NORWEGIAN PETROLEUM DIRECTORATE

The Norwegian Petroleum Directorate's and the Ministry of Petroleum and Energy's stand «The Norwegian Continental Shelves» was voted best stand over 50 square metres at ONS 2016.

12 January 2017

The Shelf in 2016

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Prepared for the future

Oil and gas production on the Norwegian shelf is high. The adjustment process has been extensive, but the cost reductions implemented by the industry will lay the foundation for profitable activity for many years to come.

Oil production increased for the third consecutive year in 2016, and gas production was at the same level as the previous year, which was a record year for production. The high level is in part due to good regularity on the fields, and the fact that various efficiency measures have led to substantial reductions in operating and exploration costs.

“The foundation has been laid for increased profitability in both existing and new projects. This is essential in order to maintain a high activity level for upcoming years,” says Director General Bente Nyland. She believes that cost reductions of 30 to 50 per cent in development projects should mean that companies will view more projects as being profitable.

“We must prevent the focus on short-term profits from coming at the expense of long-term value creation for society,” she says.

Investments on the Norwegian shelf in 2016 amounted to NOK 135 billion, about NOK 50 billion less than the peak years 2013 and 2014. Nyland predicts that the current year and next year will also be challenging for the industry, but investments are then expected to increase again. A number of new development projects are undergoing evaluation, and an extensive portfolio of new field developments will be continued and developed over the next few years.

Five Plans for Development and Operation (PDO) were submitted in 2016, with a total investment value of NOK 23 billion. Seven development projects with a total value of NOK 233 billion are currently ongoing.

After several years of high exploration activity, 36 exploration wells were drilled in 2016, 20 fewer than the preceding year. Eighteen discoveries were made, one more than in 2015. Exploration activity was highest in the North Sea, where a total of 14 discoveries were made. Two discoveries were made in both in the Norwegian Sea and the Barents Sea.

“Many of the discoveries are small, but most are located near existing infrastructure. This means that they can quickly become profitable developments if they are tied in to operational fields and facilities,” says Nyland.

According to the Director General, there is a great deal of uncertainty associated with exploration activity going forward. This depends on new discoveries being followed up, and presumes that the industry will be awarded new acreage for exploration.

“It is very important to maintain exploration activity at a high level in order to maintain stable production in the future,” she says.

Despite the decline in the number of exploration wells, the number of applications and awards in the most recent licensing rounds demonstrates that the interest in the Norwegian shelf is still high. Fifty-six production licences were awarded in APA 2015, while ten were awarded in the 23rd licensing round. All awards in the 23rd round were located in the Barents Sea, and three are located in the recently opened area in the southeastern Barents Sea. The first exploration well in this area will be drilled as early as this year.

The probability of making new big discoveries is also highest in this area, according to Bente Nyland.

“New surveys also indicate significant opportunities in areas that are not open for petroleum activities,” she concludes.

1 Investment and cost forecasts

The petroleum industry's effort to reduce costs, along with falling supplier prices, have resulted in a considerably lower cost level. This is reflected both in lower investments in new projects, reduced costs for new production wells on fields in operation, as well as reduced operating and exploration costs.

A lower cost level boosts profitability in current production as well as future projects.

Controlling cost development is a precondition for future profitable activity on the shelf. This presumes that the reductions are not merely short-term measures, but that they safeguard considerations for long-term value creation, for health, safety and the environment, and ensure that the supplier industry is competitive and ready to participate when activity on the shelf picks up again.

There is little doubt that 2017 will be yet another demanding year for the industry. Although investments are still falling, the decline is slowing. Investments are expected to rise gradually following a minor drop from 2017 to 2018. The drop in investments is partially due to lower activity, but is also a consequence of the reduced cost level. The start-up of a number of new projects, both on fields currently in operation as well as new field developments, is expected to contribute to greater investments starting in 2019.

Operating and exploration costs will also be further reduced from 2016 to 2017, followed by levelling out and a gradual increase.

Substantial cost level reductions

The cost-cutting efforts are now yielding results, but this has been challenging, particularly for parts of the supplier industry, where many people have lost their jobs. Development costs for a number of projects, both ongoing developments and projects under evaluation, have been significantly reduced. The primary causes of this are changes in development solutions, optimisation and efficiency measures, as well as lower prices in various supplier markets.

A rough indicator of cost level development is a comparison of construction costs on a selection of seven field development projects. [1] In 2014, the operators' projected total investments for these projects were slightly less than NOK 220 billion (Figure 1-1). The equivalent projection for the autumn of 2016 was NOK 110 billion, i.e. a 50 per cent reduction. Recoverable resources for these projects remain virtually unchanged. The greatest cost reduction is for new facilities and development wells. More optimised solutions and simpler designs for both facilities and wells, as well as more efficient implementation, have yielded considerable cost reductions. This is in addition to the effects of lower supplier prices.

The reduction in costs is of great significance for the projects' profitability. As regards the included projects, the main picture is a break-even price of less than USD 40, and for some less than 30. For some projects, break-even prices have been reduced by more than half.

[1] The following seven projects are included: Johan Sverdrup phase II, Johan Castberg, Utgard, Oda, Trestakk, Dvalin and Snilehorn. With the exception of Johan Castberg, which has reported a development solution with a floating production vessel (FPSO), and Johan Sverdrup phase II, which has reported a development solution with a facility resting on the seabed, the others are seabed developments. A common feature of all these projects is that their development concepts have not changed from 2014 to 2016.

