STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION OF IONA ENERGY INC.
FORM 51-101F1

PART 1 DATE OF STATEMENT

Item 1.1 Relevant Dates

This Statement of Reserves Data and Other Oil and Gas Information (the "**Statement**") is dated April 29th, 2014. The effective date of the information provided in this Statement is December 31, 2013 and is based on information in the GCA Report (as defined herein), except where otherwise indicated. The preparation date of the information in the Statement is April 23rd, 2014. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. The information is presented on a consolidated basis for Iona Energy Inc. ("**Iona**") and its wholly-owned subsidiaries as of December 31, 2013, Iona Energy Company (UK) Limited ("**Iona UK**") (renamed to Iona Energy Company (UK) plc) subsequent to December 31, 2013) and Iona Energy Company (US) Limited.

PART 2 DISCLOSURE OF RESERVES DATA

Gaffney, Cline & Associates Ltd. ("**GCA**") prepared a report dated April 23rd, 2014 (the "**GCA Report**"), in which it evaluated, as at December 31, 2013, the oil and natural gas reserves attributable to the principal properties of Iona.

The GCA Report also presents the estimated net value of future revenue of Iona's properties before and after taxes, at various discount rates. Assumptions and qualifications relating to costs, prices for future production and other matters are summarized in the notes to the following tables.

The extent and nature of all information supplied by Iona and/or the operator of its properties, which may have included ownership data, well information, geological information, reservoir studies, timing and future production, gas sales contract information, current product prices, operating cost data, capital budget forecasts and future operating plans, have been relied upon by GCA in preparing the GCA Report and were accepted as represented without independent verification. In the absence of such information, GCA relied, with the approval of Iona, upon its opinion of reasonable practice in the industry. All information provided to GCA was as at December 31, 2013 and, accordingly, certain of such information may not be representative of current conditions.

The definitions of the various categories of reserves and expenditures are those set out in National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**").

Barrels of oil equivalent or "boes" may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

It should not be assumed that the present worth of estimated future net revenue represents the fair market value of the reserves. There is no assurance that the escalating price and cost assumptions contained in the GCA Report will be attained and variances could be material. The reserve and revenue estimates set forth below are estimates only and the actual reserves and realized revenue may be greater or less than those calculated.

Additionally, "possible reserves" as disclosed herein are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

Item 2.1 Reserves Data - Forecast Prices and Costs

The following table discloses, in the aggregate, Iona's gross and net proved reserves, proved plus probable reserves and proved plus probable plus possible reserves, estimated using forecast prices and costs, by product type. "Forecast prices and costs" means future prices and costs used by GCA in the GCA Report that are generally accepted as being a reasonable outlook of the future, or fixed or currently determinable future prices or costs to which Iona is bound.

Table 2.1.1
Summary Oil and Gas Reserves
As of December 31, 2013
Forecast Prices and Costs

	Reserves									
	Light and Medium Oil		**Heavy Oil**		**Natural Gas Associated and Non-Associated**		**Coalbed Methane**		**Natural Gas Liquids**	
Reserves Categories	**Gross MMbbl (1)**	**Net MMbbl (2)**	**Gross MMbbl (1)**	**Net MMbbl (2)**	**Gross Bscf(1)**	**Net Bscf(2)**	**Gross MMbbl (1)**	**Net MMbbl (2)**	**Gross MMbbl (1)**	**Net MMbbl (2)**
Proved										
Developed Producing	3.01	3.01	-	-	5.96	5.96	-	-	-	-
Developed Non-Producing	-	-	-	-	-	-	-	-	-	-
Undeveloped Reserves	7.29	7.29	5.10	5.10	14.75	14.75	-	-	-	-
Total Proved	10.3	10.3	5.10	5.10	20.71	20.71	-	-		
Probable	8.40	8.40	4.61	4.61	12.71	12.71				
Total Proved Plus Probable	18.70	18.70	9.71	9.71	33.42	33.42				
Possible	6.06	6.06	2.47	2.47	7.45	7.45				
Total Proved Plus Possible Plus Probable	24.76	24.76	12.18	12.18	40.87	40.87				

Notes:

(1) "Gross Reserves" are Iona's working interest share of remaining reserves before deduction of royalties**.**

(2) "Net Reserves" are Iona's working interest share of remaining reserves less all crown, freehold and overriding royalties and interests owned by others.

(3) May not add due to rounding.

The following table discloses, in the aggregate, the net present value of Iona's future net revenue attributable to the reserves categories in the previous table, estimated using forecast prices and costs, before and after deducting future income tax expenses, and calculated without discount and using discount rates of 5%, 10%, 15% and 20%.

Table 2.1.2
Summary of Net Present Values of
Future Net Revenue
As of December 31, 2013
Forecast Prices and Costs (U.S.$ MM)

	Net Present Values of Future Net Revenue[1][2]										
	Before Income Taxes Discounted at (%/Year)					After Income Taxes Discounted at (%/Year)					
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%	Before Tax Net Value at 10% ($/boe)
Proved:											
Developed Producing	268.69	258.00	248.05	238.81	230.26	182.44	176.61	171.05	165.81	160.89	61.96
Developed non-Producing	-	-	-	-	-	-	-	-	-	-	
Undeveloped	711.82	530.23	398.92	301.95	228.99	498.29	366.09	270.28	199.40	145.98	26.87
Total Proved:	980.50	788.23	646.98	540.77	459.25	680.73	542.70	441.34	365.21	306.87	34.32
Total Probable:	1,089.92	815.95	633.50	506.32	414.11	566.66	425.10	331.56	266.64	219.62	41.88
Total Proved + Probable:	2,070.43	1,604.18	1,280.47	1,047.09	873.36	1,247.39	967.80	772.90	631.85	526.49	37.68
Total Possible:	876.68	588.30	424.38	323.03	255.97	341.76	235.57	173.46	134.11	107.60	43.43
Total Proved + Probable + Possible:	2,947.11	2,192.48	1,704.86	1,370.11	1,129.33	1,589.15	1,203.37	946.36	765.95	634.09	38.97

Notes:
(1) May not add due to rounding.
(2) Net present value of future net revenue includes all resource income, appropriate income tax calculations and prior tax pools.

