CO_2-EMISSIONS EFFECT OF ELECTRIFICATION

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1 EXECUTIVE SUMMARY AND CONCLUSIONS

Most greenhouse gas emissions from the Norwegian Continental Shelf stem from generating electric power needed for the oil and gas extraction process, more commonly referred to as the operational phase. Electrification of the shelf refers to supplying the required power from the mainland via a transmission cable rather than from on-site gas-fired power generation equipment. Electrification would as such considerably reduce the emissions from the installations themselves, but at the same time yield an increase in generation from onshore power plants that may at least in part be based on fossil fuels.

The effect on emissions that electrification yields is influenced by the characteristics of the Norwegian power market and the European market for CO_2 allowances. Understanding how these two markets work is thus important when assessing alternative sources of power supply for offshore activities from a climate perspective. On behalf of Statoil, Econ Pöyry has addressed this issue by estimating CO_2 emissions from alternative power supply solutions to the Dagny and Draupne/Luno fields on the Utsira High in the North Sea. The conclusions of this analysis can be summarized into 4 major points:

Electrification will not affect total European CO_2 emissions. Petroleum companies involved in oil and gas extraction activities on the Norwegian shelf are included in the European market for CO_2 allowances (EU ETS) where supply of allowances is fixed to pre-defined emission target levels. While electrification can lead to lower emissions compared to the "traditional" on-site (offshore) power supply, this merely implies that allowances from power supply are freed up for other EU ETS sectors, such as processing industry. As such, total EU ETS emissions will comply with the pre-defined EU emission targets regardless of electrification, meaning that electrification has no net effect on emissions in Europe.

Electrification of Norwegian oil and gas projects will in most cases have an abatement cost higher than the price of CO_2 allowances. One implication of this is that the EU ETS does not need to finance as many emission reduction measures in order reach the reduction target. Due to the way the EU ETS market is designed this lowers the CO_2 price. Electrification thus amplifies the trend towards low CO_2 prices already triggered by compliance with EU's Renewable Directive and Energy Efficiency Directive, as well as lower industry activity resulting from the economic recession. From an EU perspective, sluggishly low CO2 prices undermine the purpose of the EU ETS, and developments that lead to lower prices should therefore induce a more ambitious carbon policy. Electrification of Dagny and Draupne/Luno on its own is too marginal to influence EU policy, but constitutes one of many developments that could spur tighter emission targets in the future.

Electrification will yield lower CO_2 emissions from power supply compared to on-site gas-fired power generation. The traditional source of power supply for offshore oil and gas extraction activities is relatively inefficient offshore gas turbines. When, in the case of electrification, this power supply originates from onshore power plants, it mostly comes from combined-cycle gas turbines (CCGTs), which can generate the same amount of power as on-site gas turbines using considerably less natural gas, thus emitting less CO_2.

Reductions in national CO_2 emissions are partly offset by increased emissions from European *replacement power*. Connecting offshore installations to the Norwegian central grid means that required power for oil and gas extraction will originate from generation based on renewable sources (mainly hydropower) rather than from offshore gas turbines. CO_2 emissions from power generation in Norway (including the shelf) are therefore reduced. However, emission reductions are substantially lower when the European power market is taken into account. Increased electricity demand in Norway means that Norwegian exports of hydropower are withdrawn from the European power market. Power generation in Europe will therefore have to *replace* the withdrawn hydropower imports to balance the market. The European *replacement power* will mostly consist of generation from fossil-based power plants.

The impact on emissions from construction and decommissioning of installations and equipment related to power supply play a marginal role over the lifetime of the projects. The main difference in emissions between different concepts for power supply is found in the operational phase of the projects. Emissions for construction and decommissioning of installations and equipment are negligible. This conclusion may be generalized to other similar projects worldwide relatively independent of location and water depth.

Analysis of different power supply concepts

The above conclusions are based on a power market analysis using Econ Pöyry's BID model for European electricity and carbon markets in addition to cradle to grave calculations of construction and decommissioning of platforms, cables and equipment. The emission assessment is limited to CO_2 because it is the only greenhouse gas currently included in the EU ETS and will remain the most voluminous EU ETS gas in the future. Moreover, our analysis of the EU ETS is based on future carbon abatement curves which have mostly only been reported for CO_2.

The analysis includes CO_2 emissions from the construction phase, the operational phase and the decommissioning phase for the Dagny and Draupne/Luno fields. Although the fields are separated and located approximately 60 km apart, we assume that electrification of the fields will be executed as a joint solution.

As outlined above, our main objective in this study is to analyse how an increased withdrawal of power from the Norwegian grid, in order to replace traditional offshore gas-fired power supply, will alter the global and national lifetime emissions of greenhouse gases, where the emission analysis is limited to emissions from power supply for offshore activities alone. Our analysis applies a comparative analysis of five different development alternatives with different concepts for power supply to the offshore installations. The alternatives for power supply are:

1. Standard offshore gas turbines
2. Cable from the onshore power grid, via offshore hub/sub-station
3. Cable from dedicated, new-built onshore gas power plant, via offshore hub/substation
4. Offshore gas turbines, optimized for low fuel consumption and low emissions of green house gas
5. Cable from the onshore power grid, but with 50 percent of annual power supply from offshore wind park

To illustrate a situation where electrification of Dagny and Draupne/Luno initiates development of an onshore wind-farm located at Kårstø with capacity to supply full electricity demand from the offshore installations, a sixth alternative (2b) is analyzed. In this alternative the extra wind-farm is added to the renewable development expected to be facilitated through the expected joint Norwegian-Swedish certificate market, and we assume that this wind-farm also can supply power to the central grid. As this particular choice of concept deviates from current power supply policy and expected market adaptations, it is best viewed as a solution triggered by unforeseen developments such as an insufficiently accommodated infrastructure (grid) in western Norway or inadequate short term regional power supply from existing power plants.

Calculated national and European emissions from supplying power and heat to the operational phase at Dagny and Draupne/Luno for all alternatives are summarized in Table 1.

Table 1 Accumulated European and national emissions from supplying power and heat to Dagny and Draupne/Luno during the operational phase, million tonnes CO_2

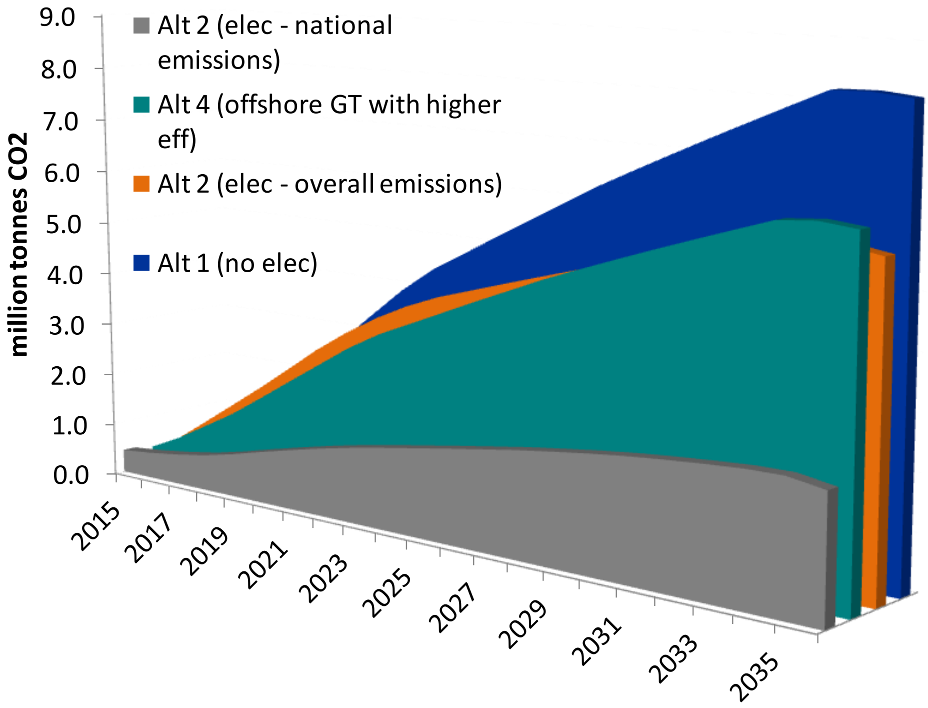
	Alt 1	Alt 2	Alt 3	Alt 4	Alt 5	Alt 2b
European emissions	7.82	5.39	5.64	5.91	3.79	0.86
National emissions	7.82	1.78	5.64	5.91	1.64	1.50

Source: Pöyry Management Consulting analysis

The analysis shows that the accumulated CO_2 emissions from mainland power generation – from Norway and Europe – supplying Dagny and Draupne/Luno (Alternative 2) is about 2.4 million tonnes lower than in the case with "traditional" offshore gas turbines (Alternative 1). If 50% of annual power supply in case of electrification originates from an offshore wind park instead of from the onshore power grid (Alternative 5), accumulated emissions of CO_2 from an alternative power supply are approximately 4 million tones lower than in Alternative 1. In the short term the replacement power in Alternative 2 is a mix of coal and gas, which yields emissions exceeding those in the case of optimized offshore gas turbines (Alternative 4), but as a larger share of the replacement power in the longer term will be produced in more efficient gas power plants, this is expected to reverse.

The accumulated emissions in Alternatives 1, 2 and 4 are presented year-by-year in Figure 1 below. The figure shows that electrification yields a considerable lower emission level than offshore power supply when only considering the effect in Norway. Also, the figure shows that accumulated emissions in the case of high-efficiency offshore gas turbines are lower than in the case with electrification in the short term where the replacement power comes from mostly coal-fired power plants, but that this is reversed in the longer term when coal plants in Europe are decommissioned and efficient CCGTs supply the replacement power.

Figure 1 *Accumulated emissions year-by-year from supplying power and heat to Dagny and Draupne/Luno, million tonnes CO_2*

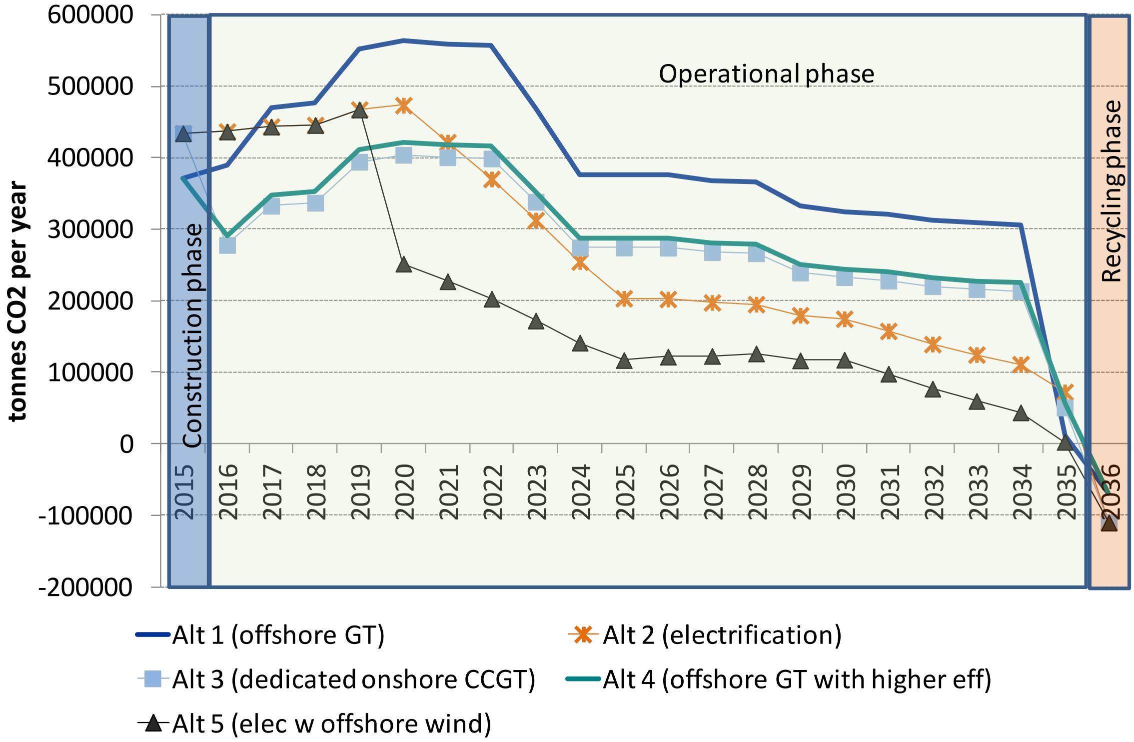


Source: Pöyry Management Consulting analysis

Alternative 2b will, like the other electrification scenarios, imply that most emissions from the offshore installations are removed. This alternative will also yield lower emissions from the mainland – Norwegian and European – power market than in the non-electrification alternatives. There would be no need for replacement power, and the extra wind-farm would in years where its generation exceeds demand from Dagny and Draupne/Luno export its power to Europe, thereby replacing thermal power. This is provided that the inflexible generation from this extra wind-farm is not locked in by bottlenecks.

Emission profiles for all phases of the Dagny and Draupne/Luno project for the various alternatives are shown in Figure 2. The emissions from the construction phase are 22 000 tonnes higher in cases with electrification, mostly due to the construction of a separate hub-platform and installation of offshore cables. The ending point illustrates the emission benefits from re-use and recycling of the same components.

Figure 2 *Annual overall CO_2 emissions from the construction, operational and recycling phase, million tonnes CO_2*



Source: Pöyry Management Consulting analysis

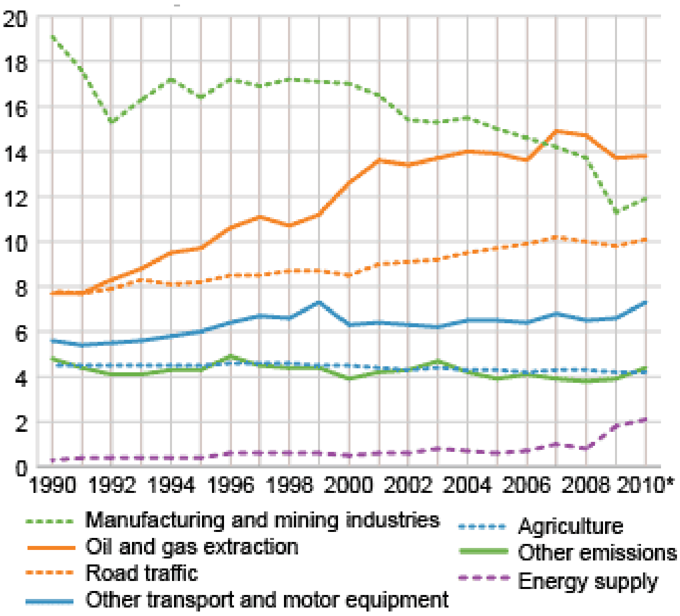
The figure above also shows the relatively small share of emissions stemming from the construction and recycling phase. Moreover, emissions in these two phases do not differ considerably between the alternatives, emphasizing that power and carbon market adaptations to electrification are the most important aspects to consider in the context of electrification.

2 BACKGROUND

2.1 OFFSHORE EMISSIONS AND NATIONAL GOALS FOR REDUCTION

Since 2007, the oil and gas sector is the largest single emitter of greenhouse gases in Norway (see Figure 2.1). The Climate Agreement (Klimaforliket) from 2008 established ambitious goals for Norwegian emissions of greenhouse gases towards 2020. The agreement states that Norway aims at reducing national emissions of greenhouse gases by 15 to 17 million tonnes of CO_2 equivalents by 2020, not including forestry. The Agreement furthermore suggests that two thirds of Norwegian emission reductions will be taken domestically. Due to these political ambitions, and the related debate regarding where and how one should realize these targets, the petroleum sector and its activities have received an extensive focus.

Figure 2.1 Emissions of greenhouse gases by source, 1990-2010. Mill tonnes CO_2-equivalents



Source: Emission inventory from Statistics Norway and Climate and pollution agency

The Government has announced that it will present a climate policy White Paper to the parliament in the spring of 2012, specifying the Government's climate policy[1]. The White Paper is likely to reiterate the necessity of cuts in national emissions of greenhouse gases. Consequently, it is likely that the oil and gas sector will be instructed to cut its emissions.

Emissions from the oil- and gas sector are mainly due to emissions from gas turbines providing power supply for the production platforms. Since the beginning of the 1990s the oil and gas sector has implemented several measures which have contributed to a significant decrease in emissions of greenhouse gases per barrel. Between 1994 and

[1] The last one was published in 2007, see St.meld. nr. 34 (2006-2007) "Norsk Klimapolitikk"

2007 reduced flaring and increased energy efficiency in the production offshore were the main contributors to that reduction with 50 percent of the total. Approximately 30 percent of the reduction is a result of storage of CO_2 from Sleipner, and the last 20 percent comes from onshore power supply of Kollsnes (including Troll A) and Ormen Lange.

Onshore power supply for producing fields at the Norwegian Continental Shelf, together with carbon capture, transportation and storage (CCS), is described by the Norwegian Climate and Pollution Agency in the Climate Cure 2020 report as the initiative that will give the largest national reductions in emissions for the oil and gas sector.[2]. In a resolution from the Norwegian parliament from 1996, all new offshore developments are instructed to investigate the possibilities for onshore power supply in order to meet the demand for electricity, rather than covering it through power generated offshore.

However, the Climate Cure 2020 project estimates the costs of onshore power supply for new offshore installations to be between 700 and 3000 NOK/tonne CO_2. Consequently, on shore power supply can be classified as a relatively expensive climate measure, even for new fields. Still, as Statoil and the oil and gas industry already have implemented several measures in order to reduce their emissions, onshore power supply is one of the most important possible actions left to be considered.

With this broad context in mind, Statoil needs to assess the environmental impact of different alternatives for power supply, including electrification, for offshore installations. As a response to this challenge the following question will be answered in this report:

How will an increased withdrawal of power from the Norwegian grid, in order to replace traditional offshore power production based on gas, alter the global and national life time emissions of greenhouse gases?

2.2 ELECTRIFICATION OF DAGNY AND DRAUPNE/LUNO – A CASE STUDY

Statoil's Dagny field is relevant to assess in this context, as it is a development near in time, and as Statoil currently is preparing the plan for development and operation (PDO) for the field. The oil and gas fields Dagny and Draupne/Luno are all situated in a cluster at the Utsira High. Dagny is operated by Statoil, Draupne by Det Norske and Luno by Lundin. They are all expected to deliver their PDO for the respective fields in 2012, and given the relative short distance between them (approximately 60 km), it is relevant to look into a joint electrification project. In October 2011 Det Norske and Lundin have been asked by the Ministry of Petroleum and Energy to accept a single, unified development of Draupne and Luno. A final agreement has not been agreed at the time of writing, however a joint development of these two fields is assumed in this report. Different solutions for power supply can be designed to serve the production platforms. Based on a selection made by Statoil, the origin and amount of CO_2 emissions for five different solutions will be assessed in this report.

[2] See Climate Cure 2020 " Measures and Instruments for achieving Norwegian climate goals by 2020" (http://www.klif.no/publikasjoner/2678/ta2678.pdf)

The five solutions described and compared in this report imply that the required electricity is generated/transmitted by:

1. *Standard offshore gas turbines*
2. *Cable from the onshore power grid, via offshore hub/sub-station*
3. *Cable from dedicated, new-built onshore gas power plant, via offshore hub/sub-station*
4. *Offshore gas turbines, optimized for low fuel consumption and low emissions of green house gas*
5. *Cable from the onshore power grid, but with 50percent of annual power supply from offshore wind park*

In addition to the 5 alternatives presented above, we have modeled a sixth alternative – Alternative 2b - at a request by Statoil. Alternative 2b reflects a hypothetical situation where a wind-farm, dedicated to supplying Dagny and Draupne/Luno is developed close to Kårstø. This alternative includes the same components for power supply as alternative 2 and 3.

The five alternatives differ both in terms of origin of the power production for Dagny and Draupne/Luno, and in terms of the power production and supply equipment that has to be installed. Consequently the amount of green house gas emissions will differ for the five alternatives.

Through the results from a power market analysis and a "cradle to grave" environmental analysis of the Dagny and Draupne/Luno fields, this report describes the difference in amount of emissions between the alternative solutions for offshore power supply.

2.3 IMPACT FROM ELECTRIFICATION ON LIFE TIME EMISSIONS

Even if electrification of offshore installations is a hot topic both in Climate Cure 2020, and in the political debate in Norway, little research has been done, neither on the global climate effect related to emissions from marginal power production onshore, nor the life time emissions related to the construction work needed. When assessing green house gas emissions, it is decisive to focus on the *global life time* effects of measures aimed at reducing emissions, as emissions of greenhouse gases have global and not local effects.

The origin and amount of emissions differ in the various phases of an offshore oil & gas project. For the construction phase emissions origin from material- and energy use related to extraction of raw materials, and energy use in processing and transporting the resources. Emissions during the operation phase are mostly related to power production. The decommissioning phase includes energy use for de-construction of the installations after the estimated production period of 20 years, and emission benefit from re-use of components and recycling of materials.

2.4 THE FOCUS OF THIS REPORT

The main focus of this report is to quantify and show, for the five alternatives for power supply to the Dagny and Draupne/Luno fields, what the *difference* in CO_2 emissions will be over the life time of the project. This difference is calculated by summarizing the emissions from the source of power production and life time emissions from the power supply equipment in each alternative. The focus of the analysis is therefore on the factors and components that *differ* between the alternatives.

As the main emissions are related to power production, we have conducted a detailed analysis of the origin of the power production in the case of electrification over the whole 20 years production period. We also include rough emission estimates for the factors and components equal in all alternatives, mainly flaring and construction of the production platforms.

Details concerning methodology, data sources and technical specifications of the installations can be found in the appendices. The results of the power market analysis are described in detail in chapter 3 while the results of the environmental analysis are discussed in chapter 4. The comparative analysis and the strength of the main conclusions of this report are presented in chapter 5.

3 EMISSIONS FROM POWER- AND HEAT SUPPLY

This part of the study analyses how electrification affects CO_2 emission levels from supplying power (and heat) to the oil and gas extraction activities at Dagny and Draupne/Luno – defined as the *operational phase*. Electrification implies that power and heat needed for the platforms is supplied from the Norwegian central grid via a transmission cable rather than from on-site (offshore) gas turbines. Consequently, the Norwegian power market has to adjust to this increase in demand. Exactly how the Norwegian power market will respond is partly influenced by national and international energy policy. Insight into the relation between electrification and energy and climate policy is provided in Appendix 5.

Any increased outtake of electric power from the grid requires adjustments in supply of power to balance the system. If offshore units are electrified, some power on the grid will be directed to the offshore units, and this power must be *replaced* by increased generation to meet power demand on the mainland. We thus refer to this increase in generation as *replacement power*. As we will discuss later, for the case described in this report replacement power is not likely to come from only Norway, but mainly from European countries. Replacement power is explained in more detail in Appendix 6. Appendix 6 also contains a full overview of the methodology applied in the operational phase analysis.

This chapter is structured as follows: First, we briefly describe the methodology applied in order to find the effect electrification has on emissions in the operational phase. As this methodology requires an analysis of how the power market adapts to a change in demand, we apply our in-house power market model BID, which is explained in the second part. The third part presents the major assumptions that underpin the operational phase analysis, while the fourth part presents the results from the analysis, i.e. the emission levels in various power supply concept solutions with and without electrification. The fifth and sixth parts discuss the external effects from electrification on the European carbon market and gas market, respectively. The final part contains a brief discussion on Guarantees of Origin.

3.1 THE METHODOLOGY IN BRIEF

3.1.1 Effect on emissions

Calculating the emission effect resulting from electrification is done by comparing emission levels from total European power supply (including on the shelf) for alternatives with and without electrification. In order to do this, we need to find the source of replacement power, i.e. the source of power supply that replaces the amount of power in the grid redirected to Dagny et al. We then compare the replacement power's appurtenant emissions with emissions from the offshore gas turbines. Identification of the replacement power and calculation of appurtenant emissions are performed applying Econ Pöyry's power market model, BID, to the electrification cases.[3] BID contains power generation capacity data on a detailed level for all North-Western European countries, and can therefore accurately pinpoint the type and source of the power generation that replaces offshore electricity generation at Dagny et al.

BID models a perfect competition (no market-power) market where an increase in demand will be met by the cheapest possible increase in supply. This is how the European power

[3] For a short introduction to BID, see next section. The BID model is moreover presented in more detail in Appendix 8.

markets work in reality. Increased demand for electricity means that several power producers will compete to generate the extra power needed, and the "winner" is the plant with the lowest cost of production. What constitutes the "winning" plant, which in this case ultimately ends up supplying the replacement power, depends on a number of plant and market characteristics:

- Marginal costs of running the different types of plants (which relies heavily on fuel and CO_2 prices).
- Thermal plant start-up costs, which restrict the operating flexibility of thermal plants
- Restrictions on run-times of Combined Heat and Power (CHP) plants
- Inflexibility of renewable generation
- Grid losses (which effectively yields a cost of transporting power from one place to another)
- Grid bottlenecks, which implies that ability to balance "another" power market with indigenous generation is limited
- Plant availability (which depends on maintenance and other planned outages)

The price that the "winning" plant bids in is the *marginal price of power*, i.e. the price required to cover the marginal increase in demand. This marginal price thus becomes the "new" wholesale price of electricity following an increase in demand.

Replacement power is most likely to come from plants already in operation where capacity is not fully used, rather than just one idle plant switching everything on. Therefore, there is likely to be more than one source of replacement power. BID is sufficiently complex to handle this feature.

