DETNORSKE

Annual Statement of Reserves

Classification of Reserves and Contingent Resources

The reserve and contingent resource volumes have been classified in accordance with the NPD classification system http://www.npd.no/global/norsk/5%20-%20regelverk/tematiske%20veiledninger/ressursklassifisering_n.pdf and are consistent with Oslo Stock Exchange's requirements for the disclosure of hydrocarbon reserves and contingent resources, see figure below.

Figure 1: NPD's classification system used by Det norske oljeselskap

	Potential Resources		Contingent Resources				Reserves		
NPD category	*9*	*8*	*7*	*6*	*5*	*4*	*3*	*2*	*1*
Description	Leads. Conceptual ideas of possible prospects	Prospects. A mapped rock volume believed to contain hydrocarbons	Discoveries under evaluation	Discoveries where development is unlikely	Discoveries where development is likely	Discoveries where development is being planned	Fields where PDO has been concluded by the Licensees	Fields under development, PDO approved	Fields in production

Reserves, Developed and Non-developed

Det norske oljeselskap ASA has interests in four fields containing reserves, all in production (Category 1):

- Varg – operated by Talisman, Det norske 5%
- Glitne – operated by Statoil, Det norske 10%
- Enoch – operated by Talisman, Det norske 2%
- Jotun – operated by ExxonMobil, Det norske 7%

The net reserves for the four fields are presented in Table 1 and amounts to a total of 1.34 million barrels oil equivalents (2P/P50 or best estimate).

The changes in reserves during 2010 are presented in Table 2. On the 2P/P50 basis, the reserves are reduced from 29.13 mboe to 1.34 mboe. The main reason for the negative change is related to the Frøy development. As a modified PDO was not submitted in 2010, a volume of 27.36 mboe has been moved out of the reserves from Category 3 (Development decided) to Category 4 (Contingent resources – Development being planned). Further reduction due to production from the four fields is partly replaced by positive revisions for Glitne, Varg, and Jotun, mainly due to extended field life.

Table 1 – Reserves by field

Reserves	$1x10^9$ Sm^3 gas = $1x10^6$ Sm^3 o.e. = 6.29 MBOE									
Developed assets (Category 1)										
As of 31.12.2010	**1P / P90 (low estimate)**					**2P / P50 (best estimate)**				
	Liquids (million barrels)	Gas (bcm)	Million barrels of oil equivalents	Interest %	Net million barrels of oil equivalents	Liquids (million barrels)	Gas (bcm)	Million barrels of oil equivalents	Interest %	Net million barrels of oil equivalents
PL 038 - Varg	2.51	0.0	2.51	5%	0.13	10.49	0.0	10.49	5%	0.52
PL 048 B - Glitne	0.44	0.0	0.44	10%	0.04	0.94	0.0	0.94	10%	0.09
Enoch Unit (Norway)	0.75	0.0	0.78	10 %	0.08	1.20	0.01	1.23	10 %	0.12
Jotun Unit	6.19	0.07	6.63	7%	0.46	7.92	0.09	8.49	7%	0.59
Total					0.71					1.34

Table 2 – Aggregated reserves, production, developments, and adjustments

Reserves development						
Net attributed million barrels of oil equivalents. Calendar years, reporting as of year end.	**Developed assets**		**Under development**		**Development decided**	
	1P / P90	2P / P50	1P / P90	2P / P50	1P / P90	2P / P50
Balance as of 31.12.2009	1.08	1.56	0.10	0.21	16.98	27.36
Production	-0.74	-0.74				
Acquisitions/disposals						
Extensions and discoveries						
New developments	0.10	0.21				
Revisions of previous estimates	0.27	0.31	-0.10	-0.21	-16.98	-27.36
Balance as of 31.12.10	0.71	1.34	0.0	0.0	0.0	0.0