Gas

A total of 116.8 billion Sm³ of gas was sold in 2016 (114.6 billion Sm³ 40 megajoules of gas). This is quite similar to 2015. The level of gas sales is difficult to predict, even over the short-term. Sales in 2016 were nine per cent higher than what we projected at the same time last year. This is, among other factors, due to continued high demand for gas from Europe. Several operating fields have raised gas production. This is evident in the prognosis for gas sales over the short-term (Figure 2-2), which illustrates a stable, high level of gas sales from the Norwegian shelf moving forward.

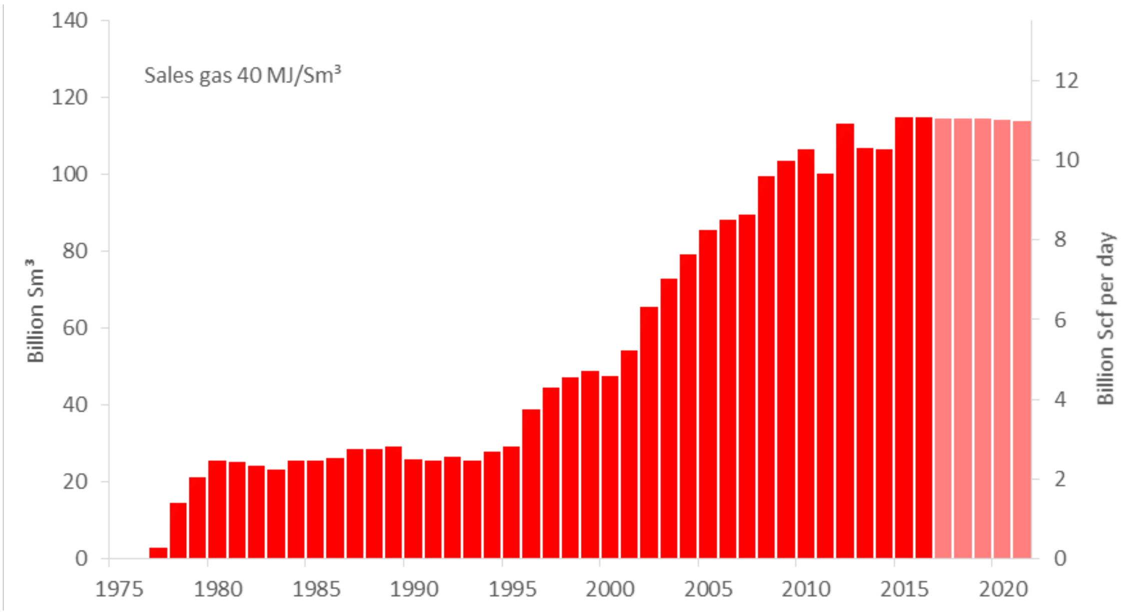


Figure 2-2: Actual and projected gas sales through 2021

Oil

94.1 million Sm³ of oil (1.62 million barrels per day) was produced in 2016, compared to 91.0 million Sm³ (1.56 million barrels per day) the preceding year. This is an increase of more than three per cent. The contribution from new fields in production amounts to more than five million Sm³ of oil in 2016. Fields that have been in production longer have seen less production decline than expected. The major causes of this are high regularity and the fact that a considerable number of new production wells are being drilled more quickly than presumed.

The NPD's prognosis forecasted somewhat lower oil production in 2016 than the preceding year. However, many of the older fields have produced vastly more than presumed, and production was five million Sm³ higher than the NPD's projections from the autumn of 2015.

As regards 2017, the NPD projects that oil production will remain at the same level as in 2016, 93.9 million Sm³ (1.62 million barrels) per day. Production is expected to decline somewhat leading up to 2020, where the contribution from Johan Sverdrup is expected to raise the production level yet again. The uncertainty is particularly related to drilling of new wells, start-up of new fields, the reservoirs' ability to deliver, and the regularity of fields in operation.

Oil production during the 2017-2021 period is projected to reach 455 million Sm³. This is eight million Sm³ more than in the previous five-year period. Production that has been approved, accounts for 93 per cent of the volume in this five-year period.

