20 March 2018

FAROE PETROLEUM PLC
("Faroe Petroleum", "Faroe", the "Company" or the "Group")

Final Results for the Year ended 31 December 2017

Faroe Petroleum, the independent oil and gas company focusing principally on exploration, appraisal and production opportunities in Norway and the UK, announces its audited results for the year ended 31 December 2017.

Highlights

Exploration and appraisal – significant Brasse resource upgrade and active exploration programme

- Successful Brasse (Faroe 50% and operator) appraisal well and flow test with 2P Reserves of 30.7 mmboe (net)
- 2P Reserves raised to 97.7 mmboe (2016: 81.3 mmboe) – incorporating Brasse upgrade and sale of 17.5% of Fenja post period end
- 2C Resources decreased to 78.6 mmboe (2016: 90.9 mmboe), reflecting transfer of Brasse from 2C to 2P
- Drilled the Goanna (Faroe 30%, fully carried) and Boné (Faroe 20%) wells during period, both announced as dry
- Eight new exploration licences awarded in Norway under 2017 APA Licensing Round, announced January 2018
- Drilling of Iris/Hades exploration well (Faroe 20%) and Fogelberg appraisal well (Faroe 25%[1]) ongoing

Development and production – excellent production performance and progress in high-quality development projects

- Average 2017 economic production of 14,349[2] boepd (2016: 17,395 boepd) – reflecting suspended production from Njord and Hyme in 2016 (pending completion of Njord Future Project) and natural decline in other fields
- Excellent progress across portfolio of high-quality development projects:
    - Tambar (Faroe 45%) – first of two infill wells on stream in March 2018; installation of gas lift continues
    - Oda (Faroe 15%) – PDO approved by the MPE and project progressing on plan and budget
    - Njord & Bauge (Faroe 7.5%) – PDO approved by the MPE and project progressing on plan and budget
    - Fenja (Faroe 25%, reduced to 7.5% in 2018) – PDO submitted in December 2017
- Further 14% of Blane oil field acquired from JX Nippon for consideration of $5.25 million (Faroe now 44.5%)

Finance – solid financial platform following $100 million bond issue and enhanced cashflow from production

- Unrestricted gross cash at 31 December 2017 £149.1 million (31 December 2016: £96.8 million). Net cash (net of 2017 $100 million bond) at 31 December 2017 was £75.0 million (31 December 2016: £96.8 million)
- Debut bond issue of a $100 million senior unsecured bond in November 2017 with a fixed coupon of 8%, complementing existing credit facilities and providing financial flexibility and optionality
- $250 million reserve based lending ("RBL") facility, undrawn at 31 December 2017 (31 December 2016: £nil), and NOK 1 billion exploration finance facility ("EFF") in place
- EBITDAX £82.2 million (2016: £25.8 million) – includes £7.8 million initial Oselvar net compensation receipt
- Exploration & appraisal capex £47.7 million (2016: £47.5 million), equates to £11.5 million (2016: £12.1 million) post-tax, and development and production capex £96.0 million (2016: £32.8 million)
- In February 2018, sold 17.5% stake in the Fenja development to Suncor for post-tax cash consideration of $54.5 million, retaining a 7.5% stake, and reducing Faroe's share of development capex by approx. $220 million

Outlook – material production growth through fully funded organic development and production investments

- Production guidance for 2018 is 12,000-15,000 boepd split approximately 67% liquids and 33% gas
- Opex in 2018 is expected to be in range $23-27 per boe
- Approximately 85% of gas production hedged to end-2018 averaging 42p/therm; and approximately 60% of oil production hedged to end-2018 averaging $57/bbl (all on a post-tax basis, principally with put options)
- Exploration and appraisal drilling programme in 2018 includes 4 to 6 wells, all in Norway
- Net capital expenditure for 2018 on exploration is estimated at approximately £80 million pre-tax (£20 million post-tax), and on development and production is estimated at approximately £175 million – all fully funded

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1 Following three separate transactions by Faroe on the Fogelberg licence PL433, all of which are expected to complete in H1 2018, Faroe's equity will be 15%, with an effective date of 1 January 2018.

2 Economic production including production from 14% of the Blane asset acquired from JX Nippon with an effective date of 1 January 2017 – the transaction completed in October 2017. Accounting production, excluding acquired production, was 14,139 boepd (2016: 8,026 boepd).

Graham Stewart, Chief Executive of Faroe Petroleum, commented:

"I am pleased to announce our full year results for 2017 which was another significant period for the Company and one in which Faroe continued its evolution into a full cycle E&P business. We had further appraisal drilling success on our largest ever oil discovery, Brasse, in Norway which contributed to record growth in 2P reserves to 98 mmboe (after our sale of part of Fenja in 2018), with further 2C contingent resources of 79 mmboe. We trebled our development capital investment year on year to approximately £100 million, and are on track to deliver our organic production growth target of over 35,000 boepd in the medium term from existing projects, representing growth of around 2.5 times 2017 production.

"Financially, the year was also strong for Faroe, generating EBITDAX of £82.2 million from ongoing operations and completing our debut bond issue in November 2017 to raise $100 million on good terms. In February 2018, as part of our ongoing management of the portfolio and capital allocation, we announced a partial sale of our interest in the Fenja oilfield development in Norway, bolstering our strong financial position and freeing up capital for allocation to the pending Brasse field development.

"Faroe now has the distinct advantage of being in a fully-funded position and with clear line of sight to deliver material value growth, whilst continuing to pursue our significant exploration, appraisal and infill programme. Opportunities to accelerate further growth through potential value-accretive acquisitions and disposals also continue to be a major focus for the Company going forward."

Webcast and analyst presentation

At 11:30am GMT (London) and 12:30pm CET (Oslo) on Tuesday 20 March 2018, the Executive Management team will host a meeting for analysts at the offices of FTI Consulting and there will be a simultaneous webcast to present the Company's results.

Telephone dial-in number: 020 3059 5868 (UK) or +44 20 3059 5868 (International) and say "Faroe Petroleum Full Year Financial Results" when prompted in order to participate.

