ANNUAL STATEMENT OF RESERVES 2015

DET NORSKE OLJESELSKAP ASA

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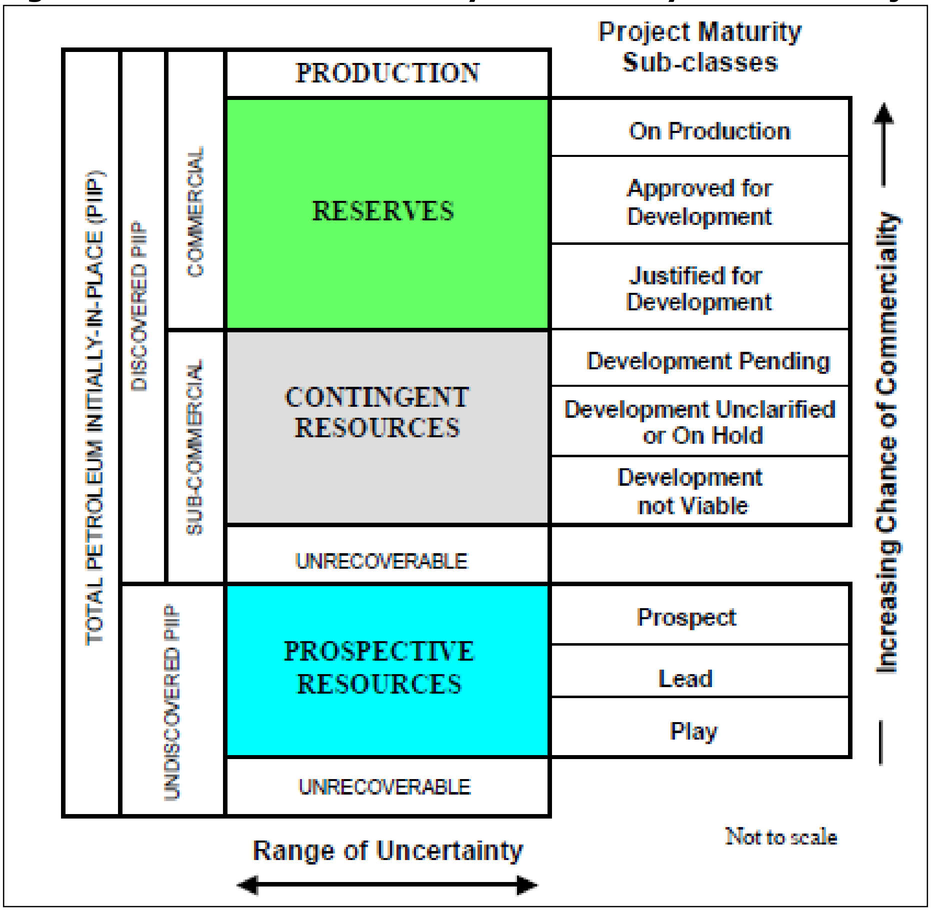
1 Classification of Reserves and Contingent Resources

Det norske oljeselskap ASA's reserve and contingent resource volumes have been classified in accordance with the Society of Petroleum Engineer's (SPE's) "Petroleum Resources Management System". This classification system is consistent with Oslo Stock Exchange's requirements for the disclosure of hydrocarbon reserves and contingent resources. The framework of the classification system is illustrated in Figure 1.

Figure 1 - SPE's classification system used by Det norske oljeselskap ASA



2 Reserves, Developed and Non-developed

Det norske oljeselskap ASA has a working interest in 17 fields/projects containing reserves, see Table 1. Out of these fields/projects, nine are in the sub-class "On Production"/Developed and eight are in the sub-class "Approved for Development"/Non-developed). Note that the Alvheim and Volund fields have reserves in both sub-class "On production" and in the sub-class "Approved for Development".

Sub-class "On Production"/Developed:

- Alvheim - operated by Det norske, Det norske 65 percent (Norwegian part)
- Volund - operated by Det norske, Det norske 65 percent
- Vilje - operated by Det norske, Det norske 46.907 percent
- Bøyla – operated by Det norske, Det norske 65 percent
- Atla – operated by Total, Det norske 10 percent
- Jette – operated by Det norske, Det norske 70 percent

- Varg – operated by Repsol, Det norske 5 percent
- Jotun – operated by ExxonMobil, Det norske 7 percent
- Enoch – operated by Talisman, Det norske 2 percent

Sub-class “Approved for Development”/Non-developed:

- Alvheim Phase 3, gas blowdown - operated by Det norske, Det norske 65 percent
- Alvheim infill well Boa Kam North– operated by Det norske, Det norske 65 percent (Norwegian part)
- Ivar Aasen Unit – operated by Det norske, Det norske 34.7862 percent
- Volund infill wells – operated by Det norske, Det norske 65 percent
- Gina Krog – operated by Statoil, Det norske 3.3 percent
- Hanz – operated by Det norske, Det norske 35 percent
- Viper/Kobra – operated by Det norske, Det norske 65 percent
- Johan Sverdrup – operated by Statoil, Det norske 11,5733 percent

Total net proven reserves (P90/1P) as of 31.12.2015 to Det norske are estimated at 374 million barrels of oil equivalents. Total net proven plus probable reserves (P50/2P) are estimated at 498 million barrels of oil equivalents. The split between liquid and gas and between the different subcategories are given in Table 1.

Table 1 – Reserves by field as of 31.12.2015

	Interest	1P / P90 (low estimate)					2P / P50 (best estimate)				
On production As of 31.12.2015	%	Gross Oil (mmbbl)	Gross NGL (mmton)	Gross gas (bcm)	Gross oe (mmboe)	Net oe (mmboe)	Gross Oil (mmbbl)	Gross NGL (mmton)	Gross gas (bcm)	Gross oe (mmboe)	Net oe (mmboe)
Alvheim Norway	65 %	55,7	-	0,6	59,7	38,8	74,5	-	1,2	81,8	53,2
Vilje	46,9 %	9,6	-	-	9,6	4,5	17,5	-	-	17,5	8,2
Volund	65 %	8,8	-	0,1	9,2	6,0	16,1	-	0,2	17,5	11,4
Bøyla	65 %	10,1	-	0,1	10,5	6,8	16,3	-	0,1	17,1	11,1
Atla	10 %	0,2	-	0,3	1,9	0,2	0,4	-	0,5	3,5	0,4
Jotun	7 %	-	-	-	-	-	-	-	-	-	-
Varg	5 %	-	-	-	-	-	-	-	-	-	-
Jette	70 %	0,1	-	-	0,1	0,1	0,2	-	-	0,2	0,1
Enoch	2 %	-	-	-	-	-	0,1	-	-	0,1	0,0
Total		84,6	-	1,0	91,0	56,4	125,2	-	2,0	137,8	84,4
	Interest	1P / P90 (low estimate)					2P / P50 (best estimate)				
Approved / Justified As of 31.12.2015		Gross Oil (mmbbl)	Gross NGL (mmton)	Gross gas (bcm)	Gross oe (mmboe)	Net oe (mmboe)	Gross Oil (mmbbl)	Gross NGL (mmton)	Gross gas (bcm)	Gross oe (mmboe)	Net oe (mmboe)
Alvheim Kam Phase 3	65 %	-	-	2,1	13,1	8,5	-	-	3,3	21,1	13,7
Alvheim Boa Kam North Norw	65 %	3,7	-	0,1	4,1	2,6	8,7	-	0,1	9,6	6,3
Viper/Kobra	65 %	4,6	-	0,1	4,9	3,2	7,8	-	0,1	8,5	5,5
Volund Infill	65 %	6,6	-	0,1	7,2	4,7	10,6	-	0,2	11,6	7,5
Ivar Aasen	35 %	108,5	0,8	4,4	145,4	50,6	146,4	0,9	4,7	186,3	64,8
Hanz	35 %	12,1	0,1	0,3	14,6	5,1	14,4	0,1	0,4	17,7	6,2
Gina Krog	3 %	80,4	2,4	7,7	157,6	5,2	105,6	3,2	11,5	216,4	7,1
Johan Sverdup	12 %	1925,6	4,7	11,3	2052,9	237,6	2452,0	6,0	14,5	2615,4	302,7
Total		2141,4	8,0	25,9	2399,8	317,5	2745,6	10,2	34,9	3086,5	413,8
Total Reserves		2226,0	8,0	26,9	2490,8	**373,9**	**2870,8**	**10,2**	**36,9**	**3224,3**	**498,2**

Note that Det norske has included recoverable volumes from a full field development scenario as undeveloped reserves for Johan Sverdrup. Only Phase 1 has an approved PDO. Det norske, however, argues in chapter 3.2.1 that recoverable reserves from further development of the field shall be classified as reserves.