3.1.2 External effects

In addition to changing emission levels, electrification can also affect the framework conditions for the European carbon market – EU ETS.[4] Electrification of projects with a higher abatement cost than the price of CO2 allowances is not a measure initiated by the CO_2 price itself, and will therefore imply a lower need for initiatives that would have been triggered by the CO_2 price. Electrification thus amplifies the trend towards low CO_2 prices already triggered by compliance with EU's Renewable Directive and Energy Efficiency Directive, as well as lower industry activity resulting from the economic recession. From an EU perspective, sluggishly low CO_2 prices undermine the purpose of the EU ETS, and developments that lead to lower prices should therefore induce a more ambitious carbon policy. Electrification of Dagny and Draupne/Luno on its own is too marginal to influence EU policy, but constitutes one of many developments that could spur tighter emission targets in the future.

3.2 THE BID MODEL

European power markets consist of many power plants with different characteristics. A *qualitative* assessment of how power plants will react to increased demand is likely to be of a general nature and inadequate to yield a precise estimate of how electrification will alter emission levels. Finding the exact sources of replacement power therefore requires a comprehensive power market simulation.

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[4] This is attributable to the Norwegian petroleum sector being a part of the EU ETS.

We undertake this simulation using our Better Investment Decisions (BID) model. BID is a fundamental optimization market simulator for all power markets in North-West Europe (including the Baltic countries and Poland), meaning that it finds the lowest possible price of power that is required to balance (make supply equal demand) all these power markets, given:

- How much it costs to run the various power plants. This depends on fuel prices and how much it costs for said plants to adjust generation up and down. For instance, if the market can be cleared by either gas plants or coal plants, BID chooses the plant with the lowest overall costs.
- Inflexibility of renewable generation. For wind plants, for example, generation cannot be adjusted in line with demand.
- What price an owner of a reservoir hydro-plant should receive given the opportunity to store or produce at any hour, taking into account uncertain inflow levels in the future.
- Transmission constraints (the size of the grid) limits the possibility for generation in one place to balance the market some other place. This is more commonly referred to as bottlenecks.

BID includes a detailed power plant database for all Western European countries. Other central input assumptions include power demand, fuel (and CO_2) prices and transmission capacity, both for the current period and also for future years. In the model, all types of power plants (producers) bid in their electricity at a certain price (determined mostly by fuel and CO_2 prices) and volume to the market to meet (pre-specified) demand in both their home market and connected power markets. The wholesale price of power is the marginal production cost of the most expensive plant needed to meet demand. As BID assumes a perfect market with no market-power, the most expensive (marginal) plant will get a power price that covers its production costs, but no more.

As mentioned above, BID takes into account grid constraints, or bottlenecks, yielding price differences between different countries (and also within some countries). Effectively, grid bottlenecks mean that the most expensive producers in surplus regions have to retract their bids if grid limitations prevent them from exporting to connected regions, while expensive producers in the deficit region can bid into the market and still sell their power. The outcome is a higher power price in the deficit region than in the surplus region. Bottlenecks do not necessarily imply, however, that a hydro-dominated region cannot export all its surplus over time. If the excess hydro-power cannot be exported during one particular period, the water is simply stored till a later period when it can be exported, provided the hydro-power capacity is reservoir-based. If, on the other hand the excess power stems from intermittent generation, then this power is “lost” if it cannot be exported, and the power price falls to (pre-specified) non-fuel variable operating costs (around 5 €/MWh). These features are captured in BID.

BID applies stochastic dynamic programming to handle uncertainty concerning future inflow. This procedure means that in the model hydro-producers base their generation and pricing decisions at a specific time on probability distributions for future inflow, and that this procedure is moved forward for every time interval. If, for instance, at time *t* a hydro producer expects a dry period over the next 10 periods, the hydro producer will be restrictive in releasing water already in period *t* and *t*+1 and so on.

Market regulatory issues, such as renewable development, nuclear capacity development, and runtime restrictions on CHP plants are featured in the model as exogenous inputs. Regulatory aspects concerning the grid (such as grid tariffs, grid investment rules etc) are not covered in the model, nor are taxes such as electricity consumption tax and VAT.

The BID model simulates the power markets in a very accurate and "real" way.[5] In particular, the treatment of uncertainty for hydro producers captures exactly how hydro producers make their dispatch decisions. Moreover, BID has an hourly time resolution, which means that it finds the optimal price for all hours of the year modeled. Other main outputs from the BID model include hourly dispatch (exactly how much and what type of electricity is generated each hour in each country), trade and CO_2 emissions from the power market.

3.3 ASSUMPTIONS

In this section we present assumptions relating directly to the Dagny and Draupne/Luno installations and an overview of the general power market assumptions, which underpin what the level of emissions from offshore and replacement power generation, respectively, will be. The most significant assumptions about the Nordic and the European power markets are presented in detail in Appendix 7.

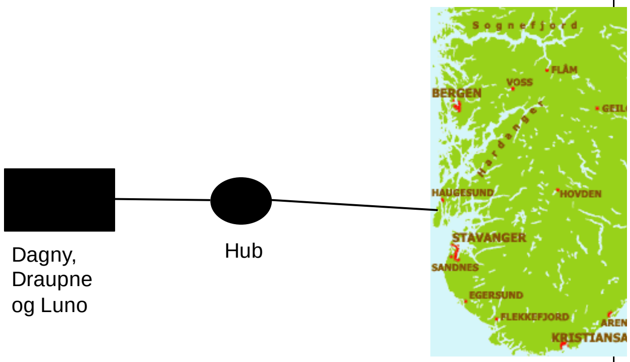
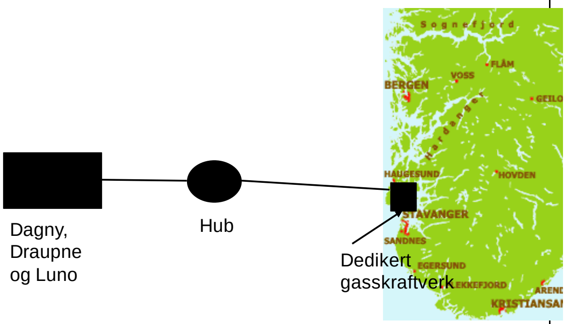
3.3.1 Scenario definitions

We start by presenting how the various alternatives are comprised in terms of the operational phase. An overall description of the scenarios (already described in the executive summary and section 2.2) is repeated in Figure 3.1. The only difference between the scenarios is where, in geographical terms, the source of electricity (and heat) is generated. In terms of the power market modeling, the electrification scenarios assume that a higher demand, corresponding to annual power requirements at Dagny and Draupne/Luno, is placed on the Norwegian power market. All other factors are assumed constant.

The alternatives in this study have been modeled for the years 2016, 2020, 2025, 2030 and 2035. Over this long-term horizon, many developments in both the Nordic and European power markets will take place. Although many of these developments are specified by current policies (renewable targets, nuclear decommissioning in Germany, grid developments etc) any development not yet under construction is uncertain. Our Base Case simulates the market developments we see as most likely given current forward market prices, trends and current and expected policy drivers. The Base Case thus represents the scenario with "traditional" on-site power supply on the shelf detached from the Norwegian power market, and therefore represents our Alternative 1 (see section 2.2). Alternatives 3 and 4 assume different sources of dedicated power supply, and are thus in a power market context no different than Alternative 1. These scenarios are not modeled with BID.

[5] Several backtesting exercises, in which BID has provided both price levels and price variations very close to historical levels, confirm this point.

Figure 3.1 Scenario description for the power market modeling

<table>
<tr><td>Alternative 1: Base Case</td><td>Alternative 2: Onshore electrification</td></tr>
<tr><td>
</td><td>
</td></tr>
<tr><td>All electric power for processes at platforms is generated by gas turbines located at the platforms.</td><td>No gas turbines on the platforms (though heat is partly supplied by gas boilers), electric power supplied from central grid onshore. Electrification yields a small increase in renewable investments onshore.</td></tr>
<tr><td>Alternative 3: Dedicated CCGT with high efficiency</td><td>Alternative 4: As Alt 1 but with more efficient offshore elec generation</td></tr>
<tr><td>
</td><td>
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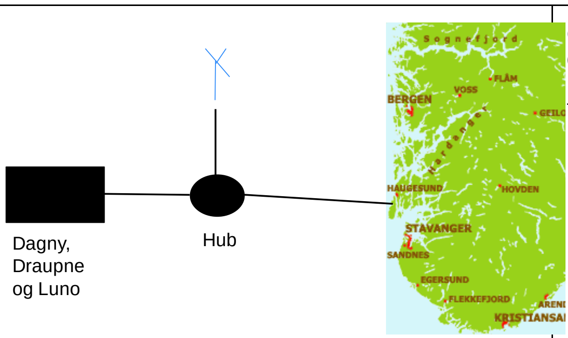
<tr><td>No gas turbines on platforms (though gas boilers supply som heat). Electric power supplied by dedicated onshore CCGT with high effeciency.</td><td>Electric power supplied by gas turbines at platforms, though more efficiently than Alt 1.</td></tr>
<tr><td colspan="2">Alternative 5: Onshore electrification and offshore wind</td></tr>
<tr><td>
</td><td>Offshore wind-power supplies half of required electricity demand at platforms from 2020. Wind-plant capacity delivers half of electricity required in 2020 and therefore delivers more than half for remaining years.

No offshore wind in Norway assumed in the other alternatives.</td></tr>
</table>

We expect that electrification will not lead directly to increased investments in renewable generation. First, the target for new (renewable) power generation is dictated by the Law of certificates which states that 13.2 TWh of new supply is to be facilitated between 2012 and 2020. This target is based on an estimated general demand growth of *certificate-obliged* demand. Whether electricity demand from offshore petroleum activities is certificate-obliged or not is inconclusive in the current judicial framework. If we assume that electrification of Dagny and Draupne/Luno will be certificate-obliged, and that electrification is not part of the demand forecast, then a demand increase of 800 GWh will lead to roughly 150 GWh of extra renewable investments in order to comply with the certificate target.[6]

Second, current power price forecasts are too low to incentivize commercial development of conventional natural gas generation (which is anyway politically restricted), and electrification will only have a negligible impact on power prices. In other words, electrification of Dagny et al will not push the Norwegian power market into a situation of shortage (except perhaps in extremely tight situations). The Norwegian power system is designed to handle supply/demand fluctuations of around 20-30 TWh between years. These mechanisms are discussed in detail in Appendix 5.

We have modeled a sixth Alternative, labelled 2b, as requested by Statoil to show what would happen *if* electrification would trigger a dedicated development of renewable generation (wind-power) also connected to the central grid. As this particular choice of concept deviates from current power supply policy and expected market adaptations, it is best viewed as a solution triggered by unforeseen developments such as an insufficiently accommodated infrastructure (grid) in western Norway or inadequate short term regional power supply from existing power plants. In this alternative, a development of an extra 320 MW is added on top of the 13.2 TWh facilitated by the certificate market. 320 MW is sufficient to supply peak demand at Dagny and Draupne/Luno in 2020. Consequently, the wind-plant will, when demand from Dagny et al is lower, supply the excess power to the central grid.

3.3.2 Bottlenecks and grid investments

For all alternatives we expect that Statnett's targets for internal grid development outlined in the 2010 Grid Development Plan are met. This removes most current Norwegian bottlenecks. One exception is the limited transmission capacity between the southern/southwestern part of the country.

Furthermore, we assume some investments in increased transmission capacity between Norway and other countries. In our Base Case as well as the other alternatives these investments include by 2020 a cable to Sweden (Southwest link, 1200 MW), Denmark (Skagerrak 4, 600 MW) and one transmission cable to Germany (1400 MW). We believe this assumption to be quite conservative and find it more probable that this capacity will increase beyond our Base Case assumptions. These developments will not remove bottlenecks between Norway and other countries, but are sufficient to export the entire Norwegian power surplus, a statement verified by our model results (described below). As Norwegian power generation is dominated by reservoir-hydro capacity, this implies that the producers in periods with grid capacity constraints will store more water and in turn release more in other periods. In other words, the transmission capacity will allow

[6] The 150 GWh are derived on the basis of the target quota for certificates, which in 2020 is roughly 18% of certificate-obliged demand.

Norwegian producers to export the total surplus throughout the year, but export grid bottlenecks will affect the exact timing of the export.

3.3.3 Efficiency/Loss assumptions and sources of CO_2 emissions

Electricity generation offshore is based on relatively inefficient gas turbines. Moving power generation onshore will therefore increase the inherent efficiency of the unit supplying power. Another component which offsets the efficiency gains is the loss of power that occurs when transmitting power across HVDC and AC cables. Most input data related to characteristics of offshore gas turbines and loss on transmission lines to the shelf have been provided by Statoil, while characteristics of the European power market are from Pöyry Management Consulting analysis. Technical assumptions are presented in Table 3.1.

Table 3.1 Efficiency and loss assumptions

	Alt 1 (Base)	Alt 2	Alt 3	Alt 4	Alt 5
Efficiency gas turbine	35% (21% off-peak)	Model result	58% (Dedic. onshore CCGT)	50%	Model result
Efficiency diesel generation	40%	Na	na	40%	na
Loss on HVDC cable	Na	5% (average)	5% (average)	Na	5% (average)
Losses on inter-national cables	Na	3-4%	3-4%	Na	3-4%

Source: Statoil, Pöyry.

We assume that the average distribution loss within Norway is 5.6%. This distribution loss and the loss on international cables in the table above reflect the physical loss by transmitting power on the grid from one place to another, implying that generation needs to exceed demand as some generated power is lost on the grid. This means that any CO_2 emissions reported in the results takes into account transmission losses.

For the different alternatives, there are several sources of CO_2 emissions related to the generation of power and heat. These sources are shown in Table 3.2.

Table 3.2 Sources of CO_2 emissions from heat and power generation

	Alt 1 (Base)	Alt 2	Alt 3	Alt 4	Alt 5
Source of electricity supply	GT offshore	Marg gen (model result)	Dedic. onshore CCGT	GT offshore	Marg gen (model result)
Heat demand Draupne/Luno	Exhaust from GT	18 MW gas boiler	18 MW gas boiler	Exhaust from GT	18 MW gas boiler
Diesel generator	5 MW 360 hours per platform	-	-	5 MW 360 hours per platform	-
Off-peak turbine operation with lower eff.	5 MW, 240 hours per platform	-	-	5 MW, 240 hours per platform	-
Emergency diesel generator (test)	2 MW 1 hour per week	-	-	2 MW 1 hour per week	-
Emergency diesel generator (ops)	5 MWh	-	-	5 MWh	-
Initialising generator ops	5 MW 50 days per platform	-	-	5 MW 50 days per platform	-
Flaring	0.3% of generation	Same as 1	Same as 1	0.3% of generation	Same as 1

Source: Statoil, Aker.

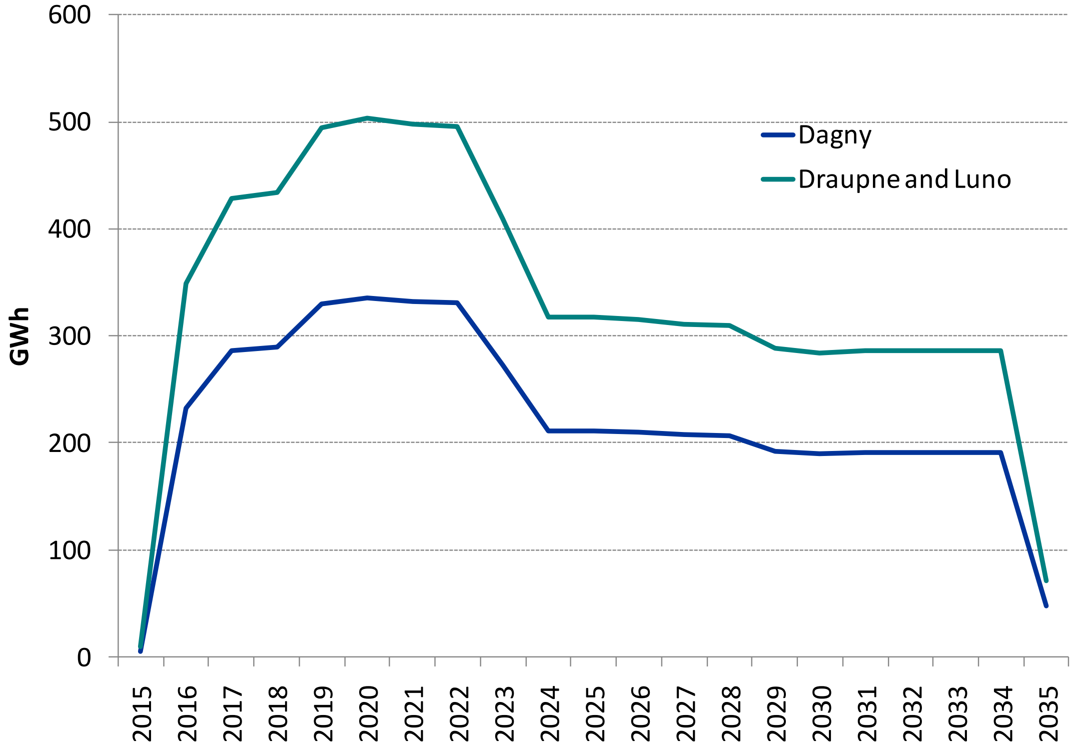
3.3.4 Increased demand for power

The only difference between the Base Case, which is our reference case without electrification – namely Alternative 1, and the case with electrification – Alternative 2, is a higher overall demand for electricity that needs to be balanced by more generation from the European power market.[7] The amount of electricity needed for extraction and other activities at Dagny has been provided to Econ Pöyry by Statoil. Figures for demand are based on Aker's Dagny Platform Concept Study (2011).[8] Electricity demand for Draupne/Luno has been set by Statoil to 1.5 times annual demand at Dagny. Total demand from these installations amounts to 11 620 GWh spread over the lifetime period of these installations, 2015-2035. The annual demand levels and profile is shown in Figure 3.2, where we see that demand peaks at 830 GWh in 2020.

[7] There is also an interconnector between the mainland and Utsira-høyden in Alternatives with electrification, though the interconnector itself will not yield any implications on the power market.

[8] Aker Engineering and Technology: "Dagny Platform Concept Study, Gas Injection Case. Attachment A09-01 Dagny Environmental Budget" (2011).

Figure 3.2 Demand for onshore electricity from Dagny and Draupne/Luno, GWh



Source: Statoil, Aker report.

Incremental demand for onshore electricity which follows from electrification is the same in Alternatives 3, 5 and 2b as in Alternative 2.

3.3.5 Other power market assumptions

Below is a summary of power market assumptions. A more detailed presentation can be found in Appendix 7.

- Deployment of new electricity generation based on renewable sources is mainly based on energy policy rather than commercial investment decisions, as the price of electricity is too low to yield long term profitability for most technologies.
- Through the EU RES Directive and the proposed joint certificate market between Norway and Sweden, we expect 26.4 TWh of new renewable power generation to be built in these two countries.
- Demand growth in the Nordic region will come mainly from establishments of new power-intensive industry.
- It is not expected that the planned renewable development will suffice in replacing all planned phase-outs of thermal power plants in Europe, implying that some new generation capacity is expected to be based on fossil fuels.
- The generation technology that will increase most compared to today's levels is wind-power.
- The overall share of gas-power relative to coal-power is expected to increase.
- As most existing coal plants will be phased out and replaced with renewable and gas-fired generation, the EU electricity market will get increasingly "cleaner".

- Fuel prices are based on Pöyry's Central scenario global market expectations for coal, oil and natural gas.
- Carbon market assumptions applied in the modelling implies an increase in CO_2 prices from 11 €/tCO_2 in 2011 to 55 €/tCO_2 in 2035 due to:
  - The EU Commission is committed to continuing the EU ETS scheme beyond the third trading period (2013-2020). Although a target for the subsequent period has not yet been set, we believe that the EU Commission will be looking to tighten the supply of allowances significantly as a) the EU ETS has so far failed to make low-carbon technologies competitive and b) other directives such as the Renewable Directive and Energy Efficiency Directive make the 2020 EU ETS target compliance relatively effortless.
  - While coal prices are expected to stay constant, higher demand increases the price of natural gas. This raises the cost of fuel-switching which is required to cut emissions also in the long term.
  - The most cost-efficient abatements in industry are undertaken first. This means that over the long term, increasingly more expensive abatements from industry are needed to meet the target.

Regarding transmission capacity, assumptions for the future are, as with any assumption, uncertain. Non-compliance with internal Norwegian grid developments described in the Grid Development Plan could as such imply that if a considerable power surplus is developed, this power surplus could be "locked in". Electrification would in this context be a valuable contribution to the Nordic power market in that spill is avoided. If this were the case, the environmental benefits of electrification would also be greater as replacement power would at least in part consist of power that would otherwise have ended up as spill.

3.4 RESULTS: EMISSIONS AND EMISSION FACTORS IN THE VARIOUS ALTERNATIVES

This section presents the quantitative results and conclusions on to what degree electrification of Dagny and Draupne/Luno decreases CO_2 emissions from the fields' electricity use during operations. The operational phase involves all processes involving generating electricity and heat for the Dagny and Draupne/Luno platforms, as outlined in Table 3.2.

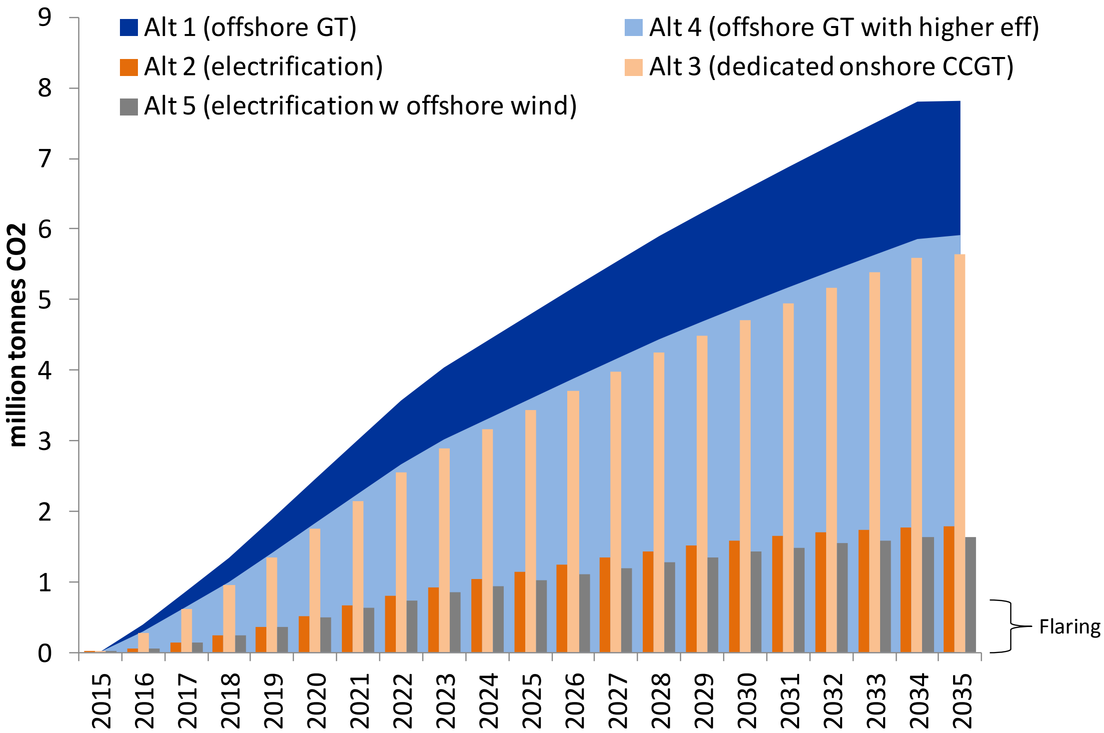
3.4.1 Net change in emissions

Change in emissions for the plants' operational phase resulting from electrification is split into emission changes in Norway (national emission effects) and emission changes in overall Europe (European emission effects). Emission changes in this context refer solely to emissions stemming from power and heat generation. National emission effects reflect how levels of emissions from mainland power plants *in Norway* compare to the emissions from a given offshore gas turbine. European emission effects reflect how levels of emissions from mainland power plants *in Europe,* compare to the emissions from an offshore gas turbine.

National emission effects – power and heat supply

Figure 3.3 shows the accumulated year-by-year CO_2 emission levels from sources that generate electricity and heat to Dagny and Draupne/Luno over the period 2015-2035. The blue areas show emissions in the alternatives with offshore GTs, while the bars show emissions from the extra level of electricity generation from the Norwegian mainland required to supply the platforms. Please note that the area for Alternative 4 is stacked “in front of” the area for Alternative 1. Emission levels in the Alternatives 2, 3 and 5 also include emissions from 18 MW gas boilers at Draupne/Luno required for heat generation that is not needed in Alternatives 1 and 4. Moreover, emission levels from flaring are included in all alternatives.

