CGG Services (UK) Limited

COMPETENT PERSONS REPORT

on the Italian assets of :-

Po Valley Operations Pty Limited

Dated: 25th July 2022

CGG project no: BP526

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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 licence basis, CGG and its employees who worked on preparation of this report, are independent of Po Valley Operations 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.

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.

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 has in the Properties, as communicated by PVO. CGG has not verified nor do CGG make any warranty as to PVO'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 PVO.

CGG affirm that from 27th June (the cut-off date for inclusion of data) to the date of issue of this report, 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 and is presented in accordance with the requirements of the AIM Rules for Companies and the "Guidance Note For Mining and Oil & Gas Companies" issued by AIM in June 2009 ("AIM

Guidance Note"). This report conforms with the guidelines and definitions of the Petroleum Resources Management Systems (PRMS) (2007 and 2011) 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

If substantive new data or facts become available or known after the date of issue of this report, then this report should be updated to incorporate all relevant new information.

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 PVO 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 PVO'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.

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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.

CGG Services (UK) Limited Reference No: BP526				
Rev	**Date**	**Originator**	**Checked & Approved**	**Issue Purpose**
final	25/07/22	AS, PW	AJW	Final Report

Date	Originator	Checked & Approved
Signed:		

Prepared for:	Prepared By:
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2.3 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. Reserve and resource ranges have been determined using deterministic methods. For prospective resources the associated chance of geological success (GCoS) has also been independently estimated.

PVO staff demonstrated and reviewed the seismic workstation interpretations during CGG visits to PVO in 2013 and 2015. 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. CGG followed the assessment and drilling of the Podere-Maiar-1 well in late 2017. Prospects worked up after 2015 (Riccardina, Selva South B and North A+B levels and Torre del Moro) have been fully reviewed by CGG. Independently derived prospective resource assessments are provided in this document.

CGG has independently constructed development profiles, and validated estimates of capital and operating costs provided by PVO. For those assets that have been categorised as reserves, the NPV (Net Present Value) of the cash flows derived from exploiting those reserves has been calculated using industry standard discounted cash flow techniques based on forecasts of costs and production rates.

In estimating cash flows, CGG has extrapolated economic parameters based upon recent and current market trends. Estimates of these parameters (notably the future price of gas and oil) are uncertain, and cash flows at low and high price scenarios have therefore also been determined. It should be noted that there is no guarantee that the outturn economic parameters will be within the ranges considered.

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 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.

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 30 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 26 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.

2.5 ITALIAN OIL AND GAS INDUSTRY

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 domestic 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.

On 11th February 2019 the Italian government issued a decree relating to the exploration and production of hydrocarbons in Italy, both onshore and offshore. The decree introduced an 18 month (extendable up to 24-month) suspension of the processing of permits for exploration licences and new exploitation concessions and a substantial increase in rental fees. The objective of the suspension was to determine those areas of the country that are suitable, from an environmental and socio-economic perspective, for hydrocarbon activities going forwards. This was followed by the introduction of the PiTESAI legislation (Piano per la Transizione Energetica Sostenibile delle Aree Idonee; "*Sustainable Energy Transition Plan for Suitable Areas*").

In areas deemed unsuitable, exploration licences will be withdrawn, and new production licences will not be granted or renewed. The development of new oil fields has been suspended. In addition, the pre-existing 12 nautical mile limit for offshore exploitation has been moved out to 24 nautical miles, because two new marine protected areas have been instituted near by original 12 nautical miles line. It is understood that compensation will be payable to companies in relation to past costs incurred on any exploration licences that are withdrawn. However, in cases of exploitation or production Concessions already presented (prior to 13/02/2019) and having exploration wells drilled which demonstrate proven reserves of over 150 Mscm gas, these Concessions may continue to be evaluated and proceed to development as long as they fulfil all the environmental and economic requirements. CGG therefore understands that the suspension does not affect Selva Malvezzi and Teodorico Concessions.

2.6 REGIONAL GEOLOGICAL 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 GEOPHYSICS AND GEOLOGY

3.1 PODERE GALLINA LICENCE

3.1.1 Selva

The Selva Stratigraphic redevelopment represents a part of the former ENI-operated Selva gas field. The extension of the Selva Field was interpreted by Po Valley Operations Ltd. mainly using depth maps derived from seismic interpretation and 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.

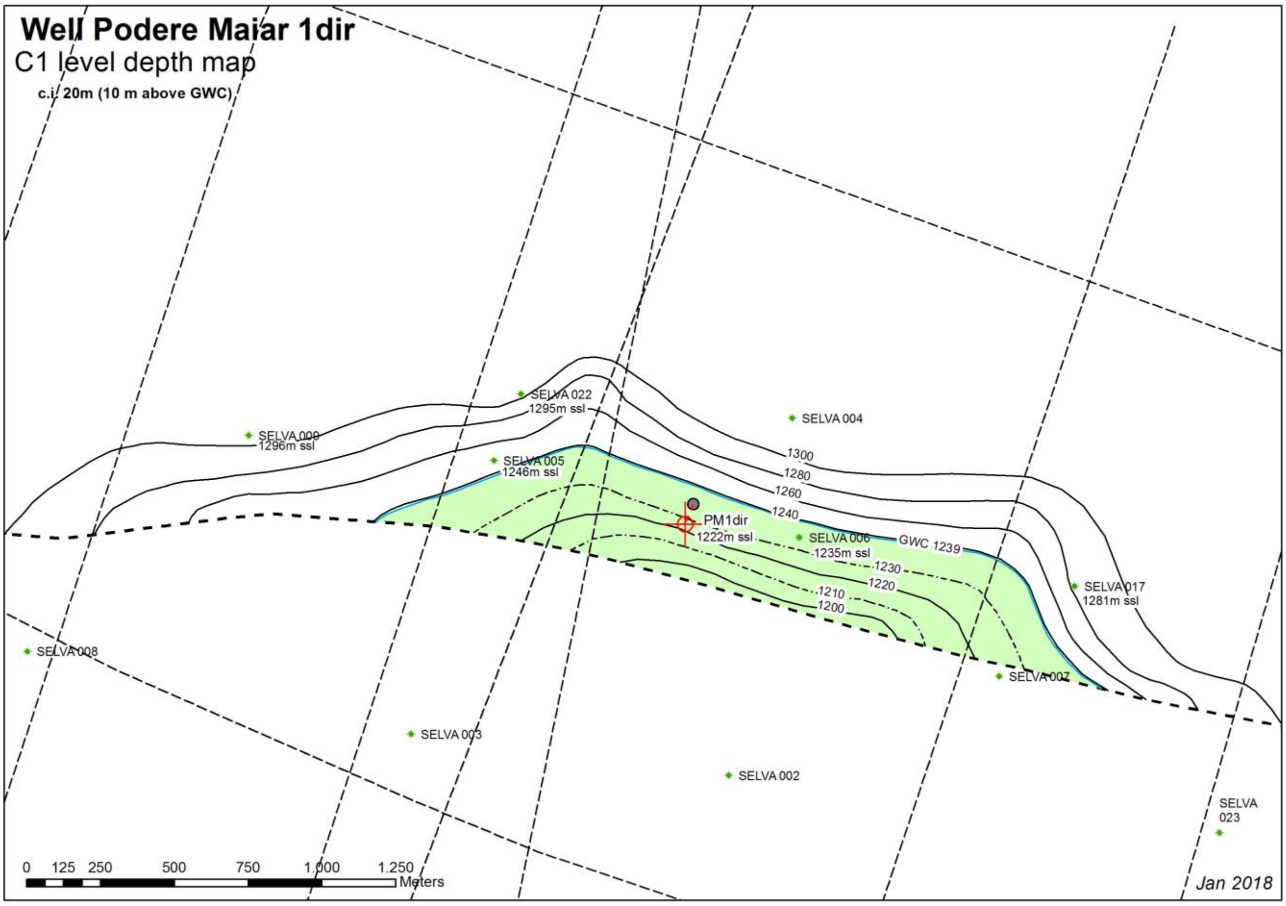


Figure 3.1 Selva stratigraphic structure map (Podere Maiar Gas FIeld)

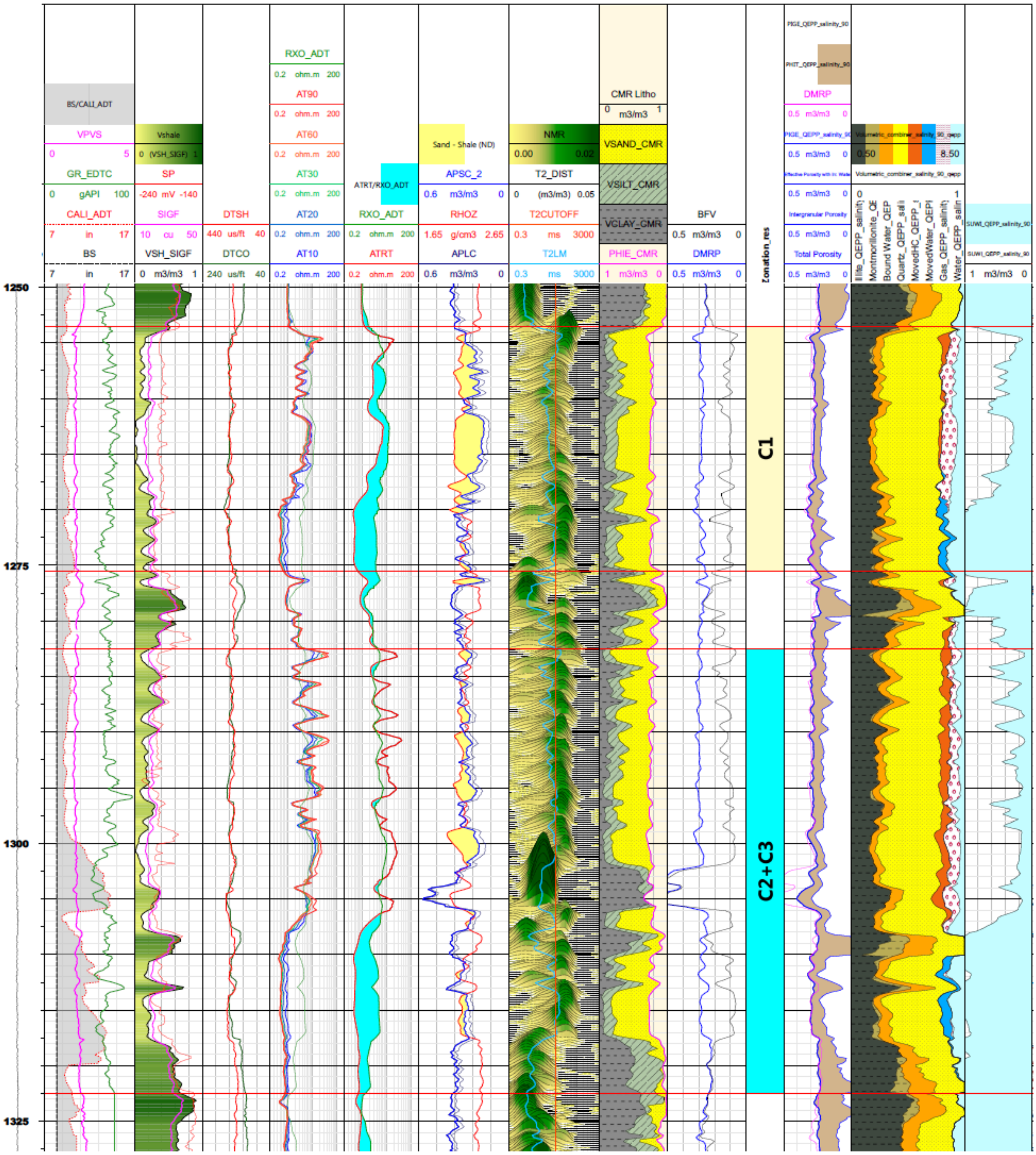


Figure 3.2 Podere Maiar-1: C1 and C2 Sand Reservoirs, Extract from ELAN Interpretation Plot

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 3.2.6.

