CGG Services (UK) Limited

COMPETENT PERSONS REPORT
on the assets of :-
Saffron Energy plc
Apennine Energy S.p.A.
Po Valley Operations Pty Limited

FOR

Saffron Energy plc
Grant Thornton UK LLP
Turner Pope Investments (TPI) Ltd

CGG Services (UK) Limited Reference No: BP512

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DISCLAIMER AND CONDITIONS OF USAGE

Professional Qualifications

CGG Services (UK) Limited (CGG) is a geological and petroleum reservoir consultancy that provides a specialist service in field development and the assessment and valuation of upstream petroleum assets.

CGG has provided consultancy services to the oil and gas industry for over 50 years. The work for this report was carried out by CGG specialists having between five and 20 years of experience in the estimation, assessment and evaluation of hydrocarbon reserves.

Except for the provision of professional services provided on a fee basis and products on a license basis, CGG has no commercial arrangement or interest with Saffron Energy plc (Saffron) or the assets, which are the subject of the report or any other person or company involved in the interests.

Data and Valuation Basis

In estimating petroleum in place and recoverable, CGG have used the standard techniques of petroleum engineering. There is uncertainty inherent in the measurement and interpretation of basic geological and petroleum data. There is no guarantee that the ultimate volumes of petroleum in place or recovered from the field will fall within the ranges quoted in this report.

CGG have independently assessed the proposed development schemes and validated estimates of capital and operating costs, modifying these where CGG judges it appropriate. CGG have carried out economic modelling based on forecasts of costs and production. The capital and operating costs have been combined with production forecasts based on the reserves or resources at the P90 (Proved), P50 (Proved + Probable) and P10 (Proved + Probable + Possible) levels of confidence and the other economic assumptions outlined in this report in order to develop an economic assessment for these petroleum interests. CGG's valuations do not take into account any outstanding debt or accounting liabilities, nor future indirect corporate costs such as general and administrative costs.

CGG have valued the petroleum assets using the industry standard discounted cash flow technique. In estimating the future cash flows of the assets CGG have used extrapolated economic parameters based upon recent and current market trends. Estimates of these economic parameters, notably the future price of crude oil and natural gas, are uncertain and a range of values has been considered. There is no guarantee that the outturn economic parameters will be within the ranges considered.

In undertaking this valuation CGG have used data supplied by Saffron in the form of geoscience reports, seismic data, engineering reports and economics data. The supplied data has been supplemented by public domain regional information where necessary.

CGG has used the working interest percentages that Saffron will have in the Properties, as communicated by Saffron. CGG has not verified nor do CGG make any warrant as to Saffron's interest in the Properties.

Within this report, CGG makes no representation or warranty as to: (i) the amounts, quality or deliverability of reserves of oil, natural gas or other petroleum; (ii) any geological, geophysical, engineering, economic or other interpretations, forecasts or valuations; (iii) any forecast of expenditures, budgets or financial projections; (iv) any geological formation, drilling prospect or hydrocarbon reserve; (v) the state, condition or fitness for purpose of any of the physical assets, including but not limited to well, operations and facilities related to any oil and gas interests or (vi) any financial debt, liabilities or contingencies pertaining to Saffron.

CGG affirm that from 15th January (the date for final inclusion of data) to the date of issue of this report, 15th February, 1) there are no material changes known to CGG that would require modifications to this report, and 2) CGG is not aware of any matter in relation to this report that it believes should and may not yet have been brought to the attention of Saffron.

In order to conform to the AIM Guidance Note for Mining, Oil & Gas Companies (June 2009), CGG has compiled this CPR to confirm with the guidelines and definitions of the Petroleum Resources Management Systems (2007) as published by the Society of Petroleum Engineers (SPE). Further details of these definitions are included in Appendix A of the CPR.

Conditions of Usage

The report was compiled using existing data during the period November 2017 to January 2018. However, if substantive new data or facts become available or known, then this report should be updated to incorporate all the relevant data.

CGG has made every reasonable effort to ensure that this report has been prepared in accordance with generally accepted industry practices and based upon the data and information supplied by Saffron for whom, and for whose exclusive and confidential use (save for where such use is for the Purpose), this report is made. Any use made of the report shall be solely based on Saffron's own judgement and CGG shall not be liable or responsible for any consequential loss or damages arising out of the use of the report.

The copyright of this CPR document remains the property of CGG. It has been provided to Saffron for the purpose of Admission and its inclusion in the related AIM Admission Document and disclosure on Saffron's website in accordance with the AIM Rules (these together being the "Purpose"). CGG agrees to disclose the enclosed CPR to Saffron for the Purpose. The recipient should also note that this document is being provided on the express terms that, other than for the Purpose, it is not to be copied in part or as a whole, used or disclosed in any manner or by any means unless as authorised in writing by CGG. Notwithstanding these general conditions, CGG additionally agrees to the publication of the CPR document, in full, on Saffron's website in accordance with AIM rules.

The accuracy of this report, data, interpretations, opinions and conclusions contained within, represents the best judgement of CGG, subject to the limitations of the supplied data and time constraints of the project. In order to fully understand the nature of the information and conclusions contained within the report it is strongly recommended that it should be read in its entirety.

CGG Services (UK) Limited Reference No: BP512				
Rev	**Date**	**Originator**	**Checked & Approved**	**Issue Purpose**
04	February 2018	Peter Wright / Arthur Satterley / Potcharaporn Pongthunya	Andrew Webb	Final Report

Date	Originator	Checked & Approved
Signed:		

Prepared for:	Prepared By:
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1 EXECUTIVE SUMMARY

This Competent Persons Report (CPR), prepared by CGG, presents the results of an independent evaluation of the petroleum reserves and resources of Saffron Energy plc (Saffron), Po Valley Operations Pty Ltd (PVO) and Apennine Energy SpA (Apennine).

The petroleum reserves and resources definitions used in the CPR are those published by the Society of Petroleum Engineers (SPE) and World Petroleum Congress (WPC) in 1998, supplemented by the Petroleum Resource Management System (PRMS), published by the SPE/WPC in 2007.

The report evaluates the principal petroleum interests currently held by Saffron, PVO and Apennine. The latter two companies are part of a proposed merger with Saffron.

1.1 Saffron assets

The principal assets of Saffron are the Sillaro, Bezzecca and Sant'Alberto gas fields. They are all located in the Po Valley in northern Italy. The licences are held by Northsun Italia SpA (NSI), a wholly owned subsidiary of Saffron Energy plc.

Table 1-1 Saffron - Summary of Licences/ Fields

Field (Licence)	Operator	Interest (%)	Status	Licence expiry date	Licence Area	Comments
Sillaro (Sillaro)	Saffron	100%	Production	29/10/2028	7.37km^2	On production
Bezzecca (Cascina Castello)	Saffron	90%	Production	22/10/2028	38.59km^2	On production
Santa Maddalena (Sant'Alberto)	Saffron	100%	Development	19/2/2032	19.51km^2	Development about to commence

Reserves and resources associated with these fields have been evaluated in accordance with PRMS (2007) and are presented below in both gross and net terms. Full definitions of the categories are provided in Appendix A.

Table 1-2 Saffron - Summary of Reserves

Field	Gross (MMscm)			Net attributable (MMscm)			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Sillaro	0.3	61.5	74.8	0.3	61.5	74.8	Saffron
Bezzecca	37.6	73.0	104.3	33.9	65.7	93.9	Saffron
Sant' Alberto	46.7	58.9	78.9	46.7	58.9	78.9	Saffron

Table 1-3 Saffron - Summary of Contingent Resources

	Gross (MMscm)			Net attributable (MMscm)				
Field	1C	2C	3C	1C	2C	3C	Risk factor[1]	Operator
Sillaro	16.2	31.3	42.7	16.2	31.3	42.7	60%	Saffron
Bezzecca	56.0	79.0	102.0	50.4	71.1	91.8	60%	Saffron

1. *The risk factor for Contingent Resources means the estimated chance that the volumes will be commercially extracted*

The NPVs of the cash flows (net to Saffron) derived from exploiting the reserves are presented below for each uncertainty level and for base, low and high gas prices. The base gas price is based on the forward curve for Italian spot gas, with a 2018 price of Euro 0.213/m^3. Low and high price cases assume sensitivities to the base case of +/-15% for two years, and then +/- 20% thereafter.

Table 1-4 NPVs of Reserves (net Saffron)

Field	Gas price	NPV_{10} € MM		
		Proved	Proved & Probable	Proved, Probable & Possible
Sillaro	Base	-1.8	2.0	3.3
	Low	-1.8	0.9	2.0
	High	-1.8	3.1	4.6
Bezzecca	Base	-3.2	0.3	2.5
	Low	-4.1	-1.2	0.8
	High	-2.2	1.6	4.2
Sant'Alberto	Base	1.1	1.7	1.4
	Low	0.2	0.6	0.1
	High	2.1	2.7	2.8

1.2 PVO assets

The principal assets of PVO are the Teodorico offshore gas discovery and the Selva Strat onshore gas appraisal project, together with the East Selva, Cembalina, Fondo Perino and PL3-C prospects.

Table 1-5 PVO – Summary of Licences / Fields

Field / Prospect (Licence)	Operator	Interest (%)	Status	Licence expiry date	Licence Area	Comments
Selva Strat (Podere Gallina)	PVO	63%*	Exploration	02/02/2018 (requested 2nd exploration period)	506 km2	Production concession application to be filed Feb 2018
Teodorico (d40ACPY)	PVO	100%	Development	Preliminary production concession awarded	65.89 km2	Also contains PL3-C prospect
Rita (AR94PY)	PVO	100%	Exploration	10/07/2018 (requested 2nd exploration period)	526 km2	Pending further studies
Torre del Moro (Torre del Moro)	PVO	100%	Exploration	03/02/2023	111 km2	Prospect

** After the farm-in of United Oil and Gas and Prospex Oil and Gas*

Reserves and resources associated with these assets have been evaluated in accordance with PRMS (2007) and are presented below in both gross and net terms. Full definitions of the categories are provided in Appendix A.

Table 1-6 PVO - Summary of Reserves

Name	Gross (MMscm)			Net attributable (MMscm)			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Teodorico$_1$	756.1	1033.6	1345.1	756.1	1033.6	1345.1	PVO

1. *Volumes outside the 12 mile zone*

Table 1-7 PVO - Summary of Contingent Resources

	Gross (MMscm)			Net attributable$_2$ (MMscm)				
Name	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**	**Risk factor$_1$**	**Operator**
Teodorico$_3$	209.9	300.5	395.9	209.9	300.5	395.9	75%	PVO
Selva Strat Trap	322.9	481.5	651.4	203.4	303.3	410.4	*>80%*	PVO

1. *The risk factor for Contingent Resources means the estimated chance that the volumes will be commercially extracted*
2. *Post farm-in by United Oil and Gas and Prospex Oil and Gas*
3. *Volumes inside the 12 mile zone*

Table 1-8 PVO - Summary of Prospective Resources

	Gross (MMscm)			Net attributable* (MMscm)				
Name	**Low**	**Best**	**High**	**Low**	**Best**	**High**	**Risk factor$_1$**	**Operator**
East Selva	824.1	985.6	1149.8	519.2	620.9	724.4	13%	PVO
Cembalina	59.5	93.5	133.1	37.5	58.9	83.9	51%	PVO
Fondo Perino	288.9	413.5	580.6	182.0	260.5	365.8	34%	PVO
PL3-C	223.7	450.3	708.0	223.7	450.3	708.0	17%	PVO

1. *The risk factor for Prospective Resources means the estimated chance of discovering hydrocarbons in sufficient quantity for them to be tested to the surface*
2. *Post farm-in by United Oil and Gas and Prospex Oil and Gas*

The NPVs of the cash flows (net to PVO) derived from exploiting the reserves are presented below for each uncertainty level and for base, low and high gas prices. The base gas price is based on the forward curve for Italian spot gas, with a 2018 price of Euro 0.213/m^3. Low and high price cases assume sensitivities to the base case of +/-15% for two years, and then +/- 20% thereafter.

Table 1-9 NPVs of Reserves and Contingent Resources (net PVO)

Name	Gas price	NPV_{10} € MM		
		Proved	Proved & Probable	Proved, Probable & Possible
Teodorico	Base	5.8	17.7	28.0
	Low	-5.6	3.5	11.0
	High	17.1	32.0	45.0
		1C	2C	3C
Selva Strat Trap*	Base	11.7	16.2	19.8
(Contingent Resources)	Low	8.4	11.8	14.6
	High	15.0	20.5	25.0

*** The economics outlined above were prepared before the Podiere Maiar -1d well was drilled and do not incorporate the well results. The development plan may change once the well results are analysed and a detailed development plan is prepared.**

1.3 Apennine assets

The principal assets of Apennine are the producing Rapagnano and Casa Tiberi onshore gas fields, together with the Sant'Andrea, Laura, Marciano and Manfria discoveries.

Table 1-10 Apennine – Summary of Licences / Fields

Field (Licence)	Operator	Interest (%)	Status	Licence expiry date	Licence Area	Comments
Rapagnano (Rapagnano)	Apennine	100%	Production	28/11/22	8.42km^2	On production
Casa Tiberi (San Lorenzo)	Apennine	100%*	Production	24/2/32	4.92 km^2	On production
Manfria (Costa del Sole)	Apennine	100%	Application for Exploration Permit	-	41.52 km^2	Discovery – pending further studies
Cielo (Costa del Sole)	Apennine	100%	Application for Exploration Permit	-	41.52 km^2	Prospect – pending further studies
Sant'Andrea (Casa Tonetto)	Apennine	100%	Concession	14/07/2035	4.50 km^2	Discovery with suspended production
Thin Beds and Level1 (Santa Maria Goretti)	Apennine	100%	Exploration Permit	19/12/19	101.30 km^2	Prospects pending further studies
Laura (DR74-AP)	Apennine	100%	Exploration Permit	New expiry date to be determined	63.13 km^2	Discovery – pending further studies
Laura East (DR74-AP)	Apennine	100%	Exploration Permit	New expiry date to be determined	63.13 km^2	Prospect - pending further studies
Dalla (D503-BR-CS)	Apennine	100%	Application for Exploration Permit	-	82.61 km^2	Prospect pending further studies
Marciano (Fonte San Damiano)	Apennine	100%	Concession	18/07/2018	23.71 km^2	P&A complete, site restoration ongoing
Zibido (Badile)	Apennine	100%	Exploration Permit	1st extension requested	154.50 km^2	Prospect pending further studies

** after transfer to Apennine of SARP Spa 25% interest*

Reserves and resources associated with these assets have been evaluated in accordance with PRMS (2007) and are presented below in both gross and net terms. Full definitions of the categories are provided in Appendix A.

Table 1-11 Apennine - Summary of Reserves (Gas)

	Gross (MMscm)			Net attributable (MMscm)			Operator
Name	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Rapagnano	13.2	18.0	25.0	13.2	18.0	25.0	Apennine
Casa Tiberi*	0.4	1.0	1.0	0.4	1.0	1.0	Apennine

** Casa Tiberi is categorised as reserves even though the economics are negative as producing the field has a less negative impact than abandoning the field sooner and incurring the abandonment costs*

Table 1-12 Apennine - Summary of Contingent Resources (Gas)

	Gross (MMscm)			Net attributable (MMscm)				
Name	1C	2C	3C	1C	2C	3C	Risk factor[1]	Operator
Sant Andrea [2]	45.4	54.7	68.0	45.4	54.7	68.0	90%	Apennine
Laura	348.3	401.6	606.1	348.3	401.6	606.1	40%	Apennine
Casa Tiberi	16.2	30.7	59.1	16.2	30.7	59.1	90%	Apennine
Marciano	-	70.8	-	-	70.8	-	65%	Apennine

1. *The risk factor for Contingent Resources means the estimated chance that the volumes will be commercially extracted*
2. *Sant Andrea Volumes are stated as 100%; CSTI have a 36.5% profit interest for the first 4 years of production*

Table 1-13 Apennine - Summary of Contingent Resources (Oil)

	Gross (MMbbl)			Net attributable (MMbbl)				
Name	1C	2C	3C	1C	2C	3C	Risk factor[1]	Operator
Costa del Sole (Manfria)[2]	2.2	2.4	2.7	2.2	2.4	2.7	50%	Apennine

1. *The risk factor for Contingent Resources means the estimated chance that the volumes will be commercially extracted*
2. *Application for exploration permit being made by Apennine*

Table 1-14 Apennine - Summary of Prospective Resources (Gas)

	Gross (MMscm)			Net attributable (MMscm)				
Name	**Low**	**Best**	**High**	**Low**	**Best**	**High**	**Risk factor**[1]	**Operator**
Laura East	17.4	82.9	118.3	17.4	82.9	118.3	56%	Apennine
Santa Maria Goretti:Thin Beds	265.8	927.7	1,886.3	265.8	927.7	1,886.3	68%	Apennine
Santa Maria Goretti:Level 1	8.6	19.3	30.2	8.6	19.3	30.2	34%	Apennine
D503-BR-CS (Dalla)[2]	252.1	696.7	1,430.2	252.1	696.7	1,430.2	56%	Apennine
Zibido (Gas Case	-	3,689.0	-	-	3,689.0	-	14%	Apennine

1. *The risk factor for Prospective Resources means the estimated chance of discovering hydrocarbons in sufficient quantity for them to be tested to the surface*
2. *Application for exploration permit being made by Apennine*

Table 1-15 Apennine - Summary of Prospective Resources (Oil)

	Gross (MMscm)			Net attributable (MMbbl)				
Name	**Low**	**Best**	**High**	**Low**	**Best**	**High**	**Risk factor**[1]	**Operator**
Costa del Sole (Cielo)[2]	2.4	2.8	3.3	2.4	2.8	3.3	43%	Apennine
Zibido (Oil Case)	-	19.2	-	-	19.2	-	14%	Apennine

1. *The risk factor for Prospective Resources means the estimated chance of discovering hydrocarbons in sufficient quantity for them to be tested to the surface*
2. *Application for exploration permit being made by Apennine*

The NPVs of the cash flows (net to Apennine) derived from exploiting the reserves are presented below for each uncertainty level and for base, low and high gas prices. The base gas price is based on the forward curve for Italian spot gas, with a 2018 price of Euro 0.213/m^3. Low and high price cases assume sensitivities to the base case of +/-15% for two years, and then +/- 20% thereafter.

Table 1-16 Estimated NPVs for Reserves (net Apennine)

Field	Gas price	NPV_{10} € MM		
		1P	2P	3P
Rapagnano	Base	0.4	0.7	0.8
	Low	0.1	0.3	0.3
	High	0.7	1.0	1.3
Casa Tiberi	Base	-0.6	-0.5	-0.5
	Low	-0.7	-0.6	-0.6
	High	-0.6	-0.5	-0.5

2 INTRODUCTION

This independent Competent Person's Report (CPR) was prepared by CGG (UK) Services Ltd (CGG) during the period from November 2017 to January 2018. The report evaluates the principal petroleum interests currently held by Saffron Energy plc (Saffron), Po Valley Operations Pty Ltd (PVO) and Apennine Energy SpA (Apennine). The latter two companies are part of a proposed merger with Saffron.

2.1 Details and location of assets

2.1.1 Saffron

The principal assets and licences of Saffron that have been evaluated in this report are:

- The Sillaro Production licence containing the producing Sillaro gas field
- The Cascina Castello production licence containing the producing Bezzecca gas field
- The Sant'Alberto production licence containing the Santa Maddalena gas field

The licences are all located in the Po Valley in northern Italy. The location of the assets is shown in the map below. The licences are held by Northsun Italia SpA (NSI), a wholly owned subsidiary of Saffron Energy plc.

Figure 2-1 Location of Saffron licences

2.1.2 PVO

The principal assets and licences of Po Valley that have been evaluated in this report are:

1. The Podere Gallina licence, containing the Selva stratigraphic trap gas discovery and the Cembalina, Fondo Perino and East Selva gas prospects.
2. The AR94PY licence, located offshore northern Italy, containing the PL3-C gas prospect.
3. The D40ACPY licence, located offshore northern Italy, containing the Teodorico gas discovery
4. The Torre del Moro licence containing the Torre del Morro oil prospect.

The location of the licences are shown in the map below.

Figure 2-2 Location of PVO licences

2.1.3 Apennine

The principal assets and licences of Apennine that have been evaluated in this report are:

- The Rapagnano licence containing the producing Rapagnano gas field
- The San Lorenzo licence containing the Casa Tiberi gas field
- The Costa del Sole licence, located onshore Sicily, containing the Manfria oil discovery and Cielo oil prospect (licence application submitted)

- The CasaTonetto concession containing the Sant'Andrea gas discovery
- The Santa Maria Goretti permit Thin Beds and Level 1 gas prospects
- The DR74-AP permit, located offshore southern Italy, containing the Laura gas discovery and the Laura East prospect
- The D503-BR-CS licence containing the Dalla offshore gas prospect (licence application submitted)
- The Fonte San Damiano licence containing the Marciano gas discovery
- The Badile licence containing the Zibido prospect (oil or gas)

The location of the licences are shown in the map below.

Figure 2-3 Location of Apennine licences

A map showing all the licences of the combined company is shown in Figure 2-4.

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Figure 2-4 Location Map of Combined Company's Licences

2.2 Sources of Information

In completing this evaluation, CGG have reviewed information and interpretations provided by Saffron, as well as utilising complementary information from the public domain.

Data utilised by CGG in the preparation of this CPR included:-

- Location maps
- Geological and reservoir reports
- Well logs of drilled wells
- Seismic workstation projects and associated interpretations
- Historical production and pressure data
- AFE's and budgets

CGG have drafted the following CPRs and letters over the last five years on the assets, and as a result are familiar with the geology and production history of the fields. This previous work has been drawn upon and included where appropriate in this report.

- December 2012 – CPR for PVO (Sillaro, Sant'Alberto)
- May 2013 – CPR for PVO (Teodorico and other assets)
- December 2013 – CPR for PVO (Sillaro, Sant'Alberto, Bezzecca)
- December 2014 – CPR for PVO (Sillaro, Bezzecca)
- April 2015 – CPR for Apennine (Italian assets)
- February 2017 - CPR for Saffron (Sillaro, Sant'Alberto, Bezzecca)
- May 2017 – CPR for PVO (Teodorico)
- June 2017 – CPR for Saffron (Selva)

In conducting the evaluation, CGG have accepted the accuracy and completeness of information supplied by Saffron, and have not performed any new interpretations, simulations or studies.

A site visit to the following assets was conducted by Mr Peter Wright of CGG on the 7th and 8th November 2017:

- Bezzecca
- Nervesa
- Selva Strat (well site)
- Sillaro
- Casa Tiberi
- Rapagnano

A visual inspection was made at all the sites, and the well site equipment and processing plant was found to be in good general condition and had the appearance of being well maintained.

2.3 Evaluation Methodology

In estimating the resource volumes, CGG has used the standard techniques of geological estimation to develop the technical sections of this CPR. Resource ranges (low, mid and high cases) have been determined using deterministic methods.

Saffron staff demonstrated and reviewed the seismic workstation interpretations during CGG visits to the company in 2013 and 2016, conducted as part of the previous CPRs. At the same time, maps and geological issues were discussed face to face with senior Saffron staff. The seismic picks, reservoir structure and gross rock volume, according to these interpretations, was demonstrated to CGG. Saffron interpretations have not changed since that time. Estimates of reservoir properties have been checked by CGG, and these are thought to be reasonable.

CGG has independently constructed development profiles, and validated estimates of capital and operating costs provided by Saffron. CGG has carried out economic modelling based on these forecasts of costs and production.

CGG has valued the petroleum assets using the industry standard discounted cash flow technique. In estimating the future cash flows of the assets CGG has extrapolated economic parameters based upon recent and current market trends. Estimates of these economic parameters (notably the future price of gas) are uncertain, and low and high price sensitivities derived from the base case have been considered. There is no guarantee that the outturn economic parameters will be within the ranges considered.

The report contains descriptions of the assets, and evaluates the range of petroleum (gas and oil) volumes that could be produced from the assets. For those assets that have been categorised as reserves, the NPV of the cash flows derived from exploiting those reserves has been calculated. For prospective resources the associated chance of geological success (GCoS) has been estimated.

2.4 Principal Contributors

CGG employees and consultants involved technically in the drafting of this CPR have between five and 20 years of experience in the estimation, assessment and evaluation of hydrocarbon reserves.

CGG confirms that itself and the authors of this report are independent of the Saffron, its directors, employees and advisers, and has no interest in the assets that are the subject of this report.

The following personnel were involved in the drafting of the CPR.

Andrew Webb
Mr Andrew Webb has supervised the preparation of this CPR. He is the Manager of the Petroleum Reservoir & Economics Group at CGG, having joined the company as Economics Manager in 2006. He graduated with a degree in Chemical Engineering and now has over 29 years' experience in the upstream oil and gas industry.

He has worked predominantly for US independent companies, being involved with projects in Europe and North Africa. He has extensive experience in evaluating acquisition and disposals of asset packages across the world. He has also been responsible for the booking and audit of reserves both in oil and gas companies, but also as an external auditor. He is a member of the Society of Petroleum Engineers and an associate of the Institute of Chemical Engineers.

Dr. Arthur Satterley

Has a BSc 1st Class in Geology, University College of Wales and a PhD from the University of Birmingham on Upper Triassic reef limestones and a post-doctoral research experience on platform carbonate margins. He has 20 years' experience of petroleum geological evaluations and resource assessments for both oil and gas fields throughout the exploration and development life cycle. He has experience of carbonate and clastic reservoirs in most major petroleum provinces including onshore northern and southern Italy.

Dr. Potcharaporn Pongthunya

Has an MSc in Petroleum Engineering from Texas A&M University and a PhD in Petroleum Engineering from Imperial College London. She has 14 years' work experience in the upstream oil and gas industry, and over 9 years' experience in reserves and resources assessment for a variety of field types both as a resources evaluator and as an external resource auditor. Her career has included working for operating and consulting companies in both production and reservoir engineering roles in the Far East, North America and Europe. She is a member of the Society of Petroleum Engineers.

Mr. Peter Wright

Has an MA in Engineering from Cambridge University and an MBA from Cranfield University. He has over 20 years' experience in the economic evaluation of upstream oil and gas assets including exploration prospects, development projects and producing assets. His career has included working as a director of specialist economics focussed consulting companies, and has covered a variety of asset types both onshore and offshore in Europe and the rest of the world. He also regularly delivers training courses on petroleum economics and risk analysis at various centres around the world. He is a member of the Society of Petroleum Engineers.

3 COUNTRY AND REGIONAL BACKGROUND

3.1 Market overview

Italy is one of the major gas producers in southern Europe, although in global terms represents only a small percentage of total gas production. Gas is produced from onshore fields predominantly in the north of Italy (Po Valley) and offshore fields in the Adriatic Sea, with some production from Sicily. Gas has been produced in the Po Valley since the Second World War, initially exclusively by ENI.

The gas markets were liberalized in 1998, which saw the end of the ENI monopoly over production, and the opening up of licences to independent oil and gas companies. Gas production is currently about 6.2 billion cubic metres per year, which satisfies about 10% of domestic demand. The remaining demand is met by imports from Russia, Algeria, Norway, Qatar and Libya. Italy is the third largest gas consumer in Europe after Germany and the UK.

The mainland of Italy is extensively served by national and local gas pipeline networks, facilitating the export and sale of production. A sophisticated market has also developed within the country for all aspects of servicing exploration and production activities, including well drilling and logging, process plant design and fabrication, and maintenance/operations.

3.2 Geological overview

The Po Basin is a major hydrocarbon province which was estimated by the US Geological Survey to have approximately 16 TCF of ultimately recoverable gas (Lindquist, USGS, 1999, on-line review paper). The basin occurs on the margins of the Alpine mountain chain to the North and the Apennine chain to the South. The basin opens into the Adriatic Sea to the East. Compression associated with the building of these mountain belts created a large deep basin (or “foredeep”) into which large thicknesses of sediment were shed from the surrounding uplands. As the basin deepened, turbidite sands were created and the high sediment supply began to fill the basin. Many of these turbidite sands are now gas-bearing, including long-established reservoirs discovered and developed by ENI, as well as thin-bedded reservoirs that are becoming new targets at the present time. Pliocene reservoirs include marine sands of significant lateral extent, which are folded over faulted structures that were formed during the compressional phases. At least 6km of Pliocene sediments were deposited in the foredeep, and as this was filled, the Po River drainage system became established, depositing marine sands in a delta-front environment. These may be overlain by fluvial sands as subsidence slowed and the basin filled.

The source of the gas is the Miocene and Pliocene shales that are interbedded with the turbidites and other sediments; the gas is predominantly biogenic rather than associated with deep burial of the shales. Biogenic gas may be generated at shallower depths than is required for the generation of gas by burial, and is related to the activity of bacteria acting on organic matter buried with the shales. However, the deepest known bacterial gas generation is recorded in the Po Basin at a depth of 4,500 metres. As such, the process can generate large gas volumes throughout a basin, and the source may continue to be active at the present time. These aspects have led directly to the hydrocarbon richness of the Po Basin. Many structures and many reservoirs have proven to be gas-bearing, which explains the 263 developed fields in the Po Basin. Much potential for new discoveries remains, as do many opportunities for field re-development (missed pays and remaining gas in old fields).

The assets under consideration here include Miocene and Pliocene reservoir sands, stacked vertically, and including both thick, good quality gas sands and thin-bedded gas reservoirs. Reservoir sands are interbedded with shaley and marly fine-grained sediments. In many cases, the sands are pressure isolated from each other and may be drained in succession according to well designs and completion strategies employed.

4 SILLARO

4.1 Geology and Geophysics

The Sillaro gas field is located in the Emilia Romagna region, east of Bologna, in northern Italy. Sillaro is the new name given to the Pliocene gas sequences above the former Budrio Field (Miocene production), one of ENI's old assets. Gas was discovered in April 1955 with the drilling of well Budrio-2. The field was abandoned in 1982.

Saffron identified an undrained series of sands and has successfully put these on-stream by means of well Sillaro-1dir. Well logs confirm the clear presence of gas bearing sands and each of three production tests flowed at peak gas rates in excess of 100,000 scm/d.

The Sillaro Field consists of seven vertically stacked, gas-charged Pliocene sands above the Top Miocene reflector of the Budrio Field. Depth structure maps at Top PL2-A, B1, C0, C1, C2, C3 and E1 reservoirs suggest four-way dip closed traps up to 0.9 sq. km in size (Figure 3.2).

As shown on Figure 3.2, the available 2D seismic lines do not provide adequate coverage of the structure. However, the depths of the different reservoir zones are known from the old Budrio wells in addition to the Sillaro wells. Regional knowledge supports the definition of a simple closure as presented in Figure 3.2 but there is a significant level of uncertainty regarding Gross Rock Volume (GRV) at Sillaro. The lack of high resolution seismic data over the asset is a serious limitation on the understanding of reservoir connectivity field-wide.

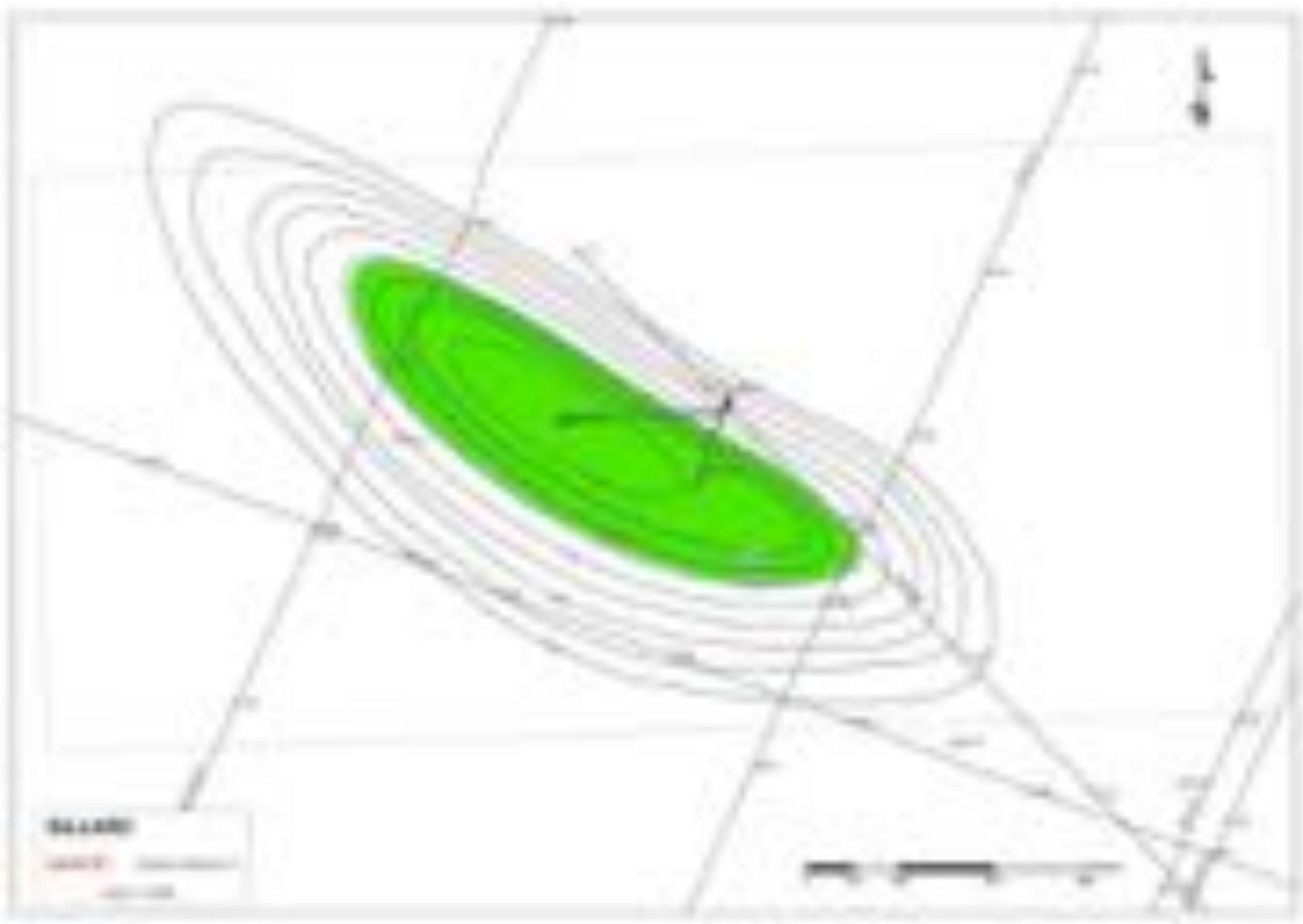

Figure 4-1 Example Depth Structure Map at Top Pliocene Level C1, Sillaro Field

The underlying Miocene has sandy reservoir formations, which are rather silty and thin-bedded. A modern log suite is not available over the section. Permeability of the target Miocene reservoir ranges from much less than 0.1mD to a few millidarcies. The old logs include SP (Spontaneous Potential), sonic and resistivity only, so identification of reservoir beds is problematic.

Mapping and petrophysical analysis provided the following in-place estimates for the Miocene reservoirs of Sillaro (ref. Table 4.1):

Table 4-1 Estimated Gas in Place, Miocene Reservoirs, Sillaro Field

Reservoir Horizon	Gross Bulk Volume (GBV) - MMscm	Original Gas In-place (OGIP) - MMscm
Mid Miocene	34.5	145.7
Deep Miocene	3.4	33.6

The above Gas Initially In-place (GIIP) values appear reasonable considering the available dataset for the evaluation. However, they are subject to significant uncertainty arising from:

- poor seismic coverage (Gross Rock Volume definition and ability to assess compartmentalization risk)

- limited wireline log data availability (limits determination of reservoir properties)

4.2 Reservoir Engineering

The development of the Sillaro gas field was begun by Saffron in 2005, when the well Sillaro-1-Dir was drilled (the well Sillaro-1 was dry). Three hydraulically separated gas bearing levels: A, B1, and C1+C2 were successfully tested and the well was completed with a single selective string. The Sillaro-2 Dir well was drilled in 2009. This well has a dual selective completion (Short and Long strings) and has successfully tested five different gas levels (namely, A, C0, C2+C3 and E1). All these different gas bearing levels are hydraulically separated and there is no pressure communication between them. Figure 4.2 is a schematic of the reservoir levels and also a cross sectional diagram of the well completions. The C0 level is the only currently producing layer in the Sillaro field as shown in the green box. The suspended production levels are shown in the grey boxes.

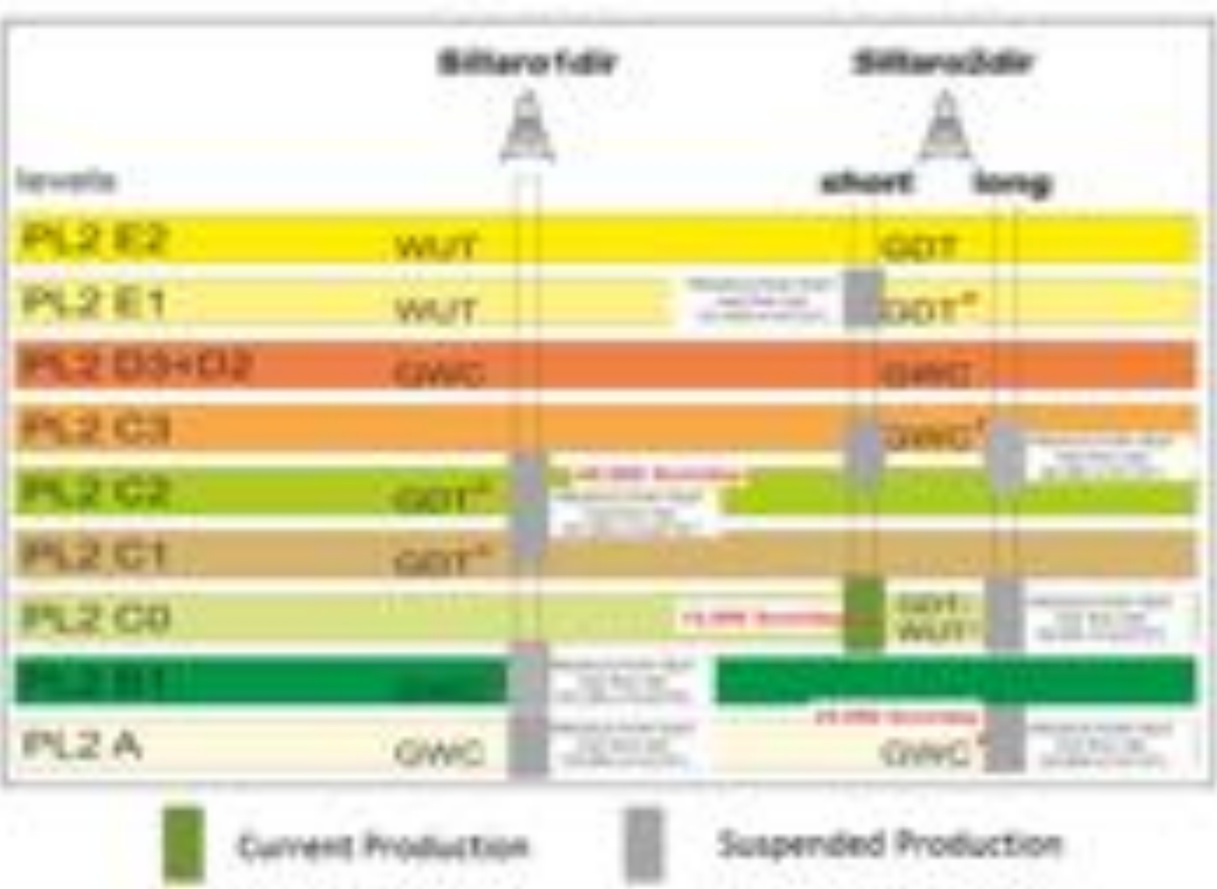

Figure 4-2 Sillaro Field Producing Levels and Well Completions (as of 31st October 2017)

Key:- WUT = Water Up To, GWC = Gas Water Contact, GDT = Gas Down To

Production from the Sillaro field started in May 2010 from 3 different reservoir levels; the field is currently producing from C0 in Sillaro-2dir (Short String). The Sillaro production data have been provided as at 31st October 2017. The total production of the Sillaro field as of 31st October 2017 is 121.62 MMscm. The current producing level and the production from the suspended levels are tabulated in Table 4.2. Figure 4.3 shows the daily gas production of each level in Sillaro.

Level E1 was producing from Sillaro-2Dir (Short String), and was suspended in August 2011 due to excessive water breakthrough.

C2+C3 levels were put on production in July 2013 via Sillaro-2dir (Short String). The C2+C3 levels were switched to produce via Sillaro-2dir (Long String) in November 2014 before it was suspended due to water load up. Attempts were made in 2016 to bring the levels back online but were unsuccessful.

C1+C2 levels started production from Sillaro-1Dir in June 2010 producing at fairly good gas production rates until January 2012, when the flow was stopped due to the facilities being unable to handle associated condensate. The facilities have been upgraded to resolve the issue, and the level C1+C2 resumed production in July 2013. In 2014, there was a significant increase of the water production in Sillaro-1dir from the level C1+C2. Consequently, the C1+C2 levels were suspended in April 2014. During 2015-2016, Saffron has attempted but failed to shut off water from C2 and to bring C1 online in Sillaro-1Dir and Sillaro-2Dir (Long String). The operations have blocked future access to the B1 and A levels.

Level C0 is thin bedded and below log resolution. Notwithstanding the fact that it cannot be defined by logs, as at 31st October 2017 level C0 has produced 17.74 MMscm of gas. This demonstrates additional potential in thin bedded zones. Level C0 was the only level on production as of 31st October 2017. Decline curve analysis has been performed to estimate remaining reserves.

Level B1 was put on production via Sillaro-1Dir in 2012. B1 was shut-in during 2013-2014 while the Sillaro-1Dir was producing from C1+C2. B1 was online again in June 2014. There was a significant increase in water production in 2015. B1 was shut-in in November 2015 for intervention on C1+C2 level in Sillaro-1Dir. The interventions in both Sillaro-1Dir and Sillaro-2Dir (Long String) prevent future access to level B1 from the existing wells.

Level A has been produced from Sillaro-2Dir (Long String) between 2010 and 2014 before watering-out. The interventions in both Sillaro-1Dir and Sillaro-2Dir (Long String) prevent future access to level A from the existing wells.

Studies of historic production and pressure have judged that there had been a misallocation of production between C1, C2, and A levels due to leakage. In addition level C1 has produced 1 MMscm of gas when comingled with C2 (i.e. at 31st October 2017, level C1, C2, and A have produced 1 MMscm, 51 MMscm, and 16 MMscm, respectively). Therefore, there is the potential of undrained gas volumes in C1 hence the intervention attempts during 2015-2016.

Level E1 has produced 5.91 MMscm of gas as at 31st October 2017and has been suspended due to water.

Table 4-2 Sillaro Production Levels and Cumulative Production as of 31st October 2017

Level	Status	Well(String)	Cumulative Production (as of 31st October 2017)
E1	Suspended due to high water	Sillaro-2-Dir(SS)	5.91 MMscm
C2+C3	Suspended due to high water	Sillaro-2Dir(SS)	11.90 MMscm
C2+C3	Suspended due to high water	Sillaro-2Dir(LS)	0.28 MMscm
C1+C2	Suspended due to high water	Sillaro-1Dir	30.91 MMscm
C0	Current producing level	Sillaro-2Dir(SS)	17.74 MMscm
B1	Suspended due to high water/inaccessible	Sillaro-1Dir	16.44 MMscm
A	Suspended due to high water	Sillaro-2Dir(LS)	38.44 MMscm

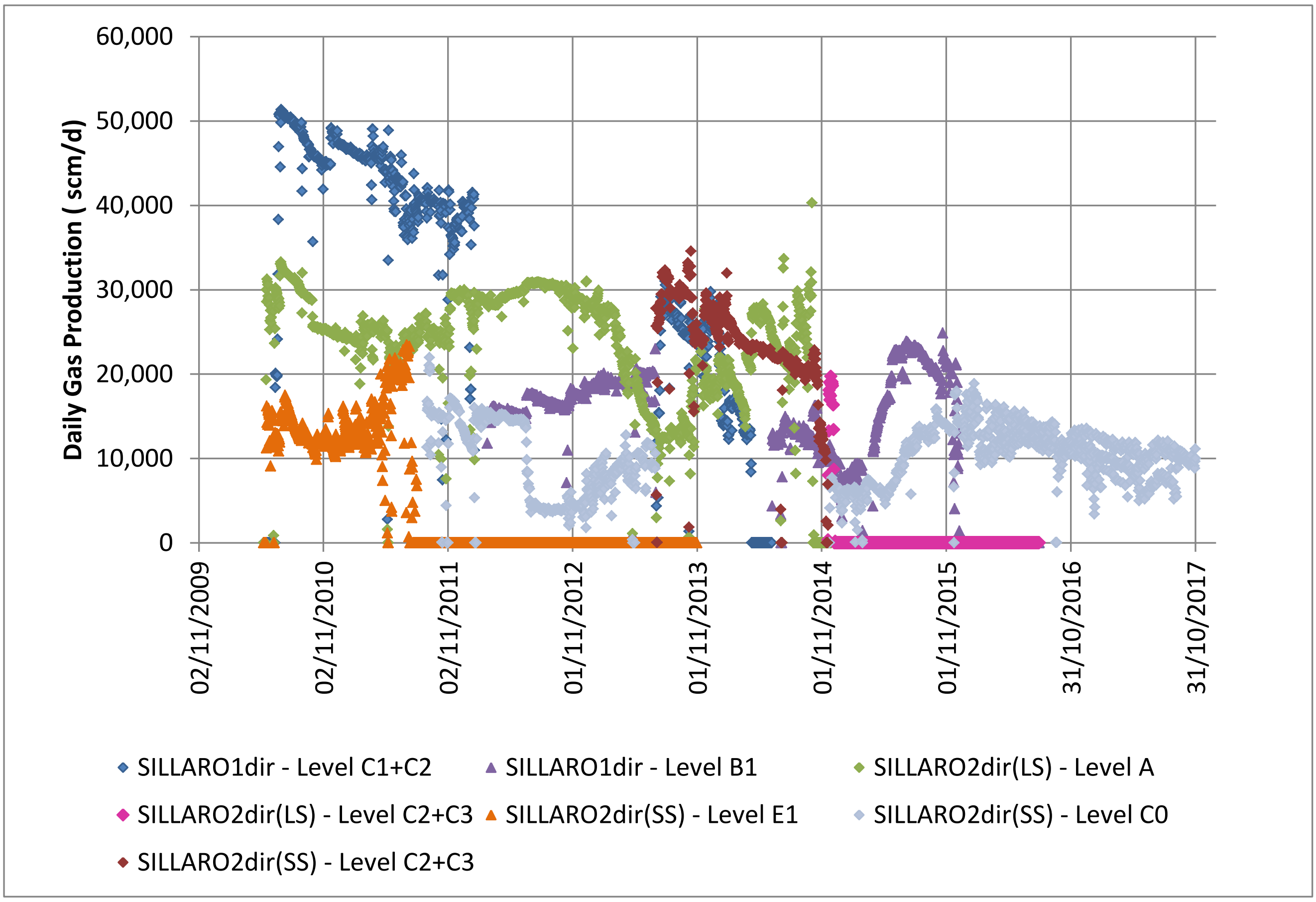

Figure 4-3 Daily Gas Production of Each Level in Sillaro

CGG has classified petroleum resources using the SPE Petroleum Resource Management System (2007). The reserves and contingent resources reported are as at 1st January 2018. Table 4.3 is the summary of the remaining reserves and contingent resources in the Sillaro field.

Table 4-3 Sillaro Remaining Reserves and Contingent Resources by Layer as of 1st January 2018

Remaining technical reserves and resources as of 1st January 2018 (100%)						
Layer	Reserves, MMscm (1)			Contingent Resources, MMscm (1)		
	1P	2P	3P	1C	2C	3C
E1						
E0 (2)	-	-	2.9			
D (2)	-	-	7.9			
C2						
C1 (3)				16.2	27.5	38.8
C0	0.3	0.8	3.5			
B1 (3)				-	3.8	3.8
A						
Miocene Medium (3)	-	47.8	47.8			
Miocene Deep (3)	-	13.4	13.4			
Total (4)	**0.3**	**62.0**	**75.4**	**16.2**	**31.3**	**42.7**

(1) MMscm is Million standard cubic metres.
(2) E0 and D layers are assumed to be recovered from one string of Sillaro-3 (dual string, side-tracked from Sillaro-1) well drilled in Q2 2018. The reserves and resources are subjected to final board approval and funding.
(3) C1, B1, Miocene Medium, and Miocene Deep are assumed to be recovered from the other string of Sillaro-3 (dual string, side-tracked from Sillaro-1) well drilled in Q2 2018. The reserves and resources are subjected to final board approval and funding.
(4) Total remaining volumes are arithmetically summation of all layers and may not add due to rounding error.