Figure 3.3 Accumulated national emissions from supplying power and heat to Dagny et al, mtCO₂



Source: Pöyry Management Consulting analysis

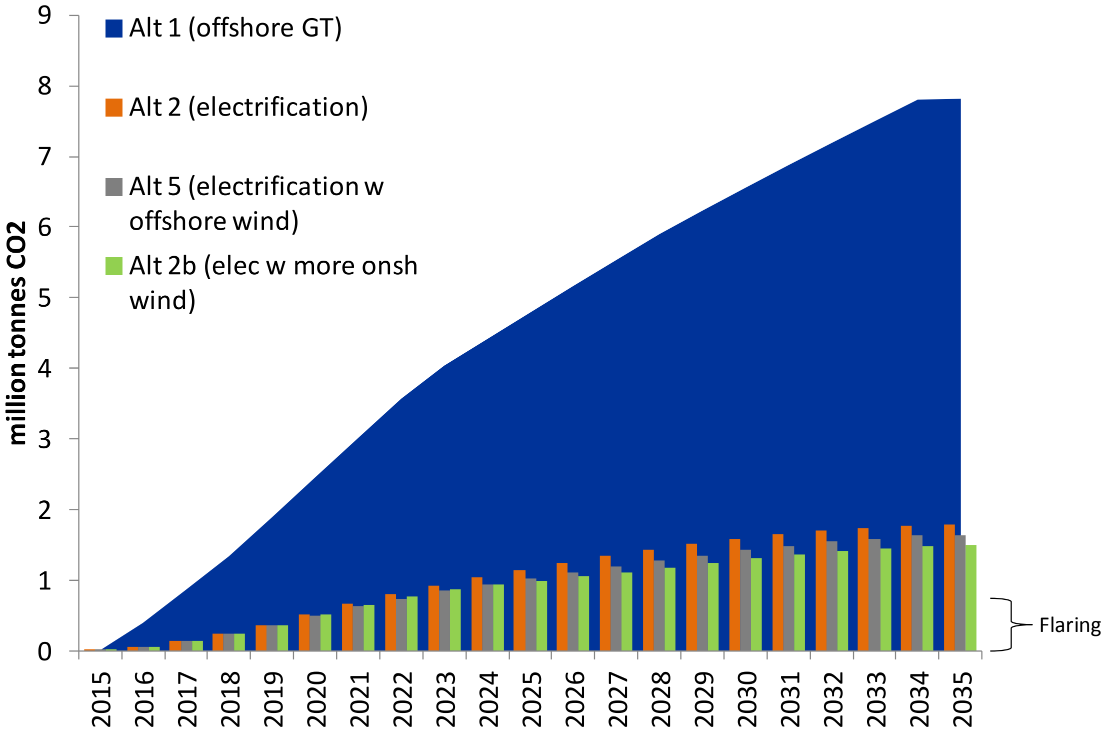
The net emissions saving following electrification is represented by the difference between the areas and the bars. Electrification of Dagny and Draupne/Luno saves a total of 6 million tonnes of CO_2 over the lifetime of the fields, and a further 0.2 million tonnes of CO_2 if offshore wind supplies half of the required electricity. As the supply of power from Norwegian power plants is based on renewable sources, most emissions stemming from alternatives with electrification (2 and 5) come from flaring and heat generation from gas boilers. These figures show that there are considerable gains to be made in terms of national emission reductions by electrification of offshore activities.

Reduction in national emissions from power generation following electrification is largely a result of having available excess power in Norway. Our modelling shows that increased indigenous demand leads to more of the power surplus being used in Norway, while net exports are reduced. Implicitly, this means that electrification will not yield higher annual power generation in Norway (a mechanism which is discussed below). The exception is that our modelling yields a slightly higher generation from the Kårstø and Mongstad gas-fired power plants. In the electrification Alternatives 2 and 5 Kårstø increases generation in 2020 with roughly 150 GWh, which is a result of slightly higher power prices yielding a marginal improvement in the spark spread. The increase in generation at Mongstad is negligible.

Alternative 3 also yields lower emissions than the alternatives with offshore electricity supply, as power is generated by a plant with better efficiency. The emission reductions are, however, offset by the loss on the interconnector between the mainland and the offshore installations.

Figure 3.4 shows accumulated emissions from the operational phase of the offshore installations for Alternative 2b, where wind capacity is developed to fully cover the electricity demand from Dagny and Draupne/Luno. In this alternative emissions are, not unexpectedly, lower than the other electrification scenarios. In fact, emissions from onshore power generation are lower than in Alternative 1 (not including the emissions from offshore power generation). This is because generation at the extra wind power plant mostly exceeds what is required at Dagny and Draupne/Luno, and therefore replaces power generation from Kårstø. For most years in the projection period, emissions from the operational phase in Alternative 2b therefore stem only from heat supply at Draupne/Luno and flaring.

Figure 3.4 Accumulated national emissions from supplying power and heat to Dagny et al – Alternative 2b, mtCO$_2$

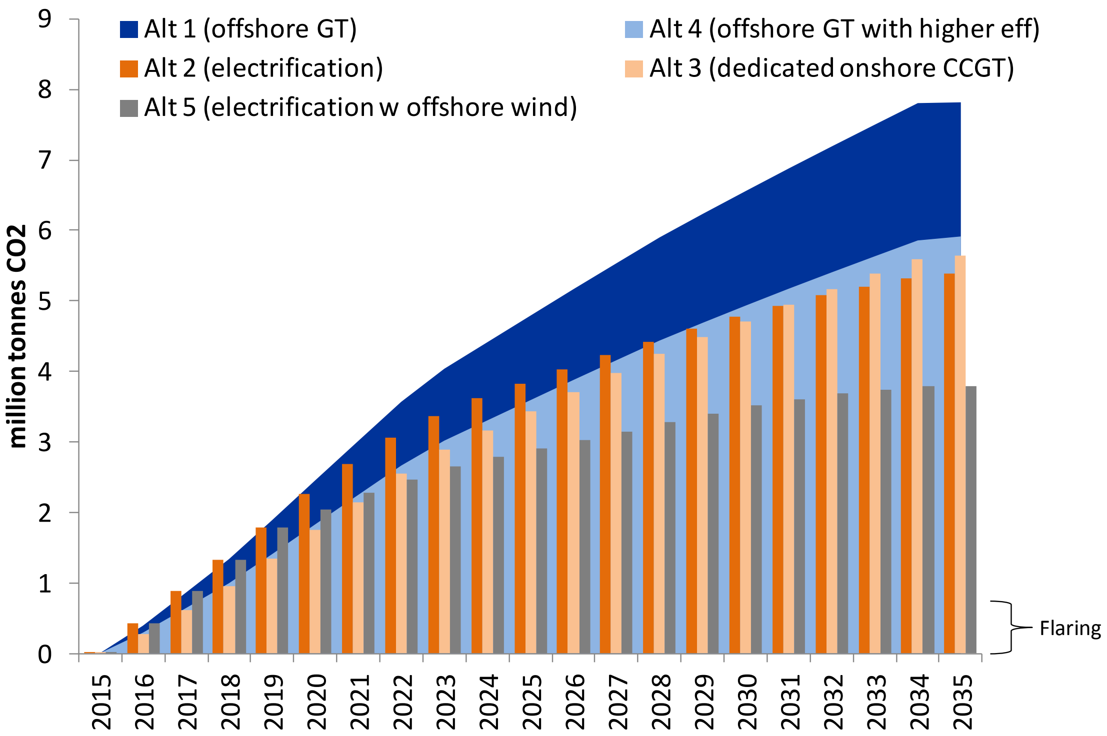


Source: Pöyry Management Consulting analysis

European emission effects – power and heat supply

Our model results show that higher electricity demand in Norway, *inter alia* from electrification from shore of offshore installations, does not in itself lead to higher electricity generation in Norway (Kårstø apart), but rather lower exports of Norwegian renewable generation. This means that Norwegian renewable generation is withdrawn from the European power market, which necessitates higher generation in the European power market to replaces "withdrawn" Norwegian exports. Replacement power is mostly based on thermal sources as renewable generation varies with climatic conditions rather than demand. Accumulated emissions taking into account higher thermal generation in Europe is shown in Figure 3.5.

Figure 3.5 Accumulated European emissions from supplying power and heat to Dagny et al, mtCO$_2$



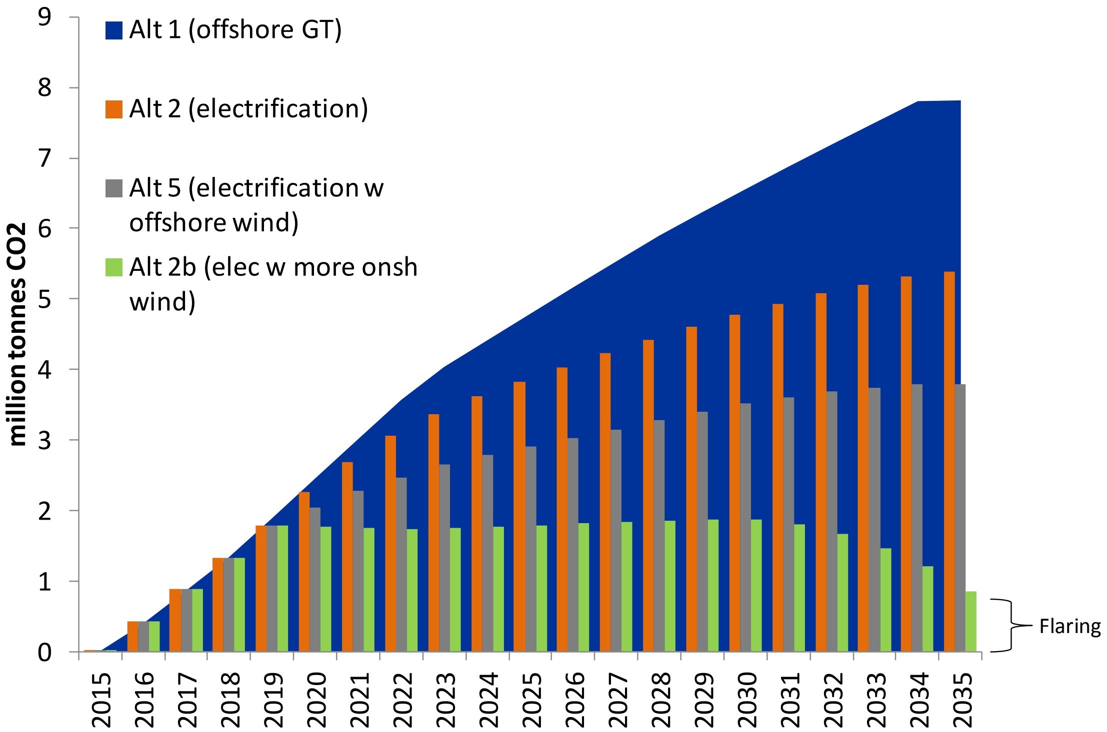
Source: Pöyry Management Consulting analysis

Total net savings in power supply CO_2 emissions from electrification of Dagny and Draupne/Luno for the whole of Europe over the period 2015-2035 is around 2.4 million tonnes (difference between Alternative 1 and Alternative 2 in 2035), i.e. considerably less than the national savings described above. Installing a dedicated gas power plant with high efficiency (Alternative 3) yields almost the same emission levels as when power is taken from the central grid. When offshore wind with capacity equal to half the electricity demand at Dagny and Draupne/Luno is installed savings are almost 4.5 million tonnes.

Replacement power from thermal power plants explains the relatively modest emission reductions for Europe as a whole. As we can see from Figure 3.5, the replacement power required to cover the withdrawal of Norwegian hydro-power in the short term (up to 2020) actually has a higher carbon intensity per unit of MWh produced than the offshore gas turbines. Over the projection period, however, the replacement power gradually gets “cleaner” as coal gradually will account for less of the overall capacity mix in Europe and thus its role as replacement power will decrease. This development is presented in more detail in Appendix 7.

Figure 3.6 shows the corresponding net changes in emissions for Alternative 2b with more onshore wind. Installing additional wind capacity to meet power requirements from offshore installations yields a total accumulated emission saving of around 7 mtCO_2, which exceeds savings in the alternative with offshore wind as well as national savings in the same scenario.

Figure 3.6 Accumulated European emissions from supplying power and heat to Dagny et al – Alternative 2b, mtCO_2



Source: Pöyry Management Consulting analysis

Emission savings in Europe in Alternative 2b actually exceed national emission savings in the same alternative. This is because the capacity at the extra wind-farm covers full demand at Dagny and Draupne/Luno in 2020. In the period after 2020, electricity demand from the offshore installations decreases while annual generation at the extra wind-farm stays constant. Therefore, the excess power from the additional wind-power is exported and thus replaces thermal power in European power markets.

This result is due to there being sufficient transmission capacity to export the extra wind-power, which effectively breaches the rationale for Alternative 2b. But this does not mean that Alternative 2b is inconsistent. The Norwegian power market is a dynamic market in which things develop co-ordinately over time. Alternative 2b can in this respect be seen as case in which extra wind capacity is built with the expectation of regional power not being available in 2020, yet after 2020 grid developments suffice to at least in part remove the bottlenecks.

A summary of the accumulated European and National emissions in the various alternatives is presented in Table 3.3.

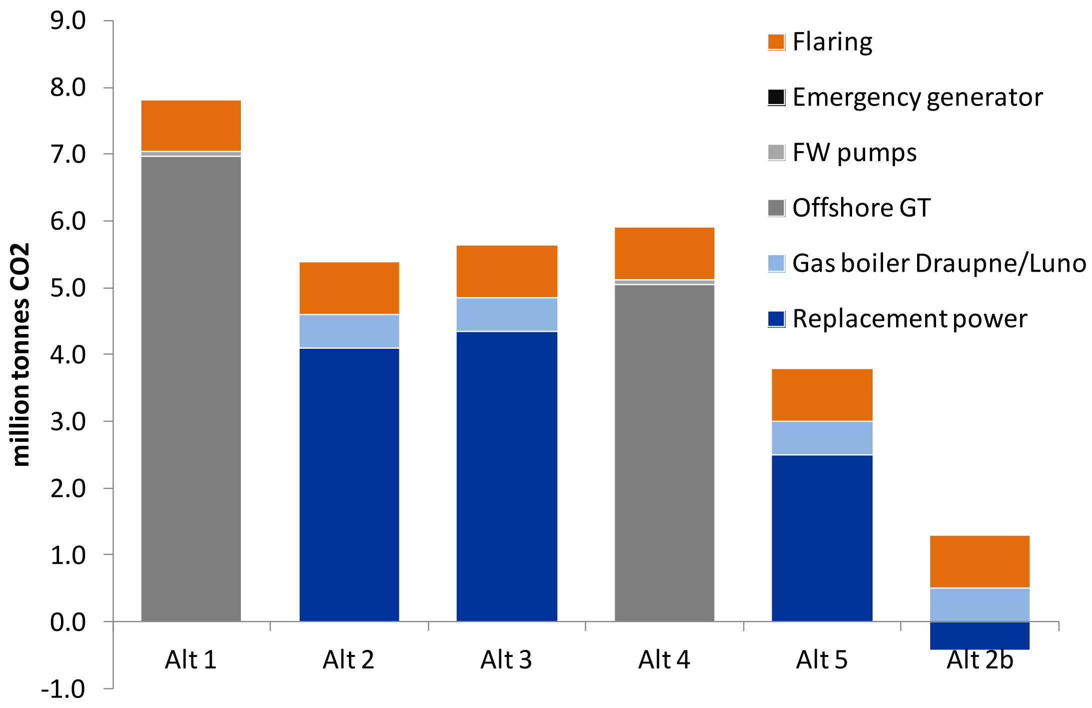
Table 3.3 Accumulated emissions from supplying Dagny et al with operational phase power and heat in all scenarios, million tonnes CO_2

	Alt 1	Alt 2	Alt 3	Alt 4	Alt 5	Alt 2b
European emissions	7.82	5.39	5.64	5.91	3.79	0.86
National emissions	7.82	1.78	5.64	5.91	1.64	1.50

Source: Pöyry Management Consulting analysis

Share of emission sources for the operational phase varies between the alternatives. In alternatives with offshore supply of power, offshore gas turbines comprise the highest share, while replacement power accounts for most emissions in electrification alternatives. These results are shown in Figure 3.7.

Figure 3.7 Emission by source in various alternatives – accumulated 2015-2035, million tonnes CO_2



Source: Statoil, Pöyry Management Consulting analysis

From the figures above we can establish that electrification of Dagny and Draupne/Luno means that emissions from supplying the required power and heat falls compared to a situation with no electrification. That this also happens in cases where electrification does not yield a significant increase in renewable power supply in Norway (Alternative 2) testifies to the robustness of this conclusion.

Effect on total European emission level

Given that offshore petroleum activities are part of the EU ETS, electrification will not yield an overall decrease in emissions in Europe beyond the EU ETS emissions reduction target. This is attributable to the way the cap-and-trade system is designed. The total amount of allowances available to sectors included in the EU ETS, or the cap, is pre-determined by the Commission, where the amount of available allowances decrease each year between 2012 and 2020.[9] Available allowances are traded freely between EU ETS sectors, such that any sector with higher emissions than its allowances needs to procure additional allowances from sectors with a surplus. If there are not enough allowances for

[9] Between the years 2013 and 2020, the amount of available allowances (cap) will decrease from 2.04 billion tCO_2 in 2013 to 1.78 billion tCO_2 in 2020. The cap will reduce annually by 1.74% (37,435,387 tCO_2).

all EU ETS sectors together, emission reduction measures need to be undertaken. Failure to meet the cap will result in penalties which have a higher cost than the CO_2 price.

Electrification is one of many possible measures to reduce CO_2 emissions, and thereby meet the EU ETS emission reduction target. If electrification is carried out, it means that some other emission reduction measure has become redundant and need not to be undertaken in order to meet the target. The emission reduction target is met regardless of which measures are carried out to meet it, and over time total EU ETS emission levels will equal the target whether or not electrification is executed.

With today's CO_2 price, electrification will have a negative price effect on CO_2 allowances. The EU ETS mechanism implies that if abatement measures are required to meet the cap, the most cost optimal abatement measures are carried out first. The price of CO_2 allowances, equal to 10 €/tCO_2 in late 2011, is the cost of the most expensive abatement measure needed to meet the cap. The abatement costs of electrification exceed this level. If electrification is carried out anyway, some measures with abatement cost lower than the CO2 price that otherwise *would* have been required are not needed as the emission reductions that would have been obtained from this measure, are covered by electrification.

The following example illustrates the above: Suppose that the two most expensive abatements required in a situation without electrification had respective abatement costs of 14 €/tCO_2 and 15 €/tCO_2 and that both these measures saved 1 million tonnes of CO_2. The CO_2 price would in this case be 15 €/tCO_2. If we assume that electrification is executed and saves 1 million tonnes of CO_2, there will be no need for the 15 €/tCO_2 abatement, and the CO_2 price would therefore be reduced to 14 €/tCO_2.

It is important to note that electrification would only yield a decrease in the price of CO_2 if it actually leads to lower net emissions from heat and power supply. If, on the other hand, replacement power is made up entirely of coal-fired electricity, the power sector would end up demanding more allowances than would be freed from electrification. The EU ETS would therefore require *more* emission reduction measures to balance the carbon market, which would result in an *increase* in costs for CO_2 allowances. However, as we have seen in the case of Dagny et al., replacement power is mostly made up of efficient gas-power, and the outcome is that electrification yields lower emission reductions from European power supply.

If, in a hypothetical sense, the petroleum industry was not part of the EU ETS, replacement power would raise the demand for allowances by the power sector. If the petroleum industry was outside EU ETS, no allowances would be freed from electrification, and the CO_2 price would increase as long as replacement power is partly supplied by fossil-based power generation. Increased emissions from replacement power would therefore be offset by other emission reduction measures. Taking the emission reduction from the offshore installations into account, electrification in this situation would yield an overall decrease in European emission levels as emissions from the offshore installations would fall while EU ETS emissions remained the same.

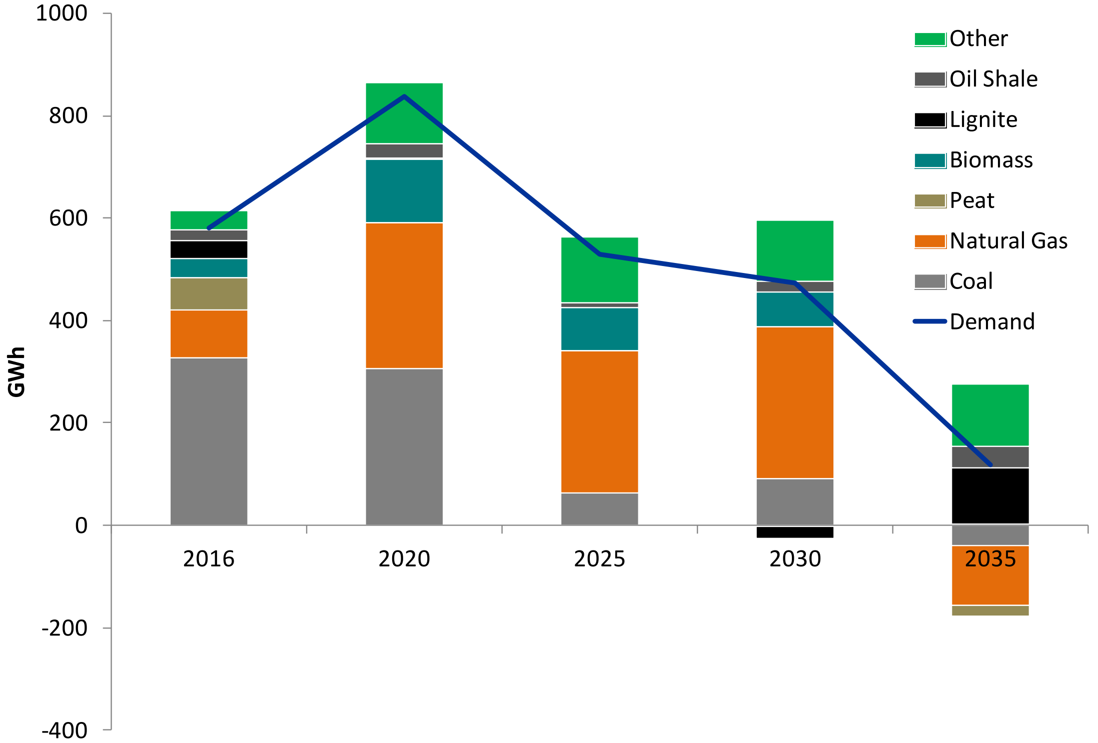
3.4.2 Replacement power and emission factors

This section presents the composition of replacement power in Alternative 2 (and Alternative 5), which explains the overall emission effects presented above. Replacement power composition also provides emission factors, i.e. the average unit of CO_2 emission per kWh supplied to the Dagny and Draupne/Luno operational phase. Our calculation of emission factors is compared to emission factors calculated by the Norwegian Water Resources and Energy Directorate (NVE)/Norwegian Petroleum Directorate (NPD).[10]

Replacement power

Relative modest power supply emission savings in Europe following electrification can be attributed to the nature of the replacement power, i.e. what power replaces the withdrawal of Norwegian renewable power for the thermal power market in the case of electrification. In Figure 3.5, we see that emission levels are in fact greater in Alternative 2 than Alternative 1 in the early years. This is because the marginal power from the Continent is made up of mainly coal power. The composite of the marginal power is shown in Figure 3.8.

Figure 3.8 Replacement power by technology following electrification, GWh



Source: Pöyry Management Consulting analysis

The composition of the replacement power is mainly a result of the relative marginal production costs in the modeled years and also of plant availability. As renewable and nuclear power are intermittent and inflexible, and therefore do not vary with (small) changes in demand, it is mostly coal and gas generation that changes. In 2016 coal makes up most of the replacement power due to:

- In 2016 there remains significant coal-fired capacity with sufficient flexibility
- CO_2 prices in 2016 are relatively low, making coal generation more competitive than gas generation

Over the longer period, coal accounts for less of the overall capacity mix in Europe while CO_2 prices also increase. Therefore, replacement power is increasingly made up of CCGT

10 "Kraftforsyning fra land til sokkelen" (2002).

generation, which yields higher emission reductions in CO_2 emissions in the longer term in Alternative 2 compared to Alternative 1.

Hydro generation is not part of the replacement power composition.[11] This is because generation from hydro-plants is not adjusted upwards as a result of increased consumption, as generation from these plants is determined by inflow rather than demand. For inflexible run-of-river plants this is obvious. Larger reservoir hydro-plants also restrict their annual generation to equal the inflow they get over the same year. If they did not, then subsequent over- or under-generation could lead to either dry reservoirs or spill, which is something that hydro-producers are keen to avoid. So, although electrification could change the generation pattern in hydro reservoirs (i.e. shift generation between periods), the overall generation level would remain the same.

Emission factors

An emission factor is typically defined as the amount of CO_2 emitted from generating 1 kWh of electricity – kg CO_2/kWh (or any other polluting source, such as NOX). Fossil fuels such as coal and gas have a fixed emission content (content of CO_2 in one unit of energy), which is adjusted for plant efficiency to find the emission factor. If a gas-fired plant, say, has an efficiency of 50% it needs 2 kWh of gas to generate 1 kWh of electricity. If we assume that natural gas has a CO_2 content of 0.2 kg CO_2/kWh, the emission factor from this gas-fired plant is 0.4 kg CO_2/kWh. Coal plants have higher emission factors than gas plants, while the emission factor from renewable plants is typically zero.

Emission factors are applied in various contexts. In terms of practical use, emission factors are sometimes used as benchmarks to which an installation applying for concession needs to compare its emissions to. Emission factors are also used as indicators for the "cleanness" of future power markets. For instance, CO_2Focus calculated an emissions factor for the Nordic countries in 2008 equal to 0.099 kg CO_2/kWh. In its contribution to Klimakur, NVE reported a Norwegian emission factor for power generation of close to zero, while the Norwegian Ministry of Municipalities and Counties (KRD) report an emission factor for electricity for heating around 0.36 kg CO_2/kWh. The difference between the Statnett/NVE factor and the KRD factor is most likely to do with methodology, where Statnett/NVE calculate an *average* emission factor for Norway whereas KRD calculates a *marginal* emission factor (i.e. the emission factor comes from the increase in generation, a CCGT without CCS, required to meet a marginal increase in demand).