The following table discloses, in aggregate, certain elements of Iona's future net revenue attributable to its proved reserves, its proved plus probable reserves, and its proved plus probable plus possible reserves estimated using forecast prices and costs, and calculated without discount.

Table 2.1.3
Future Net Revenue
Undiscounted
As of December 31, 2013
Forecast Prices and Costs (U.S.$ MM)[1]

	Revenue	Royalty	Operating Costs	Development Cost	Abandonment and Reclamation Costs	Pre-tax Future Net Revenue	Future Income Tax	Post-tax Future Net Revenue
Total Proved	1,721.88	4.59	288.20	367.46	76.79	980.50	299.78	680.73
Total Proved plus Probable	3,176.96	13.15	497.57	466.12	123.74	2,070.43	823.03	1,247.39
Total Proved plus Probable plus Possible	4,164.44	14.11	602.93	466.12	128.14	2,947.11	1,357.96	1,589.15

Note:
(1) Totals may not add due to rounding.

This table discloses, by production group, the net present value of Iona's future net revenue attributable to its proved reserves, its proved plus probable, and its proved plus probable plus possible reserves, before deducting future income tax expenses, estimated using forecast prices and costs, and calculated using a 10% discount rate.

Table 2.1.3c
Net Present Value of Future Net Revenue
by Production Group
as of December 31, 2013
Forecast Prices and Costs

Reserve Category	Production Group	Future Net Revenue Before Income Tax (Discounted at 10% per year) (M$)	Unit Value Before Income Tax (Discounted at 10% per year) ($/boe)
Proved	Light and Medium Crude Oil (including solution gas and associated by-products)	766.42	74.41
	Heavy Oil (including solution gas and associated by-products)	263.48	51.66
	Natural Gas (including associated by-products)	115.69	33.52
	Coalbed Methane (including associated by-products)	-	-
Proved plus Probable	Light and Medium Crude Oil (including solution gas and associated by-products	1,309.15	70.01
	Heavy Oil (including solution gas and associated by-products)	498.32	51.32
	Natural Gas (including associated by-products)	184.13	33.06
	Coalbed Methane (including associated by-products)	-	-
Proved plus Probable plus Possible	Light and Medium Crude Oil (including solution gas and associated by-products	1,574.24	63.61
	Heavy Oil (including solution gas and associated by-products)	564.38	46.34
	Natural Gas (including associated by-products)	225.07	33.04
	Coalbed Methane (including associated by-products)	-	-

*Includes corporate capital G&A, if applicable
Unit values are based on net reserve volumes

PART 3 PRICING ASSUMPTIONS

Item 3.2 Forecast Prices Used in Estimates

The forecast reference prices used in preparing Iona's reserves data are provided in the below table.

Summary of Pricing and
Inflation Rate Assumptions
As of December 31, 2013
Forecast Prices and Costs

Year	Brent Price (US$/bbl)	UK Gas Price (US$/Mscf)	Inflation Rate	Exchange Rate (US$/£UK)
2014	108.80	63.56	2%	1.60
2015	102.88	64.61	2%	1.60
2016	97.05	63.17	2%	1.60
2017	96.28	61.69	2%	1.60
2018	97.42	60.26	2%	1.60
2019	99.37	58.71	2%	1.60
Thereafter	+2.0% p.a.	+2.0% p.a.	2%	1.60

The above table quotes GCA's standard price scenario effective December 31, 2013 and reflects the prices used in the GCA Report. GCA is a qualified reserves evaluator under the definitions of NI 51-101 and is independent of Iona. In the GCA Report, the Exchange Rate for all years shown in the table above is assumed to be US$1.60/£UK and all future operating and capital costs are assumed to escalate at 2% per year starting on January 1, 2015.

PART 4 RECONCILIATION OF CHANGES IN RESERVES AND FUTURE NET REVENUE

Item 4.1 Reserves Reconciliation

The following table provides a reconciliation of Iona's gross reserves based on forecast prices and costs.

Reconciliation of Iona's Gross[1] Reserves (Before Royalty)
by Principal Product Type
As of December 31, 2013
Forecast Prices and Costs

Factors	Light and Medium Oil			Heavy Oil			Natural Gas (Associated and Non-Associated)			Natural Gas Liquids		
	Gross Proved (MMbbl)	Gross Probable (MMbbl)	Gross Proved Plus Probable (MMbbl)	Gross Proved (MMbbl)	Gross Probable (MMbbl)	Gross Proved Plus Probable (MMbbl)	Gross Proved (Bcf)	Gross Probable (Bcf)	Gross Proved Plus Probable (Bcf)	Gross Proved (MMbbl)	Gross Probable (MMbbl)	Gross Proved Plus Probable (MMbbl)
December 31, 2012	9.72	9.88	19.60	5.09	4.62	9.71	21.61	17.34	38.95	-	-	-
Extensions	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions[2]	-	-	-	-	-	-	2.46	-3.47	-1.01	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	3.45	1.01	4.46	-	-	-	2.90	0.80	3.70	-	-	-
Dispositions	-2.43	-2.47	-4.90	-	-	-	-4.92	-1.97	-6.88	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	-0.44	-	-0.44	-	-	-	-1.34	-	-1.34	-	-	-
December 31, 2013	10.30	8.42	18.72	5.09	4.62	9.71	20.71	12.71	33.42	-	-	-

Notes:

(1) Gross Reserves means Iona's working interest reserves before calculation of royalties, and before consideration of Iona's royalty interests.