The webcast can be accessed via the Company's website (http://www.fp.fo) or at the following address:
https://secure.emincote.com/client/faroepetroleum/faroe002

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CHAIRMAN'S AND CHIEF EXECUTIVE'S STATEMENT

Faroe's consistent strategy of creating value through the drillbit has delivered another year of strong progress and reserves growth. Year-on-year reserves grew by 20% and in the last five years reserves have grown by more than 400% – mainly as a result of maturing our discoveries into attractive development projects. This strategy continues in 2018. With an average finding cost in Norway of approximately $1.20/boe, Faroe has developed a compelling route to sustainable value creation for the Company. We look forward in 2018 to drilling up to six exploration and appraisal wells and progressing our material programme of several high-quality developments in order to deliver a significant ramp-up in production in the coming years.

Faroe's exploration is backed by a solid and diverse production base with healthy cashflow – in 2017 Group production of 14,349 boepd generated EBITDAX of £82.2 million. Following the debut issue of a $100 million senior unsecured bond in November 2017, the part-divestment to Suncor in February 2018 of 17.5% of Fenja for a cash consideration of $54.5 million, and with an undrawn $250 million RBL credit facility together with a NOK 1 billion EFF facility, Faroe is now fully funded for all programme investments including the pending Brasse development, at the Company's current 50% equity. Faroe is also in a strong position to invest in new value accretive developments and potential M&A activity.

Brasse project underpins Faroe's strategic focus on near-field exploration, appraisal and development

The Brasse licence in the Norwegian North Sea, operated by Faroe with a 50% equity stake, was awarded to Faroe in 2015 in the APA 2014 round. Already in the following summer of 2016 an exploration well and side-track were drilled, discovering material oil and gas volumes in a high quality reservoir. In the summer of 2017, appraisal drilling, including a drill stem test was undertaken, proving up an increase in recoverable hydrocarbons of approximately 20%. By the end of 2017, development project feasibility was confirmed and Faroe booked net 2P reserves of 30.7 mmboe. The concept selection phase has commenced with PDO submission expected in 2019. Gross plateau flow rates for the field have the potential to reach 30,000 boepd.

The Brasse field is now a core project with attractive economics, robust at low commodity prices. Brasse's close proximity to competing nearby infrastructure combined with its prolific reservoir qualities and location in shallow water will allow the field to be developed expediently and cost effectively. Significant further exploration and appraisal upside remains to be pursued in the licence and adjacent licence extensions recently awarded to Faroe.

The Brasse success underpins Faroe's strategic focus on near-field exploration and appraisal opportunities as we continue to pursue our consistent exploration-led business model. The Brasse project also establishes Faroe as a dynamic operator on the Norwegian Continental Shelf with less than three years passing from licence award to the booking of 2P reserves on the field.

Growth pushing ahead with two field PDOs approved in 2017 and a further PDO submitted for approval

In May 2017, the Oda partnership (Faroe 15%) received PDO approval from the MPE for development of the Oda oil field. Oda, located in the shallow waters of the Norwegian North Sea, and operated by Spirit Energy (formerly Centrica E&P and Bayerngas), is being developed as a four-slot seabed template with a subsea tie-back to the Ula platform (Faroe 20%) and will connect to the existing pipeline between Oselvar (Faroe 55% and operator) and Ula, using the Oselvar facilities at the Ula platform. Production from Oselvar is due to cease in Q2 2018 to allow the Oda tie-in to be undertaken, with the Oselvar partners being financially compensated accordingly. As part of that compensation, Faroe has already received in H1 2017 an initial net receipt from Oda partners of £7.8 million (net of Faroe's share, as an Oda partner, of compensation payments to the Oselvar partners) with further net compensation receipts to Faroe due in the coming months. First oil from Oda is scheduled for H1 2019.

MPE approval of the PDO for the Statoil-operated Njord Future Project and Bauge field (Faroe 7.5%) was granted in June 2017. The Njord Future Project together with the Bauge subsea tie-back are on budget and on timetable, with production scheduled to commence in 2020.

In December 2017 the PDO was submitted for the Fenja field in the Greater Njord Area (Faroe will hold 7.5% following completion of the recently announced partial sale to Suncor Energy Norge AS), comprising three horizontal production wells, one gas injector and two water injector wells. Fenja will be tied back to the Njord A floating production facility for processing and export via the Njord B FSO (floating storage and offloading vessel). The Fenja licence partners are planning to invest NOK 10.2 billion (approximately £900 million) with planned production start-up in Q1 2021 and a planned field life of 16 years.

Faroe continues to make significant investments in boosting production through infill drilling on the Tambar and Brage fields. On Tambar (Faroe 45%) the redevelopment project, encompassing infill drilling and a gas-lift installation, is making good progress with the first of two new Tambar wells on stream and the second expected very soon, and two new Brage (Faroe 14.3%) wells also brought on stream.

Successfully monetising discoveries through divestment

In February 2018 we announced the sale of a 17.5% working interest in the Fenja development, located in PL586 in the Norwegian Sea, to Suncor Energy Norge AS for a post-tax cash consideration of $54.5 million. Upon completion, Faroe will retain a 7.5% stake in the Fenja development, underlining our support for the project, and aligning Faroe's equity at 7.5% across the entire Greater Njord Area, encompassing Fenja, Njord, Bauge and Hyme, constituting one of the most significant oil and gas investment projects underway offshore Norway. The transaction is expected to reduce Faroe's future capital expenditure on Fenja from £230 million to approximately £70 million, based on the operator's gross projected development cost of NOK 10.2 billion. As detailed in the PDO, the operator, VNG Norge AS, expects total gross recoverable reserves on Fenja of approximately 97 mmboe (70% of which is oil). The transaction, which has a 1 January 2018 effective date, is expected to complete in H1 2018.

This transaction marks a major milestone for Faroe, which has so far taken Fenja through exploration and appraisal drilling to the pre-development phase and further validates Faroe's business model of generating strong shareholder returns through exploration. Having held a significant interest in PL586 from its discovery, Faroe has now realised cash returns through this partial-monetisation, while retaining exposure to future cash flows from Fenja. Importantly, the transaction also frees up capital for investment in Faroe's flagship Brasse field which is expected to commence development in 2019, such that Faroe is fully funded for Brasse at its current 50% equity level.

Production portfolio performing well

Faroe's production portfolio performed very well in 2017, delivering net average production of 14,349 boepd in 2017 with an average opex per boe of $26.5 for producing fields. Faroe's production is spread across a balanced and high quality portfolio of assets with an approximate geographic volume split currently of 80%/20% Norway/UK and an oil/gas split of 55%/45% respectively.

