CGG Services (UK) Limited

COMPETENT PERSONS REPORT

PODERE GALLINA LICENCE, ITALY

Prepared for:-

PO VALLEY ENERGY LIMITED
UNITED OIL AND GAS PLC
PROSPEX OIL AND GAS PLC

CGG project no: BP521

CGG Services (UK) Limited
Crompton Way, Manor Royal Estate
Crawley, West Sussex RH10 9QN, UK
Tel: +44 012 9368 3000, Fax: +44 012 9368 3010

cgg.com

CGG GeoConsulting

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 licence basis, CGG and its employees who worked on preparation of this report, are independent of Po Valley Energy Limited (PVO) and their directors, senior management and other advisers; have no economic or beneficial interest (present or contingent) in the company or in any of the mineral assets being evaluated and is not remunerated by way of a fee that is linked to the admission or value of the issuer.

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

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

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CGG affirm that from 1st October (the cut-off date for inclusion of data) to the date of issue of this report, 5th October 2018, 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 PVO.

The report has been prepared in line with European Securities and Market Authority (ESMA) Recommendations for Oil and Gas Companies as set out in paragraphs 131 to 133 and Appendix I and III of the ESMA Recommendations, and conforms 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.

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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.

Created by
Andrew Webb, Manager, Petroleum Reservoir and Economics
Tel: +44 (0)1293 683000 – andrew.webb@cgg.com

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Date	**Originator**	**Checked & Approved**
Signed:		

Prepared for:	Prepared By:
Po Valley Energy Limited Via Francesco Crispi 90 00187 Rome, Italy	Andrew Webb CGG Services (UK) Limited Crompton Way, Manor Royal Estate Crawley, West Sussex RH10 9QN United Kingdom

TABLE OF CONTENTS

Created by
Andrew Webb, Manager, Petroleum Reservoir and Economics
Tel: +44 (0)1293 683000 – andrew.webb@cgg.com

Figures

Tables

1 EXECUTIVE SUMMARY

This report has been prepared for the Directors of:-

Po Valley Energy Limited
Via Francesco Crispi 90
00187
Rome, Italy

United Oil & Gas plc
200 Strand
London
WC2R 1DJ

Prospex Oil & Gas Plc
Tintagel House
92 Albert Embankment
London SE1 7TY

This Competent Persons Report (CPR) is an independent evaluation, prepared by CGG Services (UK) Ltd (CGG), for Po Valley Energy Limited (PVO) in accordance with the request dated 24th August 2018. The subject of the report is the Podere Gallina exploration licence, located in the Po Valley, northern Italy.

This report is based CGG's previous CPRs on the Podere Gallina licence for United Oil & Gas plc (UOG), and updated with the initial findings from the Podere Maiar appraisal well that was spudded in November 2017.

1.1 Location

The Po Basin runs south east from Milan to the Adriatic coast at Venice. Oil and gas has been produced in the area for over sixty years. The Podere Gallina Licence is located approximately 10 km to the east of Bologna, and about 30 km from the coast in the Ferrara and Bologna provinces of the Emilia-Romagna region.

Figure 1.1 Location map for Podere Gallina licence

1.2 Data sources

In completing this evaluation, CGG have independently reviewed information and checked the validity of interpretations provided by PVO, as well as utilising complementary information from the public domain. CGG have produced several previous CPRs on the three fields over the last four years for the operator PVO, and as a result are familiar with the geology. Much of the data supplied by PVO for this report was in the form of updates to existing data previously provided to and reviewed by CGG. In conducting their evaluation, CGG have accepted the accuracy and completeness of data supplied by PVO, and have not performed any new interpretations, simulations or studies. Resource volumes presented in this report have been worked up independently by CGG.

1.3 Licence Description

The Podere Gallina Licence is located in the Po Valley plain, and covers an area of 506 square kilometres. The currently shut-in Selva gas field lies within this licence area. This field, operated by ENI, the Italian oil and gas multinational, produced 83 Bcf over a 35 year period from 15 wells. Production ceased in 1984.

As a result of a farm-in agreement between PVO and UOG signed on 4th May 2017, UOG acquired a 20% working interest in the licence on funding 40% of the cost of the Podere Maiar appraisal well that was drilled in Q4 2017. PVO, who were awarded the licence in September 2008, is the licence operator and have a 63% working interest in the licence. Prospex Oil and Gas plc hold the remaining 17% working interest.

Table 1.1 Podere Gallina licence details

Operator	PVO Interest (%)	Status	Licence expiry date	Licence Area
PVO	63%	Exploration	3rd February 2018*	506 km^2

** In July 2016 PVO lodged the application for the first 3-year extension of the exploration period. When awarded, it is expected that the extension will be back dated to* 3rd February 2018*. The recent production concession application has not superseded this application.*

1.4 Reserves

A summary of the resources associated with the “Selva Stratigraphic” redevelopment opportunity and the three prospects, both gross and net, in accordance with the 2007 Petroleum Resource Management System (PRMS) published by the SPE, are shown in the tables below.

The volumes associated with the “Selva Stratigraphic” redevelopment opportunity have been updated since the previous CPR, and now incorporate the results of the Podere Maiar-1 well. This well confirmed the presence of undrained gas in the structure, and has further de-risked the progression towards a commercial development. A development plan dated May 2018 was submitted to Italian authorities and application was made to convert to a Production Concession, allowing gas production to commence from the PM-1 well after tie-in to the gas network pipeline nearby. CGG has reviewed the relevant application documents in detail and reports the following Reserves and Resources for the assets.
In light of the award of the production concession which was awarded in January 2019 by the Italian authorities, the “Selva Stratigraphic” redevelopment is clarified as reserves

These volumes have been based on integrating all of the geological and historic production data, including the well test results, to arrive at a range of reserves that reflects the uncertainties that exist in the Selva field.
Once production has started, over time it is expected that this range of reserves will narrow as the production history gives certainty to the recoverable volumes.

Table 1.2 Summary of Reserves for the Selva Redevelopment Project and Net Attributable to PVO

Selva Stratigraphic Trap	Gross (MMscm)			63% Net attributable (MMscm)*			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
C1 Sand	48	129	209	30	81	132	PVO
C2 Sand	69	250	637	43	158	401	
Total	**117**	**379**	**846**	**74**	**239**	**533**	

** The net attributable may not add due to rounding error.*

Table 1.3 Summary of Reserves for the Selva Redevelopment Project and Net Attributable to UOG

Selva Stratigraphic Trap	Gross (MMscm)			20% Net attributable (MMscm)*			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
C1 Sand	48	129	209	10	26	42	PVO
C2 Sand	69	250	637	14	50	127	
Total	**117**	**379**	**846**	**23**	**76**	**169**	

** The net attributable may not add due to rounding error.*

Table 1.4 Summary of Reserves for the Selva Redevelopment Project and Net Attributable to Prospex Oil&Gas Plc

Selva Stratigraphic Trap	Gross (MMscm)			17% Net attributable (MMscm)*			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
C1 Sand	48	129	209	8	22	36	PVO
C2 Sand	69	250	637	12	43	108	
Total	**117**	**379**	**846**	**20**	**64**	**144**	

** The net attributable may not add due to rounding error.*

NPVs at base, low and high gas prices are tabulated below for the Selva Redevelopment Project for a 100% field interest and respective net interests. It should be noted that the NPVs presented are not deemed to be the market value of the asset, and that the values may be subject to significant variation with time due to changes in the underlying input assumptions as more data becomes available and interpretations change.

Table 1.5 Summary of NPV10s for the Selva Redevelopment Project and Net Attributable to PVO

Gas Price	Gross (€ MM)			Net attributable (€ MM)			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Base	10.1	27.4	46.1	6.4	17.3	29.0	PVO
Low	7.6	21.3	36.2	4.8	13.4	22.8	
High	12.7	33.5	56.0	8.0	21.1	35.3	

Table 1.6 Summary of NPV10s for the Selva Redevelopment Project and Net Attributable to UOG

Gas Price	Gross (€ MM)			Net attributable (€ MM)			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Base	10.1	27.4	46.1	2.0	5.5	9.2	PVO
Low	7.6	21.3	36.2	1.5	4.3	7.2	
High	12.7	33.5	56.0	2.5	6.7	11.2	

Table 1.7 Summary of NPV10s for the Selva Redevelopment Project and Net Attributable to Prospex

Gas Price	Gross (€ MM)			Net attributable (€ MM)			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Base	10.1	27.4	46.1	1.7	4.7	7.8	PVO
Low	7.6	21.3	36.2	1.3	3.6	6.2	
High	12.7	33.5	56.0	2.2	5.7	9.5	

CGG's gas price assumption follows the forward Italian PSV spot gas price curve until 2025, and thereafter escalates at 2% per year. Low and high price decks have been taken as +/- 15% for 2019 and 2020, and +/-20% for 2021 onwards.

1.5 Prospective Resources

With the commerciality of the field demonstrated, an application for an exploitation concession was submitted in May 2018. 3D seismic acquisition over the field is also being planned. Acquisition is expected in 2019, and this will help delineate any further opportunities for undrained gas within the Selva structure.

Table 1.8 Summary of Gas Prospective Resources by Prospect

	Gross (MMscm)				
Name	**Low**	**Best**	**High**	**Risk factor**	**Operator**
Cembalina	59.5	93.5	133.1	51%	PVO
Fondo Perino	288.9	413.5	580.6	34%	PVO
East Selva	824.1	985.6	1149.8	30%	PVO

Notes:-

1. *Prospective resources are the volumes estimated to be potentially recoverable from undiscovered accumulations through future development projects*
2. *Prospective resources have both an associated chance of discovery and a chance of development*
3. *Volumes are sub-divided into low, best and high estimates to account for the range of uncertainty in the estimates*
4. *Prospective Resources are stated before the application of a risk factor and an economic cut-off*
5. *Full definitions of the Prospective Resource categories can be found in Appendix A*
6. *The risk factor means the estimated chance of discovering hydrocarbons in sufficient quantity for them to be tested to the surface*

Created by
Andrew Webb, Manager, Petroleum Reservoir and Economics
Tel: +44 (0)1293 683000 – andrew.webb@cgg.com

2 INTRODUCTION

This independent Competent Person's Report (CPR) was prepared by CGG at the request of Po Valley Energy Ltd (PVO). The report evaluates reserves and resources associated with the Podere Gallina licence in the Po Valley in northern Italy, which is operated by PVO.

