
Johan Sverdrup. Illustration: Statoil

NORWEGIAN PETROLEUM
DIRECTORATE

The shelf in 2015

Press release

14 January 2016

The Shelf in 2015 - Summary

Low oil prices have given rise to considerable challenges for the petroleum industry over the past year. Nevertheless, significant remaining resources, combined with cost reductions and improved efficiency, can ensure continued high activity and future profitability on the Norwegian continental shelf.

We have had some positive news in 2015, despite the negative trends. Several new wells and good regularity on the fields have delivered an increase in oil production for the second consecutive year, and it will remain high in the years to come. A new gas sales record was also set as a result of higher demand from Europe.

There was a substantial drop in revenues, but the industry continues to make a strong contribution toward maintaining Norway's general welfare level.

"Even in a demanding year, it's good to see that the oil and gas industry is still the country's largest, with total export values reaching well over NOK 400 billion," says Director General Bente Nyland.

"It is also gratifying to see that the industry has invested substantial effort in increasing efficiency. This work is starting to materialise in the form of lower costs."

Eighty-two fields were in operation at the end of 2015, compared with 51 ten years ago. This illustrates the enormous development activity that has taken place in recent years. Never before have more wells been drilled than in 2015, when exploration wells are included. Fifty-six exploration wells were spudded; 11 discoveries were made in the North Sea, and six in the Norwegian Sea. However, most of these discoveries were minor.

From a record level in 2013 and 2014, investments fell by about 16 per cent from 2014, to just under NOK 150 billion. They are expected to continue their decline going forward, followed by a moderate increase from 2019. The NPD estimates that total costs will be well in excess of NOK 200 billion per year in the next few years.

The authorities approved four plans for development and operation (PDOs), compared with just one in 2014. These four have led to an increase in the reserves estimate on the Norwegian shelf – despite the fact that around 230 million Sm^3 oil equivalents of the reserves were produced.

Four new fields came on stream in 2015. Six fields are currently being developed in the North Sea, two in the Norwegian Sea and one in the Barents Sea. The NPD expects to receive development plans for three new fields this year.

"Activity will remain high in the years to come, in spite of the decline since 2014. Therefore, it is important that the companies make wise decisions and keep a long-term perspective," says Bente Nyland.

More than half of the resources on the Shelf have yet to be produced. The Director General is concerned that sinking oil prices will mean that measures will not be implemented, and resources will be left in the ground.

"We see a tendency for the companies to prioritise short-term earnings rather than long-term value creation," says Nyland.

The Norwegian Petroleum Directorate expects the industry to make decisions that will secure these assets in the years to come, and that it accelerates efforts to implement measures that can reduce costs and boost efficiency, for example through the use of new technology.

"Reduced costs mean greater profitability. This can help pave the way and make it easier to develop more discoveries," concludes the Director General.

The shelf in 2015 – Investment and cost forecasts

From a historically high activity level in 2013 and 2014, the falling oil price has caused substantial challenges for the petroleum industry, and projects on operating fields and new developments are being postponed. At the same time, the foundation for future profitability can be laid now through cost-reducing measures and by utilising new technical solutions. Presuming a higher oil price and improved profitability, remaining resources can be realised at a later date and at a lower cost.

From a record investment level of nearly NOK 180 billion in 2013 and 2014, investments dropped to just under NOK 150 billion in 2015, according to a new estimate. This was a 16 per cent reduction from 2014 to 2015. Investments are expected to decline even further over the next few years, and then show a moderate increase from 2019. A considerable drop in exploration costs from 2015 to 2016 is expected, as low oil prices have a sobering effect on exploration activity.

In light of the fact that 2013 and 2014 were historical peak years for investments, operating and exploration costs, activity will still remain high despite the significant decline since 2014. Overall costs are expected to be at a higher level than a few years ago because of many facilities in operation, considerable development activity, fields in operation and exploration.

The combination of a high cost level and the drop in oil price has provided both oil companies and the supplier industry with significant challenges, with reduced activity and downsizing as consequences. At the same time, major remaining petroleum resources on the Norwegian shelf provide a basis for continued high value creation and a high activity level going forward. This presumes a price and cost level that makes it possible to identify solutions that can realise new profitable projects – both on current operating fields and new field developments.

A number of activities have been initiated as a result of the high cost level and oil price drop, with the aim of improving efficiency in the industry and reducing the cost level, which will help to increase profitability. The Norwegian Petroleum Directorate sees that the industry is doing considerable work to improve efficiency, and to reduce investments, operating and exploration costs. The results of this work are starting to materialise, for example in the form of lower drilling costs.

SOME KEY ASSUMPTIONS

Declining oil prices create considerable uncertainty related to future investment levels. These current investment forecasts presume that the oil price will increase from today's level in the near future. If this presumption proves wrong, and oil prices remain at the current level for a longer period, this could entail further postponement of activities, resulting in even lower investments and exploration costs.

The Norwegian Petroleum Directorate presumes lower costs as a result of reduced market prices and efficiency gains in the industry. This leads to a lower cost level for individual projects, and contributes to making more projects profitable.