(2) Technical revisions primarily reflect revisions in respect of oil reserves to the Corporation's interest in Tyne and Trent (as of December 31, 2012) resulting from the completion of the T6 development well.

(3) Acquisitions reflect the increases associated with the Corporation's acquisitions of the Huntington Asset. Dispositions reflect the sale of a 25% interest in Orlando and Kells to Volantis Exploration.

(4) All production shown in the above table relates to the Corporation's Huntington and Trent & Tyne Assets.

Reference: Item 4.1 of Form 51-101F1

PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Item 5.1 Undeveloped Reserves

Table 5.1.1
Proved Net Undeveloped Reserves
Most Recent Three Years
Forecast Prices and Costs

	Light & Medium Oil		Heavy Oil		Natural Gas[2]	
	First Attributed or Reduced (Mbbl)	Cumulative at Year-End[1] (Mbbl)	First Attributed or Reduced (Mbbl)	Cumulative at Year-End[1] (Mbbl)	First Attributed or Reduced (MMscf)	Cumulative at Year-End[1] (MMscf)
2011	-	2,380[3]	-	-	-	-
2012	2,380[3]	9,720[4]	-	5,090[5]	-	19,670[6]
2013	9,720[4]	7,290[7]	5,090[5]	5,090[5]	19,670[6]	14,750[8]

Notes:

(1) Cumulative at Year End = Residual Cumulative of Previous Year plus First Attributed.
(2) Includes Associated and Non-Associated Gas.
(3) 2.38 MMbbls of proved oil reserves attributed to Orlando.
(4) 7.83 MMbbls of proved oil reserves attributed to Orlando and 1.89 MMbbls of proven oil reserves attributed to Kells, both at 100% working interest.
(5) 5.09 MMbbls of proved oil reserves attributed to West Wick.
(6) 19.67 MMscf of proved gas reserves attributed to Kells at 100% working interest.
(7) 5.87 MMbbls of proved oil reserves attributed to Orlando and 1.42 MMbbls of proven oil reserves attributed to Kells, both at 75% working interest.
(8) 14.75 MMscf of probable gas reserves attributed to Kells at 75% working interest.

Table 5.1.2
Probable Net Undeveloped Reserves
Most Recent Three Years
Forecast Prices and Costs

	Light & Medium Oil		Heavy Oil		Natural Gas[2]	
	First Attributed or Reduced (Mbbl)	Cumulative at Year-End[1] (Mbbl)	First Attributed or Reduced (Mbbl)	Cumulative at Year-End[1] (Mbbl)	First Attributed or Reduced (MMscf)	Cumulative at Year-End[1] (MMscf)
2011	-	1,488[3]	-	-	-	-
2012	1,488[3]	9,850[4]	-	4,610[5]	-	7,860[6]
2013	9,850[4]	7,390[7]	4,610[5]	4,610[5]	7,860[6]	5,900[8]

Notes:

(1) Cumulative at Year End = Residual Cumulative of Previous Year plus First Attributed.
(2) Includes Associated and Non-Associated Gas.
(3) 1.49 MMbbls of probable oil reserves attributed to Orlando.
(4) 7.54 MMbbls of probable oil reserves attributed to Orlando and 2.31 MMbbls of probable oil reserves attributed to Kells, both at 100% working interest.
(5) 4.61 MMbbls of probable oil reserves attributed to West Wick.
(6) 7.86 MMscf of probable gas reserves attributed to Kells at 100% working interest..
(7) 5.66 MMbbls of probable oil reserves attributed to Orlando and 1.73 MMbbls of probable oil reserves attributed to Kells, both at 75% working interest.
(8) 5.9 MMscf of probable gas reserves attributed to Kells at 75% working interest.

Development Plans

Huntington (15% Working Interest)

The first phase of the development of the Huntington Field was completed by the Operator (E.ON) in 2013. This phase comprised the drilling and completion of four production wells and two injection wells, all tied back to the Voyageur Spirit FPSO. These wells all target a Paleocene Forties reservoir horizon. A subsequent phase of development is under evaluation by the owners and a first development well into the deeper Jurassic Fulmar reservoir is being targeted for 2016. Further development of the Fulmar horizon may follow depending on the performance of the first well and on geoscience evaluation of the overall extent of this reservoir.

Orlando (75% Working Interest)

The appraisal of Orlando is complete following the logging and suspension of the 3/3b-13z well in March 2012. A Field Development Plan has subsequently been prepared and approved by DECC. The development plan for Orlando contemplates the re-entering of the 13z well and drilling as a 3000 foot horizontal producer. The well will be completed with dual ESPs. Additionally, a subsea pipeline, power supply and control umbilical are expected to be laid between the well-head and the Ninian Central platform approximately 10 kilometres ("**km**") to the south west. Engineering modifications will be completed at Ninian allowing tie-in and first production shortly after completing the development well. It was contemplated that each of these items would be completed in 2015 and first oil from Orlando expected in the second half of 2015. However, subsequent to December 31, 2013, Iona has determined that there is a risk that some of these items may not be completed in 2014, however Iona aims to achieve first oil from Orlando as soon as possible in 2016.