The C0 reserves have been assessed using decline curves. The additional reserves and contingent resources are estimated based on the current development plan of drilling Sillaro-3Dir by sidetracking from Sillaro-1. Saffron has informed CGG that the Sillaro-3Dir development plan has been approved and funded. The Miocene sequence is split into Miocene Medium and Miocene Deep. The Miocene Medium was previously produced in the 1960s as the Fantuzza field from Budrio-2 and Budiro-3Dir wells. Total gas production was 10.6 MMScm, but the historical daily production has not been made available for review. The 2P reserves of Miocene Medium and Miocene Deep are estimated by applying 40% recovery factor to the gas-initially-in-place. The C1 and B1 levels have been classified as contingent resources. In order for C1 and B1 to be re-classified as reserves, the Sillaro-3Dir must be drilled, logged, and tested. It should be noted that disappointing evaluation results for Sillaro-3Dir could lead to reclassification/reduction of resources.

The Sillaro-3Dir well is planned as a dual string completion. One of the strings is for Miocence production targeted in July 2018. The D and E0 levels are assumed to be recovered by the other string of Sillaro-3Dir with production targeted in July 2018 and November 2020 respectively. There are no remaining reserves in the E1, C2, and A levels.

The production profiles for 1P, 2P and 3P reserves are graphically shown in Figure 4.4. Table 4.4 shows the annual production and cumulative production.

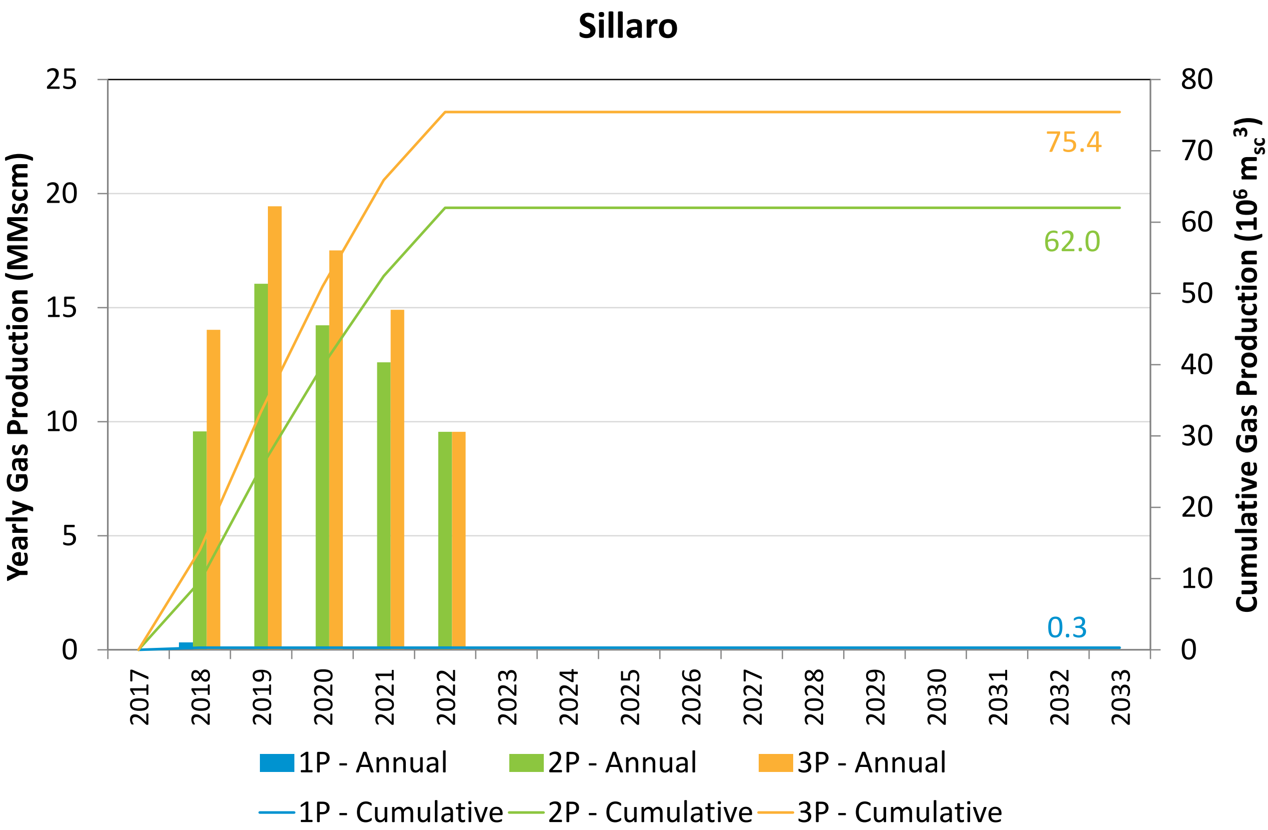

Figure 4-4 Technical Production Profiles of Sillaro 1P, 2P and 3P (before Economic Cut-off)

Table 4-4 Annual Production and Cumulative Production of Sillaro (before Economic Cut-off)

Year	1P		2P		3P	
	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)
2018	0.32	0.32	9.58	9.58	14.03	14.03
2019	0.00	0.32	16.04	25.62	19.45	33.47
2020	0.00	0.32	14.22	39.85	17.51	50.98
2021	0.00	0.32	12.60	52.45	14.91	65.89
2022	0.00	0.32	9.56	62.00	9.56	75.45

5 BEZZECCA

5.1 Geology and Geophysics

CGG has reviewed the methods, interpretations and results of new geological interpretations carried out by Saffron for the Bezzecca Field. During the last 18-24 months, new structural maps have been generated from re-processed 2D seismic lines. Saffron's seismic project and interpretation has been reviewed on workstations by CGG.

The distribution of 2D lines over the area of interest is shown in Figure 5.1 below:

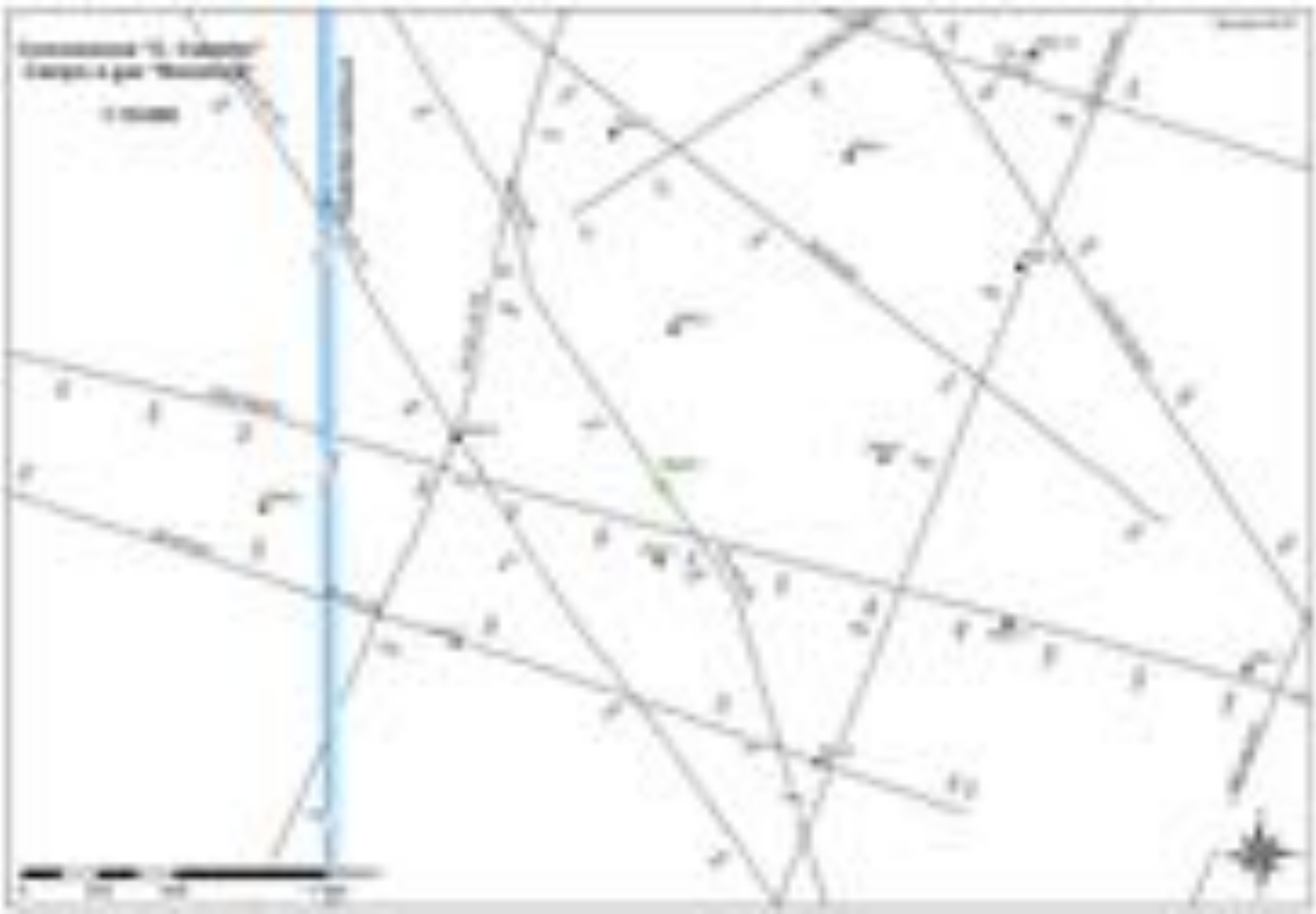

Figure 5-1 Seismic Base Map and Location of Wells, Bezzecca Field

Whereas the seismic coverage is adequate for a general view of the structure, the interpretation of faults and fault-bounded blocks is subject to uncertainty. The old Pandino wells provide accurate depth markers at top reservoir and intra-reservoir levels in between 2D lines.

The re-processing has resulted in improved imaging of reservoir and faults, and as a result of the re-interpretation, the future development plan has been modified.

Created by:
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The main result of the re-mapping has been the identification of four isolated structural blocks, each having different fluid contacts as shown in Figure 5.2 below:

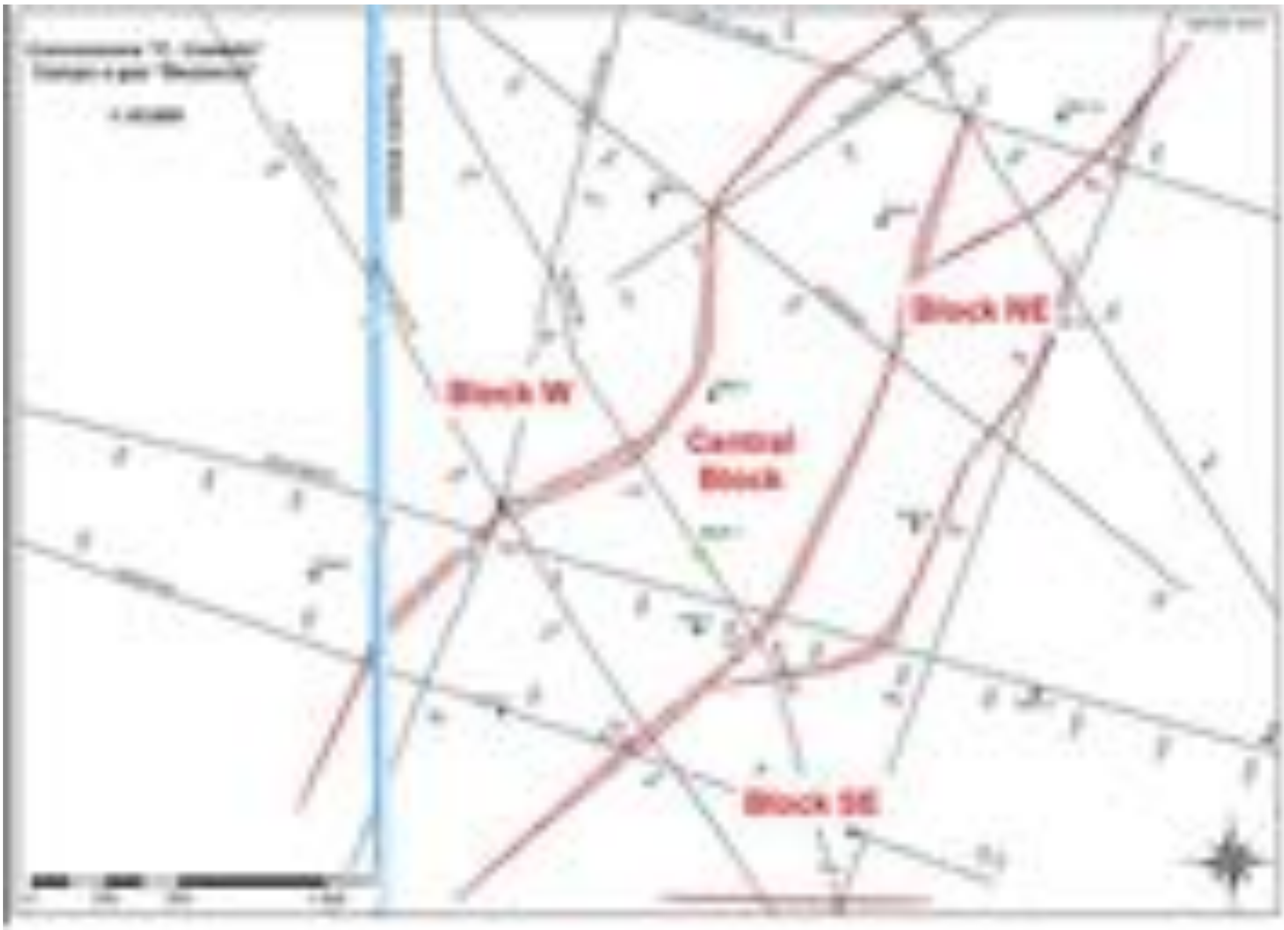

Figure 5-2 Identified Fault Blocks, Bezzecca Field

In the Bezzecca Field, there are six target reservoirs, three in the Pliocene (PL1C, PL1B and PL1A) and three more in the underlying Miocene (MI3-T, MI3-S and MI3-R).

Reservoir correlations (between wells) have been reviewed and revised as necessary. Whilst the correlations appear to be sound, there is always scope for mis-correlation between wells in the absence of 3D seismic. It is assumed that reservoir sands are laterally continuous, and whereas experience suggests that this is normally the case in the area, and is geologically the most reasonable, only long-term production will reveal just how laterally connected the sands are. They are thin enough that a small (unmapped) fault could conceivably compartmentalize the reservoir, for example.

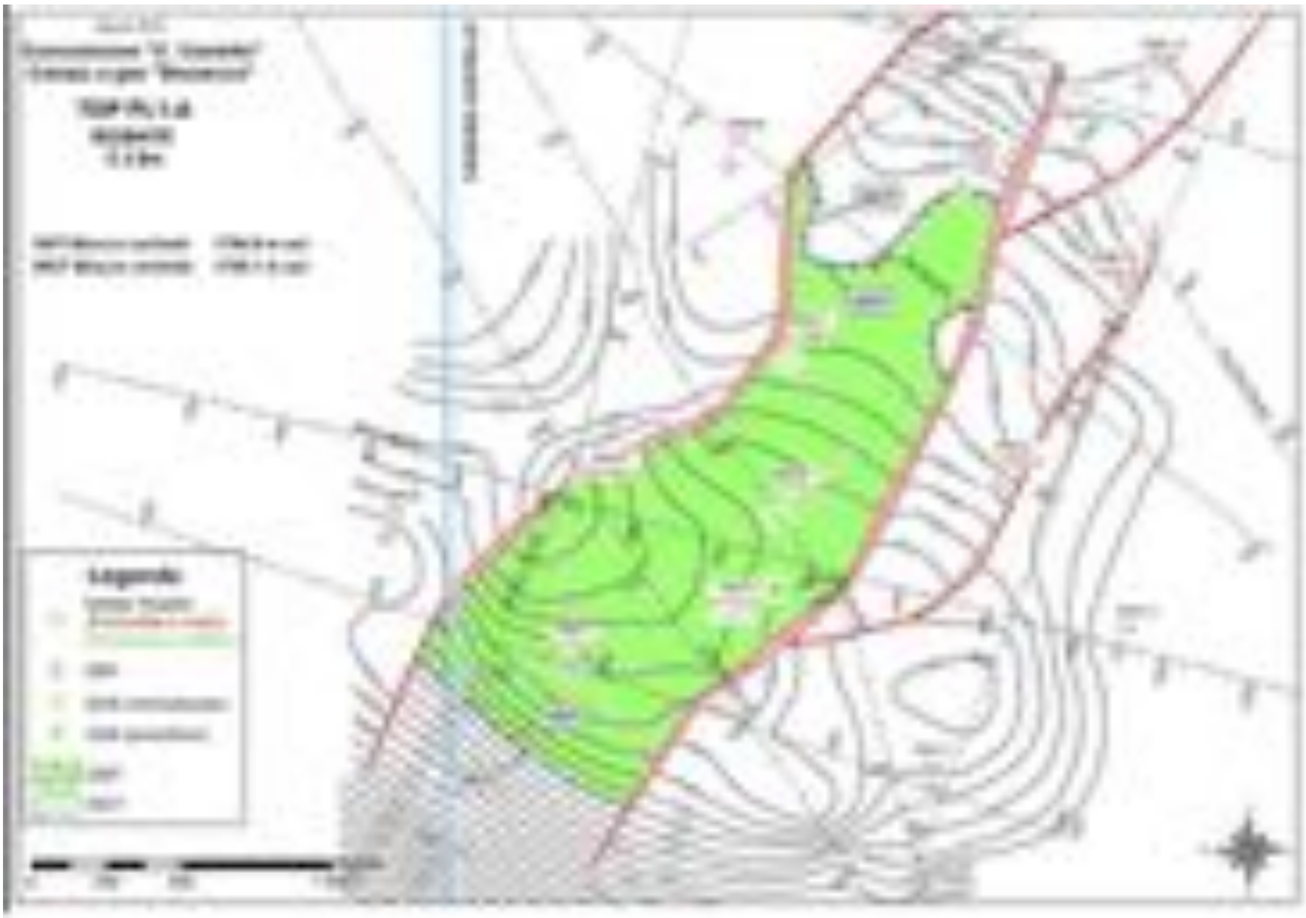

Figure 5-3 Pliocene Reservoir Level PL-1A Depth Structure, Bezzecca Field

In addition to a revision of the structural and stratigraphic interpretation, a full and detailed review of the rock properties has been undertaken by a petrophysicist with experience in the region. The wireline log data underlying the petrophysical interpretations is dominated by older log suites in the old Pandino wells, but also includes the latest Bezzecca suite of logs. There remains some uncertainty in the input parameters and output results, but this is not as significant as the uncertainty in Gross Rock Volume that derives from the 2D seismic coverage.

Figure 5-4 Miocene Reservoir Level MI3-T Depth Structure, Bezzecca Field

Reservoir properties for the different gas-bearing target layers are provided in Figure 5.1 below:

Table 5-1 Reservoir Properties in Bezzecca Reservoir Zones, Bezzecca Field

LEVELS	Net/Gross (fraction)	PHIE (fraction)	Sw (fraction)	1-Sw (fraction)	Bg (fraction)	1/Bg (fraction)
PL1-C	0.6	0.18	0.30	0.70	0.005176	193.19
PL1-B	0.9	0.18	0.30	0.70	0.005156	193.94
PL1-A	0.75	0.15	0.40	0.60	0.005135	194.73
MI3-T	0.341	0.11	0.55	0.45	0.005088	196.55
MI3-S	0.439	0.13	0.40	0.60	0.005049	198.07
MI3-R	0.387	0.11	0.55	0.45	0.005022	199.12

The calculation of GIIP proceeded by means of standard and reliable industry methods, including the use of the depth structure maps, initial gas-water contacts (in each fault block) and the reservoir and fluid properties as tabulated above. GIIP is reproduced in the three tables below. Significant uncertainties in the Gross Rock

Volume and field-wide average reservoir properties, as well as the presence of undetected structural or stratigraphic discontinuities, could have an impact on the reserves that are estimated from these GIIP numbers.

Table 5-2 Original Gas-in-Place, Central Fault Block, Bezzecca Field

Levels	GIIP of Central Fault Block NNE-SSW (wells Pandino 1,2,4,7 & Bezzecca 1)					
	GRV	Phi	NtG	Sg	1/Bg	GIIP
	MMscm	(frac)	(frac)	(frac)		MMscm
PL1-B	1.26	0.18	0.9	0.7	193.94	27.71
PL1-A	4.17	0.15	0.75	0.6	194.73	54.81
MI3-T	33.8	0.11	0.341	0.45	196.55	112.14
MI3-S	8.9	0.13	0.439	0.6	198.07	60.36
MI3-R	37.1	0.11	0.387	0.45	199.12	141.52
Total						**396.54**

Table 5-3 Original Gas-in-Place, North East Fault Block, Bezzecca Field

Levels	GIIP of NE Fault Block (wells Pandino 6 & 10)					
	GRV	Phi	NtG	Sg	1/Bg	GIIP
	MMscm	(frac)	(frac)	(frac)		MMscm
PL1-B $_{GDT-WUT}$	1.2	0.18	0.9	0.7	193.94	26.39
MI3-T	11.4	0.11	0.341	0.45	196.55	37.82
MI3-R	10.7	0.11	0.387	0.45	199.12	40.81
Total						**105.03**

Table 5-4 Original Gas-in-Place, South East Fault Block, Bezzecca Field

Levels	GIIP of SE Fault Block (wells Pandino 3 & 11)					
	GRV	Phi	NtG	Sg	1/Bg	GIIP
	MMscm	(frac)	(frac)	(frac)		MMscm
PL1-C	9.49	0.18	0.6	0.7	193.19	138.60
MI3-T	9.42	0.11	0.341	0.45	196.55	31.25
MI3-S	5.56	0.13	0.439	0.6	198.07	37.71
Total						**207.57**

Historical production from the Pandino Field has been subtracted to arrive at the remaining GIIP, and the current position of the gas-water contact (GWC) has been estimated using standard techniques.

Generally speaking, the aquifer in the region is an active one. Some gas wells have watered out, or coned water. Saffron's stated approach is to attempt to limit this risk by producing at sustainable rates, thus helping to avoid water coning into the production perforations.

5.2 Reservoir Engineering

The field "Bezzecca" (formerly ENI's Pandino field) is located in the "Cascina S.Pietro" Permit, in the Northern part of the Po Valley between Cremona, Lodi, Bergamo and Milano Provinces. The Pandino gas field was discovered by ENI in 1955 through drilling of the well PAN-1. In total thirteen wells were drilled in the structure until 1964; eight of them were producers as PAN-1, PAN-2, PAN-3, PAN-4, PAN-5, PAN-6, PAN-7, and PAN-10. Production started from the two main Miocene zones in 1956 and ceased in January 1964. The field's cumulative gas production is reported as 144.4 MMscm from all producing levels in all blocks. All historical producers are currently plugged and abandoned.

Saffron drilled a new well Bezzecca-1 in March 2009, and tested gas from the Miocene and Pliocene reservoirs. Well test interpretation indicates a permeability range of 1.3 - 37.9 mD in different producing layers.

During 2015-2016, with the interpretation of a new seismic line and petrophysics, Saffron has reassigned the gas produced. There is uncertainty on which levels were on production and how much gas had been produced from such levels due to commingled production and thinly bedded layers (i.e. some production was assigned to PL1-A then re-assigned to PL1-B after new petrophysics interpretation). Table 5.5 is the summary of Bezzecca GIIP and cumulative production before Bezzecca-1 production. CGG has taken cumulative production to be 152.47 MMscm. It should be noted that this is higher than the reported figure of 144.4 MMscm.

Table 5-5 Bezzecca GIIP and Cumulative Production before Bezzecca-1 Production

Layer	GIIP, MMscm (1)	Cumulative Gas Production before Bezzecca-1 Production, MMscm (1)
Central Block		
PL1-B	27.71	1.62
PL1-A	54.81	22.11
MI3-T	112	39.41
MI3-S	60.36	23.53
MI3-R	141.51	32.70
North-East Block		
PL1-B (2)	13.00 (GDT) 26.39 (WUT)	1.68
MI3-T	37.82	3.92
MI3-R	40.81	9.86
South-East Block		
MI3-T	31.25	0.00
MI3-S	37.71	0.00
PL1-C (3)	138.02 (original) 21.52 (current)	14.35
West Block		
MI3-S	0.68	0.29
MI3-R	9.69	3.00

(1) MMscm is Million standard cubic meters.
(2) For PL1-B-NE, GIIP of GDT, Avg(GDT, WUT), WUT are used to calculate 1P, 2P, 3P, respectively.
(3) For PL1-C-SE, the current GIP is used to calculate 1C, 2C, 3C.

5.2.1 Bezzecca-1 Production and Remaining Reserves by Well

The Bezzecca-1 well was on production in April 2017 and has been produced from 3 different reservoir levels: PL1-A, MI3-S, and MI3-R (reference Figure 5.5). Initially, MI3-S opened for 16 days, then PL1-A for seven days, then MI3-R for two days, then back to PL1-A from May 2017 to July 2017. The production has been comingled from MI3-S and PL1-A since July 2017 (reference Figure 5.6).

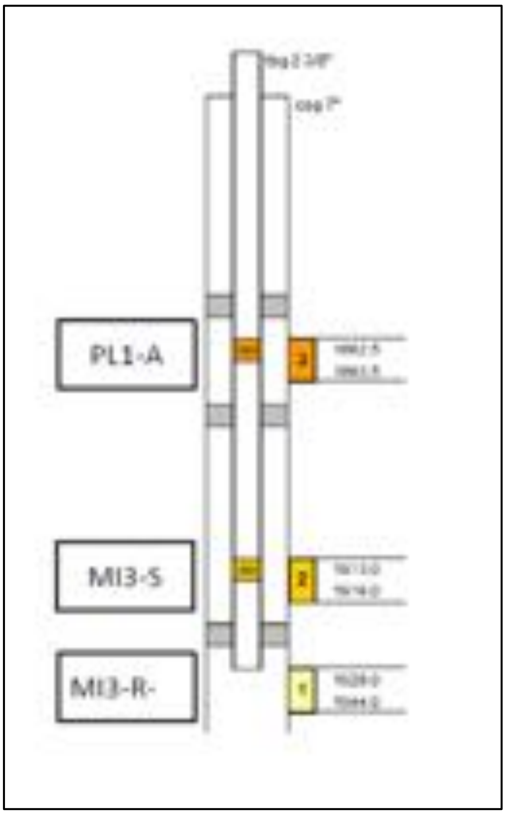

Figure 5-5 Bezzecca-1 Well Schematic

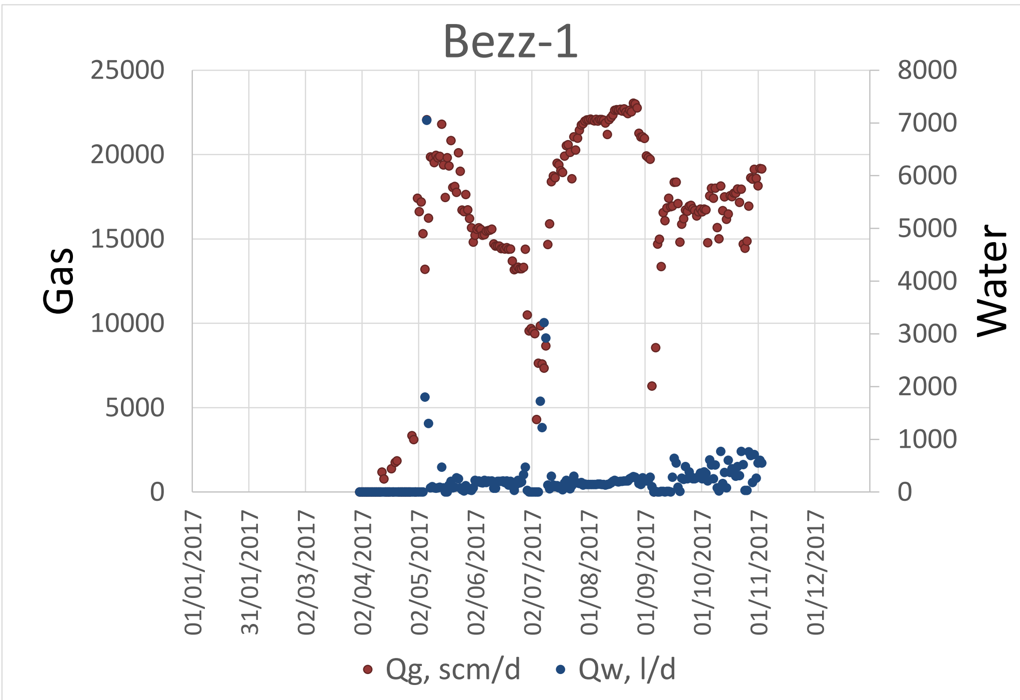

Figure 5-6 Daily Gas and Water Production in Bezzecca-1

As the MI3-S and PL1-A levels have been on comingled production since July 2017, CGG evaluated their performance and estimated reserves together using decline curve analysis.

There was an attempt to open MI3-R in July for four days with the total production of 6,150 litres of water and 3,239 scm of gas. CGG therefore has not booked any remaining reserves for MI3-R in Bezzecca-1.

Table 5-6 Bezzecca-1 Remaining Reserves as of 1st January 2018

BEZZECCA-1 (MI3-S + PL1-A) CENTRAL BLOCK			
	1P	2P	3P
Recoverable Volumes, MMscm	4.5	5.0	6.0
Cumulative Production as of 31st October 2017, MMscm		3.20	
Estimated Production in Nov-Dec 2017, MMscm		1.10	
Remaining Reserves as of 1st January 2018, MMscm	**0.20**	**0.70**	**1.70**

The production from Bezzecca-1 well has fallen below expectations. One of the reasons could be its location, which is in the middle of the central block. Saffron identifies updip gas volumes and has proposed to drill a new well (Bezzecca-2) into the updip location to recover the updip gas. In addition, Saffron has proposed to drill another well, Bezzecca-3, into the North-East block. Saffron has informed CGG that the proposed Bezzecca-2 and Bezzecca-3 development plan has been approved by the board of directors and has received approvals from the relevant Italian authorities.

CGG has estimated the volume of updip gas that could be recovered by Bezzecca-2 as tabulated in Table 5.7.

In MI3-S and PL1-A levels in the central block, the volumes recovered by Bezzecca-2 is estimated at 1.40, 12.42, 22.94 MMscm for 1P, 2P, 3P, respectively. The total recovery factors of MI3-S-Central are 0.4, 0.5, and 0.6 for 1P, 2P, 3P, respectively. The total recovery factors of PL1-A-Central are 0.5, 0.6, and 0.7 for 1P, 2P, 3P, respectively.

In MI3-R level in the central block, the volume recovered by Bezzecca-1 is almost zero with high water production. It is suspected that the current gas-water contact (GWC) is higher than expected. However, there is uncertainty of the current gas-water contact (GWC) depth as MI3-R level consists of four sands.

CGG has estimated MI3-R reserves that could potentially be recovered by Bezzecca-2 by using three GWC assumptions:

- Bezzecca-2 MI3-R 1P case: GWC estimated at top of current perforations (1928m MD), results in GIP of 27.8 MMscm, assumed recovery factor of 50%; giving 1P reserves of 13.88 MMscm. In this case, we assume gas coning (downwards) is responsible for observed gas flow.

- Bezzecca-2 MI3-R 2P case: GWC estimated at half way up current perforations (1936m MD), results in GIP of 49.7 MMscm, assumed recovery factor of 50%, giving 2P reserves of 24.83 MMscm
- Bezzecca-2 MI3-R 3P case: GWC estimated to cover only the deepest perforation (water up to 1942m MD), results in GIP of 60.7 MMscm, assumed recovery factor of 50%, giving 3P reserves of 30.37 MMscm

CGG has been informed that Saffron is working on bringing the MI3-R in Bezzecca-1 back on production during November – December 2017 by isolating the bottom layers. The outcome of the water shutoff operation is expected to be concluded in Q1 2018. At this stage, CGG has booked no reserves for MI3-R in Bezzecca-1 and booked reserves for MI3-R in Bezzecca-2 using the methods mentioned above.

Table 5-7 Bezzecca-2 Remaining Reserves as of 1st January 2018

BEZZECCA-2 (MI3-S + PL1-A + MI3-R) CENTRAL BLOCK			
	1P	2P	3P
MI3-S + PL1-A, MMscm	1.40	12.42	22.94
MI3-R, MMscm	13.88	24.83	30.37
Remaining Reserves as of 1st January 2018, MMscm	**15.28**	**37.25**	**53.31**

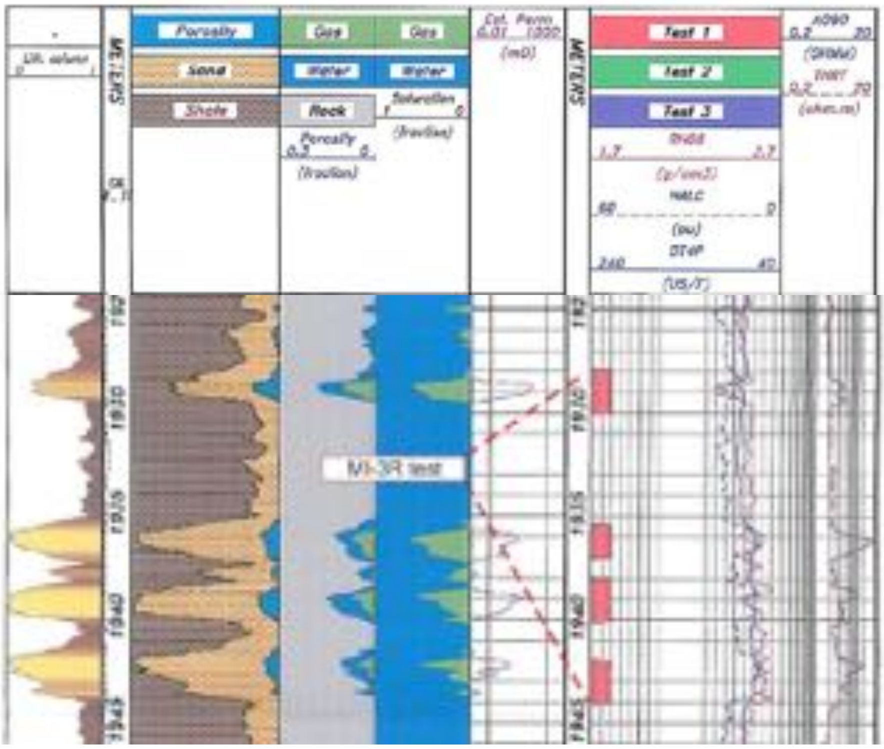

Figure 5-7 Bezzecca-1 Well Log of MI3-R

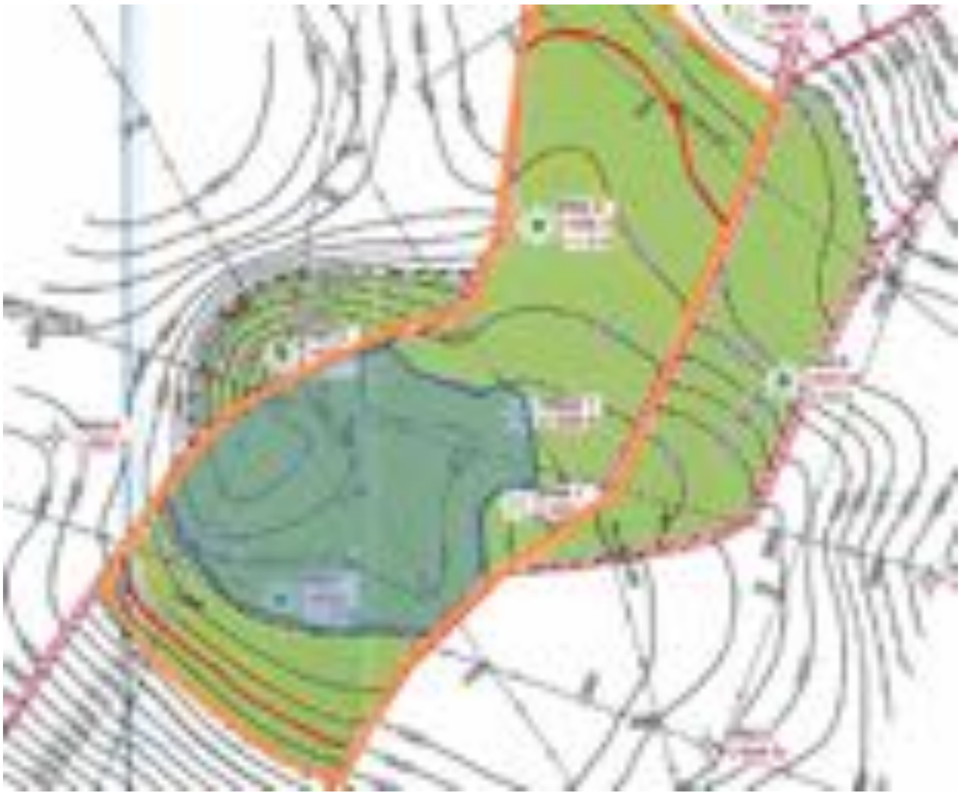

Figure 5-8 MI3-R Structure Map for Bezzecca-2 Volume Estimation

KEY: Blue – GWC for 1P, Yellow – GWC for 2P, Red – GWC for 3P, Orange – Assumed GWC before opening MI3-R zone for flow testing/production

CGG has estimated the volume of gas in the North-East block that could be recovered by Bezzecca-3 as tabulated in Table 5.8.

Table 5-8 Bezzecca-3 Remaining Reserves as of 1st January 2018

BEZZECCA-3 (PL1-B + MI3-T + MI3-R) NORTH EAST BLOCK			
	1P	**2P**	**3P**
PL1-B, MMscm	4.82	10.14	16.80
MI3-T, MMscm	11.21	14.99	18.77
MI3-R, MMscm	6.46	10.54	14.63
Remaining Reserves as of 1st January 2018, MMscm	**22.49**	**35.67**	**50.20**

Bezzecca-2 and Bezzecca-3 are planned as a dual completion. Bezzecca-2 is planned to produce from MI3-R in one string and MI3-S + PL1-A in the other string with the first production targeted in March 2020. Bezzecca-3 is planned to produce from MI3-R in one string and MI3-T in the other string with the first production targeted in January 2022. In Bezzecca-3, PL1-B is expected to produce after MI3-T in 2025 (1P, 2P cases) and in 2027 (3P case). The production profiles for 1P, 2P and 3P reserves are graphically shown in Figure 5.9. Table 5.9 shows the annual production and cumulative production.

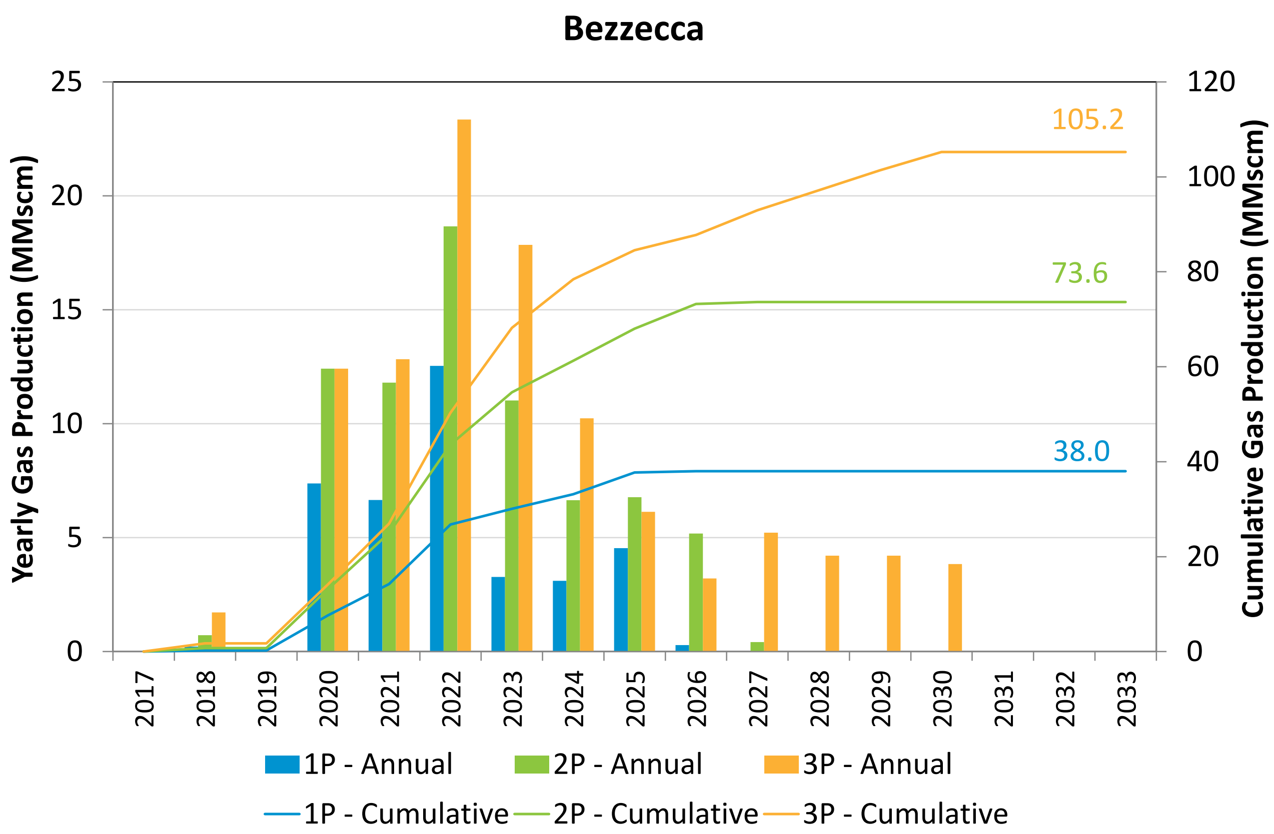

Figure 5-9 Technical Production Profiles of Bezzecca 1P, 2P and 3P (before Economic Cut-off)

Table 5-9 Annual Production and Cumulative Production of Bezzecca (before Economic Cut-off)

Year	1P		2P		3P	
	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)
2018	0.22	0.22	0.72	0.72	1.72	1.72
2019	0.00	0.22	0.00	0.72	0.00	1.72
2020	7.38	7.60	12.42	13.14	12.42	14.14
2021	6.65	14.25	11.80	24.94	12.83	26.97
2022	12.54	26.78	18.66	43.60	23.35	50.33
2023	3.28	30.06	11.02	54.62	17.85	68.18
2024	3.11	33.17	6.65	61.26	10.23	78.41
2025	4.54	37.71	6.77	68.04	6.13	84.54
2026	0.28	37.99	5.18	73.22	3.21	87.75
2027	0.00	37.99	0.42	73.64	5.22	92.97
2028	0.00	37.99	0.00	73.64	4.21	97.18
2029	0.00	37.99	0.00	73.64	4.21	101.39
2030	0.00	37.99	0.00	73.64	3.84	105.23

5.2.2 Remaining Reserves and Resources by Layer

CGG has classified petroleum resources using the SPE Petroleum Resource Management System (2007). The reserves and contingent resources reported are as at 1st January 2018. Table 5.10 summarises the remaining reserves and contingent resources in the Bezzecca field.

The range of recovery factors have been applied to the gas initially in-place volumes to calculate a range of recoverable volumes. The cumulative production is then subtracted to obtain remaining recoverable volumes. In the PL1-C-SE layer, the supposed current GWC has been used to calculated the gas currently in-place. There is, therefore, no need to subtract the cumulative production.

- For Pliocene levels, recovery factors of 50%, 60%, and 70% are applied for low, best, and high estimates.
- For Miocene levels, recovery factors of 40%, 50%, and 60% are applied for low, best, and high estimates.

MI3-T-SE and MI3-S-SE have been classified as contingent resources pending future development. These two layers could be reclassified as reserves in the future when an additional well is planned and approved in the South-East block.

The other three layers: PL1-B-Central, MI3-T-Central, and PL1-C-SE have been classified as contingent resources. In order for them to be reclassified, the following "decision gates" must be met:

PL1-B-Central:

- Pressure tests – there is uncertainty on which layers have been produced. Therefore this is contingent on a physical pressure test of the layer which provides evidence of commercially producible gas.

MI3-T-Central:

- Bezzecca-1 well performance and timing – the layer is contingent on production data and layer performance so that intervention timing can be optimised in order to maximise overall recovery (Reserves + Contingent Resources). If the MI3-T-Central layer volumes accessed via an intervention, once the timing and intervention plan are established, are shown to be commercially producible then these may be moved to reserves.

PL1-C-SE:

- Drilling and successful logging – once a new well is drilled, it may be possible to access this layer so it is contingent on a successful logging operation which establishes commercially producible gas.

Table 5-10 Bezzecca Remaining Reserves and Contingent Resources by Layer as of 1st January 2018

Remaining technical reserves and resources as of 1st January 2018 (100%)						
Layer	**Reserves, MMscm (1)**			**Contingent Resources, MMscm (1)**		
	1P	**2P**	**3P**	**1C**	**2C**	**3C**
Central Block (recovered by existing Bezz-1 well and Bezz-2 new well)						
PL1-B				12.24	15.01	17.78
MI3-T				5.39	16.59	27.79
MI3-S + PL1-A	1.60	13.12	24.64			
MI3-R	13.88	24.83	30.37			
Total in Central Block	**15.48**	**37.95**	**55.01**	**17.63**	**31.60**	**45.57**
North-East Block (recovered by Bezz-3 well - approved well)						
PL1-B	4.82	10.14	16.80			
MI3-T	11.21	14.99	18.77			
MI3-R	6.46	10.54	14.63			
Total in North-East Block	**22.49**	**35.67**	**50.20**			
South-East Block (recovered by 1 well - not approved)						
MI3-T				12.50	15.63	18.75
MI3-S				15.08	18.86	22.63
PL1-C				10.76	12.91	15.07
Total in South-East Block				**38.34**	**47.40**	**56.45**
West Block						
Total in West Block						
Summary of all Blocks (recovered by 3 development wells)						
PL1-B	4.82	10.14	16.80	12.24	15.01	17.78
MI3-S + PL1-A	1.60	13.12	24.64	0.00	0.00	0.00
MI3-T	11.21	14.99	18.77	17.89	32.22	46.54
MI3-S	0.00	0.00	0.00	15.08	18.86	22.63
MI3-R	20.34	35.37	45.00	0.00	0.00	0.00
PL1-C	0.00	0.00	0.00	10.76	12.91	15.07
Total in All Blocks (2)	**37.97**	**73.62**	**105.21**	**55.97**	**79.00**	**102.02**

(1) MMscm is Million standard cubic meters.

(2) Total remaining volumes are arithmetically summation of all layers and may not add due to rounding error.

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6 SANT'ALBERTO

6.1 Geology and Geophysics

Saffron has submitted a licence application, named Sant'Alberto, to the Italian authorities which would allow them to carry out this gas field redevelopment project. The old field (S.Pietro in Casale) was divided into blocks by faults; it is incompletely drained with updip gas remaining in Block number 5.

This Block is an eastern extension of the old field and has been drilled by the Santa Maddalena-1dir well. In addition, Saffron acquired seven new seismic lines in 2011 (41 km). Seismic line spacing is 0.6km to 1.9km over the structure, which is therefore well defined. The Sant'Alberto – Santa Maddalena structure is a well-defined WNW-ESE oriented hanging-wall anticline at Pliocene level with associated back-thrust and several NNE-SSW oriented tear faults. The seismic shows several hydrocarbon indicators: a bright/flat spot and amplitude inversion at PL1-H level. The prospect polygon is sub-elliptical and lies between seismic lines 02 and 05 acquired by Saffron in 2011.

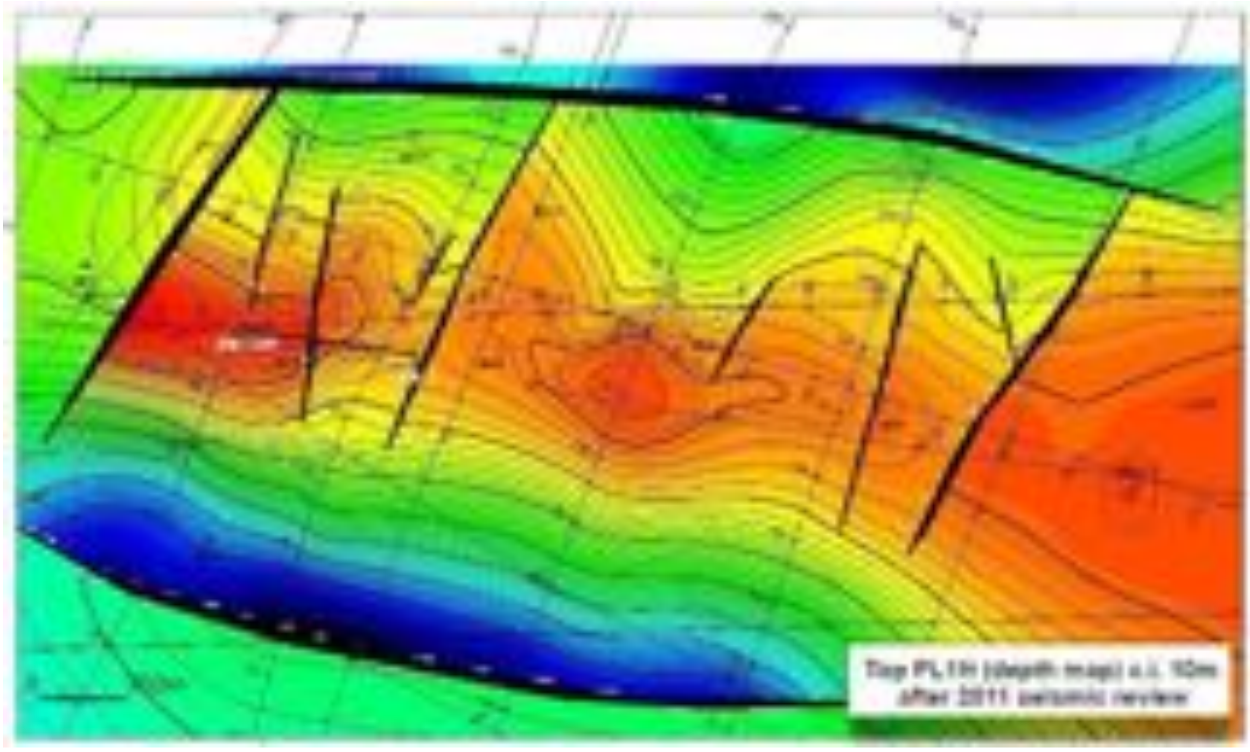

Figure 6-1 Depth Structure Map of the Sant'Alberto Field at Pliocene level

The prospect area (Zone A and Zone B) is comprised between two NNE-SSW oriented tear faults, with Zone A closed against the western boundary fault and Zone B to the east showing a four way dip closure. Gas is trapped in Middle and Lower Pliocene sands, with some possible additional undeveloped gas in the Quaternary.