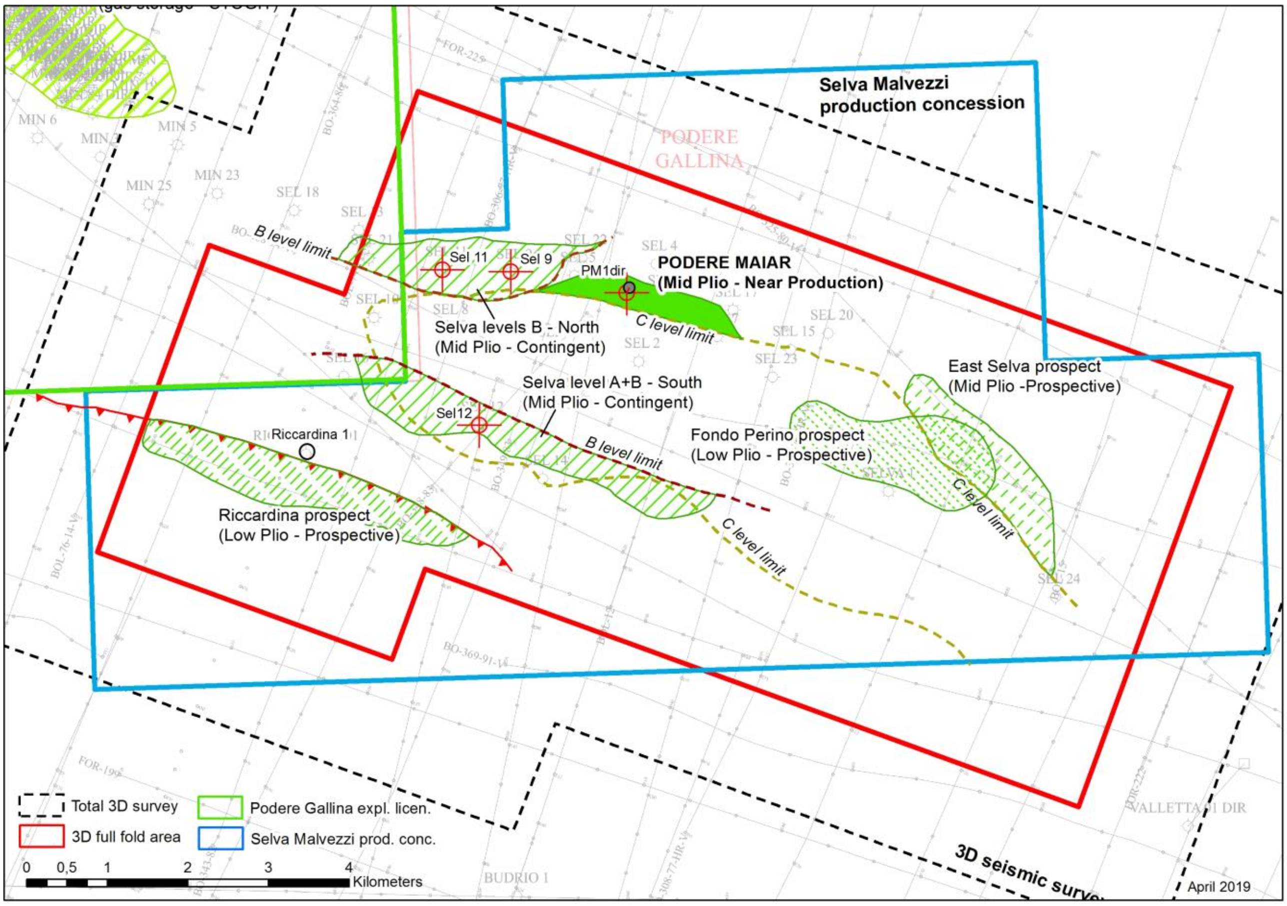


Figure 3.3 Selva Malvezzi Production Concession, Podere Maiar Gas Field and Associated Prospects

3.1.2 Selva North and South Prospects

Following the successful Podere Maiar-1 well drilled in late 2017, PVO have firmed up a further two prospects on the North and South crest of the old Selva gas field (Figure 3.4). Both prospects rely on the same stratigraphic pinch-out concept successfully proved viable by the Podere Maiar-1 well.

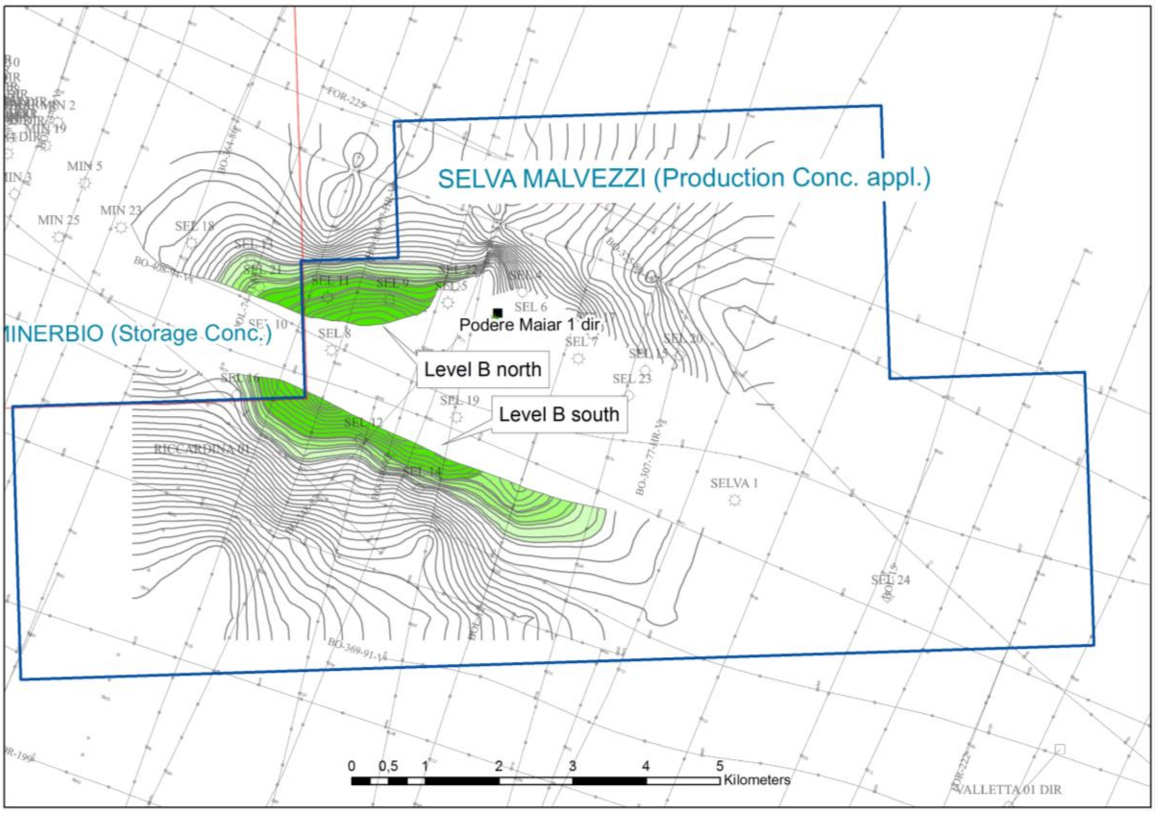


Figure 3.4 Level B North and South Prospects, Selva Malvezzi Production Concession

Although these are named as Prospects by PVO, they fall into the Contingent Resource category because they have already produced gas to surface in commercial quantities leaving a remaining updip gas volume.

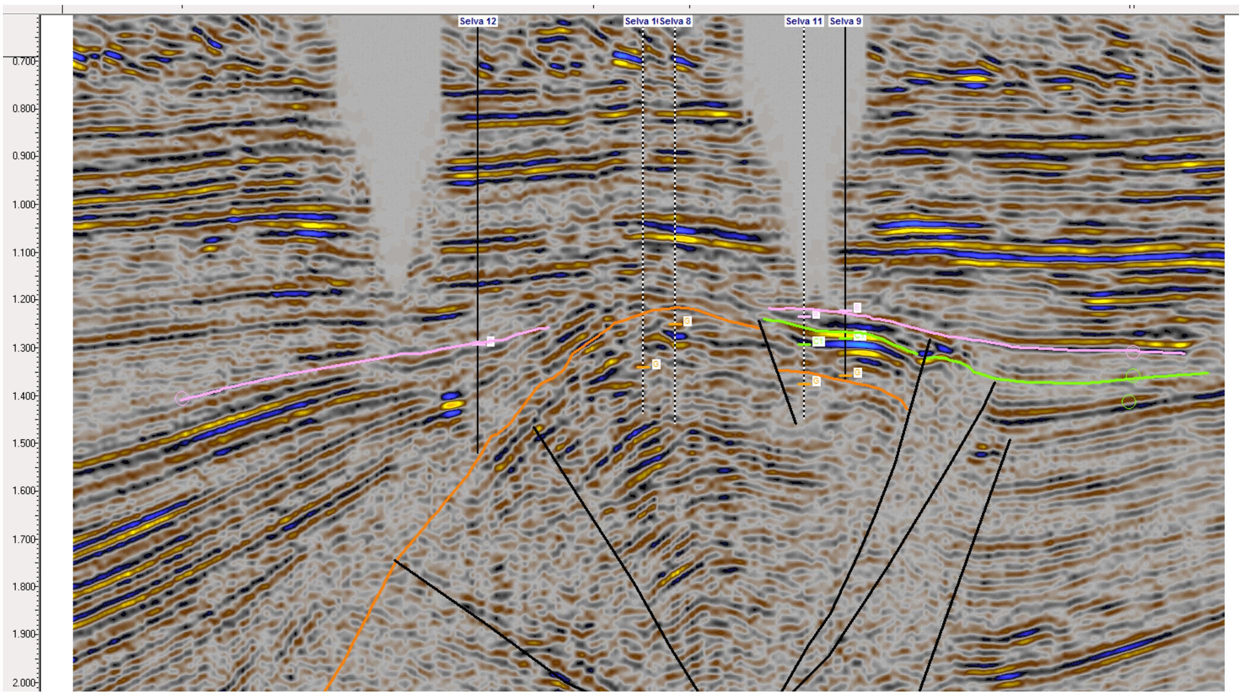


Figure 3.5 Seismic line BO327-80 showing Selva Level B North and South Prospects

After proof of concept was established by means of the successful Podere Maiar-1 well, similar updip pinch-out prospects have been worked up by PVO. The Level A and Level B sands, productive in the main Selva gas field, pinch out onto the underlying thrust fold structure in the same way that Level C sands do (drilled and proven to be good quality sands and gas-bearing by PM-1 well). Comparable reservoir properties are anticipated, and the sand thickness is known from some of the old Selva producing wells, particularly Selva-9 for North Prospect and Selva-12 for South Prospect. For the North Prospect, only Level B sand is expected, whereas for the South Prospect Level B plus slightly shallower Level A sands are taken into account.