This report is based on CGG's previous CPR on the Podere Gallina licence for UOG issued in January 2018, and is updated to reflect the anticipated grant of a Production Concession and on the basis of a firm Field Development Plan submitted in support of this application.

As a result of a farm-in agreement between PVO and UOG signed on 4th May 2017, UOG acquired a 20% working interest in the licence on funding 40% of the cost of the Podere Maiar appraisal well. PVO, who were awarded the licence in September 2008, is the licence operator and have a 63% working interest in the licence. Prospex Oil and Gas plc hold the remaining 17% working interest.

Details of the licence are summarised below.

Table 2.1 Podere Gallina licence details

Operator	PVO Interest (%)	Status	Licence expiry date	Licence Area
PVO	63%	Exploration	3rd February 2018*	506 km^2

** In July 2016 PVO lodged the application for the first 3-year extension of the exploration period. When awarded, it is expected that the extension will be back dated to 3rd February 2018. The recent production concession application has not superseded this application.*

The report contains descriptions of the licence area, and evaluates the range of gas volumes that could be present in the identified assets and the associated risk factors.

2.1 Sources of Information

In completing this evaluation, CGG have reviewed information and interpretations provided by PVO, 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
- Well logs (Podere Maiar well)
- Well testing reports (Podere Maiar well, latest interpretations)
- Contents of Field Development Plan dated May 2018

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

As the assets in question are still to be developed, no site visits have been conducted by CGG.

2.2 Evaluation methodology

In estimating the reserves and 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.

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

2.3 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 PVO, 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.

<u>Andrew Webb</u>
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.

Toni Uwaga

Has an MSc from Heriot Watt University, Edinburgh, in Petroleum Engineering. He has 22 years' industry experience. Over the years he has worked on oil and gas projects spanning the North Sea, East Irish sea, Gulf of Guinea, Middle East, India, Malaysia, North America and the Caribbean Sea. He functioned as Reserves Coordinator for Shell Petroleum Development Company, Nigeria. He has participated as Lead Reservoir Engineer in several CPRs across the various regions he has worked. He is a member of the Geological Society of Trinidad and Tobago (GSTT) and the Society of Petroleum Engineers (SPE). He has several technical papers, published by GSTT and SPE.

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 GEOPHYSICS AND GEOLOGY

The Exploration Licence that is the subject of this report is located in the Po Valley onshore northern Italy. The Po Valley runs south east from Milan to the Adriatic coast at Venice. Oil and gas has been produced in the area for over sixty years.

3.1 Regional Context

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 Miocene and Pliocene shales that are interbedded with 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 4500 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.

3.2 Selva Stratigraphic Reserves

The Selva Stratigraphic redevelopment opportunity represents a part of the former ENI-operated Selva gas field. The extension of the Selva Field into the Podere Gallina Licence was interpreted by Po Valley Energy Ltd. mainly using isopach mapping from well data at Upper Mid Pliocene level. Recent modelling (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 in the Selva-6 well) leaving a potential undrained updip gas volume.

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. Although the depth structure map is quite well constrained by existing well penetrations, the 2D seismic (in terms of line spacing and vintage) is imperfect for imaging small features and part of the Operator's plan is to revise the structure mapping using additional data in the near future. The Podere Maiar-1 well was drilled in late 2017 and tested in early 2018. It targeted the updip volume based upon a new interpretation of the position of the lapout edge towards the Selva-3 well. The latest interpretation of the well test and its implications are fully incorporated into this CPR and into CGG's consideration of Reserves.

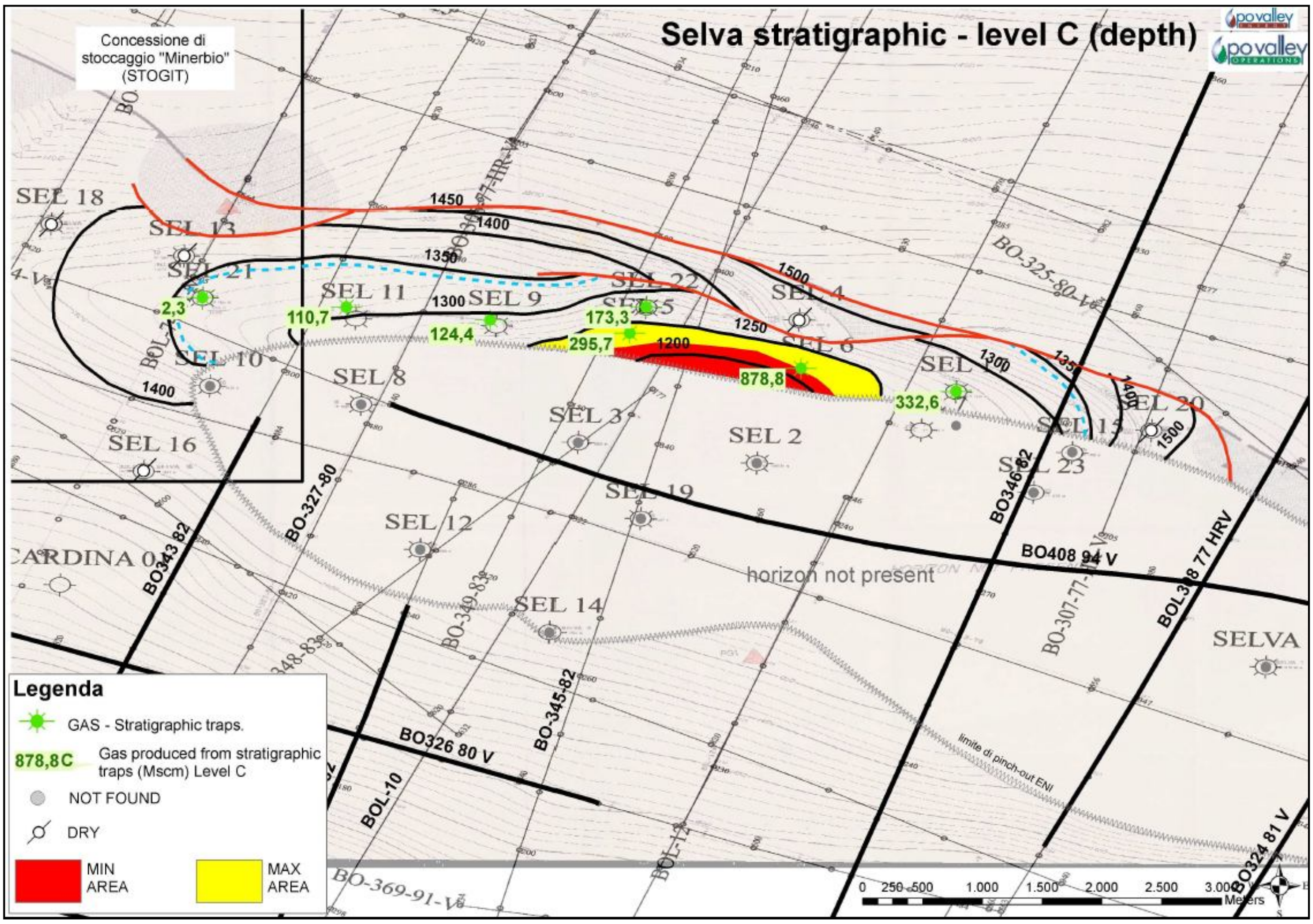


Figure 3.1 Selva stratigraphic structure map

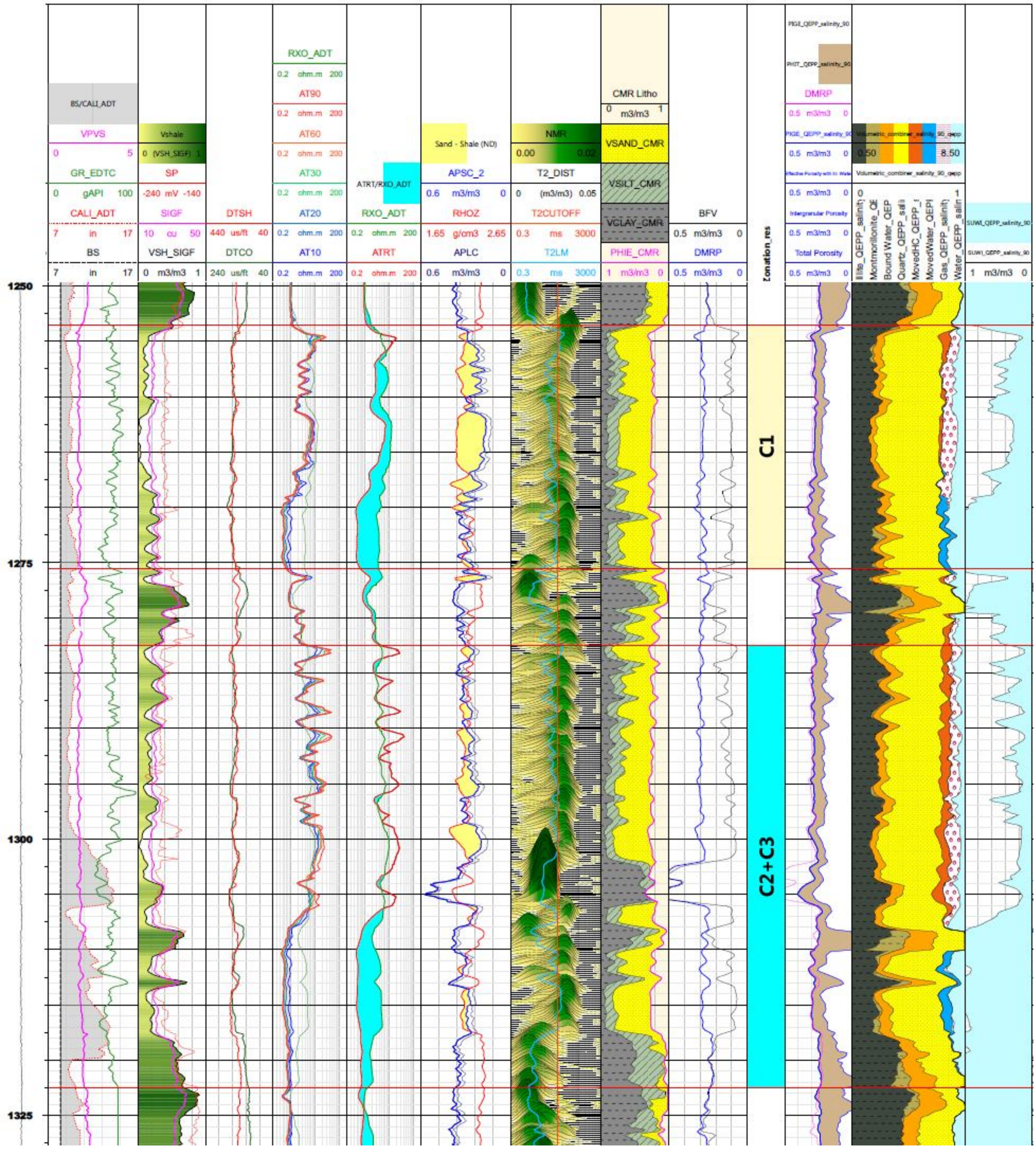


Figure 3.2 Podere Maiar-1: C1 and C2 Sand Reservoirs, Extract from ELAN Interpretation Plot

The ELAN log and interpretation plot is provided as Figure 3.2, above.