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6.2 Reservoir Engineering

The Sant' Alberto field, formerly the San Pietro in Casale (SPC) field, is located in the "San Vincenzo" Permit, in the Emilia-Romagna region. The field was historically developed by AGIP through four producers: SPC-1, SPC-4, SPC-8 and SPC-9 from two culminations, known as Zone A and Zone B. The target of the field development was level PL1-H and PL2-C, belonging to the Porto Corsini and Porto Garibaldi formations respectively. Production started from level PL1-H in September 1960 and ceased in January 1976 with a cumulative gas production of 178.4 MMscm. Level PL2-C was opened in April 1976 and production was ceased in August 1985 with cumulative gas production of 23.5 MMscm. All historical producers are currently plugged and abandoned.

EDISON (former operator and partner) drilled a new well SM-1 in 2004, which encountered PL1-H below the gas-water contact (GWC). The well was side-tracked and encountered gas in the main level of the field (PL1-H). The well was completed as a single selective completion by installing three Sliding Side Doors (SSDs). In July 2004, separate production tests were carried out for units PL1-H1 and PL1-H2. A commingled production test of these two units was also carried out in November 2005. The well was not able to produce from PL2-C; therefore CGG has considered PL1-H as the main target for future development.

CGG has reviewed the reports for evaluating the predicted production performance of the existing well and future development wells. The reported estimated remaining gas-in-place (GIP) of Zone A and Zone-B based on new seismic interpretation and mapping is tabulated in Table 6.1.

Table 6-1 Zone-A and Zone-B remaining Gas in Place

Level	Remaining gas-in-place, MMscm
Zone A	93.44
Zone B	31.15
Total	**124.59**

The "Santa Maddalena Field Static and dynamic reservoir study" is a dynamic simulation model study, wherein the model was calibrated with historical production data. The study concluded that the two culminations are currently separated by an aquifer, which invaded a relevant portion of the porous volume as a consequence of the historical production. The presence of a strong water drive has been confirmed. The calibrated simulation model was used to predict the remaining recoverable resources from the existing well and an additional well.

CGG has classified petroleum resources using the SPE Petroleum Resource Management System (2007). The reserves and contingent resources reported are as at 1st January 2018. Table 6.2 summarises the remaining reserves and contingent resources in the Sant'Alberto field.

1P reserves are based on the production from PL1-H level through the existing well - SM-1d. According to the simulation study, the well is capable of producing 50.6 MMscm. 1P reserves are from Zone A culmination only. Production is targeted for Q4 2018.

2P reserves are based on production from PL1-H level through the existing well SM-1d with better recovery based on simulation results. The well is capable of producing 59.5 MMscm. 2P reserves are from Zone A culmination only. Production is targeted for Q4 2018.

3P reserves are based on production from PL1-H level through the existing well SM-1d (as 2P reserves). The additional 3P reserves are from Zone B. An additional well is required to recover from the Zone B culmination. The additional well is capable of producing 20.1 MMscm from Zone B. The 65% recovery factor has been taken from the simulation results of the Zone-B culmination. The additional well is targeted for drilling in Q3 2019 with one month field shut down during that time. First production from the additional well is targeted to be in Q4 2019.

It should be noted that disappointing evaluation results from SM-1d could lead to reclassification/reduction of resources.

The production profiles for 1P, 2P and 3P reserves are graphically shown in Figure 6.2. Table 6.3 shows the annual production and cumulative production.

The current development plan is to have the first year production exported via a low pressure connection at about 260 m from the well head. The max production will be subjected to seasonal gas demand and would have a peak at 9.600 scm/d during winter time, with very low rate during summer time. From the second year, Sant'Alberto is planned to connect to a high pressure connection (70 bar) at about 3.5 Km from the well head.

Table 6-2 Sant' Alberto Remaining Reserves and Contingent Resources by Layer as of 1st January 2018

Remaining reserves and resources as of 1st January 2018 (100%)						
Layer	**Reserves, MMscm (1)**			**Contingent Resources, MMscm (1)**		
	1P	**2P**	**3P**	**1C**	**2C**	**3C**
Zone A	50.6	59.5	59.5			
Zone B	-	-	20.1			
Total (2)	**50.6**	**59.5**	**79.6**			

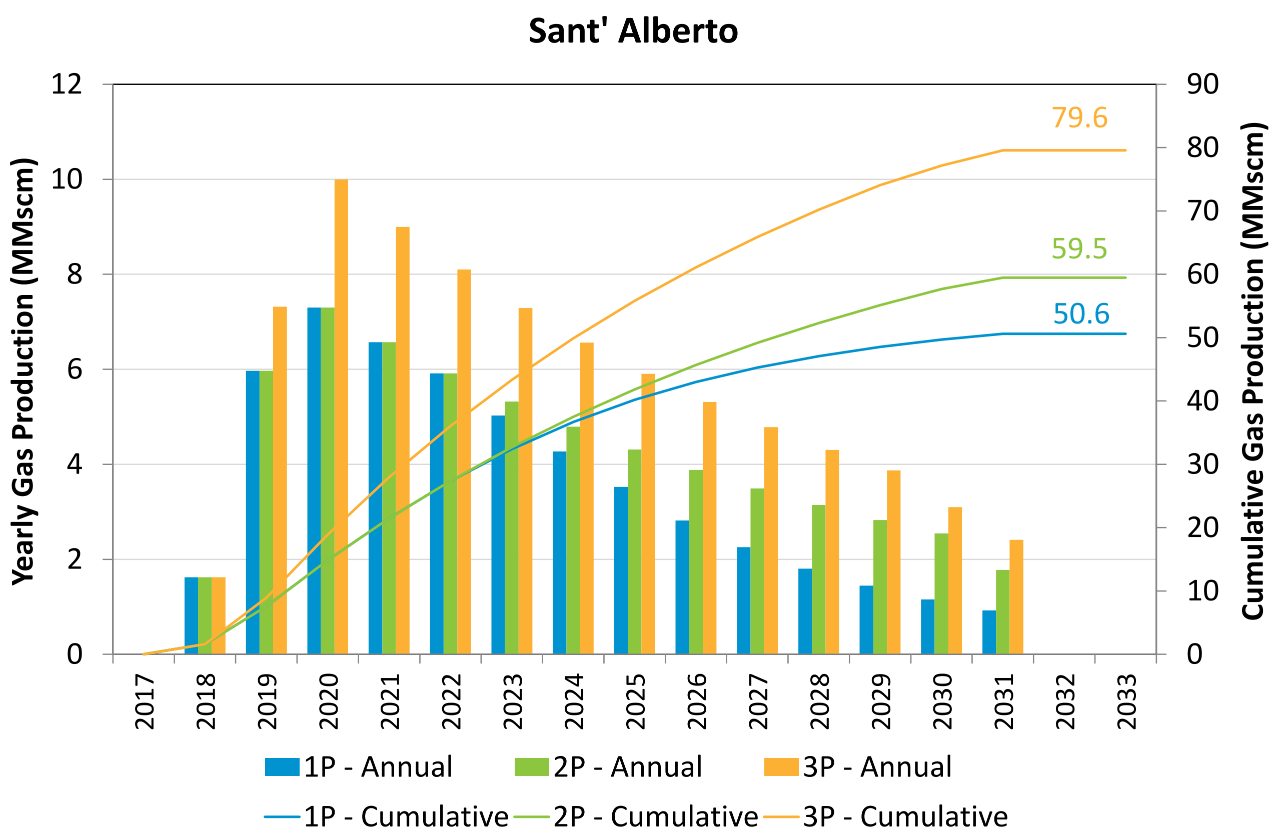


Figure 6-2 Technical Production Profiles of Sant' Alberto 1P, 2P and 3P (before Economic Cut-off)

Table 6-3 Annual Production and Cumulative Production of Sant' Alberto (before Economic Cut-off)

Year	1P		2P		3P	
	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)
2018	1.62	1.62	1.62	1.62	1.62	1.62
2019	5.97	7.59	5.97	7.59	7.32	8.94
2020	7.30	14.89	7.30	14.89	10.00	18.94
2021	6.57	21.46	6.57	21.46	9.00	27.94
2022	5.91	27.37	5.91	27.37	8.10	36.04
2023	5.03	32.40	5.32	32.69	7.29	43.33
2024	4.27	36.67	4.79	37.48	6.56	49.89
2025	3.52	40.20	4.31	41.79	5.90	55.80
2026	2.82	43.02	3.88	45.67	5.31	61.11
2027	2.26	45.27	3.49	49.17	4.78	65.89
2028	1.80	47.08	3.14	52.31	4.30	70.20
2029	1.44	48.52	2.83	55.14	3.87	74.07
2030	1.15	49.67	2.55	57.68	3.10	77.17
2031	0.92	50.60	1.78	59.46	2.41	79.58

7 WEST VITALBA

Saffron obtained a 9 sq. km portion of the Settala 3D seismic survey acquired within C.Castello production licence. The 3D survey, which was acquired for STOGIT in 2006/2007, is intersected by 2D seismic line MI-498 within the Cascina Castello Production License. Using the new 3D data Saffron has mapped two new prospects: West Vitalba and “Up West”.

The West Vitalba prospect occurs as the western extent of Early Pliocene San-A1 and San–A2 reservoirs intersected in the Agnadello-1 well. Each reservoir exists as a pinch-out trap which onlaps a lower sequence boundary. Reservoir quality has been proven by nearby Agnadello field production. Two areal prospect closure cases are defined:

1) the limit of the structural closure from the lap-out edge to the spill point of each pinch-out (San-A1 and –A2)

2) the limits of an amplitude anomaly located immediately east of case 1.

The amplitude anomalies are restricted to single peak reflection events and are interpreted as hydrocarbon indications of gas charged sands based on similar seismic expression of the San-A1 and –A2 reservoirs in the nearby Agnadello Field.

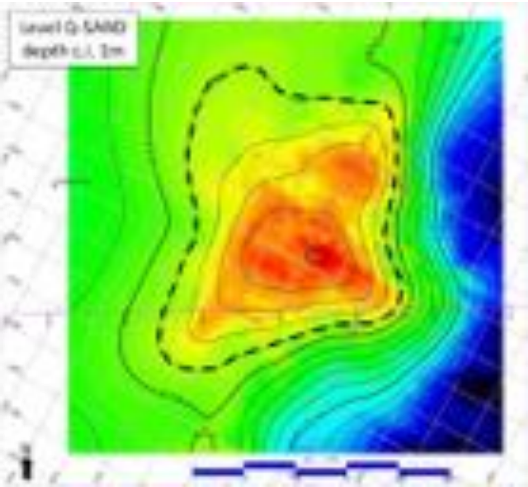
The “Up West” Prospect is defined by a number of amplitude anomalies located above and to the west of the Early Pliocene prospects, with similarly restricted to single peak reflection events at probable Pleistocene level of between 900-1000 msec. As for the West Vitalba prospect, the amplitude anomalies are interpreted as hydrocarbon indications of gas charged sands. As the amplitude anomalies are restricted to single peak reflections they could be considered as a series of stacked reservoirs separated by probable silty intervals in the seismic troughs. The largest of these amplitude anomalies has been mapped as a four-way dip closed and named Up West Prospect. In order to account for the possibility of stacked reservoirs above and below the mapped event, a range of reservoir thicknesses have been used in the probabilistic resource assessment.

The prospective resource estimates for West Vitalba and “Up West Vitalba” are given below in Table 7.1.

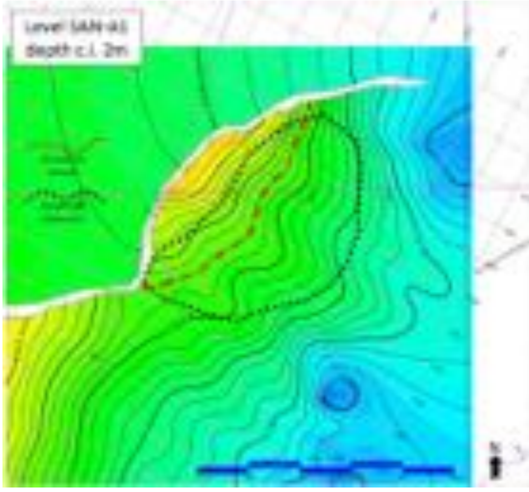
Table 7-1 Prospective Resource Estimates for West Vitalba and “Up West” Prospects

Prospect	Prospective Resources (MMscm)			
	CoS	Low	Best	High
West Vitalba	54%	44.7	69.1	90.9
"Up West"	13%	39.6	62.3	87.8

The Agnadello-1 well, drilled in 1978, is a good analogue to estimate the production potential of Up West Vitalba and West Vitalba prospective resources. The well Agnadello-1 encountered two gas bearing zones separated by a shale interval. These two intervals had been tested with gas rates between 90,000 scm/d and 150,000 scm/d.



(A) Up-west Q-sand depth map



(B) West Vitalba San-1 and San-2 time structure map

Figure 7-1 West Vitalba structures

For the Up West Vitalba gas prospective resources, one deviated well is required to develop this prospect which will also target the West Vitalba prospect. If successful, a 2 km gas pipeline will connect the well to the existing Vitalba gas plant for first gas during 2020.

8 THE PODERE GALLINA LICENCE

8.1 Introduction

PVO drilled, completed and successfully flowed gas to surface from the Podere Maiar-1 well during Q4 2017 and early 2018. The well confirmed the presence of gas at the Selva Stratigraphic asset (a field re-development project; see Section 8.2).

The location of the licence under consideration is provided in Figure 8.1 below.

Figure 8-1 Map showing location of the Podere Gallina licence

8.2 Selva Stratigraphic

The Selva Stratigraphic redevelopment forms part of the former ENI operated Selva Field. The extension of the Selva Field into the Podere Gallina License was interpreted by PVO mainly using isopach mapping from well data at Upper Mid Pliocene level. The most recent reserves modelling study by DREAM (2013) was based on the conservative assumption that the initial GWC of the Selva Field at 1336m TVDSS had risen to 1235m (top level C on Selva 6 well) leaving a potential undrained gas volume updip from this well.

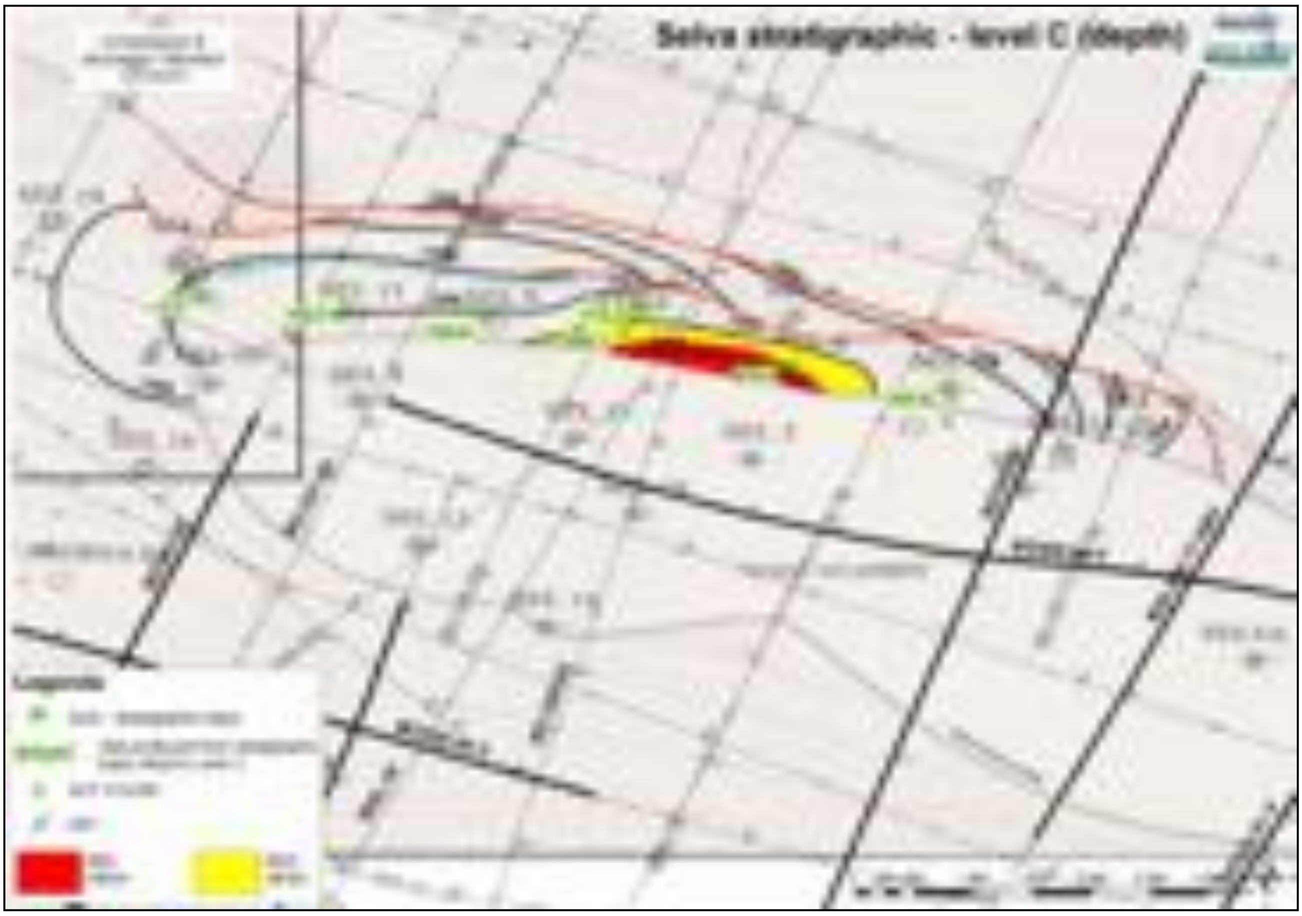


Figure 8-2 Selva stratigraphic structure map with pre-drill expectation of gas extent

PVO have targeted the updip gas volume based upon a new interpretation of the position of the lapout edge towards the Selva-3 well.

Seismic and well data show the Selva stratigraphic redevelopment to be an Upper Middle Pliocene onlap to a Lower Pliocene thrust bounded anticline. However, interpretation of seismic lines suggests the reservoir is also displaced by reactivated thrust splays which detach onto the main thrust fault.

Gas bearing reservoirs are the Lower Pliocene sands of the old Selva field, which had average properties of 70m thickness, 70% net-to-gross, 27-31% porosity and roughly 80% gas saturation. A recovery factor of 77-86% is assumed across the 1C to 3C cases.

As a proposed re-development of an old field, this appears relatively low risk; the major risk component is the location of the reservoir edge line along the length of the field. The pre-drill contingent resources proposed by PVO are, in CGG's opinion, very reasonable estimates; in the 1C category we estimate 322.9 MMscm recoverable gas, with a 2C volume of 481.5 MMscm and a 3C resource of 651.4 MMscm (Table 8.1).

Table 8-1 Summary of Contingent Resources for Selva Stratigraphic

	Gross (MMscm)		
Redevelopment	**1C**	**2C**	**3C**
Selva Stratigraphic	322.9	481.5	651.4

8.2.1 Selva Stratigraphic: The Podere Maiar-1 Well and Initial Results

Podere Maiar-1 was drilled in Q4 2017, with LWD. High resistivity was encountered in thick reservoir sand sequences at the expected interval. The reservoir section came in thicker than prognosis, suggesting that the pinch-out of sand on top of the structure is further away rather than closer than expected. MDT pressure data suggests a continuous gas column in an upper sand and a second continuous gas column in a lower sand interval. The two sands are separated by a shale barrier, the recorded formation pressures being 1921psi (132.4 bar) in C1 sand and 1966 psi (135.5 bar) in C2 sand.

A gas-water contact has been identified from the pressure data points at 1270.5m depth in the C1 sand and at 1309.5m depth in the C2 sand. These GWCs are both deeper than the most optimistic assumption prior to drilling the well (see Figure 8.2 where the “Max Area” at Level C is 1250m).

A re-evaluation of the resource volumes must wait until all acquired data has been fully worked over and new interpretations can be made available for review. In addition, PVO’s application for a Production Concession will be the next critical step. Until these things are in place, CGG considers that the gas resource at Selva Stratigraphic remains a contingent resource and although we expect the volumes to go up, the values reported in this document do not reflect the changes that the new well results bring to our understanding of the asset.

In terms of dynamic performance, the well yielded positive results. Well clean-up was done on 19th and 20th December 2017. With C1 and C2 perforations open, coiled tubing nitrogen lift was carried out to lift brine in the wellbore. Gas followed to surface. Most of the water was produced within the first hour of clean up, while water free gas flowed in the last couple of hours. Clean up ended at 12:15 pm of 20 December with 16/64” with a stable (more than 4 hours) pressure (115,7 bar at the well head) and rate (Qg = 62.000 Sm^3/g). Total recovered liquids have been 3260 lt. One minute after the well was closed WHP stabilized at 123,0 bar.

Subsequent to the clean up period, the C2 sand was subjected to a preliminary flow test in January of 2018.

Three flow periods of 6 hours each were carried out with the following results:

- 1/8 choke ;Qg 18kscm/d; WHP 124.2 bar
- 2/8 choke;Qg 65kscm/d; WHP122.1
- 18/64 choke; Qg 81kscm/d; WHP 120.9

Build up started at 09:15 am; after seven minutes the Well Head Pressure reached 124.3bar.

The C2 Sand test will be followed by a flow test of the C1 sand. The positive performance of the deeper C2 sand triggered an application to the Italian ministry (UNMIG) for permission to carry out an additional flow test of C2 starting with a 3/8” choke with a view to verifying the full flow potential of the well. An additional gas flare is required as the one used so far has a limit of 100,000 scm/d.

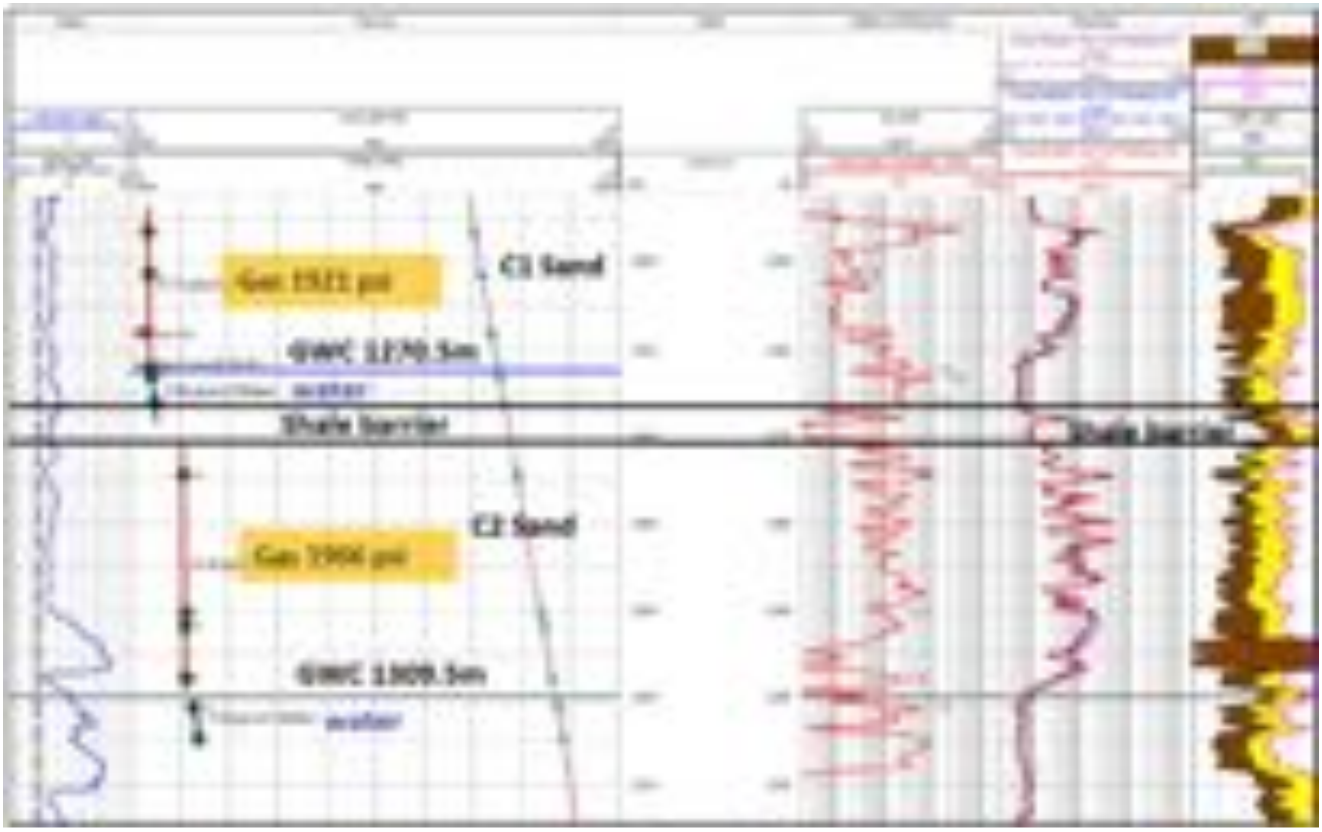
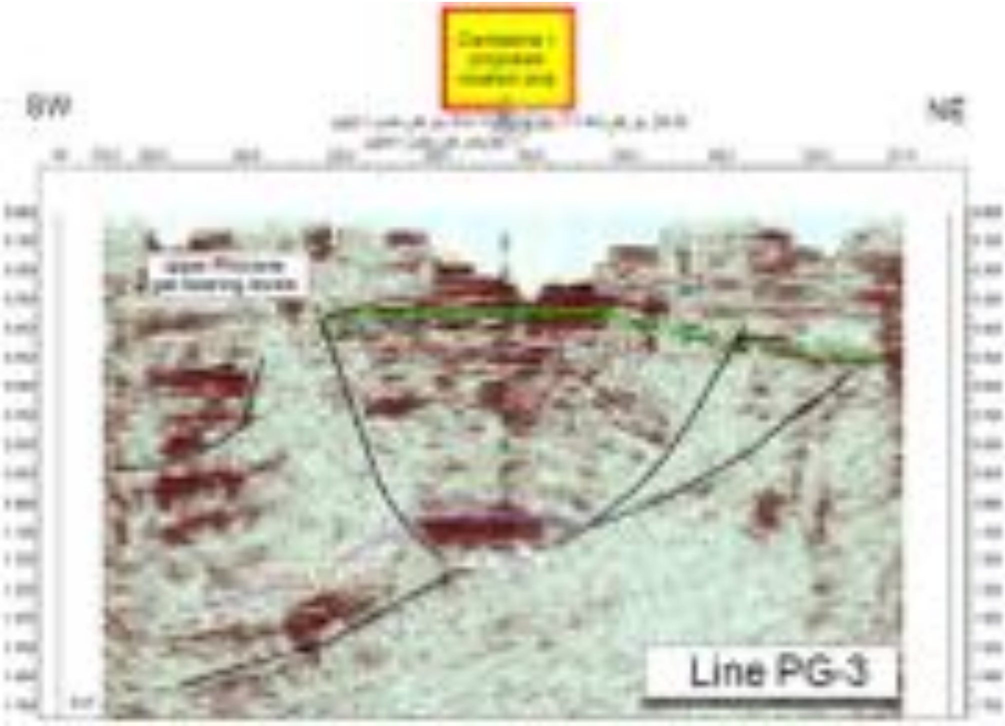


Figure 8-3 Well Podere Maiar-1 Preliminary Results

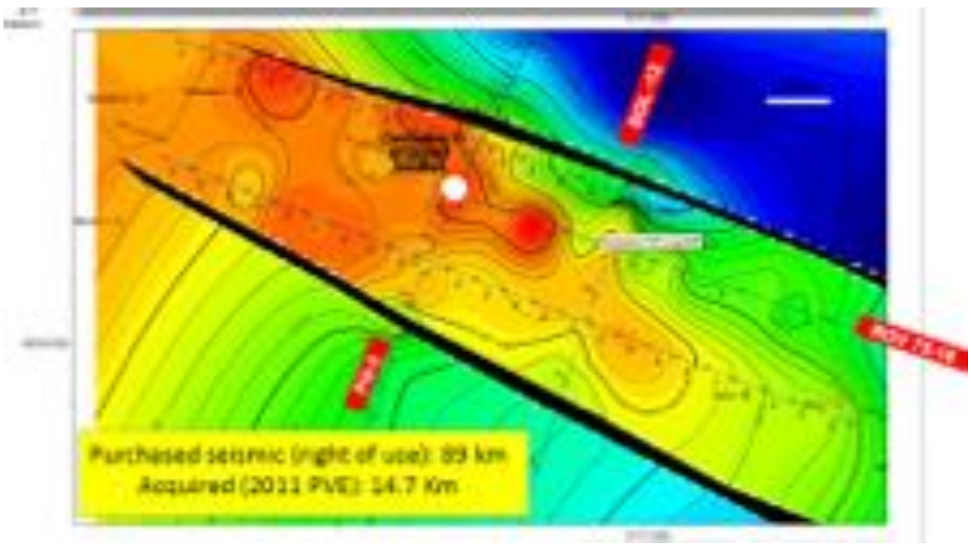
8.3 Cembalina

The Cembalina prospect is defined on five seismic lines at Upper Pliocene level. Lines are oriented NNE-SSW 1.2km to 3.4km apart and WNW-ESE 0.4km to 7km apart. The structure is a WNW-ESE oriented hanging-wall anticline with associated back thrust at Early Pliocene level with fold drape above the structure at Upper Pliocene level. The seismic interpretation of horizons has been checked and validated.

Additional seismic lines acquired by PVO in 2011 resulted in a revised structural interpretation which had the effect of increasing the size of the Cembalina prospect as compared to pre 2011.



(A) Cross-section through Cembalina structure



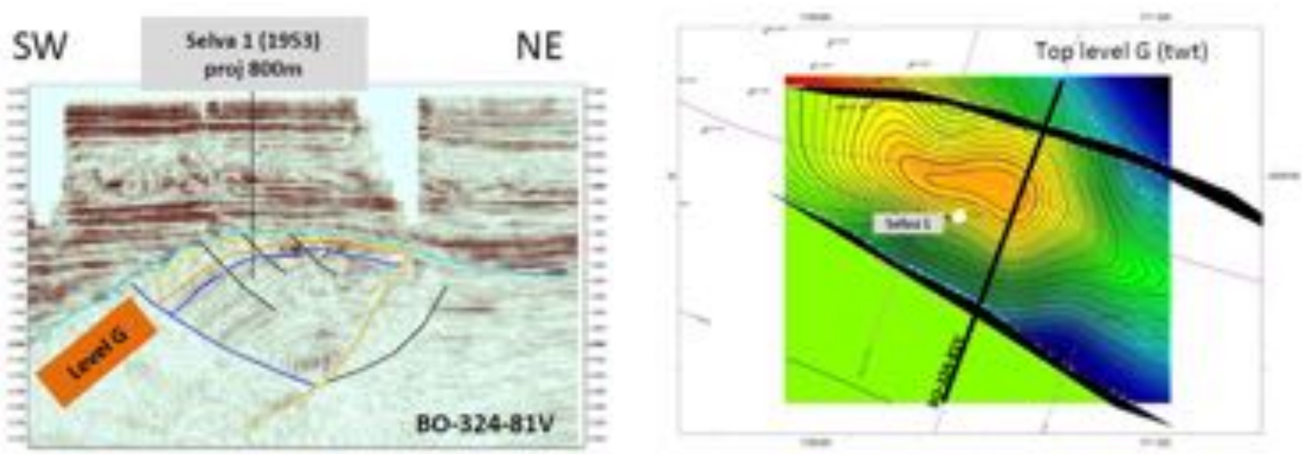
(B) Depth map of Cembalina structure

Figure 8-4 Cembalina structure

Prospective reservoirs are the Early Pliocene marine sands which, in nearby wells, exhibit up to 30% porosity with 70% average gas saturation. The thickness of these sands is expected to be about 20 metres with a net-to-gross of about 50%. In a success case, then, we concur with the prospective resource estimates stated by PVO. These are a Low estimate of 59.5 MMscm, a Best estimate of 93.5 MMscm and a High estimate of 133.1 MMscm. The CoS relating to these resources is 51% due to the proximity of gas fields producing from these Early Pliocene sands.

8.4 Fondo Perino

The Fondo Perino prospect is the dip closed cap of a hanging-wall anticline located between the Selva-1 and Selva-23 wells. The trap is interpreted on two NNE-SSW oriented seismic lines located 1.3km apart and a WNW-ESE line. The limits of the prospect closure exist between smaller faults in the core of the anticline.



(A) Fondo Perino seismic cross-section **(B) Fondo Perino depth structure map**

Figure 8-5 Fondo Perino structure

The reservoirs are Lower Pliocene sandstones of the Selva gas field; the prospect is the updip gas bearing level tested on Selva-1 well. The CoS is good at 34% for prospective resources of 288.9, 413.5 and 580.6 MMscm recoverable gas at Low, Best and High estimate cases respectively.

8.5 East Selva

The East Selva structure is identical in concept in the Selva Stratigraphic structure but has not previously been drilled. PVO reinterpreted the mapped closure area of this structure using available seismic data and CGG review of this work indicates that it presents a fair and reasonable view of the prospect.

Figure 8-6 East Selva structure map

The East Selva reservoirs are expected to be as good as those in the Selva Field itself. CGG's review of the Operator's work has concluded that the stated prospective resources are very reasonable. The prospect could hold recoverable resources of 824.1, 985.6 and 1149.8 MMscm in Low, Best and High estimate cases respectively for a CoS of 13%. The primary risk is definition of the gross rock volume based on a small number of seismic lines.

Table 8-2 Summary of Prospective Resources

Prospect	Gross (MMscm)			Risk factor
Cembalina	59.5	93.5	133.1	51%
Fondo Perino	288.9	413.5	580.6	34%
East Selva	824.1	985.6	1149.8	13%

8.6 Reservoir Engineering

8.6.1 Selva Stratigraphic

The old Selva field, which produced between 1956 and 1984, was penetrated by some 24 wells. Total production from the field was approximately 2380 MMscf, with individual wells shut-in once they watered out. The location of the key Selva wells is shown in Figure 8.7 together with the proposed new Podere Maiar-1d well.

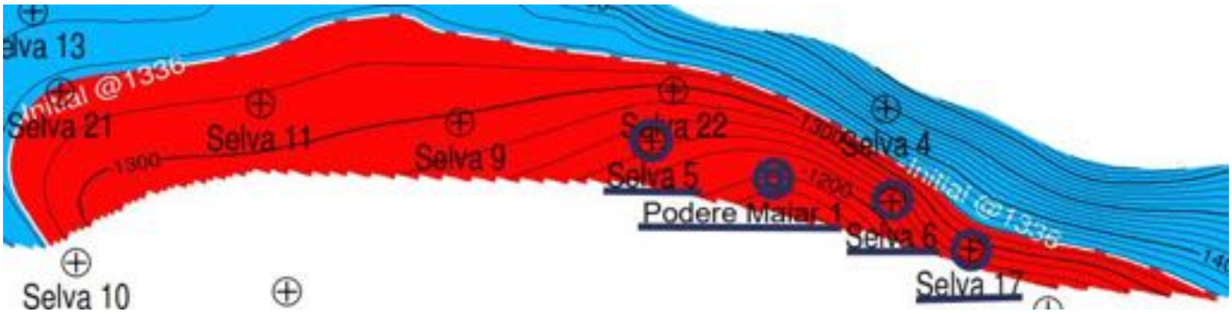


Figure 8-7 Selva key well locations

Production history plots for the key Selva wells are presented in Figure 8.8.

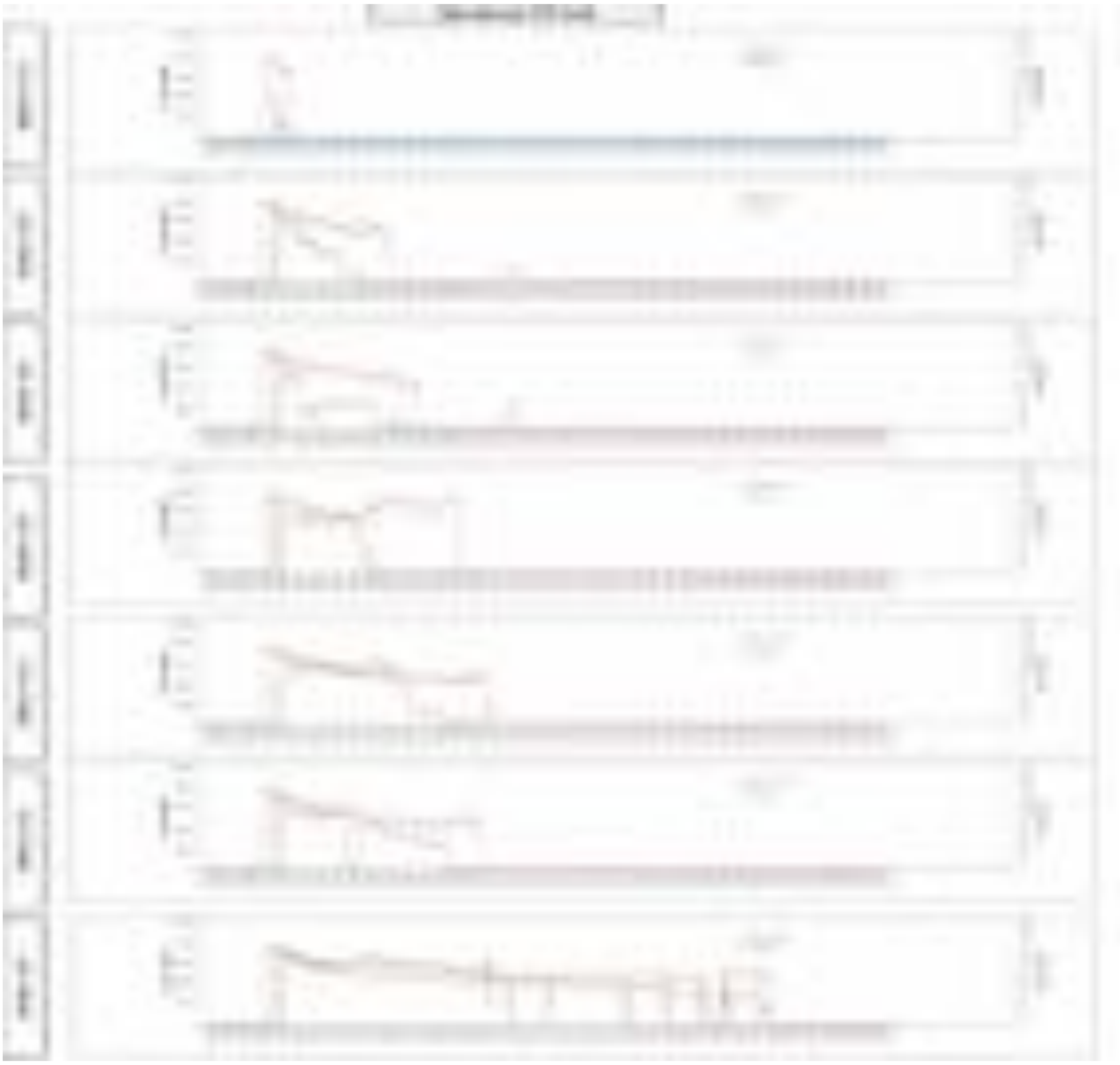


Figure 8-8 Selva: Production History for Key Wells

The water cut history of the old Selva wells is therefore informative for the Selva Stratigraphic redevelopment opportunity. The first well to water out was Selva-21, closest to the original gas water contact. As production occurred, the aquifer rose, apparently fairly uniformly, within the field, leading to the successive watering out of wells that were progressively higher up the structure. The order in which the old wells watered out was Selva-21, 11, 9, 22, 17, then 5 and finally Selva-6. This type of behaviour indicates a well-connected, rather homogeneous, reservoir without internal barriers. This observation also implies that any future well should behave similarly, producing gas at good rates until the aquifer reaches the lower perforations in the well.

The question arises as to whether the water is a simple aquifer, rising constantly across the field, or whether the water is getting into the perforations by coning. Inspection of the production history of well Selva-6 indicates that this well continued long after the other wells had watered out, even though it is not significantly shallower than Selva-5 which watered out in about 1969. Selva-6 continued producing for another 25 years, principally because the well was choked back a little and the rate reduced from about 125,000 scm/d to 100,000 scm/d. The ability to extend dramatically the producing life of Selva-6 and the early watering out of other wells strongly suggests coning is the major culprit for early water influx. Selva-6 produced a total of approximately 878.8 MMscm over its life.

The range of contingent resources, derived from volumetric calculations presented in section 8.2, is considered to be reasonable and consistent with the production history of the field. However, achieving these volumes will require the application of prudent reservoir management, in particular the control of production rates and timely work-overs to implement appropriate water shut-offs.

8.6.2 Appraisal and Development Plans for Selva Stratigraphic

The Podere Maiar-1d well, which will appraise the Selva Stratigraphic redevelopment opportunity, was spudded on 21st November 2017. The well will be drilled to a target depth of 1,350 meter in the Pliocene which is expected to take 20-25 days to drill and complete and the evaluation of results will be available in Q1 2018.

Selva gas consists of approximately 99% methane and has a negligible hydrocarbon liquids content, and as such will require minimal surface processing if the field is redeveloped. The Italian gas grid is located within 500 metres of the proposed field facilities, which will permit low cost export of any production. PVO, the operator, is experienced in developing similar small scale gas projects in the Po Valley.

There are currently no firm plans to drill wells on the other prospects within the licence area.

9 THE AR94PY LICENCE

9.1 Asset Description

This section concerns the AR94PY licence, which is located off the east coast of Italy, approximately 30 kilometres south-east of Venice in the Adriatic Sea. The AR94PY licence is 100% owned and operated by PVO, and contains the undeveloped Teodorico gas discovery and the PL3-C gas prospect.

PVO was awarded a six year licence for appraisal of the offshore block AR94PY in Q3 2012. In the middle of 2015, PVO applied for and in Q4 2015 was granted a Production Concession by the Italian Ministry. This paved the way for development of Teodorico gas field.

This asset has the largest gas in place of all those described in this CPR and is at an advanced stage of assessment and is ready for development. Close to one million Euros has been spent by Po Valley on technical and facilities studies in order to reach this stage and all relevant permits are in hand. The Environmental Impact Assessment has been successfully filed and accepted by Governmental Authorities and Po Valley's formal development plan has been fully sanctioned by the Italian Ministry. Costs have been scoped and quotes obtained for Capex planning, covering the whole execution process. CGG considers that having reached this advanced stage, having made these commitments, it is now reasonable to expect that the Operator will proceed to development within five years of the date of this report.

CGG has used their understanding of the area and resource assessment experience in judging whether the assumptions made by PVO are valid and reasonable. Independent estimations have also been made to confirm any interpretations where required.

The location of the AR94PY offshore licence, and the d40ACPY Production Concession, with the 12 nautical mile development limit is shown in Figure 9.1.

Figure 9-1 Location of the AR 94 PY original Exploration Licence and d40 AC PY Production Concession

9.2 Dataset

In completing this evaluation CGG has relied upon the data collected and reviewed at a data room in Rome in 2013 and a second review in 2017, as well as complementary information within the public domain. This data included, amongst others:

Power Point presentation for reserves and resources including general geological information.

Location maps, log intervals of the reservoir, and hydrocarbons in-place estimations made by PVO and independently by ourselves.

- Well logs of all drilled wells
- Seismic workstation projects, interpreted figures, time- and depth-structure contour maps
- Documents, graphs and tables of general geological and well data
- Portfolio summary and PVO interpretation
- Fiscal terms

CGG has relied upon PVO for the completeness of the data set provided.

CGG has independently reviewed in detail the volumetric estimates and reservoir parameters using the following workflow:

1. CGG spent a day with Po Valley technical staff (their senior geologist and senior geophysicist) at their workstations in Rome checking the interpretation of the reflections and depth conversion processes and assumptions made by Po Valley technical team. CGG were convinced that the work carried out by Po Valley was of a high standard, that the data used was of sufficiently high quality and the resulting Gross Rock Volumes (GRVs) computed are as accurate as possible.
2. The quality of the 3D seismic data used for delineating the gas field is very good and provides a very good basis for understanding the potential asset value range.
3. Areas of high amplitudes observed in the 3D seismic volume – often associated with gas presence in these relatively shallow and moderately consolidated reservoir sequences - were independently checked for each reservoir layer. CGG areas were higher than Po Valley areas, which were considered conservative. Po Valley areas were therefore taken forward in our evaluation.
4. A range of reservoir properties including thickness, net-to-gross, porosity, saturation and formation volume factor, all verified as reasonable and independently derived from well logs and from petrophysical interpretations, was then applied to the areas. CGG has developed independent parameter ranges based on our own observations made of the data and we have tested the assumptions used by Po Valley. Using Po Valley area data, CGG generated volumetric estimations that were comparable to or larger than Po Valley's.
5. A conservative estimation of water saturation (from 45% to 65%) in these gas sands, combined with conservative recovery factors of 40% to 55% were then applied to the GIIP estimates. The use of low recovery factor allows for the possibility of early water breakthrough and loss of well productivity as a result of liquid loading. The low relief of the structure suggests that water breakthrough could be the major factor in loss of production, water levels in the reservoir moving rapidly towards the well for small changes in depth of contact. No account has been taken of possible remedial actions that the Operator might take to maximise gas recovery once water has broken through to the perforations, and the Operator may be reasonably expected to take such mitigating action in due course.

Having checked Po Valley's methods and inputs, and found them to be fair and reasonable, we have carried forward Po Valley's stated gas-in-place estimates into our own, independently generated, production forecasts and economic assessments.

The basis of CGG's assessment has therefore been to check the technical, logical and interpretation basis for Po Valley's own assessments of the Teodorico Discovery, and CGG has found Po Valley's conclusions to be reasonable, given the data available.

9.2.1 Teodorico Discovery

9.2.1.1 Geological and Geophysical Assessments

PVO was awarded a six year licence for the offshore exploration block AR 94 PY in Q3 2012 and this expires on 10th July 2018. A sub-section of this license has been converted to a 20-year Production Concession (65.89km^2) by PVO effective 5th August, 2015. PVO purchased the well data for the two Carola wells and the two Irma wells in 2013.

The Teodorico Discovery (formerly Carola/Irma) consists of a low-relief four-way dip closure located in 30m of water in the northern Adriatic Sea. The well Ametista-1 was drilled in 1972 and today forms an important tie for structural definition and trap closure in the North. Four wells including the discovery well, Carola-1, were then drilled on the structure in the period 1986 to 2001. Gas was observed in several sands within the Pleistocene and Quaternary intervals, the sands with the largest potential volumes being the Pleistocene C, D and E sands, as well as the Quaternary QU-4 sand.

The discovery well, Carola-1, was drilled in 1986 to a depth of 2620 metres, and tested gas at a rate of up to 62,000 scm/d (1/4" choke) from sand PLQ-C2. This sand is partially within the 12 nautical mile limit and has not been considered as reserves in consideration of current Italian law. Sand QU-4 is very shallow and also extends within the 12 nautical mile limit; it was tested at a rate of up to 87,800 scm/d through a ½" choke.

Well Irma-1, drilled in 1988 to a depth of 2572 metres, tested gas at up to 131,000 scm/d from level PLQ-E2/F through a 5/16" choke and from PLQ-D1 at a maximum rate of 281,000 scm/d through a ½" choke.

The well Carola-2 was drilled in 1992 and showed very clear indications of gas on logs, similar to log indications in the previous two wells. Core was cut from Levels D and E of the Pleistocene "Carola Formation" in Carola-2, yielding porosity measurements in the range of 22.6% to 37.3% with permeabilities from 0.14mD to 174mD.

