2014 HIGHLIGHTS

2014 PRODUCTION OF 22.5 MBOEPD

SIGNIFICANT PROGRESS ON THE AIN TSILA PROJECT IN ALGERIA; FRONT END ENGINEERING AND DESIGN AND GAS SALES CONTRACTS AWARDED

ALGERIAN FARM-OUT TO SONATRACH CONCLUDED, COSTS CARRIED TO Q2 2016

EGYPTIAN RECEIVABLE DECREASED BY 38% IN THE YEAR TO $50 MILLION (2013: $81 MILLION)

YEAR-END NET DEBT SIGNIFICANTLY REDUCED TO $153 MILLION (2013: $246 MILLION)

SHARE PLACING RAISED GROSS FUNDS OF $100 MILLION

CAPITAL EXPENDITURE OF $109 MILLION

OPERATIONS AT A GLANCE

	Production	Development/ Late Appraisal	Exploration	Further information
Algeria		●		14
Egypt	●		●	18
Bulgaria	●			22
Romania (relinquished)			●	24
Kurdistan Region of Iraq (relinquished)			●	25
Italy		●	●	26
Greece			●	27

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CHAIRMAN'S STATEMENT

Dear Shareholder

I am pleased with Petroceltic's production and development business which performed well in 2014. Production was in line with guidance and a series of contract awards in respect of the Ain Tsila development asset in Algeria confirm the encouraging progress of this project. During 2015, we are focussing strongly on delivering value from our core producing assets and de-emphasising certain exploration initiatives, while maintaining exposure to long term growth.

Operations

Average 2014 production from the Company's interests in Egypt and Bulgaria was in line with guidance at 22.5 Mboepd on a working interest basis (11.9 Mboepd on a net entitlement basis). The average daily production rate for 2015 is expected to be in the range of 14 to 15 Mboepd, comprising approximately 85% gas and 15% liquids. Egypt and Bulgaria are expected to contribute 85% and 15% of the total production volume, respectively.

While production remains an important element of our business, the Algeria project is the largest asset in the portfolio, accounting for over 80% of proved plus probable reserves. The decision by Sonatrach to pre-empt the Ain Tsila farm-out is a clear indication of the high quality of the Ain Tsila asset and the quality of the relationship between Sonatrach and the Petroceltic team leading the development. A crucial milestone that was achieved during the year was the signing of the fully termed Gas Sales Agreement in September 2014. The carry by Sonatrach will enable a number of critical project activities to be achieved at no cost to Petroceltic; critical amongst these is the award of the Engineering Procurement and Construction (EPC) Contract and commencement of development well drilling before the end of 2015. While many other important workstreams are also making encouraging progress, these will be the key determinants of the schedule to ensure the delivery of plateau production – and thus return of joint venture partner investments – following first gas in 2018.

In Egypt, 2014 saw an encouraging return to economic and political stability, with presidential elections and the initiation of a more progressive economic policy including measures designed to mitigate the impact of subsidies on the state finances. These positive developments, combined with the strong payment performance demonstrated by EGPC during the year – Petroceltic's receivable reduced by over 30% and most other international oil and gas companies also recorded significant reductions - further support the attractiveness of Egypt as an investment location for oil and gas companies.

Our experience in Kurdistan is an illustration of the fundamental risks of exploration – the blocks are located in a prolific basin, very close to some of the largest discoveries of recent years and with numerous oil seeps evidencing the existence of a working hydrocarbon system. The joint venture conducted a structured and comprehensive programme of geological work, which strongly supported the potential for commercial discoveries. Unfortunately, the ultimate test – that of drilling the wells – did not yield the result we had hoped for, and did not suggest that any further work was justified. In recognition of this, and despite our investment of over $120m since 2011, Petroceltic (along with Hess as operator) took the decision to withdraw, and to refocus the business on regions where risks and costs are lower, particularly given the overall industry environment at present.

Petroceltic's Italian portfolio contains both onshore and offshore prospects of material scale and both made encouraging progress during 2014 and we are now at a point where all environmental permitting processes could be completed during 2015, leading to potential drilling in 2016. As part

While production remains an important element of our business, the Algeria project is the largest asset in the portfolio, accounting for over 80% of commercial reserves.

of the preparations for drilling, Petroceltic will consider farmouts or similar partnering initiatives to mitigate our financial exposure to these projects and has commercially concluded farmout negotiations for one of its Italian licences. In parallel, the passing of the "Restart Italy" decree in late 2014 represented an important advance in the planning and permitting framework for oil and gas projects and has already had a positive impact on the activities of Petroceltic and other operators.

Financing

The bulk of Petroceltic's 2014 revenue came from Egypt providing $106m of the total $157m, where improved availability of external capital to the Egyptian Government facilitated material payments to international oil and gas companies operating in the country, including Petroceltic. As a result, the level of receivables in Egypt at year end was $50m (2013: $81m) and net debt at year end was significantly reduced to $153m (2013: $246m). The remaining revenue of $51m was from gas sales in Bulgaria. The loss for the year was $282m (2013: $19m) which primarily arose from exploration costs written off of $183m and an impairment charge of $86m, of which $80m relates to oil and gas assets and $6m relates to inventory write off.

Petroceltic invested $109m in capital expenditure during 2014 and has a relatively active exploration and development programme scheduled for 2015 with forecasted capital expenditure of $167m (of which $79m relates to development of Ain Tsila to be carried by Sonatrach pursuant to the terms of the Algerian farm-out agreement completed in July 2014). Some of this planned exploration expenditure could be reduced if the farm-out initiatives currently under way are successfully concluded.

The year-end reserves adjustment in Egypt and Bulgaria and the current volatility in oil pricing has negatively impacted on the availability of funds under the Group's reserve based lending facility which has resulted in the Group working with the existing lenders and new providers of finance to put in place a finance solution that addresses the funding requirement for the Group. In June 2015, the Group announced plans to issue up to $175m 3 year Secured Bond; while further financing will be required to fully fund the Algerian development, successful conclusion of this Bond is a critical step in the Groups long term financing strategy. The Group has appointed Pareto Securities to advise and assist us in this process.

Board and Governance

The period since January 2014 has been one of major transition for the Board of Petroceltic, with only four Directors having served consistently throughout. As part of an agreement with Worldview Capital Management, the largest shareholder in the Company, the Petroceltic Board was reduced from nine to seven members in July 2014. Hugh McCutcheon and Dr Robert Arnott resigned as Non-Executive Directors; Rob and Hugh had been on the board since January 2010 and December 2011 respectively and we will miss their insights and support. David Thomas and Tom Hickey stepped down from the Board, but continued to hold their executive roles in the Company. David, who was formerly the CEO of Melrose from June 2007 to October 2012 and made a major contribution to the business, has since left the Company. The Company welcomed Don Wolcott and Joe Mach to the Board as Non-Executive Directors in July 2014.

In December 2014, James Agnew advised the Board of his intention to resign with effect from January 2015. James was on the Melrose Board from November 2007 and throughout his time on the Board, made a major contribution to the business. In January 2015, Worldview requisitioned an EGM to seek to remove Brian O'Cathain as a director and appoint two of its own nominees, Angelo Moskov and Maurice Dijols. Petroceltic in turn nominated Neeve Billis and Nicholas Gay as independent Non-Executive Directors. At the EGM, shareholders rejected all the Worldview resolutions, while Neeve Billis and Nicholas Gay were appointed to the Board with effect from February 2015. Don Wolcott and Joe Mach resigned from the Board in February 2015, and in March 2015, Tom Hickey was re-appointed to the Board. The series of changes to Board composition, coupled with uncertainty surrounding financing, has prevented the Group from progressing its plan to step up to the official lists of the London and Irish stock exchanges as previously planned. We remain committed to undertaking this at the earliest opportunity.

In December 2014, the Company announced that Worldview had issued legal proceedings against it. The proceedings alleged that the Company had failed to undertake a review of its business and sought direction from the Court as to the manner in which the review was undertaken. On 21 May 2015, the English High Court dismissed Worldview's action and awarded costs on a standard basis to Petroceltic.

CHAIRMAN'S STATEMENT
CONTINUED

We expect to benefit from the current price weakness in oil markets to attract competitive bids for our main Ain Tsila EPC contract.

Dragon Oil Approach

In October 2014, the Company announced that it was in detailed discussions with Dragon Oil Plc ("Dragon Oil") regarding a possible offer to be made by Dragon Oil for the Issued, and to be issued, share capital of the Company.

Dragon Oil confirmed to the Company that it had completed its due diligence and planned to seek an irrevocable undertaking to support its making of an Offer of 230 pence Sterling per share in cash from its majority shareholder, the Emirates National Oil Company L.L.C. ("ENOC"). The Board of Petroceltic had agreed, subject to consultation with its shareholders, that it would be willing to recommend such an Offer to shareholders, if this irrevocable undertaking was obtained from ENOC, noting that such Offer would be subject to the approval of Dragon Oil's shareholders.

In December 2014, Dragon Oil announced that it would no longer be making an Offer at that time for the Company, citing prevailing oil and gas pricing market conditions. While we devoted significant resources to supporting the Dragon process, and were disappointed that Petroceltic shareholders did not get the opportunity to fully consider the potential offer, we continue to believe that Petroceltic has a strong and positive future as an independent company.

Sector and Market Sentiment

Oil and Gas is a global industry, with supply and demand driven by technology, pricing, global economic performance and geopolitical stability. Each of these factors has exerted a material influence on the prices received by producers, and caused a reduction of over 40% in the Brent oil price over the period since mid-2014; similar uncertainty also surrounds the forecasts of future pricing. Against this backdrop, smaller exploration and production companies have struggled to secure finance and attract investor attention, while larger ones have undertaken material portfolio rationalisation, with exploration budgets and personnel the most impacted. Petroceltic was no exception in this regard and in 2015 made 40% of Head Office and corporate personnel redundant as part of an overall effort to refocus the Company on its tangible reserve base of existing production, developments and discoveries.

While we greatly regretted doing this, and have lost talented colleagues as a result, our business is now significantly streamlined from a geographical and operational perspective, and a number of existing or anticipated farmout and portfolio management initiatives have materially mitigated our exposure to future capital investment. By taking these actions, we believe we have preserved and protected value in our core assets for the benefit of all shareholders, but also retained sufficient exposure to potentially material future exploration and appraisal projects to renew and expand our portfolio at modest cost as industry conditions improve. We also expect to benefit from the current price weakness in oil markets to attract competitive bids for our main Ain Tsila Engineer Procure Construct ("EPC") contract.

This environment has, however, provided a focus on delivering efficiencies and the recent restructuring of the organisation will ensure that Petroceltic is resourced appropriately to effectively deliver the planned work programme. Finally, the contemplated bond issue is a crucial step towards providing the financial resources to continue to implement the Group's long term strategy of delivering value from core assets.

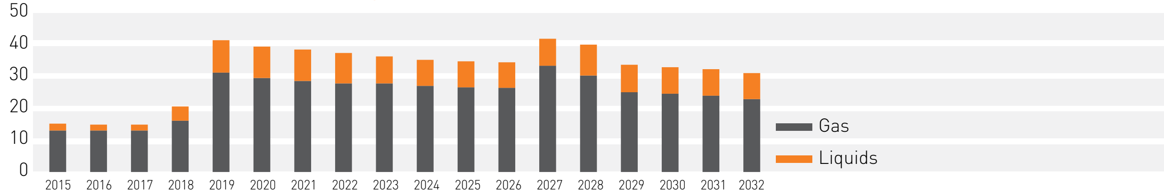
Robert Fm Adair

Robert Adair
Chairman

CORPORATE STRATEGY

Our strategy is to bring our development asset to first gas on schedule and to maximise the value of our producing assets through on-going investment, active reserves management and cost control. Through discovery of assets with material hydrocarbon resource potential, we develop these assets to deliver superior shareholder value. We focus on developing material asset positions in attractive fiscal regimes with strong partners that can add complementary skills as well as financial strength. Our geographical focus is Middle East-North Africa ("MENA"), the Black Sea and the Mediterranean basin.