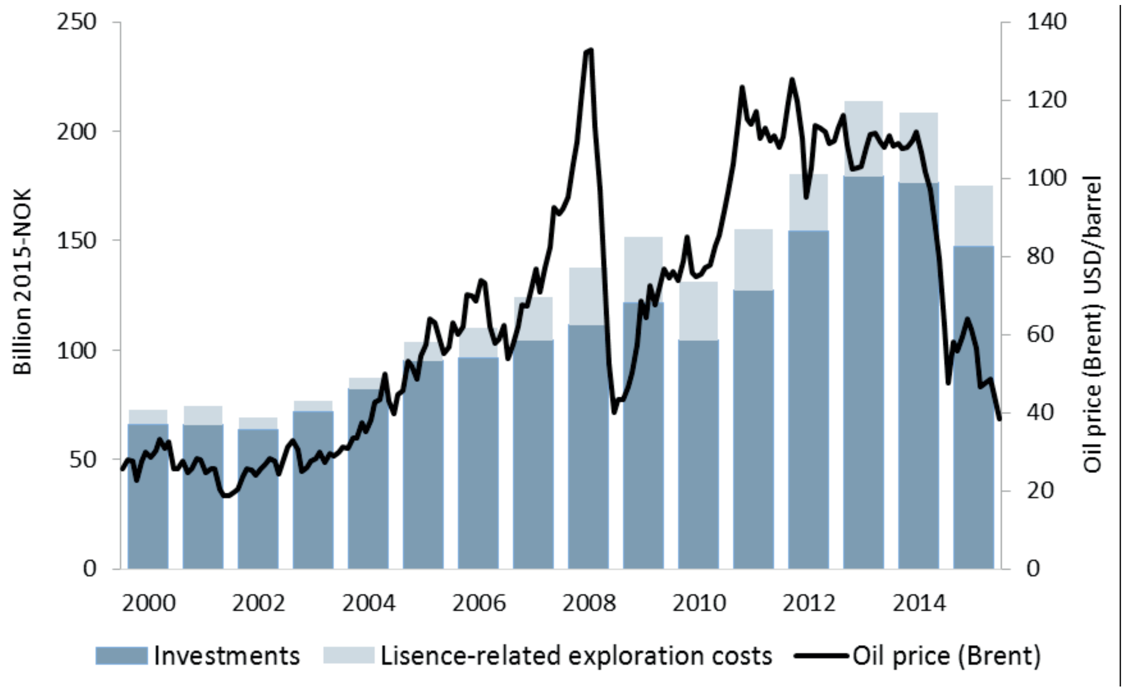

Figure 1: Development in investments including exploration costs and oil price

INVESTMENTS

Total investment estimate

From a record investment level of nearly NOK 180 billion in 2013 and 2014, investments in 2015 dropped to just under NOK 150 billion. This represents a reduction of about 16 per cent from 2014 to 2015. Investments for 2016 are estimated at about NOK 135 billion (see Figure 2).

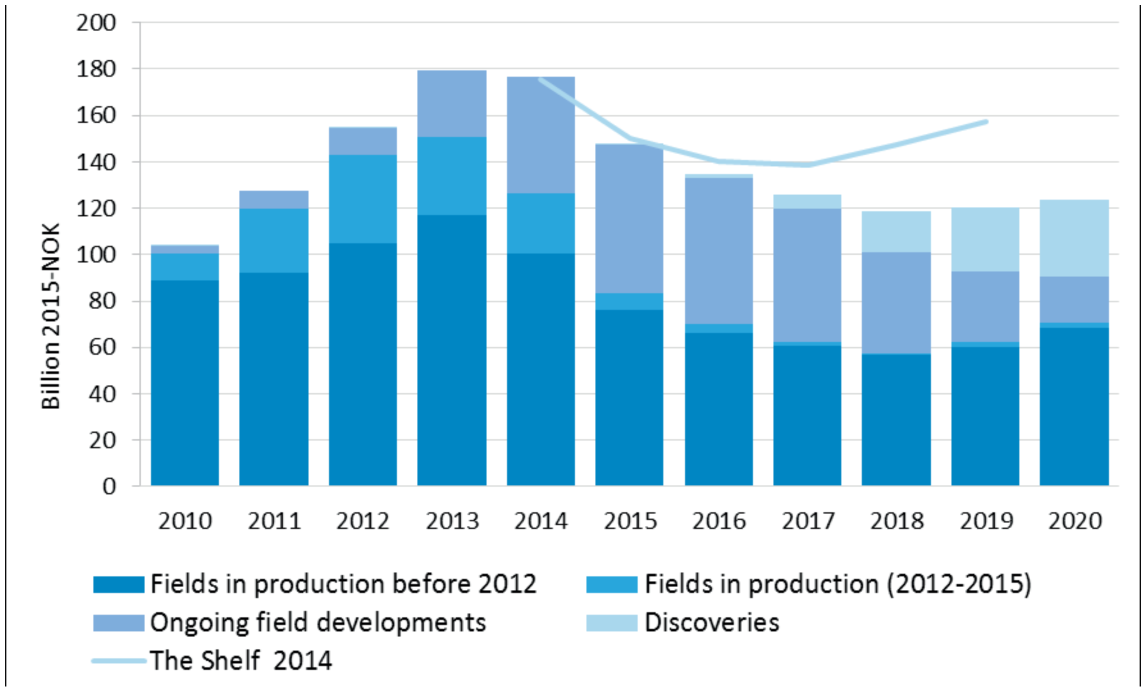

Figure 2: Investments excluding exploration, forecast for 2015-2020

A historically high number of projects, both on operating fields and new field developments, resulted in record investments in 2013 and 2014. However, new projects will not replace activities that have been or will be finalised in upcoming years. Various efficiency measures and declining prices for goods and services also contribute to reduced investments, and increase profitability at the same time. Presuming an increase in the oil price and improved profitability, remaining resources will be realised at a later date and at a lower cost.

Investments on existing fields constitute a substantial share of overall investments. Following a peak in 2013, investments on operating fields have dropped significantly. Major projects have been finalised or are in a final phase, without a corresponding influx of major new projects.

Nine fields are under development, two with a floating platform and four with a platform resting on the seabed. The other three are subsea developments. This entails substantial investments. For 2016, investments in these fields are estimated at about NOK 60 billion, which will decline as the fields come on stream.

Investments are significantly lower, compared with the forecast presented for The shelf in 2014. Given the presumption of higher oil prices and improved profitability, these are resources that are still expected to be realised, but at a later date and at a lower cost.

Figure 3 shows the investment forecast broken down by main categories of investment. From 2014 to 2015, the biggest reduction was in investments in operations and in new subsea facilities, nearly 40 per cent. Investments will drop within most categories. One exception is operations investments, which are expected to remain stable and increase towards the end of the period due to several major modification projects on existing facilities.

The investment estimates in Figure 3 show considerable investments in facilities resting on the seabed and floating facilities. These are related to ongoing field developments, including Johan Sverdrup.

