Private and confidential

Competent Person's Report

Valuation of Certain UK assets on behalf of Premier Oil and Gas Services Limited

Prepared by: Gavin Ward

7th April 2016

15.0092

decisions with confidence

Declaration

Premier Oil and Gas Services Limited ("Premier") has commissioned RISC (UK) Ltd ("RISC") to provide an independent valuation of the Reserves and a review of the Contingent and Prospective Resources of E.On E & P UK Limited and E.On E & P UK EU Limited ("E.On") to form a Competent Person's Report.

The assessment of petroleum assets is subject to uncertainty because it involves judgments on many variables that cannot be precisely assessed, including reserves, future oil and gas production rates, the costs associated with producing these volumes, access to product markets, product prices and the potential impact of fiscal/regulatory changes.

The statements and opinions attributable to RISC are given in good faith and in the belief that such statements are neither false nor misleading. In carrying out its tasks, RISC has considered and relied upon information obtained from a data room as well as information in the public domain. The information provided to RISC has included both hard copy and electronic information supplemented with discussions between RISC and key Premier staff.

Whilst every effort has been made to verify data and resolve apparent inconsistencies, neither RISC nor its servants accept any liability for its accuracy, nor do we warrant that our enquiries have revealed all of the matters, which an extensive examination may disclose. In particular, we have not independently verified property title, encumbrances, regulations that apply to this asset(s). RISC has also not audited the opening balances at the valuation date of past recovered and unrecovered development and exploration costs, undepreciated past development costs and tax losses.

We believe our review and conclusions are sound but no warranty of accuracy or reliability is given to our conclusions.

RISC has no pecuniary interest, other than to the extent of the professional fees receivable for the preparation of this report, or other interest in the assets evaluated, that could reasonably be regarded as affecting our ability to give an unbiased view of these assets.

Our review was carried out only for the purpose referred to above and may not have relevance in other contexts.

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Revision History

Revision	**Date**	**Description**	**Checked by**	**Approved by**
#1	8-Feb-2016	Final review by G.Salter	G.Ward	G.Ward
#2	10-Feb-2016	Update to price assumptions	G.Ward	G.Ward
#3	17-Feb-2016	Amend text & charts	G.Ward	G.Ward
#4	25-Feb-2016	Add Reserves & NPV @ 31 Dec 2015	G.Ward	G.Ward
#5	14-Mar-2016	Add valuation of pipelines	G.Ward	G.Ward
#6	24-Mar-2016	Correction to reservoir ages in tables	G.Ward	G.Ward
#7	30-Mar-2016	Amend title and date on title page	G.Ward	G.Ward

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1. Executive Summary

E.On Exploration and Production through its subsidiaries, E.On E & P UK Limited and E.On E & P UK EU Limited ("E.On") is divesting its interests in the UK North Sea. The E.On assets assessed in this report include producing fields, fields which have ceased production, undeveloped fields, key prospects and immature discoveries, and exploration leads.

E.On's UK assets also include seven producing fields in the Central North Sea (Elgin, Franklin, West Franklin, Scoter, Merganser, Glenelg & Huntington), which are not addressed in this report and have been addressed by another independent assessor.

This report presents the conclusions of an independent evaluation by RISC of E.On's UK assets excluding the omitted fields (Elgin, Franklin, West Franklin, Scoter, Merganser, Glenelg & Huntington). The data and information used in this report were obtained from a data room run by E.On, data supplied by Premier and public data.

Unless stated otherwise, the effective date of 1st January 2015 has been chosen for reserves (Table 1-1) and values in this report to align with a Sale and Purchase agreement between Premier Oil and E.On.

The reserves and net present values have also been calculated with an effective date of 31st December 2015 to meet the requirements of the UK Listing Authority (Table 1-2).

RISC has not advised Premier on the acquisition strategy or price bid for E.On's interests.

Key attributes of the portfolio (excluding the Omitted Fields) are:

- Proved+Probable (2P) gas reserves of 208.2 Bcf net to E.On on a working interest basis at 1st January 2015.
- Net 2P average daily production of approximately 28 MMscf/d in 2016
- Addition of 43 MMscf/d net average daily 2P sales production from Tolmount development in 2019, rising to 84 MMscf/d in 2020.

The location of E.On's interests are shown in Figure 1-1 and the producing assets are summarised in Table 1-3. E.On's development interests are summarised in Table 1-4, while discoveries and key prospects are shown in Table 1-5 and additional prospectivity in Table 1-6.

Table 1-1 Summary of Reserves as at 1 January 2015

Field Gas Reserves	Age	Gross Field Reserves (Bcf)			E.On Working Interest (%)	E.On Net Working Interest Reserves (Bcf)		
		1P	2P	3P		1P	2P	3P
Babbage	Permian	40.1	54.5	91.7	47.00%	18.8	25.6	43.1
Johnston	Permian	13.0	15.6	18.3	50.10%	6.5	7.9	9.2
Hunter	Triassic	1.5	1.5	1.5	79.00%	1.2	1.2	1.2
Rita	Carboniferous	2.2	2.2	2.2	74.00%	1.6	1.6	1.6
Caister	Triassic & Carb	1.5	1.5	1.5	40.00%	0.6	0.6	0.6
Orca	Carboniferous	1.6	1.6	1.7	23.47%	0.4	0.4	0.4
Ravenspurn Nth	Permian	6.4	6.7	6.9	28.80%	1.8	1.9	2.0
Tolmount	Permian	0	338.8	833.4	50.00%	0	169.4	416.5
Total		**66.3**	**421.6**	**956.8**		**30.9**	**208.2**	**474.6**

Field Oil+Condensate Reserves	Age	Gross Field Reserves (MMstb)			E.On Working Interest (%)	E.On Net Working Interest Reserves (MMstb)		
		1P	2P	3P		1P	2P	3P
Babbage	Permian	0	0	0	47.00%	0	0	0
Johnston	Permian	0	0	0	50.10%	0	0	0
Hunter	Triassic	0	0	0	79.00%	0	0	0
Rita	Carboniferous	0.014	0.014	0.014	74.00%	0.010	0.010	0.010
Caister	Triassic & Carb	0.008	0.008	0.008	40.00%	0.003	0.003	0.003
Orca	Carboniferous	0	0	0	23.47%	0	0	0
Ravenspurn Nth	Permian	0	0	0	28.80%	0	0	0
Tolmount	Permian	0	3.098	7.396	50.00%	0	1.549	3.698
Total		**0.022**	**3.12**	**7.418**		**0.013**	**1.562**	**3.711**

Field Oil Equivalent Reserves	Age	Gross Field Reserves (MMboe)			E.On Working Interest (%)	E.On Net Working Interest Reserves (MMboe)		
		1P	2P	3P		1P	2P	3P
Babbage	Permian	6.68	9.08	15.28	47.00%	3.13	4.27	7.18
Johnston	Permian	2.17	2.60	3.05	50.10%	1.08	1.32	1.53
Hunter	Triassic	0.25	0.25	0.25	79.00%	0.20	0.20	0.20
Rita	Carboniferous	0.38	0.38	0.38	74.00%	0.28	0.28	0.28
Caister	Triassic & Carb	0.26	0.26	0.26	40.00%	0.10	0.10	0.10
Orca	Carboniferous	0.27	0.27	0.28	23.47%	0.07	0.07	0.07
Ravenspurn Nth	Permian	1.07	1.12	1.15	28.80%	0.30	0.32	0.33
Tolmount	Permian	0	59.43	146.23	50.00%	0	29.72	73.11
Total		**11.08**	**73.39**	**166.88**		**5.16**	**36.28**	**82.80**

Notes: 1) Gross Field Reserves are 100% of the volumes estimated to be economically recoverable from the field from 1st January 2015. 2) Oil equivalent converted at 6,000 scf = 1 Boe.

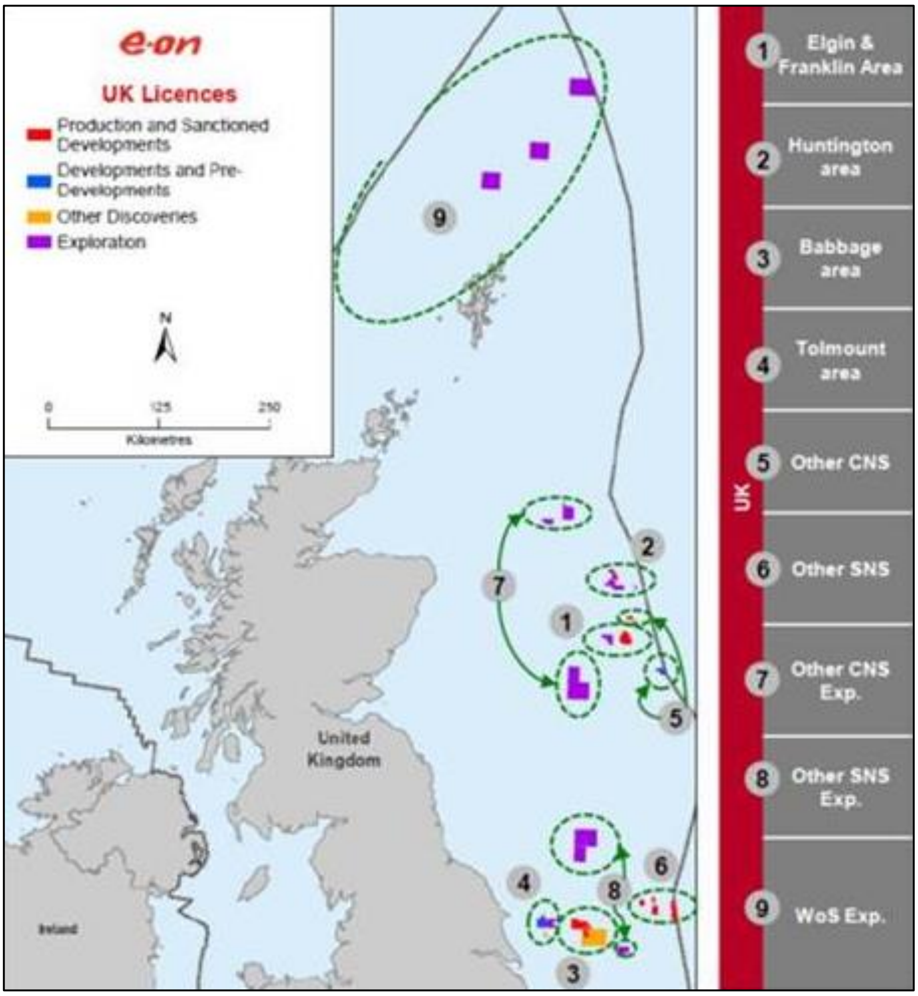
Table 1-2 Summary of Reserves as at 31 December 2015

Field Gas Reserves	Age	Gross Field Reserves (Bcf)			E.On Working Interest (%)	E.On Net Working Interest Reserves (Bcf)		
		1P	2P	3P		1P	2P	3P
Babbage	Permian	26.4	40.6	78.0	47.00%	12.4	19.1	36.7
Johnston	Permian	10.3	12.9	15.5	50.10%	5.2	6.5	7.7
Hunter	Triassic	0.9	0.9	0.9	79.00%	0.7	0.7	0.7
Rita	Carboniferous	0	0	0	74.00%	0	0	0
Caister	Triassic & Carb	0	0	0	40.00%	0	0	0
Orca	Carboniferous	0	0	0	23.47%	0	0	0
Ravenspurn Nth	Permian	0	0	0	28.80%	0	0	0
Tolmount	Permian	0	338.8	833.4	50.00%	0	169.4	416.5
Total		**37.7**	**392.4**	**927.4**		**18.3**	**195.3**	**461.6**

Field Oil+Condensate Reserves	Age	Gross Field Reserves (MMstb)			E.On Working Interest (%)	E.On Net Working Interest Reserves (MMstb)		
		1P	2P	3P		1P	2P	3P
Babbage	Permian	0	0	0	47.00%	0	0	0
Johnston	Permian	0	0	0	50.10%	0	0	0
Hunter	Triassic	0	0	0	79.00%	0	0	0
Rita	Carboniferous	0	0	0	74.00%	0	0	0
Caister	Triassic & Carb	0	0	0	40.00%	0	0	0
Orca	Carboniferous	0	0	0	23.47%	0	0	0
Ravenspurn Nth	Permian	0	0	0	28.80%	0	0	0
Tolmount	Permian	0	3.098	7.396	50.00%	0	1.549	3.698
Total		**0**	**3.098**	**7.396**		**0**	**1.549**	**3.698**

Field Oil Equivalent Reserves	Age	Gross Field Reserves (MMboe)			E.On Working Interest (%)	E.On Net Working Interest Reserves (MMboe)		
		1P	2P	3P		1P	2P	3P
Babbage	Permian	4.4	6.8	13.0	47.00%	2.1	3.2	6.1
Johnston	Permian	1.7	2.2	2.6	50.10%	0.9	1.1	1.3
Hunter	Triassic	0	0	0	79.00%	0	0	0
Rita	Carboniferous	0	0	0	74.00%	0	0	0
Caister	Triassic & Carb	0	0	0	40.00%	0	0	0
Orca	Carboniferous	0	0	0	23.47%	0	0	0
Ravenspurn Nth	Permian	0.4	0.4	0.4	28.80%	0.1	0.1	0.1
Tolmount	Permian	0	59.43	146.23	50.00%	0	29.72	73.11
Total		**6.5**	**68.83**	**162.23**		**3.1**	**34.12**	**80.61**

Notes: 1) Gross Field Reserves are 100% of the volumes estimated to be economically recoverable from the field from 31st December 2015. 2) Oil equivalent converted at 6,000 scf = 1 Boe.



REGION	Producing	Developments	Discoveries	Exploration
1 – Elgin, Franklin	Not part of this report		Corfe	West Franklin Terrace, Elgin West
2 – Huntington Area	Not part of this report			Ekland
3 - Babbage Area	Babbage, Johnston, Ravenspurn North		Cobra, Hawking	Ada, Newton, Python, Newton Deep, Dodgson, Joly, Adder, Viper, Boa
4 – Tolmount Area		Tolmount	Artemis, Mongour	Artemis East, Malin, Cluin
5 – Other CNS	Not part of this report		Arran, Austen	
6 – Other SNS	Caister, Hunter, Orca, Rita & Minke (ceased production), CMS, ETS			North Rita, Deep Hunter
7 – Other CNS Exploration				TR7, Tumbleweed, Chimera
8 - Other SNS Exploration				Lyra
9 – West of Shetlands				Colza, Mardyke, Gunnison
Note: Third Party Revenue analyses for Huntington, Babbage and Tolmount areas are not included in this report				

Figure 1-1 Location map and key of main E.On licenced UK blocks and fields

Table 1-3 E.On's Production Interests

Area	Asset Name	Status	Operator	E.On's Working Interest (%)
Southern North Sea	Babbage	Producing	E.On	47.00
Southern North Sea	Caister	Ceased Production in 2015	ConocoPhillips	40.00
Southern North Sea	Hunter	Restarted Production in 2015	E.On	79.00
Southern North Sea	Johnston	Producing	E.On	50.10
Southern North Sea	Minke	Ceased Production	GDF Suez	42.67
Southern North Sea	Orca	Producing	GDF Suez	23.47
Southern North Sea	Ravenspurn North	Producing	Perenco	28.80
Southern North Sea	Rita	Currently Shut-in	E.On	74.00
Southern North Sea	Caister Murdoch System	Infrastructure	ConocoPhillips	20.00
Southern North Sea	Esmond Transportation System	Infrastructure	Perenco	30.00

Table 1-4 E.On's Development Interests

Area	Asset Name	Status	Operator	E.On's Working Interest (%)
Central North Sea	Arran	Awaiting development sanction	Dana	5.12
Central North Sea	Austen	Under review	GDF Suez	25.00
Southern North Sea	Tolmount	Development pending FID	Eon	50.00

Table 1-5 E.On's Discoveries and Key Prospect Interests

Area	Asset Name	Field Area	Eon's Working Interest (%)
Central North Sea	Corfe Discovery	Elgin/Franklin	25
Central North Sea	Ekland Prospect	Huntington	40
Southern North Sea	Cobra Discovery	Babbage	50
Southern North Sea	Hawking Discovery	Babbage	50
Southern North Sea	Ada Prospect	Babbage	47
Southern North Sea	Newton Prospect	Babbage	50
Southern North Sea	Python Prospect	Babbage	50
Southern North Sea	Artemis Discovery	Tolmount	100
Southern North Sea	Artemis East Prospect	Tolmount	100
Southern North Sea	Mongour Discovery	Tolmount	50
Southern North Sea	Malin prospect	Tolmount	50

Table 1-6 E.On's Additional Prospectivity Interests (Leads)

Area	Asset Name	Field Area	Eon's Working Interest (%)
Southern North Sea	Cluin	Tolmount	50
Southern North Sea	Newton Deep	Babbage	50
Southern North Sea	Dodgson	Babbage	50
Southern North Sea	Joly	Babbage	50
Southern North Sea	Adder	Babbage	50
Southern North Sea	Viper	Babbage	50
Southern North Sea	Boa	Babbage	50
Southern North Sea	North Rita	Rita	74
Southern North Sea	Deep Hunter	Caister	79
Southern North Sea	Lyra	Breagh	35
Central North Sea	West Franklin Terrace	Elgin/Franklin	5.2
Central North Sea	Elgin West	Elgin/Franklin	5.2
Central North Sea	TR7	Galley	40
Central North Sea	Tumbleweed	Kittiwake	40
Central North Sea	Chimaera	Galley	40
West of Shetland	Colza	-	100
West of Shetland	Mardyke	-	100
West of Shetland	Gunison	-	100

1.1. Production Assets and Reserves

RISC estimates that Eon's assets have 208.2 Bcf of 2P gas reserves and 1.562 MMstb of 2P oil+condensate reserves as at 1st January 2015 on a net working interest basis. This reduces to 195.3 Bcf and 1.549 MMstb of 2P oil+condensate with an effective date of 31st December 2015. Table 1-7 and Table 1-8 summarise the reserves derived from these assessments. Deterministic methods have been used to estimate reserves.

Table 1-7 E.On Net Reserves as at 1 January 2015 (Price Scenario A)

Field	Status	E.On WI	Case	Economic Limit	Gas Bcf[1]	Condensate MMBbl	Gas+Liquids Equivalent MMboe[2]
Ravenspurn North	Producing	29%	1P	2016	1.8	0	0.30
			2P	2016	1.9	0	0.32
			3P	2016	2.0	0	0.33
Johnston	Producing	50%	1P	2028	6.5	0	1.09
			2P	2028	7.9	0	1.30
			3P	2028	9.2	0	1.54
Caister	Ceased Production	40%	1P	2016	0.6	0.003	0.10
			2P	2016	0.6	0.003	0.10
			3P	2016	0.6	0.003	0.10
Babbage	Producing	47%	1P	2021	18.8	0	3.14
			2P	2024	25.6	0	4.27
			3P	2030	43.1	0	7.19
Orca	Producing	23%	1P	2016	0.3	0	0.06
			2P	2016	0.3	0	0.06
			3P	2016	0.3	0	0.07
Hunter	Producing	79%	1P	2018	1.2	0	0.19
			2P	2018	1.2	0	0.19
			3P	2018	1.2	0	0.19
Rita	Currently Shut-in	74%	1P	2016	1.6	0.010	0.28
			2P	2016	1.6	0.010	0.28
			3P	2016	1.6	0.010	0.28
Tolmount	Development pending FID	50%	1P		0	0	0
			2P	2040	169.0	1.549	29.72
			3P	2043	416.5	3.698	73.11

[1] NPV's based on energy units Trillion British Thermal Units (TBTU). 1 TBTU is equivalent to 1 Billion Cubic Feet of Gas assuming that the calorific value/heating content of the gas is 1 therm = 1,000 BTU. The calorific value will depend upon the percentage of inert gases such as nitrogen and carbon dioxide in the sales gas and RISC has converted TBTU to Bcf of each field based on the specific calorific value of the gas in that field eg: Orca field : 737 BTU/standard cubic feet of gas (0.737 TBTU = 1 Bcf).

[2] Calculated using an average conversion factor of 6 Mscf per barrel of oil equivalent (boe)

Table 1-8 E.On Net Reserves as at 31 December 2015 (Price Scenario A)

Field	Status	E.On WI	Case	Economic Limit	Gas Bcf[3]	Condensate MMBbl	Gas+Liquids Equivalent MMboe[4]
Ravenspurn North	Producing	29%	1P	2016	0	0	0
			2P	2016	0	0	0
			3P	2016	0	0	0
Johnston	Producing	50%	1P	2028	5.18	0	0.89
			2P	2028	6.46	0	1.11
			3P	2028	7.74	0	1.33
Caister	Ceased Production	40%	1P	2016	0	0	0
			2P	2016	0	0	0
			3P	2016	0	0	0
Babbage	Producing	47%	1P	2021	12.41	0	2.14
			2P	2024	19.10	0	3.29
			3P	2030	36.67	0	6.32
Orca	Producing	23%	1P	2016	0	0	0
			2P	2016	0	0	0
			3P	2016	0	0	0
Hunter	Producing	79%	1P	2018	0.72	0	0.12
			2P	2018	0.72	0	0.12
			3P	2018	0.72	0	0.12
Rita	Currently Shut-in	74%	1P	2016	0	0	0
			2P	2016	0	0	0
			3P	2016	0	0	0
Tolmount	Development pending FID	50%	1P		0	0	0
			2P	2040	169.0	1.549	29.72
			3P	2043	416.5	3.698	73.11

The following Net Present Values (Table 1-9 to

[3] NPV's based on energy units Trillion British Thermal Units (TBTU). 1 TBTU is equivalent to 1 Billion Cubic Feet of Gas assuming that the calorific value/heating content of the gas is 1 therm = 1,000 BTU. The calorific value will depend upon the percentage of inert gases such as nitrogen and carbon dioxide in the sales gas and RISC has converted TBTU to Bcf of each field based on the specific calorific value of the gas in that field eg: Orca field : 737 BTU/standard cubic feet of gas (0.737 TBTU = 1 Bcf).

[4] Calculated using an average conversion factor of 6 Mscf per barrel of oil equivalent (boe)

Table 1-12) have not been adjusted for other factors (eg analogous transactions, strategic, political and security risks) that a buyer or seller may consider in any transaction concerning these assets and therefore may not be representative of the fair market value.

Four price scenarios have been evaluated at two different effective dates, 01-Jan-2015 and 31-Dec-2015:

- RISC's base case price estimate (Scenario A)
- Sensitivities on RISC's base case price estimate, representing the higher prices achieved in the last twelve months (Scenarios B, C and D).

The economic results for the pipelines are independent of the oil and gas price scenarios. A single scenario was evaluated for each of the Esmond Transmission System (ETS) and Caister Murdoch System (CMS) working interests, at each of the effective dates.

Table 1-9 Pre-Tax Valuation Summary (NPV at 10% discount rate in US$MM at 1 January 2015)

Field	Status	E.On WI	Case	Price Scenario 'A'	Price Scenario 'B'	Price Scenario 'C'	Price Scenario 'D'
Rita	Currently Shut-in	74%	1P	0	0	0	0
			2P	0	0	0	0
			3P	0	0	0	0
Ravenspurn North	Producing	29%	1P	-60	-60	-60	-60
			2P	-59	-59	-59	-59
			3P	-59	-59	-59	-59
Johnston	Producing	50%	1P	5	9	7	10
			2P	10	14	12	15
			3P	14	19	16	21
Caister	Ceased Production	40%	1P	-37	-37	-37	-37
			2P	-37	-37	-37	-37
			3P	-37	-37	-37	-37
Babbage	Producing	47%	1P	4	16	10	21
			2P	20	39	30	47
			3P	51	78	66	90
Orca	Producing	23%	1P	-20	-20	-20	-20
			2P	-20	-20	-20	-20
			3P	-20	-20	-20	-20
Hunter	Producing	79%	1P	-11	-10	-10	-10
			2P	-11	-10	-10	-10
			3P	-11	-10	-10	-10
Minke	Ceased Production	43%	1P	-12	-12	-12	-12
			2P	-12	-12	-12	-12
			3P	-12	-12	-12	-12
Tolmount	Development pending FID	50%	1P	-33	-33	-33	-33
			2P	111	214	160	267
			3P	584	789	682	897
CMS Pipeline	Facility	20%		-4	-4	-4	-4
ETS Pipeline	Facility	30%		29	29	29	29
Total (Including Pipelines)			**1P**	**-139**	**-122**	**-130**	**-116**
			2P	**27**	**154**	**89**	**216**
			3P	**535**	**773**	**651**	**895**

Table 1-10 Post Tax[5] Valuation Summary (NPV at 10% discount rate in US$MM at 1 January 2015)

Field	Status	E.On WI	Case	Price Scenario 'A'	Price Scenario 'B'	Price Scenario 'C'	Price Scenario 'D'
Rita	Currently Shut-in	74%	1P	0	0	0	0
			2P	0	0	0	0
			3P	0	0	0	0
Ravenspurn North	Producing	29%	1P	-60	-60	-60	-60
			2P	-59	-59	-59	-59
			3P	-59	-59	-59	-59
Johnston	Producing	50%	1P	5	9	7	10
			2P	10	14	12	15
			3P	14	17	16	17
Caister	Ceased Production	40%	1P	-37	-37	-37	-37
			2P	-37	-37	-37	-37
			3P	-37	-37	-37	-37
Babbage	Producing	47%	1P	4	16	10	20
			2P	20	31	27	36
			3P	42	54	49	58
Orca	Producing	23%	1P	-20	-20	-20	-20
			2P	-20	-20	-20	-20
			3P	-20	-20	-20	-20
Hunter	Producing	79%	1P	-11	-10	-10	-10
			2P	-11	-10	-10	-10
			3P	-11	-10	-10	-10
Minke	Ceased Production	43%	1P	-12	-12	-12	-12
			2P	-12	-12	-12	-12
			3P	-12	-12	-12	-12
Tolmount	Development pending FID	50%	1P	-33	-33	-33	-33
			2P	28	81	53	108
			3P	256	363	307	418
CMS Pipeline	Facility	20%		-4	-4	-4	-4
ETS Pipeline	Facility	30%		17	17	17	17
Total (Including. Pipelines)			**1P**	**-151**	**-134**	**-142**	**-129**
			2P	**-68**	**1**	**-33**	**34**
			3P	**186**	**309**	**247**	**368**
Consolidated Tax benefit			**2P[6]**	76	71	75	66

Table 1-11 Pre-Tax Valuation Summary (NPV at 10% discount rate in US$MM at 31st December 2015)

Field	Status	E.On WI	Case	Price Scenario 'A'	Price Scenario 'B'	Price Scenario 'C'	Price Scenario 'D'
Rita	Currently Shut-in	74%	1P	-12	-12	-12	-12
			2P	-12	-12	-12	-12
			3P	-12	-12	-12	-12
Ravenspurn North	Producing	29%	1P	-62	-62	-62	-62
			2P	-62	-62	-62	-62
			3P	-62	-62	-62	-62
Johnston	Producing	50%	1P	-1	3	1	4
			2P	3	8	6	10
			3P	8	13	10	15
Caister	Ceased Production	40%	1P	-43	-43	-43	-43
			2P	-43	-43	-43	-43
			3P	-43	-43	-43	-43
Babbage	Producing	47%	1P	-24	-10	-18	-5
			2P	-7	13	4	23
			3P	25	55	41	68
Orca	Producing	23%	1P	-20	-20	-20	-20
			2P	-20	-20	-20	-20
			3P	-20	-20	-20	-20
Hunter	Producing	79%	1P	-12	-11	-11	-11
			2P	-12	-11	-11	-11
			3P	-12	-11	-11	-11
Minke	Ceased Production	43%	1P	-13	-13	-13	-13
			2P	-13	-13	-13	-13
			3P	-13	-13	-13	-13
Tolmount	Development pending FID	50%	1P	-36	-36	-36	-36
			2P	122	235	176	294
			3P	656	882	763	1,000
CMS Pipeline	Facility	20%		-4	-4	-4	-4
ETS Pipeline	Facility	30%		32	32	32	32
Total (Including Pipelines)			**1P**	**-195**	**-176**	**-186**	**-170**
			2P	**-16**	**123**	**53**	**194**
			3P	**555**	**817**	**681**	**950**

[5] Tax losses acquired in respect of EPUK EU have been applied

[6] Consolidated tax benefit calculated for arithmetic total of field 2P cash flows only

Table 1-12 Post Tax[7] Valuation Summary (NPV at 10% discount rate in US$MM at 31st December 2015)

Field	Status	E.On WI	Case	Price Scenario 'A'	Price Scenario 'B'	Price Scenario 'C'	Price Scenario 'D'
Rita	Currently Shut-in	74%	1P	-12	-12	-12	-12
			2P	-12	-12	-12	-12
			3P	-12	-12	-12	-12
Ravenspurn North	Producing	29%	1P	-62	-62	-62	-62
			2P	-62	-62	-62	-62
			3P	-62	-62	-62	-62
Johnston	Producing	50%	1P	-1	3	1	4
			2P	3	8	6	10
			3P	8	13	10	15
Caister	Ceased Production	40%	1P	-43	-43	-43	-43
			2P	-43	-43	-43	-43
			3P	-43	-43	-43	-43
Babbage	Producing	47%	1P	-24	-10	-18	-5
			2P	-7	13	4	23
			3P	25	44	38	49
Orca	Producing	23%	1P	-20	-20	-20	-20
			2P	-20	-20	-20	-20
			3P	-20	-20	-20	-20
Hunter	Producing	79%	1P	-12	-11	-11	-11
			2P	-12	-11	-11	-11
			3P	-12	-11	-11	-11
Minke	Ceased Production	43%	1P	-13	-13	-13	-13
			2P	-13	-13	-13	-13
			3P	-13	-13	-13	-13
Tolmount	Development pending FID	50%	1P	-36	-36	-36	-36
			2P	31	89	58	119
			3P	295	413	352	473
CMS Pipeline	Facility	20%		-4	-4	-4	-4
ETS Pipeline	Facility	30%		18	18	18	18
Total (Including Pipelines)			**1P**	**-209**	**-190**	**-200**	**-184**
			2P	**-121**	**-37**	**-79**	**5**
			3P	**180**	**323**	**253**	**390**
Consolidated Tax benefit			**2P[8]**	84	78	82	73

[7] Tax losses acquired in respect of EPUK EU have been applied

1.2. Processing Terminals and Pipelines

RISC has valued the net tariff income and abandonment liability of the Caister Murdoch System and Esmond Transmission System pipelines. The costs associated with the Freon replacement project at Theddlethorpe Gas Terminal, which is used by the Caister, Rita and Hunter fields is part of a cost share agreement with the users of the terminal and this cost forms part of field Operating Expenditure (Opex).

The following Net Present Values (Table 1-13) have not been adjusted for other factors (eg analogous transactions, strategic, political and security risks) that a buyer or seller may consider in any transaction concerning these assets and therefore may not be representative of the fair market value.

The economic results for the pipelines (Table 1-13) are independent of the oil and gas price scenarios. A single scenario was evaluated for each of the ETS and CMS working interests at the effective date of 31-Dec-2015.

Table 1-13 Pre-Tax & Post-Tax Valuation (NPV at 10% discount rate in US$MM at 31st December 2015)

Field	Status	E.On WI	Pre-Tax NPV	Post-Tax NPV
Caister Murdoch System Pipeline	Facility	20%	-4	-4
Esmond Transportation System	Facility	30%	32	18

[8] Consolidated tax benefit calculated for arithmetic total of field 2P cash flows only

1.3. Contingent Resources

RISC has reviewed the Contingent Resource volumes.

Table 1-14 Contingent Resources

Field	Status	E.On WI	Case	Net Gas Resource Bcf	Net Condensate Resource MMstb	Gas+Liquids Equivalent MMboe
Producing Field Projects						
Ravenspurn North	Upside wells plus sub-economic production	29%	1C	27.4		4.57
			2C	47.2		7.87
			3C	68.0		11.33
Babbage	J infill well plus sub-economic production	47%	1C	14.4		2.40
			2C	23.3		3.88
			3C	27.1		4.52
Rita	Currently Shut-in		1C	3.8	0.02	0.65
			2C	4.5	0.03	0.78
			3C	5.1	0.04	0.89
Orca	Sub-economic production	23%	1C	0.3		0.05
			2C	0.5		0.08
			3C	0.7		0.12
Undeveloped discoveries						
Tolmount	Development pending FID	50%	1C	76.9	0.666	13.50
			2C	0	0	0
			3C	0	0	0
Austen	Development too immature to assess volumes	25%	1C	-	-	-
			2C	-	-	-
			3C	-	-	-
Arran	Development pending decision	5%	1C	5.1	0.138	0.99
			2C	8.0	0.215	1.54
			3C	11.4	0.328	2.23

1.4. Exploration Potential

RISC has not valued the Exploration potential. There are eleven prospects which have reached a mature level in order to be relatively confident of a calibrated Geological Chance of Success. There are a further fifteen leads in the Southern and Central North Sea, and a further three leads in the West of Shetlands blocks.

1.5. Opportunities and Risks

In addition to the uncertainty expressed by the ranges of resource volumes, costs and prices identified above, the group of assets are characterised by the following opportunities and risks:

Risks:

- Facility and pipeline integrity in the mature assets could lead to unforeseen outages
- Tariff/cost share uncertainties where gas is exported in third party infrastructure
- Tolmount (and other) project delays due to lack of confidence in current environment
- Significant number of late life mature assets with uncertain abandonment liability
- Eleven suspended wells which will require either permanent abandonment or regular monitoring in line with guidance given by the Oil and Gas Authority.

Opportunities:

- New field development at Tolmount, which has a field life of over twenty years in the 2C volume case
- Contingent resources in undeveloped fields indicate potential for reserves additions
- Operating cost reductions with move to unmanned/not normally manned installations
- Capital and operating cost reductions as operators find efficiencies and suppliers become more competitive in the current market
- Abandonment cost reductions as the North Sea industry gains experience and perhaps economies of scale with multi-field abandonment campaigns. Greater cooperation between operators leading to efficiencies and cost reductions
- Third party revenues in CMS and ETS pipelines

2. Basis of Assessment

2.1. Data Availability and Methodology

In preparing this Competent Person's Report, RISC has relied on information provided by E.On and Premier as well as information from the public domain. A RISC team visited E.On's physical data room during June 2015 and December 2015 and accessed a Virtual Data Room (VDR) to review seismic data, well data, geological models, reservoir engineering models, cost data and commercial terms.

The dataset included data provided between June 2015 and January 2016.

RISC has reviewed basic and interpreted data as presented by E.On and made adjustments as required to form an independent view of future production, resources, costs, schedule for selected assets.

Reserves and Net Present Values have been reported as at 1st January 2015 to align with the Effective Date of a Sale and Purchase Agreement between Premier Oil and E.On.

A total of four price scenarios have been run with Price Scenario 'A' representing RISC's view of future prices. The three other scenarios (Price Scenario 'B', Price Scenario 'C' & Price Scenario 'D') represent price sensitivities above RISC's base scenario.

We have not conducted a site visit.

2.2. Qualifications

RISC is an independent oil and gas advisory firm. All of the RISC staff engaged in this assignment are professionally qualified engineers, geoscientists or analysts, each with many years of relevant experience and most have in excess of 20 years. The preparation of this report has been managed by Mr Gavin Ward. Mr Ward has a B.Sc (Hons) Geology & Physics (Aston University), an MBA from the Cranfield School of Management, is a Chartered Accountant and Fellow of the Association of Chartered Certified Accountants (FCCA). Mr Ward has 28 years of experience in the sector, is a member of the Society of Petroleum Engineers and is a Council Member of the Petroleum Exploration Society of Great Britain. Mr Ward is a Competent Person as defined in London Stock Exchange, AIM Guidance Note for Mining, Oil and Gas Companies, March 2006.

RISC was founded in 1994 to provide independent advice to companies associated with the oil and gas industry. Today the company has approximately forty highly experienced professional staff at offices in Perth, Brisbane, Jakarta and London. We have completed over 2,000 assignments in sixty eight countries for nearly 500 clients. Our services cover the entire range of the oil and gas business lifecycle and include:

- Oil and gas asset valuations, expert advice to banks for debt or equity finance;
- Exploration/portfolio management;
- Field development studies and operations planning;
- Reserves assessment and certification, peer reviews;
- Gas market advice;
- Independent Expert/Expert Witness;
- Strategy and corporate planning.

2.3. Limitations

The assessment of petroleum assets is subject to uncertainty because it involves judgments on many variables that cannot be precisely assessed, including reserves/resources, future oil and gas production rates, the costs associated with producing these volumes, access to product markets, product prices and the potential impact of fiscal/regulatory changes.

The E.On assets assessed in this report comprise producing fields, fields which have ceased production, undeveloped fields, key prospects and immature discoveries, and exploration leads. Additional assets that form part of the proposed transaction but which are not included in this report and are referred to as the 'Omitted Fields'.

The Net Present Value estimates presented in this report have not been adjusted for hedging contracts or other factors (eg strategic, political and security risks) that a buyer or seller may consider in any transaction concerning these assets and therefore may not be representative of the fair market value. The statements and opinions attributable to RISC are given in good faith and in the belief that such statements are neither false nor misleading. While every effort has been made to verify data and resolve apparent inconsistencies, neither RISC nor its servants accept any liability for, or warrant the accuracy or reliability of our conclusions, nor do we warrant that our enquiries have revealed all of the matters, which an extensive examination may disclose. In particular, we have not independently verified property title, encumbrances and regulations that apply to these assets.

RISC has not audited the opening balances at the valuation date of past recovered and unrecovered development and exploration costs, undepreciated past development costs and tax losses.

We believe our review and conclusions are sound but no warranty of accuracy or reliability is given to our conclusions.

2.4. Independence

RISC makes the following disclosures:

- RISC is independent with respect to E.On and Premier and confirms that there is no conflict of interest with any party involved in the assignment.
- Under the terms of engagement between RISC and Premier for the provision of this report, RISC will receive a fee, payable by Premier. The payment of this fee is not contingent on the intended purpose of this report.
- Neither RISC Directors nor any staff involved in the preparation of this report hold interests in Premier.

2.5. Standard

Reserves and resources are reported in accordance with the definitions of reserves, contingent resources and prospective resources and guidelines set out in the Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers in 2007 and European Securities and Markets Authority (ESMA).

2.6. Consent

Neither the whole nor any part of this report nor any reference to it may be included in or attached to any prospectus, document, circular, resolution, letter or statement without the prior consent of RISC.

3. Production Assets

The producing assets covered in this report are all in the Southern North Sea. The E.On assets assessed in this section include five producing fields, two fields which have ceased production and one currently shut-in.