Trent & Tyne (20% Working Interest)

The T5 Sidetrack Well (now renamed T6) reached total depth in December 2012 and was tied-in to the production system in January 2013. The well commenced production at rates in line with Iona's expectations. Additionally, and following a seismic acquisition program in summer 2011, Perenco UK Limited ("**Perenco**"), the Operator together with Iona are considering further development options for the field. These options include drilling the Tyne North West prospect, sidetracking the T1Z well to unlock a lower high-pressure zone, and developing the discovered but undeveloped Trent East Discovery. Iona has commissioned a field redevelopment study to refine the reserve estimates for these projects and expects the resulting work to be conducted in 2015 and beyond.

Kells (75% Working Interest)

Iona completed the acquisition of the Kells oilfield in January 2012. The Kells Field is located in Block 3/8d in the UK North Sea and lies approximately 14 km south-east of the producing Ninian Central platform. The Kells Field is a three-way fault closed structure approximately 4 km long by 2 km wide with an observed oil column of 568ft (true vertical thickness) in Upper Brent sandstone reservoirs. The key Kells discovery wells 3/8b-10 and 3/8b-14z flowed 40° API Oil at stabilized rates of 3,500 and 8,600 bopd respectively. The Kells field subsequently produced 4.2 MMstb at rates of up to 12,000 bopd between the years 1992 and 1994 and was decommissioned when the Brent crude oil price was approximately US$13/bbl to US$15/bbl.

Kells is slated for development through Ninian Central following tie-in of Orlando to the same facility. The Kells development plan comprises two subsea production wells, an oil pipeline, a control umbilical, and some pipework modifications at Ninian. A draft Field Development Plan has been prepared and project activity will be phased through 2015 and 2016, with first oil expected in the second half of 2016. A subsequent water injection project is planned to unlock additional reserves. This 2017 project will involve the laying of water injection and gas lift lines, and the conversion of the second well to water injection service.

West Wick (58.73% Working Interest)

Iona completed the acquisition of operatorship and a 58.73% working interest in West Wick in August 2012. Iona is the Operator. The West Wick discovery is located within block 13/21a and is an oil accumulation lying in the inner Moray Firth area of the North Sea, some 3.75 km west of the Captain field Producing Platforms. Oil was discovered within the Cretaceous Upper and Lower Captain sandstone reservoirs and correlates to the same reservoirs of the Captain field that have produced since 1997. The West Wick field has remained undeveloped since discovered by Amoco in 1990 with the drilling of well 13/21a-1A. Since that time, four delineation wells have been drilled appraising the accumulation. The last wells (13/21a-5 and 13/21a-6) were drilled by Enterprise Oil in 2001. The West Wick field is a three-way dip closed structure approximately 3 km long by 2 km wide with an observed oil column of 228 ft (true vertical thickness) with oil proven though wire-line sampling that gives an API range of 13 - 21°, with an estimated 100cp viscosity crude in the reservoir.

West Wick is programmed for a three well subsea development targeting first oil in 2016. The development will comprise two producers and one injector. The most likely development is via offset field infrastructure however Iona is also considering stand-alone facilities.

Item 5.2 Significant Factors or Uncertainties Affecting Reserves Data

The reserve data included herein are expressions of judgment based on knowledge, experience and industry practice. In general, estimates of economically recoverable oil and natural gas reserves and the future net revenue there from are based upon a number of variable factors and assumptions, such as expected reservoir characteristics based on geological, geophysical and engineering assessments; ultimate reserve recovery; timing and amount of capital expenditures; future production rates based on historical performance and expected future operating and investment activities; future oil and natural gas prices and quality differentials; marketability of oil and gas; royalty rates; assumed effects of regulation by governmental agencies; and future development and operating costs, all of which may vary materially from actual results. It should not be assumed that estimated future net revenue is representative of the fair market value of Iona's properties. In addition, estimated reserves may change from time to time based on new or reprocessed information or new interpretations of existing or new information.

Iona’s future crude oil and natural gas reserves and production, and therefore its operating cash flows and results of operations, are highly dependent upon Iona’s success, and the success of their joint venture partners, in exploiting the current reserve base and acquiring or discovering additional reserves. Without reserve additions through exploration, acquisition or development activities, Iona’s reserves and production will decline over time as reserves are produced. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient and external sources of capital become limited or unavailable, the ability to make the necessary capital investments to maintain and expand Iona’s oil and natural gas reserves will be impaired.

Item 5.3 Future Development Costs

The following table provides information regarding the development costs deducted in the estimation of future net revenue attributable to Iona's reserves, as reflected in the GCA Report.

Table 5.3
Future Development Costs(1)

	Forecast Prices and Costs	
Year	**For Proved Reserves (US$ MM)**	**For Proved + Probable Reserves (US$ MM)**
2014	71.82	99.10
2015	207.58	207.58
2016	88.07	125.70
2017	-	33.75
2018	-	-
Other	-	-
Total	367.47	466.13
Undiscounted	367.47	466.13
Discounted at 10%/Yr	303.01	379.14

Note:

(1) Future Development Costs shown are associated with booked reserves in the GCA Report and do not necessarily represent Iona's exploration and development budget.

Iona expects that the funds required for future development costs will be obtained from the combination of positive working capital, internally-generated cash flow, credit facilities and equity financing. There can be no guarantee that funds will be available or that Iona will allocate funding to develop all of the reserves attributed in the GCA Report. Failure to develop those reserves would have a negative impact on future cash flow.