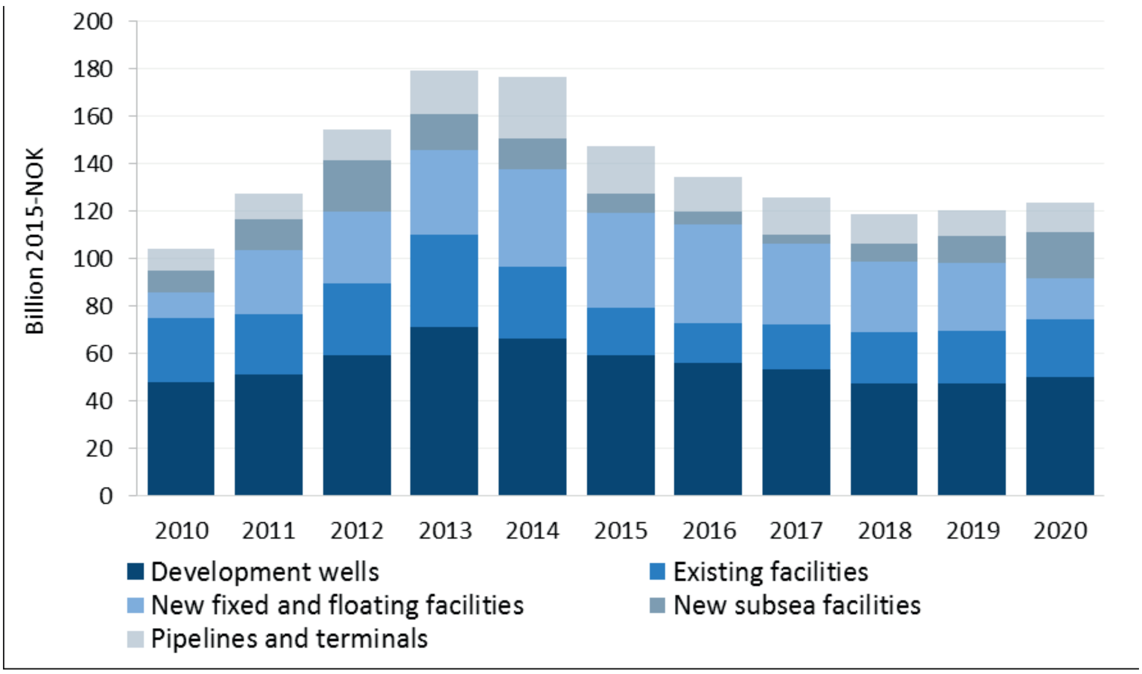

Figure 3: Historical investment, forecast for 2015-2020

As described above, the investment forecast is based on a number of assumptions regarding oil price development, cost level development and company behaviour/decisions. With regard to investments on the shelf in 2016, many of these investment decisions have already been made. Uncertainty will, however, increase with time. The development in oil price and the effect of ongoing cost-reducing measures will be important for investments up to 2020 and beyond.

EXPLORATION COSTS

The number of exploration wells in 2015, 56 wells, was considerably higher than assumed in the forecast one year ago (40 wells), and virtually the same as in 2014, 57 wells. However, there has been a clear decline in exploration costs. The main cause of the higher number of wells in 2015 was the drilling of sidetracks. These wells are much cheaper than “initial” exploration wells.

Exploration costs mainly comprise costs for seismic and drilling of exploration wells. In 2015, 56 exploration wells were spudded – 41 wildcat wells and 15 appraisal wells – with overall exploration costs estimated at NOK 33 billion. For 2016, it is expected that the number will drop to about 30 exploration wells with total exploration costs of NOK 22 billion. This assumes a smaller drop in exploration costs from 2016 to 2017, followed by a gradual increase. While 30 wells is a significantly lower number compared with recent years, it is still substantial in a historical perspective.

The reduction in exploration costs is primarily a consequence of the estimated reduction in the number of exploration wells, but increased drilling efficiency and lower market prices, primarily regarding rigs, also contribute to a reduced cost estimate.

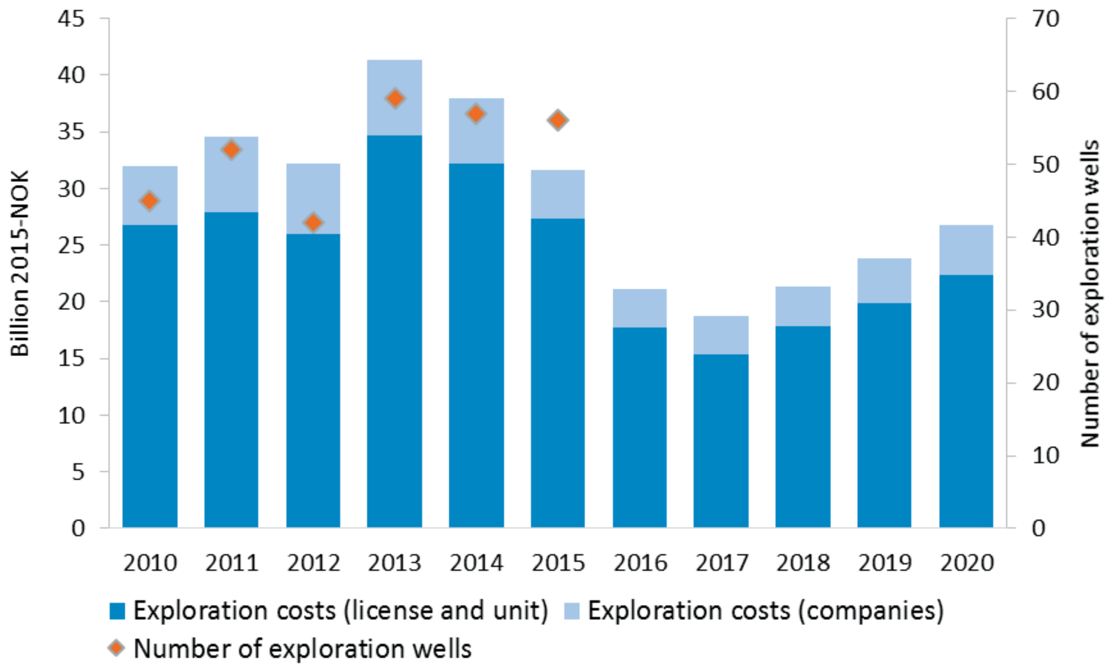

Figure 4: Estimate of exploration costs, forecast 2015-2020.

OPERATING COSTS

Eighty-two fields were producing at the end of 2015. Ordinary operating expenses and maintenance of facilities and wells constitute the majority of operating costs. A reduction in operating costs is expected over the next few years (see Figure 7).

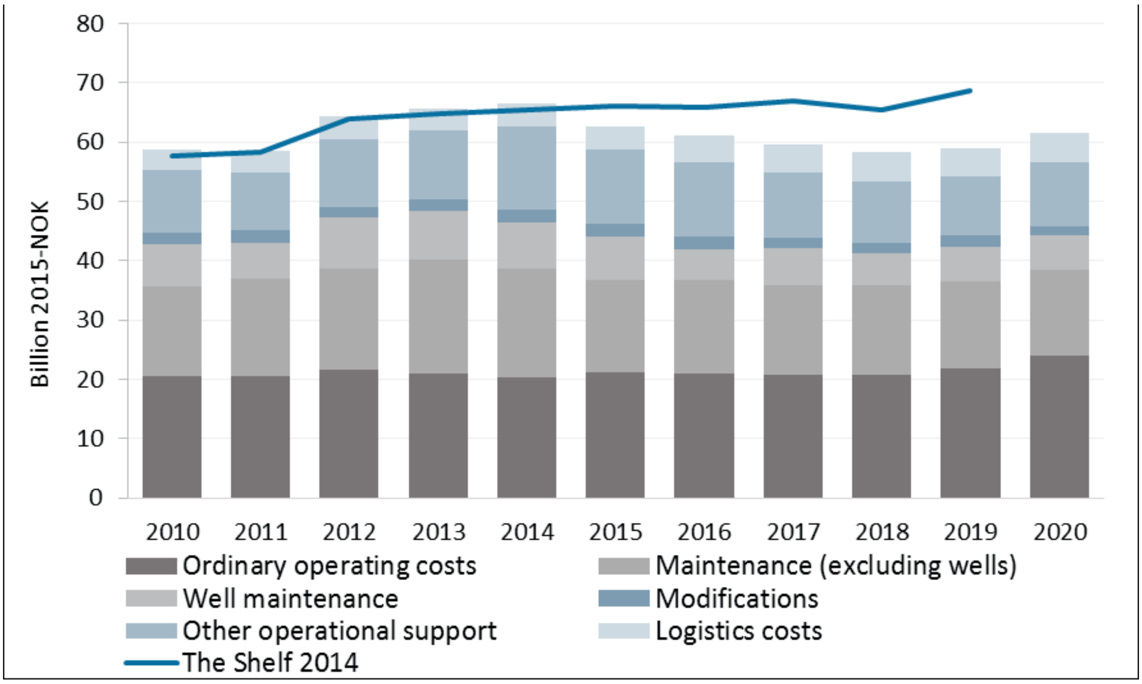

Figure 5: Operating costs (excluding gas purchases and preparation for operations). Forecast 2015-2020

The decline in operating costs is mainly due to a reduction in operating fields, cf. Figure 6. An important cause of the decline is targeted work by operators to reduce operating costs on the fields through various efficiency measures. As measures are implemented, they are included in the cost forecasts for the fields. Reduction in well maintenance also contributes to reduced operating costs on operating fields. New fields will gradually start producing and contribute to increased operating costs at the end of the period.

