Figure 21: Seismic Section through the Nimblefoot-1 and Lightfinger-1 Wells showing the Far Stack and Gas Sand Probability Inversion Cubes



7.3 Engineering Review

A total of 8 down-hole samples were collected from the Nimblefoot-1 and Lightfinger-1 wells. Reservoir conditions at Nimblefoot are at the dewpoint. Gas gravity has been measured at 0.7, with a gas expansion factor of 241 scf/rcf. The CO_2 concentration is low at 0.5% and the N_2 is approximately 2%.

CGR has been estimated from samples and recombination laboratory experiments to be 20 bbl/MMscf. Laboratory testing has indicated a maximum liquid drop in the reservoir of less than 1% with production, which should prevent the issue of near-wellbore condensate banking from occurring.

7.3.1 Well Tests

No well tests were performed on the Nimblefoot-1 and Lightfinger-1 wells. Two well tests were performed on the Barrow sands at the Rimfire-1 well on the Bravo Field. The Bravo and Nimblefoot Fields have similar depositional environments as they are both Lower Barrow Group basin floor fans. Well deliverability is expected to be extremely high with significant thicknesses of high net-to-gross, high permeability sands evident in the petrophysical logs.

7.3.2 Development Plan

The Equus Project plan considers that the Nimblefoot Field will be developed as part the Phase 1 development. Nimblefoot is included in Phase 1 due to its proximity to the FPS, reasonably high CGR and high well deliverability. Under this plan, a single Nimblefoot well is scheduled to be drilled in 2020 and come online in 2021. The development plan includes a horizontal development well in a crestal location to maximize the stand-off from the GWC. The well will be placed along the eastern bounding fault in the west of the field as shown in **Figure 20.** The well will be tied back to the Equus FPS facility via a 10 inch flowline.

7.3.3 Recovery Factor

Hess assessed the deliverability and recovery of gas and condensate from the Nimblefoot field using reservoir simulation and analogue data. GCA has deemed this as approach as reasonable.

Hess has assumed that the reservoir drive mechanism at Nimblefoot is mainly depletion drive with no significant aquifer support. There is no sizeable water volume to the north and east of the field due to a stratigraphic pinch-out. Water influx from the west is prevented by the field's western bounding fault. The Lower Barrow Group sands can be continuously mapped to the Grafter-1 well 8 km south of the Nimblefoot Field. However, the water chemistry measured at the Grafter-1 well is considerably different to that measured at the Nimblefoot-1 and Lightfinger-1 wells indicating that the Nimblefoot water leg does not extend to the Grafter-1 well. For a gas reservoir with depletion drive, recovery is typically determined by minimum inlet pressure at the production facility, in this case the Equus FPS.

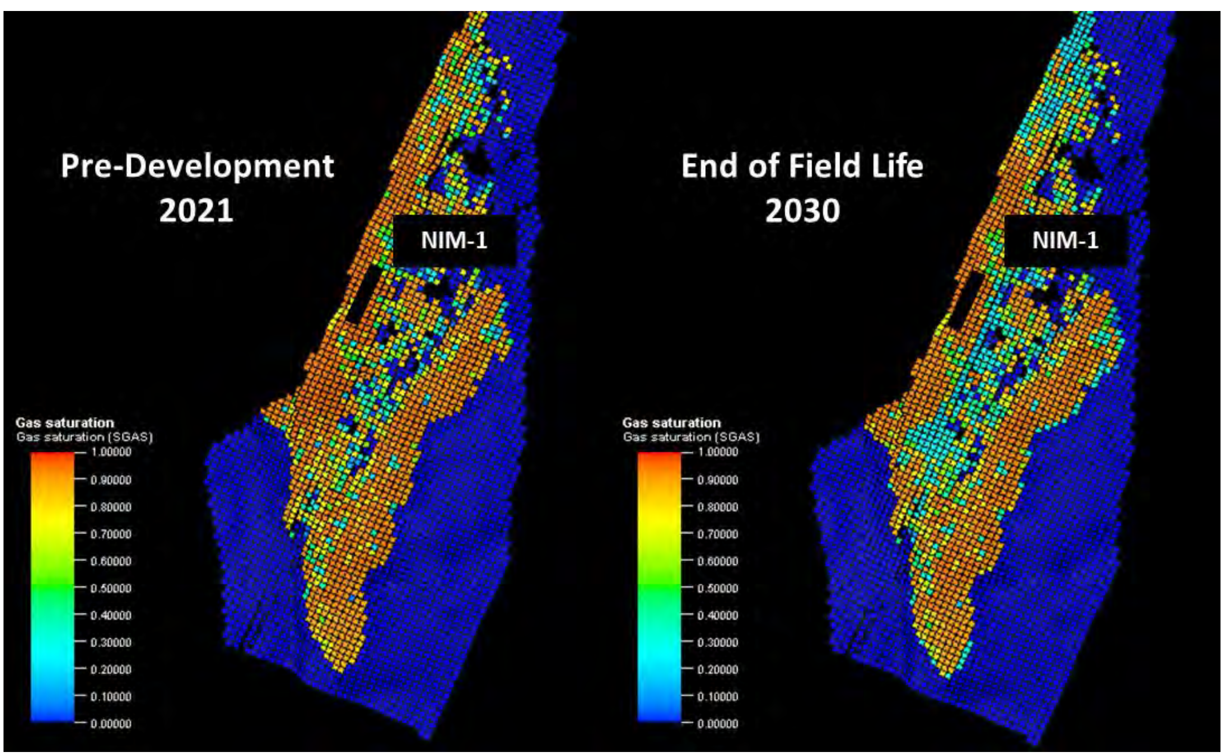
There are no Lower Barrow group basin-floor fan analogues in the area for gas field developments. Hess has identified some Upper Barrow Group fields in the Carnarvon Basin with similar properties. These include:

- John Brookes Field – approximately 80% recovery factor
- Halyard Field – 59% to 71% recovery factor
- Campbell/Sinbad Field – 59% to 73% recovery factor.

Hess ran a number of dynamic simulation cases in order to quantify the uncertainty contributing to gas recovery at the Nimblefoot Field. The methodology that Hess followed was similar to that for the Mentorc Field, generating a number of models based on different subsurface realisations by varying static and dynamic model properties. By running the different simulation model realisations, Hess was able to generate an S-curve of estimated ultimate recovery (EUR) outcomes. As part of the process, Hess was able to identify the key uncertainties contributing to EUR, which are gross rock volume and facies distribution.

The recovery factor range derived from the simulation uncertainty modelling was 45% to 85%, with the proposed development case achieving a recovery factor of 65%. **Figure 22** shows the deterministic model associated with the 65% recovery factor case. The deterministic Best Case did not include a strong aquifer and the main reservoir drive mechanism was depletion drive. The map on the left shows the gas saturation prior to commencing production, whilst the map on the right shows gas saturation at the end of field life. Without the presence of a strong aquifer there is no significant water movement into the reservoir from the aquifer.

Figure 22: Nimblefoot Field Deterministic Best case Simulation Model



The Nimblefoot Field gas recovery factor range proposed by Hess is 54%, 65% and 72% for the Low, Best and High Cases, respectively. This recovery factor range is consistent with the ranges from simulation and analogue analysis, and also with the range GCA would expect from a high permeability gas field subsea tieback development with uncertain reservoir drive mechanism.

7.4 Resource Estimate

The GIIP and Contingent Resources for the Nimblefoot Field were estimated using a 1D Monte Carlo Model. Reservoir parameter inputs are based on the sums and averages calculated from GCA's petrophysical interpretation. For the GRV inputs into the calculation, GCA considers that the Hess' Low and Best Case Petrel surfaces are reasonable and so has calculated GRVs based on these and using the -2,676 m TVDss GWC for the P90 and P50 inputs. Because the GCA depth conversion suggested the possibility of potential upside, a GRV calculated using the Hess Base Case interpretation depth converted using GCA's velocity model was used to calculate the P10 GRV. GCA's input parameters into its 1D Monte Carlo Model, together with the resulting GIIP estimates, are given in **Table 16**.

GCA's estimates of GIIP for the Nimblefoot Field are given in **Table 17**.

Gas Contingent Resources are given in **Table 18** and associated Condensate Contingent Resources are summarized in **Table 19**.

Table 16: GCA's Input Parameters for its Estimate of GIIP for the Nimblefoot Field

Reservoir	Parameter	Unit	P90	P50	P10
LBG	Contact	m TVDss	-2,676	-2,677	-2,677
	GRV	MM m^3	115	229	352
	NTG	Decimal	0.392	0.642	1.000
	Porosity	Decimal	0.260	0.280	0.300
	Sg	Decimal	0.685	0.775	0.865
	Gas Expansion Factor	1/Bg	236.5	238.0	239.5
	Condensate Yield	Stb/MM scf	17.00	17.00	17.00
	Recovery Factor	Decimal	0.540	0.650	0.720
	GIIP	**Bscf**	**102**	**256**	**468**

Note: This estimate of GIIP is based on a probabilistic methodology using GCA's 1D Monte Carlo Model.

Table 17: GCA's Estimate of GIIP for the Nimblefoot Field

Reservoir	Low (Bscf)	Best (Bscf)	High (Bscf)
LBG	143.5	271.7	405.4

Note: This estimate of GIIP is based on GCA's total project GIIP volumes which were derived by calculating the average between a full arithmetic and probabilistic addition of individual field volumes to account for unknown dependencies between the fields. The average Low, Best and High Network case profiles were allocated to each field by proportionally scaling each individual field P90, P50 and P10 case to the respective average Network case profile.

Table 18: GCA's Estimate of Gas Contingent Resources for the Nimblefoot Field

Reservoir	1C (Bscf)	2C (Bscf)	3C (Bscf)
LBG	88	168	257

Table 19: GCA's Estimate of Condensate Contingent Resources for the Nimblefoot Field

Reservoir	1C (MMBbl)	2C (MMBbl)	3C (MMBbl)
LBG	1.2	2.7	4.9

7.5 Production Forecasts

The Hess Best Case raw gas production forecast is a deterministic case from simulation modeling that matches the 65% recovery factor. The associated condensate production has been forecast based on a modeled CGR versus reservoir pressure relationship.

GCA has accepted the Hess Best Case forecasts for raw gas and condensate. GCA generated Low and High Cases based on the Best Case profile but scaled for the Low and High Case GIIP estimates. These Cases are similar to deterministic simulation cases generated by Hess in their simulation uncertainty analysis.

The GCA production forecasts for raw gas and condensate for the Nimblefoot Field are shown in **Figure 23** and **Figure 24**.

Figure 23: Nimblefoot Field Raw Gas Production Forecasts

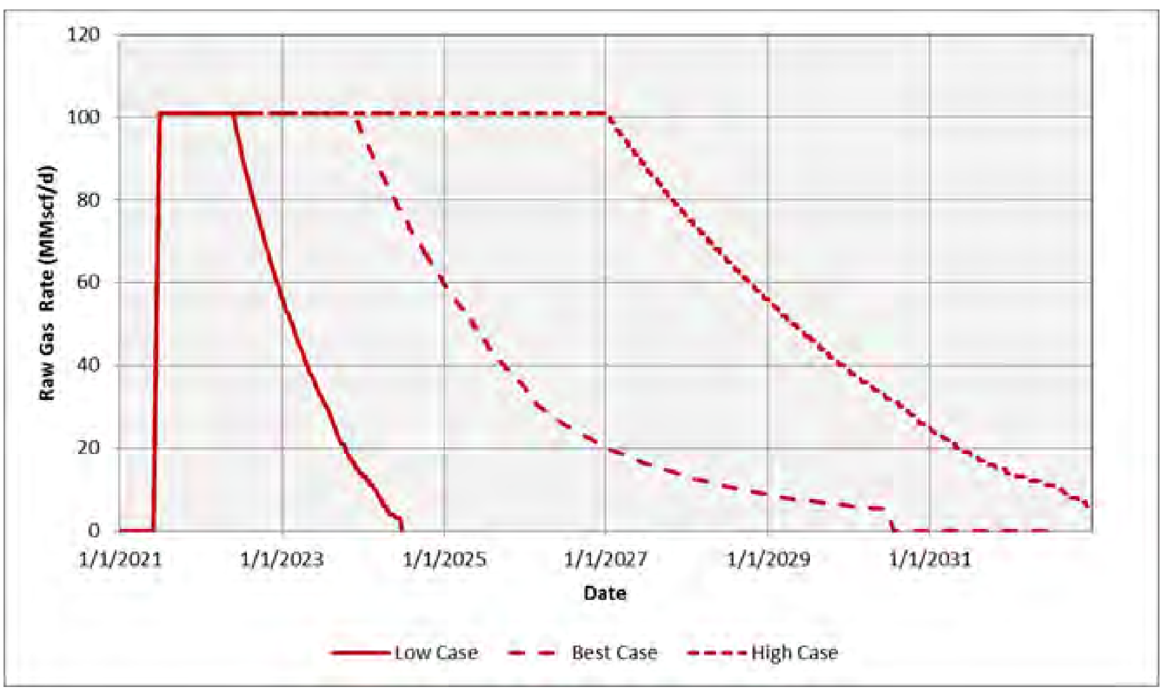
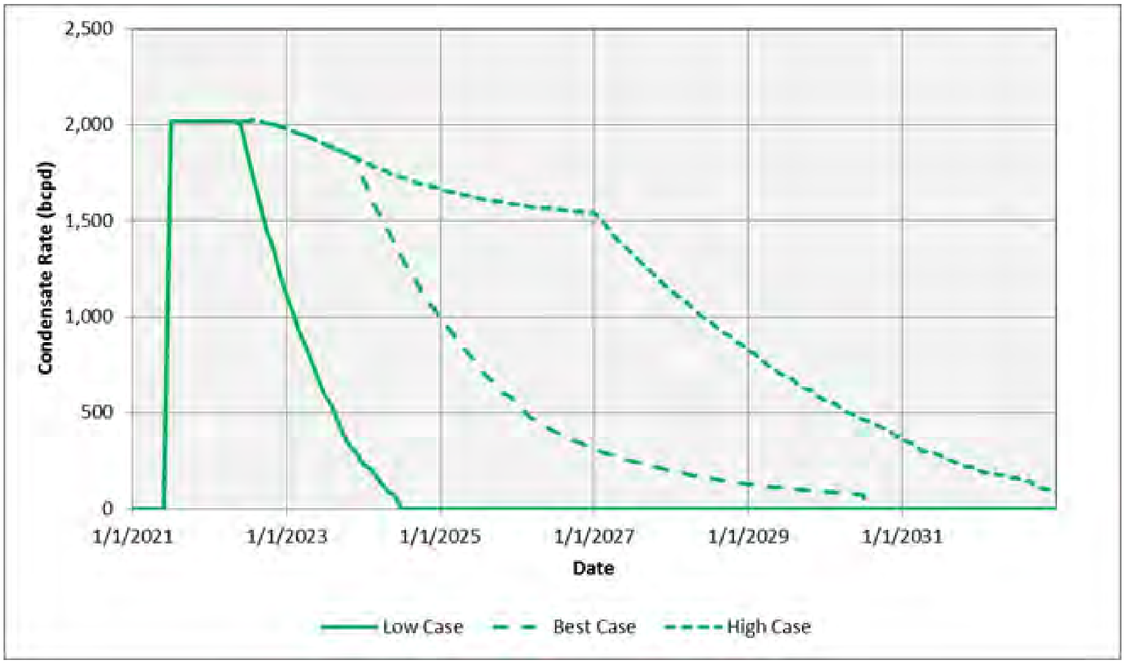


Figure 24: Nimblefoot Field Condensate Production Forecasts



8 Glencoe Discovery

8.1 Field Summary

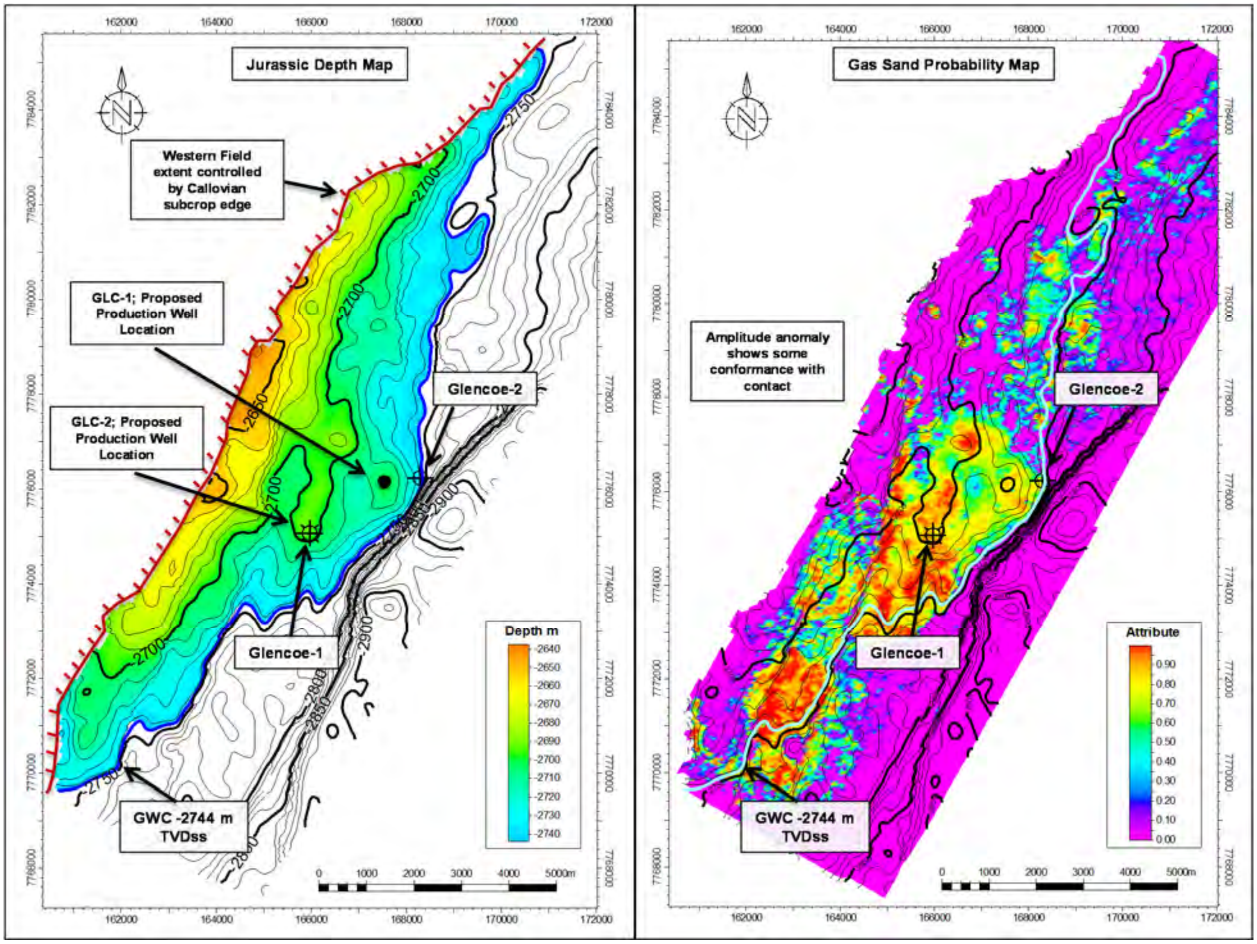
The Glencoe-1 vertical exploration well was drilled in the WA-390-P block in 2008. The well was drilled to target a northeast-southwest trending three-way dip closed structure which dips to the east (**Figure 25**). The primary target was a well-defined seismic amplitude anomaly above the Callovian Unconformity expected to be a combination structural and stratigraphic trap. The well intersected 31.8 m of net gas pay in the Upper Jurassic Lower Dingo Formation. The well was plugged and abandoned as a gas discovery after cutting 59.6 m of core in a sidetrack (Glencoe-1 CH1).

In 2011-2012, the Glencoe-2 well was drilled as a deviated well to appraise the Glencoe accumulation with a full suite of logs. Glencoe-2 intersected a 10 m thick gas bearing Oxfordian age sandstone. A gas water contact was also penetrated giving a net gas column of approximately 5 m. Glenco-2H was designed as a sidetrack to penetrate the primary reservoir section as a horizontal hole for drill stem testing which produced a maximum flow rate of 45 MMscfpd with 910 bblpd condensate and 58 bblpd water through a 23.8 mm choke. On completion of well testing operations and wireline log acquisition, the well was temporarily suspended with cement plugs.

The Glencoe structure is interpreted to be a faulted three-way dip closure. Trap closure to the west and northeast is interpreted to be the result of stratigraphic pinchout of sands due to the uplift of the underlying horst and subsequent erosion of Late Jurassic sediment. Deposition of the Oxfordian sediments was concurrent with tectonic activity. Seismic amplitudes support high negative anomalies which strengthen in far offset stacks (Class 3 AVO anomaly) and are conformable to structure at mapped gas water contact levels. The Oxfordian reservoir was deposited in a shallow marine environment and is mapped as an elongate NE-SW trending sand body.

The top seal for the structure is formed of Berriasian through Valanginian marine shales of the Barrow group. The main kitchen for Glencoe lies below the Mungaroo terrestrial carbonaceous shales and coals. Hydrocarbon generation began in the Upper Cretaceous and migration and charge has continued throughout the Tertiary to present times.

Figure 25: Hess' Jurrassic Depth Map and Gas Sand Probability map with Drilled and Planned Production Wells



8.2 Geology and Geophysics Review

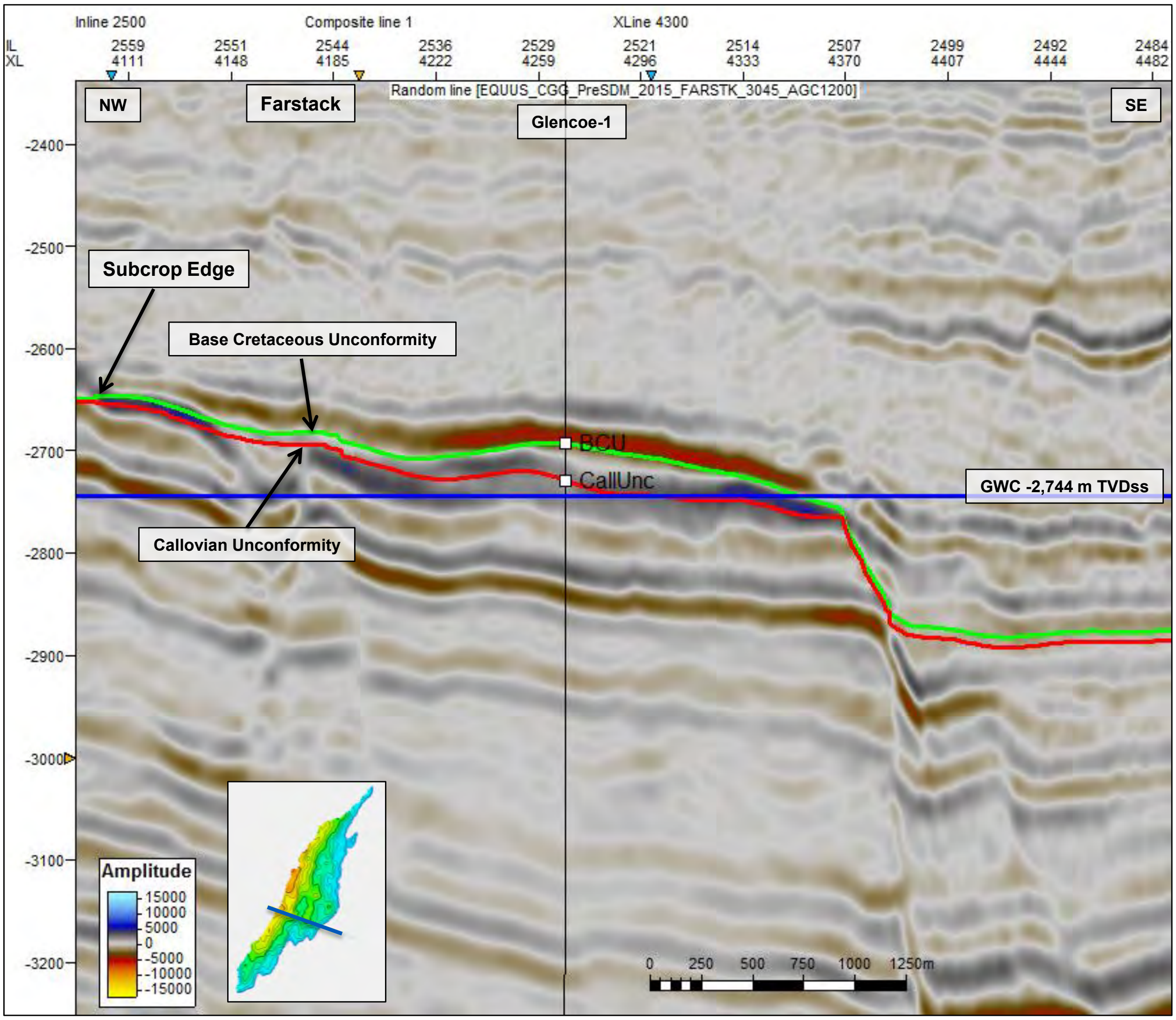
GCA has reviewed the seismic interpretation and static model of the Glencoe Field provided by Hess in the Glencoe Petrel Project and in general believes both are reasonable. The top of the reservoir is picked as a zero crossing between an over lying trough and underlying peak which marks the Base Cretaceous Unconformity. A strong seismic response is seen, particularly in the Gas Sand Probability Cube which conforms to structure and is seen to pinchout to the west where Jurassic reservoir limit is controlled by the unconformity subcrop edge (**Figure 26**).

Structural configuration is considered the greatest uncertainty of the Glencoe Discovery. While the interpretation of top reservoir is defined by a reasonably consistent pick, the stratigrapic nature of closure which requires pinchout in the north and the west leaves uncertainty over the GRV of the structure.

To generate a range of GRV inputs, Hess has undertaken Low, Base and High Case seismic interpretations of the Glencoe structure. GCA has reviewed these interpretations and believes they are a reasonable representation of the range of possible interpretations. For volumetric calculations, Hess has used these interpretations together with a GWC at -2,743.5 m TVDss established by pressure data in clean sands of Glencoe-2.

GCA used its own depth conversion to further test the structural uncertainty. Each of Hess' interpretations was converted to time using the PSDM velocity Cube, then back to depth using the GCA depth conversion. The GCA depth conversion results in a slightly flatter structure but also raises the southern part of the structure. This has the effect of lowering the GRV of the Low Case interpretation but increasing the GRV of the High Case interpretation, therefore resulting in a wider range of possible GRVs.

Figure 26: Seismic Section through Glencoe-1 Well



8.3 Engineering Review

A total of 20 down-hole and surface samples were collected from the Glencoe-2 and Glencoe-2H wells. There were slight variations in CO_2 and heavier C7+ components across samples, which is most likely due to contamination from OBM. Gas gravity has been measured at 0.7, with a gas expansion factor of 250 scf/rcf. The gas has a high concentration of methane at approximately 86%. The CO_2 concentration is low at 0.4% whilst the N_2 is 1.4%. Small concentrations of H_2S (0.2ppm) were recorded during flow-tests but were not measured in the down-hole samples.

Condensate gas ratio (CGR) has been estimated from samples and recombination laboratory experiments. Due to contamination in some samples, Hess has captured a range of 18 to 22 bbl/MMscf with a Best Case of 21 bbl/MMscf. Laboratory testing has indicated a maximum liquid drop in the reservoir of less than 1% with production, which should present no issues for near-wellbore condensate banking.

8.3.1 Well Tests

The Jurassic Oxfordian reservoir was tested by the Glencoe-2H well. The well was completed over a horizontal section of 561m to test the deliverability of the reservoir. The DST was conducted over the reservoir interval of 3,139 to 3,700mTVDRT on the 5th May 2012 to 20th May 2012. The test included an initial clean up flow period which reached a maximum gas rate of 57 MMscf/d followed by a shut-in. Subsequently a multi-rate test was conducted with rates of 15, 25, 35 and 45 MMscf/d. The drawdown at the gas rate of 45 MMscf/d was only 270 psi, which was considerably less than the expected drawdown of 500 psi. The pressure build-up period after the multi-rate test was over an extended period of approximately 20 hours.

The pressure build-up periods for both DSTs were interpreted using PTA. The contributing length from the horizontal section is uncertain so different interpretations of permeability can be made depending on the contributing well length assumed. The range of permeability estimated from PTA was 5 to 15 mD. Well deliverability has been proved by the horizontal well DST.

8.3.2 Development Plan

The Equus Project plan considers that the Glencoe field will initially be developed as part of the Phase 2 development. Under this plan, the GLC-1 well is to be drilled and produced to assess the long-term deliverability of Glencoe Field wells. The well is a re-drill of the Glencoe-2H well is scheduled to be drilled in 2020 and come online in 2021. The GLC-1 well will have a horizontal section of 800 m, and will be tied back to the Equus FPS facility via a 10 inch flowline shared with the Glenloth Field. Subsequently, the GLC-2 well is scheduled to be drilled in 2036 and come online in 2037 as part of the Phase 4 development. The well will also have an 800m horizontal section and be located close to the Glencoe-1 exploration well to maximize well control. The well will utilize the same flowline as the GLC-1 well.

The wells will be placed in the east of the field close to the existing wells as shown in **Figure 25**. Due to the low permeability reservoir and lack of aquifer support, water movement from the water leg to the production wells is expected to be minimal.

8.3.3 Recovery Factor

Hess assessed the deliverability and recovery of gas and condensate from the Glencoe field using reservoir simulation and analogue data. GCA has deemed this as approach as reasonable.

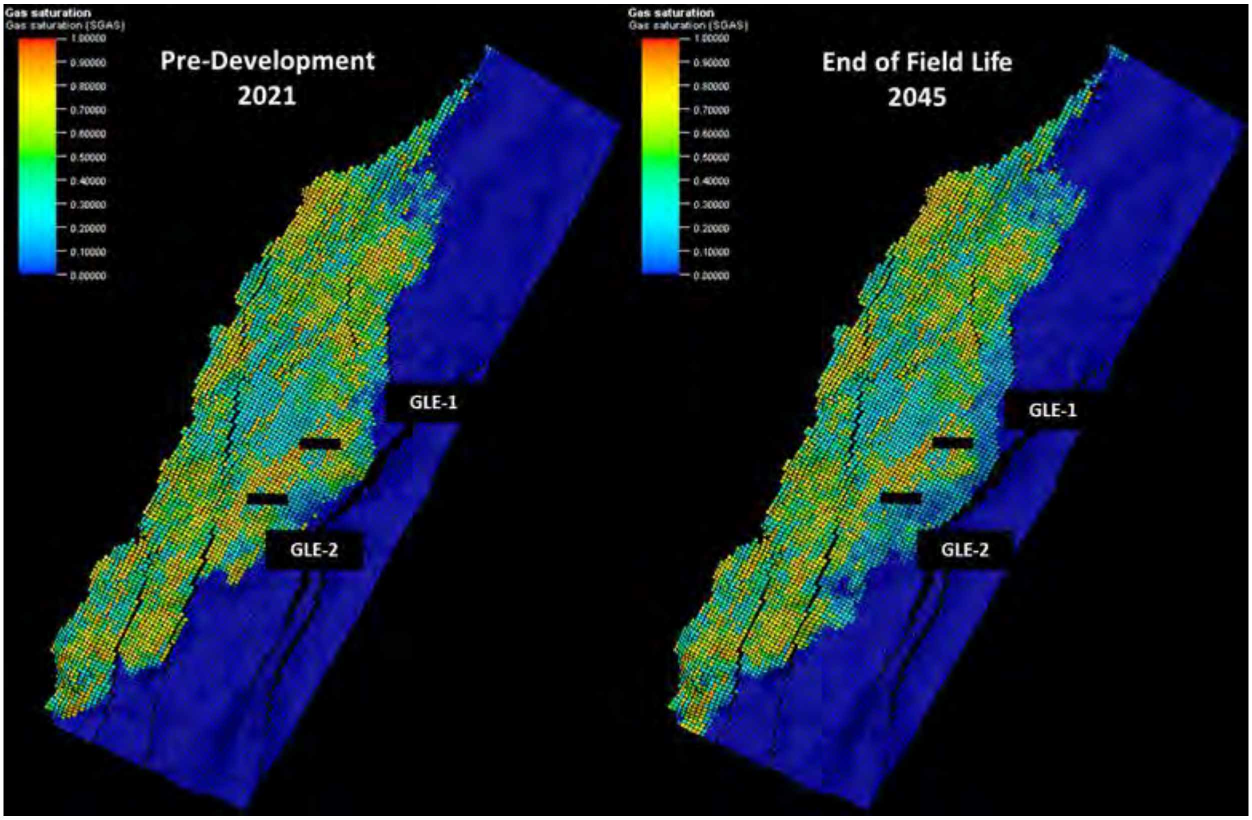
The Glencoe reservoir is a combined structural and stratigraphic trap. The lateral extent of the reservoir is limited by faulting and the depositional environment. This prevents connection to any large, regional aquifer and the reservoir drive mechanism is expected to be depletion drive with minimal water influx. For a gas reservoir with depletion drive, recovery is typically determined by minimum inlet pressure at the production facility, in this case the Equus FPS.

Hess has identified the Linda Field in the Carnarvon Basin development as an analogue for the Glencoe field. The Linda Field is a Jurassic Oxfordian age gas field with similar reservoir quality. The recovery factor reported for the Linda field is 55%.

Hess ran a number of dynamic simulation cases in order to quantify the uncertainty contributing to gas recovery at the Glencoe Field. The methodology that Hess followed was to generate a number of models based on different subsurface realisations by varying static and dynamic model properties. By running the different simulation model realisations, Hess was able to generate an S-curve of estimated ultimate recovery (EUR) outcomes. As part of the process, Hess was able to identify the key uncertainties contributing to EUR, which are gross rock volume, facies distribution and permeability.

The recovery factor range derived from the simulation uncertainty modelling was 35% to 75%, with the proposed development case achieving a recovery factor of 60%. **Figure 27** below shows the deterministic model associated with the 60% recovery factor case. The map on the left shows the gas saturation prior to commencing production, whilst the map on the right shows gas saturation at the end of field life. Without the presence of a strong aquifer there is no significant water movement into the reservoir from the aquifer.

Figure 27: Glencoe Field Deterministic Best Case Simulation Model



The Glencoe field gas recovery factor range proposed by Hess is 43%, 55% and 66% for the Low, Best and High Cases, respectively. This recovery factor range is consistent with the ranges from simulation and analogue analysis, and also with the range GCA would expect from a lower permeability, depletion drive gas field developed using horizontal wells via a subsea tieback development.

8.4 Resource Estimate

The GIIP and Contingent Resources for the Glencoe Field were estimated using a 1D Monte Carlo Model. Reservoir parameter inputs are based on the sums and averages calculated from GCA's petrophysical interpretation. For the GRV inputs into the calculation, GCA accepted the Hess Best Case Petrel surface as being reasonable and calculated GRVs based on this and using the -2,744 m TVDss GWC for the P50 input. Because the GCA depth conversion suggested the possibility of a wider range of GRVs, GRVs calculated using the Hess Low and High Case interpretations depth converted using GCA's velocity model were used to calculate a P90 and P10 GRVs. GCA's input parameters into its 1D Monte Carlo Model, together with the resulting GIIP estimates, are given in **Table 20**.

GCA's estimates of GIIP for the Glencoe Field are given in **Table 21**. Gas Contingent Resources are given in **Table 22** and associated Condensate Contingent Resources are summarized in **Table 23**.

Table 20: GCA's Input Parameters for its Estimate of GIIP for the Glencoe Field

Reservoir	Parameter	Unit	P90	P50	P10
Jurassic	Contact	m TVDss	-2,744	-2,744	-2,744
	GRV	MM m^3	285	553	1,016
	NTG	Decimal	0.550	0.700	0.850
	Porosity	Decimal	0.220	0.250	0.270
	Sg	Decimal	0.403	0.493	0.583
	Gas Expansion Factor	1/Bg	250.0	250.0	250.0
	Condensate Yield	Stb/MM scf	17.90	17.90	17.90
	Recovery Factor	Decimal	0.430	0.550	0.660
	GIIP	**Bscf**	**192**	**399**	**801**

Note: This estimate of GIIP is based on a probabilistic methodology using GCA's 1D Monte Carlo Model.

Table 21: GCA's Estimate of GIIP for the Glencoe Field

Reservoir	Low (Bscf)	Best (Bscf)	High (Bscf)
Jurassic	271.1	422.6	679.2

Note: This estimate of GIIP is based on GCA's total project GIIP volumes which were derived by calculating the average between a full arithmetic and probabilistic addition of individual field volumes to account for unknown dependencies between the fields. The average Low, Best and High Network case profiles were allocated to each field by proportionally scaling each individual field P90, P50 and P10 case to the respective average Network case profile.

Table 22: GCA's Estimate of Gas Contingent Resources for the Glencoe Field

Reservoir	1C (Bscf)	2C (Bscf)	3C (Bscf)
Jurassic	143	226	381

Table 23: GCA's Estimate of Condensate Contingent Resources for the Glencoe Field

Reservoir	1C (MMBbl)	2C (MMBbl)	3C (MMBbl)
Jurassic	2.7	4.2	8.3

8.5 Production Forecasts

The Hess Best Case raw gas production forecast is a deterministic case from simulation modeling that matches the 60% recovery factor. The associated condensate production has been forecast based on a modeled CGR versus reservoir pressure relationship. GCA has accepted the Hess Best Case forecasts for raw gas and condensate. GCA generated Low and High Cases based on the Best Case profile but scaled for the Low and High Case GIIP estimates. These Cases are similar to deterministic simulation cases generated by Hess in their simulation uncertainty analysis.

The GCA production forecasts for raw gas and condensate for the Glencoe Field are shown in **Figure 28** and **Figure 29.**

Figure 28: Glencoe Field Raw Gas Production Forecasts

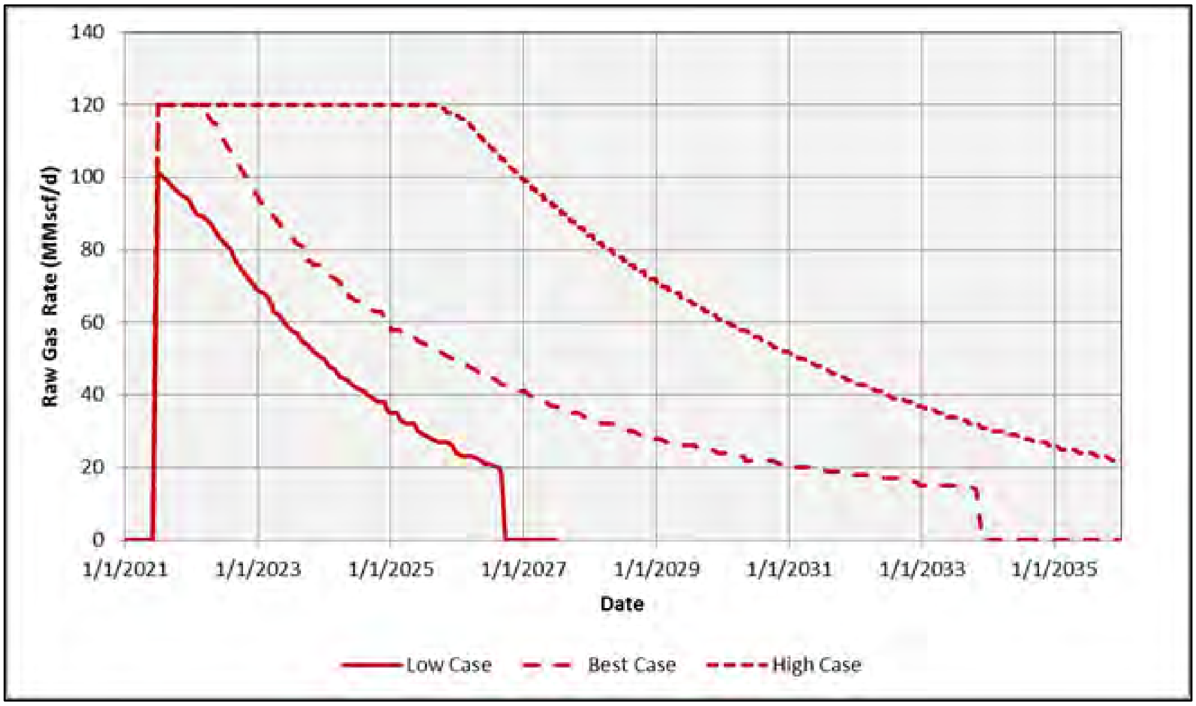
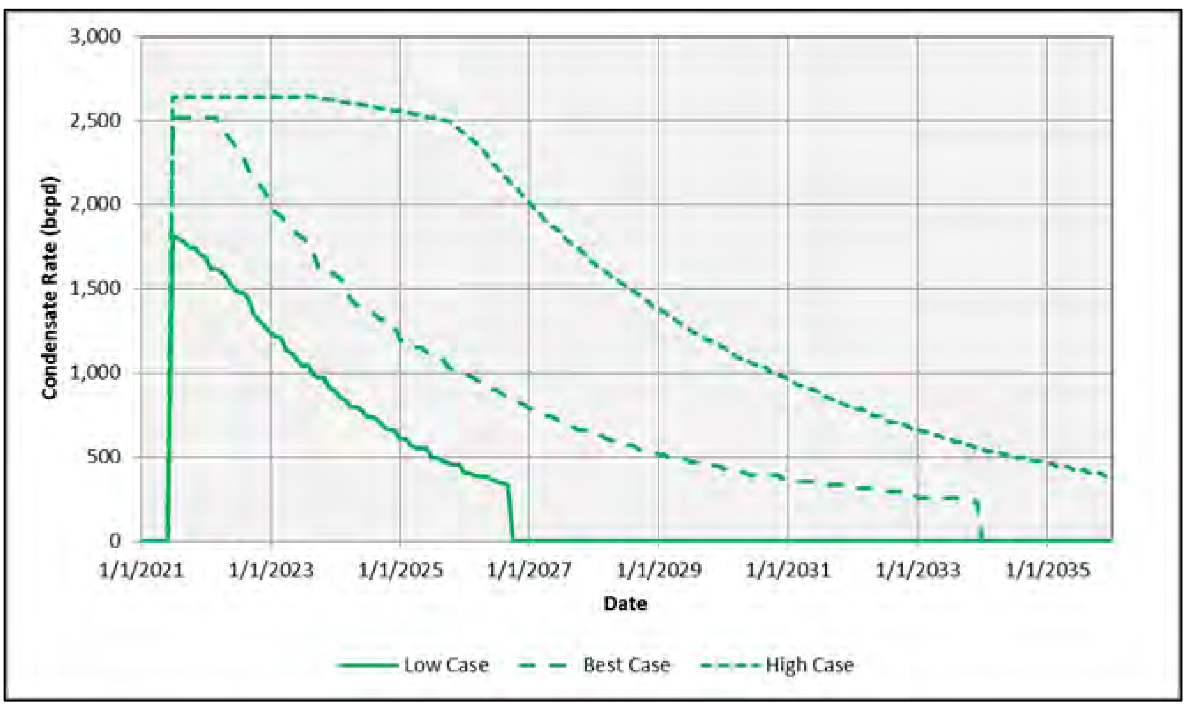


Figure 29: Glencoe Field Condensate Production Forecasts



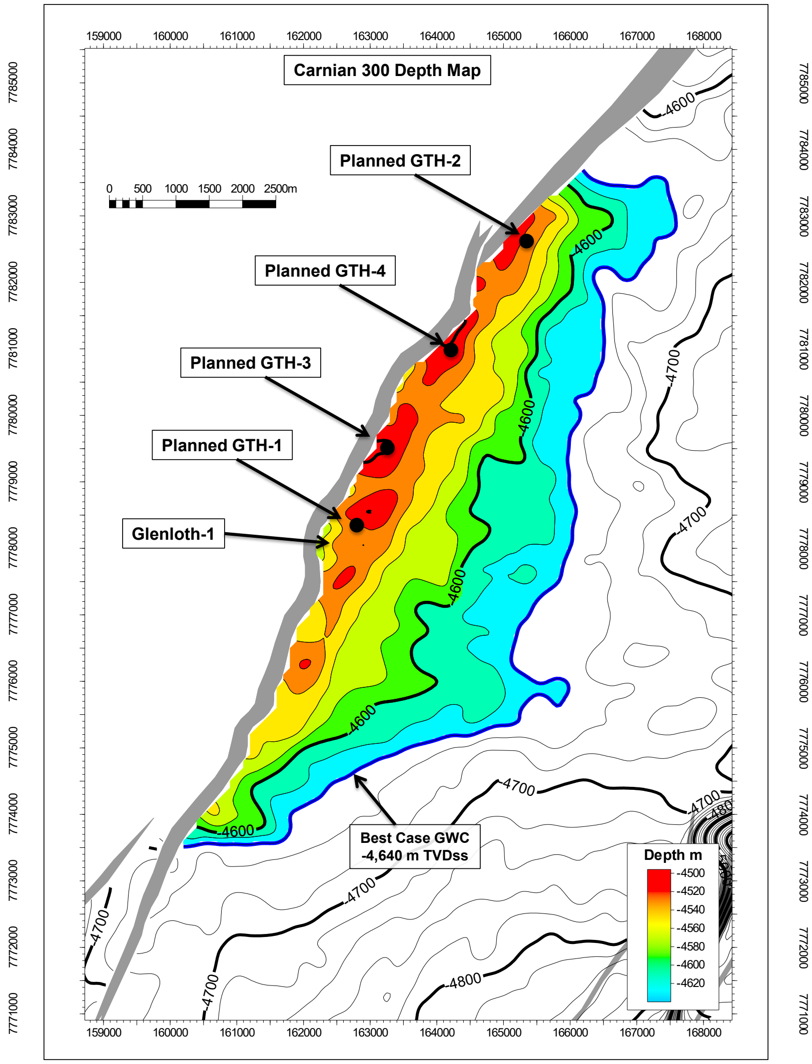
9 Glenloth Discovery

9.1 Field Summary

The Glenloth-1 deviated exploration well was drilled in WA-390-P in 2010. The well was drilled to target the Glenloth structure, a north-northeast south-southwest trending, three-way dip closed, tilted fault block (**Figure 30**). The Glenloth-1 well was drilled to target a stacked series of amplitude anomalies within the Mungaroo Formation trapped to the west against a major westerly dipping extensional fault. The well reached a TD of 5,018 m MDRT in the Mungaroo Formation and intersected 158 m of net gas pay in 13 pay zones within the Mungaroo Formation. The well was suspended as a gas discovery for later re-entry for testing.

The Glenloth structure is defined by strong amplitude anomalies with conformance to structure at some levels. The anomalies corresponded to the gas filled Mungaroo channel sands which have been subsequently rotated and truncated by a large westerly-dipping extension fault against which the structure is sealed. The Glenloth structure also requires multiple intra-Mungaroo shales and siltstones to provide top seal for each reservoir sand. Reservoirs are formed of Norian-Carnian aged channelized sandstones deposited in a delta-plain setting on the Mungaroo delta. Gas has been sourced from deeply buried Mungaroo Formation organic sediments of Ladinian to Norian age, consisting predominantly of terrestrial carbonaceous shales and coals. Hydrocarbon generation from these source rocks started in the Late Cretaceous with migration through faults and charging continuing throughout the Tertiary to present times.