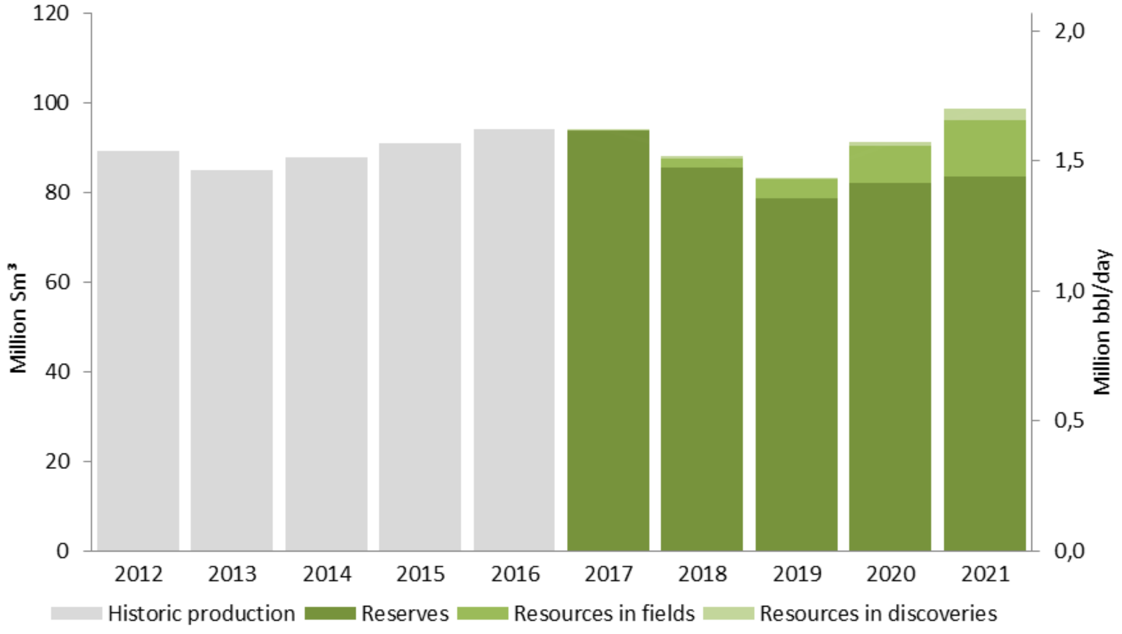


Figure 2-3: Oil production 2012-2021 distributed by maturity

These prognoses have been prepared under the prevailing assumptions for the autumn of 2016. Future development in the oil price will affect the activity level, and thus production over the somewhat longer term.

Overall production forecast

The most recent prognosis from the NPD shows a substantially higher production level than that shown in the Shelf in 2015. During the period from 2017 to 2030, it is now estimated that production will be five per cent higher than the estimate shown last year.

Production development in recent years shows that the fields, through efficiency measures, particularly within drilling of wells and regularity on the facilities, produce more than previously presumed. Now additional development wells have been included in the prognosis, and we have also premised higher gas sales during the period than previously. The NPD also presumes that several projects will start production earlier, as a result of cost reductions.

Figure 2-4 shows the new production prognosis compared to the one presented in the Shelf in 2015. The prognosis shows a relatively flat production development until the mid-2020s. Compared to the previous prognosis, production is presumed to be higher until 2027. This is, among other factors, due to expectations of greater drilling activity, better regularity on operating fields and a lower cost level, which contributes to quicker phase-in of new projects than previously presumed.

The contribution from petroleum for which production is approved remains at a stable, high level over the next five-year period. The production level will be maintained over the subsequent five years with contributions from resources from fields and discoveries for which development has yet to be approved. Leading up to 2030, production from undiscovered resources is expected to play a greater role.

Nevertheless, the production level moving forward is uncertain. It depends on which measures are implemented on the producing fields, which discoveries are approved for development and when they come on stream, and not least, which new discoveries are made during the period, how large they are and how and when they are developed.

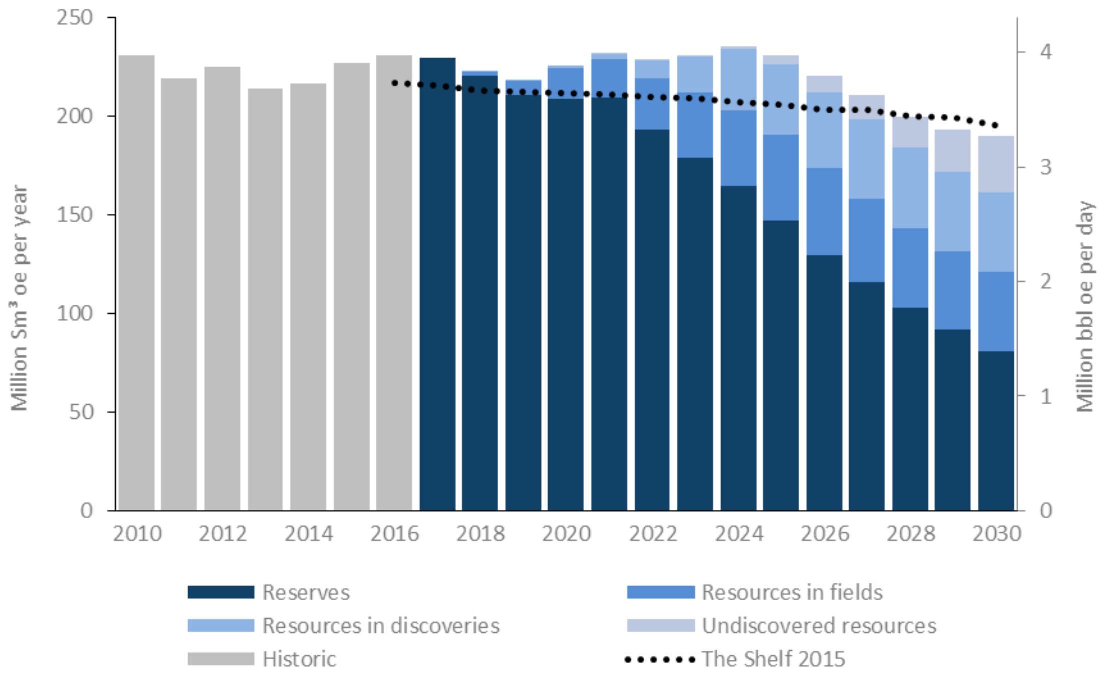


Figure 2-4: Production prognosis through 2030

3 Exploration

Many, but small discoveries

After several years of high exploration activity, 36 exploration wells were drilled in 2016, 20 fewer than the preceding year. This is mainly due to a lower oil price and cost cuts.