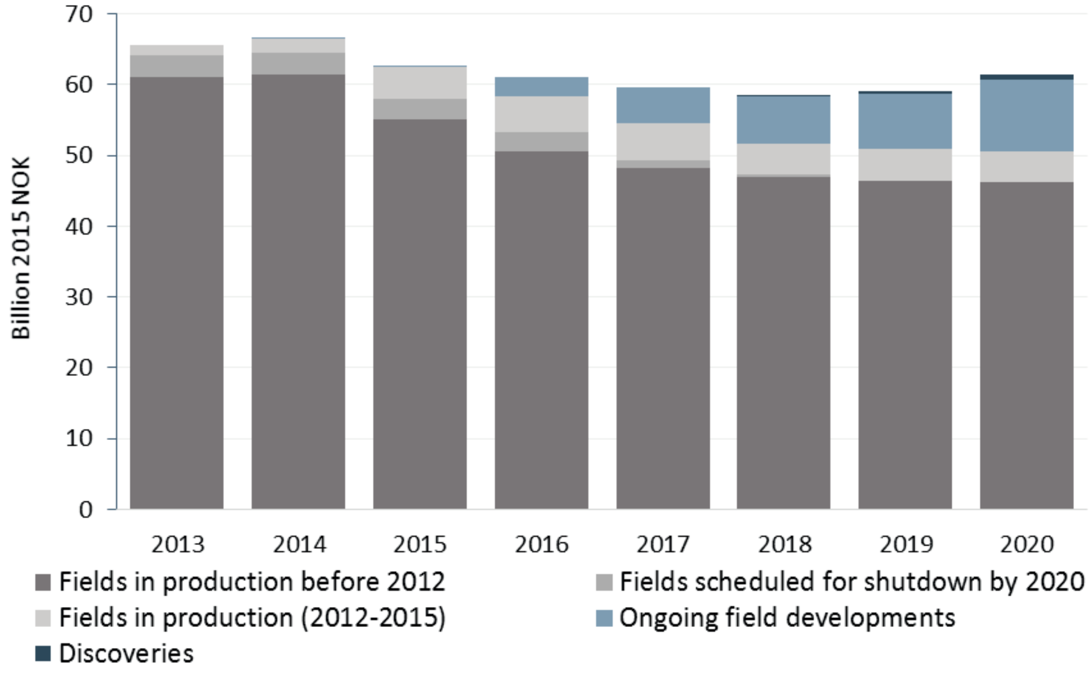

Figure 6: Operating costs forecast specified by field status. Forecast 2015-2020

TOTAL COST DEVELOPMENT ESTIMATE

Figure 7 shows an overall forecast for investments, operating costs, exploration costs, concept studies and shutdown and disposal on the Norwegian shelf. The decline from 2015 to 2016 is about ten per cent. Costs are expected to remain relatively stable from 2016.

It is important to view the development in light of the fact that 2013 and 2014 were historic peak years regarding operating costs, investments and exploration costs. Despite the estimated decline in total costs since 2014, activity on the Norwegian shelf will still remain high with many operating facilities and substantial activity related to development, fields in operation and exploration. The total future costs are expected to remain at a higher level than a few years ago.

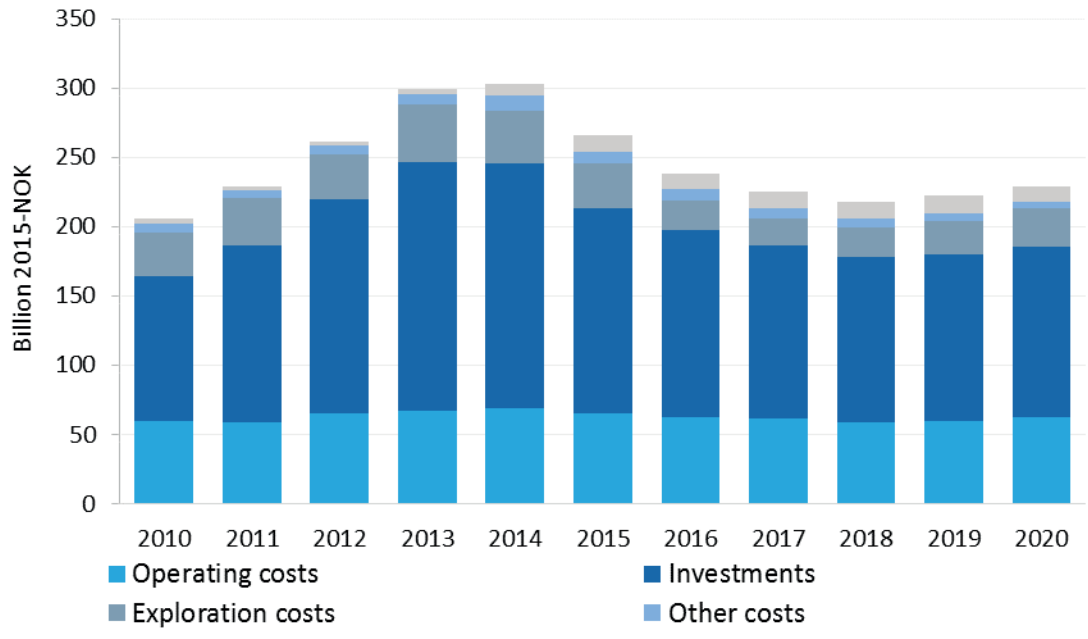

Figure 7: Total costs, forecast 2015-2020.

The shelf in 2015 – Petroleum production

Oil production increased for the second consecutive year, and a new record was set for gas sales. Production is expected to remain at a stable level over the next few years.

A total of 227.8 million sellable standard cubic metres of oil equivalents (Sm^3 oe) was produced in 2015. This is 11.6 million Sm^3 oe or 5.4 per cent more than in 2014. Total production of petroleum in 2016 is expected to be 217.1 million Sm^3 oe.