Interest and other costs of external funding are not included in the future net development costs of the reserves or in the future net revenue estimates, and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. Iona does not anticipate that interest or other funding costs would make development of any property uneconomic.

PART 6 OTHER OIL AND GAS INFORMATION

Item 6.1 Oil and Gas Properties and Wells

The following is a description Iona's principal properties on production or under development. Estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Huntington (15% Working Interest)

The area of the Huntington discovery was previously licenced by Shell and Esso who drilled two wells in 1992 in pursuit of a Jurassic, Fulmar sand, objective. This reservoir was not present in either well and the licence was relinquished. The area was subsequently relicensed and Forties reservoir was discovered in 2007 by well 22/14b-5, operated by Oilexco. The well encountered a 124 ft thick gross oil column and tested light oil at peak rates of up to 5,577 bbl/day. The reservoir interval was appraised by a further 11 well penetrations between 2007 and 2008, nine of which were side-tracks from a common surface location in order to rapidly delineate the reservoir. All of these side-tracks encountered oil columns.

The Huntington field is operated by E.ON (25%) on behalf of the license partnership. Partners in the license are Premier (40%), Altinex Oil (UK) Limited (a wholly owned subsidiary of Noreco) (20%) and the Iona (15%).

Huntington has been developed with four subsea horizontal production wells targeting the Forties Sandstone and two deviated water injection wells tied back to the Voyageur Spirit FPSO via a central subsea manifold. Crude oil is exported via shuttle tankers directly from the FPSO, with gas export to the Teesside Gas Processing Plant via a wet gas pipeline tied into the CATS pipeline. The field commenced production in April 2013 at gross initial production rates of approximately 7,000 bbl/day being temporarily constrained by gas compression facilities not yet being fully operational. The Huntington field reached its design capacity of 34,500 boe/day (gross) in early September 2013.

Iona completed the acquisition of its interest through an acquisition of Carrizo Huntington (later re-named "Iona Huntington") from Carrizo in February 2013. Iona Huntington holds a further 2.55% of economic interest through DLE and royalty income payable from the license partners.

In addition to the Forties reservoir, the discovery well also tested 4,624 bbl/day from an underlying Fulmar reservoir and the down-dip extent of this reservoir was confirmed by appraisal well 22/14b-8. This horizon extends into licence 22/14d, held 100% by Iona and is under evaluation for future development.

Orlando (75% Working Interest)

The Orlando oil discovery and 3/3-11 well was drilled by a Chevron operated group in 1989 and subsequently relinquished by Chevron. Block 3/3b was applied for and awarded to a group led by MPX North Sea Limited ("**MPX**") through the 25th Licencing Round in 2009 as Traditional Licence P1606 and held with a work program that included a commitment to drill an appraisal well to target the Brent Reservoir before the end of 2012. That well was completed in March 2012 following a successful data acquisition programme.

Following the purchase of its partners' working interests in 2012 and subsequent divestment of 25% to Volantis Exploration (a wholly owned subsidiary of Atlantic Petroleum) in 2013, Iona held a 75% working interest in Block 3/3b as of December 31, 2013. The Orlando oil field (within block 3/3b) is an offshore three-way fault closed structure approximately 2.5 km long by 0.5 km wide stratigraphically positioned within Upper Jurassic

Brent Group Reservoirs beneath the Base Cretaceous Unconformity. The structure is covered by 3D seismic data.

The two wells (3/3-11 and 3/3b-13z) discovered oil in the Upper Jurassic Tarbert and Ness sandstone reservoirs. The 3/3-11 well tested 2,850 bopd of 32 degree API oil and the data acquisition programme in 3/3b-13z confirmed the discovery well properties.

The Tarbert Formation is a stacked, tidally influenced shallow marine sandstone that generally has constant thickness and is evenly distributed spatially. The Ness Formation reservoir is comprised of marginal marine and non-marine deposits containing good reservoir quality channel sands. Iona commissioned a detailed reservoir study to fully integrate the results of the two wells into a field model. This study comprised an updated seismic interpretation, petrophysical analysis, the building of a detailed geo-cellular model in Petrel and Eclipse reservoir simulation model.

This study forms the basis of the approved Field Development Plan.

Trent & Tyne (20% Working Interest)

Iona completed the acquisition of an interest in the Trent & Tyne Assets in 2011. Through the agreement Iona acquired a 20% interest in Licences P685 and P609 with the potential to increase the interest to 37.5%, a 20% interest in the Trent and Trent Facilities, with the potential to increase the interest to 37.5%, and a 2.5% interest in the in the export pipeline under the ETS Joint Operating Agreement, with the potential to increase the interest to 4.6875%.

The Tyne Field is located offshore in Block 44/18 of the southern North Sea and is comprised of Carboniferous reservoirs within a setting of five fault blocks. Four of these fault blocks have been drilled; Tyne North, Tyne South, Tyne West and Tyne East, the remaining fault block, Tyne North West, has not been drilled.

The entire Tyne field is covered by eight exploration and appraisal wells all of which are suspended or abandoned and five production wells of which three are currently producing (including the recently side-tracked T6 well). The gas from the Tyne Field is piped to the Trent Field which supports three further wells, of which two are producing. Iona has an option to increase its equity interest in the fields to 37.5% should it elect to pay for a well to test the Tyne North West prospect.

Any such increase would be subject to the approval of the United Kingdom Department of Energy and Climate Change ("**DECC**") as well as confirmation that Iona has at least £22,000,000 in funds which can be allocated to Iona's contribution to the Tyne North West well.