Figure 30: Hess' Carnian 300 Depth Map with Phase 1& 2Drilled and Planned Production Wells



9.2 Geology and Geophysics Review

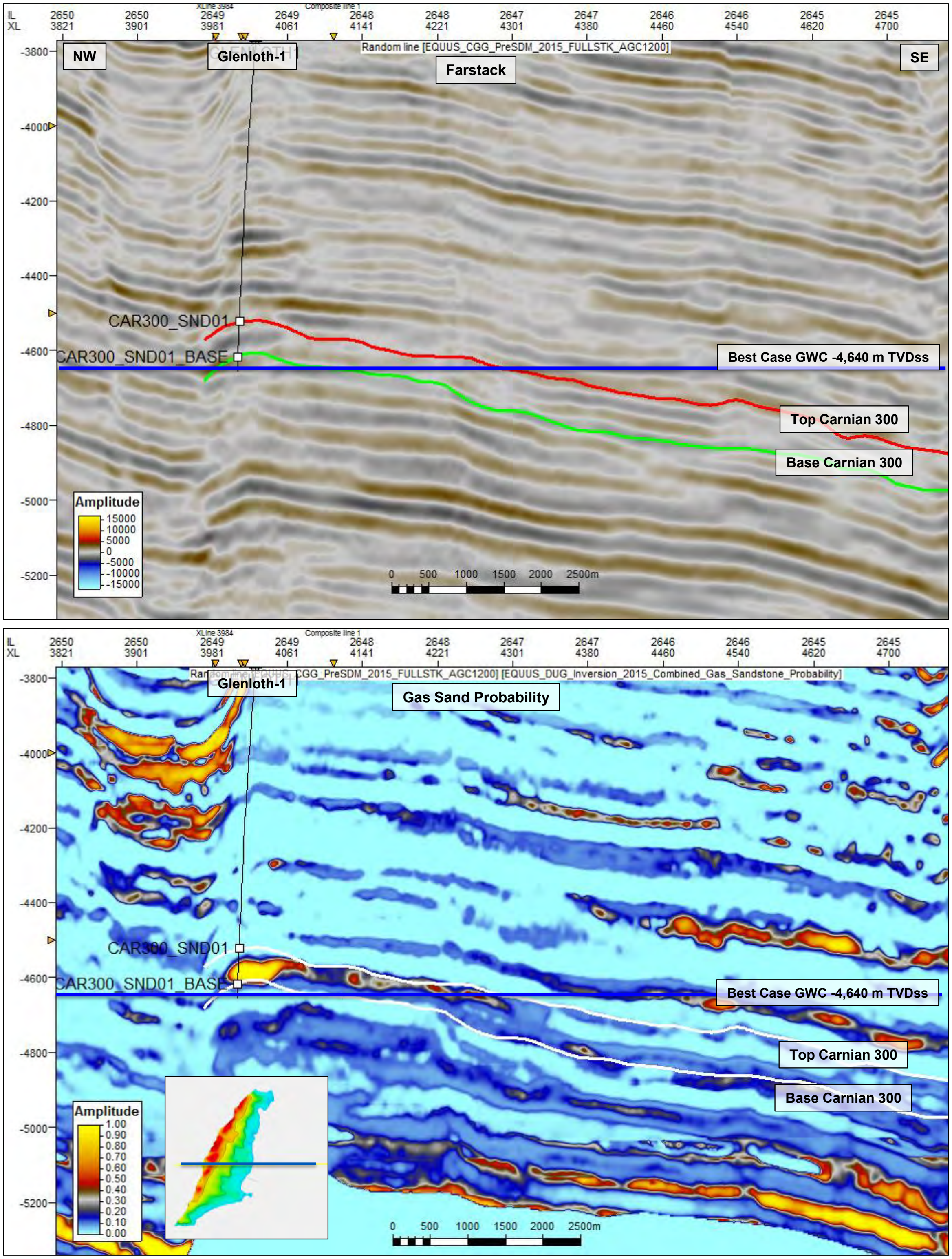
GCA has reviewed the seismic interpretation and static model of the Glenloth Field provided by Hess in the Glenloth Petrel Project and in general considers both are reasonable. A total of seven Triassic gas bearing intervals were penetrated by the Glenloth well; Norian 600 SA2, Norian 100 SA2, Norian 400 SA3, Norian 400 SA1, Norian300 SA6 , Norian 300 SA4 and the Carnian 300. The Carnian 300 is the largest.

The top of the Carnian 300 reservoir interval is picked on the seismic data as a zero crossing between an overlying trough and underlying peak. There are thickness variations within the reservoir interval with an extra loop, represented by a trough being present over parts of the field. The extra trough is coincidental with a positive Gas Sand Probability response (**Figure 31**). The Gas Sand Probability response only appears over approximately 20% of the field closure and is likely to represent better quality sands. This is supported by the Glenloth Well which penetrated a thick Carnian 300 interval with some sections showing a good Gas Sand Probability response and others without a response. Intervals without a Gas Sand Probability response still had gas pay but are of lower porosity while intervals with a response are of higher quality, higher porosity reservoir. No GWC was penetrated and Hess has estimated Mid and High Case contacts using saturation height modelling. The Hess Minimum Case contact has been based on the GDT seen in the Glenloth well. There is no northern structural closure to the Carnian 300 interval in the High Case and the areal extent has been limited to a potential sand fairway which is represented by a channel feature seen in the Far Angle Stack Seismic Cube (FARS) amplitude extractions.

Hess provided GCA with a single Base Case interpretation for the Carnian 300 and GCA has used its own depth conversion to further test the structural uncertainty. Hess' interpretation was converted to time utilising the PSDM velocity cube, then back to depth using the GCA depth conversion. The GCA depth conversion has the effect of raising the flanks of the structure slightly and consequently suggests the possibility of higher GRVs.

Hess also provided GCA with Base Case interpretations of each Norian reservoir sand interval. GCA has reviewed each of the interpretations and considers them to be reasonable. In each case, contacts have been estimated using formation pressure data if no GWC has been penetrated. Where a GDT is seen in the well this has been used for the GCA Low case contact. GCA was able to reconcile the GeoX GRVs provided by Hess with volumes calculated using the Petrel surfaces and has based its review on the GCA contact uncertainty and Petrel surfaces. GCA tested each of the Norian reservoir intervals with the GCA velocity model. In general, the GCA depth surfaces resulted in slightly higher GRVs due to a raising of the flanks of the structure.

Figure 31: Seismic Section through the Glenloth-1 Well showing the Far Stack and Gas Sand Probability Inversion Cubes



9.3 Engineering Review

A total of 20 down-hole and surface samples were collected from the Glenloth-1 well. 14 of these samples were down-hole and surface samples from the Carnian-300 reservoir zone. An additional 6 down-hole samples were collected from the Norian-300 and Norian-400 reservoir zones. There was some contamination from OBM, but compositions were consistent for the Carnian-300 samples.

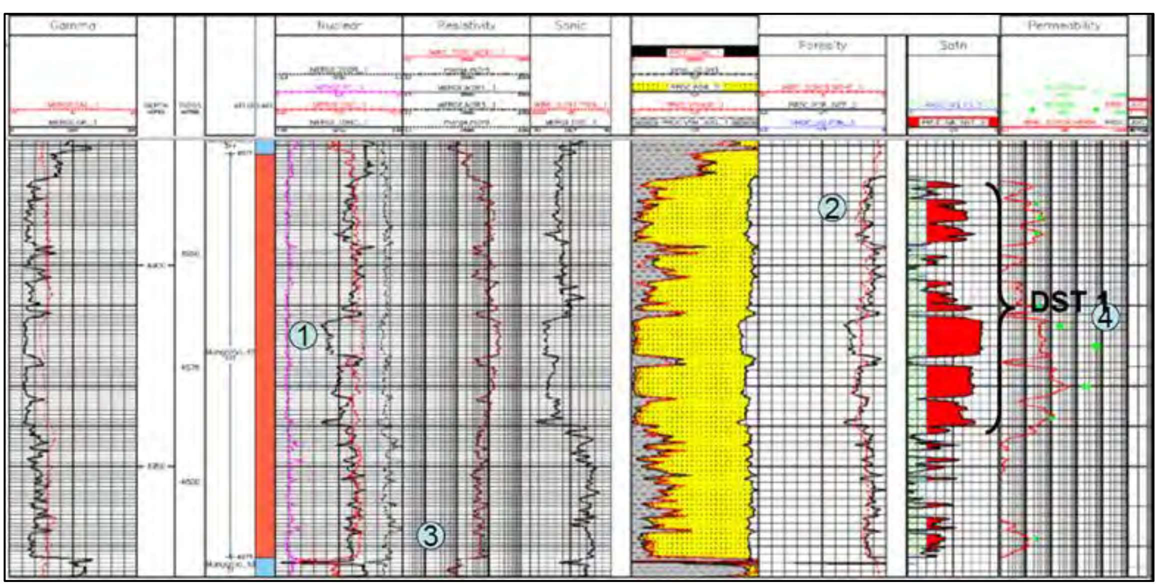
Reservoir conditions in the Carnian-300 zone at Glenloth are at the dewpoint. Gas gravity for all zones has been measured at 0.7, with a gas expansion factor in the Carnian-300 of 292 scf/rcf. The CO_2 concentration for the Carnian-300 zone is low at 1.0% whilst the N_2 is one of the highest of the Equus Fields at approximately 4.7%. For both the Norian-300 and Norian-400 zones, the CO_2 and N_2 concentrations are both approximately 1.5%. Small concentrations of H_2S (0.2ppm) were recorded during flow-testing of the Carnian-300 zone but were not measured in the down-hole samples.

CGR has been estimated from samples and recombination laboratory experiments. Hess has estimated a CGR for the Carnian-300 of 5.6 bbl/MMscf based on the production CGR from the Glenloth-1 DST. This is the lowest CGR seen across the Equus fields. The Norian-300 Best Case CGR was estimated to be 22 bbl/MMscf, whilst the Norian-400 Best Case CGR was 12 bbl/MMscf. A small range has been applied to the Low and High Case CGR for the Norian zones to capture uncertainty seen in CGR across the various samples. Laboratory testing has indicated a maximum liquid dropout in the reservoir of less than 1% with production, which should present no issues for near-wellbore condensate banking.

9.3.1 Well Tests

The Triassic Mungaroo reservoir was tested by the Glenloth-1 well. The well was perforated over a vertical interval of 53 m to test the deliverability of the Carnian-300 reservoir. The DST intervals are shown with the Glenloth-1 petrophysical logs across the Carnian-300 reservoir section in **Figure 32**.

Figure 32: Glenloth Field Petrophysical Logs with DST Intervals



Source: Hess

The DST was tested over the reservoir interval of 4,535 to 4,588 mTVDss on the 12 November 2010 to 21 November 2010. The test included an initial clean up flow period followed by a shut-in. Subsequently a multi-rate test was conducted with a maximum raw gas rate of 54 MMscf/d with a drawdown of less than 400 psi. The pressure build-up period after the multi-rate test was approximately 100 hours.

The pressure build-up periods from the DST were interpreted using Pressure Transient Analysis (PTA). The interval was interpreted as a dual-permeability system with an average permeability of 20 mD. The dual-permeability interpretation from the DST matches the petrophysical log interpretation of shallower poor facies underlain by higher quality facies. Multiple faults or boundaries were seen in the late time pressure derivative curve, which correspond to the structure of the field. The minimum connected volume interpreted by PTA was approximately 300 Bscf, which supports the Hess Min Case GIIP from volumetric analysis.

Well deliverability has been proved by the DSTs and development well productivity is expected to be high.

9.3.2 Development Plan

Initial development of the Glenloth Field targeting the Carnian-300 reservoir is considered in both Phase 1 and Phase 2 of the Equus Project development plan. The development plan includes 4 low-inclination development wells in crestal locations to maximize the stand-off from the GWC as shown in **Figure 30**.

The GTH-1 and GTH-2 wells will be drilled and produced as part of Phase 1 to assess the long-term deliverability of Glenloth Field wells. The wells are scheduled to be drilled in 2020 and come online in 2021. The wells will be tied back to the Equus FPS facility via a 10 inch flowline shared with the Glencoe Field. Subsequently, the GTH-3 and GTH-4 wells are scheduled to be drilled in 2027 and come online in 2028, sharing the same flowline as the Glenloth Phase 1 wells. The Carnian-300 reservoir will be developed first as it has the largest in-place volume.

By 2037 the Glenloth Carnian-300 reservoir is expected to be depleted. As part of the Equus Project Phase 4 and Phase 5 developments, the four Glenloth production wells will be re-entered and completed in the Norian-100, Norian-300, Norian-400, Norian-600 reservoirs plus the un-penetrated Carnian-400 reservoir at Glenloth North. To reduce well intervention costs, the Glenloth development wells have been designed for intervention from light vessels. Phase 4 and Phase 5 are scheduled to come online in 2037 and 2039, respectively.

9.3.3 Recovery Factor

Hess assessed the deliverability and recovery of gas and condensate from the Glenloth field using reservoir simulation and analogue data. GCA has deemed this approach as reasonable.

The Glenloth reservoir is a combined structural and stratigraphic trap. The lateral extent of the reservoir is limited by faulting and the depositional environment. This prevents connection to any large, regional aquifer and the reservoir drive mechanism is expected to be depletion drive with minimal water influx. For a gas reservoir with depletion drive, recovery is typically determined by minimum inlet pressure at the production facility, in this case the Equus FPS. The recovery can be lower dependent on the reservoir complexity, reservoir quality and number of reservoir zones.

Hess has identified the Pluto Field in the Carnarvon Basin development as an analogue for the Glenloth Field. The Pluto Field is a Mungaroo Norian gas field, but with better reservoir quality. The expected recovery factor reported for the Pluto field is 60% to 80%. Other Mungaroo formation gas fields on the North West Shelf report recovery factors of 60% to 65%.

Hess ran a number of dynamic simulation cases in order to quantify the uncertainty contributing to gas recovery at the Glenloth Field. The methodology that Hess followed was to generate a number of models based on different subsurface realisations by varying static and dynamic model properties. By running the different simulation model realisations, Hess was able to generate an S-curve of estimated ultimate recovery (EUR) outcomes. The recovery factor range derived from the simulation uncertainty modelling was 55% to 85%, with the proposed development case achieving a recovery factor of 76%.

The Glenloth Field gas recovery factor range for all reservoirs proposed by Hess is 55%, 65% and 75% for the Low, Best and High Cases, respectively. This recovery factor range is consistent with the ranges from simulation and analogue analysis, and also with the range GCA would expect from a stacked reservoir sand, depletion drive gas field developed using vertical wells via a subsea tieback development.

9.4 Resource Estimate

The GIIP and Contingent Resources for the Glenloth Field were estimated using a 1D Monte Carlo Model. Reservoir parameter inputs are based on the sums and averages calculated from GCA's petrophysical interpretation.

For the GRV inputs into the calculation, GCA has incorporated results of GRVs calculated using the GCA depth conversion. For the Carnian 300, this suggested a possible high side case as GRVs were higher using the GCA depth conversion. The GCA depth conversion was therefore used to calculate the P10 GRV input and the GRVs calculated using the Hess surface were used for the P90 and P50 inputs. For the Norian reservoirs, results of the GCA depth conversion in general showed lower GRVs than those calculated using the Hess surfaces. GCA has therefore incorporated these into the ranges of GRV inputs into the 1D Monte Carlo Model. GCA's input parameters into its 1D Monte Carlo Model, together with the resulting GIIP estimates, are given in **Table 24**.

GCA's estimates of GIIP for the Glenloth Field are given in **Table 25**. Gas Contingent Resources are given in **Table 26** and associated Condensate Contingent Resources are summarized in **Table 27**.

Table 24: GCA's Input Parameters for its Estimate of GIIP for the Glenloth Field

Reservoir	Parameter	Unit	P90	P50	P10
Carnian 300	Contact	m TVDss	-4,617	-4,640	-4,740
	GRV	MM m^3	954	1,467	3,034
	NTG	Decimal	0.400	0.500	0.600
	Porosity	Decimal	0.050	0.090	0.130
	Sg	Decimal	0.580	0.650	0.720
	Gas Expansion Factor	1/Bg	287.2	291.8	295.9
	Condensate Yield	Stb/MM scf	3.2	4.8	6.3
	Recovery Factor	Decimal	0.55	0.65	0.75
	GIIP	**Bscf**	**204**	**436**	**998**
Norian 600 SA2	Contact	m TVDss	-2,708	-2,708	-2,708
	GRV	MM m3	59	98	108
	NTG	Decimal	0.300	0.400	0.500
	Porosity	Decimal	0.190	0.230	0.270
	Sg	Decimal	0.640	0.710	0.780
	Gas Expansion Factor	1/Bg	232.0	235.0	238.0
	Condensate Yield	Stb/MM scf	20.0	21.0	22.0
	Recovery Factor	Decimal	0.55	0.65	0.75
	GIIP	**Bscf**	**27**	**43**	**66**
Norian 100 SA2	Contact	m TVDss	-4,098	-4,150	-4,185
	GRV	MM m3	26	264	495
	NTG	Decimal	0.590	0.690	0.790
	Porosity	Decimal	0.080	0.120	0.160
	Sg	Decimal	0.658	0.728	0.798
	Gas Expansion Factor	1/Bg	274.0	277.3	281.0
	Condensate Yield	Stb/MM scf	19.0	20.0	21.0
	Recovery Factor	Decimal	0.55	0.65	0.75
	GIIP	**Bscf**	**11**	**140**	**306**
Norian 400 SA3	Contact	m TVDss	-3,439	-3,442	-3,445
	GRV	MM m3	55	61	96
	NTG	Decimal	0.650	0.750	0.850
	Porosity	Decimal	0.120	0.160	0.200
	Sg	Decimal	0.570	0.640	0.710
	Gas Expansion Factor	1/Bg	255.0	258.3	262.0
	Condensate Yield	Stb/MM scf	11.9	11.9	11.9
	Recovery Factor	Decimal	0.55	0.65	0.75
	GIIP	**Bscf**	**33**	**51**	**76**

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Reservoir	Parameter	Unit	P90	P50	P10
Norian 400 SA1	Contact	m TVDss	-3,473	-3,473	-3,473
	GRV	MM m3	26	40	51
	NTG	Decimal	0.540	0.640	0.740
	Porosity	Decimal	0.130	0.170	0.210
	Sg	Decimal	0.536	0.606	0.676
	Gas Expansion Factor	1/Bg	259.0	262.3	266.0
	Condensate Yield	Stb/MM scf	11.9	11.9	11.9
	Recovery Factor	Decimal	0.55	0.65	0.75
	GIIP	**Bscf**	**14**	**23**	**35**
Norian 300 SA6	Contact	m TVDss	-3,612	-3,620	-3,630
	GRV	MM m3	22	50	68
	NTG	Decimal	0.400	0.500	0.600
	Porosity	Decimal	0.100	0.140	0.180
	Sg	Decimal	0.580	0.650	0.720
	Gas Expansion Factor	1/Bg	260.0	263.3	267.0
	Condensate Yield	Stb/MM scf	20.0	20.0	20.0
	Recovery Factor	Decimal	0.55	0.65	0.75
	GIIP	**Bscf**	**9**	**19**	**33**
Norian 300 SA4	Contact	m TVDss	-3,674	-3,674	-3,674
	GRV	MM m3	51	82	132
	NTG	Decimal	0.250	0.350	0.450
	Porosity	Decimal	0.120	0.160	0.200
	Sg	Decimal	0.610	0.680	0.750
	Gas Expansion Factor	1/Bg	267.0	270.1	274.0
	Condensate Yield	Stb/MM scf	20.0	20.0	20.0
	Recovery Factor	Decimal	0.55	0.65	0.75
	GIIP	**Bscf**	**15**	**29**	**53**

Note: This estimate of GIIP is based on a probabilistic methodology using GCA's 1D Monte Carlo Model.

Table 25: GCA's Estimate of GIIP for the Glenloth Field

Reservoir	GIIP (Bscf)		
	Low	Best	High
Carnian 300	286	452	843
Norian 600 SA2	37	46	57
Norian 100 SA2	18	149	268
Norian 400 SA3	45	54	65
Norian 400 SA1	19	24	30
Norian 300 SA6	13	21	29
Norian 300 SA4	21	30	45

Note: This estimate of GIIP is based on GCA's total project GIIP volumes which were derived by calculating the average between a full arithmetic and probabilistic addition of individual field volumes to account for unknown dependencies between the fields. The average Low, Best and High Network case profiles were allocated to each field by proportionally scaling each individual field P90, P50 and P10 case to the respective average Network case profile.

Table 26: GCA's Estimate of Gas Contingent Resources for the Glenloth Field

Reservoir	Contingent Resources (Bscf)		
	1C	2C	3C
Carnian 300	184	298	562
Norian 600 SA2	24	30	38
Norian 100 SA2	10	94	172
Norian 400 SA3	30	35	43
Norian 400 SA1	13	16	20
Norian 300 SA6	9	14	19
Norian 300 SA4	14	20	30

Table 27: GCA's Estimate of Condensate Contingent Resources for the Glenloth Field

Reservoir	Contingent Resources (MMbbl)		
	1C	2C	3C
Carnian 300	0.6	1.4	2.9
Norian 600 SA2	0.5	0.7	0.9
Norian 100 SA2	0.2	2.1	3.8
Norian 400 SA3	0.3	0.5	0.6
Norian 400 SA1	0.2	0.2	0.3
Norian 300 SA6	0.2	0.3	0.4
Norian 300 SA4	0.3	0.5	0.7

9.5 Production Forecasts

Hess generated production forecasts for each of the Norian and Carnian reservoirs. The Carnian-400 reservoir at Glenloth has not been penetrated and therefore GCA has classified these recoverable volumes as Prospective Resources. GCA has therefore separated the production forecasts for Glenloth into discovered and undiscovered (Glenloth North Carnian-400).

The discovered Hess Best Case raw gas production forecast is a deterministic case from simulation modeling that matches the 65% recovery factor. The associated condensate production has been forecast based on a modeled CGR versus reservoir pressure relationship. GCA has accepted the Hess Best Case forecasts for raw gas and condensate. GCA generated Low and High Cases based on the Best Case profile but scaled for the Low and High Case GIIP estimates. These Cases are similar to deterministic simulation cases generated by Hess in their simulation uncertainty analysis.

The GCA discovered production forecasts for raw gas and condensate for the Glenloth Field are shown in **Figure 33** and **Figure 34**.

Figure 33: Glenloth Field Discovered Raw Gas Production Forecasts

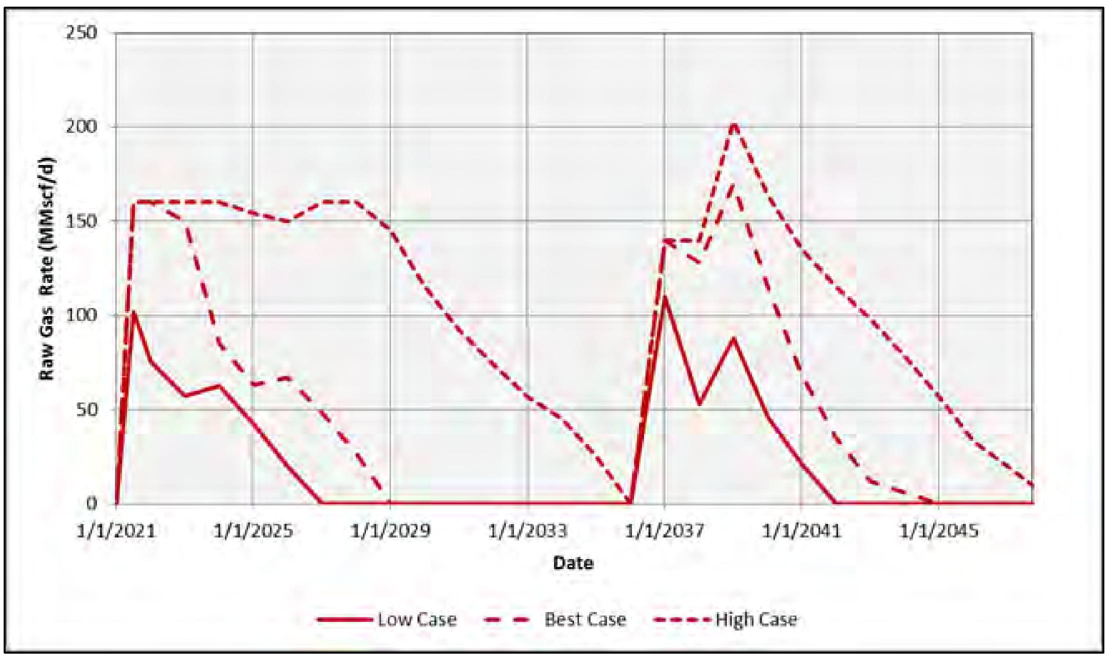
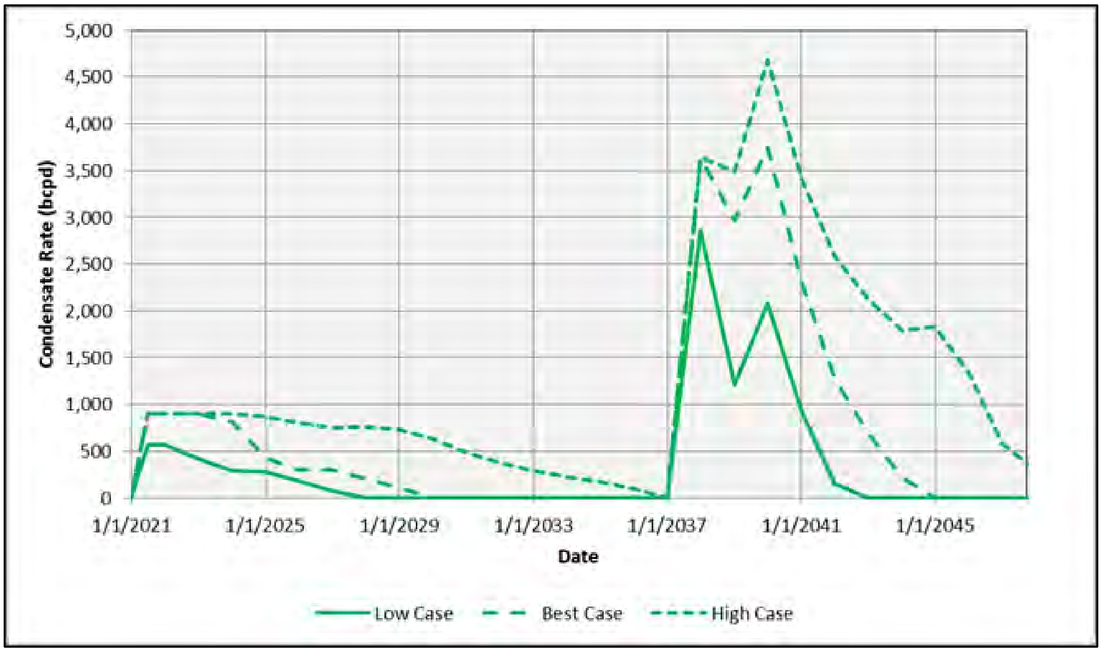


Figure 34: Glenloth Field Discovered Condensate Production Forecasts



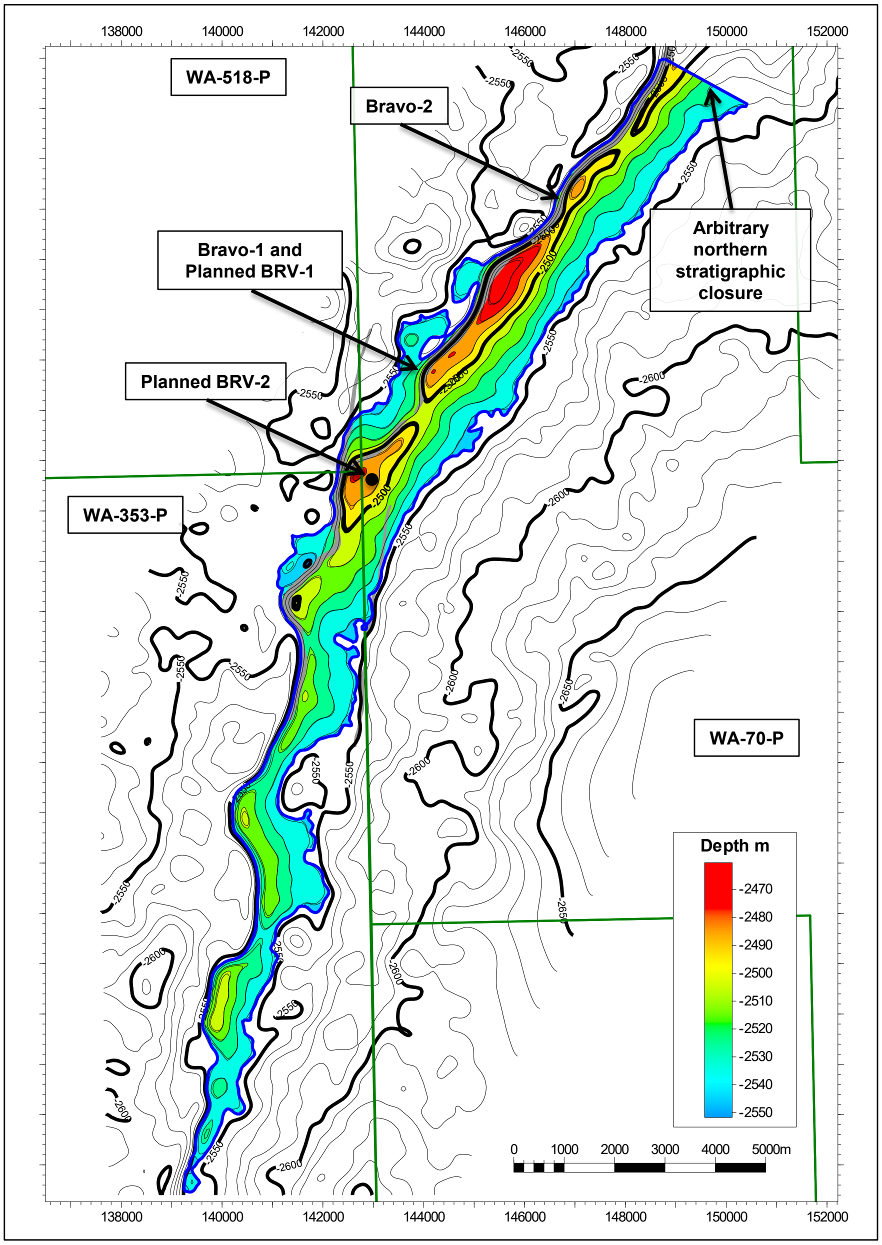
10 Bravo Field

10.1 Field Summary

The Bravo Field which lies within the WA-70-R lease is formed of a two-way dip closed, northeast – southwest trending structure which is fault closed to the northwest and lies on the footwall of a major fault (**Figure 35**). Closure to the northeast is by stratigraphic pinchout. The field was discovered in 2009 with the drilling of the Bravo-1 well which targeted an amplitude supported channel with an associated flatspot. The well intersected 16.4 m of net gas pay in the Cretaceous Lower Barrow Group Sands. The well was plugged and abandoned as a gas discovery. The field was appraised in 2011 with the drilling of Bravo-2 approximately 4.5 kms to the northeast along the crest of the structure. The structure extends beyond the WA-70-R lease boundary to the southwest. Both wells have a common GWC at -2,544 m TVDss as identified in the log data however pressure data suggests a shallower FWL at -2,540 m TVDss which suggests water has imbibed into the structure post charge.

The LBG reservoir at Bravo formed as turbidite lobes which filled antecedent topography. Two separate channels; Be5 and Be6 have been penetrated. The sands are supported by seismic amplitude anomalies, Bravo-2 was drilled beyond the extent of the seismic anomalies confirming that reservoir sands extend beyond the anomalous amplitudes.

Figure 35: Hess' LBG Depth Map and GCA's Gas Sand Probability map with Drilled and Planned Production Wells



10.2 Geology and Geophysics Review

GCA has reviewed the seismic interpretation and static model of the Bravo Field provided by Hess in the Bravo Petrel Project and in general considers both are reasonable. The top of the Cretaceous LBG reservoir is picked as a trough on the LBG Be5a Sand. Structural uncertainty is considered the greatest uncertainty of the Bravo Discovery. While the interpretation of top reservoir is defined by a reasonably consistent pick, the stratigraphic nature of closure which requires pinchout in the north, which has been picked arbitrarily leaves uncertainty over the GRV of the structure (the Hess arbitrary pick is less than the distance between Bravo-1 and 2 which extend beyond the amplitude anomalies). In the Hess Petrel model, it has included volumes to the northwest of the main bounding fault. GCA has reviewed this interpretation and considers it is reasonable (**Figure 36**). In seismic cross sections and depth maps, it appears likely that there is cross fault connectivity of the LBG interval via a fault relay ramp and so GCA feels it is reasonable to include these volumes in the estimate.

To generate a range of GRV inputs, Hess has undertaken Low and High Case seismic interpretations of the Bravo structure. GCA has reviewed these interpretations and consider they are a reasonable representation of the range of possible structural interpretations. For volumetric calculations, Hess has used these interpretations together with a GWC at -2,542 m TVDss established by a common pressure regime in both Bravo-1 and Bravo-2 wells. In its analysis GCA reviewed both the pressure data and log data and feels there is a small uncertainty over the GWC and has consequently applied a range of +/- 2 m.

GCA used its own depth conversion to further test the structural uncertainty. Each of Hess' interpretations was converted to time utilising the PSDM velocity cube, then back to depth using the GCA depth conversion. The GCA depth conversion has a significant impact on closure size as it has the effect of tilting the closure with the GCA depth map shallower in the southwest and deeper in the northeast which effectively cuts off the southwest extent of the field which could be considered a separate closure. GCA generated amplitude anomaly maps and notes that the GCA closure is supported by the amplitude extractions from the Gas Sand Probability cube (**Figure 37**). While the GCA GRV is smaller than the Hess estimate of GRV, it is important to note that the GRV reduction is all off block as the Hess interpretation extends beyond the block boundary and onto the adjacent WA-35-P block and this volume has been excluded from any profiles.

Figure 36: Seismic Strike Section across the Bravo Field

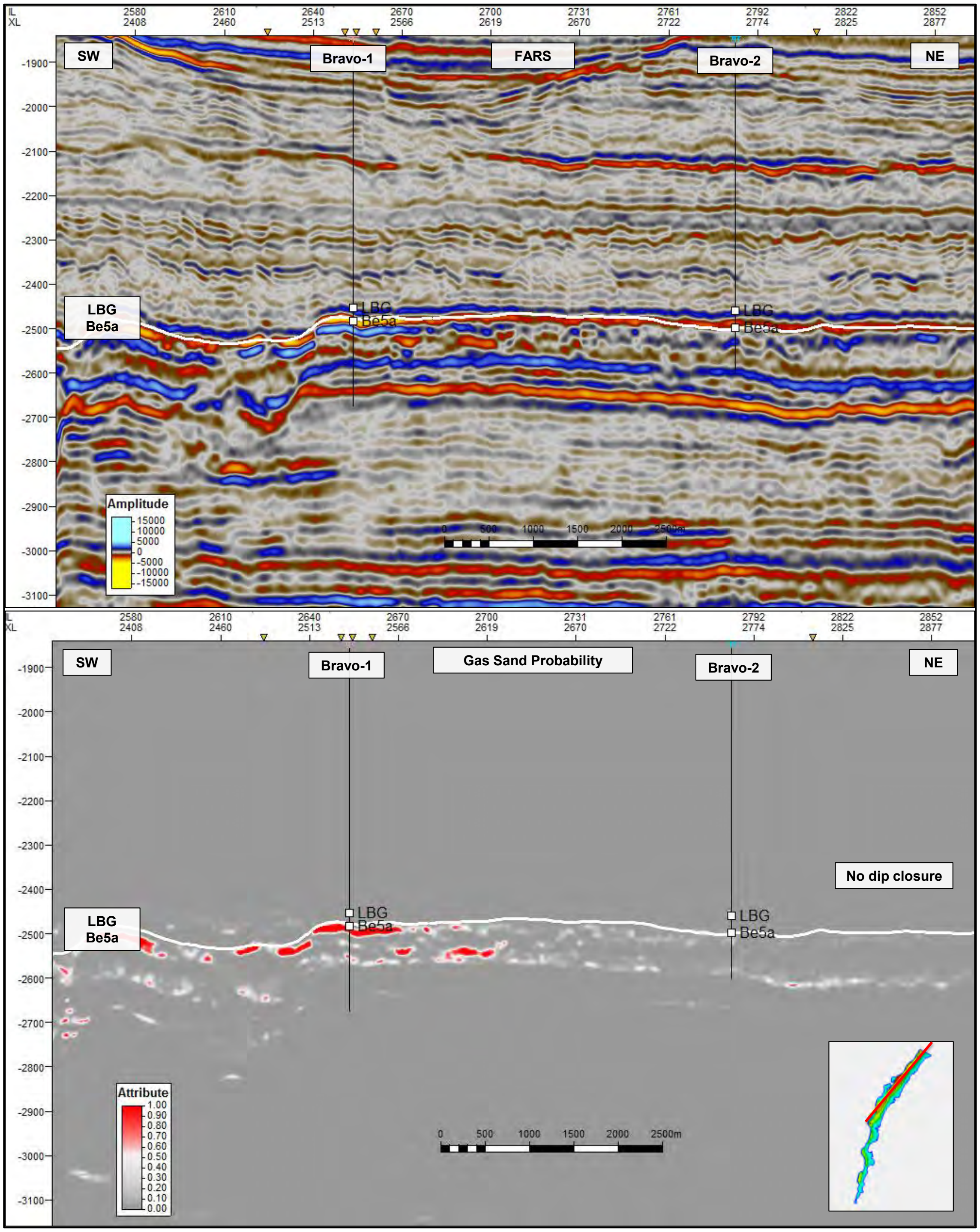
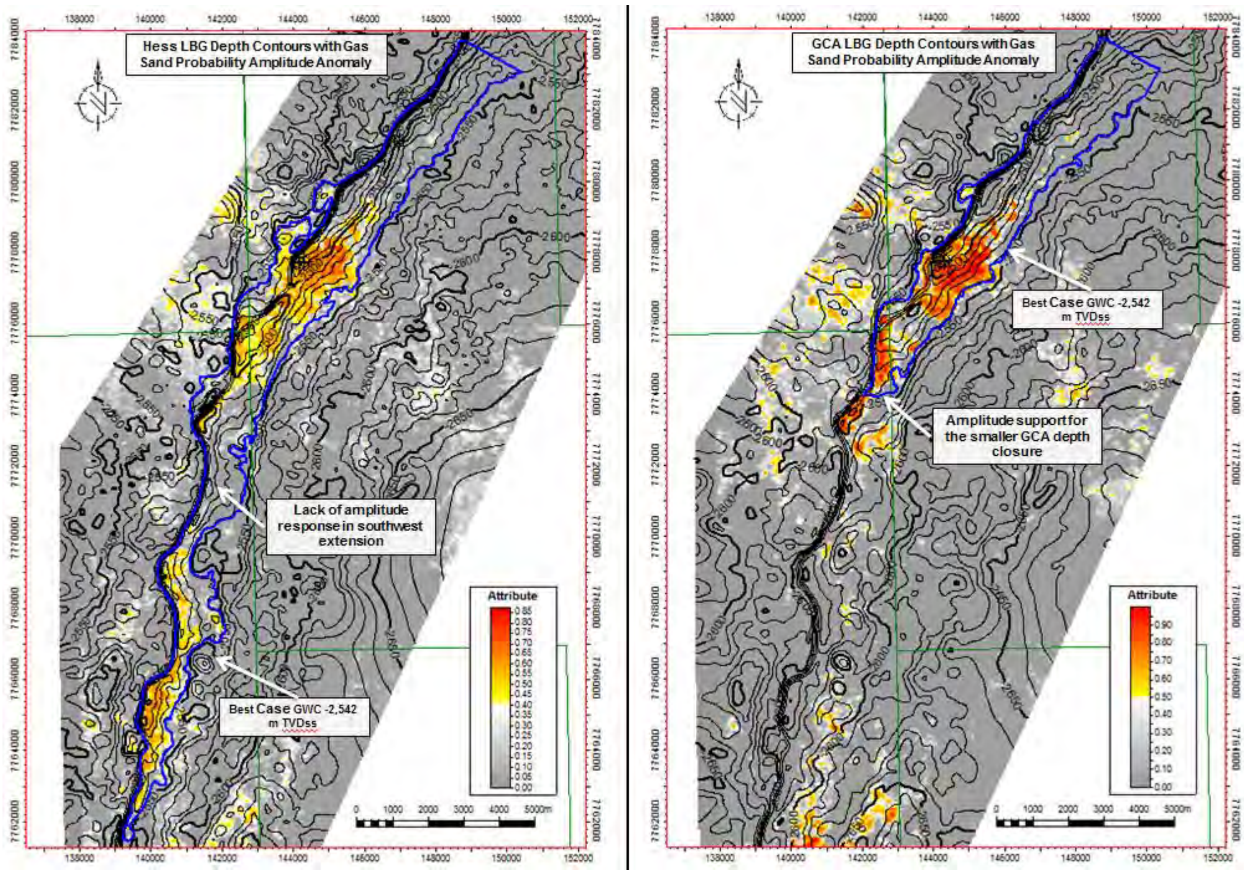


Figure 37: Hess and GCA Depth Contours with Gas Sand probability Amplitude Extractions



10.3 Engineering Review

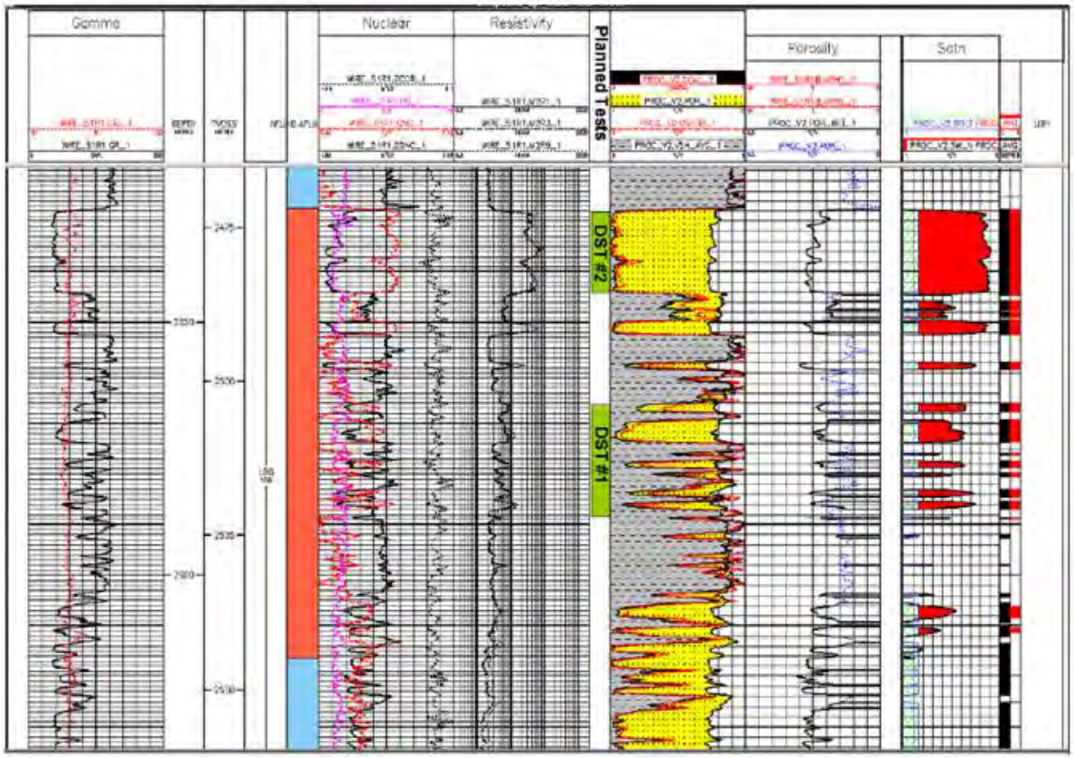
A total of 15 down-hole and surface samples were collected from the Bravo-1 well and the Rimfire-1 well at the Bravo level. The large number of samples from both down-hole and at the surface during flow testing provides a suitable data set to confirm fluid properties. Reservoir conditions at Bravo are at the dewpoint. Gas gravity has been measured at 0.7, with a gas expansion factor of 235 scf/rcf. The CO_2 concentration is low at 0.3% whilst the N_2 is 3.5%.

Condensate gas ratio (CGR) has been estimated from samples and recombination laboratory experiments. Due to some contamination in the down-hole samples, Hess has captured a range of 34 to 38 bbl/MMscf with a Best Case of 36 bbl/MMscf. This is the second highest CGR seen across the Equus fields. Laboratory testing has indicated a maximum liquid dropout in the reservoir of 3.5% with production, which should present no issues for near-wellbore condensate banking.

10.3.1 Well Tests

The Bravo Cretaceous reservoir was tested by the Rimfire-1 well. Two tests were conducted over the different quality reservoir intervals to test the deliverability of lower quality Be4b and higher quality Be5a reservoir sections. The DST intervals are shown with the Rimfire-1 petrophysical logs across the Bravo field Cretaceous reservoir section in **Figure 38**.

Figure 38: Bravo Field (Rimfire-1) Petrophysical Logs with DST Intervals



DST1 was tested over the lower quality reservoir interval of 2,532 to 2,550 m TVDRT on the 9 January 2011 to 18 January 2011. The test included an initial clean up flow period followed by a shut-in. Subsequently a multi-rate test was conducted with a maximum raw gas rate of 39 MMscf/d with a minimal drawdown of 350 psi. The pressure build-up period after the multi-rate test was over an extended period of 7 days due to the drill rig ceasing regular operations for Cyclone Vince.

DST2 was tested across the higher quality reservoir interval of 2,501 to 2,514 m TVDRT on the 6 February 2011 to 14 February 2011. The test also included an initial clean up flow period followed by a shut-in. The main flow period flowed gas at 42 MMscf/d, and was followed by a 131 hour pressure build up shut-in.

The pressure build-up periods for both DSTs were interpreted using Pressure Transient Analysis (PTA). The lower interval was interpreted as a dual-permeability system with permeability of 60 mD and 160 mD. Faults or boundaries were seen in the late time pressure derivative curve, which correspond to the structure of the field. The upper interval DST interpreted permeability of 1,200 mD with similar boundaries as DST1. The permeability interpretations from the DSTs match the petrophysical log interpretations of permeability.

High well deliverability has been proved by the DSTs and development well productivity is expected to be extremely high.

10.3.2 Development Plan

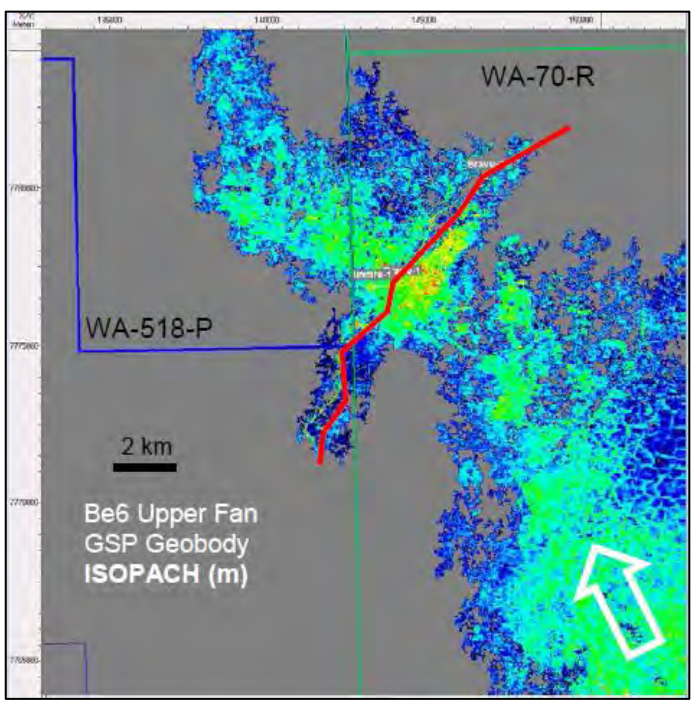
The Bravo field is included as part of the Equus Project Phase 2 development to accelerate condensate production, maximize deliverability and defer flowline CAPEX. Under this plan, the wells are scheduled to be drilled in 2027 and come online in 2028. The development plan includes 2 horizontal development wells in crestal locations to maximize the stand-off from the GWC. One horizontal well will be placed in the Be5 sand package, approximately 2 km to the south-west of Bravo-1 well. The other horizontal well will be placed in the Be6 sand close to the Bravo-1 well location. The two wells will be placed in the two different sand packages to access the highest in-place volumes across the reservoir, as shown in **Figure 35**. The two wells will be tied back to the Equus Floating Production System (FPS) facility via a 10 inch flowline.

10.3.3 Recovery Factor

Hess assessed the deliverability and recovery of gas and condensate from the Bravo field using reservoir simulation and analogue data. GCA has deemed this as approach as reasonable.

The Bravo reservoir is part of the Lower Barrow Group with the depositional environment a stacked succession of channelized sand lobes. Geo-body mapping shows that the sand systems in the both the Be5 and Be6 sands (**Figure 39**) extend to the south-east, suggesting that the Bravo field is connected to a significant water volume in this direction. Hess has therefore interpreted that the Bravo field will be supported by a medium to strong aquifer and the main depletion mechanism will be aquifer drive. For a gas reservoir with strong aquifer drive, recovery is typically determined by water breakthrough and subsequent water cut increase at the wells.