Sustainable and clear long term production profile Mboepd, Working Interest basis



2014 Key Achievements	Future Key Targets
Algeria: • Farm-out provides $160m funding to cover capex until Q2 2016 and further contingent payments of up to $20m • FEED and Gas Sales Agreement contracts awarded	• Award of Rig Contract (achieved in April 2015) and EPC contract • Project delivery on budget- circa $430m net capex spend to first gas (post carry) • First gas anticipated Q4 2018 with 14 year wet gas production plateau of 355 MMscfpd
Egypt: • Production of 19.3 Mboepd, generating revenue of $106m • Completion of two successful development wells and one workover • New acreage granted - portfolio renewal • Receivables reduced to $50m	• Maintenance of production- 2015 guidance of 12.5-13.3 Mboepd • Infill drilling and facilities investment • Gas injection to maximise liquids recovery • Farm-out exploration acreage to manage risk and financial exposure • Seismic acquisition on new licences
Bulgaria: • Production of 3.2 Mboepd generating revenue of $51m • Successful export compressor major overhaul	• Maintenance of production- 2015 guidance of 1.5-1.7 Mboepd • Kavarna East completion and tie back • Invest in Kaliakra to deliver existing reserves
Corporate/Other: • $100m share placing • Net debt reduced to $153m	• Progress financing strategy for Ain Tsila development expenditure • Divest or relinquish non-core/low graded exploration licences at minimal cost • Restructure the organisation to match reduced exploration • Retain high quality opportunities (while minimising cost)

BUSINESS MODEL

In line with our strategy, the business model has evolved to be a full cycle E&P company with a portfolio in North Africa and the Mediterranean region. The Development asset is the core driver of value and the Producing assets provide funding for the Group's activities. In difficult climates, the model can adapt and focus away from low graded or high risk exploration towards near term developments. Growth and increased value for shareholders is always a central focus.

EXPLORATION

Confined to core areas for portfolio renewal and licences where material resources are possible. Joint venture partnerships are used to mitigate risk, share costs and gain external knowledge and experience.

DEVELOPMENT

Putting the right team in place and awarding contracts to experienced suppliers to ensure proper execution of projects. Cost control, stable financing and a focus on the project delivery timetable is central to the development.

PRODUCTION

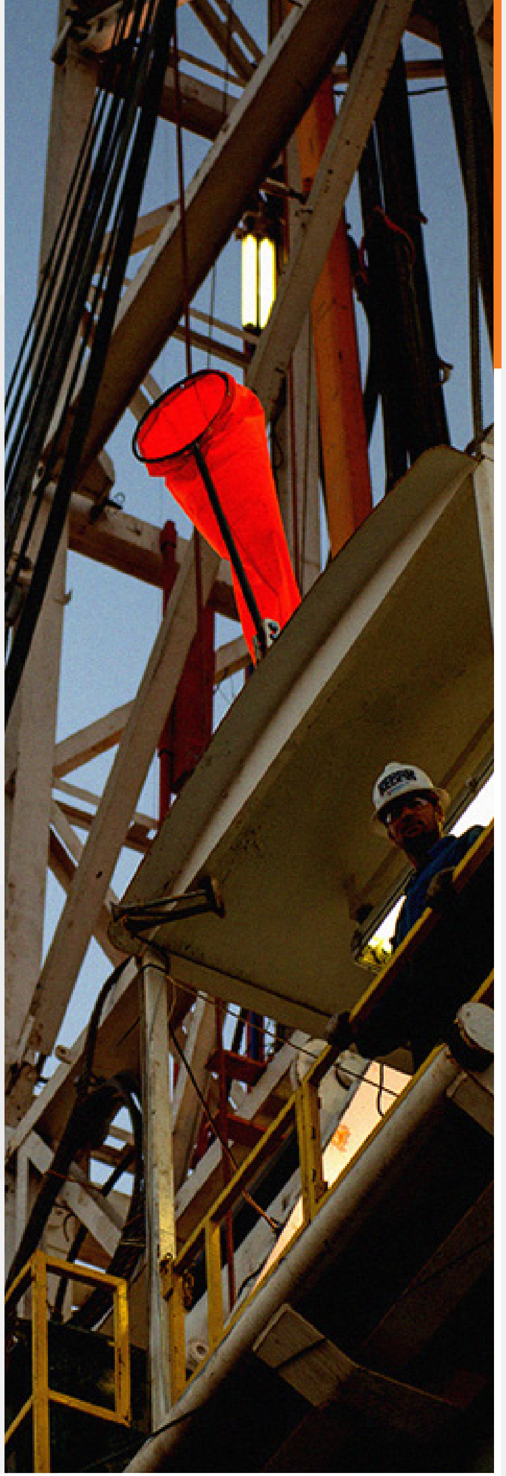
Maximise producing wells and reserves to generate a strong cash flow. Low operating costs and a stable mix of liquids and gas with predictable gas prices on long term contracts.

PORTFOLIO MANAGEMENT

As part of preparation for drilling or other significant capital expenditure programmes, farm-outs are considered to mitigate financial and operational risk.

GROWTH

Develop opportunities arising from the existing asset base. Delivering growth in shareholder value is the primary focus of the business model.



KEY PERFORMANCE INDICATORS

The Board assesses the Company's performance through the measurement of specific KPIs

- Production was in line with guidance for the year 2014
- Reserves decreased during 2014 primarily due to the farm-out to Sonatrach who acquired Algerian reserves of 97.3 MMboe
- The number of lost time injuries (LTI) reduced significantly in 2014

OPERATIONAL PERFORMANCE INDICATORS

Production - working interest (boepd)

Production - net entitlement (boepd)

Proved plus probable reserves - working interest (Mboe)

Lost time injuries

FINANCIAL PERFORMANCE INDICATORS

	2014	2013
Revenue ($ m)	157	197
EBITDAX ($ m)	102	145
Group net indebtedness ($ m)	153	246
Net indebtedness/EBITDAX	1.5	1.7
Interest cover	5.5x	6.6x
Operating costs ($ per boe -working basis)	3.1	2.3

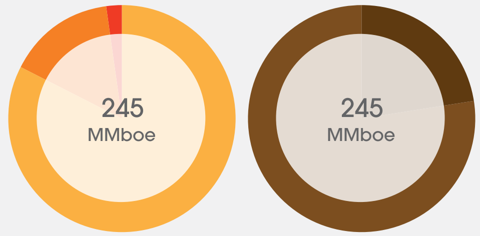
INVESTMENT ACTIVITY

	2014	2013
Capital expenditure	109	161
Exploration	70%	34%
Development	30%	66%

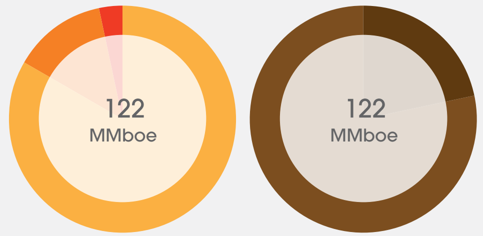
OIL AND GAS RESERVES
PROVED AND PROBABLE RESERVES AT 31 DECEMBER 2014

	Algeria Oil Mboe	Algeria Gas Mboe	Algeria Total Mboe	Egypt Oil Mboe	Egypt Gas Mboe	Egypt Total Mboe	Bulgaria Gas Mboe	Total Oil & Gas Mboe
Working interest basis								
Proved and probable reserves								
Proved developed	-	-	-	3,940	13,839	17,779	427	18,206
Proved undeveloped	25,579	83,819	109,398	1,693	4,312	6,005	1,849	117,252
Proved	25,579	83,819	109,398	5,633	18,151	23,784	2,276	135,458
Probable developed	-	-	-	1,767	7,045	8,812	834	9,646
Probable undeveloped	23,523	69,755	93,278	652	4,617	5,269	1,474	100,021
Probable	23,523	69,755	93,278	2,419	11,662	14,081	2,308	109,667
Total developed	-	-	-	5,707	20,884	26,591	1,261	27,852
Total undeveloped	49,102	153,574	202,676	2,345	8,929	11,274	3,323	217,273
Proved and probable	**49,102**	**153,574**	**202,676**	**8,052**	**29,813**	**37,864**	**4,584**	**245,125**
Movements on reserves during the year								
At 1 January	72,690	227,351	300,041	9,683	44,700	54,383	6,269	360,693
Disposals	(23,588)	(73,777)	(97,365)	-	-	-	-	(97,365)
Additions	-	-	-	-	-	-	-	-
Revisions	-	-	-	(601)	(8,888)	(9,489)	(517)	(10,006)
Production	-	-	-	(1,030)	(5,999)	(7,029)	(1,168)	(8,197)
At 31 December	**49,102**	**153,574**	**202,676**	**8,052**	**29,813**	**37,864**	**4,584**	**245,125**
Net entitlement basis								
Proved and probable reserves								
Proved developed	-	-	-	1,875	5,680	7,555	427	7,982
Proved undeveloped	13,591	46,280	59,871	806	2,041	2,847	1,849	64,567
Proved	13,591	46,280	59,871	2,681	7,721	10,402	2,276	72,549
Probable developed	-	-	-	34	875	909	834	1,743
Probable undeveloped	10,258	31,172	41,430	1,068	3,949	5,017	1,474	47,921
Probable	10,258	31,172	41,430	1,102	4,824	5,926	2,308	49,664
Developed	-	-	-	1,909	6,555	8,464	1,261	9,725
Undeveloped	23,848	77,452	101,300	1,874	5,990	7,864	3,323	112,487
Proved and probable	**23,848**	**77,452**	**101,300**	**3,783**	**12,545**	**16,328**	**4,584**	**122,212**
Movements on reserves during the year								
At 1 January	33,485	108,873	142,358	3,938	16,316	20,254	6,269	168,881
Disposals	(10,866)	(35,330)	(46,196)	-	-	-	-	(46,196)
Additions	-	-	-	-	-	-	-	-
Revisions	1,229	3,909	5,138	316	(1,075)	(759)	(517)	3,862
Production	-	-	-	(471)	(2,696)	(3,167)	(1,168)	(4,335)
At 31 December	**23,848**	**77,452**	**101,300**	**3,783**	**12,545**	**16,328**	**4,584**	**122,212**

Working interest



Net Entitlement



Algeria
Egypt
Bulgaria

Oil
Gas

Notes

1) The year end 2014, net entitlement reserves for Algeria and Egypt were calculated assuming an escalating Brent oil price of $58.82/bbl in 2015, $67.28/bbl in 2016, $70.67/bbl in 2017 then $85 per barrel (flat) (2013 - $90 per barrel (flat)).

2) A conversion factor of 5,800 is used for the calculation of barrel of oil equivalents for Bulgarian and Egyptian reserves.

3) Conversion factors for Algerian commodities are as follows; gas - 5,349 Mcf/boe, condensate - 1.15 bbl/boe, LPG - 1.61 bbl/boe.

4) The proved and probable oil reserves for Algeria includes LPG of 42,184 Mbbl and 20,522 Mbbl on a working interest basis and net entitlement basis respectively.

5) The proved and probable oil reserves for Egypt includes LPG of 2,110 Mbbl and 991 Mbbl on a working interest basis and net entitlement basis respectively.

CHIEF EXECUTIVE'S REVIEW

Petroceltic had a busy year in 2014, with material activity both in our operations and strategic direction of the business. The Group's flagship project in Algeria was a key area of focus and success, with important posts filled, major contracts advanced, a second farmout successfully concluded and the Groupement, or joint operations team, functioning effectively. We also achieved our production guidance, successfully raised $100m through an oversubscribed share placing and renewed our Egyptian business through the acquisition of highly prospective new acreage. Less positively, however, we had a number of disappointments within our exploration portfolio, while the withdrawal of a proposal to acquire Petroceltic by Dragon Oil deprived shareholders the chance to consider a potential cash bid.

From an industry and market perspective, 2014 was especially challenging, with volatile oil pricing, weak equity market sentiment and mixed exploration outcomes being reflected in generally poor share price performance across the sector.

Algeria

During 2014, Petroceltic made significant progress on the Ain Tsila development, following the establishment of the Groupement Isarene ("Groupement"), the joint operating organisation staffed by seconded personnel from Petroceltic, Enel and Sonatrach, the national oil and gas company of Algeria. During 2014 a contract for Front End Engineering and Design ("FEED") was awarded to Chicago Bridge and Iron Company, which will define the detailed basis for Ain Tsila production facilities and infrastructure. The outputs from the FEED will be used in 2015 to tender the major Engineer, Procure and Construct ("EPC") contract for the project, with contract award and commencement of construction planned for late 2015 / early 2016. This timing should allow the project to benefit from an industry-wide softening in materials and construction prices. An additional critical milestone is the fully termed Gas Sales Agreement which was signed in September 2014. The development plan remains on schedule, and we are targeting first gas from the Ain Tsila field in the last quarter of 2018.