The reserves from phase 1 is categorized in sub class “Approved for Development”/under development. More than 80 % of the reserve from a full field development will be recovered through a Phase 1 development only. Even though a PDO for future phases has not yet been submitted, Det norske has chosen to include all reserves from a full field development in sub category “Approved for Development”/under development. Even though several development solutions currently is discussed, reserve estimates are very much independent of the development solution. Even a “minimum development” which includes drilling of wells only and with marginal or no CAPEX spent on increasing production capacities compared with Phase 1 capacities will give approximately the same reserves as a large/expensive further development with additional process capacities installed. Thus, an investment in increased process capacities is linked to acceleration of production and consequently increased NPV and not for increasing reserves.

Table 2 below shows reserves Johan Sverdrup reserves from Full Field development compared to Phase 1development only.

Table 2 - Comparison Johan Sverdrup reserves – Full Field development vs. Phase 1 only.

Remaining 2015	Interest	1P / P90 (low estimate)					2P / P50 (best estimate)				
As of 31.12.2015	%	Gross Oil (mmbbl)	Gross NGL (mmton)	Gross gas (bcm)	Gross oe (mmboe)	Net oe (mmboe)	Gross Oil (mmbbl)	Gross NGL (mmton)	Gross gas (bcm)	Gross oe (mmboe)	Net oe (mmboe)
Johan Sverdrup full field dev.	12 %	1925,6	4,7	11,3	2052,9	237,6	2452,0	6,0	14,5	2615,4	302,7
Johan Sverdrup Phase 1 dev.	12 %	1623,2	4,0	9,6	1731,6	200,4	2004,2	5,0	12,0	2139,4	247,6

Even though the Jotun and Varg fields will produce marginal volumes in 2016, Det norske has not included any reserves from Jotun in the company's reserve base as of 31.12.2015. The reason for this is that both the proven and proven plus probable production profiles for both fields indicates negative cash flow as of 31.12.2015. This is in accordance with the SPE's "Petroleum Recourse Management System".

Changes from 2014 reserve report are summarized in Table 3. The main reason for increased net reserve estimate is that Johan Sverdrup has been classified as reserves in 2015. As of 31.12.2015 Johan Sverdrup represent 64% and 61% of total net proven reserves (1P/P90) and proven plus probable reserves (2P/P50) respectively.

Except for Johan Sverdrup there has been only minor changes in the reserve estimate. Two infill wells on Volund were sanctioned in 2015 and have been included in "Approved for Development". In addition two infill wells successfully drilled and completed on Alvheim in 2015 have been moved from "Approved for Development" and included in Alvheim base estimate ("On Production"). Also Bøyla came on production in 2015 and are therefore reclassified from "Approved for Development" to "On Production".

Table 3 – Aggregated reserves, production, developments, and adjustments

Net attributed million barrels of oil equivalents (mmboe)	On Production		Under development		Total	
	1P/P90	2P/P50	1P/P90	2P/P50	1P/P90	2P/P50
Balance as of 31.12.2014	**50**	**81**	**93**	**125**	**143**	**206**
Production	-22	-22			-22	-22
Acquisitions/disposals					0	0
Extensions and discoveries					0	0
New developments	3	7	231	289	234	296
Revisions of previous estimates	25	19	-7	0	18	19
Balance as of 31.12.2015	**56**	**84**	**317**	**414**	**374**	**498**
Delta	**6**	**4**	**224**	**289**	**231**	**292**

The future oil price assumption for the reserves given in Table 1 is 60 USD/bbl. Average oil price in the period 01.10.2014 to 01.10.2015 was 60.3 USD/bbl. A sensitivity with a higher oil price of 70 USD/bbl had only minor impact on net total reserves to Det norske. Also a lower price scenario with an oil price of 50 USD/has been tested. This gave 1% lower total net proven (1P) reserves and 3% lower proven plus probable (2P) reserves compared to the base oil price assumption of 60 USD/bbl.

Total net production to Det norske averaged 60 mboepd in 2015.

3 Description of reserves

3.1 Producing assets

3.1.1 Alvheim (PL036C, PL088BS, PL203)

Alvheim is an oil and gas field located in the Norwegian sector of the Northern North Sea in a water depth between 120-130 meters. The field is located in Blocks 24/6, 24/9, 25/4 and 25/7 and is comprised of the producing Alvheim field (Boa, Kneler, Kameleon/East Kameleon and Viber/Kobra structures) and the Gekko discovery (the "Alvheim Area Fields"). The productive horizon for the Alvheim fields is the Middle to Late

Palaeocene Heimdal Formation sandstone which exists at a depth of approximately 2,100 meters. Alvheim was developed using a floating production, storage and offloading FPSO vessel (the “Alvheim FPSO”). The development provides for the transport of oil by shuttle tanker and transportation of gas to the SAGE system. The Alvheim FPSO is characterized by high regularity, over 98% uptime (excluding planned down-time for maintenance).

First production for the Alvheim field was in June 2008. The Alvheim Area Fields have seen significant year-on-year increases in the estimated recoverable volumes of oil and gas since the initial development of the Alvheim field. Recoverable oil has increased as a function of greater in-place volumes than previously estimated, development of satellite fields, additional horizontal and multi-lateral wells, and better than anticipated reservoir performance. Furthermore, improved reliability combined with optimization work has increased the production capacity of the Alvheim FPSO to about 150,000 boepd up from the original design of 120,000 boepd.

During 2015 two new wells has been put on production and reserves from these wells have been reclassified from non-developed reserves to developed reserves since last year’s reserve report. These are the wells Alvheim East Kam L4 and Alvheim Kneler. No new well targets has been included in the 2015 report compared to the 2014 report although Det norske continuously evaluates drilling targets on Alvheim and has defined several possible new drilling targets.

Net production from Alvheim, including Boa, averaged 34.1 mboepd in 2015 which is approximately 5% lower than expected in RNB2015. The main reasons for this discrepancy are delayed startup of the two infill wells and failure in the gas export system in the period November 17th to December 13th. Reservoir performance has been as expected.

The cessation of production of the Alvheim field is estimated to 2033, with subsequent abandonment between 2033 and 2035.