Perenco holds the balance of the interest in these fields.

Kells (75% Working Interest)

The Kells field is located offshore in the North Sea and was discovered by BP in 1985 with the 3/8b-10 exploration well. Oil was discovered in sandstones of the Tarbert and Ness Formations of the Brent Group. Two east-west trending faults run westwards from the main bounding fault into the reservoir and divide the reservoir into two separate fault blocks; Kells Main and Kells South. Three zones were tested and flowed at 2,760 bopd (Lower Ness Formation), 4,100 bopd (Upper Ness Formation) and 2,500 bopd (Tarbert Formation). A 190 ft. oil column was found in the Lower Ness Formation. The combined oil column in the Upper Ness and Tarbert Formations was 345 ft. The oil obtained on test was light (39-44^{o} API) with 3% CO_2 and a solution GOR of 1,940 scf/bbl.

Kells was initially developed as the Staffa Field in 1992 by LASMO who produced 4.26 MMbbl of oil from two wells; 3/8b-10 and 3/8b-14Z. Production was through a tie-back to the nearby Ninian South platform. First oil was achieved in March 1992, and the field was shut in from June to October 1993 whilst a 2 km section of the un-insulated pipeline, blocked with a combination of wax, emulsion and hydrate, was replaced. Further hydrate/emulsion problems in November, 1994 resulted in the field once again being shut in. Following economic evaluation it was decided by the operator at such time that further repairs to the pipeline were not merited and an application was made for abandonment. Consequently, no further production occurred and all subsea equipment and pipelines have been removed.

Prior to Iona's acquisition in 2012 and subsequent divestment of 25% to Volantis Exploration (a wholly owned subsidiary of Atlantic Petroleum) in 2013, Fairfield (the previous owner) performed substantial subsurface studies and remapped Kells based on new seismic to produce a new 3D interpretation and created a new Petrel model to recalculate volumetrics. Following the acquisition, Iona reviewed the static (i.e. Petrel) and dynamic (i.e. Eclipse) models to optimise the development plan. This and other new work formed the basis for the new Iona FDP.

West Wick (58.73% Working Interest)

The West Wick oil field is a moderately heavy-oil accumulation lying offshore in the Inner Moray Firth area of the North Sea, some 10 km west of the Captain Field. The field was discovered by Amoco in 1990 with the drilling of Well 13/21a-1A. Since that time, four delineation wells have been drilled into the accumulation. The last wells (13/21a-5 and 13/21a-6) were drilled by Enterprise Oil in 2001. None of the wells have been tested.

Iona acquired Centrica's interest in the West Wick field in 2012 and is the field operator. The balance of the working interest is held by Idemitsu.

The previous operator, Centrica, had conducted extensive studies and prepared a draft Field Development Plan. Iona has reviewed the geological interpretation of the oil bearing Upper Captain Sands, the Petrel geo-cellular model and the Eclipse reservoir simulation model. Iona have conducted further optimisation studies in order to refine its draft development plan for the property.

Location of Production

Presently, there are nine wells on stream, four producing from the Huntington Field, two producing from the Trent Field, and three wells producing from the Tyne Field. Additionally there are two water injection wells on Huntington.

By the end of 2013, the Tyne Field had produced 151.6 Bscf and the Trent Field had produced 102.6 Bscf. At year end Huntington had produced 2.828 MMbbls of oil and 1.6 Bcf of gas.

The Tors gas field is connected to the Trent and Tyne system and pays a tariff comprising US$0.42/Mscf for processing and compression. Additionally, Tors pays US$0.39/Mscf to ETS in which Tyne and Trent owners hold 12.5%. The Tors field is a mature gas field and process revenues were included in the evaluation on the basis of approximately 50 Bscf expected to be produced over the next eight years.

Agreements are also in place for tying the Cygnus Field into the Trent and Tyne system and then the volumes will flow into ETS. The tariff for these volumes will amount to US$0.26/Mscf, with the Trent and Tyne owners receiving 25% of the revenues, with 75% of the revenues going to ETS. Since the Trent and Tyne partners own 12.5% of the ETS, the Trent and Tyne interest owners would be entitled to 34.375% of the Cygnus tariff stream. Production profiles for the Cygnus gas field were estimated by the Cygnus operator. Production is forecast to commence in 2015, peak at 233 MMscf/d and continue over a period of approximately 16 years. Once Trent and

Tyne become uneconomic and are shut, the revenue stream is reduced to the partners 12.5% interest of the ETS.

The Tors and Cygnus tariff streams were included in the Trent and Tyne cash flow analyses and served to lower operating costs and extend the lives of both fields. The Operator’s production forecast was selected for this assessment, with 650 Bscf produced over the forecast period.

The following table shows information regarding Iona’s wells at December 31, 2013.

Table 6.1.2

Oil and Gas Wells

	Producing		**Non-Producing**	
	Gross(1)	**Net(2)**	**Gross(1)**	**Net(2)**
Wells				
United Kingdom	9	1.6	4	0.8
Total	9	1.6	4	0.8

Notes:

(1) "Gross" wells means the number of wells in which Iona has a working interest or a royalty interest that may be converted to a working interest.

(2) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Iona's percentage working interests therein.

Item 6.2 Properties with No Attributed Reserves

The following table sets forth information respecting Iona's undeveloped lands as at December 31, 2013.

