

Barents Sea Gas Infrastructure





Document information

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The Barents Sea Gas Infrastructure (BSGI) Forum was established by Gassco in the second half of 2013 to investigate the potential for new cost-effective gas infrastructure for the resources in the Barents Sea.

26 oil and gas companies on the Norwegian Continental Shelf (NCS) have participated in the BSGI Forum. The Norwegian Petroleum Directorate (NPD), the industry association Norsk olje og gass and the Norwegian power transmission system operator Statnett, have participated as observers. The research institute SINTEF has been engaged by Gassco to develop the modelling tool used in the analysis.

This report builds on the valuable contributions from more than 100 experts from the participating companies. These have provided in-depth knowledge of the industry as such and the specific challenges related to the development of natural gas in the Northern Norway.

This report reflects Gassco's interpretation of information provided, and analyses thereof. Representations, interpretations, analysis and opinions herein do not necessarily reflect those of the participating companies.

Gassco would like to thank all the participants in this study. Their engagement, knowledge and contribution have been highly appreciated, and have made this study possible.





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1 Executive summary

Global and European gas markets are currently characterised by complexity and uncertainty. The future energy mix is unclear, the price differentials across regional gas markets are significant, and political turbulence is influencing existing trading patterns.

On the NCS, the situation is also evolving. The centre of gravity of undiscovered resources is moving north, covering a huge geographic area and with an increasing numbers of participants.

Against this backdrop, the development of the petroleum resources in the Barents Sea takes place. The Barents Sea is the next horizon in the development of the natural gas and oil resources on the NCS. While a significant amount of natural gas has already been discovered and is waiting for additional gas transport capacity, the next step in the development of gas infrastructure capacity is not obvious. Oil developments are also likely to require gas infrastructure for associated gas. Such oil developments could face a delay due to the lack of gas infrastructure with the consequence that important field developments would be put on hold or alternatively that value creation could be lost due to undesired re-injection of gas.

The BSGI Forum was established to investigate the potential for new cost effective gas infrastructure for the resources in the Barents Sea, in particular whether production from current fields and discoveries are sufficient to justify new infrastructure investments near-term. The analyses are based on a unique set of data with the latest resource estimates from the companies. Volume scenarios have been developed to span the potential outcome of near-term exploration activities in the Barents Sea.

The main observations in this study are as follows:

- 1. The Barents Sea has the resource potential to play a key role in sustaining NCS gas production during the 2020s and beyond.
- 2. Existing discoveries are not sufficient to justify investment in new gas infrastructure from the Barents Sea, both from a post- and pre-tax perspective.
- 3. New gas infrastructure is socioeconomically¹ more profitable in four out of five near-term exploration scenarios, and marginally lower than Liquefied Natural Gas (LNG) lifetime extension in one of the scenarios. Both pipeline and LNG are relevant export solutions.
- 4. It will be challenging to realise new gas infrastructure from the Barents Sea from a post-tax project-robustness perspective.
- 5. The rate of return from field investments could be improved if separated from investments in the gas transportation system with regulated return.
- 6. Collaboration across licenses will be needed as no individual license seems able to carry significant new gas infrastructure investment on its own.
- 7. Late start-up of a new gas infrastructure to align with development of the Barents Sea Southeast will reduce the pre-tax Net Present Value (NPV) at 7 percent discount rate and only marginally improve the post-tax rate of return. The project robustness could improve due to an increased reserve base.

¹ Socioeconomic value is defined as NPV of the gas resources applying a reel discount rate of 7 percent pre-tax. Ripple effects etc. are not included.



- 8. A late development of the Barents Sea may lead to consolidation of existing gas infrastructure and cost for rebuilding capacity.
- 9. There is a potential upside by realising parts of the resources currently evaluated to be uneconomic.
- 10. To have decision-making flexibility wrt. an early start-up in 2022, a feasibility study needs to be initiated in 2015.

To maintain an early start-up option for a new gas transport solution from the Barents Sea, such infrastructure would have to be progressed in parallel with improving the understanding of the resource base.

Identification of possible measures to bridge the gap between socioeconomic and project economic perspectives should be a focus area in near-term. Two specific issues are recommended to be addressed to create a basis to start a feasibility study by mid-2015.

- 1. Update the resource basis following the results from Barents Sea exploration activity and revisit the basis for starting a feasibility study.
- 2. Assess organisation of infrastructure developments in the Barents Sea.

Clarifying these issues will enable the industry and the authorities to make informed decisions to maximise the value of the Barents Sea resources and to secure alignment with decisions that are taken in the existing system.



2 Context and purpose

The white paper - Meld. St. 28 (2010 - 2011): An industry for the future – Norway's petroleum activities – outlines ambitious targets for future NCS production. The white paper states; "Through a broad commitment to exploiting the entire resource base, including measures to improve recovery rates on fields and facilitating new discoveries through effective exploration and licensing policies, we can achieve a high level of employment for decades to come. New regions of the country, such as Northern Norway, can experience renewed growth stimulus as a result of such a broad commitment." Further it is expressed; "Norwegian gas will help meet the European gas demand, and will be an attractive and valued energy source for many decades to come. This means there will be a basis for profitable exploration, development and production of the gas resources on the Norwegian Continental Shelf."

Several dimensions characterise the gas markets.

- **European security of supply**: With declining indigenous production, Europe will need to increase its natural gas imports in the coming decades. Norway and potential new suppliers of LNG, e.g. North America, will be robust options for long-term stable natural gas supplies.
- The role of gas in the energy mix: Low carbon emission prices and low coal prices currently create a challenging competitive situation for natural gas in the European power market. In the mid to longer term and with a higher price on carbon, natural gas is expected to have a central position in the energy mix due to its abundance, cost competitiveness as no subsidies are required, generation flexibility and a low carbon footprint.
- **Unprecedented variations in regional gas prices**: Unprecedented variations in regional gas prices, driven by the shale gas revolution in the US combined with demand increase in Asia and South America. These prices do not represent a stable equilibrium, but it takes time to establish new capacity, both for exports and imports, and price differentials between regions will remain as long as there are imbalances.

On the NCS, the situation is evolving.

- **Participants on the NCS**: The NCS has attracted a large number of new oil and gas companies looking for exploration and production opportunities and financial investors looking for investment opportunities in regulated infrastructure. One result of this diversity is the need for explicit collaboration between more companies than before to identify cost efficient and sustainable development solutions.
- **Resources on the NCS**: Gas production from existing fields and discoveries on the NCS is expected to grow until the end of this decade. 80 percent of undiscovered natural gas resources are expected to be in the Norwegian Sea and the Barents Sea. Both the distances to the market and the development costs create commercial challenges.