During 2014, Petroceltic successfully completed a second farm-out of an 18.375% interest in the Ain Tsila project to Sonatrach. The transaction required Sonatrach to pay Petroceltic an upfront cash payment of $20m, and fund $140m of Petroceltic's development expenditure obligations from the effective date of 4 July 2013. As at 31 December 2014, approximately $120m of the carry remained available, and based on forecast 2015 expenditure levels, the carry should ensure that Petroceltic's capital expenditure on Algeria will be fully funded until after work has commenced on the EPC contract and into Q2 2016. Post completion of the second farm-out to Sonatrach in July 2014, Petroceltic has a 38.25% interest and remains operator of the licence, Sonatrach has a 43.375% interest and Enel

The Group's flagship project in Algeria was a key area of focus and success, with important posts filled, major contracts advanced, a second farmout successfully concluded and the Groupement or joint operations team, functioning effectively.

maintains its 18.375% interest. In addition, the recent approval for the transfer of Petroceltic's interest in Ain Tsila to a wholly owned subsidiary, Petroceltic Ain Tsila Limited, is an important support to our longer term funding plan for the asset.

The development plan for the Ain Tsila field, which was approved in late 2012, is expected to result in the field producing 355 MMscfpd for a wet gas plateau production period of 14 years and over the period of the licence, will result in approximately 2.1 tcf , or 24% of the currently estimated gas in place being recovered. This is regarded as a comparatively low recovery factor for a field such as Ain Tsila, and there are a number of regional analogues where ultimate recovery factors approaching 50% have been achieved or are anticipated based on field performance. Petroceltic also believes that the Ain Tsila field has significant potential to achieve similar levels of ultimate recovery should positive production and reserve data be demonstrated during the development and early production phase. To achieve higher daily production and recovery levels, significant investment in additional gas processing and transmission facilities would be likely to be required; such investments and the related incremental gas sales would be covered by the terms of the existing Isarene PSC and Gas Sales arrangements and thus would be expected to generate a positive return on investment.

In April 2015, the Groupement awarded the drilling rig contract to SINOPEC, a company with extensive experience in Algeria. The 1,500 horse power rig will drill up to 24 new development wells. The first 12 drilling locations, all in the northern region of the field, have already been selected and approved. This represents the achievement of a further milestone for the Ain Tsila project and will enable drilling to commence on schedule in 2015. Also in April, the Groupement launched the process to identify suitable companies to perform the EPC contract via publication of an invitation to pre-qualify in the Algerian Bulletin of Public Tenders in the Energy and Mine Sector. This demonstrates the significant progress that Petroceltic and its partners are making towards the development of the Ain Tsila gas condensate field. The project remains on track to deliver first sales gas in the last quarter of 2018.

Egypt

Production for 2014 benefited by 1.9 Mboepd due to reduced gas reinjection at the West Dikirnis field in Egypt in response to requests from the Egyptian Government to increase gas sales in the first three quarters of the year. Egypt is a core area for Petroceltic and in 2014 $38m was invested in a range of development and exploration activities. While the production figure for the year was positive, a small number of reservoir performance issues have required a downwards adjustment to booked reserves as at 31 December 2014. In particular, recent well performance on West Khilala has been negatively impacted by water and sand production, requiring a reduction to reserves of 35 Bcf; a more modest reduction was made in respect of West Dikirnis where heavier risking was applied to the gas reserves which will be recovered during the gas cap blowdown phase late in field life. The combination of these factors and the weaker oil price environment applying in 2015 necessitated the recognition of an impairment of $47m in the carrying value of our Egyptian tangible assets at 31 December 2014.

In 2015, the work programme includes three new infill production wells in the West Khilala and West Dikirnis fields and minor facilities investments aimed at infrastructure rationalisation and hence the reduction of long term operating costs. We also plan to convert three additional wells in the West Dikirnis field to gas injection to maximise hydrocarbon liquids recoveries.

Bulgaria

Production in Bulgaria averaged approximately 18.6 MMscfpd in 2014, with strong performance from the Galata field somewhat offset by increased water production and lower gas recovery from the Kaliakra field. We also conducted a detailed review of the remaining exploration potential of the greater Galata licence, with limited further prospectivity identified. Looking forward, our priority is thus to optimise future production from Galata and satellite fields, with a particular focus on completing the tie in of the Kavarna East discovery during 2015, and the active management of operating costs. The Kaliakra-1 well rate has continued to slowly decline to its current rate of 2 MMscfpd suggesting that the well is only in partial pressure communication with the main field area. Hence, the Company is considering an additional well (Kaliakra-3) to ensure all reserves are accessed and to fully drain the field. The Kavarna-1 well has experienced water breakthrough and is likely to be shut-in when the Kavarna East field comes on stream. Both Kaliakra-3 and Kavarna East contribute to the future capital expenditure required in Bulgaria and this has a direct impact on the net present value of the asset. An impairment charge of $33m in Bulgaria is principally due to lower projected gas prices and higher future capital expenditure estimates.

CHIEF EXECUTIVE'S REVIEW
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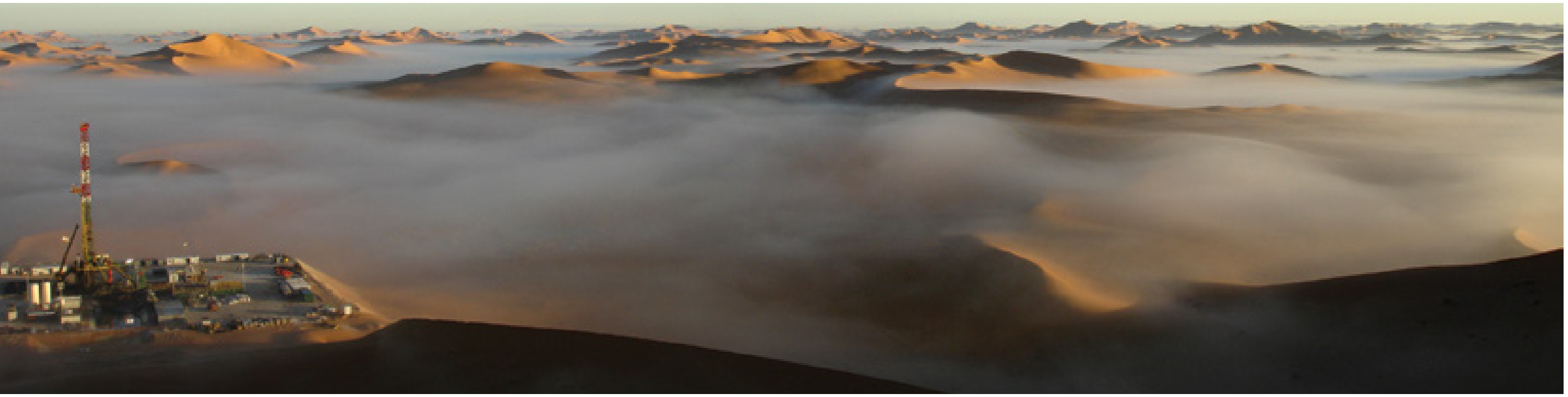


Kurdistan
Petroceltic entered Kurdistan in 2011, participating in two exploration licences, Shakrok and Dinarta, through a joint venture with Hess Corporation. Both blocks were in regions believed to be potentially prospective based on adjacent discoveries and geology, and each contained a number of structures with potential for material discoveries. The exploration programme in each licence consisted of a 2D seismic campaign and the drilling of an exploration well during the first 3 year licence period.

During 2012 and 2013, a significant amount of seismic acquisition and interpretation, surveying and geological modelling work was undertaken to increase the joint venture's understanding of the structures and associated exploration risks. From this work, the Shakrok structure on the Shakrok block and the Shireen structure on the Dinarta block were high graded for drilling.

The Shakrok prospect commenced drilling in late 2013 and reached its target depth in March 2014. While a number of prospective zones were identified and gas condensate was identified on logs, the production tests did not provide any encouragement as to the possibility for a commercial discovery and the joint venture took the decision to relinquish the licence in July 2014, and all costs in relation to the licence were written off.

The Shireen prospect commenced drilling in June 2014, and encountered significant delay due to operational challenges and security concerns which led to the evacuation of all international personnel in October 2014. The well ultimately reached a maximum depth of 1,430m in Jurassic formations in December 2014 before being suspended while forward options were reviewed. This review concluded that an additional well would be required to further evaluate the exploration potential of the prospect, and that further operational difficulties could not be ruled out. Following this analysis, and as all exploration work program obligations had been fulfilled, Hess and Petroceltic jointly elected to withdraw from the Dinarta licence without any further drilling. All costs in relation to the licence have thus been written off and a provision made for committed costs to exit the licences.

The Elsa oil discovery, offshore Abruzzo, contains 95 MMbbls of gross 2C contingent resources

Romania
Over the last 18 months, Petroceltic and its partners have drilled two exploration wells offshore Romania, one in each of the Blocks 27 and 28 on high graded prospects defined by 3D seismic acquired in 2012. Both wells were located approximately 170 kilometres northeast of Constanta and drilled using the GSP Prometeu jack up drill rig. Unfortunately, neither well encountered commercial quantities of hydrocarbons and both were plugged and abandoned. While the Cobalcescu South-1 well in Block 28 did encounter good quality sandstones at the target Miocene stratigraphic levels, with gas shows while drilling indicating an active hydrocarbon system, the Muridava-1 well in Block 27 failed to demonstrate any significant prospectivity or encouragement for further exploration in the immediate vicinity.

The drilling results have confirmed an active hydrocarbon system and that good quality reservoir is present, but significantly increased the risk of discovering a commercial oil or gas accumulation from the remaining prospect inventory in either block. Accordingly, Petroceltic made the decision to withdraw from the licences and in June 2015, sold its regional operating subsidiary, Petroceltic Romania BV for a nominal consideration to GVC Investment B.V a company under common ownership with Petromar, which also held an interest in each licence.

Italy

In the Western Po Valley, the EIA for the Carpignano Sesia-1 well was submitted by the Operator, Eni, to the authorities in December 2014. This well is being designed to test a large oil prospect located some 25km west of the analogous Villafortua-Trecate Field, and has gross mean unrisked prospective resources of 237 MMboe. Petroceltic has a 47.5% equity interest in the licence, but has concluded farmout negotiations aimed at reducing the Group's exposure to drilling and testing costs, while maintaining a material participation in the prospect. Further details of this transaction will be announced upon completion of the interest transfers.

The Elsa oil discovery, offshore Abruzzo, contains 95 MMbbl of gross 2C contingent resources (Petroceltic 55%). The EIA for the Elsa-2 well was resubmitted in July 2014, following consultative discussions with the government and local institutions, and was approved from a technical perspective in March 2015 by the independent EIA Commission. The final step in this process will be the issue of a formal ministerial decree confirming the approval. Following this, Petroceltic will recommence its detailed well planning work, with the objective of drilling the Elsa-2 well in late 2016. As part of the preparations for drilling, Petroceltic will consider farmouts or similar partnering initiatives to mitigate our financial exposure to the project. Should Elsa be successful, a number of additional prospects within the Group's Italian portfolio would likely become the focus of accelerated exploration work.

Financial

The loss for the year was $282m (2013: $19m). The Group recognised an impairment charge of $86m of which $80m relates to its tangible oil and gas interests, principally driven by lower forecast commodity prices, an adjustment to the Group's reserves in Egypt and an increase in anticipated capital expenditure in Bulgaria and the remaining $6m relates to inventory write off in Egypt. Unsuccessful exploration costs of $183m, including $129m relating to Kurdistan, $47m relating to Romania and approximately $7m of Egyptian and other new venture costs, have also been recorded in the income statement.

Litigation

During 2014, the Company reached a settlement agreement in conclusion of legal proceedings issued by Petroceltic in 2013. The legal proceedings were against two former consultants, Seghir Maza and Samir Abdelly, and an associated company, AAIC, and were seeking to set aside a number of consultancy agreements entered into in 2004 and 2005.

In November 2013, the High Court of Ireland granted Petroceltic judgement, in default of appearance, against Seghir Maza and, in August 2014, a settlement agreement was reached in respect of the remaining proceedings against Samir Abdelly and AAIC. Under the settlement agreement, claims on both sides were withdrawn and no other legal or contractual arrangements exist between the parties.