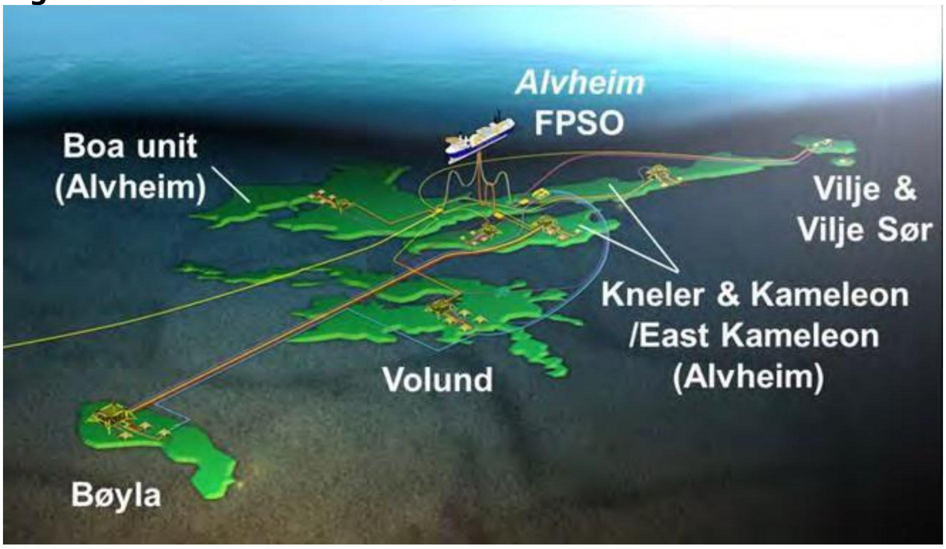
The Viper/Kobra structures are planned developed with two wells tied back to the FPSO through the Volund manifold extension. The project has been sanctioned and the wells are planned drilled and completed within 1st half 2016.

The Boa Kam North well was pr. January 2016 nearly complete with first oil is estimated to mid-2016. The well results are positive and with reservoir properties between base and high pre-drilling case.

Det norske is the operator of the Alvheim Area Fields with a 65% working interest. The other partners are ConocoPhillips Skandinavia AS holding a 20% interest and Lundin Norway AS holding a 15% interest.

Figure 2 shows is a location map of the Alvheim Area Fields:

Figure 2 - Alvheim area location



The Boa reservoir straddles the Norway-UK median line. The Boa reservoir is unitized with Maersk Oil & Gas and Verus Petroleum, who are the owners on the UK side. Det norske's interest in the Boa unit is 57.62%.

3.1.2 Vilje (PL036D)

The Vilje field is located North East of Alvheim at a water depth of 120 meters. The productive horizon for the Vilje field is the Middle to Late Palaeocene Heimdal Formation sandstone at a depth of approximately 2,100 meters. The main structure is developed by two subsea production wells tied back to the Alvheim FPSO through a 19 km pipeline. Production from these wells commenced in 2008. A third production well, Vilje South, was drilled and completed as a satellite subsea well tieback to the Vilje subsea facilities. Production from this well commenced in April 2014.

Net production from Vilje averaged 6.4 mboepd in 2015 which is approximately 10% above prognosed volume. Production from the Vilje field is expected to cease in 2031, with subsequent abandonment scheduled to take place between 2033 and 2035, which coincides with the expected cessation of production from the Alvheim area.

Det norske holds a 46.904% interest in the license and serves as operator. The other license partners are Statoil Petroleum AS holding a 28.853% interest and Total E&P Norge AS with a 24.243% interest.

3.1.3 Volund (PL150)

The Volund field is located approximately eight km south of Alvheim, and was the second field developed as a subsea tieback to Alvheim. The Volund field, comprising of four production wells and one water injection well, started producing in 2009 and was utilized as a swing producer when the capacity at the Alvheim FPSO allowed it. The field was opened for regular production in 2010. The Volund reservoir is a large-scale injective feature, formed by sands of the Palaeocene Hermod Formation. These have become remobilized and subsequently injected into the overlying stratigraphy during the Early Eocene, creating steeply dipping "wings" of injected sand dykes from flat sand sills, at depths from approximately 1,800 meters to 2,000 meters.

A drilling campaign including drilling of two infill wells on Volund has been sanctioned. These two wells has been included as reserves "Approved for Development" (Table 1). Current plan calls for drilling start late 2016 and production start 1. half 2017.

Net production at Volund averaged 9.0 mboepd in 2015 which is approximately 11% above prognosed volume. Cessation of production from the Volund field is expected in 2033.

Det norske holds a 65% interest in Volund and serve as operator, while Lundin Norway AS holds the remaining 35% interest.

3.1.4 Bøyla (PL 340)

Bøyla came on stream January 2015 and is therefore re-classified from "Approved for Development" to "On Production".

The Bøyla field is located south of Volund approximately 28 kilometers from Alvheim at a water depth of 120 meters. The Bøyla reservoir interval is within the Palaeocene Hermod Formation sandstone, a deep marine, channelized submarine fan system, at a depth of approximately 2,050 meters. The field was discovered in 2009 and the PDO was approved in 2012. The field is developed with two horizontal production wells (targeting each of the eastern and western structural closures) and one water injection well, placed at the eastern edge of the western structural closure and between the two producers. Pilot wells were drilled in order to optimize the horizontal section of the western structure producer. The field produces via a four-slot subsea production manifold and is tied-back to the Alvheim FPSO via the Kneler A production manifold.

Bøyla started production in January 2015 and net production averaged 9.0 mboepd for the year. Cessation of production from the Bøyla field is expected in 2033 together with abandonment activities relating to the other Alvheim Area fields.

Det norske, as operator, holds a 65% interest. Core Energy AS holds a 20% interest and Lundin Norway AS holds the remaining 15%.

3.1.5 Atla (PL102C)

Atla is a small gas/condensate field in the central part of the North Sea in a water depth of 119 meters. The reservoir contains gas/condensate in sandstones in the Brent Group of Middle Jurassic age at a depth of about 2,700 meters. The field produces with a subsea installation tied back to the existing pipeline between the Heimdal and Skirne fields. Production started two years after the discovery in October 2010.

It is estimated that the field will continue to produce until 2017. Atla stop of physical production is planned in early 2016 dependent on the inlet separator pressure at Heimdal. The reserves for Atla throughout 2016-2017 reflect Skirne compensation to Atla.

Net production from Atla averaged 0.4 mboepd in 2015.

Det norske holds a 10% interest in the license. Total E&P Norge AS is the operator holding a 40% interest while Petoro AS holds a 30% interest and Lotos Exploration and Production Norge AS holds the remaining 20% interest.

3.1.6 Jette (PL027D, PL169C, PL504)

Jette is a small oil field in the central part of the North Sea in a water depth of 127 meters. The reservoir consists of a submarine fan system in the Heimdal Formation of Late Palaeocene age, and lies at a depth of approximately 2,200 meters. The field has been developed with a subsea installation tied back to the Jotun B platform. A number of modifications to Jotun B, in addition to minor modifications on Jotun A, were required in order to tie the two fields together. The chosen development concept enables future tie-up to additional wells. The well stream from Jette is mixed with the well stream from Jotun on Jotun B and transported to Jotun A for further processing, storage and export.

The field is developed with two producers. Since start-up the field has experienced increasing water cut and a steady decline in production. The initial agreement with the Jotun unit included tariff payment regime until 31.12.2015. From this date it was assumed a model including OPEX-sharing between the units. It was, however, obvious that this would result in a negative cash-flow situation for Jette. A renegotiated agreement has therefore been established securing Jette a marginal net profit until Jotun is shutting down late 2016.

Net production from Jette averaged 0.6 mboepd in 2015.

Det norskes's interest in the Jette unit is 70% while Petoro AS holds the remaining 30% interest.