Against this backdrop, the development of the petroleum resources in the Barents Sea takes place. The Barents Sea is the next step in the development of the natural gas resources on the NCS. While significant natural gas volumes have already been discovered and are waiting for gas transport capacity, the development of new gas infrastructure is not straightforward with respect to timing, pipeline versus LNG, capacity needs, investors, regulatory framework etc.

In 2013, Gassco therefore took the initiative to set up the BSGI Forum to investigate the potential of developing new gas infrastructure providing a long-term, cost effective transport solution for the resources in the region.

The main objectives of the BSGI Forum are to evaluate the value-chain economics of the gas resources in the Barents Sea and specifically to identify competitive export solutions supporting development of the resources in this strategically important region.

The intention is to give the participants and authorities a realistic view of the prospects for the region based on the most updated resource assessment and to describe gas processing and transport solutions that will create the best value both for the Norwegian society and the investors.



3 Work process and methodology

Evaluating new gas transport solutions from the Barents Sea requires an assessment of all parts of the value chain, from the subsurface to the market. The BSGI analyses are assessing the full value chain economics of developing the gas resources in the Barents Sea, by incorporating cost estimates from field development, offshore and onshore processing facilities, and transport trough pipelines or by vessels to the relevant market.

The work in BSGI has been organised in six work groups with defined scope of work and led by industry representatives with relevant expertise within the area (ref. Figure 1).



In the following sections, the approach and key assumptions for each of these work groups are described.

3.1 Resources

A work group developed a set of scenarios for future gas production from the Barents Sea.

The main focus in the report have been to evaluate whether expected discoveries in the 2014 to 2017 exploration portfolio are sufficient to justify investments in new gas infrastructure. A conservative approach with focus on dry gas only is selected as base case for the study. The impact of Natural Gas Liquids (NGL) is included as sensitivities (ref. Section 5.2.1.3).

Three building blocks have been used to assess gas resources and future gas production from the Barents Sea:



- **Building block 1: Existing fields and discoveries.** Existing fields and discoveries have for this study been defined as fields reported within NPD's resource classification 1 to 7.
- **Building block 2: Scenarios for 2014 to 2017 prospects.** Various volume scenarios have been established based on gas production potential from awarded licences with a drilling schedule in the period 2014 to 2017. Licence operators have shared information with Gassco to enable an assessment of the opportunity for future gas developments in the Barents Sea. Gassco have consulted NPD to ensure consistency in the data reported from the individual licensees.
- **Building block 3: Long-term scenarios for undiscovered resources.** Building block 3 was provided to evaluate the long-term perspective for a potential new transport solution based on NPD's expectations for the area. In addition to the near-term outlook given by the license owners, building block 3 also contains undiscovered resources beyond 2017, including not awarded areas, divided in to Barents Sea South and Barents Sea Southeast.

These three building blocks are used as basis for identification of solutions for gas infrastructure investments at different points in time and with different information sets. The first building block is basis for an assessment of whether production from current fields and discoveries are sufficient to justify new infrastructure investments near-term. The second building block indicates whether the results from the 2014 to 2017 drilling plans are likely to result in sufficient gas discoveries to justify infrastructure investments. The third building block does not give specific input on near-to-medium term infrastructure decisions, but is used to evaluate the robustness of such decisions and provides a test on required capacity by including information on the longer-term gas production outlook for the Barents Sea.







The following assumptions have been made to limit the scope of the study:

- **Geographical scope:** For all production scenarios, the geographical scope is limited to the Barents Sea West, Central and Southeast (ref. Figure 3). Future potential production from Lofoten/Vesterålen or Barents Sea North is not included in this study.
- **Flow rates:** Each prospect has been given a generic production profile based on whether it is assumed to be a low or high energy reservoir. Low energy reservoirs would require a large number of production wells and compression at production start-up due to low reservoir pressure.

The details of the resource scenarios are given in the Section 4 and the Appendix.



Figure 3: Areas in the Barents Sea and awarded licensees

3.2 Technology

A work group evaluated different technologies relevant for development of new gas production and transport capacity within and from the Barents Sea.

The following technologies were included as relevant for production and transport in and from the Barents Sea:

Production alternatives:

• Offshore top-side processing - floating unit or a seabed-based installation.



• Sub-sea development - as tie-back to an offshore top-side unit or as tie-back to an onshore processing facility.²

Transport alternatives:

- Pipeline connected to the existing gas transport system.
- LNG, both onshore and floating offshore.
- Compressed Natural Gas (CNG) transported by ship.

All technologies listed were evaluated relevant for development in the Barents Sea, assuming sufficient time for necessary technology qualification prior to expected time for application.

The different technologies were designed as generic building blocks needed as input for the analyses. Each building block was documented based on functionality and specifications, size and capacity, capital expenditure³ (CAPEX) and operational cost (OPEX). CAPEX scaling rules were applied where relevant⁴. An overview of the cost estimates used in the analyses is provided in Table 1.

Cost component	Cost	Unit			
Drilling (low energy reservoirs)	560	MNOK/well			
Drilling (high energy reservoirs)	780	MNOK/well			
Subsea production system	540	MNOK/well			
Subsea compression	450	MNOK per MSm ³ /d			
Power cable	14 740	NOK/meter cable			
Onshore pre-compression	1 800	MNOK per 20 MSm ³ /d capacity			
Pipelines	Gassco's cost estimate model				
Export pipeline 42" (1000 km)	24 000	MNOK			
Export pipeline 32" (1000 km)	17 400	MNOK			
Umbilicals	12 120	NOK/meter			
LNG facility	60 000	MNOK for 5 Mtpa train			
LNG brownfield at Melkøya	Input from Snøhvit license				
LNG lifetime extension at Melkøya	Input from Snøhvit license				
Processing node offshore	24 570	MNOK per 20 MSm ³ /d facility			
Processing node onshore	22 540	MNOK per 20 MSm ³ /d facility			
Export compression	5 430	MNOK per 20 MSm ³ /d facility			

Table 1: Cost estimates used in the value chain analyses⁵

² Maximum distance for sub-sea to offshore top-side unit or onshore processing facility is set to 100 km and 300 km respectively.

³ General investment phasing profile: 10%, 30%, 40%, 20%

⁴ Scaling rule: cost1/cost2 = (capacity1/capacity2)^(2/3). Used down to 50 percent of original capacity and upwards to 200 percent of original capacity.

⁵ Real 2013 numbers. Including Project management cost of 17 percent of EPCI and Contingency of 40 percent of EPCI (30 percent for pipelines). Winterization conditions included.



3.3 Market

A work group assessed the parts of the value chain from the existing gas infrastructure system to the market.