In December 2014, the Company announced that legal proceedings against it had been issued by Worldview. The proceedings alleged that the Company had failed to undertake a review of its business and sought direction from the Court as to the manner in which the review was undertaken. On 21 May 2015, the English High Court dismissed Worldview's action and awarded costs on a standard basis to Petroceltic.

HSE

We saw a significant reduction in the number of Lost Time Injuries in 2014, from six in the prior year to two. In total, four Recordable Injuries occurred in 2014, with resulting Total Recordable Injury Rate ("TRIR") being upper second quartile when compared to industry peers. We believe that our focus on contractor management and hazard and risk awareness has had a positive effect in the occupational safety results we saw this year.

During 2014, we also made considerable progress in embedding the new HSES Management System into both existing and new operations. Particular emphasis was placed upon adoption of procedures addressing risk management, emergency response, contractor management, incident investigation and performance reporting.

Greenhouse Gas emissions increased in 2014 primarily as a result of additional compression use in both Egypt and Bulgaria. Operated drilling activity occurred in both Romania and Egypt during the year resulting in associated emissions.

Summary and conclusions

2014 was a year with significant highlights in the areas of production, development progress, portfolio management, reduction of net debt and equity raising, offset by disappointing well results from our exploration activities, a reduction of reserves and lower commodity prices which caused asset impairments, and a potential offer for the Company which did not materialise. I would like to thank all staff and stakeholders for their hard work and contribution during 2014.

In 2015, the Company is focussing its efforts on its core assets and away from high risk or low graded exploration. In difficult industry times, the ability to adapt is critical to succeed and we continue to focus on project delivery with a constant view towards increasing value for shareholders.

Brian O'Cathain
Chief Executive

OPERATIONAL REVIEW ALGERIA

Highlights

Ain Tsila development Front End Engineering and Design contract awarded

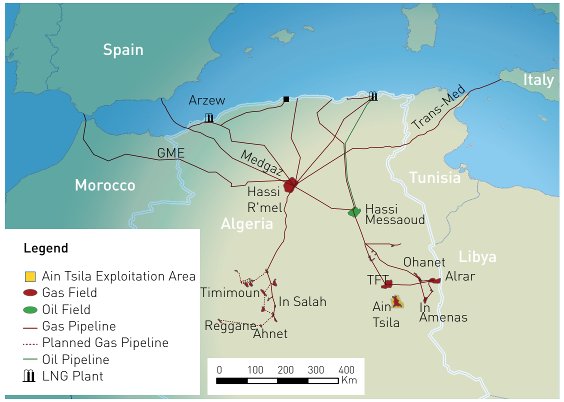
Contract awarded to Sinopec for drilling rig

First 12 development well locations agreed

Mobilisation of the Joint Operating Organisation to Hassi Messaoud complete

Fully termed Gas Sales Agreement signed and approved

Divestment to Sonatrach of an 18.375% interest in the field



During 2014, Petroceltic made significant progress towards the development of the strategically important Ain Tsila gas condensate field, which lies within the Isarene concession in the Illizi basin in south east Algeria.

An experienced Project Team has been established and the Joint Operating Organisation ("JOO" or "Groupement"), which is responsible for executing the field development plan, is now conducting operations on behalf of Sonatrach, Petroceltic and Enel. The Front End Engineering and Design ("FEED") contract was awarded in September and the Gas Sales Agreement was signed and approved by the Algerian authorities in November. By early 2015, the JOO had relocated from Algiers to the main Algerian oil and gas operating centre at Hassi Messaoud. Planning for the drilling programme is also well advanced with a rig contract awarded to Sinopec in April 2015 and contract award recommendations made for long lead time equipment, and the first 12 development well locations agreed.

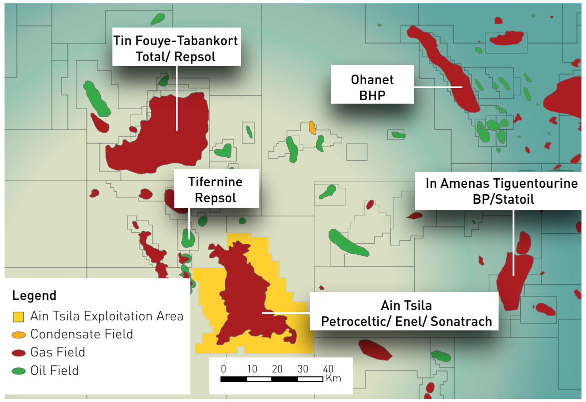
Of particular importance during the year was the successful completion of a second farm-out of a 18.375% interest in the Ain Tsila field to Sonatrach, the National oil and gas company of Algeria. The total consideration for the farm-out is $160m, with up to $20m of potential further payments contingent on certain project milestones. Under this agreement, Petroceltic's cost in the project will be carried until the second quarter 2016.

2015 will see the completion of the FEED studies and the tender and award of the EPC contract for the major project construction contracts. During the course of the FEED studies, the project cost estimate and schedule will also be updated. Subsurface engineering and geoscience activities will focus on optimising the development plan prior to the commencement of drilling late 2015. In April 2015, the Groupement successfully completed the tendering process for the rig contract resulting in the award and signature of the contract to SINOPEC. The 1500 horse power rig, which is now built and ready to ship, will drill up to 24 new development wells. The first 12 drilling locations, all in the northern region of the field, have already been selected and approved. This will enable drilling to commence on schedule in 2015.

In June 2015 an amendment to the Algerian PSC approving the transfer of Petroceltic's interest in the Isarene development to a subsidiary company was signed by all parties; this amendment and the associated transfer will become effective on gazettal following approval by the Algerian Council of Ministers.

Background

Petroceltic was awarded operatorship of the Isarene PSC in April 2005 with a 75% equity interest, this was subsequently reduced to



2015 will see the completion of the FEED studies and the tender and award of the EPC contract for the major project construction contracts.

56.625% through the divestment of an 18.375% interest to Enel SpA in early 2012, and reduced further to 38.25% through divestment of a further 18.375% to Sonatrach in 2014.

After the initial Ain Tsila discovery in 2009, Petroceltic applied for a two year extension period, from the end of the exploration period in April 2010 through to 26 April 2012, to allow time for the appraisal of the gas accumulation. During this period, the Group drilled six appraisal wells on the Ain Tsila structure.

Approved development plan

Following the completion of the appraisal drilling campaign and technical and economic studies, a full field development plan was submitted to the Algerian authorities and approved in December 2012. The plan envisages the production of 2.1 Tcf of sales gas and 179 MMbbl of liquids (comprising 69 MMbbl of condensate and 110 MMbbl of liquid petroleum gas or "LPG") from the field during the 30 year Production Sharing Contract ("PSC") exploitation period. The initial plan will result in a recovery factor of 24% of the Gas Initially in Place ("GIIP") in the field and the Company anticipates that the recovery factor is likely to grow over time with additional well data and the potential installation of additional gas processing facilities.

The field plateau production rate is forecast to be 355 MMscfpd gross wet gas and the plateau should last for some 14 years. The development plan involves the drilling and completion of 124 vertical development wells, of which 30 (including 6 existing wells) are scheduled to be available prior to first production. Along with basic in-field support infrastructure, the facilities will comprise a gas processing plant with water separation, condensate and LPG recovery equipment, gas compression, export pumps and metering facilities. The gas will be evacuated via a 95 kilometre pipeline which will tie into the main Algerian gas transmission network near the Tin Fouye Tabankort field. Dedicated condensate and LPG export lines will also be constructed to tie into liquids transmission infrastructure.

The gross project cost prior to first production is expected to be in the region of $1.6 billion with the majority of the expenditure incurred from 2016 through 2018. The capital estimate and phasing will be confirmed in more detail after the FEED studies have been completed and EPC contract awarded.

Gas commercialisation

Following the execution of a legally binding Heads of Terms for the Gas Sales Agreement with Sonatrach in 2012, the comprehensive Gas Sales Agreement detailing operation procedures and processes required for nominations and payments was signed in September 2014 and approved by the Algerian Energy Ministry in November 2014.

OPERATIONAL REVIEW ALGERIA
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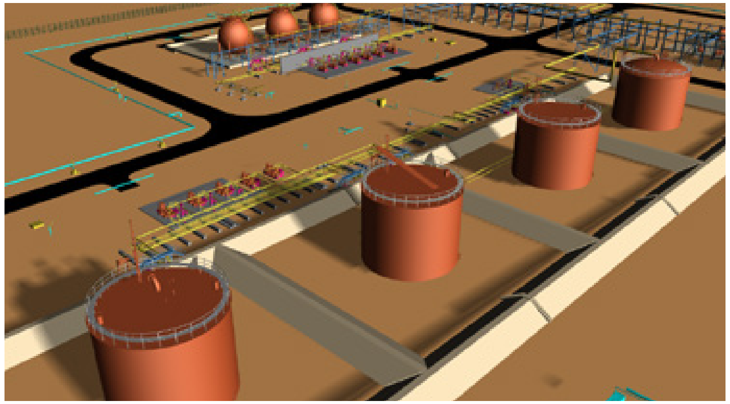


Isarene concession timeline

2005 - Award of Isarene Production Sharing Contract

2006 - First exploration drilling of two wells

2008 - 3D seismic acquisition

2009 - Five wells drilled, resulting in the Ain Tsila discovery, the year's 9th largest worldwide

2010 - Two year delineation licence extension awarded

2011 - Successful six well drilling campaign

2012 - Farm-out of 18.375% interest to Enel
- Declaration of Ain Tsila field commerciality
- Development Plan and Gas Sales Heads of Terms approval
- Award of 30 year exploitation licence
- Booking of 304 MMboe of proved plus probable reserves

2013 - Formation of Joint Operating Organisation to develop the field
- FEED tender issued to market

2014 - FEED contract awarded and studies commence
- Farm-out of 18.375% interest to Sonatrach
- Drilling contracts tendered

2015 - Mobilisation of Joint Operating Organisation to Hassi Messaoud
- Rig contract awarded
- Major project EPC contract to be tendered and awarded
- Commencement of development drilling

2016 - 2018 Project execution phase including, drilling 24 wells and constructing gas processing plant and related infrastructure

Liquids
Condensate and stabilised LPG form a significant part of the reserves and revenues from the Ain Tsila field. Based on data from similar developments, the Company anticipates that both condensate and LPG will be sold in the local market at a price related to Brent.

Second farm-out
A process to divest an additional 18.375% of Petroceltic's equity in the Isarene PSC was initiated in 2012 as part of the Company's strategy to manage its overall financial and operational commitment to the Ain Tsila development. In early 2013, Petroceltic agreed a farm-out proposal from an international oil company and initialled a Sale and Purchase Agreement. However, in July 2013, Sonatrach exercised their right to pre-empt the transaction and acquire the interest on similar terms.

The agreement to effect the transfer of the interest to Sonatrach was signed in February 2014 and ratified by the relevant Algerian government authorities in June. The consideration included a $20m initial cash payment, a cost carry of up to $140m and two potential further $10m payments contingent on the achievement of certain key project milestones. Petroceltic retained a 38.25% interest in the project through to first gas.

The farm-out has resulted in a reduction in Petroceltic's booked proved plus probable reserves from 300.0 MMboe to 202.7 MMboe, which has been reflected in the Company's year end 2014 reserves figures.

Exploration licencing round
The Algerian government launched a new exploration licencing round in 2014. The Group evaluated the tendered blocks, but due to a combination of technical and commercial considerations decided against making a licence application in the round.

The agreement to effect the transfer of the interest to Sonatrach was signed in February 2014 and ratified by the relevant Algerian government authorities in June.

CASE STUDY
GROUPEMENT ISARENE

When the Isarene PSC was awarded in 2005, Petroceltic was qualified as an operator in Algeria. During the initial exploration and appraisal phase of activity, almost 10,000 km of 2D and 900 sq km of 3D seismic were shot, processed and interpreted, supporting the drilling and testing of 13 wells and the preparation of a field development plan for the Ain Tsila gas field. Enel joined Petroceltic as an investor in the field in 2012 and Petroceltic remained as joint venture operator.