When the oil companies have to improve cash flow, exploration investments are usually impacted first. This is because exploration expenses can more easily be suspended or adjusted along the way than expenses that are linked to fields in operation and approved development projects. This development is not unique to Norway, but is rather part of an international trend that follows from the companies' adaptations to a situation with lower oil prices.

Historically, in times such as these, oil companies are more cautious and prioritise exploration in familiar/mature areas where discoveries are more likely – but often small discoveries – where the resource potential is high, but the probability of discovery is lower. 2016 has therefore seen considerable exploration in areas near existing fields, and many, but smaller discoveries have been made.

Of the 36 spudded exploration wells, 28 are wildcat wells and eight are appraisal wells. With 12 spudded exploration wells, Statoil has drilled the most in 2016, followed by Wintershall with seven and Det norske oljeselskap (now Aker BP) with five.

Eighteen discoveries were made on the Norwegian shelf in 2016, one more than in 2015. Exploration activity is greatest in the North Sea, where a total of 14 discoveries have been made. Two discoveries were made in both the Norwegian Sea and the Barents Sea. See Figure 3-1.

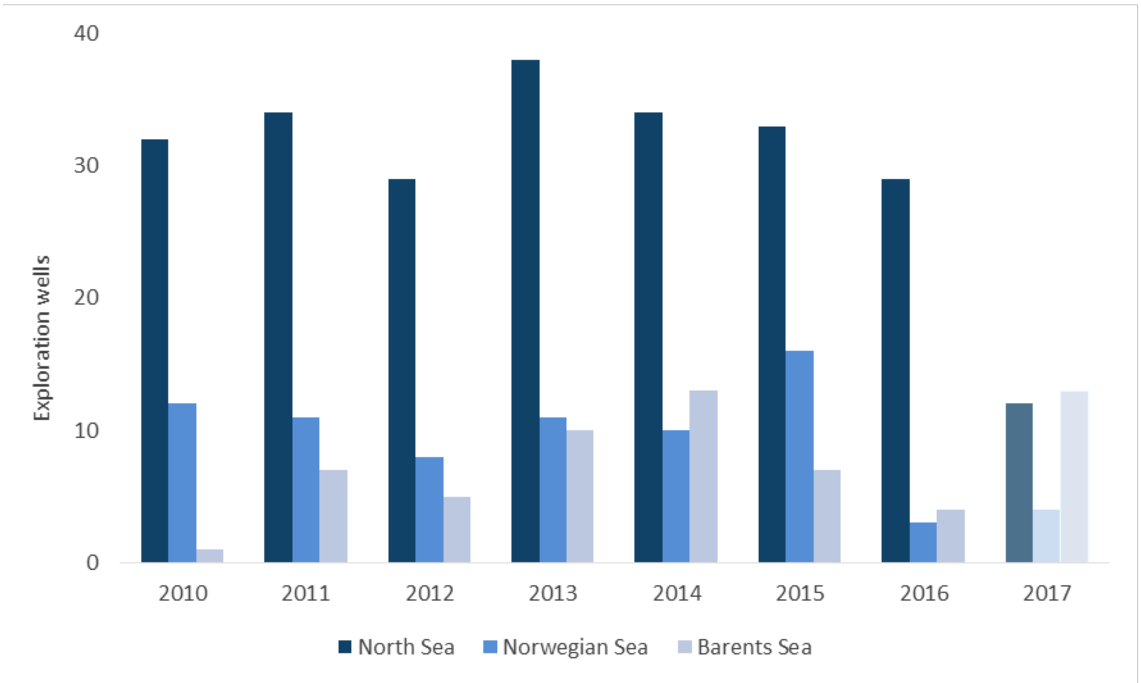


Figure 3-1: Spudded exploration wells

Most discoveries are located near existing infrastructure and can quickly become profitable developments if they are tied into fields and facilities in operation. Resources in the new discoveries amount to between 18 and 44 million standard cubic meters (Sm^3) of recoverable oil and between 12 and 33 billion Sm^3 of recoverable gas.

The largest discoveries were Faroe's oil and gas discovery in wildcat well 31/7-1 (Brasse), Det norske's (now Aker BP) oil discovery in wildcat well 25/2-18 S (Langfjellet) and Engie's oil and gas discovery in wildcat well 36/7-4 (Cara). They are located in the central and northern North Sea.

Around 30 wells are expected to be drilled in 2017, a relatively high number in a historical perspective. However, the decline in the number of exploration wells is cause for concern. In order to maintain oil and gas production beyond 2025, new profitable resources must be proven. See Figure 3-2. High exploration activity is therefore important.