Figure 39: Kangaroo Syncline Regional Aquifer



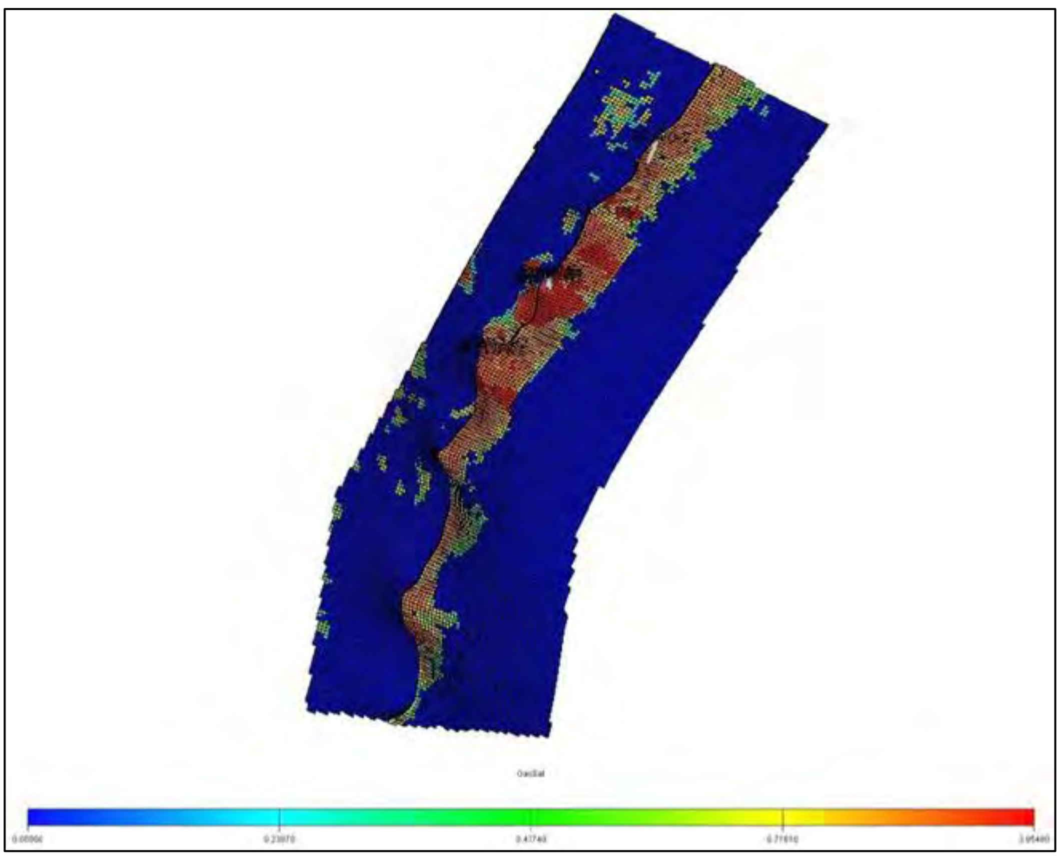
Source: Hess

As stated in the Nimblefoot Field section, there are no Lower Barrow group basin-floor fan analogues in the area for gas field developments. Hess has identified some Upper Barrow Group fields in the Carnarvon Basin with similar properties. These fields are the same fields stated in the Nimblefoot section and include:

- John Brookes Field – approximately 80% recovery factor
- Halyard Field – 59% to 71% recovery factor
- Campbell/Sinbad Field – 59% to 73% recovery factor.

Hess ran a number of dynamic simulation cases in order to quantify the uncertainty contributing to gas recovery at the Bravo Field. The methodology that Hess followed was to generate a number of models based on different subsurface realisations by varying static and dynamic model properties. By running the different simulation model realisations, Hess was able to generate an S-curve of estimated ultimate recovery (EUR) outcomes. The recovery factor range derived from the simulation uncertainty modelling was 34% to 68%, with the proposed development case achieving a recovery factor of 41%. **Figure 40** shows the deterministic model associated with the 41% recovery factor case.

Figure 40: Bravo Field Deterministic Best Case Simulation Model



The Bravo Field gas recovery factor range proposed by Hess is 40%, 50% and 60% for the Low, Best and High Cases, respectively. This recovery factor range is low when compared to the analogue fields, but the development deterministic simulation case recovery factor of 41% lies nearer the Low Case in the Hess recovery factor range. GCA has deemed the recovery factor range for Bravo as reasonable based on the variable reservoir quality in stacked sands, expected strong aquifer and subsea tieback development.

10.4 Resource Estimate

The GIIP and Contingent Resources for the Bravo Field were estimated using a 1D Monte Carlo Model. Reservoir parameter inputs are based on the sums and averages calculated from GCA's petrophysical interpretation. For its GRV inputs into the calculation, GCA has used P90 and P50 GRVs calculated from LBG depth maps made using the GCA depth conversion. These were chosen due to the amplitude support provided by the Gas Sand Probability cube. For the P10 GRV, the Hess High Case interpretation which includes the southwest extension was used. GCA's input parameters into its 1D Monte Carlo Model, together with the resulting GIIP estimates, are given in **Table 28**.

Gas GIIP and Contingent Resources are given in **Table 29** and **Table 30** and associated Condensate Contingent Resources are summarized in **Table 31** and have both been calculated for full field and on block by GCA. Only on block volumes have been included in production profiles and below.

Table 28: GCA's Input Parameters for its Estimate of GIIP for the Bravo Field

Reservoir	Parameter	Unit	P90	P50	P10
LBG	Contact	m TVDss	-2,540	-2,542	-2,544
	GRV	MM m^3	326	415	738
	NTG	Decimal	0.200	0.450	0.700
	Porosity	Decimal	0.225	0.245	0.265
	Sg	Decimal	0.608	0.698	0.788
	Gas Expansion Factor	1/Bg	234.0	235.0	236.0
	Condensate Yield	Stb/MM scf	34.00	36.00	38.00
	Recovery Factor	Decimal	0.400	0.500	0.600
	GIIP – Full Field	**Bscf**	**119**	**275**	**541**
	GIIP – On Block	**Bscf**	**110**	**248**	**426**

Note: This estimate of GIIP is based on a probabilistic methodology using GCA's 1D Monte Carlo Model.

Table 29: GCA's Estimate of GIIP for the Bravo Field

Reservoir	On Block GIIP (Bscf)		
	Low	Best	High
LBG	155	261	369

Note: This estimate of GIIP is based on GCA's total project GIIP volumes which were derived by calculating the average between a full arithmetic and probabilistic addition of individual field volumes to account for unknown dependencies between the fields. The average Low, Best and High Network case profiles were allocated to each field by proportionally scaling each individual field P90, P50 and P10 case to the respective average Network case profile.

Table 30: GCA's Estimate of Gas Contingent Resources for the Bravo Field

Reservoir	On Block Contingent Resources (Bscf)		
	1C	2C	3C
LBG	76	128	186

Table 31: GCA's Estimate of Condensate Contingent Resources for the Bravo Field

Reservoir	On Block Contingent Resources (MMBbl)		
	1C	2C	3C
LBG	2.4	4.9	6.7

10.5 Production Forecasts

The Hess Best Case raw gas production forecast is a deterministic case from simulation modeling that matches the 50% recovery factor. The associated condensate production has been forecast based on a modeled CGR versus reservoir pressure relationship. There is only minor reservoir pressure decline due to the strong aquifer so the CGR shows little decline over field life.

GCA has accepted the Hess Low, Best and High Case gas recovery factor range. GCA modified the Hess deterministic Best Case forecast for raw gas to match the Low, Best and High Case EUR consistent with the Hess gas recovery factor range. The associated condensate production was forecast based on the same CGR versus reservoir pressure relationship as the Hess forecast.

The GCA production forecasts for raw gas and condensate for the Bravo Field are shown in **Figure 41** and **Figure 42**.

Figure 41: Bravo Field Raw Gas Production Forecasts

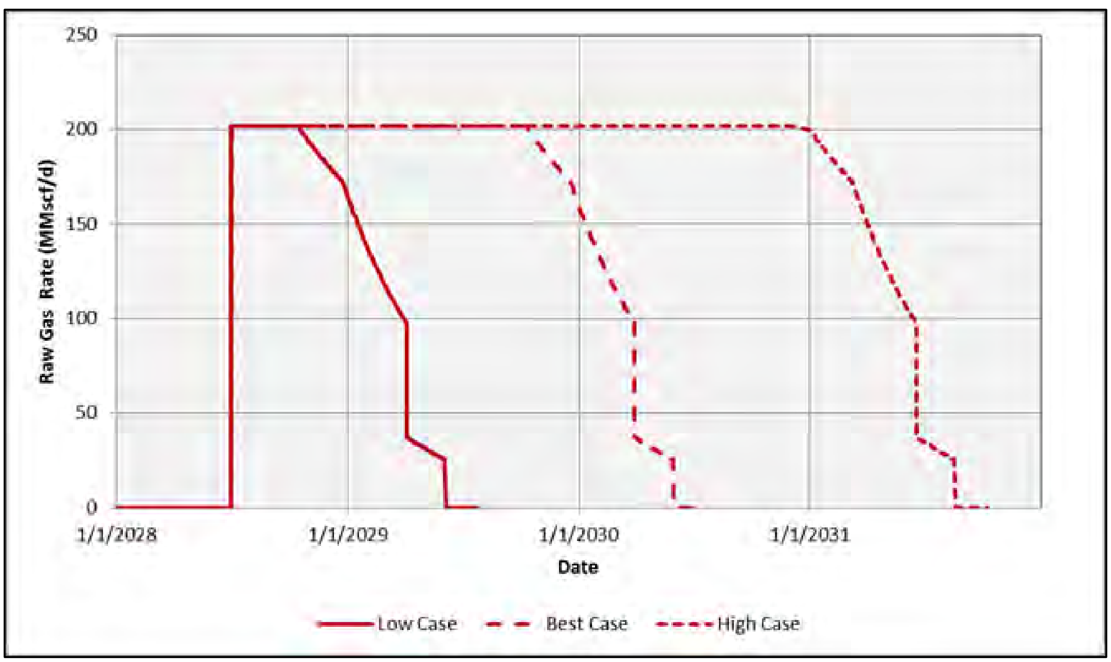
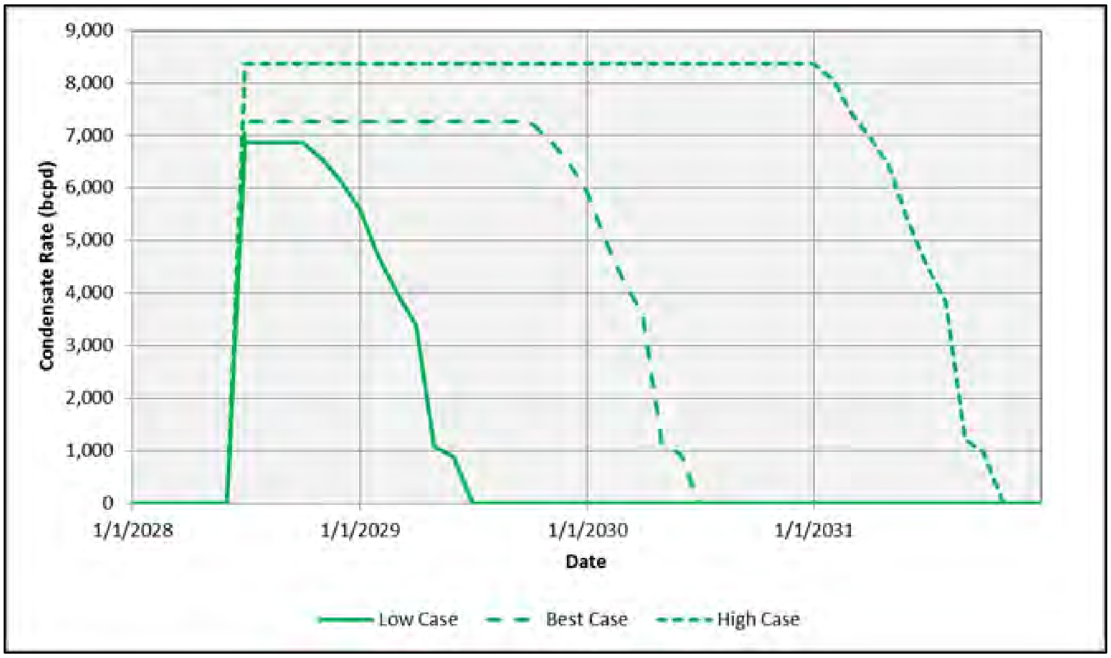


Figure 42: Bravo Field Condensate Production Forecasts



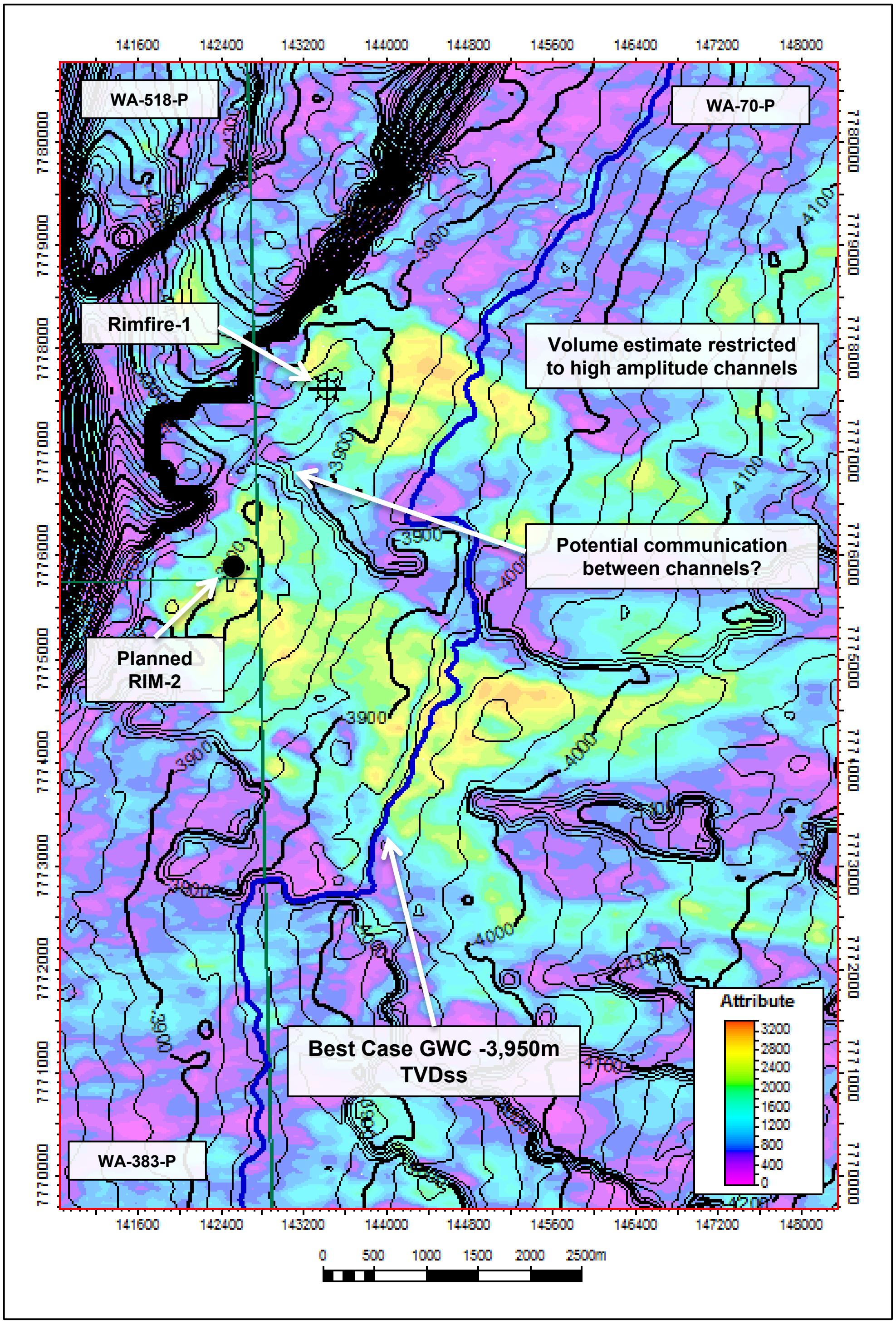
11 Rimfire Discovery

11.1 Field Summary

The Rimfire Field, located in the WA-70-R lease was discovered by the drilling of the deviated Rimfire-1 exploration well which was drilled as a sidetrack of the Bravo-1 wellbore in 2009. The well was drilled to target a northeast – southwest trending three-way fault and dip closed structure which dips to the south east (**Figure 43**). The well reached a total depth of 4,726 m MDRT in the Triassic Mungaroo Formation after intersecting a total of 90.74 m net gas pay in the Mungaroo Formation in two reservoir intervals; the Norian-100 and Carnian-400. The well also intersected 27.4 m net gas pay in the Lower Barrow Group. The well was plugged and abandoned as a gas discovery.

The Rimfire structure is formed of a combination structural and stratigraphic trap which has three-way dip closure combined with channel margin pinchout. The structure was defined by a stacked series of far offset seismic blooms in the footwall of a major northeast-southwest trending half graben fault. The Triassic Mungaroo reservoirs penetrated by the well were deposited as a series of northwest – southeast and northeast – southwest trending incised channels and distributor channels deposited across a delta plain. The structure is sealed by the Late Triassic, Rhaetian argillaceous calcilutites and claystones. Intra-formational seals are provided by Triassic Mungaroo claystones. Juxtaposition of Triassic sealing shales in the hanging wall, against Triassic footwall sands provide lateral fault seal.

Figure 43: Norian 100 Depth Contours with Gas Sand Probability RMS Amplitude Extraction with Drilled and Planned Production Wells



11.2 Geology and Geophysics Review

GCA has reviewed the seismic interpretation of the Rimfire Field provided by Hess in the Bravo Petrel Project and in general believes both are reasonable. Multiple gas sands were penetrated by the Rimfire-1 Well over a 2,000 m interval and various seismic responses are seen.

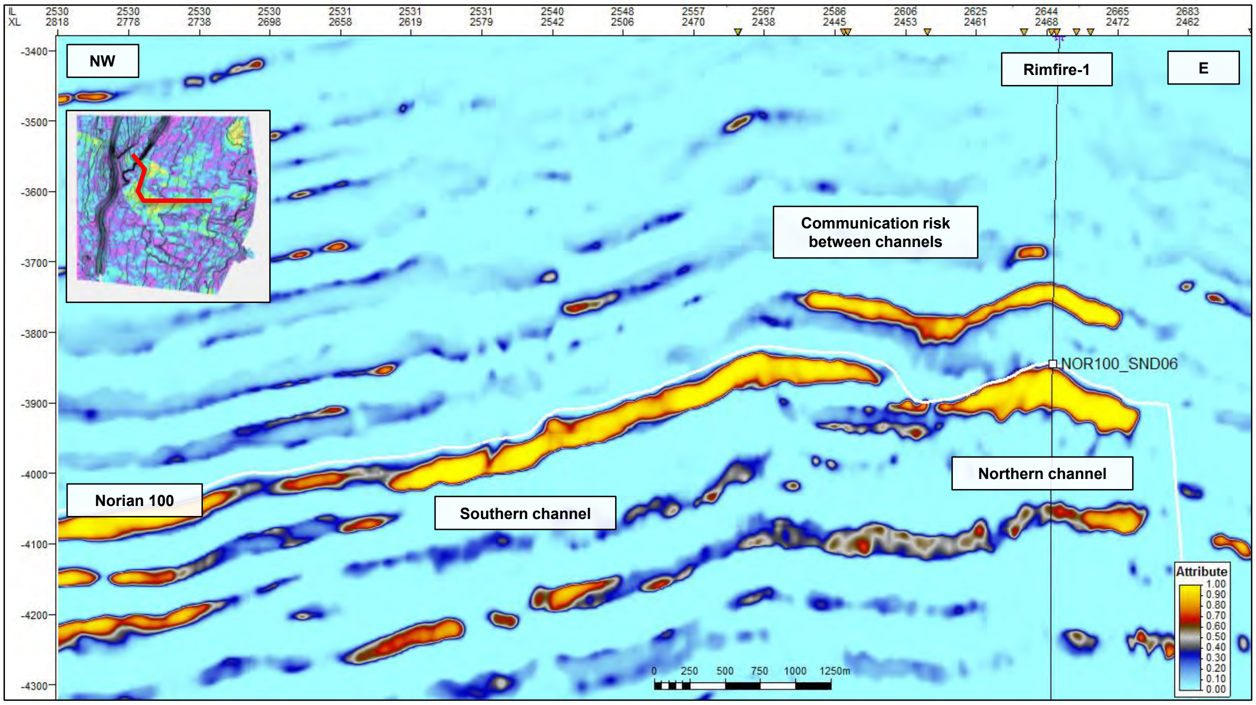
The Norian 100 structural pick is defined by a trough within a fairly low amplitude package. The surface gives a strong Gas Sand Probability response which has allowed the mapping of the Norian 100 geo-body upon which Hess has based its volumetric estimate. Closure is purely stratigraphic with no structural closure mapped. Amplitude extraction maps suggest that there are two main channels within the geo-body, only the northern one of which has been penetrated by the Rimfire-1 Well. The amplitude maps do appear to show connectivity between the two channels however this remains an uncertainty and consequently the connected GRV of the structure is the greatest uncertainty. No clear FWL in the Norian 100 is evident from pressure data. Hess calculated a GDT of -3,905 m TVDss in its log analysis. The GCA petrophysical interpretation suggested the GDT is shallower at -3,890 m TVDss. Hess' attribute analysis using the Fluid Factor and Absolute P Impedance seismic volumes suggests the possibility of a deeper contact at -3,991 m TVDss (**Figure 44**).

The Carnian 400 is also picked on a trough. Unlike the Norian 100, the Carnian 400 has a weak Gas sand Probability response although this does improve slightly updip of the well penetration. The weak response is attributed to low porosity seen in the Rimfire Carnian Sands. A good Inverse Shale Probability response is seen at the Carnian 400 and consequently Hess has mapped the channel geobody based on this seismic volume using a 0% shale cut-off. Tests using higher shale cut-offs of 3.5% show that the Carnian channel could be larger than the one mapped by Hess. In addition to uncertainty over channel extent, no GWC has been penetrated in the Carnian at Rimfire. Hess has used contact ranges based on capillary pressure data, seismic attributes and the regional Mungaroo formation water pressure to estimate a range of contacts. GCA has in addition carried out its own review of contacts and has estimated a slightly shallower GDT than Hess based on its petrophysical analysis.

Hess provided GCA with a single Base case interpretation of each of the Norian 100 and Carnian 400 reservoir surfaces and has used contact range and areal polygons limiting closure to the picked channel geobodies to provide a range in GRV. GCA has similarly limited its GRV calculation to the channel geobody areas and has applied its own estimates of contacts.

GCA used its own depth conversion to further test the structural uncertainty. Each of Hess' interpretations was converted to time using the PSDM velocity cube, then back to depth using the GCA depth conversion. For both the Norian 100 and Carnian 400, the GCA depth conversion resulted in slightly lower GRVs than the Hess depth surfaces.

Figure 44: Arbitrary Line Across the Rimfire Field



11.3 Engineering Review

A total of 8 down-hole samples were collected from the Rimfire-1 well across the Norian reservoir sands. No fluid samples were collected from the Carnian-400 reservoir zone. The sampling tool used in the Rimfire-1 well was the RCI tool, and samples from this well all suffered contamination from OBM used during drilling.

Gas gravity for the Norian-100 reservoir has been measured at 0.7, with a gas expansion factor of 269 scf/rcf. The CO_2 concentration is low at 1.5% whilst the N_2 is the approximately 3.0%. CGR has been estimated from samples and recombination laboratory experiments to be 26 bbl/MMscf. Similar to the other Equus reservoirs there should be no issues for near-wellbore condensate banking due to liquid drop out.

Reservoir fluid properties for the Carnian-400 reservoir zone have been estimated based on properties seen in the Carnian-300 at the Glenloth-1 well.

11.3.1 Well Tests

No well tests were performed on the Rimfire-1 well in the Carnian and Norian reservoirs. However, well tests have been performed on other fields which have the same reservoirs as the Rimfire Feld. Well tests have been performed on wells in the Triassic Norian (Chester Field) and Triassic Carnian (Glenloth Field) across the Equus Fields.

The Triassic Norian reservoir was tested by the Chester-1ST1 well in the Norian-700 reservoir unit. The well also produced at high flow rates with low drawdown pressures. The Norian-700 is not planned to be developed in the Rimfire Field but is deemed to be a reasonable analogue for other units within the Triassic Norian, in this case, the Rimfire Field Norian-100.

The Triassic Carnian reservoir was tested by the Glenloth-1 well. The well tested an interval over the Carnian-300 reservoir unit. The test supports the estimated flow rates for the Rimfire development well for the Carnian-400 reservoir sands.

11.3.2 Development Plan

The Norian-100 and Carnian-400 zones of the Rimfire Field are considered for development in Phase 3 of the Equus Project. The development plan includes 2 low-inclination development wells in crestal locations to maximize the stand-off from the GWC as shown in **Figure 43**.

The RIM-1 well will be completed in the Carnian-400 reservoir, whilst the RIM-2 will produced from the Norian-100 reservoir. Under the Equus Project plan, the wells are scheduled be drilled in 2031 and come online in 2032. The wells will be tied back to the Equus FPS facility via a 10 inch flowline shared with the Nimblefoot and the Bravo Fields, and the Gaulus prospect.

11.3.3 Recovery Factor

Hess assessed the deliverability and recovery of gas and condensate from the Rimfire Field using analogue data. GCA has deemed this as approach as reasonable.

The Rimfire Triassic reservoirs are combined structural and stratigraphic traps. The lateral extent of the reservoir is limited by faulting and the depositional environment. This prevents connection to any large, regional aquifer and the reservoir drive mechanism is expected to be depletion drive with minimal water influx. For a gas reservoir with depletion drive, recovery is typically determined by minimum inlet pressure at the production facility, in this case the Equus FPS. The recovery can be lower dependent on the reservoir complexity, reservoir quality and number of reservoir zones.

Hess has based recovery factors on the same Mungaroo analogues cited in previous sections. These recovery factors are consistent with the recovery factors estimated by Hess for other Norian and Carnian reservoirs in the Equus Fields. The Rimfire Field gas recovery factor range for Norian reservoirs proposed by Hess is 55%, 65% and 75% for the Low, Best and High Cases, respectively. For the deeper Carnian reservoirs the range proposed is 55%, 60% and 65%. These recovery factor ranges are consistent with what GCA would expect from a stacked reservoir sand, depletion drive gas field developed using vertical wells via a subsea tieback development.

11.4 Resource Estimate

The GIIP and Contingent Resources for the Rimfire Field were estimated using a 1D Monte Carlo Model. Reservoir parameter inputs are based on the sums and averages calculated from GCA's petrophysical interpretation. The P90 GRV was based on GCA's depth converted surfaces for both the Norian 100 and Carnian 400 to account for the reduction in GRV calculated when using GCA's depth surfaces. For the P50 and P10 GRV inputs, the Hess depth converted surfaces were accepted.

The Rimfire Field lies in the west of the WA-70-R block and closure extends beyond the block boundary into the adjacent WA-383-P Block at the Norian 100 level. GCA's input parameters into its 1D Monte Carlo Model, together with the resulting GIIP estimates, are given in **Table 32**.

GCA has estimated GIIP for both full field and on block volumes of the Rimfire Field, with on block volumes given in **Table 33**. Similarly Gas Contingent Resources are given in **Table 34** and associated Condensate Contingent Resources are summarized in **Table 35**. Only on block volumes have been included in production profiles and below.

Table 32: GCA's Input Parameters for its Estimate of GIIP for the Rimfire Field

Reservoir	Parameter	Unit	P90	P50	P10
Norian 100	Contact	m TVDss	-3,890	-3,950	-3,991
	GRV	MM m^3	198	467	648
	NTG	Decimal	0.400	0.500	0.600
	Porosity	Decimal	0.090	0.130	0.170
	Sg	Decimal	0.461	0.520	0.579
	Gas Expansion Factor	1/Bg	265.0	268.5	272.0
	Condensate Yield	Stb/MM scf	19.4	21.4	23.4
	Recovery Factor	Decimal	0.55	0.65	0.75
	GIIP – Full Field	**Bscf**	**55**	**128**	**231**
	GIIP – On Block	**Bscf**	**36**	**117**	**203**
Carnian 400	Contact	m TVDss	-4,410	-4,475	-4,741
	GRV	MM m3	586	933	2,701
	NTG	Decimal	0.150	0.250	0.350
	Porosity	Decimal	0.075	0.115	0.155
	Sg	Decimal	0.450	0.500	0.550
	Gas Expansion Factor	1/Bg	288.6	292.0	295.4
	Condensate Yield	Stb/MM scf	3.8	4.8	5.8
	Recovery Factor	Decimal	0.55	0.65	0.75
	GIIP – Full Field	**Bscf**	**59**	**137**	**408**
	GIIP – On Block	**Bscf**	**60**	**137**	**408**

Note: This estimate of GIIP is based on a probabilistic methodology using GCA's 1D Monte Carlo Model.

Table 33: GCA's Estimate of GIIP for the Rimfire Field

Reservoir	On Block GIIP (Bscf)		
	Low	Best	High
Norian 100	50	124	176
Carnian 400	84	146	368

Note: This estimate of GIIP is based on GCA's total project GIIP volumes which were derived by calculating the average between a full arithmetic and probabilistic addition of individual field volumes to account for unknown dependencies between the fields. The average Low, Best and High Network case profiles were allocated to each field by proportionally scaling each individual field P90, P50 and P10 case to the respective average Network case profile.

Table 34: GCA's Estimate of Gas Contingent Resources for the Rimfire Field

Reservoir	On Block Contingent Resources (Bscf)		
	1C	2C	3C
Norian 100	33	79	115
Carnian 400	51	94	227

Table 35: GCA's Estimate of Condensate Contingent Resources for the Rimfire Field

Reservoir	On Block Contingent Resources (MMBbl)		
	1C	2C	3C
Norian 100	0.9	1.7	3.5
Carnian 400	0.3	0.4	1.6

11.5 Production Forecasts

Hess generated production forecasts for the Norian-100 and Carnian-400 reservoirs. The Hess Best Case raw gas production forecasts are based on production profiles from the other Equus fields from the corresponding reservoirs that match the 65% recovery factor in both the Norian & Carnian reservoirs. The associated condensate production has been forecast based on a modeled CGR versus reservoir pressure relationship. GCA has accepted the Hess Best Case forecasts for raw gas and condensate. GCA generated Low and High Cases based on the Best Case profile but scaled for the Low and High Case GIIP estimates.

The GCA discovered production forecasts for raw gas and condensate for the Rimfire Field are shown in **Figure 45** and **Figure 46**.

Figure 45: Rimfire Field Raw Gas Production Forecasts

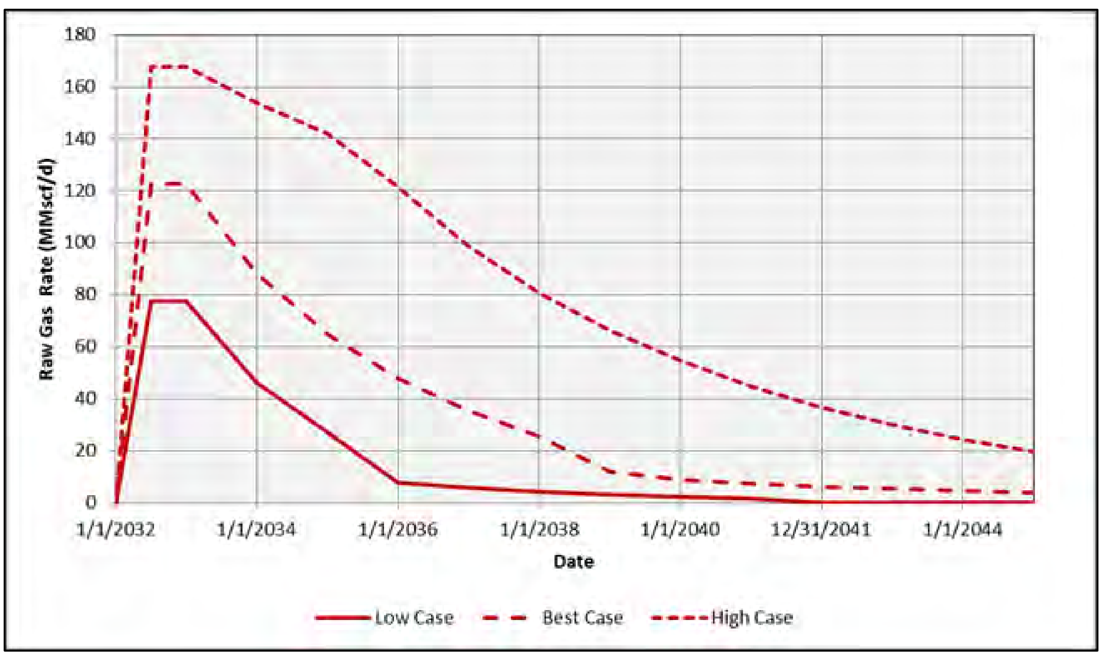
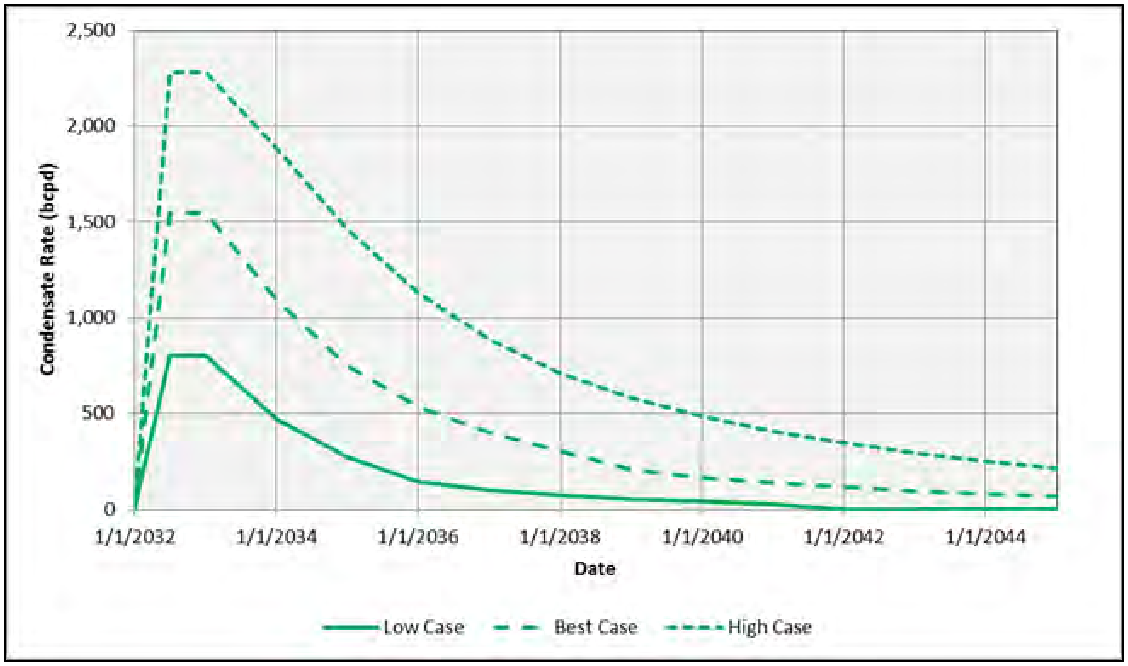


Figure 46: Rimfire Field Condensate Production Forecasts



12 Brisies Discovery

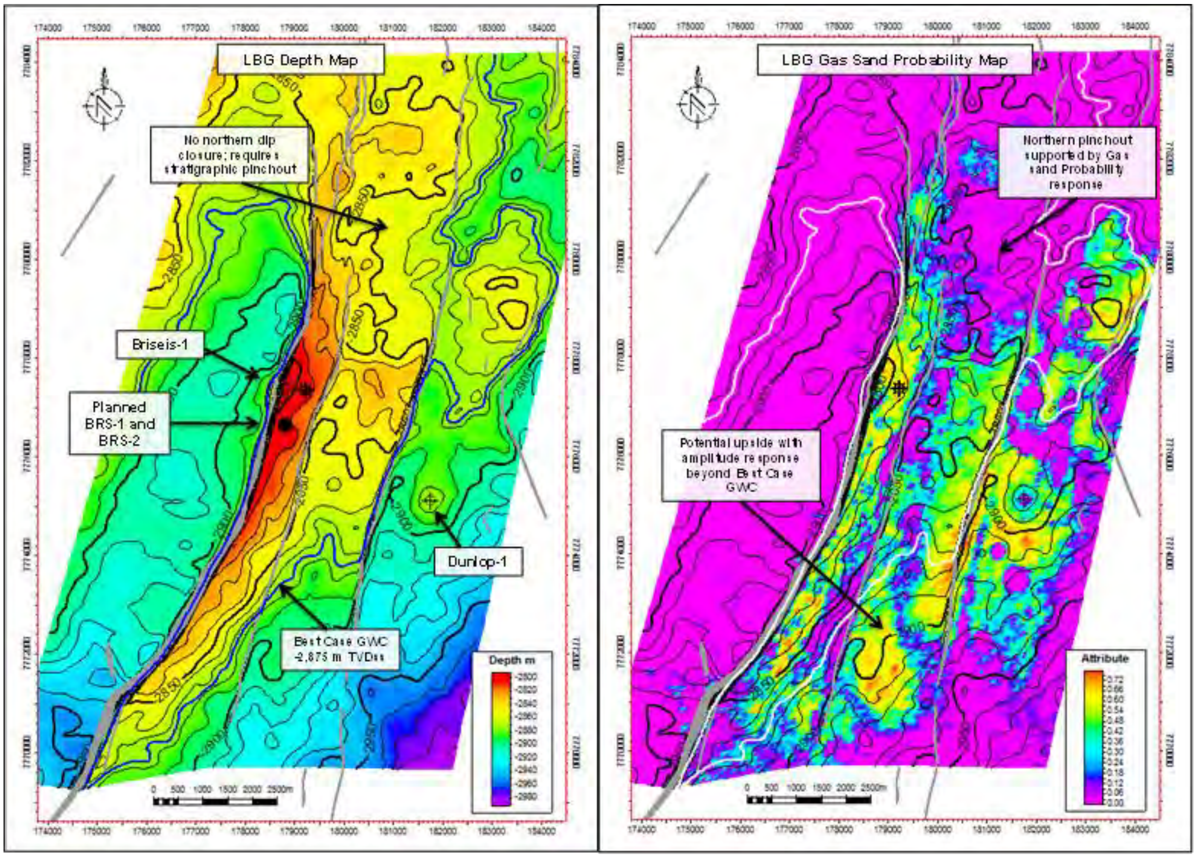
12.1 Field Summary

The Briseis Field was discovered with the drilling of the vertical Briseis-1 exploration well in 2008 which was drilled to target Jurassic Lower Dingo and Triassic Mungaroo sands. The structure is formed of a northeast-southwest trending three-way dip closure dipping to the east. The primary target was a well-defined seismic amplitude anomaly in the Jurassic which was a combination of a structural and stratigraphic trap (**Figure 47**). The Triassic Mungaroo was a secondary target.

The well reached a total depth of 3,554 m MDRT and intersected 4.9 m net gas pay in the Cretaceous Barrow Sand and 309.5 m of net gas pay in the Mungaroo. The well was plugged and abandoned as a gas discovery after 29.9 m of core was cut from the Biseis-1 CH1 sidetrack.

The Briseis closure requires stratigraphic pinchout to the north and south and is defined by a strong amplitude anomaly with Type III AVO. The Lower Barrow Group sand unit reservoir was deposited in a deltaic environment and is mapped as an elongate northeast – southwest trending sand body. The Mungaroo sands were deposited in a fluvial deltaic environment and are mapped as a complex of amalgamated channel sands. The top seal for the Briseis structure comprises marine shales of the Barrow Group. Intraformational seals result in a stacked pay system. The main kitchen for the Briseis Field lies to the south in the Exmouth Sub-basin where the source rock consists of terrestrial carbonaceous shales and coles of the Mungaroo Formation. Migration and charging began in the Upper Cretaceous and has continued through the Tertiary until present times.

Figure 47: Hess' LBG Depth Map and Gas Sand Probability Map with Drilled and Planned Production Wells



12.2 Geology and Geophysics Review

GCA has reviewed the seismic interpretation of the Briseis Field provided by Hess in the Briseis Petrel Project and in general considers it is reasonable (**Figure 48**).

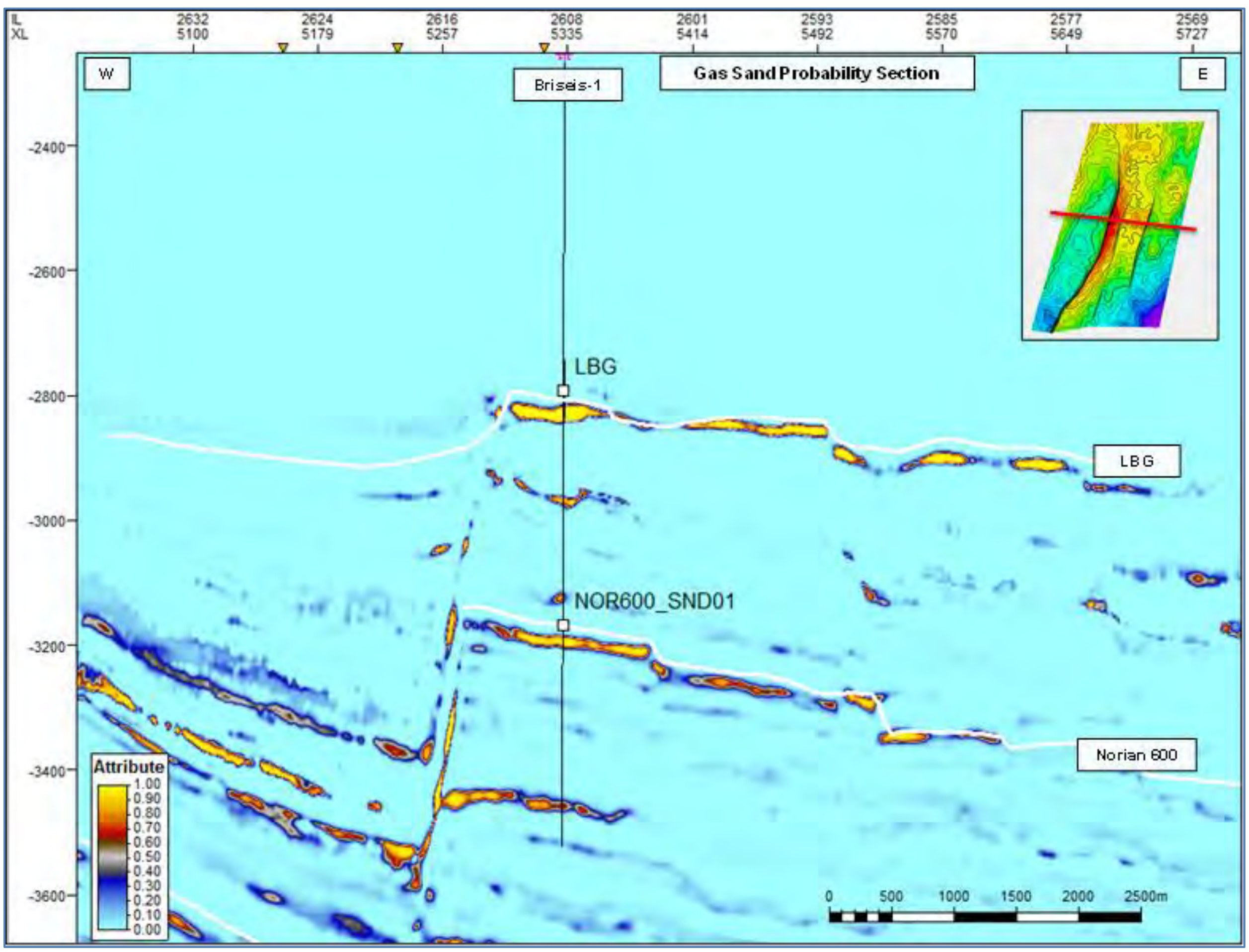
The Briseis well penetrated good quality LBG sandstones which was deposited as a deepwater turbidite fan and is overlain by poorer quality, non-reservoir sands which are in turn overlain by a thick Muderong Shale top seal. The LBG reservoir surface is picked on a zero crossing between an overlying peak and an underlying trough and is marked by a strong Gas sand Probability response. No GWC was penetrated in the LBG and Hess has estimated contacts using the gas gradient and Norian 700/800 water gradient. Hess' estimates give a 45 m range in uncertainty. GCA has reviewed Hess' contacts and while it agrees with the P50 and P10 contacts, GCA has used the GDT seen in Briseis-1 as its P90. The closure at the LBG interval is formed of a relatively flat structure and the uncertainty over the GWC means that the GRV is the largest uncertainty.

The Triassic Mungaroo Norian 600 reservoir at Briseis was deposited as a thick fluvial deltaic section. The surface is picked on a peak and is characterised by a strong Gas sand Probability response. Mapping of the areal extent of the reservoir is determined by the gas sand response which appears to dim or shut off at faults suggesting fault seal. Closure to the south is determined by a channel shaped body which is interpreted to be shale filled and consequently sealing. As with the LBG reservoir, no GWC has been penetrated in the Norian 600. Hess has estimated contacts using the Norian 600 gas gradient and the Norian 700/800 water gradient. GCA has reviewed the contacts used by Hess, which give a 14 m range in uncertainty and consider them to be reasonable.

Hess provided GCA with Low, Base and High Case interpretations of each of the reservoir intervals and has used contact range and areal polygons limiting closure to the picked channel geobodies to provide a range in GRV. GCA has similarly limited its GRV calculation to the channel geobody areas and has applied its own estimates of contacts where appropriate.

GCA used its own depth conversion to further test the structural uncertainty. Each of Hess' interpretations was converted to time using the PSDM velocity cube, then back to depth using the GCA depth conversion. For both the LBG and Norian 600, the GCA depth conversion resulted in higher GRVs than the Hess depth surfaces.

Figure 48: Seismic Dip Section across the Briseis Field



12.3 Engineering Review

A total of 8 down-hole and surface samples were collected from the Briseis-1 well. 4 of these samples were down-hole samples from the Triassic Norian-600 reservoir zone, and 4 of these samples were down-hole samples from the Cretaceous Lower Barrow Group reservoir zone. There was some contamination from OBM, but compositions were generally consistent across the samples from each reservoir zone.

Gas gravity for both the Norian-600 and Cretaceous zones has been measured at 0.7. The gas expansion factor in the Norian-600 zone was estimated to be 254 scf/rcf, whilst it was estimated to be 243 scf/rcf in the Cretaceous zone. The CO_2 concentration for the Norian-600 zone is low at 1.5% whilst the N_2 is approximately 1.1%. For the Cretaceous zone, the CO_2 and N_2 concentrations are approximately 0.9% and 1.3%, respectively.

CGR has been estimated from samples and recombination laboratory experiments. Hess has estimated a Best Case CGR for the Norian-600 of 17 bbl/MMscf, and a Cretaceous Best Case CGR was estimated to be 20 bbl/MMscf. A range has been applied to the Low and High Case CGR for the Norian zones to capture uncertainty seen in CGR across the various samples in the 2 zones. Laboratory testing has indicated a maximum liquid drop in the reservoir of less than 1% with production, which should present no issues for near-wellbore condensate banking.

12.3.1 Well Tests

No well tests were performed on the Briseis-1 well. However, well tests have been performed on other fields which have the same reservoirs as the Briseis field. Well tests have been performed on wells in the Cretaceous (Bravo Field), Triassic Norian (Chester Field) and Triassic Carnian (Glenloth Field) across the Equus Fields.

Two well tests were performed on the Cretaceous Barrow sands at the Rimfire-1 well on the Bravo field. The Bravo DST1 showed high deliverability and low drawdown pressure. The Bravo field exhibits the same reservoir quality as Briseis due to being a Lower Barrow Group basin floor fan.

The Triassic Norian reservoir was tested by the Chester-1ST1 well in the Norian-700 reservoir unit. The well also produced at high flow rates with low drawdown pressures. The Norian-700 is not planned to be developed in the Briseis Field but is deemed to be a reasonable analogue for other units within the Triassic Norian, in this case, the Briseis Field Norian-600.

12.3.2 Development Plan

The Briseis Field is being considered for development as part of Phase 3 of the Equus Project and will initially target the un-penetrated Carnian-300 and Carnian-400 zones. The development plan includes 2 low-inclination development wells in crestal locations to maximize the stand-off from the GWC as shown in **Figure 47**.

The BRS-1 and BRS-2 wells will be drilled and produced initially from the un-penetrated Briseis Deep Carnian reservoirs, in order to allow the wells to later be recompleted in shallower reservoirs. The wells are scheduled to be drilled in 2031 and come online in 2032. The wells will be tied back to the Equus FPS facility via a 10 inch flowline shared with the Glencoe and Glenloth Fields.

By 2037 the Briseis Deep Carnian-300 and Carnian-400 reservoirs are expected to be depleted. As part of the Equus Phase 4 and Phase 5 developments, the two Briseis production wells will be re-entered and completed in the Cretaceous and Norian-600 reservoirs. The BRS-1 well will be side-tracked as the BRS-1R horizontal well completed in the Cretaceous reservoir. The BRS-2 well will be recompleted in the Norian-600 reservoir as BRS-2R. Phase 4 and Phase 5 are scheduled to come online in 2037 and 2039, respectively.

12.3.3 Recovery Factor

Hess assessed the deliverability and recovery of gas and condensate from the Briseis Field using reservoir simulation and analogue data. GCA has deemed this as approach as reasonable.