- **Tariffs in existing pipeline system**: The tariffs used in the analysis are based on the regulated tariffs in the existing system. It is assumed that the operating costs of the system adapt to the required capacity level and that required investments to extend the lifetime of relevant parts of the system are made.
- **LNG shipping cost:** Unit costs have been calculated for the freight of LNG from the gas liquefaction plant to relevant market destinations based on current new-build fuel efficient vessel rates. Shipping costs to North West Europe are estimated to be 0.84 USD/mmBtu (including regasification).
- **Gas prices in northwest Europe**: This study uses the assumption in the Revised National Budget (RNB) of long-term gas prices at 1.93 NOK per standard cubic metre. This assumption is in line with estimates for long-run marginal cost of supply to northwest Europe from Russia, North Africa and Northern Norway.
- **NGL prices:** As sensitivity this study uses the assumption in RNB of NGL price at 4088 NOK per tonne and estimated fractionation tariff at Kårstø of 350 NOK per tonne. Income or cost for condensate is not included in the analyses.
- **LNG flexibility value**: The companies participating in the study have not discussed the level of a realistic future flexibility value. In the base case, this study technically assumes that the price realised by LNG in northwest Europe is as high as in any other market, adjusted for LNG transport cost differentials. In other words, the flexibility value of LNG is set to zero in the base case. The lower bound of the LNG flexibility value is zero, while there in principle is no upper bound. A LNG flexibility value of 0.20 NOK/Sm³ has been applied as sensitivity for all scenarios.⁶

3.4 NCS synergies

A work group addressed NCS synergies. Two main issues relating to the inter play between the Barents Sea and the existing gas infrastructure system on the NCS have been explored:

- Does existing production in other NCS areas limit the capacity in the existing system for gas from the Barents Sea?
- How would new gas from the Barents Sea affect the production in existing areas of the NCS, e.g. by reducing the unit cost in the existing transport system?

3.5 Other relevant considerations

A work group assessed potential constraints in the development of the petroleum resources in the Barents Sea. The focus has primarily been on the power supply in the north of Norway.

⁶ The LNG flexibility value is provided by an external consultant.





3.6 Gas transport analyses

The last work group has built on the input from all the other groups and evaluated the implications for gas transport solutions from the Barents Sea.

Gas transport solutions are evaluated based on a SINTEF made model identifying the value-maximising development, production and transport solutions.

- The results are presented as NPV at 7 percent real pre-tax discount rate as an indicator for the socioeconomic value of the different alternatives. This means that only fields passing the 7 percent threshold end up being developed in the model.
- The timing of developments and gas transport solutions are determined optimally from an NPV perspective.

All solutions are assessed on NPV and real rate of return on capital.



4 Resource scenarios

The Barents Sea holds the promise of becoming a new core area for gas production on the NCS. According to the latest NPD estimates⁷:

- At 765 BCM, it contains 51 percent of the undiscovered gas resources on NCS.
- It is a potentially a relatively gas-rich area, with gas representing 60 percent of total expected oil equivalents.
- More than 70 percent of the gas resources in the Barents Sea are expected yet to be discovered.

With high exploration activity in the Barents Sea and the opening of new potentially gas-rich areas, the likelihood of making new gas discoveries that create a basis for new gas transport solutions increases.

In this study, scenarios for resource and production levels are based on the three underlying building blocks (ref. Section 3.1).

- 1. Existing fields and discoveries
- 2. Prospects with drilling schedule 2014 to 2017
- 3. NPD undiscovered resources

This Section 4 presents total resource estimates. A large portion of these discoveries are at present not consider economically recoverable. This is further described in Section 5.

4.1 Existing fields and discoveries

The following fields and discoveries have been included in the resource base (NPD's resource classification 1 to 7): 8

- Snøhvit (incl. Albatross and Askeladd) Tornerose
- Goliat
- Alke Ververis
- Skalle

Iskrystall

- Gamma

Norvarg

Caurus

- Salina

-

The Goliat oil field has been included in the gas resource base as the plan for development and operations (PDO) requires gas transport. Other oil discoveries as Johan Castberg, Gotha and Wisting are not included, as the need for and timing of gas transport is still unknown.

The Snøhvit field is a subsea development with processing at the Melkøya LNG plant. The Snøhvit field (Snøhvit, Askeladd and Albatross) has potential to accelerate production with increased gas export capacity from the Barents Sea. Resources with

⁷ All numbers are according to the latest NPD estimates found in Original Recoverable Petroleum Resources on the Norwegian Continental Shelf as of 31 December, 2013.

⁸ The analysis exclude volumes not passing the 7 percent return threshold, e.g. Norvarg/Ververis that already are relinquished.



potential for acceleration has been included in this study while volumes planned produced through the existing LNG train at Melkøya, in the period 2014 to 2032, is not included in the resource base.

In total, around 200 BCM⁹ of natural gas is included from existing fields and discoveries (ref. Figure 5).

4.2 Scenarios for 2014 to 2017 prospects

Five volume scenarios, Scenario A to E, have been developed to span the potential outcome of near-term exploration activities in the Barents Sea. Scenarios A and B represent a high resource outcome (p5) with discoveries of either several small fields (A) or a few larger (B). Scenarios C and D represent a low resource outcome (p95) with small or large fields, respectively. Scenario E represents a median scenario (p50) with respect to resource potential and a mix of smaller and larger fields. This is illustrated in Figure 4.



Figure 4: Resource scenarios for prospects 2014 to 2017

Other factors affecting the economics such as size of the largest discovery, distance to shore or between discoveries, as well as production characteristics have been taken into account when developing the scenarios.

The resource scenarios are based on information provided by the operators of awarded licenses (including the 22nd license round) in the Barents Sea South with drilling plans in the period 2014 through 2017. A regional drilling schedule has been established based

⁹ A large portion of these discoveries are at present not considered commercial (ref. Section 5)



on input from the industry. The number of wells required to explore a prospect, both exploration and appraisal wells, have been used. Drilling plans for oil fields have been included in the overall drilling schedule to ensure that the total number of wells drilled reflects operator plans and assumed number of active rigs in the region.

The resources in each scenario are illustrated in Figure 5. Resources in existing fields and discoveries are around 200 BCM. Undiscovered resources from 2014 to 2017 represent an addition of around 60 BCM in scenarios C and D, 200 BCM in Scenario E and 440 BCM in scenarios A and B.



Figure 5: Total gas resources across scenarios¹⁰

The five scenarios have been selected from Monte Carlo simulations to reflect appropriate overall characteristics. The variables that have been taken into account are resource size (p5, p50, p95), timing of discoveries, number of discoveries (several small in A and C, or a few larger fields in B and D), size of the largest discovery, production characteristics (low/high energy and poor/good quality), and distance between discoveries.

Figure 6 illustrates the accumulation of gas discoveries over time for the five scenarios.



Figure 6: Cumulative gas resources across scenarios for 2014 to 2017 prospects

¹⁰ Existing LNG facility at Melkøya is fully utilised up to 2032 and the numbers in Figure 5 to Figure 7 only include accelerated volumes from the Snøhvit field.