The production portfolio generated EBITDAX of £82.2 million, including the compensation payments recognised at Oselvar following Oda PDO consent in the period. Faroe has benefitted from higher oil prices in 2017, and so far in 2018, as well as stronger gas prices. We continue to hedge a significant portion of production and currently have hedged to end-2018 approximately 60% of oil production with put options with an average floor of $57 per barrel and 80% of gas production at an average price of 42p/therm, again mainly with put options (all on a post-tax basis).

Faroe's medium term objective, as it unlocks value in its portfolio, is to reduce unit opex and full cycle costs further, such that the Company grows increasingly profitable and robust. With a fully funded pipeline of ongoing investments in developments and producing fields, together with the maturing of existing discoveries, we are on target to reach our objective of more than doubling production to over 35,000 boepd in the medium term.

Outlook

Faroe now has an asset base with clear line of sight to deliver material growth in high value production to over 35,000 boepd on an organic and fully-funded basis. We also expect to add further new organic projects to this growth plan through maturing a number of discoveries and infill wells as well as potential new discoveries generated from our ongoing exploration programme.

At the core of our value creation model, we actively manage our exploration portfolio in order to maintain a significant ongoing drilling programme from prospects matured in the portfolio. Faroe's exploration track record has been exceptional, with finding costs in Norway around $1.20/boe. We are set to ramp up our E&A drilling in 2018 and 2019 with a total of six exploration and appraisal wells already scheduled, all capitalising on competitive rig rates and Norwegian State tax incentives, through which 78% of exploration and appraisal costs are recovered.

Faroe has an outstanding team of professionals, committed to the Company's ethos and strategy and we are very grateful for their commitment and excellent achievements. Complementing our team and successful exploration model, Faroe also has a strong track record of growth through M&A, and we aim to capitalise on these strengths together with our excellent strategic and financial position, as we pursue value-accretive M&A opportunities in on our core areas.

John Bentley Chairman	Graham Stewart Chief Executive

REVIEW OF ACTIVITIES

The Company has continued to make good progress across all areas of activity, delivering: production from the portfolio at the higher end of guidance; a substantial increase in the Company's 2P reserve base; the successful operated appraisal programme on the Brasse discovery, and approval of two key new field development PDOs; and further new licence awards in Norway.

Exploration and Appraisal

In the first half of 2017, Faroe participated in two E&A wells, the Eni-operated Boné exploration well in the Barents Sea (dry) and the Faroe-operated Brasse appraisal well (discovery). The Company also added four licences to the portfolio through awards in the 2016 Norwegian APA licensing round. The drilling programme continued with the Goanna exploration well (Faroe 30%) in August 2017. The well was dry but Faroe was fully carried on the well cost.

The OMV-operated Iris/Hades (formerly known as Aerosmith) exploration well in the Norwegian Sea (Faroe 20%) commenced in November 2017. The well is targeting two separate formations, one in Cretaceous and one in the Jurassic and the results are expected soon.

The Spirit Energy-operated Fogelberg appraisal well commenced drilling in February 2018 and operations are ongoing. The main objectives are to narrow the range in the resource estimate, currently estimated between 105 and 530 bcf (19-116 mmboe including the condensate), and to carry out a contingent production test to provide additional information for development planning. Following three separate transactions by Faroe on the Fogelberg licence PL433, all of which are expected to complete in H1 2018, Faroe's equity will reduce from 25% to 15%, with an effective date of 1 January 2018.

Faroe has committed a further four E&A wells: Rungne (Faroe 40%), Cassidy (Faroe 15%), Pabow (Faroe 20%) and Yoshi (Faroe 30%). Yoshi is expected to spud in 2019 and the other three are expected to spud in 2018.

Rungne is located in licence PL825 immediately north of the Oseberg field in the Northern North Sea and is operated by Faroe. The primary targets are in Jurassic with unrisked gross resources estimated to be c. 70 mmboe. The Transocean Arctic drilling rig has been contracted for this drilling operation and the well is expected to spud in H2 2018. The Cassidy exploration well will be drilled back-to-back with the production wells in Oda and is expected towards the end of 2018. The prospect sits to the north of Oda and will target the same Jurassic Ula formation level as in Oda with gross unrisked potential of c. 50 mmboe. The Statoil operated Pabow prospect is located on the western flank of the Stord Basin in licence PL870. The well is expected to be drilled in late 2018 or H1 2019. Yoshi is operated by Wintershall and located in licence PL 836 S west of the former Faroe Maria Field in the Norwegian Sea and is expected to be drilled in 2019.

Progress is also being made in the interpretation of Brasse and the evaluation of the potential for adding further resources to Brasse in northern and eastern directions. A possible exploration and appraisal well to target this area is currently being considered for drilling in late 2018.

All of these wells are located in Norway where Faroe receives a tax rebate of 78% on all exploration and appraisal expenditure.

Norwegian licence round awards

In January 2018, Faroe was awarded eight new prospective exploration licences including four operatorships under the 2017 Norwegian APA Licence Round on the Norwegian Continental Shelf. Three of the licences are targeting new plays for the Company, namely the Blue Libelle prospect on the Tampen Spur on the north-western margin of the North Viking Graben (Faroe operator), the Århus prospect in the Åsta Graben (Statoil operator), north of the Trym Field and the Skræmetindan prospect (Aker BP operator) on the Cod Terrace in the Central Graben.

Production

Faroe achieved net average economic production of 14,349 boepd (2016: 17,395 boepd), a reduction over the previous year reflecting the temporary loss of production from the Njord and Hyme fields whilst the Njord Future Project continues.

Faroe's production base is spread across a portfolio of oil and gas assets in Norway and the UK. Approximately 76% of total production came from Norwegian fields and approximately 54% of total production was oil. In Norway, the main producing fields are Trym, Tambar, Ula, Brage and Ringhorne East, and in the UK, the main fields are Schooner, Ketch and Blane.

The future of the Trym field beyond 2019 (Faroe 50% and operator) has been secured following the final investment decision to redevelop the Tyra platform in Denmark which serves as a gathering hub for the Trym gas (Faroe has no working interest in Tyra). Trym is now scheduled to produce for an extended period until mid-2019 before being suspended temporarily in order to allow the Tyra redevelopment works to be carried out over a period of around three years. Trym production was temporarily shut in during Q1 2018 as a result of a pipeline integrity issue at the Tyra gathering hub, but resumed production in March 2018.