Podere Maiar-1 penetrated a gross thickness of 62.5 metres of Lower Pliocene (C1 and C2) gas sands of the old Selva field. Petrophysical analysis has indicated average properties in each sand as follows:

C1 Sand

22 metres gross thickness, 70% net-to-gross, 22-26% porosity and 65% gas saturation. A recovery factor of 60-70% is assumed across the P90 to P10 case.

C2 Sand

40.5 metres gross thickness, 63% net-to-gross, 21-25% porosity and 70% gas saturation. A recovery factor of 60-70% is assumed across the P90 to P10 cases.

The logging tools deployed for the assessment of the reservoirs were high quality and comprehensive, including a CMR (Figure 3.2). Porosity estimation is considered reliable as the CMR-Density technique was used (ideal for gas-filled shaly sandstones), and the CMR also clearly distinguishes sand from shale. The ELAN interpretation has been checked and appears to be reliable, showing long reservoir sections with good gas saturations. The quality of the reservoir section encountered by the well appears good and reliably defined.

Pressure data taken over the reservoir section has established a separate gas-water-contact in C1 and C2 sands which are separated by a shale. In both sands, the contact derived from pressure data points falls close to the GWC identified on the petrophysical interpretation plot. The location of the water, therefore, is quite well established from independent evidence.

Gas initially in place estimates have been reviewed and the following parameters are considered fair estimates:

Table 3.1 Parameters used in the estimation of gas-initially-in-place (GIIP)

Sand	Case	GWC	NtG	Phi	Sg	Bg	GIIP (MMscm)
C1	min	1,237.0	0.66	0.22	0.65	140	81
C1	max	1,239.6	0.75	0.26	0.65	144	299
C2	min	1,274.5	0.58	0.21	0.7	140	261
C2	max	1,277.8	0.68	0.25	0.7	144	910
Total	min						342
	max						1,208

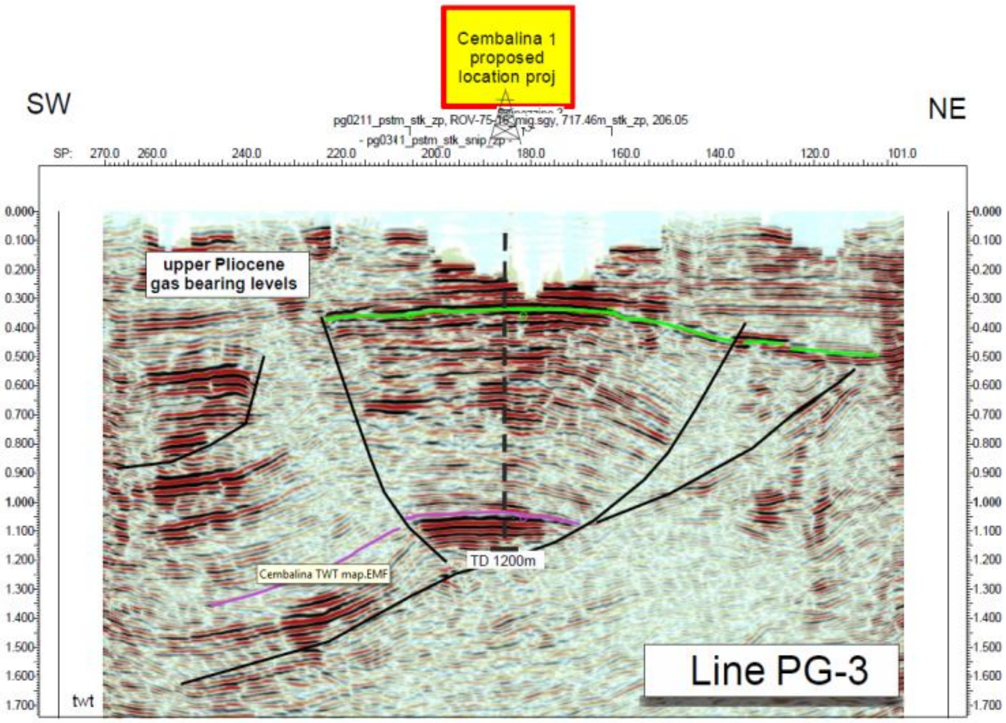
The mid-case GIIP is taken as the average of low and high.

As a proposed re-development of an old field, this appears relatively low risk; the major geological risk component is the location of the reservoir zero thickness line (pinch-out) and the shape of the pinch-out as drawn on the structure map (currently the zero line is drawn as a smooth, straight line which could be correct or could be substantially incorrect). Lack of high-resolution structural definition means Gross Rock Volume remains the greatest geological uncertainty. At this stage, post appraisal well but prior to production start-up, there is remaining uncertainty regarding the interpretation of the well test, in particular the meaning and significance of the “boundaries” seen in C1 and C2 sands. These boundaries are the result of non-unique interpretations of well test data, although the slope of the derivative is a clear reservoir signature for both sands. At the present time, CGG considers that the derivative signature from the C2 sand flow test may be significant in terms of a geological feature that limits the contacted gas volume or accelerates water coning. The major risk to recoverable gas volumes is considered to be the timing of water breakthrough. In the Po Valley region, accurately predicting the timing of water breakthrough in comparable reservoirs has been a source of uncertainty in the past. The well test and production risks will be discussed in Chapter 4.

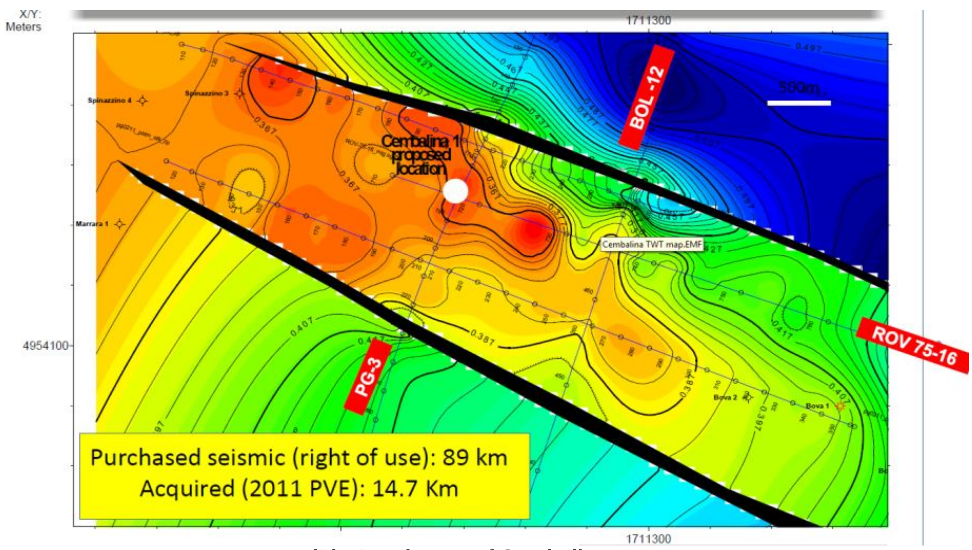
3.3 Cembalina Prospective Resource

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 purchased 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

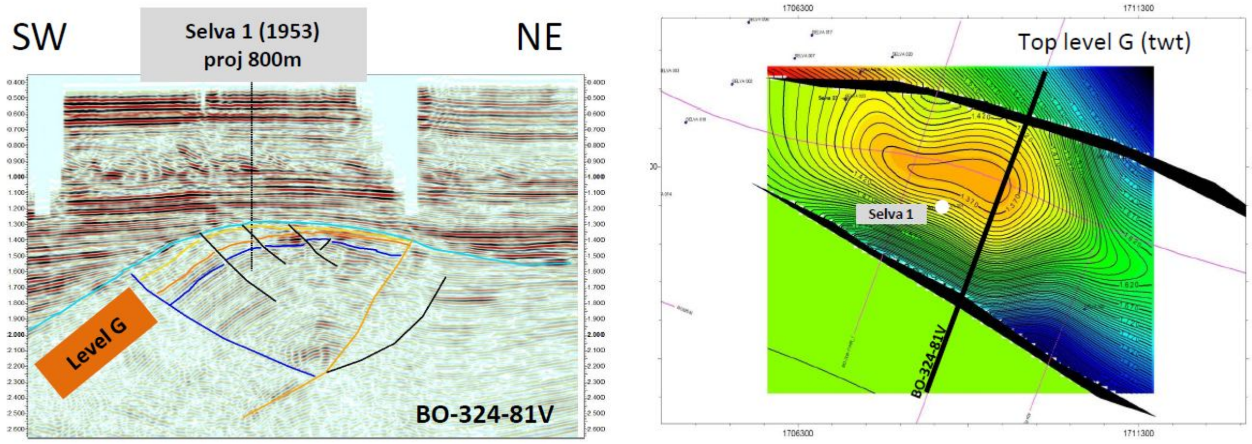
Created by
Andrew Webb, Manager, Petroleum Reservoir and Economics
Tel: +44 (0)1293 683000 – andrew.webb@cgg.com

Figure 3.3 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 given by PVO. These are a P90 of 60 MMscm, a P50 of 94 MMscm and a P10 of 133 Mscm. The CoS relating to these resources is 51% due to the proximity of gas fields producing from these Early Pliocene sands.