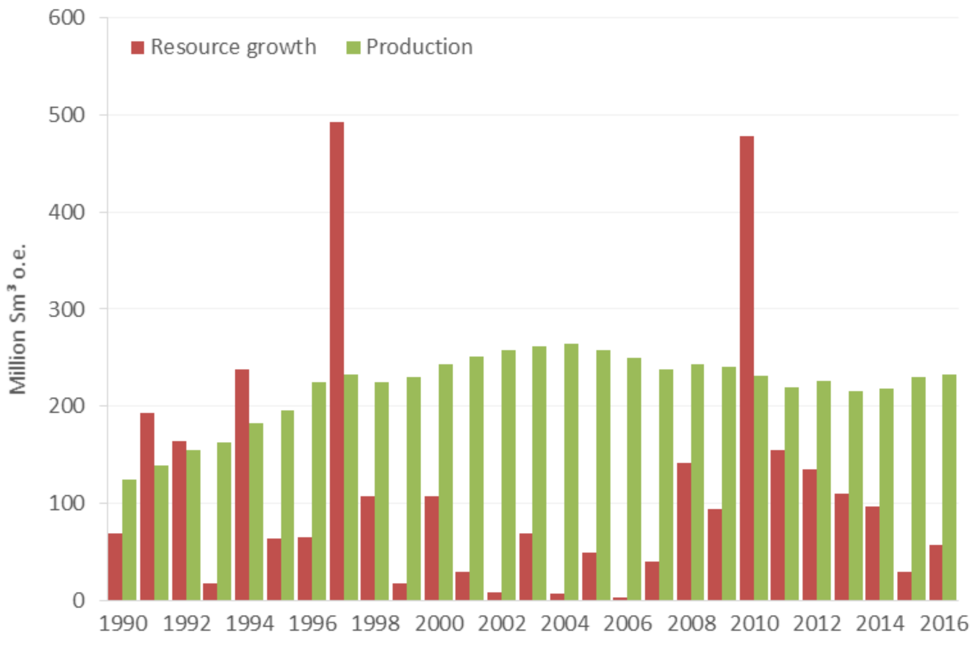


Figure 3-2: Resource growth and production

Good access to data, consistent access to attractive acreage and stable framework conditions are the authorities' contribution toward maintaining a high level of exploration activity.

Although a decline in the number of exploration wells is expected in 2017, the number of applications and awards in the most recent licensing rounds shows that there is still considerable interest in the Norwegian shelf. In addition, several of the planned wells in 2017 have high potential and substantial geological information value.

There has been a stable, high level of awards of new production licenses in recent years, including in APA 2015 and the 23rd licensing round. The interest in APA 2016 was on a par with previous years.

The authorities have started work on the 24th licensing round. The deadline for nominating blocks for the licensing round was 30 November 2016, and the authorities expect the schedule to be the same as for previous numbered rounds.

The North Sea

2016 was the 50th anniversary of the first wildcat well being drilled in the North Sea. After such a long time and many wells, it is gratifying to see that discoveries are still made in the area.

The oil company Det norske (now Aker BP) proved oil in wildcat well 25/2-18 S (Langfjellet). The discovery was delineated with wells 25/2-18 A and 25/2-18 B. The preliminary estimate of the size of the discovery is between 3.8 and 12 million Sm³ of recoverable oil. This makes the discovery one of the year's largest.

Northeast of the Martin Linge field, Total has proven gas and condensate in wildcat well 30/4-3 S (Herja). The discovery has been estimated at 2.0-12 million Sm³ of recoverable oil equivalents. The resources will be produced from Martin Linge when the field starts up.

West of Oseberg, Statoil made a minor gas discovery in wildcat well 30/9-28 S (B-Vest). The discovery is estimated to contain between 1.2 and 1.7 million Sm³ of recoverable oil equivalents.

Statoil has carried out a drilling campaign in the North Sea in the area where the 30/11-8 S (Krafla) discovery was proven in 2011. Several discoveries were made, starting with a minor gas discovery in 30/11-11 S (Madam Felle) with 0.9-1.6 million Sm³ of recoverable oil equivalents. The next discovery was 30/11-12 S (Askja SE), which proved 0.8-1.7 million Sm³ of recoverable oil. Appraisal well 30/11-12 A was dry. 30/11-13 (Beerenberg) proved gas and condensate, and the discovery was between 1.8-3.2 million Sm³ of recoverable oil equivalents. The last wells in the drilling campaign were 30/11-14 (Slemmestad) and 30/11-14 B (Haraldsplass). They proved gas-condensate and oil, respectively, with 1.4-2.5 million Sm³ of oil equivalents in 30/11-14 and 1.8-3.1 million Sm³ of oil equivalents in 30/11-14 B.

South of the Brage field, Faroe made an oil and gas discovery in wildcat well 31/7-1 (Brasse), which was delineated by 31/7-1 A. So far, the discovery is estimated to contain between 8.1 and 15 million Sm³ of recoverable oil equivalents and the reservoir quality is good. 31/7-1 was thus among last year's largest discoveries. The licensees will consider tie-in to existing infrastructure on the Brage field.

Wintershall has proven oil in wildcat wells 35/11-20 S (Orion) and 35/11-20 B (Mira). These wells are located near the Vega field. Appraisal wells 35/11-20 A and 35/11-20 B were also drilled in the area. Overall, the discoveries are estimated at between 0.6 and 4.5 million Sm³ of recoverable oil. Wintershall also encountered oil in wildcat well 35/8-6 A (Robbins) just northwest of the Vega field. The size of this is estimated at 0.7-0.8 million Sm³ of recoverable oil.

The oil and gas discovery in wildcat well 36/7-4 (Cara) was also one of the largest last year, and is estimated at between 4.5 and 12 million Sm³ of recoverable oil equivalents. The discovery was made by Engie, and has good reservoir properties.

The Norwegian Sea

The Norwegian Sea has seen little exploration in 2016, but an increase is expected in 2017. Among other things, a wildcat well will be drilled in deep water, which may provide additional resources for the Aasta Hansteen discovery.

In the Norwegian Sea, just north of the Njord field, Statoil proved petroleum deposits in two wells. Wildcat well 6407/7-9 S (Nordflanken 2) proved oil and gas/condensate. 6407/7-9 A (Nordflanken 3) proved gas in the Tilje formation and Åre formation. The size of the discoveries is 0.2-2.0 million Sm^3 of oil equivalents in 6407/7-9 S and 0.2-1.0 million Sm^3 of recoverable oil equivalents in 6407/7-9 A.