3.1.7 Jotun (PL027B, PL103B)

Jotun is an oil field located in the central part of the North Sea in a water depth of approximately 126 meters. The Jotun unit comprises three structures; the easternmost structure has a small gas cap. The reservoirs consist of sandstones in the Heimdal Formation of Palaeocene age. The reservoirs, which consist of deposits of a submarine fan system, are at a depth of about 2,000 meters. To the west, the reservoir quality is good, while the shale content increases towards the east.

The Jotun installations comprise of an FPSO, Jotun A, and a wellhead platform, Jotun B. Production commenced in 1999 and is now in the tail-end phase. A firm plan for closing down the Jotun production has been establish which includes last production 31.09.2016. Even though the field will produce marginal volumes in 2016, Det norske has not included any reserves from Jotun in the company's reserve base as of 31.12.2015. The reason for this is that both the proven and proven plus probable production profiles indicates negative cash flow as of 31.12.2015. This is in accordance with the SPE's "Petroleum Recourse Management System".

Net production at Jotun averaged 0.1 mboepd in 2015.

Det norske's interest in the unit is 7%. The operator is ExxonMobil Exploration & Production Norway AS with a 90% interest. The other licensee is Faroe Petroleum Norge AS with a 3% interest.

3.1.8 Varg (PL038)

The Varg Field is an oil field located in the central part of the North Sea at a water depth of 84 meters. The reservoir is in Upper Jurassic sandstones at a depth of approximately 2,700 meters. The structure is segmented and includes several isolated compartments with varying reservoir properties.

Varg is developed with a wellhead platform, Varg A, and an FPSO, Petrojarl Varg. Varg A is normally unmanned. The wellhead platform and the FPSO are connected through flexible pipelines for oil production, water and gas injection and umbilical for power supply and control. The oil is offloaded from the FPSO to shuttle tankers via a discharging system located aft on the FPSO.

All gas was initially re-injected into the reservoir. After 15 years of oil production, gas production was started in 2013, which has contributed to extend the lifetime for the Varg facilities. Varg is very much on tail end production and also for Varg a firm shut-down plan exist. It is estimated that the field will cease production in 2Q 2016. The current OPEX level and estimated production forecasts, however, gives no proven (1P/P90) or proven plus probable (2P/P50) reserves after 31.12.2015.

Net production from Varg averaged 0.3 mboepd in 2015.

Det norske holds a 5% interest in the license, while the operator Repsol holds 65%. The remaining 30% is held by Petoro AS.

3.2 Development Projects

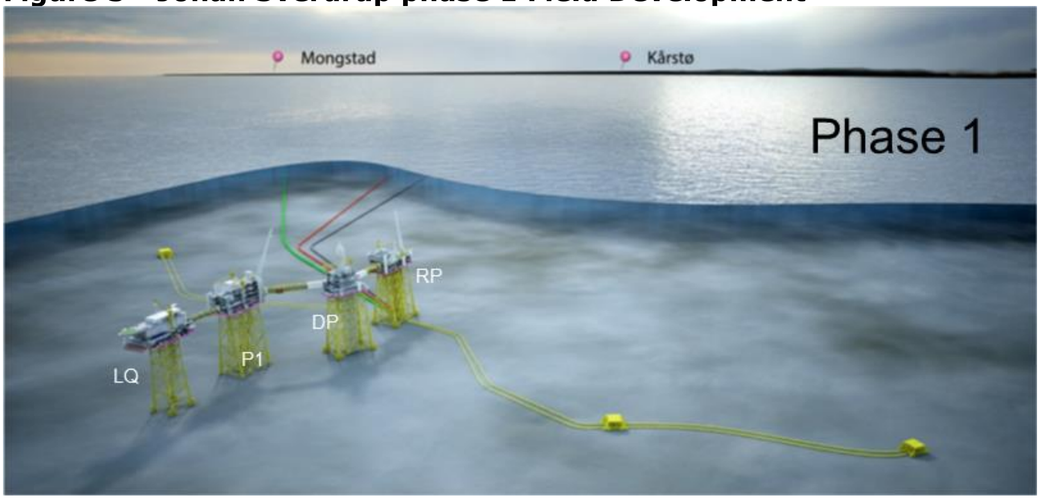
3.2.1 Johan Sverdrup

The discovery well 16/2-6 on the giant Johan Sverdrup discovery was drilled in 2010. The well proved oil in Jurassic and pre-Jurassic sandstones on eastern part of the Utsira High. Since that time, more than 30 appraisal wells including sidetracks have been drilled. Seven drill stem tests have confirmed excellent reservoir properties with massive continuous sands with permeability of tens of Darcy.

The reservoir consist of late Jurassic coarse grained sandstones in the Draupne Formation, the middle Jurassic Vestland Group and early Jurassic to late Triassic fine to medium grained sandstones in the Statfjord Group. The apex of the discovery is estimated at approximately 1800 mMSL TVD, with a varying FWL from approximately 1922 to 1934 mMSL TVD. The reservoir fluid is highly undersaturated oil with low a GOR of 40 Sm3/Sm3 and with a viscosity of approximately 2 cP.

Current plans call for a phased development of the field and the PDO for the phase 1 development was issued in February 2015 and approved by the authorities in June 2015. A unit agreement was signed by all parties in August 2015. The unit agreement gives Det norske an 11. 5733% share of the field.

Figure 3 - Johan Sverdrup phase 1 Field Development



The Phase 1 development plan assumes a field center with four platforms; processing platform, drilling platform, riser and export platform and living quarters (Figure 3). The platforms will be installed on steel jackets linked by bridges. Phase 1 also includes 18 oil production and 16 water injection wells and 3 subsea water injection templates. Future development phases shall maximize value creation and ensure optimal utilization of all areas that constitute the field. Concept selection for future phases is scheduled for Q3 2016. The PDO for the future phases is planned for Q4 2017 and production start is planned in 2022. Fully developed, approximately 70 oil production and water injection wells will be drilled on Johan Sverdrup and the oil plateau production is expected to be approximately 600,000 barrels of oil pr. day.

The export solution for oil and gas will be transportation to shore via dedicated pipelines. The oil will be transported to the Mongstad terminal and the gas will be transported via the Statpipe system to Kårstø for processing and onward transportation.

Note that Det norske has different view of the reserves on Johan Sverdrup compared to the Operator. Det norske has throughout the last years done substantial subsurface evaluations of the field. A fully integrated subsurface team constituted by highly experienced professionals has worked on a 100% basis since 2012. The team has utilized all available date and state of the art modeling tools to establish most likely in place and recoverable volumes with associated uncertainty range. This work resulted in higher reserves (P90 and P50) compared to the Operators estimates. Det norske therefore engaged AGR Reservoir Services in order to do an independent evaluation of the work/analyses performed both by the Operator (PDO-volumes) and Det norske volumes. AGR supported parts of the work/analyses done by Det norske and also parts of the work done by the Operator. Det norske has chosen to use the in place volumes and recovery efficiencies resulted from this independent evaluation study as official reserve estimates for Johan Sverdrup. Note that Det norske consider these volumes to be conservative estimates for Johan Sverdrup.

Note also that Det norske has included reserves for a full field development of the field in the reserve base, even though a PDO for future phases not yet has been issued. The reason for this is summarized below.

Reserve classification system

As described in Chapter 1 Introduction, Det norske is classifying petroleum according to the Society of Petroleum Engineer's (SPE) Petroleum Resources Management System (PRMS). PRMS is pre-approved by Oslo Stock Exchange (OSE) as a classification system in its Listing and Disclosure Requirements for oil and natural gas companies

The purpose of a classification system is to classify petroleum in a way that make sense for an investor in his or her valuation when making an investment decision. The distinction between the main resource classes, a) reserves and contingent resources and b) between contingent and prospective resources are clearly more important to an investor than the subdivision within a main resource class, as the delineation between reserves and resources marks the line between commercial petroleum and sub-commercial petroleum volumes.