In this study we quantify emission factors from European power generation that constitutes the replacement power as mentioned above (i.e. marginal emission factor). In the report released by NVE/NPD in 2002, CO_2 emission factors from extra electricity imports following electrification were assumed to decrease from 0.788 kg CO_2/kWh in 2003 (mostly coal) to around 0.29 kg CO_2/kWh in 2028 (from mostly natural gas) taking carbon contents of coal/natural gas and expected efficiency developments into account. NVE/NPD's methodology is applicable to this study.

Our analysis has calculated the emission factors from all forms of electricity generation in the various alternatives. In the alternatives with natural gas generation either offshore or onshore (Alternatives 1, 3 and 4) the emission factors are based on the efficiency from the different turbines. In Alternatives 2 and 5, the emission factors are calculated as a weighted average of emission factors from all types of replacement power in the alternatives. The results are shown in Table 3.4.

11 Hydro generation in this context refers to generation from the available capacity. I.e. it is not to be confused with the additional hydro generation from new hydro investments triggered by the certificate market, which, as we have discussed, will come online whether Dagny et al is electrified or not.

Table 3.4 Emission factors from power generation, net of efficiency, kg CO_2/kWh

	Alt 1	Alt 2	Alt 3	Alt 4	Alt 5	Alt 2b	*NVE/OD*
2016	0.621	0.727	0.375	0.435	0.727	0.727	*0.333*
2020	0.621	0.504	0.375	0.435	0.202	0.000	*0.333*
2025	0.621	0.304	0.375	0.435	0.080	0.000	*0.333*
2030	0.621	0.325	0.375	0.435	0.125	0.000	*0.286*
2035	0.621	0.444	0.375	0.435	0.019	0.000	*0.286*

Source: Pöyry Management Consulting analysis.

The table above shows that emission factors from replacement power gradually decrease as the European power market to an increasing degree consists of renewable and natural gas generation capacity. Moreover, we see that emission factors are considerably lower when additional offshore wind covers half of electricity requirements (Alternative 5) and additional onshore wind covers the full electricity requirement (Alternative 2b).

Emission factors in Alternative 2 are mostly higher than emission factors from the NVE/NPD study from 2002. This is likely to do with the following:

- NVE/NPD emission factors take into account a significant improvement in efficiency as several old thermal plants were expected to be phased out. However, the lifetime of several thermal plants in Europe has been extended over the last ten years.
- NVE/NPD broadly assume that one particular technology (gas-fired plants) will provide replacement power. Our model shows that replacement power is a composite of several generation types, including coal.
- NVE/NPD assume that electrification will increase power prices and therefore curb generation. We argue that the price effect is negligible, and so ignore this mechanism.
- NVE/NPD assume that an increase in demand from electrification will trigger developments in new power generation. We argue that this is broadly not the case, and therefore assume the same level of generation between our Base Case (Alternative 1) and electrification scenario (Alternative 2) – except a minor wind development triggered by (uncertain) certificate market mechanisms which contributes to a lower emission factor in our study than NVE/NPD.

3.5 POTENTIAL EU POLICY RESPONSE TO ELECTRIFICATION

As the petroleum sector is part of the European carbon market, emission reductions in the EU resulting from electrification are modest compared to national emission savings and will most likely not lead to emission reductions at all. We argue, however, that electrification may lead to lower CO_2 emissions in both the short and the long term on the condition that climate measures such as electrification is followed up by a stricter international climate policy in the long term and that the market expects this to happen.

As we have seen from the emission factors above, electrification of the shelf leads to lower overall emissions from power supply in Europe (including the Norwegian shelf) than would be the case with “traditional” offshore gas turbines supplying heat and power. This means that fewer other emission reduction measures are needed to meet the emission target, and the price of CO_2 falls. The price reduction can be explained by electrification being an emission reduction measure not triggered by the market, i.e. the carbon cost of abatement is higher than the cost-effective solutions that the EU ETS will trigger.

Lower carbon prices have implications for EU ETS in both the short and long term. First of all, allowances can be saved between trading periods. Second, carbon prices are mostly driven by market participants' expectations. Lower carbon prices in the short term will as such affect both market behaviour and policy response. The effects are outlined below:

- A lower carbon price in the short term makes it more attractive for market participants to save allowances in the current trading period (i.e. undertake more abatements) and sell these at a later stage, provided market participants expect prices to increase. If the market participants believe that lower prices in the short term yields a tightening of the market in the long term, this effect is amplified.
- In policy terms, a lower price in the short term makes it less costly to raise the target in the longer term. If measures outside the EU ETS have achieved a significant reduction of emissions (which gives a lower price), it means that fewer abatements are needed within the EU ETS when the target is raised.
- There are strong indications from the EU that the EU ETS has been devised so as to obtain a specific price of CO_2 emissions. The intention with the EU ETS, as well as the climate directive, is to make low-carbon technologies competitive, or make energy-intensive industries adapt to a tighter quota regime. This is a development current low CO_2 prices are not capable of triggering. Lower CO_2 prices will also curb income for the EU Commission by selling allowances, an income which partly serves as a fund for technological development of, among other things, CCS. Lower CO_2 prices also make abatement measures in developing countries, through CDMs, less competitive.

Recent signals from the EU suggests that current low carbon prices resulting in part from compliance with the Renewable and Energy Efficiency Directives incentivizes tighter emission targets both in the short and in the long term. First of all, the EU Commission has decided that if an international climate agreement is reached before 2020, the 20 percent emission reduction target will be increased to 30 percent.[12] Second, in its 2050 Roadmap publication[13], the EU Commission communicates that the 2020 target should be increased to 25 percent if EU member states comply with the targets set out in the Energy Efficiency Directive. Third, the Roadmap states that a transition towards a low carbon economy means that the EU should prepare for reductions in *domestic* emissions by 80 percent by 2050 compared to 1990.

Although the suggested targets in the above paragraph have not yet been set, they clearly signal what the EU is aiming towards. The 25 percent target and the 80 percent have been derived by internal EU analysis, which suggests that targets of this magnitude are the most cost-efficient way of achieving a low carbon economy in the longer term. The EU argues that less stringent targets could imply a "lock-in" of carbon intensive investments in the short run as short term carbon prices with lose targets would remain low. These investments could then result in infeasibly high carbon prices towards 2050.

Locked in carbon intensive investments in the short term is thus something EU wants to avoid. The Roadmap moreover clearly outlines that the EU Commission will continue to ensure that the EU ETS remains a key instrument to drive low carbon investments in a cost-efficient manner. Both these statements clearly indicate that the EU is prepared to set tough emission targets in the longer term, and that these targets be clearly communicated to carbon market participants.

Electrification thus amplifies the trend towards low CO_2 prices already triggered by compliance with EU's Renewable Directive and Energy Efficiency Directive, as well as

[12] In the current international climate, an international climate agreement by 2020 seems unlikely.

[13] COM/2011/0122 final: "A roadmap for moving to competitive low carbon economy in 2050", March 2011.

lower industry activity resulting from the economic recession. As discussed above, from an EU perspective, any developments that lead to lower prices should therefore induce a more ambitious carbon policy. It is important to note that electrification of Dagny and Draupne/Luno on its own is too marginal to influence EU policy, but nevertheless constitutes one of many developments that could spur tighter emission targets in the future.

The roadmap also says that the EU will remain attentive to the risk of carbon leakage in order to ensure a level-playing field for industry. This signals that although the EU Commission is prepared to set tough targets, the current arrangement of free allowances for industries deemed to be exposed to carbon leakage is set to continue.

All communication from the EU Commission regarding the future of EU ETS was moreover published before the implications of debt in the PIGS countries became clear. Imposing tougher and more expensive regulations at a troubled European economy may not be a feasible policy for the EU, at least with current market conditions.

3.6 IMPLICATIONS FOR THE GAS MARKET

A common objection to electrification as a climate measure is that if the gas extracted at offshore fields is not used for power generation on the fields themselves, it will be shipped to gas power plants and continue to emit CO_2, thereby offsetting the emission reductions. Analyzing this statement comprehensively and quantitatively is outside the scope of this study, but we include a qualitative assessment of whether this argument will alter our results.

While electrification will yield an extra amount of gas that will most likely be burned somewhere, whether or not this affects our results depends on where the extra gas ends up. As most natural gas exports from Norway end up in European power plants, and these are CCGTs, the extra gas from Dagny et al ends up in a gas power plant with higher efficiency than the offshore gas turbines.

In our analysis, the composition of replacement power does not take into account what type of gas or amount of gas is available for thermal power plants in Europe, although we do assume that over time the gas market will tighten and prices increase. As such, we assume that natural gas is a scarce, yet fully available resource for European power generation. As natural gas exports from Norway contribute to a delinkage between gas and oil-indexed contracts, an increase in Norwegian gas exports will most likely yield lower gas prices, although this effect is likely to be marginal. That gas prices are lowered implies that CCGTs gain (a small) competitive advantage against coal-fired generation, yielding increased incentives for gas generation.

Conclusively, we can say that the extra amount of gas does not affect our conclusions in this study, and if there is an emissions effect from extra gas being exported it most likely leads to a downside, i.e. further reductions in emissions.

3.7 EFFECTS OF PURCHASING ORIGIN CERTIFICATES

The purchase of Guarantees of Origins (GoOs) means that the power consumer is guaranteed that the extra power comes from renewable sources. This is an option that is available to the operators at Dagny and Draupne/Luno.

Purchasing GoOs simply means that the emissions from the operational phase of the installations falls compared to our results for Alternative 2. The overall emissions effects would, however, be negligible. This is because GoOs do not affect the overall power generation in Norway, but rather channels renewable power somewhat differently. The only implication for overall Norwegian power generation would be if channeling more renewable power to Dagny et al has implications on the grid, and thereby affects other producers' opportunities to adjust generation.

Following the same reasoning as above, purchase of GoOs is not expected to affect European power generation and appurtenant emissions.

There is, however, one implication of purchasing GoOs that is worth mentioning. If operators at Dagny and Draupne/Luno decide to purchase GoOs it would raise the price of the certificates as demand increases. This in itself makes investments in renewable generation more profitable. Although the profitability effect on Norwegian renewable investments is arguable (electricity certificate market ensures profitability) it could have an (albeit marginal) impact on renewable investments in other countries.

4 EMISSIONS FROM THE POWER SUPPLY SYSTEM

The focus of the analysis is the accumulated green house gas emissions for the projects Dagny and Draupne/Luno with different solutions for power supply. Here we assess emissions related to production, and de-commissioning of the installations.

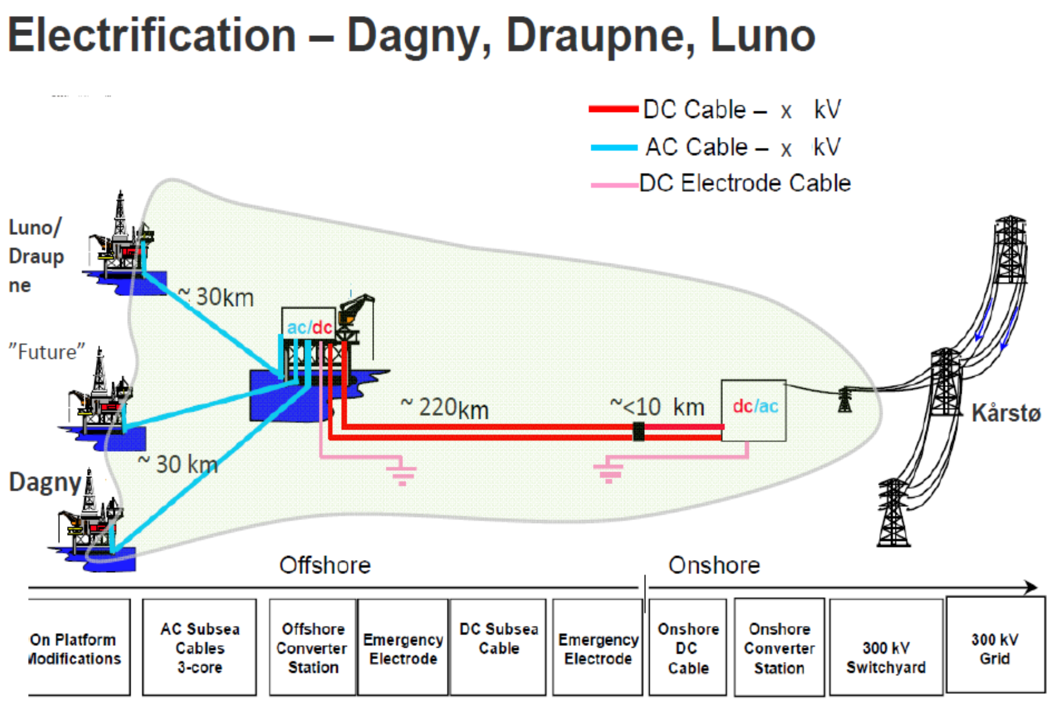
The assessment is summarized in an environmental account for the different alternatives. These findings will be linked with the findings of the power market analysis presented in chapter 3, and a full picture of the total CO_2 emissions of the various solutions, distributed to local/global, offshore/onshore and per year will be presented in chapter 5.

4.1 SYSTEM BOUNDARIES AND DATA SOURCES

4.1.1 System boundaries

Installations included in the analysis are indicated in Figure 4.1. As we can see emissions from construction of onshore power plant and power grid is not included in the analysis. Emissions from power generation are however assessed in chapter 3.

Figure 4.1 Delimitation



Source: Statoil

The different alternatives will include some common components, mainly the production platforms, while other components will differ between different choices of power supply. In Table 4.1 all major components and factors are listed, and it is indicated if the component is a part of the alternatives.

Table 4.1 Overview of components in the five alternatives

Components	Alt. 1 Offshore gas turbins	Alt. 2 Power supply from onshore grid	Alt. 3 Dedicated power from Norwegian gas power plant	Alt. 4 Optimized offshore power production	Alt. 5 50% Norwegian offshore wind power
Onshore converter station	-	+	+	-	+
Onshore switchgear	-	+	+	-	+
Onshore DC cable	-	10 km	10 km	-	10 km
Offshore DC cable	-	220 km	220 km	-	220 km
Offshore AC cable	-	30 km	30 km	-	30,1 km
Transformer	-	-	-	-	+
Offshore Hub platform	-	+	+	-	+
Offshore converter station	-	+	+	-	+
Offshore switchgear	-	+	+	-	+
Offshore gas turbine	5	-	-	5	-
Luno/Draupne platform	Equal for all alternatives				
Dagny platform	Equal for all alternatives				

Source: Statoil

The core of this part of the analysis is the quantification of the life time emissions related to the infrastructure that differ between the alternatives. Emissions related to power production is not part of the scope. A wide variety of processes and components are included in the infrastructure. We will limit our assessment to components that both differ and are major contributors to the environmental account. The boundaries are elaborated on in appendix 3.

We will, however, also quantify emissions related to elements independent of choice of power supply, like the production platforms, but these analyses will be less detailed.

In this project the assessment of greenhouse gas emissions is limited to CO_2. This is a natural delimitation because the current EU ETS market of emission quotas is limited to CO_2, and the quota market holds a key position in this study.

Technical lifetime for cables, hub platform, including converter and other equipment, is set to 40 years. The lifetime of the field developments is on its side set to 20 years. This implies that only half of the life cycle emissions from the components related to electrification will be assigned to the development projects, while the other half are assigned to a future use, not specified.

In the case of electrification we assume that cables and hub-stations are re-used when operations at Dagny and Draupne/Luno are shut down. Possible re-use can be related to an offshore wind park or electrification of future installations in the area.

Recycling will generate a positive effect for the environmental account in accordance with saved emissions related to the production of new materials. We will calculate the benefits of recycling according to present technology.

4.1.2 Transport and installation

According to the client and producers of cables, most input materials are likely to be produced somewhere in Europe and be transported to the cable manufacturing plant in Sweden. We assume that this will lead to transport, by lorry, for an average of 1000 km.

Raw materials used in platform construction may origin from all over the world, but are most likely also to be produced in Europe. We therefore assume that the production of metal products needed to build the platforms is carried out in Europe, and will require transport of 1000 km by vessel. Since we do not know where recycling will take place in the future, we assume the same transport need as for metal products, namely 1000 km by vessel.

We have calculated tonnes-kilometers (tonnes x kilometer distance), and multiplied the total with emission factors per tonnes-kilometers. For ships the factor used is 3.5 g CO_2/tonnes-km[14]. This factor can vary quite a lot, but is an average estimated for short sea shipping in Norway. For lorry the equivalent is 76 g CO_2/tonnes-km[15].

4.1.3 Data sources

Different sources of data have been used in the analysis. Where available, we have used Life Cycle Assessments (LCA) or similar environmental assessments made available by the producer of the various components.

Where environmental information has not been available from the producer, we have collected weight information for material use, and information about energy consumption in the production of the various components. This information has, together with life cycle data and available emission factors for the materials and production processes, been used to calculate emissions. Data sources are further described in appendix 4.

We have been able to collect these kinds of data for all components separating the alternatives. For the production platforms we have assumed that the total weight consists of only steel. This implies that these estimates are considerably more uncertain than the rest of the analyzed data, but as the production platforms are the same in all alternatives they do not affect the calculation of the *difference* between the alternatives.

4.2 CONNECTION TO ONSHORE POWER GRID

100 percent onshore power supply is assumed in alternative 2 and 3, while 50 percent onshore power supply and 50 percent offshore wind power is assumed in alternative 5. The power will be taken from the onshore net.

An onshore converter station will convert power from the onshore net to the HVDC offshore cable. No new buildings are needed. ABB has provided us with a rough estimate for CO_2-emissions related to the converter stations. The onshore and offshore converters are identical, and have the same emissions related to them. The converters consist of one valve and one transformer. It is assumed that the converter has a continuous workload of 70 percent[16]. Total life cycle emissions per converter are estimated to 250 tonnes CO_2.

An onshore switchyard is already present, but will need additional switchgear. The same kind of switchgear will also be installed at the offshore hub. Siemens has provided an LCA

14 Source: Møreforskning.

15 Source SSB – "Energiforbruk og utslipp fra innenlandsk transport" (2008).

16 This gives the valve an estimated lifetime of 30 years, the transformer 40 years. We do however assume 40 years lifetime for all components. This has minor impact on the calculations.

conducted on equivalent switchgear, and total emissions per switchyard are calculated to 125 tonnes CO_2. All emissions are defined as onshore, global and to take place during the construction phase.

4.3 CABLES ONSHORE AND OFFSHORE

Electrification requires offshore power cables, and these include fiber for data transmission offshore. We assume that cables with fiber will be installed regardless of choice of power supply. We also assume that the cables will have the same total length, and that installation of fiber cables for both Dagny and Draupne/Luno will be coordinated, as is the assumption for electrification.

For offshore application, the cables will be surface laid with a cable laying vessel and a second vessel will perform the post lay trenching. Due to the quantity of cable there will be a number of laying campaigns dependant of the final cable design and the power supply alternative selected. The cable to shore will be floated and winched ashore. The installation vessel will lay the cables along the pre-determined routes with minimal residual tension to assist with the post trenching. Siemens has estimated that a total of 280 km of trenches are needed, and that 100 days will be needed for the job.

Information from Statoil indicates that a vessel suitable for the job on average uses 14 tonnes of diesel per day of operation.

The cables will be collected by the installation vessel from a factory. We have assumed that the cables will be produced in Karlskrona, Sweden, approximately 1000 km from Kårstø. The offshore cables have an estimated weight (DC and AC) of a total of 12 700 tonnes, and transportation is therefore estimated to approximately 12 700 tonne-km (distance x weight) with vessel, which equals 45 tonnes CO_2.

International experience with submarine power cables indicates that the main causes of failure are ships' anchors, heavy fishing tackles, hooking, impacting, major earth quake, and vandalism. The damage is usually in shallow water, 10 to 50 m water depth. In this study we assume no emissions related to repair and maintenance off the offshore cables during the operation period.

Three cables are needed for onshore power supply for the production platforms: First, 10 km of onshore feeder cable to the converter is needed. Second, an offshore DC-cable is connecting the onshore converter with the hub-station. This cable is 220 km long, with a total weight of 9 314 tonnes, and is one of the heaviest components in the electrification system. Finally, on the hub-station the power is converted back to AC from DC, and is further transmitted to each of the two production platforms through separate AC cables, 30 km each. As the power demand of the production platforms differ, the cables are dimensioned somewhat differently with Draupne/Luno: 3 x 240 mm^2, and Dagny: 3 x 150 mm^2.

In Alternative 5 50 percent power supply from an offshore wind park is assumed. In that alternative we include 100 meters of AC-cable to connect the hub with the wind park.

CO_2-emissions for all cables have been estimated based on information provided by Nexans about material use and energy consumption in the production of the cables. For the AC-cable Nexans has conducted an analysis of a cable with size 185 mm2, which is then used as an average for all AC cables in this study.

In the case of laying only fiber cables (no electrification) we assume 50 percent of the emissions from laying and installation of the power cable. The reason for this is the fact that the power cable will have larger diameter and higher weight than a fiber cable. The length of the HVDC cable might also be somewhat different, depending on where the fiber cable reaches the onshore connection. These matters are however thought to have minor impact on the overall calculations.

All emissions are defined as onshore, global and to take place during the construction phase.

4.4 THE OFFSHORE HUB-STATION

Electrification of multiple production platforms is simplified by establishing a hub-station between the installations converting and distributing the power. The alternative would be to establish a converter on one of the production platforms, and send the power on to the next one from there. But this would result in a rigid system in which the last platform is dependent on the first one with regard to start-up and shut-down date, and possible down time.

The hub-station is located between the production platforms, approximately 30 km from each. Estimated water depth is 116 meters. It includes a converter and switchgear– equivalent to the onshore equipment. The hub is unmanned, but includes helideck and emergency shelter, used for maintenance operations.

We have received a detailed inventory list for the topside of the hub, and have calculated emissions based on the amount of steel and aluminium used. For converter and switchgear we use LCAs made available by producers. The hub will include a jacket mounted on the seabed with piles. The jacket and piles consist of a total of 7000 tonnes steel, and emissions have been estimated by the weight of the construction. In Alternative 5 an additional transformer will be needed. Here we have used LCA-information from ABB to calculate emissions. Installation of this transformer is not believed to have any further significant impact on the design of the platform.

Installation of the topside on the hub-station will be conducted by a semi-submersible crane vessel, and it is assumed that the chosen vessel will lift the topside of the hub in one operation, and the production platforms in two operations. Emissions from installation of a process-platform have previously been assessed by Statoil for the fields Gudrund and Sigrun (Statoil 2010). Based on this information emissions related to the installation of the hub topside are estimated to 5 500 tonnes CO_2.

4.5 POWER GENERATION BY OFFSHORE GAS TURBINES

Offshore gas turbines provide power supply for Alternatives 1 and 4. The difference here is that power generation has been optimized in Alternative 4. However, this does not affect this part of the analysis, as optimization is not considered to have a significant impact on the emissions from the construction of gas turbines.

Required power capacity at Dagny and Draupne/Luno is 40MW and 60MW respectively. These requirements can be met with different kinds and combinations of gas turbines, but for the analysis we assume that two 25 MW turbines are installed at Dagny while three 25 MW turbines will be installed at Draupne/Luno in alternatives 1 and 4. CO_2 emissions from a comparable 25 MW turbine have been analysed in a previous LCA study (Siemens, no date). Based on this, CO_2 emissions from the manufacturing of the gas turbines required are calculated to 170 tonnes of CO_2 for the alternatives with offshore gas power production. This figure includes emissions from production of raw materials, manufacturing processes, transportation and installation at site. In addition to the actual turbines, steel housing is needed to protect the equipment. These structures are estimated to 500 tonnes at Dagny and 750 tonnes at Draupne/Luno. Emissions related to these structures and the actual turbines, subtracted benefits from recycling at end of life, sums up to 4 152 tonnes CO_2. All emissions are defined as onshore, global and to take place during the construction phase.

4.6 THE PRODUCTION PLATFORMS

The production platforms are identical in all alternatives. Our emission estimates for these platforms are therefore based the total weight, and calculations of emissions are based on the assumption that the entire topside consists of steel just like jacket and piles. This is of course a rough assumption, but gives an estimate of the emissions related to the construction of the platforms.

If the power generator is removed, the platform and main deck may be optimized, but with slight or no reduction in weight. This will, according to Statoil, mean no change to jacket substructure, and it is assumed that this will not affect emissions associated with construction of the platforms.

As for the hub-platform, it is assumed that the installation is done by a semi-submersible crane vessel, and CO2 emissions are estimated to 11 000 tonnes CO_2 per production platform.

4.7 EMISSIONS FROM THE ENVIRONMENTAL ANALYSIS SUMMARIZED

Emissions have been allocated to different phases, and different years in the life cycle. We assume that the electrification equipment has a life time of 40 years, and that it will be re-used after 20 years of production. For the electrification equipment we therefore allocate half of the emissions to this project, while the other half is seen as a benefit allocated to year 20, when the re-use is assumed. Production platforms, including gas turbines will be recycled after 20 years.

Furthermore we assume that the platforms, will be shipped onshore and recycled at the end of life. We also assume that the cables will be recycled, mainly because we assume that it will be economically interesting given the high content of copper and other metals.

LCA data used to assess emissions from the various components related to electrification has not been available broken down on the construction and recycling phase for all components included in the analysis. For that reason recycling benefits stemming from converters, switchgear, transformer and gas turbines are included in the construction phase. This means that emissions calculated in year zero will be somewhat lower than it would otherwise have been, and benefits stemming from recycling at end of life will be equally lower. Total emissions over the life time will however not be affected by this. Recycling benefits from the metal used in cables and platforms are calculated explicitly. Due to the large amount of metal in these elements they are responsible for the main part of emissions and consequently also recycling benefits.