On the Brage field (Faroe 14.3%), the Statfjord and the Fensfjord producer wells, drilled in 2017, have been brought on stream. The second Statfjord producer was completed in January 2018 and will be put on stream in the coming weeks. Based on drilling results, the well is expected to deliver production rates well above pre-drill expectations. A further horizontal well in the Sognefjord formation is being evaluated for drilling in H1 2018.

The redevelopment project on the Tambar field (Faroe 45%) continues with the installation of gas lift in three existing wells. The two infill wells, which targeted undrained areas in the north and south of the field, have now been drilled and completed with results from both wells exceeding pre-drill expectations. The first well was brought on stream earlier this month and a second is expected later in March 2018. Initial production rates from the two wells are estimated to be in the range of 10,000 - 15,000 boepd (Faroe 4,500-6,750 boepd). It is expected that the overall investment programme including gas lift will extend field life by up to 10 years, with the additional benefit of lowering unit operating costs in the Ula hub area. The encouraging results from the infill campaign will be used to refine the field model and to evaluate further development opportunities in the Tambar reservoir.

On the Ula field (Faroe 20%), the operator Aker BP continues to mature targets for a new infill campaign. Potential infill targets include wells to expand the use of WAG (water alternating gas) injection to increase recovery, the deeper Triassic reservoir which has only one well in production today, as well as near field discoveries such as Ula North. The 4D seismic survey successfully acquired in 2017 will provide important new information when processing is complete in Q2 2018. A number of significant upgrades to the field facilities are also under way which will support long term production.

In the UK, the operator RepsolSinopec is considering the selection of infill targets on the Blane Field (Faroe 44.5%), following the successful completion of the subsea upgrades in 2017. Production from Schooner and Ketch is expected to cease in Q3 2018 with the closure of the export system and onshore gas facility at the Theddlethorpe terminal, operated by ConocoPhillips.

Development projects

Brasse (Faroe 50%): at the end of 2017, the Brasse feasibility study phase was completed confirming several attractive development solutions and export routes. The preliminary reservoir drainage plan includes three to six subsea production wells and possible water injection for pressure support. Gross plateau flow rates for this field have the potential to reach 30,000 boepd. The next key project milestone will be the Concept Selection including the selection of a reservoir drainage plan and a processing host. Several key studies are progressing according to schedule including the subsurface development planning, subsea architecture and host selection alternatives. In addition, the tie-back and commercial processes are being pursued. The PDO submission is expected in 2019.

Oda (Faroe 15%): this field is being developed as a subsea tie back to the Ula platform (Faroe 20%), approximately 13 kilometres to the west. The project, which is both on schedule and within budget is now entering a busy offshore construction phase this spring with three wells being drilled in the field (two producers and one water injection well). First oil is scheduled for mid-2019, with gross plateau production expected to be 30,000 boepd (4,500 boepd net to Faroe). Production from the Oselvar field (Faroe operated 55%) is scheduled to cease in Q2 2018 to allow the Oda tie-in to be undertaken. Upon cessation of production the Oselvar owners (Faroe 55%) will receive a final compensation payment, dependent on the Oselvar field production level at the time it is shut in. An initial payment to Faroe of £7.4 million net was received in June 2017.

Njord and Bauge (Faroe 7.5%): the Njord Future project encompasses refurbishment of the Njord facilities to allow continued production and development of the Njord and Hyme fields and upgrading and modifications to enable the Bauge and Fenja fields to be tied back. The Njord Future Project is progressing on schedule and within budget. In 2018, key milestones include installation of blisters to enhance stability on all four columns, installation of column top extensions and deck boxes. Truss work reinforcement is also ongoing. Current timing is for the Njord A platform to be towed offshore during spring 2020. The Bauge development project is also progressing on schedule and within budget. Contracts for marine and drilling operations are currently being progressed. Njord and Hyme are expected to recommence production in Q4 2020 followed by first oil from Bauge shortly thereafter.

Fenja (Faroe 7.5% following completion in H1 2018): in December 2017, the PDO was submitted for the Fenja field in the Greater Njord Area comprising three horizontal production wells - one gas injector well and two water injector wells, to be tied back to the Njord A floating production facility for processing and export via the Njord B FSO. The Fenja licence partners are planning to invest NOK 10.2 billion (approximately £900 million) with planned production start-up in Q1 2021 and a planned field life of 16 years. In February 2018, the Company announced a sale of a 17.5% interest in Fenja to Suncor for cash consideration of $54.5 million, to reduce its interest to 7.5%, harmonise its equity interests with its other interests in the Njord area and to rebalance capital allocations across the portfolio. The sale is subject to final approval by the MPE.

Reserves & Resources

Reserves

The Company's internal estimate of Proven and Probable (2P) Reserves at 1 January 2018, prepared in accordance with the Petroleum Resource Management System guidelines endorsed by the Society of Petroleum Engineers, World Petroleum Congress, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers has been estimated at 114.1mmboe (1 January 2017 81.3 mmboe) – increasing reserves by 40% over the year (before adjusting for the disposal of a 17.5% interest in the Fenja field). The significant increase (reserves replacement of approximately seven times) is a result of both the conversion of Brasse from 2C contingent resources to 2P reserves and incremental projects across the portfolio, which generated positive reserve revisions notably on Tambar. Adjusting for the divestment of a 17.5% interest in the Fenja field, announced in February 2018 and with an effective date of 1 January 2018, 2P reserves at 1 January 2018 were 97.7 mmboe, which represents an increase of 20% year on year.

2P Reserves	Gas (bcf)			Liquids (mmbbls)			Total (mmboe)
	Norway	UK	Group	Norway	UK	Group	Group
1 January 2017	108.0	14.3	122.3	58.0	2.9	60.9	81.3
Revisions	7.5	(6.3)	1.2	8.0	(0.1)	7.9	8.2
Acquisitions	-	-	-	-	1.0	1.0	1.0
Transfer from 2C	32.1	-	32.1	23.5	-	23.5	28.8
Production	(9.2)	(4.6)	(13.8)	(2.4)	(0.4)	(2.8)	(5.2)
1 January 2018	**138.4**	**3.4**	**141.8**	**87.1**	**3.4**	**90.5**	**114.1**

Contingent Resources

At 1 January 2018, 2C Resources were estimated to be 86.0 mmboe (before adjusting for the disposal of a 17.5% interest in the Fenja field) representing a decrease of 5% over the year (1 January 2017: 90.9 mmboe). Additional contingent resources, mainly in Ula, Tambar and Oselvar, did not fully compensate for the transfer of Brasse to reserves. Adjusting for the divestment of a 17.5% interest in the Fenja field, 2C Contingent Resources at 1 January 2018 were 78.6 mmboe, which represents a decrease of 14% year on year.