PVO have used eleven reprocessed 2D seismic lines and information from old Selva gas wells to work up these prospects. CGG has reviewed the information supplied by PVO and have validated their presence. Level B sands were formerly exploited by ENI in Selva gas field in the period from 1959 to 1971 and 1977 to 1982. During this time, Level B in the north flank produced 248 MMScm of gas and 0.94 MMScm from the south flank leaving undrained gas updip from these producers.

The definition of the potential volumes remaining in the updip pinchout is dependent upon the location of the pinch-out (zero sand thickness) line, which is difficult to determine using the available 2D seismic lines. Nevertheless, CGG believes that there is good potential for success in pursuing the concept in this area.

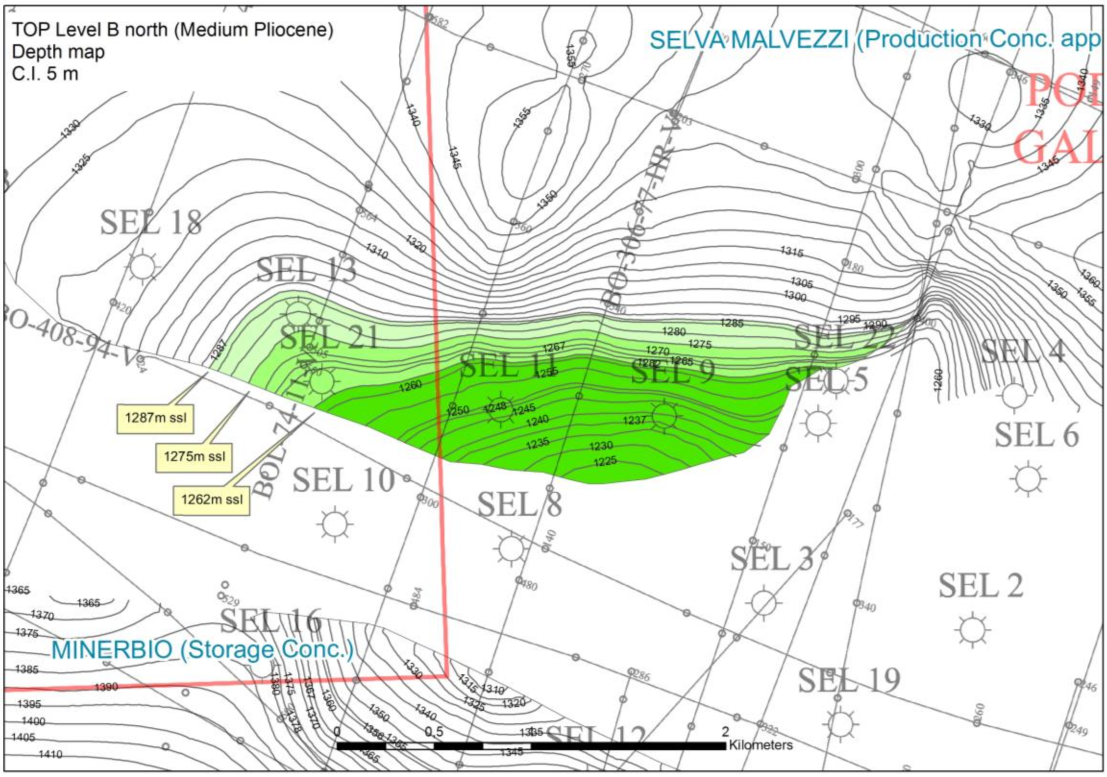


Figure 3.6 Level B North Prospect, Depth Structure Map showing Low, Mid and High Case contacts

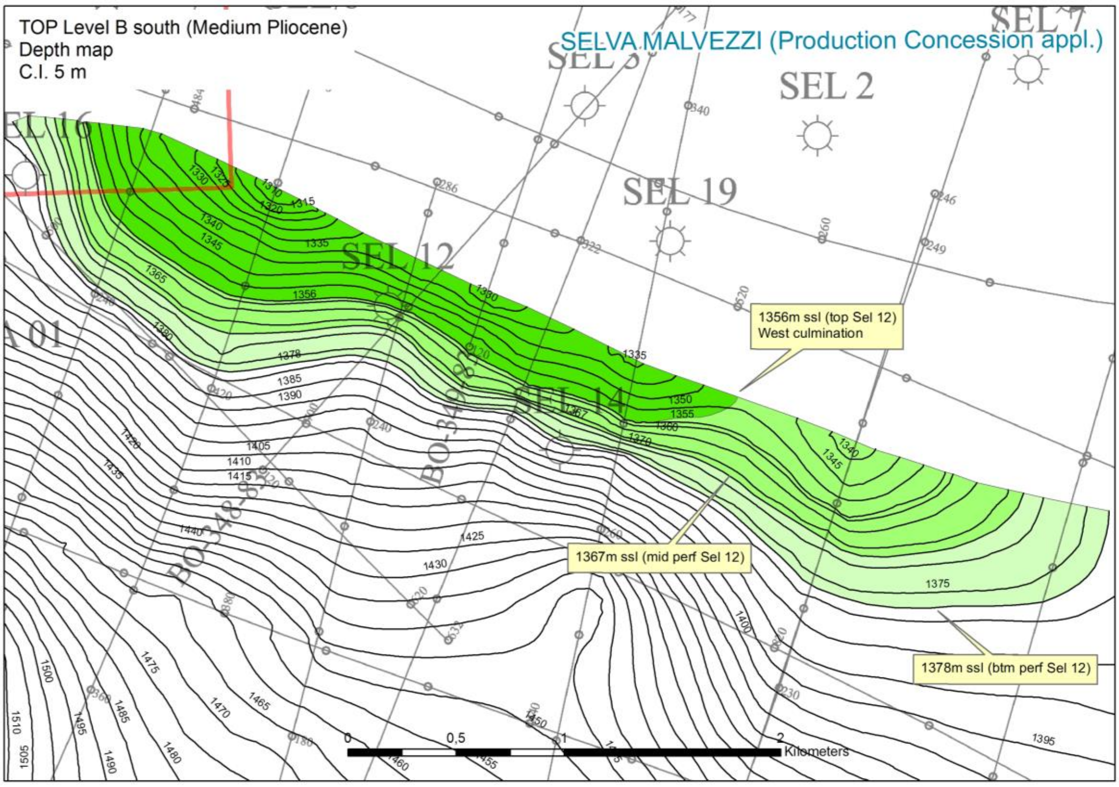


Figure 3.7 Level B South Prospect, Depth Structure Map showing Low, Mid and High Case contacts

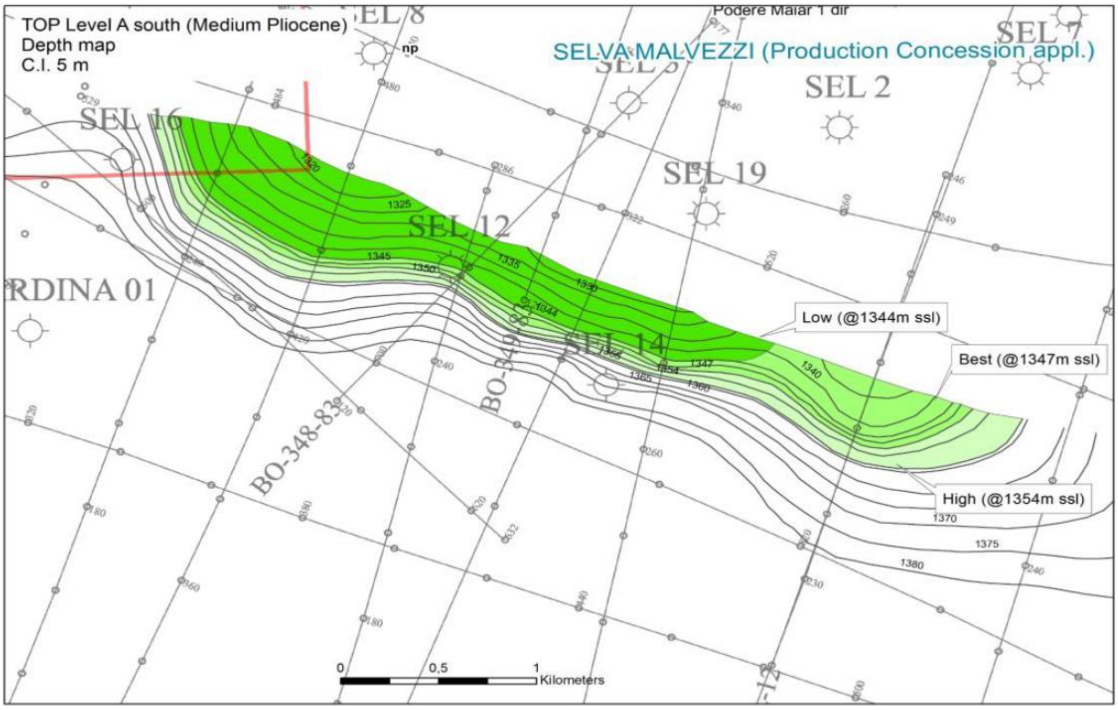


Figure 3.8 Level A South Prospect, Depth Structure Map showing Low, Mid and High Case contacts

Information from nearby wells is limited to old log plots and very limited log coverage (SP and resistivity). In spite of this, a thick sand package appears to be present on the Northern side of the structure. The assessment presented by PVO appears to present a reasonable reflection of the available data. CGG consider that the values presented in Table 3.2 below provide a balanced view of uncertainty range and likely resource potential:

Table 3.2 Level B North Contingent Resource; Parameters used in the estimation of gas volumes

LOW CASE	GBV MMscm	NtG frac	Phi frac	Sw frac	Bg	GIIP MMscm	RF %	Resource MMscm
GWC -1262	18.0	0.55	0.2	0.40	0.008333	143	70	99.8
BEST CASE	**GBV MMscm**	**NtG frac**	**Phi frac**	**Sw frac**	**Bg**	**GIIP MMscm**	**RF %**	**Resource MMscm**
GWC -1275	35.0	0.6	0.22	0.35	0.008333	360	70	252.3
HIGH CASE	**GBV MMscm**	**NtG frac**	**Phi frac**	**Sw frac**	**Bg**	**GIIP MMscm**	**RF %**	**Resource MMscm**
GWC -1287	55.0	0.65	0.24	0.30	0.008333	721	70	504.5

Concerning Level B South Prospect, available well data suggests a much thinner sand package, having an estimated thickness range of 4 – 6.5 – 9 metres. CGG has used these and the area-thickness method to estimate volume and applies the reservoir parameters in Table 3.3 below. The Level A sand package is also evaluated from sand thickness information in the Selva-12 well where it appears to be a little over 3 metres thick and of good quality. An average thickness range of 2.5 – 3.25 – 4 metres for the whole area is assumed, with the reservoir parameters shown in Table 3.4.