3.1. Southern North Sea Regional Geology

The evolution of the Southern North Sea Basin occurred through several main phases in geological history. Firstly was the creation of the Sub-Cambrian peneplain, before the Caledonia Orogeny in the late Silurian to Devonian. The Variscan Orogeny followed throughout the Carboniferous and into the Permian causing folding and faulting of Carboniferous strata. This generated a dominant north west to south east orientated structural grain in the Southern North Sea Basin with a subordinate orthogonal north east to south west (De Keysers) fault set exhibiting a dominant strike-slip offset rather than vertical movement. These fault trends controlled the early deposition of the Permian sandstones that provide the dominant reservoir rocks in the Southern North Sea, with deposition unconformable above a largely peneplaned Carboniferous subcrop. Basinal extension and subsidence throughout the Permian and into the Mesozoic provided accommodation space. Deposition of the Permian Zechstein evaporites followed Permian clastic deposition, providing the regional seal for the Permian Sandstone play. Continued extension and regional subsidence into the Mesozoic resulted in widespread continental clastic deposition in the Triassic before sea level rise towards the end of the Triassic resulted in marine conditions in the Jurassic and Cretaceous Periods. Uplift during Late Cretaceous and Tertiary inversions, associated with the Alpine orogeny, resulted in almost all of the Late Mesozoic section being eroded. Undifferentiated Quaternary-Tertiary marine sands and clays top the regional stratigraphy.

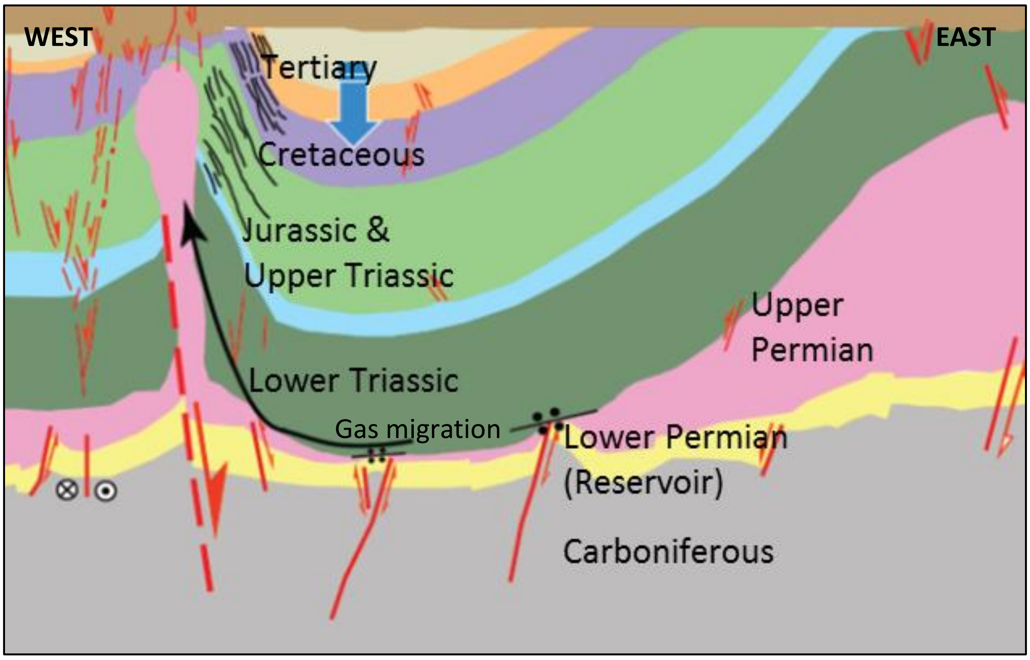


Figure 3-1 Regional geological cross section through Southern North Sea

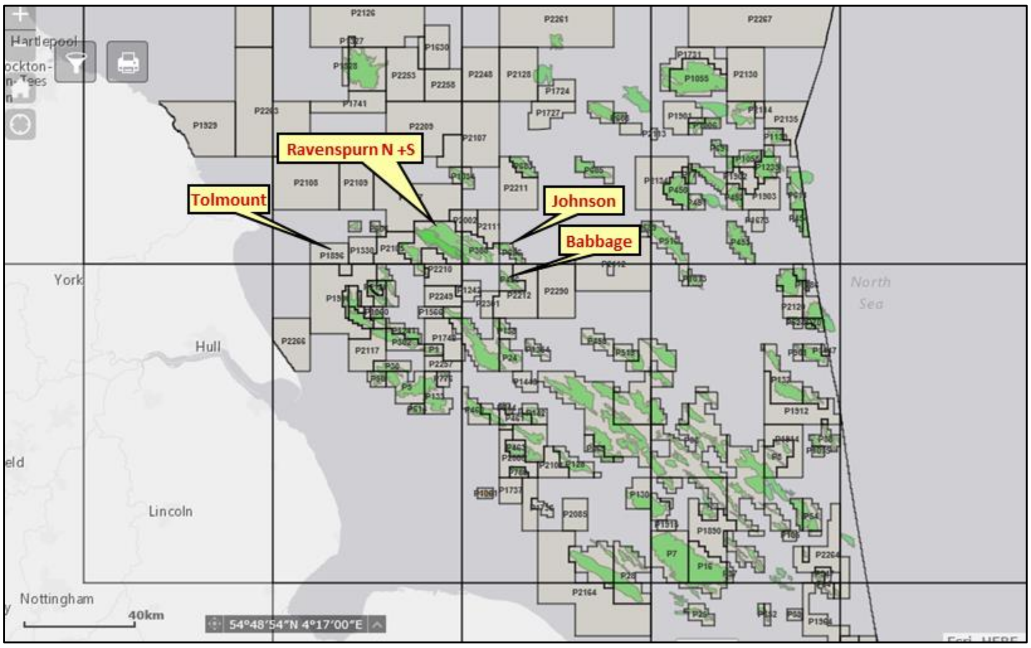


Figure 3-2 Southern North Sea Location Map

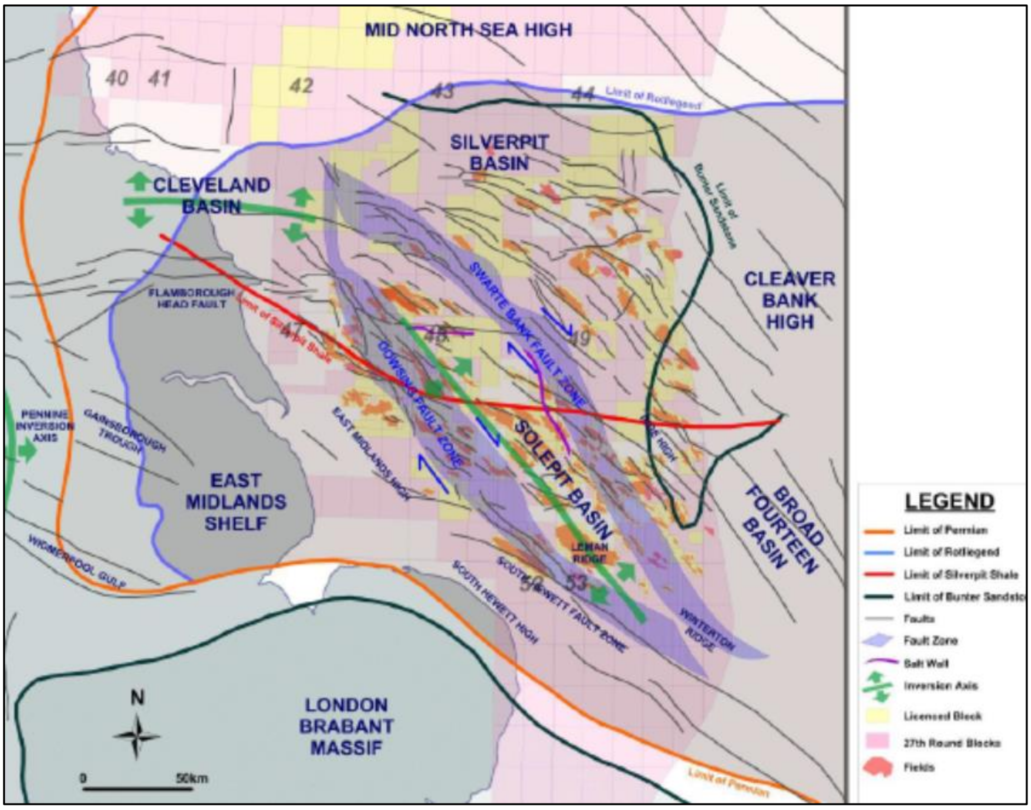


Figure 3-3 Southern North Sea Structural Elements

3.1.1. Source Rocks

Hydrocarbons encountered in the Southern North Sea are thought to be sourced from Carboniferous Westphalian Coals and Namurian marine shales. These either directly underlie the Permian reservoir sands or lie adjacent to eroded palaeohighs, such as around the Babbage Field. As a consequence migration pathways are generally short and often vertical with intra-Carboniferous sands acting as carrier beds. Gas quality and composition are known to vary across the basin in relation to local geological conditions.

3.1.2. Reservoirs

The primary reservoir exploited in the region is the Lower Leman Sandstone Formation of Rotliegendes (Permian) age, comprising aeolian, fluvial and sabkha facies, deposited along the southern margin and to the south of the Silverpit Lake (Figure 3-4). Reservoir facies and thickness are known to vary locally in relation to local structural setting and climatic controls. Aeolian deposition dominates to the south and west, whilst fluvial influence increases with proximity to the Silverpit Lake which itself is characterised by mudstone and evaporitic facies. Reservoir quality is heavily dependent on depositional facies with the aeolian sequences providing the best quality reservoir.

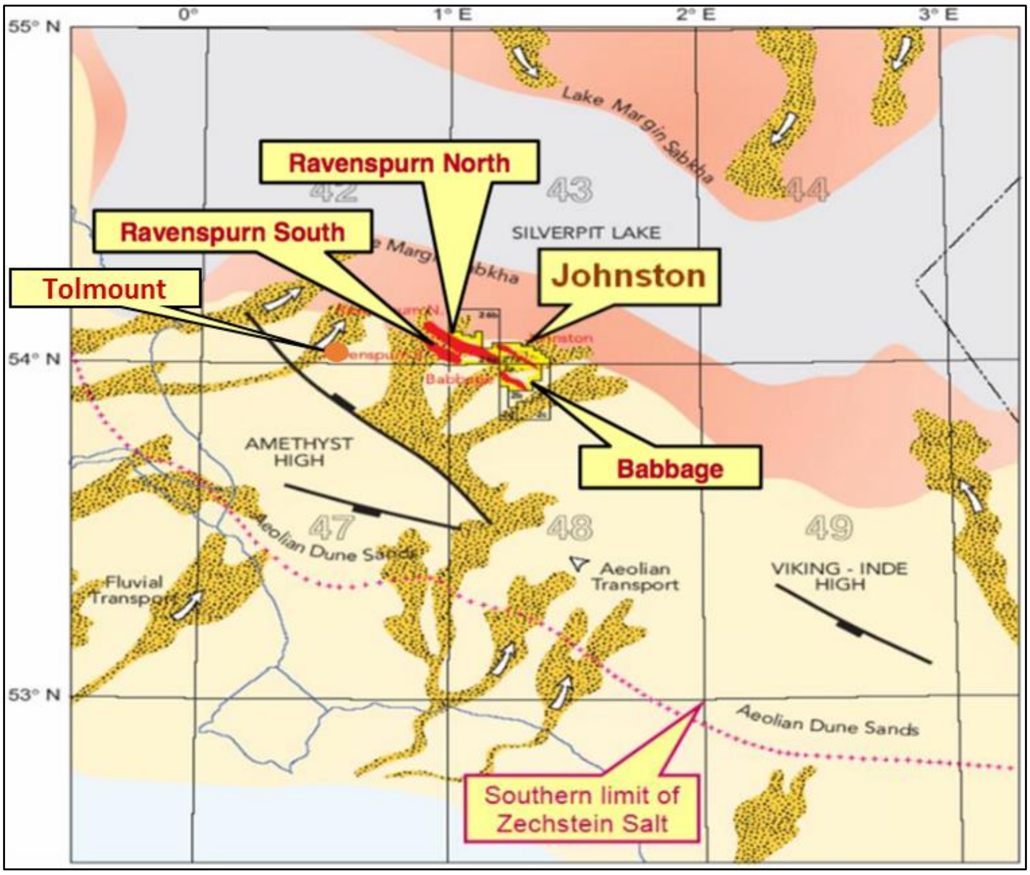


Figure 3-4 Leman Palaeogeography

3.1.3. Traps

All producing fields in the Southern North Sea are wholly structural traps apart from Ravenspurn North which lies on the fringe of the basin and has an element of stratigraphic trapping on the northern flank due to pinch out of the reservoir. Traps are dominantly fault bound structural closures where the top seal is provided by the Silverpit mudstones (where developed) or the Zechstein evaporites. Fault seal is commonly provided by juxtaposition of Leman Sandstones against Silverpit Mudstones.

3.2. Babbage Gas Field, Block 48/2a (Licence P.456)

3.2.1. Overview

Babbage Field was discovered by the 48/2-2 well in 1988. The well flowed at a rate of 3.8 MMscf/d and was considered uneconomical for development at the time. A second well, 48/2a-4, was drilled onto the crest of the structure in 2006 which achieved a flow rate of 11 MMscf/d on test, establishing the presence of a significant gas accumulation. E.On have a 47% interest in the Babbage development area that includes Babbage Field and earlier development of Johnston and Ravenspurn North Fields. Although they are part of the same development area, E.On holds different interests in Johnston (50%) and Ravenspurn North (29%).

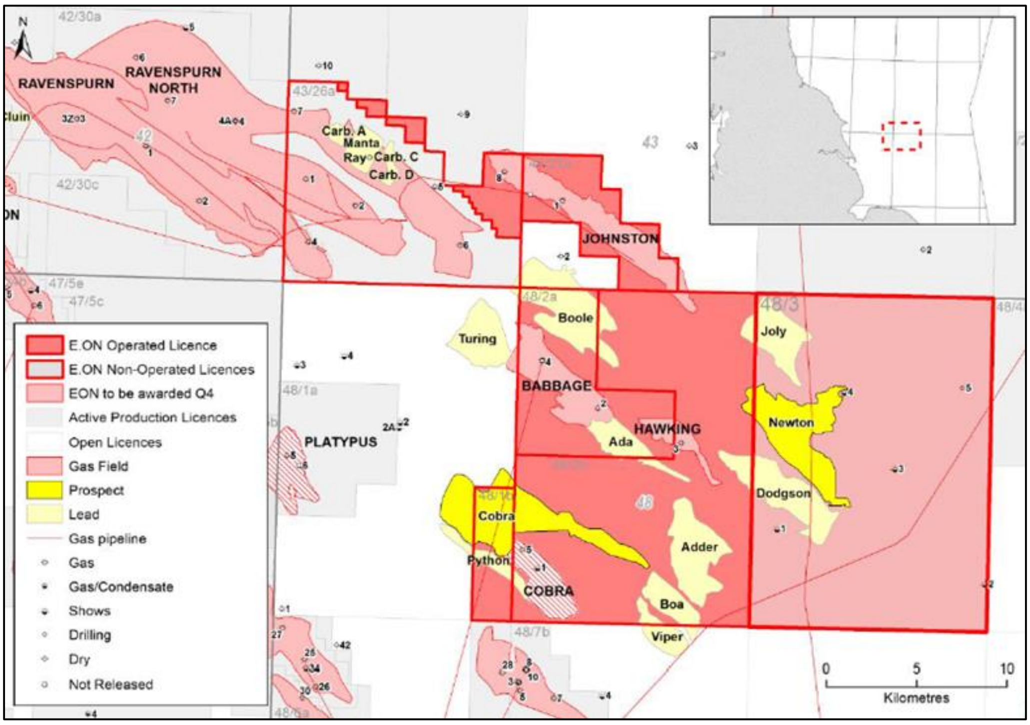


Figure 3-5 Babbage Feld Location

3.2.2. Development and current status

Babbage has undergone two phases of development well drilling to-date. In Phase 1, between 2008 and 2010, three horizontal, multi-fracced wells were drilled (B1, B2z and B3), along with installation of the nine-slot minimum facilities platform. First gas was achieved in August 2010. Phase 2 comprised the drilling of two horizontal, multi-fracced wells (B4 and B5y) from the platform in 2012-2013, with resultant first gas in October 2013.

The platform has a 50 MMscf/d test separator and produced water treatment, cyclone for sand (proppant) removal, power generation, crane, helideck, utilities and accommodation for thirty people. Gas is exported to West Sole through a 28” & 14” pipeline and 80 km on to Dimlington Gas Terminal through a 24” pipeline. The platform has initially been manned to support well drilling, fraccing and clean-up operations. However there are plans to reduce manning to daylight hours only. It has a capacity of 75 MMscf/d.

Production peaked at 60 MMscf/d in 2011 and was restored in 2014 with the two new wells. 2015 production up to August averaged 43 MMscf/d. The gas is largely methane with 1 mole% CO_2, 2.4 mole% nitrogen and minor condensate (0.1 bbl/MMscf).

Phase 3 of development is currently in the planning stage and, subject to all approvals, may include: an infill well (‘J’-well); an ‘Ada’ appraisal well and if successful development drilling and tie-back; well workovers; and changes to facilities.

Figure 3-6 Babbage Platform

3.2.3. Reservoir description and In Place Volumes

Located in UKCS Block 48/2 in the Sole Pit Basin of the Southern Gas Basin, the Babbage Field sits in a north-west trending tilted fault block, with tightly fault-sealed compartments. The gas producing interval is from a Lower Leman Sandstone Formation reservoir of Rotliegendes age, which lies at a depth of 10,500 ft TVDSS. The reservoir is composed of an 80 ft thick upper interval and a 200 ft thick lower interval of aeolian, fluvial and sabkha facies. On both a local and regional scale these facies have been extensively studied and are fairly well understood. The diagenetic overprint on the facies is particularly significant due to the occurrence of illite which, where present, can significantly reduce permeability in the reservoir (blocking the pore throats). There appears to be a regional correlation between illite precipitation and timing and maximum depth of burial. Babbage appears to have been affected by such illitisation, in particular within the fluvial facies where permeability is markedly lower than in the associated aeolian facies. Aeolian and fluvial facies make up the large proportion of the reservoir, the remainder being sabkha, which acts as an effective barrier to vertical flow.

An additional control on reservoir quality and therefore its production, is the presence of fracture systems which intercept the wellbores of B1 and B3. These are naturally occurring and have been the subject of extensive study, both regionally and locally, and their impact modelled dynamically to account for the presence of water influx in the wells at high drawdown (i.e. scenarios are modelled in which the fractures are extended into the aquifer).

In 2014, the Operator adopted a five-layer lithostratigraphic, reservoir zonation scheme, developed by PM Geos, based solely on the 48/2-2 well data (including core). This scheme identifies the major wet-dry cycles and lithology packages. The major shale intervals mark layer boundaries and the scheme divides the Leman into units of similar lithology and reservoir properties (Figure 3-7). It has been recognised, however, that there is a larger variability of facies across the field than seen in this one well: for example, in 48/2a-4, the equivalent aeolian dune succession in 42/2-2 shows greater variability in frequency and variation in fluvial and aeolian facies, resulting in greater variability in reservoir quality. This, along with regional, offset well and field data, forms the basis for the Operator’s static field model and consequently for dynamic reservoir simulation modelling. A number of revisions have been undertaken by the Operator and are still ongoing in order to obtain a better representation of the reservoir and its performance. The most recent full field modelling resulted in a downgrade of the 2007 GIIP of 461 Bcf to a range from 262 Bcf (P90) to 376 Bcf (P10). The Operator’s ‘Best Technical’ case is 328 Bcf.

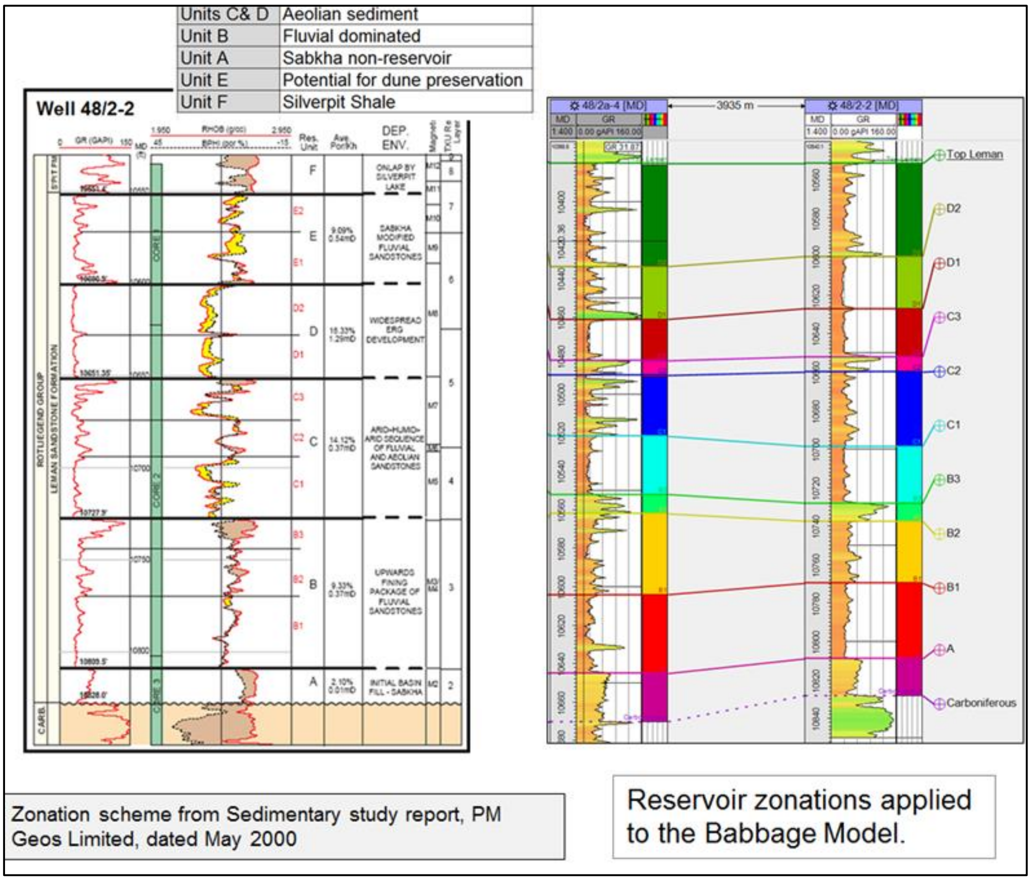


Figure 3-7 Lithostratigraphic sub-units of the Babbage Field

3.2.3.1. In Place Volumes

E.On has estimated the developed GIIP for the Babbage Field at 231 bcf in what they refer to as their 'Best Technical Case' and total GIIP 328 bcf.

Table 3-1 Babbage Field Gross Gas Initially in Place by Fault Block

Developed segments	E.On Preferred Technical Case (Bcf)	P90 (Bcf)	P10 (Bcf)	Undeveloped segment	E.On Preferred Technical Case (Bcf)	P90 (Bcf)	P10 (Bcf)
B3 Block	89	64	94	SW Block (Ada)	48	41	64
B1 Block	49	36	56	NW Block	7	5	9
B2 Block	84	77	101	NE Block	15	10	16
B5y Block	9	7	10	48/2-2 Block	27	21	28
Developed Total	**231**			**Undeveloped[9] Total**	**97**		

[9] Arithmetic addition of probabilistic volumes is a mathematically incorrect method of assessing the P90 or P10 totals.

3.2.3.2. *Depth Mapping*

The Operator performed an internal review of the seismic data quality, interpretation and depth conversion, using the CGG 2007 PrSTM Depth Migrated seismic across the Johnston and Babbage areas. This review has revealed that the existing interpretation is still relevant for Johnston and Babbage, but the results are not sufficiently confident over Ada (possible extension of Babbage, to the SE) to proceed with further work on the prospect. Consequently, an update of the inversion study using the 2011 GXT seismic, refined interpretation, wavelet and seismic velocity (for creating the low frequency model) is proposed to further de-risk the 'J' well area and Ada. Technical work is ongoing at this stage.

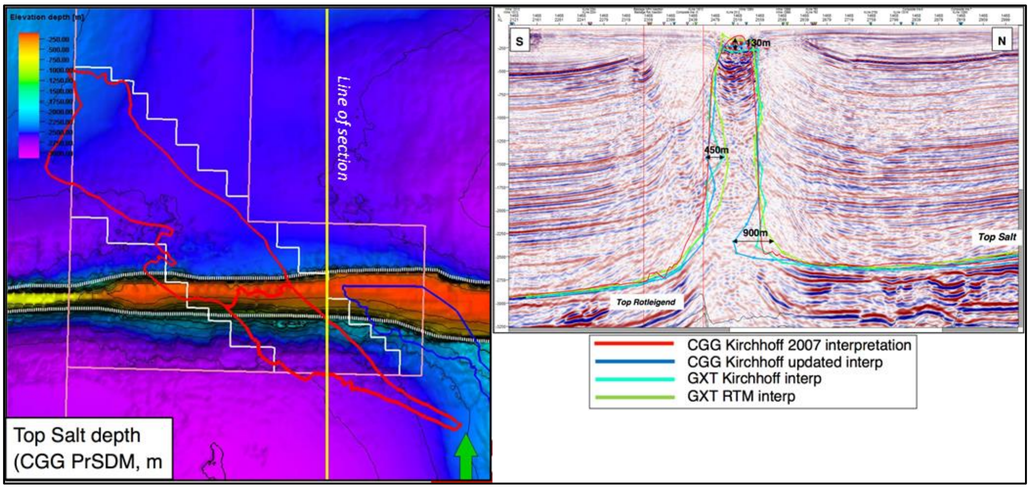


Figure 3-8 Salt Topography

3.2.4. Reservoir Performance and Production Forecasts

Figure 3-9 shows the field gas production history by well.

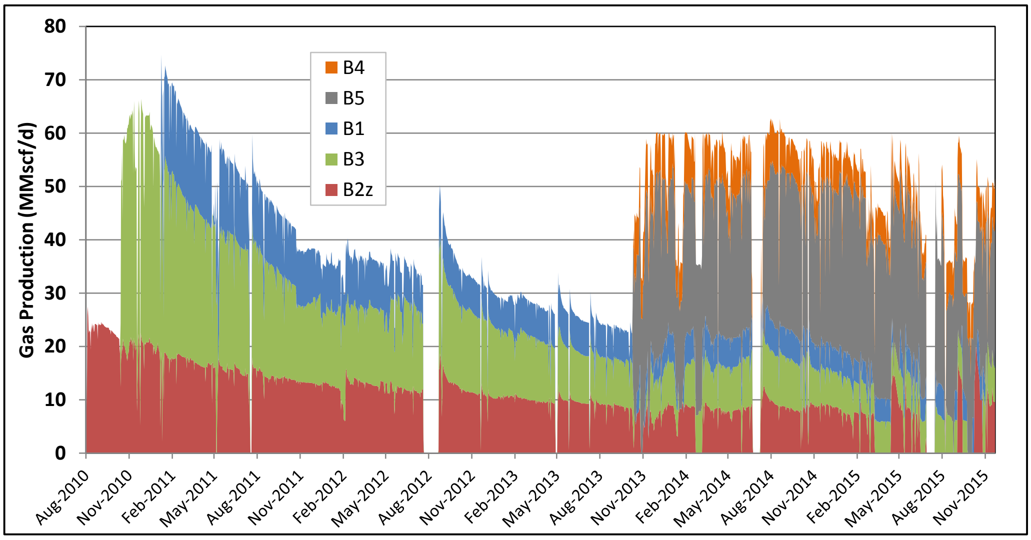


Figure 3-9 Babbage Well Production History

Declining gas rates are apparent in the three Phase-1 wells. However, production has been constrained by gas demand and facility constraints since the two Phase-2 wells were added. Figure 3-10 shows the data from Phase-2 well B5y.

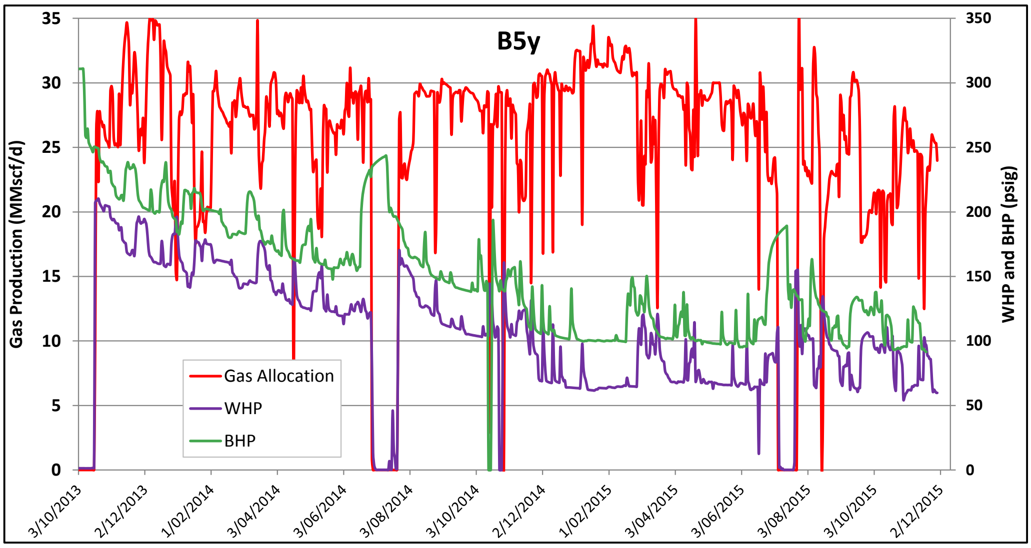


Figure 3-10 Babbage Phase-2 Well B5y Production History

Allocated gas production from well B5y has remained reasonably constant at 30 MMscf/d over two years of production. However, the flowing WHP (wellhead pressure) and BHP (bottom hole pressures) have declined or been reduced to maintain gas production. At a certain point the minimum WHP required for gas export will be reached and the gas rate will decline. Traditional production decline analysis is not appropriate in this situation so RISC has conducted flowing material balance analysis to analyse field performance.

RISC has also conducted exponential and harmonic rate decline analysis on wells where well head pressures have been uniform. Figure 3-11 shows exponential decline analysis of well B3, using a period of relatively uniform WHP.

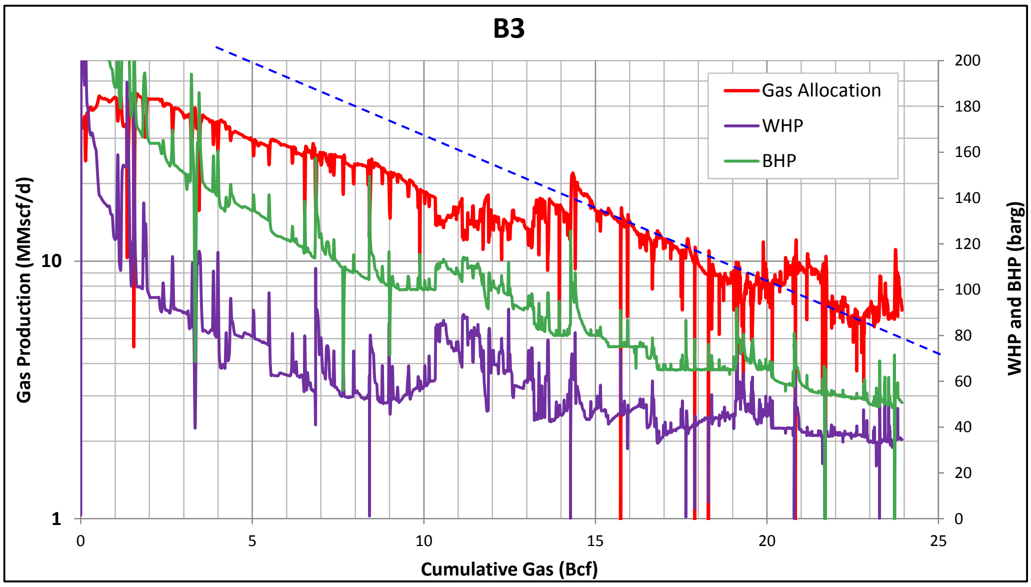


Figure 3-11 Babbage Well B3 Rate Decline Analysis

Babbage is divided into a number of fault segments as illustrated in Figure 3-12 with the development well locations.

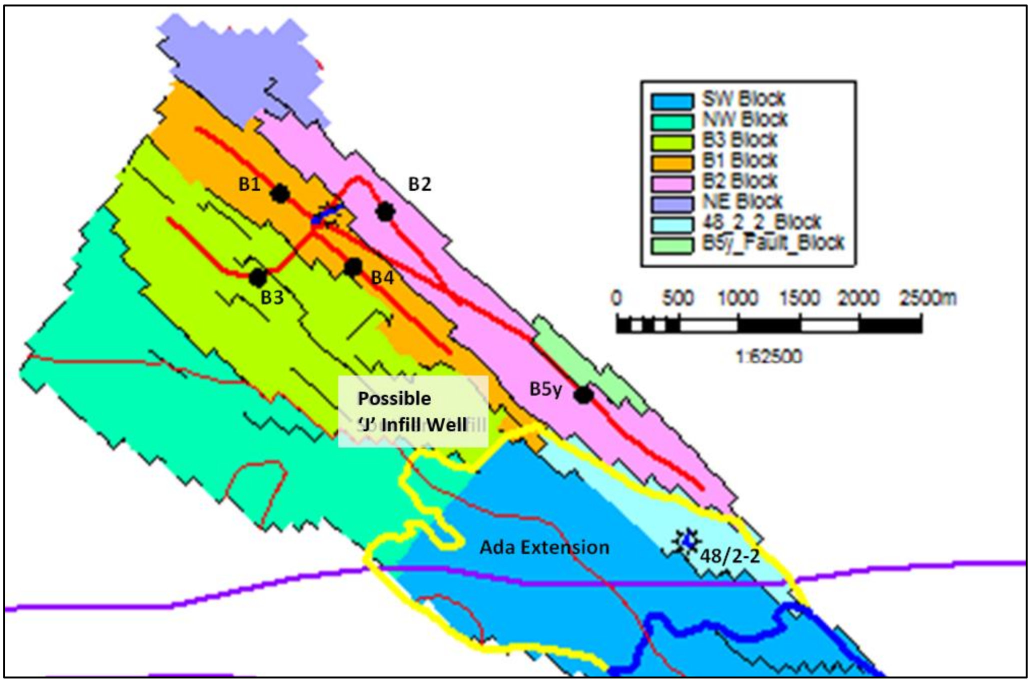


Figure 3-12 Babbage Fault Segments and Planned Wells

Communication between wells is limited due to faulting and the low permeability reservoir. RISC has conducted flowing material balance analysis for each individual well to estimate the GIIP connected to each well. Figure 3-13 shows an example of the analysis for well B1.

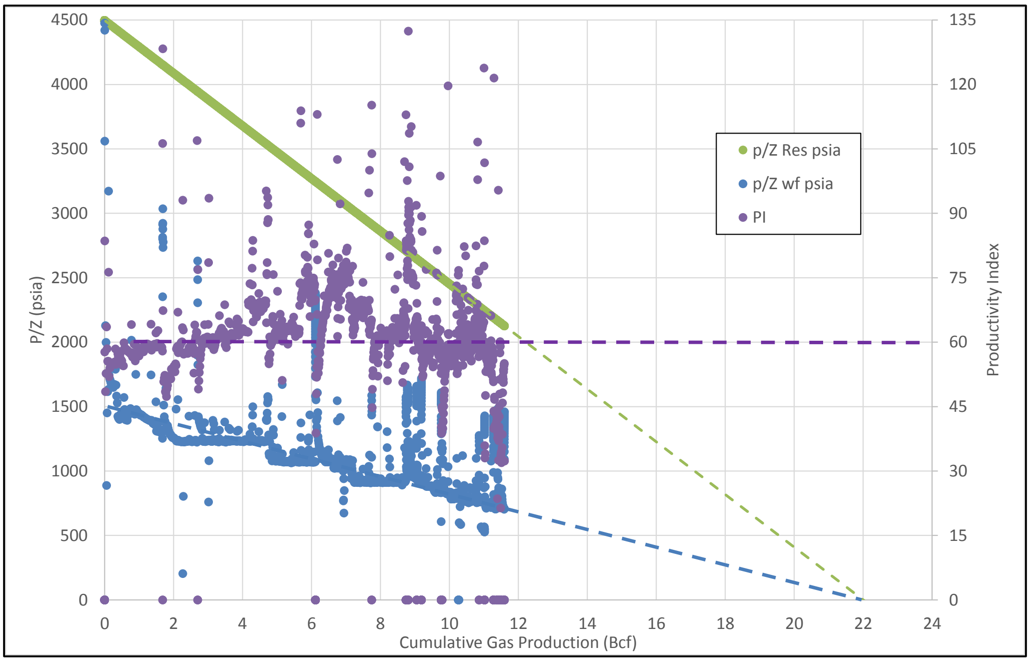


Figure 3-13 Babbage Well B1 Flowing Material Balance Analysis

The GIIP estimated by E.On from geological modelling and by RISC from flowing material balance for each well are shown in Table 3-2.

Table 3-2 Babbage GIIP (Bcf) by well

Well	GIIP from E.On Geological Modelling (Bcf)			GIIP Method #1 (RISC Flowing Material Balance)
	P90	P50	P10	
B1	36	49	56	22
B4				12
B3	64	89	94	37
Infill				n/a
B2	77	84	101	50
B5				75

There is reasonable agreement between the total GIIP ranges estimated from the different sources of data and analysis methods. The flowing material balance connected GIIP estimate supports E.On's developed Best Technical Case GIIP in aggregate.

The B3 segment contains well B3 and the proposed southern infill well. The infill well is targeting the GIIP not accessed by well B3.

RISC has estimated production forecasts (Figure 3-14) using the flowing material balance models and Decline Curve Analysis where appropriate.