2C Contingent Resources	Gas (bcf)			Liquids (mmbbls)			Total (mmboe)
	Norway	UK	Group	Norway	UK	Group	Group
1 January 2017	150.6	-	150.6	65.8	-	65.8	90.9
Revisions	46.9	-	46.9	12.8	1.7	14.5	22.4
Acquisitions	7.6	-	7.6	0.5	-	0.5	1.8
Disposals	-	-	-	(0.3)	-	(0.3)	(0.3)
Discoveries	-	-	-	-	-	-	-
Transfer to 2P	(32.1)	-	(32.1)	(23.5)	-	(23.5)	(28.8)
1 January 2018	**173.0**	**-**	**173.0**	**55.3**	**1.7**	**57.0**	**86.0**

FINANCE REVIEW

Overview

The year end gross cash position was £149.1 million, with net cash of £75.0 million (2016: gross / net £96.8 million). The increased cash position was due to the issue of a $100 million senior unsecured bond in the Nordic bond market in November 2017, as well as EBITDAX increasing to £82.2 million in the year (2016: £25.8 million). Faroe's active exploration and appraisal programme in Norway, which benefits from the 78% exploration tax refund, has continued with four wells drilled in 2017, of which the Faroe-operated Brasse appraisal well resulted in an increase in estimated recoverable resource volumes and the Boné well (Faroe 20%) and Goanna (Faroe's costs fully carried for its interest of 30%) being dry. The Iris/Hades exploration well spudded in December 2017 and drilling is still in progress. In February 2018, the Group announced a partial divestment of the Fenja discovery for a cash consideration of $54.5 million, reducing the Group's exposure on future capital expenditure on Fenja to approximately £70 million, upon completion of the deal.

Adjusted revenue, including realised hedging losses of £1.9 million (2016: gain £4.7 million), averaged $46 per boe (2016: $42 per boe) after taking account of £30.7 million of underlift (2016: £7.0 million overlift), included in revenue and cost of sales. Opex per boe on producing assets excluding accrued facility upgrade costs was $26.5/boe (2016: $24.8/boe). Total opex per boe was $30 in 2017 compared to $31 in 2016 reflecting one off tariff costs in relation to future upgrades, operating costs on non producing and development assets, including Njord and Hyme opex post production suspension. DD&A per boe increased by $0.8 to $11.3 boe (2016: $10.5 boe).

Income statement

IFRS accounting revenue in the year was £152.9 million (2016: £94.8 million) and is different to 'adjusted revenue' of £181.8 million (2016: £92.5 million) as the former excludes volumes of oil and gas produced but not physically lifted in the period ("Underlift") and realised hedging losses. In calculating IFRS revenue, the underlift movement of £30.7 million (2016: £7 million overlift) is credited to (i.e. reduces) cost of sales under IFRS. Faroe sells most of its oil under payment quantity contracts, and so at the year-end had received payment for the outstanding underlift. The payment sits within deferred income on the balance sheet until the crude is lifted and then is released to IFRS revenue. The increase in revenue reflects higher accounting production, 14,139 boepd (2016: 8,026 boepd), mainly due to the acquisition of interests in producing fields from DONG in December 2016, and a higher realised price per boe. Overall, the Company realised a £1.9 million loss (2016: £4.7 million gain) on its hedging and forwards sales activities in 2017.

Cost of sales, including depreciation of producing assets, but before impairment charges, was £132.5 million (2016: £96.7 million). Cost of sales excluding net underlift movement (see paragraph above) was £163.2 million (2016: £89.7 million) reflecting an increase in accounting production from 8,026 boepd to 14,139 boepd and one-off estimated future upgrade tariff costs of £9.5 million falling due to Ula as a result of the planned shut-down of Oselvar, and is partially offset by the estimated £2.0 million tariff receipt which is included in Revenue as a result of the Group's interest in Ula. Pre-tax impairment charges of £13.0 million (post-tax £6.6 million) (2016: £2.9 million and £0.9 million pre- and post-tax respectively) mainly related to Schooner and Ketch and were driven by an increase in abandonment cost estimates. The other impairment charge related to Brage. The Group made a gross profit for the year of £7.4 million (2016: loss £4.8 million).

Other income was £17.4 million (2016: expense £8.4 million), of which £18.2 million related to compensation income between Oselvar (Faroe 55%) and Oda (Faroe 15%) and was offset by a realised hedging loss of £1.9 million. £9.1 million of the compensation income was received in June 2017 following PDO approval of the Oda development. A further £9.1 million has been accrued and recognised as income and will be received in 2018 when Oselvar is taken offline. The compensation income is partially offset due to the Group's ownership of Oda, with capex costs of £1.3 million being paid in June 2017 and a further £1.2 million being accrued at the year end reflecting further compensation due to Oselvar for the planned shut down. EBITDAX in 2017 increased to £82.2 million compared to £25.8 million in 2016.

The Group made a post-tax gain of £0.7 million (pre-tax £7.2 million) on the disposal of Jotun, an asset due for abandonment. The Group paid £1.1 million on completion to Exxon of the disposal of Jotun, leading to a reduction in the pre-tax decommissioning provision of £8.2 million (post-tax £1.8 million).

Pre-tax exploration and evaluation expenses for the year were £25.9 million (post-tax: £6.9 million) (2016: £33.5 million and £14.5 million pre- and post-tax respectively). This includes pre-award exploration expenses of £4.3 million and write-offs of licence-specific exploration and evaluation expenditure of £21.5 million on previously capitalised licences where active exploration has now ceased. The majority of the exploration costs which were written off during the year related to PL716 (Boné), along with other exploration costs on a number of licences.

Expensed administration costs in 2017 were reduced to £7.7 million (2016: £10.2 million) mainly due to an additional charge in 2016 of £2.0 million following a true-up of 2015 time-writing rates, and due to increased activity on operated assets (in particular Brasse) leading to a higher G&A recharge to assets.

The Group's reported loss before tax was £13.7 million (2016: £61.6 million). Loss after tax was £11.4 million (2016: £32.9 million).