These discovery profiles have been translated into potential production profiles based on a standard assumption of 10 years from discovery to first oil and a standard production profile for each discovery (for given reservoir characteristics).

Production characteristics were established based on production and exploration experiences in the Hammerfest basin and the Bjarmeland platform (ref. Section A.1.2). Low energy reservoirs have poorer flow capability and more production wells are needed. The high energy reservoirs have better flow capability. The field development CAPEX varies significantly between the two reservoir types.

4.3 Long-term scenarios for undiscovered resources

A large part of the Barents Sea is non-licensed areas including the newly opened Barents Sea Southeast where the forthcoming license round will be the first opportunity for the companies to apply for licenses. NPD has a view over the total potential recoverable resources, both in licensed and non-licensed areas.

Figure 7 shows a comparison between the cumulative discoveries for building blocks 1 and 2 compared to the NPD's resource estimates for the Barents Sea as a whole. NPD has provided p5 and p95 estimates for the evolution of discoveries towards 2045.



Figure 7: Comparison of scenarios for 2014 to 2017 prospects and long-term NPD scenarios¹¹

In this study, the long-term resource scenarios are used to test the robustness of infrastructure development based on existing fields and discoveries and the discoveries made from the 2014 to 2017 prospects.

 $^{^{11}}$ Please note that the NPD scenarios (p5 and p95) illustrated in the figure includes all volumes from the Snøhvit field.



5 Potential development of gas resources in the Barents Sea

This section illustrates how the resources in building blocks 1 to 3 could support a future development of gas production in the Barents Sea. The economics of new infrastructure developments are reviewed based on existing fields and discoveries (Section 4.1), the 2014 to 2017 prospects (Section 4.2) and the long-term scenarios for undiscovered resources (Section 4.3).

Key premises for the economic analysis are the following:

- As previously stated, only fields that pass a 7 percent pre-tax real rate of return threshold are included in the economic analyses.
- The best development and transport solutions are identified based on value chain economics.
- Only dry gas (no NGL) is assumed in the base case.
- LNG and pipeline gas is in the calculations technically assumed to realise the same price in the market (ref. Section 3.3).

Further, the economics are assessed from an overall portfolio perspective:

- The results are presented as NPV at 7 percent real discount factor as an indicator for the socioeconomic value of the different alternatives (ref. Section 3.6).
- Real pre- and post-tax internal rate of return (IRR) is included to provide the return for the respective cash flows.
- Company specific comparisons between the various cases will vary from the overall portfolio evaluation depending on the companies' specific portfolio and project selection criteria. This study does not include any assessment of the individual companies selection criteria.

5.1 Existing fields and discoveries

Existing fields and discoveries represent a significant volume basis for any medium term gas infrastructure development in the Barents Sea.

Based on existing fields and discoveries, the economics indicate that the natural decision is to postpone new gas infrastructure developments until additional gas resources have been discovered. With the present reserve base the existing LNG train represents the more attractive and capital efficient alternative. While the pre-tax NPV at 7 percent real discount rate is similar for a new 32" pipeline and various LNG solutions, the lifetime extension option for the existing LNG train is better than the others when measured by the real IRR on investments. This is driven by the moderate CAPEX requirements for the lifetime extension solution, which raises the pre-tax IRR to 16 percent. A new pipeline has an IRR of 13 percent. These findings correspond well with the decision in 2012 in the Snøhvit Future Development project to postpone a development of a LNG train 2 at Melkøya.





Figure 8: Value chain economics for developing existing fields and discoveries

5.2 Scenarios for 2014 to 2017 prospects

5.2.1 Scenario E

As described in Section 4, Scenario E represents the median case, with a median amount of resources discovered and a representative distribution of larger and smaller discoveries.

5.2.1.1 Resource basis and production

The discoveries in Scenario E translate into potential production profiles across the three areas of the Barents Sea as illustrated in Figure 9.¹²

In this example, a new transport solution starts up in 2022 based on production from existing fields and discoveries, and production from new discoveries are phased in from 2026 and onwards. In total, potential production from existing fields and discoveries and new discoveries made up to 2017 reach around 35 MSm³ per day. The split between the West and Central areas of the Barents Sea is relatively balanced. No production comes from the Barents Sea Southeast, simply because no licensees have currently been awarded in that area.

Around 50 percent of the total resource base passes the 7 percent pre-tax real return threshold on total investments.

¹² Note that these production profiles represent one of many median outcomes. The production split between Central and West could be different in other median outcomes. Also note that the production profile for Central in this case declines in year 5 to allow area West to start production.





Figure 9: Gas production in the Barents Sea in Scenario E

5.2.1.2 Economic analysis and assessment of transport solutions

Given the assumptions in the base case, with no flexibility value of LNG, a pipeline is, from a socioeconomic perspective, the preferred gas transport solution in Scenario E. This is illustrated in Figure 10. The new gas transport solution could start up in 2022, supported by existing fields and discoveries the first year, until new production from area Barents Sea Central and West would start in 2026. This timing coincides well with the emergence of available transport capacity in the existing gas infrastructure system in the early 2020s.





Figure 10: Economics of transport solutions in the Scenario E base case

Several further observations can be made about the relative merits of the various gas transport solutions: $^{\rm 13}$

- The 42" pipeline solution gives the highest pre-tax NPV at 7 percent real discount rate.
- A LNG flexibility value of 18 øre per Sm³ would equalise the pre-tax NPV of the pipeline solution and the new LNG solution.
- The LNG life time extension is a capital efficient option providing the highest pre-tax and post-tax IRR.
- The new LNG alternative gives lower pre-tax IRR but a higher post-tax IRR than the pipeline due to the accelerated tax depreciation for LNG projects in the Barents Sea.¹⁴
- Existing discoveries have shown large variations in reservoir quality and flow rates per well in the Barents Sea, and will be a key factor for the economics of developing the gas resources. Flow rates in the lower end of what has been observed would make the economics significantly more challenging than in the above calculations, while flow rates in the higher end would improve the returns.

Figure 11 illustrates the capacity utilisation of the pipeline solution and the new LNG solution for Scenario E.

¹³ CNG solutions have been assessed for this and other scenarios, but did not pass the 7 percent pre-tax real return threshold mainly due to high CAPEX.

¹⁴ According to Prop. 94 LS (2013-14) p. 77 the accelerated tax depreciation has been approved as regional aid by the EFTA Surveillance Authority (ESA) until 30 June 2014. The document states that due to developments in state aid law, it is unclear to what extent the accelerated tax depreciation will be approved by ESA beyond 1 July 2014. The Norwegian government is exploring the possibility to maintain the current rules within the state aid rules in the EEA-agreement.







5.2.1.3 Sensitivities

A large number of variables may affect the economics of developing the gas resources beyond what is included in the base case. The impact of some of these is illustrated in Figure 12.