Table 6.2
Properties with No Attributed Reserves

	Unproved Properties[(1)]		2013 Expiring
	Gross Acreage	**Net Acreage**	**Net Acreage**
Location			
United Kingdom	64,766[(2)]	64,766[(2)]	64,766 [(2)]
United States	2,304[(3)]	2,304[(3)]	-
Total	67,070	67,070	-

Notes:

(1) Unproved properties have not attributed reserves as of December 31, 2013. Undeveloped acreage within properties where reserves have been booked as of December 31, 2013 has not been included.

(2) Comprised of UK Block 3/7c (part) (19,027 acres), UK Block 3/8c (2,595 acres), UK Block 3/12 (part) (24,463 acres) and UK Block 22/14d (part) (18,681 acres).

(3) Comprised of U.S. Block 6767 (2,304 acres) in Alaska's Chukchi Sea.

In early 2008, Iona (through its subsidiary, Iona Energy Company (US) Limited) participated in Alaska's offshore land sale 193 and was successful in acquiring Block 6767 located within the Chukchi Sea. The block owned 100% by Iona and is proximal to the Burger Gas Discovery currently held under license by Shell. Iona maintains a work program on the block through license rental and a security treasury bond of $50,000 lodged with the regulatory body.

On October 30, 2012, DECC awarded Iona's UK Subsidiary, Iona Energy Company (UK) Limited, three UK North Sea Blocks at 100% working interest, including two oil discoveries. The three awarded Blocks, 3/7c (part), 3/8c, and 3/12 (part), are located in the Northern North Sea, to the south-west of the Ninian field and immediately adjacent to Iona's 100% Block 3/8d which includes the to-be-developed Kells Oil and Gas field. Detailed subsurface and development concepts are under review with the selection of the first appraisal location nearing completion.

Item 6.2.1 Significant Factors or Uncertainties Relevant to Properties with no Attributed Reserves

The presence of economic quantities of hydrocarbons on lands with no attributed reserves is uncertain until drilled and tested. Beyond the need to drill and test exploration areas, additional factors may influence the Iona's ability to develop these lands, including escalation of capital costs and operating costs, the potential requirement to expand existing infrastructure and a material drop in commodities prices.

Item 6.3 Forward Contracts

As of December 31, 2013, Iona is not bound by any agreement (including a transportation agreement), directly or through an aggregator, under which it may be precluded from fully realizing, or may be protected from the full effect of, future market prices for oil or gas.

Item 6.4 Additional Information Concerning Abandonment and Restoration Costs

Table 6.4
Abandonment and Reclamation Costs
Forecast Prices and Costs
Total Abandonment and Reclamation Costs Including Well Abandonment and Disconnect Costs
(Millions of US$)

	2014	2015	2016	2017	2018	2019	Remainder	Total	Discounted at 10%
Proved Producing	-	-	-	-	11.7(1)	7.1(1)	-	18.8(1)	11.3(4)
Total Proved	-	-	-	-	11.7(2)	7.1(2)	58.0(2)	76.8(2)	31.0(5)
Total Proved + Probable	-	-	-	-	-	14.6(3)	109.1(3)	123.8(3)	31.5(6)

Notes:

(1) Comprised of Proved Producing abandonment cost from Trent & Tyne of US$ 7.1MM and Huntington of US$ 11.7MM.

(2) Comprised of Total Proved abandonment cost for Orlando of US$ 15.8MM, Kells of US$ 15.5MM, West Wick of US$ 26.7MM, Trent & Tyne of US$ 7.1MM, and Huntington of US$ 11.7MM.

(3) Comprised of Total Proved + Probable abandonment cost for Orlando of US$ 38.5MM, Kells of US$ 33.5MM, West Wick of US$ 29.5MM, Trent & Tyne of US$ 7.7MM, and Huntington of US$ 14.6MM.

(4) Comprised of a 10% discounted abandonment cost on Trent & Tyne of US$ 4.0MM and Huntington of US$ 7.3MM.

(5) Comprised of a 10% discounted abandonment cost on Orlando of US$ 6.1MM, Kells of US$ 6.6MM, West Wick of US$ 7.0MM, Trent & Tyne of US$ 4.0MM, and Huntington of US$ 7.3MM.

(6) Comprised of a 10% discounted abandonment cost on Orlando of US$ 5.7MM, Kells of US$ 9.7MM, West Wick of US$ 4.8MM, Trent & Tyne of US$ 3.0MM, and Huntington of US$ 8.3MM.

Iona estimates the costs associated with abandonment and reclamation for wells and facilities based on previous experience or by estimating such costs. The above table includes the abandonment costs with respect to the Orlando, Kells Huntington, and West Wick Assets for wells and facilities with reserves assigned at December 31, 2013 calculated both undiscounted and at a 10% discount rate. Iona currently anticipates incurring abandonment and reclamation costs on 6 net wells and on associated subsea infrastructure, being subsea pipelines which tie back the wells to third party platforms for processing. Iona estimates it will not incur any abandonment and reclamation costs in the next four financial years. Total abandonment costs in respect of development of the proved reserves associated with the Orlando, Kells, Huntington and West Wick Assets are estimated to be US$ 69.7MM.

The above table also includes the abandonment costs for wells and facilities of the Trent & Tyne Assets with reserves assigned at December 31, 2013 calculated both undiscounted and at a 10% discount rate. Iona currently anticipates incurring abandonment and reclamation costs on 1.6 net wells and on associated offshore infrastructure. The Trent & Tyne gas field developments consist of two lightweight jackets in approximately 80 feet of water with multiple wells tied back through multi-slot manifolds on the platforms. Iona estimates it will not incur any abandonment and reclamation costs in the next four financial years. Total abandonment costs in respect of development of the proved reserves of the Trent & Tyne Assets are estimated to be US$35.5 MM, of which Iona's 20% share would be US$7.1 MM.