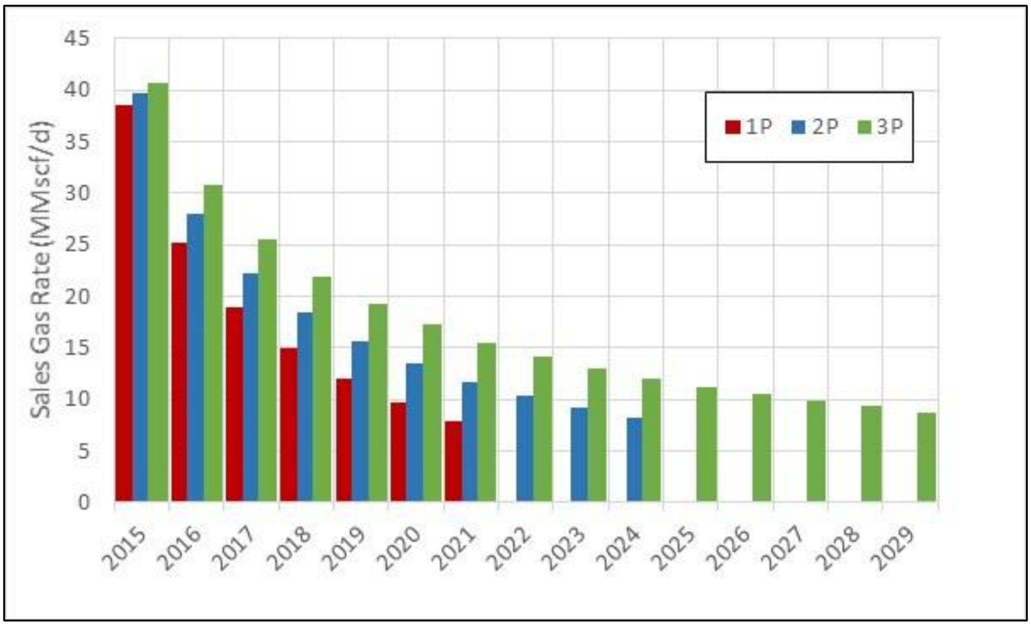


Figure 3-14 Babbage Gas Sales Forecasts

The Operator's forecast is based on a 3D simulation model. RISC has reviewed results presented by E.On in their 10 Nov 2014 Babbage dynamic simulation model report. The dynamic modelling work appears thorough with reasonable matches to well test results, PLTs and production history. The Operator's forecast is approximately mid way between RISC exponential and harmonic decline forecasts, and similar to RISC flowing material balance forecast.

RISC has used the exponential and harmonic decline forecasts for 1P and 3P developed reserves and used a mid forecast for 2P.

Babbage sales gas has 1 mole% CO_2, 2.4 mole% nitrogen and an estimated heating value (HHV) of 37.8 MJ/m^3 (1015 BTU/scf). Condensate production is effectively zero.

3.2.5. Future Development and Costs

3.2.5.1. Babbage 'J' Infill well (Block 2-2)

The Babbage 'J' infill well (48/2-2 area) is targeted in a region to the SE of the platform to access undrained gas areas. In the October 2014 TCM the well was described as having a 3,500m step-out (from the platform) with a 4,000ft horizontal section and five fracs, at a cost of £77.5 MM (or £76.3 MM for a subsea well). This well is still in planning and under discussion within the JV. A proposed schedule for well design, planning and approvals is shown in Figure 3-17 below.

If the J well is successful, E.On plans to develop of potential southeast extension of Babbage called Ada (discussed in section 6.4.1).

The Operator's mid-case GIIP for J infill is 68 Bcf, with estimated recovery of 28 Bcf, with marginal economics.

If drilled the proposed infill well would target the GIIP in fault segment B3 not accessed by well B3. RISC estimates that it will access 30 to 50 Bcf GIIP, and has generated a range of production forecasts as shown in Figure 3-15.

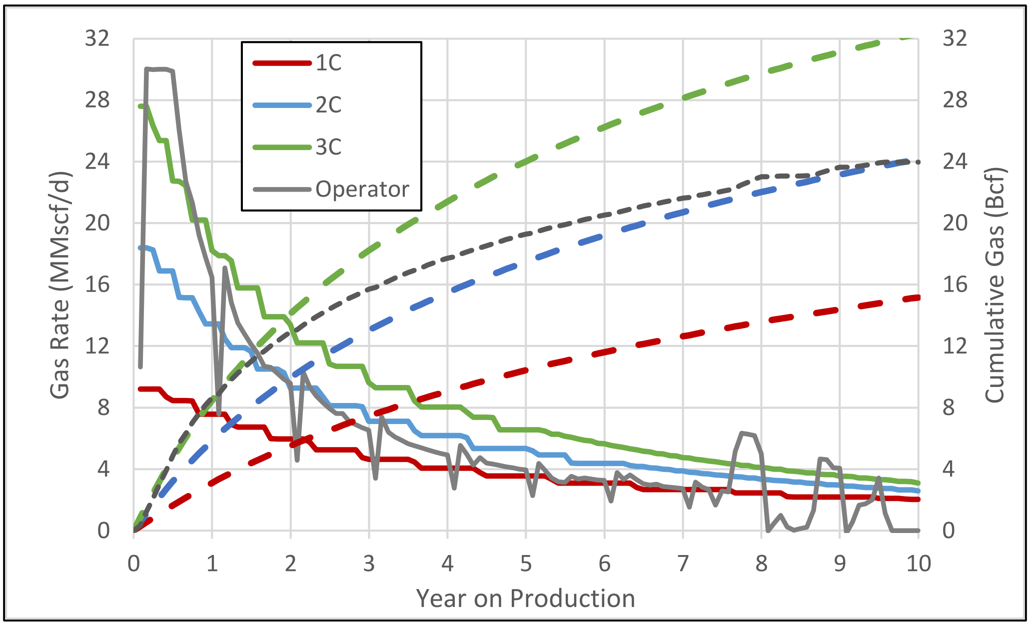


Figure 3-15 Babbage Southern Infill Well Gas Sales Forecasts

Babbage wells have had initial rates of between 10 and 45 MMscf/d (average 24). RISC estimate an initial rate for the southern infill of 10 to 30 MMscf/d. The Operator has presented a similar P50 recovery as RISC but higher initial well rate. The resources associated with the potential southern infill well are classified as contingent. Table 3-3 shows the potential gas recovery over 15 years.

Table 3-3 Babbage Contingent Resources

Contingent Resource Sales Gas (Bcf) Gross	1C	2C	3C
J Infill Well	18	28	37

The block also contains the Hawking and part of the Cobra gas discoveries. These require further appraisal and are currently viewed as uneconomic (discussed in sections 6.4.2 and 6.4.4). There are also exploration prospects in the permit.

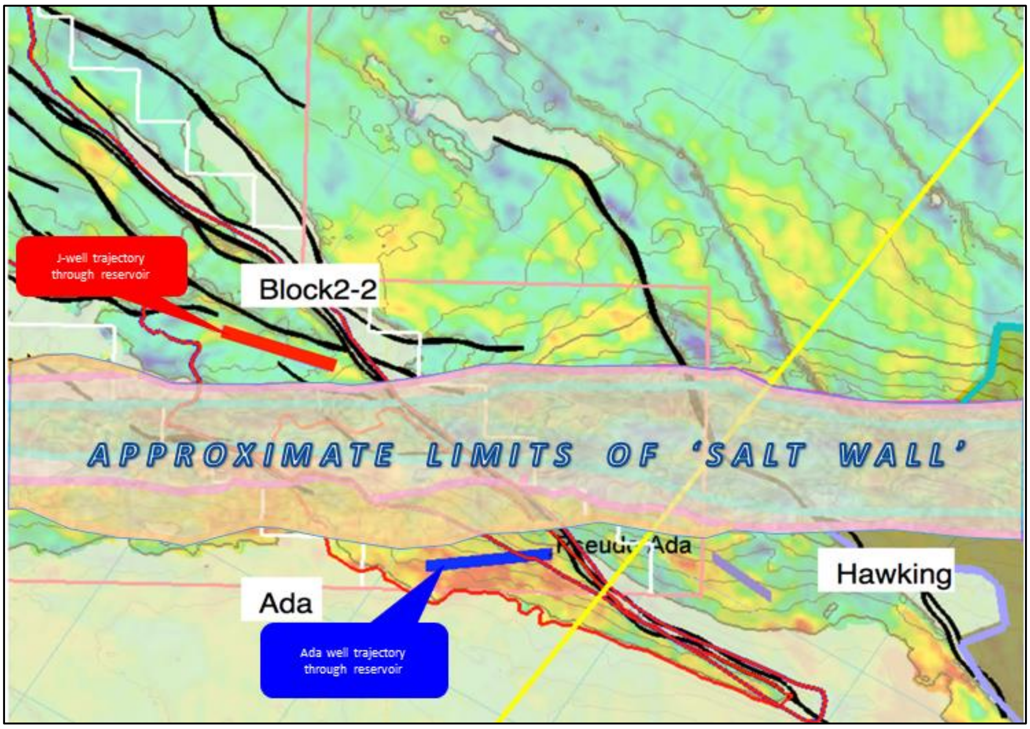


Figure 3-16 Babbage Infill Well and Ada Locations

Both the Babbage 'J' infill well in Block 48/2-2 and the 'Ada' Prospect targets lie immediately adjacent to the 'salt wall' which straddles the southern portion of the Babbage structure.

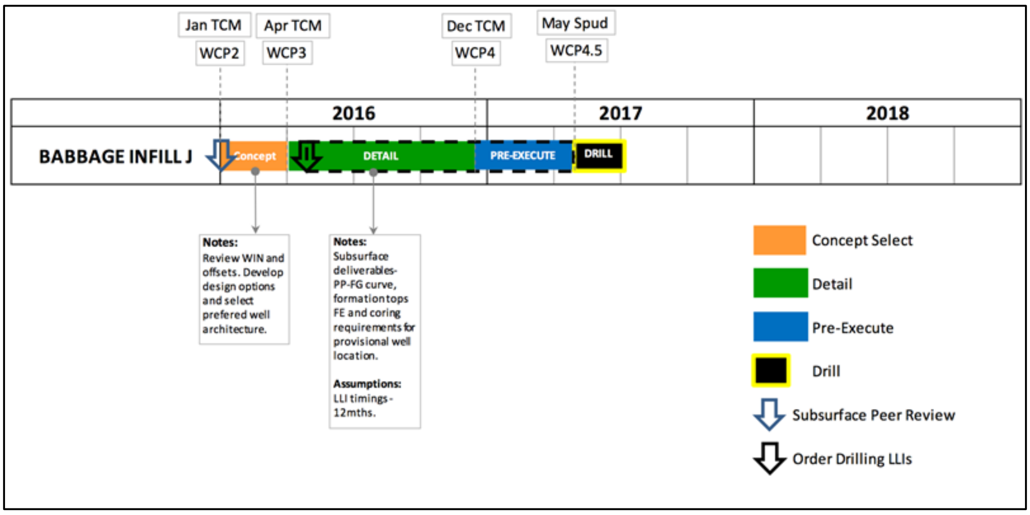


Figure 3-17 Babbage 'J' Infill Well Project Schedule

3.2.5.2. Capital Costs

The results of the infill well are not included in our production forecasts for reserves and no other development activities are planned hence no capital costs are forecast.

3.2.5.3. *Operating Costs*

Operating costs were approximately £25m gross in 2015, this included approximately £7m gross for the Dimlington Freon removal project. According to the 2016 budget there are no further costs for this project in 2016 as costs were accrued in 2015. Gross operating costs are forecast to be approximately £23-30m (£12-15m net) in 2016 depending on whether a well intervention (coiled tubing campaign) is conducted. We assume that the historical performance on which our production forecast is based will have included some well intervention activity therefore have included it in our cost forecast. Beyond 2016 gross operating costs are budgeted to be £15-20m gross 2017-2019, with gradual reductions thereafter.

3.2.5.4. *Decommissioning Costs*

The plan is to P&A wells and remove all facilities. E.On have conducted a level 1 (-50%/+75%) cost estimate based on engineering judgements and analogy. The estimate is £78m gross, RISC considers this to be reasonable. £2.8m gross is budgeted for abandonment of 48/02-1 exploration well in 2016.

3.2.6. Reserves

RISC's estimates of reserves at 1/1/2015 are shown in Table 3-4.

Table 3-4 RISC Estimate for Babbage Field Reserves as at 1 January 2015

Babbage Field Reserves	Net to E.On					
	1P (Proved)		2P (Proved + Probable)		3P (Proved + Probable + Possible)	
	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)
Reserves at 01 January 2015	18.8	0	25.6	0	43.1	0

3.2.7. Contingent Resources

Additional volumes that could be produced in the event of higher gas prices, by an extension of field life beyond the economic limit, have been assigned as contingent resources.

Table 3-5 RISC Estimate for Babbage Field Contingent Resources

Babbage Field Contingent Resources	Net to E.On					
	1C		2C		3C	
	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)
Contingent Resources after the Economic Limit	5.9	0	10.2	0	9.7	0
J Well	8.5	0	13.1	0	17.4	0

3.3. Caister Murdoch System and Quadrant 44 Area

3.3.1. Overview

The Caister Murdoch System (CMS) consists of the Murdoch complex with E.On tiebacks from Caister NUI, subsea wells in Hunter and Rita. Gas is aggregated at Murdoch and exported via the CMS export line to Theddlethorpe gas terminal. E.On has field interests in the CMS Area (Table 3-6).

Table 3-6 E.On interests in CMS Area

Field	E.On Interest	Development
Caister	40%	NUI tied back to Murdoch K Platform
Hunter	79%	One subsea well tied back to Murdoch, stopped production in 2010 and restarted in 2015
Rita	74%	Dual lateral well tied back via Hunter. Shut-in during 2015
Orca	23.4685%	Three well platform development exporting to D/15-FA in Dutch sector
Minke	42.67%	Single subsea well tied to D-15. Ceased production in 2011
Infrastructure		
CMS Pipeline	20%	

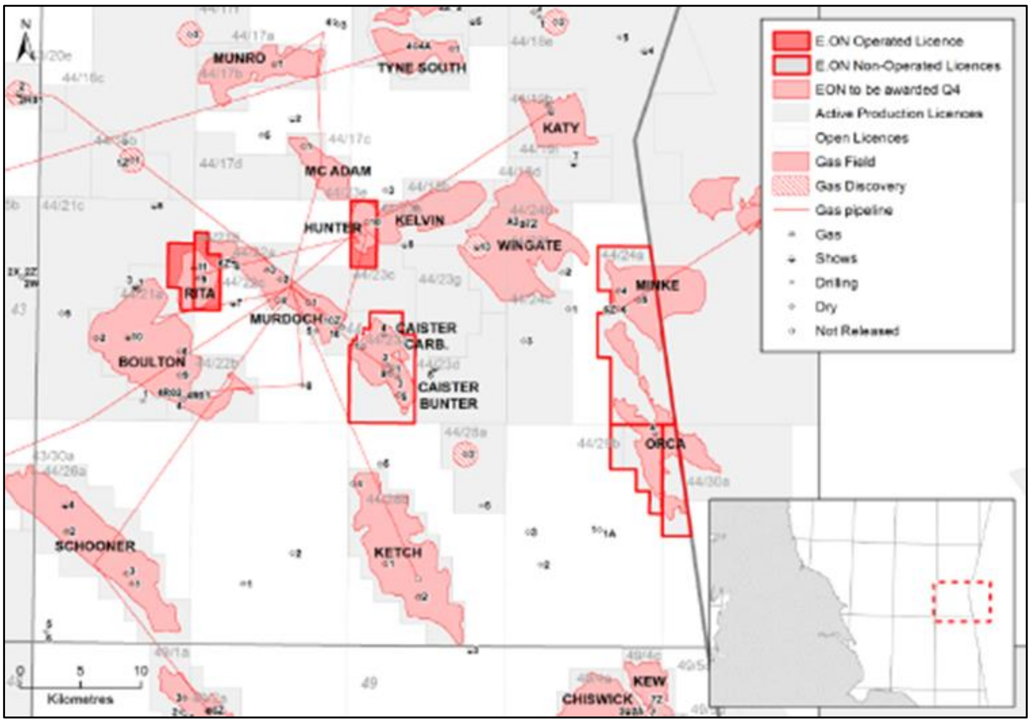


Figure 3-18 Location Map of Caister Murdoch System Fields

The Minke and Orca Fields straddle the UK/Netherlands border.

The Caister Murdoch System is centred on the Murdoch complex. The fields in which E.On has an interest are Caister, Hunter and Rita. Caister is developed with eight wells and a Normally Unmanned Installation (NUI) satellite platform. Rita is developed with a dual lateral well tied back to the Hunter field via a 14km, 8" carbon steel pipeline. Hunter was developed with a single subsea well and an 8km, 8" subsea tieback to Murdoch. Production ceased in 2012 but the subsea pipeline is still used for Rita production. In 2015 Rita was shut-in and production restarted from Hunter. There is also a flexible flowline from Rita to Murdoch that was disconnected in 2012. Gas is aggregated at Murdoch and end exported via the 26", 188km CMS export line to Theddlethorpe gas terminal. The NUI is remotely operated from Theddlethorpe. The layout of Hunter, Caister and Rita is shown schematically below:

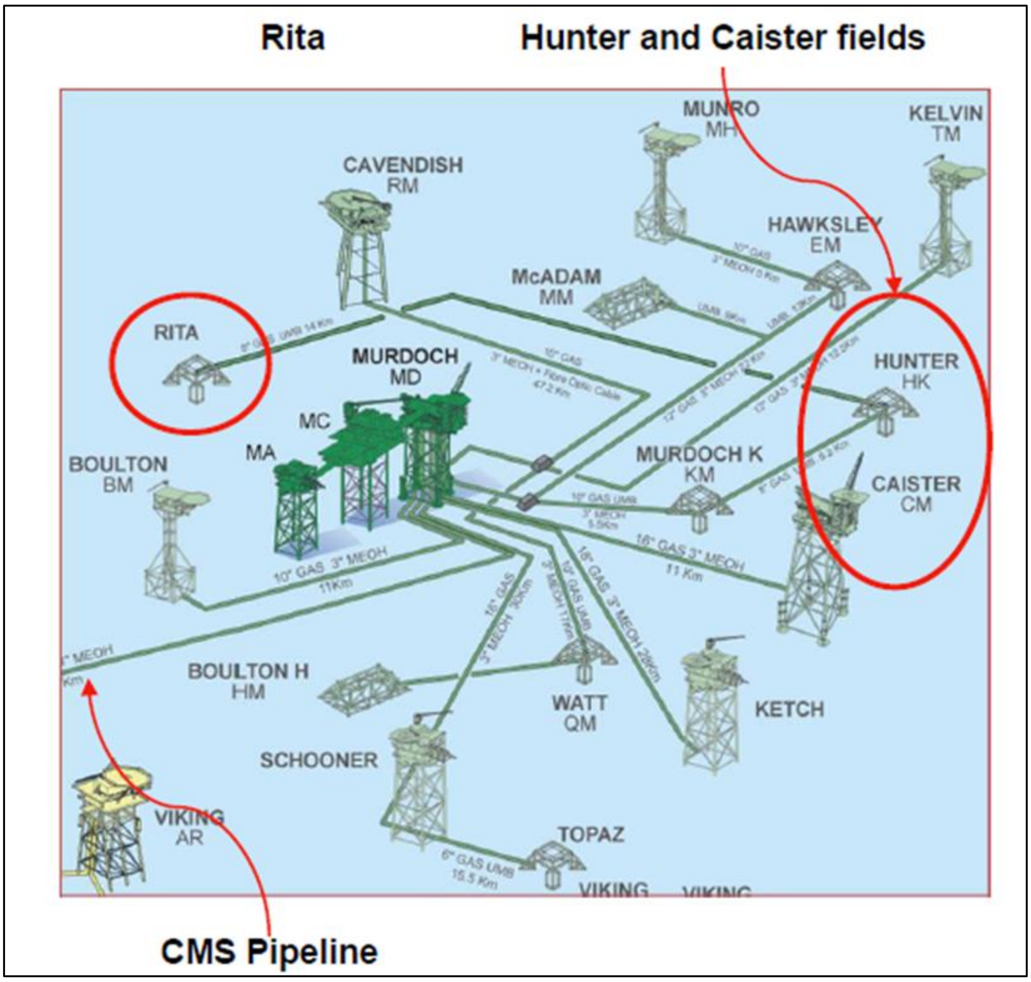


Figure 3-19 Hunter, Caister and Rita Development Schematic

3.4. Caister Gas-Condensate Field, block 44/23a (Licence P.452)

3.4.1. Overview

The field consists of two reservoir formations discovered in 1968. Production started in 1993 via a NUI with eight production wells drilled. The gas has a CGR of about 5 bbl/MMscf.

3.4.2. Development and Current Status

Developed in 1993 using a NUI in 42m water depth with twenty-five year design life. Asset Integrity Rectification (AIR) campaign is essential to allow for extended life and continued operations beyond end-2015. Integrity issues mean that facility is unlikely to continue production beyond its twenty-five year design life (2018). According to the Operator's 'Cessation of Production' document (January 2016), "The asset integrity rectification project is deeply uneconomic and there are no known remaining development opportunities in the Caister Field."

No further reservoir development is planned.

3.4.3. Reservoir Description and In Place Volumes

The Bunter reservoir is good quality with an active aquifer developed with three wells A1, A3 and A8. E.On estimate a GIIP of 172 Bcf with 77 Bcf or 45% recovery to date. Bunter reservoir gas contains 15 mole% CO_2. Production from the Bunter reservoir has ceased.

The Carboniferous reservoir is divided into northern and southern accumulations. E.On estimate the north, developed with two wells A4 and A5, to contain 62 Bcf GIIP. It has recovered 18 Bcf or 30% recovery to date. The southern accumulation is estimated to contain 187 Bcf GIIP, developed with three wells A2, A5 and X9. It has recovered 134 Bcf or 79% to date. Only two wells (A5 and X9) can produce continuously at 4 and 7 MMscf/d respectively, with occasional cyclic production from A2 due to water loading. Carboniferous reservoir gas contains less than 3 mole% CO_2.

3.4.4. Reservoir Performance and Production Forecasts

The Bunter reservoir has not produced in 2015 and the Carboniferous reservoir produced at up to 9 MMscf/d with an average of 5 MMscf/d.

Figure 3-20 shows Caister gas sales history since Jan-2014 with sales declining from 10 to 5 MMscf/d.

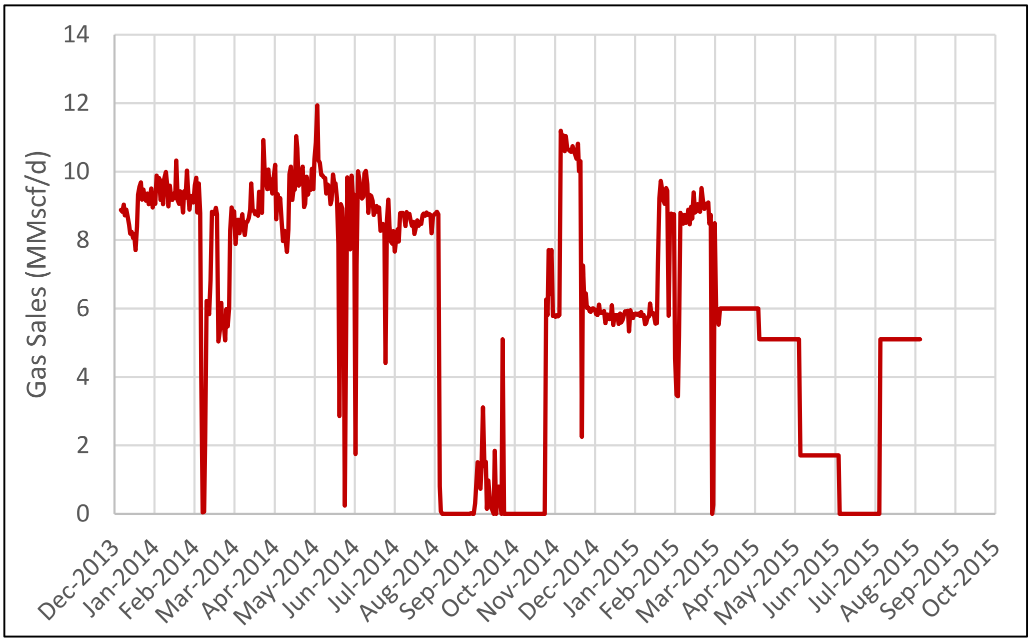


Figure 3-20 Caister Recent Gas Sales History

No further production is expected from Caister.

3.4.5. Future Development and Costs

The Caister NUI was to reach the end of its design life in 2018, however integrity rectification works are required to maintain asset integrity to meet design life. Production ceased in late 2015, with no further planned development activity.

3.4.5.1. Capital Costs

E.On was treating rectification works as operating costs therefore there are no capital costs for these late life assets.

3.4.5.2. Operating Costs

Operating costs are very sensitive to whether production from Caister proceeds beyond 2015. We have assumed production ceased at end 2015 but surveillance costs of £1m pa gross will be incurred until decommissioning occurs in 2018.

3.4.5.3. Decommissioning Costs

Decommissioning plans involve full removal of topsides and jacket with onshore disposal, flushing of pipelines and P&A of wells.

A detailed Caister decommissioning cost estimate has not been prepared. The estimated range of costs is £50m – £100m. We recommend using a mid point until firm plans are drawn up and experience is gained from other abandonment programmes by the same Operator (Conoco Phillips, who are also abandoning the V fields).

Hunter and Rita P&A and decommissioning cost estimates are very immature. Abandonment of Rita subsea well and subsea facilities is estimated to cost £12m gross and Hunter £14m gross.

3.4.6. Reserves

RISC's estimates of reserves are shown below. As production is currently shut-in, the reserves effective 1/1/15 are equal to 2015 production. As a result the 1P, 2P and 3P are identical.

Table 3-7 RISC Estimate for Caister Field Reserves as at 1 January 2015

Caister Field Reserves	Net to E.On					
	1P (Proved)		2P (Proved + Probable)		3P (Proved + Probable + Possible)	
	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)
Reserves at 01 January 2015	0.6	0.003	0.6	0.003	0.6	0.003

3.5. Hunter Gas-Condensate Field, block 44/23e (Licence P.452)

3.5.1. Overview

Hunter was discovered in 1992 and was acquired by E.On in September 2005. Hunter started production in 2006 from a single subsea well tied back to Murdoch K Platform.

3.5.2. Development and Current Status

Hunter was developed with single subsea well and an 8km, 8” subsea tieback to Murdoch. Gas from the Hunter field is exported via the Murdock K to the Murdoch platform and onward via the Caister Murdoch System (CMS) to the ConocoPhillips-operated facilities at Theddlethorpe. Hunter production ceased in 2010 but the subsea pipeline remained in use for Rita production. With Rita offline in late 2015, Hunter’s production was restarted with cyclic production.

3.5.3. Reservoir Description and In Place Volumes

The Bunter Sandstone reservoir comprises braided fluvial and alluvial plain deposits characterized by sandstones and siltstones with local shales. Reservoir quality is generally moderate with average porosity at 15% and permeabilities in the 1-10 mD range (up to 1000 mD). E.On estimated GIIP in 2006 to be 9.1 – 21.5 – 58 Bcf (P90 – P50 – P10).

3.5.4. Reservoir Performance and Production Forecasts

Production ceased in 2010 with an estimated 2.2 Bcf produced giving an implied recovery factor of 10%. ROV work may be required to maintain long-term production. However, cyclical production is expected and it is unclear whether further subsea work will progress.

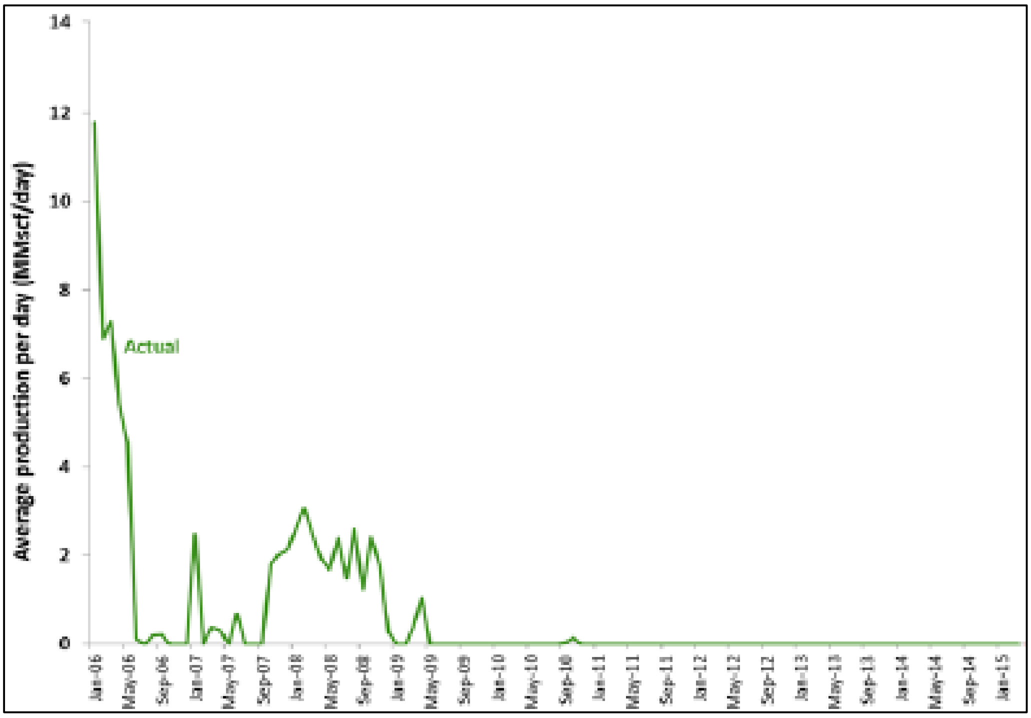


Figure 3-21 Hunter Gas Production History

Given that production from Rita is currently shut-in (and therefore doesn't back out Hunter production), we have assumed intermittent production from Hunter for the next two years as summarised below (Table 3-8 & Figure 3-22).

Table 3-8 Hunter field forecast production

Quarter	2016 Q1	2016 Q2	2016 Q3	2016 Q4	2017 Q1	2017 Q2	2017 Q3	2017 Q4
Gas rate, MMscf/d	4.0	0	4.0	0	2.0	0	2.0	0

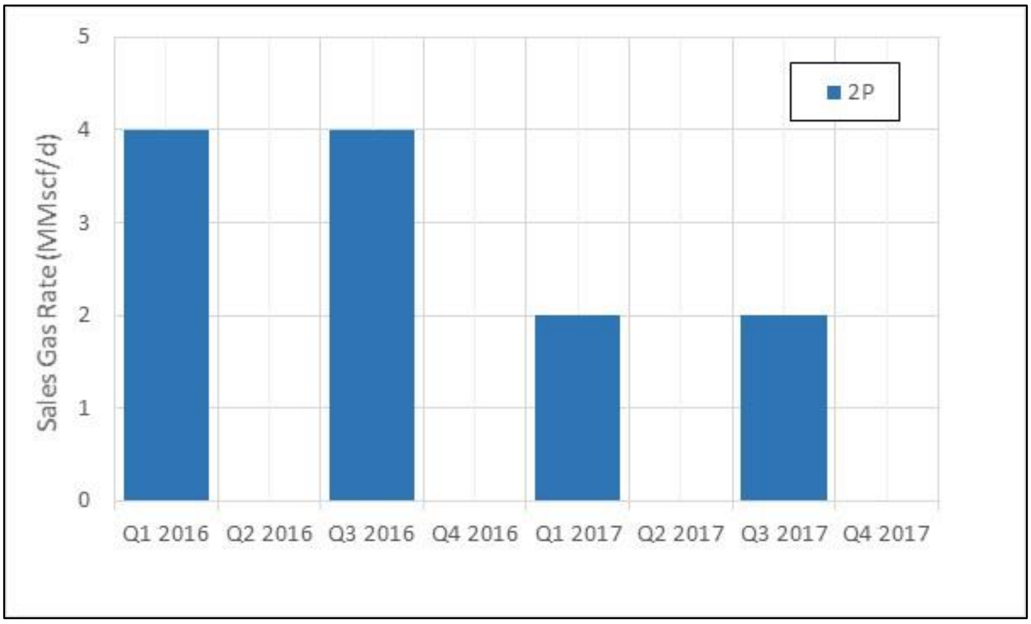


Figure 3-22 Hunter Gas Sales Forecasts, Annual Quarterly Rates

3.5.5. Future Development and Costs

Operating costs are estimated to be approximately £1 million pa gross. Decommissioning costs are estimated to be £14 million gross.

3.5.6. Reserves

RISC's estimates of reserves are shown in Table 3-9.

Table 3-9 RISC Estimate for Hunter Field Reserves as at 1 January 2015

Hunter Field Reserves	Net to E.On					
	1P (Proved)		2P (Proved + Probable)		3P (Proved + Probable + Possible)	
	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)
Reserves at 01 January 2015	1.2	0	1.2	0	1.2	0
The Net Present Value for Hunter was calculated using 830 Btu/scf.						

3.5.7. Contingent Resources

RISC assigns no Contingent Resources.

3.6. Johnston Gas Field, Block 43/27a (Licence P360)

3.6.1. Overview

The Johnston Field is a dry gas accumulation located within blocks 43/26a and 43/27a in the UK Southern North Sea in approximately 39 m depth of water, 85km north-east of Easington. Gas is transported across Ravenspurn North to the Easington Gas Processing Terminal. E.On is the Operator with 50.1% interest.

3.6.2. Development and Current Status

The discovery well was drilled in 1990 and after drilling one appraisal well in 1991, a development plan was submitted and approved in 1993. Initially two horizontal development wells were drilled from a four slot subsea template, tied back to Ravenspurn North through a 12” pipeline. Commercial production commencing in October 1994. An additional four subsea wells have been drilled with two tied back to the template. Wells J1, J2 and J3 have watered out, J4 produces cyclically due to liquid loading. There are no firm plans for further development.

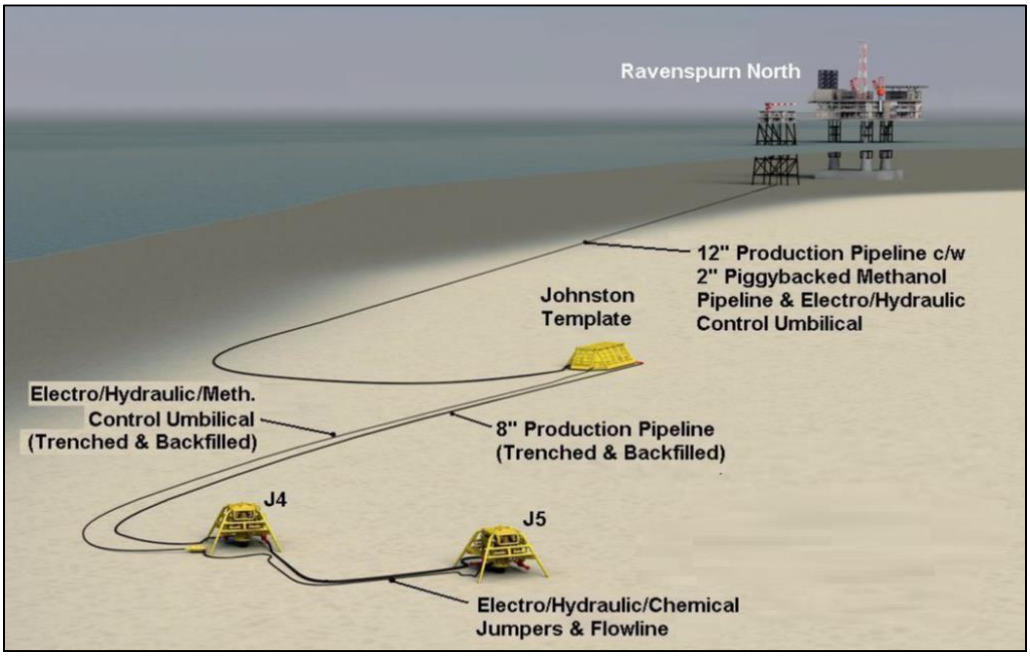


Figure 3-23 Johnston Subsea Tieback

The last well J6 was drilled in October 2013 but performance has been disappointing and hydraulic fracturing is being considered. The well is currently shut-in due to a mechanical failure at the subsea wellhead. It is unclear if and when the wellhead will be repaired to restore production.

2015 production up to end August has averaged 8.2 MMscf/d.

3.6.3. Reservoir Description In Place Volumes

The field is a structural trap, fault bounded to the SW and dip-closed to the north, east and south. High quality 3D seismic data, enhanced by seismic attribute analysis has been used to establish the field geometry and optimum well locations. The sandstone reservoir is Early Permian, Lower Leman Sandstone Formation of the Upper Rotliegend Group. This reservoir is a series of interbedded aeolian dune, fluvial, and clastic sabkha lithofacies resulting in variable reservoir quality. The top seal and fault bounding side seal are provided by the overlying clay stone of the Silverpit Shale Formation and the evaporite dominated Zechstein Supergroup.

E.On estimate the P50 GIIP to be between 378 and 402 Bcf from material balance and history matched simulation.

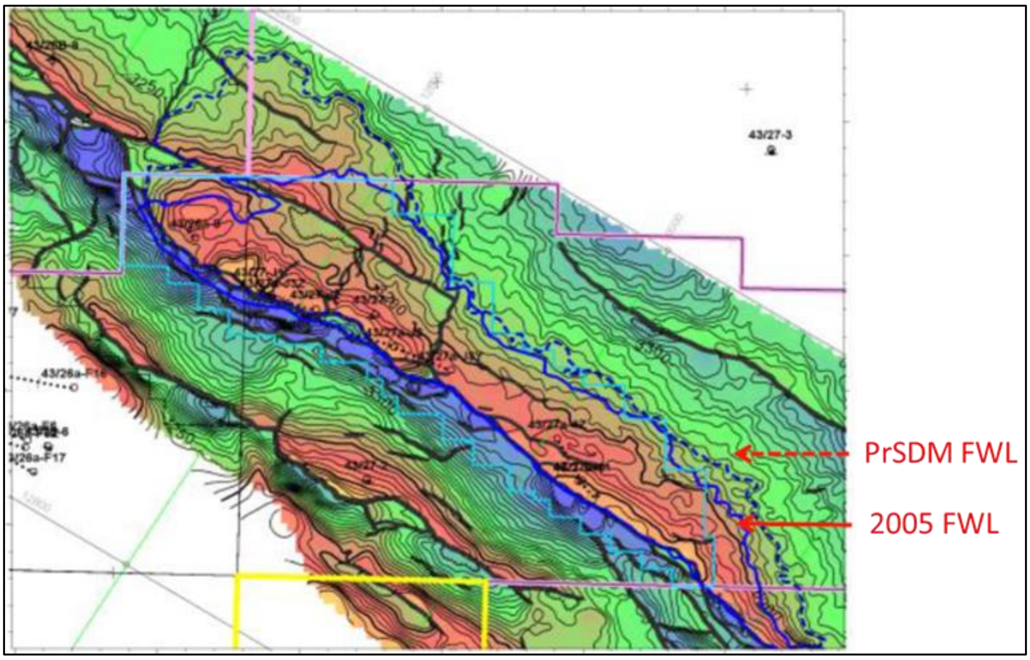


Figure 3-24 Depth Structure Map of Johnston Field

3.6.4. Reservoir Performance and Production Forecasts

Gas production started in Sept-1994 with a peak monthly production of 90 MMscf/d. Cumulative production at end 2014 was 237 Bcf with a rate of 15 MMscf/d.