	Pre-tax M investme billion NOI	NPV on ups ents <	NupstreamReal return post-tax on upstream investments Percent points			Description			
Regulated tariffs	egulated 0 ariffs					 The rate of return from field investment could be improved if separated from investments in the gas transportation system with regulated return. 			
NGL content			23	2		 NGL content as in Åsgard area (vs. 0 NGL in base case) 			
Acceleration of oil production		6		1		 5 year acceleration of oil field production 			
Reduced regularit on existing LNG f	ty acility	7		1		 90% regularity on liquefaction plants (vs. 100% in base case) 			
Developing marginal fields		2	-1			Develop fields with less than 7% real return pre tax			
Capex level	-25	25	-3	6		40 percent higher or lower CAPEX vs base case			
	Scen base		Sc ba	Scenario E base case 10%					

Figure 12: Impact on pre-tax NPV and post-tax real IRR for the 42" pipeline alternative

• **Regulated return on gas infrastructure:** CAPEX relating to new joint gas transportation and processing facilities from the Barents Sea would be subject to tariff regulation. Approximately 2/3 of the CAPEX in Scenario E relates to gas transport and processing facilities that is calculated to give a regulated rate of



return of 7 percent real pre-tax. The return on field investments could be significantly improved by separating it from the regulated upstream transportation investment. The effect will among others depend on the size of the transportation investment, possible payment obligation for the field investors and the risk profile associated with infrastructure investments.

- **NGL content**: Based on typical discoveries on NCS, NGL would create a positive influence on the gas value chain economics. Assuming similar NGL content¹⁵ to the levels in the Åsgard area, would improve the IRR significantly, from 10 percent to 12 percent post-tax, with the NPV increasing by about 50 percent from 44 to 67 billion NOK.
- Acceleration of oil production: Oil discoveries have historically been a driver for gas infrastructure developments. The impact of delaying an oil discovery of 100 MSm³ by five years due to lack of gas infrastructure is tested. Assuming 50 percent of the acceleration gain from oil fields contributes to financing¹⁶ of the gas infrastructure, the real IRR after tax would increase from 10 to 11 percent. The pre-tax NPV at 7 percent discount rate would increase by 6 billion NOK accordingly.
- **LNG regularity:** The initial experience at Melkøya indicates that the regularity at the existing liquefaction facility may be lower than at traditional processing facilities. As sensitivity, a 90 percent regularity level at Melkøya (vs. 100 percent in the base case) is analysed. Lower regularity at the existing LNG facility would add to the volume basis for a new infrastructure solution, and would serve to strengthen the economics of such investments. The after-tax IRR goes from 10 percent to 11 percent, with the pre-tax NPV increasing by 7 billion NOK.
- **Developing marginal fields**: Around 50 percent of the resources remain undeveloped in Scenario E with a 7 percent pre-tax real return threshold. If all these resources were to be developed, the effect on overall economics would be moderate. Before tax, the NPV increases by 2 billion NOK. While these fields are not economical at 7 percent discount rate when they have to pay for their proportionate share of new infrastructure, they do pass the 7 percent threshold when they only pay for their marginal cost of new infrastructure. However, since the average field IRR declines, the overall post-tax IRR also declines, from 10 percent to 9 percent.
- **CAPEX levels**: The cost of new developments in the Barents Sea is uncertain and a sensitivity of 40 percent higher or lower CAPEX is included. The pre-tax NPV is affected by more than 50 percent, moving up or down by 25 billion NOK from a base case level of 44 billion NOK. The impact on IRR is asymmetric. With higher CAPEX, the post-tax real IRR declines by 3 percentage points, while it increases by 6 percentage points with lower CAPEX.

A NPV at 4 percent discount factor is calculated as a sensitivity. The calculated socioeconomic value would then increase from 44 billion NOK for to 93 billion NOK for the 42" pipeline and from 28 to 73 for the LNG life time extension alternative.

¹⁵ This might be a high case since the existing Barents Sea discoveries have NGL contents below the Åsgard area.

¹⁶ The value of accelerated oil is subtracted from the gas infrastructure CAPEX (6.5 billion NOK).



5.2.2 Scenarios A-D

The results from scenarios A, B, C and D are in some respects similar to the results in the mid case Scenario E. An overview of the results is provided in Table 2.

Scenario		Scenario E		Scenario A		Scenario B		Scenario C		Scenario D	
	BNOK13		LNG								
Concept			lifetime								
		Pipeline	extension								
CAPEX - PV 7%		-62	-13	-72	-18	-75	-16	-43	-9	-55	-13
OPEX - PV 7%	PEX - PV 7% come - PV % Pre-tax		-13	-25	-14	-31	-16	-16	-11	-19	-12
Income - PV %			54	130	56	166	57	83	43	105	49
NPV 7%		44	28	33	24	61	25	23	24	31	24
IRR (%)		14.3 %	15.3 %	12.2 %	14.6 %	15.1 %	14.9 %	12.9 %	16.2 %	13.5 %	15.1 %
NPV 8%		5.3	5.5	2.2	4.7	8.1	5.0	2.1	4.7	3.1	4.8
NPV 10%	Post-tax	0.6	2.8	-2.2	2.2	2.0	2.4	-0.8	2.6	-0.6	2.4
IRR (%)		10.3 %	14.8 %	8.9 %	14.1 %	10.9 %	14.4 %	9.4 %	15.6 %	9.6 %	14.5 %

Table 2: Overview of results for all scenarios

Several observations can be made from this overview:

- The selected start-up year is the same in all scenarios, i.e. 2022. The main reason is the importance of existing fields and discoveries for the business case.
- The 42" pipeline solution is socioeconomically more profitable in four out of five exploration scenarios, and marginally lower than LNG lifetime extension in one of the low scenarios.
- LNG lifetime extension gives a higher pre-tax and post-tax IRR than investing in a 42" pipeline for all scenarios, except pre-tax in Scenario B.
- The post-tax internal rate of return is relatively stable (9-11 percent real) for the pipeline case, mainly due to the high upfront CAPEX in gas infrastructure.
- Reservoir quality is the driver of value creation, not the total resource level in itself (ref. Section 4.2 and the Appendix).

The next sections provide a brief review of scenarios A to D.

5.2.2.1 Scenario A

Scenario A is a high-resource scenario (p5) with many, but smaller discoveries. Relatively few fields pass the 7 percent real pre-tax rate of return threshold. In this scenario only 1/3 of the discovered resources end up being developed.

A pipeline is the best gas transport solution from a pre-tax NPV perspective. This yields an NPV of NOK 33 billion at a 7 percent real discount factor and a pre-tax real internal rate of return of 12.2 percent. The LNG life time extension option gives a higher pre-tax and post-tax IRR than the 42" pipeline alternative. A lifetime extension of existing LNG facility yields an NPV of 24 billion NOK and a real IRR of 14.6 percent.