PRMS defines reserves as - *Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.*

It is not a requirement in the PRMS that a PDO has been submitted to the authorities in order to classify recoverable volumes as reserves.

Oslo Stock Exchange

The Oslo Stock Exchange (OSE) introduced a revised set of guidelines and requirements (Listing and disclosure requirements for oil and natural gas companies) for oil and natural gas companies which was effective and mandatory from 1st January 2014.

The guideline from OSE prescribes the use of classifications systems widely recognized and in use throughout the oil and gas industry and the following classification systems are pre-approved:

- The SPE PRMS classification system (the SPE/WPC/AAPG/SPEE *Petroleum Resources Management System document*)
- SEC (ie reporting in line with the US Securities and Exchanges Commissions requirements)
- NPD (ie reporting in line with the Norwegian Petroleum Directorate's requirements)
- NI 51-101 (reporting in line with Canadian National Instrument 51-101)

As mentioned above, Det norske is using the pre-approved PRMS for classification of reserves.

In the guidelines from OSE the following is stated:

"It is the opinion of Oslo Børs as regulator that an overly conservative approach to reserves reporting may be just as misleading as an overly optimistic one, if the result is that the market at large does not have the ability to analyse the less conservative but perhaps more relevant data which to a greater extent forms the basis for the company's internal evaluation and actual decision making"

As there is a very high probability for a Future Phase project on Johan Sverdrup, Det norske is of the opinion that not reporting these volumes as reserves would be an *overly conservative approach.*

Further in the guidelines the following is stated in section 3.10:

"Reserves may be assigned only to those volumes where a Plan for Development and Operation (PDO) has at least been filed (but not necessarily approved) by relevant authorities (or where similar development approval has been granted by relevant authorities). If the approval of a PDO may be anticipated with reasonable certainty and within a predictable lead time of its filing, reserves may be assigned to the volumes in question prior to the filing of a PDO, providing the license holder or partners have decided upon and committed financial resources towards the commercial development of the volumes in question".

The paragraph open up for the possibility to include recoverable volumes as reserves even though a PDO is not submitted. Det norske management's view is that the requirements in this pharagraph is met on Johan Sverdrup for booking reserves for the full field and the reasons for this are (see details below):

- Firm plan for a Future Phases PDO established within the license
- Approval of such a PDO is anticipated with reasonable certainty
- Lead time for approval of such a PDO is very predictable
- Significant pre-investments have been made for the Future Phases.

Based on this, Det norske management is of the opinion that the company is in a position to book reserves for the full field on the Johan Sverdrup license.

3.2.2 Ivar Aasen Unit and Hanz (PL001B, PL028B, PL242, PL338BS, PL457)

The Ivar Aasen Field is an oil field situated west of the Johan Sverdrup discovery in the North Sea at a water depth of 110 meters. The reservoir consists of shallow marine sandstones in the Hugin Formation and fluvial sandstones in the Sleipner and Skagerrak Formations. The reservoir contains oil at a depth of approximately 2,400 meters. Parts of the reservoir have an overlying gas cap.

The PDO was approved in June 2013. First oil is planned in the fourth quarter of 2016 and the anticipated economic life is 20 years. The development of the Ivar Aasen field is so far on time and on budget.

The Ivar Aasen unit development plan (Ivar Aasen and West Cable discoveries) includes production of the reserves also from the Hanz (PL028B) discovery. The approved PDO sets out that Ivar Aasen and West Cable (Ivar Aasen Unit) will be developed in the first phase and Hanz in the second phase. The Ivar Aasen and West Cable reservoirs will be developed with a manned production platform located above the Ivar Aasen reservoir and with a planned subsea installation on Hanz tied to the Ivar Aasen platform. The West Cable discovery will be drained through one well drilled from the Ivar Aasen platform.

The development of Ivar Aasen is coordinated with the adjacent Edvard Grieg field, which will receive partially processed oil and gas from the Ivar Aasen field for further processing and export. The Edvard Grieg platform will also provide the Ivar Aasen platform with gas lift and electricity.

On June 30, 2014, a unitization agreement for Ivar Aasen and West Cable was entered into with the licensees in PL457 and PL338BS. The unitization agreement was approved by the MPE on October 29, 2014. A commercial solution for Hanz is likely to be entered into in connection with a final decision on when to initiate Hanz production.

Several wells have been drilled on Ivar Aasen during 2015. This includes 5 geological pilot wells and four development wells. A new geological model has been established which includes results from all the pilot wells. The up-dated model indicates a somewhat lower oil in place number compared to previous model. This is mainly due to somewhat thinner Sleipner Formation and deeper top reservoir in the western part of the field.

The sand quality in the Skagerrak Formation, however, proved to be better than the prognosis with higher porosity and permeability. Hence, dynamic reservoir simulation based on the up-dated geological model indicates higher recovery efficiency than indicated by the previous model resulting in no change in recoverable reserves compared to last year's reserve report.

Det norske holds a 34.7862 interest in the Unit. The other licensees are Statoil Petroleum AS (41.4730), Bayerngas Norge AS (12.3173%), Wintershall Norge AS (6.4615%), VNG Norge AS 2.0230%), Lundin Norway AS 1.3850%) and OMV (Norge) AS (0.5540%).

3.2.3 Gina Krog (PL029B)

Gina Krog, formerly known as Dagny, is an oil field discovered in 1974. The reservoir contains oil and gas in Middle Jurassic sandstones in the Hugin Formation. The reservoir lies at a depth of about 3,700 meters. The field is located in the middle of the North Sea 250 kilometers west of Stavanger and 30 kilometers northwest of the Sleipner A installation, with a water depth of 110 to 120 meters. The development solution for Gina Krog is a new steel platform and a storage vessel for oil with a capacity of 850,000 barrels. Drilling is planned using a jack-up rig. Oil will be transported by tankers via offshore loading (FSU). The rich gas will be transported to Sleipner for processing and onto Gassled for export. Condensate and NGL will be exported to Kårstø, in Norway. The PDO for Gina Krog was approved in May 2013.

First oil is scheduled for the second quarter 2017 and the field is expected to be in production until 2037.

The field is unitized and Det norske holds an interest of 3.3% unit. The operator Statoil Petroleum AS holds a 58.7% interest, Total E&P Norge 30%*,and PGNiG the remaining 8%. (*Total E&P Norge AS entered 19th October 2015 into an agreement with Tellus Petroleum regarding assignment of 15% participating interest in Gina Krog Unit to Tellus Petroleum. Awaiting final closing)

3.2.4 Viper-Kobra (PL203)

Viper-Kobra is located within the Alvheim field approximately three kilometers south of the Kneler structure at a water depth of 120 to 130 meters. The development project includes the two separate structures Viper and Kobra which are believed to be in pressure communication. Viper-Kobra will be developed by two wells tied back to the FPSO through the Volund manifold extension, one targeting Viper and one targeting Kobra.

The concept selection was passed by the partnership in April 2014 and the development was approved by the Board of Directors of Marathon Norge in May 2014. The license partners approved the development plan in December 2014 and the wells are planned drilled and completed within 1st half 2016.

Det norske, as operator, holds a 65% interest. ConocoPhillips Skandinavia AS holds a 20% interest and Lundin Norway AS holds the remaining 15%.

3.2.5 Enoch (PL048 D)

Enoch is an oil field located in the middle part of the North Sea which straddles the border between the NCS and the UKCS at a water depth of 112 meters. The reservoir contains oil in Palaeocene sandstones at a depth of approximately 2,100 meters and the reservoir quality is variable. Production started in 2007. The field is developed with one subsea well tied back to the British Brae field. The oil is processed on Brae A and exported through the Forties pipeline system to the UK.