The **Varg Field** (PL 038) is located to the south of Sleipner Øst. The field is developed with the production vessel "Petrojarl Varg" with integrated oil storage, and connected to a wellhead platform. Oil is exported using shuttle tankers. One producer and one injector were completed in 2010, proving up new reserves and increasing the total production to around 26,000 bopd by year-end. Total ultimate recoverable reserves are estimated at 95 million barrels of oil, while total remaining proved and probable reserves are 10.5 million barrels. All of these are classified as developed (Category 1) and contain the volumes from the base case production profile assuming no further infill drilling and an economic production cut-off at the end of 2013. Two new infill production wells are scheduled for 2011, and these are estimated to extend the life of the field until the end of 2014. Associated volumes of 6.3 million barrels are not included in the reserve estimate, but classified as resources in Category 4. Gas blow-down volumes of 10 million barrels oil equivalents, including oil production until the end of 2015 are classified as Category 5. Further infill targets and potential near infrastructure exploration are expected to further extend life of the field.

The **Glitne Field** (PL 048 B) is located 40 kilometers northeast of the Sleipner area. The field is produced by sub-sea wells tied to the production vessel "Petrojarl 1", and oil is exported using shuttle tankers. Total reserves are determined by the operator, based on a production cut-off in August 2011. Remaining reserves are assessed probabilistically considering relevant uncertainties related to the production. Total initial recoverable reserves are estimated at 55 million barrels of oil, while remaining reserves are estimated at 0.9 million barrels of oil. The main uncertainty in future production is the water cut development for individual wells. A new infill production well will likely be drilled in 2011 and could potentially extend the life of the field by 2-3 years. Associated volumes of 3.4 million barrels are not included as reserves but classified as resources in Category 4.

The **Enoch Field** (PL 048 D) straddles the Norwegian/UK border and is located in the UK block 16/13a and in the Norwegian block 15/5 southwest of the Glitne Field. The field is developed by a single, horizontal sub-sea well and tied back to the UK Brae A platform where the oil is processed and exported via the Forties pipeline network. The gas is sold to the Brae Field. Production started in May 2007 and field shut down is expected in 2017. Depending on reservoir performance, one additional producer may be drilled using the extra well slot which is available. The field has been unitized with the license owners in British sector, and Det norske's overall share is 2% (10% of the Norwegian license PL 048 D). Total initial proved plus probable reserves (Enoch Unit) are estimated by the operator at 14 million barrels of oil equivalents of which 6.2 million barrels remain. Volumes in Table 1 include only the Norwegian part of the field and are included under "Developed assets".

The **Jotun Field** (PL 027 B, PL 103) is developed with an integrated well head platform (Jotun B) of 24 well slots and an FPSO (Jotun A). Oil is shuttled to the Slagen refinery and gas is exported into Statpipe. Proved plus probable reserves (2P/P50) include expected volume from existing wells, assuming no new wells being drilled and abandonment of the field at the end of 2016. Remaining reserves are determined by the operator based on decline analysis. The main uncertainty in future production is the water cut development in individual wells. Total ultimate recoverable reserves are estimated at 152 million barrels of oil equivalents, while remaining reserves are estimated at 8.5 million barrels and classified as developed (Category 1). The operator is assessing the economic viability of carrying out work-overs in wells currently not producing.

Det norske's share of production from the Varg, Glitne, Enoch, and Jotun fields during 2010 amounts to 0.74 million barrels of oil equivalents.

Contingent Resources

Det norske oljeselskap ASA has interests in 22 discoveries classified as contingent resources, and a complete list is provided below. Eight of these discoveries are in the planning phase (Category 4); Frøy, Draupne, Hanz, West Cable, Jetta, Storklakken, Dagny, and Fulla. Five are classified as "Development likely"; Frigg Gamma, Frigg Delta, Grevling, Tir, and David, and six are still under evaluation; Litjklakken, Freke, Ragnarrock Basement North, P-Graben, Desmond, and Bumblebee. Three discoveries are classified as non-commercial; Storskrymten, Eitri, and Ragnarrock Chalk.