The NPV of 33 billion NOK for the pipeline solution compares to the NPV of 23 billion NOK for existing fields and discoveries. However, the NPV increase of 10 billion NOK requires an additional 60 billion NOK of CAPEX due the small discoveries and lack of economies of scale in the upstream developments.



For the LNG alternative to be competitive with the pipeline solution on a pre-tax basis, a modest premium of 10 øre per Sm^3 is required. The differential between the two solutions is modest to begin with, due to the high CAPEX intensity of the pipeline development compared to the extended LNG case.



Figure 13: Scenario A production profiles vs. Scenario E production profiles

5.2.2.2 Scenario B

Scenario B is also the high-resource scenario (p5), but with fewer, larger discoveries, which improves the resource utilisation and economics compared to Scenario A.

In this scenario, a larger share of the resources pass the 7 percent real pre-tax rate of return threshold, with 294 BCM developed vs 228 in Scenario A, with the same number of total discoveries. However, note that even in this case only around 45 percent of the resources are developed.

The development in Scenario B is more efficient than in Scenario A. The total CAPEX of 129 billion NOK is the same as for Scenario A, even though around 1/3 more resources end up being developed.

On a pre-tax basis, the 42" pipeline solution is the best transport solution, with a 15.1 percent real IRR and an NPV of 61 billion NOK. The NPV is almost double that of Scenario A. Post-tax, however, the real IRR falls to 10.9 percent, whereas the real IRR for the lifetime extension of existing LNG facilities remains relatively high at 14.4 percent. However, pre-tax, the latter solution gives an NPV of only 25 billion NOK.

The best LNG solution in this case is a new LNG facility combined with lifetime extension of existing LNG facilities, which gives an NPV of 40 billion NOK (without any LNG



premium). The LNG premium at 28 øre pr Sm³ is required to make the NPV of the LNG solution equivalent to a pipeline solution. The upfront CAPEX of the relatively more expensive new LNG facility would in other words make the required premium significantly higher than for Scenario A.



Figure 14: Scenario B production profiles vs. Scenario E production profiles

5.2.2.3 Scenario C

Scenario C is a low-resource scenario (p95) with several, smaller discoveries.

In this scenario, no new discoveries pass the 7 percent pre-tax real return threshold. The preferred transport solution (lifetime extension of existing LNG facility) and the economic outcomes are therefore equivalent to that of existing fields and discoveries (ref. Section 5.1).

5.2.2.4 Scenario D

Finally, Scenario D is a low-resource scenario (p95) with a few, larger discoveries.

Even though Scenarios A and D are very different in terms of the resource base, the economic results end up being very similar. Total resources produced in Scenario D is 165 BCM, only 30 BCM higher than for existing fields and discoveries, and 60 BCM less than in Scenario A.

The NPV for Scenario D is 31 billion NOK, only slightly lower than for Scenario A at 33 billion NOK. The real IRR, on the other hand, is higher for Scenario D than for Scenario A (13.5 percent vs 12.2 percent).



This illustrates the value of high-quality discoveries and economies of scale in the development phase. While total CAPEX is 88 billion NOK in Scenario D, it is 127 billion NOK in Scenario A.

As for the other scenarios, the 42" pipeline solution is the economically preferred solution pre-tax. Post-tax, however, the lifetime extension of existing LNG facilities is the preferred solution.

For the existing LNG alternative to be competitive with the pipeline solution on a pre-tax basis, a modest premium of 10 øre per Sm³ is required.



Figure 15: Scenario D production profiles vs. Scenario E production profiles

5.3 Long-term scenarios for undiscovered resources

All results up to now have only included resources from existing fields and discoveries and potential resources from prospects to be drilled in the period 2014 to 2017. The NPD's estimates indicate significant potential beyond what is included in these scenarios. This section describes the results from several sensitivity analyses that assess the potential contribution from resources discovered beyond 2017, and how these may contribute to the robustness of the infrastructure solutions above. These sensitivities are within the resource estimates provided by the NPD.

5.3.1 Potential additional volumes in Barents Sea Central and West

To evaluate the potential contribution from undiscovered resources beyond 2017, an assessment has been done based on estimates from NPD. Given Scenario E, a sensitivity analysis with full capacity utilisation of the pipeline, from 2028 to 2040 and



2050, respectively, has been performed. The additional resource volume added is well within the boundaries of NPD's resource estimates (ref. Figure 7).

The impact on Scenario E discoveries (pre 2017) by getting tariff revenues from these new discoveries is illustrated in Figure 16 below. The figure illustrates that potential additional volumes could contribute to paying for a significant share of the infrastructure CAPEX. The unit tariff from the Barents Sea to the existing system would decline by 23 percent and 36 percent, provided upside volumes contributing to full capacity utilisation to 2040 or 2050 respectively.



Figure 16: Unit tariffs inclusive additional volumes

The pre-tax NPV in Scenario E for the existing fields and discoveries and the 2014 to 2017 prospects would increase from 44 billion NOK to 53 and 58 billion NOK in the two cases. The after tax IRR would increase from 10 to 11 percent in both cases.

5.3.2 Potential additional volumes in Barents Sea Southeast

To evaluate the impact of resources from the Barents Sea Southeast, a moderate case for the Barents Sea Southeast between NPD's p5 and p95 case have been included. 130 BCM of economically robust discoveries are assumed developed. 50 billion NOK of additional CAPEX is needed to develop and transport these resources in the Barents Sea Southeast.

Figure 17 illustrates the results given that production in the Barents Sea Southeast starts in 2029. In a case where the Barents Sea West and Central starts up in 2022, as in Scenario E, the Barents Sea Southeast adds 15 billion NOK of NPV while the real IRR is unaffected both before and after tax. Including the Barents Sea Southeast will by itself require significant additional CAPEX, and is as such not a mechanism for increasing IRR on the total value chain.

Late start-up of new gas production from the Barents Sea to 2029, to ensure high capacity utilisation from day 1, would serve to reduce the NPV due to the delay, while



the return is only marginally positively affected (from 10.4 to 10.6 percent real IRR post-tax) due to the loss of acceleration value. A late start-up will however prepare for a more matured volume basis and accordingly reduced risk.



Figure 17: Impact of additional volumes from the Barents Sea Southeast for the 42" pipeline alternative

5.4 Other relevant factors for the development of the Barents Sea

5.4.1 Existing system

Natural gas production from other areas on the NCS starts to decline in the early 2020s. Figure 18 shows that there would be available capacity for production from the Barents Sea in the existing gas transport system. The evaluation shows that capacity for new gas will be available at all relevant existing gas infrastructure facilities, i.e. Nyhamna, Kollsnes and Kårstø. Potential capacity constraints may be solved through debottlenecking or connecting branch lines between tie-in points. Quality and processing requirements for gas from the Barents Sea will be of major importance when evaluating relevant connection points.