Following approval of that development plan by the Algerian authorities at the end of 2012, Sonatrach joined the venture as a paying participant in the exploitation phase. Upon commencement of this phase, consistent with the requirements of the PSC, the responsibility for the execution of petroleum operations on the Isarene permit passed to a newly constituted Joint Operating Organisation called "Groupement Isarene". This entity was set up in mid-2013 under the control of the PSC parties. It is financed by monthly cash calls to the Isarene PSC partners and is directed by a management council with representation of all the PSC parties.

Prior to the constitution of the Groupement Isarene, Petroceltic and Sonatrach negotiated the organisational structure and the allocation of positions between the parties, and, through the course of 2013, Petroceltic has redeployed or recruited more than 50 experienced professionals on behalf of itself and Enel to take up these positions, primarily in management, supervisory, finance and technical roles. These secondees are located alongside their Sonatrach counterparts in the Groupement offices, initially in Algiers through to the end of 2014, prior to their deployment to major contractor sites, the field and Hassi Messaoud (the oil and gas operating and logistical centre of Algeria).

Through 2014, the Groupement project team concentrated on the preparation of the contract tender packages for the Ain Tsila production facilities and infrastructure FEED and development drilling. The FEED contract was awarded to Chicago Bridge & Iron BV in the Netherlands, while at year end the drilling rig had been identified and the contract was subsequently awarded in 2015, to Sinopec International Petroleum Services Corporation.

In January 2015, the Groupement relocated its main office from Algiers to Hassi Messaoud to allow access to a larger resource pool of Sonatrach secondees, and from there development operations will ramp up with the preparation of the tenders for the main production facilities construction packages, the award of those construction packages, and the commencement of drilling. In the Ain Tsila field, a forward operations base and basic infrastructure will be constructed, allowing for the mobilisation of drilling rigs and construction crews in the second half of the year. Opportunities were taken during 2014 to optimise the timing of drilling start-up which will now take place in Q4 2015. This will ensure that the required number of wells are available to be hooked up for production at first gas in Q4 2018.

In line with other operators in Algeria, the Company has prepared and issued a Development Security Philosophy to ensure appropriate security controls for all in-country activities. The FEED study will address a number of these critical controls – physical, procedural, organisational – and ensure that best practice is designed and engineered into all aspects of construction and subsequent operation of the project facilities.

Through 2014, the Groupement project team concentrated on the preparation of the contract tenders packages for the Ain Tsila production facilities and infrastructure FEED and development drilling.

OPERATIONAL REVIEW EGYPT

Highlights

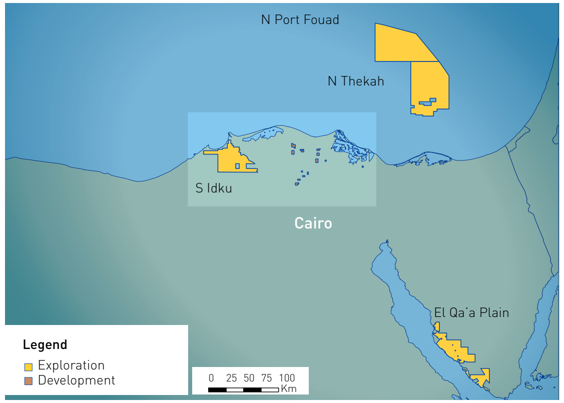
Average production of 95.3 MMscfpd of gas and 2,821 bopd of hydrocarbon liquids

Completion of two successful development wells and one workover

Commissioning of the West Khilala and South Damas compression projects

Ratification of two new exploration licences and the award of a third

EGPC receivables reduced from $81m to $50m



Petroceltic's core area of operations in Egypt is in the onshore Nile Delta where it holds a 100% operated interest in 12 producing fields in 14 development concessions in the El Mansoura and the South East El Mansoura concession areas. The field development operations are managed through a Joint Operating Company called Mansoura Petroleum Company jointly owned by Petroceltic and the Egyptian Government.

During 2013 and 2014, the Company has significantly renewed its exploration portfolio in Egypt and in January 2014 PSCs were signed for two new licences. These include a 75% interest in the onshore South Idku concession and a 50% interest in the exciting, deep water North Thekah block, which is thought to contain an extension of the prolific Levantine basin exploration play. In the second half of the year, the Company was also awarded a 50% interest in the North Port Fouad block, which is adjacent to North Thekah, and the PSC was signed in January 2015. These licences, combined with the Company's existing 37.5% interest in the El Qa'a Plain concession, provide Petroceltic with a diversified exploration portfolio, containing oil and gas prospectivity and with high volume potential.

Political and economic situation

2014 marked a return to political stability in Egypt with a number of key developments taking place. In January the new Egyptian constitution was approved by referendum and this was shortly followed by Presidential elections in May. The winner of the elections was President El Sisi who assumed office in June and swiftly formed a new Government. Preparations are now underway for Parliamentary elections in 2015.

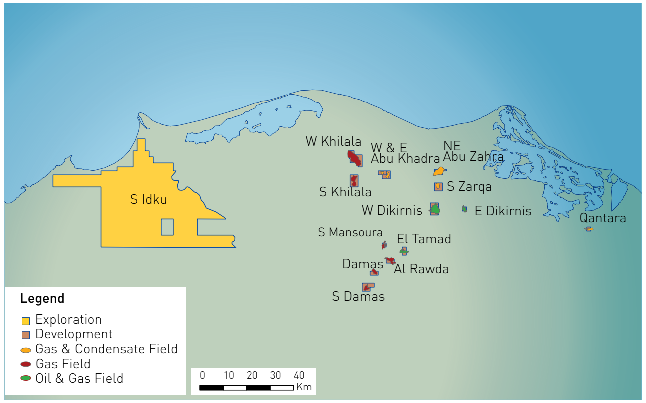
The economy continued its gradual path of improvement during the year and the country's credit rating and outlook were raised by Standard & Poor's and Fitch twice from "CCC+/C" to "B-/B" with a "stable" outlook. Several initiatives are being pursued by the government to attract foreign investment and the decision in the summer of 2014 to reduce fuel subsidies by an average of 30% was a clear sign of the government's desire to begin to implement important market reforms.

During the year, the Government continued to address the issue of payment arrears with the international oil and gas companies and in December made a significant disbursement amounting to the equivalent of $2.1bn. This brought the total paid to the industry since December 2013 to around $5bn (over 60% of the arrears).

Petroceltic received payments totalling $120m in 2014, and the receivables were reduced from $81m to $50m over the course of the year. The payments were made in cash and also by means of the allocation of sales proceeds from part cargoes of crude and crude oil products.

Production and reserves

In 2014, Petroceltic's daily production in Egypt averaged 19,256 boepd on a working interest



basis, which is equivalent to 8,675 boepd on a net entitlement basis. The working interest production split between hydrocarbon types was 95 MMscfpd of gas and 2,821 bpd liquids (oil, condensate and LPG) representing an 85%/15% split on a volume basis. Approximately 74% of the production was derived from the West Dikirnis, South Damas, and the West and South Khilala fields, with the remainder from eight smaller accumulations.

Throughout the year, the Company continued to invest in its producing assets with new compression facilities installed at the West Khilala field to reduce the well head flowing pressures and hence maximise gas recovery, and a small booster compressor commissioned for the South Damas field. The Company also drilled and completed two successful development wells during the year, namely West Khilala-4ST and East Abu Khadra-1ST and conducted work-overs to re-establish production from the West Dikirnis-2 and 8 wells. While the production figure for the year was positive, a small number of reservoir performance issues have required a downwards adjustment to booked reserves as at 31 December 2014. In particular, recent well performance on West Khilala has been negatively impacted by water and sand production, requiring a reduction of 35 Bcf; a more modest reduction was made in respect of West Dikirnis where heavier risking was applied to the gas reserves which will be recovered during the gas cap blowdown phase late in field life.

West Dikirnis field

The West Dikirnis field, which contains a 70 foot oil rim, overlain by a gas cap, was discovered In 2005. The field commenced production in 2007 and to date, the Company has focused on maximising the hydrocarbon liquids recovery by drilling a combination of vertical, high angle and horizontal wells and installing Liquid Petroleum Gas ("LPG") extraction and Gas Reinjection facilities. These facilitates are used to strip the hydrocarbon liquids out of any gas which is produced with the oil, and then to re-inject the gas back into the reservoir to maintain the reservoir pressure.

An active reservoir management programme is in place for the field, and individual well withdrawal rates are managed to prevent excessive quantities of water, sand or gas being produced. We are also planning to implement an Enhanced Oil Recovery Scheme using a form of miscible gas flood. This will take advantage of the fact that the West Dikirnis crude oil is highly volatile and can be vapourised in the reservoir if it is contacted by re-injected gas. To implement the scheme, Government approval is being sought to convert 3 redundant oil wells to gas injection in 2015/16 (to supplement the one existing gas injector) and to increase the gas cycling rate in the field. Two more additional producers will also be drilled in 2015/16.

During the year, a successful workover was performed on the West Dikirnis-8 well to correct a safety problem (tubing to casing pressure communication) and the well was returned to production at 200 boepd. A low cost rig-less workover was also conducted on West Dikirnis-2 to add perforations and the well, which had been shut-in due to water production, resumed production at 400 bopd.

The field's average production rate in 2014 was 1,967 bopd of oil, condensate and LPG, and approximately 33 MMscfpd of gas. Approximately 19 MMscfpd of the produced gas were re-injected into the reservoir, 11 MMscfpd were sold to the local market and the remainder used to run the facilities. Gas sales were maintained sporadically during the year until the end of September in response to a request from the Government to supply gas during periods of domestic supply shortfall (particularly during the summer months).

The field's ultimate proved and probable reserves are estimated at 18.2 MMbbl of hydrocarbon liquids and 62.4 Bcf of gas. By the end of 2014, the field had produced 10.9 MMbbl of liquids and 26.2 Bcf of gas.

West Khilala field

The West Khilala gas field was discovered in 2005 and came on stream in February 2007. The average production rate during 2014 was 30 MMscfpd of gas and 30 bopd of condensate from six wells.

The field is now relatively mature and the focus of the field management programme is to minimise the impact of water and sand production on individual well performance and surface flowlines and facilities. As part of a programme, the Company has standardised on open hole gravel packs as being the best downhole completion design and in early 2014 the watered out West Khilala-4 well was sidetracked and successfully

OPERATIONAL REVIEW EGYPT
CONTINUED

completed with a gravel pack and returned to production at 6 MMscfpd. At the end of the year, the West Khilala-3 well was also sidetracked but unexpectedly encountered a swept area of the reservoir and was plugged and abandoned in early 2015.

The year end 2014 ultimate proved plus probable reserves are 250 Bcfe and the remaining reserves estimated at 42 Bcfe. These figures reflect a downward revision of some 35 Bcfe based on the West Khilala-3 sidetrack results and other recent well performance data. This reserve write-down had a direct impact on the NPV of the asset and this contributed to the impairment charge at year end.

South Khilala field

The South Khilala field was discovered in May 2009 and was placed on production in October 2009 through the West Khilala processing facilities. The average production rate in 2014 was 9 MMscfpd of gas and 13 bopd of condensate from two wells. A third well (South Khilala-3) is under consideration to drain the most crestal part of the field, to help maintain the field's production rate and maximise reserves. The field's remaining reserves as at year end 2014 are estimated at 24 Bcfe and the cumulative gas production to date is 30 Bcfe.

Damas and South Damas fields

The Damas and South Damas fields were discovered in 2008 and 2010 respectively. Damas was brought on production during 2009 but was temporarily shut in during 2010 to enable the South Damas field to flow through a common pipeline to the South Mansoura production facilities. In November 2014, the flow line pressure was decreased by transferring a booster compressor from the South Batra gas plant to the South Mansoura gas plant. This allows for the continuity of the production from this field and potential upgrade of its ultimate recoverable reserves.

The South Damas field has performed exceptionally well since inception and the field's initial gas in place has been progressively upgraded to 67 Bcf. The field is being drained by 2 wells, with one completed with a gravel pack to control sand production. The average production rate for the year was 18 MMscfpd of gas and 144 bopd of condensate.

The ultimate proved plus probable recoverable reserves are estimated at around 58 Bcfe and the field had produced about 25 Bcfe by year end 2014.

> The South Damas field has performed exceptionally well since inception and the field's initial gas in place has been progressively upgraded to 67 Bcf.

Other fields

The Group also operates eight smaller fields in the Nile Delta which contributed 5,244 boepd of the total production in 2014.