The Briseis Triassic reservoirs are combined structural and stratigraphic traps. The lateral extent of the reservoir is limited by faulting and the depositional environment. This prevents connection to any large, regional aquifer and the reservoir drive mechanism is expected to be depletion drive with minimal water influx. For a gas reservoir with depletion drive, recovery is typically determined by minimum inlet pressure at the production facility, in this case the Equus FPS. The recovery can be lower dependent on the reservoir complexity, reservoir quality and number of reservoir zones.

The Briseis Cretaceous reservoir is part of the Lower Barrow Group with the depositional environment a stacked succession of channelized sand lobes. Hess has interpreted that this depositional environment will support a medium to strong aquifer and the main depletion mechanism will be aquifer drive. For a gas reservoir with strong aquifer drive, recovery is typically determined by water breakthrough and subsequent water cut increase at the wells.

Hess has identified the Pluto Field in the Carnarvon Basin development as an analogue for the Briseis Norian-600 reservoir. The Pluto Field is a Mungaroo Norian gas field, but with better reservoir quality. The expected recovery factor reported for the Pluto field is 60% to 80%. Other Mungaroo formation gas fields on the North West Shelf report a recovery factor of 60% to 65%.

As stated in the Nimblefoot and Bravo Field sections, there are no Lower Barrow group basin-floor fan analogues in the area for gas field developments. Hess has identified some Upper Barrow Group fields in the Carnarvon Basin with similar properties. These fields are the same fields previously stated and include:

- John Brookes Field – approximately 80% recovery factor
- Halyard Field – 59% to 71% recovery factor
- Campbell/Sinbad Field – 59% to 73% recovery factor.

There are no producing Carnian reservoir analogues in the Carnarvon Basin. However, due to similar reservoir quality and depositional environment, Carnian reservoir units are expected to have similar recovery factor ranges to the Norian reservoirs.

Hess ran a number of dynamic simulation cases in order to quantify the uncertainty contributing to gas recovery at the Briseis Field for the Norian-600 and the Cretaceous reservoirs. The methodology that Hess followed was to generate a number of models based on different subsurface realisations by varying static and dynamic model properties. By running the different simulation model realisations, Hess was able to generate an S-curve of estimated ultimate recovery (EUR) outcomes. The recovery factor range derived from the simulation uncertainty modelling for the Norian-600 was 40% to 80%, with the proposed development case achieving a recovery factor of 76%. For the Cretaceous the range was 42% to 72%, with the proposed development case achieving a recovery factor of 52%.

The Briseis field gas recovery factor range for the Norian-600 reservoir proposed by Hess is 55%, 65% and 75% for the Low, Best and High Cases, respectively. For the Cretaceous reservoir the range is 40%, 50% and 60%.

The recovery factor ranges for each reservoir are consistent with the ranges from simulation and analogue analysis. GCA has deemed the recovery factor range for the Cretaceous reservoir as reasonable based on the variable reservoir quality in stacked sands, expected strong aquifer and subsea tieback development.

12.4 Resource Estimate

The GIIP and Contingent Resources for the Briseis Field were estimated using a 1D Monte Carlo Model. Reservoir parameter inputs are based on the sums and averages calculated from GCA's petrophysical interpretation. The P90 and P50 GRVs were based on Hess' depth surfaces while for the P10, the GCA depth converted surface was used to allow for potential high side suggested by the increased GRV calculated using the GA depth conversion. GCA's input parameters into its 1D Monte Carlo Model, together with the resulting GIIP estimates, are given in **Table 36**.

GCA's estimates of GIIP of the Briseis Field are given in **Table 37**. Similarly Gas Contingent Resources are given in **Table 38** and associated Condensate Contingent Resources are summarized in **Table 39**.

Table 36: GCA's Input Parameters for its Estimate of GIIP for the Brisies Field

Reservoir	Parameter	Unit	P90	P50	P10
LBG	Contact	m TVDss	-2,837	-2,875	-2,890
	GRV	MM m^3	185	348	1,311
	NTG	Decimal	0.150	0.400	0.650
	Porosity	Decimal	0.083	0.103	0.123
	Sg	Decimal	0.480	0.510	0.540
	Gas Expansion Factor	1/Bg	231.0	243.0	255.0
	Condensate Yield	Stb/MM scf	15.0	20.0	25.0
	Recovery Factor	Decimal	0.40	0.50	0.60
	GIIP	**Bscf**	**22**	**63**	**249**
Norian 600	Contact	m TVDss	-3202	-3,210	-3,216
	GRV	MM m3	96	114	132
	NTG	Decimal	0.799	0.899	0.999
	Porosity	Decimal	0.185	0.225	0.265
	Sg	Decimal	0.569	0.678	0.782
	Gas Expansion Factor	1/Bg	250.0	253.5	257.0
	Condensate Yield	Stb/MM scf	15.3	15.5	15.7
	Recovery Factor	Decimal	0.55	0.65	0.75
	GIIP	**Bscf**	**98**	**135**	**181**

Note: This estimate of GIIP is based on a probabilistic methodology using GCA's 1D Monte Carlo Model.

Table 37: GCA's Estimate of GIIP for the Briseis Field

Reservoir	Low	Best	High
LBG	30	65	212
Norian 600	137	142	157

Note: This estimate of GIIP is based on GCA's total project GIIP volumes which were derived by calculating the average between a full arithmetic and probabilistic addition of individual field volumes to account for unknown dependencies between the fields. The average Low, Best and High Network case profiles were allocated to each field by proportionally scaling each individual field P90, P50 and P10 case to the respective average Network case profile.

Table 38: GCA's Estimate of Gas Contingent Resources for the Briseis Field

Reservoir	1C (Bscf)	2C (Bscf)	3C (Bscf)
LBG	14	33	107
Norian 600	87	92	103

Table 39: GCA's Estimate of Condensate Contingent Resources for the Briseis Field

Reservoir	1C (MMBbl)	2C (MMBbl)	3C (MMBbl)
LBG	0.3	0.7	2.4
Norian 600	1.4	1.5	1.8

12.5 Production Forecasts

Hess generated production forecasts for each of the Norian and Cretaceous reservoirs. The discovered Hess Best Case raw gas production forecasts for the Norian and Cretaceous reservoirs are deterministic cases from simulation modeling that matches the 65% and 50% recovery factors, respectively. The associated condensate production has been forecast based on a modeled CGR versus reservoir pressure relationship for each reservoir. GCA has accepted the Hess Best Case forecasts for raw gas and condensate. GCA generated Low and High Cases based on the Best Case profile but scaled for the Low and High Case GIIP estimates. These Cases are similar to deterministic simulation cases generated by Hess in their simulation uncertainty analysis.

The GCA discovered production forecasts for raw gas and condensate for the Briseis field are shown in **Figure 49** and **Figure 50**.

Figure 49: Briseis Field Discovered Raw Gas Production Forecasts

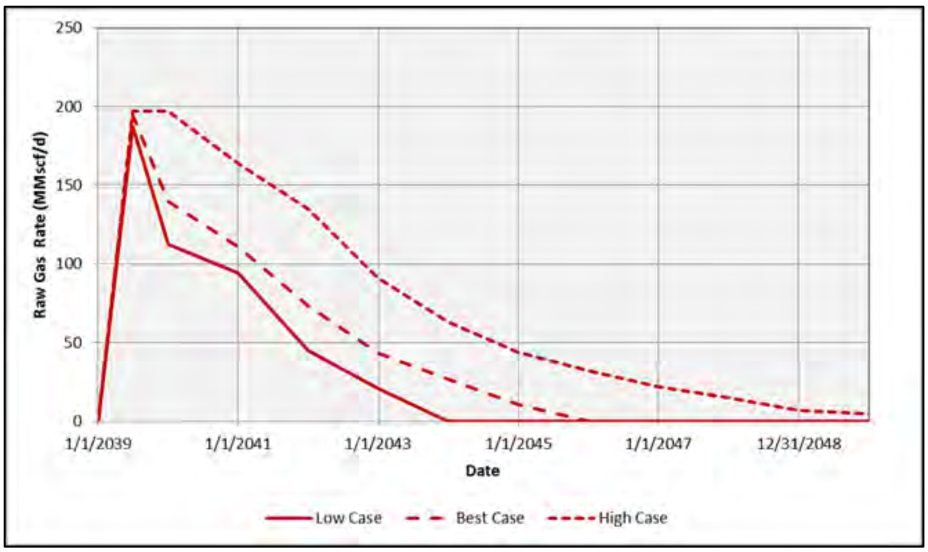
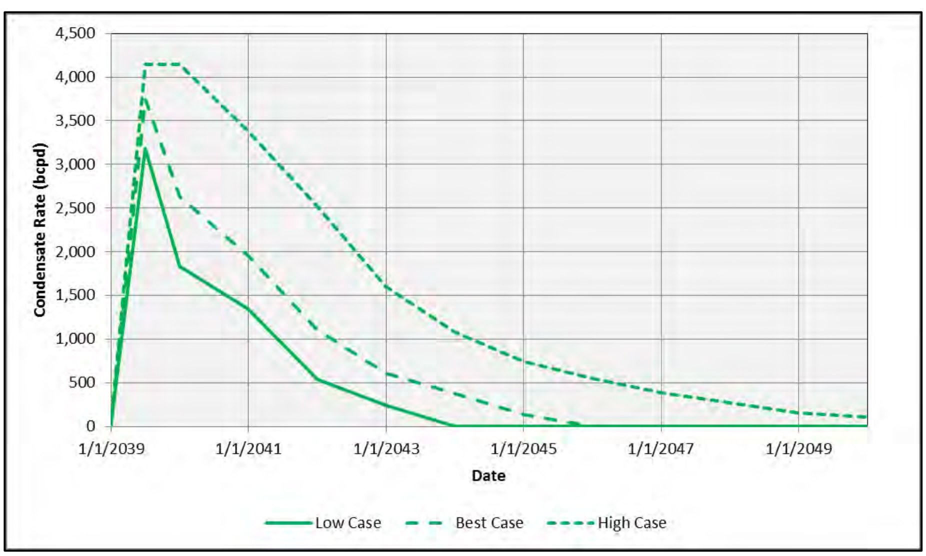


Figure 50: Briseis Field Discovered Condensate Production Forecasts



13 Chester Discovery

13.1 Field Summary

The Chester discovery, which lies on the southern margin of the WA-70-R block was discovered by the drilling of the deviated Chester-1 exploration well in 2010. The structure is formed of a northeast – southwest trending, highly faulted, three way dip closed fault block with closure to the east requiring fault seal (**Figure 51**).

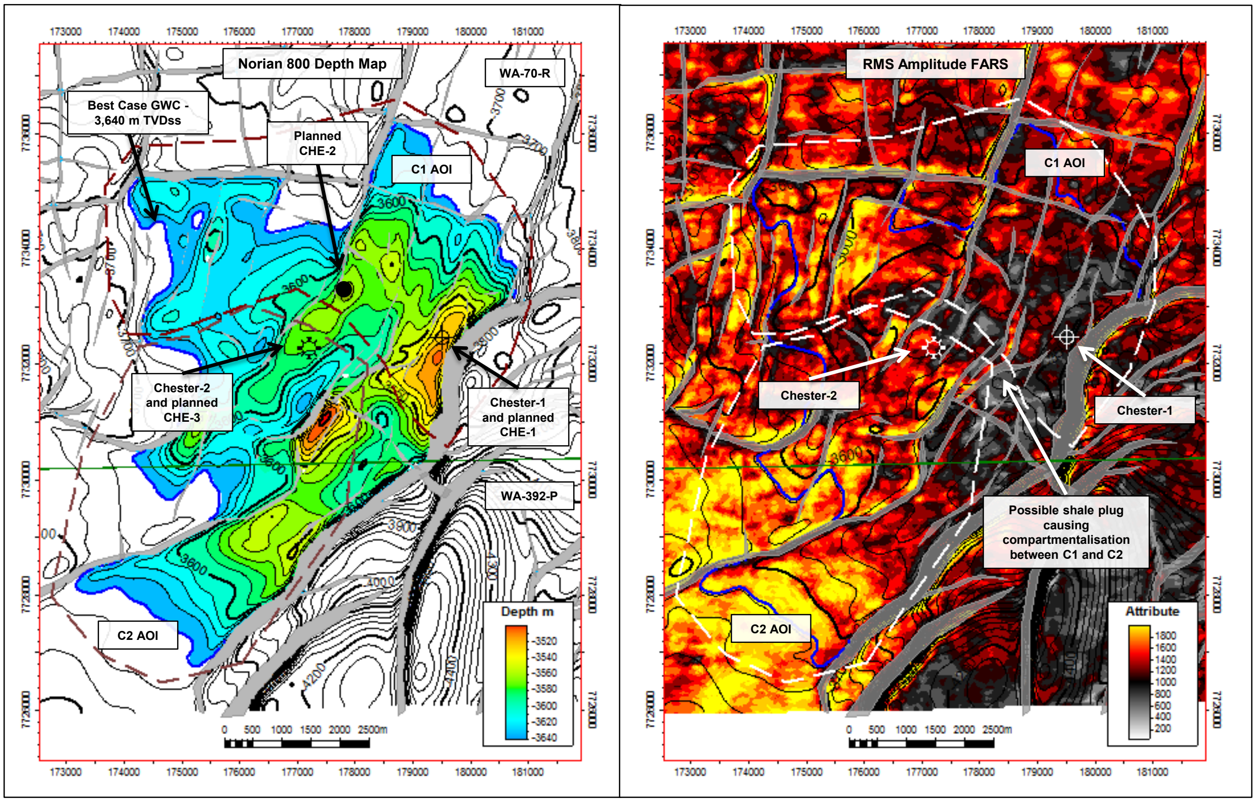
The well targeted fluvial-deltaic reservoirs of the Late Triassic Mungaroo Formation. The well reached a TD of 4,255 m however following unsuccessful attempts to control losses the well was plugged back and Chester-1 ST-1 was kicked off as a sidetrack from 2,314 m. The sidetrack penetrated 13.6 m of net gas pay in the Lower Barrow Group and 90.7 m net gas pay in a series of sands in the Triassic Mungaroo.

In August 2011, Hess drilled the Chester-2 appraisal well. The objectives of the well were to;

- Encounter the same gas bearing Mungaroo reservoirs as the discovery wells in a down-dip position
- Step out several fault compartments from the discovery well to understand compartmentalization
- Establish a GDT or an aquifer gradient for the accumulation
- Acquire core, wireline logs and image logs to evaluate depositional environment
- Appraise the Lower Barrow Group as a secondary objective.

The Chester accumulation is contained within a faulted, three-way dip closed structure which is bound to the east by a major, north-south trending, eastward dipping normal fault. The Mungaroo reservoir is formed of Norian aged fluvio-deltaics and shallow marine sands and shales. The sands are formed of stacked channels resulting in a thick fluvial reservoir with high net to gross. The reservoir is sealed by fine grained Rhaetian Marl which is directly overlying the Mungaroo Formation. Lateral cross fault seal is likely to be through juxtaposition of gas bearing reservoir sands against shale beds. The main kitchen for Chester lies below the Mungaroo terrestrial carbonaceous shales and coals. Hydrocarbon generation began in the Upper Cretaceous and migration and charge has continued throughout the Tertiary to present times.

Figure 51: Hess' Norian 800 Depth Map and RMS Amplitude Far Stack Map with Drilled and Planned Production Wells



13.2 Geology and Geophysics Review

GCA has reviewed the seismic interpretation of the Chester Field provided by Hess in the Chester Petrel Project and in general considers it is reasonable. The Chester wells penetrated two gas bearing intervals within the Triassic Mungaroo; Norian 800 and Norian 700. Pressure data shows that the two wells are not in pressure communication. The Chester area is characterised by a complex fault pattern which is likely to cause compartmentalisation of reservoir sands.

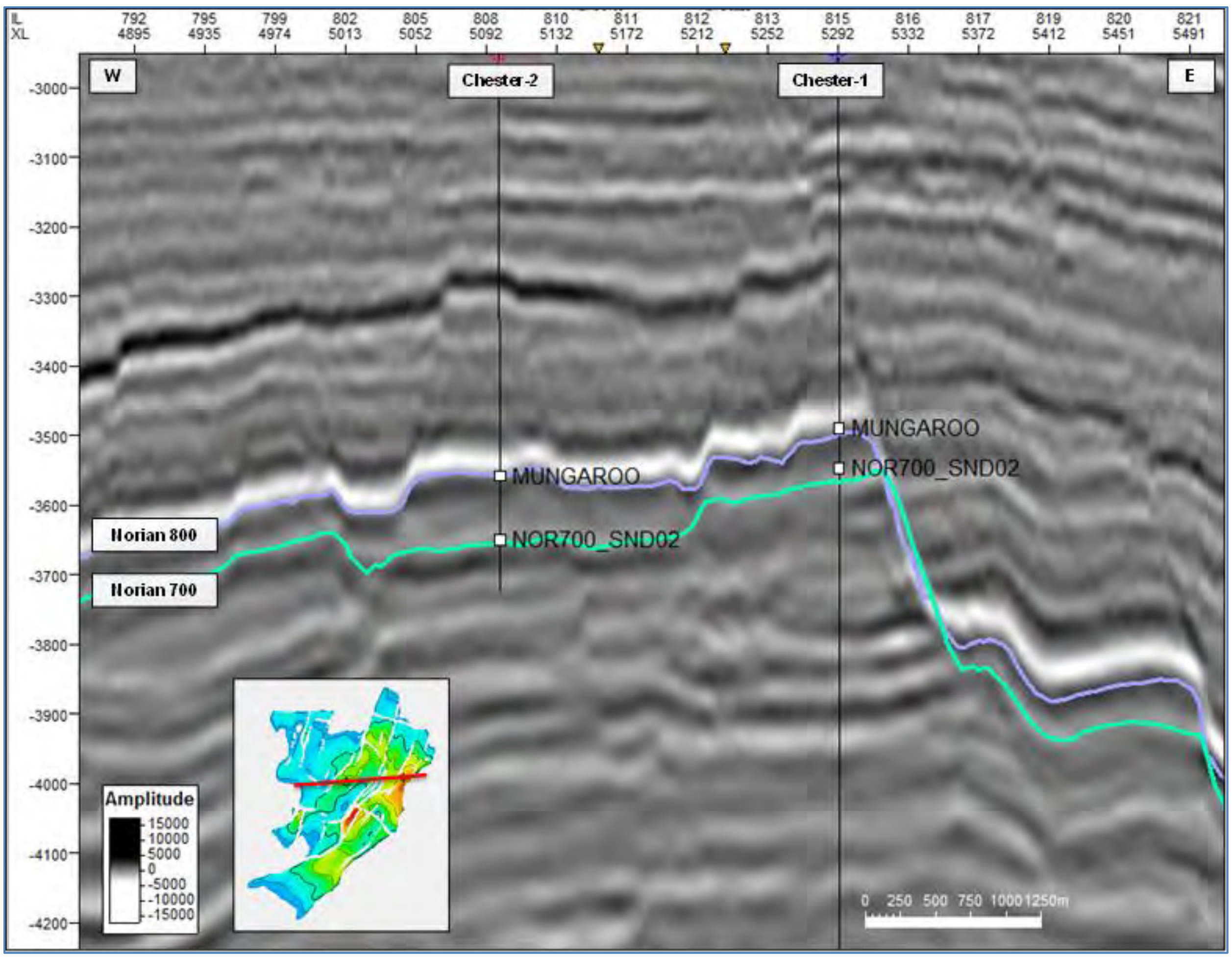
The Norian 800 reservoir, which is tidally influenced, represents the transgression of the uppermost Mungaroo Formation within the area, this is supported by core acquired from Chester-2. The interval is picked at the Top Mungaroo as a trough representing a strong negative acoustic impedance contrast with the overlying Rhaetian Marl which is fairly consistent across the field (**Figure 52**). The pick is also marked by a positive Gas Sand Probability response. RMS amplitude extraction maps show a clear seismic anomaly but also indicate the possibility of a shale filled channel or plug between the Chester-1 and Chester-2 wells (**Figure 51**) which may be the cause of the lack of pressure communication between the wells. Consequently, the Chester-1 and Chester-2 areas have been evaluated separately as C1 and C2 respectively. Reservoir connectivity and therefore GRV is likely to be the largest uncertainty in the field.

The Norian 700 reservoir interval is marked by a weaker trough within the Mungaroo Formation and does not have a Gas Sand Probability response as seen in the Norian 800. The Norian 700 is interpreted to be formed of stacked and coalescing channel bodies. Hess has mapped the Norian 700 channel body using the Inverse Shale Probability volume to estimate the GRV of the closure. The Norian 700 is considered as a single unit with communication between the two wells however, as with the Norian 800, complex faulting may cause compartmentalisation of the reservoir.

Hess provided GCA with Low, Base and High case interpretations of each of the reservoir intervals and has used contact range and areal polygons limiting closure to the picked channel geobodies to provide a range in GRV. GCA has similarly limited its GRV calculation to the channel geobody areas and has agreed with the contacts used by Hess.

GCA used its own depth conversion to further test the structural uncertainty. Each of Hess' interpretations was converted to time using the PSDM velocity cube, then back to depth using the GCA depth conversion. For both the Norian 800 and the Norian 700, the GCA depth conversion resulted in slightly higher GRVs than the Hess depth surfaces.

Figure 52: Seismic Dip Section across Chester Field



13.3 Engineering Review

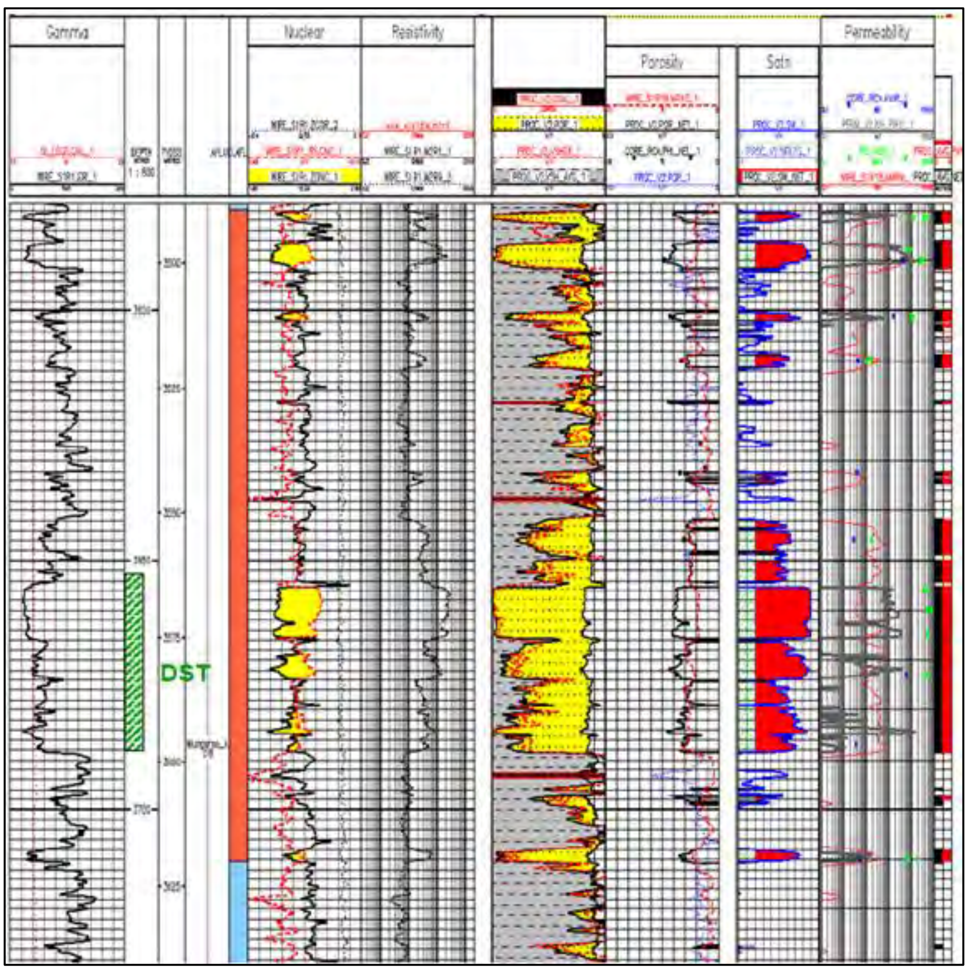
A total of 20 down-hole and surface samples were collected from the Chester-1ST and Chester-2 wells. The large number of samples from both down-hole and at the surface during flow testing provides a suitable data set to confirm fluid properties. Gas gravity has been measured at 0.7, with a gas expansion factor of 274 scf/rcf. The CO_2 concentration is low at 3.5% whilst the N_2 is 1.3%. A H_2S concentration of 3.5 ppm was measured during sampling.

Condensate gas ratio (CGR) has been estimated from samples and recombination laboratory experiments as 8 bbl/MMscf. Laboratory testing has indicated a low liquid drop in the reservoir as it is produced, so near-wellbore condensate banking should not be an issue.

13.3.1 Well Tests

The Chester Norian-700 reservoir was tested by the Chester-1ST1 well. The DST interval is shown with the Chester-1ST1 petrophysical logs across the Chester field Norian-700 reservoir section in **Figure 53**.

Figure 53: Chester-1ST1 Petrophysical Logs with DST Intervals



Source: Hess

The Chester-1ST1 well was flow tested over the Norian-700 reservoir interval of 3,655 to 3,688 mMDRT on the 27 June 2012 to 6 July 2012. The test included an initial clean up flow period followed by a shut-in. Subsequently a multi-rate test was conducted with a maximum raw gas rate of 68 MMscf/d with a minimal drawdown of 300 psi. The pressure build-up period after the multi-rate test was over a period of 100 hours.

The pressure build-up period for the DST was interpreted using Pressure Transient Analysis (PTA). The average permeability from the tested interval was interpreted to be 240 mD. The permeability interpretation from the DST was consistent with the petrophysical log interpretation of permeability. Multiple faults or boundaries were seen in the late time pressure derivative curve, which correspond to the structure of the field. A minimum connected gas volume of 45 Bscf was interpreted by PTA.

High well deliverability has been proved by the DST and development well productivity is expected to be extremely high.

13.3.2 Development Plan

The Chester Field is considered for developed by two wells as part of Phase 2 of the Equus Project development. The CHE-1 well will be drilled in the Norian-700 reservoir unit, close to the Chester-1ST1 exploration well for high well control. CHE-2 will be drilled in the Norian-800 reservoir to the north of the Chester-2 well. The results of the CHE-2 well and data from well performance should provide information on the compartmentalization of the Norian-800 reservoir.

The wells are scheduled to be drilled in 2027 and come online in 2028. The two wells will be tied back to the Equus Floating Production System (FPS) facility via the same 10 inch flowline as the Mentorc Field. However, at the time the Chester Field comes online the Mentorc Field is expected to be depleted and no longer producing.

The CHE-3 is planned to be drilled and completed in the Norian-800 reservoir as part of the Phase 3 development. The well will be drilled close to the Chester-2 well. The spacing of CHE-2 and CHE-3 wells is planned to mitigate against possible field compartmentalization seen in the seismic and DST results. However, this will be dependent on information from the CHE-2 well and its performance.

The locations of the development wells in the Norian-700 and Norian-800 reservoirs are shown in **Figure 51.**

13.3.3 Recovery Factor

Hess assessed the deliverability and recovery of gas and condensate from the Chester Field using reservoir simulation and analogue data. GCA has deemed this approach as reasonable.

The Chester Triassic reservoirs are combined structural and stratigraphic traps. The lateral extent of the reservoir is limited by faulting and the depositional environment. This is confirmed by the overpressure seen in the Chester reservoir pressure measurements. This precludes connection to any large, regional aquifer and the reservoir drive mechanism is expected to be depletion drive with minimal water influx. For a gas reservoir with depletion drive, recovery is typically determined by minimum inlet pressure at the production facility, in this case the Equus FPS. The recovery can be lower dependent on the reservoir complexity, reservoir quality and number of reservoir zones.

Hess has identified the Pluto Field in the Carnarvon Basin development as an analogue for the Briseis Norian-600 reservoir. As stated in previous sections, the Pluto Field is a Mungaroo Norian gas field, but with better reservoir quality. The expected recovery factor reported for the Pluto field is 60% to 80%. Other Mungaroo formation gas fields on the North West Shelf report a recovery factor of 60% to 65%.

Hess ran a number of dynamic simulation cases in order to quantify the uncertainty contributing to gas recovery at the Chester Field. The methodology that Hess followed was to generate a number of models based on different subsurface realisations by varying static and dynamic model properties. By running the different simulation model realisations, Hess was able to generate an S-curve of estimated ultimate recovery (EUR) outcomes. The recovery factor range derived from the simulation uncertainty modelling was 28% to 70%, with the proposed development case achieving a recovery factor of 47%. A key parameter affecting the EUR was found to be compartmentalization.

The Chester field gas recovery factor range for the Norian-700 reservoir proposed by Hess is 40%, 50% and 60% for the Low, Best and High Cases, respectively. For the Norian-800 reservoir the range is 35%, 48% and 60%. The recovery factor ranges for each reservoir are consistent with the ranges from simulation and analogue analysis. The ranges match what GCA would expect from a stacked reservoir sand, depletion drive gas field developed using vertical wells via a subsea tieback development.

13.4 Resource Estimate

The GIIP and Contingent Resources for the Chester Field were estimated using a 1D Monte Carlo Model. Reservoir parameter inputs are based on the sums and averages calculated from GCA's petrophysical interpretation. GRV inputs for both the Norian 800 and Norian 700 used P90 and P50 GRVs based Hess' depth surfaces; the high case GCA depth converted surface was used for the P10 input to allow for the potential high side case demonstrated by GCA's velocity model.

The Chester Field lies in the south of the WA-70-R block and closure extends beyond the block boundary into the adjacent WA-392-P Block at both the Norian 800 and Norian 700 intervals. GCA has therefore estimated both full field and on block volumes. GCA's input parameters into its 1D Monte Carlo Model, together with the resulting GIIP estimates, are given in **Table 40**.

GCA estimated GIIP for both full field and on block volumes of the Chester Field with on block volumes provided in **Table 41**.

Similarly Gas Contingent Resources are given in **Table 42** and associated Condensate Contingent Resources are summarized in **Table 43**. Only on block volumes have been included in production profiles and below.

Table 40: GCA's Input Parameters for its Estimate of GIIP for the Chester Field

Reservoir	Parameter	Unit	P90	P50	P10
Norian 700	Contact	m TVDss	-3,605	-3,626	-3,654
	GRV	MM m^3	69	235	479
	NTG	Decimal	0.649	0.749	0.849
	Porosity	Decimal	0.110	0.150	0.190
	Sg	Decimal	0.620	0.690	0.760
	Gas Expansion Factor	1/Bg	270.0	274.0	278.0
	Condensate Yield	Stb/MM scf	7.10	8.10	9.10
	Recovery Factor	Decimal	0.40	0.50	0.60
	GIIP – Full Field	**Bscf**	**56**	**174**	**381**
	GIIP – On Block	**Bscf**	**51**	**135**	**270**
Norian 800 C1	Contact	m TVDss	-3,605	-3,640	-3,650
	GRV	MM m3	124	248	504
	NTG	Decimal	0.624	0.724	0.824
	Porosity	Decimal	0.140	0.180	0.220
	Sg	Decimal	0.610	0.680	0.750
	Gas Expansion Factor	1/Bg	273.0	274.0	275.0
	Condensate Yield	Stb/MM scf	7.60	8.60	9.60
	Recovery Factor	Decimal	0.35	0.48	0.60
	GIIP – Full Field	**Bscf**	**97**	**210**	**442**
	GIIP – On Block	**Bscf**	**97**	**210**	**449**
Norian 700 C2	Contact	m TVDss	-3,605	-3,640	-3,650
	GRV	MM m3	121	225	408
	NTG	Decimal	0.650	0.750	0.850
	Porosity	Decimal	0.120	0.160	0.200
	Sg	Decimal	0.530	0.600	0.670
	Gas Expansion Factor	1/Bg	273.0	274.0	275.0
	Condensate Yield	Stb/MM scf	8.00	9.00	10.00
	Recovery Factor	Decimal	0.35	0.45	0.55
	GIIP – Full Field	**Bscf**	**77**	**154**	**302**
	GIIP – On Block	**Bscf**	**34**	**58**	**112**

Note: This estimate of GIIP is based on a probabilistic methodology using GCA's 1D Monte Carlo Model.

Table 41: GCA's Estimate of GIIP for the Chester Field

Reservoir	On Block GIIP (Bscf)		
	Low	Best	High
Norian 700	71	142	233
Norian 800 C1	138	221	388
Norian 800 C2	48	61	96

Note: This estimate of GIIP is based on GCA's total project GIIP volumes which were derived by calculating the average between a full arithmetic and probabilistic addition of individual field volumes to account for unknown dependencies between the fields. The average Low, Best and High Network case profiles were allocated to each field by proportionally scaling each individual field P90, P50 and P10 case to the respective average Network case profile.

Table 42: GCA's Estimate of Gas Contingent Resources for the Chester Field

Reservoir	On Block Contingent Resources (Bscf)		
	1C	2C	3C
Norian 700	34	71	117
Norian 800 C1	61	102	184
Norian 800 C2	21	27	44

Table 43: GCA's Estimate of Condensate Contingent Resources for the Chester Field

Reservoir	On Block Contingent Resources (MMBbl)		
	1C	2C	3C
Norian 700	0.3	0.6	0.9
Norian 800 C1	0.5	0.9	1.6
Norian 800 C2	0.2	0.2	0.6

13.5 Production Forecasts

Hess generated production forecasts for each of the Norian-700 and Norian-800 reservoirs in the Chester Field. The discovered Hess Best Case raw gas production forecasts for the Norian-700 and Norian-800 reservoirs are deterministic cases from simulation modeling that matches the 50% and 48% recovery factors, respectively. The associated condensate production has been forecast based on a modeled CGR versus reservoir pressure relationship for each reservoir. GCA has accepted the Hess Best Case forecasts for raw gas and condensate. GCA generated Low and High Cases based on the Best Case profile but scaled for the Low and High Case GIIP estimates. These Cases are similar to deterministic simulation cases generated by Hess in their simulation uncertainty analysis.

The GCA production forecasts for raw gas and condensate for the Chester Field are shown in **Figure 54** and **Figure 55**.

Figure 54: Chester Field Raw Gas Production Forecasts

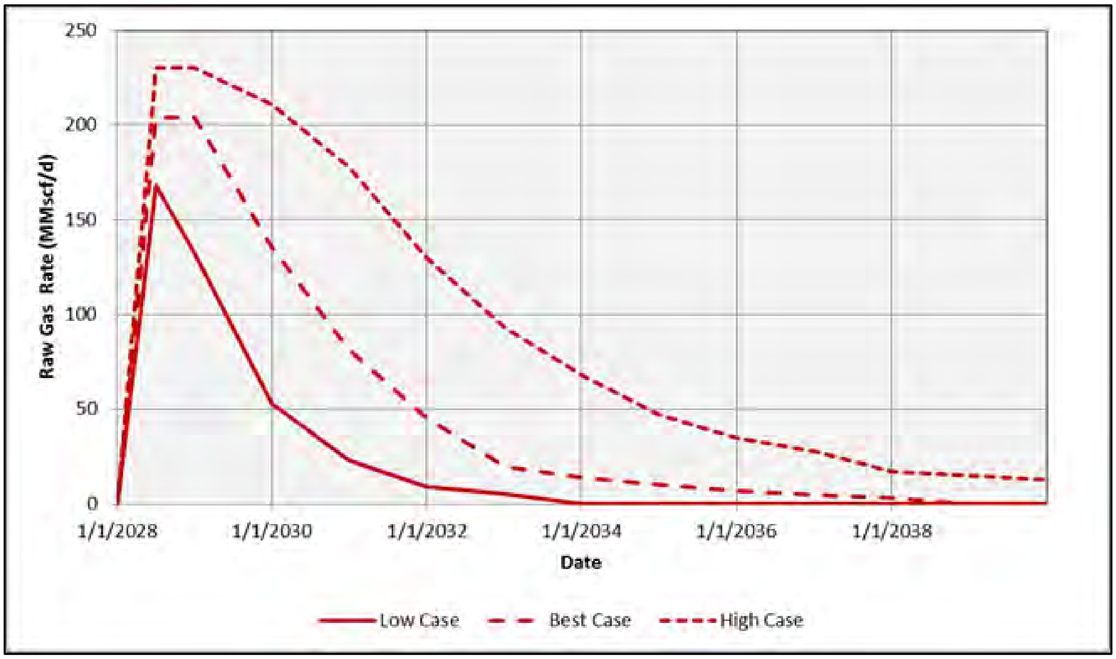
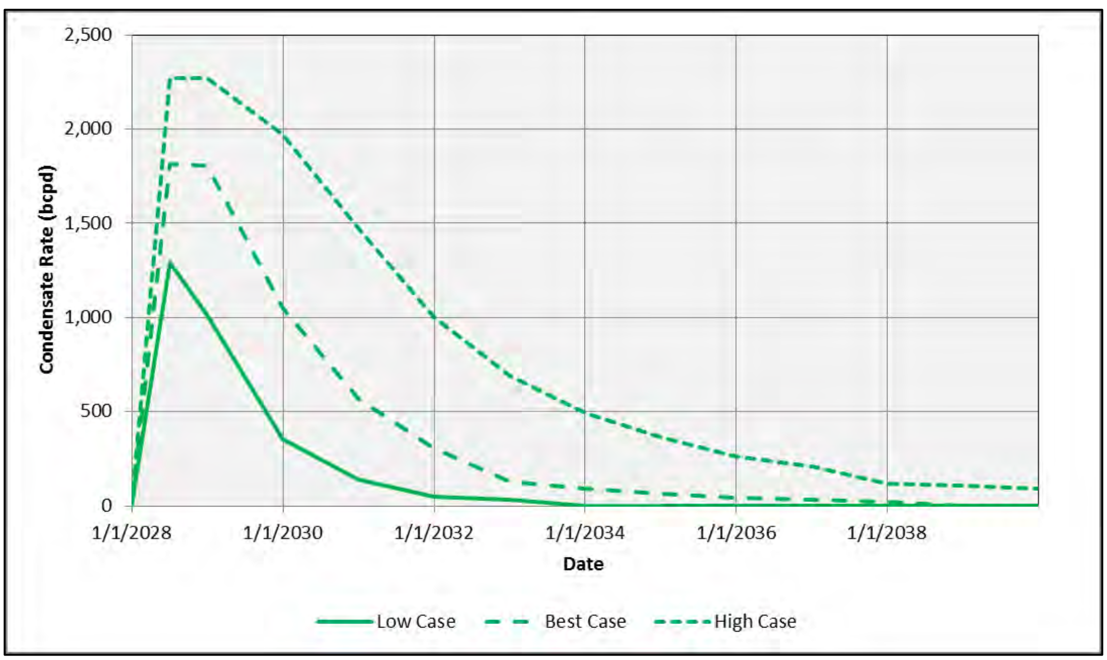


Figure 55: Chester Field Condensate Production Forecasts



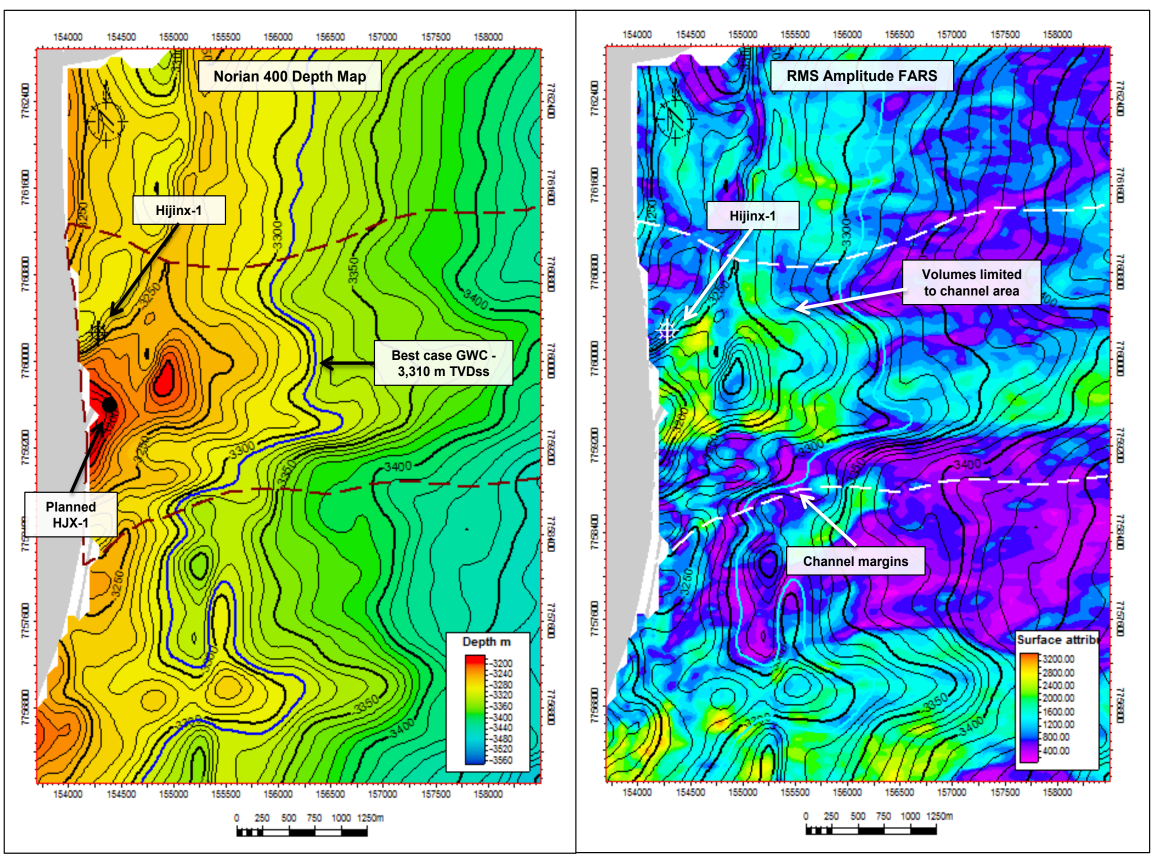
14 Hijinx Discovery

14.1 Field Summary

The Hijinx Field was discovered with the drilling of the Hijinx-1 well in 2009-2010. The Hijinx structure is mapped as a north northeast – south southwest trending three-way dip closure which dips to the east and has both structural and stratigraphic closures (**Figure 56**). The primary target of the well was a well-defined intra-Mungaroo seismic amplitude anomaly. The well was drilled to a TD of 4,559 m MDRT in the Mungaroo Formation and intersected 42 m of net gas pay in the Norian aged Mungaroo Formation. The well was plugged and abandoned as a gas discovery.

The Mungaroo structure has a combination of structural and stratigraphic closure with stratigraphic pinchouts to the northeast and southwest. The structure is defined by a northeast and southwest orientated normal fault which formed during Jurassic rifting. The structure was identified by an amplitude anomaly with Type III AVO on 3D seismic data. The Norian reservoir at Hijinx was deposited in a non-marine to marginal marine fluvial deltaic environment with sand bodies mapped with channel morphologies. The top seal for the structure is formed of Norian flood plain shales of the Mungaroo Formation. Fault juxtaposition of the reservoirs against Jurassic to Cretaceous shale prone facies in the hanging wall ensure fault seal. The main kitchen for the Hijinx structure is located to the east and the source rock is formed of Ladinian to Norian aged Mungaroo terrestrial carbonaceous shales and coals. Hydrocarbon generation began in the Upper Cretaceous and has continued throughout the Tertiary until the present time.

Figure 56: Hess' Norian 400 Depth Map and RMS Amplitude Far Stack Map with Drilled and Planned Production Wells



14.2 Geology and Geophysics Review

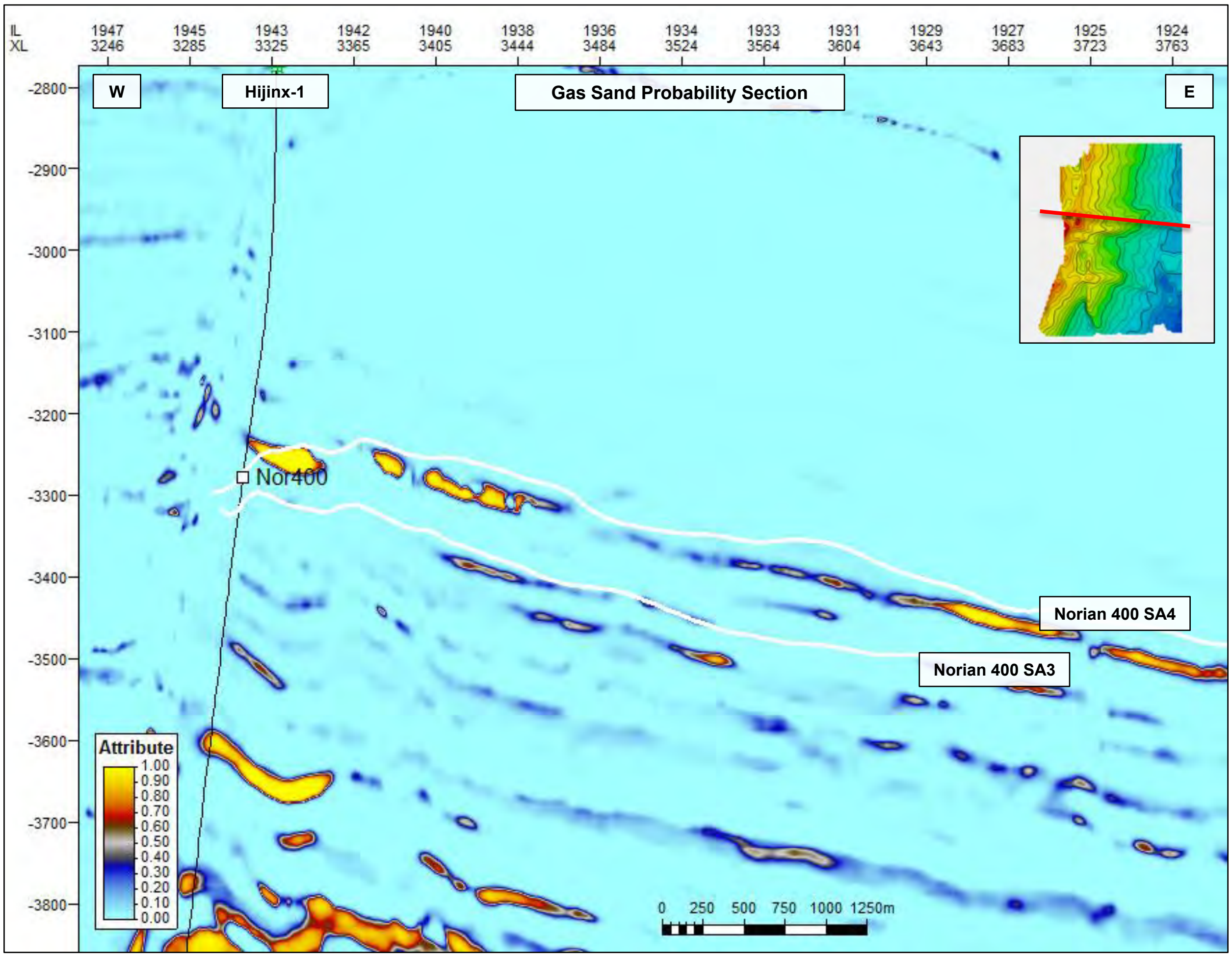
GCA has reviewed the seismic interpretation of the Hijinx Field provided by Hess in the Hijinx Petrel Project and in general considers it is reasonable (**Figure 57**). The Hijinx-1 well penetrated two gas bearing intervals within the Triassic Mungaroo; Norian 400 SA4 and Norian 400 SA3. The Norian interval is interpreted to have been deposited as a thick fluvio-deltaic succession on a low relief coastal plain. The Norian at Hijinx shows a fining upwards sequence into the overlying transgressive Rheatian Marl.

The Top Norian 400 SA4 is picked on a trough. The sand appears to vary in thickness across the field and it is displaced by several southwest to northeast trending faults however fault throw does not appear to displace the sands enough to result in compartmentalization. The Norian 400 SA4 gives a positive Gas Sand Probability response and this continues across faults; also suggesting sand on sand juxtaposition across the faults. Amplitude extraction maps in both the Relative Vp/Vs and the Gas Sand Probability volumes show a distinct channel feature running from west – east on which the Hijinx Well appears to be drilled at the channel margin which suggests that improved reservoir properties may be present in the center of the channel as the sediments likely grade laterally to finer grained, more mud rich overbank and splay deposits. The volumetric estimate for the Hijinx Norian 400SA2 has been restricted to within the mapped channel limits. No GWC was penetrated in the well and a range of contacts have been estimated using the Norian 400 water pressure gradient, a saturation height function and the base of sand.