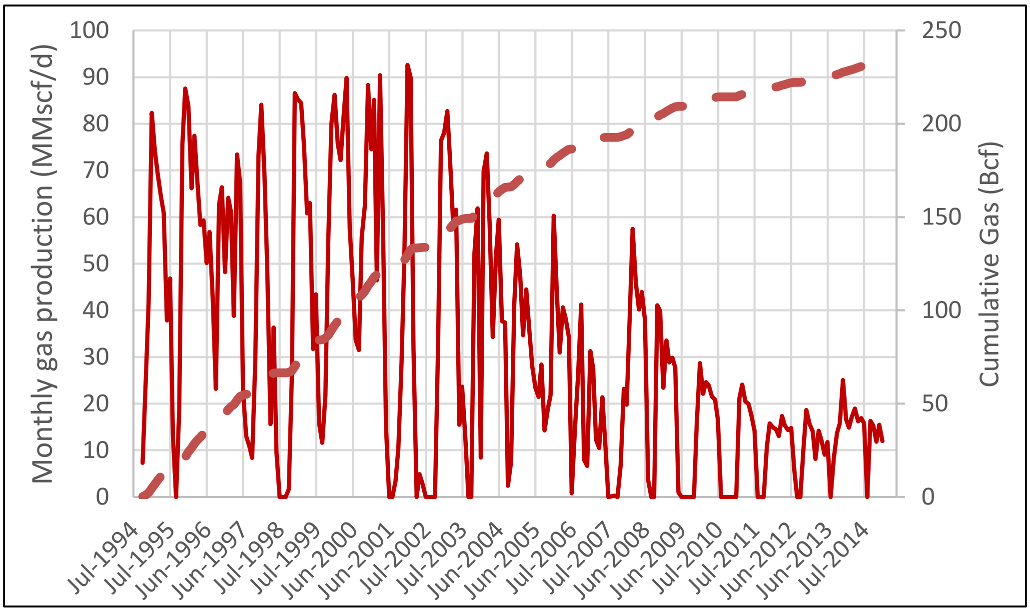


Figure 3-25 Johnston Gas Production History

The recent daily production history of the three active wells is shown below. Field monthly production is shown from Mar-Aug 2015.

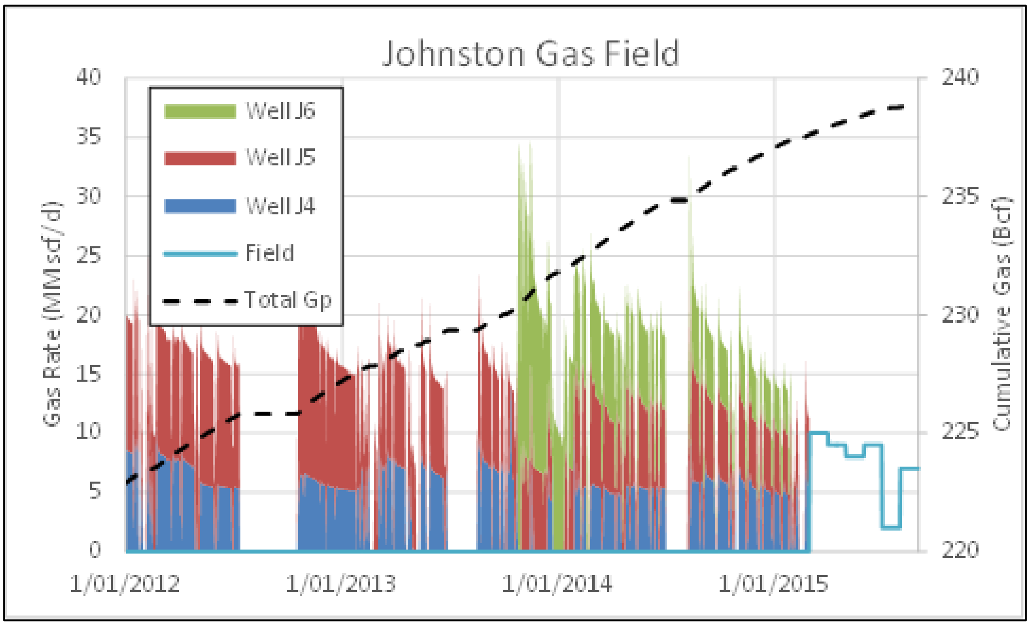


Figure 3-26 Johnston Recent Gas Production History

- Well J4 cannot produce stably due to a high and increasing Water-Gas-Ratio (WGR) of 63 bbl/MMscf and pressure depletion. It is produced cyclically with shut-in period to re-charge reservoir pressure. The historic well uptime has been 54%.
- Well J5 producers stably with a WGR of 18 bbl/MMscf. The historic well uptime has been 80%.
- Well J6 was shut in Jan-2015 due to mechanical problem with the subsea tree. It is not clear if and when the tree will be repaired. The WGR has increased from an initial 10 bbl/MMscf to 120 bbl/MMscf.

RISC has reviewed the historic decline trend of the three active wells up to 28/2/2015 and generated production forecast as follows:

- Decline analysis has been conducted on each producing well using daily production data up to 28 Feb 2015. The forecast has then been matched to total field production up to end August 2015 and forecast from that point.
- The 1P forecast is based on exponential decline fitted to well J4 and J5. Well uptime is estimated at 75% reducing to 45% once well rates drop below the critical rate and production becomes cyclic.
- The 3P forecast is based on harmonic decline fitted to well J4 and J5. Well uptime is estimated at 85% reducing to 65% once well rates drop below the critical rate and production becomes cyclic.
- The 2P forecast is mid way between the 1P and 3P.

The developed reserves forecasts are shown in Figure 3-27.

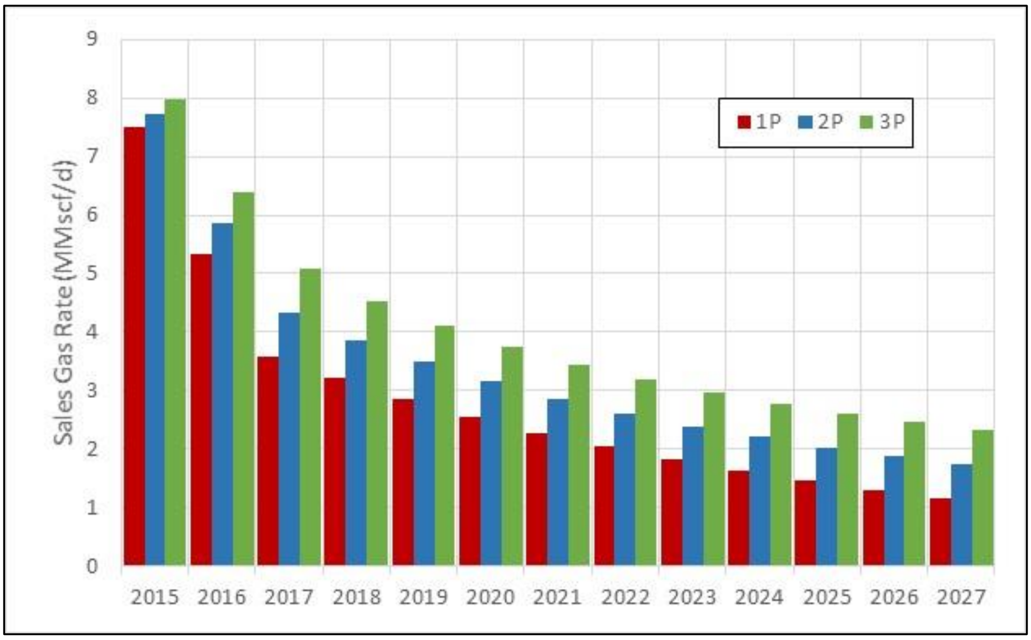


Figure 3-27 Johnston Gas Production Forecast

Gas sales are estimated to be 97.2% of production based on historical data. The gas heating value (HHV) is estimated to be 37.2 MJ/m3 (998 BTU/scf).

3.6.5. Future Development and Costs

No further development of the field is expected.

3.6.5.1. Capital Costs

No further capital expenditure is forecast.

3.6.5.2. Operating Costs

E.On forecasts net annual OPEX to reduce from \$2.2m (£2.8m gross) in 2015 to \$1.5m (£2.0m gross) in 2016 to \$0.7m (£0.9m gross) in 2017 and more modest (10% pa) reductions beyond 2017. RISC has seen no information on operating costs and the rationale for the reductions. We understand some of the costs will be tariff related and therefore will decline with production. We also expect cost reduction measures to be implemented in the current environment. However in the absence of explanation we believe the forecast reductions to be optimistic. We therefore estimate a 25% reduction in OPEX from 2015 levels in 2016 and 2017 and 10% pa thereafter. This assumes that no material campaign maintenance or well or subsea intervention is required over remaining field life.

3.6.5.3. Decommissioning Costs

E.On estimates £47m (gross) decommissioning costs. We consider this estimate to be reasonable.

3.6.6. Reserves

RISC's estimates of reserves are shown in Table 3-10.

Table 3-10 RISC Estimate for Johnston Field Reserves as at 1 January 2015

Johnston Field Reserves	Net to E.On					
	1P (Proved)		2P (Proved + Probable)		3P (Proved + Probable + Possible)	
	Sales Gas (Bcf)	Condensate (MMBbl)	Sales (Bcf)	Condensate (MMBbl)	Sales (Bcf)	Condensate (MMBbl)
Reserves at 01 January 2015	6.5	0	7.9	0	9.2	0

3.6.7. Contingent Resources

RISC assigns no Contingent Resources.

3.7. Minke-Orca Gas-Condensate Fields, blocks 44/29b & Q44/30 (Licences P454, P611)

3.7.1. Overview

Minke and Orca gas field straddle the UK/Dutch border. Minke is a single well subsea development tieback to the D15 Platform facility in Dutch waters with gas exported via the Noordgastransport pipeline to Netherlands. Minke started production in 2007 and ceased in 2011 after producing 5.5 Bcf. Decommissioning is required. The D15 reception facilities are now used by Orca.

3.7.2. Development and Current Status

Orca was developed with three wells from the Orca Platform with gas exported 20 km to the D/15-FA facility.

From D/15-FA gas is transported via the 36-inch diameter, 130 kilometre long Noordgastransport (NGT) extension to L/10, for onward transportation via the existing Noordgastransport pipeline to the Uithuizen terminal.

Figure 3-28 Schematic of Orca Development

Orca has been unitised with UK share set at 49%. E.On's share of Orca is 23.4685%.

3.7.3. Reservoir Description and In Place Volumes

The gas has 3 mole% CO_2 and 20-26% Nitrogen. Less than 0.3 bbl/MMscf of condensate is extracted. Due to the high Nitrogen content, the heating value (HHV) is low at 737 BTU/scf (27.5 MJ/m3).

3.7.4. Reservoir Performance and Production Forecasts

Orca gas production peaked at 35 MMscf/d early 2014 and declined to 5 MMscf/d. Well A2 watered out and stopped production in Feb-2014. Well A3 started production after A2 watered out but production has become cyclical and effectively stopped July-2014. Well A1 produces steadily.

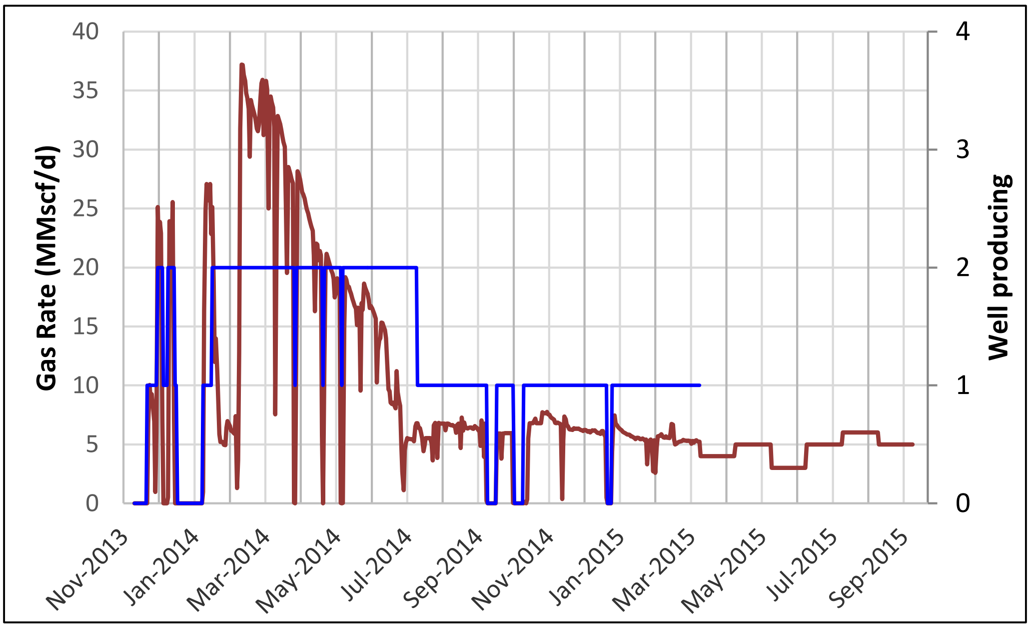


Figure 3-29 Orca Production History

RISC has analysed uptime and fitted a range of decline curves and used these to generate production forecasts. The forecasts to the economic limit are shown in Figure 3-30.

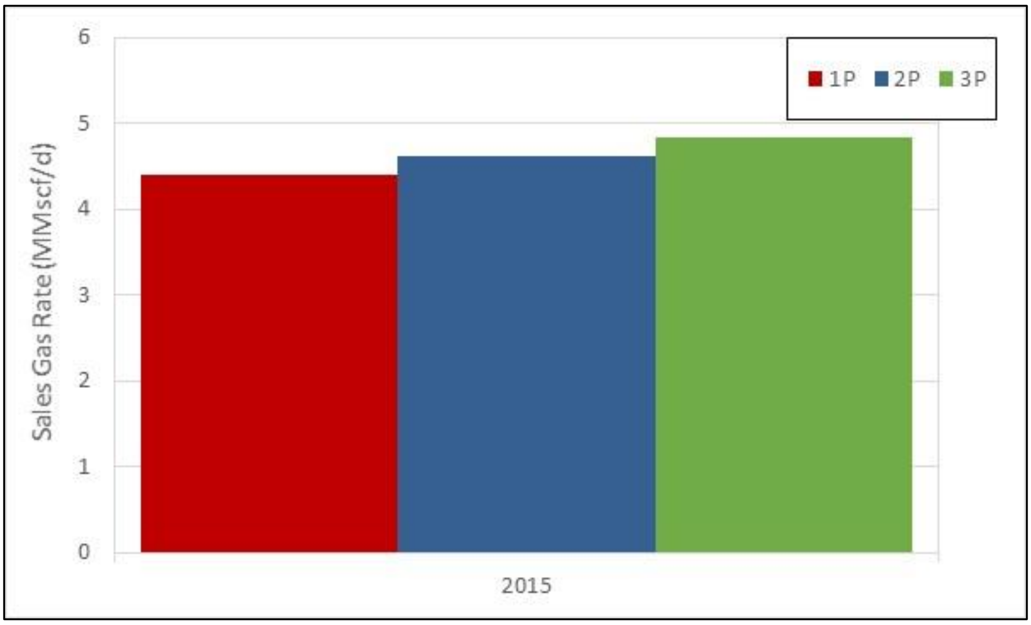


Figure 3-30 Orca Production Forecasts

Gas sales are estimated to be 97% of production based on historical data. The gas heating value (HHV) is estimated to be 27.5 MJ/m3 (737 BTU/scf). Condensate production is negligible.

3.7.5. Future Development and Costs

No further development is planned.

3.7.5.1. *Operating Costs*

Orca field 2016 OPEX is forecast to be approximately £10m gross (£4m net) beyond this OPEX is forecast to be approximately £4m gross (£1.5m net).

3.7.5.2. *Decommissioning Costs*

It is planned to remove the Orca topsides and jacket with piles cut 6m below the mudline. Wells will be P&A and also cut 6m below the mudline. Pipelines will be flushed and left in situ. E.On estimate platform and pipeline costs of €81m (£65m) gross, this appears to exclude well P&A costs however the pipeline cost estimate of €34m appears high if the pipeline is to be left on the seabed. We estimate facility decommissioning and well P&A costs of £60m gross (£14m net).

Minke P&A and decommissioning costs is estimated to be £22m gross although a full decommissioning study has not been conducted.

3.7.6. Reserves

RISC's estimates of reserves are shown in Table 3-11.

Table 3-11 RISC Estimate for Orca Field Reserves as at 1 January 2015

Orca-Minke Field Reserves	Net to E.On					
	1P (Proved)		2P (Proved + Probable)		3P (Proved + Probable + Possible)	
	Sales Gas (Bcf)	Condensate (MMBbl)	Sales Gas (Bcf)	Condensate (MMBbl)	Sales Gas (Bcf)	Condensate (MMBbl)
Reserves at 01 January 2015	0.3	0	0.3	0	0.3	0
The Net Present Value for Orca was calculated using 737 Btu/scf.						

As Minke production ceased in 2011, there are zero reserves at the effective date of 1/1/15.

3.7.7. Contingent Resources

Additional volumes that could be produced in the event of higher gas prices, by an extension of field life beyond the economic limit have been assigned as contingent resources (Table 3-12). RISC assigns no Contingent Resources from additional infill drilling.

Table 3-12 RISC Estimate for Orca Field Contingent Resources

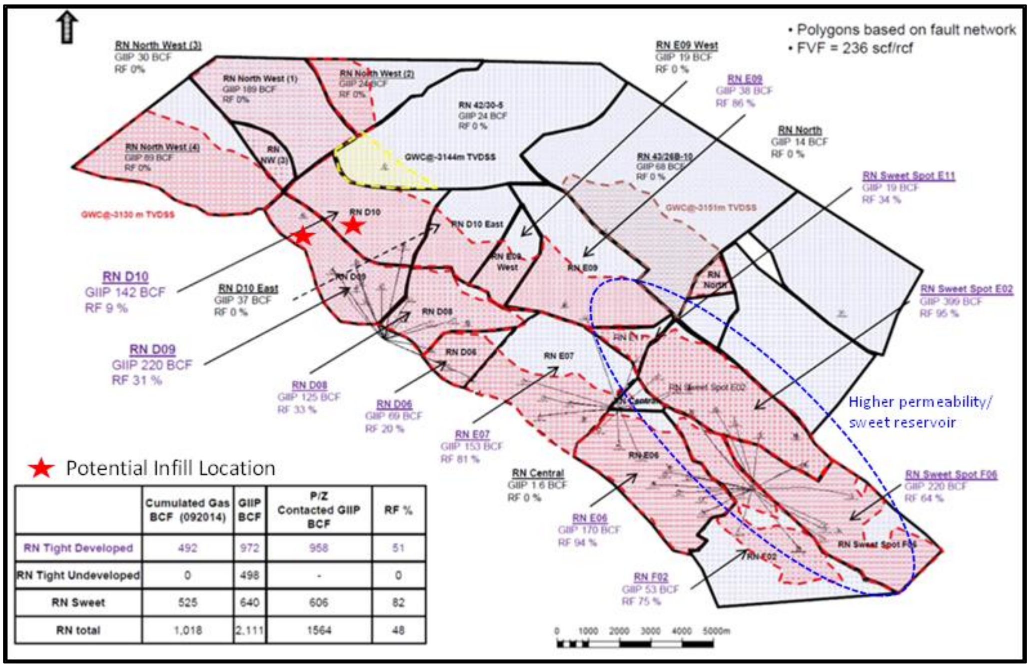
Orca-Minke Field Contingent Resources	Net to E.On					
	1C		2C		3C	
	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)
Contingent Resources beyond Economic Limit	0.3	0	0.5	0	0.7	0

3.8. Ravenspurn North Gas Field, blocks 42/30a & 43/26a (Licence P380)

3.8.1. Overview

Ravenspurn North is a dry gas field discovered in 1984 within blocks 42/30a and 43/26a in the UK Southern North Sea. It came on-stream in 1990, had a peak rate of approximately 450 MMscf/d in 1997 and is currently producing 25 MMscf/d. Perenco is the Operator (71.255%) and E.On has the remaining 28.745% interest.

The field is a fault and dip closed faulted anticline broken into a series of fault blocks (Figure 3-31).



	Cumulated Gas BCF (092014)	GIIP BCF	P/Z Contacted GIIP BCF	RF %
RN Tight Developed	492	972	958	51
RN Tight Undeveloped	0	498	-	0
RN Sweet	525	640	606	82
RN total	1,018	2,111	1564	48

Figure 3-31 Ravenspurn North field segments

The gas has a low CGR of 1.6 bbl/MMscf, 1 mole% CO_2 and minor (<1ppm) amounts of H2S.

3.8.2. Development and Current Status

The Ravenspurn North field development consists of a gravity based concrete platform with accommodation, process facilities and compression linked to a steel wellhead platform. Two additional wellhead platforms were subsequently installed. Gas is exported to the Cleeton facilities then onward via the Cleeton/Ravenspurn South line to the Perenco operated terminal at Dimlington.

Forty-two development wells have been drilled although three were not completed. Wells are largely deviated and hydraulically fractured. There are two horizontal wells.

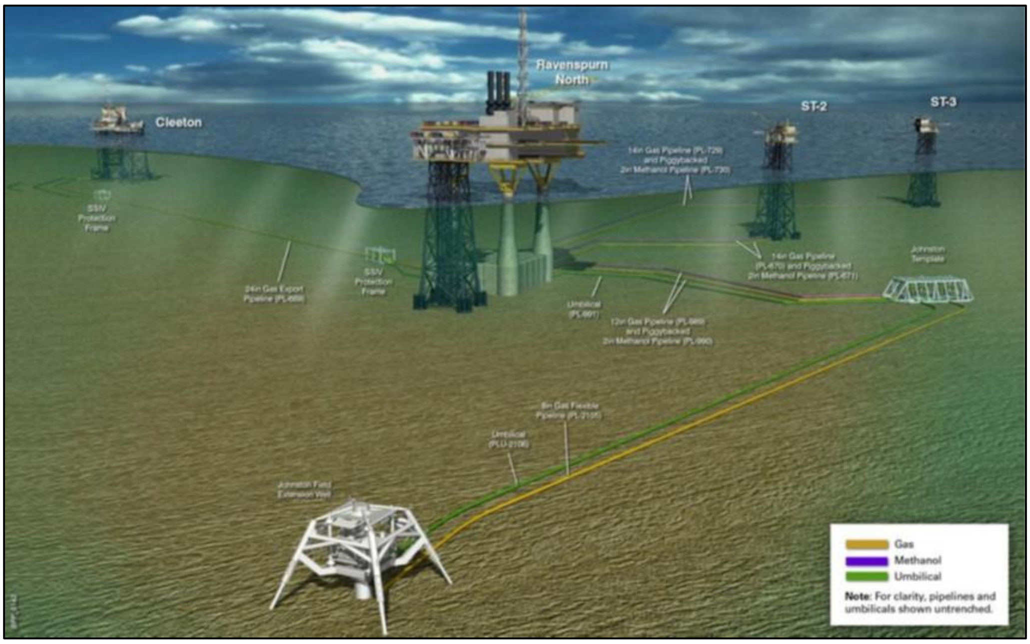


Figure 3-32 Ravenspurn North Surface Layout

3.8.3. Reservoir Description and In Place Volumes

The Lower Permian Rotliegendes Leman sandstone at 3,000 mTVDSS consists of aeolian sands and low permeability sabkha and fluvial sands. As shown in Figure 3-31 the reservoir is divided into areas of:

- Better permeability (1-50 mD) or 'Sweet Developed' reservoir with an estimated GIIP of 606-640 Bcf (E.On)
- Low permeability (<1 mD)or 'Tight Developed' reservoir with an estimated GIIP of 958-972 Bcf (E.On)
- Low permeability or 'Tight Undeveloped' reservoir with an estimated GIIP of 498 Bcf (E.On)

3.8.4. Reservoir Performance and Production Forecasts

Historic gas sales are shown in Figure 3-33. There has been negligible water production in any well.

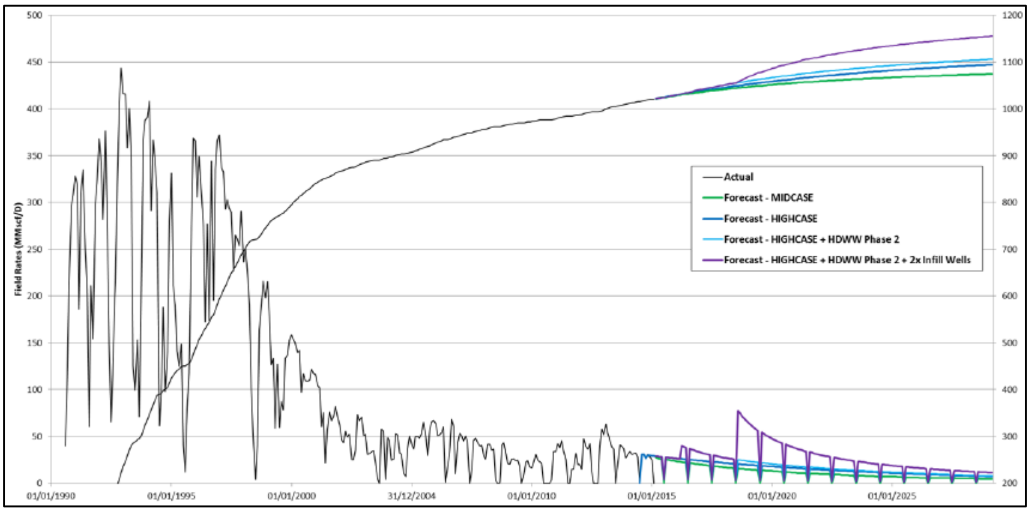


Figure 3-33 Ravenspurn North Historic and Forecast Gas Production (Gross 100%)

Of the forty-two development wells, three never produced (tight), nineteen have died and twenty are still producing. The gas recovery per well varies from zero to 107 Bcf with an average of 24 Bcf/well. The range is shown in Figure 3-34.

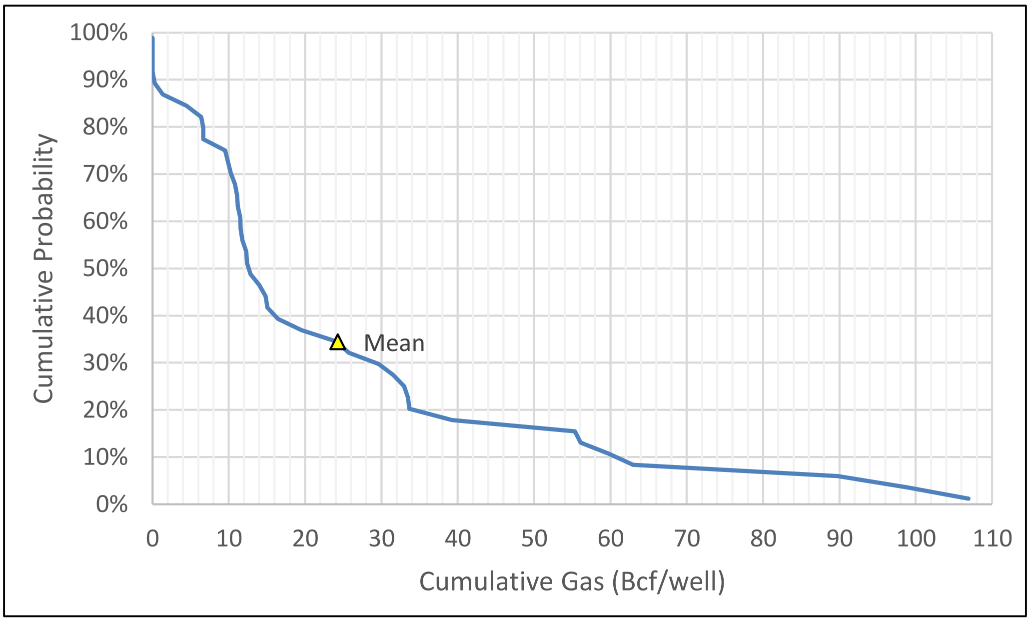


Figure 3-34 Ravenspurn North Historic Cumulative Gas per well

The last well drilled (F17) was horizontal and started production in 1997 and produced 34 Bcf to date. The other horizontal well, F10 died in 1999 after producing 30 Bcf.

Figure 3-35 shows the monthly gas production over the past 3 years.

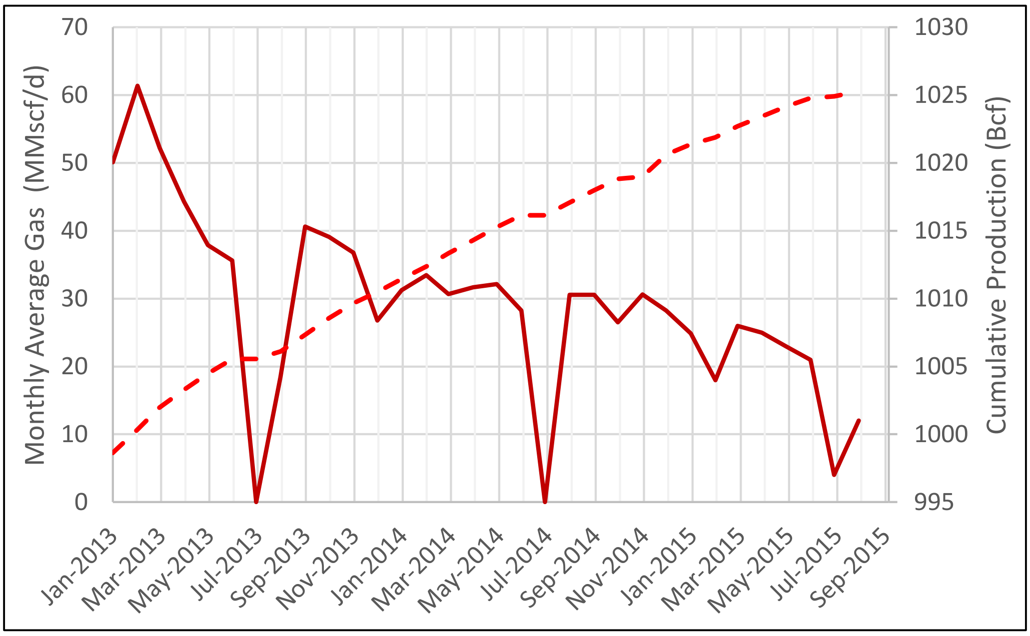


Figure 3-35 Ravenspurn North Recent Historic Production

The average gas production in 2014 was 27.8 MMscf/d. The 2015 average up to end August has been 19.2 MMscf/d although there appears to have been a lengthy shutdown in July-Aug 2015.

RISC has reviewed the historic decline trend of the field and generated production forecast based upon:

- The forecast matched to actual field production up to end August 2015 and forecast from that point.
- The 3P forecast is based on harmonic decline fitted to the field decline. Based on historic production, well uptime is estimated at 56%. The uptime is low because on average wells are only open 17 days per month. Most wells are on cyclical production with shut-in periods to re-charge reservoir pressure.
- The 1P forecasts is based on exponential decline fitted to the field decline. A lower well uptime of 45% is used to account for potential deterioration in well uptime.
- The 2P forecast is mid way between the 1P and 3P.

The economic cutoff leads to uneconomic production in 2016, so reserves are based on 2015 only. This truncated forecast is shown in Figure 3-36 below.

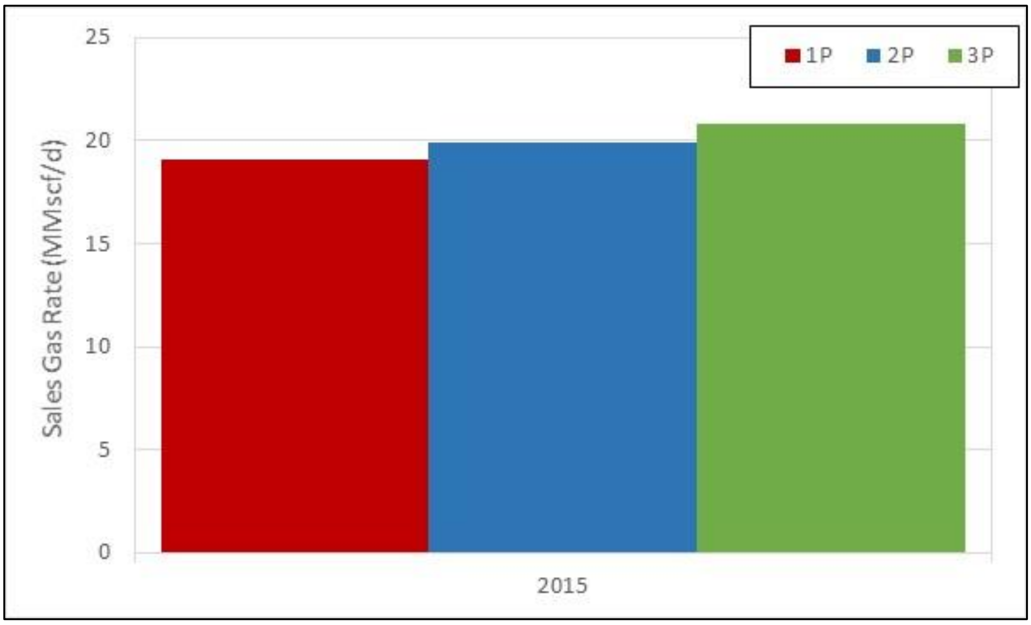


Figure 3-36 Ravenspurn North Production Forecast (Developed Reserves)

Ravenspurn North gas sales are estimated to be 91.4% of production based on historical data, with the remained used for offshore fuel including compression. The gas heating value (HHV) is estimated to be 37.5 MJ/m3 (1006 BTU/scf).

3.8.5. Future Development and Costs

There is no firm further development planned. Workovers are being considered to install velocity strings. It appears this work has not been suspended by the JV so we have not included the benefit in our reserves assessment.

3.8.6. Upside Opportunities (Contingent Resources)

Two upside opportunities have been identified:

- One or two horizontal infill wells in the North, with multistage fracs, expected to recover 25 Bcf over 15 years from mid 2018
- A second phase of Heavy Duty Well Work on shut-in wells D2, D3, D4, D6 and D14 starting 2Q 2016. The objective is to clear proppant from the wellbores using coiled tubing and restore production. The cost is estimated to be £13.2 million and recover an incremental 6.6 Bcf.

The previous Operator (BP) conducted a similar operation and restored production in D1, D12 and D13. However, the fill in three other wells was too extensive and could not be removed. The Phase-2 work was proposed in 2012 but not been carried out yet. RISC classifies the resources as contingent, being contingent on the project progressing.

As an example of the five clean-out candidates, Well D4 is an average well. It stopped production in 2008 at a rate of 1.5 MMscf/d and has been confirmed to contain proppant fill.

Figure 3-37 shows the stream day production history and exponential decline analysis.

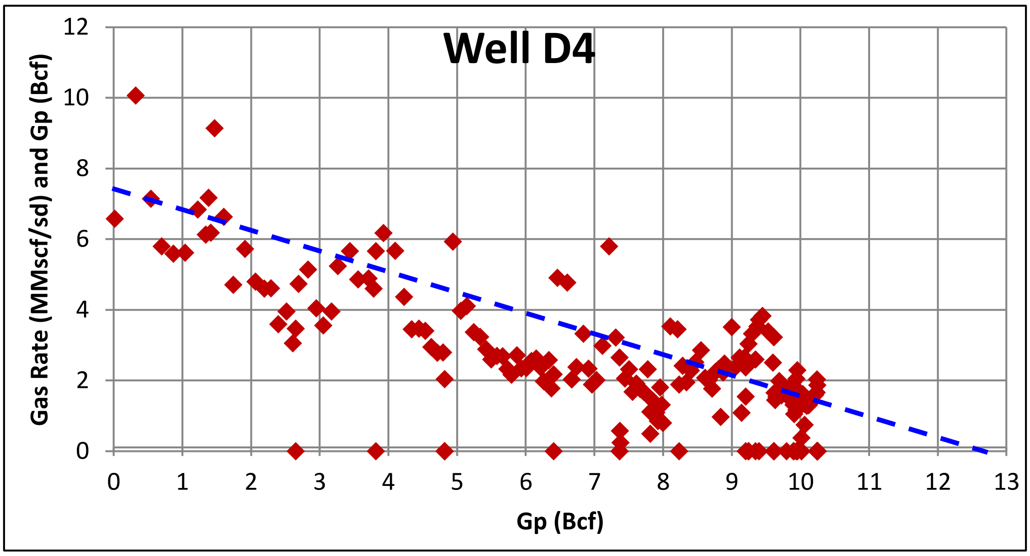


Figure 3-37 Ravenspurn North Well D4 Exponential Decline

Successful restart of D4 could recover an additional 2 Bcf from an initial rate of 1.5 MMscf/d. However reservoir depletion since the well last produced in 2008 may reduce this resource.

RISC has analysed the historic production of the well work candidates, estimated the potential incremental recovery, well rate and forecast as shown in Figure 3-38.

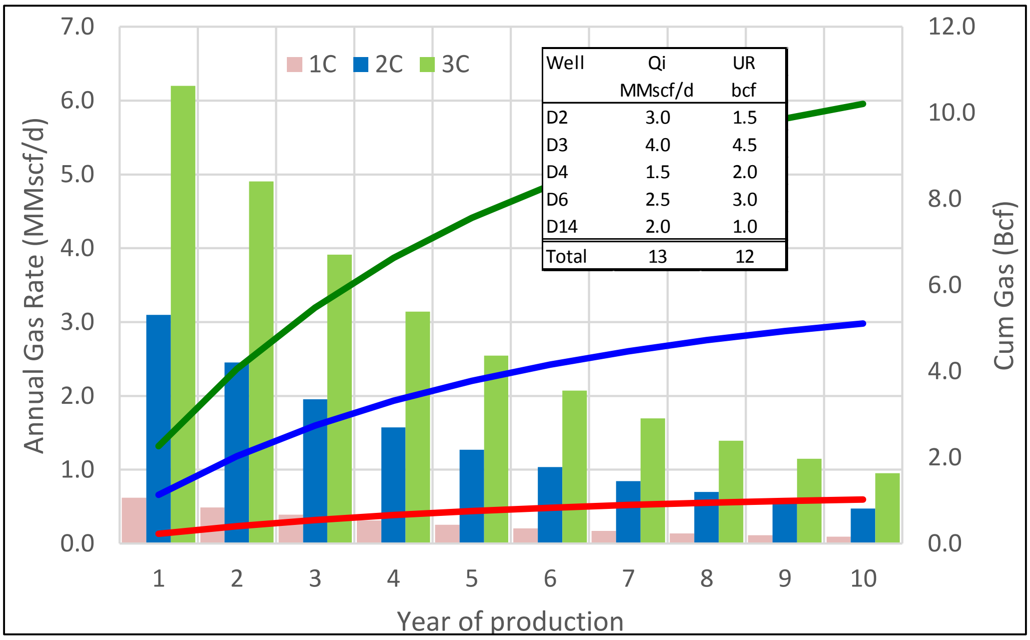


Figure 3-38 Ravenspurn North Well Work Forecast

The 3C forecast is based on the coiled tubing operations restoring the pre shut-down performance in each well. 10 Bcf of the 12 Bcf technical ultimate recovery is recovered in 10 years. The 2C assumes 50% discount rate (compared to the 3C case) to account for the potential risk of depletion and risk of mechanical failure of the clean-up operations. The 1C assumes 10% of the 3C case.