1101 million Sm^3 oe was produced during the five-year period 2011-2015. Production over the next five years is expected to remain at about the same level.

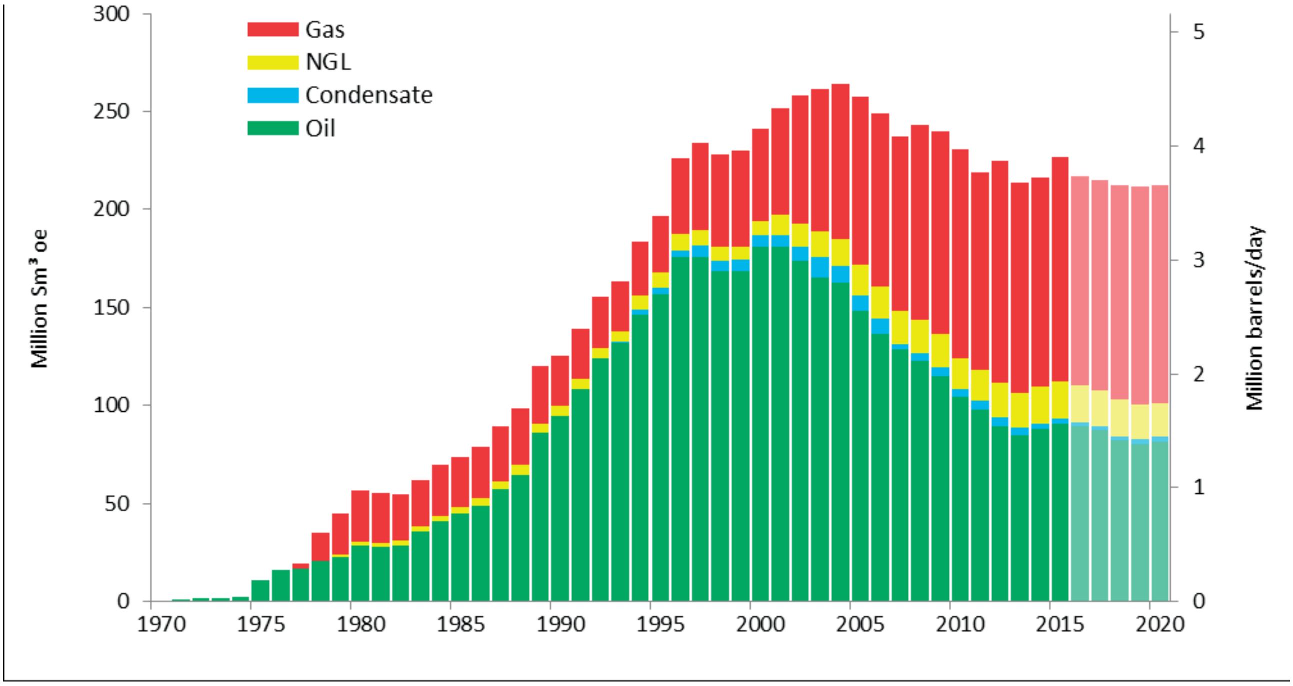

Figure 1. Actual and forecast sales of petroleum 1971-2020.

Gas

In 2015, 117.2 billion Sm^3 gas (115 billion Sm^3 - 40 megajoules of gas) was sold. This is 8 billion Sm^3 more than in 2014. The level of gas sales is hard to predict, even in the short term. The actual sales in 2015 rose seven per cent compared with our estimates at the same time last year. This is a result of factors such as significantly higher gas demand from Europe.

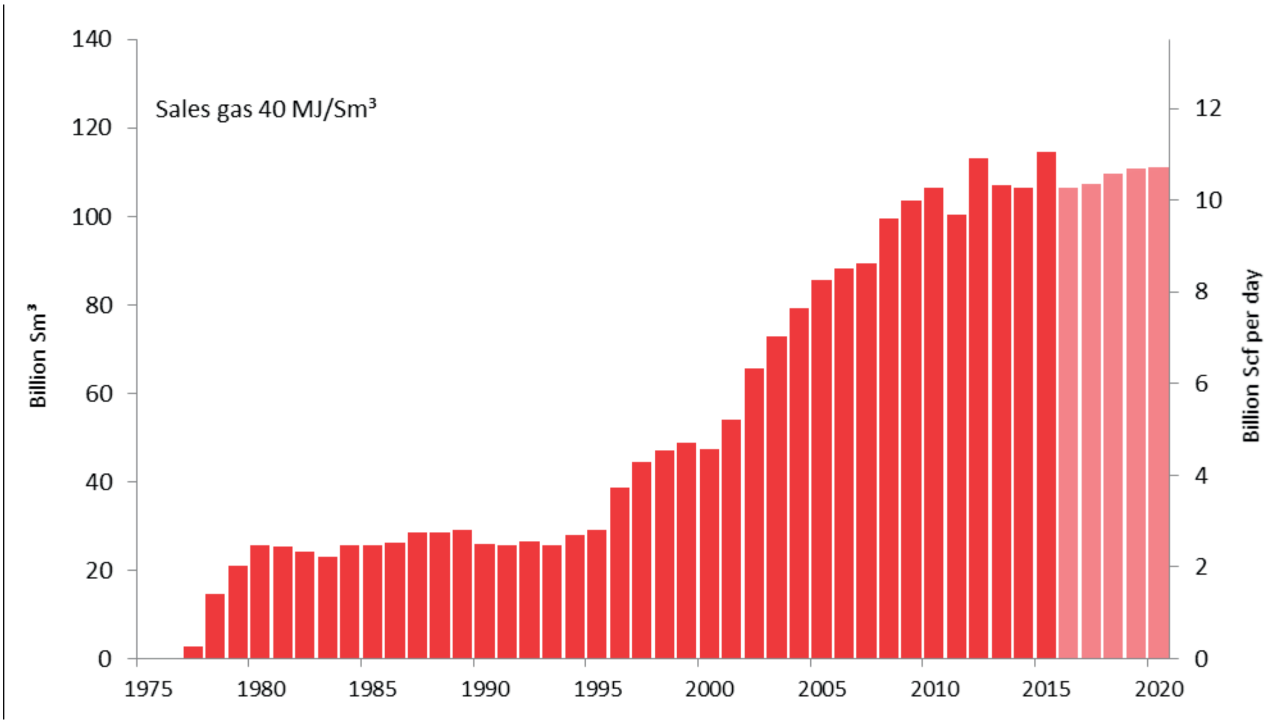

Figure 2. Actual and forecast gas sales up to and including 2020.

Oil

In 2015, 90.8 million Sm^3 oil (1.57 million barrels per day) was produced from 80 fields, compared to 87.7 million Sm^3 (1.51 million barrels per day) from 77 fields in the previous year. This is an increase of more than three per cent. The most important reasons for this are high regularity and the fact that a large number of new production wells were drilled faster than expected.