Figure 18: NCS production outlook¹⁷

The expected reduction in gas production from existing fields on the NCS will reduce the utilisation of the existing infrastructure. A possible implication is that the capacity in the existing system will be consolidated. A late start-up of a new gas infrastructure from the Barents Sea will create additional costs related to rebuilding gas processing capacity.

5.4.2 Effect on oil developments

Oil developments are also likely to require gas infrastructure for associated gas. Such oil developments could face a delay due to the lack of gas infrastructure with the consequence that important field developments would be put on hold or alternatively that value creation, in particular for society, could be lost due to undesired re-injection of gas. The impact of delaying an oil discovery due to lack of gas infrastructure is illustrated in Section 5.2.1.3.

5.4.3 Power grid

Statnett is the system operator of the Norwegian national power grid. The consumption in the northern region is increasing both as a result of increased population and industrial development. Statnett has therefore already established plans to reinforce the grid from the Ballangen area (in Nordland) all the way to Skaidi (in Finnmark) via Balsfjorden (in Troms). The necessary applications are progressing and installation will start on the southern section already this summer. Statnett's plans include reinforcement all the way to Hammerfest and the new 420 kV grid may be available connecting the most northern region with the rest of the national grid by 2020, provided necessary licenses and approvals are granted in due time.

5.4.4 Project decision process

Based on a representative governance structure for project maturation, 7 years is needed from a feasibility study until start-up to have a robust decision-making process. This means that to maintain the decision-making flexibility wrt. an early start-up in 2022, a feasibility study needs to be initiated for relevant gas infrastructure developments in the second half of 2015. This schedule will be reviewed as a function of the actual exploration outcome.

¹⁷ Except Snøhvit





Figure 19: Tentative project schedule with a 2022 start-up



6 Main observations

1. The Barents Sea has the resource potential to play a key role in sustaining NCS gas production during the 2020s and beyond.

As natural gas production from other areas on the NCS is expected to decline in the early 2020s (ref. Figure 18), new production from the Barents Sea is the main opportunity reduce the decline.

The analysis show that in a p50 scenario (Scenario E), the Barents Sea could produce around 35 MSm³ per day by the mid-2020s from the 2014 to 2017 exploration outcome and existing fields and discoveries (excluding Melkøya). This would represent an addition of about 15 percent to overall NCS natural gas production.

2. Existing discoveries are not sufficient to justify investment in new gas infrastructure from the Barents Sea, both from a post- and pre-tax perspective.

Postponing new developments and production until capacity frees up in existing infrastructure is a capital efficient, solid-return solution that currently is better than investing in new gas infrastructure (16 percent vs 9 percent real IRR post-tax, ref. Figure 8). Also pre-tax NPV at 7 percent discount rate is marginally lower for new infrastructure (24 vs 23 billion NOK), showing that more resources are required also for socioeconomic perspective.

3. New gas infrastructure is socioeconomically more profitable in four out of five near-term exploration scenarios, and marginally lower than LNG lifetime extension in one of the scenarios. Both pipeline and LNG are relevant export solutions.

Pre-tax NPV is positive for scenarios covering the entire range of scenarios for exploration up to 2017, and increases as further resources are added later (ref.Table 2).

For e.g. Scenario E the 2014 to 2017 exploration portfolio is expected to double the natural gas resource base in the Barents Sea (ref. Figure 5). A new transport solution would yield a higher pre-tax NPV compared to lifetime extension of LNG facilities and delaying production (44 vs. 28 billion NOK at 7 real discount rate, ref. Figure 10).

4. It will be challenging to realise new gas infrastructure from the Barents Sea from a post-tax project-robustness.

Even if an investment in the gas value appears robust from a socioeconomic perspective, such projects would have to compete for capital among individual company's portfolio of development projects, where the project selection criteria may vary.

For e.g. Scenario E the 2014 to 2017 exploration portfolio it appears challenging to sanction the gas transport solution providing the highest pre-tax NPV as the LNG alternatives yield higher pre-tax and post-tax IRR (15 percent vs. 14 percent pre-tax and 15 vs. 10 percent post-tax ref. Figure 10).

5. The rate of return from field investments could be improved if separated from investments in the gas transportation system with regulated return.



CAPEX related to new joint gas transportation and processing facilities from the Barents Sea would be subject to tariff regulation. Approximately 2/3 of the CAPEX in in Scenario E relates to gas transport and processing that in the calculations give a regulated rate of return of 7 percent real pre-tax.

The analysis shows that the return on field investments could be significantly improved by separating it from investments in gas infrastructure subject to the tariff regulation. The effect will among others depend on the size of the gas infrastructure investment, possible payment obligation for the field investors and the as risk profile associated with infrastructure investments (ref. Figure 12).

6. Collaboration across licenses will be needed as no individual license seems able to carry significant new gas infrastructure investment on its own.

Background material provided by the field operators show that it is not a likely scenario for the Barents Sea that new gas infrastructure will be driven by an individual license due to the expected resource base and the high CAPEX needed. Several gas discoveries and potentially associated gas and NGL from oil discoveries are likely to provide the basis for infrastructure decisions in the Barents Sea.

New gas infrastructure will therefore most likely require broad and efficient technical and commercial collaboration between a set of licenses representing a large number of companies, each with their unique interests.

7. Late start-up of a new gas infrastructure to align with development of the Barents Sea Southeast will reduce the pre-tax NPV at 7 percent discount rate and only marginally improve the post-tax rate of return. The project robustness could improve due to an increased reserve base.

Aligning new infrastructure with development of the Barents Sea Southeast will reduce the value creation contribution from the early production from existing fields and discoveries. This loss of acceleration value neutralise the value of postponing CAPEX until the resource base is further strengthened (ref. Figure 17).

A late start-up will however prepare for a larger and more matured volume basis and accordingly improve the project robustness.

8. A late development of the Barents Sea may lead to consolidation of existing gas infrastructure and cost for rebuilding capacity.

The expected reduction in gas production from existing fields on the NCS will reduce the utilisation of the existing infrastructure. A possible implication is that the capacity in the existing system will be consolidated. A late start-up of a new gas infrastructure from the Barents Sea will create additional costs related to rebuilding gas processing capacity.

9. There is a potential upside by realising parts of the resources currently evaluated to be uneconomic.

Based on the price and cost assumptions and economic thresholds (7 percent real pre-tax rate of return) applied in this study, 50 to 70 percent of the existing and expected discoveries in the 2014 to 2017 prospects remain undeveloped in the analysed scenarios (ref. Section 5.2).

Reaching high resource utilisation levels will require that such fields are developed. This will amongst others require a combination of lower development costs through higher efficiency and technological development and/or higher natural gas prices.