Table 3.3 Level B South Contingent Resource; Parameters used in the estimation of gas volumes

LOW CASE 1C	GBV MMscm	NtG frac	Phi frac	Sw frac	Bg	GIIP MMscm	RF %	Resource MMscm
GWC -1356	5.6	0.55	0.2	0.40	0.008065	46	60	27.5
BEST CASE 2C	GBV MMscm	NtG frac	Phi frac	Sw frac	Bg	GIIP MMscm	RF %	Resource MMscm
GWC -1367	14.0	0.6	0.22	0.35	0.008065	149	65	96.6
HIGH CASE 3C	GBV MMscm	NtG frac	Phi frac	Sw frac	Bg	GIIP MMscm	RF %	Resource MMscm
GWC -1378	27.9	0.65	0.24	0.30	0.008065	378	70	264.5

Table 3.4 Level A South Contingent Resource; Parameters used in the estimation of gas volumes

LOW CASE	GBV MMscm	NtG frac	Phi frac	Sw frac	Bg	GIIP MMscm	RF %	Resource MMscm
GWC -1344	2.75	1	0.22	0.35	0.008065	49	60	29.3
BEST CASE	GBV MMscm	NtG frac	Phi frac	Sw frac	Bg	GIIP MMscm	RF %	Resource MMscm
GWC -1347	4.06	1	0.23	0.32	0.008065	79	65	51.2
HIGH CASE	GBV MMscm	NtG frac	Phi frac	Sw frac	Bg	GIIP MMscm	RF %	Resource MMscm
GWC -1354	7	1	0.24	0.30	0.008065	146	70	102.1

A risk factor has been estimated for these two opportunities (the risk factor is the estimated chance that the volumes will be commercially extracted). Level B North Prospect is the better prospect having a project risk factor of 70% whereas the less well defined South Prospect is assigned a project risk factor of 60%. The main uncertainties exerting an effect on project risks are the current situation in terms of gas water contact elevation and sand architecture, both of which can be established by the drilling and flow testing of a well.

3.1.3 Riccardina Prospect

The prospect lies within the Selva Malvezzi Production Concession approximately 5km distant from the Podere Maiar-1 well. Already identified by ENI, the Riccardina-1 well tested the prospect in 2004 but encountered water-bearing sands and was abandoned. PVO have re-interpreted the available seismic data (ten 2D lines) and have come to the opinion that this well just missed the prospect, coming in on the wrong side of a thrust fault and lying outside of the high amplitude area that is interpreted to signify gas presence. Target reservoirs are sands of the lower Pliocene Canopo Formation, which is a silty-sandy succession offering some 250m of section in the target area. PVO are planning to acquire a small 3D survey over the area.

The structure is reasonably well defined by means of the available 2D seismic lines (Figure 3.9, Figure 3.10).

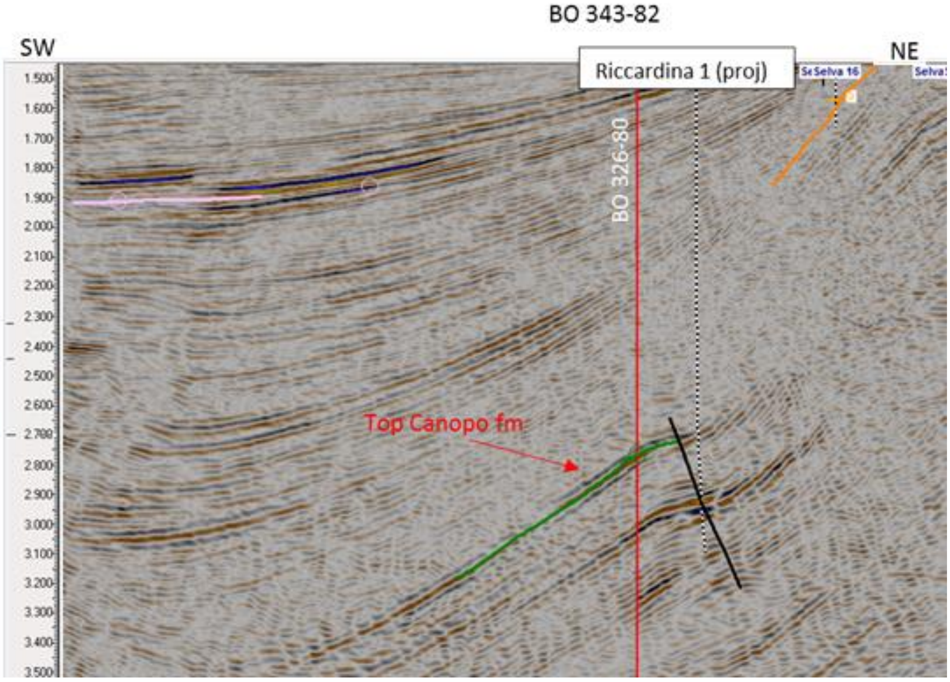


Figure 3.9 Riccardina Prospect: Seismic Line BO343-82 shows gas prospect in Canopo Formation

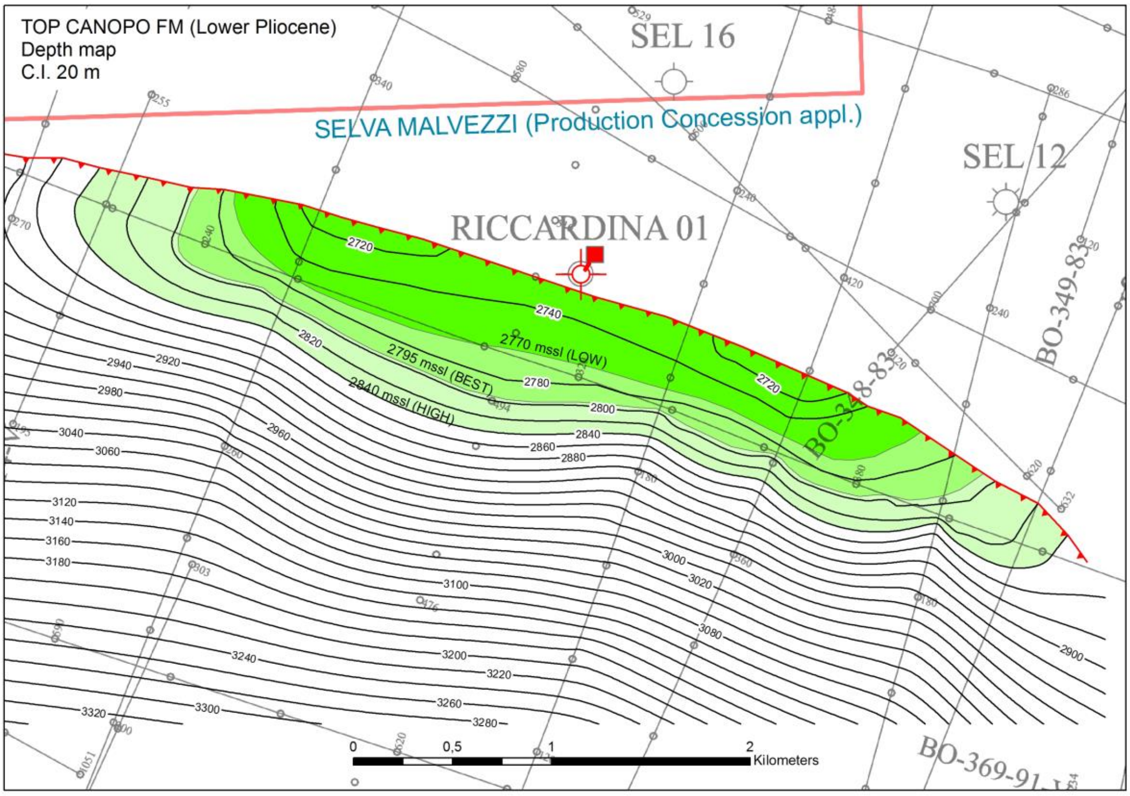


Figure 3.10 Riccardina Prospect; PVO depth structure map at top Canopo Formation (metres subsea)

CGG has inspected the Riccardina-1 well logs. The Upper Canopo Formation consists of alternating sands-silts with fairly thick and permeable sands ranging from 1 – 10 metres. There is separation between shallow and deep resistivity logs indicating invasion and SP suggests permeable formation. Resistivity readings confirm the presence of saline formation water in this well. The reservoir geology appears positive but there is chance of encountering sand of less than 20% porosity at this depth. CGG has made an independent assessment of reservoir parameters based on evidence provided by PVO (Table 3.5).

PVO have made the following assumptions regarding gas fill for this prospect:

- Low: contact at 2770 m ssl
- Best: contact at 2795 m ssl
- High: contact at spill point of the structure (@2840 m ssl)

Table 3.5 Selva Riccardina Prospect; Parameters used in the estimation of gas-initially-in-place (GIIP)

LOW CASE	GBV MMscm	NtG frac	Phi frac	Sw frac	Bg	GIIP MMscm	RF %	Resource MMscm
GWC -2770	34	0.45	0.18	0.40	0.0027	612	60	367.2
BEST CASE	**GBV MMscm**	**NtG frac**	**Phi frac**	**Sw frac**	**Bg**	**GIIP MMscm**	**RF %**	**Resource MMscm**
GWC -2795	76	0.5	0.2	0.35	0.0027	1830	60	1097.8
HIGH CASE	**GBV MMscm**	**NtG frac**	**Phi frac**	**Sw frac**	**Bg**	**GIIP MMscm**	**RF %**	**Resource MMscm**
Spill Point -2840	194	0.55	0.22	0.30	0.0027	6086	60	3651.5

Table 3.6 Selva Riccardina Prospect; Risk Assessment

RISK ELEMENTS		RISK SCORE (probability)	
CLOSURE	**Interpretation**	0.9	0.85
	Depth Conversion	0.85	
SEAL	**Top Seal**	0.85	0.425
	Base / Side Seal	0.5	
RESERVOIR	**Presence**	0.8	0.8
	Quality	0.8	
CHARGE	**Source Rock**	0.85	0.7225
	Migration	0.85	
	RISK TOTAL		**0.21**

Risk score for closure and reservoir is the lowest of two assigned values but for seal and charge it is the product of the two assigned values.