The Barents Sea

The Barents Sea has also seen relatively few exploration wells drilled in 2016 with few and small discoveries. Several appraisal wells were drilled on the Alta discovery and Wisting discovery, which have significance for further activity in the area. The appraisal well on Wisting was a successful test of how it is possible to drill horizontally in very shallow reservoirs. This is important knowledge as some exploration wells in the Barents Sea explore shallow exploration targets.

Lundin proved gas in the Barents Sea in wildcat well 7130/4-1 (Ørnen), and the size is estimated at 0.4-1.5 million Sm^3 of recoverable oil equivalents.

Lundin has also proved oil and gas in wildcat well 7220/6-2 R (Neiden) east of the Johan Castberg discovery. The discovery has so far been estimated at 4-9 million Sm^3 of recoverable oil equivalents.

A number of exploration wells will be drilled in the Barents Sea in 2017, where one of the most interesting is planned to be drilled in the newly opened area in the Norwegian part of the Southeastern Barents Sea. This is one of the major structures in this area, and the well will contribute important new knowledge about the area.

Outlook

The NPD has not carried out new analyses for undiscovered resources in 2016. The estimate has been reduced by the volume discovered in 2016 and is around 3 billion Sm^3 of oil equivalents. However, the volume is uncertain – if the high estimate is correct, there could be as much as 5.5 billion Sm^3 of oil equivalents.

More than half of the undiscovered resources are in the Barents Sea, which is also where the most exciting exploration wells in 2017 can be found. It is gratifying that the companies that will be drilling exploration wells in 2017 have high expectations for the prospects.

Cooperation agreement with Russia

In order to increase geological understanding on both sides of the demarcation line in the Barents Sea, a cooperation agreement was signed last summer with Russia concerning exchange of seismic data. This is important for further exploration of the Barents Sea.

Table 3-1: Recoverable resources in new discoveries in 2016

Discovery	Operator	Hydrocarbon type	Oil/condensate (million Sm³)	Gas (billion Sm³)
16/1-26 S	Aker BP	Oil and gas	0.9 - 1.3 - 1.7	<1
25/2-18 S (Langfjellet)	Aker BP	Oil	3.3 - 6.7 - 10	0.6 - 1.1 - 1.7
30/11-11 S (Madam Felle)	Statoil	Oil	0.7 - 1.0 - 1.3	<1
30/11-12 S (Askja Southeast)	Statoil	Oil	0.7 - 1.1 - 1.5	<1
30/11-13 (Beerenberg)	Statoil	Gas/condensate	<1	1.0 - 1.4 - 1.8
30/11-14 (Slemmestad)	Statoil	Gas	<1	<1
30/11-14 B (Haraldsplass)	Statoil	Oil and gas/ condensate	<1	0.9 - 1.3 - 1.6
30/4-3 S	Total	Gas/condensate	0.2 - 1.0 - 1.3	1.6 - 6.5 - 8.8
30/9-28 S	Statoil	Gas	<1	1.0 - 1.2 - 1.4
31/7-1 (Brasse)	Faroe	Oil and gas	4.8 - 6.7 - 9.0	2.0 - 2.4 - 3.5
35/11-20 B	Wintershall	Oil	<1	<1
35/11-20 S	Wintershall	Oil	<1	<1
35/8-6 A	Wintershall	Oil	<1	<1
36/7-4	ENGIE	Oil and gas	1.5 - 3.0 - 4.8	2.4 - 3.9 - 5.7
6407/7-9 A	Statoil	Gas		<1
6407/7-9 S	Statoil	Oil and gas/ condensate	<1	<1
7130/4-1	Lundin	Gas		0.4 - 1.1 - 1.5
7220/6-2 R	Lundin	Oil and gas	3 - 5 - 7	1.0 - 1.5 - 2.0
Total			**18 - 30 - 44**	**12 - 23 - 33**

4 Field developments

Good progress despite difficult times

Despite difficult times, considerable values are still being created on the Norwegian shelf. Five Plans for Development and Operation (PDOs) were submitted over the course of the year, with total investments valued at NOK 23 billion. There are also seven ongoing new field development projects with a total PDO investment estimate of NOK 233 billion.

The costs related to development and operation projects have been reduced by 30-50 per cent over the last few years. This contributes to increased profitability. However, it is important to make sure that cost reductions do not have an adverse impact on future value creation possibilities.

It is essential to collaborate in using existing infrastructure, such as pipelines and available process capacity on the platforms, in order to maximise value creation. Time-critical oil and gas resources, such as minor discoveries near infrastructure, must be prioritised in the process facilities on the platforms before they are shut down and removed.

This will require good collaboration spanning across production licences. Good area solutions can help make more marginal discoveries profitable. Utilising newly developed technology will also be crucial for realising the marginal resources.

Increased recovery

In recent years, the Norwegian Petroleum Directorate has seen that companies are increasingly emphasising short-term profits when deciding to invest in development of discoveries and in measures for improved recovery from fields. This is why it is important to shift the attention towards solutions that generate the highest overall value creation, also for our society – and which safeguard future opportunities for improved recovery from the fields.

It is very positive that the same number of development wells are being drilled as in 2013/2014, which is when the oil price was at its highest. Many plans are progressing well, which leads to new developments.