The final well, Irma-2X, drilled in 2001, showed water in the sands of interest, with traces of gas, and was categorised as "dry". All the aforementioned wells were plugged and abandoned.

Core data from Carola-2 indicates porosities of 22.6 – 37.3% and permeabilities of 0.14 – 174 mD.

Figure 9-2 AR 94 PY License in Area of Producing Gas Fields

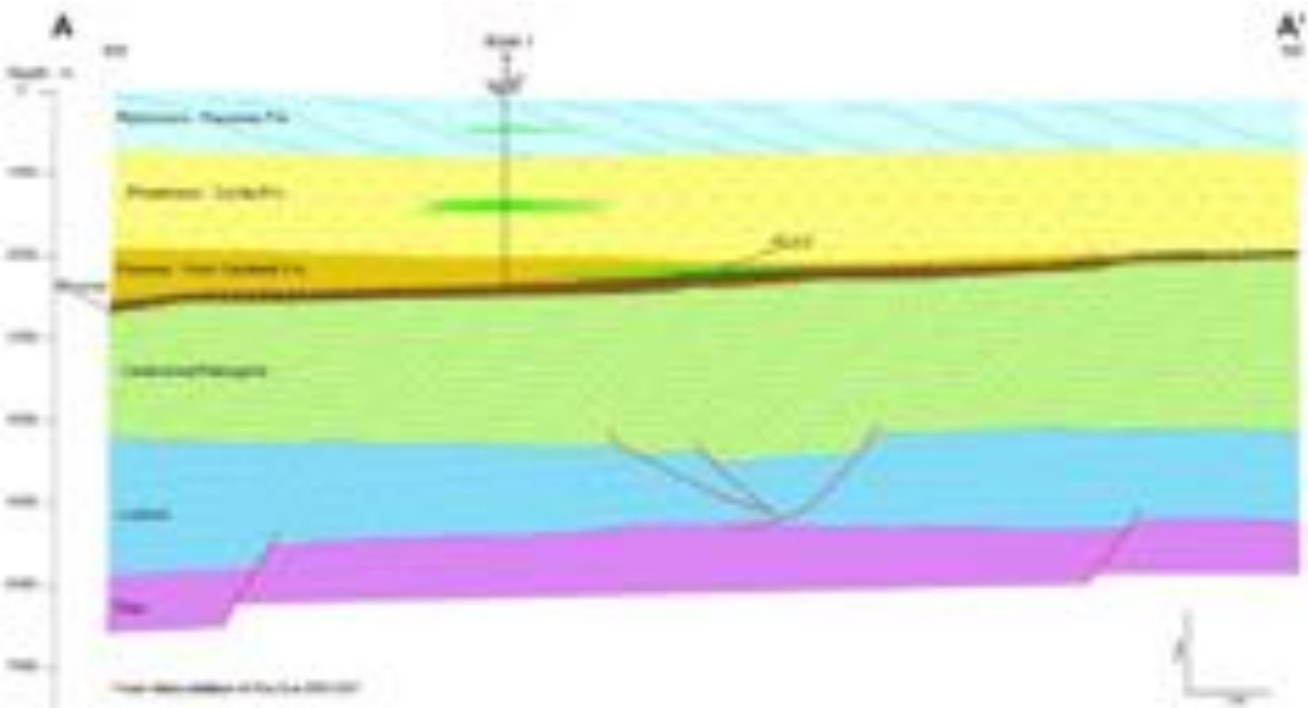
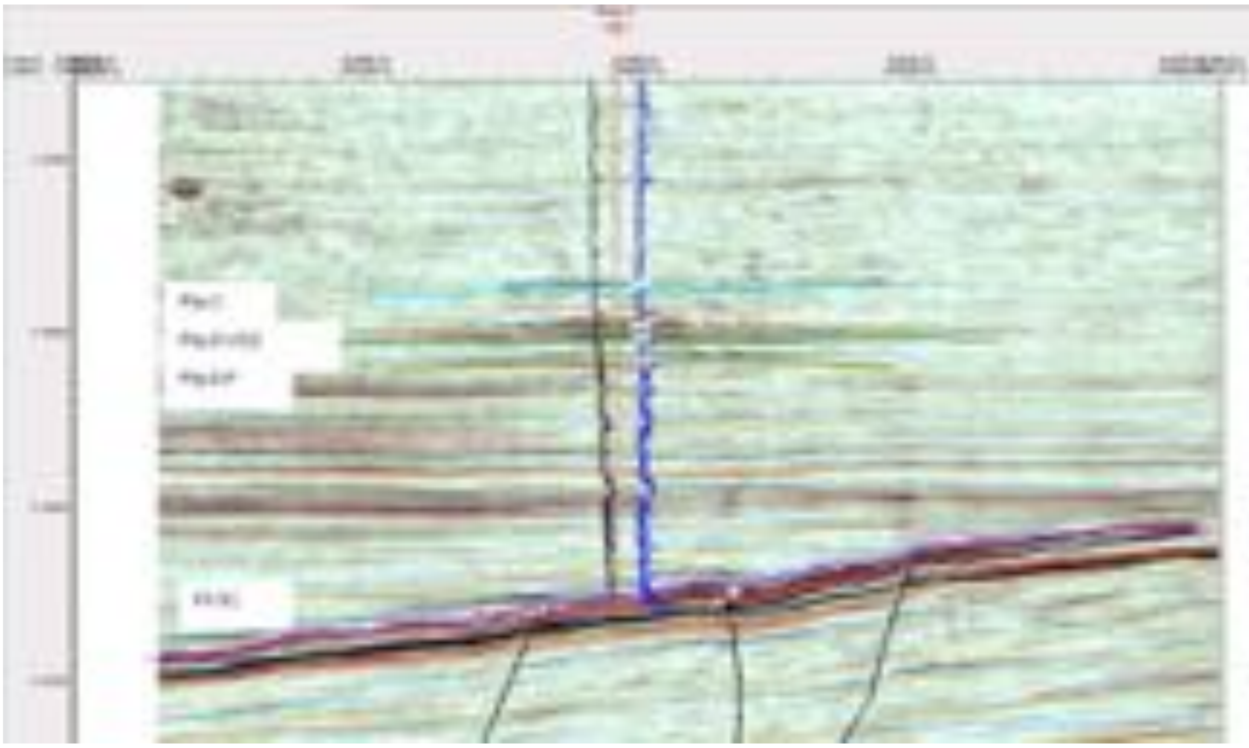


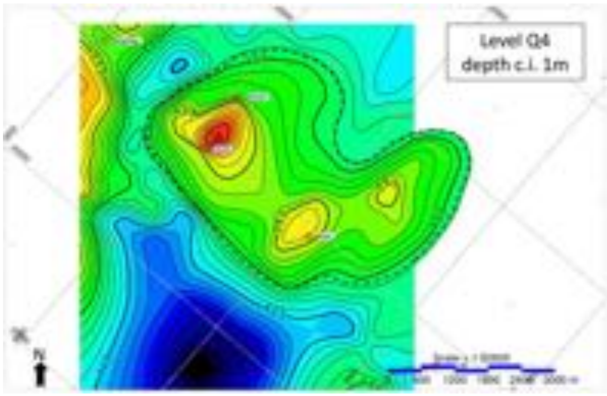
Figure 9-3 Schematic Cross-Section through well Irma-1 showing target reservoir zones

PVO has identified seven gas sands: two in Upper Pleistocene (QU-3, QU-4) and five in the Lower Pleistocene: PLQ-C, PL1-C2/C6, PLQ-D1, PLQ-D2 and PLQ-E2-F. Each forms a low-relief 4-way dip closure forming stacked reservoirs. The reservoirs are made up of turbidite sands, silts and shales; the source sediment being washed off the Alpine and Apennine mountain chains into subsiding basins.

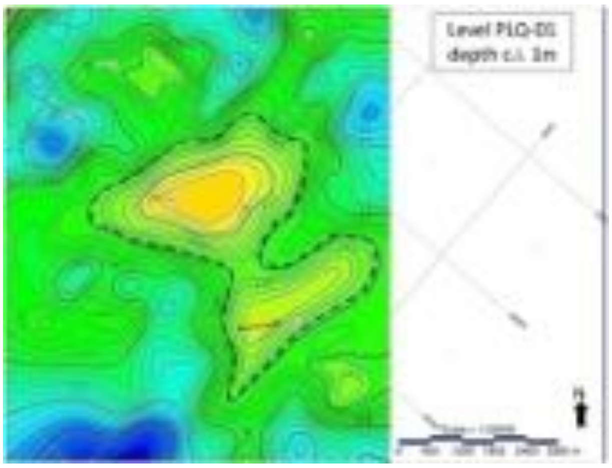
The area of interest contains five key wells: Ametista-1, Carola-1, Carola-2, Irma-1 and Irma-2X and is covered by the 3D ADRIA seismic survey, acquired and processed between 1993 and 1997 then reprocessed in 1998. PVO purchased and interpreted 118 sq. km of this 3D seismic volume. Depth conversion using VSP, check shot data and average velocity where no data is available in the well path confirms 4-way dip closure at each reservoir horizon. A velocity anomaly that exists between the Ametista-1 and Carola-1 wells is corrected using average velocities at QU-3 and QU-4 levels.



(A) Seismic section through Teodorico reservoirs and well Irma-1



(B) Top QU-4 depth map



(C) Top PLQ-D1 amplitude map

Figure 9-4 Teodorico structure and seismic attribute maps

CGG independently took the seismic data and calculated the area of the amplitude anomalies; CGG's computed areas were 20-40% larger than Po Valley "P50" areas, and a little larger than their "P10" areas. Po Valley had stated to CGG that they had taken a conservative approach to the areas, so Po Valley's smaller areas (constrained by depth structure mapping and the water in Irma-2X well) were therefore taken forward in our evaluation.

Table 9-1 Teodorico Field, PVO Calculated Areas versus Area of Amplitude Anomaly

RESERVOIR	PVO Area Calculations (sq.km)					Area of Amplitude Anomaly (sq.km)
	Min	P90	P50	P10	Max	
Q4	5.00	7.57	10.70	13.70	16.00	14.28
PLQ-C	8.00	8.64	11.20	13.80	14.40	14.29
PLQ-D1	4.47	4.63	5.25	5.87	6.03	6.35
PL3-C Prospect	2.00	2.46	3.03	3.64	4.13	4.21

Table 9-2 Teodorico Field: Parameters, Reserves and Contingent Resources for P90, P50 and P10 Cases

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**GIIP, Reserves, and Contingent Resource are statically calculated*

9.2.1.2 Reservoir Engineering

Wells Carola-1, Carola-2, Irma-1 and Irma-2X were drilled by ENI between 1988 and 2001. These wells generated successful production tests for different sands as quoted earlier. Production profiles are based on these production test data.

The Teodorico field is divided into different horizons. Because of the wide range of depths at which these horizons are located, crossflow from one deeper horizon to another shallower horizon may occur if the horizons are not isolated from each other. Hence some of the horizons cannot be produced at the same time. Consequently the development wells will be dual completion with selective sleeves. Table 9.2 provides a list of the horizons associated with the reserves and contingent resources and Table 9.3 below provides our estimates of reserves and contingent resources for the Teodorico discovery. The criterion for classifying gas volumes to contingent resources is that they are in sands that extend within the 12nm limit and so we assume they cannot be developed under current Italian law.

Table 9-3 Teodorico Field: Summary of Reserves and Contingent Resources

		Reserves (MMscm)			Contingent Resources (MMscm)		
Licence	**Field**	**1P**	**2P**	**3P**	**1C**	**2C**	**3C**
d40 AC PY	Teodorico	770.3	1039.4	1365.1	209.8	300.5	395.9

Two wells with dual string completion are proposed with the first production targeted in July 2022. CGG has constructed production profiles sand-by-sand using various initial rates and decline rates as tabulated in Table 9.4 to Table 9.6. The range of initial rates is similar to the production tests of Wells Carola-1 and Irma-1 as stated earlier in section 9.3.1.1.

To demonstrate the field's deliverability, unconstrained production profiles are constructed for 1P, 2P and 3P cases as graphically shown in Figure 9.5 and Table 9.7 shows the estimated unconstrained annual production and cumulative production.

A permanent offshore facility is proposed for field development with the gas rate capacity of 300,000 scm/d. The unconstrained production profiles were updated to honour this gas capacity. The constrained production profiles with the maximum gas rate of 265,000 scm/d were constructed. The spare capacity of 35,000 scm/d is planned in order to allow maintenance down time and seasonal fluctuations to the delivery rates. The constrained production profiles for 1P, 2P and 3P cases are graphically shown in Figure 9.6. Table 9.8 shows the estimated constrained annual production and cumulative production.

Table 9-4 Initial Rates and Decline Rates for 1P reserves in Teodorico Field

Sand	Recoverable Volumes (MMscm)	Initial Rate (Day 1), scm/d	Decline Rate per Year	First Production	Well
PLQ-C	181.3	100,000	0.15	Jul-2022	Teodorico-1 S1
PLQ-D1	184.1	120,000	0.22	Jul-2022	Teodorico-2 S1
PLQ-D2	87.8	80,000	0.22	Jul-2022	Teodorico-2 S2
PLQ-E2-F	317.2	100,000	0.10	Jul-2022	Teodorico-1 S2

Table 9-5 Initial Rates and Decline Rates for 2P reserves in Teodorico Field

Sand	Recoverable Volumes (MMscm)	Initial Rate (Day 1), scm/d	Decline Rate per Year	First Production	Well
PLQ-C	277.5	120,000	0.12	Jul-2022	Teodorico-1 S1
PLQ-D1	212.4	120,000	0.19	Jul-2022	Teodorico-2 S1
PLQ-D2	133.1	100,000	0.15	Jul-2022	Teodorico-2 S2
PLQ-E2-F	416.3	130,000	0.10	Jul-2022	Teodorico-1 S2

Table 9-6 Initial Rates and Decline Rates for 3P reserves in Teodorico Field

Sand	Recoverable Volumes (MMscm)	Initial Rate (Day 1), scm/d	Decline Rate per Year	First Production	Well
PLQ-C	413.5	150,000	0.09	Jul-2022	Teodorico-1 S1
PLQ-D1	243.6	140,000	0.19	Jul-2022	Teodorico-2 S1
PLQ-D2	186.9	120,000	0.15	Jul-2022	Teodorico-2 S2
PLQ-E2-F	521.1	150,000	0.10	Jul-2022	Teodorico-1 S2

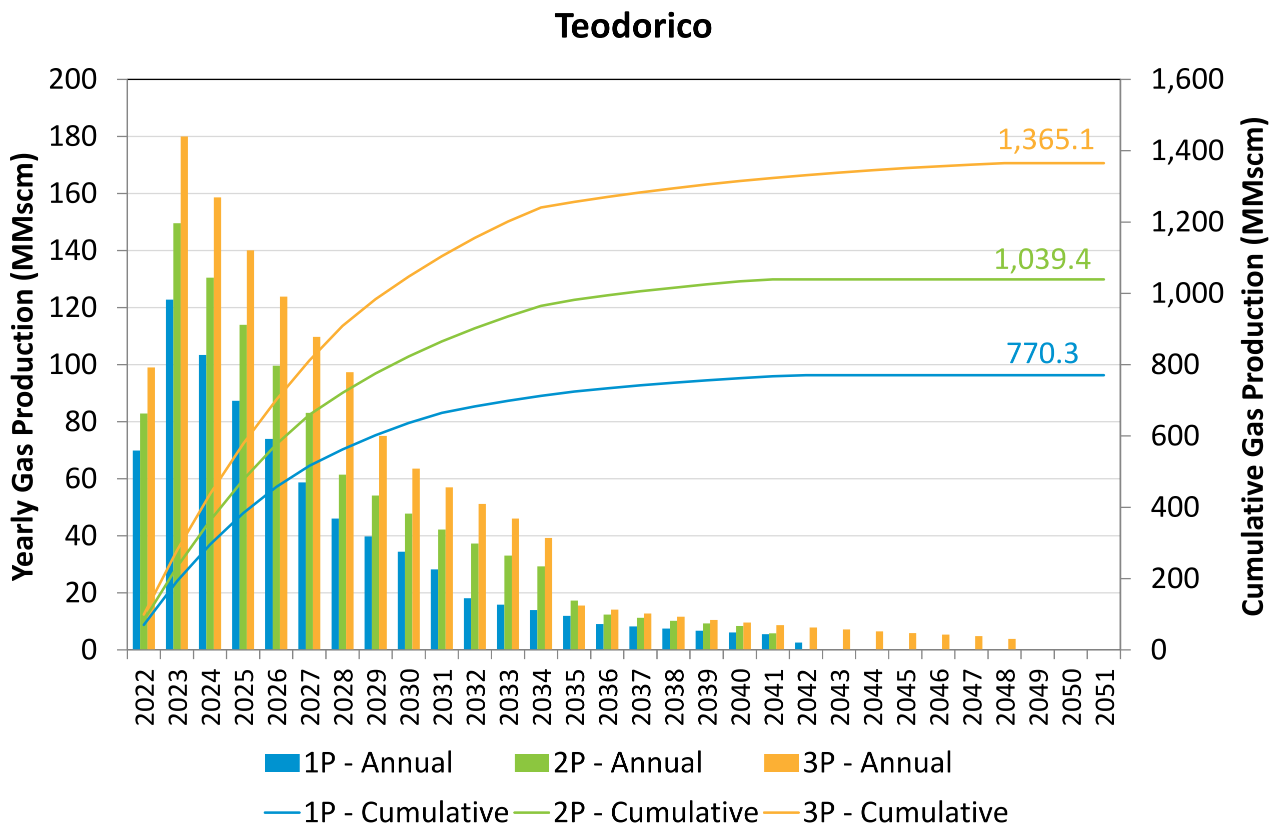

Figure 9-5 Unconstrained Technical Production Profiles of Teodorico 1P, 2P, 3P (before economic cut-off)

Table 9-7 Unconstrained Annual Production and Cumulative Production, Teodorico (before economic cut-off)

Year	1P		2P		3P	
	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)
2022	69.90	69.90	82.88	82.88	98.99	98.99
2023	122.78	192.68	149.58	232.47	180.00	279.00
2024	103.39	296.07	130.47	362.94	158.66	437.66
2025	87.32	383.40	113.93	476.87	140.08	577.73
2026	73.97	457.37	99.62	576.49	123.87	701.61
2027	58.74	516.11	83.09	659.58	109.72	811.33
2028	46.02	562.13	61.43	721.01	97.34	908.67
2029	39.76	601.90	54.13	775.13	75.04	983.70
2030	34.44	636.34	47.76	822.89	63.54	1047.24
2031	28.26	664.60	42.19	865.08	56.99	1104.23
2032	18.10	682.70	37.31	902.39	51.19	1155.42
2033	15.90	698.59	33.04	935.43	46.04	1201.46
2034	14.00	712.59	29.29	964.71	39.22	1240.68
2035	11.95	724.54	17.31	982.02	15.54	1256.22
2036	9.10	733.64	12.37	994.39	14.10	1270.32
2037	8.24	741.88	11.24	1005.64	12.80	1283.12
2038	7.46	749.34	10.21	1015.85	11.62	1294.74
2039	6.75	756.09	9.28	1025.12	10.54	1305.28
2040	6.12	762.20	8.43	1033.55	9.57	1314.85
2041	5.54	767.74	5.81	1039.36	8.69	1323.54
2042	2.57	770.31	0.00	1039.36	7.88	1331.42
2043	0.00	770.31	0.00	1039.36	7.16	1338.58
2044	0.00	770.31	0.00	1039.36	6.49	1345.07
2045	0.00	770.31	0.00	1039.36	5.89	1350.97
2046	0.00	770.31	0.00	1039.36	5.35	1356.32
2047	0.00	770.31	0.00	1039.36	4.86	1361.18
2048	0.00	770.31	0.00	1039.36	3.88	1365.06
2049	0.00	770.31	0.00	1039.36	0.00	1365.06
2050	0.00	770.31	0.00	1039.36	0.00	1365.06
2051	0.00	770.31	0.00	1039.36	0.00	1365.06

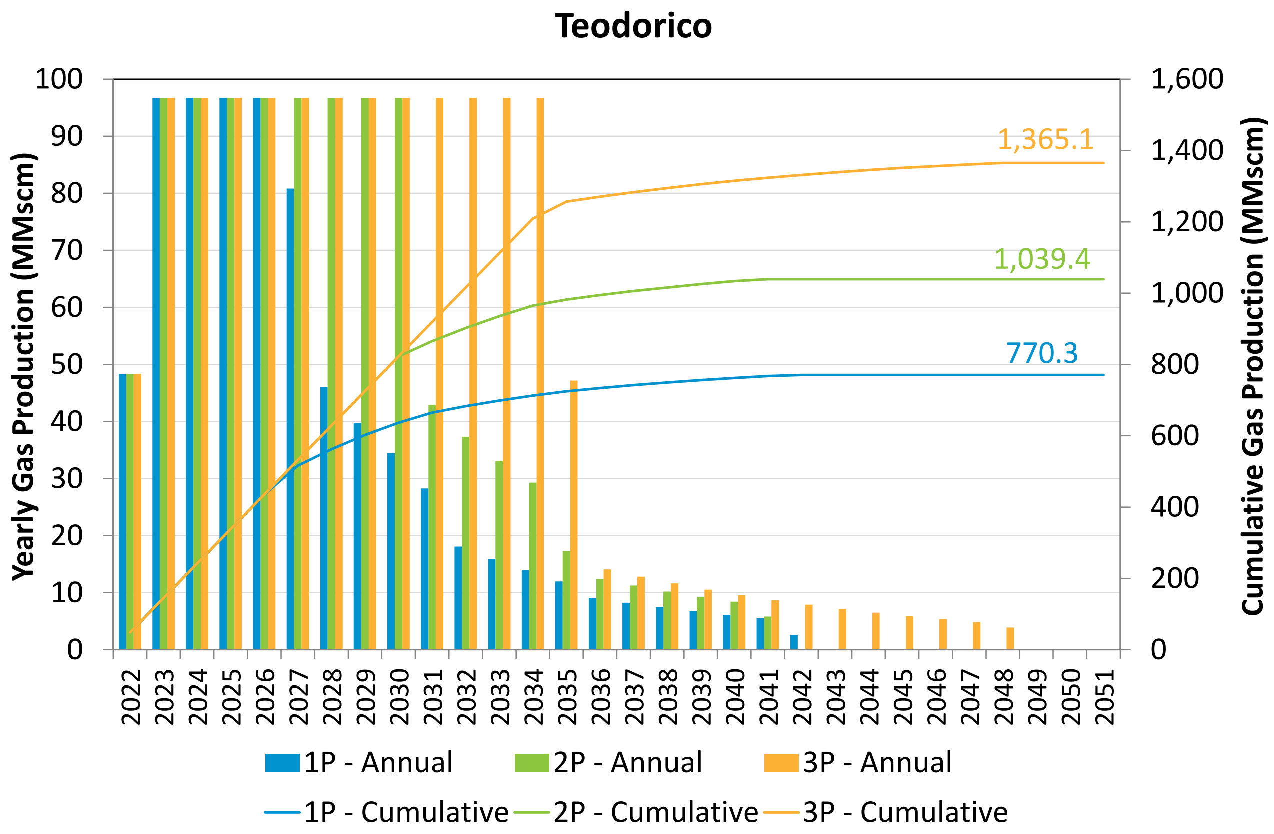

Figure 9-6 Constrained Technical Production Profiles of Teodorico 1P, 2P, 3P (before economic cut-off)

Table 9-8 Constrained Annual Production and Cumulative Production, Teodorico (before economic cut-off)

Year	1P		2P		3P	
	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)
2022	48.36	48.36	48.36	48.36	48.36	48.36
2023	96.73	145.09	96.73	145.09	96.73	145.09
2024	96.73	241.81	96.73	241.81	96.73	241.81
2025	96.73	338.54	96.73	338.54	96.73	338.54
2026	96.73	435.26	96.73	435.26	96.73	435.26
2027	80.85	516.11	96.73	531.99	96.73	531.99
2028	46.02	562.14	96.73	628.71	96.73	628.71
2029	39.76	601.90	96.73	725.44	96.73	725.44
2030	34.44	636.34	96.73	822.16	96.73	822.16
2031	28.26	664.60	42.91	865.08	96.73	918.89
2032	18.10	682.70	37.31	902.39	96.73	1015.61
2033	15.90	698.59	33.04	935.43	96.73	1112.34
2034	14.00	712.59	29.29	964.71	96.73	1209.06
2035	11.95	724.54	17.31	982.02	47.16	1256.22
2036	9.10	733.64	12.37	994.40	14.10	1270.32
2037	8.24	741.88	11.24	1005.64	12.80	1283.12
2038	7.46	749.34	10.21	1015.85	11.62	1294.74
2039	6.75	756.09	9.28	1025.12	10.54	1305.28
2040	6.12	762.20	8.43	1033.55	9.57	1314.85
2041	5.54	767.74	5.81	1039.36	8.69	1323.54
2042	2.57	770.31	0.00	1039.36	7.88	1331.43
2043	0.00	770.31	0.00	1039.36	7.16	1338.58
2044	0.00	770.31	0.00	1039.36	6.49	1345.08
2045	0.00	770.31	0.00	1039.36	5.89	1350.97
2046	0.00	770.31	0.00	1039.36	5.35	1356.32
2047	0.00	770.31	0.00	1039.36	4.86	1361.18
2048	0.00	770.31	0.00	1039.36	3.88	1365.06
2049	0.00	770.31	0.00	1039.36	0.00	1365.06
2050	0.00	770.31	0.00	1039.36	0.00	1365.06
2051	0.00	770.31	0.00	1039.36	0.00	1365.06

9.2.2 Teodorico Late Pliocene Prospective Resource

During the appraisal phase, the well Irma-2X tested a water-wet Late Pliocene pinch-out structure against the Messinian unconformity which is named PL3-C (Figure 9.7, Figure 9.8). To the South East of the AR94PY licence the same reservoir horizon and structural configuration has tested gas in the nearby Naomi-Pandora gas field. PVO anticipates that the updip extension of PL3-C sand is a prospective structure which they propose to test with a well. After data review and volumetric QC, CGG agree with PVO that there could be prospective gas resources of 223.7, 450.3 and 708 MMscm in this structure with a chance of success (CoS) of 17% (Table 9.9). The greatest risks to this prospect are considered to be gas charge and trap integrity (fault seal). If successful, the gas could be treated using the Teodorico facilities.

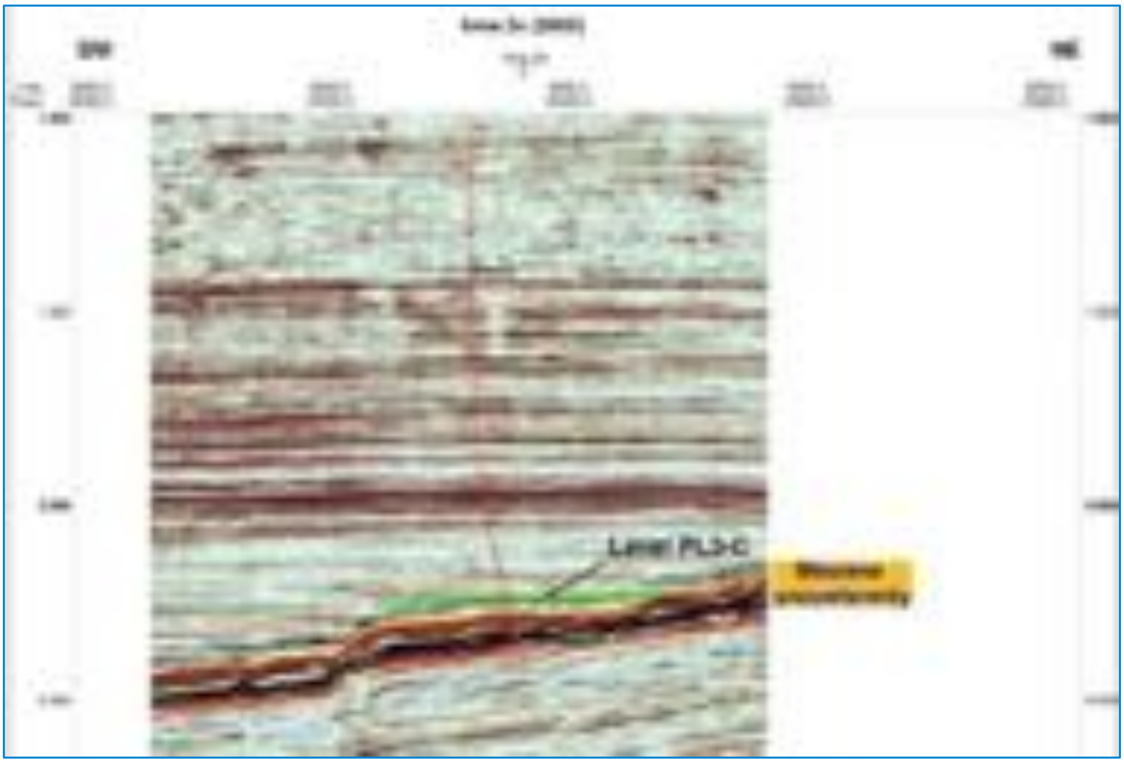

Figure 9-7 Seismic Line showing Late Pliocene pinch-out (PL3-C) NE of Irma-2X well

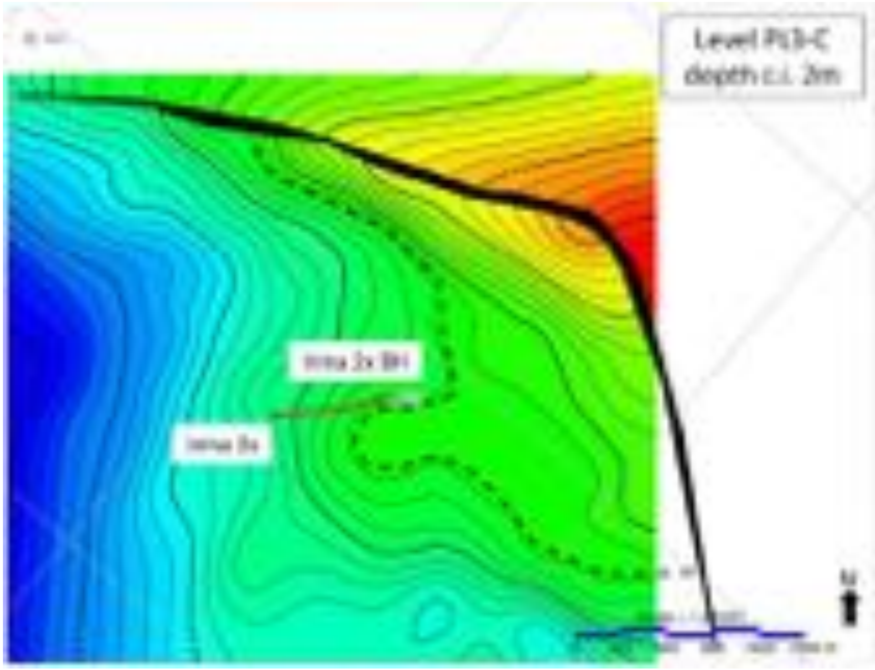

Figure 9-8 Depth Structure Map at Late Pliocene pinch-out (PL3-C) NE of Irma-2X well

Table 9-9 Gas Resource Estimation; Teodorico, PL3-C

Prospect	Prospective Resources (MMscm)			
	CoS	Low	Best	High
PL3-C	17%	223.7	450.3	708.0

9.2.3 The Rita Lead

Well Rita-1 was drilled by ENI in 1971 but was P&A as a dry hole (water-bearing). When drilling this well, ENI was exploring for gas in sands that pinch out against the underlying Miocene. Nearby, ENI discovered gas in the form of the Naomi-Pandora gas field. Prospectivity updip from the Rita well is indicated on seismic data inspected during a data room visit to ENI (CGG not present). PVO have stated that 3D seismic data clearly show the Rita well was drilled in the downdip portion of a positive seismic amplitude anomaly onlapping the Miocene. The geology and trap is closely analogous to the Naomi-Pandora gas field.

PVO has indicated that their future work program will be to purchase and interpret the seismic data around the Rita Lead in order to firm up a possible drilling target and location. For now, a technical evaluation is lacking and it is not possible to comment on potential gas volumes.

9.2.4 Adele and Azzura-Ginevre Discoveries

In addition to the Rita Prospect (which lies beyond the 12 mile nearshore limit) there are also the Adele and Azzurra-Ginevra gas discoveries. However, these cannot be appraised further or developed because they lie within the 12 mile limit.

Both discoveries are therefore inaccessible to PVO and are considered as Contingent Resources requiring legislative change on the part of the Italian Authorities before anything can be done. Under these circumstances, we are not reporting any contingent resource volumes for these discoveries.

Figure 9-9 Rita Prospect, Adele and Azzura-Ginevra Discoveries within the AR 94 PY Licence Area

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10 TORRE DEL MORO LICENCE

This Oil Exploration Licence in the Emilia Romagna region of Northern Italy was awarded to Po Valley Operations Pty Ltd. with 100% working interest in February of 2017 (Figure 10.1). The licence area is 111 km^2 and expires February 3rd, 2023.

In terms of underlying geology, the Licence encompasses an area on the Eastern margin of the Apennines, having Lower Jurassic carbonates of the Marmarone Formation at 3500 to 6000 feet depth or greater, buried by overlying Miocene to Pleistocene sediments. Oil shows were encountered in the target limestones in the Sarsina-1 well that was drilled some 15 km away on the lower flank of a large thrust fold. The crestal part of the fold structure remains undrilled, with a crest at about 3500-4000 metres depth; this being the main Lead in the Licence area (Figure 5.2).

Figure 10-1 Map showing Location of the Torre del Moro Exploration Licence

PVO have inspected 2D seismic lines held at ENI in support of the gross rock volume of the structure and have reviewed publically available well log information relating to the Villafortuna oil field which is considered to be a good analogue for the Torre del Moro Lead. CGG has not been able to review these 2D seismic lines, as they have not yet been purchased by PVO and remain the property of ENI. Given that additional technical work is required before this can be regarded as a *viable drilling target*, CGG considers that the Torre del Moro structure is, at this point in time, a Lead rather than a Prospect according to PRMS definitions

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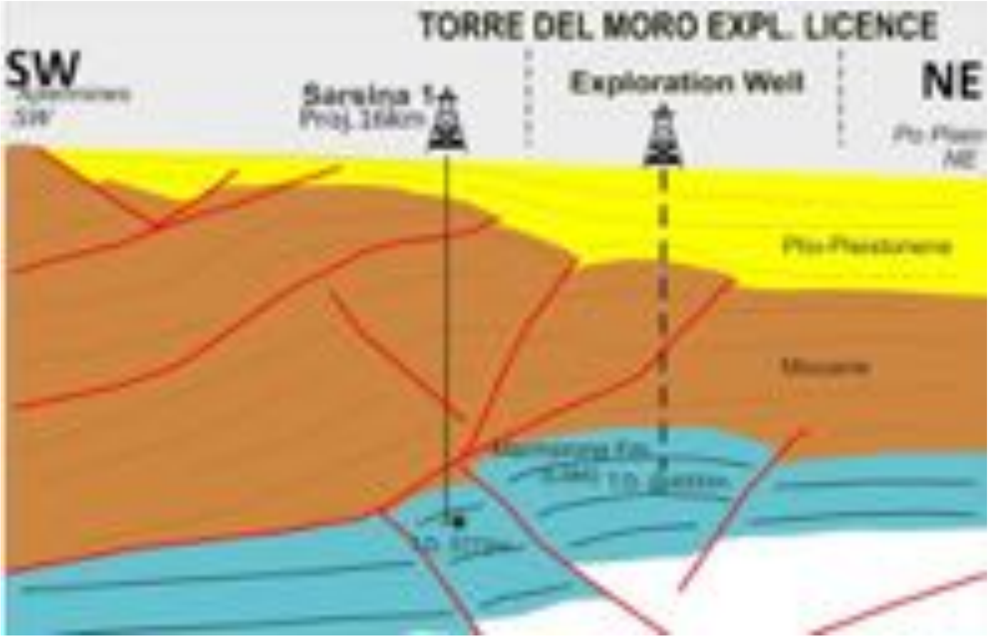

Figure 10-2 Schematic Cross-Section, Torre del Moro Prospect, showing notional exploration well location

PVO have stated that the prospect could contain approximately 150-250 MM bbl of recoverable oil. The working up of the Torre del Moro feature is at a relatively early stage, and the stated technical work programme in year one involves the purchase of 50km 2D seismic lines from ENI followed by geological and geophysical studies. In Years 2 and 3 the acquisition of some 50km of new 2D seismic data is considered, subject to the outcome of Year 1 activities. Drilling is envisaged for Year 4 (exploration well to 4500 metres depth) and in Year 5.a second well, contingent upon the success of the first, could follow.

CGG has reviewed the assumed reservoir properties and considers them reasonable (Figure 10.3) being from the analogue field “Villafortuna”. In CGG’s experience, the chosen reservoir properties are also comparable to those seen in other large limestone reservoirs in Southern Italy (of which CGG staff have experience).

*PARAMETERS ASSUMED FROM “VILLAFORTUNA” AREA
Area: 25-30 sqkm
Pay: 120-150 m
*Porosity: 3-4%
*Sw: 30%
Bo: 1-1.2
*RF: 30%

Figure 10-3 Potential Reservoir Properties, Torre del Moro Prospect

In CGG’s opinion, Torre del Moro looks attractive but requires a higher level of technical work before a prospective resource volume can be assigned.

11 RAPAGNANO

11.1 Introduction

The Rapagnano gas field is located onshore Italy in the Fermo Province, in Marche region. It is represented by a Plio-Quaternary piggy-back basin lying in the central Apennine inner foredeep, filled with thick turbidite sequences with alternating shale and sand layers, which constitute interbedded combinations of sources and reservoirs to several biogenic gas fields of this area. The field was first discovered by ENI in 1952 by means of well Rapagnano-1, which produced 108.54 MMscm dry gas from the Pliocene Carassai Fm "Sabbie" reservoir (top at 1527.4 m SSL, composed by S1 and S2 sand bodies) until 1996, when the well was shut in because of a water and gas production imbalance due to the high delivery pressure (70 bar) requirement at the time. In 2000, during a work-over, the well was recompleted with a 2 3/8" tubing and after a cement squeeze the perforation interval was extended from 1652.5 mRT to 1658 mRT (5.5 m interval) into the S1 sand body only. The Sabbie reservoir (S1+S2) was tested after the workover with unsatisfactory results. ENI therefore decided to abandon the Sabbie reservoir and move to the shallower completion interval A2 (top at 1290 mBSL). This produced a total of 7.07 MMscm up to December 2001, when it was once again shut in due to water production (final water gas ratio of 67 bbl/MMscf for 0.14 MMscf/d produced, Figure 11-1).

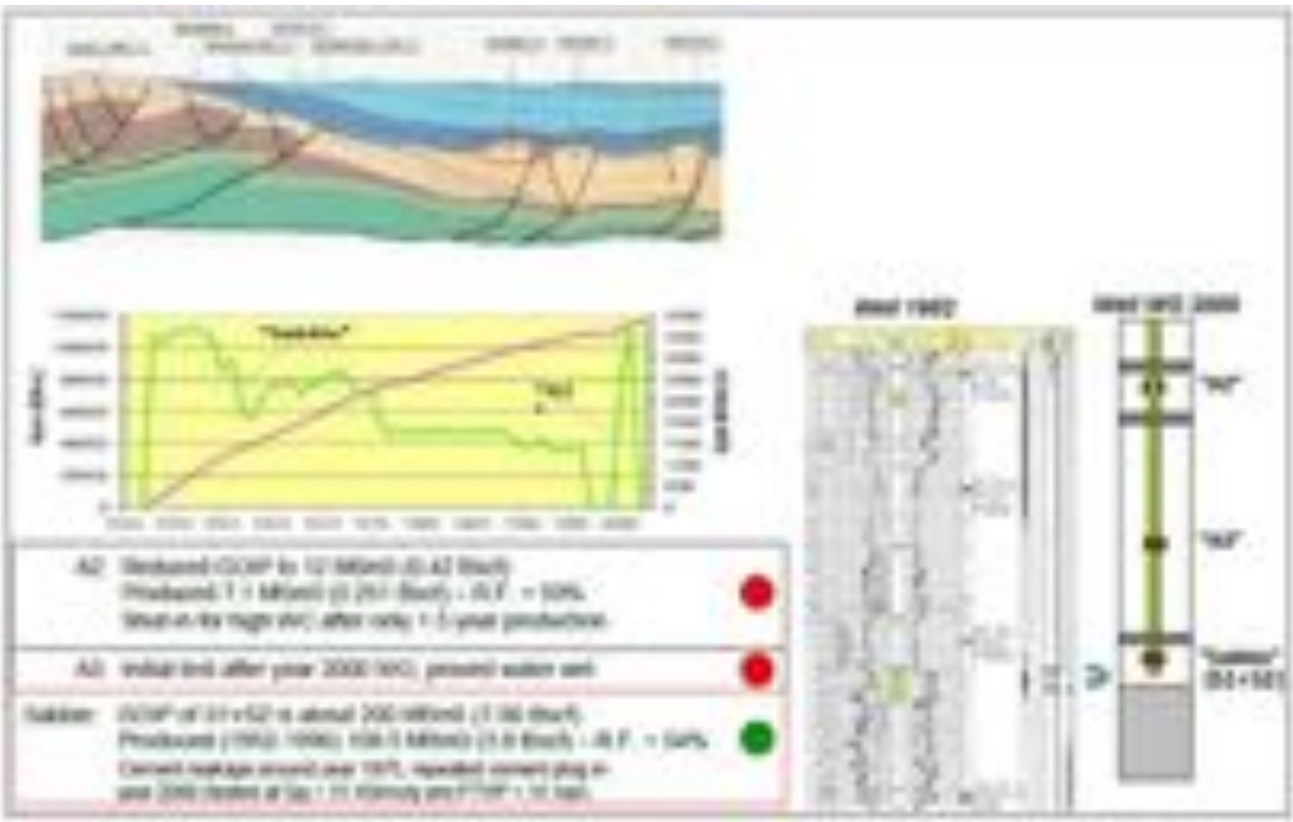

Figure 11-1 Rapagnano-1 well main reservoir levels (source: Apennine)

In November 2012 the operatorship transferred to Apennine, who isolated sand A2 and removed the plug isolating the Sabbie reservoir with a coiled tubing operation. The well was put into production on 15th May 2013 and exported via low delivery pressure (5 bar). A stabilized static profile was recorded in May 2014 and based on new SBHP measurements in May 2013 and May 2014 a revised P/z plot was produced, suggesting a minimum amount of remaining gas volume of about 37 MMscm. In the light of this, Apennine revised the static GIIP creating a 3D static model of the reservoir, using the top of the Sabbie reservoir structural map. Petrophysics and GWC depth for the Sabbie reservoir (S1+S2) have been updated and included in the model, provided to CGG for review.

11.2 Geology

Apennine conducted a petrophysical interpretation which has been reviewed by CGG. Pay zones have been identified and average parameters are 70% net-to-gross (NtG), 20% porosity and 40% water saturation. The GWC depth chosen by Apennine for the 3D static model (-1545 m TVDSS) represents the observed gas-down-to (GDT) in the Rapagnano-1 well. The 3D static model generated by Apennine is quite simple and reflects the results of Apennine's petrophysical interpretation of the Sabbie reservoir. The Top Sabbie map, shown in Figure 11-2, has been used as a reference surface for generating the other horizons in the model.

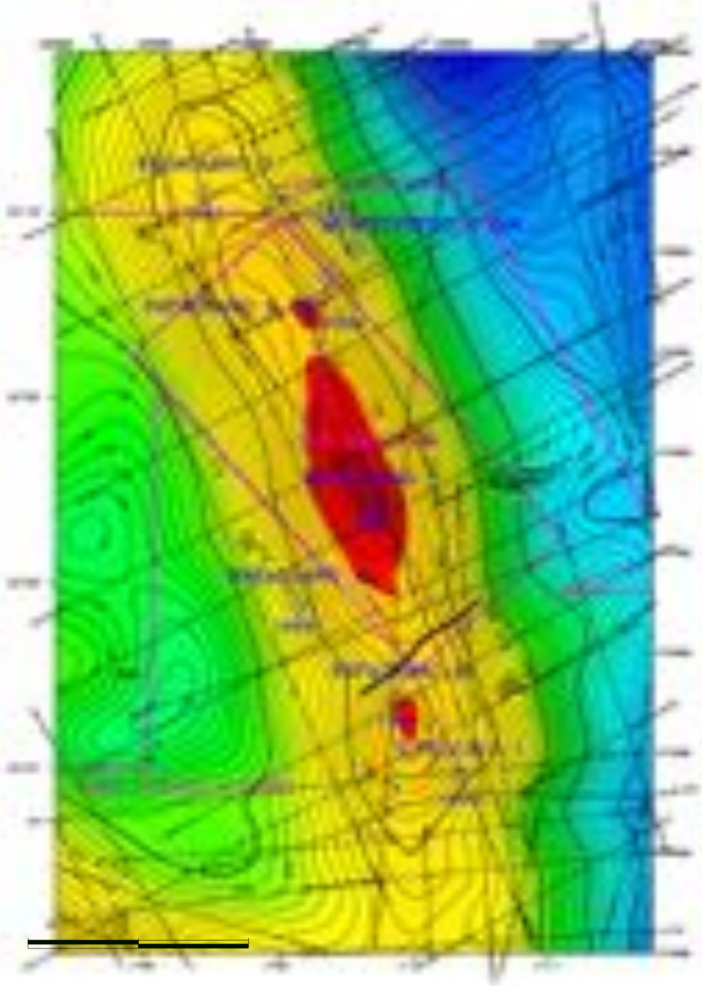

Figure 11-2 Depth map at Top Sabbie Formation, Rapagnano Gas Field (source: Apennine).

The reservoir interval is divided into 5 zones, among which the productive zones are S1 and S2, the two sand bodies constituting the Sabbie reservoir, which are separated by a shale interval. Gas in-place volumes for the

Sabbie reservoir in the Rapagnano field were calculated only with regard to the main structural closure, drilled by well Rapagnano-1 (Figure 11-3 and Figure 11-4).

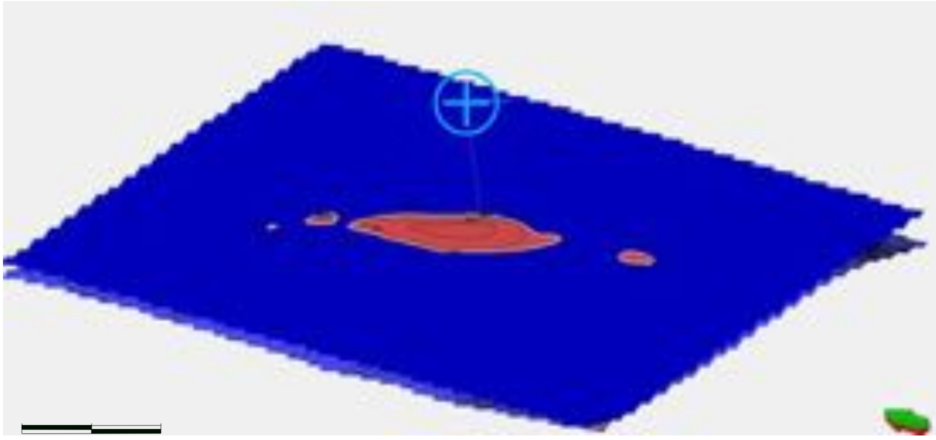

Figure 11-3 Top S1 reservoir structure above contact (red). Only the main structure penetrated by Rapagnano-1 well was considered for gas in-place volumes.

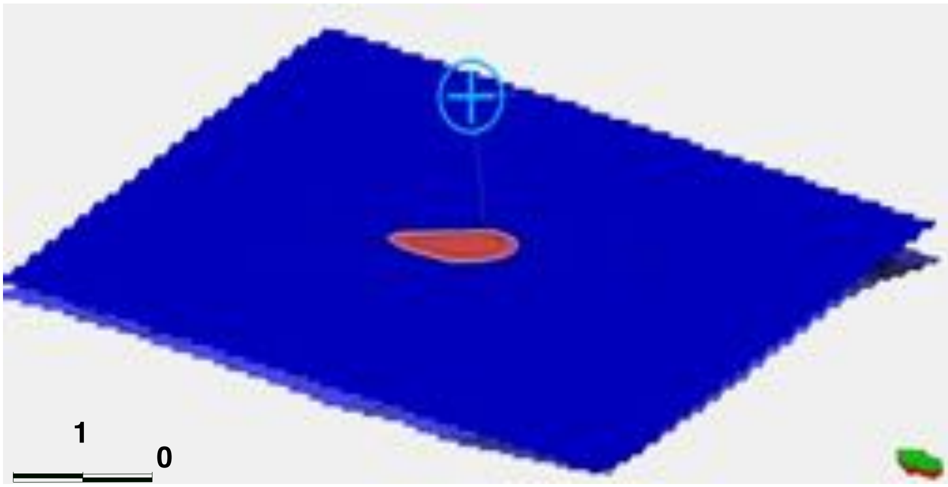

Figure 11-4 Top S2 reservoir structure above contact (red) around Rapagnano-1 well.