The primary risk is considered to be the seal capacity of the fault that defines the northern margin of the trap. Overall chance of success for the Riccardina Prospect is estimated to be 21%.

3.1.4 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.

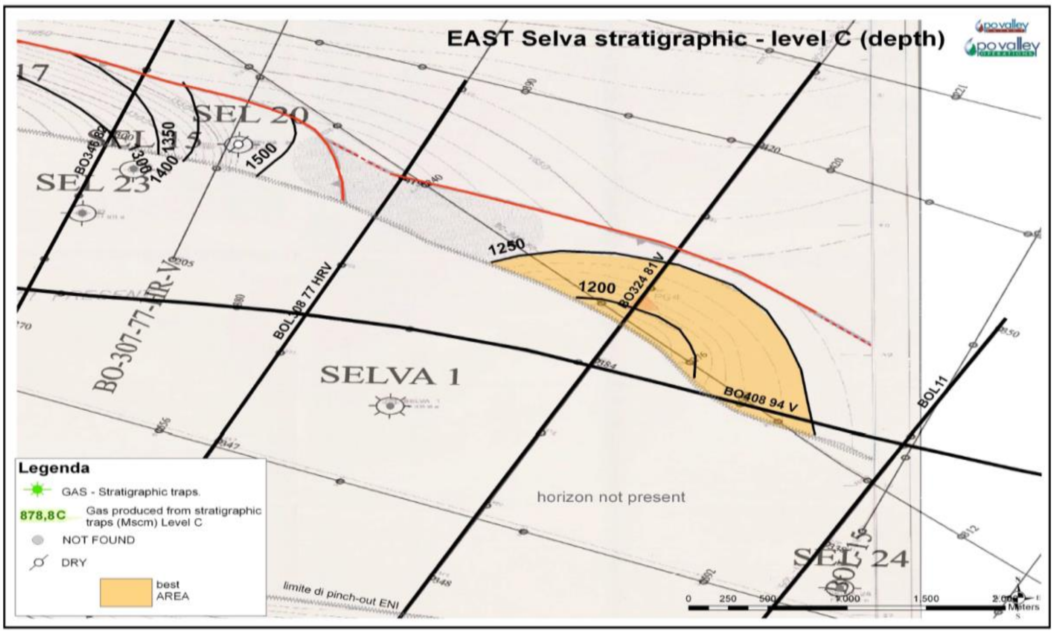
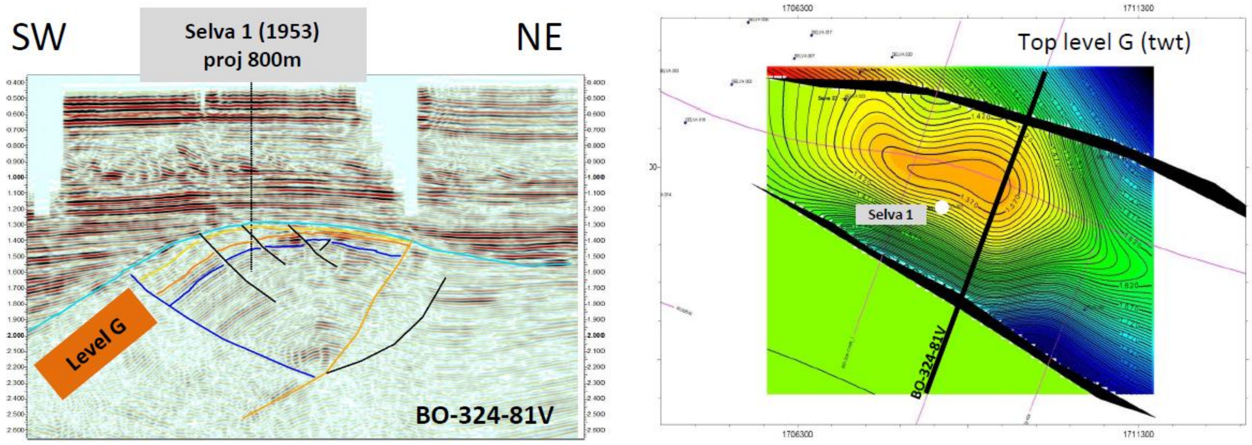


Figure 3.11 East Selva structure map

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. Since the drilling and successful outcome of the Podere Maiar-1 well, which proves the concept that Selva East is based upon, the CoS has been revised upward from 30% to 40%. The primary risk remains the definition of the gross rock volume based on only a small number of seismic lines, plus the presence of good quality reservoir sand (location of pinch-out).

3.1.5 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 3.12 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.

Table 3.7 Summary of Gas Prospective Resource by Prospect (MMscm)

	Gross (MMscm)		
Prospect	**Low**	**Best**	**High**
Fondo Perino	288.9	413.5	580.6
East Selva	824.1	985.6	1149.8
Riccardina	367.2	1097.8	3651.5

There are currently no firm plans to drill wells on the Fondo Perino, Riccardina and East Selva prospects located within the licence area. The 3D seismic that is planned across the Selva Field will also cover the East Selva, Riccardina and Fondo Perino prospects. It should help to de-risk these structures and progress them towards drill-ready status.

4 RESERVOIR ENGINEERING

4.1 SELVA

4.1.1 Historical production

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 (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, CGG 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. CGG 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, CGG 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.

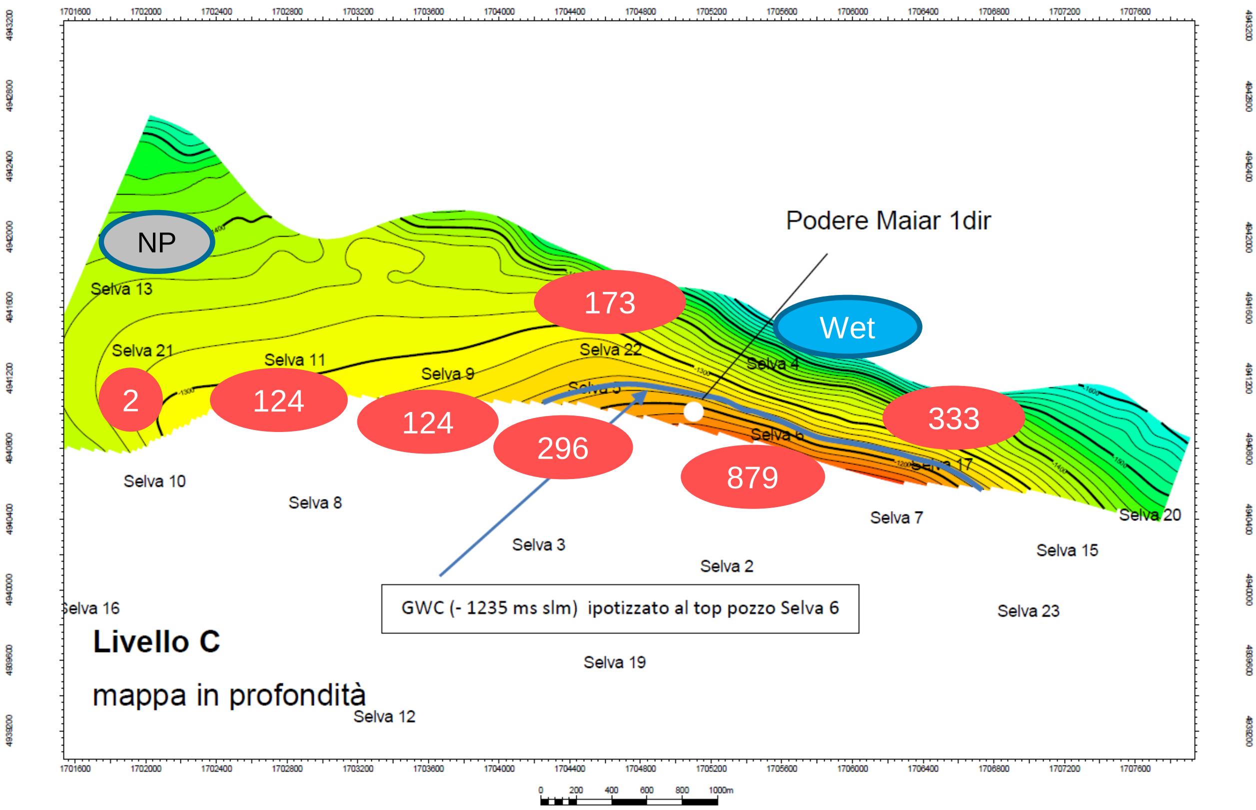


Figure 4.1 Historical Well Locations in Selva Stratigraphic Trap and Well Total Gas Production (MMscm)

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-mingled.

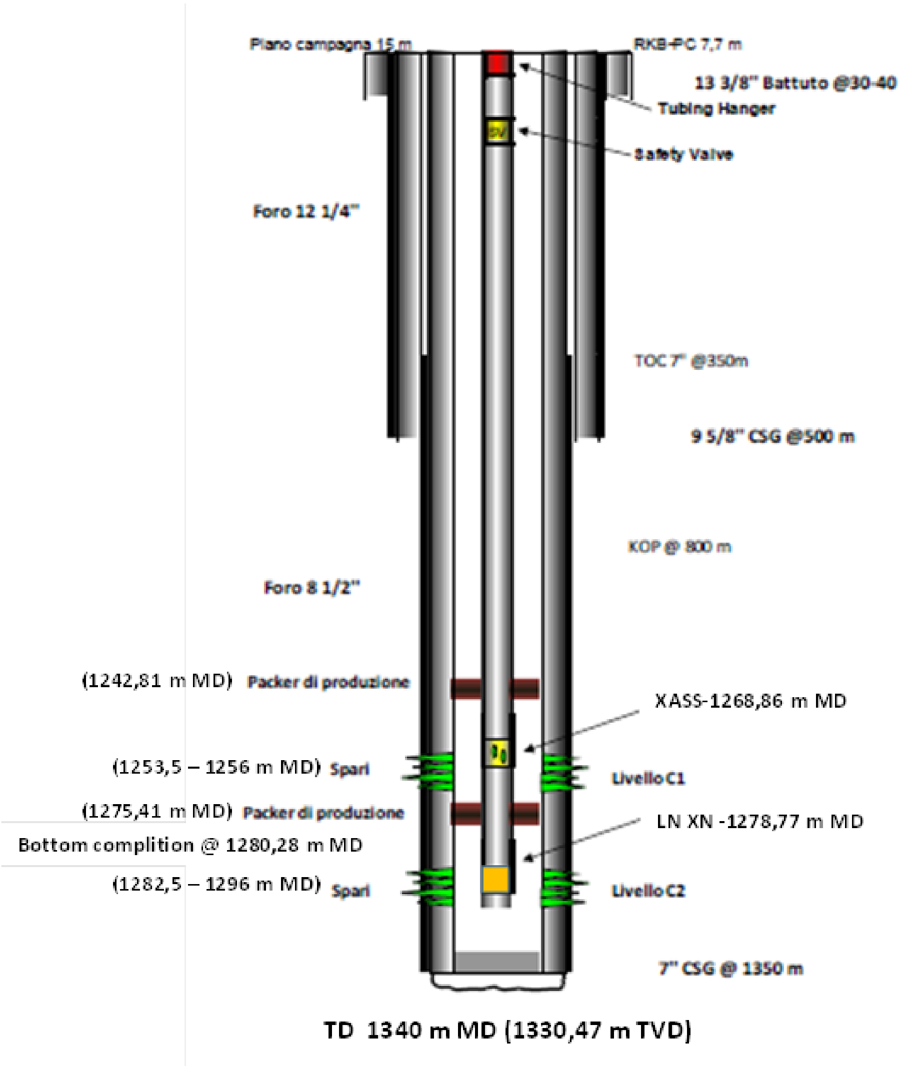


Figure 4.2 Podere Maiar-1dir – Well Schematic

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 PVO'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 CGG 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.