The Tamad field gas cap blow down commenced in 2013 and, in 2014, the field contributed 10.4 MMscfpd and 93 bopd of condensate.

The South Zarqa field, which has a very active aquifer and produces from a single gravel packed well, contributed 7.9 MMscfpd of gas and 254 bopd of condensate.

In the East Abu Khadra field, an old watered out production well was successfully sidetracked to an updip location during the year and the new wellbore is currently producing at a rate of 3 MMscfpd.

The East Dikirnis oil and gas field, which has a thin oil rim, was tied back to the West Dikirnis facilities in January 2013 and the single production well is currently flowing at approximately 226 bopd and 0.9 MMscfpd under rate control.

Exploration

Petroceltic has been expanding its exploration portfolio in Egypt during 2013 and 2014 in order to replenish the prospect inventory. The Company now has interests in four exploration concessions as follows:

El Qa'a Plain
(Petroceltic 37.5%, Dana 37.5% (operator), Beach Energy 25%)

This concession is located in an under-explored sub basin on the eastern shore of the Gulf of Suez and contains a substantial number of oil leads identified on existing 2D seismic data. The gross unrisked mean prospective resource potential is estimated at 140 MMbbl. The concession was ratified in October 2013 and signed in January 2014 and the forward plan is to acquire 450 sq km of 3D seismic in 2015 followed by the drilling of one or more exploration wells in 2016. The seismic contract was tendered, evaluated and signed by Q2 2015.

South Idku
(Petroceltic 75% (operator), Edison 25%)

This concession was awarded in April 2013 and is located in an under explored part of the onshore Nile Delta on trend with Edison's offshore producing Abu Qir field (1.5 Tcf + 40 MMbbl). A number of amplitude supported leads have been identified in the Miocene formations on 2D seismic and the total prospective resources are estimated to lie in the range 400 Bcf to 1900 Bcf. A tendering process is underway for the acquisition of a 3D seismic survey and exploration drilling is likely to occur in 2016.

North Thekah
(Petroceltic 50%, Edison 50% (operator))

This concession was also awarded in April 2013 and is located in the deepwater Nile Delta within an underexplored part of the Levantine Basin. The primary exploration target in this block are Nile Delta Oligocene and Levantine Basin Miocene plays on trend with the giant Leviathan and Tamar discoveries in Israel. A number of potentially significant leads and prospects have been identified on existing 2D seismic. 3D seismic acquisition is now completed and although there are no commitment wells in the current exploration period, a decision will be made with respect to exploration drilling following evaluation of the new 3D seismic survey.

North Port Fouad
(Petroceltic 50%, Edison 50% (operator))

The concession which was awarded in September 2014, is adjacent to North Thekah in the deepwater Nile Delta and has similar plays and objectives. 3D seismic tendering will start later in 2015 and a decision will be made with respect to any exploration drilling which is likely to occur in 2018/2019.

Exploration in Development Concessions
(Petroceltic 100%)

Exploration well South Dikirnis-1 was drilled in May 2014 to test the extension of Qawasim formation reservoir in a tilted fault block within the West Dikirnis development concession. The well results showed minor gas shows in Qawasim formation which indicated the main reason for failure was the ineffective lateral seals in the well.

OPERATIONAL REVIEW BLACK SEA BULGARIA

Highlights

Average gas production rate of 18.6 MMscfpd

Kavarna East development planning completed

Successful export compressor major overhaul

Petroceltic has a 100% operated interest in three producing gas fields and one future development in the Galata Exploration Block, which is located in shallow water, offshore Bulgaria, in the Black Sea. The producing fields were developed using an unmanned platform located on the main Galata field, to which the Kaliakra and Kavarna fields have been tied-back using subsea completions.

Production

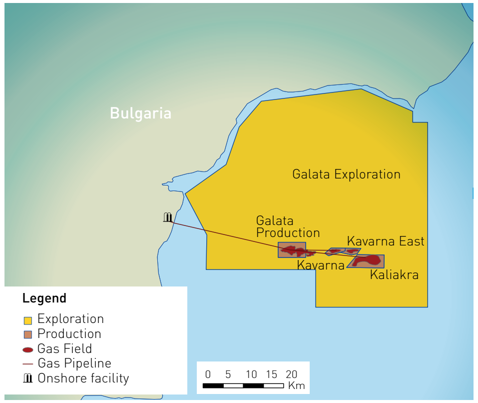
The combined production rate from the Galata, Kaliakra and Kavarna fields averaged 18.6 MMscfpd during the year, with a cumulative production volume of 6.8 Bcf. The gas was sold to two customers, Bulgargaz (the state gas utility company) and Agropolychim (an independent fertiliser plant) at an average price of $8.34/Mcf giving total revenues of $51m.

The Galata field continued to perform well during 2014 and data acquisition surveys run in the wells have confirmed a relatively static water level in the field and continued gas recharge into the main reservoir from the remote areas of the field. Consequently, the field was capable of producing at an average rate of 9.7 MMscfpd during the year.

Given the positive field performance, the Company is evaluating the technical merits of performing a low cost wireline workover to potentially restore production from the GP-2 well. This well was shut-in in late 2008 due to the onset of water production but data shows there has been limited movement in the gas water contact ("GWC") in the vicinity of the well and there is still a significant interval of gas bearing perforations above the GWC. The workover would involve the mechanical isolation of the water bearing interval, enabling production to be resumed from the gas bearing zone.

The two smaller fields, Kaliakra and Kavarna produced a combined average rate of 8.9 MMscfpd during the year, which was slightly below forecast. The Kaliakra-1 well rate has continued to slowly decline suggesting that the well is only in partial pressure communication with the main field area. Hence, the Company is actively considering whether an additional well will be required to

The Galata field continued to perform well during 2014 and data acquisition surveys run in the wells have confirmed a relatively static water level in the field and continued gas recharge into the main reservoir from the remote areas of the field.



The Kavarna East field was discovered in 2010 and contains approximately 9.6 Bcf of gas reserves.

fully drain the field. The Kavarna-1 well has experienced water breakthrough and is likely to be shut-in when the Kavarna East field comes on stream.

Given the recent field performance, the year end 2014 reserves for the Bulgarian fields have been marginally downgraded and the combined remaining reserves are estimated at 26.6 Bcf.

In November, all the Company's Bulgarian fields were shut-in for a period of 20 days to complete a planned overhaul of the high pressure export compressor. This involved the replacement of the compressor bundle and main drive unit and the work was completed for a cost of $2.5m. Excluding the compressor related work activity, the production facilities uptime in Bulgaria continues to be world class at over 99 percent.

Development

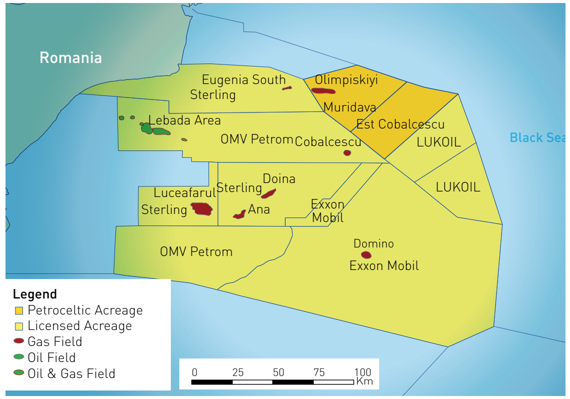
The Kavarna East field was discovered in 2010 and contains approximately 9.6 Bcf of gas reserves. The field will be developed using a single subsea well tied back to a manifold near the Kavarna field and, from there, the gas will flow to the Galata platform using the existing Kavarna flowline. As this is an existing discovery with pipeline laid, the development involves re-entry and completion of the existing well. The project execution plans are well advanced with all the long lead time equipment procurement activities completed. The exact project timing is now dependent on rig and diving support vessel availability.

OPERATIONAL REVIEW BLACK SEA ROMANIA

Highlights

Safely completed the drilling of South Cobalcescu-1 and Muridava-1 exploration wells

Licences divested in June 2015



During 2014, Petroceltic operated two offshore exploration concessions in the Romanian sector of the Black Sea with a 40% operated interest in each. The licences, Block 27 Muridava and Block 28 Est Cobalcescu, are located in shallow water and have a combined area of approximately 2,000 sq km. Both blocks cover an area that has historically been under-explored due to a previous maritime border dispute.

The Block 27 Muridava partnership comprised Petroceltic Romania B.V. (40% equity and operator), Midia Resources S.R.L. which is a wholly owned subsidiary of Sterling Resources Ltd (40% equity) and Petromar Resources S.A. (20% equity). The Block 28 Est Cobalcescu partnership comprised Petroceltic Romania B.V. (40% equity and operator), Beach Petroleum S.R.L. which is a wholly owned subsidiary of Beach Energy Ltd (30% equity) and Petromar Resources S.A. (30% equity). The initial minimum work programme for each Block comprised seismic acquisition and three wells.

The Joint Venture partners has now drilled two wells, one in each of the Blocks, on the highest graded prospects as defined using the 3D seismic acquired in 2012. Both wells were located approximately 170 kilometres northeast of Constanta and drilled using the GSP Prometeu jack up drill rig. Unfortunately, neither of the wells encountered commercial quantities of hydrocarbons and both were subsequently plugged and abandoned. The Cobalcescu South-1 well in Block 28 did encounter good quality sandstones at the target Miocene stratigraphic levels with gas shows while drilling, indicating an active hydrocarbon system. The Muridava-1 exploration well in Block 27 licence was drilled to a total depth of 2,747 metres but failed to encounter commercial quantities of hydrocarbons in the primary Eocene, Paleocene and Upper Cretaceous reservoir targets.

The disappointing drilling results confirmed an active hydrocarbon system and that good reservoir quality is present, but significantly increased the risk to the residual prospect inventory. A detailed technical review of the remaining prospectivity in each licence was conducted and the conclusion was that the remaining prospects were either sub-commercial from a scale perspective or of unacceptable technical risk to justify further investment.

In June 2015, Petroceltic completed the sale of the entire share capital of Petroceltic Romania B.V (which held the interests in Block 27 and Block 28) to GVC Investment B.V, a private limited company which has considerable oil and gas assets in the region.

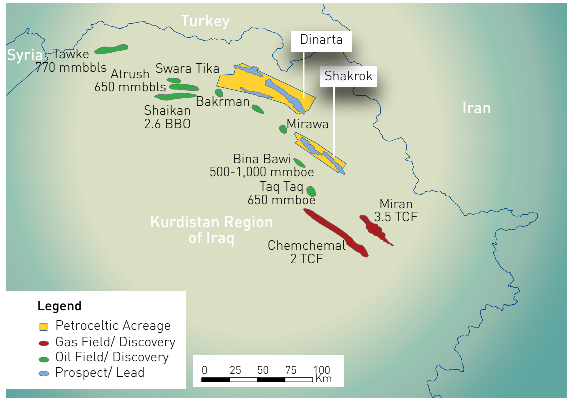
Following the completion of this sale to GVC, Petroceltic has no remaining obligations in Romania.

OPERATIONAL REVIEW KURDISTAN REGION OF IRAQ

Highlights

Shakrok 1 well plugged and abandoned and the Shakrok licence relinquished

Shireen 1 well encountered operational problems and without positive indications of commercial hydrocarbons the Dinarta licence was relinquished



Petroceltic has been active in the Kurdistan Region since 2011 when the Shakrok and Dinarta blocks were awarded with Petroceltic holding a 16% interest (20% paying interest) in each Production Sharing Contract ("PSC") in the northern area of the Kurdistan Region of Iraq ("KRI"). The blocks were awarded in partnership with the operator, Hess Middle East New Ventures Ltd ("Hess"), with a 64% participating interest (80% paying interest) and the KRG with a 20% carried interest.

The work programme for each block consisted of 2D seismic and the drilling of two exploration wells, one on each block. The Company's first exploration well in the KRI, Shakrok-1, was spudded in August 2013 and reached a total depth of 3,538 metres in the Triassic Geli Khana formation in March 2014. Drill Stem Tests were carried out over four prospective zones in the Jurassic. No hydrocarbons flowed to surface although the water flow rates confirmed the presence of some very high quality fractured reservoirs. Wireline logging and fluid sampling established the presence of a 27 metre gas-condensate column in the Triassic formation but this was not viewed as commercial. Hence the well was plugged and abandoned as a sub-commercial gas discovery in May 2014. All work program commitments have been fulfilled on the Shakrok PSC and it was formally relinquished in July 2014.