In addition to the workovers, two horizontal infill wells have been proposed in the tight reservoir in the north.

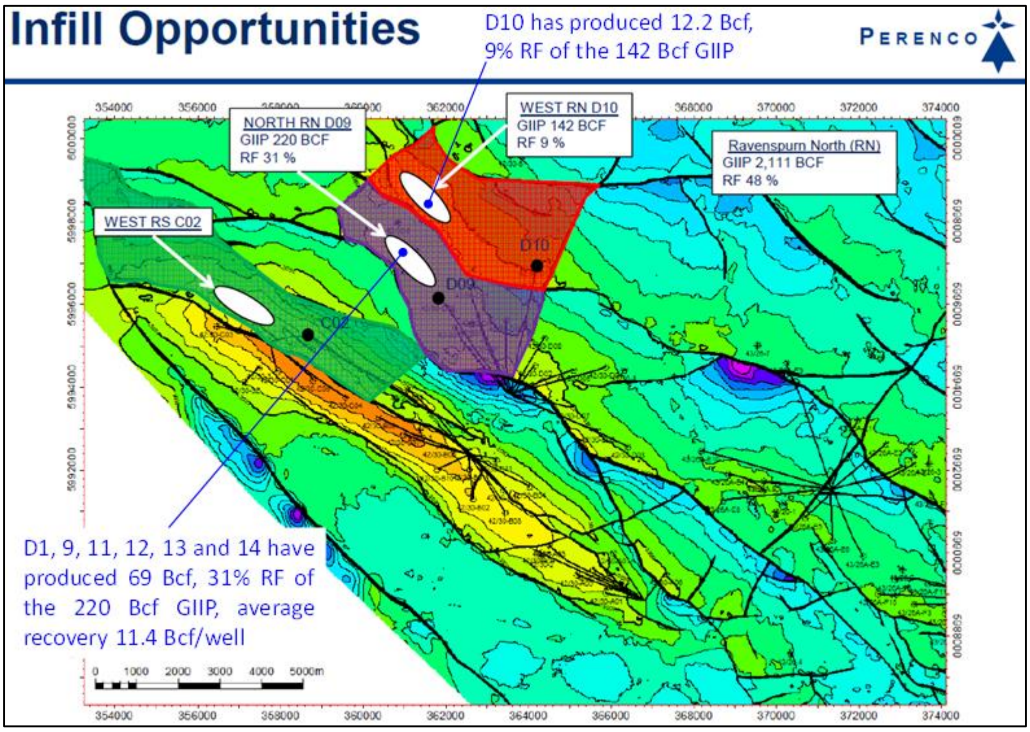


Figure 3-39 Ravenspurn North Proposed Infill Opportunities

- An infill well north of D09 in a block of 220 Bcf GIIP with 31% recovery factor to date from D01, D09, D11, D12, D13 and D14. Average recovery per well to date is 11.4 Bcf.
- An infill well north of D10 in a block of 142 Bcf GIIP and only 9% recovery factor to date from D10. Production from D10 is shown below:

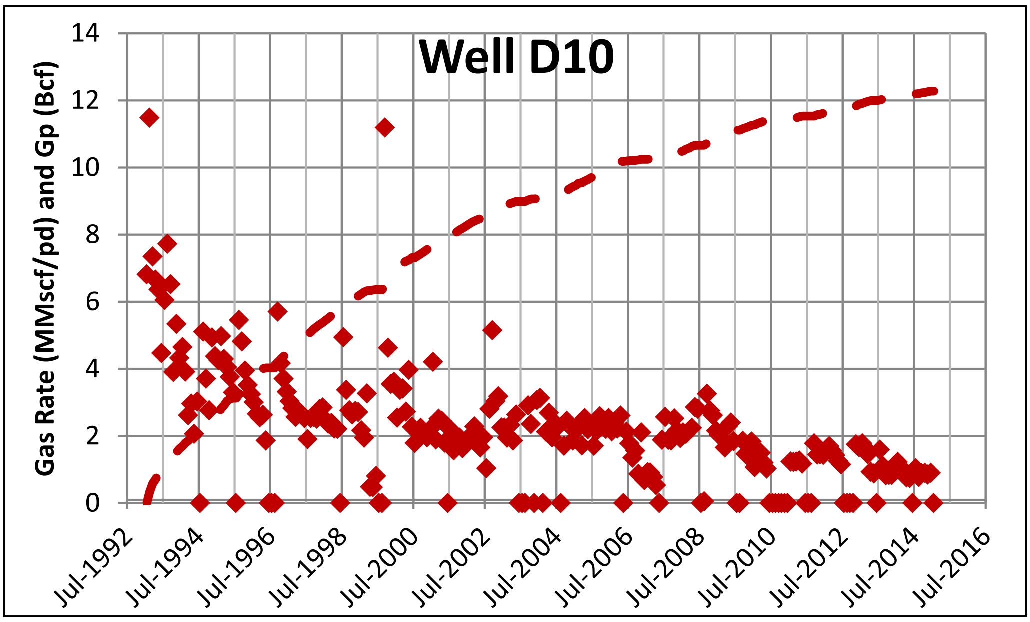


Figure 3-40 Ravenspurn North Well D10 Production History

A second well in the D10 block is likely to have similar performance +/- 50%.

RISC estimates that the infill opportunities could recover the same as previous wells in the block with the higher productivity horizontal design offsetting potential depletion. Therefore RISC estimates the flowing contingent resources.

Table 3-13 Ravenspurn North Contingent Resources

Contingent Resource (Bcf, wellhead) Gross	1C	2C	3C
D-09 Infill	6	12	18
D-10 Infill	6	12	18
Well Work	1	5	10
Total	13	29	46

3.8.6.1. Capital Costs

E.On report £2.8m gross of CAPEX in 2015 for base production. It is not clear what activity this covers and RISC was unable to validate if it was incurred. However RISC has included this sum in its forecasts.

In the upside case E.On forecast £13m gross ($4m net) in 2016 for workovers to remove proppant from 5 wells (wells D2, D3, D4, D6 and D14) and install velocity strings. Production as a result of these activities are classified as contingent resources.

The two potential horizontal infill wells in the tight reservoir in the North of the field are estimated by E.On to cost £120m gross. As the production for Contingent Resources are is not included in our forecasts we have not included these costs.

3.8.6.2. Operating Costs

Operating costs at Ravenspurn North are forecast to cost £35m pa gross ($10m pa net) for 7 years. We forecast reductions 10% pa after that. There is no incremental OPEX associated with the contingent resources as production would come from existing wells.

Costs at this level are likely to be unsustainable given the modest production. This would also impact Johnston as Ravenspurn North is the host platform for the Johnstone subsea tieback.

3.8.6.3. Decommissioning Costs

E.On forecast decommissioning costs of £92m gross. We consider this to be too low and estimate costs in the range £100-£200m. There is considerable uncertainty as we are unsure of the plans for decommissioning the concrete gravity structure.

3.8.7. Reserves

RISC's estimates of reserves are shown in Table 3-14.

Table 3-14 RISC Estimate for Ravenspurn North Field Reserves as at 1 January 2015

Ravenspurn North Field Reserves	Net to E.On					
	1P (Proved)		2P (Proved + Probable)		3P (Proved + Probable + Possible)	
	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)
Reserves at 01 January 2015	1.8	0	1.9	0	2.0	0

3.8.8. Contingent Resources

This first line in the table below is the additional volume that could technically be produced in the event of higher gas prices, by an extension of the reserves forecast field life beyond an the economic limit. The second line in the table refers to the sum of the upside development wells.

Table 3-15 RISC Estimate for Ravenspurn North Field Contingent Resources

Ravenspurn North Field Contingent Resources	Net to E.On					
	1C		2C		3C	
	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)
Contingent Resources not Classified as Economic Reserves	14.4	0	18.2	0	22.0	0
Upside Development Wells	13	0	29	0	46	0

3.9. Rita Gas-Condensate Field, blocks 44/22c & 44/21b (Licence P766 & P771)

3.9.1. Overview

Rita is a dual lateral subsea well tied back via Hunter to CMS.

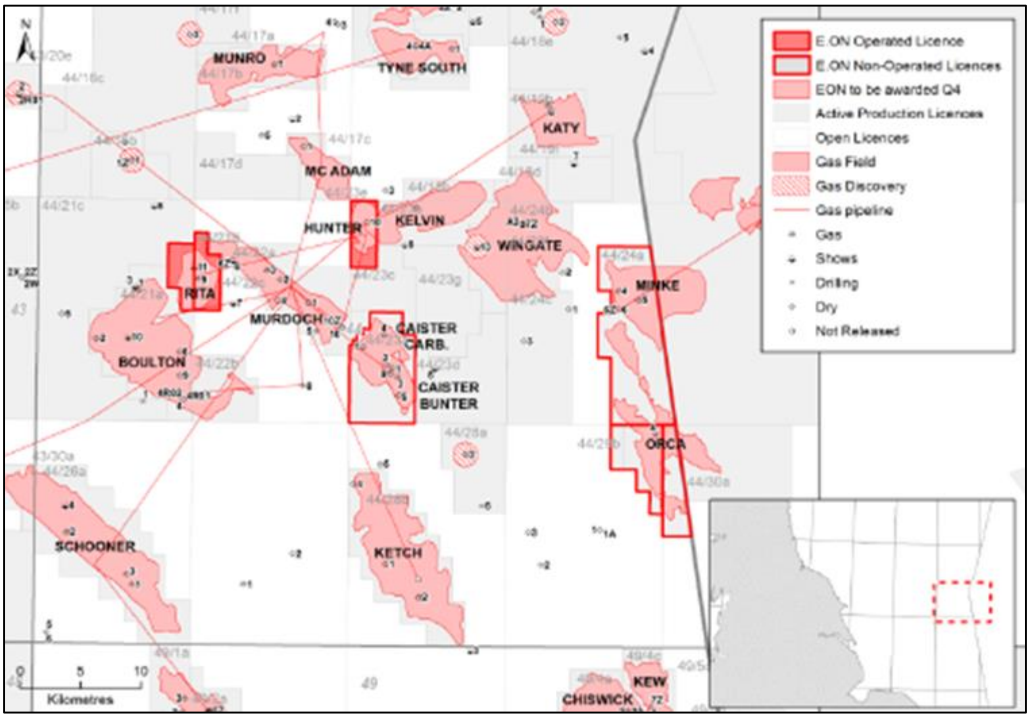


Figure 3-41 Location Map of Caister Murdoch System Fields

3.9.2. Development and Current Status

Rita is developed with a dual lateral well tied back to the Hunter field via a 14km, 8" carbon steel pipeline. Hunter was developed with single subsea well and an 8km, 8" subsea tieback to Murdoch. Hunter production ceased in 2012 but the subsea pipeline was used for Rita production. There is also a flexible flowline from Rita to Murdoch that was disconnected in 2012. Gas is aggregated at Murdoch and exported via the 26" 188km CMS export line to Theddlethorpe gas terminal. The NUI is remotely operated from Theddlethorpe. The layout of Hunter, Caister and Rita is shown in Figure 3-42 below.

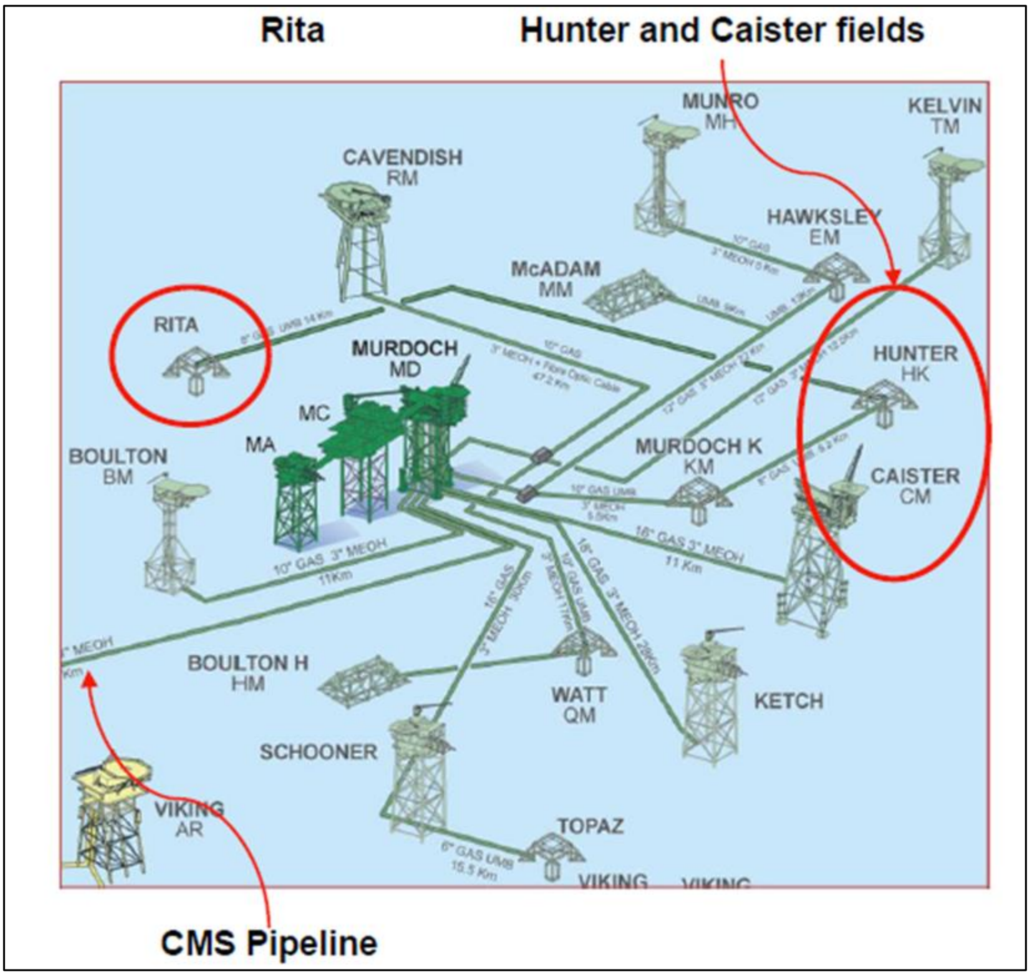


Figure 3-42 Hunter, Caister and Rita Development Schematic

Rita was discovered in 1996, appraised in 1998 and started production in April 2009. No further development is planned. The field has experienced several long outages due to pipeline and umbilical integrity issues.

3.9.3. Reservoir Description and In Place Volumes

The Rita structure comprises two adjacent tilted fault block compartments, Rita West and Rita East, accessed via two horizontal wells 44/22c-12 and 44/22c-12z respectively. The reservoir for the Rita field is the Carboniferous Westphalian C/D sands characterised by fluvial channel sandstones preserved beneath the Base Permian Unconformity. Individual channel sands are up to 50 ft thick with overall net to gross around 25% and porosities ranging from 6% to 10 %. E.On estimate a base case GIIP for Rita of 55 Bcf (estimated 48.9 Bcf recoverable – 89% recovery) with an upside GIIP estimate of 71 Bcf (estimated 51.2 Bcf recoverable – 72% recovery).

3.9.4. Reservoir Performance and Production Forecasts

Initial production of 70 MMscf/d declined to 30 MMscf/d in 2011 when production stopped due to issues with the flexible flowline. A new rigid flowline was installed and production restarted in 2013. Production declined to 11 MMscf/d after producing 39 Bcf.

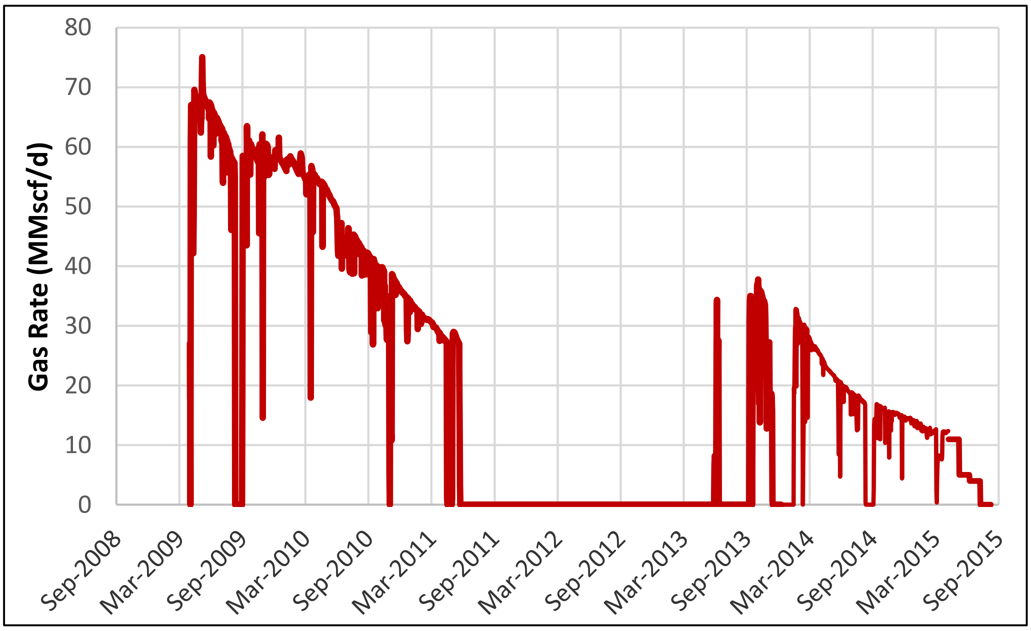


Figure 3-43 Rita Gas Production History

Rita's production was shut-in from late 2015. Investigations are underway as to cause and possible remedy to the well failure. In the absence of clear plans and costs to reinstate production, for the purposes of current valuation, we assume the field remains shut-in.

Figure 3-44 shows the production forecasts, based on production decline modelling, for production being restarted. The volumes after 2015 are attributed to the Contingent Resources, not reserves.

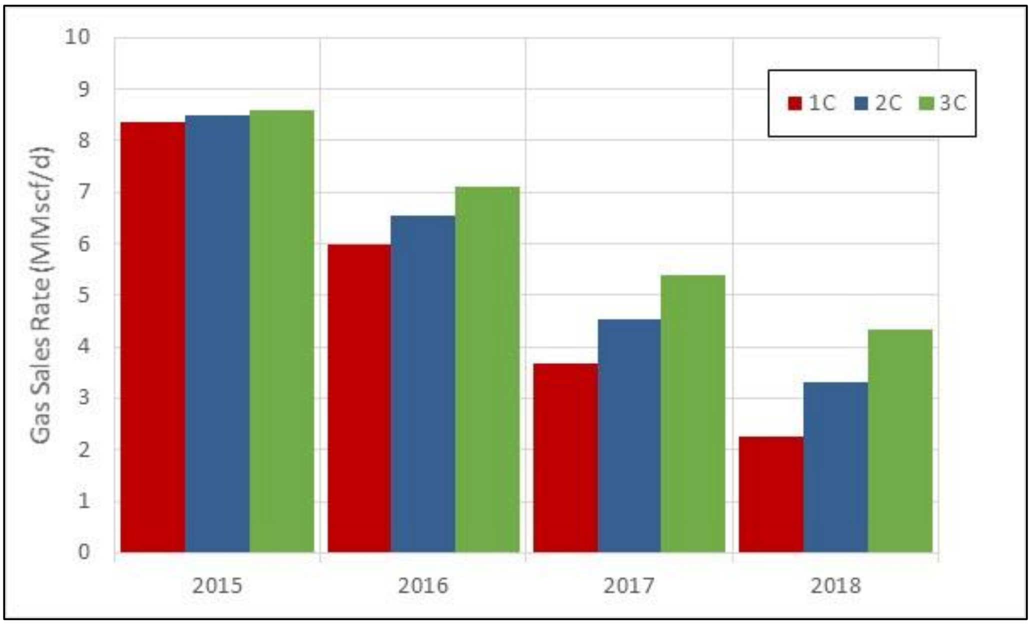


Figure 3-44 Rita Field Production Forecasts (Contingent Resources)

3.9.5. Future Development and Costs

No further development is planned.

3.9.6. Reserves

RISC's estimates of reserves are shown in Table 3-16. These are the volumes produced during 2015.

Table 3-16 RISC Estimate for Rita Field Reserves as at 1 January 2015

Rita Field Reserves	Net to E.On					
	1P (Proved)		2P (Proved + Probable)		3P (Proved + Probable + Possible)	
	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)
Reserves at 01 January 2015	1.6	0.01	1.6	0.01	1.6	0.01

3.9.7. Contingent Resources

This is the volume that could technically be produced by restarting production (Table 3-17). RISC assigns no Contingent Resources from additional infill drilling.

Table 3-17 RISC Estimate for Rita Field Contingent Resources

Rita Field Contingent Resources	Net to E.On					
	1C		2C		3C	
	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)
Contingent Resources not Classified as Economic Reserves	3.8	0.02	4.5	0.03	5.1	0.04

4. Undeveloped Discoveries

4.1. Overview

E.On have three undeveloped fields in the portfolio (Figure 4-1). RISC has reviewed these and offers the following comments.

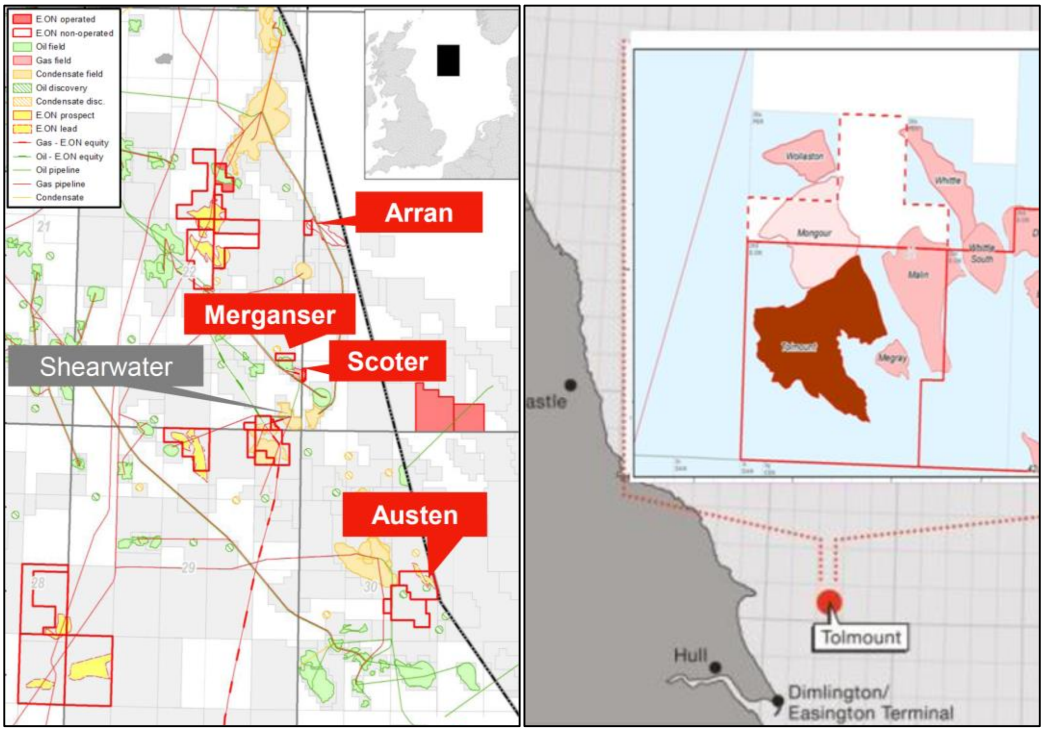


Figure 4-1 Arran, Austen & Tolmount Field Location Map

4.2. Tolmount Gas Field, block 42/28d (licence P1330)

4.2.1. Overview

The Tolmount Field is situated in the UK Southern North Sea, Block 42/28d, Licence P.1330. The licence was originally awarded, in the 23rd Licencing Round, to Dana in 2005 with 100% equity, with E.On farming-in at 50% equity and assuming Operatorship in 2010.

Tolmount Field was discovered by well 42/28d-12 in 2011, with further appraisal drilling of wells 42/28d-13 and -13z in 2013 confirming the presence of high quality, Lower Leman Sandstone Formation reservoir. A work programme of PSDM seismic to evaluate and rank prospectivity, and mature locations to 'drill-ready' status was underway at the time of the Information Memorandum (June 2015). Project SELECT Phase activities were also ongoing in the form of subsurface activities, drilling studies, offshore surveys and pre-development studies. The Final Investment Decision (FID) is expected in Q1 2017, with First Gas 2019.

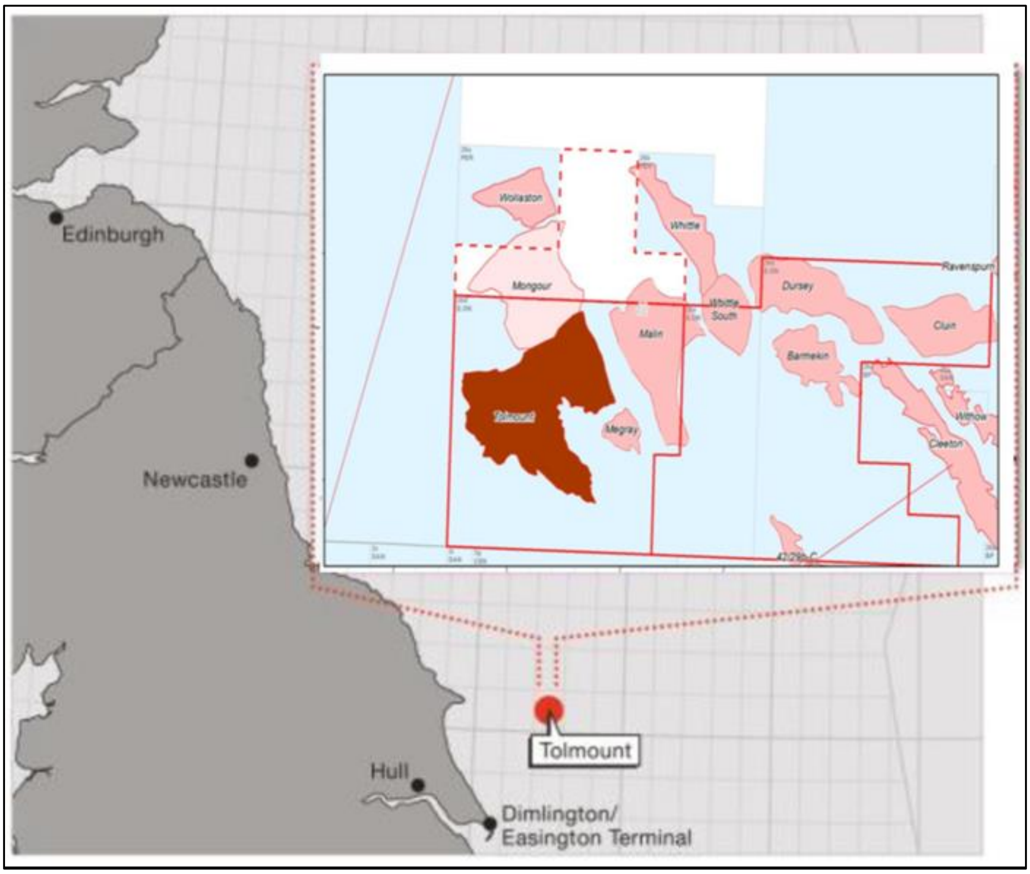


Figure 4-2 Area Map of Tolmount Field and surrounding prospects

4.2.2. Reservoir Description and In Place Volumes

The Tolmount Field sits within the Lower Leman Sandstone Formation Play Fairway to the south of the Permian 'Silver Pit Lake' and north of the 'Amethyst High'. Aeolian dunes and fluvial sands predominate, with local sabkha and 'wet'/'damp' inter-dune facies, deposited unconformably on the Carboniferous (Base Permian Unconformity) terrain. Prevailing easterly winds dominate the orientation of dune deposition, whilst the fluvial transport is predominantly from the south and southwest (Figure 4-3).

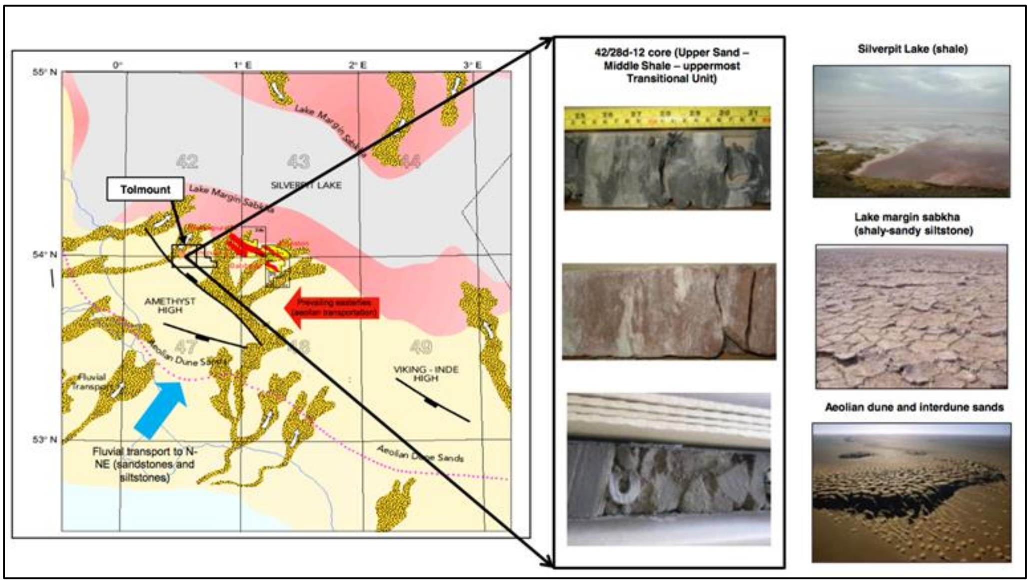


Figure 4-3 Lower Leman Sandstone Fm – Depositional Setting

4.2.2.1. Structure

The structure of Tolmount is linear, with a crest striking broadly northwest-southeast, with parallel faulting setting up the structure, along with a set of faults perpendicular to strike. As a consequence of these two fault sets, compartmentalisation is likely to be an issue. A Badley's Fault Seal study has concluded that the northwest-southeast striking faults have a higher seal potential than those striking northeast-southwest. Gas pressures appear to be on the same gradient and PVT analysis indicates no significant compositional differences or evidence of gravitational gradient, suggesting equilibration over the geological time scale. Overall, the Operator concludes there is a small risk of compartmentalisation. Where compartmentalisation appears to be a risk, it can be mitigated to a large degree by drilling wells into the largest 'compartments' and if necessary, across faults to maximise drainage.

4.2.2.2. Depth Mapping

RISC reviewed the quality of the data provided by E.On in the data room and found it good quality but limited in detail. The data room contained extensive data from the latest E.On depth conversion, the associated E.On depth conversion report and a depth conversion report from an independent contractor which was completed a year earlier.

E.On has elected to produce a 10 layer depth conversion in model MV09v6. The layers reflect the major velocity changes observed in the southern North Sea and is accepted as standard practice in depth conversion in this area of the Southern North Sea. The surfaces both Two Way Time (TWT) and depth included Seabed, Top Chalk, Base Chalk, Top Corallian, Top Bunter, Top Zechstein, Top Rotliegendes, Top Leman and Carboniferous.

The TWT interpretation was validated by RISC in Premier's office from the screen captures of various seismic lines from the 3D seismic survey. The TWT grids honoured the seismic data apart from the edges of the grids, which may have been an issue in the production of the grids, where the interpretation area had not been defined. The Top Corallian TWT grid has been smoothed by E.On in order to remove the depth conversion artefacts seen below Top Corallian, due to the extensive faulting of the Corallian. Inevitably this issue and approach will lead to some potentially large uncertainties in the depth conversion.

Table 4-1 E.On Depth Model 10 layer cake

Layer	Interval	Velocity Model
1	Water	1,500 m/s
2	Tertiary	2,200 m/s
3	Chalk	V = -5.1T + Vo(map)
4	Base Chalk - Top Corallian	Interval velocity map
5	Top Corallian - Top Bunter	V =- 1.1Z + V0(map)
6	Bunter	V = 0.85Z + Vo(map)
7	Zechstein Salt	Interval velocity map
8	Zechstein Anhydrite and Dolomite	6,000 m/s
9	Silverpit	4,481 m/s
10	Leman	4,422 m/s

The lower Cretaceous and upper Jurassic is dominated by lower velocity mudstones and claystones which push the top reservoir seismic pick down in TWT. The remaining Jurassic and Triassic has significantly more evaporates and limestones which are higher velocity and represent a pull up in TWT. The splitting of the Zechstein into high velocity Anhydrite (circa 20,000 ft/s) and lower velocity Halite (circa 15,000 ft/s) in principle is a sound method, especially when the high velocity anhydrite layers can be mapped as in many areas of the gas basin. However, E.On has not directly mapped the thickness of the Anhydrite and has assumed a constant thickness. E.On has used an interval velocity of 6,000m/s (19,685 ft/s), which is acceptable in the Southern Gas Basin.

An audit of the E.On velocities has been carried out by producing Interval velocity maps from E.On TWT and depth maps. In addition, the Interval velocities at the wells have been calculated from E.On well tops and TWTs. The TWT values at the wells are understood to be pseudo TWTs. Interval velocities at wells have been posted on interval velocity maps to observe how well the interval velocities used in the depth conversion ties the interval velocity derived from the well data. Graphs of TWT at top and base of seismic interval vs interval velocity were derived from E.On tops and time files and plotted on the velocity maps as a further audit of the E.On model.

The Chalk interval velocity map exhibits the poorest tie to the interval velocity at the wells, with the map showing 300 m/s higher interval velocities at Tolmount. The Base Chalk to Corallian interval velocity map has reasonable ties to the wells, although it does show lower interval velocities at Tolmount and may compensate for the higher velocities of the Chalk. The interval velocity map of Top Corallian to Top Bunter and Bunter interval velocity map match the well velocities and suggests that the E.On Modelling of this layer is acceptable. E.On has elected to split the Zechstein into an Anhydrite layer of 120m with a velocity of 6,000m/s and a Halite layer where they have depth converted by contouring the Halite interval velocities. The derived Anhydrite interval velocity map shows the 6,000m/s velocity and slightly lower Anhydrite well velocities at Tolmount. The derived Halite map is more uncertain, as it shows an increasing velocity trend to the north that is not readily visible in the derived well interval velocities. A single interval velocity of 4,440 m/s (14,566 ft/s) for Halite may be more appropriate for the Tolmount area. The analysis indicates that E.On have used a slightly higher Anhydrite velocity and slightly lower Halite velocity over Tolmount that will compensate but will result in a larger error residual at Top Rotligendes reservoir. Overall, the E.On Depth conversion appears sound with the Chalk and Zechstein layers giving the largest error residuals. The single interval velocities at the Silverpit of 4,481m/s is reasonable though slightly higher than the 4,400 and 4,100m/s seen at the Tolmount wells.

The E.On interval velocities were validated by producing new interval velocity maps for each of the layers an example is shown below.

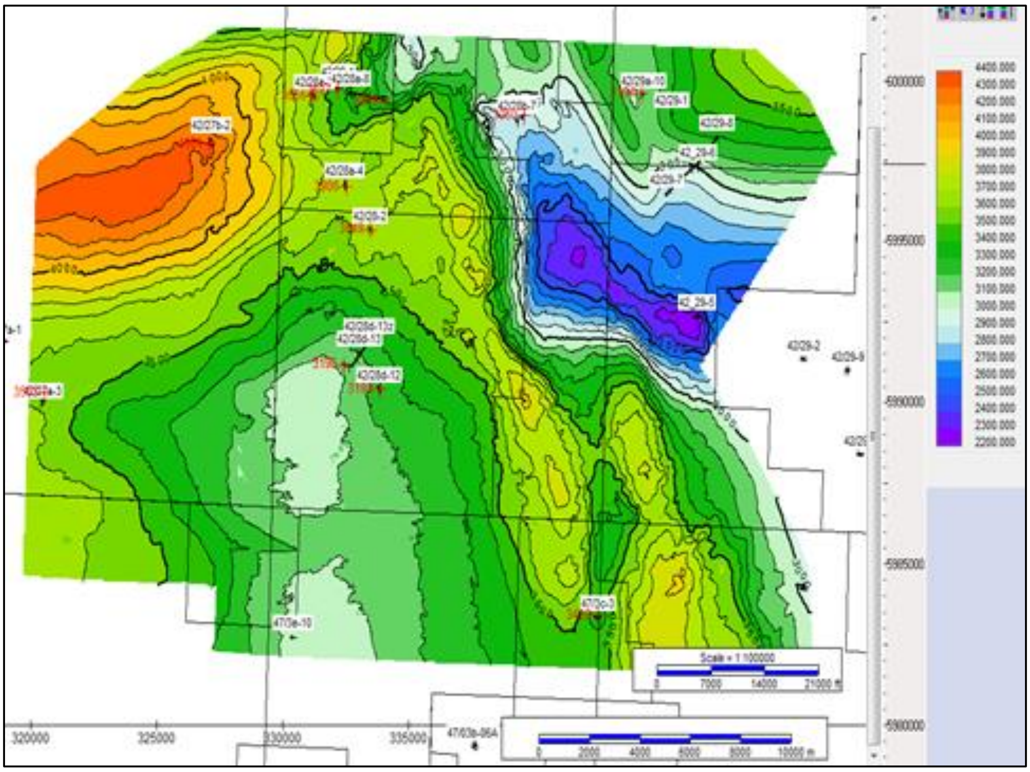


Figure 4-4 Interval Velocity map Top Corallian-Bunter

The map shows all the wells in the area used to plot the TWT against the Interval velocity to give a correlation of R^2= 0.7554.