Table 4.2 Emissions from all components per phase

CO_2-emissions installations - phases (tonnes CO_2)					
	year 0	**year 20**			
	Construction	**Reuse/recycling**		**Total**	
Offshore converter + switchgear	376	-188		188	
Onshore converter + switchgear	376	-188		188	
Onshore DC cable	729	-535		195	
Offshore DC cable	16 048	-11 613		4 436	
Offshore AC cable	6 027	-4 212		1 815	
Offshore AC cable (wind park)	10	-7		3	
Transformer (wind park)	148	-74		74	
Laying cabels	4 480	-		4 480	
Hub platform	42 583	-25 187		17 396	
Gas turbines	5 182	-1 029		4 152	
Luno/Draupne	215 524	-40 862		174 661	
Dagny	147 349	-27 241		120 108	

Note: Recycling benefits stemming from converter, switchgear, transformer and gas turbines are included under construction

As seen in Table 4.2 the most CO_2-intensive components are the platforms and the cables. If we focus on the power supply components we see that the electrification equipment has a significantly higher impact than gas turbines. The reuse/recycling phase consists of rather large benefits for the electrification components, due to the fact that we assume reuse of this equipment after 20 years. For converters, switchgear and transformer recycling benefits are included in the construction phase, and all benefits in year 20 relate to reuse of the equipment. Recycling benefits associated with the actual gas turbines are also included in the construction phase, and benefits shown in year 20 are due to assumed recycling of the steel housing protecting the gas turbines. For the cables and the hub platform 50 percent of the initial emissions, plus 50 percent of the possible recycling effect, are calculated as a benefit in year 20.

In Table 4.3 we summarize emissions for each of the components needed in the different alternatives:

Table 4.3 Emissions from all components for all alternatives

CO_2-emissions alternatives - total (tonnes CO_2)					
	Alternative 1	**Alternative 2**	**Alternative 3**	**Alternative 4**	**Alternative 5**
Offshore converter + switchgear		188	188		188
Onshore converter + switchgear		188	188		188
Onshore DC cable		195	195		195
Offshore DC cable		4 436	4 436		4 436
Offshore AC cable		1 815	1 815		1 815
Offshore AC cable (wind park)					3
Transformer (wind park)					74
Laying cabels	2 240	4 480	4 480	2 240	4 480
Hub platform		17 396	17 396		17 396
Gas turbines	4 152			4 152	
Luno/Draupne	174 661	174 661	174 661	174 661	174 661
Dagny	120 108	120 108	120 108	120 108	120 108
TOTAL	**301 161**	**323 466**	**323 466**	**301 161**	**323 543**

Note: "Laying cables" in alternative 1 and 4 include emissions related to laying fiber cables only.

As we can see, the alternatives including electrification, will produce about 22 000 tonnes more CO_2-emissions compared to the alternatives with power supply from offshore gas turbines. The hub-platform generates approximately 17 000 of these tonnes of extra emissions.

Alternatives 1 and 4 have identical emission profiles, while Alternatives 2, 3 and 5 have almost the same emission profile. Alternative 5 has additional emissions of 77 tonnes due to some extra equipment needed for connection to a wind park.

If we isolate emission related to power supply only, i.e. take out the production platforms, we can see that the total emissions from construction and deconstruction phase for the gas turbines is approximately 6 400 tonnes (laying fiber cables included), while the equivalent for electrification is 28 500 tonnes.

5 CONCLUSION – TOTAL EMISSIONS

In this chapter we will answer the main question related to the effect of electrification of offshore oil & gas fields:

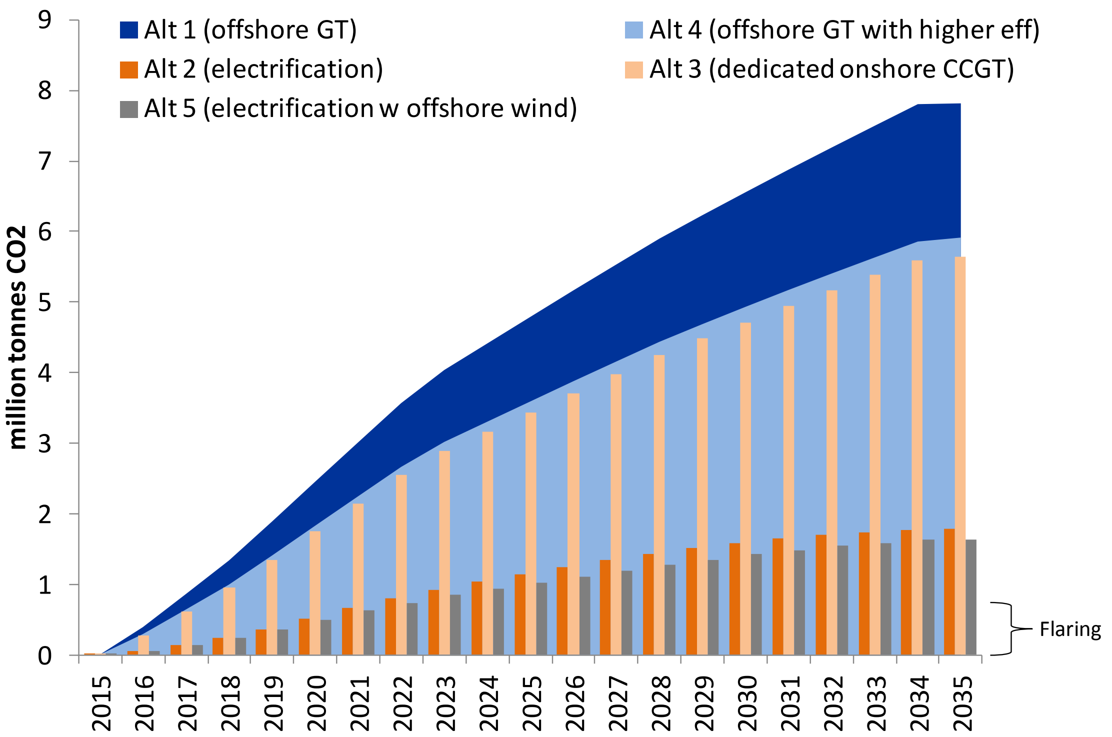
How will a withdrawal of power from the Norwegian grid, in order to replace traditional offshore power production based on gas, alter the global and national lifetime emissions of greenhouse gases, when emissions from construction and recycling are taken into account?

Numerous comparisons of the alternative solutions for power supply, presented in preceding chapters, have been conducted to comprehensibly answer the question above. In this chapter we aggregate the findings from the construction, operational and decommissioning phases, thereby quantifying the overall effect electrification of Dagny and Draupne/Luno has on CO_2 emissions.

5.1 ELECTRIFICATION CURBS OVERALL NATIONAL EMISSIONS

In terms of reducing emissions from all three project phases combined, electrification yields an overall reduction in national CO_2 emissions. Accumulated savings from electrification are in the magnitude of 6 million tonnes CO_2 (difference between Alt 2 and Alt 1 in 2036), and roughly 6.2 million tonnes CO_2, if we assume that an offshore wind-plant with capacity to supply half the electricity demand at the installations is built. This is shown in Figure 5.1.

Figure 5.1 Accumulated national emissions from the construction, operational and recycling phases at Dagny and Draupne/Luno, million tonnes CO_2



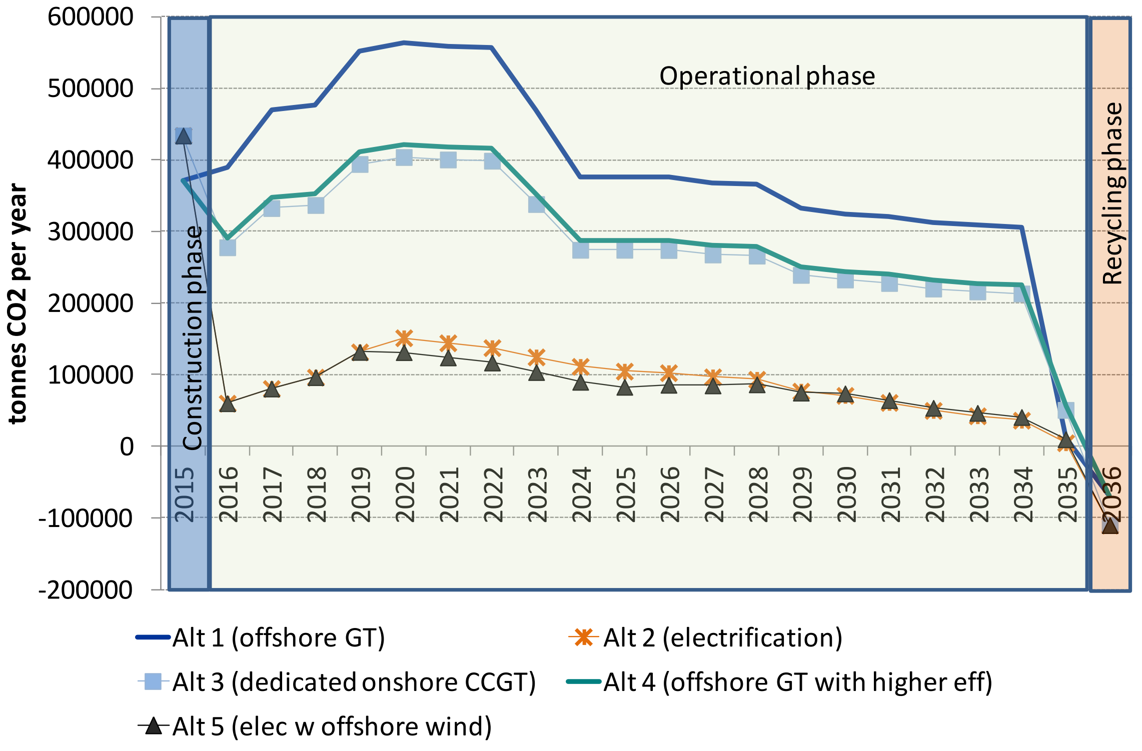
Source: Pöyry Management Consulting analysis

The figure above shows *national Norwegian* emission savings resulting from electrification. As we will see below, the results are significantly different when *European* emission savings are considered.

5.1.1 The largest propotion of emissions reduction can be realised during the operational phase

Although emissions from the construction phase exceed 300 000 tonnes of CO_2 in all alternatives, the difference between alternatives with and without electrification is negligible. Moreover, emissions offsets from recycling and reuse are higher in the electrification scenarios, implying that emissions from the construction and recycling/reuse phases are 22 000 tonnes of CO_2 higher in the cases with electrification. This is illustrated in Table 4.3.

Figure 5.2 Calculated annual national emissions from supplying heat and power to Dagny and Draupne/Luno, million tonnes CO_2



Source: Pöyry Management Consulting analysis

5.1.2 National onshore- and offshore emissions

Power and heat required during the operational phase is generated for different purposes. These purposes are: generation of electricity for extraction and other processes (from gas turbines in cases without electrification or from onshore power plants in cases with electrification), power for firewater pumps, power for emergency generators and heat demand. Flaring is also a component that contributes to emissions in the operational phase. The breakdown of emissions from offshore and onshore activities is outlined in Table 5.1.

Table 5.1 Annual emissions from operational phase split by source, tonnes CO_2

	2016	2020	2025	2030	2035
Offshore gas turbines					
Total emissions from main generators	351545	506963	319473	286170	6313
Total emissions from FW pumps	3601	3601	3601	3601	3601
Total emissions from testing of Emergency Generator	10	10	10	10	10
Tot. emission from flaring 0.3% of yearly production rate	35056	53703	53703	35208	1407
Total	**390212**	**564276**	**376786**	**324989**	**11330**
Electrification					
Emissions from replacement power	0	61683	28427	15399	-1662
Heat demand at Draupne and Luno	25120	36225	22828	20448	5112
Tot. emission from flaring 0.3% of yearly production rate	35056	53703	53703	35208	1407
Total	**60176**	**151612**	**104958**	**71056**	**4857**

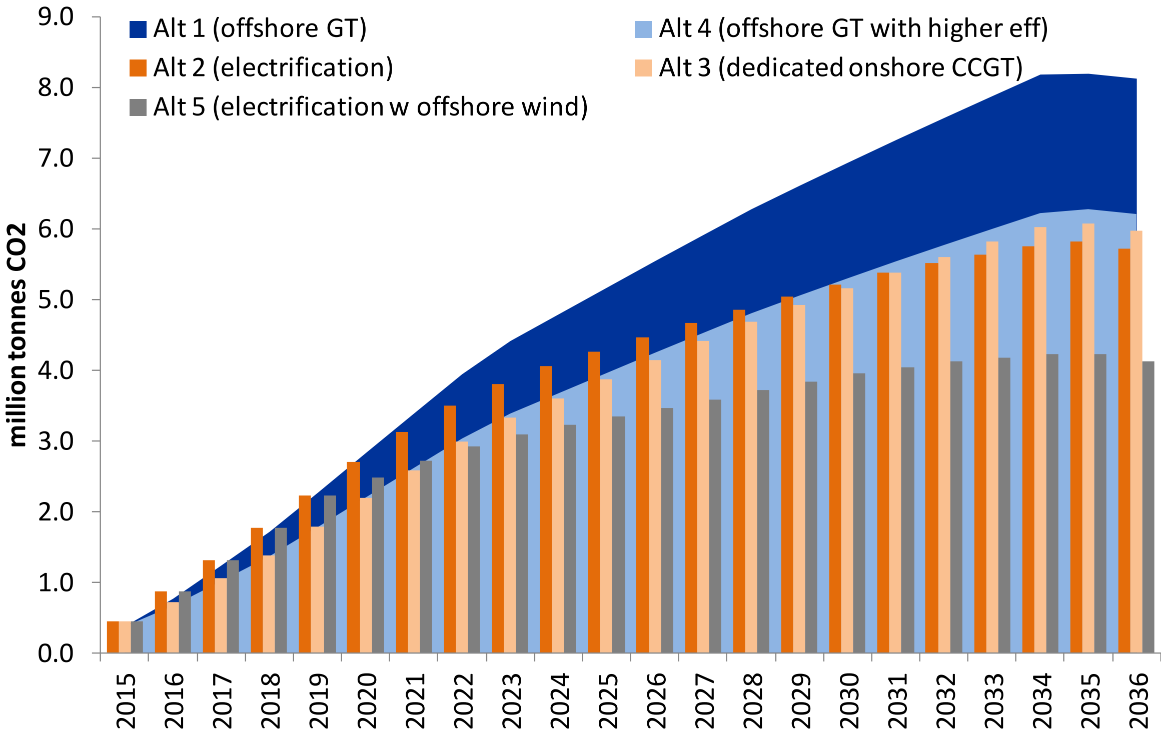
Source: Statoil, Pöyry Management Consulting analysis

In Table 5.1, which compares national emissions from Alternative 1 (gas turbines) and Alternative 2 (electrification), the only onshore emission source is the replacement power, which is the extra power generation in Norway needed to replace power from offshore gas turbines. As hydro power generation is fixed for all scenarios (and also emission-free) emissions from Norwegian replacement power origin from the Kårstø gas power plant.

5.2 EUROPEAN EMISSIONS

Although emissions from power production within Norwegian borders, including the continental shelf are significantly reduced through electrification from shore, overall emission reductions by this measure from power produced to supply Dagny and Draupne/Luno is far lower when European emissions are taken into account. This is because increased consumption of electricity in Norway withdraws exports of Norwegian hydro-power. European power plants, which are mainly thermal, will therefore increase generation to replace the shortfall. Emissions from this increase in thermal-based power generation offsets the emissions reductions that are achieved in Norway. This effect is shown in Figure 5.3.

Figure 5.3 *Accumulated European emissions from supplying heat and power to Dagny and Draupne/Luno during the operational phase, million tonnes CO_2*



Source: Pöyry Management Consulting analysis

Total accumulated emissions in Europe resulting from supplying heat and power to Dagny and Draupne/Luno are roughly 2.4 million tonnes of CO_2 lower if Dagny and Draupne/Luno are electrified (Alternative 2) compared to use of standard gas turbines (Alternative 1). This is largely a result of replacement power coming from CCGT plants that are more efficient than offshore gas turbines. This is also illustrated by the relatively small difference between alternatives with electrification and an alternative with more efficient offshore gas turbines (Alternative 4)

In any case, overall emissions in the EU ETS, of which petroleum activities are a part, will not be affected by choice of development concept. This is because the supply of allowances is fixed to the EU emission reduction targets, and spare allowances resulting from electrification will be purchased by other carbon market participants, meaning that total emissions equal the EU target level in cases both with and without electrification.

However, electrification could contribute to a downward pressure on prices for CO_2 allowances, which is contrary to what the intention of the EU ETS is. Electrification as a measure may therefore (albeit marginally) incentivize tougher targets from the EU Commission in the longer term.

If electrification triggers renewable investments in Norway (Alternative 2b), overall changes in emissions from European power generation are in fact negative if the renewable investment is large enough to supply Dagny and Draupne/Luno in the peak year. There would first of all be no need for replacement power, and renewable generation will in later years with lower production at Dagny and Draupne/Luno be exported to Europe provided this renewable capacity is not locked in by bottlenecks.

5.3 SENSITIVITY OF THE RESULTS

As we have described emissions related to the construction of the power supply components play a minor role in the overall picture. This indicates that factors like distance to the onshore grid and water depth will not change our conclusions with respect to what power supply solution is the most CO_2- effective. The main conclusion, that the emissions from the construction of the electrification system plays a marginal role, can therefore be generalized to other similar projects worldwide relatively independent of location and water depth. This part of the report can thus serve as a general tool for assessing the climate effect of electrification in general.

Whether similar electrification projects at other locations and mainland connection points, such as for example Finnmark or Møre og Romsdal, have similar effects depends on regional power market characteristics in Norway. Today, Norway is split into five electricity price areas, reflecting that power system characteristics differ between Norwegian regions. For example, electrification of offshore installations off the coast of middle Norway could yield different results as the middle of Norway is a power deficit area, as opposed to the Kårstø region which is a power surplus area. Increased demand for power in the middle of Norway could then potentially lead to a greater use of thermal generation to supply the offshore installations, either through new-build or making use of the mobile gas plants at Tjeldbergodden and Nyhamna. However, our assumptions and model runs show that by 2020 most price differences in Norway are eradicated due to internal grid developments (most notably Ørskog-Fardal) and lower regional power deficits due to increased renewable development. This suggests that the national emission effects will be similar wherever the electrification occurs, as a “bigger” grid can ship more available renewable generation freely across the country.

When we consider the results from the power market analysis, we observe a considerable reduction in national emissions from power production, more moderate reduction in European emissions stemming from power production, but no effect on overall emissions within the EU ETS do to the rules at play in the quota market. Interpretation of the efficiency of electrification as a climate measure should therefore make clear that there are both national and European climate policy aspects to consider.

The merit of electrification as a climate measure in a European context depends on what input assumptions we make for the European power and carbon markets. One particular assumption of importance is the price of CO_2 allowances. In our analysis, CO_2 prices in the short term reflect the cost of meeting the 20 percent target in 2020. If, however, this target is raised to 25 percent, as signaled by the EU Commission, CO_2 prices would most likely increase. The outcome of this would be that a larger share of replacement power in short term, which would boost accumulated emissions savings from electrification. Higher CO_2 prices in the short term would also most likely push forward phase-outs of coal capacity, yielding less available coal capacity for replacement power.

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APPENDIX 1: ABBREVATIONS

AC – Alternating Current

DC – Direct Current

BID model – Power market model developed by Pöyry

CCGT – Combined Cycle Gas Turbine

CCS – Carbon Capture and Storage

CDM – Clean Development Mechanism

CHP – Combined Heat and Power

DCS -, Demand Curve for Storage.

DCR – Demand Curve for Release

EEA – European Environment Agency

EPD – Environmental Product Declaration

EU ETS – European Union Emission Trading System

FW – Firewater

GI – Gas Injection

GoOs – Guarantees of Origins

GT – Gas Turbine

GWh – Gigawatt hour

HHV – Higher Heating Value

HVAC – High Voltage Alternating Current

HVDC – High Voltage Direct Current

LCA – Life Cycle Assessment

MW - Megawatt

NVE – Norges vassdrags- og energidirektorat

OD – Oljedirektoratet

NORSOK – Standards for the Norwegian shelf

PAD – Site and operation plan (Plan for Anlegg og Drift)

PDO – Plan for Developement and Operation

PUD – Construction and operation plan (Plan for Utbygging og Drift)

RES – Renewable Energy Source

SK4 – Skagerak 4 connection

Sm^3/d – Standard cubic meters per day

STEM – Svenska Energimyndigheten (STatens EnergiMyndighet)

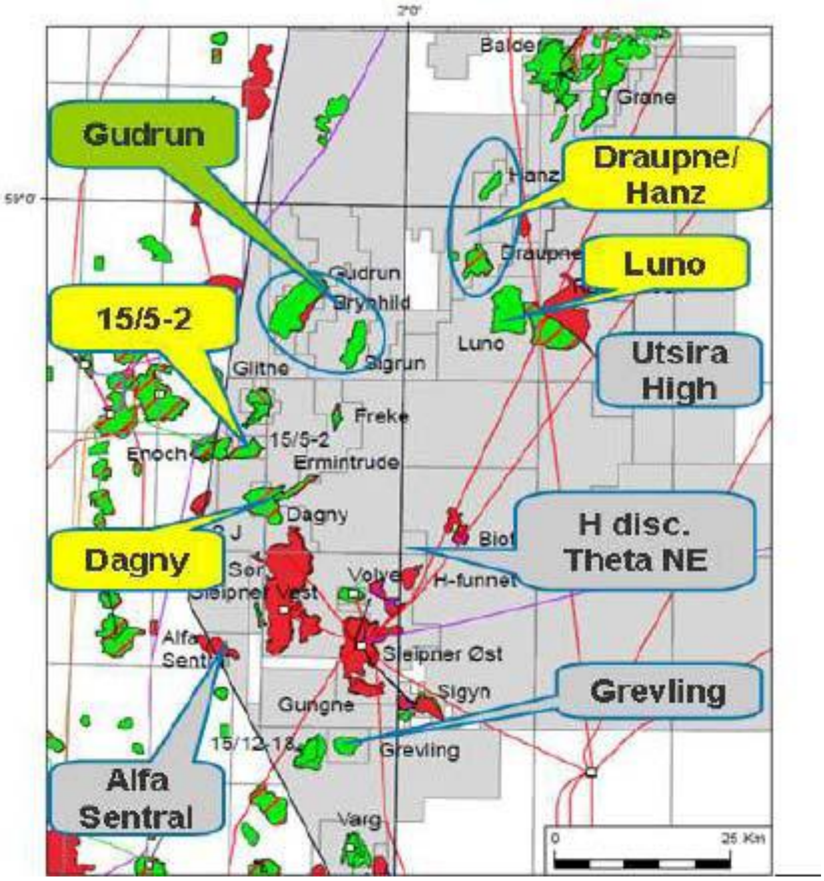
TGC – Tradable Green Certificates

TWh – Terrawatt hour

APPENDIX 2: THE FIELDS DAGNY, DRAUPNE AND LUNO

The fields Dagny, Draupne and Luno is located approximately 220 km offshore from Kårstø, and are as the figure illustrates, all located close to each other.

Figure A.2.1 Localization of the oil- and gas fields Dagny, Luno and Draupne



Source: ABB (2011)

This study assumes that one production platform will be located at the Dagny field and one production platform common for both Luno and Draupne will be placed at either one of the fields. Further it is assumed common land-based power supply for both platforms. In practice this is done by establishing a hub platform between the fields. Direct current (HVDC) power is then supplied by offshore cable from Kårstø to the hub platform (220 km). At the hub the power is transformed to alternating current (HVAC) and transported by offshore cables to the production platforms (30 km).

APPENDIX 3: METHODOLOGY AND BOUNDARIES

An environmental account is a compilation/summary of the environmental impacts caused by a certain product or service in the form of resource use and emissions to air, ground and water. The quantitative element of the account in this study is limited to calculation of CO_2 emissions. Depending on the underlying definitions of the scope of the study, an environmental account will review the whole or parts of a product's/service's lifecycle, the most comprehensive approach being a 'cradle-to-grave' perspective. For a product, this means following the whole process from the extraction of raw materials, production, transportation, installation, operation, reusing and/or recycling of materials, and final disposal. This is the chosen approach for this study.

BOUNDARIES AND ASSUMPTIONS

The goal of the analysis is to assess the *differences* in emissions between the alternatives at hand, and we emphasis precision for the installations and components that differ between the alternatives. Installations common to all alternatives have not been subject to the same level of detailed analysis.

For the sake of this study it is assumed that the construction of Draupne and Luno will be coordinated. In reality this will not necessarily be the final solution, as both Det Norske (the operator of Draupne) and Lundin (the operator for Luno) has suggested that a joint solution will be more costly than separated solutions.

This analysis will assess CO_2 emissions during the life span of Dagny and Draupne/Luno given five defined alternatives of power supply. The choice of power supply will impact the production, transportation, installation, operation and de-installation of the different components needed.

We assess the emissions related to all required components with major impact on the level of CO_2-emissions in the different alternatives.

As the goal is to assess the *differences* in emissions between the alternatives at hand, we will focus on emissions related to different type of power supply in the alternatives. We will also quantify emissions related to elements independent of choice of power supply, like the production platforms, but these calculations are not subject to deep analysis in this project.