The Norwegian Petroleum Directorate was expecting somewhat lower oil production in 2015 compared to the previous year. However, several of the fields already in operation have produced substantially more than assumed, and the increase was 4.6 million Sm^3 higher than the Norwegian Petroleum Directorate's autumn 2014 estimate. The fields that were planned to start production in 2015 have, overall, produced less than half of what was reported in the autumn of 2014, mainly as a result of delayed start-up.

For 2016, the Norwegian Petroleum Directorate estimates that oil production will drop somewhat compared to 2015, to 89 million Sm^3 (1.53 million barrels) per day. Production is expected to remain at a relatively stable level over the next few years, but will decline somewhat more than predicted in the previous prognosis. The uncertainty is particularly contingent on ability of the reservoirs to deliver, drilling of new development wells, start-up of new fields and the regularity of the operational fields.

The below table shows the production forecast according to product for the next five years.

	2016	2017	2018	2019	2020
Olje / *Oil* (mill. Sm^3)	89.0	87.3	82.0	80.2	81.7
NGL / *NGL* (mill. Sm^3 oe)	19.4	18.8	18.4	17.9	17.1
Kondensat / *Condensate* (mill. Sm^3)	2.0	1.8	2.4	2.6	2.3
Væske / *Liquid* (mill. Sm^3 oe)	110.5	107.9	102.8	100.8	101.1
Væske / *Liquid* (mill. barrels oe per day)	1.9	1.9	1.8	1.7	1.7
Gass / *Gas* (billion Sm^3)	106.6	107.3	109.7	111.0	111.1
Totalt / *Total* (mill. Sm^3 oe)	217.1	215.1	212.5	211.7	212.1

For 2016, expected production of condensate and NGL are 2.0 million Sm^3 and 10.2 million tonnes, respectively. Total liquid production is therefore estimated at 110 million Sm^3 oe (1.9 million barrels oe per day).

During the period 2016-2020, oil production is expected to reach 420 million Sm^3. This is 30 million Sm^3 less than in the previous five-year period. Most of the oil is expected to come from producing fields and fields under development, including measures for improved recovery on the same fields. Production that is approved represents 95 per cent of the volume in the five-year period.

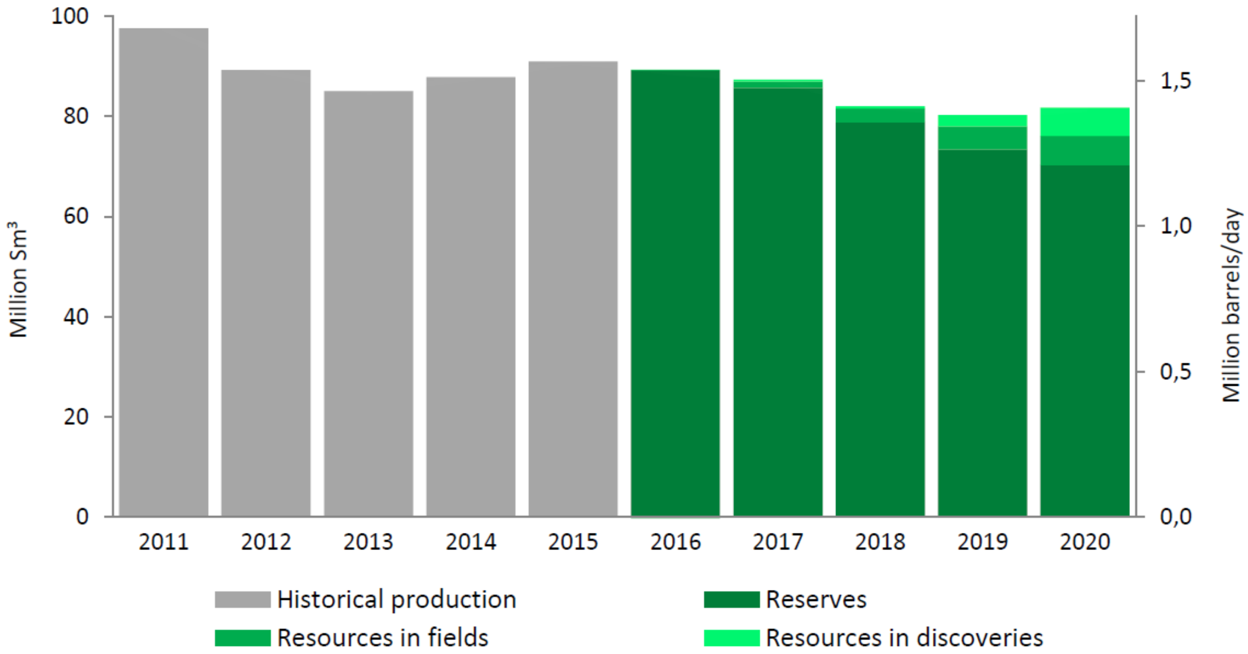

Figure 4. Oil production 2011-2020 distributed by maturity.

The prognoses were prepared under the assumptions in effect in autumn 2015. Developments in the oil price going forward will impact the activity level, and thus production in the somewhat longer term.

The shelf in 2015 – Exploration

Exploration activity on the Norwegian shelf remains at a high level, though it declined somewhat at the end of the year. Seventeen discoveries were made, 11 in the North Sea and six in the Norwegian Sea. The discoveries are all minor and close to other fields.

Fifty-six exploration wells were spudded in 2015, and 57 were completed. Thirty-three exploration wells were spudded in the North Sea, 16 in the Norwegian Sea and seven in the Barents Sea. This is approximately on par with 2014, with 57 spudded exploration wells.

Resource growth from the 17 new discoveries is approx. 8-20 million standard cubic metres (Sm^3) of oil and 14-40 billion Sm^3 of recoverable gas/condensate.

The two largest players in 2015 were Statoil and Lundin, with 14 and 13 spudded exploration wells, respectively. Wintershall and Det norske oljeselskap follow, each with five spudded wells. VNG and Suncor have both drilled three exploration wells, while Maersk and BG drilled two each. The remaining nine exploration wells are distributed among the same number of companies.

North Sea

Activity was highest in the North Sea, with 33 spudded exploration wells. Eleven discoveries were made. Two of these were located in the southern part, both operated by Statoil. The discoveries are located in the northern part of the Greater Ekofisk area.

In wildcat well 2/4-22 (Romeo), oil was proven in the Ula formation in the Upper Jurassic and in the Permian in the Rotliegend group. The size of the discovery is between 0.7-1 million Sm^3 recoverable oil. In the following well, 2/4-23 (Julius), gas/condensate was proven in the Ula formation in the Late Jurassic. Proven volumes are approx. 2-12 billion Sm^3 of recoverable gas/condensate. The well also delineated the 24/4-21 (King Lear) discovery in a shallower level in the Farsund formation in the Upper Jurassic, without changing the original resource estimates. This discovery was made in 2012.