In general terms, CGG accepts Apennine's approach regarding the petrophysics, 3D static model building and gas in-place volume calculation for the Rapagnano field and agrees with Apennine's most recent GIIP estimate, amounting to 177 MMscm GIIP for the Sabbie reservoir (122 MMscm for S1and 55 MMscm for S2). The gas in-place volume for S1 (122 MMscm) is in line with the p/z plot reported in Figure 11-5 (red line through 1970 pressure point).

The petrophysical inputs and resulting in-place volumes are shown in Table 11.1.

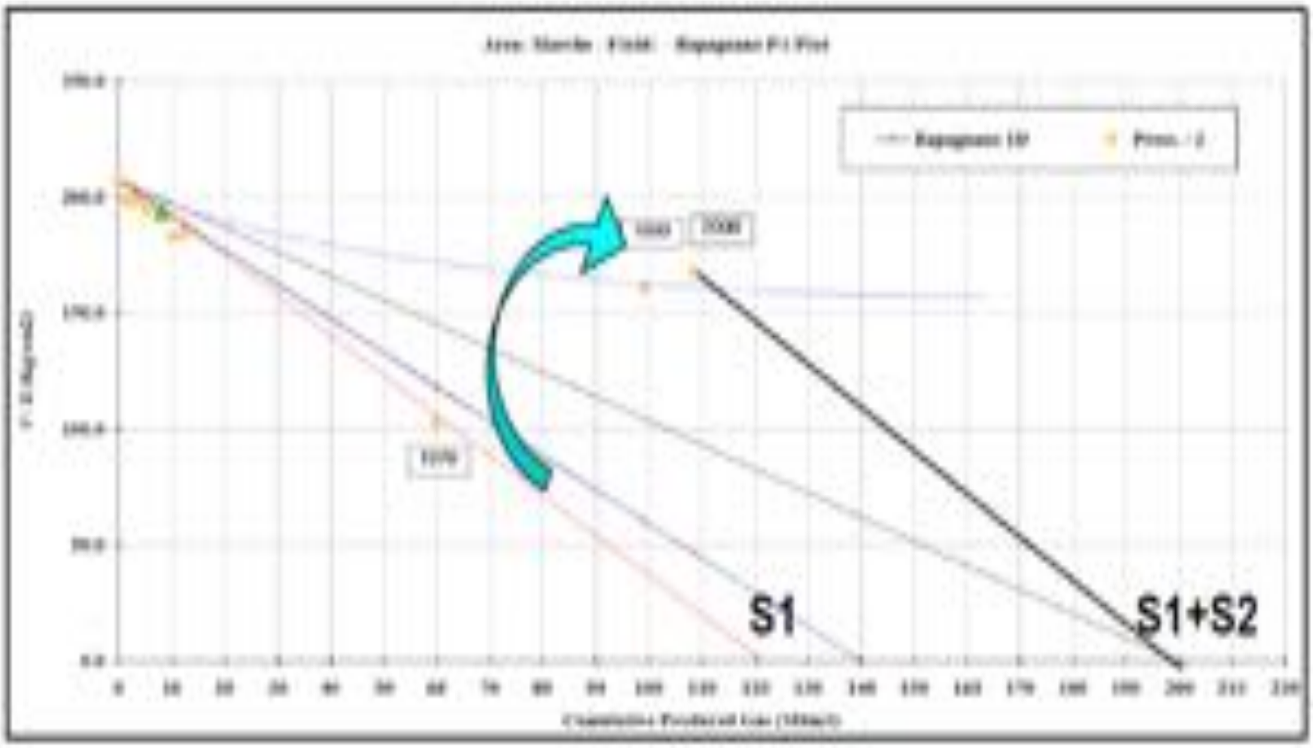

Figure 11-5 P/Z plot; pressure increase recorded in 1990 by a SBHP survey (source Apennine 2014).

Table 11-1 Apennine evaluation made in May 2012 for A2 reservoir in Rapagnano field

RAPAGNANO – A2				
Parameters	**Unit**	**Low**	**Mid**	**High**
Area	**km^2**	0.80	0.90	1.00
Gross pay	**m**	10	13	15
Net To Gross	**%**	25	30	35
Porosity	**%**	18	20	22
Water Saturation	**%**	48	50	52
Formation Volume Factor (1/Bg)	**-**	125	130	135
Recovery Factor in 2001	**%**	-	22	-
In Place Volumes				
			P50	
Gas	**MMscm**		12.0	
Produced Volumes till 1996				
			P50	
Gas	**MMscm**		7.1	

11.3 Reservoir Engineering

CGG has reviewed the reservoir engineering data provided by Apennine. The well consists of three production levels as shown in Table 11.2.

Table 11-2 Rapagnano Production Levels and Cumulative Production

Level	Status	Cumulative Production (as of 31st October 2017)	Recovery Factor (as of 31st October 2017)
A2	Suspended due to high water	7.1 MMscm	59%
A3	Watered Out	Not available	Not available
S1+S2	Current producing level	124.2 MMscm	70%

The remaining recoverable volumes proposed by Apennine are in the Sabbie reservoir only (S1+S2). The S1+S2 were previously produced by ENI between 1952-2002 with cumulative production of 108.5 MMscm. The well was worked over and production resumed in May 2013. The daily gas and water production are shown in Figure 11-6.

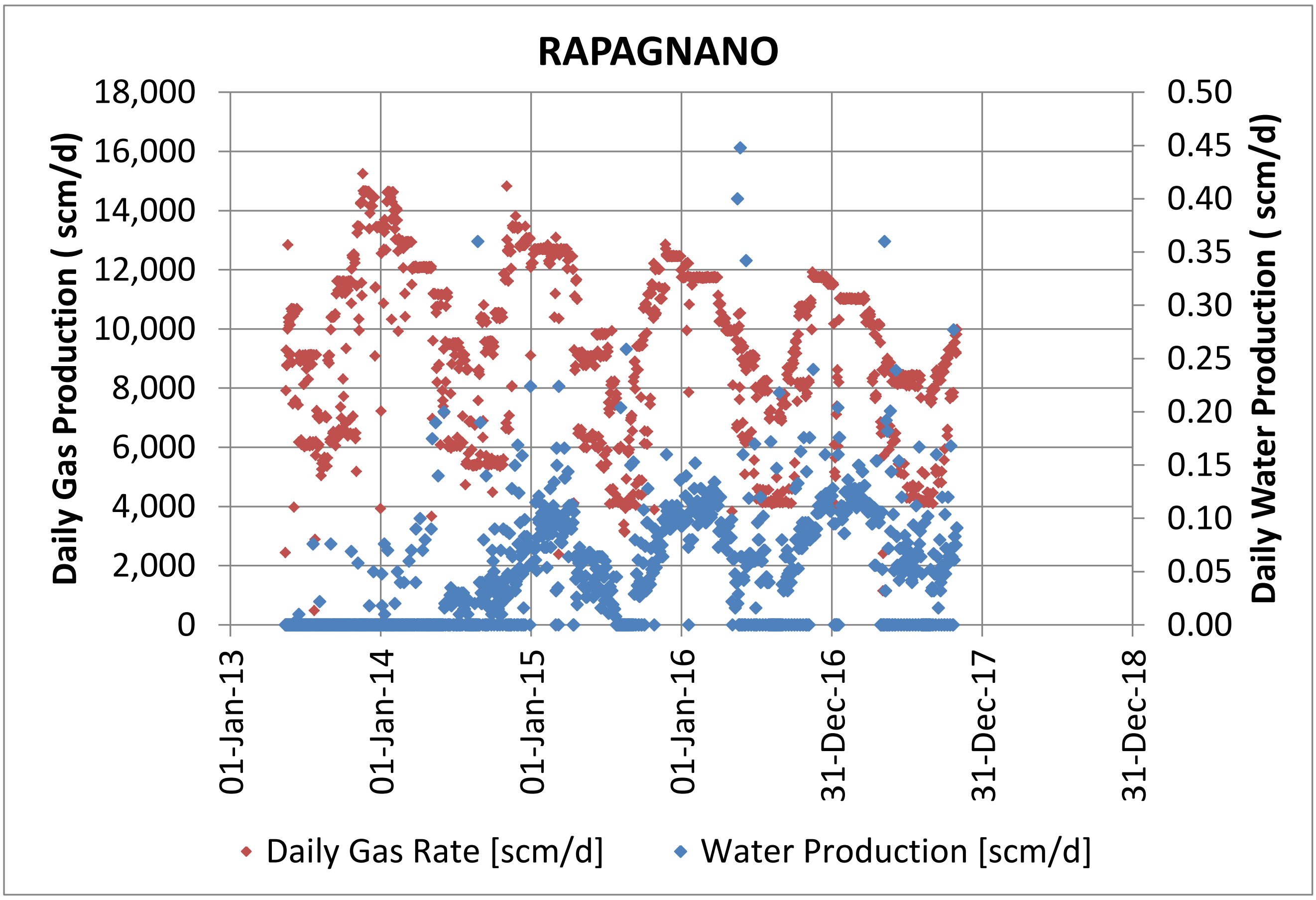

Figure 11-6 Rapagnano Production History from May 2013 to October 2017

CGG has conducted P/Z material balance analysis (Figure 11-7). It indicates water drive, which can potentially reduce the remaining recoverable volumes. CGG has estimated 1P, 2P, and 3P recoverable volumes using Decline Curve Analysis (Rate vs Cumulative) plot (Figure 11-8). The 1P case assumes strong water causes early water breakthrough. In the 2P case, the decline follows the observed trend. The 3P case assumes weak water influx. The remaining recoverable volumes for these cases are tabulated in Table 11.3.

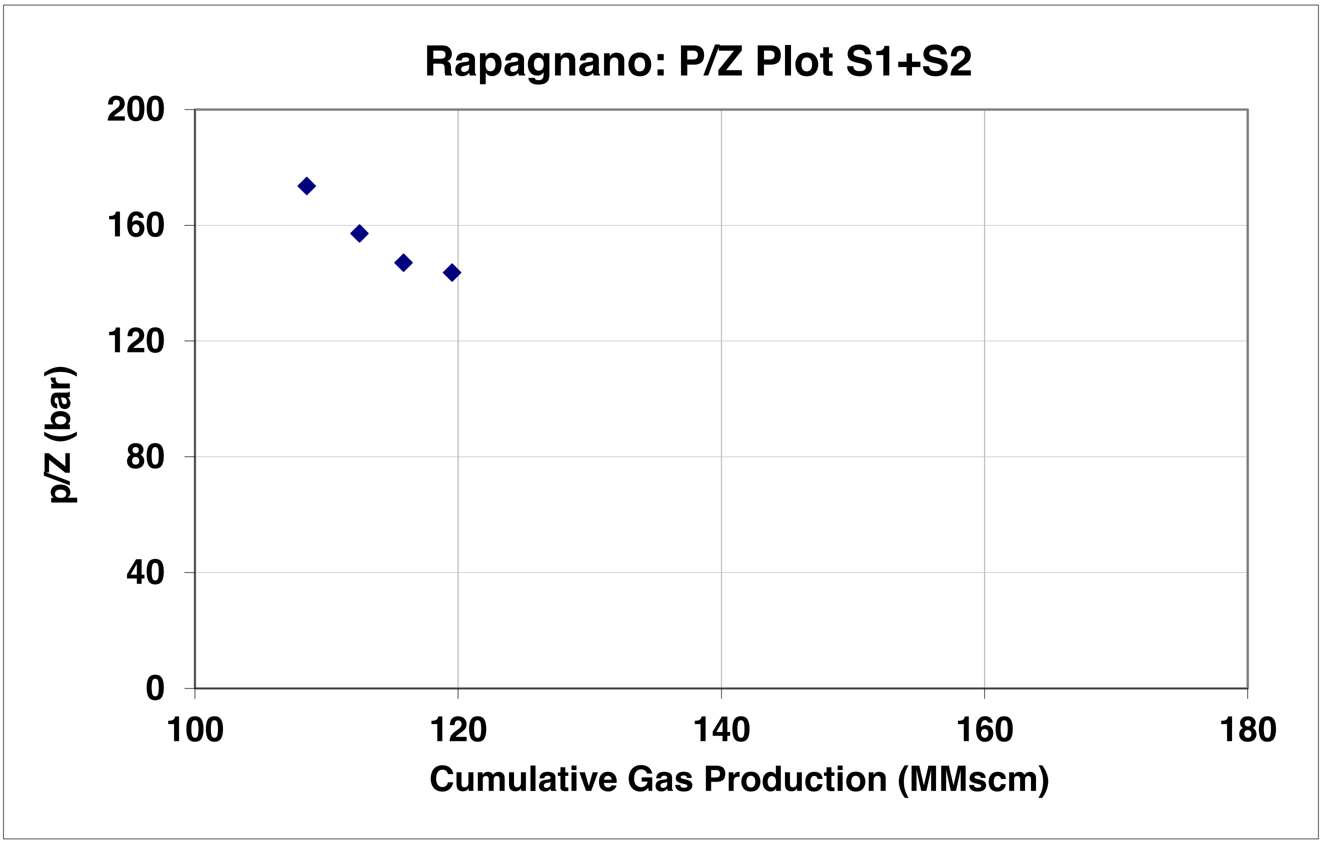

Figure 11-7 Rapagnano P/Z Plot

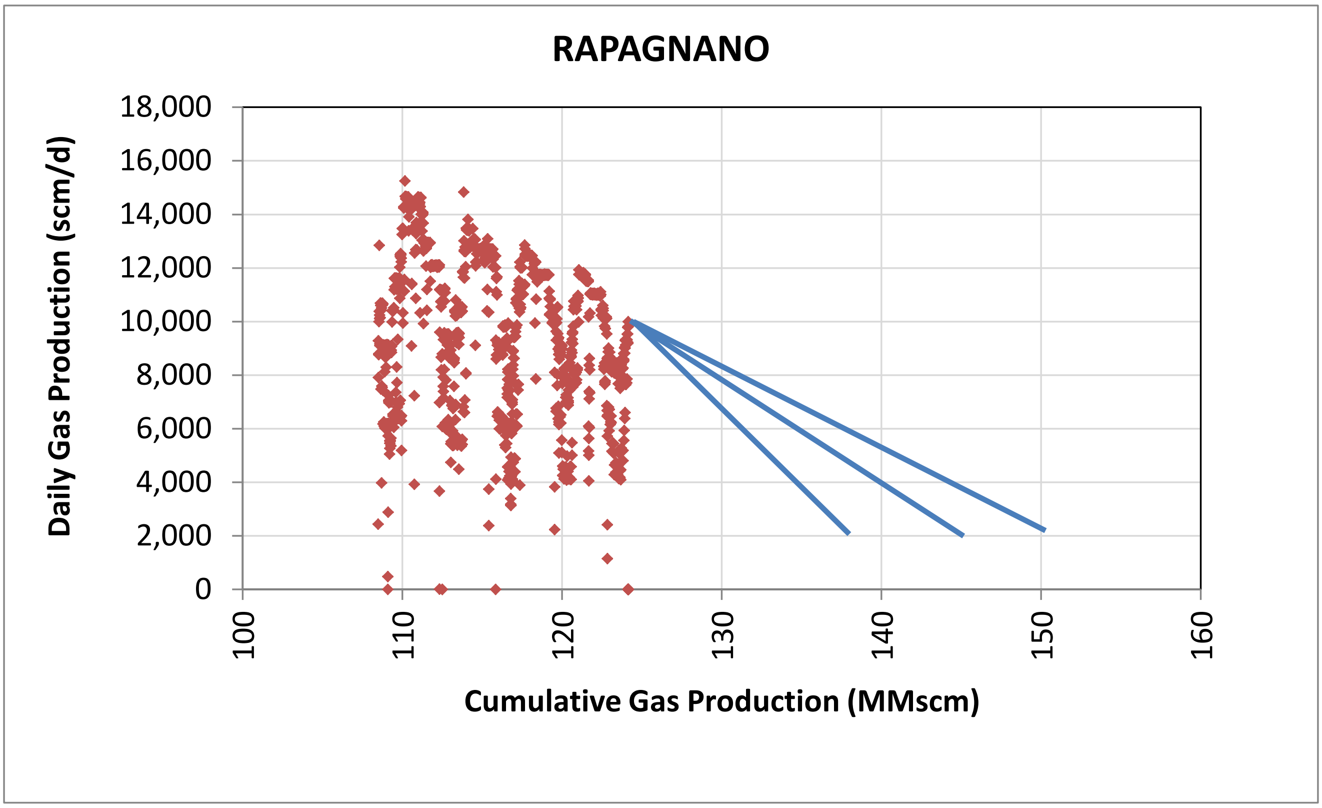

Figure 11-8 Rapagnano Gas Production vs Cumulative Gas

Table 11-3 Gas Recoverable Volumes in Rapagnano

RAPAGNANO			
	1P	2P	3P
In Place Volumes, MMscm		176.9	
Recoverable Volumes, MMscm	138.1	144.2	150.3
Cumulative Production as of 31st October 2017, MMscm		124.2	
Estimated Production in Nov-Dec 2017, MMscm		0.7	
Remaining Reserves as of 1st January 2018, MMscm	13.2	19.3	25.4
Total Recovery Factor	0.78	0.82	0.85

The production profiles for 1P, 2P and 3P cases are graphically shown in Figure 11-9. Table 11.4 shows the annual production and cumulative production.

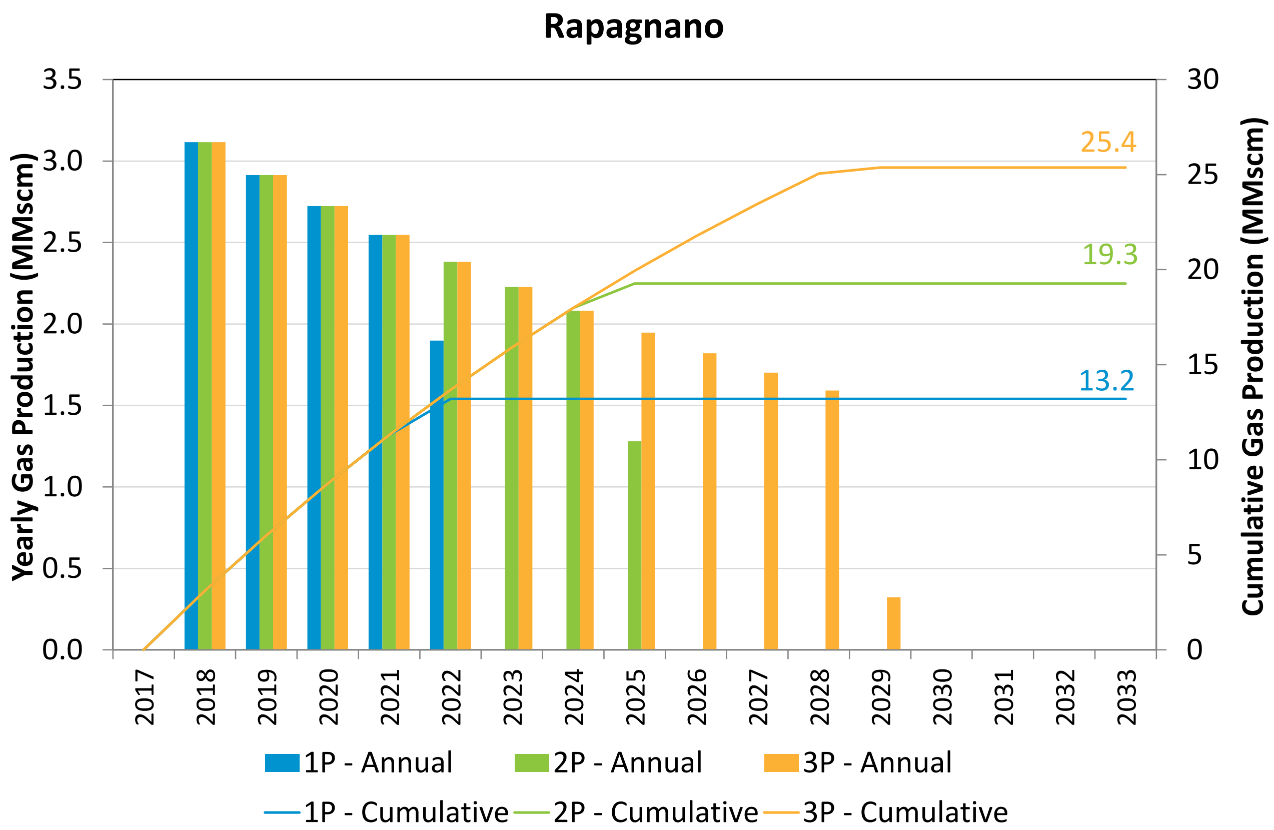

Figure 11-9 Technical Production Profiles of Rapagnano 1P, 2P and 3P (before Economic Cut-off)

Table 11-4 Annual Production and Cumulative Production of Rapagnano (before Economic Cut-off)

Year	1P		2P		3P	
	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)
2018	3.12	3.12	3.12	3.12	3.12	3.12
2019	2.91	6.03	2.91	6.03	2.91	6.03
2020	2.72	8.75	2.72	8.75	2.72	8.75
2021	2.55	11.30	2.55	11.30	2.55	11.30
2022	1.90	13.20	2.38	13.68	2.38	13.68
2023	0.00	13.20	2.23	15.91	2.23	15.91
2024	0.00	13.20	2.08	17.99	2.08	17.99
2025	0.00	13.20	1.28	19.27	1.95	19.94
2026	0.00	13.20	0.00	19.27	1.82	21.76
2027	0.00	13.20	0.00	19.27	1.70	23.46
2028	0.00	13.20	0.00	19.27	1.59	25.05
2029	0.00	13.20	0.00	19.27	0.32	25.37

12 SANT'ANDREA

12.1 Introduction

The Caritá Permit was awarded in July 2010, and was assigned to Apennine from previous owners in November 2011. Apennine have a 100% working interest in the Caritá permit. The assets of interest included the Nervesa and adjacent Sant'Andrea gas discoveries. The Nervesa discovery was re-named Cascina Daga.

The Nervesa gas field is an anticlinal structure in an area of complex tectonic history (Figure 12-1). Data reviewed includes new petrophysical interpretations, a new static model and new estimates of in-place and recoverable volumes. Approximately 1km to the North of Nervesa lies the Sant'Andrea culmination, which is part of the same structure but they are separated by a fault.

The Nervesa field was discovered by ENI in 1985 by means of the Nervesa-1 and Nervesa-1dir wells. The wells encountered 13 gas-bearing Miocene sand intervals within the Tortonian (Miocene) marls and shales of the Marne di San Doná Formation. Of these, interval 9a was completed and put on production between 1989 and 1991. Cumulative gas production of 18.17 MMscm occurred from Level 9a before being shut in during February of 1991 as a result of water breakthrough. Produced gas was 99.6% methane. The well was later plugged and abandoned, the wellsite being removed.

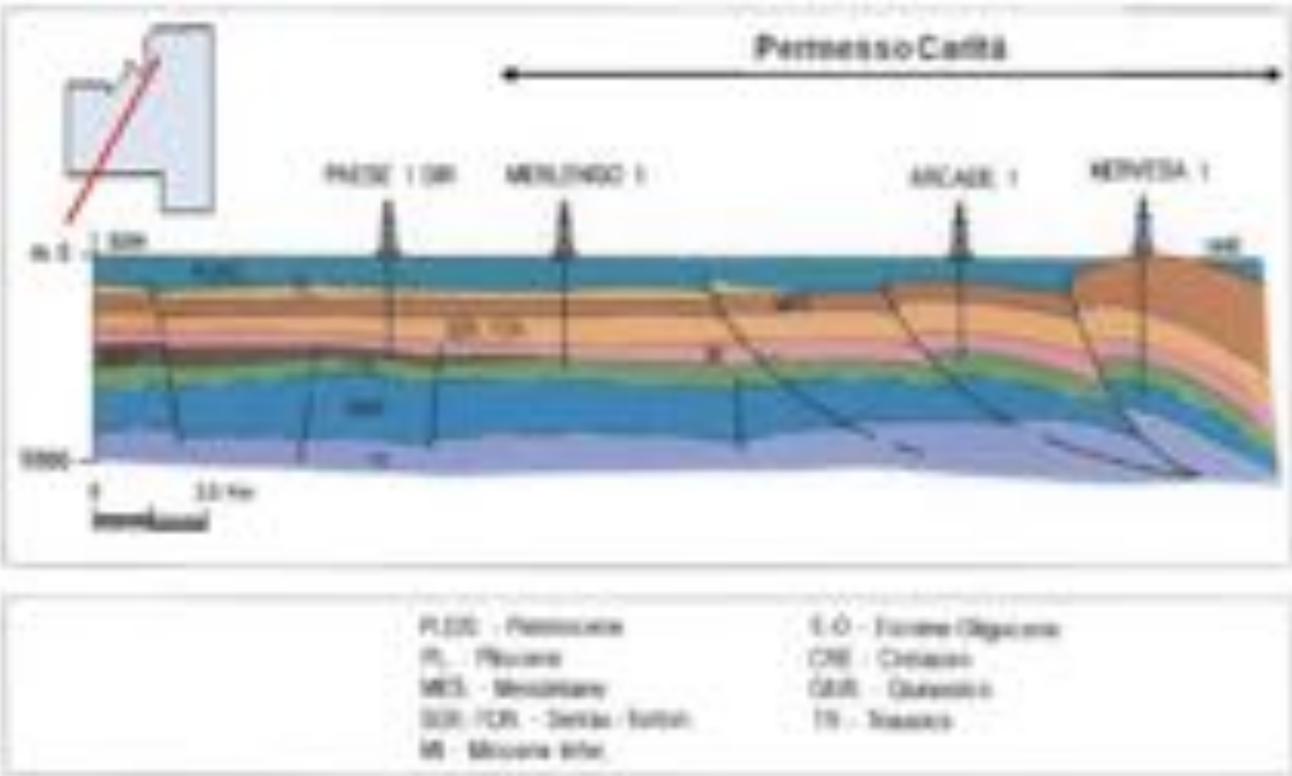

Figure 12-1 Schematic Cross-Section through the Carita Permit Area

Source: Sound Presentation (2014)

12.2 The Sant'Andrea-1 Dir (ST) Well

During June and July 2013, a new appraisal well (Sant'Andrea-1 Dir ST) was drilled on the northern culmination of the structure and encountered gas in the same Miocene sands that had produced in the Nervesa well. However, the gas was present in deeper sands than in the main Nervesa culmination, implying the presence of a greater gas column and sealing faults.

The well was tested between 27th August and 2nd September 2013. It is a dual string completion, with Short String perforations in Level 14A and Level 14B (flowed 30,400 scm/d) and Long String perfs in Levels 5, 6D and 6C (flowed 47,000 scm/d from Level 5). In both tests, the radius of investigation was small; 50 metres or less, and pressure decline was observed on test.

Since the production start-up in 2016, the Sant'Andrea-1 Dir ST well has been put on continuous production from three layers (5+6D+6C) and suffered rapid pressure and rate decline as shown in Figure 12-2. The cumulative gas as of 31st December 2016 was 1.4 MMscm. The well has been temporarily shut-in during 2017 as a result and periodically flowed to surface for brief periods.

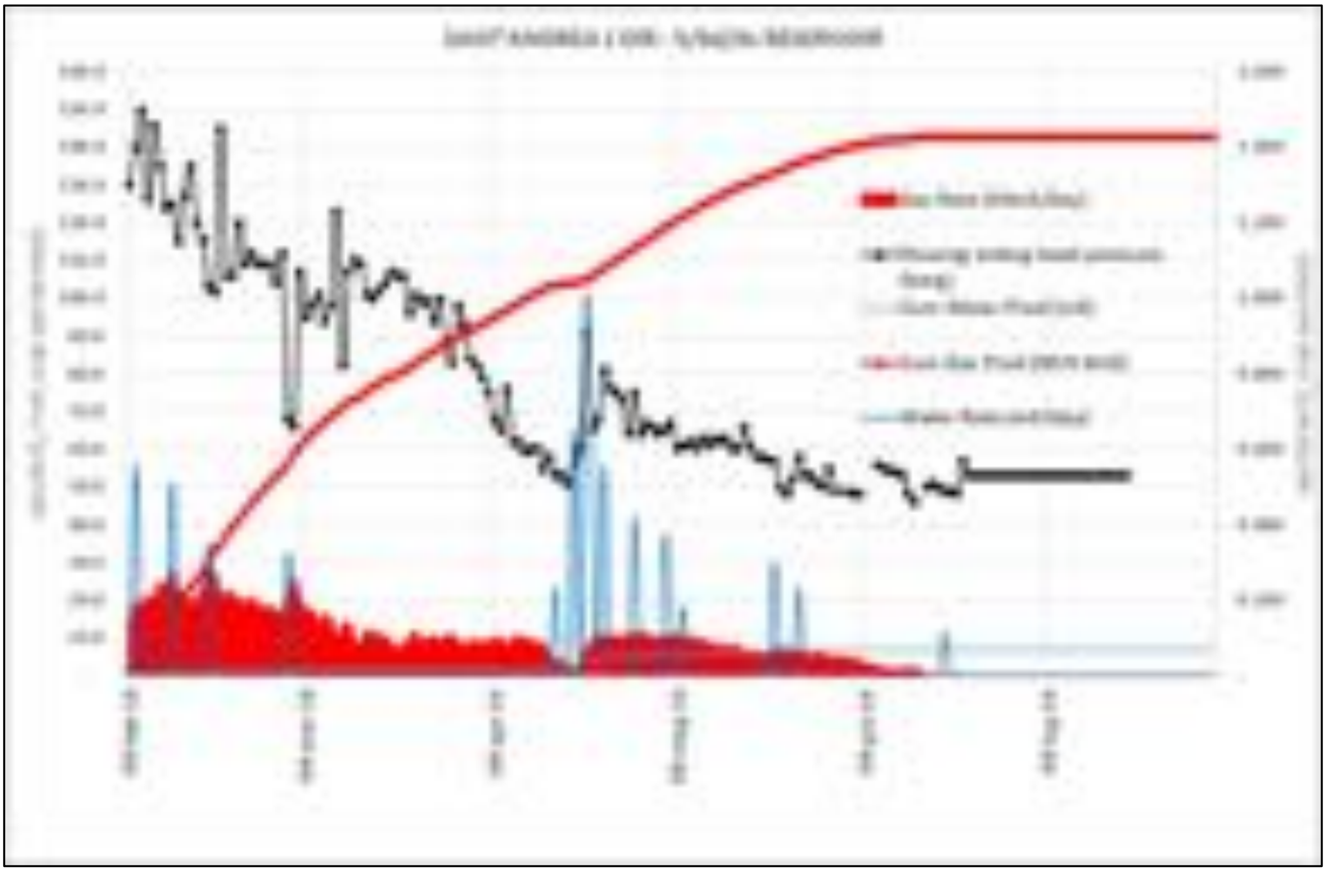

Figure 12-2 Sant'Andrea-1 DirST Production History

Source: Appenine Presentation (2017)

Appenine reviewed gas in-place connected to Sant'Andrea-1 Dir ST and believed that the well unluckily entered a small fault compartment. Appenine has updated the structure map following the disappointing production performance of Sant'Andrea-1 Dir ST (Figure 12-3).

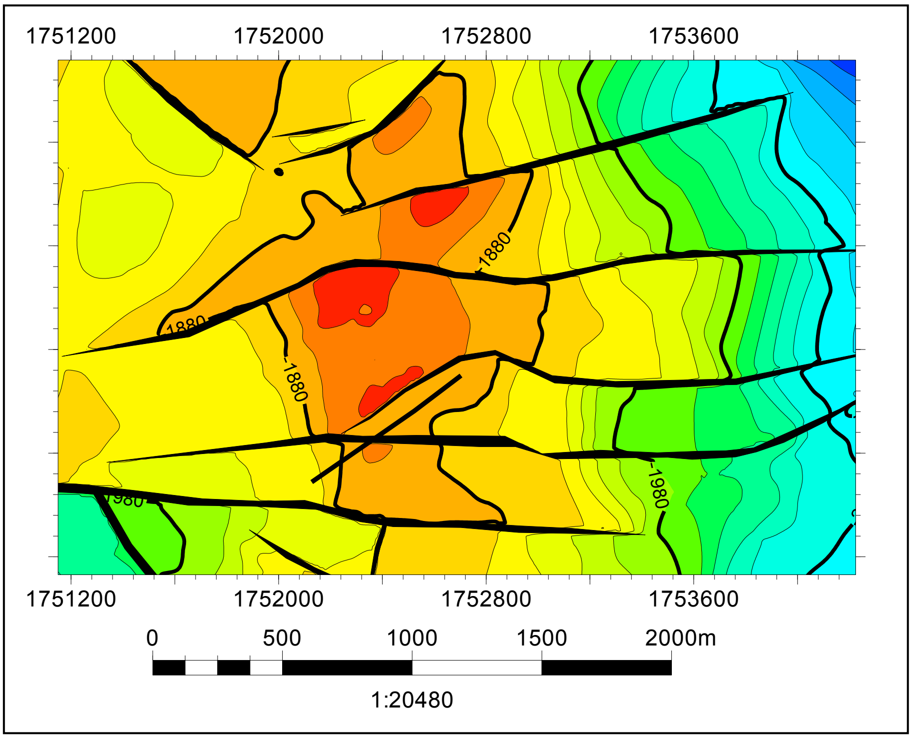

Figure 12-3 Depth Structure Map, 2017; Sant'Andrea-1 DirST Encounters small, fault-bounded compartment

Source: Appenine Presentation (2017)

12.3 Petrophysical Interpretation

A range of different petrophysical techniques has been applied to the interpretation of the well logs arising from the Nervesa-1dir and Sant'Andrea-1dir ST1 wells. Whereas the interpretation of the older Nervesa log suite has been limited to a classical petrophysical analysis, the CMI tool run in the Sant'Andrea well allowed a "Thin-Layer Analysis" to be carried out using the tool's micro-conductivity capability. Whilst thin-beds can be recognized better using this tool (and therefore the definition of Net-to-Gross ratio), there remain difficulties in assigning PhiE and Sw to the succession.

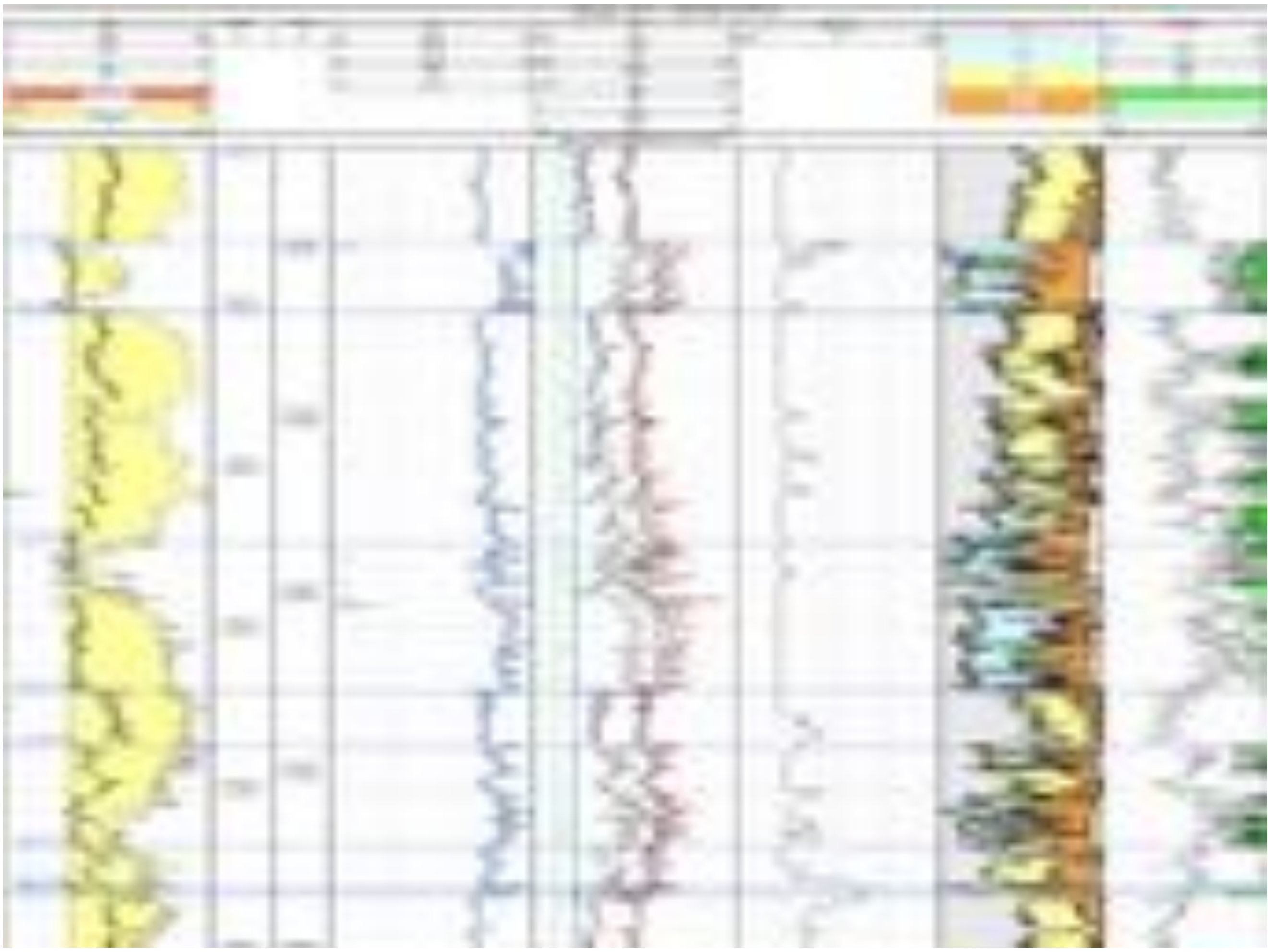

Figure 12-4 Nervesa-1 dir A Interpreted Log Example: Levels 15 to 13

Source: Apennine Petrophysical Evaluation (dated August 2013)

The Thin Layer Analysis (TLA) carried out by Apennine on the Sant'Andrea-1dir ST1 well data has given confidence to the net-to-gross estimations for the field overall. The TLA provides results that are, overall, lower in net-to-gross, higher in average porosity and lower water saturation than the classical petrophysical analysis.

The petrophysical estimations are considered fit for purpose, even if gas saturations might be under-estimated as a result of thin-bed effects on the logging tools.

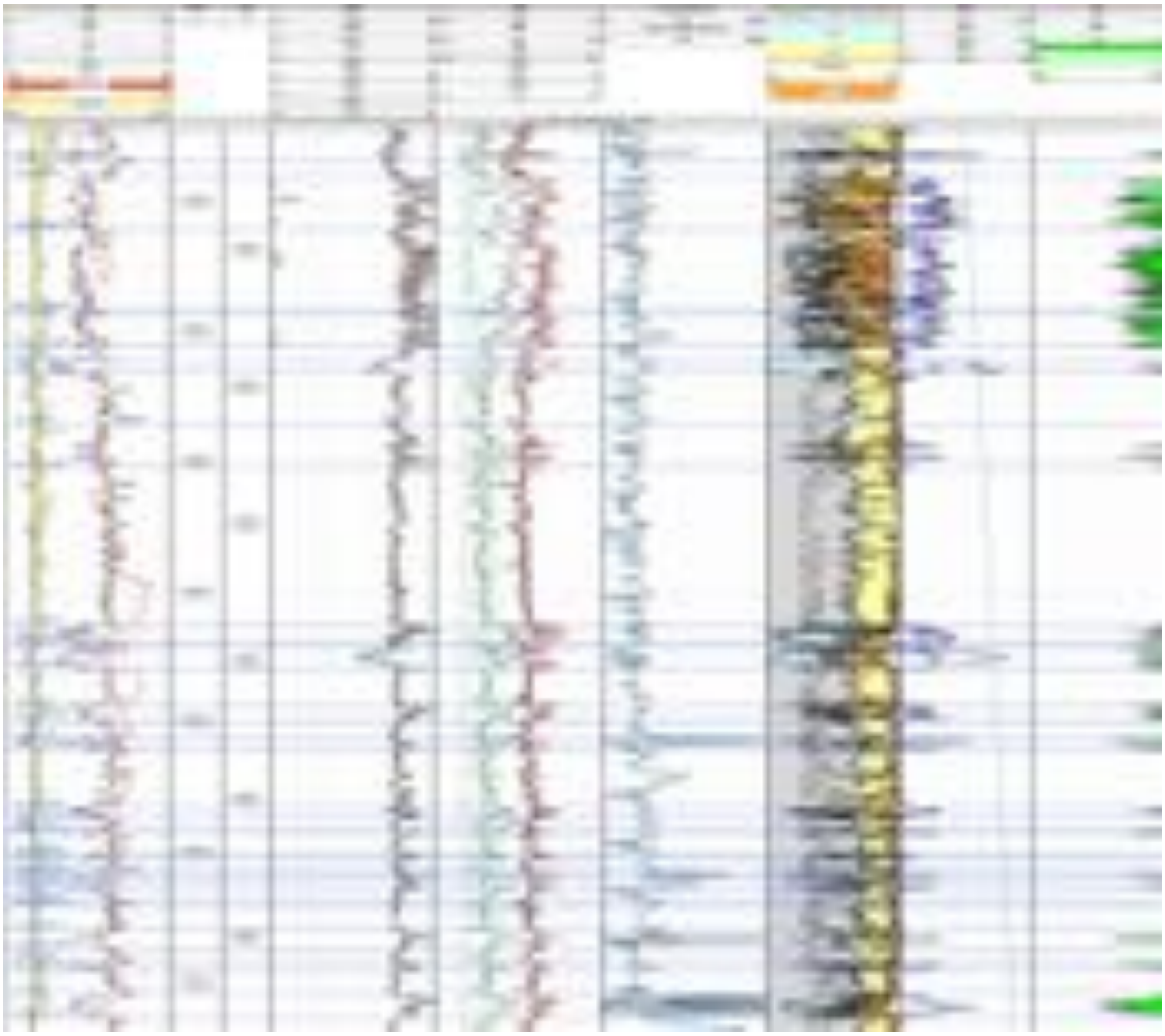

Figure 12-5 Sant'Andrea-1dir ST1 Interpreted Log: Levels 13 to 5

Source: Apennine Petrophysical Evaluation (dated August 2013)

12.4 Volumetric Estimations

Considering the negative result and current status of the Sant'Andrea-1 Dir (ST), CGG assigns no reserves to Sant'Andrea. However, given the updated structure map (Figure 12-3), it appears that the well unluckily entered a small fault compartment, confirmed the presence of producible gas and that the structure and concept remain robust and prospective. Should a sidetrack be drilled, it could access gas resource volumes in the updip fault block as shown in Table 12.1.

In working up these contingent resource volumes CGG has used Gross Rock Volumes from a 3D static model and layer average reservoir properties for each of the considered reservoir zones. The reservoir zones selected are the best of those encountered by the Sant'Andrea well. The zones chosen were either flowed during production (6C, 6D, 5) or tested gas to surface (14A, 14B), and CGG takes the cautious view that other zones would not necessarily contribute to gas production in any future sidetrack. The resultant contingent resource is given in Table 12.1.

Table 12-1 Contingent Resource Summary for Sant'Andrea, as verified by CGG

Case	Sand	2017 GRV	NtG	Phi	Sg	Gas FVF	GIIP	Total GIIP MMscm	RF %	Contingent Resource MMscm
1C	14A	9.59	0.50	0.13	0.33	175	35.0	100.8	45%	45.4
	14B	7.98	0.51	0.14	0.41	175	40.0			
	6C	2.03	0.49	0.11	0.36	175	7.2			
	6D	0.94	0.50	0.13	0.33	175	3.4			
	5	3.03	0.51	0.14	0.41	175	15.2			
2C	14A	9.59	0.83	0.12	0.32	180	52.2	99.5	55%	54.7
	14B	7.98	0.49	0.10	0.28	180	19.6			
	6C	2.03	0.49	0.11	0.39	180	7.9			
	6D	0.94	0.50	0.12	0.38	180	3.7			
	5	3.03	0.51	0.14	0.42	180	16.1			
3C	14A	9.59	0.83	0.12	0.32	190	55.1	104.6	65%	68.0
	14B	7.98	0.49	0.10	0.28	190	20.6			
	6C	2.03	0.49	0.11	0.38	190	8.2			
	6D	0.94	0.50	0.12	0.37	190	3.8			
	5	3.03	0.51	0.14	0.42	190	16.8			

13 LAURA DISCOVERY

13.1 Introduction

The Laura Field was discovered by ENI/Agip in 1980 by the Laura-1 well. The field is located in 197m of Adriatic water, about 4km from the shore (Figure 13-1). From a geological point of view, Laura field is located in the Sibari basin, developed in the Neogene as a series of Mio-Pliocene post-orogenic sediment units overlapping the crystalline basement westwards and the Liguride flysh eastwards. The trap is a NW-SE trending faulted anticline, formed under compressive stress regimes in the Pleistocene. The reservoir consists of sands and conglomerates of the San Mauro Formation (late Pliocene). The cap and source rock is shale of the Argille di Crotone Formation. The concession was kept by ENI from 1984 to 2005, when ENI relinquished it without implementing the development plan. In June 2014 the DR74-AP permit area was awarded to Apennine, who completed seismic data purchase and re-processing in November 2014.

Laura-1 well discovered a commercial gas accumulation in two sand intervals at a depth of 1305 m to 1343 m in the San Mauro Formation (Levels A1 and A2) and at the depth of 1450 m to 1480 m in the Gessoso Solfifera Formation (Level B). Both intervals were tested separately: Level A proved an excellent deliverability (320,000 scm/d), while Level B showed worse behaviour. Due to inferior performance during well tests on Laura-1, Level B has not been considered by Apennine in the current development plan, but development cannot be excluded in future. It is Apennine interest to drill and develop contingent resources for Laura Main block with Liuba-1 ERW horizontal well (Phase-1) and to subsequently side-track Liuba-1 well to develop prospective resources in the undrilled East block (Phase-2). The presence of the San Mauro reservoir in the East block is thought to be confirmed by seismic and amplitude data.

While the development of Laura is planned from onshore drilling, the Laura field lies within 12 nautical miles of the Italian coastline and so, currently, cannot be progressed to development. Legislation change by the Italian Government would be required in order to lift the ban on developments within 12 nautical miles.

Figure 13-1 Laura field location (source: Apennine)

13.2 Reservoir Model

Apennine has worked up a reservoir model based on their own analysis on both Laura Main and Laura East blocks. Reservoir properties have been determined by means of petrophysical analysis carried out on available well logs for the gas bearing intervals 1307-1317.5 m (A1) and 1321.5-1343.9 m (A2). Apennine also performed a seismic re-interpretation of ten 2D seismic lines (D85-154, D85-155, D85-158, DF80-31, DF-3021-77, DR77-005, FR314-78, DR3024-77, DF80-29, D85-156), with direct mapping of the top and bottom of the A reservoir. Time maps were depth-converted using a velocity model developed for Laura-1 well. Three main faults have been identified on the seismic lines: a main thrust, a back thrust and a normal fault, as shown in Figure 13-2 and Figure 5-3.

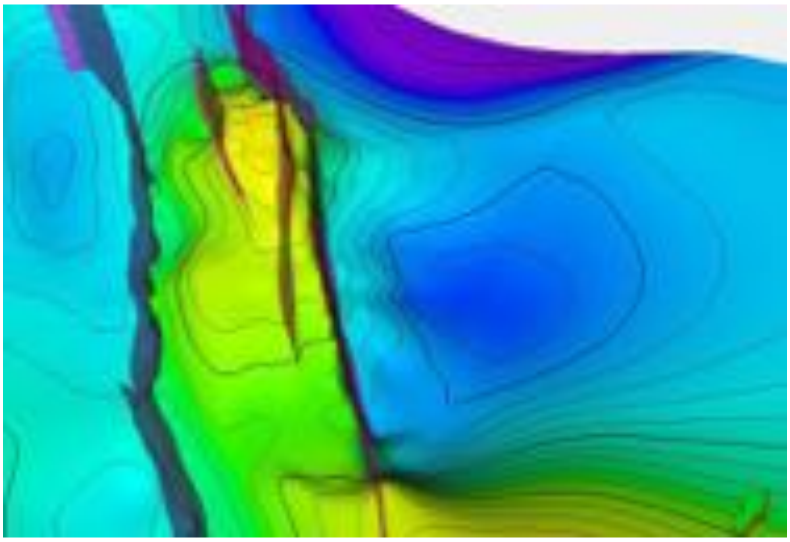

Figure 13-2 Structural map of the San Mauro Fm. Top and interpreted faults in Sound static reservoir model.

The results of the petrophysical and seismic analysis represent the input for the static model built in Petrel and were used to calculate gas in-place volumes. Apennine's static model comprises both Laura Main and East blocks. Faults interpreted on seismic have been modelled vertically, apart from the two major NW-SE faults which cross the entire grid of the model, and were used to define the trends of the static model grid.