Figure 2 illustrates resource movements for fields and discoveries in 2010. Det norske participated in two discoveries in 2010; the PL 460 Storklakken discovery and the PL 102 C David discovery. Both discoveries are likely to be commercial; Storklakken is now in the planning phase, and David is classified as "Development likely". Nine of the previous discoveries have moved forward in the value chain during 2010. The Draupne, West Cable, Fulla, and Jetta discoveries have moved into the planning phase following decisions for concretization (DG1/BOK). Two of the producing fields, Varg and Glitne, also have contingent resources in Category 4 and 5 related to planned IOR activities as discussed above. Re-development of the Frøy Field failed to submit a modified PDO in 2010 and has therefore been moved out of the reserves and into contingent resources. An ongoing study on drainage strategy must be completed before the partnership may decide to proceed to a front-end engineering design (FEED) study and a potential PDO towards the end of 2011.

Discoveries in Category 4 (Development being planned):

- PL 364 (Well 25/5-1) Frøy - operated by Det norske (50% share)
- PL 001 B (Well 16/1-9) Draupne - operated by Det norske (35% share)
- PL 028 B (Well 25/10-8) Hanz - operated by Det norske (35% share)
- PL 242 (Well 16/1-7) West Cable - operated by Det norske (35% share)
- PL 027 D, PL 504, PL 169 C (Well 26/8-17) Jetta - operated by Det norske (60% share)
- PL 460 (Well 25/1-11) Storklakken - operated by Det norske (100% share)
- PL 029 B (Well 15/6-9 S) Dagny - operated by Statoil, Det norske 20% share
- PL 035 B and PL 362 (Well 30/11-7) Fulla – operated by Statoil, Det norske 15% share

Discoveries in Category 5 (Development likely):

- PL 442 (Well 25/2-10 S) Frigg Gamma - operated by Statoil, Det norske 20% share
- PL 442 (Well 25/2-17) Frigg Delta - operated by Statoil, Det norske 20% share
- PL 038 D (Well 15/12-23) Grevling – operated by Talisman, Det norske 30% share
- PL 102 C (Well 25/5-5) Tir – operated by Total, Det norske 10% share
- PL 102 C (Well 25/5-7) David - operated by Total, Det norske 10% share

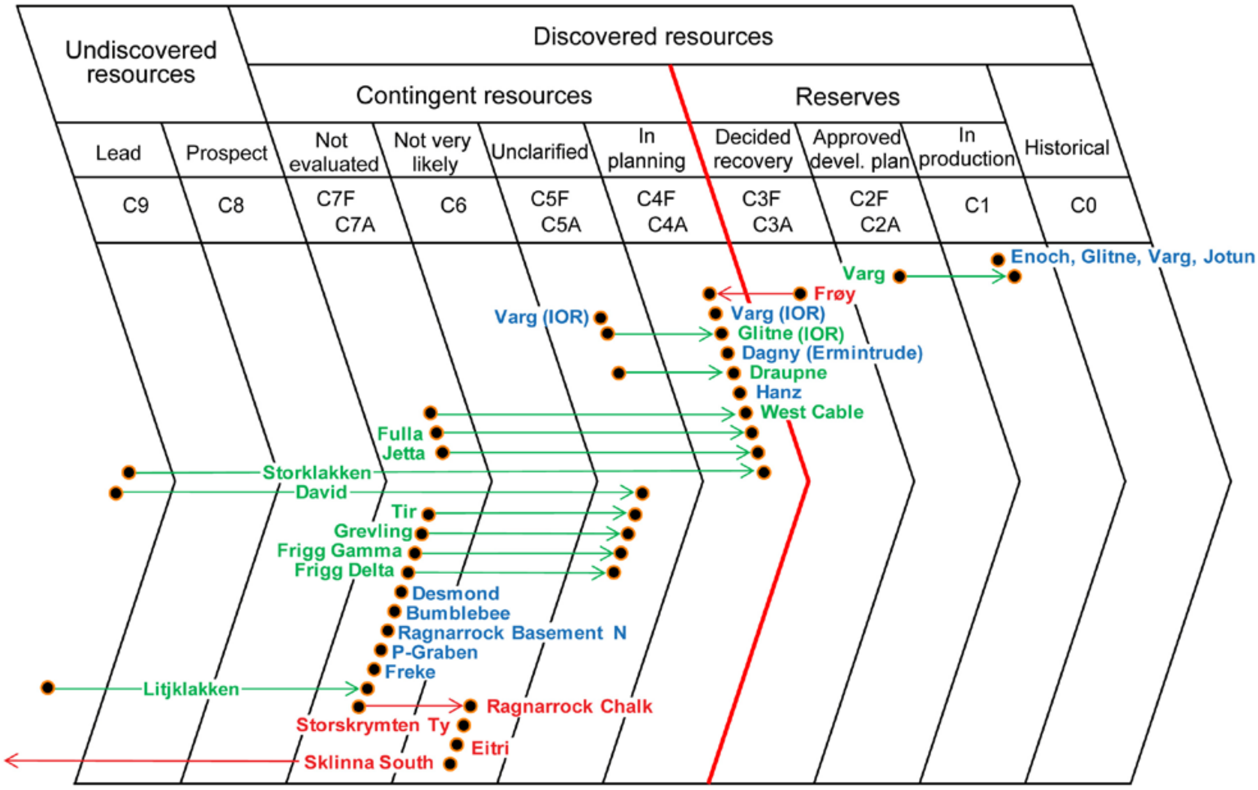
Discoveries in Category 7 (Under evaluation):