Improved profitability

Following a period with an exceedingly high cost level on the Norwegian shelf, the industry has successfully cut costs in development projects by 30 to 50 per cent over the last few years. This should mean that companies will see more projects as profitable. It can be challenging to push through large and small investment decisions in the production licences based on requirements for short-term returns, or due to capital constraints in the companies. A lot of time may pass from investment to returns in an industry with a time horizon as long as the petroleum industry. The authorities are concerned with ensuring companies choose solutions that, overall, provide maximum value creation, and emphasise that it is important to maintain a long-term perspective rather than seeing what will provide the highest returns in the short-term.

The cost reduction work must lead to a lasting lower cost level on the Norwegian shelf. At the same time, this cannot have an adverse impact on future possibilities for improving recovery and facilitating optimal area solutions across production licences.

On the whole, the companies are doing a good job. However, the Norwegian Petroleum Directorate sees that it is occasionally necessary to exert some pressure to ensure decisions that will safeguard the values for society in the best possible manner. There is a good dialogue between the authorities and companies, and the Norwegian Petroleum Directorate's experience is that the companies do listen to signals from the authorities.

Fields

There are 80 producing fields on the Norwegian shelf, 62 of which are in the North Sea, 16 in the Norwegian Sea and two in the Barents Sea.

Two fields started producing in 2016, one Plan for Development and Operation (PDO) was approved and five new PDO applications were submitted. There are seven ongoing new field developments and five cessation plans were received.

New fields

Goliat

The Goliat field in the Barents Sea finally started producing in March of 2016. Goliat is an oil field located about 50 kilometres southeast of the Snøhvit field. Goliat was developed with a floating, cylindrical production unit, including eight subsea templates with 32 well slots. Daily production capacity is nearly 16 000 standard cubic metres of oil equivalents (100 000 barrels o.e.). Goliat is expected to produce for at least 15 years. The lifetime can be extended if new discoveries are made in the area.

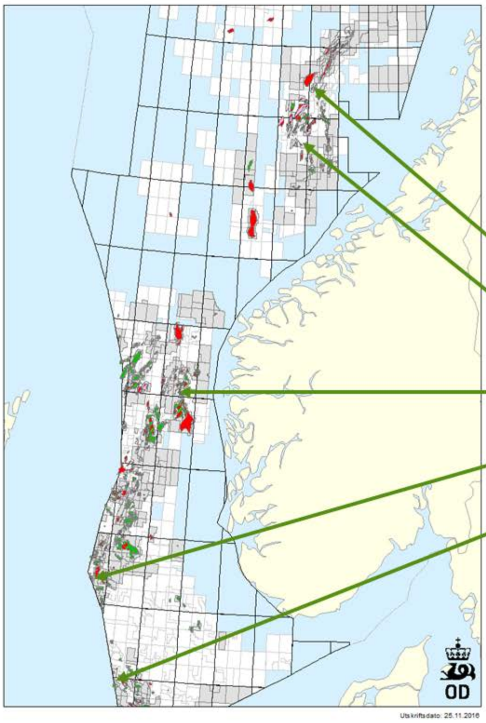
Ivar Aasen

Production at Ivar Aasen started on Christmas Eve in 2016. The oil field is located about 30 kilometres south of Grane and Balder in the North Sea. The development solution consists of a production and living quarters facility with a steel jacket and a separate jack-up drilling facility. Daily production capacity is nearly 11 000 standard cubic metres of oil equivalents (68 000 barrels o.e.). Ivar Aasen is expected to produce for 20 years, depending on the oil price and production development.

Plans for Development and Operation (PDO)

One PDO was approved in 2016, for Oseberg Vestflanken 2 in the North Sea. The resources will be produced from an unmanned wellhead platform. The PDO estimates costs of the development at NOK 8.2 billion, and the investment will make it possible to recover 17.6 million Sm^3 of oil equivalents (approx. 110 million barrels o.e.). Production start-up is scheduled for 2018. The development represents a new concept on the Norwegian shelf. Vestflanken 2 is the first of three planned phases for development of the remaining reserves in the Oseberg area. The remaining reserves for Oseberg, Oseberg South and Oseberg East are estimated at 135 million Sm^3 of oil equivalents (850 million barrels o.e.). The project will help extend the lifetime of the Oseberg field, which has been producing since 1988.

The authorities received five PDOs in 2016. These five development plans represent a total investment of NOK 23 billion and a present value of NOK 35 billion before tax.



Field	Operator	Host
Dvalin	DEA	Heidrun
Trestakk	Statoil	Åsgard
Byrding	Statoil	Fram/Troll C
Utgard	Statoil	Sleipner
Oda	Centrica	Ula

Figure 4-1: PDOs received in 2016

All of the fields will be tied in to existing infrastructure, and will contribute to the efficient exploitation of available capacity. This will also increase the profitability and lifetime for the relevant platforms that will be processing oil and gas from the new fields, and will also enable further measures that can contribute to extending tail production from these fields.

Utgard (15/8-1) is a gas and condensate discovery located west of the Sleipner area in the North Sea. The discovery spans across the Norway-UK continental shelf border, and is estimated to contain about nine million standard cubic metres of oil equivalents (57 million barrels o.e.). The majority of the reserves in Utgard are located on the Norwegian side. The development will be tied in to facilities on Sleipner. The expected investment amounts to nearly NOK 1.9 billion (Norwegian share). Production start-up is scheduled for the 4th quarter of 2019. Statoil is the operator.