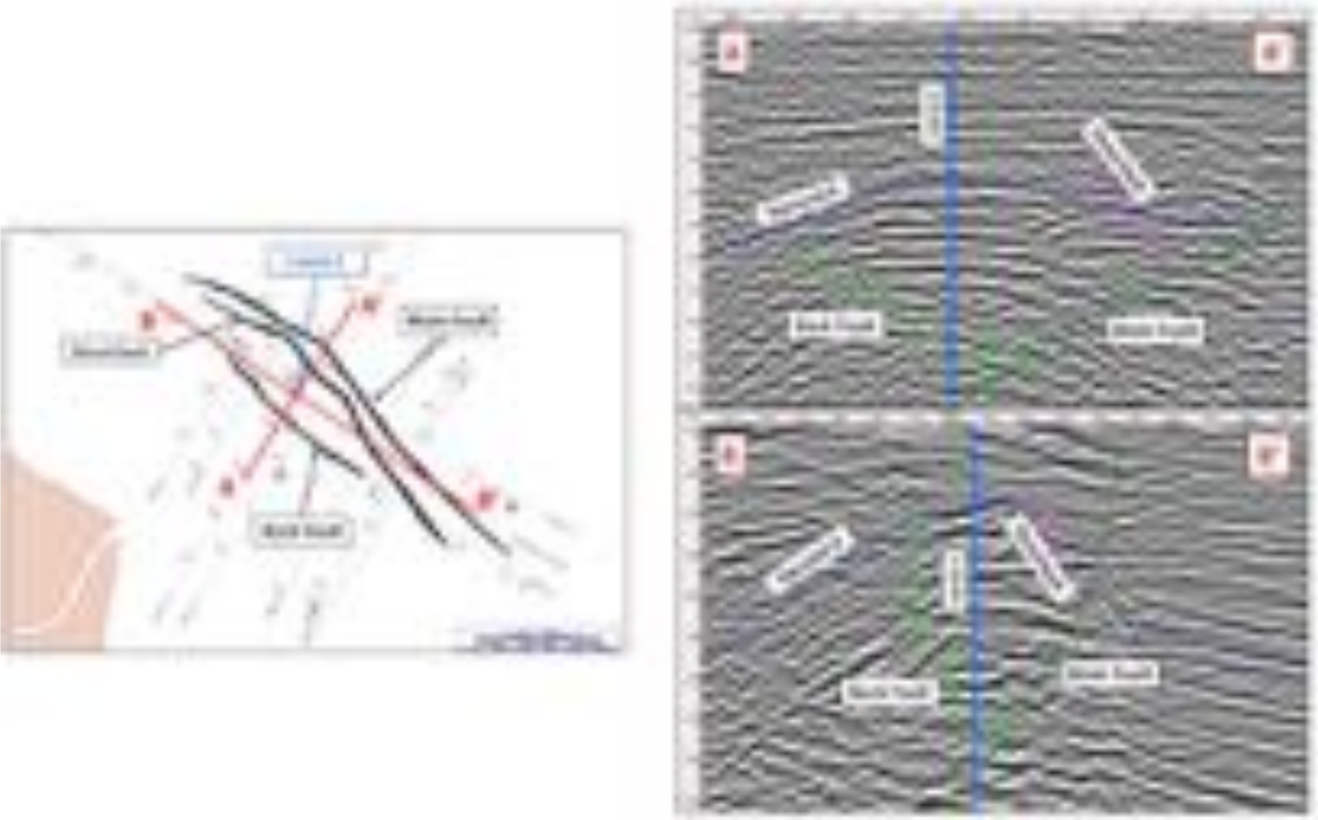

Figure 13-3 Interpreted faults (on the left) and seismic lines through Laura-1 well (on the right).

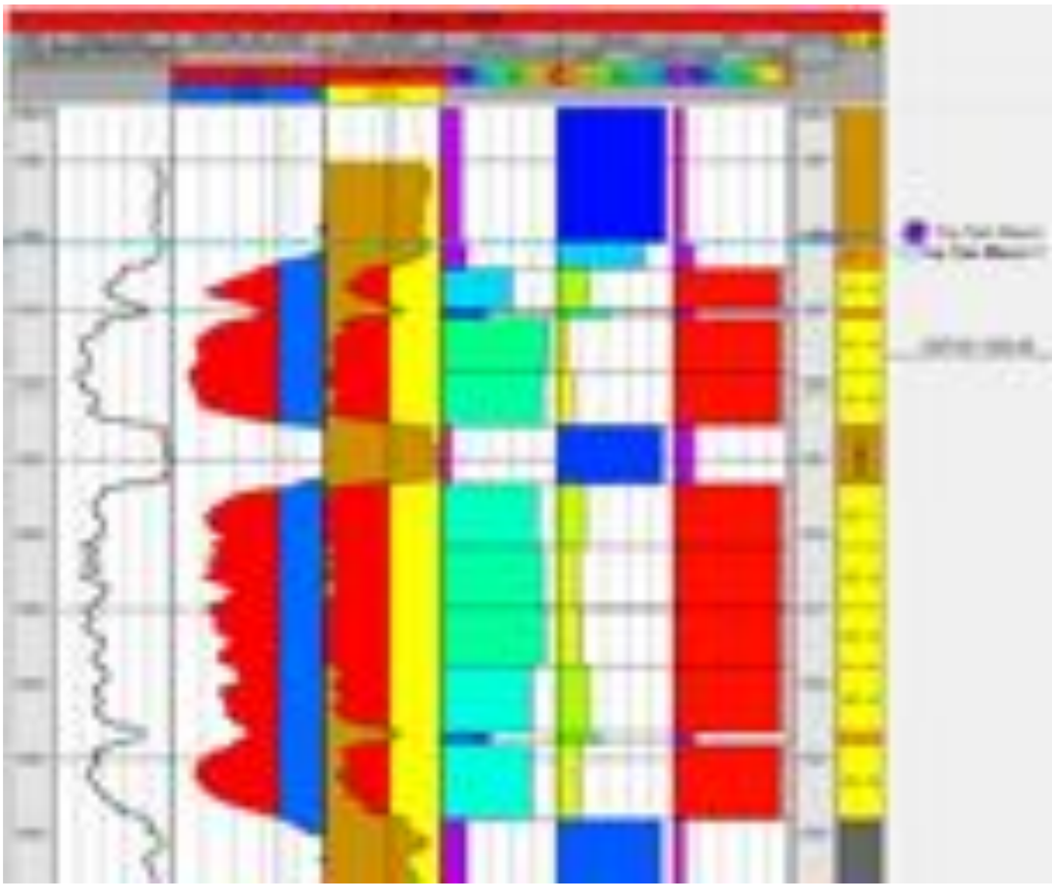

Figure 13-4 Well logs and properties for Laura static model

13.3 Reservoir Properties

The reservoir levels A1 and A2 (San Mauro Fm.) have been further subdivided into minor sub-levels as detailed in Figure 13-4. Sub-levels A-1-1, A-1-3 and A-2-5 can be described as silty sands, while the remaining intervals represent clean sands. A 4.4 m thick shale level (Shale 1) divides A1 from A2 levels. Apennine attributed a net-to-gross of 100% to clean sand intervals, while a 10% value was chosen for the interlayered silty sands (A-1-1, A-1-3 and A-2-5) and for the shale interval (Shale 1). Porosity and water saturation values have been derived from the porosity and water saturation curves produced in the petrophysical study. The mean volume weighted values for A1 and A2 levels are around 92% NtG, 23% Phi and 35% Sw.

Three cases, which Apennine term Min, Base and Max, were defined for both Laura Main and East blocks. The base case uses petrophysics directly determined from Apennine's well log interpretation. In the minimum case porosity was lowered by 1% and water saturation increased by 1%, based on the assumption that the presumed RHOgas (0.12 g/cc) could be higher. The Max case instead is based on the petrophysical analysis conducted by an ENI study on Laura field dated 1981.

13.4 Fluid Contact Definition

The GWC for all three cases in Laura Main block was fixed at -1337 m TVDSS, value firstly suggested by ENI in 2004 and successively confirmed by Apennine based pressure data analysis for the Laura-1 well. In the East block the GWC was fixed at -1424 m TVDSS for both base and maximum cases, determined considering the same pressure analysis and the same thickness for the reservoir zone as in the Main block. The minimum case for the East block, however, assumes a GWC of -1405 m TVDSS.

13.5 Seismic Mapping

CGG's review of seismic and amplitude data, provided in a Kingdom project, for both Laura Main and East blocks led to the following conclusions:

- The horizon interpretation appears reasonable, despite at times resulting in the cross-cut of seismic reflectors.
- Faults have been correctly interpreted. The back thrust could also be positioned slightly down-dip from the present interpreted location and the normal fault is difficult to interpret on available seismic.
- In most recent structural interpretations, Apennine have not mapped two NNE-SSW faults which connect to the normal and back thrust faults, rendering the Laura-1 gas accumulation completely fault-bounded (ENI 2004 study).

CGG recognises the presence of these two additional faults on seismic data, even if it is not possible to define their extension and eventual connection with other faults. We have verified that the presence or absence of these two minor NNE-SSW faults does not affect in any way the extent of the gas accumulation defined in the static model by Apennine (Figure 13-5 and Figure 13-6).

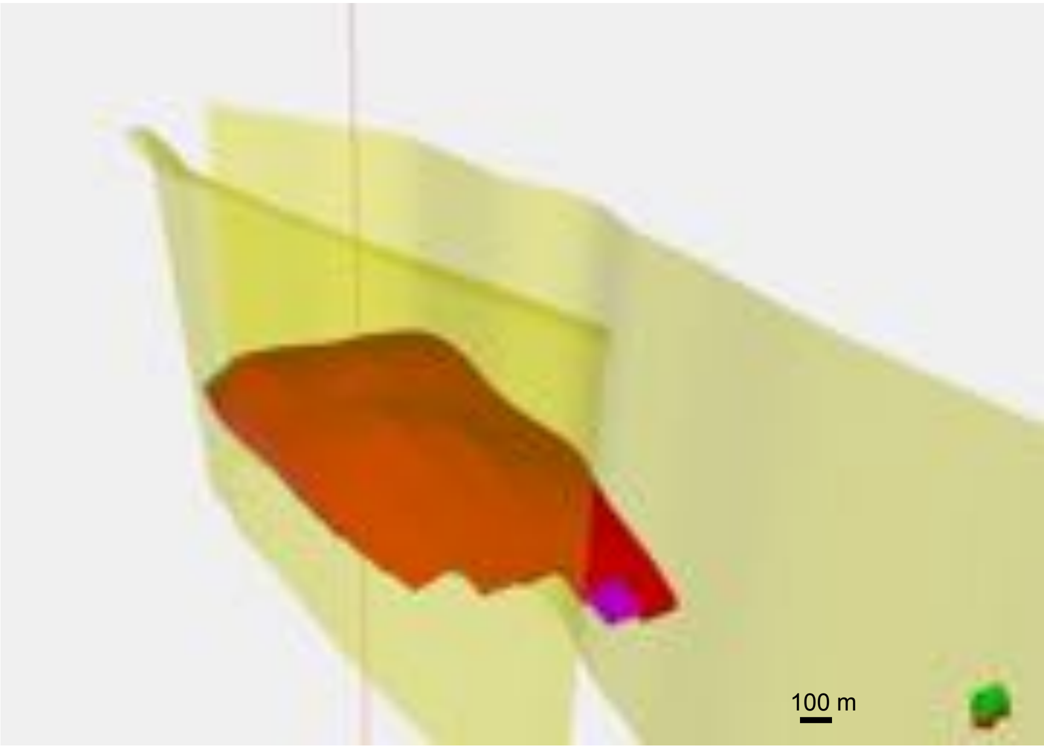

Figure 13-5 Gas accumulation in Laura Main block in Sound static model

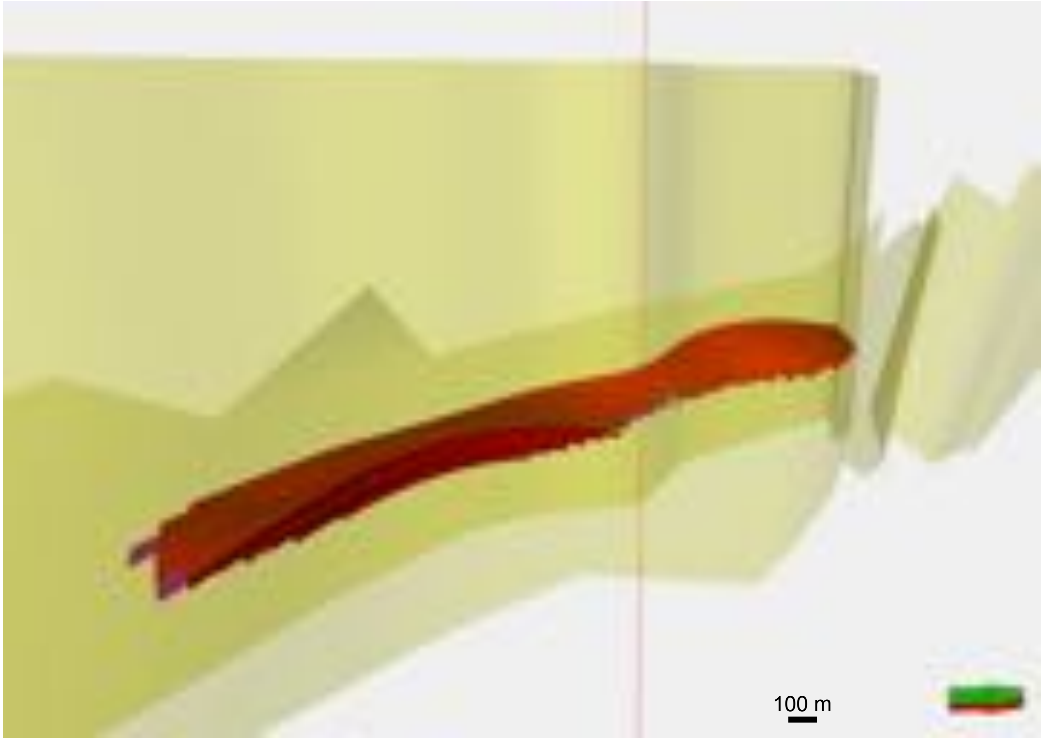

Figure 13-6 Gas accumulation in Laura East block in Sound static model

13.6 Amplitude Anomaly

CGG was able to reproduce the general features of the amplitude map created for Apennine by Ecopetrol S.r.l. The available digital seismic lines show a considerable bright spot identified at reservoir depth where well Laura-1 was drilled. This bright spot has been proven by drilling to contain gas.

Whether there is also gas in the East Block remains more uncertain, because although there is a bright spot in the East Block at reservoir depth (DR-3021-77 seismic line), it is against the fault, is considerably smaller than the drilled anomaly (approximately a quarter of the size), and has a lower amplitude. Possible migration effects close to the fault, in addition, demand caution when interpreting this bright spot as a DHI. With the data currently available to CGG, and with all the above considerations, CGG believes that it is quite difficult to assess gas presence in Laura East block based on the amplitude data alone, although the prognosis is certainly positive (gas presence in the Laura well at this depth).

13.7 Volumetric Estimations

Our review of the Laura Field static model indicates that Apennine's approach to estimating petrophysical parameters and calculating gas in-place volumes for both the Main and East blocks in Laura field is a reasonable one. Volumetric estimates are reported in Table 13.1 and Table 13.2.

Table 13-1 Gas in-place volumes for Laura Main block

	Case	GRV [10*6 sm3]	N/G (%)	Net Vol [10*6 sm3]	Phi (%)	Pore Vol [10*6 sm3]	Sw (%)	HCPV gas [10*6 sm3]	CGG GIIP [10*6 sm3]	APN GIIP [10*6 sm3]
Main Block	**Min**	24.23	81	19.68	23	4.5	32	3.07	**500.27**	**501.3**
	Base	24.23	81	19.68	24	4.76	31	3.29	**536.27**	**535.8**
	Max	24.23	85	20.62	28	5.82	22	4.53	**737.34**	**732.6**

Table 13-2 Gas in-place volumes for Laura East block

	Case	BV [10*6 sm3]	N/G (%)	NV [10*6 sm3]	Phi (%)	PV [10*6 sm3]	Sw (%)	HPVC gas [10*6 sm3]	CGG GIIP [10*6 sm3]	APN GIIP [10*6 sm3]
East Block	**Min**	2.86	73	2.1	22	0.46	30	0.32	**52.35**	**58.7**
	Base	8.63	79	6.81	24	1.64	30	1.14	**186.31**	**190.2**
	Max	8.63	84	7.26	28	2.03	22	1.58	**256.68**	**260.0**

Apennine estimated a geological chance of success of 56% for the Laura East block prospect, based on partial risk factors of 1 for source, 0.7 for reservoir, 0.8 for trap and 1 for seal. CGG is in agreement with this estimate.

CGG has reviewed the Laura field development plan provided by Apennine. One extended reach well (4 km long) is proposed to develop the Laura main field. The well will be sidetracked to the Laura East block. Three feasibility studies have been conducted by three service companies. CGG has not reviewed the proposed well design. Eclipse reservoir simulation models used for production forecasting have been reviewed by CGG, and we find that the methodology is acceptable based on the limited information on reservoir properties e.g. only one global permeability obtained from well testing was used.

For the Laura Main field, Apennine uses recovery factors of 80%, 80%, and 82% for Low, Best and High estimates. CGG takes the view that there are several uncertainties that could affect the well deliverability and recoverable volumes including reservoir heterogeneity (early water breakthrough), aquifer size and strength (early water breakthrough), drilling and completion efficiency (lower well deliverability), well may not be in the proposed/optimum location, etc. CGG applies confidence factors to the Apennine's recoverable volumes and calculates the recoverable volumes as tabulated in Table 13.3.

Table 13-3 Contingent gas resources in Laura Main

LAURA MAIN			
	1C	**2C**	**3C**
Recovery Factor	0.70	0.75	0.82
Contingent Gas Resources, MMscm	348.3	401.6	606.1
(1) Numbers have been rounded up or down and may not sum precisely.			

Apennine proposed to develop the Laura East prospect by sidetracking the well from Laura Main area. The Laura East fault block is untested by drilling. The static properties used for the Eclipse simulation model are the same as used in the main field. Recovery factors from the simulation results are 30%, 44%, and 46% in Low, Best, and High estimates. We found that these estimations are acceptable because it is a very small accumulation, potentially closer to the water. This results in lower recovery factors as compared to the main Laura accumulation. Table 13.4 shows the estimated recoverable volumes in each case.

Table 13-4 Prospective gas resource in Laura East

LAURA EAST			
	Low Estimate	**Best Estimate**	**High Estimate**
Recovery Factor	0.30	0.44	0.46
Prospective Gas Resource, MMscm	17.4	82.1	118.9
(1) Numbers have been rounded up or down and may not sum precisely.			

14 LICENSE D503-BR-CS (DALLA)

14.1 Dalla Prospect

Apennine started to evaluate the Dalla prospect in January 2015 using the available structural map in time, which depth converted using an average velocity calculated from the top of the reservoir (using data from the nearby Dora-1 well). No 3D static model has been created for the Dalla prospect but the available map was loaded into Petrel and used to constrain the reservoir GRVs for a Min, Base and Max case, respectively defined by three different gas-water contacts: -1396, -1430 and -1468 m TVDSS (Figure 14-1). These contact depths were defined considering the same pay zone thickness observed in the Dora field for the Min, Base and Max cases and the evidence that the reservoir is 20 m deeper in the Dalla prospect than in the Dora field. CGG has checked the interpretations and assumptions and has found them to be based on standard technical practice and generating very reasonable interpretations and results.

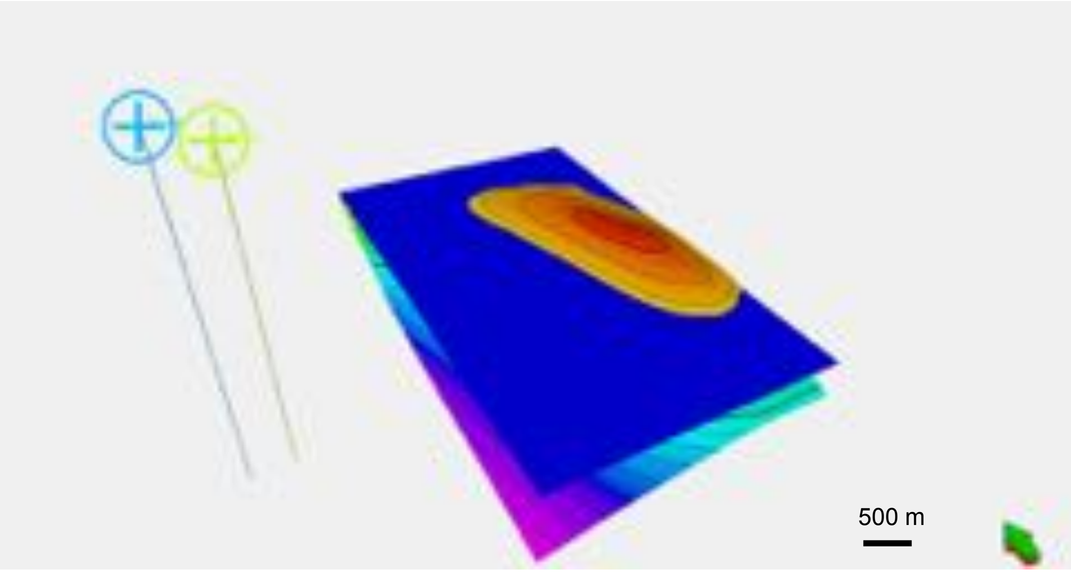

Figure 14-1 Depth map for Dalla prospect in static model

CGG reviewed Apennine's GRVs and related gas in-place volumes and found them reasonable. A comment can be made regarding the GRV value used to define the Max case, which considers a GWC at -1468 m TVDSS, clearly below the structural spill point for Dalla structure, located about -1445 m TVDSS. The GRV in the case that Dalla structure is filled until the spill point is around 378 MMscm, against the 537 MMscm proposed by Apennine, resulting in a GWC at about 1437 metres. Given that the structure is defined by a few 2D seismic lines, there is significant structural uncertainty, especially concerning the depth of that spill point. As an indication of upside potential, Apennine's larger in-place is reasonable. GRVs and gas-in place volumes for Min, Base and Max cases are presented in Table 14.1.

Table 14-1 CGG and Apennine gas in-place volumes for Dalla prospect

	MINIMUM	MEAN	MAXIMUM
Dalla prospect GWC (TVDSS)	-1396	-1430	-1468
Gross rock volumes (10*6 sm^3)	**95**	**262**	**537**
Pay zone thickness (m)	56	90	148
Net-to-Gross (%)	30	30	30
Porosity (%)	15	15	15
Water Saturation (%)	50	50	50
1/Bg	169	169	169
GIIP [MMscm]	**360**	**996**	**2041**

CGG independently estimates an overall chance of success of 56%, based on individual risk factors of 0.7 for reservoir and 0.8 for trap.

In assessing potentially recoverable volumes, a recovery factor of 70%, the same as Dora, has been applied. Table 14.2 shows the in-place volumes and the recoverable volumes in low, best, and high estimates.

Table 14-2 Recoverable volumes in block D503 B.R. CS (Dalla Prospect)

DALLA			
	Low Estimate	**Best Estimate**	**High Estimate**
Recovery Factor	0.7	0.7	0.7
Prospective Gas Resource, MMscm	252.1	696.7	1430.2

15 SANTA MARIA GORETTI

15.1 Introduction

The Santa Maria Goretti Permit (SMG) area is operated by Apennine in East Central Italy. The permit is located in the Marche region, near Ascoli-Piceno, in the Pliocene Apennine foredeep. The structuring of this geological domain is quite complex and began during the early Jurassic, when an extensional phase associated with the spreading of the 'Ligure-Piemontese Ocean' resulted in the partition of the sea floor in horst and grabens. The onset of the Apennine orogenic cycle generated several overlaps within the succession, mainly composed of limestone and basinal sequences, along thrusts which re-activated pre-existent extensional features with reverse movements. During Pliocene and Quaternary, the foredeep associated with the Apennine chain was filled with huge quantities of detrital sediments (up to 7000 m in the Pescara Basin).

Figure 15-1 Location of the Santa Maria Goretti permit

The main wells located within the SMG permit area are Torrente Tesino-1 (TT1), Torrente Tesino-2 (TT2) and Ripatransone-1, drilled by Total/Fina in the southern flank of an anticline. The crest of this anticline was successfully drilled by ENI and EDISON in the late 1970s and is currently producing gas at commercial rates from the Carassai and Grottammare fields. The Valtesino-1 well, located in the south-westernmost part of the SMG permit is on the other hand dry (P&A).

The main reservoir unit for the area is the Lower Pliocene Cellino Fm. The seal is provided by widespread claystones interbedded with Pliocene sands and the trap mechanism for the area is mainly structural. Based on well data, four reservoir units were historically distinguished within the Cellino Fm. (from bottom to top): Level-IV, Level-III, Level-II and Level-I. These levels can be extensively correlated along the SMG permit area and Grottammare-Carassai fields. Only Level-I and Level-IV have historically been produced outside the SMG permit area. DSTs carried out in Level-I in Torrente Tesino-1 well (drilled in 1969) resulted in water production and gas traces, while Level-IV showed no evidence of gas presence. No DSTs were run in Torrente-Tesino-2 well, which only passes through Level-I, as only gas shows were detected while drilling a thin bed above Level-I. Ripatransone-1 well DSTs produced water from both Level-IV and Level-I. All these wells are currently P&A.

Following data review, petrophysical and reservoir studies, Apennine has identified a 150m thick sequence consisting of “thin layers” – turbidites – also more commonly referred to as the Thin Beds (TB), lying above the Level-I producing reservoir. The Thin Beds are believed to represent an undeveloped new reservoir, capable of being produced at commercial rates. Apennine has proposed the drilling of the appraisal Brancuna-1Dir and development Brancuna-2Dir wells, located about 150m north of TT2 well and about 1.35 km far from Grottammare-2dir well (Grottammare producing field). The main target of these appraisal wells will be the Thin Beds, while Level-I (IA and IB) would be a secondary objective.

15.2 Structure and Stratigraphy

There are two main structural trends in the SMG permit area: the Eastern and the Western trends (Figure 15-2 and Figure 15-3). The Eastern Trend (also referred to as the External Trend) is a SSE-NNW oriented anticline, on the top of which the Grottammare and Carassai fields lie. These fields have supported a steady production from 4000-5000 metre deep Pliocene sands over the last 33 years. The Western Trend (also referred to as the Internal Trend) is a complex turbidite of Pliocene-Miocene age, parallel to the Eastern Trend and located in the western area of the SMG permit, near the abandoned Fiume Tronto field. Seismic data suggest the lack of evident structures in the Western Trend which could allow effective gas trapping.

Quality of the available seismic lines is not high, but faulted structures can be identified (Figure 15-3, Figure 15-4).

The stratigraphic succession in the area mainly consists of (from bottom to top):

- the Cellino Formation (main reservoir) of Lower Pliocene age, mainly composed of interbedded marly-silty argillites and quartz sandstones;
- the Mutignano Formation of Middle-Upper Miocene age, mainly composed of argillites and marly argillites with modest sand levels and a few conglomeratic intercalations at the top;
- the Quaternary succession, represented by sandy claystones passing to sands and pebbles towards the shallower part.

Figure 15-2 Location of the Eastern and Western trends in the SMG permit area (source Apennine)

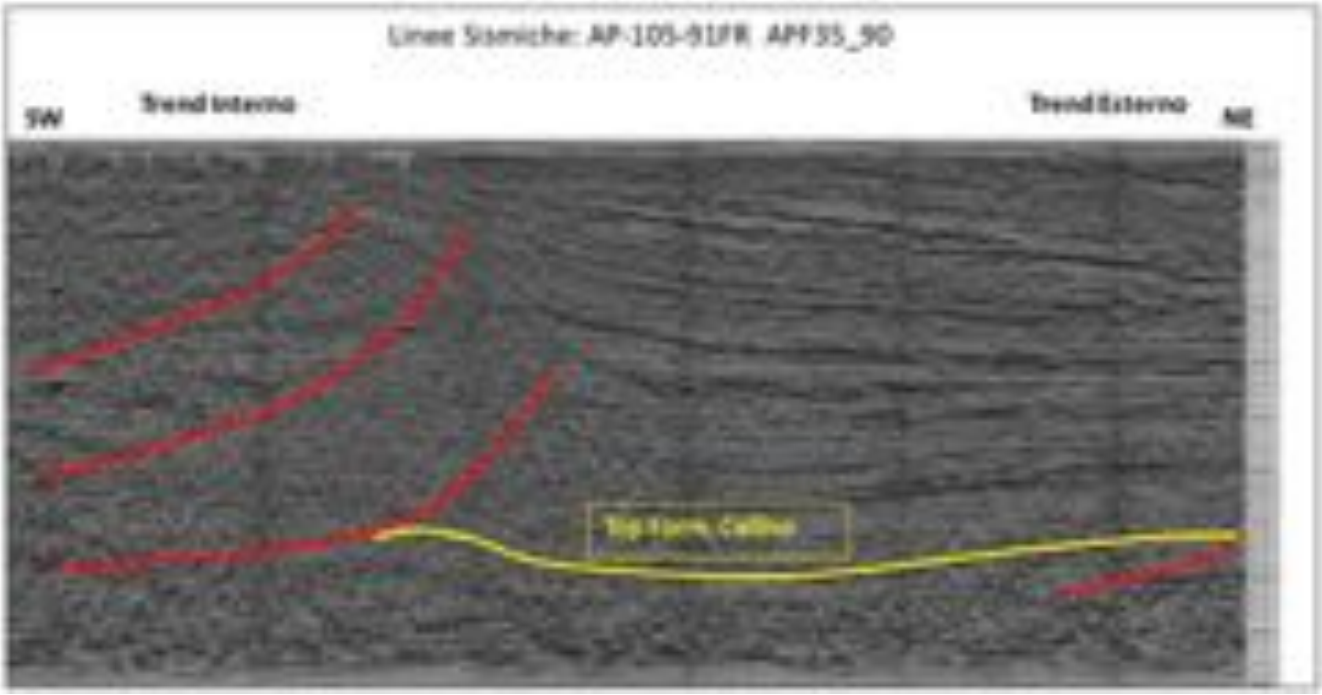

Figure 15-3 Seismic interpretation of the Internal (Western) and External (Eastern) trends (source Apennine)

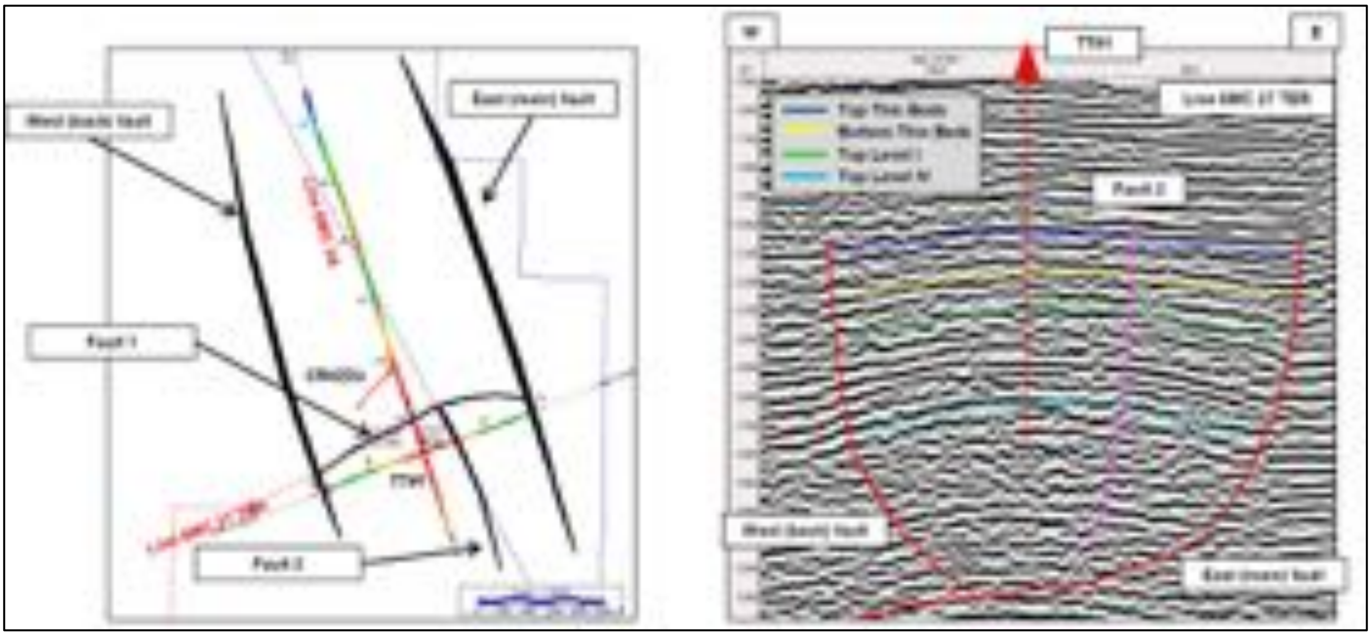

Figure 15-4 Schematic cross section (on the left) and seismic line (on the right) showing Fault-2

15.3 Source Rocks and Hydrocarbon Migration

Biogenic gas produced in the Grottammare and Carassai fields was generated within Miocene to Pliocene clay sequences. Migration occurred into Lower Pliocene reservoirs where intra-formational seals have proved to be effective in the Grottammare and Carassai anticline structure. In the down-dip part of this large structure lies the SMG permit area.

15.4 Reservoirs

The Lower Pliocene Cellino Formation represents a syn-orogenic basinal turbidite sequence having shaly, thin-bedded and thick-bedded turbidite intervals. Lateral continuity of individual beds is thought to be quite good, with the thickest, “mega-turbidite” beds having continuity over several kilometres. Regional palaeo-geographic studies for the “Marchigiano-Abruzzese” foredeep indicate a quite high lateral continuity and uniformity in thickness for the Cellino Formation. Palaeo-current analysis demonstrates a main North-South or NNW-SSE transportation trend for these turbidites.

15.5 Petrophysics

Apennine performed a petrophysical study based on available log data for Torrente Tesino-2 (TT2) and Ripatransone-1 wells.

15.5.1 Thin Beds

Well log data in the SMG area suggest that the Thin Beds sequence is characterized by thin turbidites with a general fining-upwards tendency. Gas shows were recorded while drilling the Thin Beds in TT2 (up to 10% gas) and TT1 well (2-10% gas). Apennine reported that reduced gas shows in Ripatransone-1 well (around 0.5%) was due to drilling mud density.

The Thin Beds were mainly analyzed in the Torrente Tesino-2 well where better well log availability allows a more complete evaluation of the section. In thin-bedded intervals, the ability of the wireline and particularly the resistivity logs to accurately differentiate gas-bearing sands from thin shales may be reduced, leading to an over-estimation of water in thin gas-bearing sands when a standard log analysis is employed. In such cases SCAL work can be useful in defining a saturation-height function for the sand beds within the thin-bedded section. It has not been possible to do such work in the absence of SCAL data.

Apennine performed petrophysical work in-house which has been reviewed by CGG. The interpretation of gas presence was based on an increase in resistivity and a parallel decrease in sonic. This implies a crossover between the Rdeep and DT curves that, when positive, suggests the presence of a gas bearing level. The curve named G_FLAG is used to highlight the net gas levels on Sound plots. The sum of all net gas levels indicates a global net-to-gross ratio of 44% and this has been used in the Apennine 3D static geomodel for volumetric calculation purposes. Regarding porosity, the resolution of the acoustic tool is around 80-100 cm, implying a reliable determination of porosity only for layers of comparable thickness. Porosity values directly measured from well logs in the centre of gas bearing levels is around 11-15%, while the average of all analyzed levels within the G_FLAG curve is 17%. The former (11-15%) was used in Apennine’s 3D static geomodel, while the last was considered too high for effective porosity but reasonable as a measure of total porosity. No water saturation values could be inferred from the available data and therefore the range used by Apennine in the 3D static geomodel derives from regional knowledge of thin layer turbidite reservoirs in central Italy.

Figure 15-5 displays the most promising gas bearing zone for the Thin Beds sequence in Torrente Tesino 2 well.

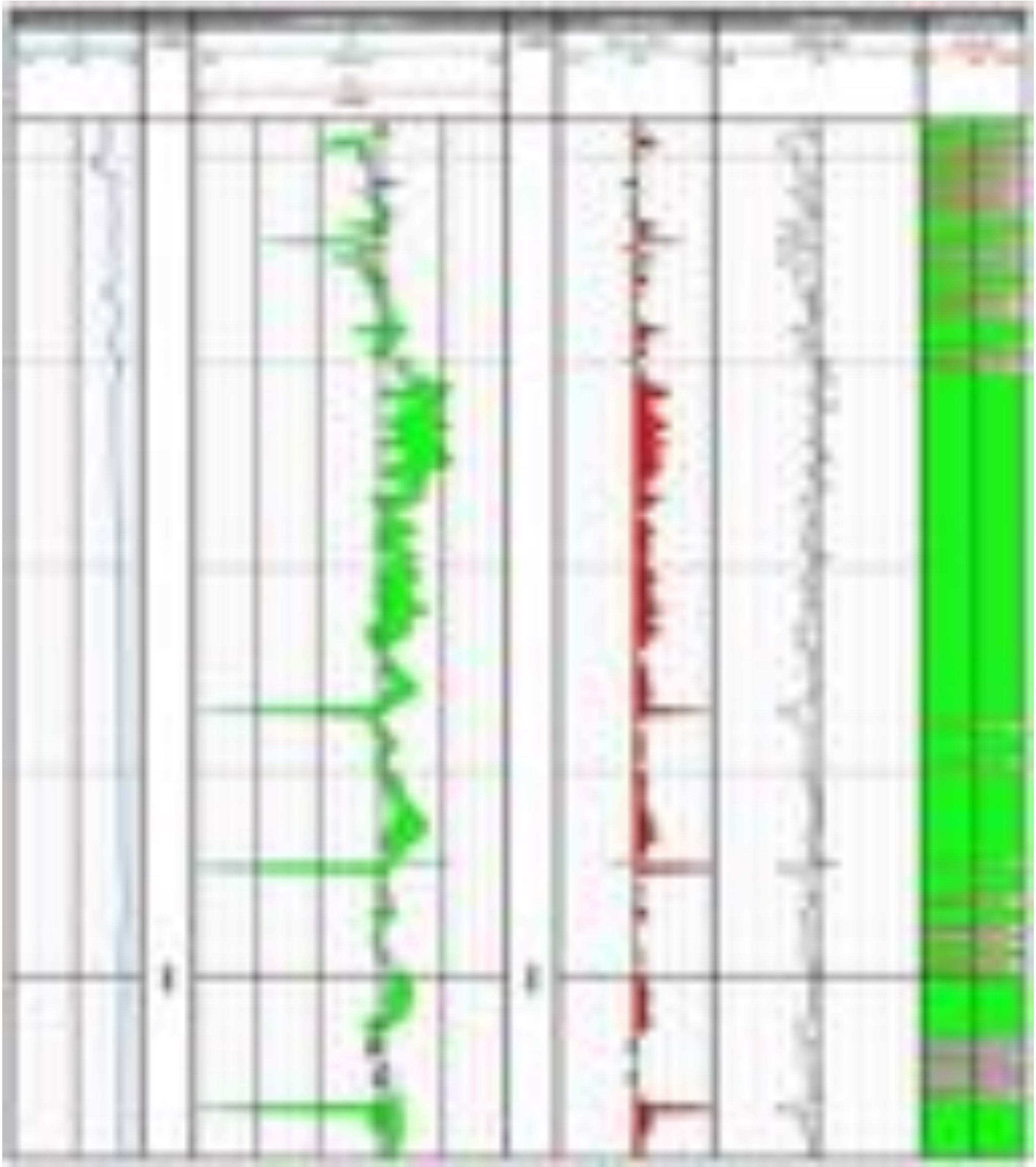

Figure 15-5 Thin Beds reservoir most promising gas bearing zone in Torrente Tesino 2 well (source Apennine)

The Thin Beds sequence is found in all wells within the SMG permit area as well as in the Grottammare/Carassai nearby field. However it has never been tested.

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Following the revision of Apennine's petrophysical study, CGG agrees with Level-I petrophysical interpretation, where evidence of residual hydrocarbon saturation in the SMG wells are quite clear, as well as the considerable probability of Level-I to be water bearing in the SMG permit area.

A more detailed review was performed on the Thin Beds, which represent the main target for the appraisal well Brancuna-1Dir and development well Brancuna-2Dir. CGG mainly focused on assessing the gas charge potential of these thin turbidite levels.

Gas in thin bedded formations is well known and documented in Italy, hence the possibility in SMG area is solidly based on regional knowledge. This region of the country is known for thin turbidite sandstones containing gas, and a number of papers have been published on the topic. The data is not optimal to analyse in detail these Thin Beds, however the techniques employed by Apennine give a fair indication for the presence of gas. Moreover, net-to-gross (44%), porosity (11-15%) and water saturation (40-50%) parameters computed by Apennine appear reasonable.

The presence of gas shows is a good indication of the consistency of Apennine petrophysical analysis. Moreover, a highly comparable resistivity signature is seen in all three wells (TT2, TT1 and Ripatransone-1). In the Thin Beds section, the resistivity increases and the shallow and deep curves show separation. In combination with strong gas shows, this evidence tends to confirm the spatial continuity and the high gas bearing potential of the Thin Beds in the SMG permit area. Attention should be paid to the possible presence of free water, which is currently impossible to define given the available data sets.

15.5.2 Level-I

Level-I was analysed in both TT2 and Ripatransone-1 wells. Here it displays a low average effective porosity (from 9 to 14%) and quite constantly high water saturations (70 to 100%). Moreover, in the most porous and permeable intervals, where Vshale is quite low, water saturation reaches 100%, suggesting gas migration away from this level. In the shaly and less permeable sand layers some residual gas remains.

Figure 7.6 shows the water bearing character of the Ripatransone-1 well and the residual hydrocarbon enrichment at the top of the deeper level in a low permeability and shaly section.

Level-I has been drilled all along the anticline structure falling into the Grottammare/Carassai and SMG permit areas. In Torrente Tesino-1 and 2 wells, Level-I forms part of the main producing reservoir section of the Grottammare/Carassai producing gas field. Even if produced in the neighboring fields, Level-I appeared to be water bearing in wells TT1 and Ripatransone-1, which both produced formation water with some gas traces during well tests. The TT2 well instead stopped inside Level-I (TD 4210 m) and did not test it, leaving some uncertainty about fluid content (if gas and undrained by production depletion from the main field, then it could represent a drilling target). On the other hand, it is known that gas has been found below the Grottammare/Carassai GWC in Level-I (about -3740 m TVDSS), suggesting the possibility of some gas potential in well TT2 and in the up-dip region, where the Brancuna wells are planned. For these reasons, Level-I remains a potential secondary target for the Brancuna wells.

Well log data in both the SMG and Grottammare/Carassai areas suggest that Level-I is composed of a sequence of arenaceous mega-turbidites, alternating with shales and pelitic facies, several tens of meters thick.

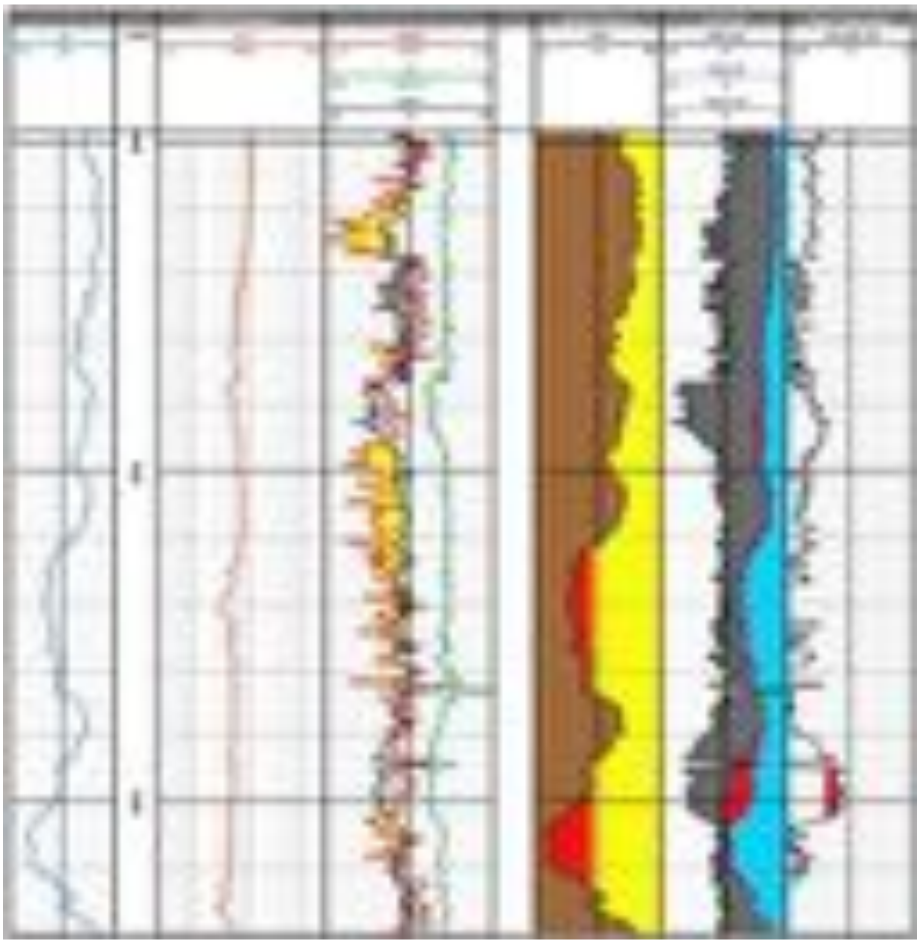

Figure 15-6 Level-I reservoir log in Ripatransone-1 well (source Apennine)

15.6 Static Reservoir Model

CGG has carefully reviewed the inputs, assumptions and results of the geological static model that is used to estimate gas volumes.