CGG 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 CGG 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. CGG therefore assign 100% of the high drainage area in CGG's 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 with CGG's reserves uncertainty, i.e. 44%, 63%, and 100% drainage area.

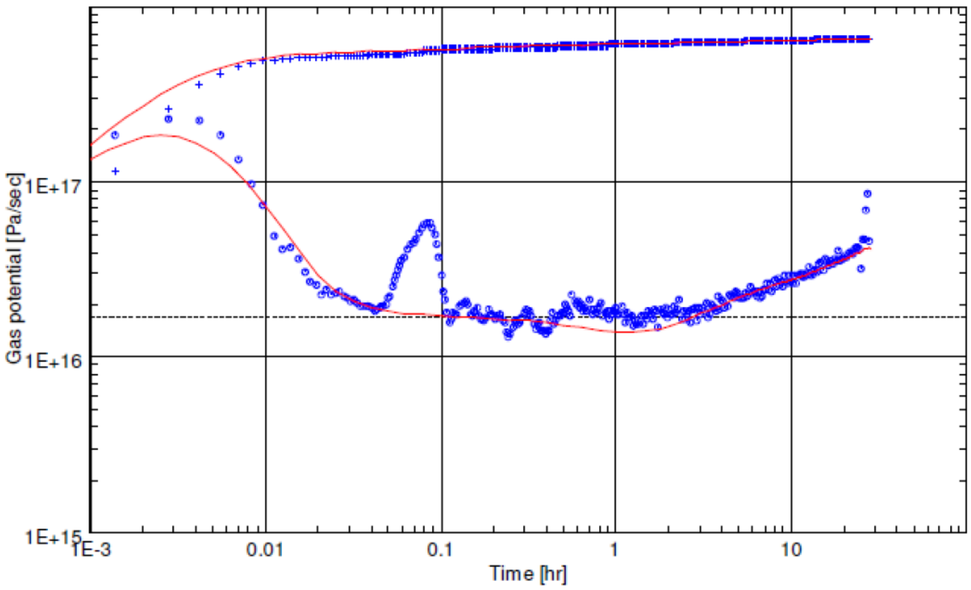


Figure 4.3 Log-log Plot of Pressure and Pressure Derivative of C1 Sand

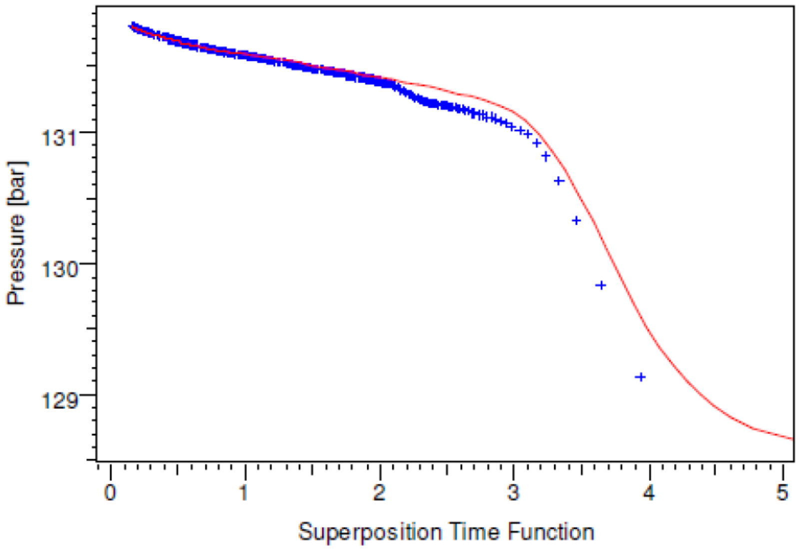


Figure 4.4 Horner Plot of C1 Sand

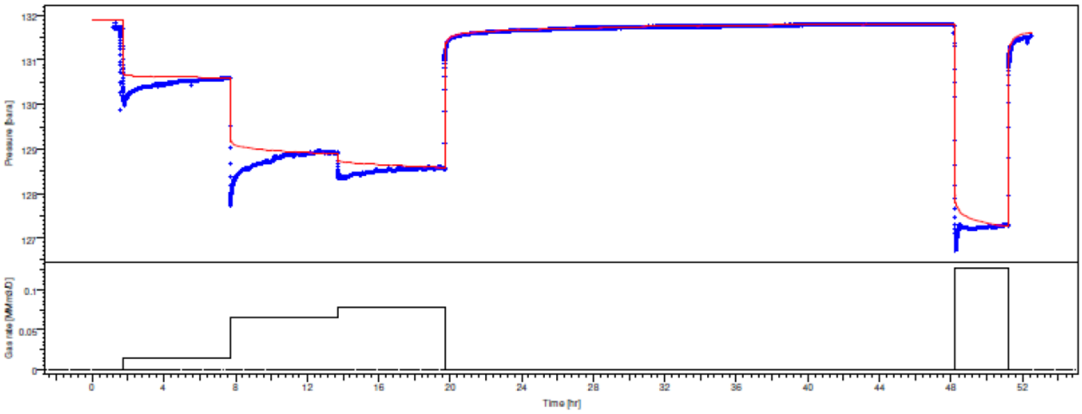


Figure 4.5 Pressure and Gas Rate of C1 Sand

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

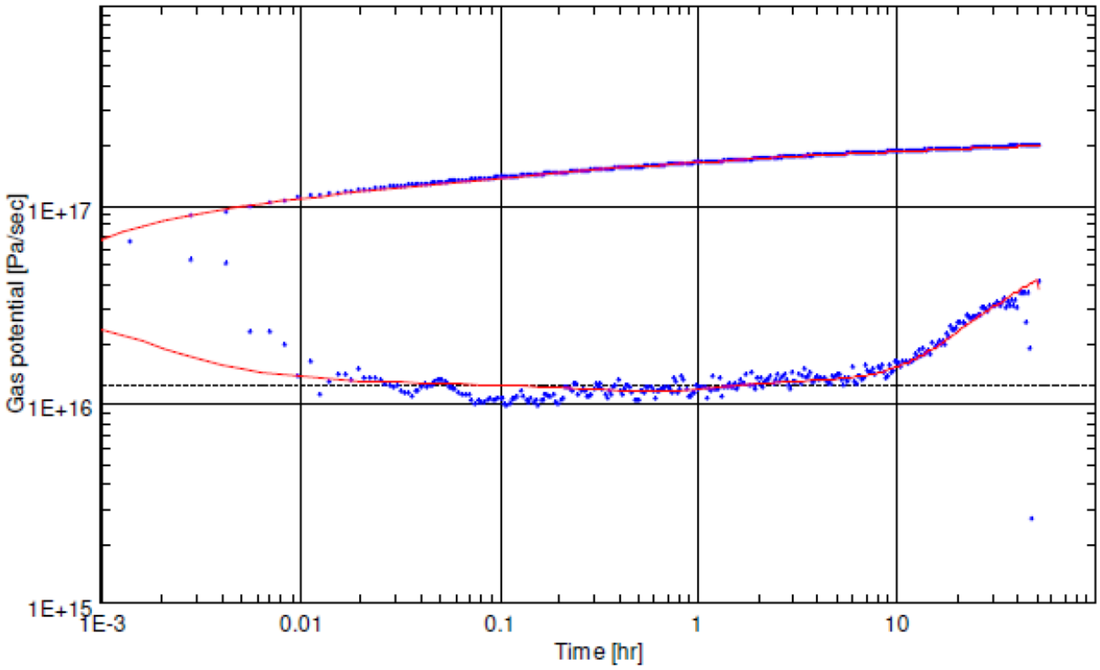


Figure 4.6 Log-log Plot of Pressure and Pressure Derivative of C2 Sand

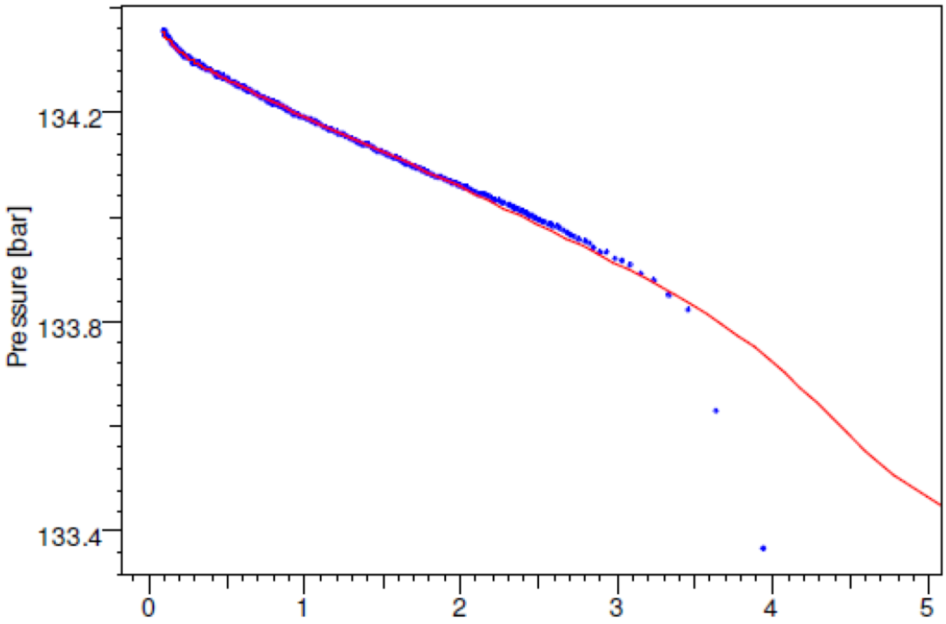


Figure 4.7 Horner Plot of C2 Sand

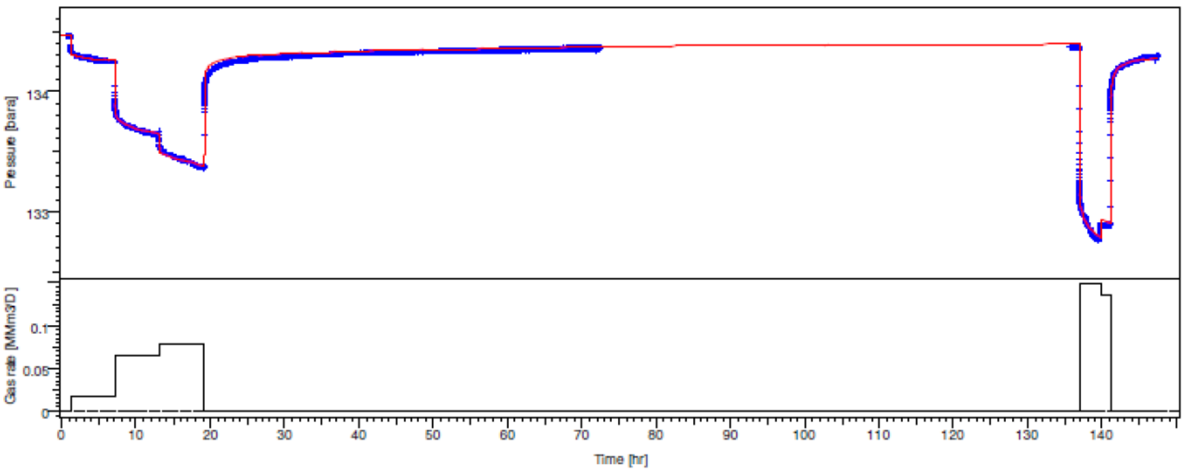


Figure 4.8 Pressure and Gas Rate of C2 Sand

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.

CGG has reviewed both historical well production and the Podere Maiar-1dir well test results. CGG have estimated 1P, 2P and 3P reserves using 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 volume, 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. CGG find the reserves are in the reasonable range of low, mid, and high historical well performance. CGG's 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.

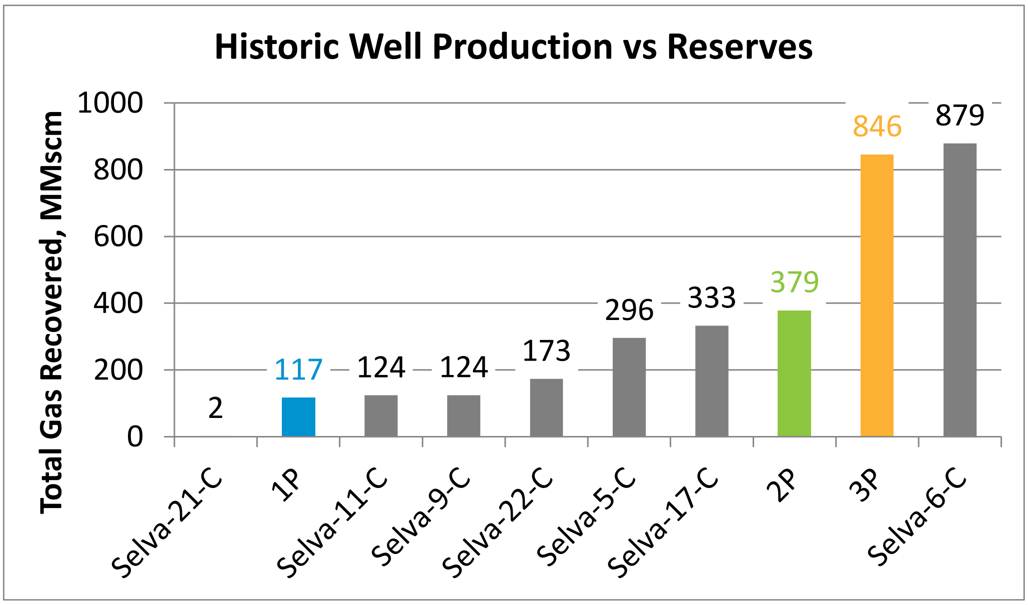


Figure 4.9 Comparison between historical production and reserves

The production profiles for 1P, 2P and 3P reserves are graphically shown in Figure 4.10. Production start-up is assumed to be April 2023, since certain official permissions remain in progress and the pipeline to tie in to the gas network has not been built yet.

Table 4.9 shows the annual production and cumulative production.

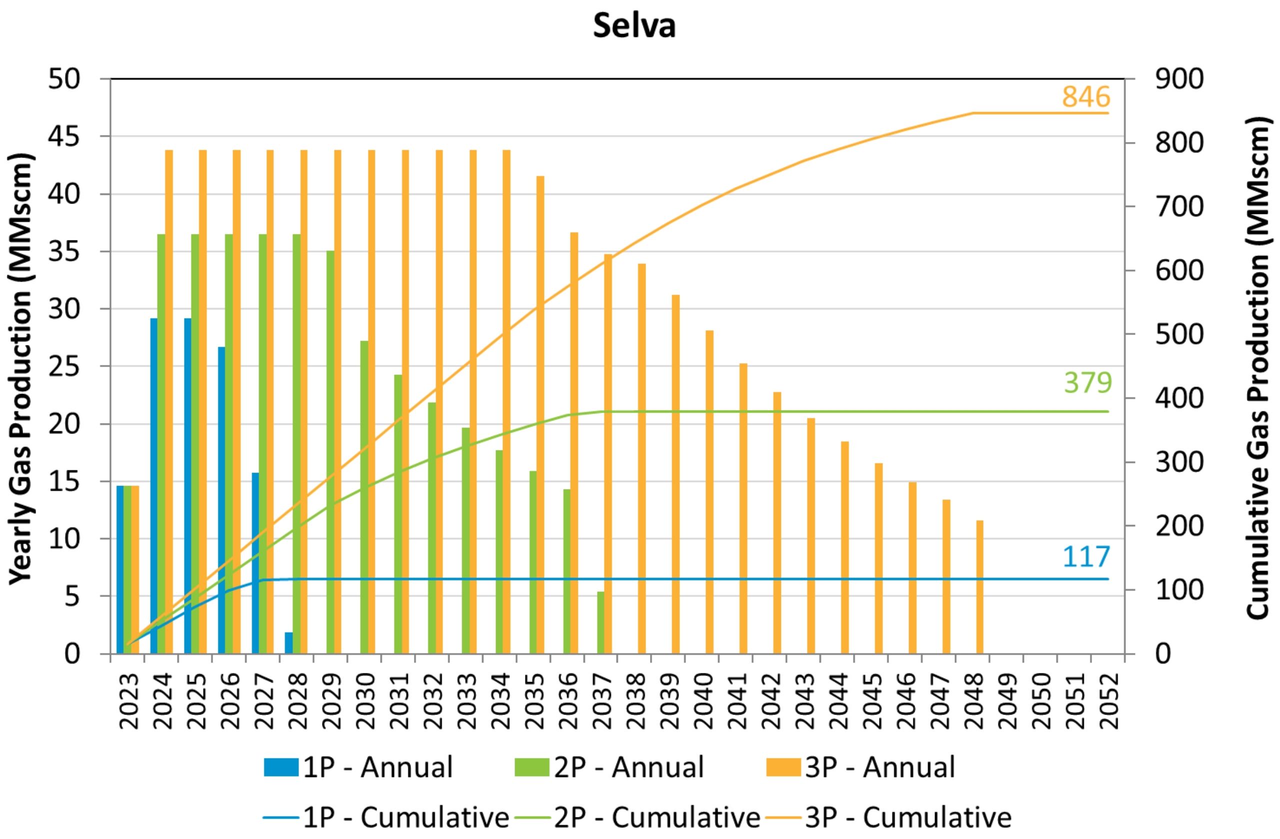


Figure 4.10 Technical Production Profiles of Selva 1P, 2P and 3P (before Economic Cut-off)

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)
2023	14.60	14.60	14.60	14.60	14.60	14.60
2024	29.20	43.80	36.50	51.10	43.80	58.40
2025	29.20	73.00	36.50	87.60	43.80	102.20
2026	26.71	99.71	36.50	124.10	43.80	146.00
2027	15.77	115.48	36.50	160.60	43.80	189.80
2028	1.88	117.35	36.50	197.10	43.80	233.60
2029	0.00	117.35	35.09	232.19	43.80	277.40
2030	0.00	117.35	27.19	259.37	43.80	321.20
2031	0.00	117.35	24.27	283.65	43.80	365.00
2032	0.00	117.35	21.85	305.49	43.80	408.80