3.4 Fondo Perino Prospective Resource

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 3.4 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 289, 413 and 581 MMscm at P90, 50 and P10 cases respectively.

3.5 East Selva Prospective Resource

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.

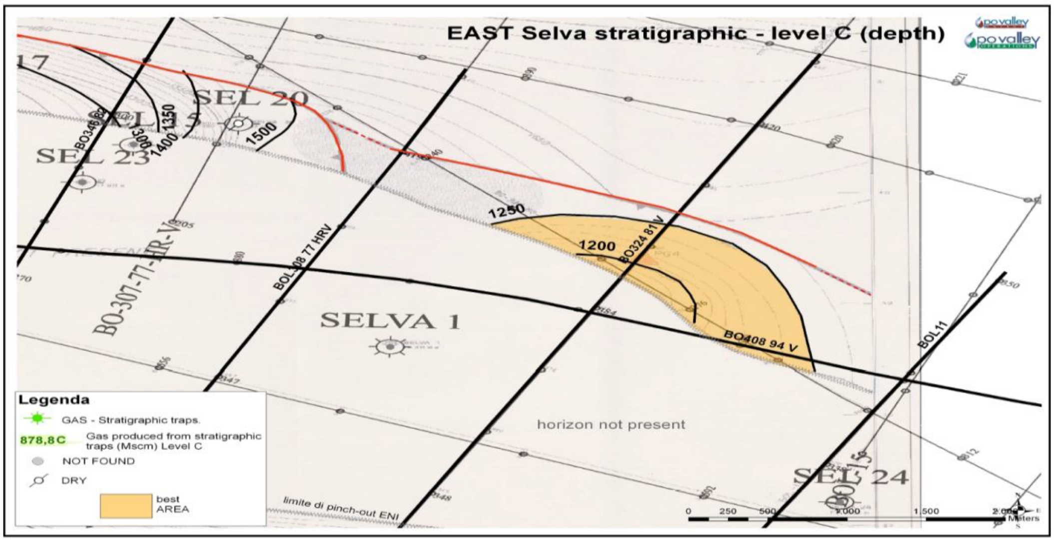


Figure 3.5 East Selva structure map

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. Given the proof of concept demonstrated by the success of the Podere Maiar-1 well, the Chance of Success at East Selva has been upgraded. The prospect could hold recoverable resources of 824, 986 and 1150 MMscm in Low, Best and High cases respectively for a CoS of 30%. The primary risk is the definition of the gross rock volume based on only a small number of seismic lines.

Table 3.2 Summary of Gas Prospective Resource by Prospect (MMscm)

	Gross (MMscm)		
Prospect	**Low**	**Best**	**High**
Cembalina	59.5	93.5	133.1
Fondo Perino	288.9	413.5	580.6
East Selva	824.1	985.6	1149.8

4 RESERVOIR ENGINEERING

4.1 Selva Stratigraphic Trap

4.1.1 Historical production of the Selva Gas Field

The Selva gas field was previously on production during the 1950s-1980s. Total historical production from the C level is shown in Table 4.1 below:

Table 4.1 Summary of Total Gas Recovered from Selva Stratigraphic Trap (MMscm)

Well	Total Gas Recovered, MMscm
Selva-5-C	295.74
Selva-6-C	878.80
Selva-9-C	124.38
Selva-11-C	124.05
Selva-17-C	332.58
Selva-21-C	2.31
Selva-22-C	173.33
Total	**1,931.19**

Figure 4.1 shows the total gas produced from each historical well. CGG has no records of perforation intervals of Level C, only well tops. Therefore, we consider "height of sand top above Gas-Water Contact (GWC)". The height above contact of each historical well is as follows:

- Selva-21 was watered-out when GWC was at ~1,340 mTVDss, assuming this is the original water contact
- Selva-11's Top C is at 1,315 mTVDss, 25 m above contact. Produced 124 MMscm
- Selva-9's Top C is at 1,296 mTVDss, 44 m above contact. Produced 124 MMscm
- Selva-22's Top C is at 1,295 mTVDss, 45 m above contact. Produced 173 MMscm
- Selva-17's Top C is at 1,281 mTVDss, 59 m above contact. Produced 333 MMscm
- Selva-5's Top C is at 1,246 mTVDss, 94 m above contact. Produced 296 MMscm
- Selva-6's Top C is at 1,235 mTVDss, 105 m from the contact. Produced 879 MMscm

CGG postulates that the PM-1dir well will perform within the range of the posted cumulative produced gas values at historical wells. We consider that height of perforations above water is a key indicator of when water breaks through.

- In the C1 sand, PM-1's GWC is estimated at 1239 mTVDss; PM-1's Top C1 is at 1222 mTVDss, that is, 17 m above contact.
- In the C2 sand, PM-1's GWC is estimated at 1278 mTVDss; PM-1's Top C2 is at 1251 mTVDss which is 27 m above contact.

Therefore, the most closely analogous wells are Selva-11 (124 MMscm cumulative), Selva-9 (124 MMscm) and Selva-22 (173 MMscm). The PM-1dir well could perform as well as Selva-5 (296 MMscm) and Selva-17 (333 MMscm). In the high case, the PM-1dir could possibly produce as much as Selva-6 (879 MMscm cumulative). On the basis that the new well is closer to the water than most Selva wells on the map prior to the well being put on production, and there being some production history, we do not expect PM-1dir to out-perform these prior to suffering water breakthrough.

It is based on these historic production histories that the reserves volumes for the PM-1dir have been bench marked against.

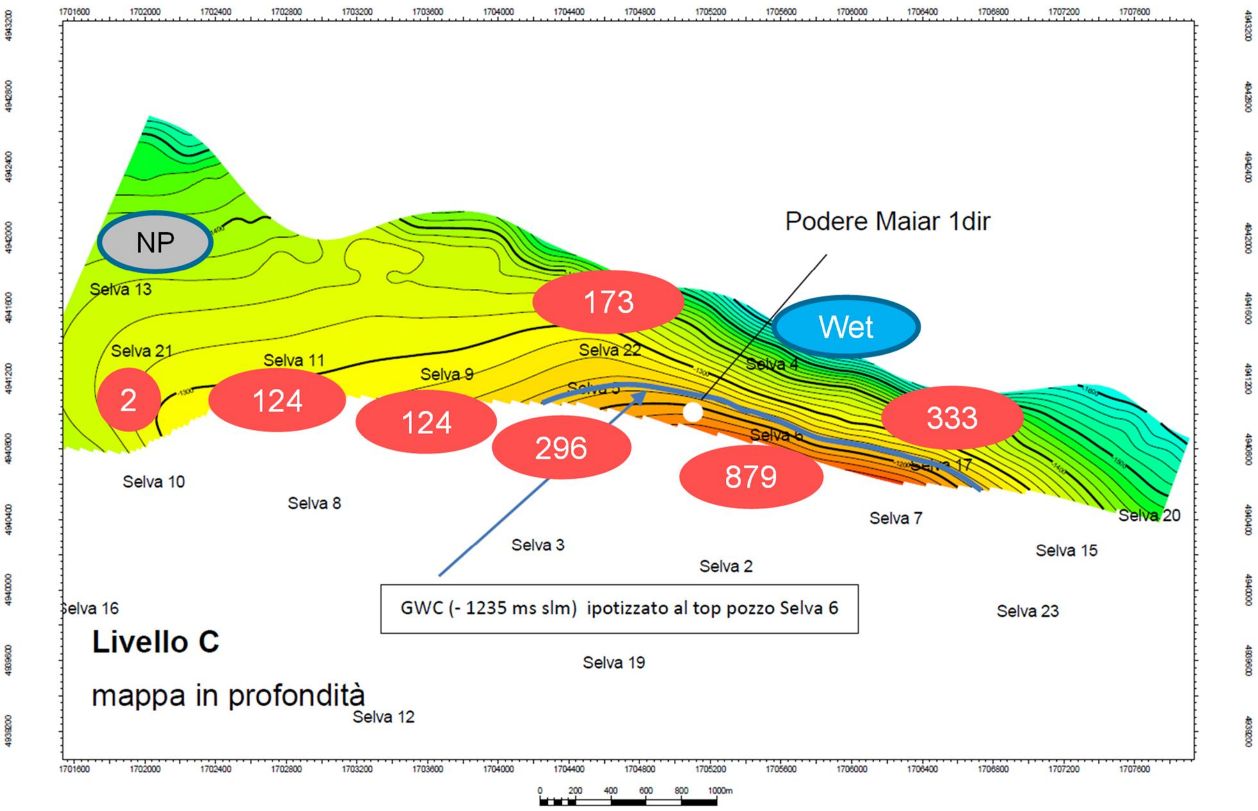


Figure 4.1 Historical Well Locations in Selva Stratigraphic Trap and Well Total Gas Production in MMscm

4.1.2 Podere Maiar-1dir well test results

Podere Maiar-1 was drilled targeting remaining updip gas of the C Level in the Selva Stratigraphic Trap. The new pressure data taken over the C level has established a separate GWC in C1 and C2 sands. In both C1 and C2 sands, the GWC has been identified. The depths of C1 and C2 sands are tabulated in Table 4.2. The bottom perforation is over 13 m above the contact.

Table 4.2 Podere Maiar-1dir – Depths of C1 and C2 Sands

Podere Maiar-1dir (RT 22.71 m)		
C1	Top, m MD RT (m SSL)	1253.5 (1221.9)
	Bottom, m MD RT (m SSL)	1275.5 (1244.4)
	GWC, m MD RT (m SSL)	1270.5 (1239)
	Perforation, m MD RT	1253.5-1256
C2	Top, m MD RT (m SSL)	1282.5 (1251)
	Bottom, m MD RT (m SSL)	1318.5 (1286.5)
	GWC, m MD RT (m SSL)	1309.5 (1277.8)
	Perforation, m MD RT	1282.5-1296

The well has been completed by a conventional completion with sliding side door (see Figure 4.2). Each sand can produce individually or co-mingle.