Operationally, the focus on the Dinarta block in 2014 was the preparation for and drilling of the Shireen-1 well. This was the highest elevation well ever drilled in Kurdistan with a surface location 2,100 metres above sea level. In addition to the logistical hurdles provided by well site excavation and access route construction, further challenges were encountered due to the karstified nature of the near-surface geological environment, the pervasive fracturing of the carbonate stratigraphy and the execution of drilling, casing and cementing operations in the shallow section above the water table.

The Shireen-1 well was spudded in June 2014, using the Parker 247 rig, and the top hole section was successfully drilled and cased. However, in August, a degradation of the regional security environment occurred due to the ISIS incursion into Northern Iraq from Syria. While these developments did not directly impact exploration activities, in line with other operators in the region, it was decided to temporarily secure and suspend operations at Shireen-1 and to evacuate non-essential personnel as a precautionary measure. Further to this temporary suspension announced in August, drilling operations resumed at the Shireen-1 exploration well in October. Subsequently, the well encountered a further series of operational problems which ultimately resulted in its premature suspension in the Jurassic formation. Prior the well suspension, no positive indications of commercial hydrocarbons had been observed.

Following a detailed review of the Shireen-1 well data and the remaining prospectivity on the Dinarta concession, a decision was taken by the Joint Venture partners to relinquish the block. All PSC work program obligations were fulfilled other than the required final remediation of the well sites. All costs associated with both the Shakrok and Dinarta licences were written off as unsuccessful exploration costs, including a provision for 2015 exit costs, in the year ended 31 December 2014.

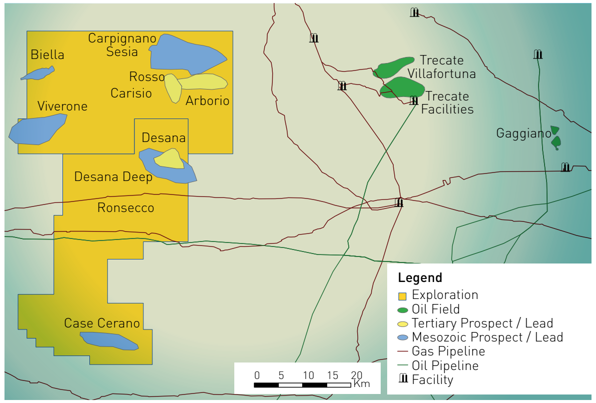
OPERATIONAL REVIEW ITALY

Highlights

Re-submission of Environmental Impact Assessments for approval for Elsa and Carpignano Sesia

International certification of country level HSES Management System

Purchase of 750km 2D seismic data over the high-graded offshore Turchese prospect



The past year has seen steady progress on the Company's Italian assets, with significant milestones achieved on key projects in the Central Adriatic and in the Po Valley. The primary focus has been on recommencing the environmental permitting process in key projects, supported by ongoing engagement with national and local institutions to demonstrate that exploration activity can deliver tangible benefits to local communities and the Government in a safe and environmentally responsible fashion. A significant milestone was achieved in June 2014 when DNV certified the country level HSES management system as meeting the requirements of ISO14001 for environmental management and OHSAS18001 for occupational health and safety management. This brings Italy into line with the Company's other operating areas which also have the international accreditation.

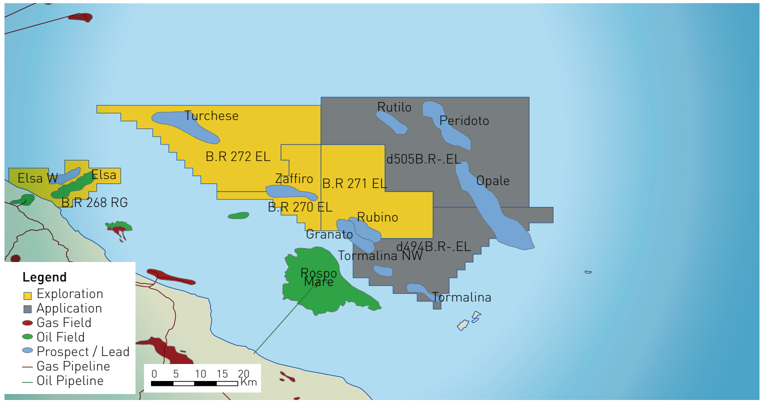
The "Restart Italy" decree, passed into law in November 2014, builds on the National Energy Strategy of 2013 in reaffirming the strategic nature of domestic hydrocarbon exploration and production activities and contains a number of measures aimed at facilitating progress in the sector whilst aligning regulation with offshore safety EU directive. These include the introduction of the "Single Permit" which aims at simplifying permitting by combining exploration and production phases into a single licence and transferring the responsibility for onshore environmental permits from the Regions to the Ministry of the Environment.

Western Po Valley

The Environmental Impact Assessment ("EIA") for the Carpignano Sesia-1 well was resubmitted by the Operator, Eni, to the authorities in December 2014, following revisions aimed at addressing stakeholder concerns relating to the proximity of the well location to the village of Carpignano Sesia. This well is being designed to test a large oil prospect located some 25km west of the analogous Villafortua-Trecate Field, which has gross mean unrisked prospective resources of 237 MMboe. Petroceltic has a 47.5% equity interest in the licence. The process to farm-out a portion of Petroceltic's interest in the block is at an advanced stage and commercial discussions with a potential farminee have been concluded.

Central Adriatic

The Group's main operated asset in Italy is the Elsa oil discovery, offshore Abruzzo, which is expected to contain 95 MMbbl of gross 2C contingent resources (Petroceltic 55%, paying interest 70%). The discovery requires further appraisal drilling and the EIA for the Elsa-2 well was resubmitted in July 2014, following consultative discussions with the government and local institutions. The Elsa-2 well aims at establishing potential production rates and acquiring a high quality fluid sample, both necessary to establishing the basis for



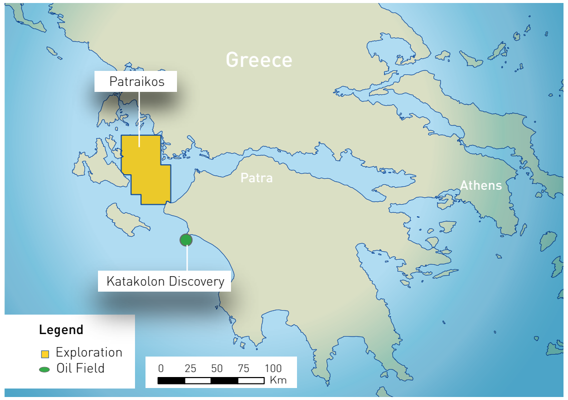
commercial development of the field. In March 2015, technical approval was issued by the EIA Commission, EIA final decree is expected soon, paving the way for the Elsa-2 well which will be started most likely in late 2016.

Further offshore from the Elsa field but in the same exploration play, the Company holds an interest in the B.R272.EL permit which contains the high graded Turchese prospect. This permit was awarded on a 100% basis to Petroceltic, however, Orca Exploration Group Inc retains an option to acquire a 15% interest in the licence. The Company purchased access to 750km of 2D seismic data over the block during the year to further evaluate the prospectivity.

For more information, please see our Petroceltic Italia website www.petroceltic.it

The Group's main operated asset in Italy is the Elsa oil discovery, offshore Abruzzo, which contains 95 MMbbl of gross 2C contingent resources

OPERATIONAL REVIEW GREECE



The award of the Patraikos block (Petroceltic, Hellenic (operator) and Edison 33.3% each) was formally ratified by the Greek parliament in October 2014.

The licence is located in the Gulf of Patra and covers an area of 1,892 sq km with water depths principally in the range of 100 to 300 metres. The concession is potentially oil prospective in the Jurassic, Cretaceous and Eocene formations and the regional hydrocarbon system has been proven by the Katakolon oil discovery wells drilled in 1982, approximately 35 kilometres south of the block. There are also several known oil seeps around the Gulf of Patra area. There is extensive 2D seismic data already available over the block and the unrisked mean prospective resources for the mapped prospects lie in the range of 80 MMbbl to 360 MMbbl.

The Group is currently considering divestment of this licence.

HEALTH, SAFETY, ENVIRONMENTAL AND SOCIAL REVIEW

At Petroceltic, we are committed to maintaining high standards of health, safety, environmental and social performance across all our operations. Our aim is to create a well governed, sustainable business with a strong sense of social responsibility which has a positive impact in the countries in which we operate.

Consistent with our guiding business principles and as declared in our HSES Policy, we strive to:

- Avoid harm to all people involved in, or affected by, our operations
- Minimise the impact of our operations on the environment
- Comply with all applicable legal and regulatory requirements
- Act in an ethical manner and ensuring transparency in our business dealings
- Have a positive impact on the people and communities directly affected by our activities and
- Achieve continuous improvement in our HSES performance.

Health, Safety, Environmental and Social performance is integral to the success of our Company, and is managed alongside all other facets of the business. In recognition of the Company's current portfolio and forward programmes, we have taken significant steps to further enhance our HSES management capability.

During 2014, we made considerable progress in embedding the new HSES Management System into both existing and new operations. Particular emphasis was placed upon adoption of procedures addressing risk management, emergency response, contractor management, incident investigation and performance reporting.

Land transport safety remains a highly ranked risk for Petroceltic, as it is for the industry. We have reviewed and enhanced our land transport safety programmes in both Algeria and Egypt, adopting recognised industry practice to improve our approach regarding equipment, driver competency and journey management.

Enhanced HSES reporting was introduced at the start of 2014 encompassing a broader and deeper range of HSES performance metrics, including the introduction of process safety metrics in line with industry guidance, focused on loss of primary containment events. This has enabled improved understanding of underlying performance and effectiveness of our management system.

Brian O'Cathain, Chief Executive Officer, has been designated as the Executive Board member responsible for the HSES Policy and Management System and formally reports on these matters on a regular basis to the Board. A HSES update is also provided at each monthly meeting of the Executive Management Committee.

Managing HSES Risks and Performance

Central to the HSES Management System Framework is the process of identifying and addressing potential health, safety, environmental and social risks at all stages of the lifecycle, from new business development, to exploration activities, subsequent development and ongoing operations.

Key HSES indicators are identified and monitored throughout the year. Performance against these is reported regularly to the Board and, when required, to regulators, investors and financial stakeholders. The results are consolidated at the end of each year and overall performance

is reviewed by the Senior Management team where areas for improvement are identified and integrated into forward plans.

Safety Performance Data

Historically Petroceltic has monitored a focused set of HSES key performance metrics at corporate level, in line with recognised industry benchmarks. These are reported here for 2014 and 2013, and include the additional metrics introduced in 2014 to enable a deeper level of monitoring and review.

Performance data is presented for all activities under Petroceltic operational control. Injury data includes both staff and contractor personnel. Contractors represent over 60% of the Company's total workforce. Included in the "other" category are Petroceltic office locations in Dublin, Edinburgh, London and Rome.

2014	Algeria	Bulgaria	Egypt	Romania	Other	Total
Safety Data						
Fatalities	-	-	-	-	-	-
Lost Workday Cases	-	-	2	-	-	2
Lost Time Injury Frequency -per million hours worked						0.77
Total Recordable Injuries	-	-	3	1	-	4
Total Recordable Injury rate						1.54
Loss of Primary Containment Events	-	-	26	-	-	26
Environmental Data						
Greenhouse Gas Emissions tCO2e		37,566	81,224	2,652	-	121,442
Produced Water Disposal Mbbl	-	118	839	-	-	957
Produced Water Reinjected Mbbl	-	-	346	-	-	346

2013	Algeria	Bulgaria	Egypt	Romania	Other	Total
Safety Data						
Fatalities	-	-	-	-	-	-
Lost Workday Cases	-	1	4	1	-	6
Lost Time Injury Frequency -per million hours worked	-	-	-	-	-	2.09
Environmental Data						
Greenhouse Gas Emissions tCO2e	-	29,207	84,652	3,548	-	117,407
Produced Water Disposal Mbbl*	-	220	560	-	-	780
Produced Water Reinjected Mbbl	-	-	700	-	-	700

*Produced water treatment & disposal in both Egypt and Bulgaria is by third party provider

Health, Safety, Environmental and Social performance is integral to the success of our Company, and is managed alongside all other facets of the business.