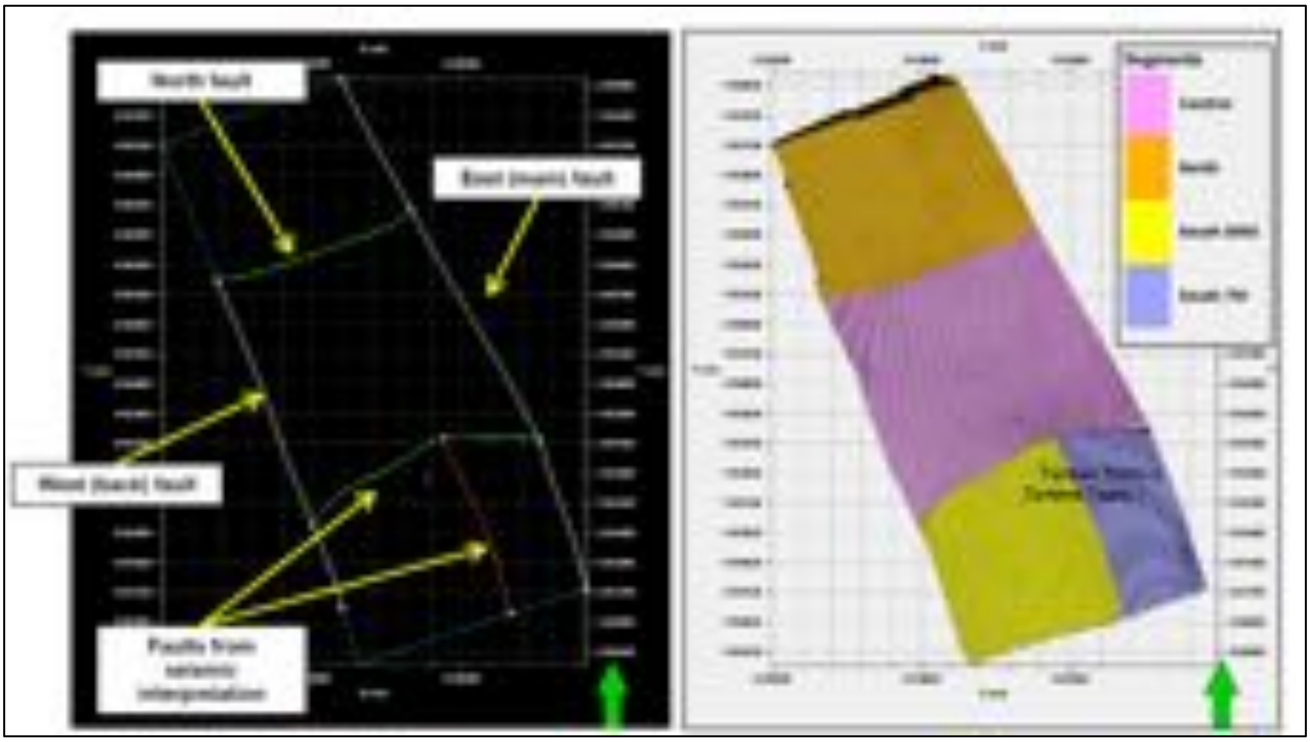

Figure 15-7 Grid and segments in the Apennine 3D static geo-model (source Apennine)

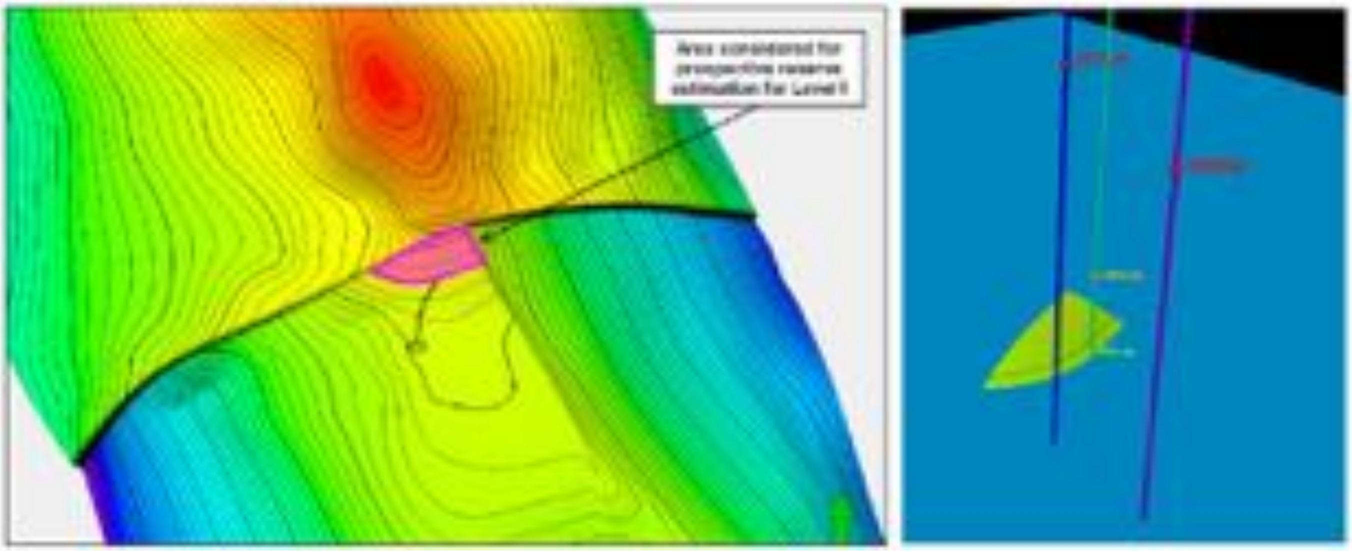

Figure 15-8 Boundary polygon (on the left) and related gross-rock-volume (on the right) used for Level-I GIIP estimate

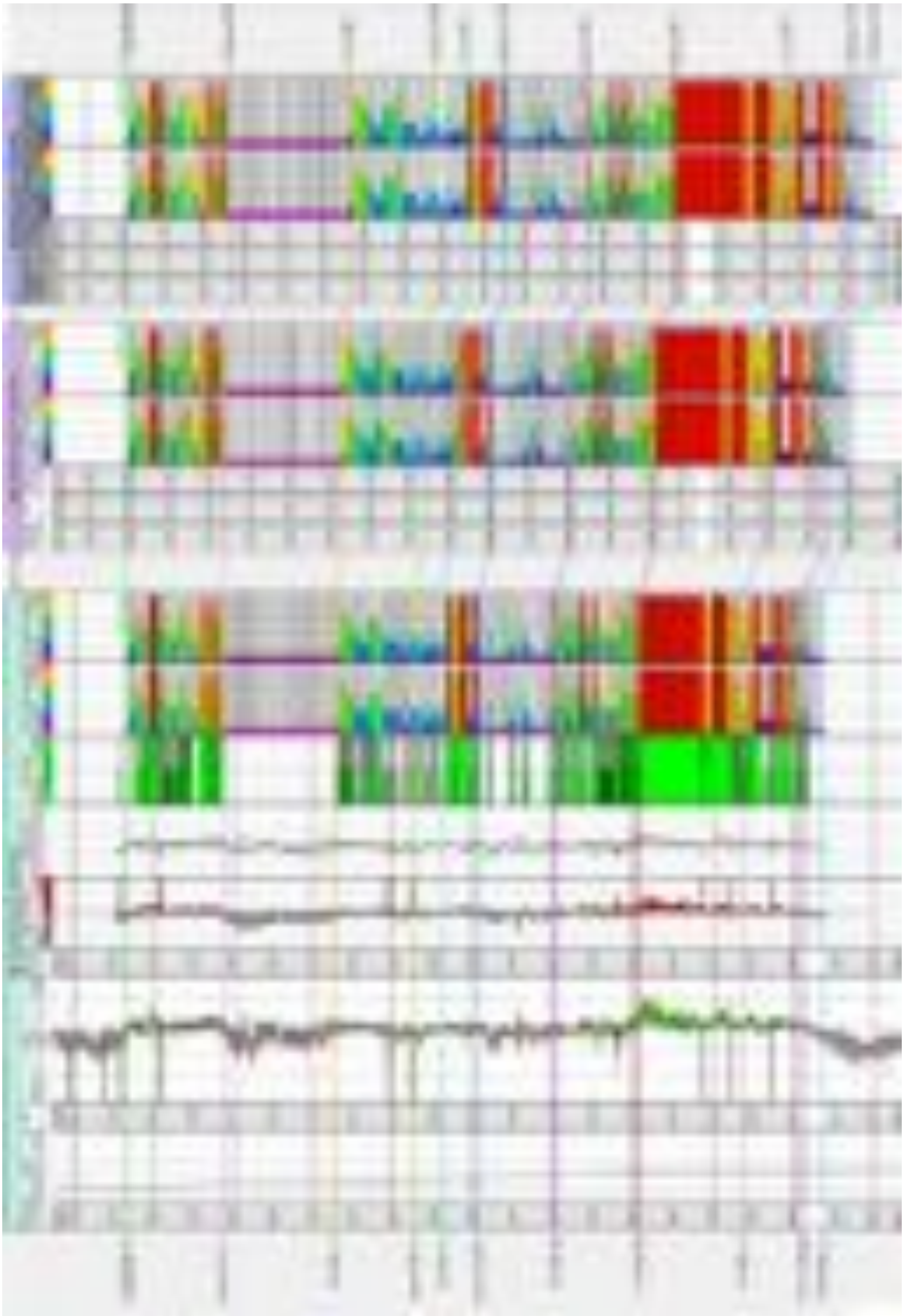

Figure 15-9 Calculated logs (G_FLAG and G_FLAG grid) and well logs correlation for TT1, TT2 and Ripatransone-1 wells

All petrophysical properties and calculated logs used in the Apennine 3D static model for the Thin Beds come from the petrophysical study results: for P90, P50 and P10 a fixed 44% net-to-gross was used, 11-13-15% porosity (P90, P50 and P10) and 50-45-40% water saturation (P90, P50 and P10). On the contrary, petrophysics used for Level-I GIIP calculation was inferred from the analysis of the Grottammare field well logs (indicative net-to-gross 70%, porosity 12-19%, water saturation 25-40%). The reason for this choice lies in the fact that the location of the Brancuna wells is up-dip from the TT1, TT2, and Ripatransone-1 wells, providing Apennine with the expectation of better petrophysical parameters with respect to the SMG permit area, possibly closer to those of the Grottammare producing field. Accordingly, the above mentioned reservoir property ranges for P90, P50 and P10 GIIP cases were developed for the Thin Beds, while only a P50 case was computed for Level-I.

CGG has reviewed the 3D static model for Santa Maria Goretti permit area built by Apennine and considers that the static model is a reasonable basis for estimating volumes of gas, and that good procedures have been followed in its construction. The subdivision of the Thin Beds into 6 sub-sequences (TB1 to TB6) based on the G_FLAG curve is considered a reasonable approach to the identification of gas reservoir intervals. The range of petrophysical parameters used for each volumetric case (Low Estimate, Best Estimate and High Estimate) is reasonable, in both Level-I and Thin Beds reservoirs.

For Level-I the boundary polygon choice and associated resulting GIIP values are sensible and based on well data. In spite of this, CGG revised Level-I GIIP estimating a wider range of petrophysical values (Low Estimate, Best Estimate and High Estimate) from well log data. This was done to better represent the levels of uncertainty present in the definition of gas volumes in this section.

For the Thin Beds the choice of modelling separate GWCs for each Thin Beds sub-sequence is based on regional knowledge of thinly bedded turbidite reservoirs in central Italy and in the Adriatic region and is therefore considered fair. However, CGG's review of the implementation the GWC by Apennine led CGG to adopt a different method.

Values for the Low Estimate, Best Estimate and High Estimate GIIP cases for both Level-I and Thin Beds are discussed in the following paragraphs. In both reservoirs, the approach used for GIIP estimate is probabilistic and the software used is Crystal Ball.

15.7 Volumetric Estimations

In this report we follow Apennine's nomenclature for GIIP classification when referring to Apennine estimates. When presenting CGG estimates, we follow the Low, Best and High Estimate nomenclature for prospective resources in conformance with SPE PRMS (2007) guidelines.

CGG has reviewed Apennine assumptions for Low, Best and High Estimate GIIP cases and has found it necessary to modify some of them to better reflect the Santa Maria Goretti permit area gas potential and risks.

15.7.1 Thin Beds

CGG has defined Low Estimate, Best Estimate and High Estimate cases based on industry standard geological assumptions and by discarding Apennine's contact approach. CGG also believes that the Apennine GIIP range does not fully reflect the level of uncertainty present in the available data, which is inconclusive on a number of critical points.

Given these considerations, CGG's assumptions were defined as follows for the High Estimate, Low Estimate and Best Estimate cases:

- The High Estimate case considers a single gas-down-to (GDT) corresponding to the bottom of the Thin Beds sequence in well TT2 (-3487 m TVDSS). No boundary polygons were used, and so the gas accumulation has broad extent reflecting upside potential. However, we acknowledge that the gas-down-to could be deeper if the resistivity signature and gas shows are considered, but at this stage of appraisal, we do not consider those indications sufficiently reliable in TT1 and Ripatransone-1 wells because of data limitations in those wells.
- The Low Estimate considers multiple GWCs inferred from the gas-down-to depths observed at the bottom of each Thin Beds sub-sequence (TB1 to TB6) in TT2 well. No boundary polygons were used.
- The Best Estimate case was not fixed by means of explicit assumptions was but obtained from a probabilistic distribution.

For each case the gross-rock-volume was calculated in Petrel, while the range of petrophysical parameters was set as following: 11-13-15% porosity (respectively as Low Estimate-Best Estimate-High Estimate); 34-44-54% (Low Estimate-Best Estimate-High Estimate) net-to-gross and 70-50-40% (Low Estimate-Best Estimate-High Estimate) water saturation.

The assumptions for CGG's Low Estimate, Best Estimate and High Estimate GIIP cases are essentially based on TT2 well data, as the confidence regarding data quality and interpretation is high for this well. On the other hand, CGG is aware that Thin Beds display similar gas shows of around 2-10% in the TT1 well, as well as an analogue trend of resistivity log track with respect to the TT2 well. Anyway, given the available data, CGG is not able to assess if the additional hydrocarbon volumes related to the TT1 well are movable or not. CGG therefore recognizes the potential to have a considerable 'Upside Volume', which takes into account TT1 well hydrocarbon volumes as well as the possibility that the structure in SMG permit area is full of hydrocarbons until the spill point, which unfortunately can't be verified at this stage of appraisal.

Results show that CGG's Best Estimate GIIP case (1881.84 MMscm) is similar to Apennine P50 case (1801 MMscm), while the Low Estimate case (544.27 MMscm) is lower than the correspondent Apennine value (1385 MMscm) and the High Estimate case (3720.40 MMscm) is higher than Apennine (2267 MMscm). The larger range of CGG's GIIP (544.27 - 3720.40 MMscm) better reflects the SMG permit area gas potential and better takes into account the uncertainty associated with the structure, GWC position and petrophysics. Recoverable volumes for Thin Beds statistically calculated by CGG using Crystal Ball™ with a 40-50-60% range of recovery factors are tabulated in Table 15.1.

Chance of Success (CoS) for the Thin Beds has been estimated by CGG based on information available for the SMG permit area and public domain data for the nearby Carassai/Grottammare gas fields. Given the fact that the SMG permit area lies in the down-dip faulted side of the main 4-way dip anticline which hosts Grottammare and Carassai gas producing fields, a score of 1 was assigned to source presence, source effectiveness and reservoir presence. Reservoir effectiveness or quality (0.75) is indicative of a quite high probability to find gas as indicated by well logs and gas shows during drilling. Trap presence is quite well defined by 2D seismic lines and well data (0.95) and trap effectiveness is quite high (0.95), due to the presence of the Grottammare and Carassai nearby producing fields in the same structure. The overall COS proposed by CGG is 68%.

Table 15-1 GIIP and Recoverable Volumes for the Santa Maria Goretti Thin Beds

SANTA MARIA GORETTI: THIN BEDS			
	Low Estimate	**Best Estimate**	**High Estimate**
In Place Volumes, MMscm	544.27	1881.84	3720.4
Prospective Gas Resource, MMscm	265.82	927.65	1886.31

15.7.2 Level-I

Apennine distinguished just one case for Level-I (P50, 74 MMscm), using petrophysics from Grottammare field. This choice was based on the evidence that the location of the Brancuna appraisal well is much up-dip with respect to TT1, TT2, and Ripatransone-1 wells, and this allows to expect better petrophysical parameters compared to the SMG permit area, possibly more similar to the Grottammare producing field. CGG revised Level-I GIIP considering the same boundary polygon used by Apennine (inferred using a -3692m GWC from TT2 well log). However CGG defined the minimum and maximum GIIP cases, on the base of which the Low Estimate, Best Estimate and High Estimate cases were accordingly calculated. The assumptions were defined as following:

- The maximum case considers the same gross-rock-volume and the same GWC of Apennine 3D static geomodel. Petrophysical parameters were inferred by Grottammare well logs (indicatively 70% net-to-gross, 17% porosity and 35% water saturation).
- The minimum case on the contrary assumes a null gross-rock-volume, representative of a GWC which lies above the top of the structure. Slightly worse petrophysical parameters (indicatively 60% net-to-gross, 13% porosity and 45% water saturation), inferred from TT1 and TT2 wells and representative of the SMG permit area, were applied.

Results for the Low Estimate, Best Estimate and High Estimate cases are shown in Table 15.2. A lower GIIP is proposed by CGG for the Best Estimate Case (32.1 MMscm) with respect to Apennine (74 MMscm). Recoverable volumes for Level-I were calculated by CGG considering a 60% recovery factor, which is in agreement with Apennine overall recovery factor.

Table 15-2 GIIP and Recoverable Volumes for the Santa Maria Goretti Level-I

SANTA MARIA GORETTI: LEVEL-I			
	Low Estimate	**Best Estimate**	**High Estimate**
In Place Volumes, MMscm	14.3	32.1	50.4
Prospective Gas Resource, MMscm	8.58	19.26	30.24

As for the Thin Beds, COS for Level-I uses the same values for source presence (1), source effectiveness (1), reservoir presence (1), reservoir effectiveness or quality (0.75), as well as trap presence (0.95) and trap effectiveness (0.95). An additional risk factor, the fluid type, was introduced for the Level-I reservoir. A value of 0.5 takes into account the risk that an appraisal well might encounter water, the gas having been already produced by the Grottammare-Carassai fields (currently producing from Level-I). The overall COS proposed by CGG is 34%, slightly lower but still consistent with the 40% COS proposed by Apennine.

16 SAN LORENZO LICENCE

16.1 Casa Tiberi Gas Field

This Licence contains the producing Casa Tiberi gas field, which lies in the Umbria-Marches Region, Province of Ancona. The permit covers 49.4 km^2 onshore. Identified as a prospect in 1988 by Total, the Casa Tiberi gas field lies on the same structural trend as the Castellaro and Cassiano gas fields in the North-West, Sette Finestre in the South-East, and the structural culmination of Montegallo farther South-East (Figure 16-1).

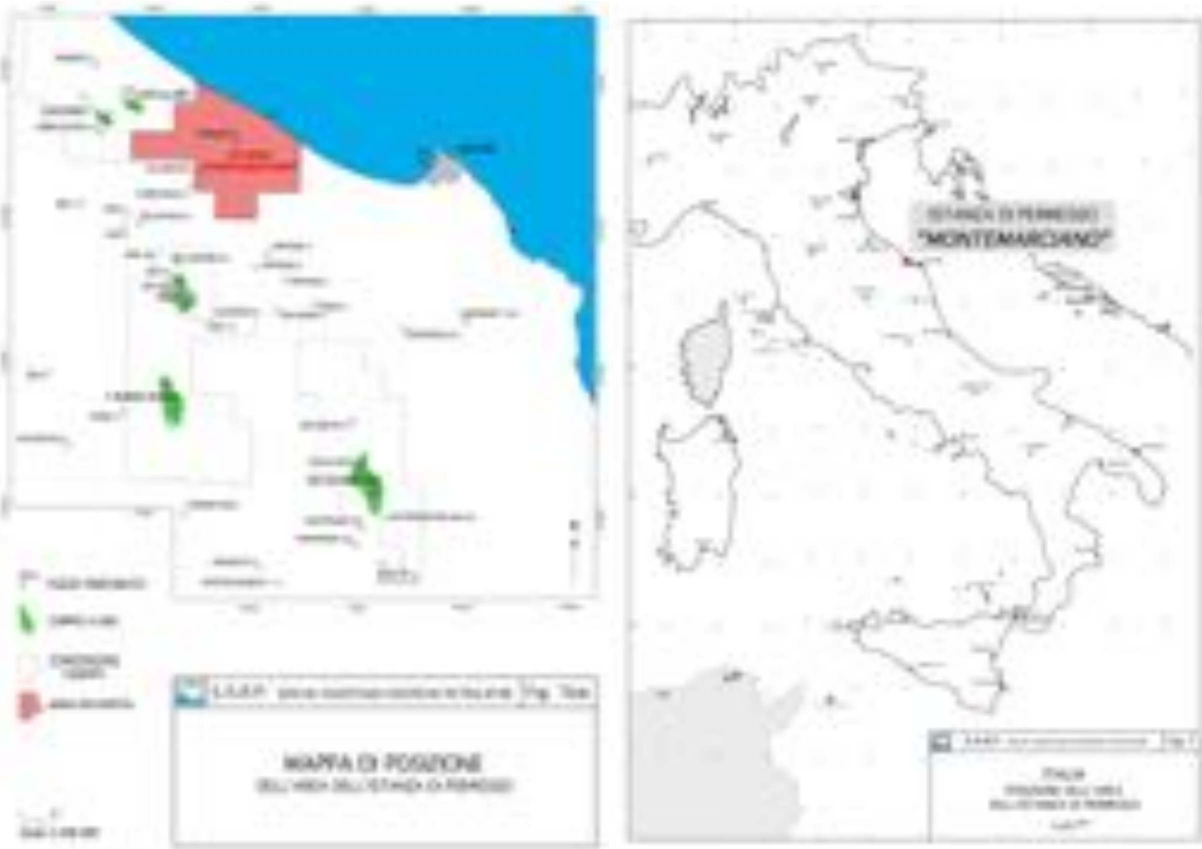

Figure 16-1 Location maps of San Lorenzo Licence, onshore Italy

The structure is a faulted thrust fold and the reservoir is found in the turbidite filling of the peri-Adriatic fore-deep that constitutes the Cellino Formation. They were recognised in well Monsano-1 (drilled in 1972) with sand layers varying in thickness from 1 to over 10 metres. Porosity in these sands is generally around 25%, with good permeability to gas. Seals are provided by the intercalated clays within the Cellino Formation itself as well as by the main topseal formed by Lower and Mid-Pliocene plays.

Apennine drilled Casa Tiberi-1 in 2012 and performed a flow test in 2013. Bedding dips at 45 degrees to the horizontal, a steep dip and liable to result in early water breakthrough. The well penetrated the reservoir down dip from the structural crest (Figure 16-2 to Figure 16-4); its position was not optimal with respect to the aquifer.

Historical production and tubing head pressure (THP) data is shown in Figure 16-5. Production started in 2014 and THP began to fall, indicating a restricted connected gas volume. Stabilisation of the THP occurred as the aquifer started to move. Water production has increased, incurring transport costs, and sand production indicates instability of the reservoir formation.

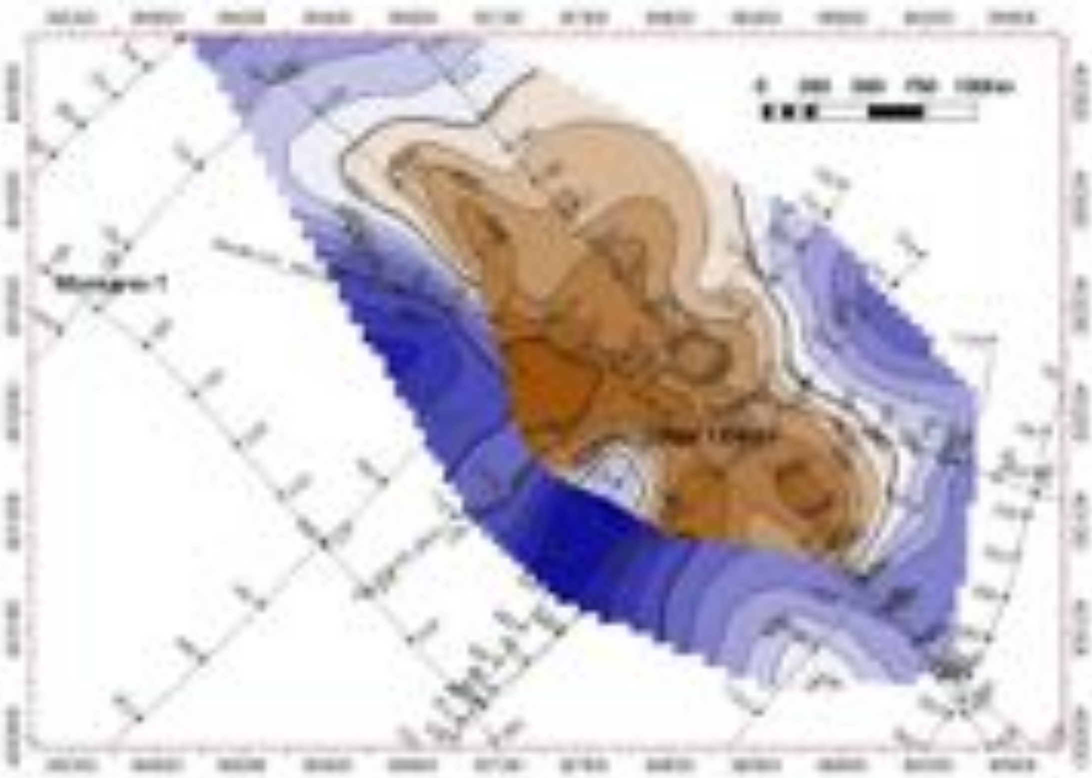

Figure 16-2 Time Structure Map with Seismic Lines, Casa Tiberi Gas Field, onshore Italy

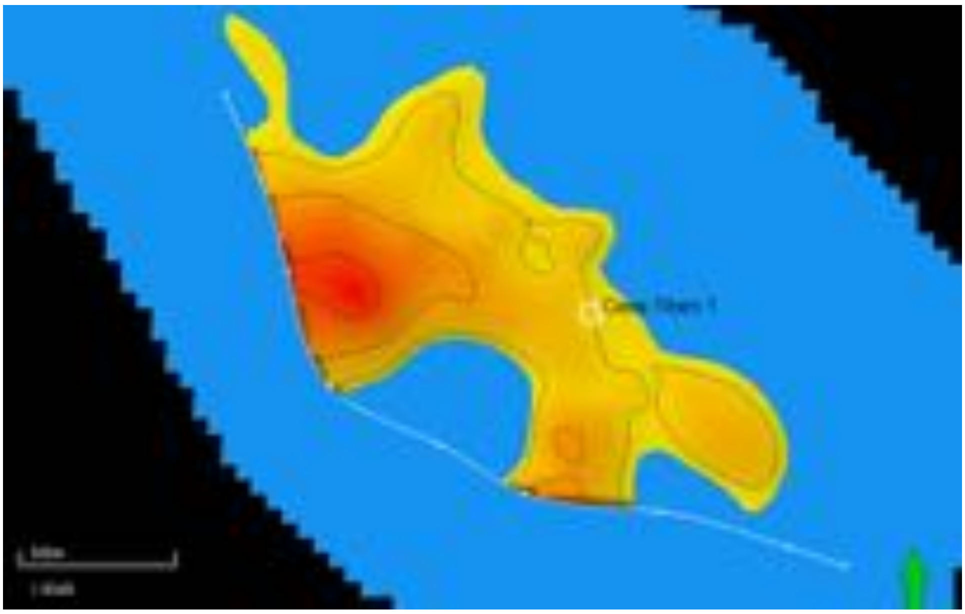

Figure 16-3 Location of Casa Tiberi-1 well, relative to Depth Structure and Aquifer at end 2017

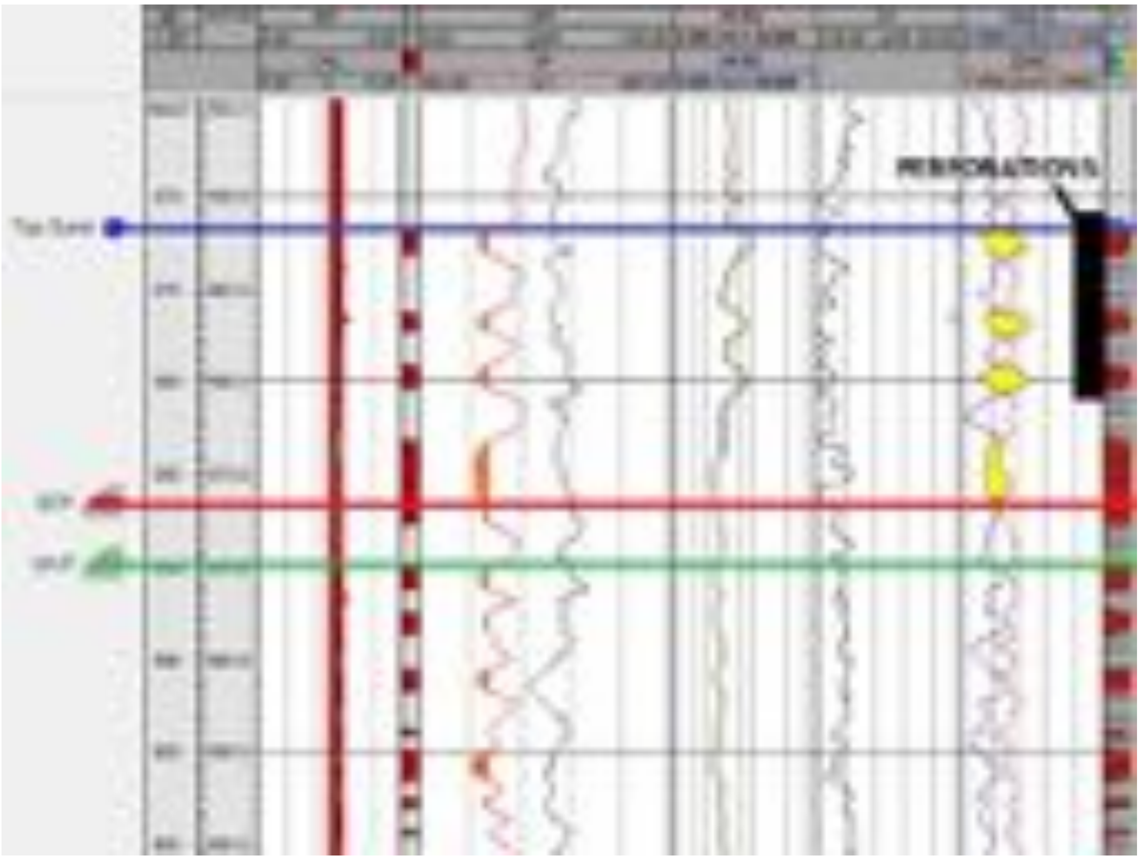

Figure 16-4 Casa Tiberi-1 Well Logs; Note Gas-Down-To (red line) and Water-Up-To (green line)

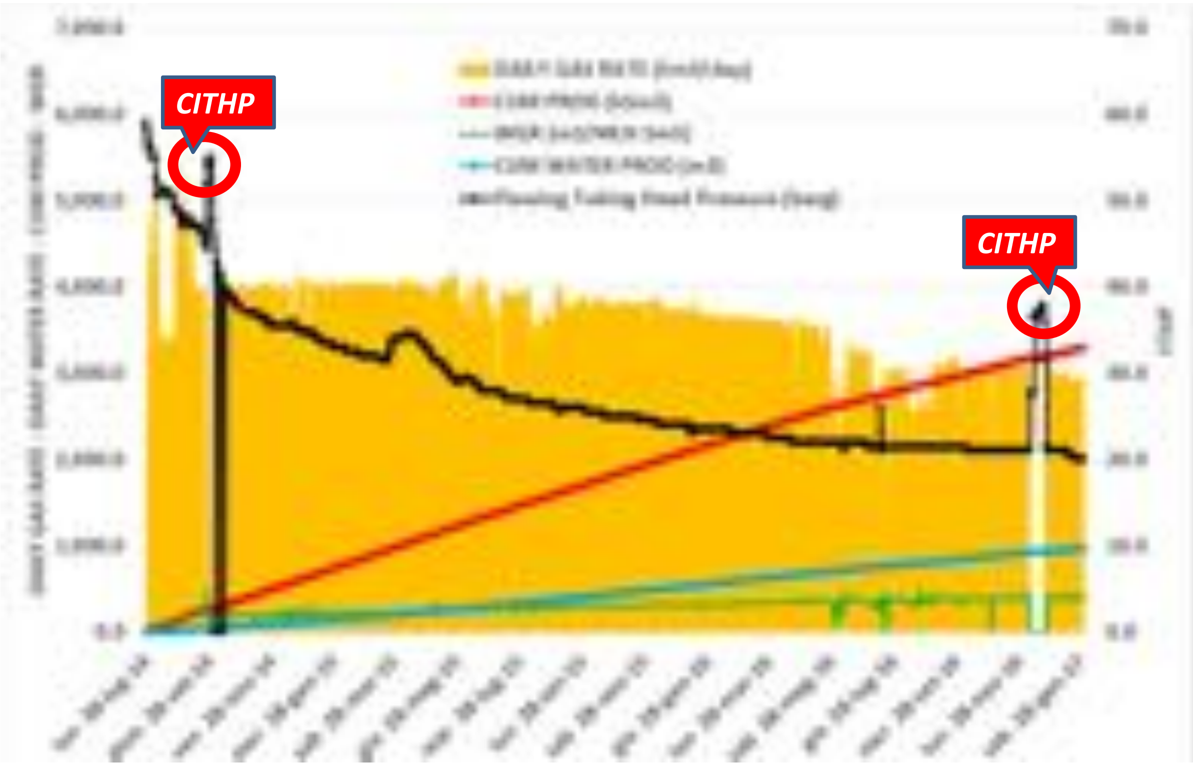

Figure 16-5 Casa Tiberi Production History from July 2014 to January 2017

Source: Appenine Presentation (2017)

CGG has conducted P/Z material balance analysis (Figure 16-6). It indicates water drive, which can potentially reduce the remaining recoverable volumes. CGG has estimated low, best, and high recoverable volumes using Decline Curve Analysis (Rate vs Cumulative) plot (Figure 16-7). In the low case, it assumes strong water influx that could cause early water breakthrough. In the best case, the decline follows the steep trend observed between 2 MMscm and 3 MMscm cumulative gas production. The high estimate is assumed weak water influx. The decline follows the gentle trend observed between 3 MMscm and 4 MMscm cumulative gas production. Estimated remaining reserves from the existing well are provided in Table 16.1.

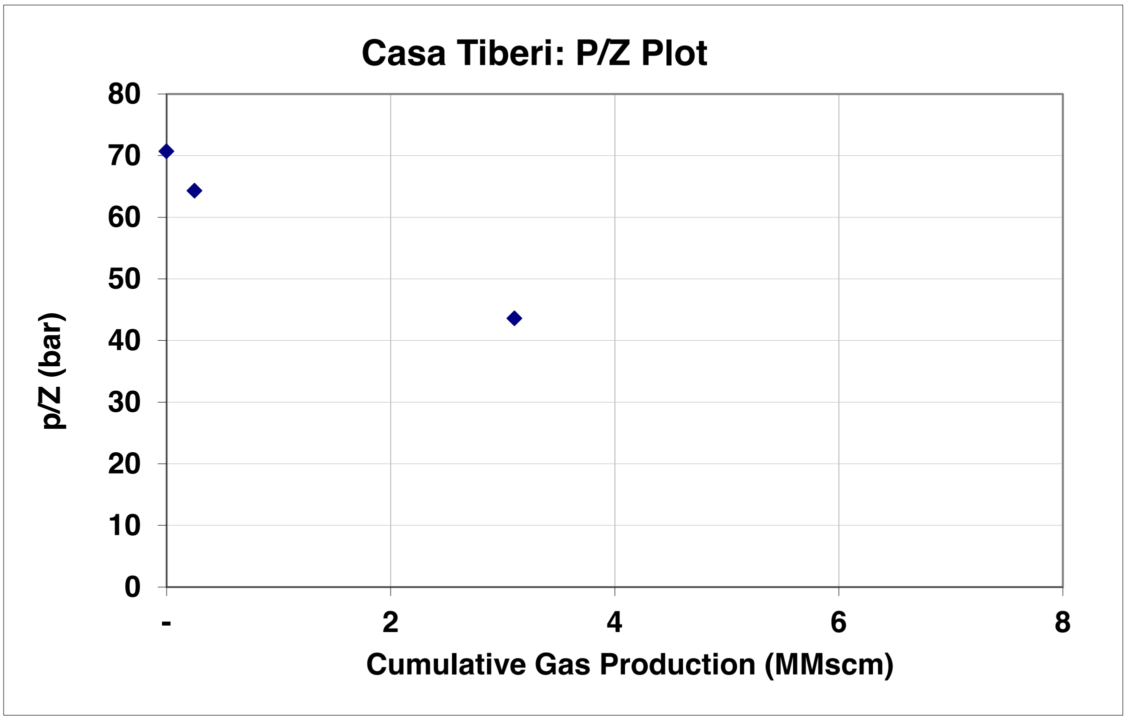

Figure 16-6 Casa Tiberi P/Z Plot

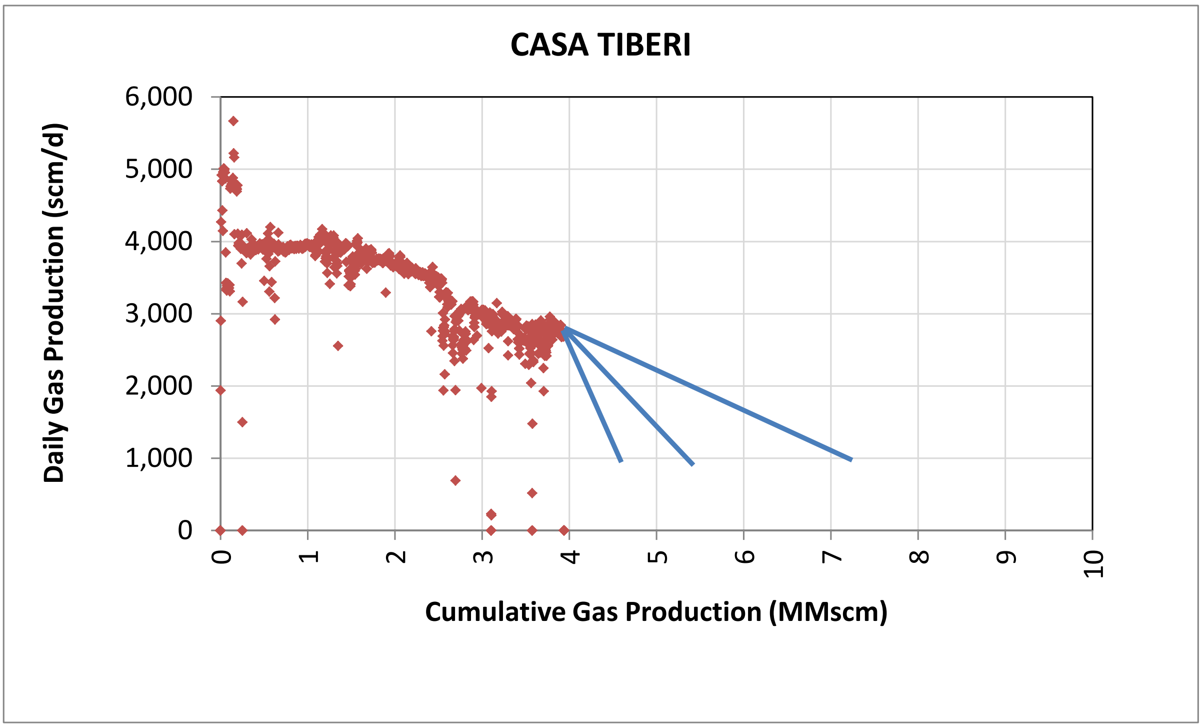

Figure 16-7 Casa Tiberi Gas Production vs Cumulative Gas

Table 16-1 Remaining Reserves in Casa Tiberi (Existing Well – No Sidetrack)

CASA TIBERI (EXISTING WELL – NO SLDETRACK)			
Reserves as of 1st January 2018	**1P**	**2P**	**3P**
Recoverable Volumes from Existing Well, MMscm	4.5	5.4	7.2
Cumulative Production as of 31st October 2017, MMscm		3.94	
Estimated Production in Nov-Dec 2017, MMscm		0.16	
Remaining Reserves from Existing Well as of 1st January 2018, MMscm	0.4	1.3	3.1

The production profiles for 1P, 2P and 3P cases are graphically shown in Figure 16-8. Table 16.2 shows the annual production and cumulative production.

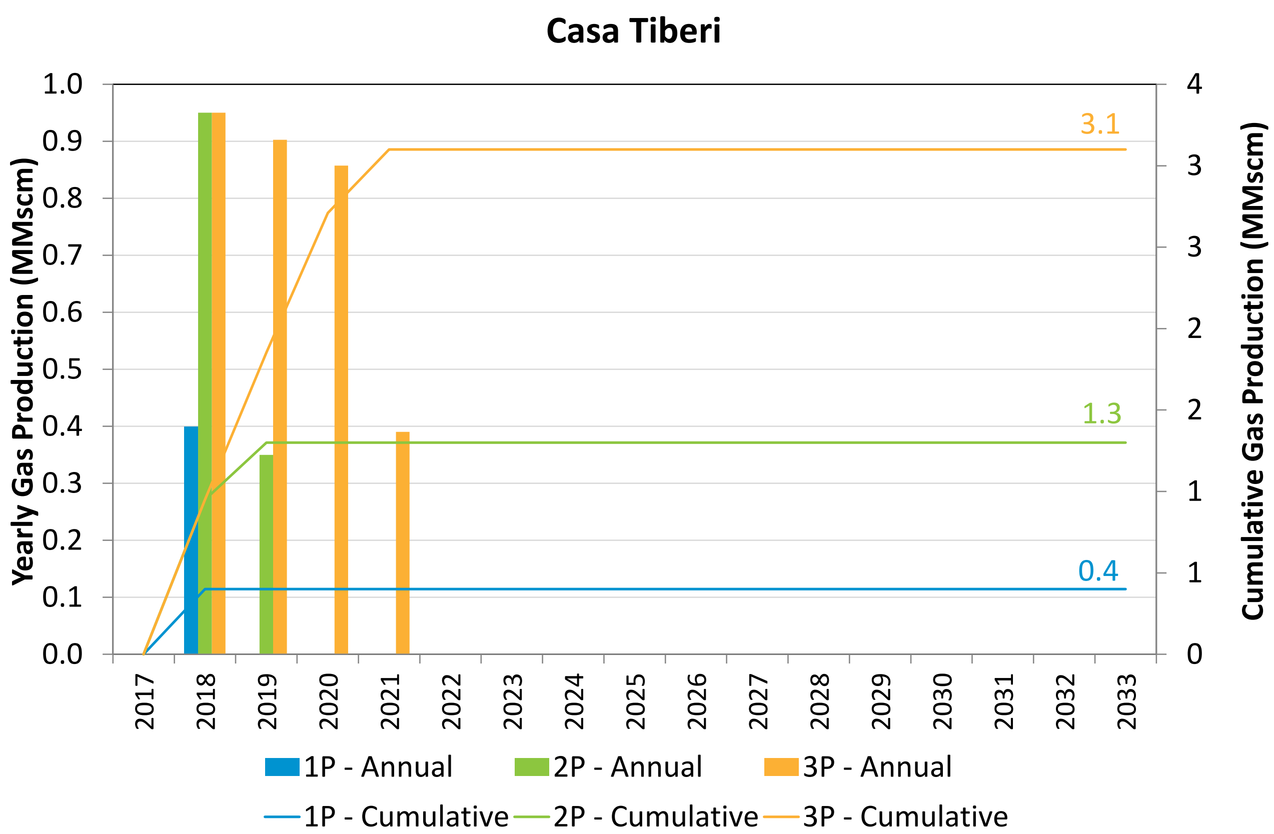

Figure 16-8 Technical Production Profiles of Casa Tiberi 1P, 2P and 3P (Existing Well, before Economic Cut-off)

Table 16-2 Annual Production and Cumulative Production of Casa Tiberi – Reserves Recovered by Existing Well (before Economic Cut-off)

Year	1P		2P		3P	
	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)
2018	0.40	0.40	0.95	0.95	0.95	0.95
2019	0.00	0.40	0.35	1.30	0.90	1.85
2020	0.00	0.40	0.00	1.30	0.86	2.71
2021	0.00	0.40	0.00	1.30	0.39	3.10

Although gas production is ongoing at Casa Tiberi, concurrent water production is problematic and limits the value of the field. Remaining reserves from the existing well are low, given current operating conditions. However, the well was drilled off-crest, and could potentially be sidetracked to penetrate reservoir at the crest. Apennine state that the updip gas volume cannot be drained with the current well. CGG agree because currently, aquifer strength is such that the updip gas may not be able to expand during ongoing production. CGG has therefore estimated the volume of updip gas that could be contacted by means of a sidetrack.

Apennine has provided CGG with an AFE to confirm its plan and allocated budget to sidetrack the existing well in order to recover the updip gas with the first production targeted in January 2020. CGG has conducted economic evaluation of the development of the updip gas and have found that the project could potentially be developed economically only at higher gas prices. Therefore we assign the updip gas to the contingent resources category. This updip gas volume can be re-classified as reserves once the project is economic to develop.

For the updip gas, the GIIP has been estimated at 32.4, 51.1, 84.4 MMscm (1C, 2C, 3C cases, respectively) by means of a 3D geological model. CGG has reviewed the seismic data, the mapping of the structure and the calculation of gas initially in place (GIIP). The results are based on assumptions that are supported by the available data. CGG has also independently checked a recent revision to the mapping projection systems being used and confirm that those used by Apennine are correct.

The reservoir properties utilised by CGG to generate the resource estimates derive from Apennine technical work, but represent our independent judgement and estimations (Table 16.3). In the 1C case, only the gas sands in Casa-Tiberi-1 are considered with no allowance for deeper, water-bearing sands rising (updip) into the gas zone. In the 3C case, a 3D net-to-gross array was created in Apennine's static model of the field using kriging. A variable Bg value reflects uncertainty in the degree of pressure depletion in the gas cap caused by CT-1 production combined with active aquifer influx (pressure support).

Table 16-3 Reservoir Properties assigned for Contingent Resources Assessment, Casa Tiberi, Updip Gas

Case	NtG	Porosity	Sw	Bg	RF (%)
1C	Fixed, 27%	Fixed, 25%	Fixed, 0.4	0.025	0.5
2C	Fixed, 35%	Fixed, 22.5%	Fixed, 0.35	0.02	0.6
3C	3D array, avge 46%	Fixed, 20%	Fixed, 0.3	0.015	0.7

CGG has used low Recovery Factors to account for uncertainty in sand connectivity and minor structural compartmentalisation risks. For the same reason, CGG uses the structure map provided by Apennine, although the significant depression SE of the CT-1 well does not appear to be geologically plausible. If not present, the GRV would be larger, however the relevant seismic line (AN-87-08 MIG) suggests it is present.

Estimated contingent resources for the updip portion of gas remaining at Casa Tiberi are given in Table 16.4 below:

Table 16-4 Updip Gas Contingent Resources Estimate, Casa Tiberi

		Updip Gas Reserves (MMscm)		
Licence	Field	1C	2C	3C
San Lorenzo	Casa Tiberi	16.2	30.7	59.1

The production profiles for 1C, 2C and 3C cases are graphically shown in Figure 16-9. Table 16.5 shows the annual production and cumulative production.

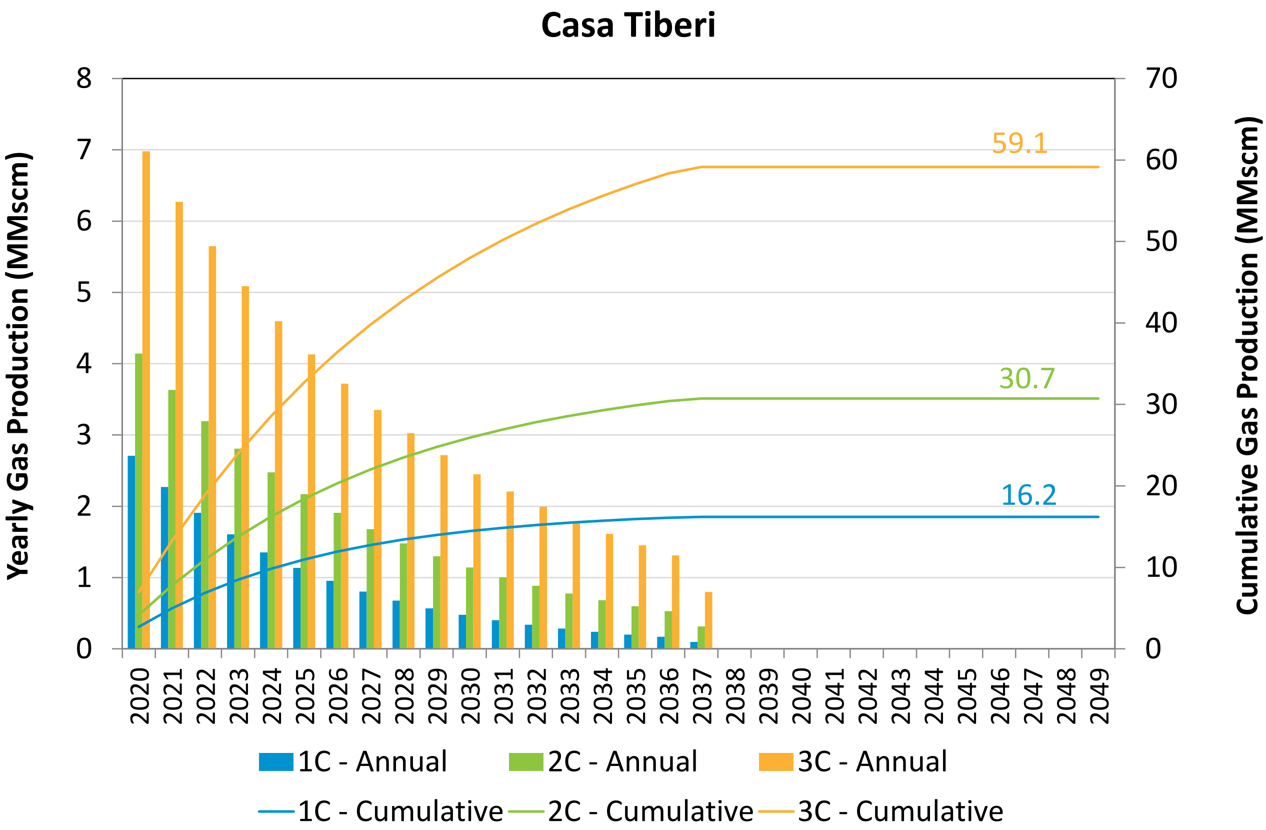

Figure 16-9 Technical Production Profiles of Casa Tiberi 1C, 2C and 3C (Sidetrack Well, before Economic Cut-off)

Table 16-5 Annual Production and Cumulative Production of Casa Tiberi – Contingent Resources Recovered by a Sidetrack Well (before Economic Cut-off)

Year	1C		2C		3C	
	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)
2020	2.71	2.71	4.14	4.14	6.98	6.98
2021	2.27	4.98	3.63	7.77	6.27	13.25
2022	1.91	6.89	3.19	10.97	5.65	18.90
2023	1.61	8.49	2.81	13.78	5.09	23.99
2024	1.35	9.85	2.48	16.25	4.60	28.58
2025	1.14	10.98	2.17	18.42	4.13	32.71
2026	0.95	11.94	1.91	20.33	3.72	36.43
2027	0.80	12.74	1.68	22.01	3.35	39.78
2028	0.68	13.42	1.48	23.49	3.03	42.81
2029	0.57	13.98	1.30	24.79	2.72	45.53
2030	0.48	14.46	1.14	25.93	2.45	47.97
2031	0.40	14.86	1.00	26.93	2.21	50.18
2032	0.34	15.20	0.88	27.81	1.99	52.17
2033	0.28	15.48	0.78	28.59	1.79	53.96
2034	0.24	15.72	0.68	29.27	1.61	55.58
2035	0.20	15.92	0.60	29.87	1.45	57.03
2036	0.17	16.09	0.53	30.40	1.31	58.34
2037	0.10	16.19	0.32	30.71	0.80	59.14

17 FONTE SAN DAMIANO

17.1 Marciano Gas Discovery

Fonte San Damiano is located in Basilicata in the south of Italy and covers an area of 23.71km^2. Geologically, it falls within the gas prolific Bradano basin – a foredeep trough of the Southern Apennines, well known for Plio-Pleistocene and Mesozoic gas plays.