Due to technical problems, the field was shut down from first quarter 2012 to 29th November 2015. Current reserve estimates includes a 24 month production period. After 24 months a pigging operation will be required. It is anticipated that this operation will be costly and noneconomic. However, a gas leak on the host platform December 26th 2015 led to a new shut-down. The field is currently shut in and timing for re-opening is uncertain. Det norske has therefore not included any proven (1P/P90) reserves on Enoch. Proven plus Probable reserves (P50/2P) assumes a 24 month production period.

The Enoch field is unitized, the Norwegian section constituting 20% and the UK section constituting 80%. Of the 20% located on the NCS, Det norske holds a 10% interest corresponding to 2% of the unitized field. Other licensees in Enoch are Talisman Sinopec North Sea Limited as the operator (24% interest in the unitized field), Dana Petroleum (BVUK) Limited (20.8%), First Oil Expro Limited (14%), Faroe Petroleum Norge AS (13.86%), Statoil Petroleum AS (11.78%), Endeavour Energy UK Limited (8%), Noreco Norway AS (4.36%), and Talisman Sinopec LNS Limited (1.2% interest).

4 Contingent Resources

Det norske oljeselskap ASA has interests in several discoveries/projects containing oil and/or gas volumes classified as contingent resources.

Four of these discoveries/projects are in the planning phase; "Development Pending". These are Frøy, Frigg Gamma/Delta, Krafla and Vette. A more detailed description of these assets are given below.

Twelve discoveries/projects are classified as "Development Unclarified or on Hold"; Storklakken, Ragnarrock Basement, P-Graben, Garantiana, Gotha, Krafla/Askja Area (Askja Øst, Askja West, Krafla Nord Tarbert, Steinbitt (Krafla), Trell, Gekko, Caterpillar, Grevling.

In addition, Det norske holds interests in 10 discoveries classified as "Development not Viable".

Note that considerable up-side potential are identified for several fields and discoveries. This is valid especially for Johan Sverdrup which has an identified IOR potential of some 300 million barrels of oil equivalents.

Development Pending:

- PL 364 (Well 25/5-1) Frøy - operated by Det norske, 100% share
- PL 442 (Well 25/2-17) Frigg Gamma/Delta - operated by Centrica, Det norske 60% share
- PL 272/035 (Well 30/11-8S) Krafla – operated by Statoil, Det norske 50% share
- PL 406/407 (Wells 17/12-1, 18/10-1) – Vette/Mackerell – Operated by Det norske, Det norske 50% share

Development Unclarified or on Hold:

- Alvheim Infill- operated by Det norske, 65% share
- PL 460 (Well 25/1-11) Storklakken - operated by Det norske, 100% share
- PL 265 (Well 16/2-3) Ragnarrock Chalk - operated by Statoil, Det norske 20% share
- PL 265 (Well 16/2-3) Ragnarrock Basement North - operated by Statoil, Det norske 20% share
- PL 265 (Well 16/2-5) P-Graben - operated by Statoil, Det norske 20% share
- PL 554 (Well 34/6-2S) Garantiana – operated by Total, Det norske 30% share
- PL 492 (Well 7120/1-3) Gohta – operated by Lundin, Det norske 40% share
- PL 272 (Well 30/11-9S) Krafla/Askja Area– operated by Statoil, Det norske 50% share
- PL 102F (Well 25/5-9) Trell – Operated by Total, Det norske 10% share
- PL203 (Well 24/5-3) Gekko – Operated by Det norske, Det norske share 65% share
- PL340 BS (Well 24/9-10S) Caterpillar – Operated by Det norske, Det norske 65%
- PL 038D (Well 15/12-23) Grevling – operated by Talisman, Det norske 30% share

4.1 Development Pending

"Development Pending" net resource estimate ranges from 110 to 215 million barrels of recoverable oil equivalents.

4.1.1 Frøy (PL364)

Frøy was in production from 1995 to 2001 with Elf as the operator. The field was shut-down the field in 2001 due to several reasons, including technical challenges, recovery rates falling below expectations and low oil price. The licensees have worked on getting the field redeveloped. In 2008, a PDO was submitted, but was postponed due to the financial crisis. Through 2010 the Frøy group matured alternative concepts to establish a more robust concept featuring a leased field center (FPSO/JUDPSO) combined with a WHP. The goal was to deliver an updated PDO. During spring 2011 the work on preparing an updated Frøy PDO was put aside. The PL364 group is currently considering its options with respect to future field redevelopment.

Gross resource estimate for the Frøy discovery ranges from 25 million barrels of oil equivalents to 46 million barrels of oil equivalents.

After acquisition of Premier Oil Norge AS Det norske holds 100% interest in Frøy.

4.1.2 Frigg Gamma Delta (PL442)

The discovery of oil in East Frigg Delta (PL442) through well 25/2-17 is being evaluated by the operator Centrica Energy and includes re-evaluation of the Epsilon prospect and the Oligocene Dalton discovery. PL42 contains a discovery and prospects that could be relevant for a Frøy redevelopment. Currently, the PL442 group is weighing its development options.

Net resource estimate for the Frigg Gamma/Delta discoveries ranges from 34 million barrels of oil equivalents to 63 million barrels of oil equivalents.

Det norske's interest in PL442 is 60%. Centrica Resources (Norge) AS is operator for the license and holds 30% interest, Lotos Exploration and Production Norge AS holds the remaining 10%.

4.1.3 Krafla Area (PL035 and PL272)

The Krafla discoveries (wells 30/11-8S and 30/11-8A) are located in the northern part of the North Sea, between the Oseberg and Frigg fields. The water depth is 108 meters.

Krafla is divided into two structures, the Krafla Main drilled by well 30/11-8S and Krafla West drilled by well 30/11-8A, which were both discovered in 2011. Several contacts and varying fluids characterize Krafla. In Krafla Main, free oil was found in the Upper/Middle Tarbert Formation and free gas was found in the Ness Formation below. In Krafla West free oil was found in the lower Heather Formation and free gas was found in the Tarbert Formation below. For most zones, an oil-down-to or gas-down-to situation exists.

The Krafla project is in the concept selection phase, and the current schedule implies DG2 in 2017. Further exploration activity is expected in 2016.

Net resource estimate for the Krafla discovery ranges from 32 million barrels of oil equivalents to 70 million barrels of oil equivalents. In addition to the Krafla discovery the license also includes the Askja discovery (2013), the Krafla Nord discovery (2013) and the Steinbit discovery (1996). Limited development considerations has been made for this discovery. Preliminary net resource estimate for the Krafla/Askja area is in the range 70-110 mmboe.

Det norske's interest in license PL035 and PL272 is 50%. Statoil Petroleum AS is operator for the license and holds the remaining 50%.

4.1.4 Vette

Through the acquisition of premier Oil Norge AS, Det norske holds a 50% interest in the PL406/PL407 Vette/Mackerel discoveries. The main discovery, Vette, was made in 1971. The two discoveries are located in block17/2 in the Egersund basin approximately 50 km northwest of the Yme Field. The main reservoir unit is the Bryne Formation (Vestland Group) of middle Jurassic age. Three wells have been drilled on the Vette structure of which one had two sidetracks (five penetrations). A DST was carried out in well 12/12-4A.

Per year-end 2015, different concepts were under evaluation for a possible Vette/Mackerel development.

Including the nearby Mackerel discovery the net resource estimate ranges from 18 to 37 million barrels of oil equivalents.

4.2 Development not clarified or on hold

Even though these discoveries are classified in the same resource class the maturity and reserve potential may vary considerable. Only the discoveries with a reasonable probability for a development within a reasonable timeframe will be further described in the following.