Byrding (35/11-13) is an oil and gas discovery located southwest of the Gjøa field in the North Sea. The discovery is estimated to contain about 1.8 million standard cubic metres of oil equivalents (11 million barrels o.e.), and will be developed using the existing subsea template in the Fram area. Production start-up is scheduled for the 2nd quarter of 2017. The expected investment amounts to nearly NOK 1 billion. Statoil is the operator.

Oda (8/10-4 S) is an oil discovery east of the Ula field in the North Sea. According to estimates, 7.5 million standard cubic metres of oil equivalents (48 million barrels o.e.) can be recovered from Oda. The investment for the development amounts to approx. NOK 5.4 billion. The field will be tied in to Ula and production is scheduled to start in the 3rd quarter of 2019. Centrica is the operator.

Dvalin (6507/7-14 S) is a gas discovery located near Heidrun in the Norwegian Sea. Estimated recoverable resources from the discovery are about 18 billion standard cubic metres of gas. The field will be tied in to Heidrun. Expected investments will exceed NOK 10 billion. Production start-up is scheduled for October 2020. DEA is the operator.

Trestakk (6406/3-2) is an oil discovery located near the Åsgard field in the Norwegian Sea. Recoverable resources are estimated at 10.5 million standard cubic metres of oil (72 million barrels). The field will be tied in to the Åsgard A platform. Expected investments amount to approx. NOK 5.5 billion. Statoil is the operator.

Future developments

The NPD's forecasts assume that about ten PDOs will be submitted over the next few years. PDOs for two major developments are expected in 2017, Johan Castberg in the Barents Sea and the further development of the Snorre field in the North Sea. The PDO for Johan Sverdrup Phase II is expected in 2018, and PDOs for several other development projects are also anticipated.

Snorre

A milestone was achieved in late November/early December 2016, when the licensees for the Snorre field in the North Sea decided to continue the project that will significantly increase production. The field was proven in 1979 and production started in 1992. The licensees are planning to submit a Plan for Development and Operation in 2017.

The new development consists of six new subsea templates tied in to the two existing platforms. The expansion will increase recovery from the field by nearly 30 million standard cubic metres of oil. This is equivalent to the size of the Goliat field in the Barents Sea, which makes Snorre the largest improved recovery project on a producing field. The lifetime of the field will be extended to 2040.

Ongoing developments

There are seven ongoing new field development projects on the Norwegian shelf, with total PDO investment estimates of NOK 233 billion (2016-NOK).

Johan Sverdrup is located south of Grane and northeast of Sleipner in the North Sea. The development solution in phase one is a field centre with four specialised platforms: living quarters, process facility, drilling facility and a riser platform that was built to receive electricity from shore. The oil will be transported through a pipeline to the Mongstad terminal located north of Bergen. The gas will be transported through a pipeline to the Kårstø terminal north of Stavanger. Production start-up for Phase I is scheduled for late-2019.

Gina Krog is an oil and gas field that is located northwest of Sleipner in the North Sea. The development solution is a new steel platform and a storage ship, as well as a jack-up drilling facility. Planned start-up is 2017.

Hanz is an oil field in the North Sea. It is being developed with a subsea template that is tied in to the Ivar Aasen field and the wellstream will be transported on to the Edvard Grieg field for final processing and export. The schedule for development and production start-up depends on available processing capacity.

Maria is located on Haltenbanken in the Norwegian Sea. Maria will be developed with a subsea production facility with two subsea templates. The development will have several “hosts”. The wellstream will be routed to the Kristin platform for processing and metering. The oil is then sent to Åsgard A for storage and offloading to shuttle tankers. The rich gas will be exported via the Åsgard transport pipeline system to the gas facility at Kårstø in Rogaland County. Gas for injection in the Maria field comes from the Åsgard B platform. The gas arrives via the gas pipeline to the Tyrihans D subsea template on the Tyrihans field. The Maria pipeline will be connected here. Water to be injected for pressure support in Maria will be delivered from the Heidrun platform. Production start-up is scheduled for late-2018.

Martin Linge is located near the UK sector border, west of the Oseberg field in the North Sea. Martin Linge will be developed with an integrated fixed production platform with a steel jacket and a floating storage and offloading unit. The wells will be drilled by a jack-up drilling facility. Start-up is scheduled for late-2017.

Aasta Hansteen is located in the Norwegian Sea, west of Bodø in Nordland County. The field will be developed with a floating Spar platform, and two subsea templates. Gas from Aasta Hansteen and other discoveries in the area will be transported in the Polarled pipeline to Nyhamna in Møre og Romsdal. Production start-up is scheduled for late-2018.

Flyndre is an oil field in the Ekofisk area in the North Sea. The field is located on the border between the UK and Norwegian shelf, and will be developed by connecting a horizontal subsea well on the UK shelf to the Clyde facility. The majority of the resources are located in the UK sector. Production start-up is scheduled for 2017.

Shutdowns

Four fields, all of which are located in the North Sea, were shut down in 2016: Varg, Volve, Jette and Jotun. Parts of the Jotun field, Jotun A/FPSO will still be used in operation of the Ringhorne and Balder fields.

In 2016, the authorities received cessation plans for an additional three fields or facilities, also all located in the North Sea: Oselvar, Gyda and the old living quarters platform on Valhall.

In 2016, the Ministry of Petroleum and Energy made disposal decisions for the following facilities: Varg, Skirne, Atla, Ekofisk 2/4 C and Tor 2/4 E, Jette and Jotun.