2033	0.00	117.35	19.66	325.15	43.80	452.60
2034	0.00	117.35	17.69	342.85	43.80	496.40
2035	0.00	117.35	15.93	358.77	41.52	537.92
2036	0.00	117.35	14.33	373.10	36.61	574.53
2037	0.00	117.35	5.41	378.52	34.78	609.31
2038	0.00	117.35	0.00	378.52	33.89	643.21
2039	0.00	117.35	0.00	378.52	31.21	674.41
2040	0.00	117.35	0.00	378.52	28.09	702.50
2041	0.00	117.35	0.00	378.52	25.28	727.78
2042	0.00	117.35	0.00	378.52	22.75	750.53
2043	0.00	117.35	0.00	378.52	20.48	771.00
2044	0.00	117.35	0.00	378.52	18.43	789.43
2045	0.00	117.35	0.00	378.52	16.58	806.02
2046	0.00	117.35	0.00	378.52	14.93	820.94
2047	0.00	117.35	0.00	378.52	13.43	834.38
2048	0.00	117.35	0.00	378.52	11.62	846.00
2049	0.00	117.35	0.00	378.52	0.00	846.00
2050	0.00	117.35	0.00	378.52	0.00	846.00
2051	0.00	117.35	0.00	378.52	0.00	846.00
2052	0.00	117.35	0.00	378.52	0.00	846.00

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 used 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 have also not been included.

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.

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 2.5%, which was the average difference between the two prices in 2021. The PSV price assumption used in the economic evaluation is based on the TTF forward curve on 30th May 2022 for the first five years, thereafter it is assumed to escalate at 2% per year. The PSV price assumption is tabulated below.

Table 5.1 PSV gas price assumption

Year	Base price (Euro/m^3)
2022*	1.031
2023	0.858
2024	0.644
2025	0.498
2026	0.363
2027	+2% pa

** remainder*

In order to capture the current large uncertainty in gas prices due to geopolitical issues, low and high price decks have been taken at +/- 40% of the base price.

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

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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 based on the wellhead value of production, with certain volumes exempt depending on the region and type of development. The applicable royalty rate for Selva gas production is assumed to be 10%, with an annual royalty free allowance of 10 million cubic metres. For Teodorico gas production the applicable royalty rate is assumed to be 10%, with an annual royalty free allowance of 30 million cubic metres. For both fields, if the annual production exceeds the royalty free volume, then royalty is payable on the total production for that year.