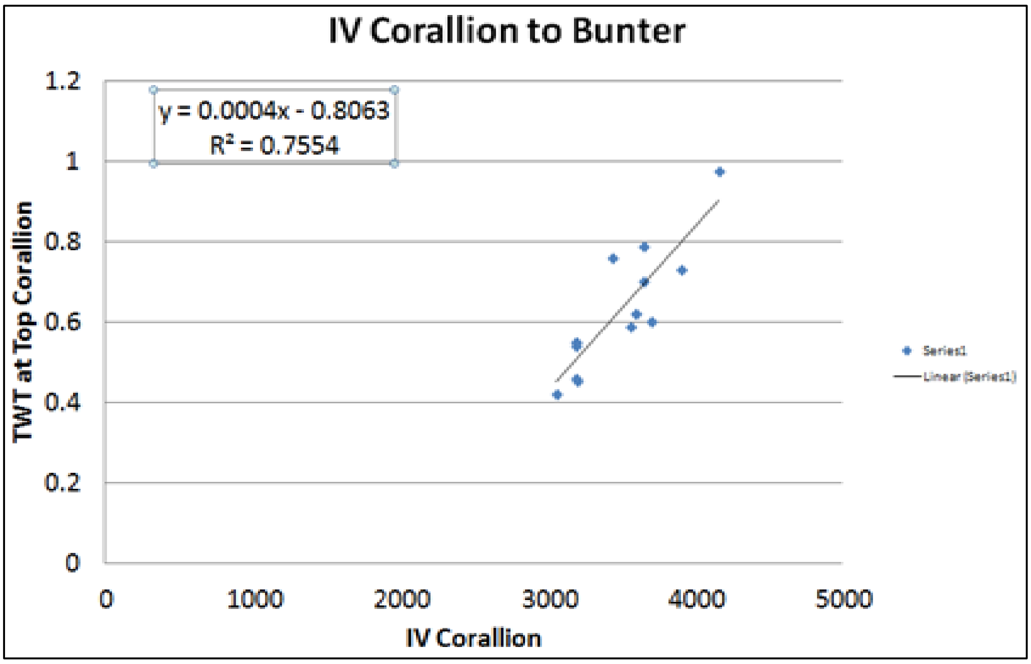


Figure 4-5 Associated TWT vs Velocity plot

4.2.2.3. Gross Rock Volume estimation

The Top Leman depth map shows structural closure to the south and west of Tolmount at the GWC of 3,119 mTVDSS. There is no structural closure to the North and West. The maps show that Tolmount can be closed by the faulting to the north and west but it includes the area to the east named Mayar by E.On and defined by the Cyan polygon on the map. There is no structural separation of Tolmount and Mayar and it requires the Top Leman surface to be depressed by 75m locally to separate the areas. The Leman isopach shows clear thinning between Tolmount and Mayar to 25-30m. The seismic in this area is below seismic resolution and it is quite possible that the reservoir is not deposited in this area at the northerm limit of the Leman fairway. The separation of Mayar and Tolmount has been chosen on this basis.

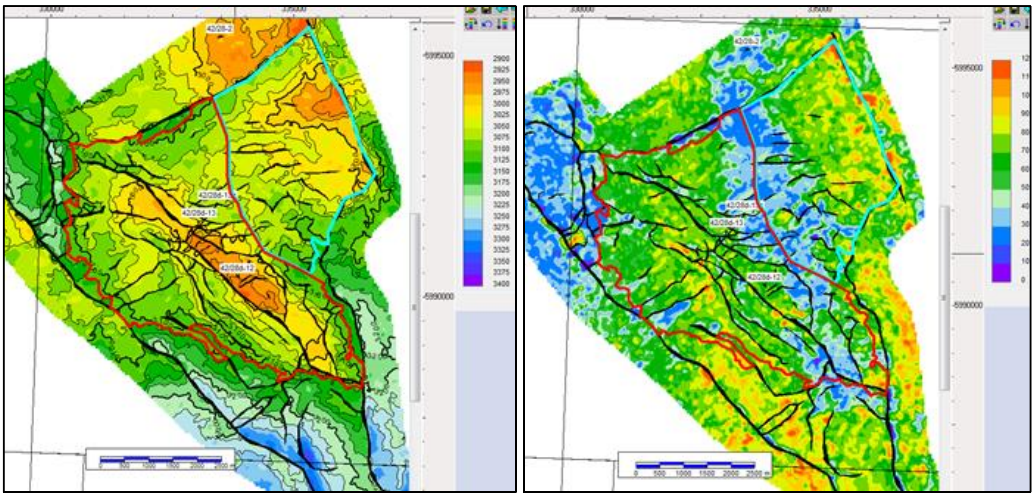


Figure 4-6 Leman Depth Map and Leman Isopach

The two polygons Tolmount (red) and Mayar (blue) illustrated on Leman depth and isopach structure map were used to calculate the P50.

The P50 GRV was calculated to the GWC of 3119m within each of the polygons for both Tolmount and Mayar.

4.2.2.4. P10 and P90 GRV cases

RISC estimate Top Leman depth uncertainty across the Tolmount structure to be up to 3% or 75-105m at any point away from well control, with an average total structure uncertainty of +/-1%.

A residual error map has been derived by scaling the Top Leman depth map by a factor of 0.01 giving an isopach ranging between 25-35m. The residual error map has been added to the Top Leman depth map to flex the surface deeper away from the wells. The error residual was also applied to the Top Carboniferous and both surfaces were used to calculate the P90 GRV using a GWC at 3119m. The same process was used to calculate the P10 surface, except the isopach was subtracted from both surfaces flexing them shallower away from the wells.

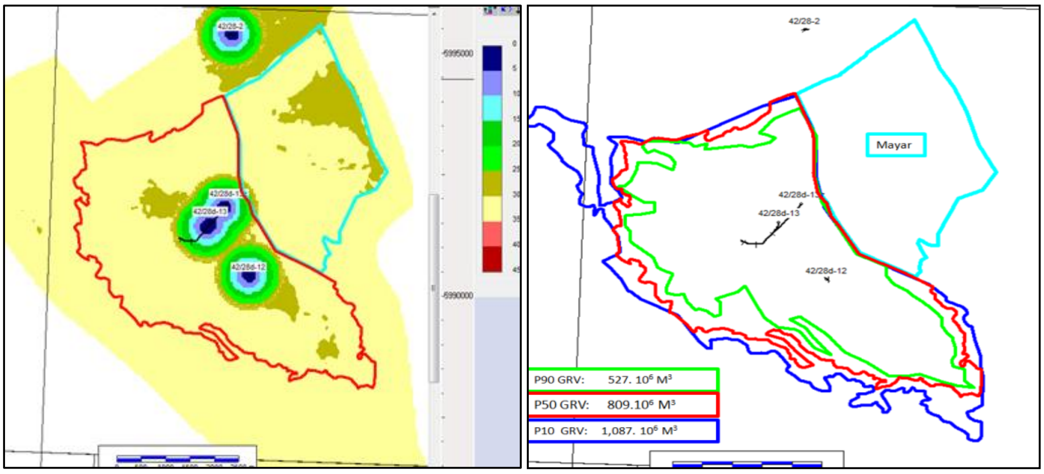


Figure 4-7 Tolmount Residual Error Map and resulting areas

On Mayar the area is predominantly above the GWC at 3,119 even on the P90 depth case. The main variable that affects GRV on Mayar is Leman thickness. The P90 and P10 GRV cases on Mayar have been derived by varying the Leman thickness by +/- 10%.

Table 4-2 Tolmount and Mayer GRV

GRV	Tolmount	Mayar
P90	527 x10^6 m^3	510 x10^6 m^3
P50	809 x10^6 m^3	560 x10^6 m^3
P10	1,087 x10^6 m^3	606 x10^6 m^3

4.2.2.5. Reservoir

The reservoir envelope has been defined by the Operator using seismic horizons at 'Top Leman' and 'Base Permian Unconformity' (Top Carboniferous) across Tolmount and Mayar. Core and well log data from well 42/28d-12 indicate reservoir quality in the Leman Sandstone to be very good in sheet flood and aeolian rock facies, with porosity typically in the 15-20% range, and permeability in the sheet flood facies of 10s mD and in the aeolian facies in the 100s mD to 1000 mD. The well flowed at 51 MMscf/d and 525 bpd condensate under test, with the majority of flow coming from the aeolian dune facies (based on the Production Logging Tool). The Operator has subdivided the reservoir into four main lithostratigraphic packages: Lower Sand, Transitional Unit, Middle Shale and Upper Sand (Figure 4-8). Further characterisation by the Operator of the reservoir into facies, using core and logs has been undertaken.

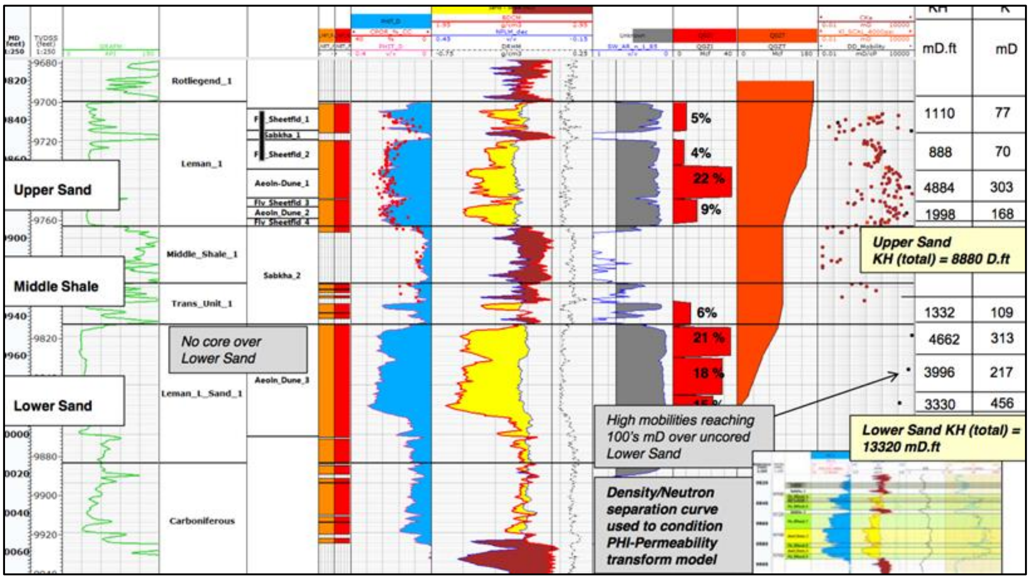


Figure 4-8 Tolmount Reservoir Quality, well 42/28d-12

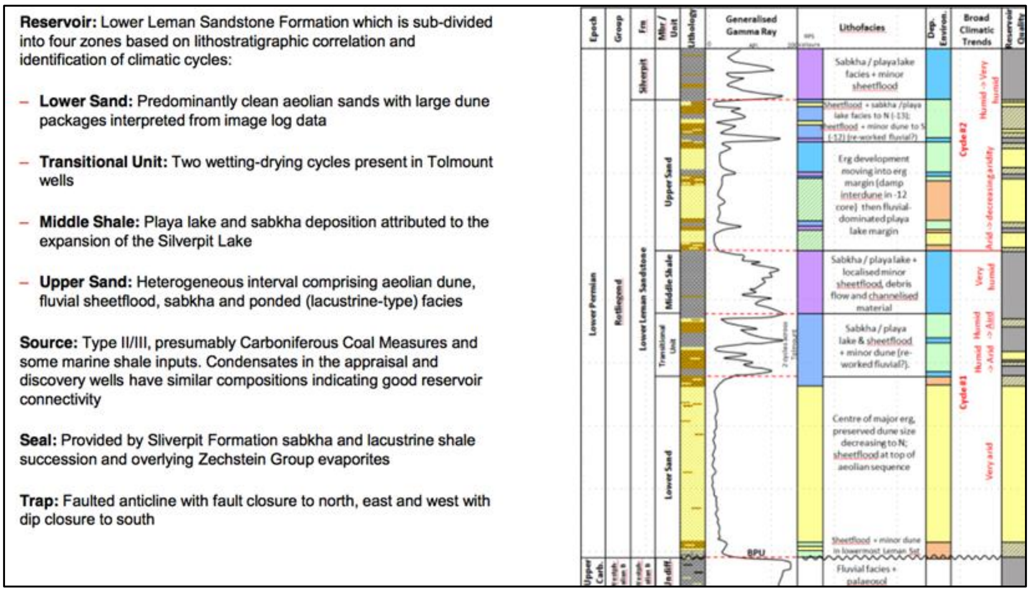


Figure 4-9 Tolmount Geological Summary

A Free Water Level has been interpreted at 3119 mTVDSS in -13z. No clear water leg has been identified in any of the Tolmount wells in the reservoir. However, the Tolmount gas leg does intercept the regional aquifer (wells 42/28a-4 and 42/29-5) at 3118 mTVDSS (Figure 4-10). To the N of the Field is the Mongour discovery well (48/28-2). With very similar reservoir to Tolmount, it has a contact at 2994m, which may be more representative of a Free Water Level in the Mayar area than the observed contact in the Tolmount well. Consequently, this has been used in modelling Mayar (a Rectangular distribution has been used: 2994m to 3119m).

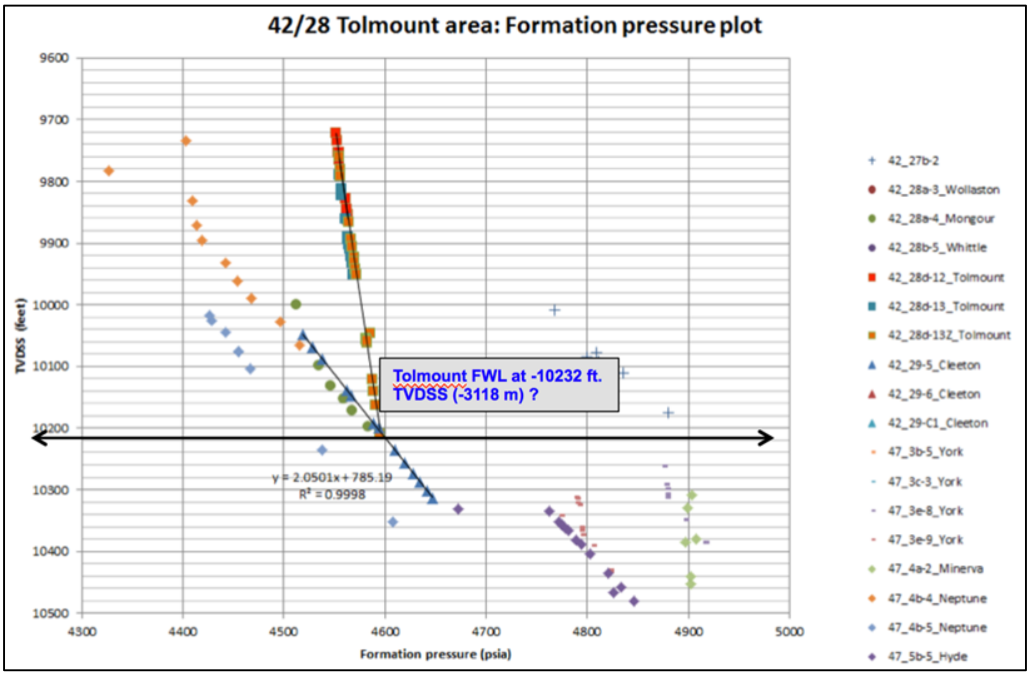


Figure 4-10 42/28 Tolmount Area Free-Water-Level

The Operator uses a Saturation Height function to model water saturation in the reservoir. Because only limited core capillary pressure data are available, which indicate an enhanced transition zone and anomalously high irreducible water saturation (Swirr), considerable modelling efforts appear to have been made to better understand water saturation, both as a function of height above FWL and in relation to facies (permeability). A modified Lambda function has been used in the most recent work, height-dependent Sw (water saturation) honouring Tolmount mercury injection data combined with log-derived Swirr component, the Operator's Reference Case for reservoir modelling, as well as a variety of other methods to test the sensitivity of the reservoir model to Sw. This Reference Case methodology seems to provide a good match to the log-derived Sw (using the Archie equation).

4.2.2.6. Gas Initially In Place

The Operator has produced two Reference Case geological models for Tolmount/Mayar: one made available to the Client in June 2015 and a second in August 2015. Upon request, E.On provided RISC with outputs from a modified June 2015 model. RISC has reviewed this model and used it as a basis for producing a probabilistic range of GRVs for Tolmount and Mayar. These were output to REP (probabilistic resource software) to estimate a probabilistic range of GIIP.

RISC's probabilistic modelling of GIIP uses a simplistic approach to Sw/H modelling for water saturation, by using the default Lambda function available in REP, providing a reasonable representation of Sw/H without taking into account changes in facies/permeability.

Porosity has been derived using calibrations of well core data to well log data by the Operator which appears to be robust.

Net-to-Gross is extremely high in the wells which have penetrated the reservoir. The Operator has used VSH <0.40, Porosity >6% and Sw 0.70 as cut-offs. RISC have used representative average values from wells -12 and -13 and used a log normal distribution.

Table 4-3 Tolmount and Mayar GIIP Estimates (RISC)

Tolmount Field In Place Volumes	**Raw Gas (Bcf, Gross)**		
	P90	P50	P10
RISC Estimate	**285**	**500**	**769**

Mayar Area In Place Volumes	**Raw Gas (Bcf, Gross)**		
	P90	P50	P10
RISC Estimate	**30**	**152**	**382**

RISC calculated In-place volumes for Tolmount and Mayar independently.

Based on E.On's updated interpretation of the depth conversion, their static reservoir model was updated. No representation of this model was made available to RISC.

4.2.3. Reservoir Performance and Production Forecasts

This gas field is under development planning and has not started production. RISC has evaluated the Tolmount field reserves and production forecast at 1P/1C, 2P/2P and 3P/3C confidence levels.

4.2.3.1. Material Balance Methodology

RISC has created a material balance model with separate tanks representing the estimated volumes drained by each well. The 1P/1C case is based on a high degree of compartmentalization and the 3P/3C case is based on wells depleting the full field.

Deterministic cases were based on RISC's P90, P50 and P10 volumetrics. This provided RISC's estimates of the 1P/1C, 2P/2C and 3P/3C gas and condensate production profiles.

4.2.3.2. Production Forecast

Reservoir fluid properties are based on downhole fluid samples that indicate consistent properties across a range of samples. RISC used the reservoir fluid composition with standard industry correlations to estimate the fluid properties of the gas. The condensate properties were based on PVT reports conducted on the downhole samples.

In generating the production forecasts, RISC has assumed that four wells are drilled in the period 2019-2020. In the 3P/3C case a further well is added for Tolmount East (Mayar).

Production is curtailed at 2040, in line with the expiry of the current estimated economic limit of approximately 3 MMscf/d in the 2C case.

RISC's gas production forecast is shown below. We note that E.On has presented more optimistic forecasts, due to an increase in interpreted GIIP as a result of recent work.

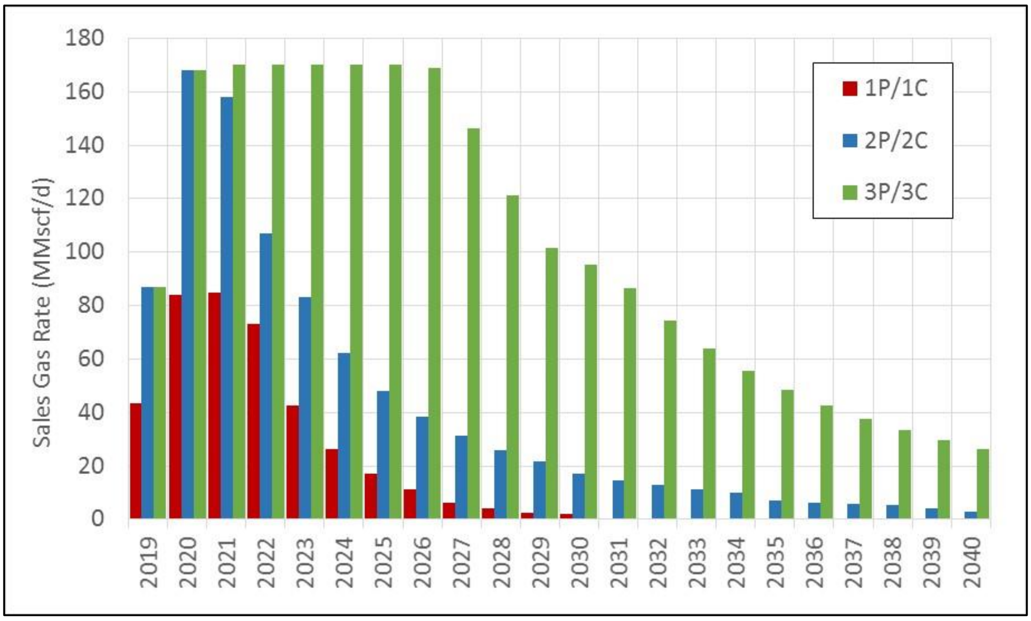


Figure 4-11 Production Forecast Summary for Tolmount Field

The recovery factors for the 1P/1C, 2P/2C and 3P/3C cases are 52%, 70% and 75% respectively. The variation is due to the different drainage volumes for the wells in each of the cases. The 1P/1C case with the lowest recovery factor is restrained by the wells' limited drainage area, due to faulting and compartmentalisation.

4.2.4. Future Development Plan

At the time of review, the project was at the Select Phase with ongoing subsurface activities, drilling studies, offshore surveys and pre-development studies. The Final Investment Decision (FID) is expected in Q1 2017, with First Gas 2019.

The development plan assumed in this evaluation comprises:

- 6 slot Minimum facilities, not normally manned platform (Topsides weight 1,456 tonnes) in 52m water
- 3 platform wells and 1 subsea at Tolmount plus 1 further subsea well for Tolmount East (Mayar) assumed only in the 3C case
- Subsea well tied back with 8" infield pipeline, 3" methanol line and control umbilical
- Vertical/low angle deviated wells completed in both major reservoir sands
- 5 ½" completions with sand control
- 49 km, 18" pipeline + 3" methanol line to an onshore terminal
- Plant arrival pressure of 85 bar from 2019, with compression to 35 bar to maintain the plateau rate, reducing further to 10 bar
- Plateau of 200 MMscf/d for 2P/2C and 3P/3C cases, 100 MMscf/d for 1P/1C case.
- Combined field and facility availability of 93%, plus 3 weeks of planned shutdown annually.

As part of the Concept Select studies E.On are also reviewing an option to develop the field with a 12", 14km tieback to a separate third party facility.

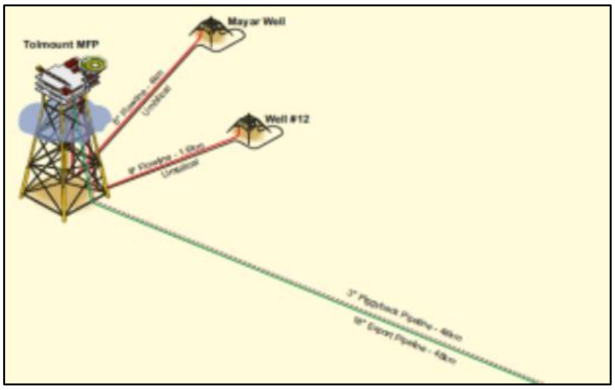


Figure 4-12 Tolmount Development Schematic

4.2.5. Reserves

RISC has classified the Tolmount volumes as Reserves rather than Contingent Resources, as an economic development has been found and the field is progressing towards development. SPE and PRMS guidelines allow for Tolmount to be classified as Reserves under these circumstances even though the field has not reached a Financial Investment Decision. The Joint Venture group is currently investigating an alternative development option, which may prove to be more economically attractive.

RISC's estimates of reserves are shown in Table 4-4. As the Proven (1P) volumes are not economic, there are no reserves at the 1P level for Tolmount. These volumes are therefore placed in the Contingent 1C category.

Table 4-4 RISC Estimate for Tolmount Field Reserves as at 1 January 2015

Tolmount Field Reserves	Net to E.On					
	1P (Proved)		2P (Proved + Probable)		3P (Proved + Probable + Possible)	
	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)
Reserves at 01 January 2015	0	0	169.4	1.549	416.7	3.698

4.2.6. Contingent Resources

Tolmount's 1C volumes would be recategorised as reserves if an approved, economic development scenario is achieved.

Table 4-5 RISC Estimate for Tolmount Field Contingent Resources as at 1 January 2015

Tolmount Field Contingent Resources	Net to E.On					
	1C		2C		3C	
	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)
Remaining Technical Recovery from 01 January 2015	72.6	0.666	0	0	0	0

4.3. Arran Gas-Condensate field, blocks 23/11, 23/16b, 23/16c (Licences P359, P1051, P1720)

Arran was formerly known as the Barbara-Phyllis field in the East Central Graben. Barbara is a Tertiary, Forties sand discovery at 8,500 – 9,600 ft TVDSS on the northern flank of a salt diapir, and Phyllis is a stratigraphic pinchout of Paleocene Forties reservoir draped across a southern low relief feature.

The Fallow licence status expired in 2015 and an Environmental Survey would be required to extend this licence. RISC has received no further update.

Dana Petroleum is the Operator (20.43207%) and E.On has 5.120% interest.

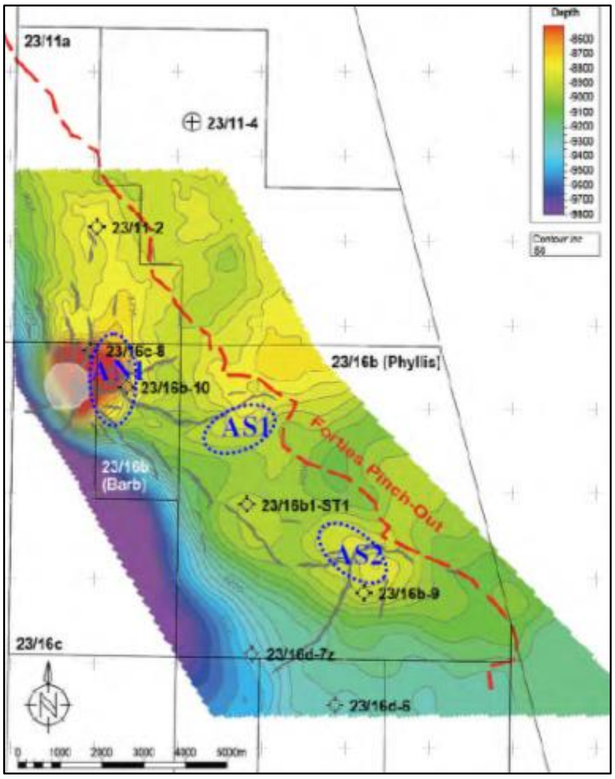


Figure 4-13 Arran Field Structure Map

RISC has not reviewed the volumes of the Contingent Resources. The table below represent the volume estimates of the Operator, based on simulations.

Table 4-6 Arran Field, Operator's Range of Simulated Cases

Contingent Resources (Gross)	P90	P50	P10
GIIP (Bcf)	221.3	347.0	543.2
Gas Production (Bscf)	99.5	155.8	223.2
Condensate Production (MMSTB)	2.7	4.2	6.4

Since April 2013 the Arran group have been working toward a revised development scheme for the field. Current studies focus on a three well subsea development tied back to the Shearwater Platform. Engineering studies are in progress to confirm the technical and commercial viability of this option and were expected to be complete mid-2015. RISC has received no further update.

The Arran group was working in parallel with other nearby undeveloped field owners to identify potential development synergies, which could better secure an economically viable development with earliest development sanction in late 2016.

4.3.1. Contingent Resources

These volumes could be expected to be recategorised as reserves if an approved, economic development scenario is achieved.

Table 4-7 Estimate for Arran Field Contingent Resources as at 1 January 2015

Arran Field Contingent Resources	Net to E.On					
	1C		2C		3C	
	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)	Gas (Bcf)	Condensate (MMBbl)
Remaining Technical Recovery from 01 January 2015	5.1	0.138	8.0	0.215	11.4	0.328

4.4. Austen Gas-Condensate Field, block 30/13b (Licence P1823)

The Austen field is located in block 30/13b (licence P079), east Central Graben, south of ConocoPhillips' J-Block area, and includes a gas condensate discovery and two oil discoveries with several unappraised compartments. The Operator is GDF Suez.

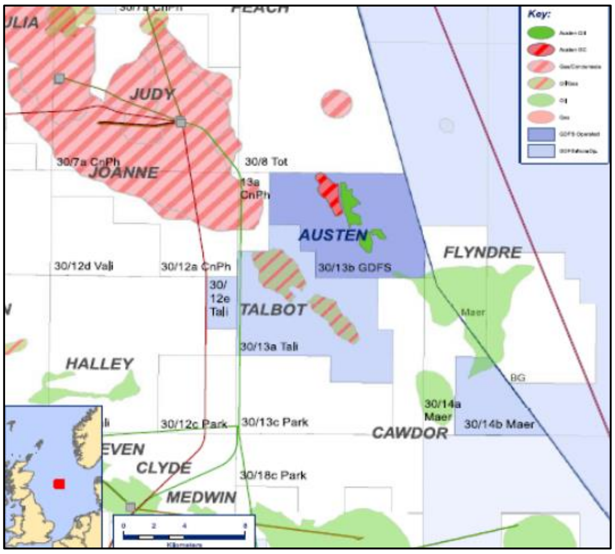


Figure 4-14 Austen Field Location Map

Austen was formerly known as the Josephine field and the initial licence term had an expiry of January 2015 with a second term ending in January 2019. RISC has received no further update. There is an outstanding contingent well into the Triassic which is contingent on seismic and the Operator has requested Oil and Gas Authority to waive this.

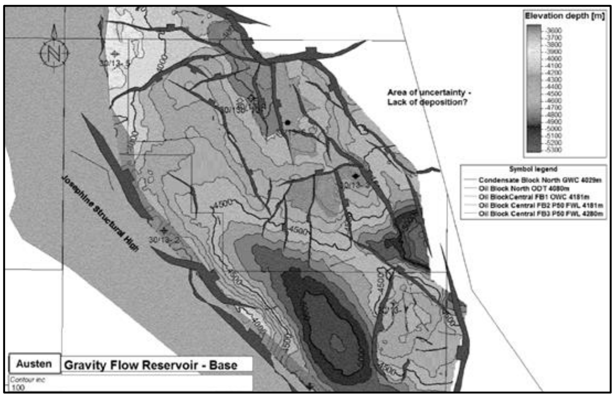


Figure 4-15 Austen Field Depth Map

The joint venture group was seeking project sanction in 2016, with first gas in 2019. Although the field qualifies for small fields tax allowance, Austen is not viable as a standalone development and requires a joint development with the nearby Talbot field (operated by Talisman) tied back over ConocoPhillips' J-Block. Talbot requires a Field Development Plan to be submitted by the end of 2015, with first oil projected in November 2017.

RISC has not reviewed the volumes of the Contingent Resources. The Operator holds a range of gross field recoverable volumes from approximately 46 Bcf to 87 Bcf based on modelling estimates from different models.

5. Processing Terminals and Pipelines

5.1. Caister Murdoch System (CMS)

The CMS facilities consist of a 26”, 180 km pipeline to Theddlethorpe Gas Terminal (TGT). Although CMS has capacity to take further gas, it is planned to be decommissioned in 2018. The Caister and Murdoch fields each own a 50% share in CMS. E.On holds a 20% interest from its 40% interest in the Caister field. All costs and revenues, including tariff income, are shared on the same equity basis. Caister and Murdoch do not pay a tariff to CMS for transportation of their own gas and under the respective Transportation and Processing Agreements (TPAs). CMS is required to pay a part of the tariff to the TGT owners (ConocoPhillips 50% and BP 50%) to have gas processed and redelivered at the entry point to the National Transmission System.

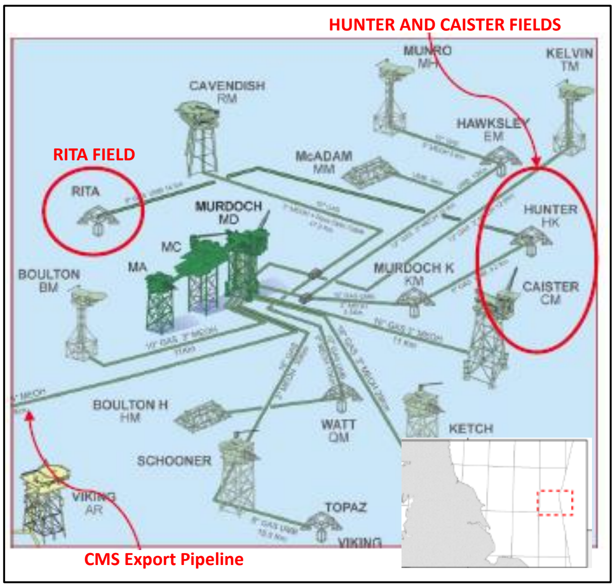


Figure 5-1 Location Map of CMS

All the TGT User fields should now be in Cost Share negotiated with TGT Operator ConocoPhillips based on Firm Capacity bookings. The exception is Hunter field, which has a zero Firm Capacity booked. The CMS owners ConocoPhillips and BP have elected to put User Fields into cost share because of low tariff receipts compared to the operating costs and also the imminent departure of ConocoPhillips as operator of TGT, which is expected within the next three to four years.

2015 Opex was £25.9 million & 2015 Capex was £3.0 million. Forecast Opex and Capex from the 2016 Budget are £33.8 million and 2.7 million. Beyond 2015, virtually all gas passing through the CMS pipeline will be from 3rd party fields operating on a cost share basis. RISC has therefore assumed no tariff revenue and that all operating costs are paid by third parties until the pipeline ceases operation in 2018, with decommissioning in 2019. As a result, there is no net income or costs until abandonment.

There are discussions related to life extensions beyond 2018, however these are considered upside scenarios only and have not been valued due to the uncertainty.

5.2. Esmond Transportation System (ETS)

The Trent and Tyne Fields and the Esmond Transmission System (ETS) pipeline (E.On 30%) are operated by Perenco UK as a single system known as the East Anglia Gas and Liquids Evacuation System ("EAGLES"). The system operates under the EAGLES Operating Agreement. Under the EAGLES Operating Agreement, all ETS operating costs are allocated to the Trent and Tyne Field owners' account. The ETS owners incur no operating costs or capital costs. ETS Pipeline abandonment costs are to be shared 50:50 with the Trent and Tyne Field owners.

ETS abandonment is likely to consist of flooding the pipeline, capping and leaving it in situ. E.On do not appear to carry abandonment costs (based on data provided by E.On in the data room) and RISC has assumed £20 million.

The Cygnus field, operated by GDF Suez, is a large gas development located in the southern North Sea with reserves of approximately 600 Bcf, first gas anticipated in 2016 and with a field life of 20 years. The field is contracted to use ETS and therefore ETS is unlikely to face abandonment in the near term. E.On advises net revenue from Cygnus is forecast to be £4.2m pa when the field is on plateau. This will decrease when the field drops off plateau, forecast to be around 2020.

Due to the age of the pipeline and the long forecast period, RISC's scenario is that after 10 years some pipeline remediation work is required of approx £10 million. According to the terms of the Transportation agreement, this will result in 50% tariff being payable for an eight year period.

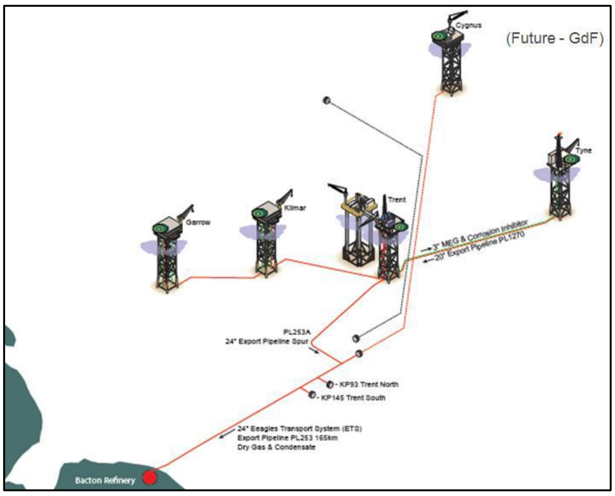


Figure 5-2 Location Map of ETS

5.3. Theddlethorpe Gas Terminal (TGT)

As operators of TGT, ConocoPhillips have established a new agreement with Shippers (terminal users) to share £153 million of costs under a new agreement for the Freon replacement project at Theddlethorpe Gas Terminal (TGT), which is required to stop usage of chlorofluorocarbons. The proposed new agreement affects the CMS fields in which E.On have an interest (Caister, Rita, Hunter).

There are provisions under the existing Transport and Processing Agreements to allow TGT owners ConocoPhillips and BP to recover costs. These fall into three categories:

1. Cost share
2. Modification cost
3. Tariff renegotiation

TGT shippers pay a share of TGT Freon Project costs in accordance with this supplemental agreement. This is equivalent to an increase in operating costs for the CMS fields.

The original 2013 installed total cost estimate has doubled to approximately £219 million gross. The new agreement applied from 1st October 2014 and runs for the remainder of the TGT Freon Project. The Freon replacement project is due to complete in 2016.

6. Exploration Potential

6.1. Overview

E.On have identified a significant portfolio of discoveries and exploration opportunities in the form of prospects and leads from three distinctly different geological regions of the UK North Sea and comprising a wide range of subsurface risks. The portfolio comprises discoveries and mature exploration opportunities, both near to existing producing fields and infrastructure and within exploration licences away from their core areas.

RISC has reviewed the Operator's interpretation for a selection of key discovery and prospect assessments (Table 6-1) and provides the following summary comments. The discoveries and prospects discussed here are deemed to be either sufficiently advanced in their technical assessment and/or low risk and/or with significant estimated recoverable resources. In addition, RISC has carried out an independent assessment of Geological Chance of Success (GCoS) for each but has not been supplied with enough data to independently derive volume estimates. The Operator's Chance of Success (where available) and best estimate Prospective Resource are reported in this section of the report.

Table 6-1 Discoveries and Key Prospects

Region	Prospect/Discovery Name	Field Area	Operator's Best Estimate Prospective Resource (MMboe)
Central North Sea	Corfe Discovery	Elgin & Franklin	17
Central North Sea	Ekland Prospect	Huntington	67
Southern North Sea	Cobra Discovery	Babbage	33
Southern North Sea	Hawking Discovery	Babbage	14.3
Southern North Sea	Ada Prospect	Babbage	3
Southern North Sea	Newton Prospect	Babbage	32
Southern North Sea	Python Prospect	Babbage	10.7
Southern North Sea	Artemis Discovery	Tolmount	27
Southern North Sea	Artemis East Prospect	Tolmount	7.9
Southern North Sea	Mongour Discovery	Tolmount	14.1
Southern North Sea	Malin prospect	Tolmount	27

6.2. Elgin/Franklin Field Area

E.On are non-operator partners in the Elgin-Franklin Field licences as well as the P1262 exploration licence to the west. The 2015 Corfe Discovery is discussed in section 6.2.1, with additional prospectivity summarised in Table 6-12. Elgin, Franklin and West Franklin are high pressure-high temperature (HPHT) gas-condensate fields in the Central North Sea operated by Total.