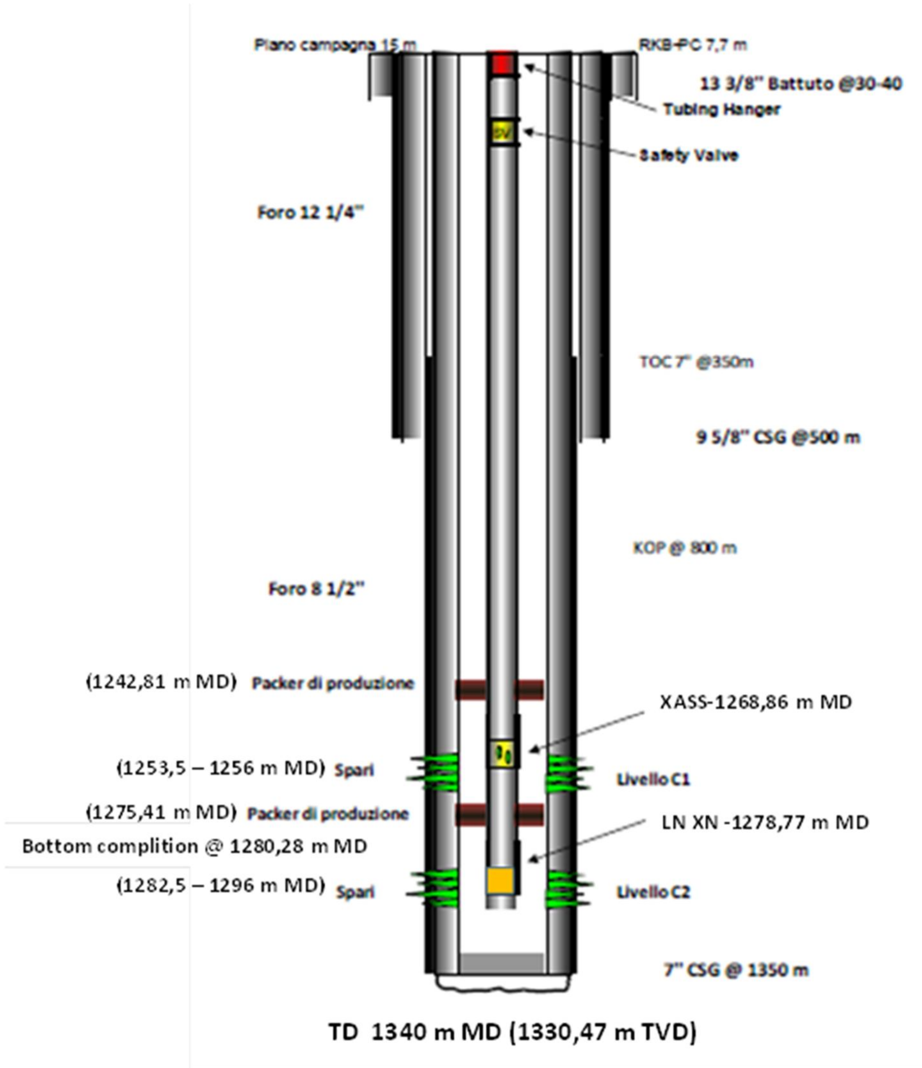


Figure 4.2 Podere Maiar-1dir – Well Schematic

The initial flow test performed in January 2018 by testing each sand individually indicates good initial gas flow rates as shown below. Although both sands have high well deliverability, the perforations of the Podere Maiar 1dir well are sited at over 13 m above the gas-water-contacts encountered in both the C1 and C2 reservoirs. An appropriate production flow rate will be required to prevent water coning and early breakthrough into the well.

Table 4.3 Summary of Flow Test Results of C1 Sand

Choke ("/64)	Avg FWHP (bara)	Avg Gas (scm/day)	Duration (hours)
SBHP 132.9 bara at 1253.5 m MD RT, STHP 120.7 bara			
8	119.3	14,300	6
16	115.0	64,000	6
18	113.2	77,400	6
Build up			30
24	105.0	127,000	3
Build up			1

Table 4.4 Summary of Flow Test Results of C2 Sand

Choke ("/64)	Avg FWHP (bara)	Avg Gas (scm/day)	Duration (hours)
SBHP 135.5 bara at 1275 m MD RT, STHP 122.9 bara			
8	122.7	17,800	6
16	120.7	64,800	6
18	119.5	78,000	6
Build up			50
24	104.6	142,000	4
Build up			6

The build-up tests have been interpreted by Po Valley's consultant (DREAM, Dedicated Reservoir Engineering And Management, based in Torino). Figure 4.3 to Figure 4.8, Table 4.5, and Table 4.6 are extracted from DREAM's interpretation in the submission document to the Italian authorities.

C1 sand's well test interpretation indicates that the well sees two no-flow boundaries. In Figure 4.3 during the late time i.e. after 3 hours, the pressure derivative shows positive slope indicating no-flow behaviour. In this case, DREAM interprets it as two parallel no-flow boundaries. CGG accepts DREAM interpretation of the C1 sand. The two no-flow boundaries can be interpreted as the pinch-out (South) and the structural closure (North). Pressure builds up to the pre-test pressure suggesting that the well has some pressure support and good connectivity. CGG therefore considers that the Podere Maiar-1dir is capable of draining the whole area of the updip gas.

For the C2 sand, DREAM interprets the well test as three boundaries and mentions that one of the boundaries might be the aquifer. In Figure 4.6, during the late time (i.e. after 1 hour), the pressure derivative starts to divert from radial flow (zero slope) to slightly positive slope and the pressure derivative continues to show positive slope indicating no-flow behaviour. The boundaries could be leaking, although we have not observed this during the short test. This could not be an aquifer effect as the derivative of pressure would have shown a negative slope in the late time. We agree with DREAM that the C2 sand has encountered three boundaries. Two of the boundaries are no-flow and can be interpreted as the pinch-out (South) and the structural closure (North). The shortest boundary, at a distance of 80 m, could indicate that there is a boundary that could not be seen in the existing seismic data. However, the well test data does not identify if the boundary at 80 m is to the East or the West of the well. The hypothesis of a third boundary is supported by the fact that the final build-up reservoir pressure that does not reach the pre-test value. This may indicate some depletion of a limited connected gas volume. Although the pressure loss during the test is very small (1/10th bar after 50 hours of shut-in), the pressure did not build-up back to the pre-test value as observed in C1 (in which the pressure returned to the pre-test value after 30 hours of shut-in, as we would expect in high quality reservoir with a longer shut-in time). CGG therefore has taken into consideration that the Podere Maiar-1dir well may only drain a limited area of the updip gas and assigns only 44% (considering the boundary is located to the West of the well) of the total drainage area of the low in-place volumes in the 1P reserves. For the 2P reserves, only 63% (considering the boundary is located to the East of the well) of the total drainage area of the mid in-place volumes is assigned. However, the 80 m no-flow boundary may not fully seal (i.e. leaking) and the whole area could possibly be drained by the Podere Maiar-1dir well. We therefore assign 100% of the high drainage area in our 3P reserves.

For the C2 sand, CGG recognises that the three no-flow boundaries interpretation may not be a unique solution. Alternative interpretations are possible. This has been taken into consideration of our reserves uncertainty i.e. 44%, 63%, and 100% drainage area.