We will not include analysis of components with minor impact on the overall CO_2-emissions. We will also exclude emissions from suppliers and sub-suppliers not directly linked with the project. This will for instance mean that emissions linked to production of vessels, helicopters etc needed in transportation will be excluded, but fuel consumption related to transportation will be included.

APPENDIX 4: DATA SOURCES

DATA SOURCES AND ASSUMPTIONS

Table A.4.1 gives an overview of data sources used to calculate emissions related to the production and decommissioning of the physical installations analysed in this report.

Table A.4.1 Overview of data sources – environmental analysis

Installation/material/process	Covered processes/information	Source
Converter (on- + offshore)	LCA[17] Production + recycling valve and transformer	ABB: EPD_light
Switchgear	EPD[18] production + recycling	Siemens: EPD - Gasisolierte Schaltanlage Typ 8DQ1 bis 420 kV, 50 kA, 5000 A
Cables	Material list and energy use during manufacturing	Nexans - mail
	Laying cables	Statoil: Fuel use Stemat Spirit Vessel
Gas turbines	LCA - Cradle to delivery at customer site (turbines)	Siemens: Life Cycle Environmental Assessment – Industrial Gas Turbine SGT-600
	Additional steel surroundings (metal recycling benefits calculated under deconstruction and recycling phase)	Statoil: Steel dimensions
Transformer (alt. 5)	EPD production + recycling	ABB – Environmental Product Declaration Power transformers 40/50 MVA (ONAN/ONAF)
Platforms	Dimensions structures	Statoil/Siemens
	Construction of steel structures, average	Ecoinvent – Simapro (steel product manufacturing, average metal working)
	Energy for dismantling	Ecoinvent (Dataset: disposal, building, reinforcement steel, to recycling)
	Lifting/installation topside	Statoil – Plan for utbygging, anlegg og drift av Gudrun
Transport	Transport cable materials to production facilities	Assumed 1000 km by lorry
	Transport cable from production facilities to site	Assumed 1000 km by boat
	Transport construction materials to production facilities	Assumed 1000 km by boat
	Transport construction	Assumed 1000 km by boat

[17] Life Cycle Assessment

[18] Environmental Product declaration

	materials to production site	
	Transport to recycling	Assumed 1000 km by boat
Steel	LCI[19] - Cradle-to-gate production of steel and recycling	World Steel Association – LCI data for reinforced steel plate
Aluminium	Cradle-to-gate production of aluminium and recycling	EAA[20] – Environmental Profile Report for the European Aluminium Industry
Copper	Mining copper-ore	Ecoinvent (Dataset: mining copper ore, GLO, [kg])
	Primary metal production (excl. mining) and recycling benefit	BIR[21] – Report on the Environmental Benefits of Recycling
Lead	Mining	Assuming same impact as copper ore mining
	Primary metal production (excl. mining) and recycling benefit	BIR – Report on the Environmental Benefits of Recycling
Plastics (in cables)	Aggregated data for all processes from raw material extraction until delivery (granulate) at plant	Ecoinvent (Datasets for polyethylene (LDPE), polypropylene (PP) and polymer (average of three)
Nordic energy mix	0,108 g CO_2/kWh	

The following assumptions and limitations are applicable for the entire environmental analysis:

- Maintenance is assumed to be equal across all alternatives, and therefore left out of the analysis.
- Recycling grade steel 85% and other metals 90%.
- Explicit recycling benefits are being calculated for the metals only.
- In some sources only CO_2 eq numbers are available, and in some it does not seem to be consistent whether the authors refer to CO_2 or CO_2 eq. The variation is in any case assumed to be insignificant, and we have used CO_2 eq as CO_2 emissions where it has not been possible to separate to two.

KEY REPORTS USED IN ANALYSIS

We have been given access to several reports from Statoil and their sub-suppliers. There reports constitute the foundation for the data collection. Here, we will shortly present the essence of the relevant reports.

Siemens: Power From Shore, Kårstø to Dagny – Draupne/Luno. Budgetary estimate and Technical comments - Draft

The report was based upon a request to provide basic budgetary information on a power from shore project associated with the Dagny Draupne/Luno field with Statoil, Det norske

19 Life Cycle Inventory.

20 European Aluminium Association.

21 Bureau of International Recycling.

oljeselskap and Lundin Norway as the respective operators. It is assumed that power (150MW) will be taken from a shore terminal at Kårstø to the platform via offshore cables and a power hub. The feedback presented in the report is not based upon dedicated studies, calculations or significant engineering dedicated for this project. The feedback is most of all based upon work and analyses performed as part of the power from shore study for the Luva field (Statoil) completed summer of 2010. Additionally there has been some coordination with work done in Europe on similar projects associated with wind power. Any deviations from the Luva project is scaled up or down with sound engineering estimations, thus to secure a +-25 percent accuracy of the numbers quoted.

ABB: Dagny and Luno/Draupne - Concept Study Power From Shore using HVDC Light technology

The objective of the concept study is to present a complete power transmission solution for supplying power from shore to Dagny and Draupne Luno/based on HVDC Light technology. The results give price estimates, overall description of main systems, scope of supply, main system components, weight and dimensions and order and delivery plan towards production start up 2014.

Aker Engineering & Technology: Dagny Platform Concept Study: Gas Injection Case

The report identifies the regular emissions to air and discharges to sea during normal operation of the Dagny Platform for the Gas Injection case (GI) incl. tie-in of 15/5-2. The calculations are based on the information available in the Conceptual design phase. Normal power is supplied by 2 x LM2500+ power generation turbines. The emissions from the turbines have been calculated for normal operation conditions for the production period. In addition, three firewater generators and one emergency generator will be installed, which will be diesel driven.

Diesel consumption and emissions have been calculated for testing of FW pumps and Emergency Generator. These are included in the overall emissions. During the drilling period produced water is assumed to be discharged to sea. After the drilling period at rates above 1000 Sm3/d the produced water will be injected to an Utsira waste well, while for water flow rates < 1000 Sm^3/d the produced water will be discharged to sea. Seawater return will be discharged to sea. Food waste and sewage will also be discharged to sea. Dagny is designed with a closed flare system, and the emission rate is calculated based on assumed rate stated by Company. The overall environmental impact from the Dagny Platform is considered to be within the Company and Authority requirements.

APPENDIX 5: ENERGY POLICY AND ELECTRIFICATION

The current targets for Norwegian energy policy can best summarized by the policy outlined in the government's Soria Moria declaration:

- Security of supply. Norway should have an adequate access to energy for households and businesses and an efficient and secure transmission system for power
- Environment: Norway should be an environmentally friendly energy nation and world-leading in developing environmental energy
- Energy efficiency: Norway is to pursue active policies to curb growth in energy demand

In light of the environmental target it has been declared that any new generation based on fossil-fuels is to be equipped with CCS technology. Strategic targets for renewable energy were adopted by the Norwegian Parliament in the spring of 2000, they are:

- By end 2010: 3 TWh increased production of wind power and minimum 4 TWh district heating based on renewable energy resources, heat pumps and waste heat. Enova did not succeed in facilitating 3 TWh of wind, but overachieved on the heat target.
- By end 2011: New generation of heat and energy from renewable sources and energy efficiency equivalent to minimum 18 TWh.
- By end 2020: Long term target of 40 TWh of new generation of heat and energy from renewable sources and energy efficiency.

Norwegian energy policy is also influenced by international agreements. Norway, as a member of the EEA, implements EU Directives relevant to the functioning of the EU internal market. Such directives include the so-called 202020 directives:

- Climate Directive, which specifies that GHG emissions are to be cut by 20% in 2020 compared to 1990 levels
- Renewable Directive, which targets a growth in renewable energy (and heat) *consumption* by 20% compared to 2005 levels
- Energy efficiency Directive, which targets a 20% decrease in use of overall energy compared to a business-as-usual energy demand forecast.

CLIMATE POLICY

In order to fulfil both Kyoto obligations, and in compliance with the Climate Directive (see above) Norway has introduced a cap and trade system for CO_2 emissions which is adopted in the EU emission trading system (EU ETS). The Norwegian emission trading system includes 40% of Norway's total emissions from 113 companies in the petroleum, energy and manufacturing sectors. In compliance with national environment policy, Norway has set a national target for emission levels, outlined in Klimaforliket (2007), which is more ambitious than what is required by the EU Climate Directive.

The EU ETS is a major pillar of EU climate policy and was initially created apart from the United Nations Framework Convention on Climate Change (UNFCCC, 1992) and the Kyoto Protocol (1997), although the EU ETS has introduced Kyoto compliance measures in the form of Joint Implementations and Clean Development Mechanisms. Under the EU ETS, large emitters of CO_2 within the EU are obliged to return to their governments that is equivalent to their CO_2 emissions each year. In order to neutralize annual irregularities of

CO_2 emissions levels that may occur due to for instance harsh weather, emission credits for any plant operator subject to the EU ETS are given for a sequence of years. Sequences are also referred to as trading periods, and we are currently in the second trading period (2008-2012). Allowances are either auctioned (e.g. to power producers) or given away (e.g. to heavy industry). Allowances not used by the emitters, either because of abatement measures or reduced activity, can either be saved between years and trading periods or sold to emitters with too few allowances.

Electrification of offshore petroleum installations is, as part of the national climate policy, mandatory to examine by oil companies as replacing offshore gas-fired turbines with electricity from mainland power stations (mostly renewable) is expected to reduce the CO_2 emissions from the petroleum industry. All plans for development and operation of oil and gas fields (PUD/PAD) are as such required to contain a good and efficient energy solution, including an analysis of possible power supply from land. This applies to both new field developments and major modifications on existing installations. Electrification as a measure is considered a means to achieve national carbon abatement targets, and therefore tallies with both Norwegian environmental policy and compliance with the EU Climate Directive. Electrification is identified as a key measure to achieve emission cuts in the Norwegian Climate and Pollution Agency Climate Cure report (2009) which analyses what measures are needed in order to meet the targets outlined in Klimaforliket. For the petroleum companies, electrification can in some instances be viewed as the optimal power supply concept, either because of favourable total costs and/or practicality.

RENEWABLE POLICY

It is expected that Norway implements the EU Renewable Energy Source (RES) Directive, hence effectively adapting to the overall policy goals of the EU regarding renewable energy. In July 2011 the Norwegian Government and the EU Commission agreed on Norway's RES target – 67.5 percent of renewable energy use in 2020.

In addition to implementation of the RES Directive, another major Norwegian policy decision is the agreement with Sweden involving a joint certificate market for new renewable power generation, which replaces the existing Enova investment support scheme (above). The target for new renewable electricity in Norway is 13.2 TWh from 2012 to 2020 (same for Sweden). This target has been mutually derived by NVE and STEM, and reflects realistic renewable potential in the two countries as well as expected increases in electricity demand. The new renewable energy triggered by the certificate market contributes to RES achievement, and so the certificate market can be seen as a tool to meet renewable targets as specified in the RES Directive.

The decision to implement the joint certificate market is, however, mostly related to security of supply policy, although political rhetoric suggests that new renewable generation complies with both national environmental policy as well as the Climate Directive. The latter argument has, however, been questioned by several parties. As Norway is not replacing any existing thermal power with new renewable supply, there will not be any direct gains in terms of cutting emissions. In terms of the Climate Directive, any emission cuts from replacing thermal power on the Continent with Norwegian renewable electricity will moreover in theory be offset through increased emissions elsewhere inside the EU ETS through the cap and trade mechanism.

Electrification is a measure that increases the share of energy consumption based on renewable sources, meaning that there is a direct relationship between electrification and compliance with the RES target. Whether there is a relationship between electrification and the certificate target is more uncertain. The current target specified in the Law of certificates at 13.2 TWh between 2012 and 2020 is based on an estimated general demand growth of *certificate-obliged* demand, which includes the petroleum sector. If we assume that electrification of Dagny and Draupne/Luno are not part of this forecast a demand increase of 800 GWh will lead to roughly 150 TWh of extra renewable investments in order to comply with the certificate target.[22] It should be noted, however, that it is still uncertain whether or not use of onshore-generated electricity on the shelf will be certificate-obliged.

As fulfillment of the certificate market targets most likely will lead to a significant power surplus in Norway and Sweden given modest demand growth expectations, a challenge for Norwegian energy authorities and the energy market is to handle this surplus. Statnett's development plans indicate that most of this surplus is expected to be exported to the Continent, either as wholesale power or as balancing power. Current statements from the energy authorities, on the other hand, have indicated that this surplus may be used for indigenous purposes, including electrification of the shelf. However, despite outspoken intentions by the current government to use a considerable amount of the perceived surplus at home, there is no clear policy in place that outlines how to achieve this. For example, no new policies are foreseen to force an increased use of electricity in order to level out the surplus and keep the electricity prices stable, meaning that any increased indigenous demand following a greater power surplus will be determined by the market (lower electricity prices).

[22] The 150 GWh are derived on the basis of the target quota for certificates, which in 2020 is roughly 18% of certificate-obliged demand.

APPENDIX 6: DESCRIPTION OF APPROACH FOR POWER MARKET STUDY

Any increased outtake of power from the grid, whether it comes from electrification or other sources of increased demand, requires an increase in generation supplied to the grid to balance the market. We refer to this increase in generation as *replacement power,* so labeled because it replaces electricity generation from offshore gas turbines. As we will discuss later in the report, replacement power is not likely to come from only Norway, but also (mainly) from European countries who need to balance the loss of Norwegian power exports.

The net change of overall CO_2 emissions from the operational phase is found by comparing emissions from increased power generation in the case of electrification with the emissions from an offshore gas turbine supplying power. Quantifying the net change of emissions necessitates identifying the source of the replacement power. We identify the replacement power and the appurtenant emissions using Econ Pöyry's BID model (see below for short description). BID contains power generation capacity data on a very detailed level for all North-western European countries, and can therefore very accurately pinpoint what type of power generation replaces offshore electricity generation at Dagny et al, and where this comes from.

Replacement power can effectively come from a number of different power plants in different countries. There is close to 750 power plants in Norway with capacity above 1 MW, while the Norwegian power market is connected to several power markets with many more plants, which vary with the type of fuel being used, what efficiency the turbines have, required maintenance etc. The composition of replacement power could therefore be a significant number of different generation technologies. There are, however, some general characteristics that dictate what this replacement power can realistically be:

- Overall plant economics. In order for a power plant to increase generation, it must make a profit. Plants with costs that exceed power prices will therefore not generate replacement power.
- Relative plant economics, or relative prices of fossil fuels and CO_2. In most European countries coal stations and CCGTs compete to supply baseload power. Which type will supply replacement power therefore depends on the competitiveness for these two technologies, which depends on coal, gas and CO_2 costs.
- Generation flexibility. Power generation from renewable sources typically varies with climatic conditions (inflow, wind, sunlight) and therefore does not vary with demand. Flexibility of some thermal technologies, such as nuclear, is also restricted.
- Plant location. If two potential sources of replacement power have exactly the same production costs and the same income (power price), the chosen source will be the one geographically closest to the location point of the incremental demand, as transmission losses are lower.

In a more general way, we can say that the power markets will decide what is the optimal replacement power.[23] Increased demand for electricity means that several power producers will compete to generate the replacement power needed, and the "winner" is the plant with the lowest production costs as this plant (as well as all competing plants) will

[23] Some features of the power market, such as CHP runtime, is often regulated, which means that the market adaptation ot increased demand is to some extent under regulatory influence.

bid in the replacement power at a price that juts covers said production costs. The price that this plant bids in is the *marginal price of power*, i.e. the price required to cover the marginal increase in demand. This marginal price thus becomes the “new” wholesale price of electricity.

Replacement power is most likely to come from plants already in operation where capacity is not fully used, rather than just one idle plant switching everything on. Therefore, there is likely to be more than one source of replacement power.

THE BID MODEL

Electrification of offshore installations has implications for CO_2 emissions in that electricity generated for processes on the relevant platforms will come from onshore power plants that either:

- Are (like offshore gas turbines) based on natural gas, but have different (higher) efficiencies

or

- Use different fuels than than the offshore gas turbines, such as coal, nuclear or renewable sources

In order to find the sources of replacement power, which could be one particular source or a composite of different sources, we apply our in-house power market simulation tool, the Econ Pöyry BID model. BID is an optimization tool that minimizes system costs of the European power market given a set of inputs such as plant capacity, electricity demand, fuel and CO_2 prices and transmission capacity. The BID model has an hourly resolution, and contains a very detailed break-up of power plants both in the Nordic and the surrounding European power market. For a more detailed description of the BID model, see Appendix 8.

In order to limit computing time and resources, BID has been run for a selected few years rather than the full period 2015-2035. The simulated years are 2016, 2020, 2025, 2030 and 2035.[24] Results for all years in between are based on linear interpolation. Moreover, all simulations assume “normal” inflow levels, i.e. that reflect the average inflow pattern for the years 1950-2010. All other input assumptions are presented in more detail in the next chapter.

In this study, we have applied BID in a scenario-context, where we model a reference scenario, Base Case, which describes what we deem to be the most likely development of the European power markets given current trends and policy drivers. Power demand in the Base Case does not include electrification of Dagny and Draupne/Luno, and therefore serves as a reference point to which alternative scenarios with electrification are compared. In terms of power generation, which is key to understanding how an interconnected power market adapts to higher demand, BID determines the optimal (least-cost) generation required to meet the extra demand, given a number of constraints such as:

- Marginal costs of running the different types of plants (which relies heavily on fuel and CO_2 prices).
- Thermal plant start-up costs, which restrict the operating flexibility of thermal plants

[24] The reason 2016 is preferred to 2015, despite operations at Dagny, Draupne and Luno commencing in 2015, is because there is practically no electricity demand from the installations in 2015. 2015 would as a modeling year therefore only have yielded very limited insight.

- Restrictions on run-times of CHP plants
- Inflexibility of renewable generation
- Grid losses (which effectively yields a cost of transporting power from one place to another)
- Grid bottlenecks, which implies that ability to balance “another” power market with indigenous generation is limited
- Plant availability (which depends on maintenance and other planned outages)

As with other power market models, BID does not contain specific characteristics for every single power plant in Europe, as this would make the model incomprehensible large and slow. However, identical types of power plants, such as CCGTs, are grouped into generic plant types. Input to our plant capacity database is based on all power plants in Europe. Table A.6.1 shows the categorization of power plants in BID.

Table A.6.1 Generic plant types in BID (HHV)

Fuel	Type	Efficiency							
Coal	Condensing	33%	36%	38%	40%	42%	44%	46%	48%
	Extraction	33%	36%	38%	40%	42%	44%	46%	48%
	Backpressure	-	-	-	-	-	-	-	-
	CCS	28%	30%						
CCGT	Condensing	47%	49%	51%	53%	55%	57%	59%	
	Extraction	47%	49%	51%	53%	55%	57%	59%	
	Backpressure	-	-	-	-	-	-	-	-
	CCS	40%							
GT (gas)	Condensing	37%	39%	41%					
GT (oil)	Condensing	37%	39%	41%					
Gas	Condensing	38%	42%	44%					
Oil products	Condensing	38%	42%						
	Extraction	38%	42%						
	Backpressure	-	-	-	-	-	-	-	-
IC	Condensing	30%							
Lignite	Condensing	33%	36%	38%	40%	42%	44%	46%	48%
	Extraction	33%	36%	38%	40%	42%	44%	46%	48%
	CCS	28%	30%						
Peat	Condensing	38%	42%						
	Extraction	38%	42%						
Waste	Backpressure	-	-	-	-	-	-	-	-
Nuclear	Existing	-	-	-	-	-	-	-	-
	New	-	-	-	-	-	-	-	-
Biomass	Condensing	38%	42%	-	-	-	-	-	-
	Extraction	38%	42%	-	-	-	-	-	-
	Backpressure	-	-	-	-	-	-	-	-
Hydro	Reservoir	-	-	-	-	-	-	-	-
	Run of River	-	-	-	-	-	-	-	-
	Pump st.	-	-	-	-	-	-	-	-
Renewables	Onsh wind	-	-	-	-	-	-	-	-
	Offsh wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-

Source: Platts, EWEA, NVE, STEM, Fingrid, Energinet.dk, Pöyry Management Consulting analysis

The detailed level of plant disaggregation also means that we capture precise estimates of emissions from power generation. The BID model applies a set of emission factors, based on various sources, outlined in Table A.6.2.

Table A.6.2 Emission factors per fuel, tCO_2/MWh[25]

Fuel	Unit	CO2 (tonnes/Unit)	*Source*
Coal	MWh	0.342	*IEA*
Heavy Fuel Oil	MWh	0.284	*IEA*
Light Fuel Oil	MWh	0.265	*IEA*
Natural Gas	MWh	0.217	*Aker-report*
Nuclear	MWh	0	*Pöyry*
Peat	MWh	0.306	*IEA*
Biomass	MWh	0	*Pöyry*
Water	MWh	0	*Pöyry*
Wind	MWh	0	*Pöyry*
Lignite	MWh	0.342	*IEA*
Waste	MWh	0	*Pöyry*
Oil Shale	MWh	0.378	*IEA*

Emission factors in the below table are not adjusted for plant efficiencies. Nor do they contain life-cycle emissions relating to materials, construction, maintenance and deconstruction.

IDENTIFYING AND CALCULATING EMISSIONS FROM THE OPERATIONAL PHASE

Emissions from the operational phase are defined as emissions from generating power and heat (energy) required for extraction and other processes, backup and domestic purposes on the Dagny and Draupne/Luno platforms. The processes that require energy, or emission sources, differ somewhat between cases with and without electrification and are identified below:

- Without electrification
  - Power and exhaust heat from offshore gas turbines to supply processes and so on (gas turbines run both baseline and off-peak with varying degrees of efficiency)
  - Diesel generator supplying power to firewater pumps
  - Emergency diesel generator that will have both effective run-time and test-periods
  - Generators run for start-up phases
  - Flaring
- With electrification
  - Power generation supplied from the Norwegian central grid
  - Offshore gas boilers to supply domestic heat at Draupne/Luno
  - Flaring

[25] Calculations from the Aker report "Dagny Platform Concept Study" yields an emission factor of natural gas equal to 0.217 kg CO_2/kWh.

Calculating the net change of emissions is done by comparing emission levels from the sources above between the Alternatives. Emission calculations from all offshore processes are based on input from Statoil. The BID model is applied for quantifying the emission effects from onshore power plants supplying an extra amount of electricity demand. This is done by comparing the total level of emissions from the power market in a case with electrification and one without, which is identical to calculating emissions from replacement power. This is shown in the equation below.

$$\Delta E = \sum_{c=1}^{C} \sum_{t=1}^{T} \mathrm{E(X2)}_{\mathrm{c,t}} - \sum_{c=1}^{C} \sum_{t=1}^{T} \mathrm{E(X1)}_{\mathrm{c,t}}$$

Where

ΔE = CO_2 emissions from replacement power

E = CO_2 emissions from power generation

X2 = scenario with electrification

X1 = scenario without electrification (Base Case)

c = country

t = plant type

National emissions

National emissions refer to emissions of CO_2 within Norwegian borders, including the shelf. A change in national emissions (in the operational phase) following electrification is the emissions from supplying power and heat to Dagny and Draupne/Luno using offshore gas turbines and appurtenant equipment less incremental emissions from Norwegian power generation.

Positive incremental emissions from the Norwegian power market resulting from electrification is likely to be modest as the share of renewable electricity generation in Norway exceeds 99%. Moreover new renewable generation targeted in the certificate market will most likely imply that there will be a power surplus in Norway in the longer term, which implies that imports from thermal-dominated countries are not likely to increase. As a result, it is expected that power supply to Dagny and Draupne/Luno be based on renewable sources and that emissions therefore decrease, though this depends on to what degree Norway's thermal plants Mongstad and Kårstø adjust generation.

Emissions in the EU

As Norway is currently connected to Continental European power markets both directly and indirectly through other countries, any developments in the Norwegian power market will have implications for power markets outside Norway. Increased demand from electrification implies in this context that the flow of exports and imports is altered. As Norway is a net exporter of electricity in the long run, electrification implies a decrease in net exports.

Norway therefore "withdraws" some of its supply of renewable power to other Nordic and/or European countries. As demand in other countries does not change as a result of electrification, it means that generation in these other countries has to increase. This explains why some replacement power from electrification will come from outside Norway. If the replacement power does not exclusively consist of renewable generation, electrification leads to an increase in emissions in the European power markets.

The net increase in emissions from the European power market depends on what power plants supply the replacement power. As the Nordic and the European power markets are liberalized, transparent and predictable markets with limited opportunities to apply market power, replacement power is likely to come from the available source with the lowest costs. The composition of replacement power therefore depends on the following factors:

- Relative fuel prices and CO_2 prices. The higher the price for coal compared to the one for gas, and the higher the CO_2 price, the more likely it is that the replacement power will consist of gas-fired electricity.
- Available capacity. If the capacity of the "cheapest" source for replacement power is exhausted, the chosen replacement power will be the second cheapest. This applies particularly to lignite plants, which are economically best-suited (with low CO_2 prices) but have limited available capacity.
- Efficiency of new plants. Technological developments to improve efficiency is expected both for CCGTs and coal plants. The plant type with the highest efficiency gains will boost competitiveness.
- Availability of renewable generation. Typically, renewable generation is intermittent and inflexible, as it is determined by climatic conditions rather than changes in demand. One exception is biomass CHP, where generation is mostly an auxiliary output from heat generation which is fixed over the year. Some biomass plants, however, do have some flexibility in adjusting generation, although this is subject to costs of biomass, efficiency alterations from adjusting generation and relative prices of electricity and heat.