The Top Norian 400 SA3 is also picked on a trough and as with the Norian 400 SA4 sand shows lateral thickness variations. The Norian 400 SA3 does not have a positive Gas Sand Probability response and seismic amplitude extractions do not show definitive amplitude anomalies to define the limits of the reservoir. No GWC was penetrated in the well and a range of contacts has been estimated using a saturation height function and the base of sand.

Hess provided GCA with Low, Base and High case interpretations of each of the reservoir intervals based on varying isochore thicknesses to provide a range in GRV. GCA used its own depth conversion to further test the structural uncertainty. Each of Hess' interpretations was converted to time, then back to depth using the GCA depth conversion. For both the Norian 400 SA4 and the Norian 400 SA3, the GCA depth conversion resulted in slightly lower GRVs than the Hess depth surfaces.

Figure 57: Seismic Dip Section across the Hijinx Field



14.3 Engineering Review

A total of 8 down-hole samples were collected from the Hijinx-1 well across the Norian-400 reservoir sands. The sampling tool used in the Hijinx-1 well was the RCI tool, and samples from this well all suffered low levels of contamination from OBM used during drilling.

Gas gravity for the Norian-400 reservoir has been measured at 0.8, with a gas expansion factor of 257 scf/rcf. The CO_2 concentration is low at approximately 1.3% whilst the N_2 is the approximately 1.8%. Best Case CGR has been estimated from samples and recombination laboratory experiments to be 27.6 bbl/MMscf. There is some variation from samples so uncertainty has been captured in the Low and High Cases. Similar to the other Equus reservoirs there should be no issues for near-wellbore condensate banking due to liquid drop out.

14.3.1 Well Tests

No well tests were performed on the Hijinx-1 well in the Norian reservoirs. However, the Triassic Norian reservoir was tested by the Chester-1ST1 well in the Norian-700 reservoir unit. The well produced at high flow rates with low drawdown pressures. The Norian-700 is not planned to be developed in the Hijinx Field but is deemed to be a reasonable analogue for the Hijinx Field Norian-400.

14.3.2 Development Plan

The Hijinx Field is planned to be developed in the Norian-400 reservoir as part of the Equus Phase 4 development. The development plan includes 1 low-inclination development well in a crestal location to maximize the stand-off from the GWC as shown in **Figure 56**.

The HJX-1 well will be completed in the Norian-400 reservoir. The well is scheduled to be drilled in 2036 and come online in 2037. The well will be tied back to the Equus FPS facility via a 10 inch flowline shared with the Nimblefoot, Bravo, Rimfire and Snapshot Fields, and the Gaulus prospect.

14.3.3 Recovery Factor

Hess assessed the deliverability and recovery of gas and condensate from the Hijinx Field using analogue data. GCA has deemed this as approach as reasonable.

The Hijinx Norian reservoir is a combined structural and stratigraphic trap. The lateral extent of the reservoir is limited by faulting and the depositional environment. This prevents connection to any large, regional aquifer and the reservoir drive mechanism is expected to be depletion drive with minimal water influx. For a gas reservoir with depletion drive, recovery is typically determined by minimum inlet pressure at the production facility, in this case the Equus FPS. The recovery can be lower dependent on the reservoir complexity, reservoir quality and number of reservoir zones.

Hess has based recovery factors on the same Mungaroo analogues cited in previous sections. These recovery factors are consistent with the recovery factors estimated by Hess for other Norian reservoirs in the Equus Fields. The Hijinx Field gas recovery factor range for Norian reservoirs proposed by Hess is 55%, 65% and 75% for the Low, Best and High Cases, respectively. These recovery factor ranges are consistent with what GCA would expect from a stacked reservoir sand, depletion drive gas field developed using vertical wells via a subsea tieback development.

14.4 Resource Estimate

The GIIP and Contingent Resources for the Hijinx Field were estimated using a 1D Monte Carlo Model. Reservoir parameter inputs are based on the sums and averages calculated from GCA's petrophysical interpretation. The GRV inputs for both the Norian 400 reservoir sands used the Hess Mid and High Case depth surfaces for the P50 and P10 GRV inputs and the GCA depth conversion as the P90 giving a slightly lower range than used by Hess to account for the lower GRVs calculated using the GCA velocity model. For both reservoirs, Hess' P50 and P10 contacts were accepted, but the GDT seen in the Hijinx-1 Well was used for P90 GRV estimate. GCA's input parameters into its 1D Monte Carlo Model, together with the resulting GIIP estimates, are given in **Table 44**.

GCA's estimates of GIIP for the Hijinx Field are given in **Table 45**. Similarly Gas Contingent Resources are given in **Table 46** and associated Condensate Contingent Resources are summarized in **Table 47**.

Table 44: GCA's Input Parameters for its Estimate of GIIP for the Hijinx Field

Reservoir	Parameter	Unit	P90	P50	P10
Norian 400 SA3	Contact	m TVDss	-3,346	-3,375	3,381
	GRV	MM m^3	39	56	82
	NTG	Decimal	0.698	0.798	0.898
	Porosity	Decimal	0.130	0.170	0.210
	Sg	Decimal	0.701	0.740	0.779
	Gas Expansion Factor	1/Bg	255.0	258.3	262.0
	Condensate Yield	Stb/MM scf	26.8	27.8	28.8
	Recovery Factor	Decimal	0.55	0.65	0.75
	GIIP	**Bscf**	**32**	**51**	**80**
Norian 400 SA4	Contact	m TVDss	-3,302	-3,310	-3,318
	GRV	MM m3	36	63	112
	NTG	Decimal	0.450	0.550	0.650
	Porosity	Decimal	0.110	0.150	0.190
	Sg	Decimal	0.604	0.670	0.736
	Gas Expansion Factor	1/Bg	254.0	257.4	260.0
	Condensate Yield	Stb/MM scf	16.1	17.1	18.1
	Recovery Factor	Decimal	0.55	0.65	0.75
	GIIP	**Bscf**	**16**	**31**	**60**

Note: This estimate of GIIP is based on a probabilistic methodology using GCA's 1D Monte Carlo Model.

Table 45: GCA's Estimate of GIIP for the Hijinx Field

Reservoir	GIIP (Bscf)		
	Low	Best	High
Norian 400 SA3	45	53	70
Norian 400 SA4	22	33	51

Note: This estimate of GIIP is based on GCA's total project GIIP volumes which were derived by calculating the average between a full arithmetic and probabilistic addition of individual field volumes to account for unknown dependencies between the fields. The average Low, Best and High Network case profiles were allocated to each field by proportionally scaling each individual field P90, P50 and P10 case to the respective average Network case profile.

Table 46: GCA's Estimate of Gas Contingent Resources for the Hijinx Field

Reservoir	Contingent Resources (Bscf)		
	1C	2C	3C
Norian 400 SA3	29	35	46
Norian 400 SA4	14	21	34

Table 47: GCA's Estimate of Condensate Contingent Resources for the Hijinx Field

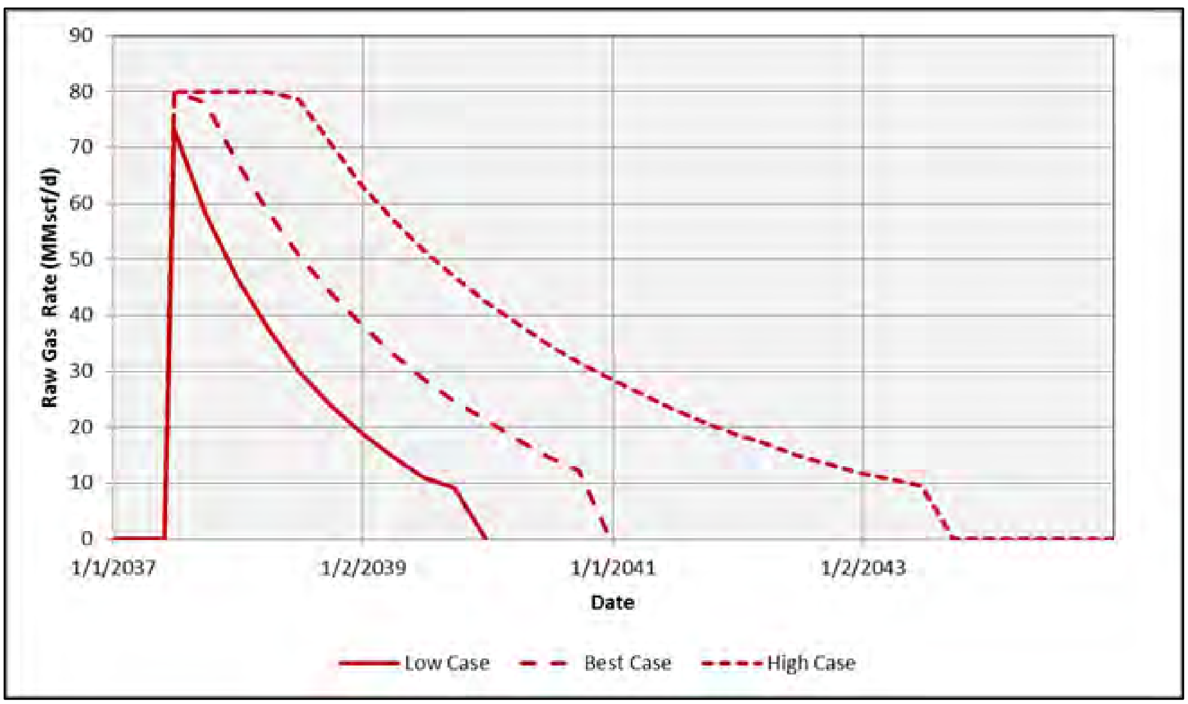
Reservoir	Contingent Resources (MMBbl)		
	1C	2C	3C
Norian 400 SA3	1.1	1.1	1.7
Norian 400 SA4	0.4	0.4	0.8

14.5 Production Forecasts

Hess generated production forecasts for the Norian-400 reservoir. The Hess Best Case raw gas production forecast is based on production profiles from the other Equus Fields from the corresponding reservoirs that match the 65% recovery factor. The associated condensate production has been forecast based on a modeled CGR versus reservoir pressure relationship. GCA has accepted the Hess Best Case forecasts for raw gas and condensate. GCA generated Low and High Cases based on the Best Case profile but scaled for the Low and High Case GIIP estimates.

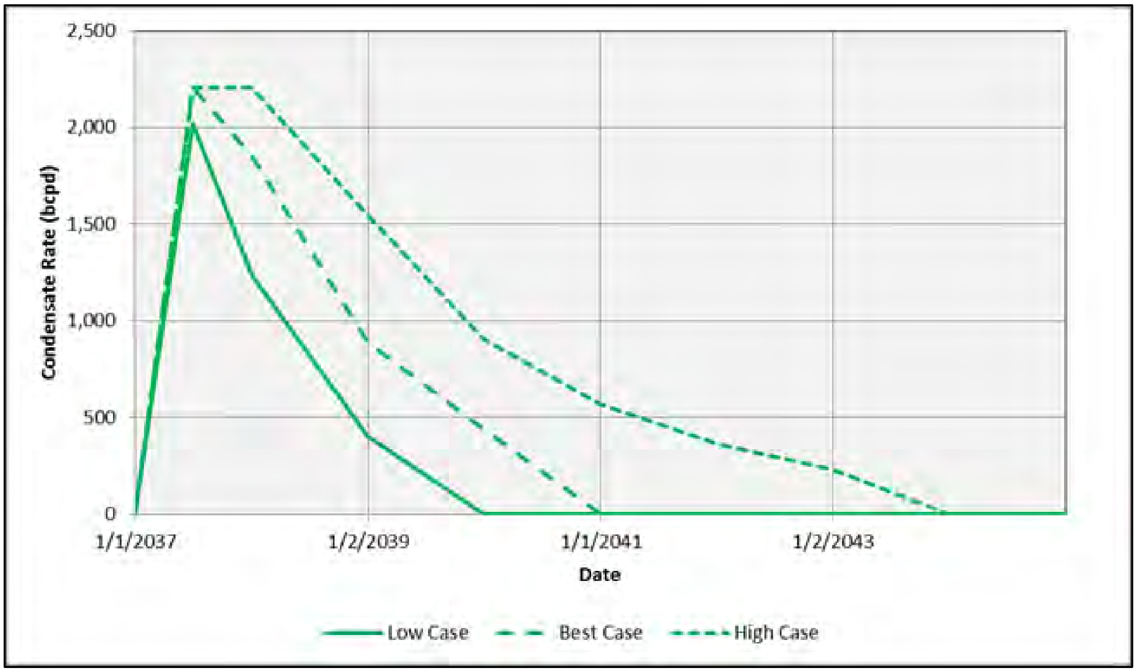
The GCA discovered production forecasts for raw gas and condensate for the Hijinx Field are shown in **Figure 58** and **Table 59**.

Figure 58: Hijinx Field Raw Gas Production Forecasts



Gaffney,
Cline &
Associates

Figure 59: Hijinx Field Condensate Production Forecasts



15 Snapshot Discovery

15.1 Field Summary

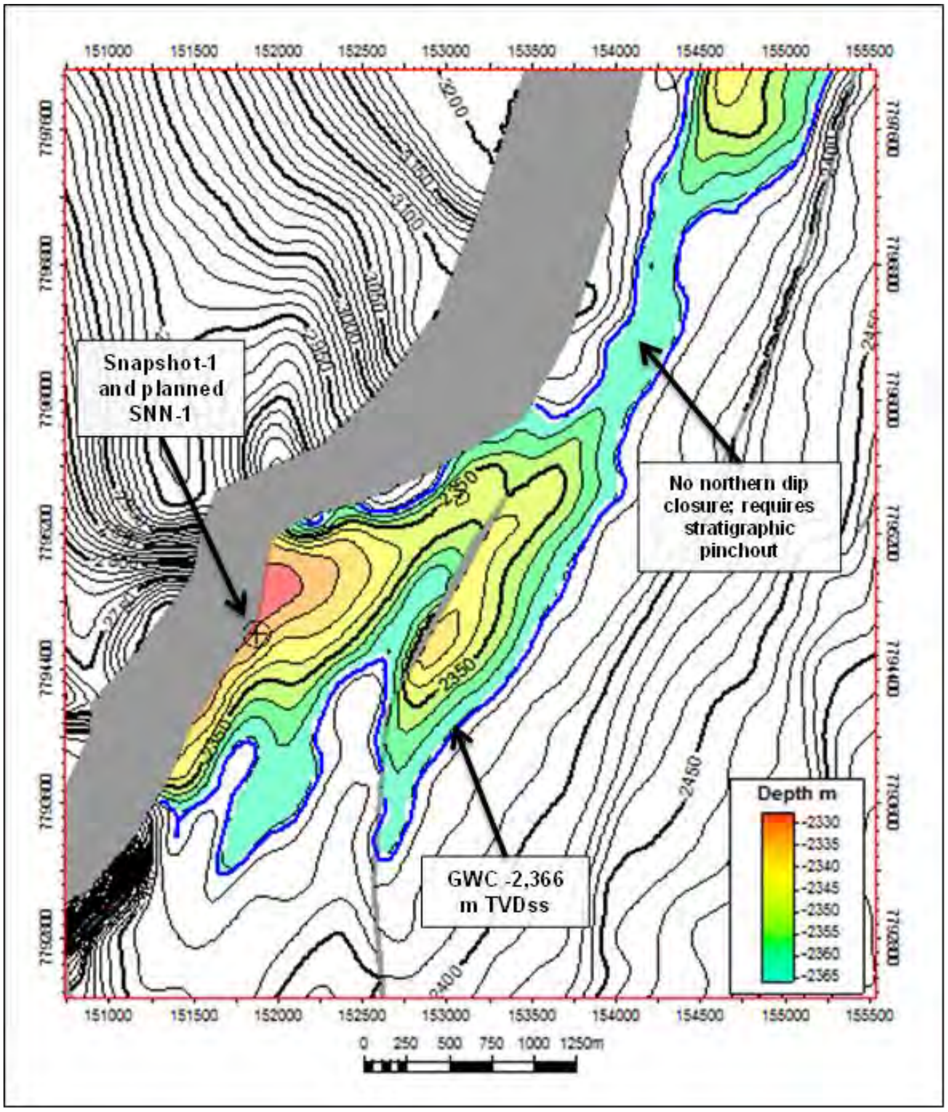
The Snapshot Field was discovered with the drilling of the Snapshot-1 well in 2016. The Snapshot structure is formed of a north northeast – south southwest trending three-way dip closure which dips to the east (**Figure 60**). The structure lies on the footwall of a large north northeast – south southwest trending normal fault, western closure is against the fault which dips to the west. The targets of the well were incised channels within the Carnian 300 and stacked fluvio-deltaic channels of the Norian 700. There is likely to be a stratigraphic element to the trapping mechanism.

The Snapshot-1 well discovered gas with GWCs encountered in both the Norian 700 and the Carnian 300. The well was drilled after the inversion re-processing of the seismic data and well results confirmed predictions made from seismic interpretations. In the Norian 700, a flatspot in the Relative P Impedance inversion volume at 2,366 m TVDss coincides with the FWL penetrated by the well. In the Carnian 300, the base of the gas predicted by the Gas Sand Probability Cube matches with the GWC at 4,427 m TVDss penetrated by the well.

The Snapshot Field is scheduled for development in Phase 4 of the Equus project. A low entry inclination development well is planned via re-entry of the suspended Snapshot-1 well. Initially, completion of the C-300 reservoir is planned with a sidetrack to the crest of the structure. Re-completion of the N-700 reservoir is planned as part of the Phase 5 recompletion campaign.

The primary target of the well was a well-defined intra-Mungaroo seismic amplitude anomaly. The well was drilled to a TD of 4,559 m MDRT in the Mungaroo Formation and intersected 42 m of net gas pay in the Norian aged Mungaroo Formation. The well was plugged and abandoned as a gas discovery.

Figure 60: Norian 700 Depth Map with Drilled and Planned Well Locations



15.2 Geology and Geophysics Review

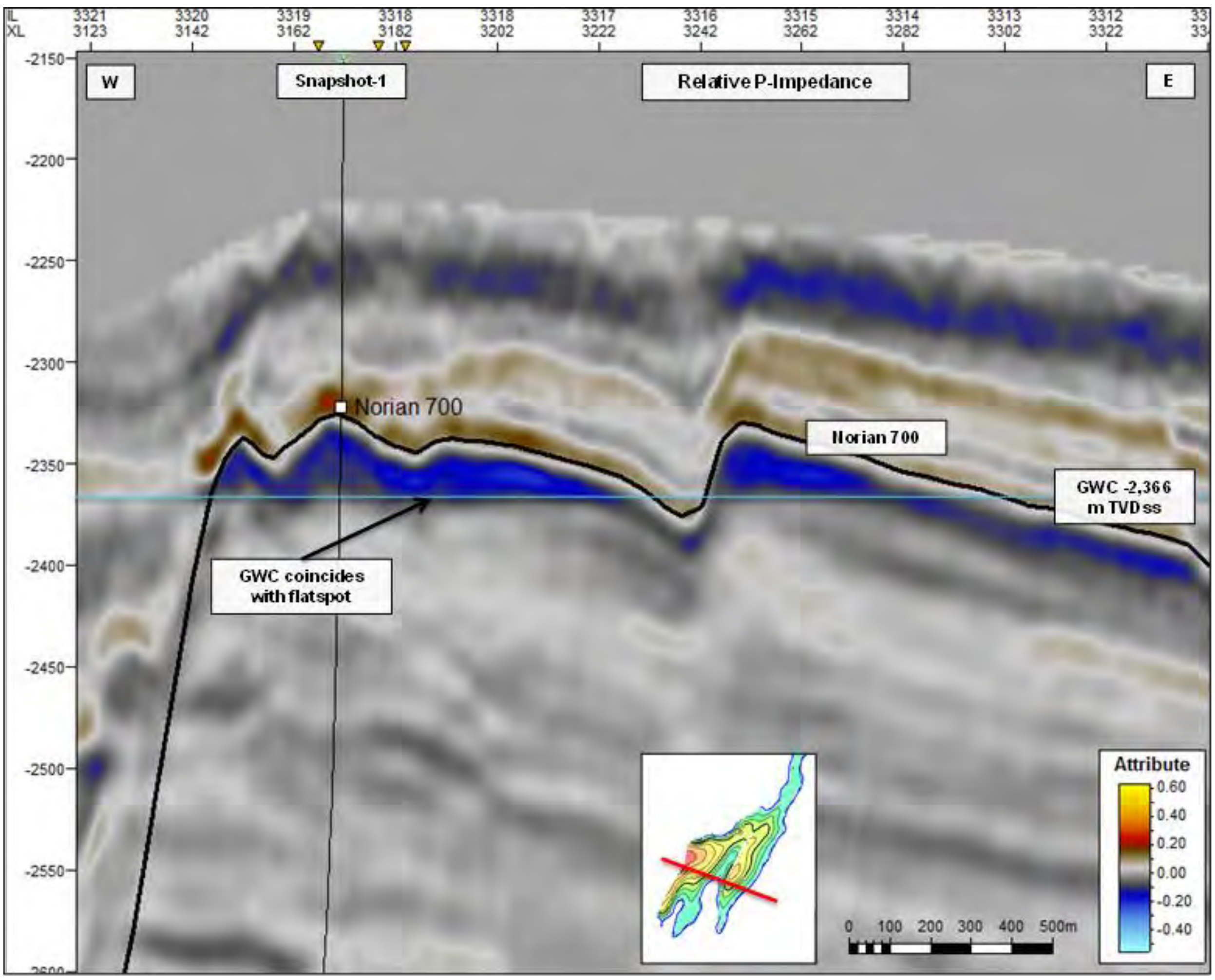
GCA has reviewed the seismic interpretation of the Snapshot Field provided by Hess in the Snapshot Petrel Project and in general considers it is reasonable. The Snapshot well penetrated two gas bearing intervals within the Triassic Mungaroo; Norian 700 and Carnian 300.

The Norian 700 reservoir interval is picked as the Top Mungaroo as a trough representing a strong negative acoustic impedance contrast which is fairly consistent across the field (**Figure 61**). A GWC was encountered in the Norian 700 at -2,366 m TVDss which coincides with a flatspot which had been identified in seismic data. The pick is also marked by a positive Gas Sand Probability response and is also clear in Far Stack PSDM seismic cube. Both anomalies are coincident with the GWC.

The Carnian 300 reservoir interval is marked by a positive acoustic impedance contrast and has been picked on a zero crossing between an overlying trough and underlying peak. The Snapshot well penetrated a GWC at -4,427 m TVDss which coincides with the base of a positive Gas Sand Probability response. Seismic attribute maps created by GCA and isochore maps created by Hess suggest the reservoir is restricted to a channel structure and north and south reservoir extent has been restricted to this feature.

Hess provided GCA with a Best case interpretation of each of the Norian 700 and the Carnian 300 reservoir intervals. GCA used its own depth conversion to further test the structural uncertainty. At the Norian 700 interval, the GCA depth conversion resulted in a very slightly lower GRV than the Hess depth conversion. GCA has therefore used its depth surface in the calculation of the P90 GRV and has accepted the Hess GRvs for the P50 and P10 inputs. At the Carnian 300 interval, the GCA depth conversion resulted in a higher GRV. GCA has therefore used this as the P10 input and accepted the Hess P90 and P50 inputs.

Figure 61: Seismic Dip Section across the Snapshot Field



15.3 Engineering Review

Down-hole reservoir fluid samples were collected from the Snapshot-1 well in the Triassic Norian-700 and Carnian-300 reservoir zones.

Gas gravity for the Norian-700 zone was measured at 0.6 and for the Carnian-300 zone it was 0.7. The gas expansion factor in the Norian-700 zone was estimated to be 224 scf/rcf, whilst it was estimated to be 286 scf/rcf in the Carnian-300. The combined CO_2 and N_2 concentration for the Norian-700 zone is low at 2.8%, whilst the Carnian-300 is approximately 4.4%.

CGR has been estimated from samples and recombination laboratory experiments. Hess has estimated a Best Case CGR for the Norian-700 of 8 bbl/MMscf, and a Carnian-300 Best Case CGR was estimated to be 27 bbl/MMscf. A range has been applied to the Low and High Case CGR to capture uncertainty seen in CGR across the various samples in the 2 zones. Similar to the other Equus reservoirs there should be no issues for near-wellbore condensate banking due to liquid drop out.

Reservoir fluid properties for the un-penetrated Triassic Norian-200 and Carnian-400 reservoir zones have been estimated based on properties seen in the other reservoir zones.

15.3.1 Well Tests

No well tests were performed on the Snapshot-1 well. However, well tests have been performed on other fields which have the same reservoirs as the Snapshot field. Well tests have been performed on wells in the Triassic Norian (Chester Field) and Triassic Carnian (Glenloth Field).

The Triassic Norian reservoir was tested by the Chester-1ST1 well in the Norian-700 reservoir unit. The well produced at high flow rates with low drawdown pressures. The Norian-700 is deemed to be a reasonable production analogue for the Snapshot Field Norian-200.

The Triassic Carnian reservoir was tested by the Glenloth-1 well. The well tested an interval over the Carnian-300 reservoir unit. The test supports the estimated flow rates for the Snapshot development wells for the Carnian-300 and un-penetrated Carnian-400 reservoir sands, also known as Snapshot South.

15.3.2 Development Plan

The Snapshot Field will initially be developed in the Carnian-300 zone and the un-penetrated Carnian-400 and Norian-200 zones (Snapshot South) as part of the Equus Phase 4 development. The development plan includes 2 low-inclination development wells in crestal locations to maximize the stand-off from the GWC.

The SNN-1 well will be drilled and produced initially from the Carnian-300 reservoir, in order to allow the well to later be recompleted in a shallower reservoir. The SNN-2 well will be completed in the un-penetrated Norian-200 and Carnian-400 zones, also referred to as Snapshot South. The wells are scheduled to be drilled in 2036 and come online in 2037. The wells will be tied back to the Equus FPS facility via a 10 inch flowline shared with the Nimblefoot, Bravo, Rimfire and Hijinx Fields, and the Gaulus prospect.

By 2039 the Carnian-300 reservoir is expected to be depleted by the SNN-1 well. As part of the Equus Phase 5 development in 2039, the SNN-1 production well will re-entered and completed as SNN-1R in the Norian-700 reservoir (**Figure 60**).

15.3.3 Recovery Factor

Hess assessed the deliverability and recovery of gas and condensate from the Snapshot field using analogue data. GCA has deemed this as approach as reasonable.

The Snapshot Triassic reservoirs are combined structural and stratigraphic traps. The lateral extent of the reservoir is limited by faulting and the depositional environment. This precludes connection to any large, regional aquifer and the reservoir drive mechanism is expected to be depletion drive with minimal water influx. For a gas reservoir with depletion drive, recovery is typically determined by minimum inlet pressure at the production facility, in this case the Equus FPS. The recovery can be lower dependent on the reservoir complexity, reservoir quality and number of reservoir zones.

Hess has based recovery factors on the same Mungaroo analogues cited in previous sections. These recovery factors are consistent with the recovery factors estimated by Hess for other Carnian and Norian reservoirs in the Equus Fields. The Snapshot Field gas recovery factor range for the Norian reservoirs proposed by Hess is 50%, 60% and 70% for the Low, Best and High Cases, respectively. The gas recovery factor range for the Carnian reservoirs proposed by Hess is 55%, 65% and 75% for the Low, Best and High Cases, respectively. These recovery factor ranges are consistent with what GCA would expect from a stacked reservoir sand, depletion drive gas field developed using vertical wells via a subsea tieback development.

15.4 Resource Estimate

The GIIP and Contingent Resources for the Snapshot Field were estimated using a 1D Monte Carlo Model. Reservoir parameter inputs are based on the sums and averages calculated from GCA's petrophysical interpretation. For the GRV input at the Norian 700 interval, GCA used its own depth conversion in the calculation of the P90 GRV and has accepted the Hess GRVs for the P50 and P10 inputs. At the Carnian 300 interval, the GCA depth conversion resulted in a higher GRV and this was, therefore, used as the P10 input; the Hess P90 and P50 inputs were accepted. GCA's input parameters into its 1D Monte Carlo Model, together with the resulting GIIP estimates, are given in **Table 48**.

GCA's estimates of GIIP volumes of the Snapshot Field are given in **Table 49**. Similarly Gas Contingent Resources are given in **Table 50** and associated Condensate Contingent Resources are summarized in **Table 51**.

Table 48: GCA's Input Parameters for its Estimate of GIIP for the Snapshot Field

Reservoir	Parameter	Unit	P90	P50	P10
Carnian 300	Contact	m TVDss	-4,427	-4,427	-4,427
	GRV	MM m^3	200	215	262
	NTG	Decimal	0.300	0.400	0.500
	Porosity	Decimal	0.080	0.120	0.160
	Sg	Decimal	0.605	0.675	0.745
	Gas Expansion Factor	1/Bg	281.3	286.2	289.9
	Condensate Yield	Stb/MM scf	3.5	5.0	6.5
	Recovery Factor	Decimal	0.55	0.65	0.75
	GIIP	**Bscf**	**42**	**71**	**110**
Norian 700	Contact	m TVDss	-2,366	-2,366	-2,366
	GRV	MM m3	50	56	70
	NTG	Decimal	0.330	0.430	0.530
	Porosity	Decimal	0.210	0.250	0.290
	Sg	Decimal	0.628	0.698	0.768
	Gas Expansion Factor	1/Bg	220.5	224.4	227.3
	Condensate Yield	Stb/MM scf	2.5	3.0	3.5
	Recovery Factor	Decimal	0.55	0.65	0.75
	GIIP	**Bscf**	**23**	**33**	**47**

Note: This estimate of GIIP is based on a probabilistic methodology using GCA's 1D Monte Carlo Model.

Table 49: GCA's Estimate of GIIP for the Snapshot Field

Reservoir	GIIP (Bscf)		
	Low	Best	High
Carnian 300	59	74	94
Norian 700	33	35	41

Note: This estimate of GIIP is based on GCA's total project GIIP volumes which were derived by calculating the average between a full arithmetic and probabilistic addition of individual field volumes to account for unknown dependencies between the fields. The average Low, Best and High Network case profiles were allocated to each field by proportionally scaling each individual field P90, P50 and P10 case to the respective average Network case profile.

Table 50: GCA's Estimate of Gas Contingent Resources for the Snapshot Field

Reservoir	Contingent Resources (Bscf)		
	1C	2C	3C
Carnian 300	37	49	63
Norian 700	19	21	25

Table 51: GCA's Estimate of Condensate Contingent Resources for the Snapshot Field

Reservoir	Contingent Resources (MMBbl)		
	1C	2C	3C
Carnian 300	0.2	0.2	0.5
Norian 700	0.0	0.1	0.1

15.5 Production Forecasts

Hess generated production forecasts for each of the Norian and Carnian reservoirs. The Norian-200 and Carnian-400 zones at Snapshot South have not been penetrated and therefore GCA has classified these recoverable volumes as Prospective Resources. GCA has therefore separated the production forecasts for Snapshot into discovered (Carnian-300 and Norian-700) and undiscovered (Snapshot South).

The Hess Best Case raw gas production forecasts are based on production profiles from the other Equus Fields from the corresponding reservoirs that match the Best Case recovery factors. The associated condensate production has been forecast based on a modeled CGR versus reservoir pressure relationship for each reservoir. GCA has accepted the Hess Best Case forecasts for raw gas and condensate. GCA generated Low and High Cases based on the Best Case profile but scaled for the Low and High Case GIIP estimates. These Cases are similar to deterministic simulation cases generated by Hess in their simulation uncertainty analysis.

The GCA discovered production forecasts for raw gas and condensate for the Snapshot Field are shown in **Figure 62** and **Figure 63**.

Figure 62: Snapshot Field Discovered Raw Gas Production Forecasts

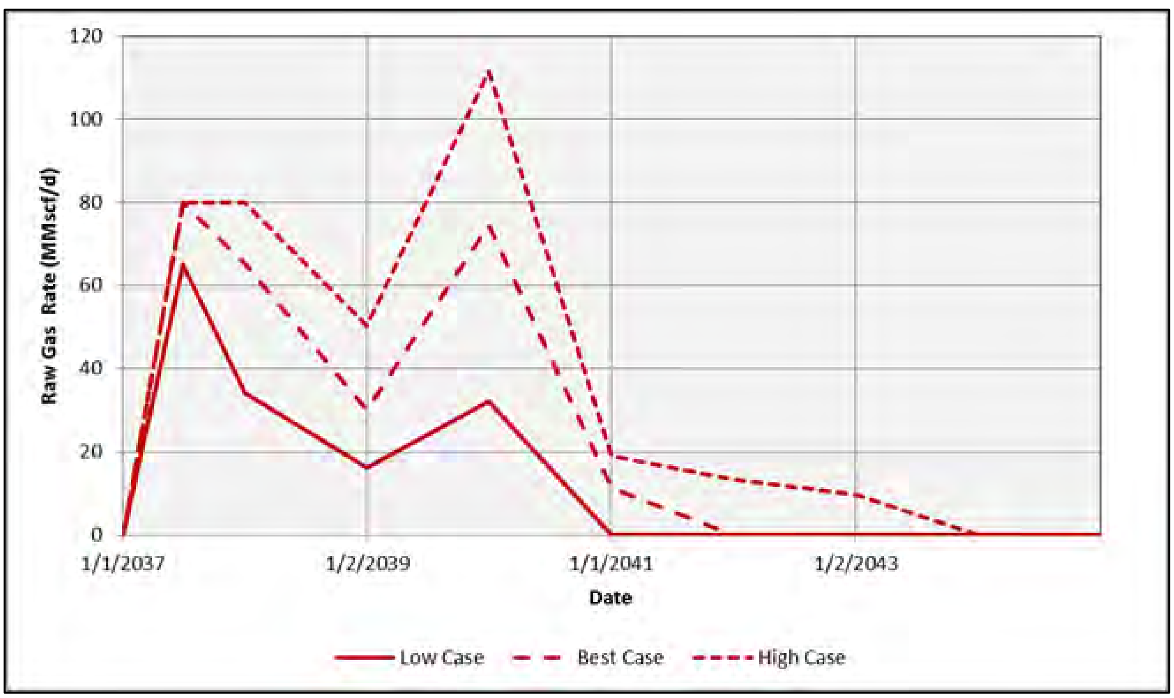
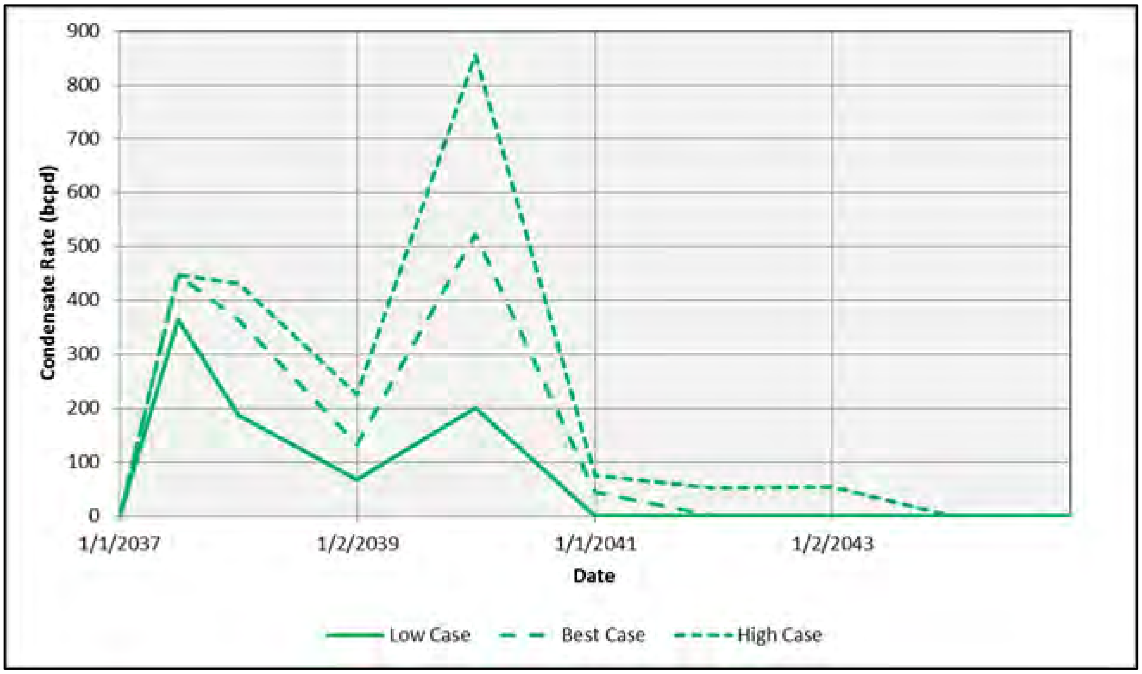


Figure 63: Snapshot Field Discovered Condensate Production Forecasts



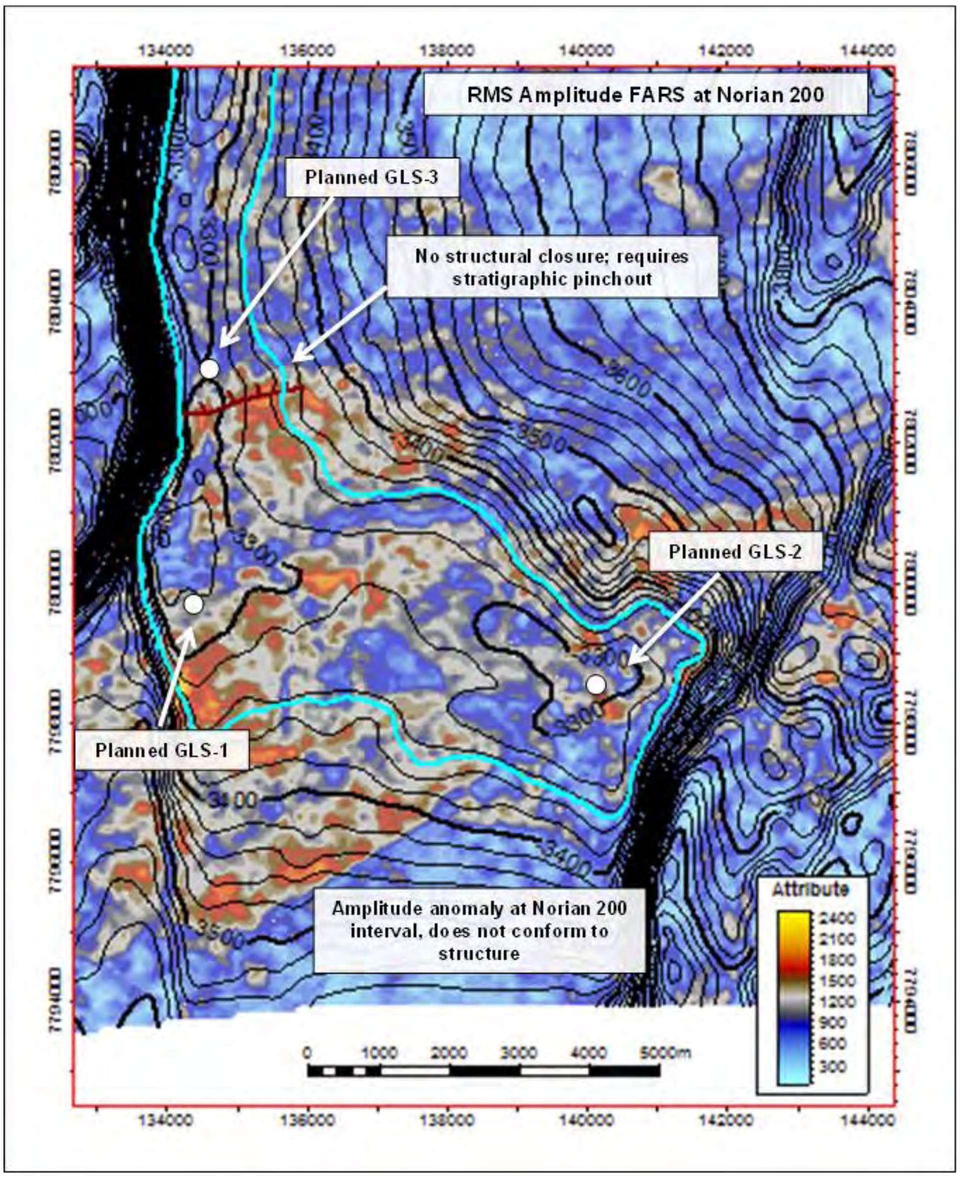
16 Gaulus Prospect

16.1 Field Summary

The Gaulus Prospect lies in the north of block WA-518-P. The structure is a north – south trending three way dip closure at the Triassic Mungaroo interval which has been defined in the 3D PSDM with an associated flatspot, analogous to the nearby Snapshot-1 Field (**Figure 64**). Closure to the west is by a north – south trending, westerly dipping extensional fault. The depositional model for the Mungaroo is channel sands deposited in a lower delta plane – delta front setting.

The primary target of the well is anticipated to be the Norian 800, where the flatspot is seen with successful wells at nearby Glenloth, Snapshot and Rimfire suggest there is also potential at the deeper Norian 200 and Carnian 300 intervals.

Figure 64: Norian 200 Reservoir at the Gaulus Prospect

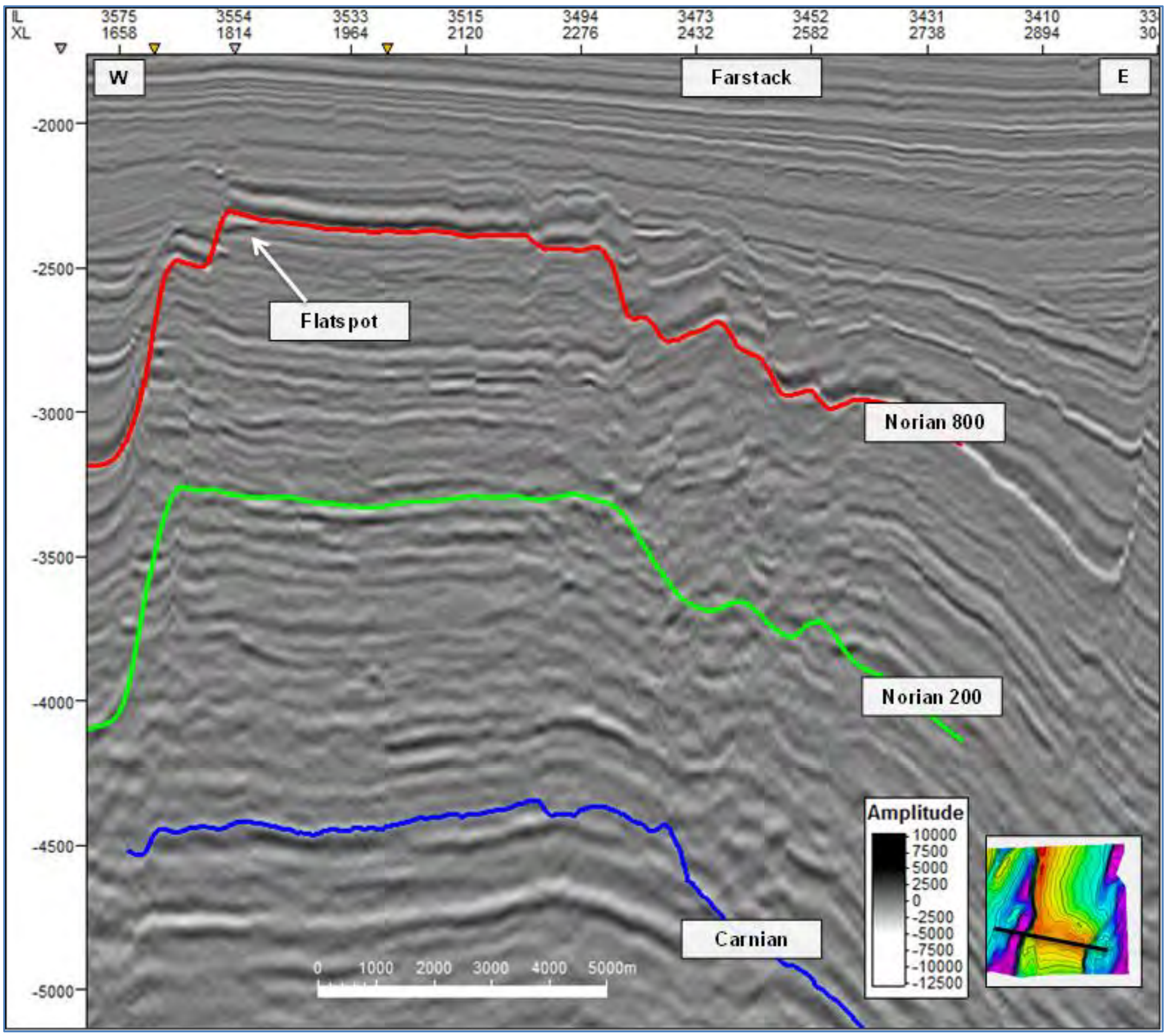


16.2 Geology and Geophysics Review

GCA has reviewed the seismic interpretation of the Gaulus Prospect provided by Hess in the Gaulus Petrel Project and in general believes it is reasonable (**Figure 65**). Each of the three interval have been picked on troughs and are represented by high amplitude responses when compared to the rest of the Mungaroo interval. RMS amplitude anomaly maps made from the Far Angle Stack suggest sand deposition is restricted to a channelized area which Hess has interpreted to be an incised valley.

Hess provided GCA with a Best case interpretation of each of the reservoir intervals. GCA used its own depth conversion to further test the structural uncertainty. The GCA depth conversion resulted in slightly lower GRVs at the Norian 200 interval but higher GRVs at the Norian 800 and carnian 300 intervals. GCA applied the same ranges of contacts and reservoir thicknesses as Hess.

Figure 65: Sesmic Dip Section across the Gaulus Prospect



16.3 Engineering Review

No well has been drilled on the Gaulus structure so no fluid samples have been collected. Reservoir fluid properties for the un-penetrated reservoir zones have been estimated based on properties seen in the other reservoir zones across the Equus Fields.

Gas gravity for the various reservoirs was estimated to be between 0.6 and 0.7. The gas expansion factor was estimated to be between 233 scf/rcf and 292 scf/rcf dependent on the depth of the reservoir. The combined CO_2 and N_2 concentration was estimated to be between 2.8% and 5.6%. CGR was estimated to be between 6 bbl/MMscf and 26 bbl/MMscf across the reservoirs.

16.3.1 Development Plan

If exploration drilling is successful, the Gaulus Field will initially be developed by a single well as part of the Equus Phase 2 development. The GLS-1 well will be a re-drill of the Gaulus-1 exploration well and will target the Carnian-400 reservoir unit. The well will be drilled in 2027 and come online in 2028. The well will be tied back to the Equus FPS facility via the same 10 inch flowline as the Bravo and Nimblefoot Fields.

The GLS-2 and GLS-3 wells will be drilled and completed as part of the Phase 3 development. The wells will target the Norian-200 and Norian-800 reservoirs, coming online in 2032. The wells will produced through the same flowline as the GLS-1 well.

The locations of the development wells on the Gaulus structure are shown in **Figure 64**.

16.3.2 Recovery Factor

Hess assessed the deliverability and recovery of gas and condensate from the Gaulus prospect based on analogue data. GCA has deemed this as approach as reasonable.

The Gaulus prospect is anticipated to be a combined structural and stratigraphic trap. The lateral extent of the reservoirs is limited by faulting and the depositional environment. This prevents connection to any large, regional aquifer and the reservoir drive mechanism is expected to be depletion drive with minimal water influx. For a gas reservoir with depletion drive, recovery is typically determined by minimum inlet pressure at the production facility, in this case the Equus FPS. The recovery can be lower dependent on the reservoir complexity, reservoir quality and number of reservoir zones.

Hess has based recovery factors on the same Mungaroo analogues cited in previous sections. These recovery factors are consistent with the recovery factors estimated by Hess for other Norian and Carnian reservoirs in the Equus fields. The Gaulus prospect gas recovery factor range for Norian reservoirs proposed by Hess is 55%, 65% and 75% for the Low, Best and High Cases, respectively. For the deeper Carnian reservoirs the range proposed is 55%, 60% and 65%. These recovery factor ranges are consistent with what GCA would expect from a stacked reservoir sand, depletion drive gas field developed using vertical wells via a subsea tieback development.

16.4 Resource Estimate

GIIP and Prospective Resources for the Gaulus Prospect were estimated using a 1D Monte Carlo Model. Reservoir parameter inputs are based on the sums and averages calculated from GCA's petrophysical interpretation.

For its GRV calculation, Hess has used reservoir thickness ranges together with varying contacts to estimate ranges in GRV. GCA has reviewed the contacts used by Hess and considers they are reasonable. For the Norian 200 and Carnian 300, GCA calculated its own reservoir thickness ranges based on the GCA petrophysical review of well data for all the Equus Project Fields. GRVs were calculated using the High Case thickness and High case contact and used as the P1 GRV input. Similarly, the Low Case thickness together with the Low case contact were used as the P99 input. P90, P50 and P10 GRVs were derived assuming a lognormal distribution.