Profits are subject to standard Italian corporate income tax (IRES), for which the current rate is assumed to be 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 applicable IRAP rate is assumed to be 3.9%, and is calculated in a similar way to IRES.

It is assumed that the 25% windfall tax introduced by the Italian government in May 2022, will not be extended beyond 2023.

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	7% in 2022 reducing to 2% over 3 years
Discount Date	1st January 2022

5.3 SELVA

5.3.1 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:

Table 5.3 Development Costs (Gross 100%)

Item	€ MM
Authorisations, compensation, legal	0.06
Land purchase	0.06
HSE	0.08
Project management and insurances	0.09
Engineering	0.09
Pipeline and connection to grid*	0.50
Gas plant	3.08
Environmental monitoring	0.36
Total Capex	**4.30**
* excludes €0.76 MM bond payable to SNAM, refundable at first gas	

Operating costs are estimated to be approximately €0.6MM per year with an additional charge of €0.03/M^3 for compression when required. Abandonment costs at the end of field life are estimated to be €2.7MM. CGG have reviewed these assumptions, which are deemed to be reasonable. First gas is assumed to be achieved in April 2023 as per PVO's latest schedule.

5.3.2 Results

NPVs are presented for the 1P, 2P and 3P cases for a 100% field interest and PVO net interest at base, low and high gas prices.

Table 5.4 Selva NPV10s (Gross and net PVO)

Gas Price	Gross (€ MM)			Net attributable (€ MM)			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Base	22.4	51.9	87.1	14.1	32.7	54.8	PVO
Low	10.5	27.5	48.4	6.6	17.3	30.5	
High	34.5	76.4	125.7	21.7	48.1	79.2	

Capital and operating cost sensitivities to NPV have been performed at the base gas price and are presented in the table below. For the 2P case the IRR is > 50%, and the payback approx. 8 months from first gas

Table 5.5 Selva NPV10 cost sensitivities (Net)

	NPV10 € MM		
	Proved	Proved & Probable	Proved, Probable & Possible
Base	14.1	32.7	54.8
Capex +25%	13.4	32.0	54.2
Capex -15%	14.5	33.1	55.2
Opex +25%	13.7	31.9	53.9
Opex -15%	14.4	33.2	55.4

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

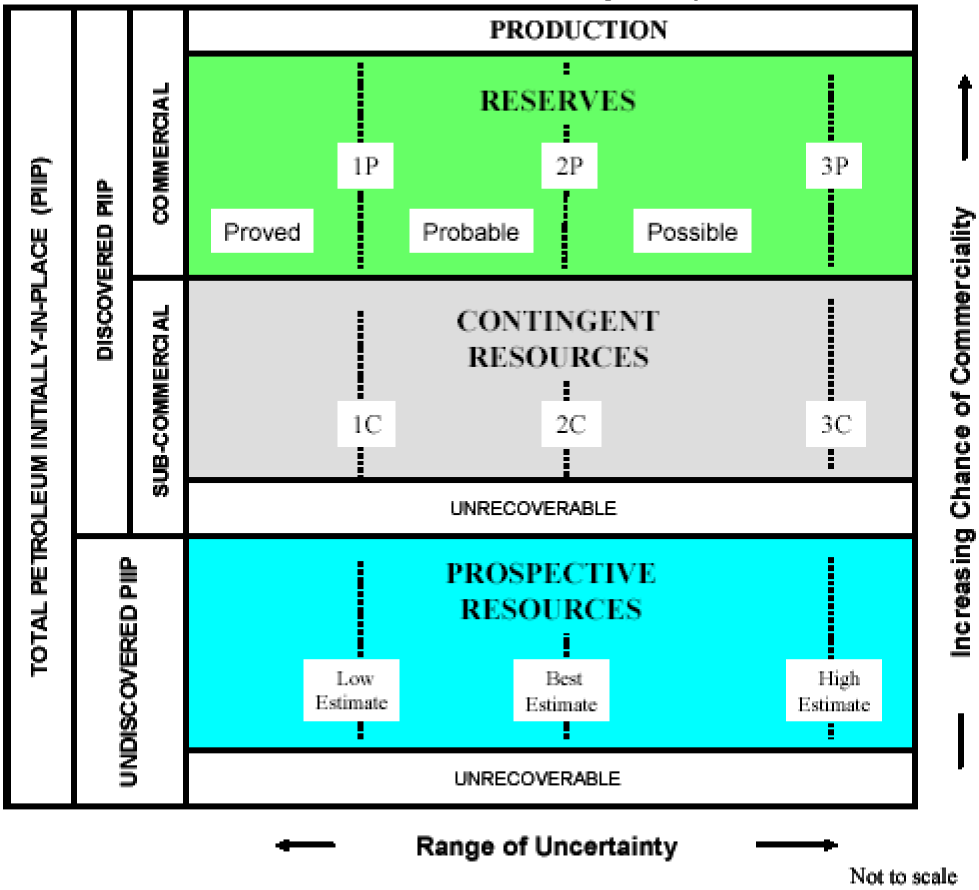
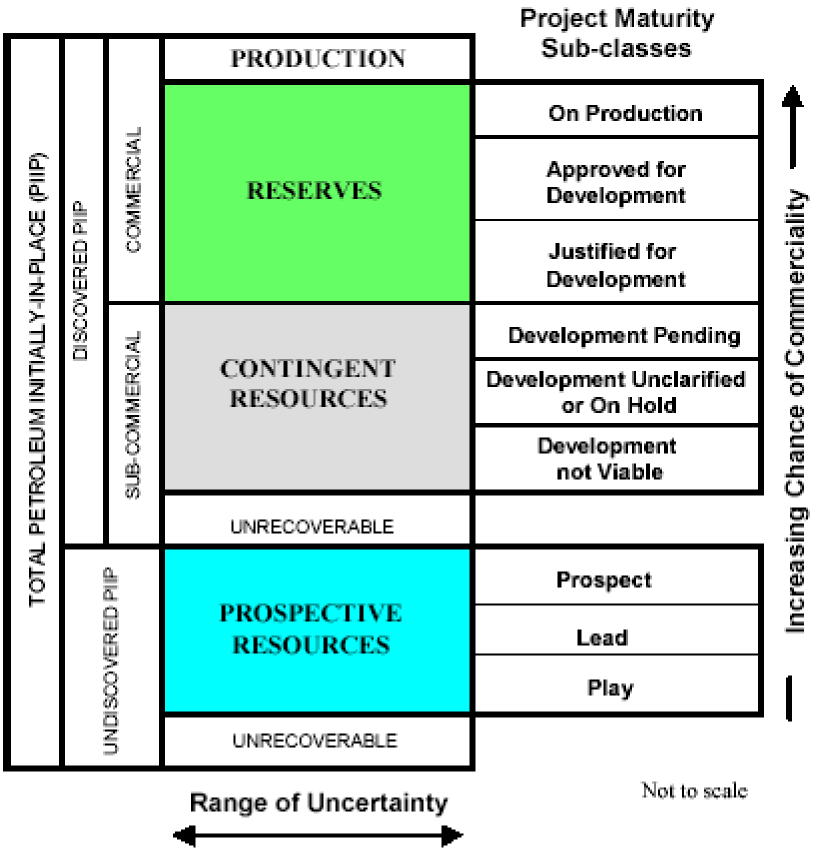


Figure 6.1 Resources Classification Framework



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.

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.

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.

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

1-D, 2-D, 3-D	1-, 2-, 3-dimensions
1P	proved
2P	proved + probable
3P	proved + probable + possible
acre	43,560 square feet
AOF	absolute open flow
API	American Petroleum Institute
av.	Average
AVO	Amplitude vs. Off-Set
bbl	barrel
bbl/d	barrels per day
BHP	bottom hole pressure
BHT	bottom hole temperature
boe	barrel of oil equivalent
Bscf	billion standard cubic feet
Bscm	billion standard cubic metres
Btu	British thermal unit
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
DHC	dry hole cost
DHI	direct hydrocarbon indicators
DPT	deeper pool test
DROI	discounted return on investment
DST	drill-stem test
DWT	deadweight tonnage
E & P	exploration & production
E	East
e.g.	for example
EAEG	European Association of Exploration Geophysicists
EOR	enhanced oil recovery
ESP	Electrical Submersible Pump
et al.	and others
EUR	estimated ultimately recoverable
FPSO	Floating Production Storage and Offloading vessel
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
kg	kilogram
km	kilometre
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	metre
M	thousand
m/s	metres per second
Ma	million years (before present)
Mbbl/d	thousands of barrels per day
Mbbl/d	thousands of barrels per day
mbdf	metres below derrick floor
mbsl	metres below sea level
mD	millidarcies
MD	measured depth
mdst.	mudstone
MFS	maximum flooding surface
mg/gTOC	units for hydrogen index

mGal	milligals	PRMS	Petroleum Resource Management System (SPE)
MHz	megahertz	psi	pounds per square inch
MJ	megajoule	RFT	repeat formation test
ml	millilitres	ROI	return on investment
mls	miles	ROP	rate of penetration
MM	million	RT	rotary table
MMbbl	million bbls of oil	S	South
MMboe	million bbls of oil equivalent	SCAL	special core analysis
MMscfd	million standard cubic feet per day	scf	standard cubic feet
MMscm	million standard cubic metres	scm	standard cubic metre*
mmsl	metres below mean sea level	SPE	Society of Petroleum Engineers
MMstb	million stock tank barrels	SS	sub-sea
MMt	million tons	ST	sidetrack (well)
mN/m	interfacial tension measured unit	stb	stock tank barrel
MPa	megapascals	std. dev.	standard deviation
Mscfd	thousand standard cubic feet per day	STOIIP	stock tank oil initially in place
Mscm	thousand standard cubic metres	Sw	water saturation
msec	millisecond(s)	TD	total depth
MSL	mean sea level	TDC	tangible drilling costs
mSS	metres subsea	Therm	105 Btu
MWh	MegaWatt-hours	Tscf	trillion standard cubic feet
N	north	TVD	true vertical depth
NaCl	sodium chloride	TVDSS	true vertical depth subsea
NFW	new field wildcat	TWT	two-way time
NGL	natural gas liquids	US$	US dollar
no.	number (not #)	US$MM	Millions of US dollars
NPV	net present value	UV	ultra-violet
Ø	porosity	VDR	virtual dataroom
OAE	oceanic anoxic event	W	West
OI	oxygen index	WD	water depth
OWC	oil-water contact	WHFP	wellhead flowing pressure
P & A	plugged & abandoned	WHSP	wellhead shut-in pressure
pbu	pressure build-up	wt%	percent by weight
perm.	permeability	XRD	X-ray diffraction (analysis)
PESGB	Petroleum Exploration Society of Great Britain		
pH	-log H ion concentration		
phi	unit grain size measurement		
plc	public limited company		
por.	Porosity		
poroperm	porosity-permeability		
ppm	parts per million		