Just north of the Gina Krog field in the Sleipner area, Statoil proved oil in well 15/6-13 (Gina Krog East 3) in the Hugin formation in the Middle Jurassic. The discovery was delineated with wells 15/6-13 A and B, and the discovery is estimated to contain between one and two million Sm^3 of recoverable oil. In the neighbouring block south of the Edvard Grieg field, Lundin proved oil in well 16/4-9 S (Lune 2 North). The discovery was made in conglomeratic Triassic/Jurassic sandstone. The size is currently estimated at 2-4 million Sm^3 of recoverable oil.

South of the Edvard Grieg field in the central part of the North Sea, Lundin delineated the 16/1-12 (Edvard Grieg South) discovery, which was proven in 2009 with well 16/1-25 S. An approx. 30-metre oil column was proven in well 16/1-12, in fractured, porous basement rock, with variable reservoir quality. It was formation-tested, with some moderately positive rates. Following this latest well, the size of the discovery has been estimated at 2-7 million Sm^3 of recoverable oil.

To the east, in well 26/10-1 (Zulu), the same company has proven gas at a shallow level in the Utsira formation in the Miocene. The discovery is estimated at 1.5-4 billion Sm^3 of recoverable gas. Further north, near the Skirne field, Total E&P proved small volumes of gas in the Hugin formation in the Jurassic, in well 25/6-5 S.

There was a great deal of delineation activity at the Ivar Aasen field in the same area. The oil company Det norske delineated the discovery with wells 16/1-21 S and A and 16/1-22 S, A and B. These wells have provided important geological information for final location of the production and injection wells. In the same block, Lundin delineated Edvard Grieg with well 16/1-23 S. The well has proven additional resources in the southeastern part of the field.

Southwest of the Oseberg field, the 30/11-8 S (Krafla) discovery, proven in 2011 in the Brent group, was delineated with well 30/11-10 A by Statoil. The results from the well have increased the resource basis from the original 2-9 million Sm^3 of oil to between 8-13 million Sm^3 of recoverable oil.

Just west of the Oseberg field, Statoil made an oil discovery in well 30/9-27. A 34-metre oil column was proven in the Tarbert formation in the Brent group. The size of the discovery is currently estimated at 1-2 million Sm^3 of recoverable oil.

Well 35/11-18 (Syrah), drilled by Wintershall Norge, proved oil northwest of the Fram field in the central part of the North Sea. The discovery was made in several levels in Jurassic reservoir rocks, and was delineated with well 35/11-18 A. The discovery has been formation-tested and shows good flow properties, and is currently estimated to contain between 1-3 million Sm^3 of recoverable oil.

Southwest of the Visund field, Statoil discovered gas/oil in well 34/8-16 S (Tarvos) in the Lunde formation in the Triassic. The size is estimated at between 0.4-1.1 million Sm^3 of recoverable oil equivalents.

In the far northwestern quadrant of the North Sea, Lundin also proved oil in what is assumed to be the Lunde formation in well 33/2-2 S (Morkel). An oil column of 175 metres was proven in the well, but the reservoir quality was poor. Preliminary calculations indicate that the discovery contains between 0.5-3 million Sm^3 of recoverable oil.

Norwegian Sea

Six discoveries were made in the Norwegian Sea. Southwest of the Njord field, VNG discovered oil in well 6406/12-4 S (Boomerang 1). The discovery was located to the east of the 6406/12-3 S (Pil) discovery, which was proven last year by the same company. A 20-metre oil column in the Rogn formation in the Upper Jurassic was proven in well 6406/12-4 S, in good reservoir rocks. The size is estimated at 2-5 million Sm^3 of recoverable oil.

Two discoveries were made in the southern Åsgard area. Wintershall discovered oil in well 6406/2-8 (Imsa). Two oil columns were proven in the well in an interval of about 130 metres in the Fangst and Båt groups in sandstone with mainly poor reservoir quality. The size of the discovery is estimated to be between 0.4-1.3 million Sm^3 of recoverable oil equivalents. In well 6406/6-4 S (Tvillingen South), Maersk Oil discovered gas/condensate in the southern Åsgard area. The discovery was made in the Garn formation in the Middle Jurassic, where a 30-metre gas/condensate column was proven in a reservoir with good quality. The discovery is estimated at 1-3 million Sm^3.

Statoil made three gas discoveries in the deepwater areas west of and near the Aasta Hansteen field. They are all in the Nise formation in the Cretaceous. The first was made in well 6706/12-1 (Snefrid North). A 105-metre gas column was proven here, of which 75 metres had very good reservoir quality. The size is estimated at 4-9 billion Sm^3 of recoverable gas. A 38-metre gas column was discovered in well 6706/12-3 (Roald Rygg), estimated to contain 2-3 billion Sm^3 of recoverable gas. In the final exploration well that proved a discovery in the area, 6706/11-2 (Gymir), a 70-metre gas column was proven, of which 40 metres had good reservoir quality. The size is estimated at 1-3 billion Sm^3 of recoverable gas. The three discoveries have provided valuable additional resources to Aasta Hansteen.

Barents Sea

Exploration activity in the Barents Sea in 2015 was lower than in 2014. Most wells are related to delineation of the 7220/11-1 (Alta) oil and gas discovery in the Gipsdalen group from the Permian. Two wells were drilled (7220/11-1 and 2 A) on the western part of the Alta discovery and two wells (7220/11-3 and 3 A) to the east on the discovery. The wells have provided valuable information on the extent of the reservoir and hydrocarbon columns. The results from these wells do not yet provide a basis for changing the original resource estimates from 2014, which are 26.1 million Sm^3 and 9.7 billion Sm^3 of gas.

Recoverable resources in new discoveries in 2015. Preliminary resource figures

Well	**Operator**	**Hydrocarbon type**	**Oil/condensate mill. Sm3**	**Gas billion Sm3**
2/4-22	Statoil	Oil	0.7-1.2	I<
2/4-23	Statoil	Gas/condensate		3-12
15/6-13	Statoil	Oil	1<	1<
16/4-9 S	Lundin	Oil	1.5-2.2-3.2	1<
26/10-1	Lundin	Gas		1.5-2.5-4
25/6-5 S	Total	Gas		1<
30/9-27 S	Statoil	Oil	1<	1<
30/6-9 29 S	Statoil	Oil	1<	
35/11-18	Wintershall	Oil	1-2-3	
34/8-16 S	Statoil	Oil	1<	1<
33/2-2 S	Lundin	Oil	0.5-1.3-3	1<
6406/12-4 S	VNG	Oil	2-3.2-4.5	1<
6406/2-8	Wintershall	Oil	0.4-1.3	
6406/6-4 S	Maersk Oil	Gas/condensate		1-1.7-2.7
6706/12-2	Statoil	Gas		4-6-9
6706/12-3	Statoil	Gas		2-2.5-3
6706/11-2	Statoil	Gas		1.3-2-2.87
			8-11-20	14-26-40

The shelf in 2015 – Field developments

In 2015, four new fields started production on the Norwegian continental shelf, all in the North Sea. The authorities approved four Plans for Development and Operation (PDOs), compared to just one in 2014.