4.2.1 Storklakken (PL450)

The Storklakken discovery operated by Det norske contains oil in the Heimdal Formation of Paleocene age. The discovery was made in 2010 and is located approximately 20 km northwest of Frøy and approximately 30 km northeast of Alvheim. The discovery will most likely be developed as a one well subsea tie-back to the Alvheim Field.

Gross/net resource estimate for the Storklakken discovery ranges from 9 million barrels of oil equivalents to 16 million barrels of oil equivalents.

4.2.2 Alvheim Area

Alvheim
Several infill drilling targets has been identified in the Alvheim Area. Three of these are currently under evaluation representing a total net potential ranging from 4 million barrels of oil equivalents to 11 million barrels of oil equivalents. In addition two somewhat less mature targets are identified with a total net potential ranging from 4 to 11 million barrels of oil equivalents. Current plan calls for drilling of these wells 2017/2018.

Gekko
The Gekko gas discovery is located approximately 10 km southeast of Alvheim and was discovered back in 1974. The reservoir sandstones are within the Paleocene Heimdal Formation. Current plan involves drilling an appraisal well in end 2020, and to develop the field with two gas producers with production through a subsea template towards Alvheim FPSO. Possible production start is 2024.

Det norske holds a 65% share in the discovery which gives a net recourse potential ranging from 7 to 23 million barrels of oil equivalents.

Caterpillar (PL340 BS)
The Caterpillar is located some 35 km south of Alvheim and approximately 6 km south east of Bøyla and was discovered in March 2011. The reservoir consist of the Hermod Formation of late Paleocene age. Current volumes and profiles are based on an updated uncertainty assessment in August 2015. Base case development scenario assumes a single producer subsea tieback development to Alvheim FPSO with gas lift. Startup is assumed 2019.

Det norske holds a 65% share in the discovery which gives net recourse potential ranging from 4 to 7 million barrels of oil equivalents.

4.2.3 Garantiana (PL554)

The Garantiana discovery is an elongated structure with a gross ~100m thick Early Jurassic / Cook formation / medium quality reservoir (200-400 mD) located at a depth of approximately 3700 m TVD MSL in the northern north sea. The reservoir is high pressure (630 bar) with somewhat challenging fluid characteristics (high content of CO_2, H_2S, high Pour point pressure and risk of asphaltene precipitation).

Garantiana has been appraised by 34/6-2S and 2A in 2012 (central area) and by 24/6-3S in 2014 (south area). The southern area has proven good reservoir properties through drill stem tests, the middle area has poorer characteristics and the middle area has poorer characteristics and the northern area is un-appraised

Up-dated volumes estimates after the well 24/6-3S indicates a net resource potential ranging from 19 to 50 million barrels of oil equivalents. The discovery will most likely be developed as a subsea tie-back to existing infra structure. Thus, a development will be dependent on available process capacity in the area. Current plans indicates production start in 2021.

Total E&P is operator and Det norske holds a 30% share in PL554.

4.2.4 Gohta (PL492)

The Gohta prospect, located on the southern part of the Loppa High in the south west Barents Sea was discovered in 2013 by well 7120/1-3. The well proved oil with an overlaying gas cap in Permian porous karstified carbonates of the Tempelfjorden Group. An appraisal well was drilled in 2014, 7120/1-4. Both wells were tested. Well 7120/1-3 tested the oil zone. Well 7120/1-4 produced gas from the gas zone but failed to produce from the oil zone. It is uncertain if this is related to reservoir performance or to a poor cement job before the DST.

A possible development will most likely be a common discovery with a nearby discovery and current net recourse potential ranges from 14 to 75 million barrels of oil equivalents.

Lundin is operator for the license and Det norske holds a 40% share in PL492

5 Management's Discussion and Analysis

The assessment of reserves and resources is carried out by experienced professionals in Det norske based on input from operators, partners, and in-house evaluations. The responsibility to carry out the evaluation lies with the business projects. The reserves and resource accounting is coordinated and quality controlled by a small group of professionals, headed by a reservoir engineer with more than 20 years of experience in such assessments.

Additionally, all volumes within the reserve category (except for the minor Enoch, Atla, and Jette fields) have been certified by an independent third party consultancy (AGR Petroleum Services AS). These are the producing fields Alvheim (including Boa), Vilje, Volund, and Bøyla and the fields under development; Ivar Aasen, Hanz, Gina Krog, Viper/Kobra and Johan Sverdrup.

The reported 2P/P50 reserves include volumes which are believed to be recoverable based on reasonable assumptions about future economical, fiscal and financial conditions. Discounted future cash flows after tax are calculated for the various fields on the basis of expected production profiles and estimated proven and probable reserves. Cut-off time for the reserves is set at zero cash flow or when facility lease expires. The discount rate applied is 10 percent nominal after tax. The company has used a long term inflation assumption of 2.5 percent, a long term exchange rate of 7.5 NOK/USD, and a fixed oil price of 60 USD/bbl (real 2015 terms).

The calculations of recoverable volumes are, however, associated with significant uncertainties. The 2P/P50 estimate represents our best estimate of reserves/resources while the 1P/P90 estimate reflects our high confidence volumes. The methods used for subsurface mapping do not fully clarify all essential parameters for either the actual hydrocarbons in place or the producibility of the hydrocarbons. Therefore there is a remaining risk that actual results may be lower than the 1P/P90. A significant change in oil prices may also impact the reserves. Low oil prices may force the licensees to close down producing fields early and lead to lower production. Higher oil prices may extend the life time of the fields beyond what is currently assumed.

Karl Johnny Hersvik
CEO

Disclaimer

This Annual Statement of Reserves ("ASR") includes and is based, inter alia, on forward-looking information and statements that are subject to risks and uncertainties. Such information and statements are only predictions, and actual events or results may differ materially. The ASR is based, inter alia, on current expectations, estimates, and projections about technical, geological, geotechnical and economic assumptions on which the reserve and resource estimates are made as well as global economic conditions, the economic conditions of the regions and industries that are major markets for Det norske oljeselskap ASA (including subsidiaries and affiliates) and its lines of business. These expectations, estimates and projections are generally identifiable by statements containing words such as "expects", "believes", "estimates" or similar expressions. Important factors that could cause actual results to differ materially from those expectations include, among others, technical, geological and geotechnical conditions, economic and market conditions in the geographic areas and industries that are or will be major markets for businesses of Det norske oljeselskap ASA (including subsidiaries and affiliates), oil prices, market acceptance of new products and services, changes in governmental regulations, interest rates, fluctuations in currency exchange rates and such other factors as may be discussed from time to time in the ASR. Although Det norske oljeselskap ASA believes that its expectations and this ASR are based upon reasonable assumptions, the company can not give any assurance that the expectations will be achieved or that the actual results will be as set out in the ASR. None of Det norske oljeselskap ASA or its subsidiaries or any such entities' directors, employees or advisors makes any representation or warranty, expressed or implied, as to the accuracy, reliability or completeness of any information contained in the ASR, and no such entities or persons shall have any liability whatsoever arising directly or indirectly from the use of this ASR.

Appendix 1: Conversion factors, definitions, and abbreviations

Conversion factors:

1 Sm^3 of oil = 1.0 Sm^3 o.e.
1 Sm^3 of condensate = 1.0 Sm^3 o.e.
1000 Sm^3 of gas = 1.0 Sm^3 o.e.
1 tonne of NGL = 1.9 Sm^3 NGL = 1.9 Sm^3 o.e.