- PL 460 (Well 25/1-9) Litjklakken - operated by Det norske (100% share)
- PL 029 B (Well 15/6-10) Freke – 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 332 (Well 2/2-2) Desmond - operated by Talisman, Det norske 40% share
- PL 332 (Well 2/2-5) Bumblebee - operated by Talisman, Det norske 40% share

Discoveries in Category 6 (Development unlikely):

- PL 337 (Well 15/12-18S) Storskrymten – operated by Det norske (45% share)
- PL 027 D (Well 25/8-16S) Eitri – operated by ExxonMobil, Det norske 60% share
- PL 265 (Well 16/2-3) Ragnarrock Chalk- operated by Statoil, Det norske 20% share

Figure 2 – Resource movements 2010



Management's Discussion and Analysis

In general, 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 central group of professionals, each of the members with more than 20 years of experience in such assessments. Exceptionally external verification is being performed. Furthermore the reported reserve volumes and classification are reviewed and approved by the company's management and the Board's audit group.

Specifically, the volumes for the four fields containing reserves are based on the operator's evaluation and no independent verification has been carried out. Volumes for Varg, Glitne, and Jotun are based on RNB 2011 (Revised National Budget) reported by the operator and adjusted for production where relevant. The Enoch Field is operated from the UK side and is not subject to RNB reporting.

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 in the various licenses 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 10.7 percent nominal after tax. The company has used a long term inflation expectation of 2.5 percent, and a long term exchange rate expectation of NOK/USD 6.00. Oil prices are based on the Company's basic assumptions for investment analysis, using a fixed oil price of 75 USD/bbl (real 2011 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 expose 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 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.

The reserves for the **Varg Field** are based on a production cut-off date at the end of 2013. One producer and one injector were completed in 2010, proving up new reserves and increasing the total production to around 26,000 bopd by year-end. Two new infill production wells are scheduled for 2011, and these are estimated to extend the life of the field until the end of 2014. Further infill targets and potential near infrastructure exploration are expected to further extend life of the field. Furthermore, export of reinjected gas to the Rev field (to Armada/UK) is being evaluated and may have a positive impact on delaying Varg abandonment. Furthermore, the 2009 Grevling discovery, if tied to Varg, may also have a positive impact on delaying Varg abandonment.

The planned shut-down on the **Glitne Field** has been postponed until August 2011, at the earliest. The main uncertainty in future production is the water cut development for individual wells. A new infill production well will likely be drilled in 2011 and could potentially extend the life of the field by 2-3 years.

The **Enoch Field** is producing from one well and there is no firm plan for additional producers. However, depending on reservoir performance, an additional well may be drilled using a spare well slot. Field shut down is expected in 2017.