For the Norian 800 reservoir, Hess has used a single contact at -2,360 m TVDss based on the flatspot seen in the seismic data. GCA's depth conversion resulted in a very similar GRV using this contact however, the GCA depth surfaces closes to the north at a LCC of -2,400 m TVDss while the Hess depth conversion doesn't. Amplitude extractions also show some support for this closure and so GCA has included this as a P10, while using the Hess closure as the P50. A P90 was estimated using a lognormal distribution. GCA's input parameters into its 1D Monte Carlo Model, together with the resulting GIIP estimates, are given in **Table 52**.

GCA's estimates of GIIP of the Gaulus Prospect are given in **Table 53**. Gas Prospective Resources are given in **Table 54** and associated Condensate Prospective Resources are summarized in **Table 55**.

Table 52: GCA's Input Parameters for its Estimate of GIIP for the Gaulus Prospect

Reservoir	Parameter	Unit	P90	P50	P10
Norian 200	Contact	m TVDss	-3,323	-	-3,406
	GRV	MM m^3	168	796	1,429
	NTG	Decimal	0.340	0.450	0.560
	Porosity	Decimal	0.130	0.160	0.190
	Sg	Decimal	0.530	0.600	0.670
	Gas Expansion Factor	1/Bg	256.7	258.0	259.3
	Condensate Yield	Stb/MM scf	5.0	10.0	15.0
	Recovery Factor	Decimal	0.55	0.65	0.75
	GIIP	**Bscf**	**96**	**305**	**593**
Norian 800	Contact	m TVDss	-	-2,360	-2,400
	GRV	MM m3	114	283	698
	NTG	Decimal	0.290	0.400	0.510
	Porosity	Decimal	0.220	0.250	0.280
	Sg	Decimal	0.730	0.800	0.870
	Gas Expansion Factor	1/Bg	231.7	233.0	234.3
	Condensate Yield	Stb/MM scf	5.0	10.0	15.0
	Recovery Factor	Decimal	0.55	0.65	0.75
	GIIP	**Bscf**	**68**	**182**	**478**
Carnian 300	Contact	m TVDss	-4,386	-4,486	-4,604
	GRV	MM m3	47	970	1,857
	NTG	Decimal	0.540	0.650	0.760
	Porosity	Decimal	0.061	0.091	0.121
	Sg	Decimal	0.530	0.600	0.670
	Gas Expansion Factor	1/Bg	290.7	292.0	293.3
	Condensate Yield	Stb/MM scf	10.0	15.0	20.0
	Recovery Factor	Decimal	0.55	0.65	0.75
	GIIP	**Bscf**	**19**	**275**	**887**

Note: This estimate of GIIP is based on a probabilistic methodology using GCA's 1D Monte Carlo Model.

Table 53: GCA's Estimate of GIIP for the Gaulus Prospect

Reservoir	GIIP (Bscf)		
	Low	Best	High
Norian 200	172	353	529
Norian 800	122	211	426
Carnian 300	27	121	637

Note: This estimate of GIIP is based on GCA's total project GIIP volumes which were derived by calculating the average between a full arithmetic and probabilistic addition of individual field volumes to account for unknown dependencies between the fields. The average Low, Best and High Network case profiles were allocated to each field by proportionally scaling each individual field P90, P50 and P10 case to the respective average Network case profile.

Table 54: GCA's Estimate of Gas Prospective Resources for the Gaulus Prospect

Reservoir	Prospective Resources (Bscf)			GCoS
	Low	Best	High	
Norian 200	110	227	345	0.38
Norian 800	78	135	277	0.50
Carnian 300	16	73	379	0.38

Table 55: GCA's Estimate of Condensate Prospective Resources for the Gaulus Prospect

Reservoir	Prospective Resources (Bscf)			GCoS
	Low	Best	High	
Norian 200	0.5	1	1.7	0.38
Norian 800	0.3	0.5	1	0.50
Carnian 300	0	1.8	6.8	0.38

16.5 Production Forecasts

The Hess Best Case raw gas production forecasts are based on production profiles from the other Equus fields from the corresponding reservoirs that match the 65% and 60% recovery factors in the Norian & Carnian reservoirs, respectively. The associated condensate production has been forecast based on a modeled CGR versus reservoir pressure relationship. GCA has accepted the Hess Best Case forecasts for raw gas and condensate. GCA generated Low and High Cases based on the Best Case profile but scaled for the Low and High Case GIIP estimates.

The GCA un-risked production forecasts for raw gas and condensate for the undiscovered Gaulus Prospect are shown in **Figure 66** and **Figure 67**.

Figure 66: Prospect Raw Gas Production Forecasts

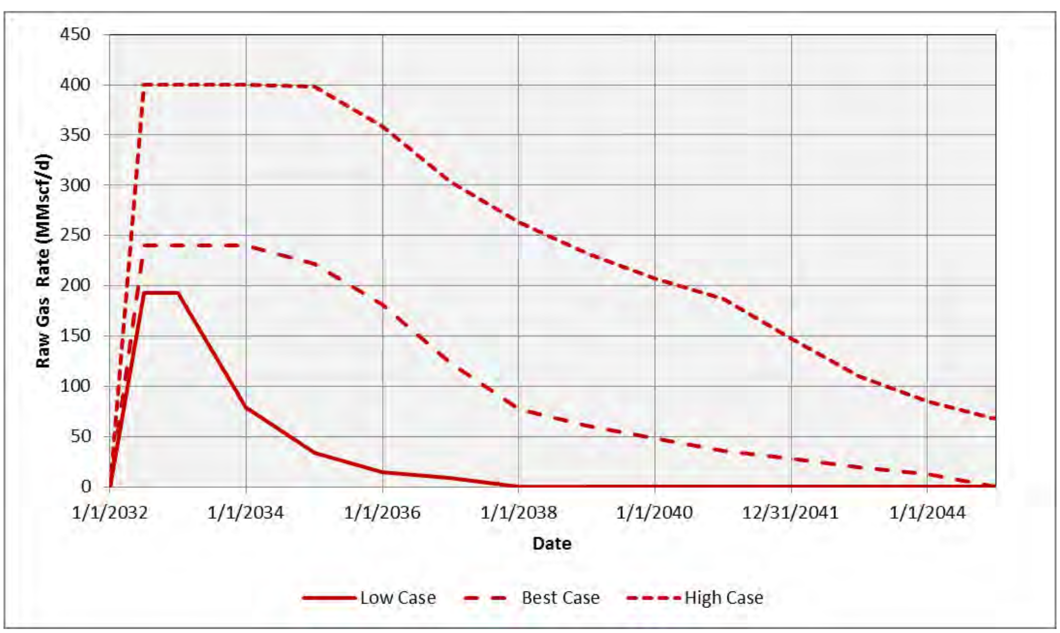
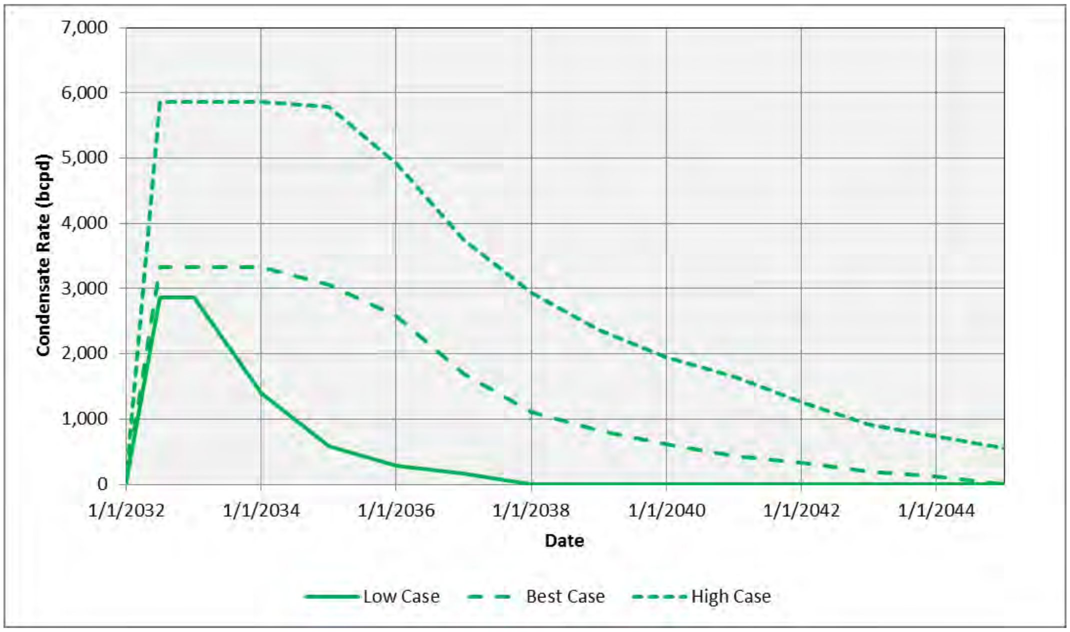


Figure 67: Gaulus Prospect Condensate Production Forecasts

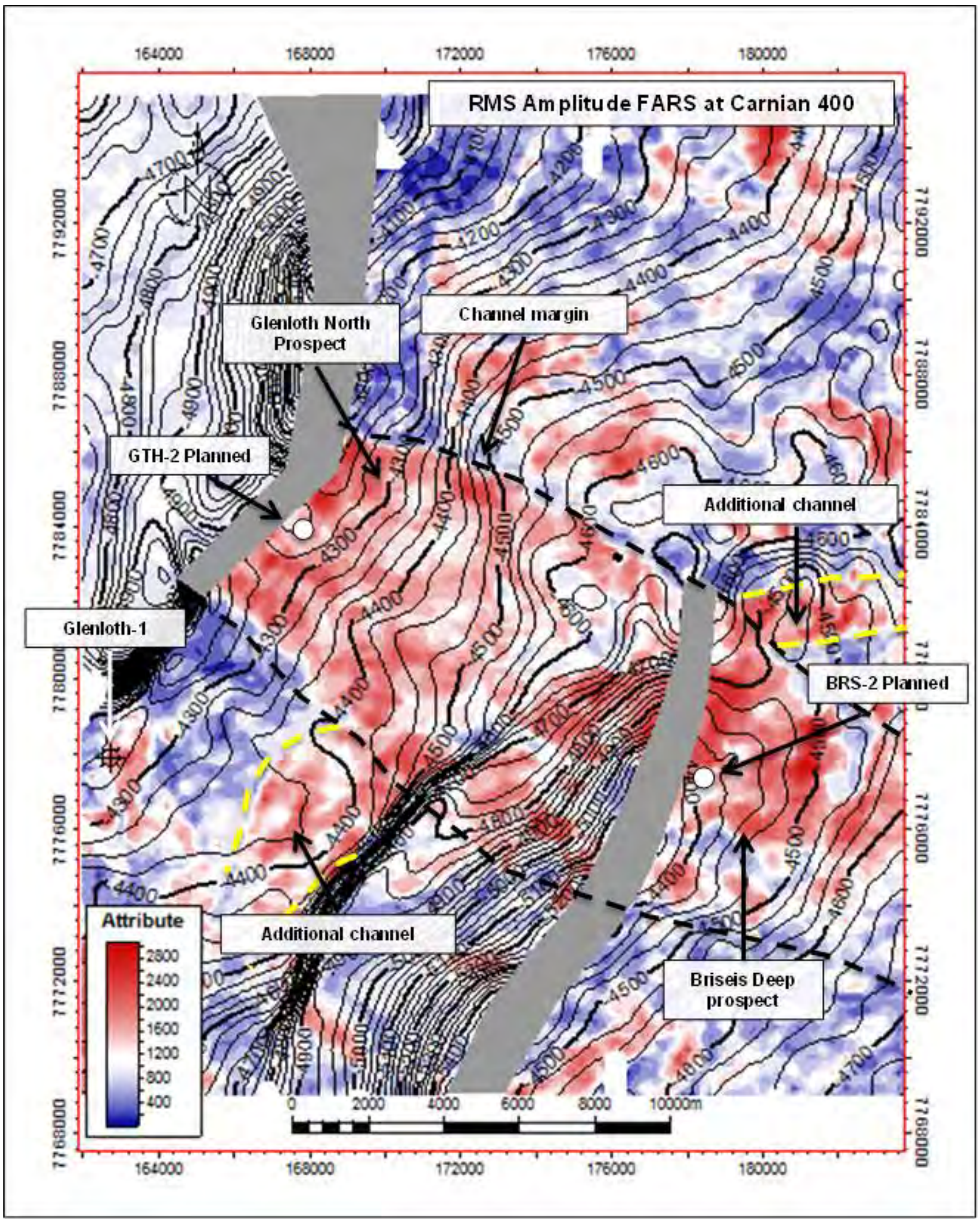


17 Glenloth North Prospect

17.1 Field Summary

The Glenloth North Prospect lies in the north of block WA-70-P. The structure is an east – west trending channel which has been identified by amplitude anomalies in the Carnian 400 interval. Closure to the northwest and southeast relies on cross fault seal while closure to the northeast and southwest is stratigraphic relying on sands thinning towards the channel margins, there is no dip closure. The Glenloth North Prospect is separated by a fault from the Briseis Deep Prospect which lies to the East within the same channel complex (**Figure 68**).

Figure 68: Carnian 400 Reservoir at the Glenloth North and Briseis Deep Prospects

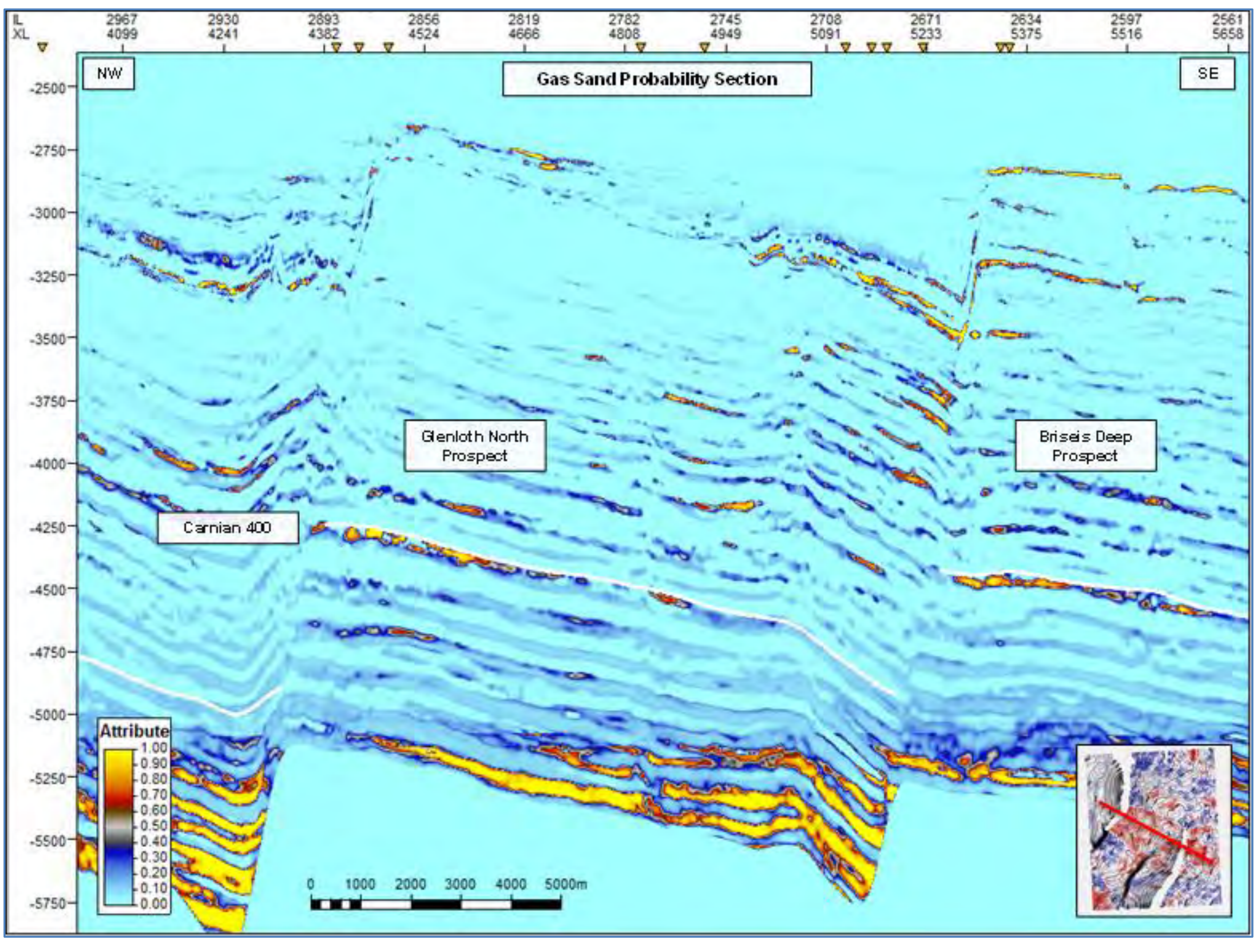


17.2 Geology and Geophysics Review

GCA has reviewed the seismic interpretation of the Glenloth North Prospect provided by Hess in the Glenloth Petrel Project and in general considers it is reasonable (**Figure 69**). A strong positive response is seen in both the Gas Sand Probability and FARS seismic volumes. An additional channel which may be in communication lies to the south however this has been excluded from the volume estimate but may offer additional upside. Further potential upside lies to the northeast where an area, which is likely within the channel boundary but which does not have a positive Gas Sand Probability response, is located. This too has been excluded from the volume estimate however may represent poorer quality reservoir sands.

Hess provided GCA with a Best Case interpretation for the Top and Base of the Carnian 300. Hess used varying contact height of to estimate a range in the GRV of the Glenloth North Prospect. GCA has reviewed the contacts used and consider they are reasonable. GCA used its own depth conversion to further test the structural uncertainty. The GCA depth conversion resulted in approximately 50% greater GRVs when applying the Hess contacts to the GCA depth maps.

Figure 69: Seismic Section through the Glenloth North and Brisies Deep prospects



17.3 Engineering Review

Reservoir fluid properties for the Carnian 400 reservoir at Glenloth North have been estimated based on properties seen in other reservoir zones in the Glenloth Field (see Section 9.3).

17.3.1 Well Tests

The Triassic Carnian reservoir was tested by the Glenloth-1 well. The well tested an interval over the Carnian-300 reservoir unit. The test supports the estimated flow rates for the Glenloth North development wells for the un-penetrated Carnian-400 reservoir.

17.3.2 Development Plan

By 2037 the main Glenloth Carnian-300 reservoir is expected to be depleted. As part of the Equus Phase 4 and Phase 5 developments, the four Glenloth production wells are planned to be re-entered and completed in the other Glenloth reservoirs plus the Glenloth North Carnian 400. To reduce well intervention costs, the Glenloth development wells have been designed for intervention from light vessels. Phase 4 and Phase 5 of the Equus project are scheduled to come online in 2037 and 2039, respectively (**Figure 68**).

17.3.3 Recovery Factor

The Glenloth North recovery factor range proposed by Hess is 55%, 65% and 75% for the Low, Best and High Cases, respectively. This recovery factor range is consistent with the Glenloth Field reservoirs and ranges from simulation and analogue analysis, and also with the range GCA would expect from a stacked reservoir sand, depletion drive gas field developed using vertical wells via a subsea tieback development.

17.4 Resource Estimate

The GIIP and Prospective Resources for the Glenloth North Prospect were estimated using a 1D Monte Carlo Model. Reservoir parameter inputs are based on the sums and averages calculated from GCA's petrophysical interpretation.

GRV inputs were estimated using a combination of the Hess and GCA depth converted surfaces to allow for the potential upside shown by the GCA surfaces. The Hess Low Case depth surface and contact and the GCA High Case depth surface with Hess' High Case contact were used to calculate GRVs for the P90 and P10 inputs respectively. A lognormal distribution was applied to estimate a P50 GRV. GCA's input parameters into its 1D Monte Carlo Model, together with the resulting GIIP estimates, are given in **Table 56**.

GCA's estimates of GIIP of the Glenloth North Prospect are given in **Table 57**.

Gas Prospective Resources are given in **Table 58** and associated Condensate Prospective Resources are summarized in **Table 59**.

Table 56: GCA's Input Parameters for its Estimate of GIIP for the Glenloth North Prospect

Reservoir	Parameter	Unit	P90	P50	P10
Carnian 400	Contact	m TVDss	-4,300	-	-4,580
	GRV	MM m^3	248	910	3,338
	NTG	Decimal	0.590	0.700	0.810
	Porosity	Decimal	0.130	0.160	0.190
	Sg	Decimal	0.516	0.586	0.656
	Gas Expansion Factor	1/Bg	245.5	249.8	253.0
	Condensate Yield	Stb/MM scf	2.0	5.0	8.0
	Recovery Factor	Decimal	0.55	0.65	0.75
	GIIP	**Bscf**	**138**	**513**	**1,922**

Note: This estimate of GIIP is based on a probabilistic methodology using GCA's 1D Monte Carlo Model.

Table 57: GCA's Estimate of GIIP for the Glenloth North Prospect

Reservoir	GIIP (Bscf)		
	Low	Best	High
Carnian 400	248	594	1714

Note: This estimate of GIIP is based on GCA's total project GIIP volumes which were derived by calculating the average between a full arithmetic and probabilistic addition of individual field volumes to account for unknown dependencies between the fields. The average Low, Best and High Network case profiles were allocated to each field by proportionally scaling each individual field P90, P50 and P10 case to the respective average Network case profile.

Table 58: GCA's Estimate of Gas Prospective Resources for the Glenloth North Prospect

Reservoir	Prospective Resources (Bscf)			GCoS
	Low	Best	High	
Carnian 400	160	382	1,136	0.38

Table 59: GCA's Estimate of Condensate Prospective Resources for the Glenloth North Prospect

Reservoir	Prospective Resources (MMBbl)			GCoS
	Low	Best	High	
Carnian 400	0.5	1.3	6.1	0.38

17.5 Production Forecasts

The GCA un-risked production forecasts for raw gas and condensate for the undiscovered Glenloth North Prospect are shown in **Figure 70** and **Figure 71**.

Similar to the discovered reservoirs, the raw gas production forecasts are based on deterministic cases from simulation modeling. The associated condensate production has been forecast based on a modeled CGR versus reservoir pressure relationship.

Figure 70: Glenloth North Prospect Raw Gas Production Forecasts

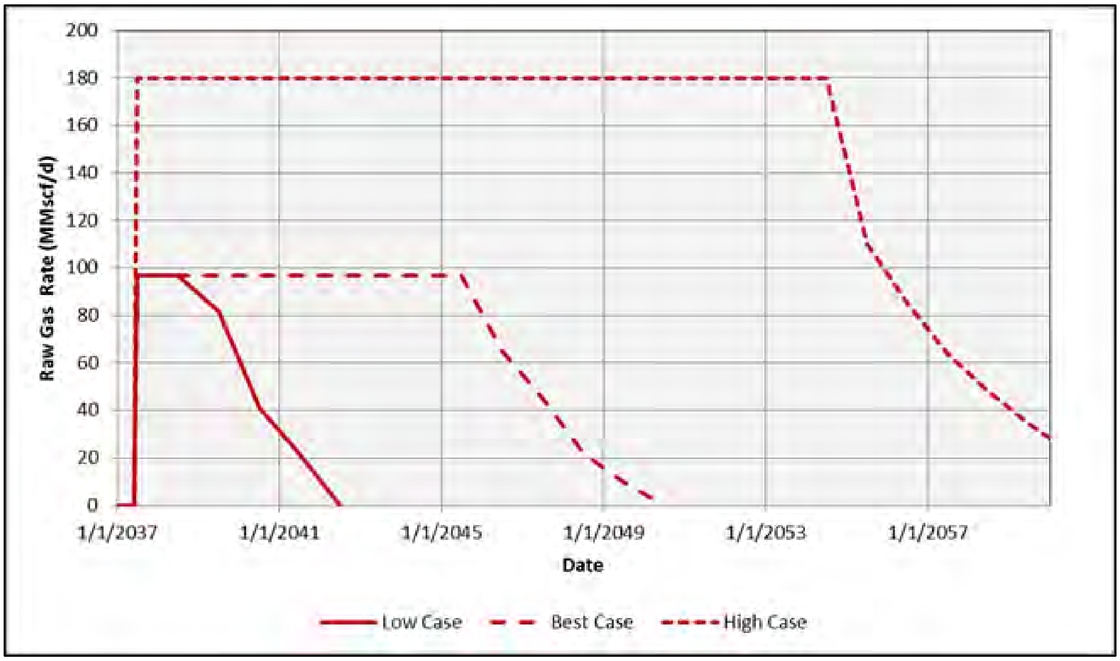
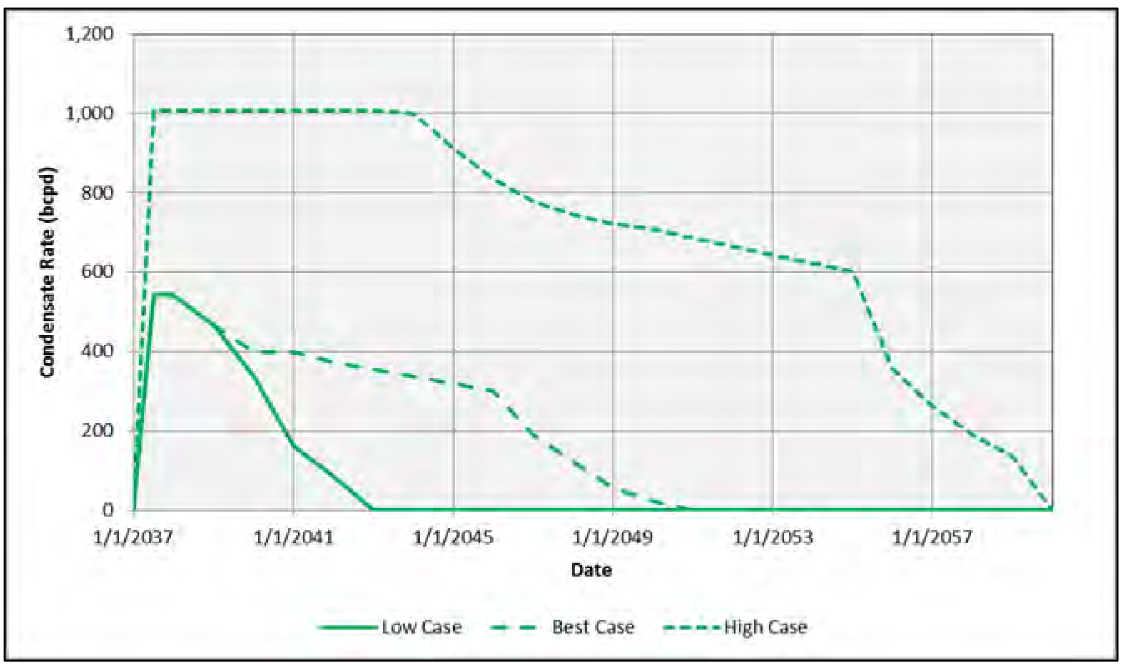


Figure 71: Glenloth North Prospect Condensate Production Forecasts



18 Briseis Deep Prospect

18.1 Field Summary

The Briseis Deep Prospect lies in the north of block WA-70-P. The structure is an east – west trending channel which has been identified by amplitude anomalies in the Carnian 400 interval and forms the eastern extent of the channel mapped as the Glenloth North Prospect (**Figure 68**). The two Prospects are separated by a structural low and two associated southwest – northeast trending extensional faults. As with Glenloth North, closure to the northwest is by fault seal while closure to the northeast and southwest is stratigraphic relying on sand thinning towards the channel margins, at Briseis Deep, amplitude maps suggest that closure to the southeast is dip controlled.

An additional target at Briseis Deep has been identified, also by amplitude anomalies, at the Carnian 300 interval. As with the Carnian 400, the Carnian 300 closure represents a channel structure and is fault sealed to the northwest, closure to the northeast and southwest is stratigraphic at the channel margins and southeast closure is dip related.

18.2 Geology and Geophysics Review

GCA has reviewed the seismic interpretation of the Briseis Deep Prospect provided by Hess in the Briseis Petrel Project and in general considers it is reasonable (**Figure 69**). At the Carnian 400 interval, a strong positive response is seen in both the Gas Sand Probability and FARS seismic volumes which lies within the same channel system seen at Glenloth North. An additional channel which may be in communication lies to the north, this has been excluded from the volume estimate but may offer additional upside.

At the Carnian 300 interval, a channel structure is highlighted in FARS amplitude extractions however, no response is seen in the Gas Sand Probability cube. Hess has interpreted this as a response to relatively harder gas-filled sands as the gas sand Probability cube has been calibrated to a soft sand response at Glenloth-1 and therefore will not see a positive response to harder sands.

Hess provided GCA with a Best Case interpretations for the Top and Base of the Carnian 400 and Carnian 300. Hess used varying contact height of to estimate a range in the GRV of the Briseis Deep Prospect. GCA has reviewed the contacts used and consider that they are reasonable. GCA used its own depth conversion to further test the structural uncertainty. The GCA depth conversion resulted in approximately 50% higher GRVs in the P90 cases, however 40% lower GRVs in the Base and High Cases when applying the Hess contacts to the GCA depth maps.

18.3 Engineering Review

Reservoir fluid properties for the un-penetrated Triassic Carnian-300 and Carnian-400 reservoir zones at the Briseis Deep Prospect have been estimated based on properties seen in the other reservoir zones at Briseis and also Glenloth Fields (see **Section 12.3**).

18.3.1 Well Tests

The Triassic Carnian reservoir was tested by the Glenloth-1 well. The well tested an interval over the Carnian-300 reservoir unit. The test supports the estimated flow rates for the Briseis development wells for the un-penetrated Carnian-300 and Carnian-400 reservoir sands.

18.3.2 Development Plan

Initially, the Briseis Field is planned to be developed in the un-penetrated Carnian-300 and Carnian-400 zones as part of the Equus Phase 3 development. The development plan includes 2 low-inclination development wells in crestal locations to maximize the stand-off from the GWC as shown in **Figure 68**.

The BRS-1 and BRS-2 wells will be drilled and produced initially from the un-penetrated Briseis Deep Carnian reservoirs, in order to allow the wells to later be recompleted in shallower reservoirs. The wells are scheduled to be drilled in 2031 and come online in 2032. The wells will be tied back to the Equus FPS facility via a 10 inch flowline shared with the Glencoe and Glenloth Fields.

18.3.3 Recovery Factor

Hess assessed the deliverability and recovery of gas and condensate from the Briseis field using reservoir simulation and analogue data. GCA has deemed this as approach as reasonable.

The Briseis Triassic reservoirs are combined structural and stratigraphic traps. The lateral extent of the reservoir is limited by faulting and the depositional environment. This restricts connection to any large, regional aquifer and the reservoir drive mechanism is expected to be depletion drive with minimal water influx. For a gas reservoir with depletion drive, recovery is typically determined by minimum inlet pressure at the production facility, in this case the Equus FPS. The recovery can be lower dependent on the reservoir complexity, reservoir quality and number of reservoir zones.

The Low, Best and High Cases proposed by Hess for the Briseis Deep Carnian reservoirs is consistent with other Carnian reservoirs and is 55%, 65% and 75%, respectively. The range matches what GCA would expect from a stacked reservoir sand, depletion drive gas field developed using vertical wells via a subsea tieback development.

18.4 Resource Estimate

The GIIP and Prospective Resources for the Briseis Deep Prospect were estimated using a 1D Monte Carlo Model. Reservoir parameter inputs are based on the sums and averages calculated from GCA's petrophysical interpretation.

GRV inputs were estimated using the Hess Low and High Case depth surfaces as P90 and P10 inputs with the P50 determined assuming a lognormal distribution which gives a lower GRV than used by Hess to account for the potential low side suggested by GCA's depth conversion. GCA's input parameters into its 1D Monte Carlo Model, together with the resulting GIIP estimates, are given in **Table 60**.

GCA's estimates of GIIP of the Briseis Deep Prospect are given in **Table 61**. Gas Prospective Resources are given in **Table 62** and associated Condensate Prospective Resources are summarized in **Table 63** together with the associated GCoS.

Table 60: GCA's Input Parameters for its Estimate of GIIP for the Briseis Deep Prospect

Reservoir	Parameter	Unit	P90	P50	P10
Carnian 300	Contact	m TVDss	-4,789	-	-4,918
	GRV	MM m^3	228	535	1,259
	NTG	Decimal	0.590	0.700	0.810
	Porosity	Decimal	0.053	0.083	0.113
	Sg	Decimal	0.438	0.508	0.578
	Gas Expansion Factor	1/Bg	290.1	295.2	299.0
	Condensate Yield	Stb/MM scf	10.0	15.4	20.0
	Recovery Factor	Decimal	0.55	0.65	0.75
	GIIP	**Bscf**	**58**	**157**	**413**
Carnian 400	Contact	m TVDss	-4,400	-	-4,580
	GRV	MM m3	150	542	1,955
	NTG	Decimal	0.590	0.700	0.810
	Porosity	Decimal	0.058	0.088	0.118
	Sg	Decimal	0.530	0.600	0.670
	Gas Expansion Factor	1/Bg	280.7	285.6	289.3
	Condensate Yield	Stb/MM scf	10.0	15.4	20.0
	Recovery Factor	Decimal	0.55	0.65	0.75
	GIIP	**Bscf**	**50**	**192**	**742**

Note: This estimate of GIIP is based on a probabilistic methodology using GCA's 1D Monte Carlo Model.

Table 61: GCA's Estimate of GIIP for the Briseis Deep Prospect

Reservoir	GIIP (Bscf)		
	Low	Best	High
Carnian 300	103	181	368
Carnian 400	90	222	661

Note: This estimate of GIIP is based on GCA's total project GIIP volumes which were derived by calculating the average between a full arithmetic and probabilistic addition of individual field volumes to account for unknown dependencies between the fields. The average Low, Best and High Network case profiles were allocated to each field by proportionally scaling each individual field P90, P50 and P10 case to the respective average Network case profile.

Table 62: GCA's Estimate of Gas Prospective Resources for the Briseis Deep Prospect

Reservoir	Prospective Resources (Bscf)			GCoS
	Low	Best	High	
Carnian 300	65	118	239	0.30
Carnian 400	57	143	427	0.38

Table 63: GCA's Estimate of Condensate Prospective Resources for the Briseis Deep Prospect

Reservoir	Prospective Resources (MMBbl)			GCoS
	Low	Best	High	
Carnian 300	0.4	0.7	1.5	0.30
Carnian 400	0.2	0.7	2.1	0.38

18.5 Production Forecasts

The GCA un-risked production forecasts for raw gas and condensate for the undiscovered Briseis Prospect are shown in **Figure 72** and **Figure 73**. The raw gas production forecasts have been based on the production profiles from the similar reservoirs. The associated condensate production has been forecast based on a modeled CGR versus reservoir pressure relationship.

Figure 72: Briseis Field Raw Gas Production Forecasts

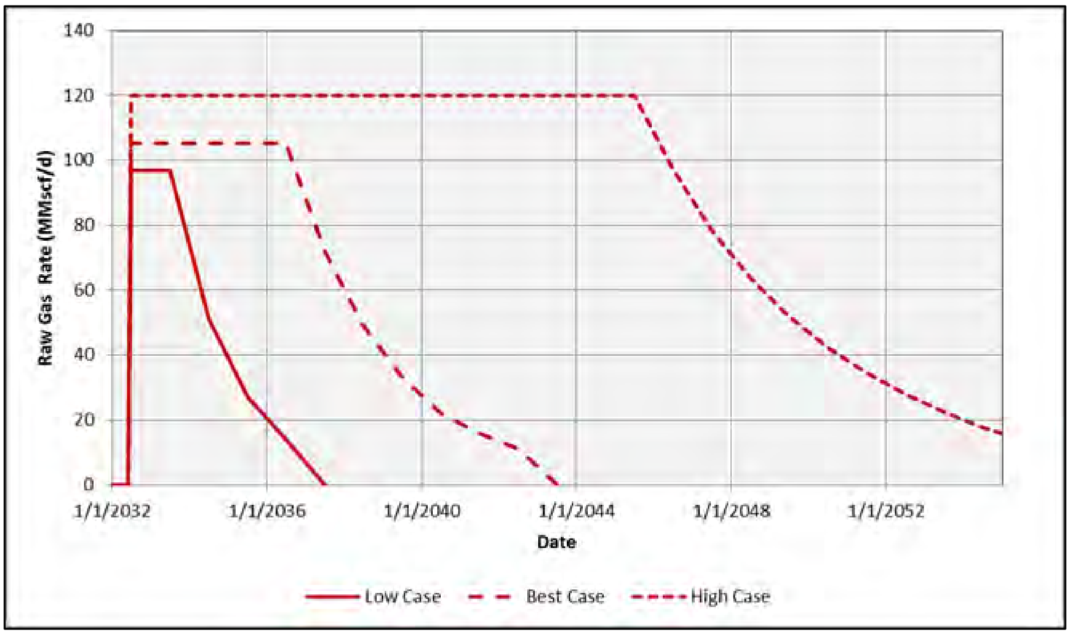
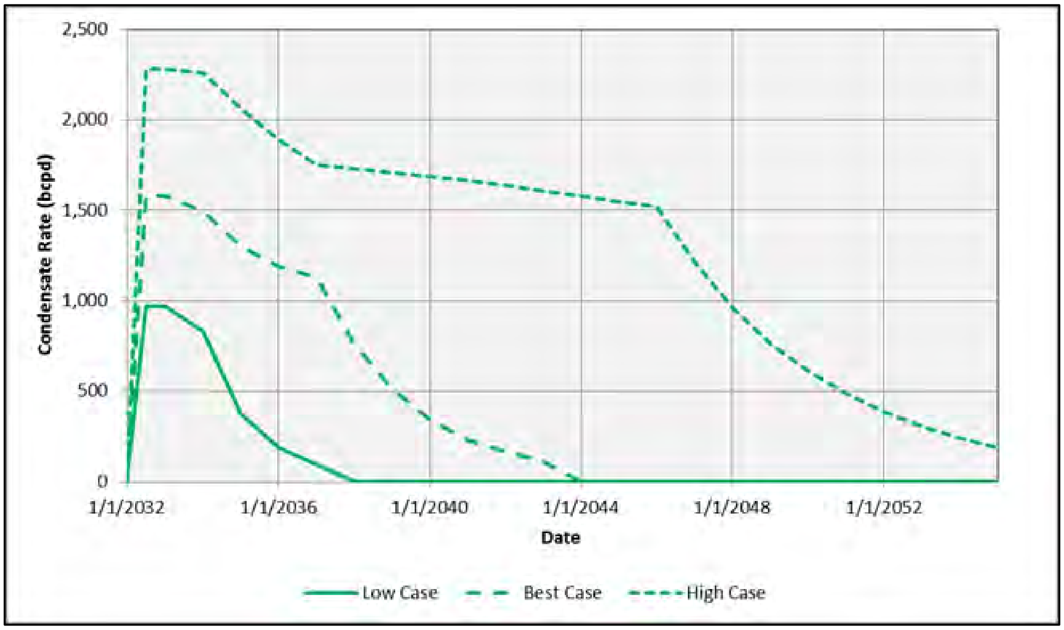


Figure 73: Briseis Field Condensate Production Forecasts



19 Network Modelling

The Equus Development is a complex, combined surface and subsea production system connecting 11 potential fields with multiple reservoirs via three 12 inch interfield flowlines back to a Floating Production System (FPS) facility. Gas and condensate export is via a 22 inch trunkline to the NWS JV LNG facility at Karratha. The original development was planned and staged over 5 Phases from 2021 to 2039, as shown in **Figure 74**. The Operator's schedule shows first year production startup for the original development at end of Q3 2021. In order to meet this timing, Phase 1 drilling operations will need to commence 24 months earlier. Phase 1 facilities design expenditure would start 60 months earlier, with major construction expenditure commencing 48 months in advance of first production. Offshore construction activities would start some 20 months prior to first production. GCA has maintained the original project schedule prior to the Equus project deferment as an indicative timeline. The example lead times mentioned above can guide the reader on any possible future scheduling of the project.

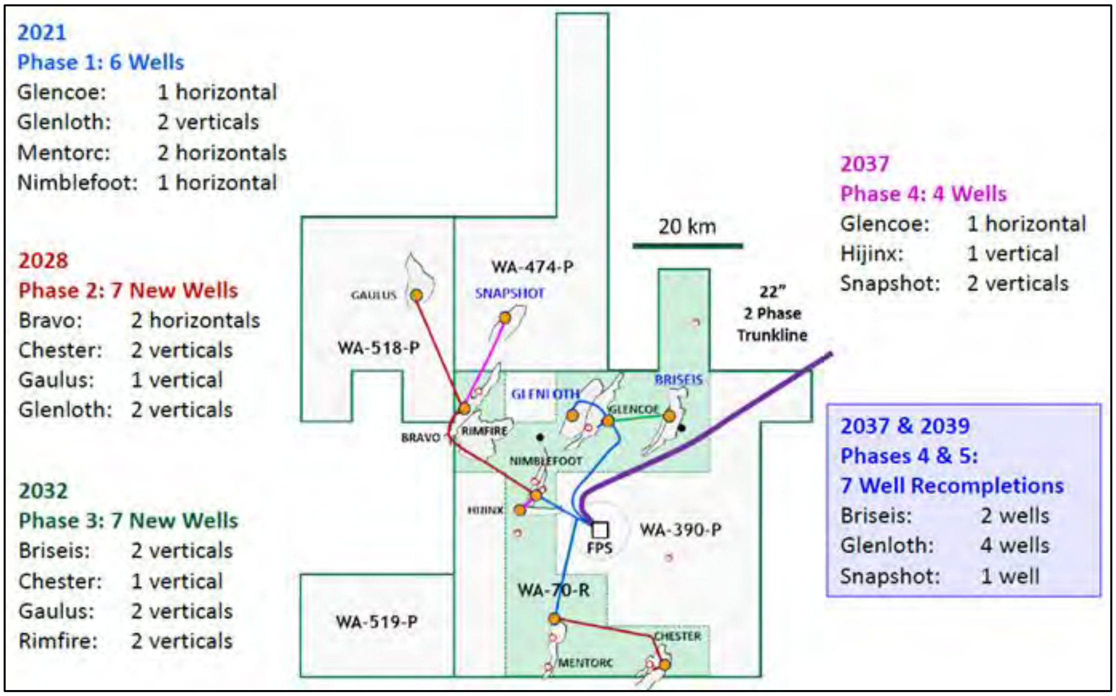
Figure 74: Equus Project Multi-Phase Development Plan

Field	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
Bravo		2			
Briseis			2		Cret & N600
Mentorc	2				
Nimblefoot	1				
Glencoe	1RE			1	
Chester		2	1		
Gaulus		1	1		
			1		
Glenloth	2	2		N400 & C400	N600 & N100
Hijinx				1	
Rimfire			1		
			1		
Snapshot				1RE	N700
				1	
Well #	6 inc. 1 RE	7	7	4 inc. 1RE	0
Recompletion #	0	0	0	2	5

Cretaceous
Jurassic
Triassic Upper Norian
Triassic Lower Norian
Triassic Carnian
Recompletion
RE Re-Entry of Existing Well

A schematic of the Equus Development including the development phases and their timing for the Hess Base Case is shown in **Figure 75**.

Figure 75: Equus Project Development Plan Schematic with Phasing



To model production from such a complex system, Hess has utilized Petroleum Expert's GAP network modeling software. This software package is a widely used nodal analysis software package, which enables optimization of a production system and limitation of the system to specified constraints. This is common industry practice, and GCA has deemed this as approach as reasonable.

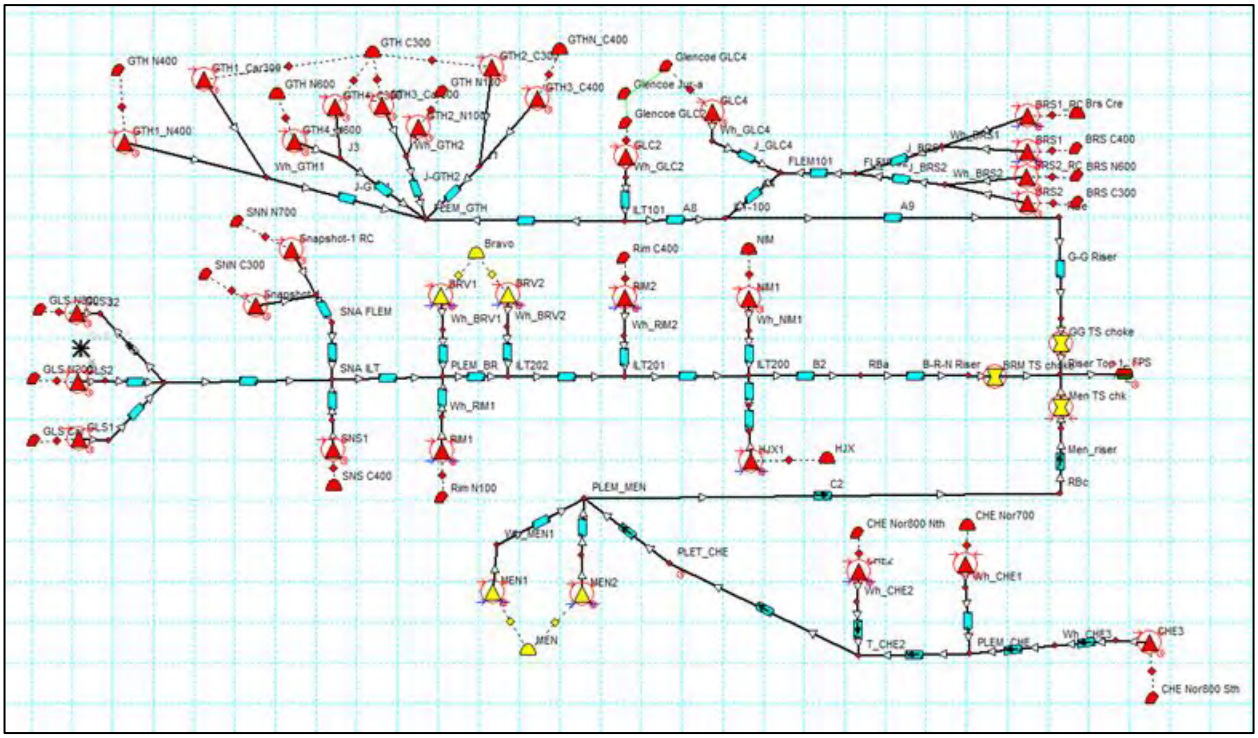
The production constraints used in the GAP model were based on those from the scoping design of the Equus development. These include:

- Maximum FPS Raw Gas Rate - 395 MMscf/d
- Maximum Gas Export Trunkline Capacity - 450 MMscf/d
- Minimum FPS Export Gas Rate - 70 MMscf/d
- Minimum Interfield Subsea Flowing Rate - 20 MMscf/d
- NWS JV CO_2 Limit - 2.8%
- NWS JV N_2 Limit - 4%

The GAP model uses material balance tanks which are calibrated to production forecasts from the individual field analysis. Well models attached to these tanks have been calibrated to results of exploration and appraisal well Drill Stem Tests and the results of the field simulation models. The GAP model also prioritizes production from high CGR fields.

A screenshot of the Equus Development GAP model is shown in **Figure 76**.

Figure 76: Equus Development GAP Network Model



20 Production Profiles

Hess has generated Low, Best and High Case Gap network models. These were deterministic cases based on the Low, Best and High Case EUR from probabilistic aggregation using GeoX. In each case, the framework of the network model was the same, but the reservoir tanks were adjusted for GIIP to match the GeoX aggregated EUR of the specified case. The Hess Low, Best and High Cases included undiscovered volumes (Gaulus, Briseis Deep & Glenloth North) which were risked for Geological Chance of Success. In the Low and High Cases, Hess removed some of the development activities due to low volumes or GCoS. In these cases Hess adjusted the timing of the development activities to ensure the production profile met the required gas sales plateau rate.

GCA ran its own Low, Best and High network cases to account for differences to Hess in GIIP and EUR volumes for a number of fields. GCA's total project resource volumes were derived by calculating the average between a full arithmetic and probabilistic addition of the individual field volumes to account for unknown dependencies between the fields. The average Low, Best and High Network case profiles were allocated to each field by proportionally scaling each individual field 1C, 2C and 3C Contingent Resource cases and Low, Best and High Prospective Resource cases to the respective average Network case profile.

GCA initially ran cases not including the undiscovered volumes, to generate production profiles to estimate Contingent Resources. Adjustments were made to timing of the different development phases to ensure the profile was able to meet the required sales volumes.

In the Low Case the production rate was limited to wet gas rate equivalent to 1.5 mtpa of LNG per annum (272 MMscf/d) based on the current Memorandum of Understanding (MOU) with the NWS JV. The Best and High Cases were run at 1.5 Mtpa until January 2024, when they were increased by 10% to 1.65 Mtpa (300 MMscf/d), which is an option under the NWS JV MOU. The MOU period is for 15 years until 2036.