Gas:

1 cubic foot	1 000.00 Btu
1 cubc metre	9 000.00 kcal
1 cubic metre	35.30 cubic feet

Crude oil:

1 Sm^3	6.29 barrels
1 Sm^3	0.84 toe
1 tonne	7.49 barrels
1 barrel	159.00 litres
1 barrel/day	48.80 tonnes/yr
1 barrel/day	58.00 Sm^3 per yr

Definitions and abbreviations:

1C: Denotes low estimate scenario of Contingent Resources.

2C: Denotes best estimate scenario of Contingent Resources.

3C: Denotes high estimate scenario of Contingent Resources.

1P: Taken to be equivalent to Proved Reserves; denotes low estimate scenario of Reserves.

2P: Taken to be equivalent to the sum of Proved plus Probable Reserves; denotes best estimate scenario of Reserves.

3P: Taken to be equivalent to the sum of Proved plus Probable plus Possible Reserves; denotes high estimate scenario of reserves.

Accumulation: An individual body of naturally occurring petroleum in a reservoir.

°API: an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil.

Appraisal well: A well drilled to confirm the size or quality (commercial potential) of a hydrocarbon discovery. Before development, a discovery is likely to need at least two or three such wells (see delineation well and exploration well).

ASR: Annual Statement of Reserves, report to be filed annually to the Oslo Stock Exchange.

CAPEX: Capital expenses.

Bcf: Billion cubic feet

bill.: billions

bbl: barrel (of oil)

boe: barrel of oil equivalent of natural gas and crude oil

boepd: barrel of oil equivalent per day.

CO: carbon monoxide

CO_2: carbon dioxide

Contingent Resources: Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are a class of discovered recoverable resources.

Deterministic Estimate: The method of estimation of Reserves or Resources is called deterministic if a discrete estimate(s) is made based on known geoscience, engineering, and economic data.

E & P: Exploration and production.

Exploration: Prospecting for undiscovered petroleum.

Exploration well: A well drilled to test a potential but unproven hydrocarbon trap or structure where good reservoir rock and a seal or closure combine with a potential source of hydrocarbons (see appraisal well and delineation well).

FEED: Front-end Engineering and Design.

Field: An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impermeable rock, laterally by local geologic barriers, or both. The term may be defined differently by individual regulatory authorities.

Flow Test: An operation on a well designed to demonstrate the existence of moveable petroleum in a reservoir by establishing flow to the surface and/or to provide an indication of the potential productivity of that reservoir (such as a wireline formation test).

High Estimate: With respect to resource categorization, this is considered to be an optimistic estimate of the quantity that will actually be recovered from an accumulation by a project. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

Hydrocarbons: Hydrocarbons are chemical compounds consisting wholly of hydrogen and carbon.

Known Accumulation: An accumulation is an individual body of petroleum-in-place. The key requirement to consider an accumulation as "known," and hence containing Reserves or Contingent Resources, is that it must have been discovered, that is, penetrated by a well that has established through testing, sampling, or logging the existence of a significant quantity of recoverable hydrocarbons.

Lead: A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect. A project maturity sub-class that reflects the actions required to move a project toward commercial production.

Low Estimate: With respect to resource categorization, this is considered to be a conservative estimate of the quantity that will actually be recovered from the accumulation by a project. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

m^3: cubic metres.

Mbbl: Million bbl

MBOE: Millions of Barrels of Oil Equivalent.

MD&A: Management Discussion and Analysis.

mill.: millions

NCS: the Norwegian Continental Shelf.

NOK: Norwegian Kroner.

NPD: the Norwegian Petroleum Directorate.

NPV: Net Present Value.

o.e.: oil equivalents

OIP: oil in place.

GIP: gas in place.

Petroleum Initially-in-Place: Petroleum Initially-in-Place is the total quantity of petroleum that is estimated to exist originally in naturally occurring reservoirs. Crude Oil-in-place, Natural Gasin-place and

Natural Bitumen-in-place are defined in the same manner (see Resources). (Also referred as Total Resource Base or Hydrocarbon Endowment).

PIIP: See Petroleum Initially-in-Place.

Possible Reserves: An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

Probable Reserves: An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

Production: Production is the cumulative quantity of petroleum that has been actually recovered over a defined time period. While all recoverable resource estimates and production are reported in terms of the sales product specifications, raw production quantities (sales and non-sales, including non-hydrocarbons) are also measured to support engineering analyses requiring reservoir voidage calculations.

Project: Represents the link between the petroleum accumulation and the decisionmaking process, including budget allocation. A project may, for example, constitute the development of a single reservoir or field, or an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership. In general, an individual project will represent a specific maturity level at which a decision is made on whether or not to proceed (i.e., spend money), and there should be an associated range of estimate.

Prospective Resources: Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.

Proved Reserves: An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Proved Reserves are those quantities of petroleum which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. Often referred to as 1P, also as "Proven."

PDO: Plan for Development and Operation.

Recovery factor (RF): The ratio between the volumes of hydrocarbons produced and produceable from a reservoir, and the hydrocarbons originally in place.

Recoverable Resources: Those quantities of hydrocarbons that are estimated to be producible from discovered or undiscovered accumulations.

Reserve Replacement Ratio (RRR): The RRR is one measure of oil company performance. It shows the ratio of new reserves added to the inventory (from exploration/upgrading from resources/acquisitions) compared to oil produced. Ideally this ratio should be greater than 100 percent. Less than 100 % implies that the company is not able to replace what it is producing.

Reserves: Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: They must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied.

Reservoir: A subsurface rock formation containing an individual and separate natural accumulation of moveable petroleum that is confined by impermeable rocks/formations and is characterized by a single-pressure system.

Resources: The term "resources" as used herein is intended to encompass all quantities of petroleum (recoverable and unrecoverable) naturally occurring on or within the Earth"s crust, discovered and undiscovered, plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional" (see Total Petroleum Initially-in-Place).

Resource Categories: Subdivisions of estimates of resources to be recovered by a project(s) to indicate the associated degrees of uncertainty. Categories reflect uncertainties in the total petroleum remaining within the accumulation (in-place resources), that portion of the in-place petroleum that can be recovered by applying a defined development project or projects, and variations in the conditions that may impact commercial development (e.g., market availability, contractual changes).

Resources Classes: Subdivisions of Resources that indicate the relative maturity of the development projects being applied to yield the recoverable quantity estimates. Project maturity may be indicated qualitatively by allocation to classes and sub-classes and/or quantitatively by associating a project's estimated chance of reaching producing status.

RNB: Revised National Budget. The reporting for the RNB contributes basic data for the Government's oil and environmental policy, the state and national budgets as well as a number of products from the Norwegian Petroleum Directorate (NPD), the Ministry of Petroleum and Energy (MPE), etc. Every autumn, all the operators report data related to the fields, discoveries, transport and land facilities which they operate.

Royalty: Royalty refers to payments that are due to the host government or mineral owner (lessor) in return for depletion of the reservoirs and the producer (lessee/contractor) for having access to the petroleum resources. Many agreements allow for the producer to lift the royalty volumes, sell them on behalf of the royalty owner, and pay the proceeds to the owner. Some agreements provide for the royalty to be taken only in kind by the royalty owner.

SEC: The US Securities and Exchange Commission. The primary US regulatory agency for the securities industry.

Sm^3: standard cubic metre

Stochastic: Adjective defining a process involving or containing a random variable or variables or involving chance or probability such as a stochastic stimulation.

Sub-Commercial: A project is Sub-Commercial if the degree of commitment is such that the accumulation is not expected to be developed and placed on production within a reasonable time frame. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. Discovered sub-commercial projects are classified as Contingent Resources.

Tcf: Trillion cubic feet

USD: US Dollar.