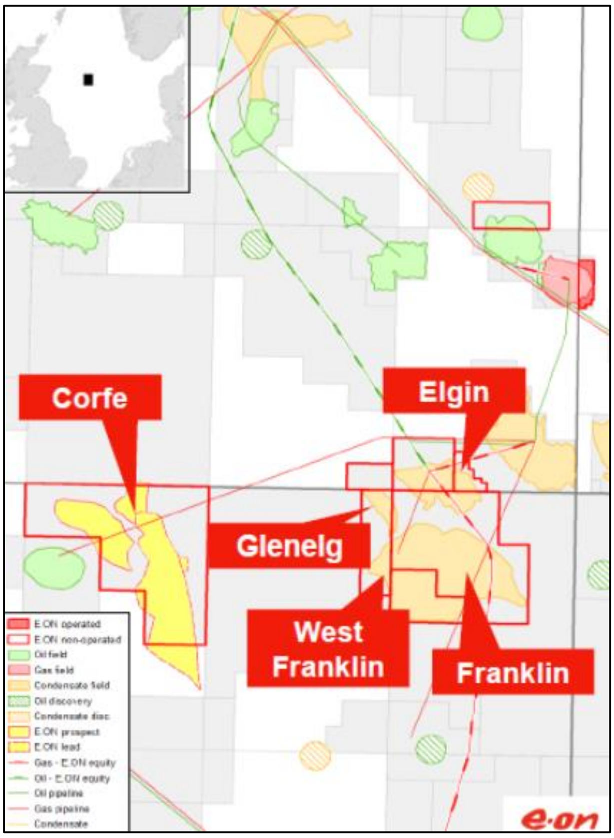


Figure 6-1 Location Map for Elgin and Franklin Fields and near field prospectivity

6.2.1. Corfe Discovery, block 29/3b (P1626 Licence)

The High Pressure, High Temperature (HPHT) Corfe Prospect in Block 29/3b was drilled in Q1-Q2 2015 with the primary target being the Joanne and Judy sands of the Triassic Skagerrak Formation and a secondary target of the Jurassic Fulmar Formation. The main Triassic objective was found to be water wet and the secondary Fulmar objective found to be gas bearing (gas shows, logs and sample). Volumes were initially reported to be in the range of 8 – 17 – 32 MMboe gross recoverable. HP and HT conditions were reported as 14,873 psia and 168°C respectively.

The Fulmar Corfe discovery is defined as a tilted fault block with 3 way dip closure and fault closure to the northeast. The lateral fault seal is against the Kimmeridge Clay Formation. The Fulmar appears to be thin in this area (17m gross thickness in the well) and is interpreted as a wedge that thins towards the fault, causing problems with imaging as the Fulmar is below tuning thickness across most of the defined area of the discovery. This is highlighted by an absence of amplitude anomaly over the discovery coincident with the area within tuning. Reservoir thickness appears to be one of the main uncertainties for the discovery. This has been addressed by sensitivity modelling where different wedge models and Fulmar thicknesses were used to generate a set of post-well volumes for the Corfe Discovery.

Prospective resources are reported to range from P90 - 3.58 MMboe to P10 - 56 MMboe as dependant on the sensitivity model as outlined in the table below.

Table 6-2 E.On's Post Corfe well analysis – sensitivity on gross prospective resources (MMboe)

Gross Prospective Resources (MMboe)	Thin Fulmar Modelled Pinch-out	Thick Fulmar Modelled Pinch-out	Fulmar 30m Constant Thickness	Thin Fulmar Faulted Model (thicker crest)	Thick Fulmar Faulted model (thicker crest)
P90	3.58	9.3	8.15	8.49	13.8
P50	7.72	21.3	15.6	17.3	28.1
P10	15.7	43.3	29.1	33.3	56

The same petrophysical parameters were used for all cases above with porosity ranging from 15-17.3-20% (P90-P50-P10) and Net to Gross ranging from 40-55-70% (P90-P50-P10) (the saturation range was not reported). The contacts used were 4,955m – MIN and 5,150m – MAX which are approximately based on Gas Down To (GDT) and the deepest structural contour with amplitude anomaly conformance respectively.

The latest TCM meetings available in the data room are from June 2014, pre-drill. It is assumed that the post well evaluation work on the discovery is ongoing. In the absence of definitive volumes, the recoverable resource range of 8-17-32 (gross) MMboe initially reported post drilling is deemed appropriate. This range covers the majority of outcomes characterised by the sensitivity analysis reported by the Operator in August (Table 6-2).

6.3. Huntington Area

E.On participate as operators and non-operators in two exploration licences south of the Huntington Field. The main prospect, Ekland, targets the Fulmar Formation. The Skagerrak Formation provides a secondary target.

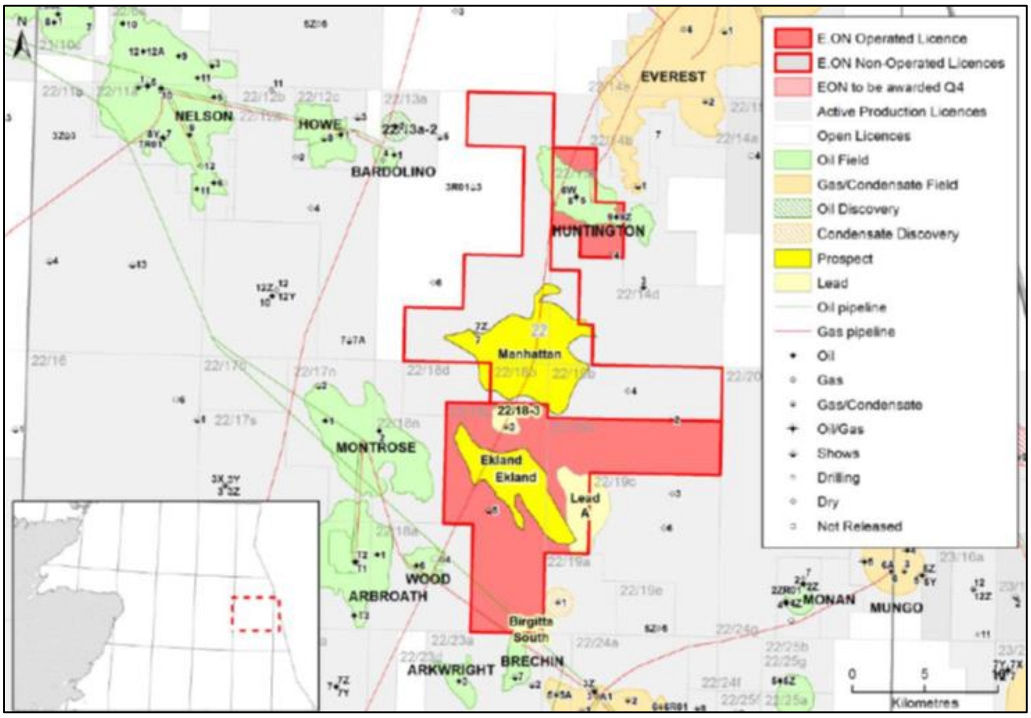


Figure 6-2 Location Map for Huntington Field and near field prospectivity

6.3.1. Ekland Prospect (P2184 Licence)

The Ekland Prospect is located in Blocks 22/18c and 22/19d which were awarded to E.On as operator in December 2014 as part of the 28th offshore licencing round. The prospect is located approximately 20km south of the Huntington Field on a fault terrace to the east of the Forties/Montrose high. The Operator identifies the key risk as reservoir presence.

Operator's Ekland Best Estimate[10] Prospective Resource (Gross Unrisked): 67 MMboe. Operator's Ekland GCoS: 30%.

[10] E.On E&P North Sea Information Memorandum Volume 2 June 2015

6.3.1.1. *RISC estimation of Geological Chance of Success for Ekland*

Table 6-3 RISC GCoS for the Ekland Prospect

<table>
<tr><th>Ekland Prospect</th><th>GCoS (%)</th><th></th><th>GCoS (%)</th><th>Key Risks</th></tr>
<tr><td>Trap</td><td>90</td><td rowspan="2">Containment</td><td rowspan="2">54</td><td rowspan="2">Main structural trap is well defined fault bound and dip closed fault terrace. The Fulmar play requires stratigraphic trapping with a wedge of Fulmar interpreted within the main structure. Trap is well defined, despite requiring stratigraphic closure, but this risk is captured in reservoir presence. Top seal is provided by Cretaceous chalk and marls. Base seal from underlying Triassic is required to give separate Jurassic accumulation, otherwise a fault seal is required for a joint Jurassic/Triassic accumulation.</td></tr>
<tr><td>Seal</td><td>60</td></tr>
<tr><td>Reservoir presence</td><td>50</td><td rowspan="2">Reservoir</td><td rowspan="2">50</td><td rowspan="2">Reservoir presence is inferred between the BCU and the top Triassic seismic reflectors. The two closest wells, already drilled on the main structure, did not contain Fulmar Formation. However, well 22/18-6 (Wood Field) approx. 10km to the southwest did contain oil bearing Fulmar Fm. Immediately beneath the BCU proving the concept can work in this area. If reservoir is present it is likely to be of good quality, analogous to the Wood Field.</td></tr>
<tr><td>Reservoir effectiveness</td><td>100</td></tr>
<tr><td>Source</td><td>100</td><td rowspan="2">Source</td><td rowspan="2">80</td><td rowspan="2">Proven hydrocarbon generation from the Kimmeridge Clay Formation within the East Central Graben. Migration is seen as low risk given the Wood Field to the west and the Birgitta discovery to the south. Gas condensate is the expected HC phase.</td></tr>
<tr><td>Timing and Migration</td><td>80</td></tr>
<tr><td>RISC GCoS (%)</td><td>22</td><td></td><td>22</td><td></td></tr>
<tr><td>Description of key risks</td><td colspan="4">The key risk identified on the Ekland prospect is reservoir presence. The Fulmar Fm is inferred on seismic and Fulmar is absent in the two closest wells to the prospect. Seal is also considered a risk, with the requirement for a base seal to separate Jurassic sand from underlying Triassic sands and if both are connected the requirement for a fault seal to the east.</td></tr>
</table>

6.4. Babbage Area

There are a number of Discoveries, Prospects and Leads in the immediate area around Babbage including Ada, Hawking, Newton, Cobra and Python discussed here. These are all discoveries in, or targeted at, the Lower Leman Sandstone reservoir, although in some cases there is either Carboniferous reservoir immediately underlying or Carboniferous potential.

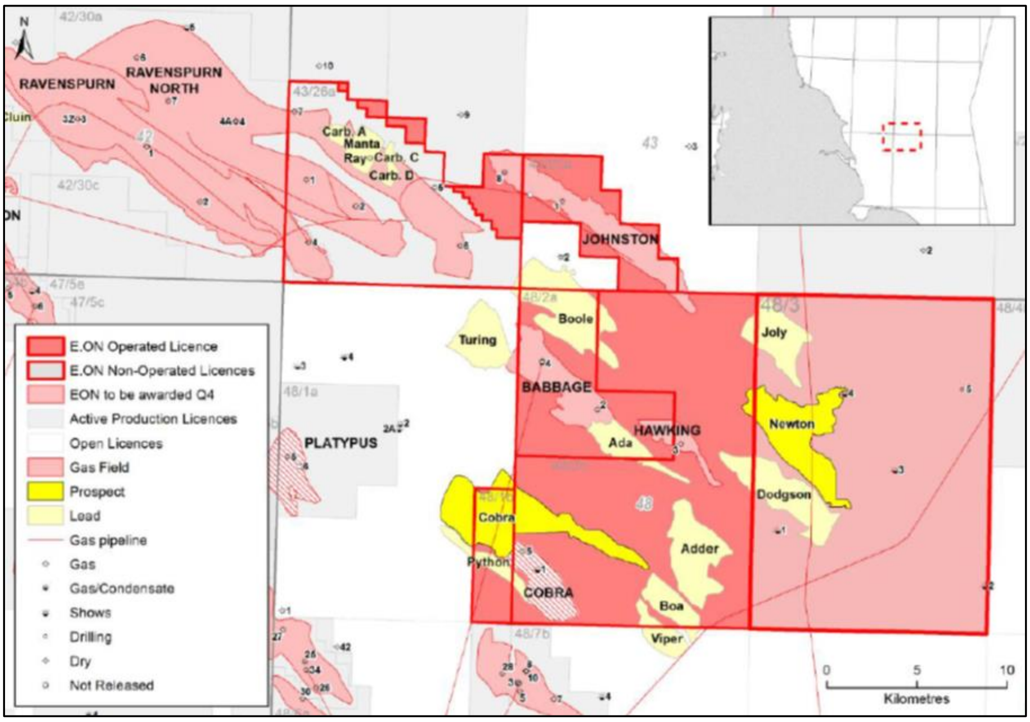


Figure 6-3 Location Map for Babbage Field and near field prospectivity

6.4.1. Ada Prospect, block 48/2

The 'Ada' prospect (formerly 'Babbage South') is an undeveloped area to the SE of Babbage, largely beneath the 'salt wall' which runs W-E across the structure. If successful it will likely require subsea tie-backs to the platform. No decision yet to drill: scheduled 'Drill/No drill' was June 2015, but does not appear to have been made (disagreement within JV).

Seismic attribute work by the Operator suggests that reservoir quality may be better than seen in Babbage and may not need to be fracced, but it is recognised that further risk reduction is unlikely and the well therefore needs to be drilled to properly assess the prospect.

The Operator carries a mid-case GIIP of 127 bcf with prospective resources of 18 bcf (14% RF).

Operator's Ada Best Estimate[11] Prospective Resource (Gross Unrisked): 3 MMboe.

[11] E.On E&P North Sea Information Memorandum Volume 2 June 2015

Table 6-4 RISC GCoS for the Ada Prospect

Ada Prospect	GCoS (%)		GCoS	Key Risks
Trap	90	Containment	81	The trapping mechanism is unclear due to the 'salt wall': may be a structural dip closure or fault combination. The lateral Seal may be a combination of fault seal and overlying shales of the Silverpit, or Zechstein evaporites/carbonates.
Seal	90			
Reservoir presence	90	Reservoir	81	The reservoir is assumed to be the same as the adjacent Babbage field. Reservoir effectiveness therefore is likely to be similar to Babbage wells, i.e. aeolian, fluvial and some associated lacustrine (sabkha) facies.
Reservoir effectiveness	90			
Source	100	Source	100	Hydrocarbon generation is proven from the underlying Carboniferous coals, with negligible risk to Timing and Migration due to proximity of Babbage. Gas is the expected HC phase.
Timing and Migration	100			
RISC GCoS (%)	66		66	
Description of key risks	This is a near-field step-out and, but for the presence of the 'salt wall' would likely be considered a development well rather than appraisal.			

6.4.2. Hawking Discovery, Block 48/2b

Hawking is a one-well gas discovery (48/2b-3) characterised as a high relief tilted fault block adjacent to the southern extent of the Babbage Field. The fluid contact is interpreted by the Operator as a GDT at 3280m that could be potentially deeper. The Operator mapped the structure using the 2011 GXT reprocessed seismic data which has revealed a larger structure than originally mapped suggesting, in a high case that the spill point may be aligned with Babbage FWL at 3370m. Potential upside exists if there is a sealing De Keyser fault between Babbage and Hawking.

This structure is high relief with dip closure to the south and west. Structural spill point is mapped close to the Babbage FWL and may therefore be in communication. Trapping is by fault seal and dip closure, with the lateral Seal formed in part by fault seal and part by overlying shales and silts of the Silverpit Formation. Situated along the margin of the Leman Fairway, the Leman Sandstone reservoir is present in the discovery well and surrounding fields. Reservoir facies are likely to be similar to offset wells in the area, i.e. aeolian, fluvial and associated lacustrine (sabkha) facies. Reservoir effectiveness is expected to be poor, as in Babbage, with low permeability (due to illitisation) observed in the discovery well. Interception of natural fracture networks or hydraulic fracturing will likely be required for successful development wells.

Operator's Hawking Best Estimate[12] Prospective Resource (Gross Unrisked): 14.3 MMboe. Operator's Hawking GCoS: 81%.

[12] E.On E&P North Sea Information Memorandum Volume 2 June 2015

6.4.3. Newton Prospect 48/3b

Lies in a tilted fault block, similar to the producing Johnston Field, approximately 10 km east of the Babbage Field. The reservoir appears not to have been as deeply buried as Babbage. The trap is defined as a large 3-way dip closure against a clearly defined fault to the southwest. Structural dip is considered critical in the NW direction to maintain gas migration through the Leman from the south. The Operator considers dip closure rather than up-dip fault closure to be the key control on gas emplacement and protection from illitisation.

Operator's Newton Best Estimate[13] Prospective Resource (Gross Unrisked): 32 MMboe. Operator's Newton GCoS: 32%.

6.4.3.1. RISC estimation of Geological Chance of Success for Newton

Table 6-5 RISC GCoS for the Newton Prospect

Newton Prospect	GCoS (%)		GCoS (%)	Key Risks
Trap	70	Containment	49	Formed of a tilted fault block, dip closed to the NW. Trapping by fault seal and dip closure, with lateral Seal formed in part by fault seal and part by overlying shales and silts of the Silverpit Fm.
Seal	70			
Reservoir presence	90	Reservoir	54	Situated along the margin of the Leman Fairway, 'tight' reservoir is present in the 48/3-4 well, down dip and in surrounding fields. Reservoir effectiveness is likely similar to nearby wells, i.e. aeolian, fluvial and some associated lacustrine (sabkha) facies, and would require wells to intercept natural fracture networks and/or multi-fracced, like Babbage.
Reservoir effectiveness	60			
Source	100	Source	70	Proven hydrocarbon generation from the underlying Carboniferous coals. Migration into the Leman is well established (residual gas in the 48/3-4 well). Gas is the expected HC phase.
Timing and Migration	70			
RISC GCoS (%)	19		19	
Description of key risks	Key risks are Containment and Reservoir effectiveness. Size of the structure is a risk despite the extensive seismic processing work. Reservoir effectiveness appears to rely on early gas migration into the structure to keep it 'illite-free', otherwise fracc'ing would be required in a success case. Despite Operator comment that 'illite-free' unpredictable, E.On has chosen to use un-illitised field analogues (28th Round Application, App.B).			

[13] E.On E&P North Sea Information Memorandum Volume 2 June 2015

6.4.4. Cobra Discovery and Python Prospect 48/1b, 48/2b (Licence P.2212) and 48/1c (P2301)

Cobra is a two well discovery, with a tight gas reservoir. The GDT implies a larger structure than the original mapping could be shown to close. Re-mapping using 2011 GXT seismic data resulted in an interpretation by the Operator of a suspected De Keyser fault sealing at the NW end of Babbage and continuing on past the northwestern up-dip part of the greater Cobra structure. Fault seal analysis predicts a sealing capacity to within seismic resolution (15m) of the GDT. Therefore the structure is broken into several segments, with Python considered as a separate prospect.

The Cobra discovery trap relies on fault seal and dip closure with the lateral seal formed in part by fault seal and part by the overlying shales and silts of the Silverpit Formation. The Leman Formation sandstone reservoir is present in the discovery wells and in surrounding fields with the reservoir characterised as aeolian and fluvial facies with some associated lacustrine (sabkha) facies. Migration into the Leman is proven in one segment of the discovery by the discovery wells. However, the timing of fault seal may be important for the charging of further fault bound segments, including the Python Prospect, if pathways rely on 'fill-and-spill' model.

Operator's Cobra Best Estimate[14] Prospective Resource (Gross Unrisked): 33 MMboe. Operator's Cobra GCoS: 80%.

Operator's Python Best Estimate[15] Prospective Resource (Gross Unrisked): 10.6 MMboe. Operator's Python GCoS: 80%.

[14] E.On E&P North Sea Information Memorandum Volume 2 June 2015

[15] E.On E&P North Sea Information Memorandum Volume 2 June 2015

6.4.4.1. *RISC estimation of Geological Chance of Success for Python*

Table 6-6 RISC GCoS for the Python Prospect

Python Prospect	GCoS (%)		GCoS (%)	Key Risks
Trap	70	Containment	49	Dip closure against seismically defined fault/s. Trapping relies on fault seal and dip closure, and lateral Seal is formed in part by fault seal and part by the overlying shales and silts of the Silverpit Fm. (or Zechstein evaporites/ carbonates).
Seal	70			
Reservoir presence	90	Reservoir	81	Situated along the margin of the Leman Fairway, the reservoir is present in offset wells and nearby fields. Reservoir effectiveness is likely similar to surrounding area wells, i.e. aeolian, fluvial and some associated lacustrine (sabkha) facies.
Reservoir effectiveness	90			
Source	100	Source	63	Proven hydrocarbon generation from the underlying Carboniferous coals. Migration dependent on timing of fault seal. Gas is the expected HC phase.
Timing and Migration	70			
RISC GCoS (%)	28		28	
Description of key risks	Although proved in Cobra, the main risks to this Prospect within the play fairway remain on Trap and Seal, and Migration.			

6.5. Tolmount Area

A number of Discoveries, Prospects and Leads can be found in the immediate area around the Tolmount Field including Artemis, Artemis East, Mongour and Malin discussed here. These are all discoveries in, or targeted at, the Lower Leman Sandstone reservoir.

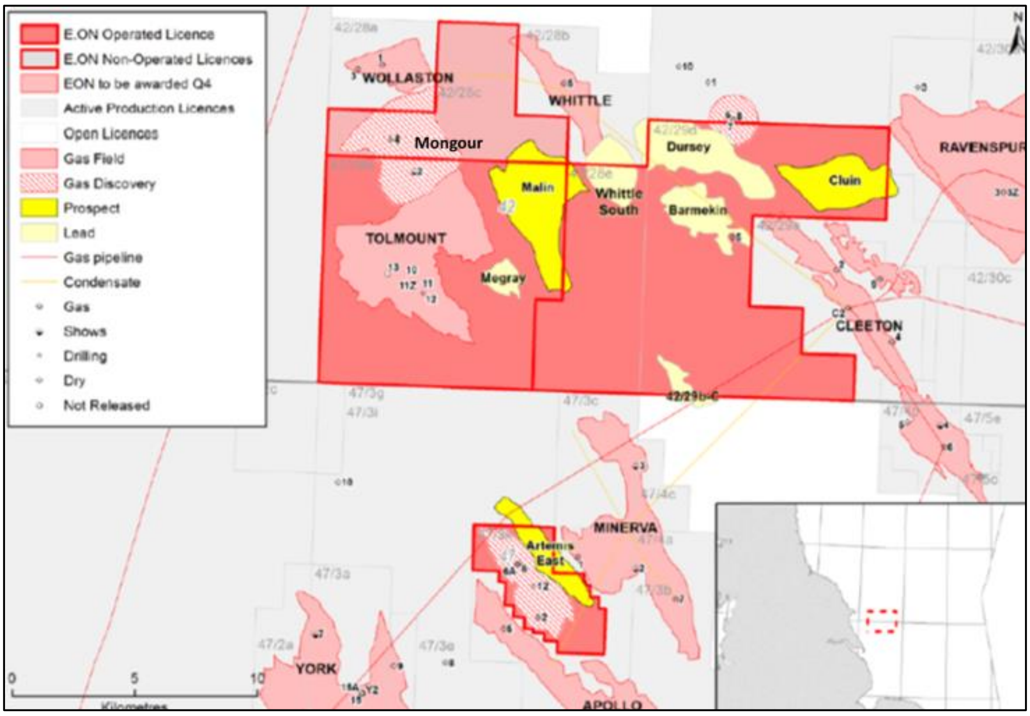


Figure 6-4 Location Map for Tolmount Field and near field prospectivity

6.5.1. Artemis Discovery and Artemis East Prospect (Licence P2136)

Artemis is a tight gas discovery, located in Block 47/3k between the Apollo and Minerva Fields, approximately 10km south of the Tolmount Field. The discovery well 47/3-2, drilled in 1974 encountered gas bearing Leman Sandstone reservoir which was appraised by well 47/3b-6A. Both wells were tested with low flow rates due to tight reservoir being encountered. In 2002 BG drilled a horizontal well 47/3b-12 in an attempt to develop the Field in a similar fashion to the Minerva and Apollo Fields. The well was ultimately a failure, intersecting poorer reservoir quality sands than expected with the well returning sub commercial flow rates.

The trap is well defined and is described as a fault-bounded anticline trending northwest – southeast with faults to the northeast and southwest and dip closure to the northwest and southeast. The FWL was not penetrated in either of the two vertical wells and is interpreted to be 10850 ft TVDSS from regional pressure data. The Artemis East prospect to the northeast has the same structural configuration as the Artemis discovery.

The reservoir is the Leman Sandstone comprising a complex interfingering mix of Aeolian, sabkha and fluvial facies with the fluvial facies dominant. Reservoir quality is moderate in terms of porosity and poor in terms of permeability. Matrix permeability is occluded by secondary illite precipitation, which is at odds to the adjacent Apollo and Minerva Fields, leading to the interpretation that the Artemis structure may have been more deeply buried before inversion during the Cretaceous. It is thought likely that the reservoir within the Artemis East Prospect would be similar. The Operator plans to develop the reservoir via long horizontal / sub-horizontal fracced wells. Consequently, the high cost of developing Artemis East (if drilled and successful) with its relatively small volume is only thought economically viable if the Artemis Discovery is developed first.

Operator's Artemis Best Estimate[16] Prospective Resource (Gross Unrisked): 27 MMboe. Operator's Artemis GCoS: 80%.

Operator's Artemis East Best Estimate[17] Prospective Resource (Gross Unrisked): 7.9 MMboe. Operator's Artemis East GCoS: 80%.

6.5.1.1. RISC estimation of Geological Chance of Success for Artemis East Prospect

Table 6-7 RISC GCoS for the Artemis East Prospect

Artemis East Prospect	GCoS (%)		GCoS (%)	Key Risks
Trap	90	Containment	72	Well defined northwest – southeast trending fault bound anticline. Fault closure to the northeast and southwest with dip closure to the northwest and southeast. Top seal provided by the overlying Silverpit claystones and Zechstein evaporites. Lateral fault seal is juxtaposition of Leman sands against Silverpit claystones. In the high case Artemis East may be connected to the Artemis Discovery.
Seal	80			
Reservoir presence	100	Reservoir	90	Situated along the margin of the Leman Fairway, the reservoir is present in the surrounding discoveries and fields. However, 'tight' reservoir is present in the wells on Artemis and similar reservoir properties can be expected at Artemis East. Gas was successfully flowed to surface in the wells drilled on Artemis, but at sub-economic rates. Successful development is likely to require long horizontal / sub-horizontal fracced wells.
Reservoir effectiveness	90			
Source	100	Source	100	Proven hydrocarbon generation from the underlying Carboniferous coals. Migration into the Leman is well established. Gas is the expected HC phase.
Timing and Migration	100			
RISC GCoS (%)	65		65	
Description of key risks	Key risks is reservoir effectiveness. As in the Artemis Discovery successful development of a potential discovery at Artemis East is likely to involve fraccing.			

6.5.2. Mongour Discovery (Licence P1330)

The Mongour Discovery is located in Block 42/28C, between the Tolmount Field and the Wollaston Field. The discovery well 42/28-2 was drilled in 1973 discovered gas-bearing sands within the Leman Sandstone interval with a GDT of 9800 ft TVDSS. Another well, 42/28-4 drilled approximately 1.5km to the northwest, penetrated a thicker section of Leman Sandstones but was found to be dry. This well is mapped within a topographic low whilst the 42/28-2 well is mapped as a small 4-way dip closure.

RISC recognises value in a future development only if the discovery forms part of a larger structure, extending to the north and south, bound by faults. The Operator proposes this as a high case scenario, for which RISC provides a GCoS below.

[16] E.On E&P North Sea Information Memorandum Volume 2 June 2015

[17] E.On E&P North Sea Information Memorandum Volume 2 June 2015

Operator's Mongour Best Estimate[18] Resource (Gross Unrisked): 14.1 MMboe.

Operator's Mongour High Case Estimate[19] Resource (Gross Unrisked): 33.4 MMboe.

6.5.2.1. RISC estimation of Geological Chance of Success for Mongour Discovery (High Case)

Table 6-8 RISC GCoS for the Mongour Discovery (high case)

Mongour Discovery High Case	GCoS (%)		GCoS (%)	Key Risks
Trap	80	Containment	32	Using the GDT in the 42/28-2 well gives two separate small closures within the prospect area. The high case trap is reliant on fault seals to the north separating the prospect from the Wollaston Field and to the south. The fault seal to the south is likely to be effective as suggested by a deeper GWC in the Tolmount Field. Top seal is provided by the overlying shales and silts of the Silverpit Fm. Some mapping and depth conversion uncertainty exists relating to the faulted region in the centre of the larger closure and the topographic low associated with the dry 42/28-4 well.
Seal	40			
Reservoir presence	100	Reservoir	100	The Leman Sandstone is proven in the two wells drilled within the main structure and reservoir is shown to be effective from core data in these wells.
Reservoir effectiveness	100			
Source	100	Source	100	Proven hydrocarbon generation from the underlying Carboniferous coals. Migration into the Leman is established by the discovery wells and surrounding discovered fields. Gas is the expected HC phase.
Timing and Migration	100			
RISC GCoS (%)	32		32	
Description of key risks	The key risk is identified as containment. A gas discovery in the 42/28-2 well proves the low case volume, however in the high case sealing faults are required to the north and south with some uncertainty on the exact size of the container.			

6.5.3. Malin Prospect (P1330 Licence)

The Malin Prospect is located 2km east of the Tolmount Field in Block 42/28d. The trap is described as a tilted fault block with fault closure to the west and north, but the closure to the south and east is unclear due to poor imaging as a result of a salt wall. The reservoir target is the Permian Leman Sandstones proven in the adjacent fields and discoveries. Source and charge are also well proven in this area.

Operator's Malin Best Estimate[20] Prospective Resource (Gross Unrisked): 27 MMboe. Operator's Malin GCoS: 27%.

[18] E.On E&P North Sea Information Memorandum Volume 2 June 2015
[19] E.On E&P North Sea Information Memorandum Volume 2 June 2015
[20] E.On E&P North Sea Information Memorandum Volume 2 June 2015

6.5.3.1. *RISC estimation of Geological Chance of Success for Malin Prospect*

Table 6-9 RISC GCoS for the Malin Prospect

Malin Prospect	GCoS (%)		GCoS (%)	Key Risks
Trap	30	Containment	24	The trap is poorly defined on the southern and western margins due to imaging problems associated with a salt wall. Further work to improve the seismic image quality could de-risk the prospect. Fault closures to the north and west appear to offset Leman against the overlying shales of the Silverpit Fm. which also provides the top seal for the prospect.
Seal	80			
Reservoir presence	90	Reservoir	90	The presence and reservoir quality of the Leman Sandstone is proven in the adjacent Tolmount and Whittle Fields and Mongour Discovery.
Reservoir effectiveness	100			
Source	100	Source	100	Proven hydrocarbon generation from the underlying Carboniferous coals. Migration into the Leman is established by the discovery wells and surrounding discovered fields. Gas is the expected HC phase.
Timing and Migration	100			
RISC GCoS (%)	22		22	
Description of key risks	The key risk is trap definition. A viable trap cannot be defined on the current dataset.			

6.5.4. Prospective Resources Summary

RISC has not valued the Exploration potential. There are six prospects, which have reached a mature level in order to be relatively confident of a calibrated Geological Chance of Success. However, six is not a statistically significant population, and therefore a calculation of Estimated Monetary Value (EMV) of the portfolio of exploration prospects will have wide error bars and will not fully reflect the range of potential outcomes.

Table 6-10 Operator's gross Prospective resources of key discoveries

Contingent Resources	
Discovery	**Operator Best Estimate Gross Prospective Resource (MMboe)**
Hawking	14.3
Cobra	33
Artemis	27
Mongour	14.1
Corfe	17
TOTAL	**105.4**

Table 6-11 Operator's gross recoverable resources with RISC's GCoS and risked recoverable resources

Prospective Resources			
Prospect	**Operator Best Estimate Gross Recoverable Resource (MMboe)**	**RISC GCoS**	**Risked Gross Resource (MMboe)**
Ada	3	66	2.0
Newton	32	19	6.1
Python	10.7	28	3.0
Artemis East	7.9	65	5.1
Malin	27	22	5.9
Ekland	67	22	14.7
TOTALS	**147.5**	-	**36.8**

6.6. Additional Prospectivity

6.6.1. Central and Southern North Sea Leads

A number of leads that have been identified by E.On are summarised below. These volumes are considered indicative and have not been evaluated by RISC. RISC do not consider these leads well enough calibrated to be used for EMV calculation.

Table 6-12 Summary of additional Central and Southern North Sea Prospectivity identified by E.On

Lead Name (HC Phase)	Lead Name	Licence	Operator	Partners	Blocks	Licence Award Date	Major Licence Commitments	Operator Best Estimate Gross Recoverable Resource (MMboe)	Operator GCoS
Cluin (Gas)	Cluin	P2105	E.On (50%)	Dana (50%)	42/28e, 42/29d	20.12.2013	Drill or Drop decision by 20.12.2017	17	30%
Newton Deep (Gas)	Newton Deep	P2290	E.On (50%)	Bayerngas (50%)	48/3	01.09.2015	1 Firm Well on the licence	6.8	35%
Dodgson (Gas)	Dodgson							7	48%
Joly (Gas)	Joly							7.2	36%
Adder (Gas)	Adder	P2212	E.On (50%)	Bayerngas (50%)	48/2b	01.12.2014	1 Firm Well on the licence	6.3	48%
Viper (Gas)	Viper							3.2	40%
Boa (Gas)	Boa							4	40
North Rita (Gas)	North Rita	P771, P766	E.On (74%)	GDF Suez (26%)	44/22c, 44/21b	14.06.1991	Licence due expiry 14.06.2025	1.3	n/a
Deep Hunter (Gas)	Deep Hunter	P452	E.On (79%)	GDF Suez (21%)	44/23e	11.05.1983	Licence due expiry 10.05.2019	4.17	n/a
Lyra (Gas)	Lyra	P2271	E.On (35%)	Bayerngas (35%), Dyas (30%)	43/1, 43/2, 43/6	01.09.2015	Drill or Drop 01.09.2019	51	17%
West Franklin Terrace (Gas + Condensate)	West Franklin Terrace	P188, P362, P666, P2068	Total (46.17%)	ENI (21.87%), BG (14.11%), E.On (5.2%), ExxonMobil (4.38%), Chevron (3.9%), Dyas (2.19%), Summit Petroleum (2.19%)	22/30b, 22/30c, 29/5b, 29/5c, 29/4d	P188 – 16.03.1972 P362 – 17.12.1980 P666 – 20.07.1989 P2068 – 01.01.2013	P188 – Due expiry 15.03.2018 P362 – Due expiry 16.12.2016 P666 – Due expiry 19.07.2025 P2068 – Initial term end date 01.01.2019	50**	48%
Elgin West (Gas + Condensate)	Elgin West							37**	40%
TR7 (Oil)	TR7	P2161	E.On (40%)	Edison (30%), Bayerngas (30%)	15/27b	01.12.2014	Drill or Drop decision by 01.01.2018	88	18%

Lead Name (HC Phase)	Lead Name	Licence	Operator	Partners	Blocks	Licence Award Date	Major Licence Commitments	Operator Best Estimate Gross Recoverable Resource (MMboe)	Operator GCoS
Tumbleweed (Oil)	Tumbleweed	P2178	E.On (40%)	Edison (30%), Bayerngas (30%)	21/17b, 21/18b	01.12.2014	Drill or Drop decision by 01.01.2018	22	46%
Chimaera (Gas + Condensate)	Chimaera	P2303	E.On (40%)	Edison (30%), Bayerngas (30%)	15/24a	Awaiting official confirmation	Drill or Drop 4 years after award	36	29%

**Numbers represent in-place estimates.

6.6.2. West of Shetlands

E.On hold three exploration licences in the West of Shetlands as Operator. E.On were recently participant in three other licences as non-operator but these are due to be relinquished in Q1 2016. The table below lists the licences with Blocks, identified leads, Operator best estimate recoverable volume and key licence information. RISC do not consider these leads well enough calibrated to be used for EMV calculation.

Table 6-13 Summary of West of Shetland Prospectivity identified by E.On

Lead Name (HC Phase)	Lead Name	Licence	Operator	Partners	Blocks	Licence Award	Outstanding Licence Commitments	Operator Best Estimate Gross Recoverable Resource (MMboe)	Operator GCoS
Colza (Gas)	Colza	P2023	E.On (100%)	-	208/14, 208/15	01.01.2013	Drill or Drop decision by 01.01.2017	68	25%
Mardyke (Gas)	Mardyke	P2073	E.On (100%)	-	209/4, 209/5	01.01.2013	Drill or Drop decision by 01.01.2017	100	17%
Gunnison (Oil or Gas)	Gunnison	P2012	E.On (100%)	-	219/13, 219/14, 219/15	01.01.2013	Drill or Drop decision by 01.01.2017	34	15%

7. Economics

7.1. Fiscal Terms

Upstream oil and gas activities in fields on the UK Continental Shelf (UKCS) are subject to several layers of taxation which are summarized below:

Fiscal Term	Description
License Term	Block specific
Royalties	No state royalties apply
Petroleum Revenue Tax (PRT)	PRT is a tax on "supra-normal" profits from individual fields with development consents prior to 16 March 2003. PRT is ring-fenced at a field level and deductible against RFCT and SCT. The only Southern North Sea E.On field subject to PRT is Ravenspurn North where PRT is applied at a rate of 50% in 2015 and 35% thereafter. PRT assessable profit is calculated as follows: + Sales Revenue + Tariff revenue - Opex, exploration & appraisal costs and capex (35% uplift on qualifying capex) - Abandonment losses - Field losses carried forward/back - Oil allowance Application of PRT is further subject to Payback and Safeguard limits under which PRT only applies after payback is achieved (defined as cumulative revenues exceeding cumulative costs), and Safeguard during which PRT is charged on 80% of adjusted profit less 15% of the ending balance of cumulative capex for the chargeable period. The Safeguard period is defined as 1.5 times the chargeable periods up to the achievement of Payback.
Ring Fence Corporation Tax (RFCT)	RFCT is levied on the Upstream profits from oil & gas activities at a rate of 30%. Allowable deductions include: ▪ PRT ▪ Opex ▪ Capital allowances of which o Capex other than long life assets (>25 years) is written down 100% as it is incurred o Capex on long life assets is written down by 24% in the 1st year and 6% pa declining balance thereafter o Abandonment expenses expensed as it is incurred ▪ Interest expenses ▪ Ring Fence Expenditure Supplement ▪ RFCT losses carried forward indefinitely or backward for up to 3 years.
Supplementary Charge (SCT)	SCT is levied on Upstream profits from oil & gas activities at a rate of 20% on a similar base to RFCT with the exceptions of interest being excluded from deductions and additional field allowances allowable as deductions.