10. To have decision-making flexibility wrt. an early start-up in 2022, a feasibility study needs to be initiated in 2015.

Such decision-making flexibility will require the industry to initiate a feasibility study in the second half of 2015 in order to meet the milestones in the project governance model (ref. Figure 19).



7 Way forward

The planned exploration portfolio from 2014 to 2017 may provide a potential for developing gas resources and associated gas infrastructure, but it may be challenging to realise from a project economics perspective.

The earliest target start-up of such gas infrastructure is assumed in 2022. To have the opportunity for a 2022 start-up, infrastructure solutions have to be matured in parallel with the resource base.

Identification of possible measures to bridge the gap between socioeconomic and project economic perspectives should be a focus area in near-term. Two specific issues are recommended to be addressed to create a basis for a potential feasibility study in mid-2015.

1. Update the resource basis following the results from Barents Sea exploration activity and revisit the basis for starting a feasibility study

This involves maintaining the analytical tools developed in the BSGI study, and update the analyses based on actual results from exploration activities in the Barents Sea and by incorporating revised exploration targets and schedules. This creates a revised assessment of whether the exploration portfolio points towards an outcome where a development is economically viable.

2. Organisation of infrastructure developments in the Barents Sea

Future gas developments in the Barents Sea will be characterised by a large share of CAPEX in infrastructure, collaboration between several licenses to realise investments, and a large share of marginal resources. Alternative models to finance gas infrastructure investments may be needed to maximise the value creation from the gas resources in the Barents Sea.

Clarifying these issues will enable the industry and the authorities to make informed decisions to maximise the value of the Barents Sea resources and to secure alignment with decisions that are taken in the existing system. An outcome of the authorities ongoing clarification process with the ESA regarding the accelerated tax depreciations for LNG in northern Norway is also appreciated.



8 Abbreviations

BCM BSGI CAPEX	billion standard cubic metre Barents Sea Gas Infrastructure Capital expenditure
CNG	Compressed Natural Gas transported by ships
DPC	Dew Point Control
IRR	Internal Rate of Return
kV	Kilo volt
LNG	Liquefied Natural Gas, both onshore and floating offshore
MSm ³	Million standard cubic metre
NCS	Norwegian Continental Shelf
NGL	Natural Gas Liquids
NPD	Norwegian Petroleum Directorate
NPV	Net Present Value
OPEX	Operating expenditure
PDO	Plan for Development and Operation



Appendix – resource scenarios

Comprehensive and consistent data collection with respect to recoverable resources in the Barents Sea is essential for running realistic analyses. The primary source for this information is held by companies with awarded licenses in the area. Major part of the Barents Sea is however not licensed. This includes the Barents Sea Southeast where the forthcoming license round will be the first opportunity to apply for licenses. NPD, however, publish resource reports over the total potential recoverable resources, both in licensed and not licensed area.

Three building blocks have been used to assess gas resources and future gas production from the Barents Sea (ref. Section 3.1). This appendix describes building block 2 in more detail.

Building block 2 establishes various volume scenarios based on potentials from awarded licensees with a drilling schedule 2014 to 2017. To enable an assessment of the opportunity for future gas developments in the Barents Sea, each operator has shared the following information with Gassco:

- Production license (location)
- Recoverable gas resources for un-risked p50 and p10 estimates
- Expected production characteristics for prospects
- Drilling schedule

Based on the input data from the field operators resource distribution per area and volume scenarios have been established by running Monte Carlo simulations. Uncertainties based on probability of finding hydrocarbons in a prospect, fluid type, resource distributions, production characteristic, and drilling schedule of each prospect have been taken into account. The following sections describe the main assumptions regarding these issues.

A.1 Probability of finding hydrocarbons in a prospect

Based on historical data, generic estimates have been made for the probability of finding hydrocarbons in a prospect:

- Discoveries in the same play-model: 35 percent
- Other prospects: 25 percent

Historical rate of discovery in the Barents Sea is approximately 55 percent including resource classification 6, and 40 percent excl. resource classification 6 in average for the period 1998 to 2012 (ref. Figure 20). The probability of finding hydrocarbons in new prospects is assumed to be somewhat lower than the observed rate of discovery. This is partly due to some promising prospects already have been explored and partly due to that it is uncertain whether all of the prospects will be drilled. However, the probability could be higher based on the recent drilling success which could indicate that the area is starting to become more mature, with both increased understanding of play models and more seismic data.



>> GASSCO

Figure 20: Historical survey of exploration wells and discovery rate (source: NPD)

A.1.1.Fluid type

Some prospects are located within regions with larger uncertainty in source rock. In such cases both gas and associated gas resources were reported with the probability of oil vs gas discovery.

A.1.2. Production characteristics

To reflect the potential variation in production characteristics, two generic production profiles have been developed based on experience in the Barents Sea (ref. Figure 21).

Low Energy Reservoirs

- 35 percent of recoverable gas volume produced at plateau
- Annual plateau rate of 7 percent of recoverable gas volume
- Well Rate of 0.7 MSm³/day
- Hyperbolic yearly decline rate of 12 percent

High Energy Reservoirs

- 57 percent of recoverable gas volume produced at plateau
- Annual plateau rate of 7.6 percent of recoverable gas volume
- Well Rate of 3 MSm³/day
- Exponential decline with yearly decline rate of 10 percent





Figure 21: Generic production profiles

Low energy reservoirs would require a large number of wells as well as compression at production start-up due to low reservoir pressure.

It has been assumed that high energy reservoirs do not require compression in this phase of the study. Larger gas fields might elect to install compression after producing 50 percent of their resources, but this simplification is expected to have minor impact on the discounted economics.

A.1.3. Drilling schedule

The overall drilling schedule is established based on input from the industry.

Number of wells

The number of wells required to explore a prospect, both exploration and appraisal wells, have been established for each prospect. Each prospect is based on the operators' plans and/or general guidance as reported. Drilling plans for oil fields have been included in the overall drilling schedule to ensure total number of wells drilled in the Barents Sea South reflects operator plans and assumed number of active rigs in the region during this period.

For some cases without previous appraisal drilling the number of appraisal wells were assumed based on size of discovery:

- Associated gas: 1 appraisal well
- < 10 BCM: 0 appraisal wells
- 10-40 BCM: 1 appraisal well
- 40-100 BCM: 2 appraisal wells
- >100 BCM: 3 appraisal wells

The timing of these appraisal wells were assumed to be one year from discovery to first appraisal well, and one year between each consecutive appraisal well. It is assumed to take 10 years from discovery date to production start-up.

Rig capacity

Three drilling rigs have been assumed available for continuous drilling in the period 2014 to 2017 in the Barents Sea. Maximum twelve wells are expected drilled per year. Appraisal drilling is assumed to be prioritised before wildcat wells in scenarios with limited rig capacity.