Higher demand from electrification can incentivice investment in new thermal generation capacity. For this effect to take place, however, electrification would have to be applied to more fields than Dagny and Draupne/Luno.

EXTERNAL CONSEQUENCES OF ELECTRIFICATION

For some field developments electrification with power from onshore power plants represents a positive contribution to the project economy, and have consequently been implemented (e.g. Troll, Gjøa and others). Electrification of the shelf is also by parts of the political establishment seen as a measure for curbing greenhouse gas emissions in Norway. As we have argued, net changes in emissions are likely to occur, both in Norway and in adjacent regions through generation adjustments. Both these effects are a result of how the commercial power market reacts to electrification as a policy-driven measure.

However, in addition to responses in the wholesale markets, electrification may have implications for regulatory mechanisms outside the markets. We refer to these implications as externalities, as they could result in unintentional policy responses. These policy responses can, moreover, if implemented further boost the attractiveness of electrification. As these externalities are mostly related to regulatory measures, they are difficult to quantify, and will therefore be discussed qualitatively.

Firstly, emissions from offshore oil and gas activities are part of the cap-and-trade EU ETS. Offshore oil companies are therefore required to hold emission allowances for every unit of CO_2 they emit, and these allowances can be traded on what is called the carbon market. As the carbon market is an ordinary (albeit artificial) market, normal market reactions are expected following electrification. However, we argue that electrification by its nature also can affect the framework conditions for the carbon market, for instance by increasing the political incentive to impose stricter emission targets, forcing both short term and long term adaptation by market participants such as power producers.

The second externality discussed (briefly) in this report is a market response, namely the response from the gas market. Although not part of this study, overall emission changes from electrification also depends on where the excess natural gas (no longer used for power supply on the platforms) is used. We therefore assess where this gas is likely to be used, and whether this changes the overall conclusions in our study.

APPENDIX 7: ASSUMPTIONS FOR THE NORDIC AND EUROPEAN POWER MARKETS

Nordic power market balance

Power supply from Norway, Sweden and Finland mainly comes from reservoir hydro. Large-scale hydro reservoirs will typically contain less water than their maximum capacity. In this respect, the Nordic power market is said to be energy-constrained rather than capacity constrained, as the available generation is determined by inflow rather than the capacity of the reservoirs. This is also partly the case for Denmark that has a considerable amount of wind.

As there in normal situations typically is excess power in the Nordics, deployment of new generation is more to do with policy rather than commercial investment decisions as prices are too low to yield long term profitability for most technologies. All Nordic countries have committed to the EU Renewable Directive[26], which sets guidelines for the amount of renewable electricity to be built. The amount of renewable electricity generation in Norway and Sweden is targeted at 26.4 TWh by 2020. Required support for this development will be financed by the certificate market scheme, while failure to comply with the target means penalization. It is therefore likely that this amount will be built independent of demand developments. We have analysed the expected share of renewable deployment in Norway and Sweden and the mixture of renewable technologies using our optimization model for the certificate market.[27] In Finland, a fifth nuclear plant is currently being built, while the government has also decided to approve concession procedures for a sixth and seventh plant. Finland has also, like Denmark, set ambitious renewable targets through the Renewable Directive

Demand growth in the Nordic region will most likely come from establishments of new power-intensive industry. This is a development that most likely will not occur without a global climate agreement or compensation schemes for carbon prices. We assume that new industrial demand amounts to roughly 5 TWh by 2030 (including demand growth from electrification projects), while demand from households and businesses decreases due to requirements specified by the Energy Efficiency Directive.[28]

Modest growth in electricity demand[29] and a considerable development in renewable generation leads to a considerable power surplus in the Nordic countries up to 2035. This is shown in Figure A.8.1.

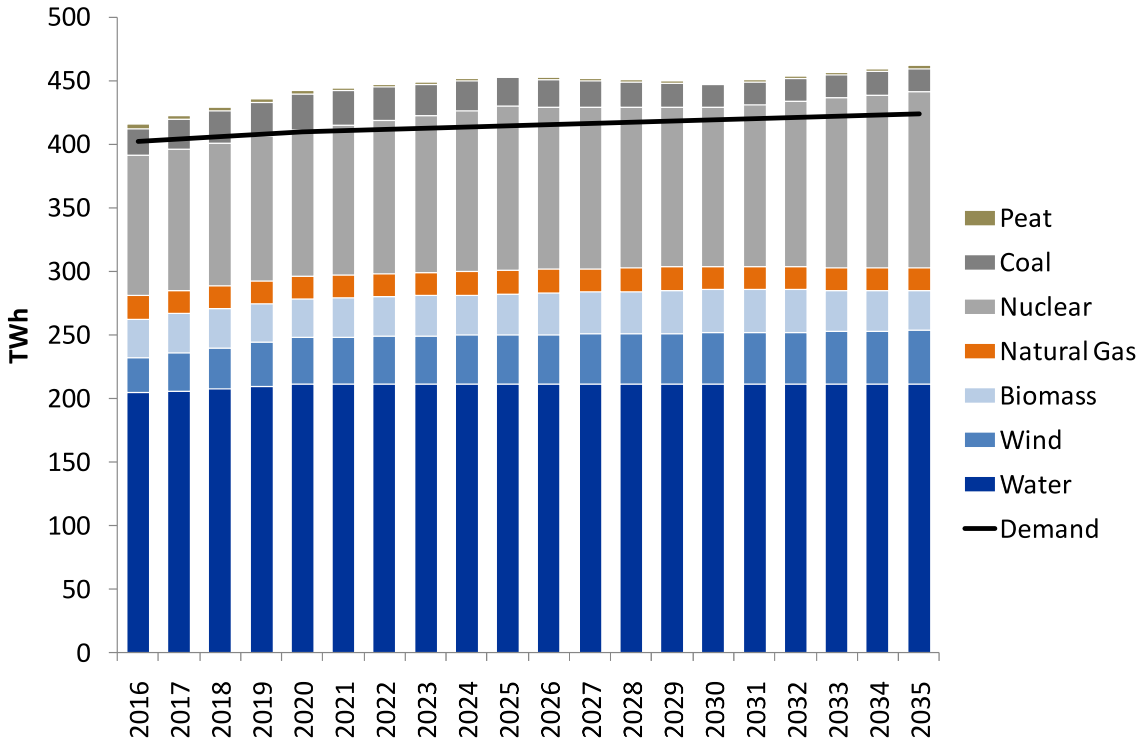
[26] Directive 2009/28/EC.

[27] Econ Pöyry's Tradable Green Certificate (TGC) model calculates certificate price and optimal deployment of renewable power based on power prices, certificate demand and renewable supply curves.

[28] COM 2011/0172 (COD).

[29] As with all other commodities traded in commercial markets, demand for power is affected by the electricity price. However, recent empirical studies by SSB ("Hvordan reagerer strømforbruket i alminnelig forsyning på spotpris", 2010) show that the price elasticities in Norway are negligible. We ignore price elasticities in our analysis.

Figure A.7.1 Nordic power balance, TWh.



Source: Pöyry Management Consulting analysis.

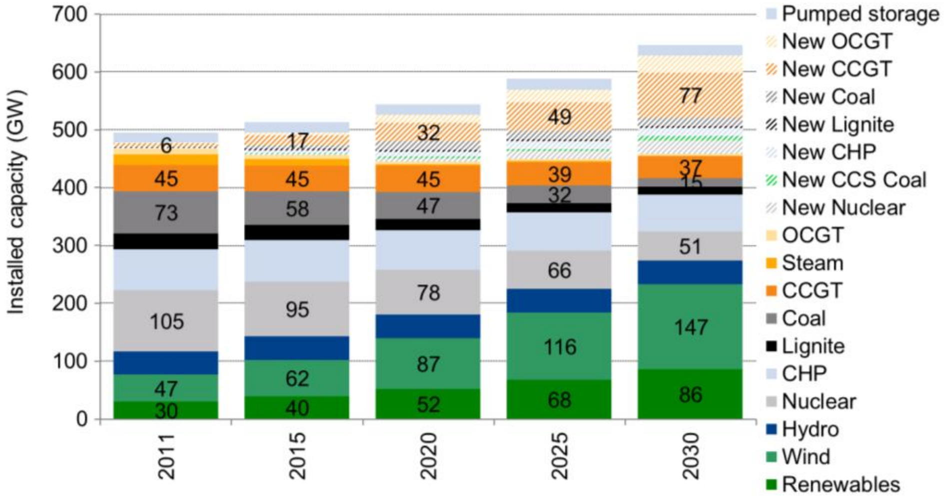
As we can see above, the power surplus is around 32 TWh in 2020 and close to 40 TWh in 2025. These surplus figures are for the Base Case and therefore do not include electrification at Dagny and Draupne/Luno. Most of this surplus accounts from a large degree of inflexible generation in the Nordic countries such as renewable generation and nuclear, but also partly from coal- and gas-fired plants which often are CHP plants with fixed production profiles. This surplus needs to be exported from the Nordic countries to the Continent over a limited amount of transmission lines, which, as we discuss later in the report, yields bottlenecks between the Nordics and Europe.

New capacity in Europe

Like the Nordic countries, all EU countries face targets for renewable deployment through the Renewable Directive, though ambitions vary between countries[30]. Renewable development thus accounts for a considerable share of new generation capacity in Europe. Unlike the Nordic countries, however, renewable development will to a large degree help replace generation from a substantial number of thermal plants (particularly coal plants and, in Germany, nuclear) that are expected to be phased out over the coming 20 years. It is not expected that the planned renewable development will suffice in replacing all phased-out thermal plants, implying that some new generation capacity is expected to be based on fossil fuels, see Figure A.7.2.

[30] "Burden sharing" is an expressed element in the Renewable Directive, which means that countries with higher GDP per capita are imposed with tougher targets.

Figure A.7.2 Capacity development on the European Continent, MW



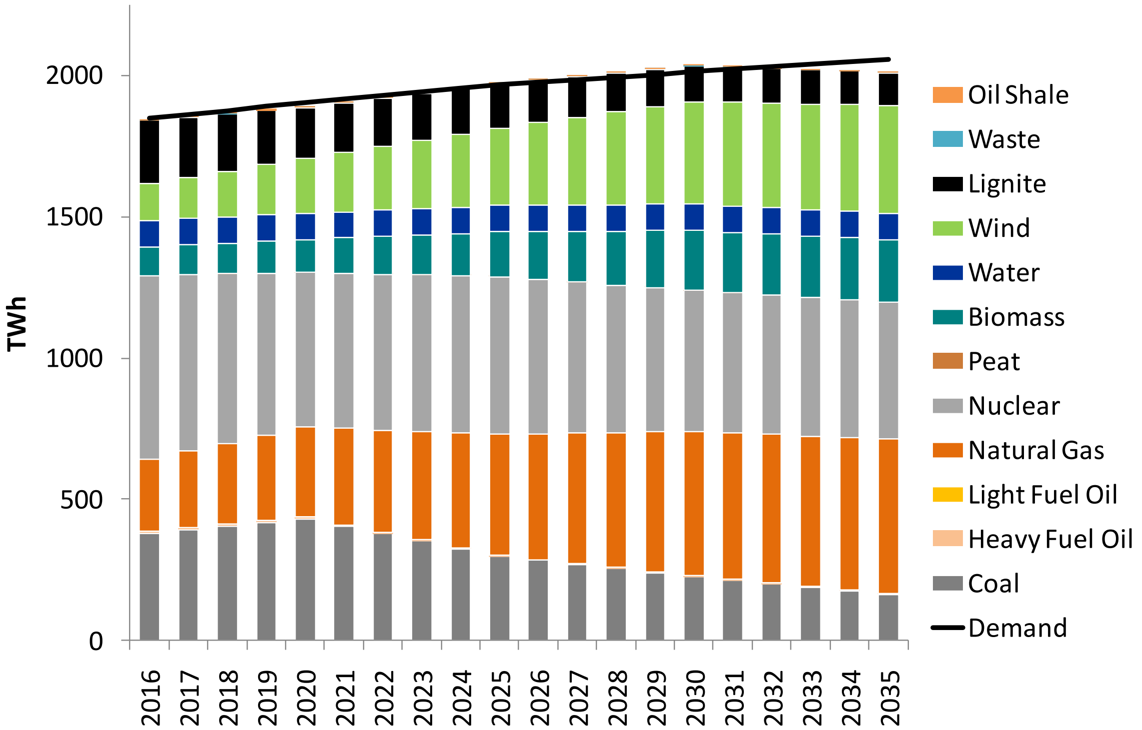
Source: Pöyry Management Consulting analysis.

Capacity development plans vary significantly between countries, but some traits are noticeable from the figure above:

- Most future generation capacity in Europe is expected to be wind-power
- Most new fossil-based electricity is expected to be generated with natural gas, through CCGT plants for baseload and open-cycle gas turbines for peak loads
- As most coal capacity will be phased out and little new coal capacity will be built, the EU electricity market will get increasingly “cleaner”

As the power markets on Continental Europe are said to *capacity-constrained* rather than *energy-constrained*, i.e. it is the installed capacity of power plants rather than energy (coal and gas that can be purchased freely on global markets) that determines how much can be supplied, a figure showing the future capacity is most applicable when showing the future European power market. However, even though most thermal capacity in the longer term is natural gas, actual generation is also influenced by relative production costs, which implies that most generation could still come from coal. Figure A.7.3 shows generation by fuel in the Nordic power markets.

Figure A.7.3 Continental European power balance, TWh



In the figure above, which is a model result and not an assumption, we see that throughout the projection period coal-fired generation is increasingly replaced by CCGTs. Also, renewable generation accounts for an increasing share. The excess generation in some years is explained by the chart above summarizing only BID regions. BID regions do however in the model have the opportunity to export to "outside" regions such as Iberia, Italy, Eastern Europe etc, modeled in BID as exogenous regions.

Transmission capacity

Transmission capacity in and between European power markets facilitate the ability to send electric power from one area to another. The amount of power that can be transmitted is restricted by the capacity in the grid. If the transmission capacity between an excess area and a deficit area is insufficient to even out relative imbalances between the two areas there is a bottleneck between these.

Bottlenecks occur both within Norway, between the Nordic countries and between the Nordic and the European countries. Limitations in transmission capacity are moreover reflected in differences in power prices between regions. If these bottlenecks are significant, i.e. the transmission capacity between regions is very restricted, it could furthermore imply that the power surplus in a specific region cannot be exported. This is a particular problem if a large share of the power generation is based on intermittent renewable sources. If, on the other hand, the capacity in the surplus region consists of mainly reservoir hydro generation, bottlenecks imply that the power surplus can nevertheless be exported as more hydro generation is shifted to periods one would otherwise save.

In terms of Norwegian grid development, we assume that the goals in Statnett's grid development (2010) plan are met.[31] These goals are summarized through the following major projects: Sima-Samnanger, Ørskog-Fardal, Ofoten-Balsfjord-Hammerfest and Rød-Hasle. These and other transmission projects are expected to be realized for the following reasons:

- Security of supply. Particular regions in Norway today have a significant power deficit due increasing demand, limited opportunities for new generation and an aging grid. Improving transmission capacity for these particular regions is part of Statnett's mandate concerning security of supply.
- Facilitate development of renewable electricity. The implementation of the joint certificate market means that a significant amount of new power generation will be located in areas with little demand. Making this new power accessible for the rest of the country is therefore seen as prerequisite for implementation of the certificate market.
- Remove Norwegian price differences. This is an outspoken priority for the current Norwegian government (although not stated as explicit goal in the Grid Development Plan). Opposition parties in the Norwegian parliament have also indicated that this is a political goal.

In our model analysis we find that Norwegian bottlenecks are mostly removed. The exception is the southern/southwestern part of the country which is the connection point for all interconnectors going to thermal markets (see below). This exposure to thermal markets yields a price profile which is slightly different than the rest of Norway as there is not enough transmission capacity to adjacent Norwegian zones to eliminate bottlenecks. A limited amount of bottlenecks otherwise is, however, a sign that the regional power surplus the certificate market is expected to yield is spread out to the rest of the country.

Norway, Sweden and Finland are fairly well-connected power markets in that the price differences for these regions is, at least in normal situations, limited. While these countries are all expected to be surplus regions in the longer term, sufficient transmission capacities between the countries is important in that, say, the Norwegian power market can offload surplus generation to Sweden in periods where ability to export to the Continent is limited. This is particularly important given that an increasing amount of power generation in the Nordics is expected to come from intermittent sources. Additionally, the forthcoming certificate market is expected to trigger grid development initiatives between Norway and Sweden in order to facilitate better opportunities to trade certificates across countries.

Table A.7.1 presents our assumptions for grid development between the Nordic countries over the longer term.

[31] Statnett (2010): Nettutviklingsplan 2010 – Nasjonal plan for neste generasjon kraftnett. http://www.statnett.no/Documents/Kraftsystemet/Nettutviklingsplaner/Statnetts%20nettutviklingsplan%202010.pdf.

Table A.7.1 Assumed future interconnector capacity between the Nordic countries

	Capacity (MW)	Status	Online year
Fennoskan 2 (Finland-Sweden)	800 FI to SE 500 SE to FI	Under construction	2012
Finland-Sweden	600	Expected decision	2020
Skagerrak 4 (Norway-Jutland)	600	Approved	2014
South West link (Norway – Sweden)	1200	Application for concession expected	2016 (earliest)

Source: Nordic TSO development plans

Statnett assumes in the Grid Development Plan that five interconnections to thermal countries will be built by 2025. These include two cables to Germany (Nord.Link and NorGer), a cable to the UK (NSN), a second NorNed and the Skagerrak 4 (SK4) to Jutland. The total capacity of these developments is 5 500 MW. We assume that only two of these, the SK4 and the Nord.Link cable, are built. Our reasoning for this is as follows:

- Concession planning, feasibility planning, construction and implementation of interconnectors is typically a lengthy procedure which increases the uncertatinty and thereby the costs associated with the projects
- All five interconnectors mentioned (with the possible exception of NSN) will have the southern part of Norway as a connection point. This necessitates a grid development in the south of Norway that will quite likely prove impractical to implement.
- An approved and feasible interconnector development from Norway still requires that connected markets have the necessary concessions, internal grid capacities and market mechanisms in place.

Table A.7.2 shows our assumptions for interconnectors connecting the Nordic market and the thermal market.

Table A.7.2 Assumed future interconnector capacity/trade between the Nordic area and the non-Nordic area

Interconnector	Energy/Capacity	Comment
Finland-Russia	- 10 TWh	The current import amounting to roughly 10 TWh to Finland is reduced to 8 TWh in 2012, 5 TWh in 2015, 3 TWh in 2020 and 0 after that.
Finland-Estonia (Estlink 2)	650 MW	Assumed to become operational by 2014.
Norway-Germany	1400 MW	New interconnector capacity between Norway and Germany is expected to come online by 2020.
Jutland-Germany	650 MW (Jutland>Germany) 500 MW (Germany-Jutland)	Assumed to increase by 2012.
Jutland-Germany	500 MW in both directions	Assumed to be reinforced by 2025.
Sweden-Lithuania	900 MW	New expected interconnector capacity by 2018.
Cobra Cable (Jutland-Netherlands	600 MW	New expected interconnector capacity by 2015.

Source: Nordic TSO development plans

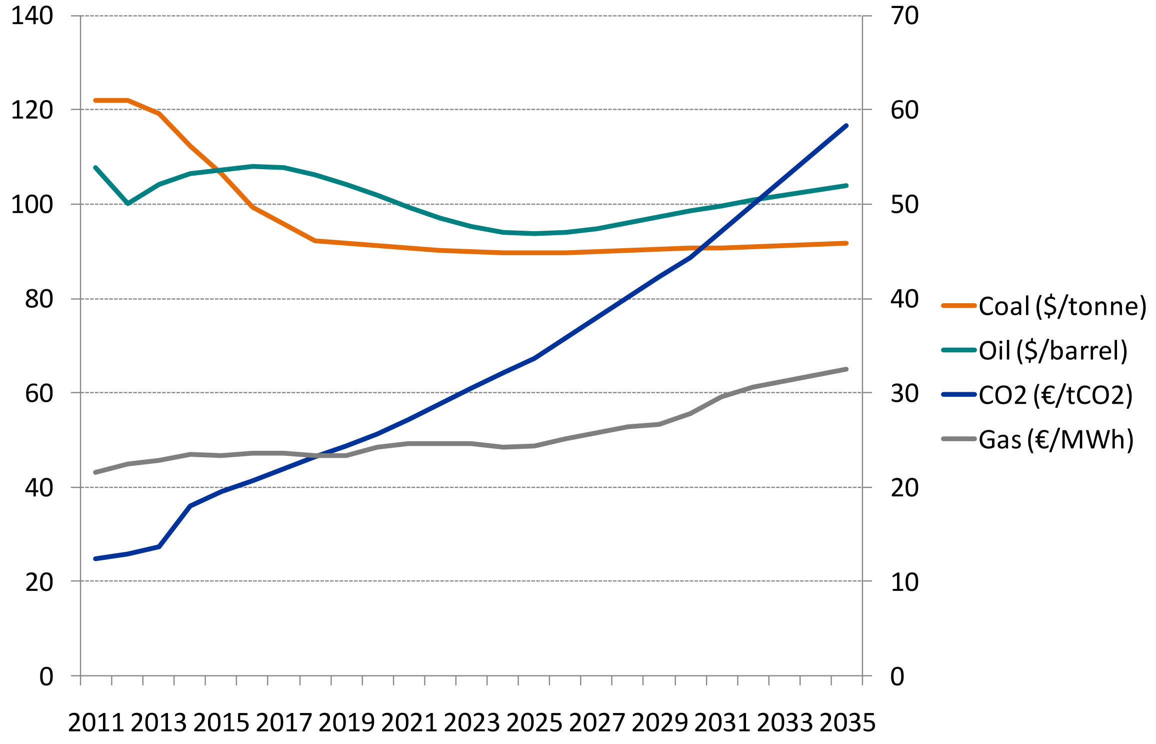
The development of the interconnectors stipulated above leads to an increase in trade between the Nordic countries and the Continent. These developments will not remove bottlenecks between Norway and other countries, meaning that there will still be price differences between the Norway and Continental Europe. Bottlenecks thus imply that Norwegian hydro-producers cannot export whatever they want whenever they want, i.e. they may have to store hydro in hours with high prices as there is not sufficient grid capacity to export it to other regions. There is still, however, sufficient transmission capacity to export the entire power surplus, though not necessarily in the hours when it is most profitable to do so.

As with any assumptions, future transmission capacity is uncertain. Non-compliance with internal Norwegian grid developments described in the Grid Development Plan could as such imply that if a considerable power surplus is developed, this power surplus could be "locked in". Electrification would in this context be a valuable contribution to the Nordic power market in that spill is avoided. If this were the case, the environmental benefits of electrification would also be greater as replacement power would at least in part consist of power that would otherwise have ended up as spill.

Fuel and CO_2 prices

Fuel prices are based on Pöyry's *Central Scenario* global market expectations for coal, oil and natural gas. Oil prices are expected to be driven by moderate economic growth (similar to historic levels) while oil demand as such is expected to increase moderately. At the same time, geopolitical unrest in the Middle east is expected to subseed while OPEC's spare capacity remains sufficient to cover temporay gluts in supply. Coal prices are also driven by modest economic growth and increase in demand. Short term bottlenecks relating to transport are expected to decrease, and the current coal suppliers are expected to continue to set global prices. Gas prices increase over the longer term as indexation of natural gas to oil contracts resumes towards 2020 due to increasing demand from power markets and declining supply from LNG and conventional gas.

Figure A.7.4 Fuel and CO_2 price assumptions (coal and oil prices read against left axis, natural gas and CO_2 prices read against right axis)



Source: Pöyry Management Consulting analysis.

Our projections show that CO_2 prises rise markedly towards the end of the projection period. The underlying reason for this is explained in the next section.

The carbon market

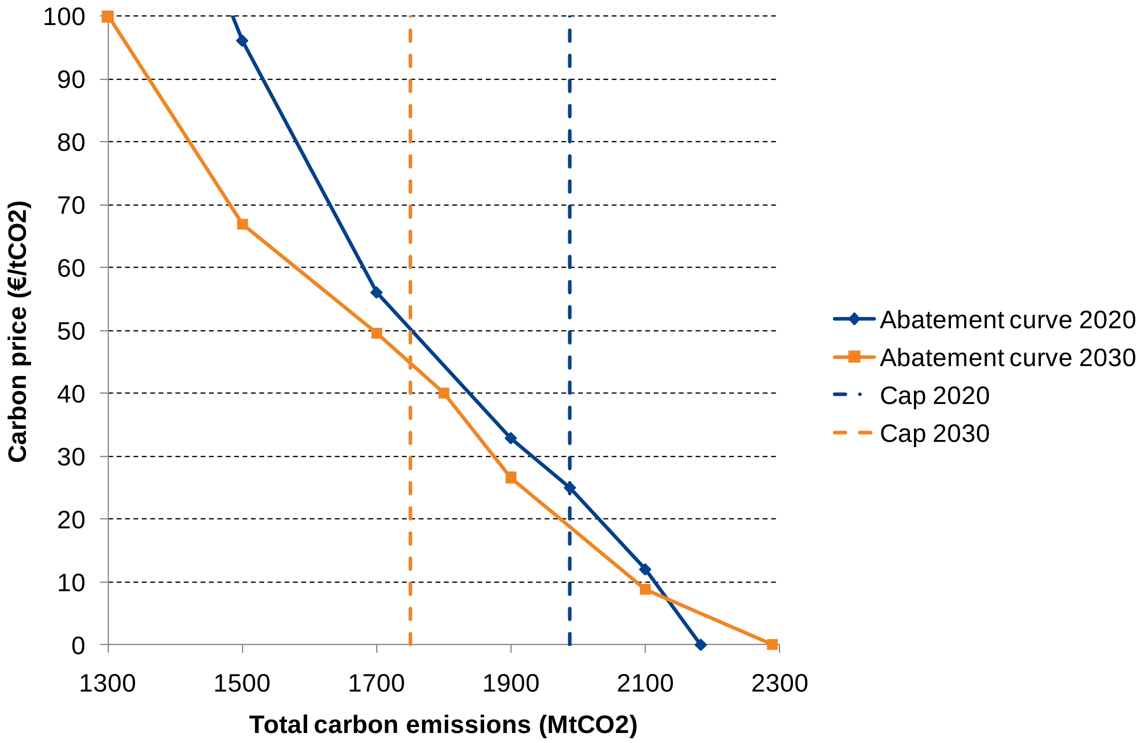
Carbon market assumptions applied in our modelling gives the CO_2 price outlined in Figure A.7.4 above, which rises considerably towards the end of the projection period. There are several reasons for this:

- The EU Commission is committed to continuing the EU ETS scheme beyond the third trading period (2013-2020). Although a target for the subsequent period has not been set, we believe that the EU Commission will be looking to tighten the supply of allowances significantly as a) the EU ETS has so far failed to make low-carbon technologies competitive and b) other directives such as the Renewable Directive and Energy Efficiency Directive make the 2020 target compliance in EU ETS relatively effortless.
- While coal prices are expected to stay constant, higher demand increases the price of natural gas. This raises the cost of fuel-switching which is required to cut emissions also in the long term.