7.2. Economic Analysis

Economic assessment of E.On's Southern North Sea producing fields have been based on discounted cash flow analyses incorporating production and cost profiles and the fiscal terms described above.

A total of four price scenarios have been run with Price Scenario 'A' representing RISC's view of future prices. The three other scenarios (Price Scenario 'B', Price Scenario 'C' & Price Scenario 'D') represent prices forecast by Premier. E.On sells its gas to other E.On subsidiaries at National Balancing Point (NBP) prices with hedging at a corporate level. RISC has not valued the hedges.

A summary description of the assumptions used in the models follows.

7.2.1. Key Assumptions

7.2.1.1. Valuation Date

The valuation has been carried out in US Dollars with an Effective Date of 1st January 2015 to align with the Sale and Purchase agreement between Premier Oil and E.On (Table 7-4 & Table 7-5). The reserves and net present values have also been calculated with an effective date of 31st December 2015 (Table 7-6 & Table 7-7) to meet the requirements of the UK Listing Authority.

7.2.1.2. Field allowances

Ravenspurn North is subject to PRT and eligible for oil allowance to reduce potential PRT payable. Information supplied by Premier indicates Ravenspurn North has a remaining oil allowance balance of 109,382 tonnes out of a total of 2.5 million tonnes and a maximum of 125,000 tonnes per chargeable period. Analysis shows Ravenspurn North generates insufficient revenue to incur any PRT charges or make use of the oil allowance hence the oil allowance is immaterial.

7.2.1.3. Tax loss pools

Premier has provided the following information on apportioned tax losses/pool deductible against Southern North Sea fields.

Table 7-1 Southern North Sea Fields Share of tax losses (Opening Position 1.1.2015 - Net £MM)

	EPUK	EU	Aggregate
RFCT Loss	9.248	60.203	69.451
SCT Loss	9.276	37.492	46.768
Plant and machinery Pool	21.759	7.223	28.982
Mineral extraction allowance	0.899	9.644	10.543

RISC has utilised EU allowances from Table 7-1.

7.2.1.4. *Commodity Prices*

A total of four price scenarios have been considered. The 2015 gas production is assumed to have been sold at monthly average of day-ahead contract prices as reported by Ofgem and liquids sold at the average of the dated Brent monthly price. Price Scenario 'A' represents RISC's view of future prices. Price scenarios B, C & D represent mid, low and high prices forecast by Premier. The prices are exclusive of any hedge contracts in place at the time of the transaction.

Table 7-2 Commodity Prices

	2015	2016	2017	2018	2019+
Oil Price (US$/bbl)					
Price Scenario 'A'	52.40	35.00	40.00	45.00	60 (2016 real +2.5% pa) i.e. 65
Price Scenario 'B'	52.40	55.00	60.00	65.00	80 (2016 real +2.5% pa) i.e. 86
Price Scenario 'C'	52.40	45.00	50.00	55.00	65 (2016 real +2.5% pa) i.e. 70
Price Scenario 'D'	52.40	55.00	70.00	75.00	95 (2016 real +2.5% pa) i.e. 102
Gas Prices – UK NBP spot (GBp/th)					
Price Scenario 'A'	44.2	33.0	34.0	35.0	+2.5% pa
Price Scenario 'B'	44.2	40.0	41.0	42.0	+2.5% pa
Price Scenario 'C'	44.2	37.5	38.0	39.0	+2.5% pa
Price Scenario 'D'	44.2	42.5	44.0	45.0	+2.5% pa

7.2.1.5. *Economic parameters*

Table 7-3 Economic Parameters

	2015	2016	2017	2018	2019+
Cost Inflation	0%	0%	0%	0%	+2.5% pa
Exchange $/£	1.5	1.5	1.5	1.5	1.5

7.2.1.6. *Discount Rate*

Project NPVs are reported at a discount rate of 10% nominal. Discount rates of 8% and 12% nominal are considered as valuation sensitivities.

7.2.1.7. *Cases*

RISC has evaluated 1P, 2P and 3P cases for producing fields and fields under development under the fiscal terms and economic parameters described above.

7.2.1.8. *Economic limit*

RISC estimates field economic limits using a look-back value methodology whereby a field is abandoned at a time beyond which operations would erode economic value.

7.3. Economic Results as of 1st January 2015

Economics have been run using the discounted cash flow method for the four price scenarios based on estimates of future production of assessed reserves/resources and forecasts of future capital and operating costs with an effective date of 1st January 2015.

The following Net Present Values have not been adjusted for other factors (eg analogous transactions, strategic, political and security risks) that a buyer or seller may consider in any transaction concerning these assets and therefore may not be representative of the fair market value.

The economic results for the pipelines are independent of the oil and gas price scenarios. A single scenario was evaluated for each of the ETS and CMS working interests at the effective date of 1st January 2015.

Table 7-4 Pre-Tax Valuation Summary (NPV at 10% discount rate in US$MM at 1st January 2015)

Field	Status	E.On WI	Case	Price Scenario 'A'	Price Scenario 'B'	Price Scenario 'C'	Price Scenario 'D'
Rita	Currently Shut-in	74%	1P	0	0	0	0
			2P	0	0	0	0
			3P	0	0	0	0
Ravenspurn North	Producing	29%	1P	-60	-60	-60	-60
			2P	-59	-59	-59	-59
			3P	-59	-59	-59	-59
Johnston	Producing	50%	1P	5	9	7	10
			2P	10	14	12	15
			3P	14	19	16	21
Caister	Ceased Production	40%	1P	-37	-37	-37	-37
			2P	-37	-37	-37	-37
			3P	-37	-37	-37	-37
Babbage	Producing	47%	1P	4	16	10	21
			2P	20	39	30	47
			3P	51	78	66	90
Orca	Producing	23%	1P	-20	-20	-20	-20
			2P	-20	-20	-20	-20
			3P	-20	-20	-20	-20
Hunter	Producing	79%	1P	-11	-10	-10	-10
			2P	-11	-10	-10	-10
			3P	-11	-10	-10	-10
Minke	Ceased Production	43%	1P	-12	-12	-12	-12
			2P	-12	-12	-12	-12
			3P	-12	-12	-12	-12
Tolmount	Development pending FID	50%	1P	-33	-33	-33	-33
			2P	111	214	160	267
			3P	584	789	682	897
CMS Pipeline	Facility	20%		-4	-4	-4	-4
ETS Pipeline	Facility	30%		29	29	29	29
Total (Incl. Pipelines)			**1P**	**-139**	**-122**	**-130**	**-116**
			2P	**27**	**154**	**89**	**216**
			3P	**535**	**773**	**651**	**895**

Table 7-5 Post Tax Valuation Summary (NPV at 10% discount rate in US$MM at 1st January 2015)

Field	Status	E.On WI	Case	Price Scenario 'A'	Price Scenario 'B'	Price Scenario 'C'	Price Scenario 'D'
Rita	Currently Shut-in	74%	1P	0	0	0	0
			2P	0	0	0	0
			3P	0	0	0	0
Ravenspurn North	Producing	29%	1P	-60	-60	-60	-60
			2P	-59	-59	-59	-59
			3P	-59	-59	-59	-59
Johnston	Producing	50%	1P	5	9	7	10
			2P	10	14	12	15
			3P	14	17	16	17
Caister	Ceased Production	40%	1P	-37	-37	-37	-37
			2P	-37	-37	-37	-37
			3P	-37	-37	-37	-37
Babbage	Producing	47%	1P	4	16	10	20
			2P	20	31	27	36
			3P	42	54	49	58
Orca	Producing	23%	1P	-20	-20	-20	-20
			2P	-20	-20	-20	-20
			3P	-20	-20	-20	-20
Hunter	Producing	79%	1P	-11	-10	-10	-10
			2P	-11	-10	-10	-10
			3P	-11	-10	-10	-10
Minke	Ceased Production	43%	1P	-12	-12	-12	-12
			2P	-12	-12	-12	-12
			3P	-12	-12	-12	-12
Tolmount	Development pending FID	50%	1P	-33	-33	-33	-33
			2P	28	81	53	108
			3P	256	363	307	418
CMS Pipeline	Facility	20%		-4	-4	-4	-4
ETS Pipeline	Facility	30%		17	17	17	17
Total (Incl. Pipelines)			**1P**	**-151**	**-134**	**-142**	**-129**
			2P	**-68**	**1**	**-33**	**34**
			3P	**186**	**309**	**247**	**368**
Consolidated Tax benefit			**2P**[21]	76	71	75	66

7.3.1. Field Valuation Sensitivities

The sensitivity of valuations considered include discount rates, sales prices and costs and are summarized for each fields 2P reserves case below. The sensitivities are applied to Price Scenario ’A’.

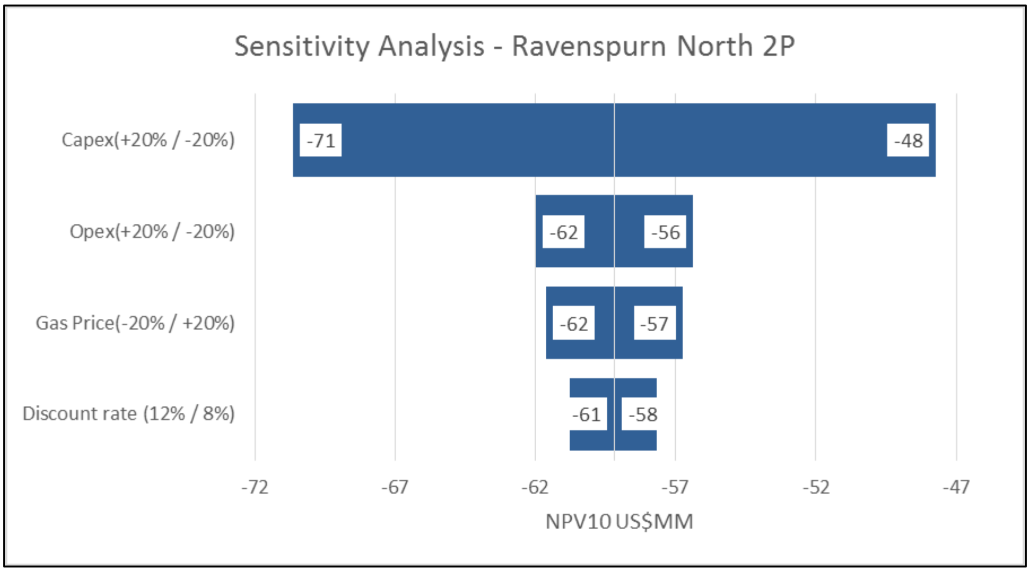


Figure 7-1 Ravenspurn North Sensitivity Analysis

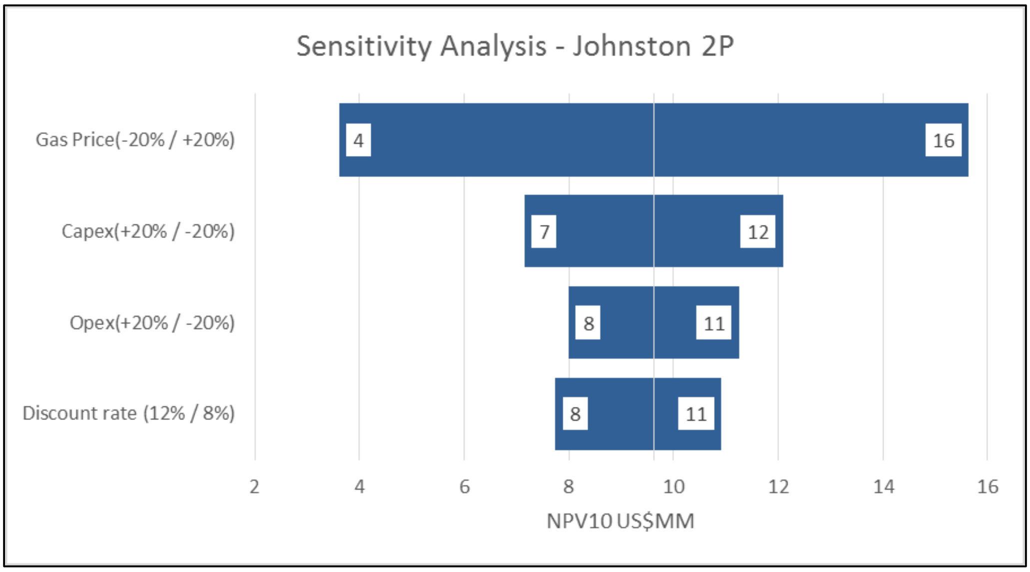


Figure 7-2 Johnston Sensitivity Analysis

[21] Consolidated tax benefit calculated for arithmetic total of field 2P cash flows only

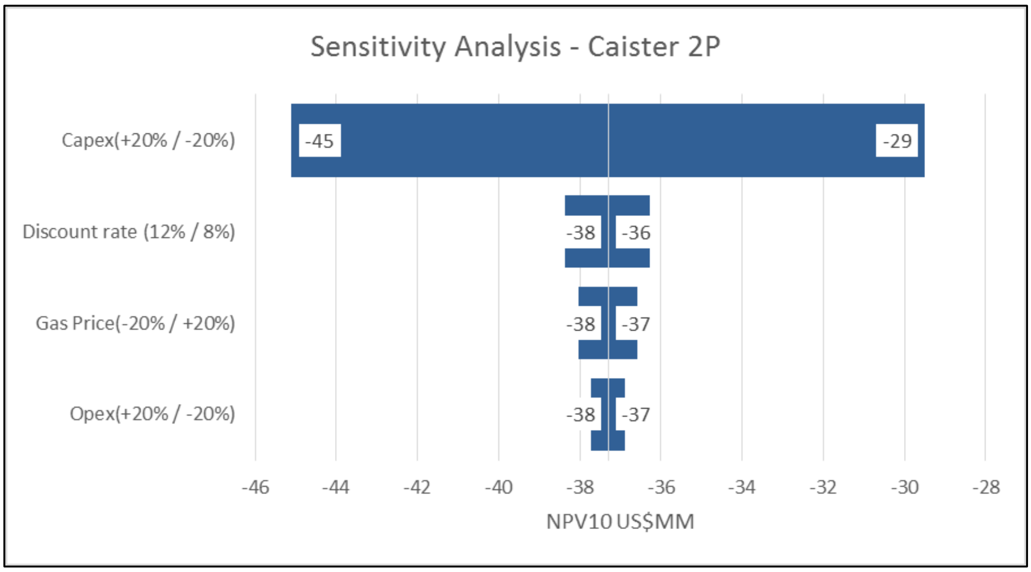


Figure 7-3 Caister Sensitivity Analysis

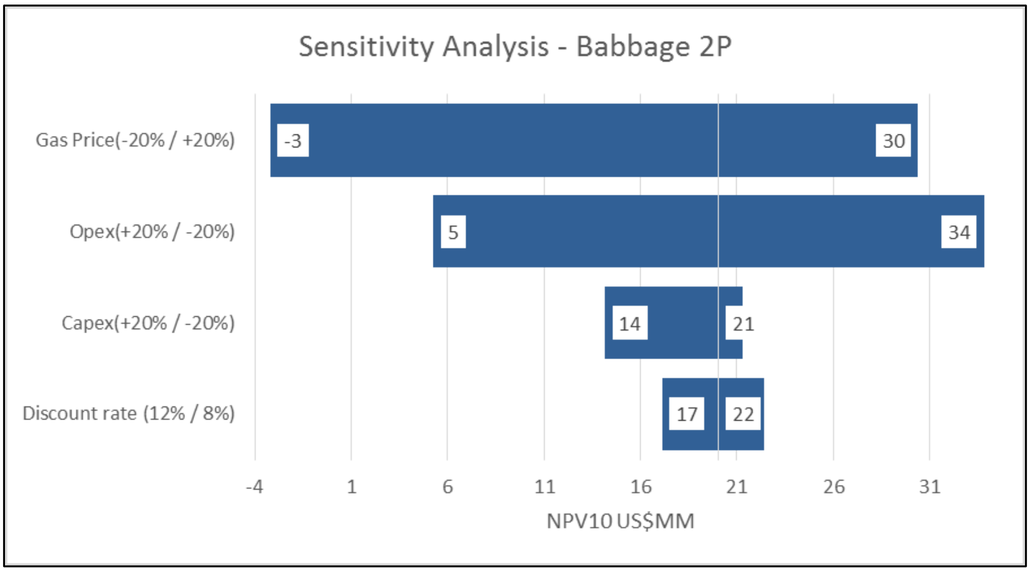


Figure 7-4 Babbage Sensitivity Analysis

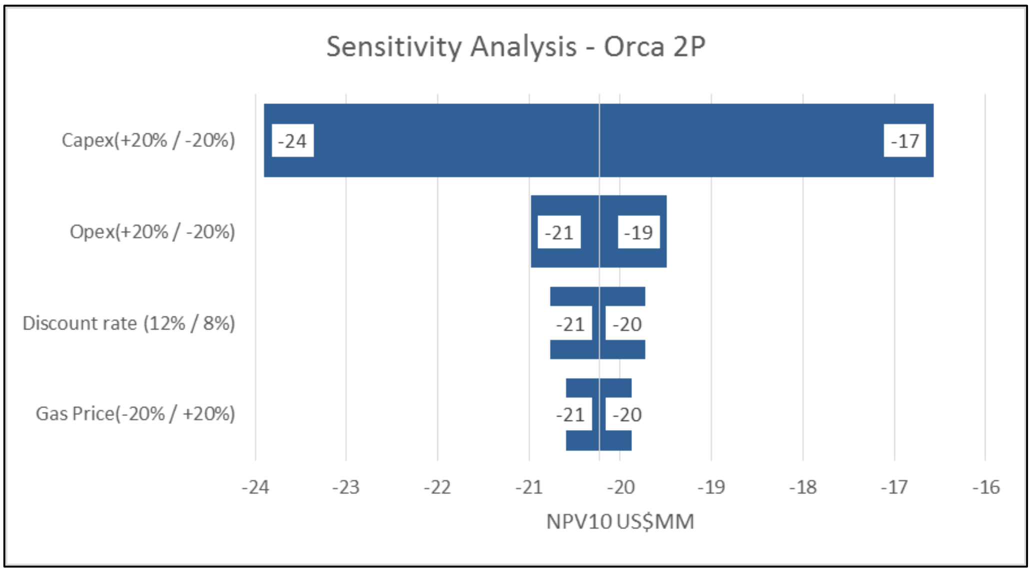


Figure 7-5 Orca Sensitivity Analysis

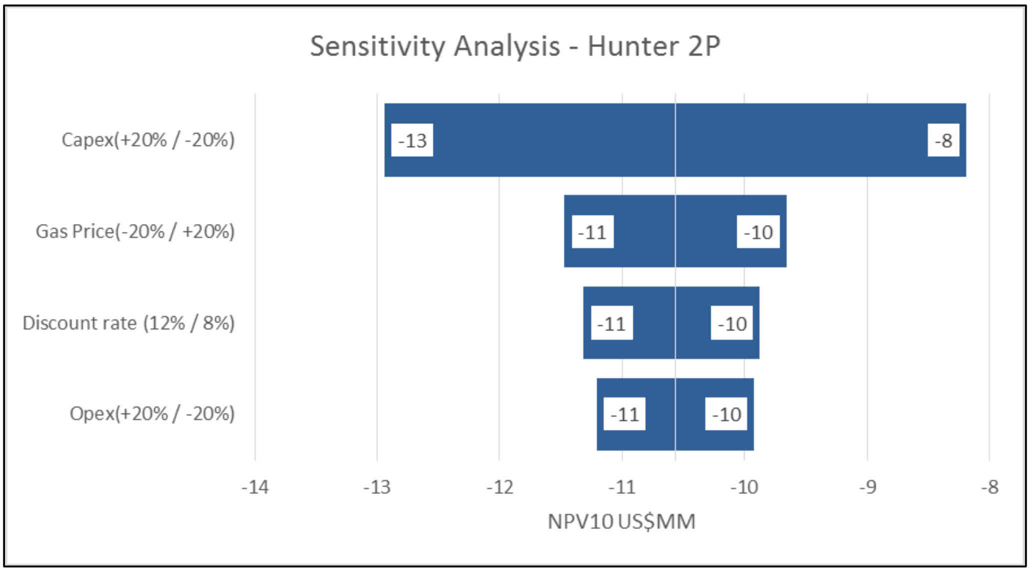


Figure 7-6 Hunter Sensitivity Analysis

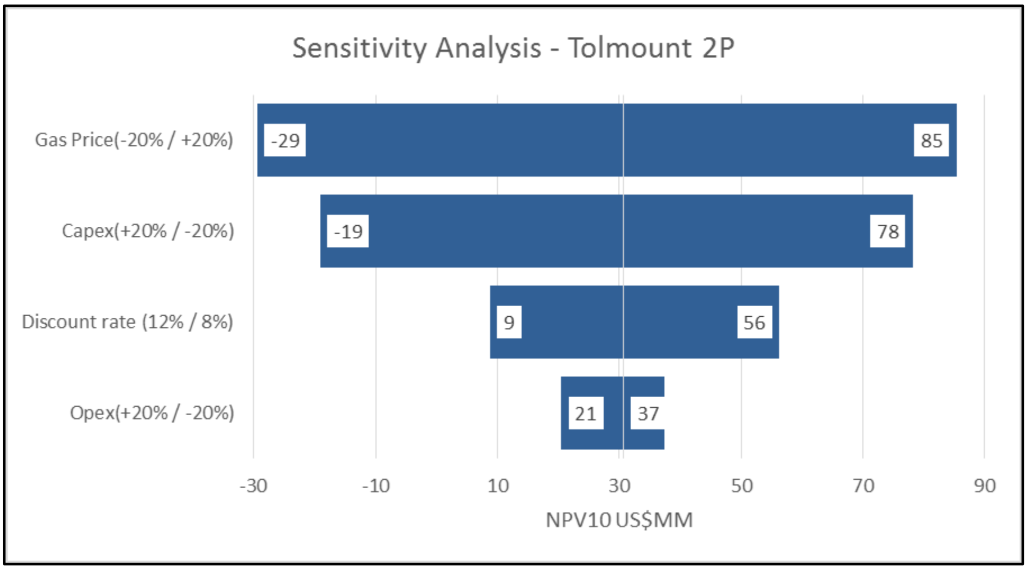


Figure 7-7 Tolmount Sensitivity Analysis

7.4. Economic Results as of 31st December 2015

Economics have also been run using the discounted cash flow method for the four price scenarios based on estimates of future production of assessed reserves/resources and forecasts of future capital and operating costs with an effective date of 31st December 2015.

The following Net Present Values have not been adjusted for other factors (eg analogous transactions, strategic, political and security risks) that a buyer or seller may consider in any transaction concerning these assets and therefore may not be representative of the fair market value.

The economic results for the pipelines are independent of the oil and gas price scenarios. A single scenario was evaluated for each of the ETS and CMS working interests at the effective date of 1st January 2015.

Table 7-6 Pre-Tax Valuation Summary (NPV at 10% discount rate in US$MM at 31st December 2015)

Field	Status	E.On WI	Case	Price Scenario 'A'	Price Scenario 'B'	Price Scenario 'C'	Price Scenario 'D'
Rita	Currently Shut-in	74%	1P	-12	-12	-12	-12
			2P	-12	-12	-12	-12
			3P	-12	-12	-12	-12
Ravenspurn North	Producing	29%	1P	-62	-62	-62	-62
			2P	-62	-62	-62	-62
			3P	-62	-62	-62	-62
Johnston	Producing	50%	1P	-1	3	1	4
			2P	3	8	6	10
			3P	8	13	10	15
Caister	Ceased Production	40%	1P	-43	-43	-43	-43
			2P	-43	-43	-43	-43
			3P	-43	-43	-43	-43
Babbage	Producing	47%	1P	-24	-10	-18	-5
			2P	-7	13	4	23
			3P	25	55	41	68
Orca	Producing	23%	1P	-20	-20	-20	-20
			2P	-20	-20	-20	-20
			3P	-20	-20	-20	-20
Hunter	Producing	79%	1P	-12	-11	-11	-11
			2P	-12	-11	-11	-11
			3P	-12	-11	-11	-11
Minke	Ceased Production	43%	1P	-13	-13	-13	-13
			2P	-13	-13	-13	-13
			3P	-13	-13	-13	-13
Tolmount	Development pending FID	50%	1P	-36	-36	-36	-36
			2P	122	235	176	294
			3P	656	882	763	1,000
CMS Pipeline	Facility	20%		-4	-4	-4	-4
ETS Pipeline	Facility	30%		32	32	32	32
Total (Incl. Pipelines)			**1P**	**-195**	**-176**	**-186**	**-170**
			2P	**-16**	**123**	**53**	**194**
			3P	**555**	**817**	**681**	**950**

Table 7-7 Post Tax Valuation Summary (NPV at 10% discount rate in US$MM at 31st December 2015)

Field	Status	E.On WI	Case	Price Scenario 'A'	Price Scenario 'B'	Price Scenario 'C'	Price Scenario 'D'
Rita	Currently Shut-in	74%	1P	-12	-12	-12	-12
			2P	-12	-12	-12	-12
			3P	-12	-12	-12	-12
Ravenspurn North	Producing	29%	1P	-62	-62	-62	-62
			2P	-62	-62	-62	-62
			3P	-62	-62	-62	-62
Johnston	Producing	50%	1P	-1	3	1	4
			2P	3	8	6	10
			3P	8	13	10	15
Caister	Ceased Production	40%	1P	-43	-43	-43	-43
			2P	-43	-43	-43	-43
			3P	-43	-43	-43	-43
Babbage	Producing	47%	1P	-24	-10	-18	-5
			2P	-7	13	4	23
			3P	25	44	38	49
Orca	Producing	23%	1P	-20	-20	-20	-20
			2P	-20	-20	-20	-20
			3P	-20	-20	-20	-20
Hunter	Producing	79%	1P	-12	-11	-11	-11
			2P	-12	-11	-11	-11
			3P	-12	-11	-11	-11
Minke	Ceased Production	43%	1P	-13	-13	-13	-13
			2P	-13	-13	-13	-13
			3P	-13	-13	-13	-13
Tolmount	Development pending FID	50%	1P	-36	-36	-36	-36
			2P	31	89	58	119
			3P	295	413	352	473
CMS Pipeline	Facility	20%		-4	-4	-4	-4
ETS Pipeline	Facility	30%		18	18	18	18
Total (Incl. Pipelines)			**1P**	**-209**	**-190**	**-200**	**-184**
			2P	**-121**	**-37**	**-79**	**5**
			3P	**180**	**323**	**253**	**390**
Consolidated Tax benefit			**2P**[22]	84	78	82	73

[22] Consolidated tax benefit calculated for arithmetic total of field 2P cash flows only

8. UK Blocks licensed by E.On

Table 8-1 Blocks licensed by E.On E & P UK Limited

E.ON E&P UK LIMITED	15/27b	40%	E.ON E&P UK LIMITED	P2161
	21/17d	40%	E.ON E&P UK LIMITED	P2178
	21/18b	40%	E.ON E&P UK LIMITED	P2178
	22/13b	22.50%	NEXEN PETROLEUM U.K. LIMITED	P1420
	22/14b	25%	E.ON E&P UK LIMITED	P1114
	22/14d REST	22.50%	NEXEN PETROLEUM U.K. LIMITED	P1801
	22/18b	22.50%	NEXEN PETROLEUM U.K. LIMITED	P1801
	22/18c	40%	PA RESOURCES NORTH SEA LIMITED	P2184
	22/19b	22.50%	NEXEN PETROLEUM U.K. LIMITED	P1801
	22/19d	40%	PA RESOURCES NORTH SEA LIMITED	P2184
	22/25a MERG	65.99%	BRITOIL LIMITED	P111
	22/27a A	20%	CNR INTERNATIONAL (U.K.) LIMITED	P114
	22/29b	5.20%	TOTAL E&P UK LIMITED	P2068
	22/30b ELGN	5.20%	TOTAL E&P UK LIMITED	P188
	22/30c	5.20%	TOTAL E&P UK LIMITED	P666
	23/26d A	100%	E.ON E&P UK LIMITED	P264
	28/15 NORTH	15%	STATOIL (U.K.) LIMITED	P2067
	28/20 NORTH	15%	STATOIL (U.K.) LIMITED	P2067
	28/20 SW	15%	NEXEN PETROLEUM U.K. LIMITED	P2067
	29/2a A	20%	CNR INTERNATIONAL (U.K.) LIMITED	P224
	29/3b	25%	TOTAL E&P UK LIMITED	P1626
	29/4d	18.57%	TOTAL E&P UK LIMITED	P752
	29/5b	5.20%	TOTAL E&P UK LIMITED	P362
	29/5c	5.20%	TOTAL E&P UK LIMITED	P666
	29/16 SE	15%	STATOIL (U.K.) LIMITED	P2067
	30/12e	20%	TALISMAN SINOPEC ENERGY UK LIMITED	P1939
	30/13a WEST	15%	TALISMAN SINOPEC ENERGY UK LIMITED	P79
	30/13b	25%	GDF SUEZ E&P UK LTD	P1823
	42/28d	50%	E.ON E&P UK LIMITED	P1330
	42/28e	50%	E.ON E&P UK LIMITED	P2105
	42/29d	50%	E.ON E&P UK LIMITED	P2105
	44/21b	68.31%	E.ON E&P UK LIMITED	P766
	44/22c	76%	E.ON E&P UK LIMITED	P771
	44/23a AREAA	40%	CONOCOPHILLIPS (U.K.) LIMITED	P452
	44/23e D	79%	E.ON E&P UK LIMITED	P452
	44/24a	42.67%	GDF SUEZ E&P UK LTD	P611
	44/29b A	35%	GDF SUEZ E&P UK LTD	P454
	44/29b B	42.67%	GDF SUEZ E&P UK LTD	P454
	44/30a	42.67%	GDF SUEZ E&P UK LTD	P611
	47/3k	100%	E.ON E&P UK LIMITED	P2136
	48/1b	50%	E.ON E&P UK LIMITED	P2212
	48/2b	50%	E.ON E&P UK LIMITED	P2212
	48/10c	50%	E.ON E&P UK LIMITED	P2103
	205/16d	50%	FAROE PETROLEUM (U.K.) LIMITED	P2011
	205/17b	50%	FAROE PETROLEUM (U.K.) LIMITED	P2011
	205/21c	50%	FAROE PETROLEUM (U.K.) LIMITED	P2011
	205/22b	50%	FAROE PETROLEUM (U.K.) LIMITED	P2011
	208/14	100%	E.ON E&P UK LIMITED	P2023
	208/15	100%	E.ON E&P UK LIMITED	P2023
	209/4	100%	E.ON E&P UK LIMITED	P2073
	209/5	100%	E.ON E&P UK LIMITED	P2073
	213/5	30%	OMV (U.K.) LIMITED	P1997
	214/1	30%	OMV (U.K.) LIMITED	P1997
	214/4c	30%	OMV (U.K.) LIMITED	P2080
	215/30	30%	OMV (U.K.) LIMITED	P1997
	216/26	30%	OMV (U.K.) LIMITED	P1997
	216/27	30%	OMV (U.K.) LIMITED	P1997
	219/13	100%	E.ON E&P UK LIMITED	P2012
	219/14	100%	E.ON E&P UK LIMITED	P2012
	219/15	100%	E.ON E&P UK LIMITED	P2012

Table 8-2 Blocks licenced by E.On E & P UK EU Limited

Equity Holder	Block / Subarea	Interest	Operator	Licence
E.ON E&P UK EU LIMITED	23/16c	30%	DANA PETROLEUM (E&P) LIMITED	P1720
	43/26a RAVE (CA)	35.94%	BP EXPLORATION OPERATING COMPANY LIMITED	P380
	43/26a RAVEA	35.94%	E.ON E&P UK EU LIMITED	P380
	43/26a RAVEB	35.94%	E.ON E&P UK EU LIMITED	P380
	43/26a RESID	72.22%	E.ON E&P UK EU LIMITED	P380
	43/27a	42.22%	E.ON E&P UK EU LIMITED	P686
	48/2a	47%	E.ON E&P UK EU LIMITED	P456

9. List of terms

The following lists, along with a brief definition, abbreviated terms that are commonly used in the oil and gas industry and which may be used in this report.

Term	Definition
1P	Equivalent to Proved reserves or Proved in-place quantities, depending on the context.
1Q	1st Quarter
2P	The sum of Proved and Probable reserves or in-place quantities, depending on the context.
2Q	2nd Quarter
2D	Two Dimensional
3D	Three Dimensional
4D	Four Dimensional – time lapsed 3D in relation to seismic
3P	The sum of Proved, Probable and Possible Reserves or in-place quantities, depending on the context.
3Q	3rd Quarter
4Q	4th Quarter
AFE	Authority for Expenditure
Bbl	US Barrel
BBL/D	US Barrels per day
BCF	Billion (10^9) cubic feet
BCM	Billion (10^9) cubic meters
BFPD	Barrels of fluid per day
BOPD	Barrels of oil per day
BTU	British Thermal Units
BOEPD	US barrels of oil equivalent per day
BWPD	Barrels of water per day
°C	Degrees Celsius
Capex	Capital expenditure
CAPM	Capital asset pricing model
CGR	Condensate Gas Ratio – usually expressed as bbl/MMscf
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 are a class of discovered recoverable resources as defined in the SPE-PRMS.
CO2	Carbon dioxide
CP	Centipoise (measure of viscosity)
CPI	Consumer Price Index
DEG	Degrees
DHI	Direct hydrocarbon indicator
Discount Rate	The interest rate used to discount future cash flows into a dollars of a reference date
DST	Drill stem test
E&P	Exploration and Production
EG	Gas expansion factor. Gas volume at standard (surface) conditions / gas volume at reservoir conditions (pressure & temperature)

Term	Definition
EIA	US Energy Information Administration
EMV	Expected Monetary Value
EOR	Enhanced Oil Recovery
ESP	Electric submersible pump
EUR	Economic ultimate recovery
Expectation	The mean of a probability distribution
F	Degrees Fahrenheit
FDP	Field Development Plan
FEED	Front End Engineering and design
FID	Final investment decision
FM	Formation
FPSO	Floating Production Storage and offtake unit
FWL	Free Water Level
FVF	Formation volume factor
GIIP	Gas Initially In Place
GJ	Giga (10^9) joules
GOC	Gas-oil contact
GOR	Gas oil ratio
GRV	Gross rock volume
GSA	Gas sales agreement
GTL	Gas To Liquid(s)
GWC	Gas water contact
H2S	Hydrogen sulphide
HHV	Higher heating value
ID	Internal diameter
IRR	Internal Rate of Return is the discount rate that results in the NPV being equal to zero.
JV(P)	Joint Venture (Partners)
Kh	Horizontal permeability
km2	Square kilometres
Krw	Relative permeability to water
Kv	Vertical permeability
kPa	Kilo (thousand) Pascals (measurement of pressure)
Mstb/d	Thousand Stock tank barrels per day
LIBOR	London inter-bank offered rate
LNG	Liquefied Natural Gas
LTBR	Long-Term Bond Rate
m	Metres
MDT	Modular dynamic (formation) tester
mD	Millidarcies (permeability)
MJ	Mega (10^6) Joules
MMbbl	Million US barrels
MMscf(d)	Million standard cubic feet (per day)

Term	Definition
MMstb	Million US stock tank barrels
MOD	Money of the Day (nominal dollars) as opposed to money in real terms
MOU	Memorandum of Understanding
Mscf	Thousand standard cubic feet
Mstb	Thousand US stock tank barrels
MPa	Mega (10^6) pascal (measurement of pressure)
mss	Metres subsea
MSV	Mean Success Volume
mTVDss	Metres true vertical depth subsea
MW	Megawatt
NPV	Net Present Value (of a series of cash flows)
NTG	Net to Gross (ratio)
ODT	Oil down to
OGIP	Original Gas In Place
OOIP	Original Oil in Place
Opex	Operating expenditure
OWC	Oil-water contact
P90, P50, P10	90%, 50% & 10% probabilities respectively that the stated quantities will be equalled or exceeded. The P90, P50 and P10 quantities correspond to the Proved (1P), Proved + Probable (2P) and Proved + Probable + Possible (3P) confidence levels respectively.
PBU	Pressure build-up
PJ	Peta (1015) Joules
POS	Probability of Success
Possible Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest 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.
Probable Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that 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.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations as defined in the SPE-PRMS.
Proved Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty 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. Often referred to as 1P, also as “Proven”.
PSC	Production Sharing Contract
PSDM	Pre-stack depth migration

Term	Definition
PSTM	Pre-stack time migration
psia	Pounds per square inch pressure absolute
p.u.	Porosity unit e.g. porosity of 20% +/- 2 p.u. equals a porosity range of 18% to 22%
PVT	Pressure, volume & temperature
QA/QC	Quality Assurance/ Control
rb/stb	Reservoir barrels per stock tank barrel under standard conditions
RFT	Repeat Formation Test
Real Terms (RT)	Real Terms (in the reference date dollars) as opposed to Nominal Terms of Money of the Day
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 further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.
RT	Measured from Rotary Table or Real Terms, depending on context
SC	Service Contract
scf	Standard cubic feet (measured at 60 degrees F and 14.7 psia)
Sg	Gas saturation
Sgr	Residual gas saturation
SRD	Seismic reference datum lake level
SPE	Society of Petroleum Engineers
SPE-PRMS	Petroleum Resources Management System, approved by the Board of the SPE March 2007 and endorsed by the Boards of Society of Petroleum Engineers, American Association of Petroleum Geologists, World Petroleum Council and Society of Petroleum Evaluation Engineers.
s.u.	Fluid saturation unit. e.g. saturation of 80% +/- 10 s.u. equals a saturation range of 70% to 90%
stb	Stock tank barrels
STOIIP	Stock Tank Oil Initially In Place
Sw	Water saturation
TCM	Technical committee meeting
Tcf	Trillion (10^{12}) cubic feet
TJ	Tera (10^{12}) Joules
TLP	Tension Leg Platform
TRSSV	Tubing retrievable subsurface safety valve
TVD	True vertical depth
US$	United States dollar
US$ million	Million United States dollars
WACC	Weighted average cost of capital
WHFP	Well Head Flowing Pressure
Working interest	A company's equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms.
WPC	World Petroleum Council
WTI	West Texas Intermediate Crude Oil