The reserves of the **Jotun Field** include only expected volumes produced from existing wells and assumed field abandonment at the end of 2016. As operator for the licenses PL 027 D, PL 169, and PL 504, Det norske is planning a potential development of the nearby 2009 **Jetta discovery** as a tie-in to Jotun, and a potential PDO is planned to be submitted to the authorities in 2011. If agreements with the Jotun Unit on tariffs and tie in conditions are reached in the first quarter of 2011, production could start in 2013, at the earliest.

A PDO for the reactivation of the **Frøy Field** was submitted to the authorities in September 2008 and the MPE granted an extension of the license for 10 years until 2019. Subsequently, the Frøy development was put on hold due to the severe downturn in the financial markets. Since then focus has been on decrease of development costs and reducing uncertainty in the range of resources. An ongoing study on drainage strategy must be completed before the partnership may decide to proceed to the next level with a front-end engineering design (FEED) study and a potential PDO towards the end of 2011. The re-development of the Frøy field was moved back from reserves to contingent resources (Category 4) in 2010. In parallel Det norske with partners is actively exploring in the area in order to prove up additional resources. The 2010 **Storklakken discovery**, which was moved directly into the planning phase, proved up additional resources in the order of 10 mboe. The discovery is planned to be tied in to Frøy or Alvheim.

In 2010 Det norske has made substantial progress in moving recent discoveries towards development, and five discoveries were moved into the planning phase (Category 4); Draupne, West Cable, Fulla, Jetta, and Storklakken (Fig. 2). In addition, five discoveries were moved forward to Category 5 (Development likely); David (new discovery in 2010), Tir, Grevling, Frigg Gamma, and Frigg Delta.

An appraisal well drilled on the **Draupne discovery** lifted the volume estimates of the total **Draupne/Hanz/West Cable discoveries** from between 110 and 150 mboe to between 112 and 192 mboe, with a most likely volume of 143 mboe. The commercialization project, which resulted in a DG1/BOK decision in 2010, showed commercial potential for several development options. The project has moved to the planning phase, where both stand alone and joint development with adjacent discoveries are being studied, including cost efficient FPSOs for a phased development resulting in early production. Det norske aims to present a DG2/BOV recommendation to the partners by the end of the first quarter of 2011, and a PDO is expected to be submitted to the authorities in 2011. Det norske with 35 % interest is operator for all three discoveries.

Det norske has a 2-7 % share of the **Dagny (earlier Dagny/Ermintrude) discovery** with total resources between 126 and 252 mboe, planned to be developed as stand-alone with first production in 2016. The low number is based on reference case field segments (proven by wells), while the high number is based on all segments potentially being included in the Dagny Unit, to be agreed before submitting the PDO.

The **Fulla discovery** made in 2009, has gross resources between 40 and 55 mboe, and is planned to be developed as a tie-back to the Heimdal or Bruce fields. Det norske has a 15 % interest in this license. First production is expected in 2014/2015, at the earliest.

The **David discovery** made in 2010, with gross resources of between 15 and 20 mboe is planned developed as a tie-back to the Heimdal Field with first production in 2012. Det norske has a 10 % interest in the license, where further exploration is being planned.

The 2009 **Grevling discovery** with gross resources between 40 and 95 mboe is planned developed as stand-alone or tie-in to Varg with first production in 2015.

The East Frigg Gamma and Delta discoveries, with gross resources between 40 and 74 mboe, will most likely be developed as part of an area development.

The six discoveries in Category 7 (PL 332 Desmond and Bumblebee, PL 265 Ragnarrock Basement North and P-Graben, PL 029 B Freke and PL460 Litjklakken(25/1-9 discovery) have not yet been concluded with respect to economical viability.

Two high potential exploration wells will be drilled in the PL 265 license in 2011. These wells appraise the promising Avaldsnes oil discovery (16/2-6), and will if successful, trigger further development in this highly prolific area.

Erik Haugane

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 Sm3 of oil = 1.0 Sm3 o.e.
1 Sm3 of condensate = 1.0 Sm3 o.e.
1000 Sm3 of gas = 1.0 Sm3 o.e.
1 tonne of NGL = 1.9 Sm3 NGL = 1.9 Sm3 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 Sm3	6.29 barrels
1 Sm3	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 Sm3 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
boe/d: 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.