Downtime was assumed to be 16.3%. All of the cases run adhere to the required CO_2 and N_2 limitations for the Karratha Gas Plant (2.8% and 4% respectively).

Figure 77 shows the GCA Best Case wet gas production profile including the development phasing for the Equus Development. The profile shows that Equus production is able to meet the required wet gas rates under the NWS JV MOU.

Figure 77: Equus Development Best Case Contingent Resources Wet Gas Production Forecast with Development Phasing

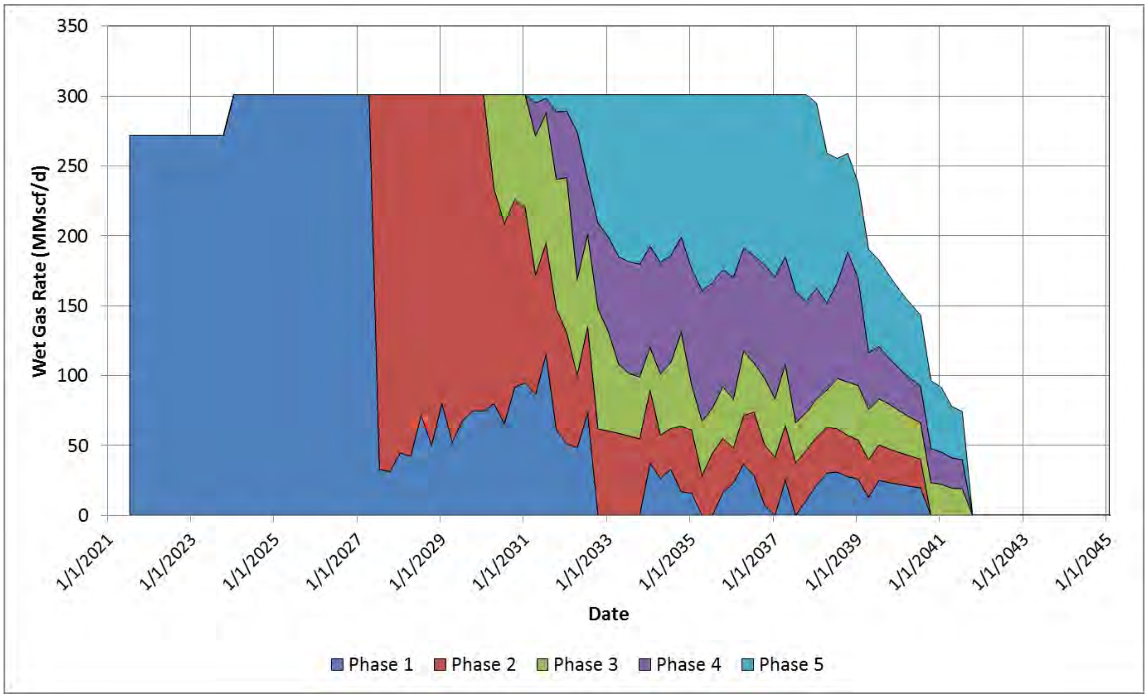


Figure 78 shows the GCA Best Case condensate production profile including the development phasing for the Equus Development. By prioritizing the high CGR fields in the early Phases, the highest condensate rates are earlier in the production profile.

Figure 78: Equus Development Best Case Contingent Resources Condensate Production Forecast with Development Phasing

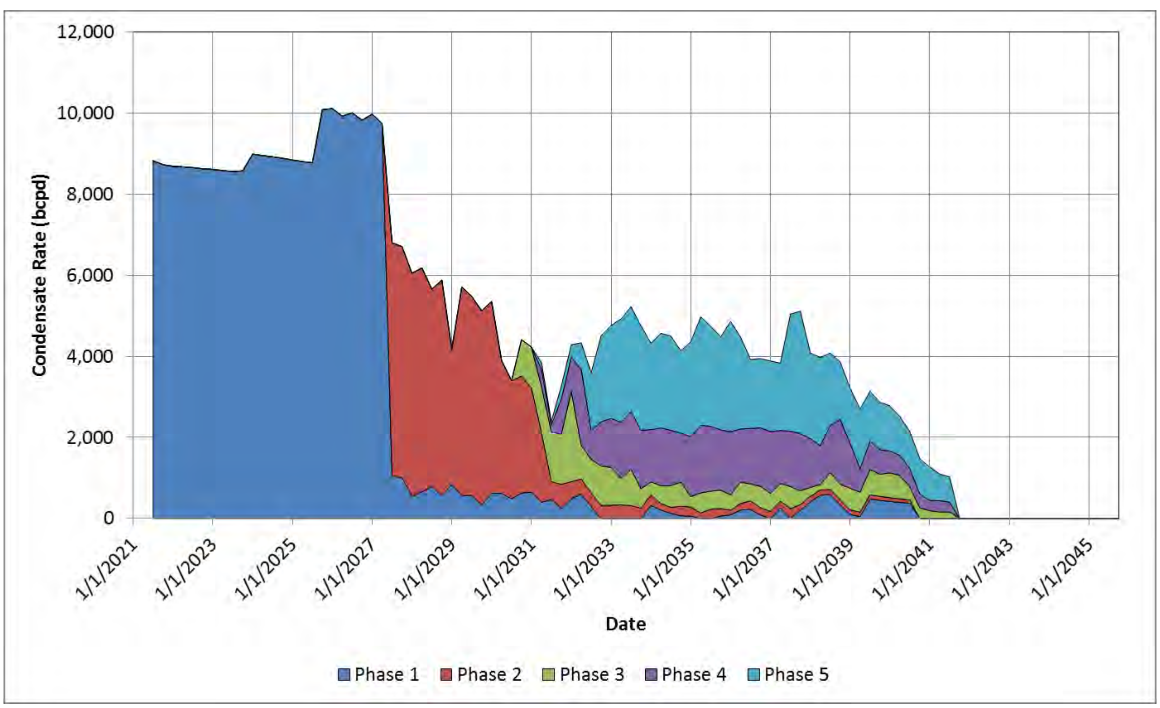


Figure 79 and **Figure 80** show the GCA Low, Best and High Case wet gas and condensate production profiles including only the discovered volumes. In all cases, the production profiles extend beyond the 15 year MOU period.

Figure 79: Equus Development Contingent Resources Wet Gas Production Forecasts

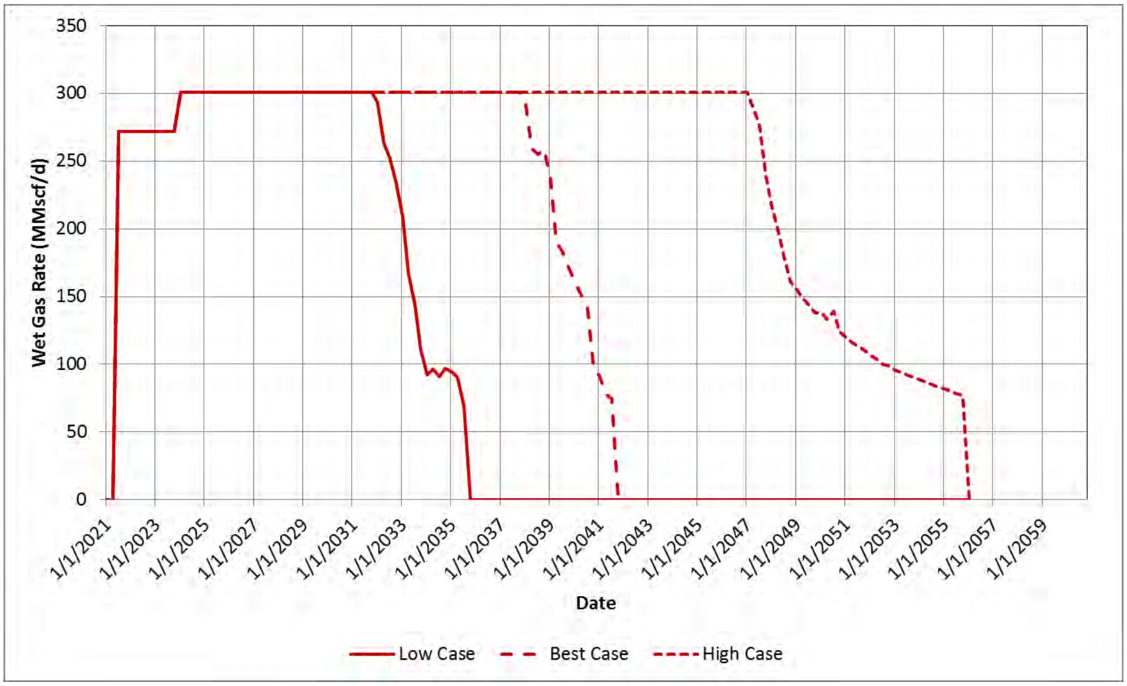
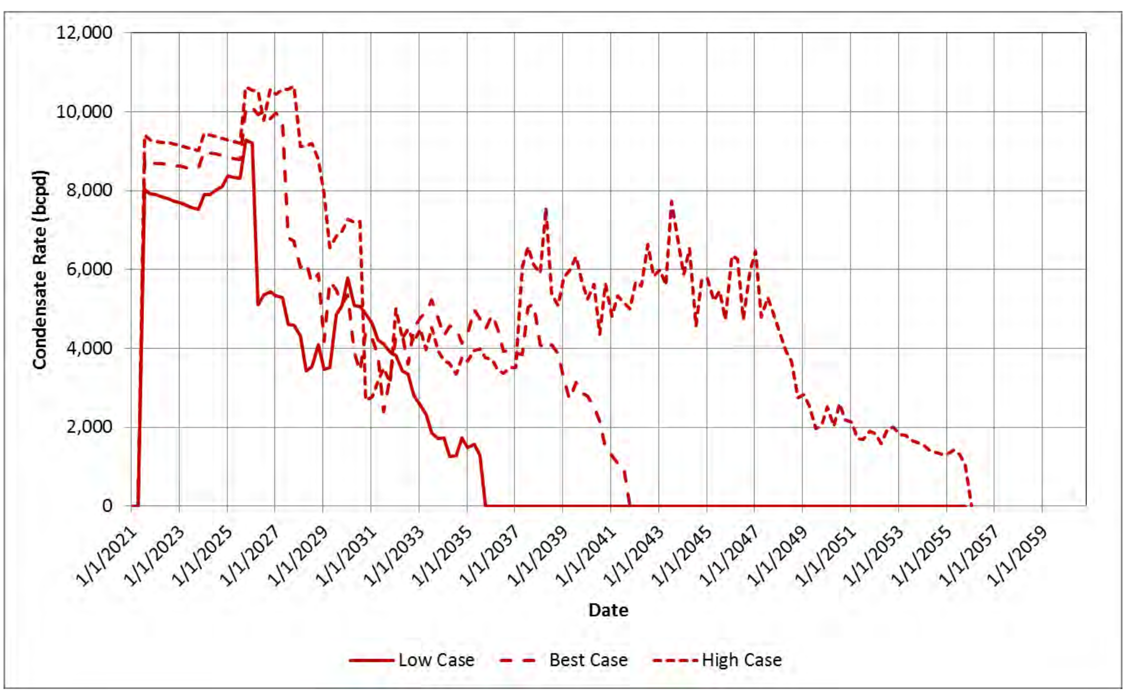


Figure 80: Equus Development Contingent Resources Condensate Production Forecasts



GCA also ran cases including both the discovered and risked undiscovered volumes to generate production profiles consistent with the Hess cases. As per the discovered only cases, adjustments were made to timing of the different development phases to ensure the profile was able to meet the required sales volumes. In all cases, the production profiles extend beyond the 15 year MOU period. In the Best and High Cases, the production plateau is able to extend for at least 5 additional years beyond 2036.

Figure 81 and **Figure 82** show the GCA Low, Best and High Case wet gas and condensate production profiles including both the discovered and undiscovered volumes.

Figure 81: Equus Full Development Wet Gas Production Forecasts

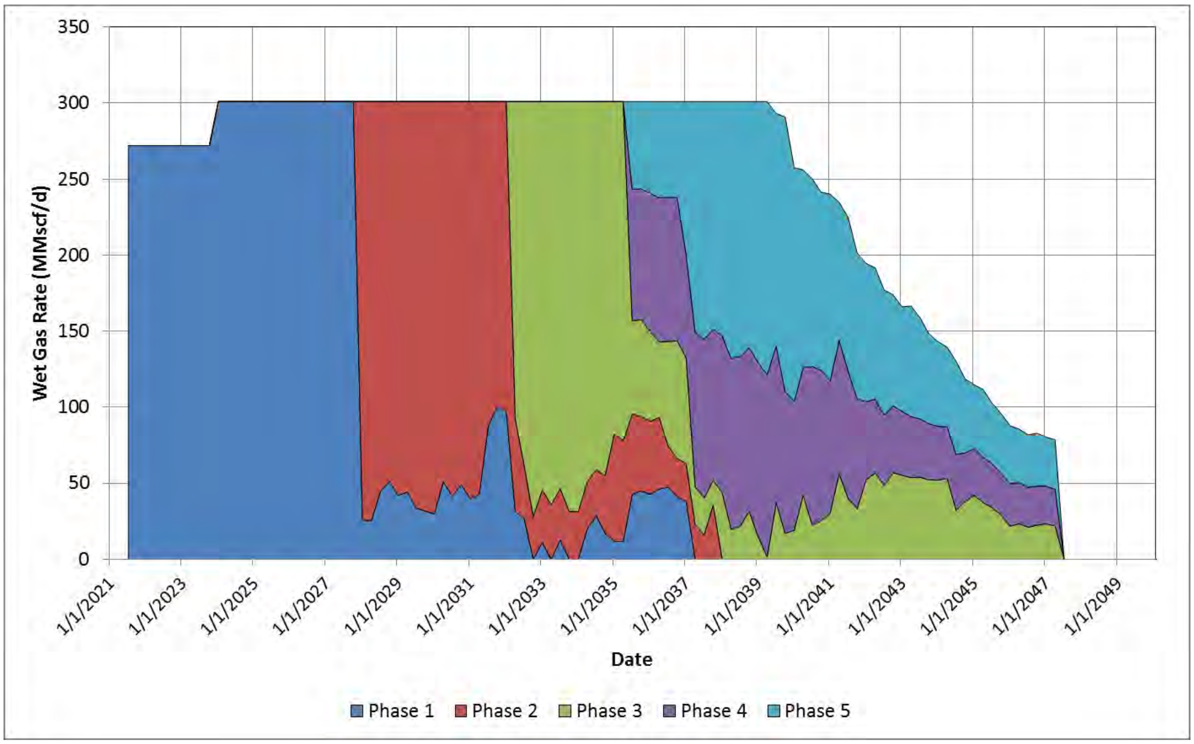


Figure 82: Equus Full Development Condensate Production Forecasts

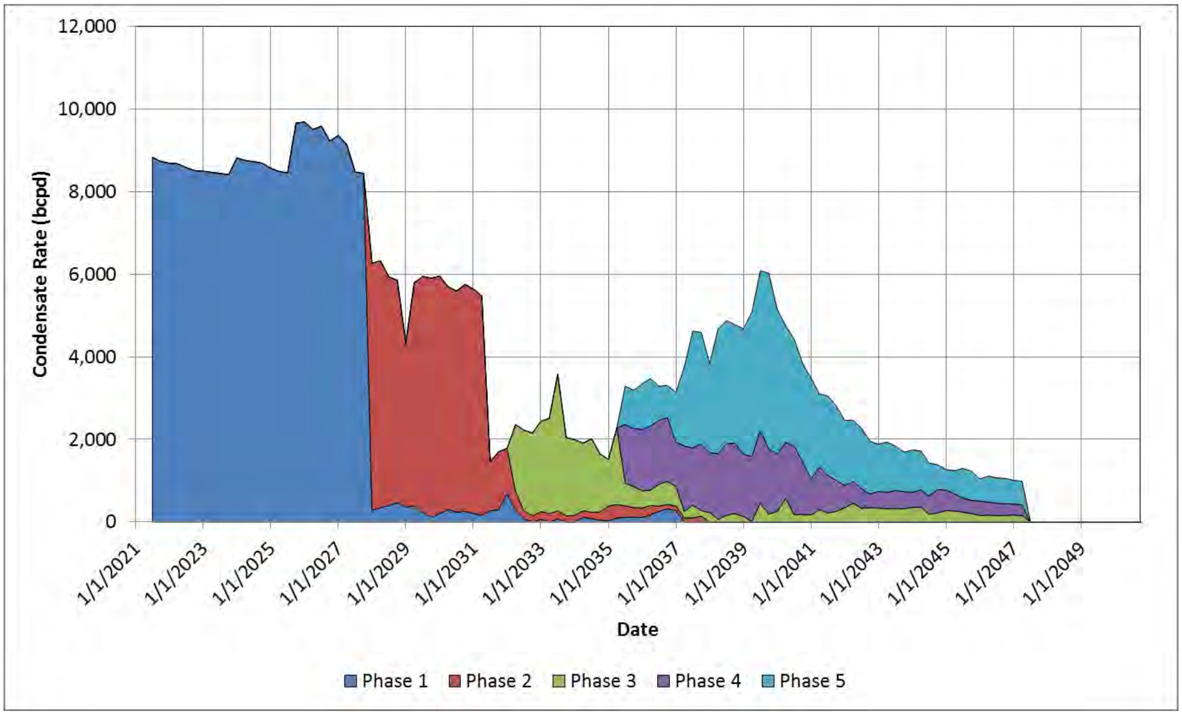


Figure 83 and **Figure 84** show the GCA Low, Best and High Case wet gas and condensate production profiles including both the discovered and risked undiscovered volumes. In the Best and High cases, the production profiles extend beyond the 15 year MOU period.

Figure 83: Equus Full Development Wet Gas Production Forecasts

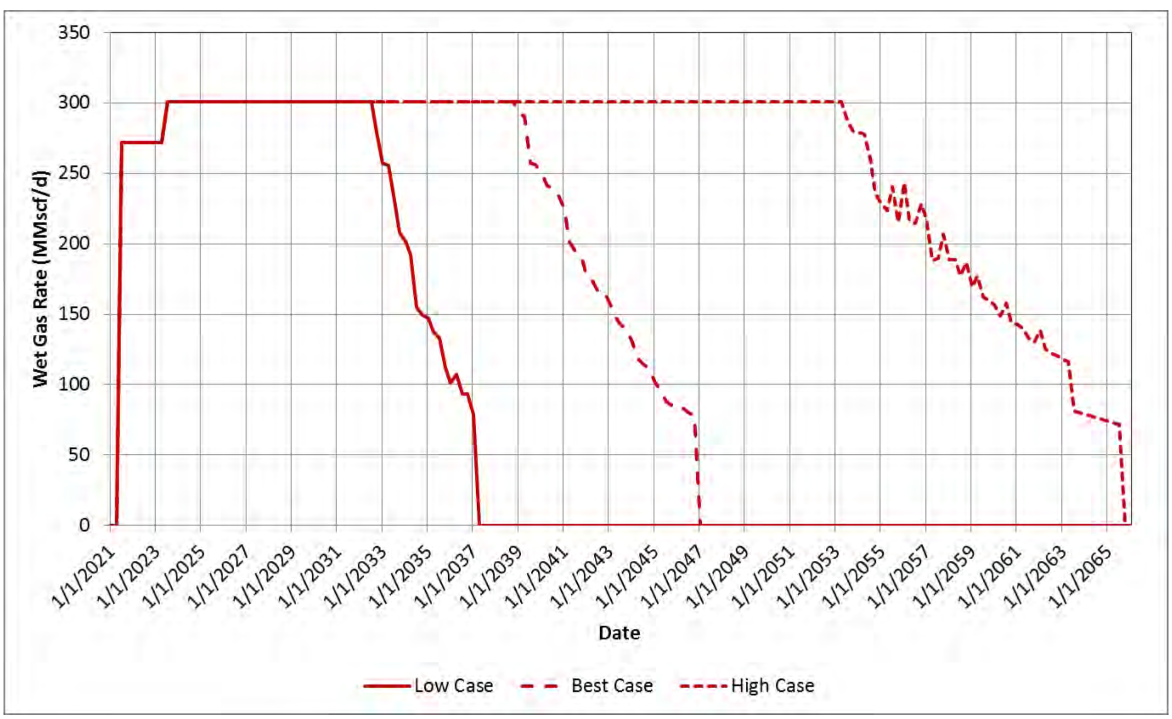
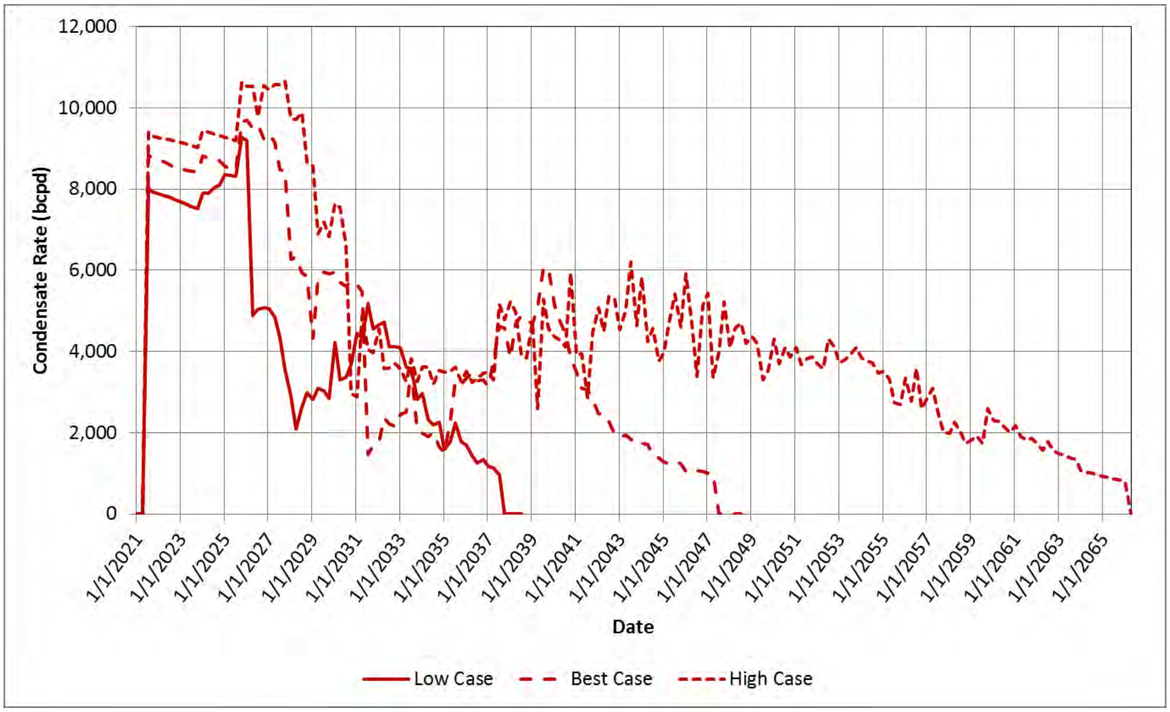


Figure 84: Equus Full Development Condensate Production Forecasts



Annualised tables of the production profiles shown in the figures above are located in **Appendix III.**

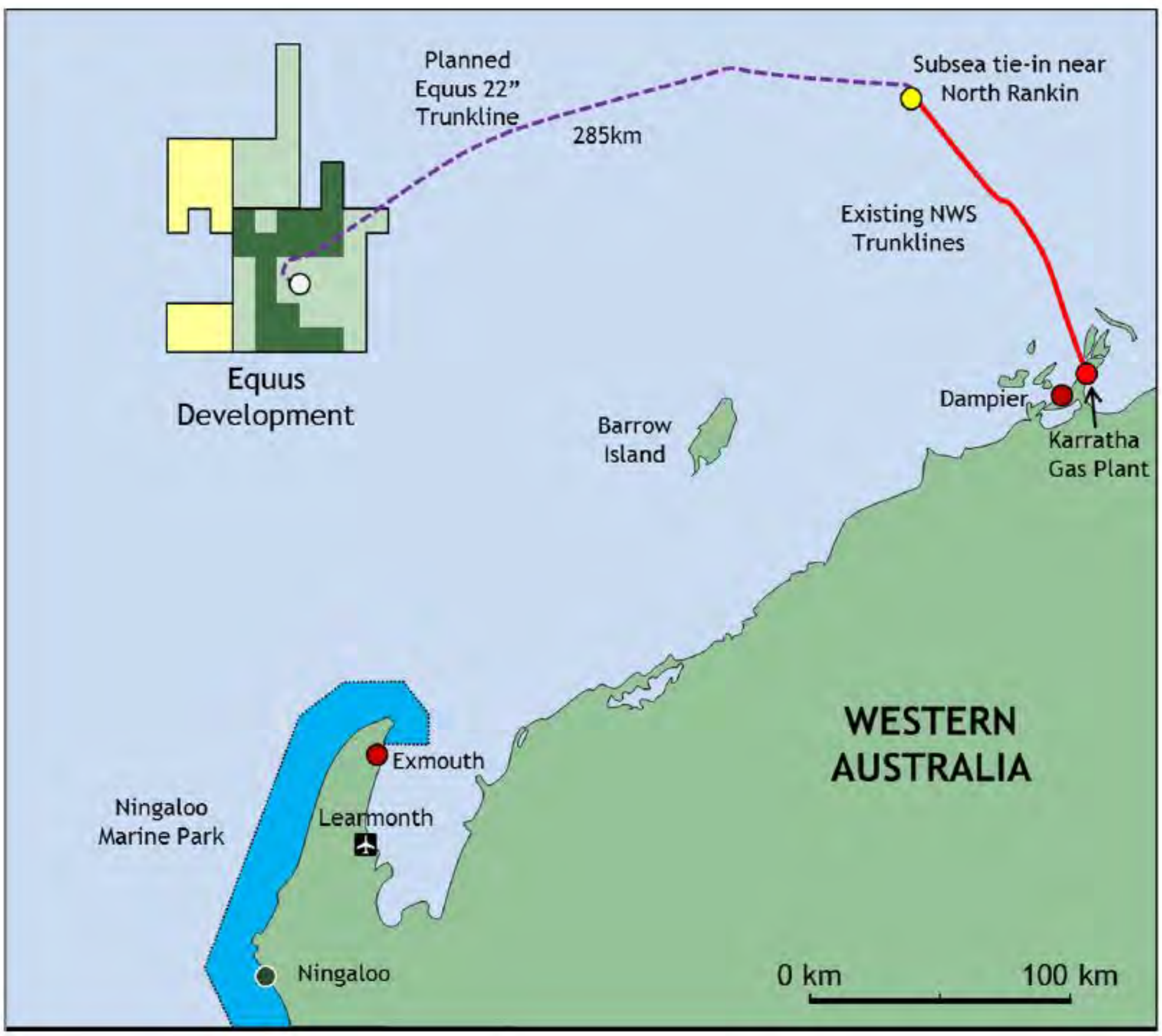
21 Facilities Engineering and Costing

21.1 Overview

The Equus Fields are located some 200 km offshore Western Australia in water depths ranging from 1,000 m to 1,200 m. The fields lie at depths from 3,000 m to 5,200 m below sea level (TVDss) or 1,200 m to 4,000 m below mudline.

The Equus Project Fields will be developed as a cluster, with subsea flowlines gathering production to a central Floating Production facility (FPS) where gas is dehydrated and compressed. The gas is transported by pipeline some 285 km to an offshore tie-in point to existing infrastructure and will be combined with flows from other North West Shelf (NWS) producers before transport to the Karratha Gas Plant and NWS LNG plant for liquefaction and sale. (**Figure 85**).

Figure 85: Equus Development Overview



The fields will be developed in five phases, with the fields brought on line to optimize the production profile, the liquids recovery, subsea architecture, and gas quality. The development phasing is discussed in more detail below. The development plan will generate revenue streams from LNG (ex-NWS LNG plant); and condensate, LPG's, and domestic gas (ex-Karratha gas plant).

21.2 Wells

The project plan is based on six different generic development well types, to be applied in 24 development wells over the five development phases. All wells will be drilled using a 6th generation dynamic positioned drilling unit. Well cost and time estimates are based on actual times of the 21 exploration and appraisal wells drilled to date. All wells will be drilled from a 36" conductor, with 20", 13 3/8", 10 ¾" and 9 5/8" casing strings depending on the depth below mudline. Wells will be completed with a 7" liner and 5 ½" corrosion resistant alloy (CRA) production tubing. The generic well types are summarized in **Figure 86** below.

Figure 86: Equus Development Generic Well Types

Well Type	Fields / Wells	Reservoir	Completion / Re-entry Type
1	Bravo, Briseis, Mentorc, Nimblefoot	Cretaceous	200m Horizontal or 75° OHGP
2	Glencoe	Jurassic	800m Horizontal OHGP
3	Briseis, Chester, Gaulus	Norian (Shallow)	100m Vertical OHGP
4	Glenloth, Rimfire, Chester	Norian (Deep)	100m Vertical Cased & Perforated
5	Glencoe-2 & Snapshot-1	Jurassic/Triassic	Re-enter, drill & complete existing well
6	Chester, Glenloth, Snapshot, Gaulus	Carnian	Inclined directional wells, Lined & Perforated

The drilling plan by field and by phase is tabulated in **Table 64** below.

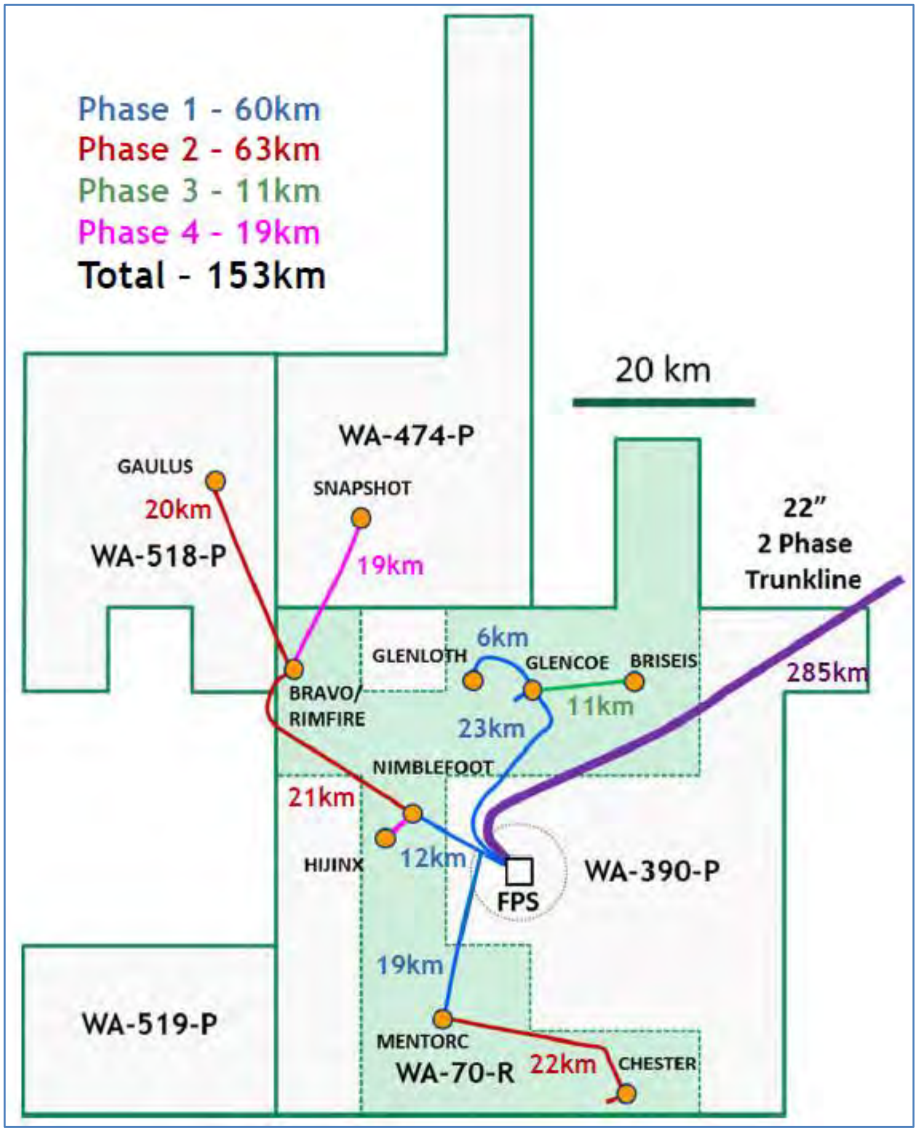
Table 64: Phased Drilling Plan

Field	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
Bravo		2 wells			
Briseis			2 wells		2 recompletions
Mentorc	2 wells				
Nimblefoot	1 well				
Glencoe	1 well re-drill			1 well	
Chester		2 wells	1 well		
Gaulus		1 well	2 wells		
Glenloth	2 wells	2 wells		1 well 2 recompletions	2 recompletions
Hijinx				1 well	
Rimfire			2 wells		
Snapshot				1 well re-drill	1 recompletion
Wells #	**6**	**7**	**7**	**4**	**0**
Recomp. #	**0**	**0**	**0**	**2**	**5**

21.3 Subsea

The subsea infrastructure will be developed in phases as the various fields are brought on line. All field flowlines will be standardized at 12” diameter, tied back to two 10” risers to the FPS. Three umbilical systems will provide control, monitoring, production chemicals, and electro-hydraulic power to all wells. The general layout and phasing of the subsea system is shown in **Figure 87** below. The field phasing and wellhead potential will provide a combined fields potential of between 420 and 800 MMscfd over the 15 year plateau production period.

Figure 87: Subsea Layout and Phasing



The flowlines are designed as CRA-clad carbon steel in the high corrosion zones close to the field, with carbon steel protected by corrosion inhibitor downstream. Hydrate control is provided by Low Dosage Hydrate Inhibitor (LDHI) across the system.

21.4 Floating Production System (FPS)

The FPS will provide gas conditioning and compression to transport pipeline specifications. It is designed as a four-column, semisubmersible unit permanently moored in 1,075 m water depth. The design capacities of the FPS are summarized in **Table 65** below.

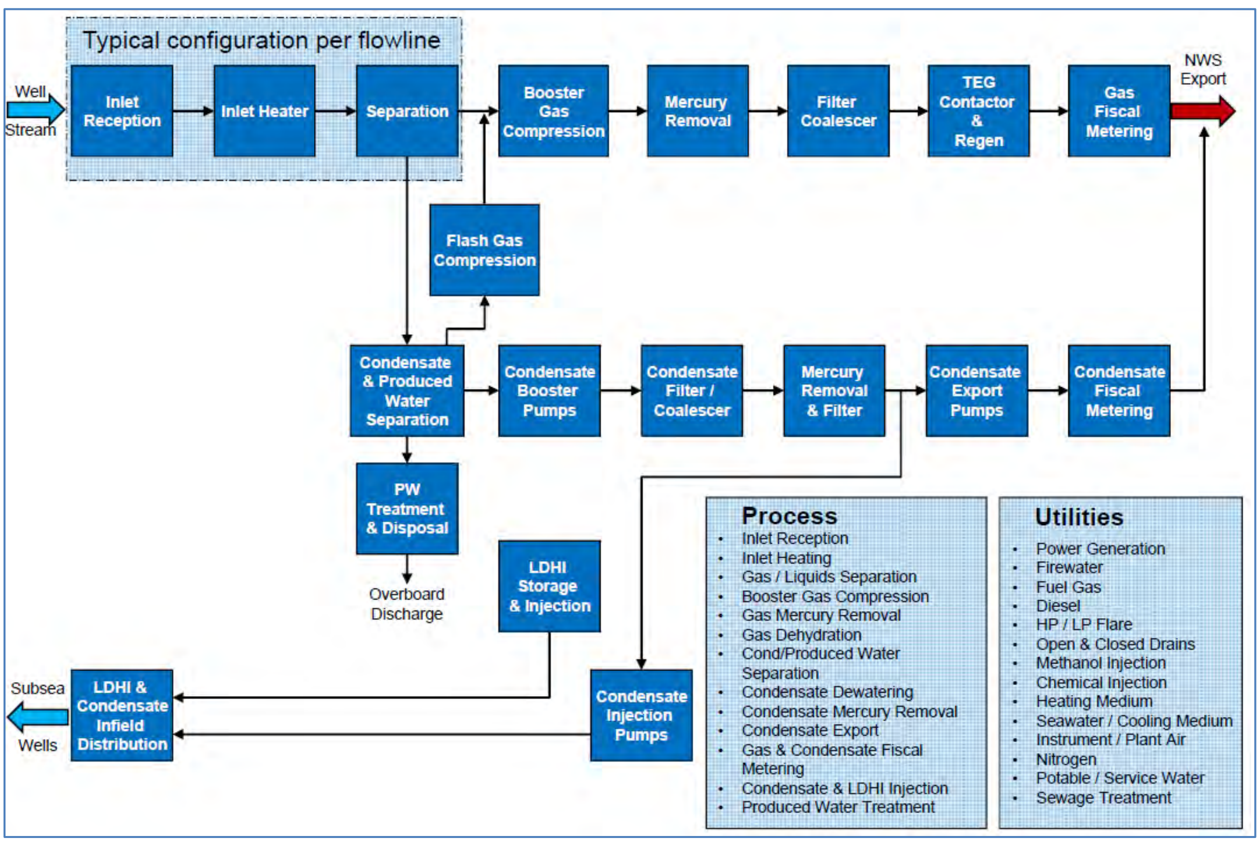
Table 65: FPS Design Capacities

System	Design Capacity	Units
Gas Compression and Export	395	MMscfd
Minimum gas flow	70	MMscfd
Condensate Export	11,000	Bopd
Water Handling	1,500	Bwpd
Condensate/LDHI injection	3,000	Bopd

The FPS design capacity is sufficient to support a sustained annual average gas flow of 328 MMscfd or 1.8 mtpa LNG. **Figure 88** shows a block diagram of the FPS facilities with a total topsides weight of the FPS is estimated at 10,406 tonnes (dry), 11,186 tonnes (operating). The FPS will be permanently manned with accommodation for a maximum of 90 persons on board.

The FPS will be installed as part of the Phase 1 development.

Figure 88: FPS Process Block Diagram



21.5 Export Pipeline, Tie-in and Onshore Processing

Dehydrated, compressed gas and condensate will flow from the FPS through a 285 km, 22" carbon steel pipeline to the offshore, subsea, tie-in point to existing infrastructure near the North Rankin field. Downstream of this point, Equus flows will be co-mingled with other field flows and brought onshore to the Karratha gas plant (KGP).

At the KGP, the gas is further treated to meet the inlet requirements to the NWS LNG plant. Condensate and LPG's are removed and stabilized to sales specification. Depending on local market demand, up to 11% of production will be allocated to domestic gas sales. Fuel and flare losses of 12% are estimated across KGP/NWS. The remaining gas (70 to 80% of Equus flow) will be liquefied to LNG in the NWS LNG plant and exported.

Access to all existing facilities (the offshore pipeline from the tie-in point, KGP, and NWS) is provided under a tariff agreement with the current owners. This agreement currently exists as a Heads of Agreement, i.e. a final processing and transport agreement is yet to be negotiated and signed.

The export pipeline and tie-ins will be installed as part of the Phase 1 development.

21.6 Development Costs

Development costs have been estimated to a near-FID accuracy level, with many of the major cost elements supported by commercial tenders and front-end engineering design (FEED) work. GCA has independently reviewed and cross-checked the Phase 1 development and operating costs (Mentorc, Nimblefoot, Glencoe and Glenloth fields, FPS, and export pipeline). GCA accepts Hess's development phase cost estimates, but has adjusted these to account for differences in the timing of the various phases to meet the contractual plateau production profile, as shown below in **Table 66**. All costs are quoted in unescalated 2017 U.S. dollars.

Table 66: GCA On-Stream Dates by Phase

GCA Cases	Low	Best	High
Phase 1	Q2 2021	Q2 2021	Q2 2021
Phase 2	Q1 2026	Q2 2027	Q1 2028
Phase 3	Q3 2027	Q1 2030	Q1 2032
Phase 4	Q3 2028	Q3 2031	Q2 2037
Phase 5	Q3 2028	Q3 2031	Q2 2037

21.6.1 Drilling Costs: DRILLEX

Drilling and completion (D&C) time and costs have been estimated by field, by phase and by well type. All work is assumed to be carried out by a 6th generation MODU at a rig rate of US$238,000/day and a spread rate of US$532,000/day during drilling work and US$600,000/day during completions work. The D&C cost estimate by phase is shown in **Table 67** below. As noted above, the timing of each phase has been adjusted depending on the field performance assumed in the respective GCA production case.

Table 67: D&C Cost by Phase

US$ MM (2017)	
Phase 1	$377.6
Phase 2	$379.6
Phase 3	$404.4
Phase 4	$301.7
Phase 5	$214.2
TOTAL D&C	**$1,677.5**

21.6.2 Facilities Capital Costs: CAPEX

Facilities CAPEX by phase is shown in **Table 68** below. Total CAPEX for all Phases is estimated at US$3,462.8 MM, unescalated 2017 dollars.

Table 68: CAPEX by Phase

US$ MM (2017)	Subsea	FPS	Pipeline	Onshore
Phase 1	$548.0	$1,173.1	$549.1	$262.5
Phase 2	$471.2			
Phase 3	$250.5			
Phase 4	$189.7			
Phase 5	$18.8			
TOTAL	**$1,478.2**	**$1,173.1**	**$549.1**	**$262.5**

21.6.3 Operating and Tariff Costs: OPEX

GCA has independently estimated field OPEX and developed a model to allow operating costs to be estimated based on the production rate, active fields, active wells, and annual fixed costs. The tariff charges (for the use of existing infrastructure, KGP, and NWS) vary with production and oil price. This model allows OPEX to be estimated based on the timing of field development. The basis of GCA's OPEX model is shown in **Table 69** below.

Table 69: OPEX Model Basis

	US$	Unit
Fixed Annual	$97.0 MM	Per annum
Per Active Field	$6.0 MM	Per field per annum
Per Active Well	$1.0 MM	Per well per annum
Production Variable	$0.20	Per mcf
Tariff at Plateau	~$70 MM	Per quarter

The tariff charges include a fixed element (for access to facilities) plus a variable element (based on production), with an adjustment factor based on oil price. Tariff costs are estimated based on information provided by Hess at a range oil prices and production rates.

21.6.4 Abandonment Costs: ABEX

Abandonment costs are estimated assuming that all works will take place in a single mobilization. The abandonment cost estimate is shown below in **Table 70**.

Table 70: Abandonment Costs

	US$ MM	Remark
Wells	$500	$26.3/well
Subsea/Pipeline	$150	$17.2/field
FPS removal	$50	
PMT/G&A	$35	
Contingency	$150	20%
Total ABEX	**$885**	

22 Economic Analysis

An economic limit test (ELT) has been carried out by considering two scenarios that include production profiles constructed utilising the discovered gas volumes to estimate Contingent Resources volumes and also a combination of the discovered and undiscovered gas volumes (Risked by GCoS) to assess Prospective Resources for the Equus Project. This preliminary analysis has been based on the production (sales) and cost profiles presented in previous sections, together with the fiscal terms potentially applicable to WA-70-R. The economic cut-off is defined as the production rate beyond which the field's net operating cash flows are negative. The purpose of the analyses is to demonstrate preliminary cases of commercial viability for the Equus Project and hence justification for project volume outputs to be classified as Contingent/Prospective Resources in all resource reporting categories.

Currently Hess the Operator holds a Retention Lease (R) over the permits which allows the permit holder to retain the lease until the commercial development is approved (or until expiry of the Retention Lease period). The Retention License is valid for a period of 15 years from the license grant date. Once the development is viable, the Operator will need to apply for a Production License (P). The production license will give the holder the right to exploit and produce hydrocarbons.

The preliminary economic analysis carried out for the Equus Project has been based upon GCA's understanding of the fiscal and contractual terms potentially governing the asset, and various economic and commercial assumptions described herein, which include the following:

- Effective date of the economic analysis is as of 31 March 2017
- Costs are escalated at 2.0% p.a. from 1 January 2018
- GCA's 1Q 2017 price scenario for Brent crude oil
- The scenario analysis assumes that the Production License will be secured in year 2017/2018 as the basis to carry out the economic analysis

22.1 Fiscal Terms

The Equus Project is under the Petroleum Resource Rent Tax (PRRT) Fiscal Regime, the terms of which are summarized below:

- No royalty since this is an offshore asset
- PRRT is applied at 40% of taxable profits derived from hydrocarbon production. PRRT payments are deductible for income tax purposes. The tax applies to profits derived from a petroleum project and not to the value or volume of production as with royalty and excise regimes. Deductions are available for all allowable expenditures and uplifts are applied to the carried-forward expenditure to ensure that PRRT taxes the economic rent generated from a petroleum project in a financial year.
- PRRT Payable is calculated as follows:
  - PRRT Payable = Taxable Profit x PRRT Rate (40%);
  - Taxable Profit = Assessable Receipts – Deductible Expenditure;

- Assessable Receipts include petroleum receipts, tolling receipts, exploration recovery receipts, property receipts, miscellaneous compensation receipts, employee amenities receipts, incidental production receipts;
- Expenditures are deductible in the year they are incurred. Expenditures include general project expenditures, exploration expenditure or closing-down expenditures[1];
- General project expenditures consists of costs incurred in carrying out or providing the operations, facilities and other activities in relation to an oil and gas project;
- Exploration expenditure is cost incurred in the exploration for oil and gas in an eligible exploration or recovery area; and
- Closing-down expenditure related to abandonment and decommissioning costs.
- Expenditures that are excluded are financing costs, dividend payments, acquisition costs, private overriding royalties, income tax and GST payments, indirect administration costs.

* No depreciation of historical Capex or acquisition consideration.
* Depreciation over 7 years with a double declining rate of 29%.
* Applicable income tax rate of 30%.

22.2 Product Price Scenario

The Equus Project will generate revenue from four different product streams: gas to the LNG plant, gas to the domestic market, condensate and LPG. The main product revenue is expected from LNG sales which are currently targeting the Japanese market. The LNG price applied in this analysis has been derived by observing the historical relationship between LNG spot prices that are landed in Japan and the Japanese Crude Cocktail (JCC) price. JCC has been historically used as the basis to determine the LNG price delivered to Japan. JCC and other price scenarios were then checked against the Brent benchmark crude price. The relationships among various historical prices in year 2015 and 2016 are summarized on **Table 71**.

Table 71: Year 2015 and 2016 Historical Prices

Year	Brent Crude Price	JCC Price	Condensate and LPG	LNG Price	Domestic Gas
	(US$/Bbl)	(US$/Bbl)	(US$/Bbl)	(US$/MMBtu)	(US$/MMBtu)
2015	52.4	55.0	50	7.9	3.7
2016	43.5	41.8	45	6.1	3.8

Notes:
1. JCC historical prices are from the statistical data in http://www.paj.gr.jp.
2. LNG prices that are landed in Japan are from the statistical data in http://www.meti.go.jp.
3. Average condensate, LPG and domestic gas prices in Australia are from the Woodside Annual Report.

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[1] Based on the provided data from Hess, Project Equus has spent US$1,420 MM up to December 2016.

JCC has been sold on average at 105% and 96% of the Brent Crude price in years 2015 and 2016, respectively. Taking into account the average sales price from years 2015 and 2016 after the global crude prices fell sharply in mid-year 2014, it is assumed that JCC will be sold at parity to Brent Crude in the future. JCC price has been used as the basis to prepare the LNG price scenario landed in Japan. Based on GCA's experience, historical data suggests a logarithmic relationship between the LNG price and the JCC price. The relationship applied was:

LNG Price (US$/MMbtu) = 9.7787 * Ln (Brent) – 30.514

Condensate and LPG prices in Australia during 2015 and 2016 have averaged 95% and 103% of the Brent Crude price, respectively. It is assumed that in future, condensate and LPG in Australia will be sold at parity with Brent Crude. The GCA 1Q 2017 Crude Price Scenario has been used for the benchmark Brent crude prices.

Following the global oil price drop at the end of 2014, Australian domestic gas prices have dropped from the average prices in 2013 and 2014 of US$4.4/MMBtu and US$4.7/MMBtu, respectively to US$3.7/MMBtu and US$3.8/MMBtu in 2015 and 2016, respectively. This analysis has assumed that domestic gas prices in Australia will remain fairly constant during 2017 averaging US$3.7/MMbtu and then increase with inflation at 2%.

Table 72: Price Scenarios shows a summary of the Brent crude price and other price scenarios that were used in the economic analysis. The assumed LNG price scenario is based on the LNG spot price that will be landed in Japan in a particular year. It is assumed that the LNG shipping cost from Australia to Japan is US$1.0/MMBtu in year 2017[2]. The shipping cost is escalated by 2% p.a. The LNG price that will be received by the Equus Project is the net gas price after considering the shipping cost to Japan. The heating value is assumed to be 854 Btu/scf[3].