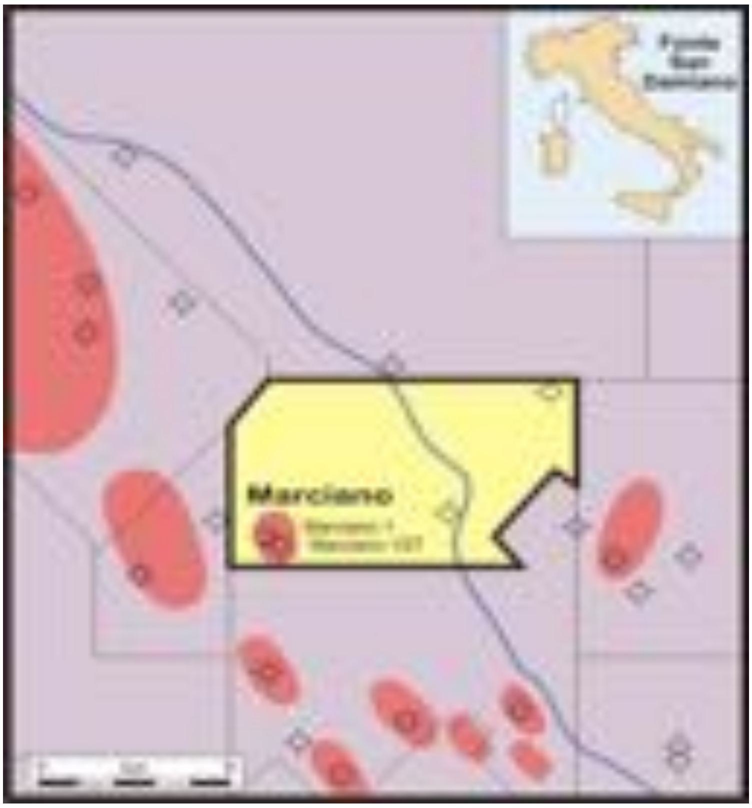

Figure 17-1 Location of the Fonte San Damiano licence

A small gas discovery was made in the concession in 1989 by Italmin. The well, Marciano 1, was drilled to test Pliocene turbidites mapped on 2D seismic. It encountered gas in a number of Pleistocene sand levels, two of which (MAR-2 and MAR-3) proved commercial accumulations and were completed. Cumulative production to date amounts to 17 MMscm. Marciano-1ST well was drilled in 2007 and discovered two thin gas bearing sand intervals, MAR-4 at 1063m and MAR-5 at 1286.5m and 1326m. Apennine's estimated 2C contingent resources of 70.8 MMscm have been reviewed by CGG and are considered a reasonable expectation.

18 BADILE LICENCE

18.1 Zibido Prospect

Two prospects were originally identified in the Badile Licence area; Badile and Zibido. The Badile prospect was drilled in 2017 and discovered non-commercial volumes of gas. Hydrocarbons of this play originate from Triassic source rocks; the marly Meride limestones and the Riva di Solto shale, both deposited in anoxic troughs in an extensional regime. The Zibido prospect is a relatively low relief, elongated, fault-bounded structure (see Figure 18-2) covering an area of about 4.4 km^2. The reservoir targets are Triassic dolomites of the Dolomia San Giorgio and Dolomia Conchodon at a depth of 5450 m. The Meride marl overlies and seals the dolomites.

Figure 18-1 Location of the Badile licence

Hydrocarbon charging is anticipated to be by lateral up-dip migration and vertical migration along faults. The Zibido Prospect lies in an "oil province" and close to the Gaggiano oil field. Given the gas discovery at Badile, it is possible that Zibido is a gas prospect, however the Badile structure was on the other side of a major fault that separates the oil province from the gas province in this area of Northern Italy.

CGG has estimated the potential oil-in-place as well as the potential gas-in-place. Estimated prospective resources are shown in Table 18.1 for both oil and gas cases. Oil having API gravity of 38-40° is considered likely, and we assume a Recovery Factor of 25%.

The chance of success for the Zibido prospect is considered to be 14%, with the major risks being reservoir quality, trap and seal reliability and charge risk.

Table 18-1 Zibido Prospect Original Gas In-Place and Prospective Resources

		Best Estimates (Oil Case)	Best Estimates (Gas Case)
Gross Rock Volume	MMm^3	565	565
N/G	fraction	0.65	0.65
Porosity	fraction	0.05	0.05
Gas Saturation	fraction	0.7	0.7
Oil/Gas FVF	rb/stb/(rcf/scf)	1.3	410
Recovery Factor	fraction	0.25	0.7
Prospective Resource	**MMbbl/MMscm**	**19.2**	**3,689**

Figure 18-2 Zibido Prospect Top Dol. San Giorgio in Depth

Source: Consul (after BGI)

19 COSTA DEL SOLE (MANFRIA / CIELO)

Costa Del Sole is located onshore southern Sicily, close to Gela (Figure 19-1). Within this block, the Manfria discovery and Cielo prospect were delineated in a horst-graben system during ENI's exploration of the area from 1984. Following an extensional phase in Mesozoic, Plio-Pleistocene wrenching phenomena induced compressive tectonics in the area, resulting in a series of NE-SW reverse and normal faults, as well as strike slip faults. The Manfria area is stratigraphically characterized by Neogene sequences overlying a Mesozoic carbonate platform (Hyblean plateau).

Figure 19-1 Costa del Sole field location, onshore Sicily (source Apennine).

The main reservoir for the Manfria area is the Siracusa Fm. (Lower-Middle Lias), representing a carbonate platform mainly composed by grainstones/packstones, locally dolomitic, fractured and vacuolar. It constitutes a NE-SW elongated gentle structure which is delimited to the W by reverse faults and in the inner part by NE-SW normal faults, which combined together cause the down-throwing of this Lias carbonate platform. On the S and E the structure is delimited by a strike-slip fault which separates Rabbito from Manfria (Figure 19-3). Reverse faults close the Cielo prospect structure, lying NE from Manfria (Figure 19-2) and separated from it by a NE-SW oriented graben. The source rock is represented by the Streppenosa black shale basin and the Noto dolomite sequences to the east.

Figure 19-2 Time map of the top Siracusa Formation (reservoir) with location of discovery Manfria and lead Cielo, and litho-stratigraphic column in well Manfria-1 Bis (source Apennine 2011).

Well Manfria-1 was drilled to a TD of 4559 m and found oil shows in the Liassic limestone platform of the Siracusa Formation, between 4113 and 4164 m. However, the well had to be abandoned before any test. Well Manfria-1 Bis followed and was drilled in December 1985, 50 m south of Manfria-1, to a TD of 4220 m. It tested 12.3 º API oil with 7.6% sulphur and a very low GOR within the interval from 4108 to 4163.5 m RT. It flowed with rates of 150 BOPD with 44.5% of diesel injected at the bottom of the well and a sucker rod pump, but suffered from a high skin (13.5 to 22.4). Well Manfria-2 was drilled in 1987 as step-out on an up-dip structure to the south as interpreted on seismic profiles. Unfortunately, the Siracusa Formation was encountered deep at 4300 m RT and dry.

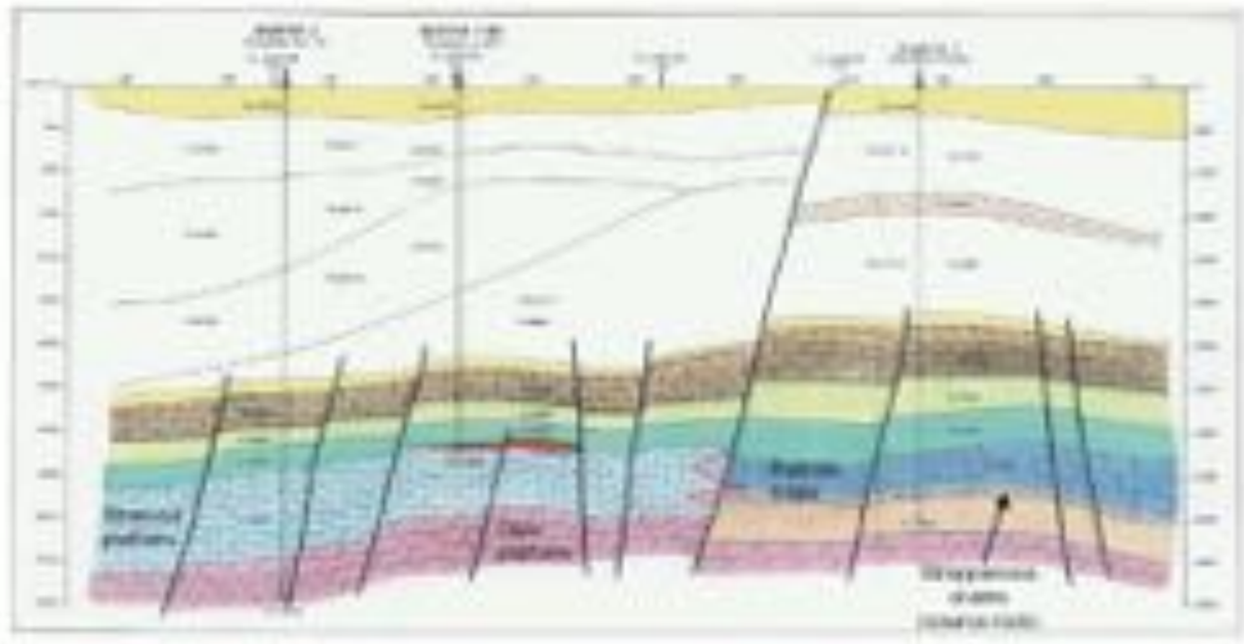

Figure 19-3 Sketch of Manfria wells (source ENI/AGIP, 1989)

In the Manfria discovery, two zones within the Siracusa reservoir having different petrophysical properties were observed: the Upper Interval between 4108 and 4240 m and the Transition Interval between 4240 and 4255 m. As the produced fluid is heavy oil and reservoir permeability is high (up to 9 D), it is expected to be recovered with a base case recovery factor of 10%. CGG's estimation is provided in Table 19.1. There is appraisal risk of 50% associated with the Manfria discovery pending further studies.

Table 19-1 Summary of input parameters for volume calculations in Manfria (Contingent Resources)

MANFRIA - Upper Interval				
Parameters	**Unit**	**Low**	**Mid**	**High**
Area	**km^2**	3.0	3.0	3.0
Gross	**m**	125	130	132
Net To Gross	**%**	80	85	90
Porosity	**%**	4.0	4.5	5.0
Water Saturation	**%**	35	35	35
Oil Volume Factor	**Bbl/stb**	1.05	1.05	1.05
Recovery Factor	**%**	7	10	12
MANFRIA - Transition Interval				
Area	**km^2**	3.0	3.0	3.0
Gross	**m**	10	12	15
Net To Gross	**%**	45	48	50
Porosity	**%**	3.0	3.0	3.0
Water Saturation	**%**	60	60	60
Oil Volume Factor	**Bbl/stb**	1.05	1.05	1.05
Recovery Factor	**%**	7	10	12
Total In Place Volumes				
		P90	**P50**	**P10**
Heavy oil	**MMBbls**	22.6	24.2	25.8
Total Recoverable Volumes				
		P90	**P50**	**P10**
Heavy oil	**MMbbls**	2.2	2.4	2.7

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Prospect Cielo was observed on seismic profiles about 3 km to the North-East of Manfria with an estimated area of 3.8 km^2. Potential reservoirs are thought to be the Siracusa limestones-dolomites and the Rabbito slope limestones (Lias) at 3980 m with OIIP estimates of 28.3 MMbbls and recoverable resources of 2.8 MMbbls with a 10% recovery factor (Table 19.2).

Table 19-2 Summary of input parameters for volume calculations in Cielo (Prospective Resources)

CIELO				
Parameters	**Unit**	**Low**	**Mid**	**High**
Area	**km^2**	2.85	2.85	2.85
Gross pay	**m**	250	260	275
Net To Gross	**%**	40	50	60
Porosity	**%**	4.0	4.5	5.0
Water Saturation	**%**	35	35	35
Oil Volume Factor	**Bbl/stb**	1.05	1.05	1.05
Recovery Factor	**%**	7	10	12
In Place Volumes				
		P90	**P50**	**P10**
Heavy oil	**MMbbls**	25.0	28.1	31.6
Recoverable Volumes				
		P90	**P50**	**P10**
Heavy oil	**MMbbls**	2.4	2.8	3.3

The main risk associated with this lead comes from the difficult seismic time-depth conversion, due to the presence of chaotic allochthonous folds at the surface. Other parameters (seal, reservoir and charge) are less uncertain as the accumulation is closer to the source rock to the east and is within the migration path toward Manfria. An overall CoS is estimated at 43% for the Cielo Prospect.

20 DEVELOPMENT FACILITIES

This section describes the development facilities in place at the fields in production, and those under development. It also contains estimates of operating and abandonment costs, and remaining development costs were appropriate.

20.1 Bezzecca (Saffron)

The Bezzecca field, from which first gas was achieved in April 2017, has been developed as a single well 7km tieback to the company's existing Vitalba gas plant. The gas plant was built in 2009 to service the company's now suspended Vitalba field. It is a standard two-phase separation plant, with the gas first processed through a separator for removal of free water, which is collected and disposed offsite. Water vapour is then removed from the gas stream using absorption in liquid triethylene glycol (TEG). The processed gas is then metered and exported to the Italian national grid, which is located within about 200 metres of the plant.

Figure 20-1 Vitalba gas processing plant (source CGG)

Further reserves will be accessed from a dual completion well in the NE Block (Bezzecca-2) in December 2020, and then from a second well in the SE Block (Bezzecca-3) in December 2021.

Bezzecca-2 is part of a work programme that has been approved at Ministry level (production concession) and Regional level (Environmental Impact Assessment). This work programme has also been signed off by Saffron's board.

Petrorep, as part of their original farm-in arrangement, pay a promote on the Bezzecca- 2 well. The gross well is estimated to cost €4.04MM of which Saffron will pay 85%. The Bezzecca- 3 well is estimated to cost €3.9MM of which Saffron will pay their full 90% share.

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The operating costs for the field were assumed to be €0.164MM per year based on forecasts provided by PVO. These were deemed to be reasonable.

Site decommissioning and well abandonment costs are estimated to be €2.10MM.

20.2 Sillaro (Saffron)

The Sillaro gas field, commenced production from two wells (one dual completion, one single completion) in May 2010. Currently only one well is on production. The wells are located within the gas plant compound.

The gas plant was built in 2010 and consists of a standard two-phase separation plant. Gas is first processed through a separator for removal of free water, which is collected and disposed offsite. Water vapour is then removed from the gas stream using absorption in liquid triethylene glycol (TEG). The processed gas is then metered and exported to the Italian national grid, which is located in close proximity to the plant.

Figure 20-2 Sillaro gas processing plant (source CGG)

At the beginning of 2012 low levels of condensate production were detected. In order to meet export specifications, condensate processing equipment has been installed.

No further drilling is anticipated for the Sillaro 1P case. The 2P and 3P reserves will be accessed by re-drilling Sillaro-1 with a deviated well (Sillaro-3Dir) in 2018 at an estimated cost of €3.4MM. In addition for the 3P case, two interventions at an estimated cost of €0.115MM each will be performed in 2018 and 2020 to access the D and E0 intervals respectively.

The operating costs for the field were assumed to be €0.380MM per year based on forecasts provided by PVO. These were deemed to be reasonable.

Site decommissioning and well abandonment costs are estimated to be €2.32MM including the Sillaro-3 well.

20.2.1 Sant' Alberto (Saffron)

Environmental Impact Assessment (EIA) approval has been granted for the development of the Sant'Alberto field, and a Production Concession was awarded by the Italian authorities in October 2017.

The current development plan is to re-enter the existing well, and commence production in mid-2018, using the redundant gas processing plant from the Sant'Andrea field. Gas export would initially be to the low pressure local grid located 260 metres from the site. The estimated cost of this first phase is €0.855MM. In 2019 it is planned to install a compressor and construct a 3.5km pipeline to the high pressure grid, and increase the export rate. The estimated cost of the compressor and pipeline is €0.930MM.

A second well in 2019 (estimated cost €2.5MM) is required to deplete the 3P resources.

Figure 20-3 Sant' Alberto wellhead (source CGG)

The operating costs for the field were assumed to be €0.288MM per year based on forecasts provided by PVO. These were deemed to be reasonable.

Site decommissioning and well abandonment costs are estimated to be €1.3MM for the 1P and 2P cases, and €2.0MM for the 3P case.

20.3 Teodorico (PVO)

The Teodorico discovery is located in 30 metres of water, approximately 20 km from the coast, in the northern Adriatic Sea. The area is a mature production province with existing gas production platforms connected to the shore by pipelines.

The Italian Ministry of Economic Development awarded PVO Exploration Permit AR94PY, that contained the Teodorico discovery in July 2012. PVO then applied for a preliminary Production Concession covering Teodorico in 2015, which was formally awarded in November 2016. PVO has subsequently submitted an environmental impact statement and subsidence study, which are expected to be completed and approved by the Ministry in early 2018, allowing a full Production Concession to be awarded.

Figure 20-4 Teodorico proposed production licence and proposed platform location re. 12 mile limit

PVE's most likely development concept for Teodorico is an unmanned tripod wellhead platform with minimal topside facilities. This platform, located outside the national 12 mile exclusion zone for economic activities, would be tied-back to, and controlled from, an existing offshore platform approximately 12 km away. This is currently assumed to be Naomi-Pandora (operated by ENI S.p.A), which would provide gas conditioning, compression facilities and an entry point to the existing export pipeline.

Gas would be transported from the Naomi-Pandora platform, using an existing pipeline, to the ENI operated Casalborsetti gas terminal on the coast. This development plan would mean that there would be no new "beach crossing" for a new pipeline and no new construction of infrastructure onshore.

Pre-FEED studies on the tripod option have been performed by RINA D'Appolonia, an experienced firm of Italian engineering consultants. These studies involved geotechnical and metocean reviews, jacket and topsides conceptual design, and well engineering. PVO has stated that to date they have invested over one million Euros in this study and other preliminary work for the field development.

As part of the submission to the Ministry for conversion to a production licence, PVE has updated their previous development cost estimate. This was collated in the PVE document entitled: Stima dei Costi – Conceptual Design Campo Gas Teodorico, Rev 2, which was also submitted to the Ministry. This document was filed and officially approved by the Ministry in November 2015.

CGG has reviewed the cost estimates and schedule provided therein and benchmarked them against its own cost database. CGG's view is that the expenditures and schedules estimated by PVE are reasonable and in line with industry norms. These estimates have therefore formed the basis of CGG's economic evaluation of the resources.

The capital costs of developing the field, assuming tie-back to Naomi-Pandora, are summarised in the table below:

-	Wells (2 No.)	21.4 €MM
-	Production facilities and platform	22.7 €MM
-	Tie-in pipeline to nearby platform	4.4 €MM
-	Project management, G&G etc.	3.2 €MM
-	Contingency	2.0 €MM
		Total 53.7 €MM

The profiles are based on production from two dual completed new wells in the Pliocene and Quaternary. Dry trees on the wellhead platform will enable close monitoring of production from multiple reservoirs and low cost work-overs to be carried out if needed.

The upper reservoirs will need compression (lower reservoirs are supported by a strong aquifer). The economics in this report are therefore predicated on there being available existing compression at the host platform as well as sufficient export pipeline capacity.

The schedule assumed by PVE is based on the following work being carried out once the environmental impact statement and subsidence study have been completed and approved.

- Obtaining wells and facilities authorization (UNMIG - National Mining Office for Hydrocarbons and Georesources)
- Platform and sea-line construction
- Wells drilling
- Gas plant construction
- First gas and production

The current schedule assumed is outlined below:

1. The EIA has been submitted and is expected to be approved by September 1 2018
2. The production Concession application will be then applied for and awarded by March 1 2019
3. Well and facilities Authorisation will be the applied for and awarded by September 1 2019
4. Construction then occurring once this is all in place, the schedule for this is 17 month construction would therefore be complete by April 2021
5. Well drilling is expected to take a further 3 to 4 months
6. Gas Plant construction to take a further 3 to 4 months
7. First Gas could be expected in November 2021 at the earliest

Allowing for contingency of 6 months, CGG have assumed a first gas date of mid-year 2022.

PVO have assumed fixed operating costs of € 1.00MM per year would be incurred for the offshore production facilities owned by the company.

In addition a tariff of €3.5 cents per m^3 has been assumed by PVO. This would cover compression and processing at the Naomi-Pandora platform, transportation through the export pipeline, and onshore processing if required.

These are deemed by CGG to be reasonable working assumptions, although it is understood that no formal tariff agreements have yet been made with third parties regarding processing and transportation services. Well work-over costs have not been included in the operating costs.

Costs for abandoning the field facilities are assumed by PVO to be € 5.00MM. These are deemed by CGG to be reasonable.

20.3.1 Rapagnano (Apennine)

The Rapagnano field was originally operated by ENI from 1952 and shut in during 2001. Production again commenced during 2013, from the original well.

The gas processing facilities for the Rampagnano field are located adjacent the Ramapgano well. The plant consists of a separator, two dehydration columns and commercial/fiscal meters. Mercaptan is also injected to odourise the gas prior to export to the nearby low pressure local gas grid. The plant was originally constructed by ENI, but extensively refurbished by Apennine, when they became the operator. The plant capacity is approximately 20,000 sM3/day. The tie-in point to the local gas grid is adjacent to the site. Operating costs have been assumed as Euro 0.250MM per year. No further development capex is expected on the field.

Figure 20-5 Rapagnano gas processing facilities (Source CGG)

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Site decommissioning and well abandonment costs are estimated to be Euro 0.625MM.

Figure 20-6 Rapagnano Concession Location

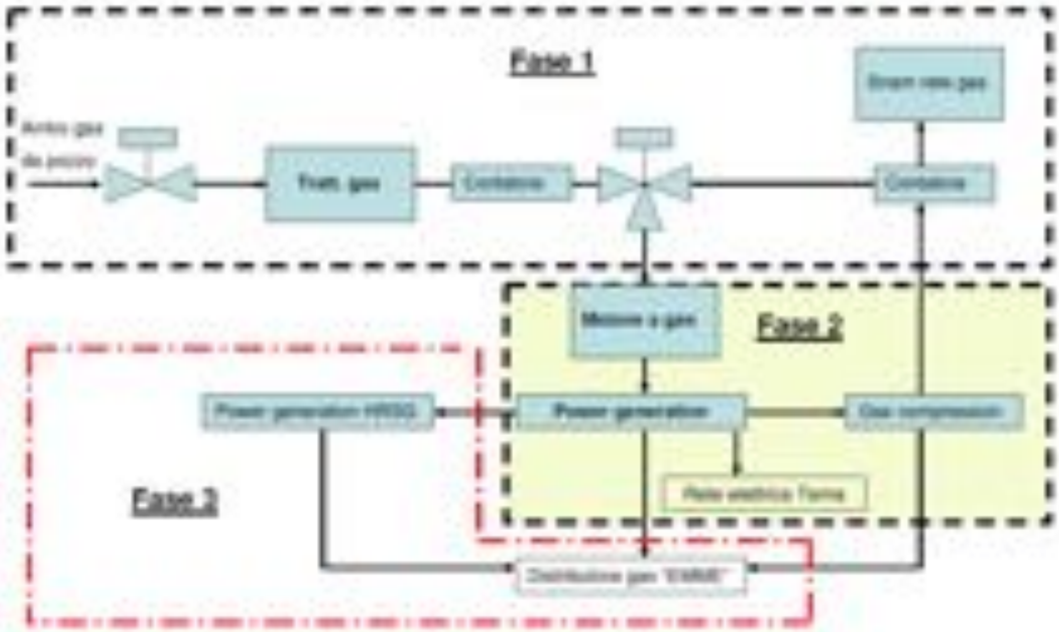

Figure 20-7 Rapagnano Facilities

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20.3.2 Casa Tiberi (Apennine)

The gas processing facilities for the Casa Tiberi field are located adjacent the Casa Tiberi well. The plant consists of a separator, two dehydration columns and commercial/fiscal meters. Nitrogen recovered from the atmosphere is used to re-generate the dehydration columns and to provide instrument air. Mercaptan is also injected to odourise the gas prior to export to the low pressure local gas grid. The plant was commissioned in 2014. The plant capacity is approximately 8,000 sM^3/day, The tie-in point to the local gas grid is adjacent to the site. Operating costs have been assumed as Euro 0.244MM per year. No further development capex is assumed for the reserves cases..

Figure 20-8 Casa Tiberi gas processing facilities (source CGG)

Site decommissioning and well abandonment costs are estimated to be Euro 0.543MM.

21 ECONOMIC ANALYSIS

21.1 Methodology

Net Present Values (NPVs) have been calculated for all assets with reserves and for Selva Stratigraphic (Contingent Resources), using industry standard discounted cash flow analysis. CGG have created an after-tax economic model in Excel™ for this purpose. The production profiles and costs described in the previous sections have then been used to calculate NPVs for each of the reserve categories.

The cash flow benefit of any historic (i.e. pre effective date) tax losses and/or brought forward undepreciated capex has not been included in the valuations. Corporate overhead costs not specifically allocated to the operating costs of each asset have also not been included.

21.2 Assumptions

21.2.1 Gas prices

Unless there is a specifically agreed price, it is assumed that future gas production is sold at the Italian spot gas price – the Punto di Scambio Virtuale (PSV) price. CGG's PSV price assumption is based on the PSV forward curve for 2018 and 2019, and is thereafter escalated at 2% per year.

In order to capture gas price uncertainty, low and high price decks have been taken as +/- 15% for 2018 and 2019, and +/-20% for 2020 onwards. The narrower near-term range reflects the greater certainty of near-term pricing.

Table 21-1 PSV Gas Price Assumptions

	Gas Price Forecast (nominal)		
	Base €/m3	**Low €/m3**	**High €/m3**
2018	0.213	0.181	0.245
2019	0.206	0.175	0.237
2020	0.210	0.168	0.252
2021	0.214	0.171	0.257
2022	0.219	0.175	0.262
2023	0.223	0.178	0.267
2024	0.227	0.182	0.273
2025	+2%	+2%	+2%

The calorific value of gas from the fields is assumed to be 38MJ/m3.

Specific gas sales contract details are as follows:-

i) Sillaro and Bezzecca. Gas is currently sold to Shell Energy Italia Srl under a short-term contract that expires on October 1st 2018. The gas price paid by Shell at the delivery point is

21.3 Euro/mWh for the first 432 GJ per day (approx.11,000 Mm^3/day), and thereafter 21.3 Euro/mWh. After expiry of the contract, all gas is assumed to be sold at the PSV price.

ii) Rapagnano. Gas is currently sold under a short-term contract to Steca Energia Srl, a local utility. The contract expires on 30th September 2018. The gas price is based on the Dutch TTF (Title Transfer Facility) virtual hub price plus a Eurocents 1.5/ m^3 premium.

iii) Casa Tiberi . Gas is currently sold under short-term contract to Prometeo SpA, a local utility. The contract expires on 30th September 2018. The gas price is based on the TTF virtual hub price plus a Eurocents 2.0/ m^3 premium.

The PSV spot price typically trades at a Euro cents 2.0/ m^3 premium to the TTF price.

21.2.2 Fiscal System

Italy's upstream oil and gas industry operates under a concessionary royalty and taxation system. Concessions are granted by the state through the National Office of Mining, Hydrocarbons and Geothermal Resources (UNMIG).

Royalty is paid on the wellhead value of production, with certain volumes exempt depending on the region and type of development. The table below presents details of the royalty system.

Table 21-2 Government Royalty

Production	Location of Concession	Annual Production Exemption	Royalty Rate Applicable
Oil	Onshore	20 Thousand Tonnes	10%
Oil	Offshore	50 Thousand Tonnes	4%
Gas	Onshore	25 Million Cubic Meters	10%
Gas	Offshore	80 Million Cubic Meters	7%
Oil and Gas	Onshore Sicily	None	10%

Profits from licences are subject to standard Italian corporate income tax (IRES), for which the current rate is 27.5%. Tax losses can be carried forward indefinitely, and allowances are as follows:

- Exploration and Appraisal costs at 100 percent as incurred.
- Non-Well Capital costs depreciated at 15 percent, on a straight line basis (10% in the 7^{th} year).
- Well Capital costs depreciated on a unit of production basis.
- Abandonment expenditure depreciated on a unit of production basis.
- Operating expenditure at 100 percent as incurred.
- Royalty payments at 100 percent as incurred.

In addition to IRES, companies with onshore production are also subject to a regional income tax (IRAP). The IRAP rate is assumed to be 3.9%.

21.2.3 Other assumptions

The following assumptions have also been used by CGG.

Table 21-3 Economic Parameters

Parameter	Value
Discount Factor	10%
Discount Methodology	Mid-Year
Cost /Price Inflation	2% per annum
Discount Date	1st January 2018

21.3 Results

NPVs are presented in the sections below for each asset with reserves, grouped by company. Results are presented for the Proven, Proven plus Probable, and Proven, Probable and Possible cases.

It should be noted that the NPVs presented in the sections below are not deemed to be the market value of the assets, and that the values may be subject to significant variation with time due to changes in the underlying input assumptions. Risk factors may also need to be applied to the values as future developments may not proceed as planned due to commercial and/or other reasons.

21.3.1 Saffron

NPVs net to Saffron at the base, low and high gas price are tabulated below for Sillaro, Bezzecca and Sant'Allberto..

Table 21-4 NPVs at Base Gas Price (net Saffron)

Field	Gas price	NPV10 € MM		
		Proved	Proved & Probable	Proved, Probable & Possible
Sillaro	Base	-1.8	2.0	3.3
	Low	-1.8	0.9	2.0
	High	-1.8	3.1	4.6
Bezzecca	Base	-3.2	0.3	2.5
	Low	-4.1	-1.2	0.8
	High	-2.2	1.6	4.2
Sant'Alberto	Base	1.1	1.7	1.4
	Low	0.2	0.6	0.1
	High	2.1	2.7	2.8

Capital and operating cost sensitivities to NPV have been performed on the Proven and Probable case at the base gas price and are presented in the table below.

Table 21-5 NPVs cost sensitivities (net Saffron)

Field	Gas price	NPV10 € MM		
		Proved	Proved & Probable	Proved, Probable & Possible
Sillaro	Base	-1.8	2.0	3.3
(WI 100%)	Capex +25%	-1.8	1.2	2.4
	Capex -15%	-1.8	2.5	3.8
	Opex +25%	-1.9	1.5	2.8
	Opex -15%	-1.8	2.2	3.6
Bezzecca	Base	-3.2	0.3	2.5
(WI 90%)	Capex +25%	-4.6	-1.1	1.1
	Capex -15%	-2.3	1.2	3.3
	Opex +25%	-3.5	0.0	2.1
	Opex -15%	-3.0	0.5	2.7
Sant'Alberto	Base	1.1	1.7	1.4
(WI 100%)	Capex +25%	0.7	1.3	0.5
	Capex -15%	1.4	2.0	2.0
	Opex +25%	0.6	1.1	0.8
	Opex -15%	1.5	2.0	1.8

21.3.2 PVO

NPVs net to PVO at the base, low and high gas price are tabulated below for Teodorico and Selva Stratigraphic.

Table 21-6 NPVs at Base Gas Price (net PVO)

Field	Gas price	NPV10 € MM		
		Proved	Proved & Probable	Proved, Probable & Possible
Teodorico	Base	5.8	17.7	28.0
	Low	-5.6	3.5	11.0
	High	17.1	32.0	45.0
		1C	**2C**	**3C**
Selva Strat*	Base	11.7	16.2	19.8
(Contingent Resources)	Low	8.4	11.8	14.6
	High	15.0	20.5	25.0

*** The economics outlined above were prepared before the Podiere Maiar -1d well was drilled and do not incorporate the well results. The development plan may change once the well results are analysed and a detailed development plan is prepared.**

Cost and schedule sensitivities to NPV have been performed on the Proven and Probable case at the base gas price and are presented in the table below. Cost sensitivities of +25% and 15% have been selected to reflect the pre-feed studies performed to date.

Table 21-7 NPVs cost sensitivities (net PVO)

Field	Gas price	NPV10 € MM		
		Proved	Proved & Probable	Proved, Probable & Possible
Teodorico	Base	5.8	17.7	28.0
	Capex +25%	-4.9	7.1	17.4
	Capex -15%	12.1	24.1	34.4
	Opex +25%	1.8	13.2	22.7
	Opex -15%	8.2	20.5	31.3
	1 year delay	3.4	14.5	24
		1C	**2C**	**3C**
Selva Strat	Base	11.7	16.2	19.8
	Capex +25%	11.3	15.7	19.4
	Capex -15%	12.0	16.4	20.1
	Opex +25%	10.8	15.1	18.5
	Opex -15%	12.3	16.8	20.6

21.3.3 Apennine

NPVs net to Apennine at the base, low and high gas price are tabulated below for Rapagnano and Casa Tiberi.

Table 21-8 NPVs at Base Gas Price (net Apennine)

Field	Gas price	NPV10 € MM		
		Proved	Proved & Probable	Proved, Probable & Possible
Rapagnano	Base	0.4	0.7	0.8
(WI 100%)	Low	0.1	0.3	0.3
	High	0.7	1.0	1.3
Casa Tiberi	Base	-0.6	-0.5	-0.5
(WI 100%)	Low	-0.7	-0.6	-0.6
	High	-0.6	-0.5	-0.5

Capital and operating cost sensitivities to NPV have been performed on the Proven and Probable case at the base gas price and are presented in the table below.

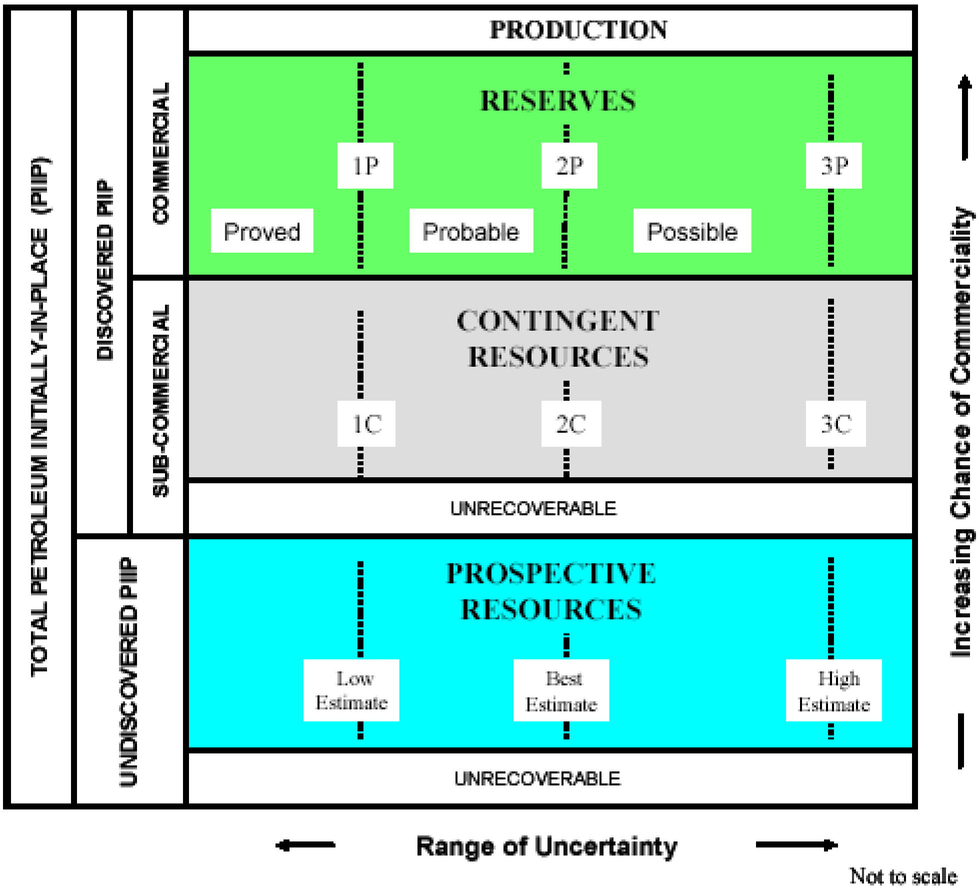
Table 21-9 NPVs cost sensitivities (net Apennine)

Field	Gas price	NPV10 € MM		
		Proved	Proved & Probable	Proved, Probable & Possible
Rapagnano	Base	0.4	0.7	0.8
	Capex +25%	0.4	0.7	0.8
	Capex -15%	0.4	0.7	0.8
	Opex +25%	0.2	0.4	0.4
	Opex -15%	0.6	0.9	1.1
Casa Tiberi	Base	-0.6	-0.5	-0.5
	Capex +25%	-0.6	-0.5	-0.5
	Capex -15%	-0.6	-0.5	-0.5
	Opex +25%	-0.7	-0.6	-0.6
	Opex -15%	-0.6	-0.5	-0.5

22 APPENDIX A: DEFINITIONS

22.1 Definitions

The petroleum reserves and resources definitions used in this report are those published by the Society of Petroleum Engineers and World Petroleum Congress in 1998, supplemented with guidelines for their evaluation, published by the Society of Petroleum Engineers in 2001 and 2007. The main definitions and extracts from the SPE Petroleum Resources Management System (2007) are presented below.



Source: SPE Petroleum Resources Management System 2007

Figure 22-1 Resources Classification Framework

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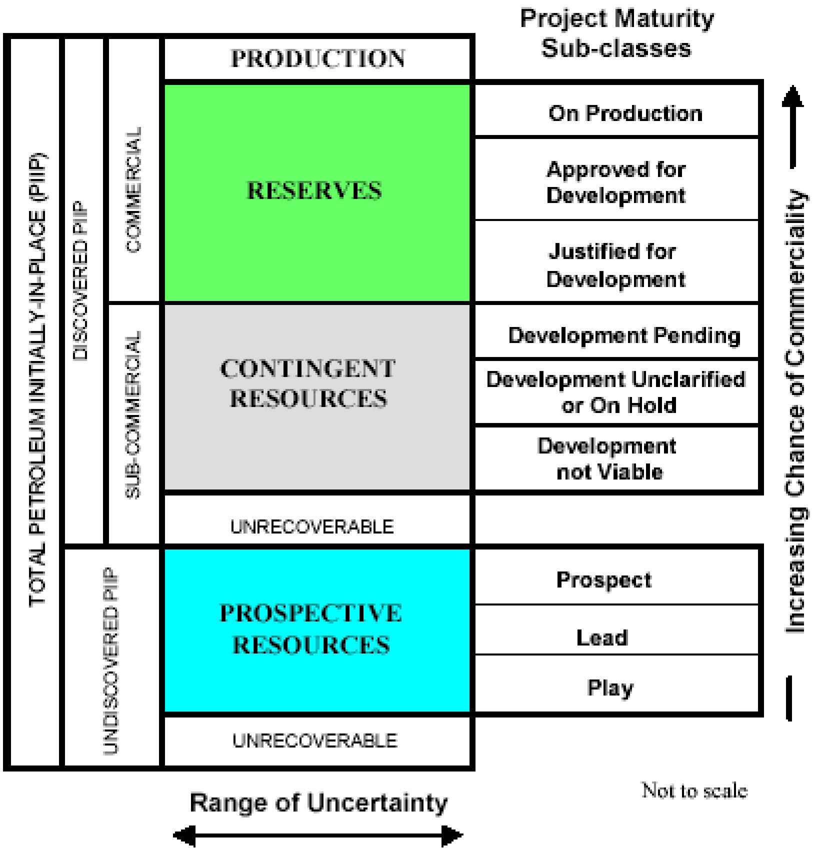

Source: SPE Petroleum Resources Management System 2007

Figure 22-2 Resources Classification Framework: Sub-classes based on Project Maturity

22.1.1 Total Petroleum Initially-In-Place

Total Petroleum Initially-In-Place is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to “total resources”).

22.1.2 Discovered Petroleum Initially-In-Place

Discovered Petroleum Initially-In-Place is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

22.1.3 Undiscovered Petroleum Initially-In-Place

Undiscovered Petroleum Initially-In-Place is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

22.2 Production

Production is the cumulative quantity of petroleum that has been recovered at a given date. Production is measured in terms of the sales product specifications and raw production (sales plus non-sales) quantities required to support engineering analyses based on reservoir voidage.

22.3 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 characterised by development and production status.

The following outlines what is necessary for the definition of Reserve to be applied.

- A project must be sufficiently defined to establish its commercial viability
- There must be a reasonable expectation that all required internal and external approvals will be forthcoming
- There is evidence of firm intention to proceed with development within a reasonable time frame
- A reasonable timetable for development must be in evidence
- There should be a development plan in sufficient detail to support the assessment of commerciality
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria must have been undertaken
- There must be a reasonable expectation that there will be a market for all, or at least the expected sales quantities, of production required to justify development
- Evidence that the necessary production and transportation facilities are available or can be made available
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated

The “decision gate” whereby a Contingent Resource moves to the Reserves class is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.

A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives.

22.3.1 Developed Producing Reserves

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

Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well.

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

22.3.2 Developed Non-Producing Reserves

Developed Non-producing Reserves include shut-in and behind-pipe reserves.

Shut-in reserves are expected to be recovered from:

- Completion intervals that are open at the time of the estimate but that have not yet started producing
- Wells that were shut-in for market conditions or pipeline connections, or
- Wells not capable of production for mechanical reasons.

Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

22.3.3 Undeveloped Reserves

Undeveloped Reserves are quantities expected to be recovered through future investments such as

- From new wells on undrilled acreage in known accumulations
- From deepening existing wells to a different (but known) reservoir
- From infill wells that will increase recovery, or
- Where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to:
    - Recomplete an existing well or
    - Install production or transportation facilities for primary or improved recovery projects

Incremental recoveries through improved recovery methods that have yet to be established through routine, commercially successful applications are included as Reserves only after a favourable production response from the subject reservoir from either (a) a representative pilot or (b) an installed program, where the response provides support for the analysis on which the project is based.

Where reserves remain undeveloped beyond a reasonable timeframe, or have remained undeveloped due to repeated postponements, evaluations should be critically reviewed to document reasons for the delay in initiating development and justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay is justified, a reasonable time frame is generally considered to be less than five years.

22.3.4 Proved Reserves

Proved Reserves are those quantities of petroleum that, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current 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.

22.3.5 Probable Reserves

Probable Reserves are those additional reserves that analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved + Probable Reserves (2P).

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.

22.3.6 Possible Reserves

Possible Reserves are those additional reserves that 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 + Probable + 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.

22.4 Contingent Resources

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality.

The term accumulation is used to identify an individual body of moveable petroleum. The key requirement in determining whether an accumulation is known (and hence contains Reserves or Contingent Resources) is that each accumulation/reservoir must have been penetrated by a well. In general, the well must have clearly demonstrated the existence of moveable petroleum in that reservoir by flow to surface, or at least some recovery of a sample of petroleum from the well. However, where log and/or core data exist, this may suffice provided there is a good analogy to a nearby, geologically comparable, known accumulation.

Estimated recoverable quantities within such discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves.

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively.

1C denotes low estimate scenario of Contingent Resources
2C denotes best estimate scenario of Contingent Resources
3C denotes high estimate scenario of Contingent Resources

Contingent Resources 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 characterised by their economic status.

22.4.1 Contingent Resources: Development Pending

Contingent Resources (Development Pending) are a discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are expected to be resolved within a reasonable time frame.

22.4.2 Contingent Resources: Development Un-Clarified/On Hold

Contingent Resources (Development Un-Clarified/On Hold) are a discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development.

22.4.3 Contingent Resources: Development Not Viable

Contingent Resources (Development Not Viable) are a discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential. The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognised in the event of a major change in technology or commercial conditions.

22.5 Prospective Resources

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

22.5.1 Prospect

A Prospect is classified as a potential accumulation that is sufficiently well defined to represent a viable drilling target.

22.5.2 Lead

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

22.5.3 Play

A Play is classified as a prospective trend of potential prospects that requires more data acquisition and/or evaluation in order to define specific Leads or Prospects.

22.6 Unrecoverable Resources

Unrecoverable Resources are that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities that are estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

23 APPENDIX B: NOMENCLATURE

acre	43,560 square feet
AOF	absolute open flow
API	American Petroleum Institute (ºAPI for oil gravity, API units for gamma ray measurement)
av.	Average
AVO	Amplitude vs. Off-Set
BBO	billion (10^9) barrels of oil
bbl, bbls	barrel, barrels
BCF	billion cubic feet
bcm	billion cubic metres
BCPD	barrels of condensate per day
BHT	bottom hole temperature
BHP	bottom hole pressure
BOE	barrel of oil equivalent, with gas converted at 1 BOE = 6,000 scf
BOPD	barrels of oil per day
BPD	barrels per day
Btu	British thermal units
BV	bulk volume
c.	circa
CCA	conventional core analysis
CD-ROM	compact disc with read only memory
cgm	computer graphics meta file
CNG	compressed natural gas
CO_2	carbon dioxide
COE	crude oil equivalent
1-D, 2-D, 3-D	1-, 2-, 3-dimensions
DHI	direct hydrocarbon indicators
DHC	dry hole cost
DPT	deeper pool test
DROI	discounted return on investment
DST	drill-stem test
DWT	deadweight tonnage
E	East
E & P	exploration & production
EAEG	European Association of Exploration Geophysicists
e.g.	for example
EOR	enhanced oil recovery
ESP	Electrical Submersible Pump
et al.	and others
EUR	estimated ultimately recoverable (reserves)
FPSO	Floating production storage unit
ft/s	feet per second
G & A	general & administration
G & G	geological & geophysical
g/cm^3	grams per cubic centimetre
Ga	billion (10^9) years
GIIP	gas initially in place
GIS	Geographical Information Systems
GOC	gas-oil contact
GOR	gas to oil ratio
GR	gamma ray (log)
GWC	gas-water contact
H_2S	hydrogen sulphide
ha	hectare(s)
HI	hydrogen index
HP	high pressure
Hz	hertz
IDC	intangible drilling costs
IOR	improved oil recovery
IRR	internal rate of return
J & A	junked & abandoned
km	kilometres (1,000 metres)
km^2	square kilometres
kWh	kilowatt-hours
LoF	life of field
LP	low pressure
LST	lowstand systems tract
LVL	low-velocity layer
M & A	mergers & acquisitions
m	metres
M	thousands
MM	million
m^3/day	cubic metres per day
Ma	million years (before present)
mbdf	metres below derrick floor
mbsl	metres below sea level
MBOPD	thousand bbls of oil per day
MCFD	thousand cubic feet per day

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MCFGD	thousand cubic feet of gas per day
mD	millidarcies
MD	measured depth
mdst.	mudstone
MFS	maximum flooding surface
mg/gTOC	units for hydrogen index
mGal	milligals
MHz	megahertz
Mscm	thousand standard cubic metres
MMscm	million standard cubic metres
ml	millilitres
mls	miles
MMBO	million bbls of oil
MMBOE	million bbls of oil equivalent
MMBOPD	million bbls of oil per day
MMCFD	million cubic feet per day
MMTOE	million tons of oil equivalent
mmsl	metres below mean sea level
mN/m	interfacial tension measured unit
MPa	megapascals
mSS	metres subsea
m/s	metres per second
msec	millisecond(s)
MSL	mean sea level
N	north
NaCl	sodium chloride
NFW	new field wildcat
NGL	natural gas liquids
NPV	net present value
no.	number (not #)
OAE	oceanic anoxic event
OI	oxygen index
OWC	oil-water contact
P90 or 1P	proved
P50 or 2P	proved + probable
P10 or 3P	proved + probable + possible
P & A	plugged & abandoned
pbu	pressure build-up
perm.	permeability
pH	-log H ion concentration
phi	unit grain size measurement
Ø	porosity
plc	public limited company

por.	porosity
poroperm	porosity-permeability
ppm	parts per million
PRMS	Petroleum Resource Management System (SPE)
psi	pounds per square inch
RF	recovery factor
RFT	repeat formation test
ROI	return on investment
ROP	rate of penetration
RT	rotary table
S	South
SCAL	special core analysis
SCF	standard cubic feet, measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
SCF/STB	standard cubic feet per stock tank barrel
SPE	Society of Petroleum Engineers
SS	sub-sea
ST	sidetrack (well)
STB	stock tank barrels
std. dev.	standard deviation
STOIIP	stock tank oil initially in place
Sw	water saturation
TCF	trillion (10^{12}) cubic feet
TD	total depth
TDC	tangible drilling costs
Therm	105 Btu
TVD	true vertical depth
TVDSS	true vertical depth subsea
TWT	two-way time
US$	US dollar, the currency of the United States of America
UV	ultra-violet
VDR	virtual dataroom
W	West
WHFP	wellhead flowing pressure
WHSP	wellhead shut-in pressure
WD	water depth
wt%	percent by weight
XRD	X-ray diffraction (analysis)

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