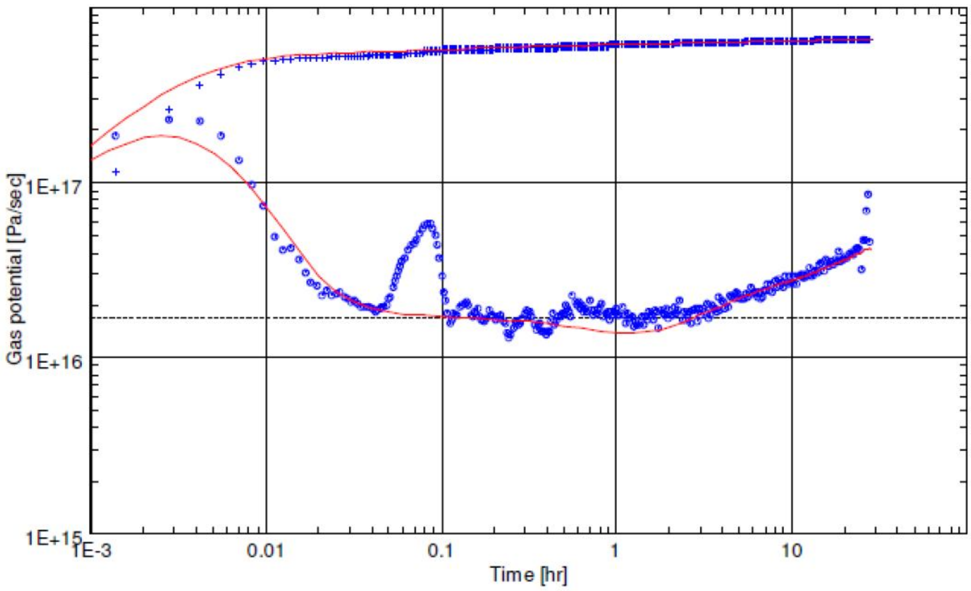


Figure 4.3 Log-log Plot of Pressure and Pressure Derivative of C1 Sand

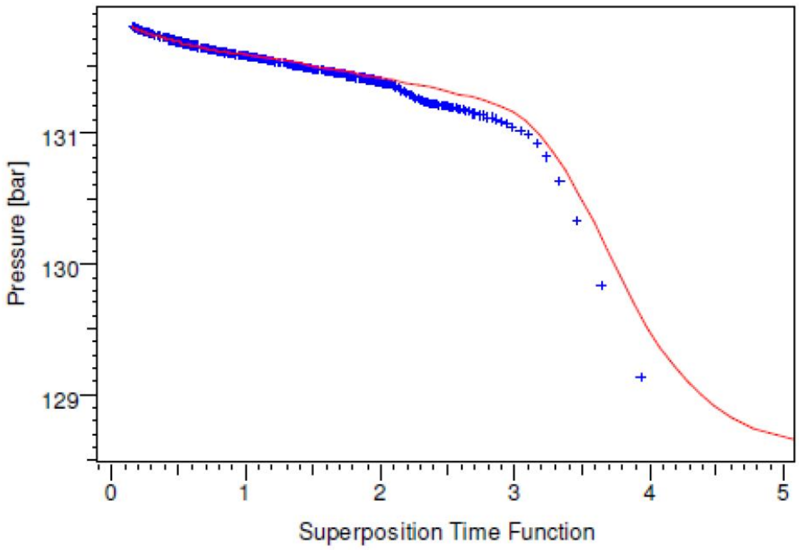


Figure 4.4 Horner Plot of C1 Sand

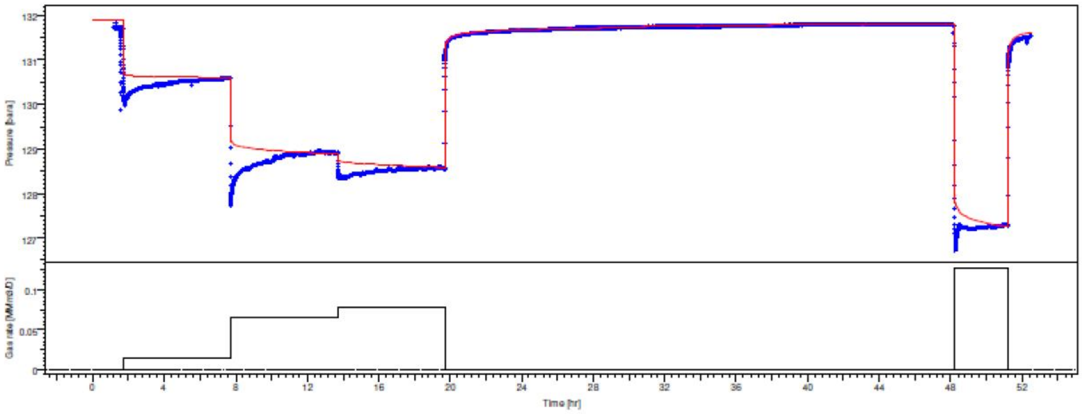


Figure 4.5 Pressure and Gas Rate of C1 Sand

Table 4.5 Well Test Interpretation Result of C1 Sand

p_i	131.9	bar
kh	949	mD m
h	2.5	m
k	380	mD
S_m	decreasing	
d1	120	m
d2	190	m

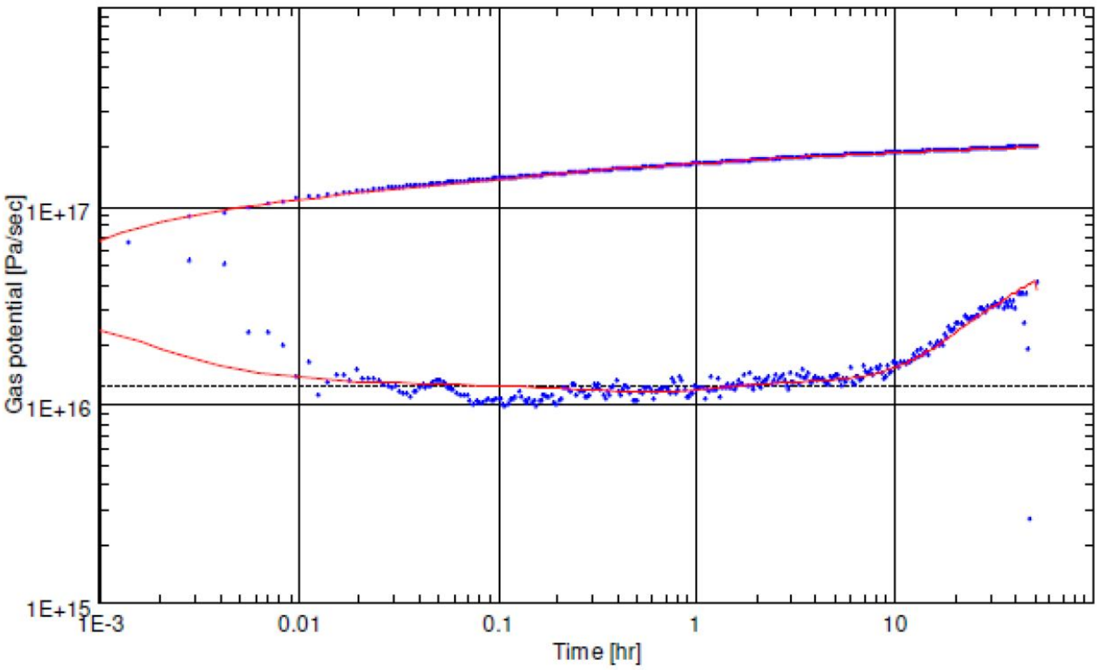


Figure 4.6 Log-log Plot of Pressure and Pressure Derivative of C2 Sand

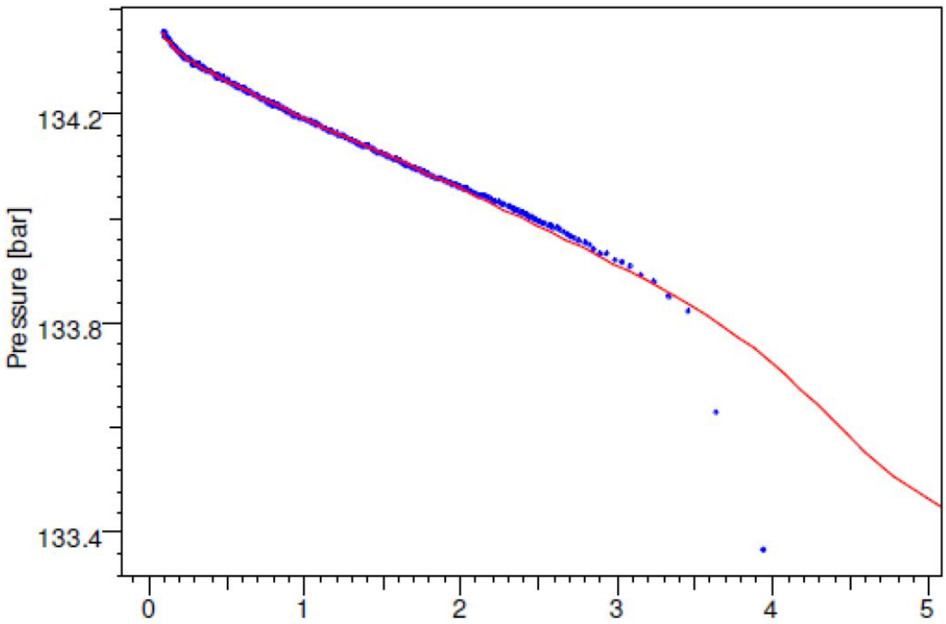


Figure 4.7 Horner Plot of C2 Sand

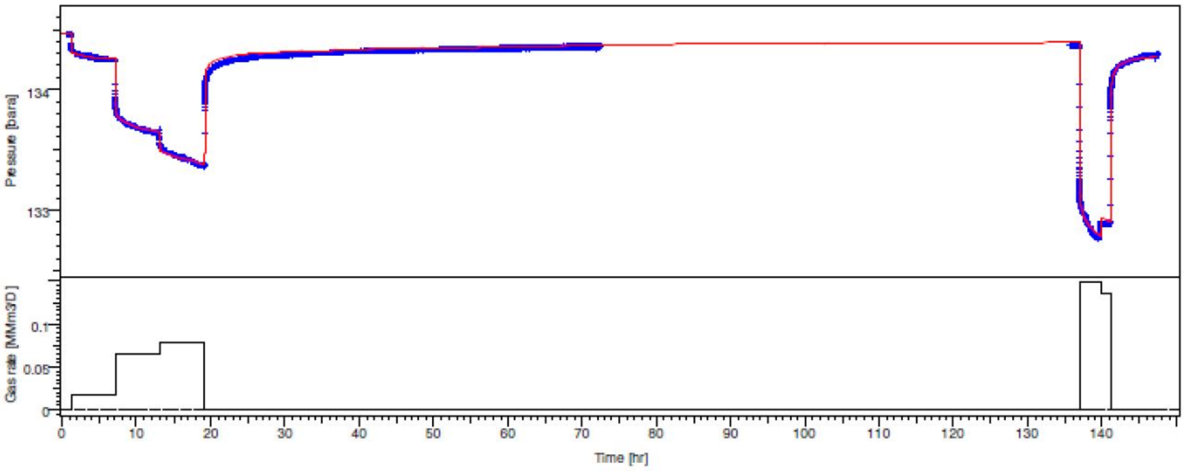


Figure 4.8 Pressure and Gas Rate of C2 Sand

Table 4.6 Well Test Interpretation Result of C2 Sand

p_i	134.5	bar
kh	1440	mD m
h	8.5	m
k	169	mD
d1	80	m
d2	120	m
d3	170	m

4.1.3 Reserves

Selva gas consists of approximately 99.5% methane and has low hydrocarbon liquids content, and as such will require minimal surface processing when the field is redeveloped. The Italian gas grid (SNAM) is also located approximately one kilometer in the South-West direction from the proposed field facilities. The field re-development plan is currently under review by the Italian authorities.

CGG has reviewed both historical well production and the Podere Maiar-1dir well test results. We have estimated 1P, 2P and 3P reserves used parameters tabulated in Table 4.7. The 1P, 2P and 3P reserves are summarized in Table 4.8.

- For 1P reserves, with low in-place volumes, C1 sand can drain 100% of the area and C2 sand can drain only 44% of the area. The recovery factor of 60% is assigned for both sands.

- For 2P reserves, with mid in-place volumes, C1 sand can drain 100% of the area and C2 sand can drain only 63% of the area. The recovery factor of 68% is assigned for both sands.

- For 3P reserves, with high in-place volumes, both C1 and C2 sands can drain 100% of the area. The recovery factor of 70% is assigned for both sands.

This range covers the uncertainties in the volumes, taking into consideration the uncertainty of the location and presence of "boundaries".

Table 4.7 Summary of Parameters Used for Reserves Calculation

Sand	Case	GIIP (MMscm)	% Area Contacted by PM-1	Contacted GIIP (MMscm)	Recovery Factor (%)	Reserves (MMscm)*
C1	1P	81	100	81	60	48
	2P	190	100	190	68	129
	3P	299	100	299	70	209
C2	1P	261	44	115	60	69
	2P	585	63	369	68	250
	3P	910	100	910	70	637
Total	1P	342	N/A	195	N/A	117
	2P	775	N/A	558	N/A	379
	3P	1,208	N/A	1,208	N/A	846

** The numbers may not add due to rounding error.*

As water breakthrough is the major risk to recoverable gas volumes, PVO proposes to produce at a maximum gas rate of around 80,000 scm/day, solely from C2 sand then switch to C1 sand. In the event of earlier than expected water breakthrough, it would have a major impact on the project and as such could require an additional well.