HEALTH, SAFETY, ENVIRONMENTAL AND SOCIAL REVIEW
CONTINUED

The Group saw a significant reduction in the number of Lost Time Injuries in 2014, from six in the prior year to two. In total, four Recordable Injuries occurred in 2014, with resulting Total Recordable Injury Rate (TRIR) being upper second quartile when compared to industry peers. In all cases the injured parties have made full recoveries and the incidents were each subject to full investigation with appropriate remedial actions identified and implemented. We believe that our focus on contractor management and hazard and risk awareness has positively affected the occupational safety results achieved this year.

Twenty six loss of primary containment events occurred in our Egypt operations during 2014, predominantly relating to near wellhead erosional issues in valves and flowlines arising as water and sand production increase as the reservoirs mature. Specific actions have been taken in light of this data, including piping redesign and reconfiguration, enhanced ultrasonic inspection and sand monitoring, and we have seen positive results through the second half of 2014. Further review of our integrity management strategy in light of changing reservoir conditions is planned for 2015.

Environmental Performance Data

For this report, Greenhouse Gas ("GHG") emissions are reported as gross operated CO2e for all countries, using UK Defra / DECC guidance on measurement and reporting of GHG emissions, aligned to the GHG Protocol, the internationally recognised standard for the corporate accounting and reporting of GHG emissions.

GHG emissions increased in 2014 primarily as a result of additional compression use in both Egypt and Bulgaria. Drilling activity occurred in both Romania and Egypt during the year resulting in associated emissions.

Total produced water volumes remained at prior year levels, however operational problems with one of our injection wells in Egypt reduced the amount of produced water re-injected and this was managed by increased safe water disposal.

Social Projects

Petroceltic is keenly aware of the potential social impacts of its oil and gas operations on local communities and strives to respect and accommodate cultural, religious and social diversity. The Company's HSES Policy formally recognises this and provides the basis for an on going programme to actively seek appropriate social investment and development initiatives. There is no pre-determined policy on the level of contribution to social projects and each is taken on its merits with a preference towards sustainable initiatives focused on education, health and job creation.

During 2014, we reviewed and refreshed our social responsibility strategy in Egypt, and as a result launched the new Mis El Kheir ("MEK") micro financing programme in the villages of Sherenkash and Salama Selim, both of which are located near the main South Batra plant facilities. The launch events took place in September and were attended by around 150 local people, the regional Governor and his support staff, the Mansoura PetCo Chairman and Petroceltic and MEK representatives.

Petroceltic also continues to financially support the school near West Dikirnis which opened in 2011 and comprises 28 classrooms for over 200 local children.

In Bulgaria, the Company provides financial and logistical support to Karin Dom, a day centre for the rehabilitation and social integration of children with special needs from the Varna region. The Company also provides support for the staff, funding training and team building events.

2015 HSES Priorities:

Our top HSES priorities in 2015 will be:
- Maintaining occupational safety performance, using TRIR as our primary measure
- Delivering a significant reduction in loss of primary containment events in our Egypt operations
- Establishing Petroceltic "Life Saving Rules" in readiness for field activity in Algeria
- Implementing Land Transport Safety programmes fully in Egypt and Algeria
- Updating our integrity management strategy and programme in Egypt
- Refreshing stakeholder mapping and assessments for all countries in support of our operations

Petroceltic is keenly aware of the potential social impacts of its oil and gas operations on local communities and strives to respect and accommodate cultural, religious and social diversity.

CASE STUDY
ELSA 2 EIA

Our aim at Petroceltic is to create a well governed, sustainable business with a strong sense of social responsibility. Acting in an ethical manner, ensuring transparency, minimising the impact of our operations on the environment and striving to build enduring relationships with the communities in which Petroceltic operates are some of the key principles of the Company's HSES Policy.

These principles are reflected in our current approach to the Elsa 2 well Environmental Impact Assessment ("EIA") process.

Petroceltic's objective since the beginning of the EIA process has been to establish and maintain open dialogue and constructive relations with stakeholders based on transparency, mutual respect and evidence-based discussion.

The Environmental Impact Study ("EIS") was prepared by leading Italian practitioners in Environmental Assessment, with the aim of providing in-depth high quality information to all stakeholders involved.

Prior to submission of the EIS, Petroceltic met with both the central and local institutions involved in the EIA process, in order to present the Company and the project. Furthermore, the Company undertook a series of actions to render the EIS documentation as accessible as possible, including the publication of the study and a specific Q&A document on the Petroceltic Italia website www.petroceltic.it. Subsequently, Petroceltic produced a further document in January 2015, which attempts to provide responses, based on factual scientific information, to each and every observation submitted by local stakeholders to the Ministry of Environment. This document was also made available on the Italian website. Meetings with stakeholders are still an essential part of the process.

In regards to the Elsa project, in the current phase we place emphasis on working with stakeholders, transparency and compliance. Should we move to development phase, we would aim to contribute to the local community through job creation and supporting social investment projects.

Petroceltic's objective since the beginning of the EIA process has been to establish and maintain open dialogue and constructive relations with stakeholders based on transparency, mutual respect and evidence-based discussion.

FINANCIAL REVIEW

The Group's financial results for 2014 reflect what has been a challenging period for the oil and gas sector with the significant decline in the oil prices and the resultant impact on both direct revenue and also the balance sheet values of assets. Given the nature of Petroceltic's production portfolio which generates the majority of its revenue from gas production, the Group's 2014 revenue has not been materially affected by the reduction in commodity prices. However, the current low price environment does impact on the asset value of the Group's oil and gas assets, which has contributed to the significant impairment charges reflected in the 2014 results.

The Group's policy is to fund operations through a combination of operating cash flow, available financial facilities and the proceeds of portfolio management. The approval for the transfer of Petroceltic's Interest in Ain Tsila to a subsidiary company in June 2015 is an important step in the overall financing process. This process has also enabled the launch of the recently announced contemplated Bond Issue for up to $175m which will be a crucial step towards providing the financial resources to continue to implement the Group's strategy with regards to delivering shareholder value from the core assets and in particular Algeria.

Revenue and Commodity Prices

The Group recorded revenue in 2014 of $157m (2013: $197m) which comprised of $106m for oil and gas sales in Egypt and $51m for gas sales in Bulgaria. Working interest production was in line with guidance and averaged 22.5 Mboepd, a decrease of 10% for the year (2013: 25.2 Mboepd). The Group's gas production in Egypt is sold under long term fixed contracts with the average price for 2014 being $2.76/Mcf, whilst the average price achieved in 2014 for sales in Bulgaria was $8.34/Mcf. On average, the liquid prices in 2014 were lower than in 2013 due to the oil price falling significantly in the second half of 2014. However sales of liquids in Egypt constituted approximately 30% of the Group's revenue for 2014 and liquids revenue averaged approximately $90.57/bbl during the year.

Operating costs, impairments and expenses

The Group operates in low cost environments with an average operating cost in 2014 of $3.12 per boe (working interest basis) (2013: $2.29 per boe), this increase is due to the decrease in production levels versus prior year. Cost of Sales of $118m (2013: $119m) includes depletion and decommissioning cost of $89m and production costs of $30m.

The Group recognised an impairment charge of $86m of which $80m relates to its producing oil and gas interests, principally driven by lower forecast commodity prices, an adjustment to the Group's reserves in Egypt and an increase in anticipated capital expenditure in Bulgaria and the remaining $6m relates to inventory write off. Unsuccessful exploration costs of $183m, including $129m relating to Kurdistan, $47m relating to Romania and approximately $7m of Egypt and other new venture costs, have also been recorded in the income statement.

Financing activities and net debt

In June 2014, Petroceltic successfully completed a share placing raising approximately $100m in gross funds through an issue of new ordinary shares by way of a placing with institutional investors at a share price of Stg£1.57, a modest premium to the share price prior to the announcement. The Company also welcomed the participation of a new strategic shareholder, Dovenby Capital, who subscribed for approximately $50m as part of the placing. The funds raised through this process in conjunction with the Group's senior secured debt facility provided the Group with the financial flexibility to continue with the pace of progress on the Ain Tsila development pending the completion of the second farm-out to Sonatrach and also to progress the planned exploration programmes that were being undertaken.

The Company received $120m in the year from EGPC which has significantly reduced the year end receivable balance to $50m (2013:$81m).

As at 31 December 2014, the Group had bank loans, net of capitalised arrangement fees and amounts held in reserve accounts set aside for capital repayment, totalling $196m. The overall debt position of the Group continued to reduce in the year, with Net Debt position of $153m at 31 December 2014 (2013:$246m).

The year-end reserves adjustment to Egypt and Bulgaria, coupled with the on-going volatility in oil pricing has negatively impacted on availability under the Group's reserve based lending facility. The Group has been working with its existing lenders and new providers of finance to remedy this and to put in place a solution that addresses the Group's funding requirement. As part of this process, the Group's existing lenders have agreed to suspend the half yearly redetermination process under the Senior Financing Facility until 30 September 2016, in return for a scheduled programme of repayment totalling $77m over the same period. In conjunction with this, the recently announced proposed up to $175m Bond Issue is an important addition to the Group's overall financing mix and while further funding will be required as the Ain Tsila development progresses over the coming years, the Bond Issue will, once completed, represent the first step in diversifying the Group's funding base as part of its long term financing plan for Ain Tsila.

Profit/loss for the year

The loss for the year was $282m (2013: $19m). This loss primarily arose as a result of exploration costs written off of $183m (2013: $37m) and an impairment charge of $86m (as discussed above).

Dividend policy

No dividend is proposed in respect of 2014 (2013: Nil). However, the future dividend policy of the Group will be regularly reviewed based on performance, investment obligations and overall shareholder value.

Portfolio Management

In July 2014, the Group announced the completion of the farm-out of an 18.375% interest in the Isarene PSC to Sonatrach, the National oil and gas company of Algeria. The terms of the agreement with Sonatrach provide for a consideration of up to a maximum of $180m, of which $20m was due on completion with a further $140m to be payable by Sonatrach towards the Company's share of the development costs in Algeria. In addition, contingent payments of up to $20m are based on the achievement of certain milestones. Based on current forecasts, Sonatrach are expected to pay the Company's share of developments costs throughout 2015 and to Q2 2016. On the basis of the stage of development, the Group accounted for the farm-out transaction in accordance with the Group's accounting policy for farm-out arrangements in the exploration phase. Consequently, the initial $20m payment has been offset against the carrying value of the asset at the completion date and no gain or loss recognised. Subsequent payments received under the carry arrangement have been directly offset against the related capital expenditure. As at 31 December 2014, approximately $120m of the carry remained available. The Group's Algerian asset is now separately disclosed on the Balance Sheet and a new note to the accounts has been prepared under the heading 'assets under development' this is to distinguish it clearly from the Group's producing assets which are held as "property, plant and equipment" and where the Algerian asset was included in the prior year.

Capital expenditure programmes

During 2014, capital expenditure amounted to $109m, which was primarily invested in the on-going development activity in Egypt and exploration drilling in Romania, Kurdistan and Egypt.

Based on current work programmes and budgets, capital expenditure for 2015 is forecast to be circa $167m, of which $79m relates to development work on the Ain Tsila gas development in Algeria which is to be funded by Sonatrach following the completion of the farmout agreement. The Group is currently engaged in a number of farm-out initiatives relating to planned exploration activity and, should they be successfully completed, expenditure levels will be correspondingly reduced.

Corporate restructure

At the capital markets day in January 2015, the Group announced that in light of the current oil price and the planned investment focus and activity levels over the coming years, it would undertake a Group reorganisation to simplify the structure of the Group. This has now been completed and has resulted in a reduction in head count of 27, from 171 in December 2014 to 144 in May 2015 comprising 75 in operations and exploration and 69 in finance and administration.

Investor relations

During 2014, the CEO, COO and CFO as well as other members of the Petroceltic management team held regular meetings with analysts and institutional investors. In addition to these regular meetings, as part of the 2014 equity placing senior management held meetings with all the Group's major shareholders in addition to a number of prospective new holders. In January 2015 the Group held a successful capital markets day in London where Petroceltic senior management presented a detailed update on the significant progress that the Group has made in Egypt and Algeria to institutional investors and other finance professionals.

Accounting policies

The Group's accounting policies and standards comply with IFRS as adopted by the EU and as required by the rules of the AIM and the ESM Markets.

Tom Hickey
Chief Financial Officer