Table 72: Price Scenarios

Year	Brent Crude Price (US$/Bbl)	JCC Price (US$/Bbl)	LNG Price (US$/MMBtu)	Condensate and LPG (US$/Bbl)
2017	58.35	58.35	9.25	58.35
2018	58.36	58.36	9.25	58.36
2019	65.00	65.00	10.31	65.00
2020	70.00	70.00	11.03	70.00
2021	71.40	71.40	11.22	71.40
2022	72.83	72.83	11.42	72.83
2023	74.28	74.28	11.61	74.28
2024	75.77	75.77	11.81	75.77
2025	77.29	77.29	12.00	77.29
2025+	+2% escalation	Parity to Brent	9.78 ln (Brent price) – 30.1514	Parity to Brent

Note: Domestic gas price is assumed to be sold at US$3.7/MMBtu in year 2017 and will be escalated at 2% p.a.

[2] Based on the public domain information, the LNG shipping cost from Australia to Japan is between US$0.9/MMBtu and US$1.1/MMBtu based on the long term charter style arrangement.

[3] The heating value is derived from the assumption that 1,000 Bscf gas will generate 0.8 MMtpa LNG for a period of 20 years.

22.3 Tariff Accessing the NWS Plant

A Letter of Intent (LOI) has been signed between the Operator and NWS partner. The processing tariff has been included as part of the OPEX in the cost assumptions.

22.4 ELT Results

The results of the ELT analysis demonstrate that the development of the Equus Project is potentially commercial. Gross Contingent Resources for Project Equus based on this analysis are presented in **Table 73**. Corresponding Risked Prospective Resources are shown in **Table 74**.

Table 73: Project Equus
Gross Contingent Resources (CR) and CR Attributable to a 100% Working Interest
as of 31 March 2017

Case	Gas (Bscf)			Condensate (MMbbls)		
	1C	2C	3C	1C	2C	3C
Gross Contingent Resources	1,338	2,028	3,221	26.5	41.5	68.4
Hess Net WI Share (100% WI)	1,338	2,028	3,221	26.5	41.5	68.4

Notes:
1. Gross Field Contingent Resources are 100% of the volumes estimated to be recoverable from the project/asset in the event that it is developed.
2. Company Net Contingent Resources in this table are Company's Working Interest fraction of the Gross Field Resources.
3. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that the project/asset may not be developed in the form envisaged or may not go ahead at all (i.e., no "Chance of Development" factor has been applied).
4. Gas volumes represent the sales gas volumes. Field usage and losses have been excluded from the reported volumes. Gas to be sold to the LNG plant and domestic market.
5. No economic cut-off has been applied for the reported Contingent Resources volumes above.

Table 74: Project Equus
Gross Risked Prospective Resources
as of 31 March 2017

Case	Gas (Bscf)			Condensate (MMbbls)		
	Low	Best	High	Low	Best	High
Gross Risked Prospective Resources	195	409	1,074	0.8	2.4	7.4
Hess Net WI Share (100% WI)	195	409	1,074	0.8	2.4	7.4

Notes:
1. The volumes reported here are "risked" in the sense that adjustment has been made for the GCoS
2. Identification of Prospective Resources associated with a Prospect is not indicative of any certainty that the Prospect will be drilled, or will be drilled in a timely manner.

22.5 Economic Results

A preliminary economic analysis has been carried out based on two production profile scenarios: discovered gas resources and discovered plus risked un-discovered gas resources to demonstrate the potential economic viability of the Equus Project. No Chance of Development risk factor has been incorporated in the analysis for the Contingent Resources. The volumes for the Prospective Resources have been risked for the Geological Chance of Success.

Using the undiscounted cash flow results from the economic analysis described above, the Equus Project would be commercially produced until year 2034, 2040 and 2052 based on the Low, Best and High case discovered resource profiles respectively. However, after taking into account discounted cash flow analysis assuming a 10% discount rate, the Net Present Values (NPVs) will only be positive for the Best (2C) and High (3C) cases.

It was assumed that in the event that all the un-drilled prospect volumes are discovered, the additional volumes will be produced as part of the Phase II or later development which at the earliest was scheduled (before deferment) to start delivering its gas in 2028. Based on the analysis conducted, these Prospective Resources will add value to the Equus Project; however, the project will only generate a positive NPV at a 10% discount rate in the Best or High Case (risked) volumes outcome.

A summary of the project IRR and NPV results at various discount rates for the Equus Project are presented in **Table 75**: . The NPVs do not represent a GCA opinion as to the market value of the asset. In assessing a likely market value, it would be necessary to take into account a number of additional factors including reserves/resources risk (i.e., that Proved and/or Probable and/or Possible reserves (if applicable) may not be realized within the anticipated timeframe for their exploitation); perceptions of economic and sovereign risk, including potential change in regulations; potential upside; other benefits, encumbrances or charges that may pertain to a particular interest; and, the competitive state of the market at the time. In estimating the required budget for this potential engagement, GCA has explicitly not taken such factors into account in order to generate NPVs in the report.

Table 75: Project Equus Economic Scenario Analysis
NPVs Attributable to a 100% Working Interest
as of 31 March 2017

Discount Rates	Contingent Resources			Contingent Resources + Risked Prospective Resources		
	1C NPV Scenario (US$MM)	2C NPV Scenario (US$MM)	3C NPV Scenario (US$MM)	1C + Risked Low Case NPV Scenario (US$MM)	2C+ Risked Best Case NPV Scenario (US$MM)	3C+Risked High Case NPV Scenario (US$MM)
0%	928	3,997	8,610	1,187	4,560	11,325
5%	71	1,596	3,246	183	1,828	3,618
8%	-260	780	1,723	-196	923	1,786
10%	-425	394	1,063	-382	500	1,050
12%	-556	97	584	-528	179	542
IRR	**6%**	**13%**	**16%**	**6%**	**13%**	**15%**

Notes:

1. Using the undiscounted cash flow as the basis, the total gas to be sold commercially for 1C, 2C and 3C are 1,315 Bscf, 2,006 Bscf and 3,127 Bscf, respectively. Total condensate to be sold commercially for 1C, 2C and 3C are 26.4 MMstb, 41.4 MMstb and 66.9 MMstb, respectively.
2. Using the undiscounted cash flow as the basis, the last commercial production year for 1C, 2C and 3C are year 2034, 2040 and 2052, respectively.
3. Using the undiscounted cash flow as the basis, the additional commercial risked volumes due to the discovery of the Prospective Resources for the Low, Best and High cases for gas are 194 Bscf, 347 Bscf and 1,014 Bscf, respectively. The additional commercial condensate volumes related to the Low, Best and High cases are 0.8 MMstb, 1.7 MMstb and 7.3 MMstb, respectively.
4. Should the Prospective Resources be discovered and developed, the additional risked volumes on the Low, Best and High case will extend the project life until year 2036, 2044 and 2061, respectively.

Appendix I
Glossary

Hess Exploration Australia Pty. Ltd.
May 2017

%	Percentage
1H05	First half (6 months) of 2005 (example)
2Q06	Second quarter (3 months) of 2006 (example)
2D	Two dimensional
3D	Three dimensional
4D	Four dimensional
1P	Proved Reserves
2P	Proved plus Probable Reserves
3P	Proved plus Probable plus Possible Reserves
ABEX	Abandonment Expenditure
ACQ	Annual Contract Quantity
°API	Degrees API (American Petroleum Institute)
AAPG	American Association of Petroleum Geologists
AVO	Amplitude versus Offset
A$	Australian Dollars
B	Billion (10^9)
Bbl	Barrels
/Bbl	per barrel
BBbl	Billion Barrels
BHA	Bottom Hole Assembly
BHC	Bottom Hole Compensated
Bscf or Bcf	Billion standard cubic feet
Bscfd or Bcfd	Billion standard cubic feet per day
Bm^3	Billion cubic metres
bcpd	Barrels of condensate per day
BHP	Bottom Hole Pressure
blpd	Barrels of liquid per day
bpd	Barrels per day
boe	Barrels of oil equivalent @ xxx mcf/Bbl
boepd	Barrels of oil equivalent per day @ xxx mcf/Bbl
BOP	Blow Out Preventer
bopd	Barrels oil per day
bwpd	Barrels of water per day
BS&W	Bottom sediment and water
BTU	British Thermal Units
bwpd	Barrels water per day
CBM	Coal Bed Methane

CO_2	Carbon Dioxide
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
cm	centimetres
CMM	Coal Mine Methane
CNG	Compressed Natural Gas
Cp	Centipoise (a measure of viscosity)
CSG	Coal Seam Gas
CT	Corporation Tax
D1BM	Design 1 Build Many
DCQ	Daily Contract Quantity
Deg C	Degrees Celsius
Deg F	Degrees Fahrenheit
DHI	Direct Hydrocarbon Indicator
DLIS	Digital Log Interchange Standard
DST	Drill Stem Test
DWT	Dead-weight ton
E&A	Exploration & Appraisal
E&P	Exploration and Production
EBIT	Earnings before Interest and Tax
EBITDA	Earnings before interest, tax, depreciation and amortisation
ECS	Elemental Capture Spectroscopy
EI	Entitlement Interest
EIA	Environmental Impact Assessment
ELT	Economic Limit Test
EMV	Expected Monetary Value
EOR	Enhanced Oil Recovery
EUR	Estimated Ultimate Recovery
FDP	Field Development Plan
FEED	Front End Engineering and Design
FPSO	Floating Production Storage and Offloading
FSO	Floating Storage and Offloading
FWL	Free Water Level
ft	Foot/feet
Fx	Foreign Exchange Rate
g	gram
g/cc	grams per cubic centimetre

gal	gallon
gal/d	gallons per day
G&A	General and Administrative costs
GBP	Pounds Sterling
GCoS	Geological Chance of Success
GDT	Gas Down to
GIIP	Gas Initially In Place
GJ	Gigajoules (one billion Joules)
GOC	Gas Oil Contact
GOR	Gas Oil Ratio
GRV	Gross Rock Volumes
GTL	Gas to Liquids
GWC	Gas water contact
HDT	Hydrocarbons Down to
HSE	Health, Safety and Environment
HSFO	High Sulphur Fuel Oil
HUT	Hydrocarbons up to
H_2S	Hydrogen Sulphide
IOR	Improved Oil Recovery
IPP	Independent Power Producer
IRR	Internal Rate of Return
J	Joule (Metric measurement of energy) I kilojoule = 0.9478 BTU)
k	Permeability
KB	Kelly Bushing
KJ	Kilojoules (one Thousand Joules)
kl	Kilolitres
km	Kilometres
km^2	Square kilometres
kPa	Thousands of Pascals (measurement of pressure)
KW	Kilowatt
KWh	Kilowatt hour
LAS	Log ASCII Standard
LKG	Lowest Known Gas
LKH	Lowest Known Hydrocarbons
LKO	Lowest Known Oil
LNG	Liquefied Natural Gas
LoF	Life of Field
LPG	Liquefied Petroleum Gas
LTI	Lost Time Injury

LWD	Logging while drilling
m	Metres
M	Thousand
m^3	Cubic metres
Mcf or Mscf	Thousand standard cubic feet
MCM	Management Committee Meeting
MMcf or MMscf	Million standard cubic feet
m^3/d	Cubic metres per day
mD	Measure of Permeability in millidarcies
MD	Measured Depth
MDT	Modular Dynamic Tester
Mean	Arithmetic average of a set of numbers
Median	Middle value in a set of values
MFT	Multi Formation Tester
mg/l	milligrams per litre
MJ	Megajoules (One Million Joules)
Mm^3	Thousand Cubic metres
Mm^3/d	Thousand Cubic metres per day
MM	Million
MMm^3	Million Cubic metres
MMm^3/d	Million Cubic metres per day
MMBbl	Millions of barrels
MMBTU	Millions of British Thermal Units
Mode	Value that exists most frequently in a set of values = most likely
Mscfd	Thousand standard cubic feet per day
MMscfd	Million standard cubic feet per day
MW	Megawatt
MWD	Measuring While Drilling
MWh	Megawatt hour
mya	Million years ago
NGL	Natural Gas Liquids
N_2	Nitrogen
NTG	Net/Gross Ratio
NPV	Net Present Value
OBM	Oil Based Mud
OCM	Operating Committee Meeting
ODT	Oil-Down-To

OGIP	Original Gas in Place
OIIP	Oil Initially In Place
OOIP	Original Oil in Place
OPEX	Operating Expenditure
OWC	Oil Water Contact
p.a.	Per annum
Pa	Pascals (metric measurement of pressure)
P&A	Plugged and Abandoned
PDP	Proved Developed Producing
Phie	effective porosity
PI	Productivity Index
PIIP	Petroleum Initially In Place
PJ	Petajoules (10^{15} Joules)
PSDM	Post Stack Depth Migration
psi	Pounds per square inch
psia	Pounds per square inch absolute
psig	Pounds per square inch gauge
PUD	Proved Undeveloped
PVT	Pressure, Volume and Temperature
P10	10% Probability
P50	50% Probability
P90	90% Probability
RF	Recovery factor
RFT	Repeat Formation Tester
RT	Rotary Table
R/P	Reserve to Production
R_w	Resistivity of water
SCAL	Special core analysis
cf or scf	Standard Cubic Feet
cfd or scfd	Standard Cubic Feet per day
scf/ton	Standard cubic foot per ton
SL	Straight line (for depreciation)
s_o	Oil Saturation
SPM	Single Point Mooring
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
SPS	Subsea Production System
SS	Subsea
stb	Stock tank barrel

STOIIP	Stock tank oil initially in place
Swi	irreducible water saturation
s_w	Water Saturation
T	Tonnes
TD	Total Depth
Te	Tonnes equivalent
THP	Tubing Head Pressure
TJ	Terajoules (10^{12} Joules)
Tscf or Tcf	Trillion standard cubic feet
TCM	Technical Committee Meeting
TOC	Total Organic Carbon
TOP	Take or Pay
Tpd	Tonnes per day
TVD	True Vertical Depth
TVDss	True Vertical Depth Subsea
UFR	Umbilical Flow Lines and Risers
USGS	United States Geological Survey
US$	United States dollar
VLCC	Very Large Crude Carrier
Vsh	shale volume
VSP	Vertical Seismic Profiling
WC	Water Cut
WI	Working Interest
WPC	World Petroleum Council
WTI	West Texas Intermediate
wt%	Weight percent

Appendix II
SPE PRMS Definitions

Society of Petroleum Engineers, World Petroleum Council, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers

Petroleum Resources Management System (PRMS)
Definitions and Guidelines[4]
March 2007

Preamble

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating development projects, and presenting results within a comprehensive classification framework.

International efforts to standardize the definition of petroleum resources and how they are estimated began in the 1930s. Early guidance focused on Proved Reserves. Building on work initiated by the Society of Petroleum Evaluation Engineers (SPEE), SPE published definitions for all Reserves categories in 1987. In the same year, the World Petroleum Council (WPC, then known as the World Petroleum Congress), working independently, published Reserves definitions that were strikingly similar. In 1997, the two organizations jointly released a single set of definitions for Reserves that could be used worldwide. In 2000, the American Association of Petroleum Geologists (AAPG), SPE and WPC jointly developed a classification system for all petroleum resources. This was followed by additional supporting documents: supplemental application evaluation guidelines (2001) and a glossary of terms utilized in Resources definitions (2005). SPE also published standards for estimating and auditing reserves information (revised 2007).

These definitions and the related classification system are now in common use internationally within the petroleum industry. They provide a measure of comparability and reduce the subjective nature of resources estimation. However, the technologies employed in petroleum exploration, development, production and processing continue to evolve and improve. The SPE Oil and Gas Reserves Committee works closely with other organizations to maintain the definitions and issues periodic revisions to keep current with evolving technologies and changing commercial opportunities.

The SPE PRMS document consolidates, builds on, and replaces guidance previously contained in the 1997 Petroleum Reserves Definitions, the 2000 Petroleum Resources Classification and Definitions publications, and the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources"; the latter document remains a valuable source of more detailed background information.,

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. It is expected that SPE PRMS will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

The full text of the SPE PRMS Definitions and Guidelines can be viewed at:

www.spe.org/industry/docs/Petroleum_Resources_Management_System_2007.pdf

[4] These Definitions and Guidelines are extracted from the Society of Petroleum Engineers / World Petroleum Council / American Association of Petroleum Geologists / Society of Petroleum Evaluation Engineers (SPE/WPC/AAPG/SPEE) Petroleum Resources Management System document ("SPE PRMS"), approved in March 2007.

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.

Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

On Production

The development project is currently producing and selling petroleum to market.

The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project "chance of commerciality" can be said to be 100%. The project "decision gate" is the decision to initiate commercial production from the project.

Approved for Development

All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way.

At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project "decision gate" is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

Justified for Development

Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.

In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity's assumptions of future prices, costs, etc. ("forecast case") and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class). The project "decision gate" is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.

Proved Reserves

Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes:

(1) the area delineated by drilling and defined by fluid contacts, if any, and
(2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data

In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplemental Guidelines," Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that the locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.

Probable Reserves

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.

It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Possible Reserves

Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves.

The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.

Probable and Possible Reserves

(See above for separate criteria for Probable Reserves and Possible Reserves.)

The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

Developed Reserves

Developed Reserves are expected quantities to be recovered from existing wells and facilities.

Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves

Shut-in Reserves are expected to be recovered from:

(1) completion intervals which are open at the time of the estimate but which have not yet started producing,
(2) wells which were shut-in for market conditions or pipeline connections, or
(3) wells not capable of production for mechanical reasons

Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Undeveloped Reserves

Undeveloped Reserves are quantities expected to be recovered through future investments:

(1) from new wells on undrilled acreage in known accumulations,
(2) from deepening existing wells to a different (but known) reservoir,
(3) from infill wells that will increase recovery, or
(4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to
  (a) recomplete an existing well or
  (b) install production or transportation facilities for primary or improved recovery projects.

CONTINGENT RESOURCES

Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.

Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

Development Pending

A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.

The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to “On Hold” or “Not Viable” status. The project “decision gate” is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.

Development Unclarified or on Hold

A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.

The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a re-classification of the project to “Not Viable” status. The project “decision gate” is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.

Development Not Viable

A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.

The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project "decision gate" is the decision not to undertake any further data acquisition or studies on the project r the foreseeable future.

PROSPECTIVE RESOURCES

Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.

Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.

Prospect

A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.

Lead

A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.

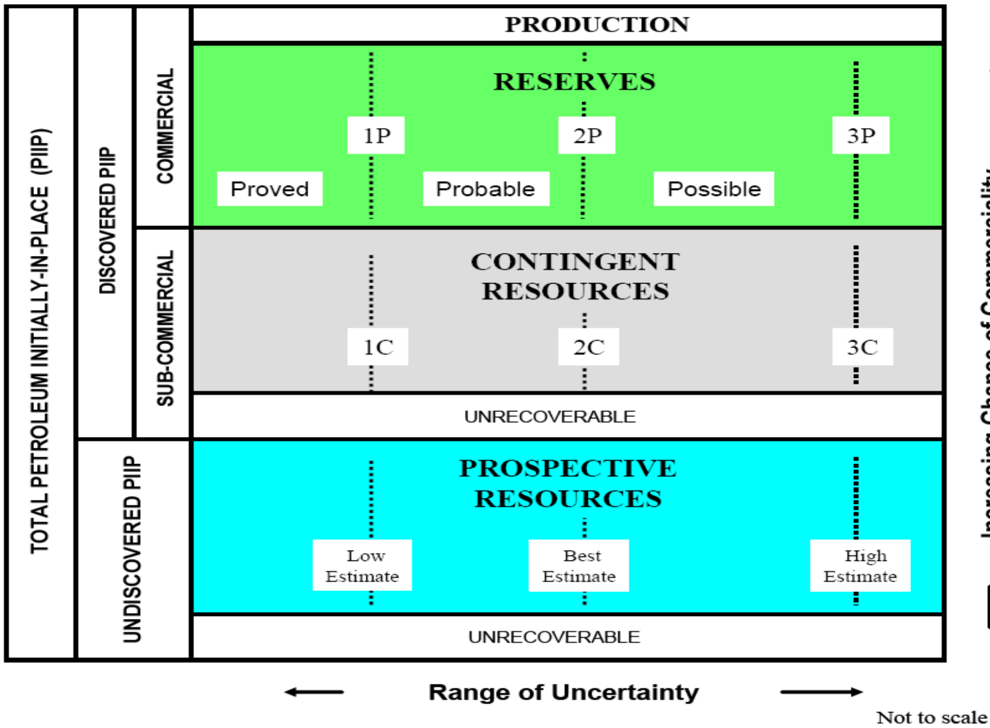
Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.

Play

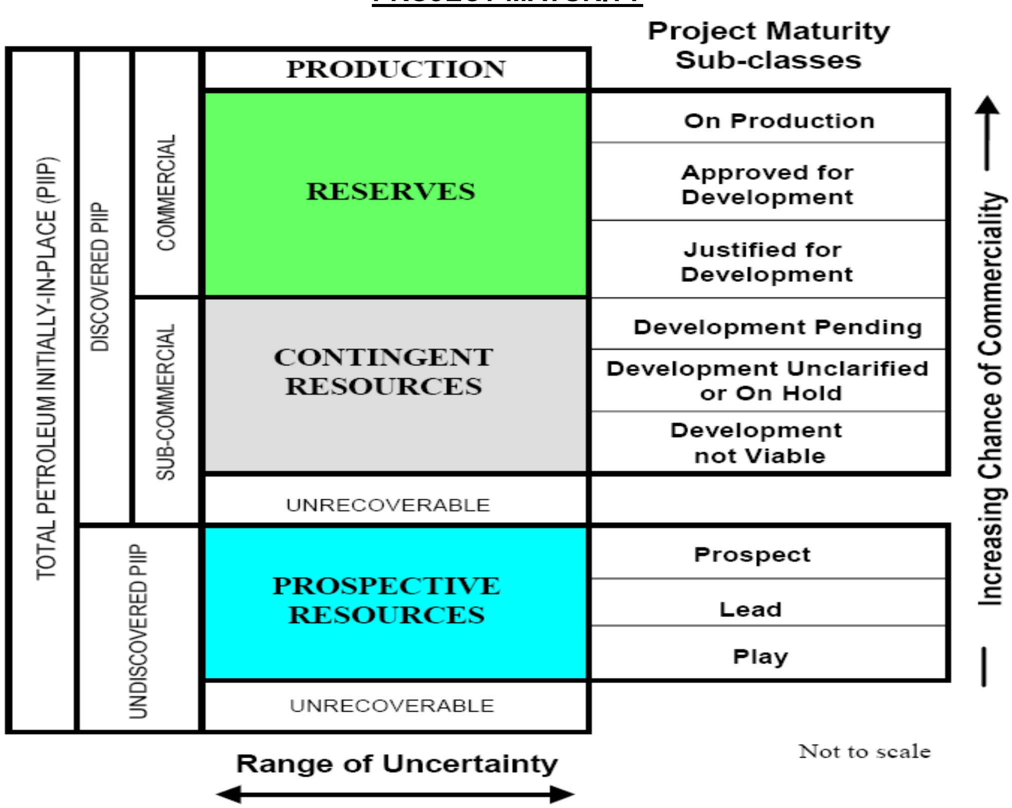
A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

RESOURCES CLASSIFICATION



PROJECT MATURITY



Appendix III
Production Profiles

Annualised tables of the production profiles shown in the Tables below.

Equus Development Contingent Resources Wet Gas Production Forecast Low Case

Year	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5	Total
2021	137.1	0.0	0.0	0.0	0.0	137.1
2022	272.0	0.0	0.0	0.0	0.0	272.0
2023	272.0	0.0	0.0	0.0	0.0	272.0
2024	301.0	0.0	0.0	0.0	0.0	301.0
2025	301.0	0.0	0.0	0.0	0.0	301.0
2026	85.3	215.7	0.0	0.0	0.0	301.0
2027	29.6	237.3	34.1	0.0	0.0	301.0
2028	49.4	74.5	139.3	22.6	15.1	300.9
2029	37.3	58.4	41.4	98.9	65.0	301.0
2030	0.0	27.2	24.5	108.4	140.9	301.0
2031	28.1	46.5	22.4	64.0	140.0	301.0
2032	34.0	36.6	22.6	64.8	102.9	260.9
2033	44.2	20.1	4.9	48.1	40.2	157.5
2034	38.6	0.0	0.0	29.9	25.8	94.3
2035	27.1	0.0	0.0	17.9	18.2	63.2
2036	0.0	0.0	0.0	0.0	0.0	0.0
2037	0.0	0.0	0.0	0.0	0.0	0.0
2038	0.0	0.0	0.0	0.0	0.0	0.0
2039	0.0	0.0	0.0	0.0	0.0	0.0
2040	0.0	0.0	0.0	0.0	0.0	0.0
2041	0.0	0.0	0.0	0.0	0.0	0.0
2042	0.0	0.0	0.0	0.0	0.0	0.0
2043	0.0	0.0	0.0	0.0	0.0	0.0
2044	0.0	0.0	0.0	0.0	0.0	0.0
2045	0.0	0.0	0.0	0.0	0.0	0.0
2046	0.0	0.0	0.0	0.0	0.0	0.0
2047	0.0	0.0	0.0	0.0	0.0	0.0
2048	0.0	0.0	0.0	0.0	0.0	0.0
2049	0.0	0.0	0.0	0.0	0.0	0.0
2050	0.0	0.0	0.0	0.0	0.0	0.0
2051	0.0	0.0	0.0	0.0	0.0	0.0
2052	0.0	0.0	0.0	0.0	0.0	0.0
2053	0.0	0.0	0.0	0.0	0.0	0.0
2054	0.0	0.0	0.0	0.0	0.0	0.0
2055	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	**605**	**262**	**106**	**166**	**200**	**1,338**

Equus Development Contingent Resources Wet Gas Production Forecast Best Case

Year	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5	Total
2021	137.1	0.0	0.0	0.0	0.0	137.1
2022	272.0	0.0	0.0	0.0	0.0	272.0
2023	272.0	0.0	0.0	0.0	0.0	272.0
2024	301.0	0.0	0.0	0.0	0.0	301.0
2025	301.0	0.0	0.0	0.0	0.0	301.0
2026	301.0	0.0	0.0	0.0	0.0	301.0
2027	165.4	135.6	0.0	0.0	0.0	301.0
2028	52.3	248.7	0.0	0.0	0.0	301.0
2029	68.8	232.2	0.0	0.0	0.0	301.0
2030	78.0	164.1	58.9	0.0	0.0	301.0
2031	89.3	94.2	91.5	20.8	5.2	301.0
2032	43.2	63.7	82.9	63.5	47.7	301.0
2033	0.0	57.6	52.2	76.5	114.7	301.0
2034	28.4	39.8	47.3	74.2	111.3	301.0
2035	8.0	39.3	35.0	87.5	131.2	301.0
2036	23.9	37.2	40.9	79.6	119.4	301.0
2037	8.9	38.6	35.2	84.5	133.7	300.9
2038	27.7	31.8	32.1	75.7	99.7	267.0
2039	21.8	26.1	35.0	46.8	65.6	195.3
2040	15.6	16.3	26.7	27.1	52.3	138.0
2041	0.0	0.0	15.2	16.3	29.2	60.7
2042	0.0	0.0	0.0	0.0	0.0	0.0
2043	0.0	0.0	0.0	0.0	0.0	0.0
2044	0.0	0.0	0.0	0.0	0.0	0.0
2045	0.0	0.0	0.0	0.0	0.0	0.0
2046	0.0	0.0	0.0	0.0	0.0	0.0
2047	0.0	0.0	0.0	0.0	0.0	0.0
2048	0.0	0.0	0.0	0.0	0.0	0.0
2049	0.0	0.0	0.0	0.0	0.0	0.0
2050	0.0	0.0	0.0	0.0	0.0	0.0
2051	0.0	0.0	0.0	0.0	0.0	0.0
2052	0.0	0.0	0.0	0.0	0.0	0.0
2053	0.0	0.0	0.0	0.0	0.0	0.0
2054	0.0	0.0	0.0	0.0	0.0	0.0
2055	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	**809**	**448**	**202**	**238**	**332**	**2,028**

Equus Development Contingent Resources Wet Gas Production Forecast High Case

Year	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5	Total
2021	137.1	0.0	0.0	0.0	0.0	137.1
2022	272.0	0.0	0.0	0.0	0.0	272.0
2023	272.0	0.0	0.0	0.0	0.0	272.0
2024	301.0	0.0	0.0	0.0	0.0	301.0
2025	301.0	0.0	0.0	0.0	0.0	301.0
2026	301.0	0.0	0.0	0.0	0.0	301.0
2027	301.0	0.0	0.0	0.0	0.0	301.0
2028	59.5	241.5	0.0	0.0	0.0	301.0
2029	50.2	250.8	0.0	0.0	0.0	301.0
2030	50.2	250.8	0.0	0.0	0.0	301.0
2031	52.6	248.4	0.0	0.0	0.0	301.0
2032	73.8	124.8	102.4	0.0	0.0	301.0
2033	59.0	103.2	138.8	0.0	0.0	301.0
2034	60.1	155.4	85.5	0.0	0.0	301.0
2035	96.5	113.8	90.7	0.0	0.0	301.0
2036	100.9	133.1	67.1	0.0	0.0	301.1
2037	28.4	110.2	47.5	80.4	34.5	301.0
2038	0.0	81.6	24.9	122.3	72.3	301.1
2039	0.0	47.2	25.4	87.7	140.6	300.9
2040	0.0	43.7	15.6	77.3	164.3	300.9
2041	5.1	45.0	35.7	68.8	146.3	300.9
2042	38.0	37.1	48.9	56.7	120.4	301.1
2043	111.5	35.5	46.9	34.3	72.8	301.0
2044	105.7	30.4	39.9	40.0	85.0	301.0
2045	85.5	25.9	35.4	49.4	104.9	301.1
2046	67.8	22.0	34.4	56.1	120.7	301.0
2047	59.0	0.0	31.1	61.4	124.5	276.0
2048	47.8	0.0	26.8	45.9	68.6	189.1
2049	40.1	0.0	25.7	38.9	41.7	146.4
2050	34.1	0.0	28.1	33.7	37.7	133.6
2051	29.8	0.0	25.7	29.7	29.8	115.0
2052	26.4	0.0	23.6	26.5	25.8	102.3
2053	24.1	0.0	21.7	24.4	22.8	93.0
2054	22.3	0.0	20.1	22.5	21.0	85.9
2055	20.5	0.0	18.5	20.7	19.4	79.1
TOTAL	**1,181**	**767**	**387**	**357**	**531**	**3,231**

Equus Development Contingent Resources Condensate Production Forecast Low Case

Year	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5	Total
2021	7,914	0	0	0	0	7,914
2022	7,707	0	0	0	0	7,707
2023	7,726	0	0	0	0	7,726
2024	8,207	0	0	0	0	8,207
2025	6,691	1,281	0	0	0	7,972
2026	636	4,712	0	0	0	5,348
2027	209	2,349	1,674	0	0	4,232
2028	232	463	1,162	1,109	685	3,651
2029	0	184	272	2,620	2,121	5,197
2030	46	167	254	1,652	2,573	4,692
2031	128	192	228	1,262	2,007	3,817
2032	291	145	175	1,212	941	2,764
2033	292	28	0	886	429	1,635
2034	657	0	0	532	327	1,516
2035	110	0	0	107	109	326
2036	0	0	0	0	0	0
2037	0	0	0	0	0	0
2038	0	0	0	0	0	0
2039	0	0	0	0	0	0
2040	0	0	0	0	0	0
2041	0	0	0	0	0	0
2042	0	0	0	0	0	0
2043	0	0	0	0	0	0
2044	0	0	0	0	0	0
2045	0	0	0	0	0	0
2046	0	0	0	0	0	0
2047	0	0	0	0	0	0
2048	0	0	0	0	0	0
2049	0	0	0	0	0	0
2050	0	0	0	0	0	0
2051	0	0	0	0	0	0
2052	0	0	0	0	0	0
2053	0	0	0	0	0	0
2054	0	0	0	0	0	0
2055	0	0	0	0	0	0
TOTAL	**14.9**	**3.5**	**1.4**	**3.4**	**3.4**	**26.5**

Equus Development Contingent Resources Condensate Production Forecast Best Case

Year	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5	Total
2021	8,732	0	0	0	0	8,732
2022	8,622	0	0	0	0	8,622
2023	8,771	0	0	0	0	8,771
2024	8,867	0	0	0	0	8,867
2025	9,728	0	0	0	0	9,728
2026	9,889	0	0	0	0	9,889
2027	816	5,620	0	0	0	6,436
2028	687	4,670	0	0	0	5,357
2029	537	4,424	0	0	0	4,961
2030	541	2,525	760	106	41	3,973
2031	452	457	1,378	948	340	3,575
2032	73	332	846	1,100	2,100	4,451
2033	133	248	533	1,396	2,408	4,718
2034	63	186	470	1,434	2,342	4,495
2035	90	173	452	1,489	2,437	4,641
2036	144	184	453	1,413	1,704	3,898
2037	298	161	311	1,237	2,546	4,553
2038	267	119	457	1,112	1,511	3,466
2039	436	96	590	584	1,119	2,825
2040	94	20	233	331	817	1,495
2041	0	0	41	60	154	255
2042	0	0	0	0	0	0
2043	0	0	0	0	0	0
2044	0	0	0	0	0	0
2045	0	0	0	0	0	0
2046	0	0	0	0	0	0
2047	0	0	0	0	0	0
2048	0	0	0	0	0	0
2049	0	0	0	0	0	0
2050	0	0	0	0	0	0
2051	0	0	0	0	0	0
2052	0	0	0	0	0	0
2053	0	0	0	0	0	0
2054	0	0	0	0	0	0
2055	0	0	0	0	0	0
TOTAL	**21.6**	**7.0**	**2.4**	**4.1**	**6.4**	**41.5**

Equus Development Contingent Resources Condensate Production Forecast High Case

Year	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5	Total
2021	9,293	0	0	0	0	9,293
2022	9,161	0	0	0	0	9,161
2023	9,236	0	0	0	0	9,236
2024	9,297	0	0	0	0	9,297
2025	10,221	0	0	0	0	10,221
2026	10,342	0	0	0	0	10,342
2027	6,176	3,690	0	0	0	9,866
2028	2,250	5,869	0	0	0	8,119
2029	652	6,417	0	0	0	7,069
2030	846	3,108	0	0	0	3,954
2031	1,632	1,697	640	0	0	3,969
2032	641	1,010	2,631	0	0	4,282
2033	839	1,051	2,054	0	0	3,944
2034	943	1,170	1,567	0	0	3,680
2035	1,433	901	1,386	0	0	3,720
2036	989	1,057	996	882	190	4,114
2037	20	759	471	3,728	1,559	6,537
2038	0	488	438	2,729	1,904	5,559
2039	0	359	178	1,760	3,427	5,724
2040	0	363	162	1,156	3,359	5,040
2041	432	348	496	1,330	2,753	5,359
2042	2,413	265	513	954	1,874	6,019
2043	3,825	252	476	678	1,482	6,713
2044	2,257	219	386	874	1,579	5,315
2045	1,825	188	378	1,050	2,260	5,701
2046	1,367	84	362	1,023	2,642	5,478
2047	1,409	0	334	1,026	1,852	4,621
2048	990	0	290	668	1,001	2,949
2049	642	0	303	539	651	2,135
2050	747	0	304	529	572	2,152
2051	475	0	278	389	614	1,756
2052	628	0	252	460	551	1,891
2053	490	0	232	370	462	1,554
2054	422	0	214	322	393	1,351
2055	346	0	198	291	348	1,183
TOTAL	**33.7**	**10.7**	**5.7**	**7.6**	**10.8**	**68.4**

Equus Full Development Wet Gas Production Forecast Low Case

Year	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5	Total
2021	137.1	0.0	0.0	0.0	0.0	137.1
2022	272.0	0.0	0.0	0.0	0.0	272.0
2023	272.0	0.0	0.0	0.0	0.0	272.0
2024	301.0	0.0	0.0	0.0	0.0	301.0
2025	301.0	0.0	0.0	0.0	0.0	301.0
2026	85.7	215.3	0.0	0.0	0.0	301.0
2027	17.9	241.0	42.1	0.0	0.0	301.0
2028	54.9	46.5	199.6	0.0	0.0	301.0
2029	15.3	56.6	229.1	0.0	0.0	301.0
2030	59.9	50.2	13.0	133.4	44.5	301.0
2031	17.8	14.5	5.5	117.8	145.4	301.0
2032	0.0	16.2	21.4	92.2	171.2	301.0
2033	11.0	35.2	26.7	79.8	120.4	273.1
2034	26.4	27.7	39.1	72.7	43.2	209.1
2035	25.9	5.2	37.3	43.5	35.2	147.1
2036	36.2	0.0	28.1	33.1	16.0	113.4
2037	21.8	0.0	15.0	19.0	10.4	66.2
2038	0.0	0.0	0.0	0.0	0.0	0.0
2039	0.0	0.0	0.0	0.0	0.0	0.0
2040	0.0	0.0	0.0	0.0	0.0	0.0
2041	0.0	0.0	0.0	0.0	0.0	0.0
2042	0.0	0.0	0.0	0.0	0.0	0.0
2043	0.0	0.0	0.0	0.0	0.0	0.0
2044	0.0	0.0	0.0	0.0	0.0	0.0
2045	0.0	0.0	0.0	0.0	0.0	0.0
2046	0.0	0.0	0.0	0.0	0.0	0.0
2047	0.0	0.0	0.0	0.0	0.0	0.0
2048	0.0	0.0	0.0	0.0	0.0	0.0
2049	0.0	0.0	0.0	0.0	0.0	0.0
2050	0.0	0.0	0.0	0.0	0.0	0.0
2051	0.0	0.0	0.0	0.0	0.0	0.0
2052	0.0	0.0	0.0	0.0	0.0	0.0
2053	0.0	0.0	0.0	0.0	0.0	0.0
2054	0.0	0.0	0.0	0.0	0.0	0.0
2055	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	**605**	**259**	**240**	**216**	**214**	**1,533**

Equus Full Development Wet Gas Production Forecast Best Case

Year	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5	Total
2021	137.1	0.0	0.0	0.0	0.0	137.1
2022	272.0	0.0	0.0	0.0	0.0	272.0
2023	272.0	0.0	0.0	0.0	0.0	272.0
2024	301.0	0.0	0.0	0.0	0.0	301.0
2025	301.0	0.0	0.0	0.0	0.0	301.0
2026	301.0	0.0	0.0	0.0	0.0	301.0
2027	301.0	0.0	0.0	0.0	0.0	301.0
2028	36.7	264.3	0.0	0.0	0.0	301.0
2029	37.8	263.2	0.0	0.0	0.0	301.0
2030	42.8	258.2	0.0	0.0	0.0	301.0
2031	67.7	233.3	0.0	0.0	0.0	301.0
2032	38.7	81.6	180.7	0.0	0.0	301.0
2033	5.9	33.9	261.2	0.0	0.0	301.0
2034	16.4	32.7	251.9	0.0	0.0	301.0
2035	27.8	59.7	141.0	43.5	29.0	301.0
2036	44.3	36.8	63.7	93.7	62.5	301.0
2037	9.4	24.9	33.5	93.3	139.9	301.0
2038	0.0	0.0	29.1	108.8	163.2	301.1
2039	0.0	0.0	17.6	107.6	171.2	296.4
2040	0.0	0.0	27.2	93.1	131.1	251.4
2041	0.0	0.0	39.9	82.6	102.6	225.1
2042	0.0	0.0	53.6	47.5	83.1	184.2
2043	0.0	0.0	53.7	39.3	66.7	159.7
2044	0.0	0.0	43.7	34.6	54.5	132.8
2045	0.0	0.0	35.5	29.2	41.4	106.1
2046	0.0	0.0	22.2	26.7	35.7	84.6
2047	0.0	0.0	11.2	12.1	16.1	39.4
2048	0.0	0.0	0.0	0.0	0.0	0.0
2049	0.0	0.0	0.0	0.0	0.0	0.0
2050	0.0	0.0	0.0	0.0	0.0	0.0
2051	0.0	0.0	0.0	0.0	0.0	0.0
2052	0.0	0.0	0.0	0.0	0.0	0.0
2053	0.0	0.0	0.0	0.0	0.0	0.0
2054	0.0	0.0	0.0	0.0	0.0	0.0
2055	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	**808**	**471**	**462**	**297**	**401**	**2,437**

Equus Full Development Wet Gas Production Forecast High Case

Year	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5	Total
2021	137.1	0.0	0.0	0.0	0.0	137.1
2022	272.0	0.0	0.0	0.0	0.0	272.0
2023	272.0	0.0	0.0	0.0	0.0	272.0
2024	301.0	0.0	0.0	0.0	0.0	301.0
2025	301.0	0.0	0.0	0.0	0.0	301.0
2026	301.0	0.0	0.0	0.0	0.0	301.0
2027	301.0	0.0	0.0	0.0	0.0	301.0
2028	60.3	240.7	0.0	0.0	0.0	301.0
2029	68.8	232.2	0.0	0.0	0.0	301.0
2030	80.6	220.4	0.0	0.0	0.0	301.0
2031	89.7	211.3	0.0	0.0	0.0	301.0
2032	41.2	108.8	151.0	0.0	0.0	301.0
2033	16.7	112.0	172.3	0.0	0.0	301.0
2034	42.0	81.2	177.8	0.0	0.0	301.0
2035	78.0	100.1	122.9	0.0	0.0	301.0
2036	80.6	112.3	108.2	0.0	0.0	301.1
2037	20.7	78.5	149.4	39.3	13.1	301.0
2038	0.0	122.3	75.6	77.3	25.8	301.0
2039	0.0	56.4	46.5	99.0	99.1	301.0
2040	0.0	73.8	34.4	86.8	106.0	301.0
2041	29.5	44.0	103.8	55.7	68.0	301.0
2042	51.5	69.6	96.5	35.7	47.8	301.1
2043	68.7	84.7	60.8	34.7	52.1	301.0
2044	52.6	86.6	43.7	47.2	70.8	300.9
2045	36.9	49.5	59.6	62.0	93.1	301.1
2046	59.5	63.1	76.3	40.9	61.3	301.1
2047	81.6	73.0	88.6	23.1	34.6	300.9
2048	83.2	62.1	104.0	20.7	31.1	301.1
2049	61.5	52.7	96.0	36.3	54.5	301.0
2050	46.9	29.7	115.2	43.7	65.5	301.0
2051	37.4	0.0	106.4	62.9	94.3	301.0
2052	31.0	0.0	96.7	80.9	92.3	300.9
2053	27.1	0.0	86.6	60.3	127.0	301.0
2054	25.6	0.0	76.9	47.2	131.3	281.0
2055	24.2	0.0	69.0	38.9	105.0	237.1
2056	22.3	0.0	61.2	33.2	112.2	228.9
2057	15.6	0.0	54.2	31.2	111.3	212.3
2058	0.0	0.0	49.4	29.5	114.6	193.5
2059	0.0	0.0	39.1	27.4	111.1	177.6
2060	0.0	0.0	31.7	25.2	99.9	156.8
2061	0.0	0.0	27.4	23.3	95.6	146.3
2062	0.0	0.0	25.1	21.5	85.3	131.9
2063	0.0	0.0	23.0	19.8	76.6	119.4
2064	0.0	0.0	0.0	0.0	79.2	79.2
2065	0.0	0.0	0.0	0.0	74.5	74.5
2066	0.0	0.0	0.0	0.0	17.7	17.7
2067	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	**1,176**	**864**	**960**	**440**	**859**	**4,295**

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Equus Full Development Condensate Production Forecast Low Case

Year	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5	Total
2021	7,914	0	0	0	0	7,914
2022	7,707	0	0	0	0	7,707
2023	7,726	0	0	0	0	7,726
2024	8,207	0	0	0	0	8,207
2025	6,691	1,229	0	0	0	7,920
2026	525	4,480	0	0	0	5,005
2027	151	1,903	1,170	0	0	3,224
2028	67	778	2,045	0	0	2,890
2029	151	642	1,077	1,034	449	3,353
2030	144	119	78	2,155	1,463	3,959
2031	0	26	91	1,545	3,122	4,784
2032	0	96	132	1,359	2,407	3,994
2033	270	127	190	1,315	1,024	2,926
2034	200	58	194	1,011	497	1,960
2035	527	0	202	511	546	1,786
2036	410	0	108	424	286	1,228
2037	97	0	22	55	66	240
2038	0	0	0	0	0	0
2039	0	0	0	0	0	0
2040	0	0	0	0	0	0
2041	0	0	0	0	0	0
2042	0	0	0	0	0	0
2043	0	0	0	0	0	0
2044	0	0	0	0	0	0
2045	0	0	0	0	0	0
2046	0	0	0	0	0	0
2047	0	0	0	0	0	0
2048	0	0	0	0	0	0
2049	0	0	0	0	0	0
2050	0	0	0	0	0	0
2051	0	0	0	0	0	0
2052	0	0	0	0	0	0
2053	0	0	0	0	0	0
2054	0	0	0	0	0	0
2055	0	0	0	0	0	0
TOTAL	**14.9**	**3.5**	**1.9**	**3.4**	**3.6**	**27.3**

Equus Full Development Condensate Production Forecast Best Case

Year	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5	Total
2021	8,732	0	0	0	0	8,732
2022	8,515	0	0	0	0	8,515
2023	8,609	0	0	0	0	8,609
2024	8,620	0	0	0	0	8,620
2025	9,329	0	0	0	0	9,329
2026	9,331	0	0	0	0	9,331
2027	4,380	2,997	0	0	0	7,377
2028	405	5,072	0	0	0	5,477
2029	214	5,664	0	0	0	5,878
2030	214	5,403	0	0	0	5,617
2031	387	1,033	408	0	0	1,828
2032	35	186	2,111	0	0	2,332
2033	48	165	2,171	0	0	2,384
2034	65	257	1,544	0	0	1,866
2035	130	240	461	1,467	1,030	3,328
2036	213	110	430	1,439	1,180	3,372
2037	0	62	182	1,513	2,676	4,433
2038	0	0	129	1,631	2,218	3,978
2039	0	0	368	1,523	3,612	5,503
2040	0	0	209	1,210	2,297	3,716
2041	0	0	321	679	1,696	2,696
2042	0	0	334	402	1,278	2,014
2043	0	0	340	409	1,000	1,749
2044	0	0	238	480	614	1,332
2045	0	0	194	329	649	1,172
2046	0	0	161	276	594	1,031
2047	0	0	0	0	0	0
2048	0	0	0	0	0	0
2049	0	0	0	0	0	0
2050	0	0	0	0	0	0
2051	0	0	0	0	0	0
2052	0	0	0	0	0	0
2053	0	0	0	0	0	0
2054	0	0	0	0	0	0
2055	0	0	0	0	0	0
TOTAL	**21.6**	**7.7**	**3.5**	**4.1**	**6.9**	**43.9**

Equus Full Development Condensate Production Forecast High Case

Year	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5	Total
2021	9,293	0	0	0	0	9,293
2022	9,161	0	0	0	0	9,161
2023	9,236	0	0	0	0	9,236
2024	9,297	0	0	0	0	9,297
2025	10,221	0	0	0	0	10,221
2026	10,342	0	0	0	0	10,342
2027	6,352	3,816	0	0	0	10,168
2028	2,213	6,289	0	0	0	8,502
2029	900	6,406	0	0	0	7,306
2030	1,746	2,589	0	0	0	4,335
2031	1,900	1,781	365	0	0	4,046
2032	0	950	2,581	0	0	3,531
2033	454	672	2,451	0	0	3,577
2034	791	1,232	1,411	0	0	3,434
2035	1,057	945	1,406	0	0	3,408
2036	812	982	1,609	0	0	3,403
2037	0	1,182	822	2,583	452	5,039
2038	0	1,044	746	1,656	320	3,766
2039	0	651	175	2,081	1,717	4,624
2040	186	587	394	1,175	2,137	4,479
2041	1184	629	745	823	851	4,232
2042	2232	937	561	544	775	5,049
2043	2168	1,054	348	740	917	5,227
2044	622	810	460	996	1,397	4,285
2045	1277	621	255	1,233	1,767	5,153
2046	1983	1,029	656	271	393	4,332
2047	1838	870	785	420	560	4,473
2048	1693	737	629	499	806	4,364
2049	949	620	814	490	836	3,709
2050	982	80	897	815	1,157	3,931
2051	580	0	744	964	1,450	3,738
2052	716	0	674	1,196	1,401	3,987
2053	565	0	597	773	1,975	3,910
2054	496	0	527	588	1,898	3,509
2055	419	0	467	470	1,536	2,892
2056	489	0	362	469	1,720	3,040
2057	99	0	221	376	1,480	2,176
2058	0	0	126	370	1,379	1,875
2059	0	0	98	373	1,759	2,230
2060	0	0	80	292	1,685	2,057
2061	0	0	74	295	1,379	1,748
2062	0	0	67	308	1,189	1,564
2063	0	0	31	136	1,039	1,206
2064	0	0	0	0	946	946
2065	0	0	0	0	836	836
2066	0	0	0	0	0	0
2067	0	0	0	0	0	0
TOTAL	**33.7**	**13.3**	**8.1**	**7.6**	**13.1**	**75.8**