Hedging
In line with Group policy approximately 60% of post-tax production was hedged in 2017, with realised hedging losses, net of cost, of £1.9 million (2016: gain £4.7 million). The cost incurred for the 2017 hedges was £2.3 million (2016: £1.0 million). The hedging was predominantly with put options, with 93% of gas and 31% of oil production (post-tax) hedged in 2017.

At December 2017, the Group had entered into hedging contracts covering approximately 85% of 2018 total expected gas production (on a post-tax production basis) and 41% of expected oil production (on a post-tax production basis). The gas hedging contracts are put options and swaps with floors between 35 and 48 pence per therm. The oil hedging contracts are put options with an average strike price of $55 per barrel. Unrealised hedging losses for the open hedge contracts for 2017 were £0.8 million (2016: £1.4 million) based on mark-to-market calculations and are recognised as derivative financial liabilities (2016: liabilities). The unrealised hedging losses (2016: losses) are shown as Other income/(expense) in the Income Statement, net of hedging costs of £2.3 million (2016: £2.6 million).

Further gas and oil hedges have been undertaken in 2018 following which approximately 60% of post-tax oil production is hedged in 2018, 6% of post-tax oil production is hedged in 2019. The Company continues to monitor the commodity market and aims to extend the current hedging programme, at opportune moments taking a layered approach to its hedging strategy.

Faroe is subject to taxation under two regimes in Norway, namely: offshore where a special tax of 53% is applied, and onshore where the standard corporation tax rate is 25%. Hedging gains fall only within the onshore regime and hence the concept of hedging "post-tax production" which implies that in order to be fully hedged in Norway on a post-tax basis, approximately 29% of pre-tax barrels need to be hedged.

Taxation
In Norway, the Company benefits from a 78% exploration cost refund, meaning that for every £1 spent the Government will return 78p of eligible expenditure in the form of a rebate in the following year, to the extent it is not offset against current year profits from producing assets. Through the EFF, Faroe can borrow 96% of the 78p per £1 rebate, thereby maximising equity leverage in Norwegian exploration and minimising the need to farm down. The Norwegian tax system therefore ensures a cost-effective fiscal environment in which to explore, and also cushions the cash impact of falling oil prices, as lower profits from production result in an increased tax rebate.

The amount of tax receivable at 31 December 2017 was £35.6 million (2016: £41.8 million) which is the tax refund on exploration expenditure in Norway net of taxable profits generated by the Norwegian producing assets. The refund will be received in November 2018. The tax credit in the Income Statement was £2.3 million (2016: £28.7 million) and consisted mainly of the Norway tax receivable, and origination of timing differences of £32.3 million.

Development capex in Norway is depreciated on a straight-line basis over six years for tax purposes. In addition, an uplift of 21.6% can be offset against the 53% special tax. The uplift is taken on a straight-line basis over four years. This means that close to 90% of capex spend is recovered through the tax system. At December 2017, Faroe had carried forward tax capex balances of £107.6 million and carried forward capex uplift of £44.5 million in Norway. In addition, at December 2017, Faroe had carried forward tax losses in Norway of £21.0 million and £14.4 million for corporation tax and special tax respectively. At December 2017 the Group had unrelieved tax losses in the UK of £53.8 million which are available indefinitely for offset against future taxable profits.

In December 2017 the Company had a deferred tax asset of £114.5 million (2016: £122.1 million) in respect of carried forward tax losses, capex balances and uplifts in the UK and Norway, net of other temporary differences.

Balance sheet
Expenditure of £144.2 million (2016: £79.4 million) on intangible and tangible assets, prior to tax rebate, was made in the year, of which £47.7 million (post tax £10.5 million) related to exploration expenditure, primarily on Brasse and Boné. £93.2 million related to development expenditure, principally reflecting pre-sanction costs on the Oda field and the Njord capital enhancement project and drilling costs on the Tambar and Brage fields. The Group also

completed the acquisition of an additional 13.9935% of Blane from JX Nippon paying $3.9 million (£2.8 million) on completion. The acquisition increases the Group's equity in the field to 44.5%.

During the period, the book value of Fenja (previously Pil & Bue) and Bauge was reclassified from intangible exploration assets to property plant and equipment, totalling £58.7 million (£12.9 million pre tax) following PDO submission and a clearly defined path and timeline to project sanction. £47.7 million of the £58.7 million related to the 17.5% interest in Fenja, which was divested in 2018, was subsequently classified as held for sale at the year end.

The Group recognises the discounted cost of decommissioning when obligations arise. The amount recognised is the present value of the estimated future expenditure determined by local conditions and requirements, net of any amounts carried by third parties. At 31 December 2017 the Group had decommissioning provisions of £262.4 million (2016: £267.1 million). The reduction in the provision is mainly due to movement in cost estimates and abandonment activity in the year, partly offset by the acquisition of additional interest in Blane. Most of the decommissioning expenditure is scheduled to be incurred from 2020 to 2035.

Cash flow

Closing cash was £149.1 million (2016: £96.8 million). Net cash at the year end was £75.0 million (2016: £96.8 million). In addition, restricted cash of £7.4 million relating to prepaid abandonment costs are included in Trade and Other Receivables. Faroe benefits significantly from an exploration financing credit facility of NOK 1,000 million for provision of 75% (as described above) of its eligible net exploration costs in Norway on a cash flow basis, such that only 25% of this expenditure is funded from Company equity. The EFF borrowings of NOK 365 million (£32.9 million) (2016: NOK380 million, £35.8 million) are repaid when the tax rebate is received in November of the year following the related expenditure. In November 2017 the Company received the tax rebate for 2016 of £41.2 million, most of which was used to repay the 2016 utilisations of the EFF.

The Group also has a secured US$250 million (approximately £203.0 million) reserve based lending facility which is available for both debt and issuance of letters of credit. At 31 December 2017 the calculated borrowing base amount was £174.6 million, of which £nil was drawn (2016: £nil million).

With a combination of the current cash in the business, cash flow from producing assets and headroom in the Group's bank facilities, the Group will be able to fund currently committed capital expenditure (exploration and development/ production). The pre-tax capital expenditure for 2018 is forecast to be approximately £255 million.

Dividend

The Directors do not recommend payment of a dividend.