Table 4.8 Summary of Technical Reserves for the Selva Redevelopment Project

Selva Stratigraphic Trap	Gross (MMscm)		
	Proved	Proved & Probable	Proved, Probable & Possible
C1 Sand	48	129	209
C2 Sand	69	250	637
Total	**117**	**379**	**846**

**The reserves classification is subject to the award of a production concession.*

CGG has compared the reserves to the historical production as shown in Figure 4.9. We find the reserves are in the reasonable range of low, mid, and high historical well performance. Our 1P, 2P and 3P reserves are based on producing with the minimum WHP of 70 barg and lower to 30 barg towards the end of well life. Therefore, it is reasonable to see slightly higher 2P reserves comparing to the historic wells that were limited at 80 barg WHP.

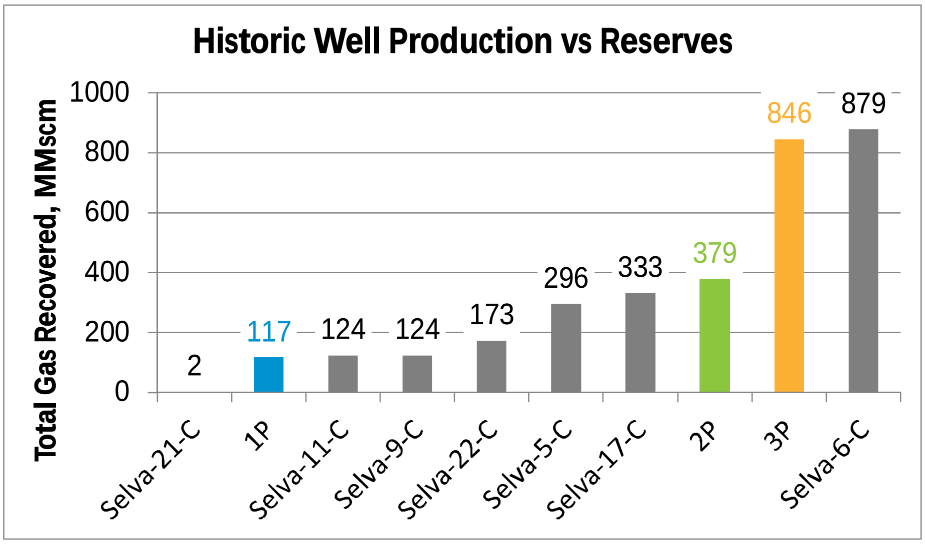


Figure 4.9 Comparison between historical production and reserves

The production profiles for 1P, 2P and 3P reserves are graphically shown in Figure 4.10. Table 4.9 shows the annual production and cumulative production.

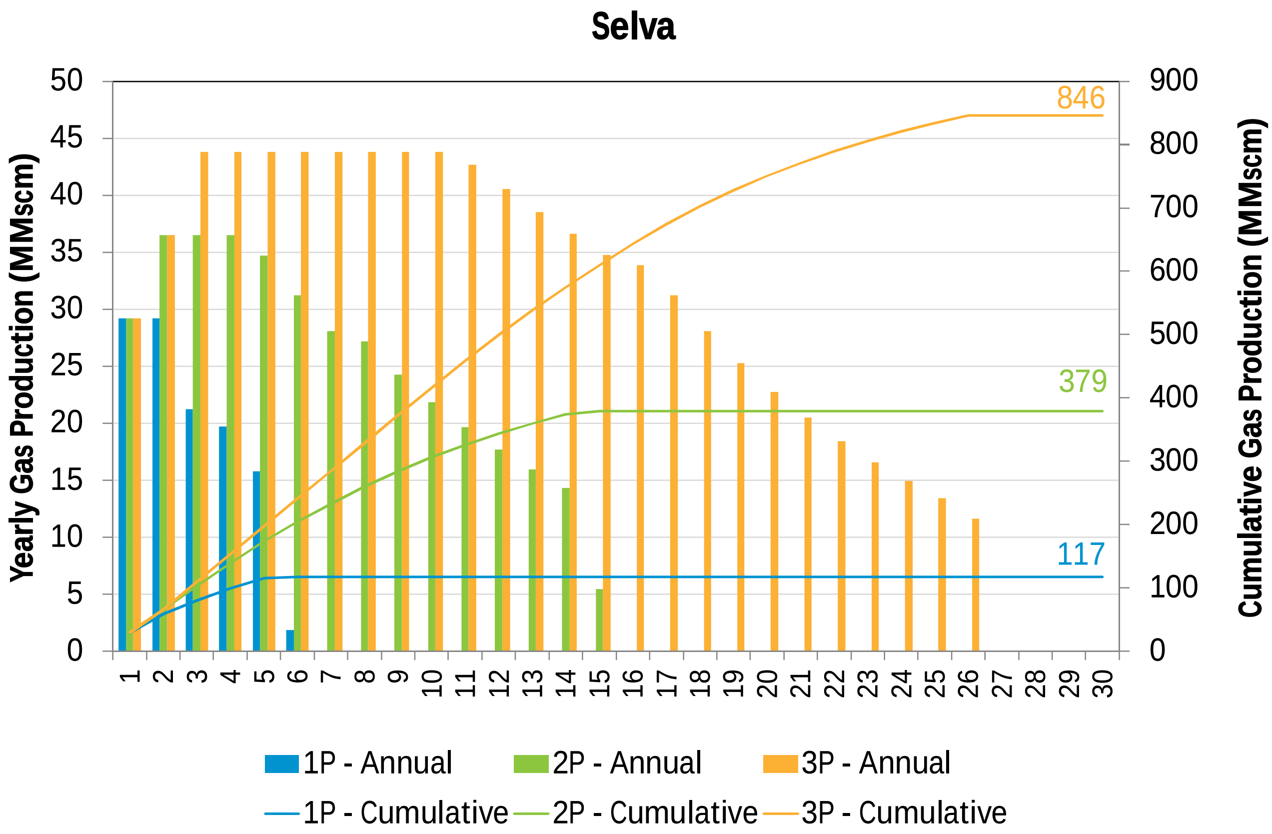


Figure 4.10 Technical Production Profiles of Selva 1P, 2P and 3P (before Economic Cut-off)

Table 4.9 Annual Production and Cumulative Production of Selva (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)
1	29.20	29.20	29.20	29.20	29.20	29.20
2	29.20	58.40	36.50	65.70	36.50	65.70
3	21.25	79.65	36.50	102.20	43.80	109.50
4	19.71	99.36	36.50	138.70	43.80	153.30
5	15.77	115.12	34.68	173.38	43.80	197.10
6	1.88	117.00	31.21	204.58	43.80	240.90
7	0.00	117.00	28.09	232.67	43.80	284.70
8	0.00	117.00	27.19	259.86	43.80	328.50
9	0.00	117.00	24.27	284.13	43.80	372.30
10	0.00	117.00	21.85	305.97	43.80	416.10
11	0.00	117.00	19.66	325.63	42.71	458.81
12	0.00	117.00	17.69	343.33	40.57	499.37
13	0.00	117.00	15.93	359.25	38.54	537.92
14	0.00	117.00	14.33	373.59	36.61	574.53
15	0.00	117.00	5.41	379.00	34.78	609.31
16	0.00	117.00	0.00	379.00	33.89	643.21
17	0.00	117.00	0.00	379.00	31.21	674.41
18	0.00	117.00	0.00	379.00	28.09	702.50
19	0.00	117.00	0.00	379.00	25.28	727.78
20	0.00	117.00	0.00	379.00	22.75	750.53
21	0.00	117.00	0.00	379.00	20.48	771.00
22	0.00	117.00	0.00	379.00	18.43	789.43
23	0.00	117.00	0.00	379.00	16.58	806.02
24	0.00	117.00	0.00	379.00	14.93	820.94
25	0.00	117.00	0.00	379.00	13.43	834.38
26	0.00	117.00	0.00	379.00	11.62	846.00
27	0.00	117.00	0.00	379.00	0.00	846.00
28	0.00	117.00	0.00	379.00	0.00	846.00
29	0.00	117.00	0.00	379.00	0.00	846.00
30	0.00	117.00	0.00	379.00	0.00	846.00

Created by
Andrew Webb, Manager, Petroleum Reservoir and Economics
Tel: +44 (0)1293 683000 – andrew.webb@cgg.com

4.2 Cembalina, Fondo Perino and East Selva

There are currently no firm plans to drill wells on the Cembalina, Fondo Perino or the East Selva prospects located within the licence area.

The 3D seismic that is planned across the Selva Field in late 2018 or 2019 will also cover the East Selva and Fondo Perino prospects. It should help to de-risk these structures, and progress them towards drill-ready status.

Created by
Andrew Webb, Manager, Petroleum Reservoir and Economics
Tel: +44 (0)1293 683000 – andrew.webb@cgg.com

5 ECONOMIC ANALYSIS

5.1 Methodology

Net Present Values (NPVs) have been calculated using industry standard discounted cash flow analysis. CGG have created an after-tax economic model in Excel™ for this purpose. The estimated production profiles and costs have then been input in order to calculate NPVs for each of the reserve categories.

The tax benefit of any brought forward losses and/or undepreciated capex arising from trading activities and expenditure prior to the effective date has not been included in the valuation. Corporate overhead costs not specifically allocated to the operating costs and any payments relating to the farm-in agreements have also not been included.

5.2 Assumptions

5.2.1 Gas prices

It is assumed that future gas production is sold at the Italian spot gas price – the Punto di Scambio Virtuale (PSV) price. CGG have assumed that the PSV price will follow the forward curve for the Dutch TTF spot price plus Euro 1.9/Mwh, which was the average difference between the two prices in 2018. Beyond the end of the current quoted forward curve in 2025, it is further assumed that the price escalates at 2% per year. The PSV price assumption used in the economic evaluation, which is based on the TTF forward curve on 23rd November 2018, is tabulated below.

Table 5.1 PSV gas price assumption

Year	Base price (Euro/m^3)
2019	0.260
2020	0.241
2021	0.228
2022	0.220
2023	0.210
2024	0.203
2025	0.200
2026+	+2% pa

In order to capture gas price uncertainty, low and high price decks have been taken as +/- 15% for 2019 and 2020, and +/-20% for 2021 onwards. The narrower near-term range reflects the greater certainty of near-term pricing.

The calorific value of gas from the field is assumed to be 38MJ/m3. No condensate production has been assumed.