Item 6.5 Tax Horizon

Iona is subject to UK Ring Fence Corporation Tax at 30% of profits and a Supplementary Charge at 20% of profits. Subsequent to the year end, the supplementary charge has been increased to 32%. The Supplementary Charge is calculated on the same basis as the Ring Fence Corporation Tax, but without deduction for finance costs. Iona’s interests are not Petroleum Revenue Tax or Royalties paying. Iona was not required to pay trade-related income taxes for the year ended December 31, 2013. Based on the current stage of Iona's development, anticipated production and price assumptions and a continuing business model whereby Iona reinvests capital, incurs general, administrative and interest costs, together with the non-capital losses available to Iona, Iona does not expect to pay trade related cash income taxes before 2015.

Item 6.6 Costs Incurred

The following table summarizes certain expenditures for the Corporation during the year ended December 31, 2013.

Table 6.6
Costs Incurred for the Year Ending December 31, 2013[(1)]

Property Acquisition	**Amount (US$ Million)**
Proved	229.0
Unproved	115.8
Capital Expenditures	
Exploration Costs	0.8
Development Costs	22.5
Total	368.1

Note:
(1) All Capital Expenditure incurred in the year is classified as exploration in accordance with the Corporation's accounting policies and as disclosed in its year-end accounts. Costs will not be classified as development costs until projects receive Field Development Approval from the DECC.

Item 6.7 Exploration and Development Activities

During 2013, Iona drilled one (0.2 net) development well, being the Tyne T6 gas well, which was completed in January 2013.

Iona's focus for the remainder of 2014 is to maintain production, progress development projects and mature the appraisal portfolio. To accomplish this Iona will work with the Operators at the producing fields to identify and implement in-field opportunities and will continue the Orlando project toward first oil. Geophysical appraisal studies will be concluded at Ronan, Oran and the greater Huntington area and firm drilling plans for 2015 will be defined.

Item 6.8 Production Estimates

The following table summarizes Iona's estimated average daily production volumes from total proved, total proved & probable reserves and total proved plus possible plus probable as at December 31, 2013 for each product type for 2014.

Estimated Summary of Oil and Gas Production Per Day for 2014[(1)]

	Light and Medium Oil		Heavy Oil		Natural Gas (Associated and Non-Associated)		Coalbed Methane		Natural Gas Liquids	
Reserves Categories	**Gross Mbbl**	**Net Mbbl**	**Gross Mbbl**	**Net Mbbl**	**Gross MMscf**	**Net MMscf**	**Gross Mbbl**	**Net Mbbl**	**Gross Mbbl**	**Net Mbbl**
Proved	8.95	1.41	-	-	12.42	2.15	-	-	-	-
Total Proved Plus Probable	10.22	1.61	-	-	13.62	2.34	-	-	-	-
Total Proved Plus Possible Plus Probable	11.24	1.77	-	-	15.94	2.77	-	-	-	-

Note:
(1) All of the data in the table is attributed to Iona's gas production at Trent & Tyne and oil and gas production at Huntington.

Item 6.9 Production History

The following two tables summarize Iona's average daily production volumes, average prices and production costs in US dollars on a quarterly basis during 2013. All production indicated below is light oil production from Iona's Huntington field or natural gas production from Iona's Huntington and Trent & Tyne fields.

Table 6.9.1(1)
Summary of UK Average Light Oil Production and Operating Income from January 1, 2013 to December 31, 2013

	Q1	**Q2**	**Q3**	**Q4**
Production Volume (Mbbl/day)	-	1,058	1,614	2,320
Realized Price (US$/Mbbl)	-	105.1	116.6	112.2
Production Costs (US$/Mbbl)	-	39.8	23.6	24.9
Average Netback (US$/Mbbl)	-	65.3	93.0	87.3

Table 6.9.1(2)
Summary of UK Average Gas Production and Operating Income
from January 1, 2013 to December 31, 2013

	Q1	Q2	Q3	Q4
Production Volume (Mscf/day)	1,896	3,936	5,022	4,584
Realized Price (US$/Mscf)	10.9	9.3	9.3	12.9
Production Costs (US$/Mscf)	4.7	6.6	3.9	5.3
Average Netback (US$/Mscf)	6.2	2.7	5.4	7.6

The following two tables summarize the Corporation's net production volumes during the year ended December 31, 2013 for each major field and in total, by product type.

Table 6.9.2(1)
Net Production History for the Huntington Field in 2013

Month	Production of Natural Gas (Mscf)	Production of Light Oil (bbl)
January	0	0
February	0	0
March	0	0
April	0	18,384
May	0	32,656
June	8,772	32,547
July	32,500	51,426
August	17,873	27,939
September	46,648	69,128
October	33,506	52,032
November	53,502	74,732
December	64,828	86,672

Table 6.9.2(2)
Net Production History for the Trent & Tyne Field in 2013 (Natural Gas)

Month	Production (Mscf)
January	96,902
February	73,986
March	0
April	60,672
May	108,397
June	180,043
July	154,900
August	93,295
September	117,042
October	85,330
November	65,530
December	42,997

Table 6.9.2(3)
Net Production History (Total) in 2013

Month	Production of Natural Gas (Mscf)	Production of Light Oil (Bbl)
January	96,902	0
February	73,986	0
March	-	0
April	60,672	18,384
May	108,397	32,656
June	188,815	32,547
July	187,400	51,426
August	111,168	27,939
September	163,690	69,128
October	118,836	52,032
November	119,032	74,732
December	107,825	86,672