Group Income Statement *for the year ended 31 December 2017*	**2017** £'000	**2016** £'000
Revenue	152,924	94,779
Cost of sales	(132,508)	(96,666)
Asset impairment	(12,992)	(2,923)
Gross profit/(loss)	7,424	(4,810)
Other income / (expense)	17,353	(8,412)
Gain on disposal of asset	7,229	-
Exploration and evaluation expenses	(25,851)	(33,468)
Administrative expenses	(7,678)	(10,189)
Operating loss	(1,523)	(56,879)
Finance revenue	4,790	6,423
Finance costs	(17,006)	(11,139)
Loss on ordinary activities before tax	(13,739)	(61,595)
Tax credit	2,313	28,686
Loss for the year from continuing operations	(11,426)	(32,909)
(Loss)/earnings per share – basic (pence)	(3.1)	(10.5)
(Loss)/earnings per share – diluted (pence)	(3.1)	(10.5)

Statement of Other Comprehensive Income *for the year ended 31 December 2017*	**2017** £'000	**2016** £'000
Loss for the financial year	(11,426)	(32,909)
Exchange differences on retranslation foreign operations net of tax	(13,274)	21,855
Total comprehensive loss for the year	(24,700)	(11,054)

Group Balance Sheet *at 31 December 2017*	**2017** £'000	**2016** £'000
Non-current assets		
Goodwill	9,386	7,744
Intangible assets	68,857	107,376
Property, plant and equipment: development & production	201,216	157,328
Property, plant and equipment: other	695	611
Deferred tax asset	114,499	122,055
	394,653	395,114
Current assets		
Inventories	10,644	10,456
Trade and other receivables	102,088	63,063
Current tax receivable	35,610	41,764
Cash and cash equivalents	149,084	96,769
	297,426	212,052
Assets held for sale	50,987	-
Total assets	743,066	607,166
Current liabilities		
Trade and other payables	(113,989)	(53,900)
Current taxation payable	(65)	(31)
Provisions	(10,002)	-
Financial liabilities – Norway exploration financing facility	(32,948)	(35,845)
Financial liabilities – other	(767)	(1,383)
	(157,771)	(91,159)
Non-current liabilities		
Interest bearing loans and borrowings	(72,742)	-
Provisions	(254,697)	(269,469)
	(327,439)	(269,469)
Liabilities directly associated with assets held for resale	(31,854)	-
Total liabilities	(517,064)	(360,628)
Net assets	226,002	246,538
Equity attributable to equity holders		
Equity share capital	36,664	36,453
Share premium account	315,580	315,580
Cumulative translation reserve	6,381	17,740
Retained earnings	(130,708)	(123,235)
Reserves of a disposal group held for sale	(1,915)	-
Total equity	226,002	246,538

Condensed Group Cash Flow Statement *for the year ended 31 December 2017*	**2017** £'000	**2016** £'000
Loss before tax	(13,739)	(61,595)
Depreciation, depletion and amortisation	45,179	23,369
Exploration asset write off	21,524	29,908
Unrealised hedging gains	(369)	13,095
Asset impairment	12,992	2,923
Fair value of share based payments	4,948	4,408
Gain on disposal of asset	(7,229)	-
Disposal of decommissioning provision	(1,092)	-
Cash cost of share based payments	(670)	-
Purchase of SIP shares	(216)	-
Movement in trade and other receivables	(42,263)	(24,478)
Movement in inventories	(188)	(4,534)
Movement in trade and other payables	61,728	22,865
Currency translation adjustments	(4,060)	(5,814)
Investment revenue	(730)	(609)
Interest and financing fees paid	17,006	11,139
Tax refund	41,031	44,729
Net cash generated in operating activities	133,852	55,406
Investing activities		
Purchases of intangible and tangible assets	(144,239)	(79,447)
Investment revenue	730	609
Net cash used in investing activities	(143,509)	(78,838)
Financing activities		
Movement in interest bearing loans and borrowings	75,915	-
Issue cost of loans	(1,920)	-
Proceeds from issue of equity instruments	-	66,901
Issue costs of shares	-	(4,145)
Net (repayments)/proceeds from borrowings	(1,404)	(19,931)
Interest and financing fees paid	(4,022)	(4,225)
Net cash inflow from financing activities	68,569	38,600
Net increase in cash and cash equivalents	58,912	15,168
Cash and cash equivalents at the beginning of year	96,769	91,515
Effect of foreign exchange rate changes	(6,597)	(9,914)
Cash and cash equivalents at end of year	149,084	96,769

Group Statement of Changes in Equity *at 31 December 2017*	**2017** £'000	**2016** £'000
Loss for the period	(11,426)	(32,909)
Other comprehensive (loss)/gain	(13,274)	21,855
Total comprehensive loss for year	(24,700)	(11,054)
Issue of ordinary shares	-	66,901
Share based payments	4,380	2,480
Share issue costs	-	(4,145)
SIP shares	(216)	-
Net movement in shareholders' funds	(20,536)	54,282
Opening shareholders' funds	246,538	192,356
Closing shareholders' funds	226,002	246,538

Notes

1. The financial information contained in this announcement for the years ended 31 December 2017 and 2016 does not constitute statutory financial statements within the meaning of Section 435 of the Companies Act 2006. An unqualified audit opinion was expressed on the statutory accounts for the years ended 31 December 2017 and 2016. This unqualified opinion did not contain a statement under either s498(2) or s498(3) of the Companies Act 2006. The statutory accounts for the year ended 31 December 2016 have been submitted to the Registrar, whereas, the statutory accounts for the year ended 31 December 2017 are yet to be submitted to the Registrar.

2. No dividend is proposed.

3. Cost of sales analysis

	2017 £000	**2016** £000
Operating costs*	72,077	40,671
Commercial tariffs*	44,386	24,524
Depreciation, depletion and amortisation	44,806	22,994
(Under)/overlift in the year	(30,729)	6,985
Other cost of sales*	1,968	1,492
Total cost of sales	132,508	96,666

* included in the opex per boe metric

4. Other income / (expense) analysis

	2017 £000	**2016** £000
Realised hedging (losses)/gains*	(1,859)	4,683
Unrealised hedging gains/(losses)	369	(13,095)
Compensation received/accrued	18,843	-
Total other income / (expense)	17,353	(8,412)

* included in the revenue per boe metric and EBITDAX

5. Earnings before interest, tax, depreciation, amortisation and exploration expenses

	2017 £000	**2016** £000
Revenue	152,924	94,779
Realised hedging gains	(1,859)	4,683
Other income	18,843	-
Operating costs	(72,077)	(40,671)
Commercial tariffs	(44,386)	(24,524)
Under/(overlift) in the year	30,729	(6,985)
Other cost of sales	(1,968)	(1,492)
EBITDAX	82,206	25,790