Created by
Andrew Webb, Manager, Petroleum Reservoir and Economics
Tel: +44 (0)1293 683000 – andrew.webb@cgg.com

5.2.2 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 applicable royalty rate for Selva is assumed to be 10%, with an annual royalty free allowance of 25 million cubic metres.

Profits are subject to standard Italian corporate income tax (IRES), for which the current rate is 24.0%. 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 7th 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%, and is calculated in a similar way to IRES.

5.2.3 Other assumptions

The following assumptions have also been used by CGG.

Table 5.2 Economic Parameters

Parameter	Value
Discount Factor	10%
Discount Methodology	Mid-Year
Cost /Price Inflation	2% per annum
Discount Date	1st January 2019

5.3 Facilities and costs

The proposed development plan for Selva consists of surface processing facilities and a 1 km export pipeline to the SNAM grid. The surface facilities will include skid mounted separation and dehydration units, fiscal metering and produced water storage tanks. An allowance has also been made to add compression later in field life. The estimated development costs are as follows:

Created by
Andrew Webb, Manager, Petroleum Reservoir and Economics
Tel: +44 (0)1293 683000 – andrew.webb@cgg.com

Table 5.3 Development Costs (Gross 100%)

Item	€ MM
Surface facilities	1.420
Compressor	0.230
Pipeline to grid	0.180
Project Management	0.137
Environmental	0.350
Insurance	0.023
Total	**2.339**

Operating costs are estimated to be approximately €0.3MM per year with an additional charge of €0.015/M^3 for compression when required.

Abandonment costs at the end of field life are estimated to be €1.363MM
The schedule to first gas from receiving an exploitation concession is assumed to be 9 months, with first gas planned for Q4 2019.

CGG have reviewed these assumptions, which are deemed to be reasonable.

5.4 Results

NPVs are presented for the Proven, Proven plus Probable, and Proven, Probable and Possible reserve cases for a 100% field interest and respective net interests.

It should be noted that the NPVs presented are not deemed to be the market value of the asset, and that the values may be subject to significant variation with time due to changes in the underlying input assumptions as more data becomes available and interpretations change.

NPVs at base, low and high gas prices are tabulated below for the Selva Redevelopment Project.

Table 5.4 Summary of NPV10s for the Selva Redevelopment Project and Net Attributable to PVO

Gas Price	Gross (€ MM)			Net attributable (€ MM)			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Base	10.1	27.4	46.1	6.4	17.3	29.0	PVO
Low	7.6	21.3	36.2	4.8	13.4	22.8	
High	12.7	33.5	56.0	8.0	21.1	35.3	

Table 5.5 Summary of NPV10s for the Selva Redevelopment Project and Net Attributable to UOG

Gas Price	Gross (€ MM)			Net attributable (€ MM)			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Base	10.1	27.4	46.1	2.0	5.5	9.2	PVO
Low	7.6	21.3	36.2	1.5	4.3	7.2	
High	12.7	33.5	56.0	2.5	6.7	11.2	

Table 5.6 Summary of NPV10s for the Selva Redevelopment Project and Net Attributable to Prospex

Gas Price	Gross (€ MM)			Net attributable (€ MM)			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Base	10.1	27.4	46.1	1.7	4.7	7.8	PVO
Low	7.6	21.3	36.2	1.3	3.6	6.2	
High	12.7	33.5	56.0	2.2	5.7	9.5	

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

Table 5.7 NPVs cost sensitivities (100% field)

Gas price	NPV10 € MM		
	Proved	Proved & Probable	Proved, Probable & Possible
Base	10.1	27.4	46.1
Capex +25%	9.5	26.8	45.5
Capex -15%	10.5	27.8	46.5
Opex +25%	9.8	26.8	45.4
Opex -15%	10.4	27.8	46.5

6 APPENDIX A: DEFINITIONS

6.1 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 in the following sections.

Source: SPE Petroleum Resources Management System 2007

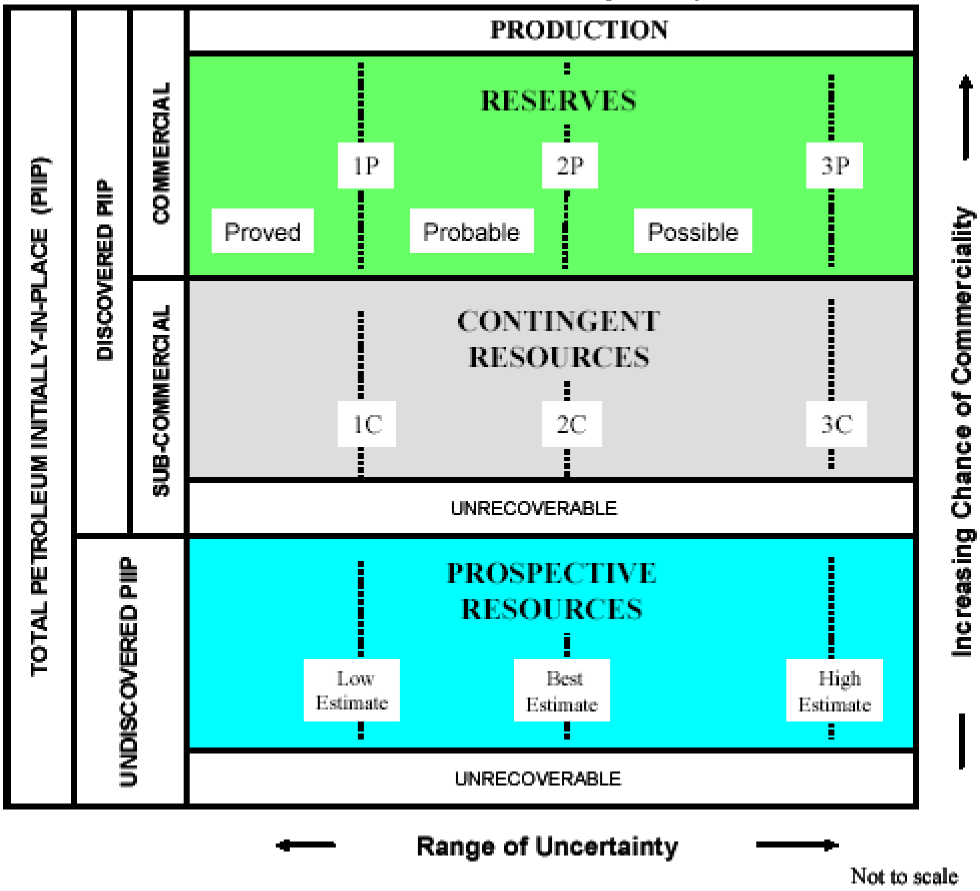
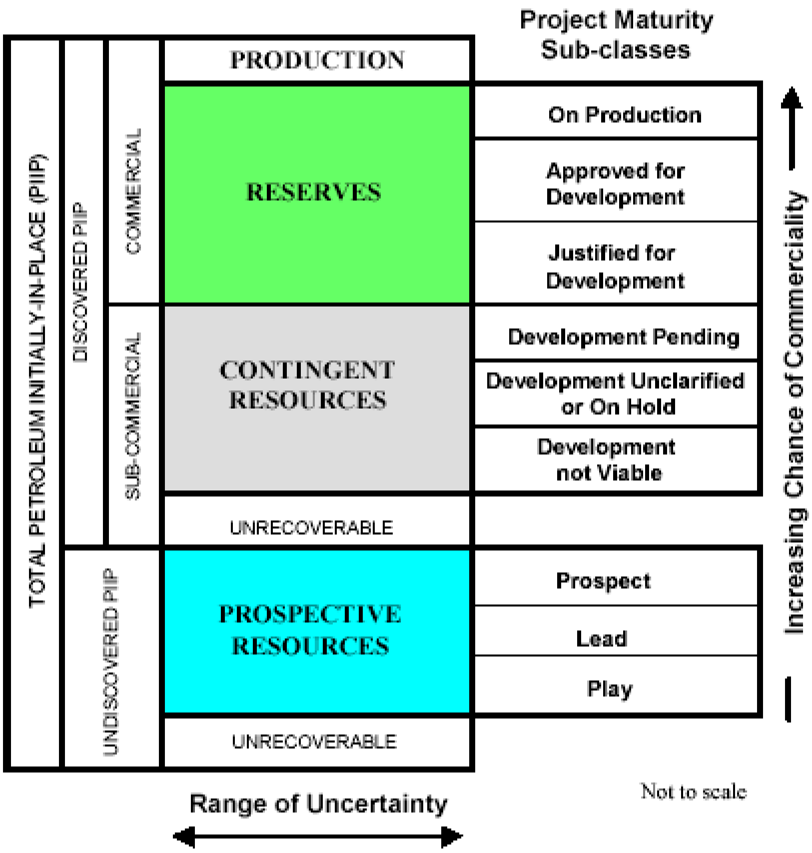


Figure 6.1 Resources Classification Framework



Source: SPE Petroleum Resources Management System 2007

Figure 6.2 Resources Classification Framework: Sub-classes based on Project Maturity

6.1.1 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”).

6.1.2 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.

6.1.3 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.

6.2 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.

6.3 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.

Created by
Andrew Webb, Manager, Petroleum Reservoir and Economics
Tel: +44 (0)1293 683000 – andrew.webb@cgg.com

6.3.1 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.

6.3.2 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.

6.3.3 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.

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Andrew Webb, Manager, Petroleum Reservoir and Economics
Tel: +44 (0)1293 683000 – andrew.webb@cgg.com

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.

6.3.4 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.

6.3.5 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.

6.3.6 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.

6.4 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.

6.4.1 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.

6.4.2 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.

6.4.3 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.

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Andrew Webb, Manager, Petroleum Reservoir and Economics
Tel: +44 (0)1293 683000 – andrew.webb@cgg.com

6.5 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.

6.5.1 Prospect

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

6.5.2 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.

6.5.3 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.

6.6 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.

7 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
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
Mm^3	thousand cubic metres
MMm^3	million cubic metres
ml	millilitres
mls	miles
MMBO	million bbls of oil
MMBOE	million bbls of oil equivalent
MMBOPD	million bbls of oil per day
MMCFGD	million cubic feet of gas 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

PESGB	Petroleum Exploration Society of Great Britain
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
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)

Created by
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Tel: +44 (0)1293 683000 – andrew.webb@cgg.com