The four new producing fields are the Statoil-operated Valemon, Det norske-operated Bøyla, BG-operated Knarr and Lundin-operated Edvard Grieg.

Ten years ago, there were 51 producing fields on the shelf, while at the end of the year, 82 fields were operational: 65 in the North Sea, 16 in the Norwegian Sea and one in the Barents Sea. So far, 18 fields on the Norwegian shelf have been shut down. The latest, and only, shutdown in 2015 was the Tor field in the Ekofisk Area.

In addition to the four fields that started producing in 2015, nine fields were under development at the end of the year. Six of these are located in the North Sea, two in the Norwegian Sea and one in the Barents Sea.

Four new fields

On 3 January 2015, **Valemon** started producing. The field is located west of Kvitebjørn in the Tampen area. The discovery was proven in 1985 and the development plan was approved in 2011. Valemon is developed with a platform resting on the seabed, with a simplified separation process. The oil and gas are sent to Kvitebjørn and Heimdal, respectively. The facility will normally be remotely operated from shore.

On 19 January, **Bøyla** started producing. The discovery was proven in 2009, and the development plan was approved in 2012. The field is developed with a subsea facility that is tied in to the Alvheim FPSO, which is located 28 kilometres to the north.

On 16 March, **Knarr** started producing. Knarr was discovered in 2008 and the PDO was approved in 2011. The field is located approx. 120 kilometres west of Florø, and is the first major development project for BG on the Norwegian shelf. The field is developed with a floating production, storage and offloading vessel (FPSO). The oil is loaded from the Knarr FPSO onto tankers, and the gas is transported to St Fergus in the UK via a new gas pipeline and the Far North Liquids and Associated Gas System (FLAGS).

On 28 November, the oil field **Edvard Grieg** started producing. The field is located on the Utsira High. It was proven in 2007, and the PDO was approved in 2012. Edvard Grieg will also supply Ivar Aasen with electricity. The oil from Edvard Grieg is sent by pipeline to the Grane oil pipeline, which runs to the Sture terminal in Hordaland. The gas is exported in a separate pipeline to the Scottish Area Gas Evacuation (SAGE) System in the UK.

Four development plants approved

The four development plans include three in the North Sea: the first construction stage for Johan Sverdrup, Gullfaks South (Rutil in Gullfaks Rimfaksdalen) and Gullfaks (amended PDO that includes Shetland/Lista Phase 1). The fourth development plan is for Maria in the Norwegian Sea. Statoil also submitted the PDO for Oseberg West Flank 2 just before the holidays.

North Sea

Six new fields are under construction. The PDO for the largest by far, the first development stage for **Johan Sverdrup**, was approved on 20 August 2015. Production start-up is scheduled for late 2019. Johan Sverdrup is located 155 kilometres west of Karmøy in Rogaland. Water depth in the area is 110 – 120 metres, and the discovery covers an area of approx. 200 square kilometres. The first development stage consists of a field centre with four specialised platforms for living quarters, processing, drilling and risers.

The Statoil-operated Johan Sverdrup will be operated with power from shore from production start-up. In the first development stage, transmission capacity of 100 megawatts will be provided for the field centre, enough to cover the demand during this stage. The area solution for power from shore, which includes the Johan Sverdrup, Edvard Grieg, Ivar Aasen and Gina Krog fields, will be established no later than in 2022.

The oil from Johan Sverdrup will be exported from the riser platform to the Mongstad terminal in Hordaland through a new oil pipeline that will be connected to existing rock storage caverns. The gas will be routed from the riser platform to the Kårstø terminal in Rogaland through a new pipeline that will be connected to the existing Statpipe (rich gas pipeline) on the seabed west of Karmøy.

Martin Linge and **Gina Krog** were both discovered back in 1978. Technology development and new information about the subsurface led the licensees to decide to develop the fields. The PDOs were approved in 2012. Total-operated Martin Linge is located about 42 kilometres west of the Oseberg area near the border to the UK sector. A storage ship will be used for the oil that is recovered, in addition to the gas resources. Martin Linge will be operated using power from shore. Planned production start-up for Martin Linge is early 2018. Statoil-operated Gina Krog is located about 30 kilometres northwest of the Sleipner area. The gas will be transferred to Sleipner for final processing, and a storage ship will be used for the oil. Production is scheduled to start in 2017.

Det norske oljeselskap received approval for the **Ivar Aasen** PDO in 2013. The discovery on the Utsira High in the North Sea was proven in 2008. Production from the field will be sent to Edvard Grieg for final processing. The Edvard Grieg field will provide power to Ivar Aasen, which is scheduled to start production in late 2016.

The **Hanz** field – operated by Det norske oljeselskap – will be developed with seabed templates tied in to Ivar Aasen. The development and production start-up dates will be adapted to the production on Ivar Aasen.

Flyndre is a small oil field in the southern part of the North Sea, west of the Ekofisk area, which spans the border between the UK and Norway. Most of the resources are on the UK side. Maersk Oil UK is the operator, and the plan is to develop the field with a seabed template, tied in to the Clyde field in the UK sector. The development plan was approved in 2014 and production start-up is scheduled for the 2nd quarter of 2016.

Norwegian Sea

Statoil-operated **Aasta Hansteen** is located about 320 kilometres west of Bodø in Nordland, and will be developed with the first ever Spar facility – a floating field centre – on the Norwegian shelf. Water depth in the area is 1270 metres, and new technology has been developed in order to make this field development possible. The field, which mainly contains gas, was proven in 1997 and the PDO was approved in 2013.

At the same time as the decision to develop Aasta Hansteen was made, a decision was also made to proceed with construction of a gas pipeline (Polarled) to the terminal at Nyhamna in Møre og Romsdal. Nyhamna will be upgraded so it can receive gas from Aasta Hansteen and Polarled. Aasta Hansteen and Polarled make it possible to develop other gas discoveries in the Norwegian Sea. Planned productions start-up is in late 2017.

The PDO for Wintershall-operated Maria was approved in September, and production start-up is scheduled for the 4th quarter of 2018. Maria – discovered in 2010 - is located on Haltenbanken in the Norwegian Sea, and will be a subsea development. The wellstream will be tied in to the Kristin platform for processing and metering, gas for gas lift will be collected from Åsgard B via Tyrihans and water for injection will come from the Heidrun field. The oil will be stored and offloaded on Åsgard C, while the rich gas will be transported through the Åsgard transport system (ÅTS) to Kårstø, where NGL and condensate will be extracted.

Barents Sea

Eni-operated **Goliat** was discovered in 2000, and the PDO was approved in 2009. This will become the first oil field in the Norwegian sector of the Barents Sea, and will be developed with a cylindrical, floating production facility – the first Sevan type on the Norwegian shelf. Eni is planning start-up of Goliat in the near future.