6. Taxation

	2017	2016
	£000	£000
Current taxation		
Overseas tax credit	35,610	41,764
UK tax	(71)	(214)
Current tax credit	35,539	41,550
Amounts under provided in previous year	138	195
Total current tax credit	35,677	41,745
Deferred taxation		
Origination of temporary differences	(34,660)	(11,316)
Change of tax rate	525	-
Not provided in earlier years	1,843	75
Total deferred tax charge	(32,292)	(11,241)
Foreign exchange differences		
Differences arising from the use of year end and average exchange rates	(1,072)	(1,818)
Total foreign exchange differences	(1,072)	(1,818)
Total tax credit in the Income Statement	2,313	28,686

7. Farm down of 17.5% of Fenja:

On 12 February 2018, the Group publicly announced the farm down of the Fenja development asset from a working interest of 25% to 7.5% to Suncor Energy Norge AS for a cash consideration of $54.5 million due upon completion. The transaction is expected to complete during the first half of 2018. Prior to the year end, the Board had approved plans to farm down the Fenja asset and the transaction is expected to complete within one year of the reporting date.

The major classes of assets and liabilities for the 17.5% interest in Fenja classified as held for sale as at 31 December 2017 are as follows:

	2017
	£000
Assets	
Property, plant and equipment: development	47,749
Current assets	3,238
Assets held for sale	50,987
Liabilities	
Current liabilities	(2,255)
Deferred tax liability	(29,599)
Liabilities directly associated with assets held for sale	31,854
Net assets directly associated with assets held for sale	**19,133**
Amounts included in reserves	
Cumulative translation reserve	(1,915)

8. Post balance sheet events:

Farm down of Fenja to Suncor Energy Norge AS

In January 2018, the Company executed a farm-down agreement with Suncor for Licence PL586 in Norway. Under the terms of the farm-down agreement, upon completion 17.5% of the Company's working interest in the Fenja development located in the Norwegian sea will be sold for a cash consideration of $54.5 million (excluding tax balances). The company will retain a 7.5% working interest.

Norwegian exploration licence awards

On 17 January 2018, the Company announced that it has been awarded eight new prospective exploration licences, under the 2017 Norwegian APA licence round on the Norwegian Continental Shelf. Due to the nature of the oil and gas industry it is not possible to quantify the financial effect of these licence awards.

Fogelberg appraisal well in Norway Sea

On 5 February 2018, the Company announced that drilling on the Fogelberg appraisal well and contingent side-track 6506/9-4A & 4S in the Norwegian Sea had commenced drilling.

Fogelberg equity

Following three separate transactions, all of which are expected to complete in H1 2018, Faroe's equity will be 15% with an effective date of 1 January 2018. The Company's equity at 31 December 2017 was 25%.

9. Accounts will be posted to all shareholders. Further copies will be available from the Company's head office at 24 Carden Place, Aberdeen AB10 1UQ, from the date of posting, telephone +44 (0)1224 650 920, and will be available on the Company's website www.fp.fo

Estimates of reserves and resources contained in this announcement were prepared in accordance with the Petroleum Resource Management System guidelines endorsed by the Society of Petroleum Engineers, World Petroleum Congress, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers.

George Y C Man, Corporate Reserves Manager of Faroe Petroleum and a Reservoir Engineer (BSc Honours in Mining and Petroleum Engineering and MSc in Information Technology Systems from University of Strathclyde, PGDip in Business Administration from University of Surrey), who has been involved in the oil and gas industry for more than 25 years, has read and approved the production, development, reserves and resources technical disclosure in this regulatory announcement.

Andrew Roberts, Group Exploration Manager of Faroe Petroleum and a Geophysicist (BSc. Joint Honours in Physics and Chemistry from Manchester University), who has been involved in the energy industry for more than 30 years, has read and approved the exploration and appraisal disclosure in this regulatory announcement.

The information contained within this announcement is considered to be inside information prior to its release, as defined in Article 7 of the Market Abuse Regulation No. 596/2014, and is disclosed in accordance with the Company's obligations under Article 17 of those Regulations.

Glossary

“APA”	awards in pre-defined areas
“Bcf”	billions of standard cubic feet
“boe”	barrels of oil equivalent
”boepd”	barrels of oil equivalent per day
“Contingent Resources or 2C”	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
“DD&A”	Depreciation, depletion and amortisation
“EBITDA”	earnings before interest, taxation, depreciation and amortisation
“EBITDAX”	earnings before interest, taxation, depreciation, amortisation and exploration expenditure (gross profit plus realised hedging gains, depreciation and impairment on producing assets). Management review EBITDAX on each of the producing fields as a measure of performance.
“Economic Production”	production to which the Company has an economic entitlement. It includes production between the effective (economic) date and the completion date of an acquisition. Accounting production excludes all pre-completion production.
“EFF”	Exploration financing facility
“FEED”	Front end engineering design
“FSO”	Floating storage and offloading vessel
“G&A”	General and administration expenditure
“IFRS”	International Financial Reporting Standards
“mmbbls”	million barrels
“mmboe"	million barrels of oil equivalent
“MPE”	Norwegian Ministry of Petroleum and Energy
“net cash”	cash and cash equivalents less financial liabilities excluding the balance of the Exploration Financing Facility which is directly linked to the Norway tax rebate (disclosed as tax receivable in the balance sheet)
“PDO”	Plan for development and production
“post-tax production”	29.3% of Norway production and 100% of other production, being a notional volume of production, taking into account the fact that in Norway, hedging gains are taxed at corporation tax only of 25%, whilst operating profits are taxed at corporation tax and special corporation tax of 53% (a combined rate of 78%) which in effect means that in order to achieve 100% hedge protection in Norway, 29.3% of Norway volumes are required to be hedged
“Proved Reserves” or “1P”	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
“Proved + Probable Reserves” or “2P”	when added to 1P, those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than 1P but more certain to be recovered than 3P. 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
“Proved + Probable + Possible Reserves” or “3P”	when added to 2P, those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than 2P. The total quantities ultimately recovered have a low probability of exceeding the sum of Proved plus Probable plus Possible (3P) Reserves, which is equivalent to the high estimate scenario. In this context, 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
"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 the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status