- The most cost-efficient abatements in industry are undertaken first. This means that over the long term, increasingly more expensive abatements from industry are needed to meet the target.

Our modelling of the carbon market is done by modelling abatement curves which are partly based on exogenous assumptions (abatement curves for industry) and partly on endogenous model output (fuel switching between coal plants and gas plants). Our methodology is illustrated in Figure A.7.5.

Figure A.7.5 Abatement curves for 2020 and 2030 (NB: Abatement curves not developed for this study).



In the figure above, the blue line represents the abatement curve for 2020. The line crosses the x-axis at roughly 2200 million tonnes CO_2. This emission level is what we end up with if there had been no EU ETS (or no abatements needed). The upwards slope of the blue line displays the increasing costs of abatements the more abatements are needed. In 2020, the emission cap for the EU ETS sectors is estimated at 1988 million tonnes CO_2. The marginal abatement needed to meet this cap has a cost of roughly 25 €/tCO_2.

The 2030 figures are not based on official EU targets as this has not yet been set. We assume, however, that the linear increase in the cap up to 2020 (which implies cutting 1.74 percent CO_2 emissions each year) is continued up to 2030.

APPENDIX 8: THE BID MODEL

Our Better Investment Decisions (BID) model is a comprehensive power market simulator for all power markets in West Europe (including the Baltic countries and Poland). The model contains a detailed power plant database for all Western European countries and assumptions for demand, fuel (and CO_2) prices and transmission capacity both for the current period and also for future years.

BID is a fundamental optimization model. This means that the model finds the lowest possible price of power that is required to balance (make supply equal demand) all Western European power markets given:

- How much it costs to run the various power plants. This depends on fuel prices and how much it costs for said plants to adjust generation up and down. For instance, if the market can be cleared by either gas plants or coal plants, BID chooses the plant with the lowest overall costs
- Inflexibility of renewable generation. For wind plants, for example, generation cannot be adjusted in line with demand
- What price an owner of a reservoir hydro-plant should receive given the opportunity to store or produce at any hour, taking into account uncertain inflow levels in the future
- Transmission constraints (the size of the grid) limits the possibility for generation in one place to balance the market some other place. This is more commonly referred to as bottlenecks.

In BID, all types of power producers bid in their electricity to the market to meet (pre-specified) demand in both their own power market and other power markets. The wholesale price of power is the marginal production cost of the most expensive plant needed to meet demand. As BID assumes a perfect market with no market-power, the most expensive (marginal) plant will get a power price that covers its production costs, but no more.

As mentioned above, BID also takes into account grid constraints, or bottlenecks. This means that there will be price differences between different countries (and also within some countries). Effectively, this means that the most expensive producers in surplus regions have to retract their bids as they cannot export to a nearby deficit region, while more expensive producers in the deficit region can bid into the market and still sell their power. The outcome is a higher power price in the deficit region than in the surplus region. It should be noted, however, that bottlenecks are typically not present on grid connections, or interconnectors, all the time. If bottlenecks occur at times where inflexible generation (say wind-power) exceeds demand and export capacity, this generation will have no alternative cost, and the model will therefore yield a wholesale price equal to the (pre-specified) non-fuel variable operating costs.

BID applies stochastic dynamic programming to handle uncertainty concerning future inflow. This procedure means that in the model hydro-producers base their generation and pricing decisions at a specific time on probability distributions for future inflow, and that this procedure is moved forward for every time interval. If, for instance, at time t a hydro producer expects a dry period over the next 10 periods, the hydro producer will be restrictive in releasing water already in period t and t+1 and so on.

Market regulatory issues, such as renewable development, nuclear capacity development, and runtime restrictions on CHP plants are featured in the model as exogenous inputs.

Regulatory aspects concerning the grid (such as grid tariffs, grid investment rules etc) are not covered in the model, nor are taxes such as electricity consumption tax and VAT.

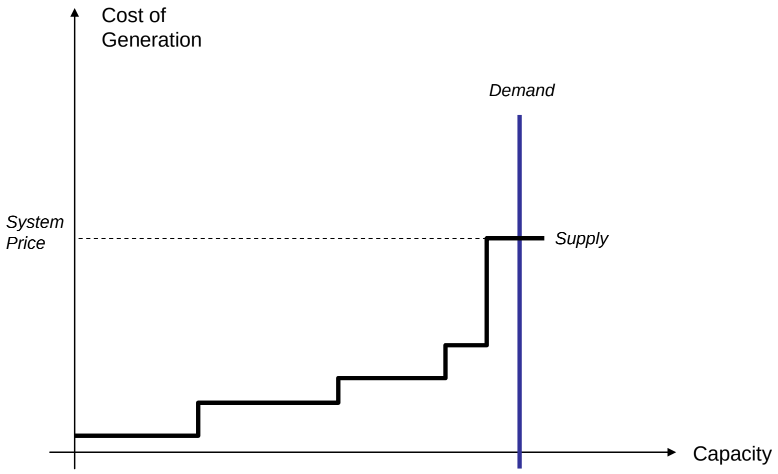
The BID model simulates the power markets in a very accurate and "real" way. In particular, the treatment of uncertainty for hydro producers captures exactly how hydro producers make their dispatch decisions. Moreover, BID has an hourly time resolution, which means that it finds the optimal price for all hours of the year modeled. Other main outputs from the BID model include hourly dispatch (exactly how much and what type of electricity is generated each hour in each country), trade and CO_2 emissions from the power market.

Methodology

The BID model is a fundamental model that estimates the price by calculating the intersections between supply and demand. The model has a regional structure with specified transmission capacity and trading regime between the regions. The supply curve is constructed as a merit order curve defined by production capacities, short term marginal costs and possibility for a value of capacity component. A special strength of the BID model is the calculation of the short term supply from the *regulated* hydro power plants. This is calculated in the water value module, which is described further below.

A schematic illustration of the solution calculated by BID in one hour and in one price area is given in Figure A.8.1. The figure depicts a supply curve and the demand level. Sorting the capacities according to marginal costs of generation (merit order) in order to satisfy demand is equivalent to minimizing the system costs subject to the constraint that generation has to equal supply. The system price is then given by the marginal costs of generation of the marginal capacity unit that is needed to meet demand.

Figure A.8.1 Fundamental Model Approach of the BID Model



Geographical Scope

The current standard version of BID covers the Nordic countries (except Iceland), the Netherlands, Belgium, France, UK, Germany, Poland, Switzerland, Austria and the Baltics, but it is easy to extend the model to other countries.

Some of these countries are divided into several regions: Norway into 7 regions, Sweden into 4 regions, Denmark into 2 regions, Finland into 2 regions and Germany into 2 regions. All data is specified on the regional level, including hydrology data, demand, generation set, distribution network and cross-border transmission network data.

Supply

The supply side modeling within BID consists of the following main components.

Thermal power

Thermal technologies are characterized by technology type (condensing, extraction, CHP), fuel types, efficiencies, start-stop costs, part load efficiencies, operating costs, and availabilities. BID also captures other aspects of thermal systems, such as must-run restrictions in order to model take-or-pay gas contract.

CHP

The model allows detailed combined heat and power (CHP) modeling. The model distinguishes between extraction CHP and backpressure CHP. Within the latter category, a further distinction between public and industrial CHP is applied. For each CHP technology, production profiles can be specified.

Wind power

The wind power production is simulated at an hourly resolution. Based on observed historical wind data, the simulation process ensures that difference between consecutive hours and between different market areas are realistic.

Hydro power

The inflows to the various hydro power regions are based on actual hydrological years. The market behaviour of hydro power producers as simulated in the model reflects the intrinsic uncertainty about future inflow. The water value modeling is described below.

Value of Capacity

"Value of capacity" is a term describing the fact that in all observable thermal dominated power markets, prices in peak periods are consistently above pure short-term marginal fuel cost levels. BID enables above-fuel-cost cost recovery for peaking plants in periods of low capacity margin. Our approach is calibrated based on the discrepancy between fuel-cost-only BID runs and historical prices.

Wind and solar Power

The wind and solar power production is simulated at an hourly resolution. The generation profiles are based on historical generation patterns. In BID, wind is a must-run generation, and therefore has priority to the grid. In effect this implies that the BID model sometimes delivers price of zero in areas with a lot of wind, like Denmark, which is very much in line with observations from the markets.

Hydro Structure

One of the key components of BID is sophisticated hydro modelling that simulates the way hydro is priced and operated in the market. Hydro in general is split in the model into Reservoir (or storage) hydro and Run-Of-River (that is, hydro plant with very small or no effective storage) hydro. Inflows are modelled on multiple levels, with inflow expectation, the ability of generators to forecast inflows ahead of time, and actual inflow levels (and the consequent impact of errors in expectation, forecast ability and (systematic) errors in forecasting), all specified explicitly in the model.

The hydro reservoir structure in each hydro-enabled region is modelled in BID as a single, large hydro reservoir that is effectively the sum of all the hydro reservoirs in the region. Each reservoir is modelled as a store of power (rather than directly as water). Thus, all storage (and consequently inflow) data is measured in units of power (e.g. storage in TWh, inflow in GWh per period).

Release from each reservoir is in the form of spill and generation. Spill occurs when either the reservoir storage levels exceed the maximum, or else generation levels in a given period are less than the minimum release level required for that period, and the shortfall is met by spilled release. Total release in a period is also subject to a specified maximum release level.

A further explanation can be found below.

Demand

BID allows for demand modeling through elasticities. Demand flexibility can be determined in terms of elasticities[32], and a calibration point, which is usually a pair of observed price and demand level. The model assumes a Cobb-Douglas demand function as a mathematical form for the demand.

Demand is often set to be fixed as data is difficult to obtain on elasticities. This generally gives good results when doing back-testing studies against historical data.

The model allows specification of up to five demand groups, each with its own demand curve. At the moment, those five groups are households, power intensive industry, service industry, other industry and electric boilers. The latter category is of importance in the Nordic context.

Transmission Structure

Cross border transmission is modelled economically (rather than via a physical load-flow approach), with each connection from any one region to any other region having a specified (linear) loss, cost, availability, and capacity.

In general, BID allows three types of inter regional transmission:

Normally the transmission is price-based, i.e. transmission between regions is based on price differences (the price includes losses and transmission fees).

The transmission can be fixed between regions based on contracts between the regions (for example Finland and Russia).

Within a given region, BID assumes there are no transmission bottlenecks. Internal transmission and distribution losses, however, are accounted for by using linear loss functions, with user specified parameters. There can, however, be bottlenecks between regions within one country, such as between Southern and Middle Norway, depending on transmission capacity assumptions.

[32] Price elasticities are an expression for a percentage change in demand following a percentage change in price. For example, if demand drops by 0.5% following a 1% price increase, the price elasticity equals 0.5. The elasticity is therefore a measure for how flexible (or sensitive) the demand is with respect to price changes.

Value of capacity

"Value of capacity" is a term describing the fact that in all observable thermal dominated power markets, prices in peak periods are consistently above pure short-term marginal fuel cost levels. Even accounting for the cost of start-up for peak plants, this behaviour can clearly be observed. Driving this is a simple fact: for upper-merit order power plants to recover their fixed and capital costs, it is necessary that they achieve a price or payment above their short-term marginal fuel cost. Without this expectation, such plant would not be invested in or would close down. Alternatively, one can argue that for low load factor plant, the traditional marginal cost concept (equals fuel + CO_2 costs) loses its meaning, and the entire cost of operation is effectively "marginal". The additional price level above what strict fuel-only marginal pricing would suggest is referred to as *Value of Capacity*.

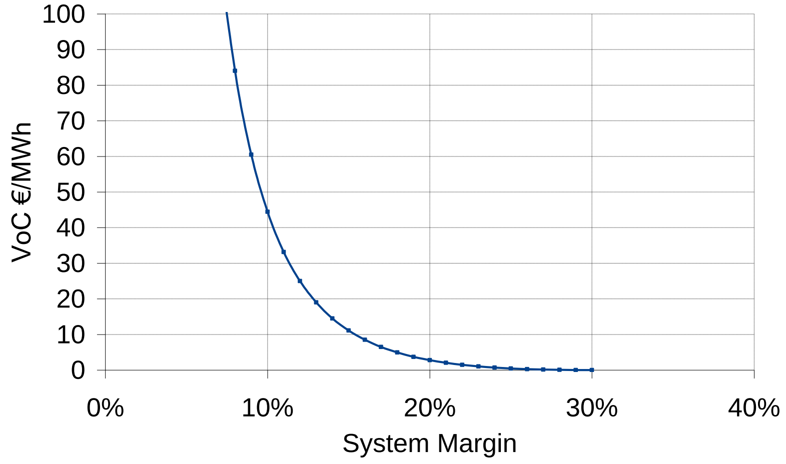
The value of capacity varies between periods/years depending on the market structure and the necessity of new entry. In years when no new entry is required, upper-merit order plants will need to recover their fixed costs through the value of capacity component. In years when new entry is required, upper-merit order plants must cover fixed costs and capital costs as well as a profit element. The value of capacity component of the wholesale power price also depends on the market design; e.g markets with explicit capacity payment will have a low or zero value of capacity component.

Comparing results from back-testing of the BID model with actual prices, we have found that the difference between the price in BID and the actual price is largest in hours with a tight power market. This suggests that upper-merit order power plants can be considered to bid in a value of capacity component in hours when they are determining the price. The ability of the upper-merit order power plants to bid above the short-term marginal cost reflects their market power, but pushing the price above the short-term marginal cost does not necessarily constitute market abuse as they recover their fixed costs and/or capital costs.

Note that we are not suggesting that there is an explicit decision along the lines of "my fuel cost is x, I shall bid in at 2x because I can". Rather, that the full cost of operation is taken into account when determining the cost per MWh for the plant. This is easiest to understand if one considers the situation in which a peaking plant is contracted to provide a physical hedge (e.g. to be on-call for 500 hours in a given year). The owner of such a plant would be unwilling to enter into such a contract that did not recover the plants full costs; in such a situation it would be more attractive to close the plant. Recovery of capital costs is more complex, and will depend upon the tightness of the market. In a market that requires such capacity, if no new actor can be expected to recover capital costs then no new capacity will be invested in. We have in effect a Nash equilibrium where in such an environment owners of capacity are able to recover up to new entry costs.

The value of capacity markup for peaking plant in the BID model is determined via a function depending on the system margin. The value of capacity function has been constructed based on the observed discrepancy between a fuel-cost-only BID analysis and historical prices. An example of a typical value of capacity markup as a function of system margin is given in Figure A.8.2 The value of capacity will be biggest in the hour with the tightest system margin, and will decrease with less tight hours. For most of the hours of the year, there will be no value of capacity component.

Figure A.8.2 Example of a value of capacity function in Econ Pöyry BID



THE WATER VALUE CALCULATIONS

The power markets in the Nordic region, as well as in France, Germany, Switzerland and Austria, are hydropower based or heavily influenced by hydropower. BID calculations reflect this, especially in the rule module. In the simulation module, all the different power generators bid in their desired generation according to their marginal costs (hydro power producers bid in their water value). These are combined with the modeled demand, and the market is cleared. We will in this chapter give an introduction to the calculations executed in BID.

An academic paper about the approach of the BID can be found in Read and Hindsberger's *Constructive Dual DP for Reservoir Optimization* in P. Pardolos (ed.) *Power Systems Handbook (PSH) handbook on Power Systems Optimization, 2009*. Another reference for the model is *Damsgaard et al*, *Exercise of Market Power in the Nordic Power Market,* Working Paper, 2007, prepared for the Swedish Competition Authorities.

Rule Module (constructing the DCR and DCS)

The rule module implements a Stochastic Dynamic Programming (SDP) methodology to construct water values for the complete range of storage levels for each period in the analysis. The module makes use of two concepts to undertake this water value analysis: the *Demand Curve for Release*, and the *Demand Curve for Storage*.

Given the market conditions at a given time, the BID constructs a Demand Curve for Release (DCR), i.e. what the market is willing to buy, given different water values, and a Demand Curve for Storage, i.e. the water value curve.

Demand Curve for Release (DCR)

What amount of hydropower the market will buy - given different water values

In any time period, given a marginal water value for a reservoir, there will be an optimal release of water for generation from the reservoir in that period. This optimal amount is a function of the market conditions, other plants, market rules, company strategies, and so forth. Extending this idea to the full range of possible water values, a Demand Curve for

Release (DCR) for a given time period gives what the market will buy, given different possible water values. One can also say that the DCR-curve represents the demand for hydro generation at a given water value.

Each hydro-enabled region in BID consists of one large reservoir. Hence, separate water values may be calculated for each region. However, regions can also be clustered into *zones*, in which the reservoir levels of the single regions are aggregated, thus calculating a water value curve for the entire zone. The zonal water value curve's maximum storage equals the sum of the maximum storage levels of the regions in the zone. It is assumed that, for a given filling percentage in the zonal reservoir, the filling percentage for all the clustered regional reservoirs is the same. In the multi – reservoir case, the Demand Curve for Release and Demand Curve for Storage are calculated for a given zone (or just one region) by aggregating the storage levels for all the other zones, meaning that you only have two reservoirs; one for the current zone of interest and one for all the other zones, and therefore two corresponding water values. All figures show examples of DCR and DCS curves for 1 – reservoir situations.

The DCR is computed via the use of the single-period market-clearing model from the Simulation Module in BID. Using the market clearing model, for a given set of market conditions in a given time period, and a fixed marginal water value for the reservoir, we are able to calculate corresponding generation levels for each plant in the market, including the hydro plant. The DCR for a given time period is in BID calculated for all regions (or zones) and load blocks. A pre-defined range of discrete water values is used for the reservoir in the current region and for the combined reservoir for all the other regions. For each combination of these water values, the single-period model then computes the corresponding release levels (for the current and combined region). Each period is treated independently, meaning that the release of one given period does not affect the releases of the next.

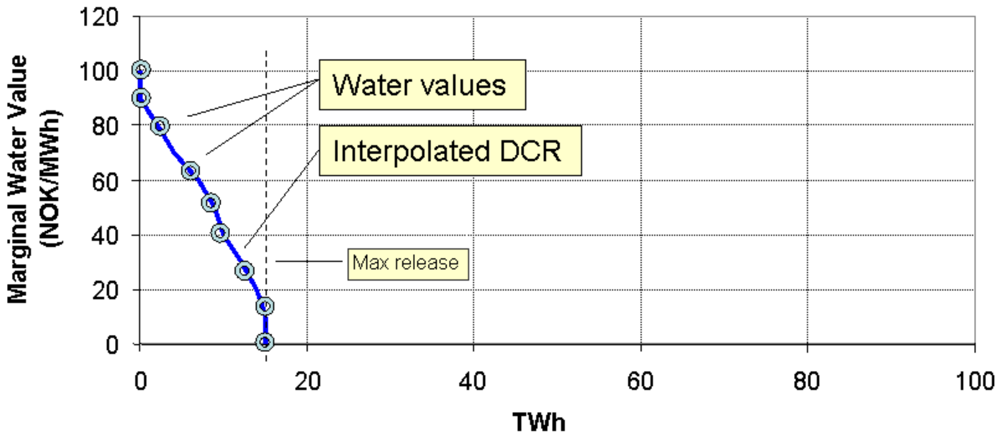
From the release output, a generation pair for region *CC* and the combined region is given for time period *t*:

$$DCR_t\left(WV_{CC}\right) = \textit{Release} = R_{CC}$$

Similar equations can be constructed for multi-reservoir examples.

An example of a 2 – dimensional DCR - curve (i.e. a single reservoir) is shown in Figure A.8.3. Note that, by convention, water values are shown on the y-axis, and generation (release) on the x-axis. The water value can be considered analogous to the marginal generation cost for a thermal plant. Thus, clearly, the lower the water values the greater the generation from the plant. Before interpolation, the DCR – curve will often have a staircase – shape, with only a few levels of hydro generation demand for a number of water value levels (either you produce a lot or nothing).

Figure A.8.3 Example 2 – dimensional DCR (Period t)



Demand Curve for Storage (DCS)

What amount of hydropower is going to be stored - given different water values or conversly The water value – given a certain level of storage

The DCR gives the desired level of release in a period for a given water value. On the other hand the Demand Curve for Storage (DCS) gives the desired level of storage for a given water value (or, conversely, the marginal value of water given a certain level of storage) in the period. The DCS is more commonly known as the Water Value Curve; however, viewing it as a demand curve for storage enables the calculation methodology to be expressed simply as the addition and subtraction of demand curves for water.

The DCS calculations make use of the fact that, in any given period, water can only be released or stored for the next period[33]. The process of calculating the DCSs for each period then simply involves the iterative addition and subtraction of the various demand curves for storage and for release. That is, the demand for water at the end of a period is given by the demand for water at the start of the period, less the demand for water to be released, adjusted for the expected level of inflow in the period. First, let the DCS for the start of a given period *t*, be denoted $DCS_{(t)}$. The DCS for this period is based on three parameters; the DCS for the start of the previous period, $DCS_{(t-1)}$, the release in the previous period, $DCR_{(t-1)}$, and the inflow in the previous period, $f_{(t-1)}$.

$$\boxed{DCS_{(t)} = DCS_{(t-1)} - DCR_{(t-1)} + f_{(t-1)}}$$

Implicitly, we here assume that water can only be stored or released.

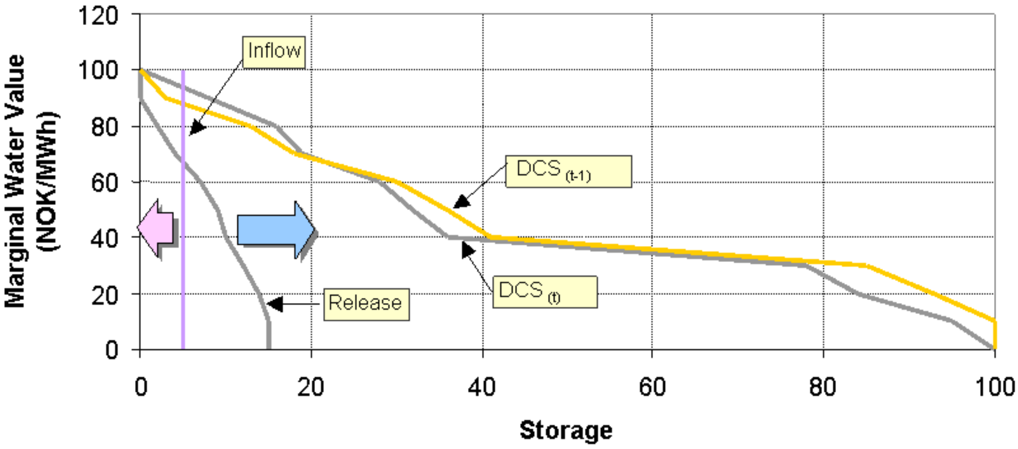
[33] Deliberate spillage of water in storage not on instruction or when the reservoir is not full is assumed to be prohibited or to attract heavy penalties, and is therefore not considered as an option.

In BID, the DCS is calculated backwards over time (i.e. beginning with an end state or period, and calculating backwards to period *t=1*). Thus, in practice the equation above is solved for $DCS_{(t-1)}$ as a function of $DCS_{(t)}, DCR_{(t-1)}, f_{(t-1)}$. This gives us the following:

$$\boxed{DCS_{(t-1)} = DCS_{(t)} + DCR_{(t-1)} - f_{(t-1)}}$$

The process of calculating $DCS_{(t-1)}$ is illustrated graphically in Figure A.8.4. The $DCR_{(t-1)}$ curve is added to the $DCS_{(t)}$. The result is then adjusted by the inflow for period *t-1* to obtain the $DCS_{(t-1)}$ curve in Figure A.8.4.

Figure A.8.4 Calculating 2 – dimensional $DCS_{(t)}$ in period t based on the knowledge of $DCS_{(t-1)}$, $release_{(t)}$ and $Inflow_{(t)}$



The optimal decisions will often aim at trying to equalize the DCS for both periods. If you release more, the value of release decreases, and the value of storage increases. In an equilibrium state these two values will approach each other.

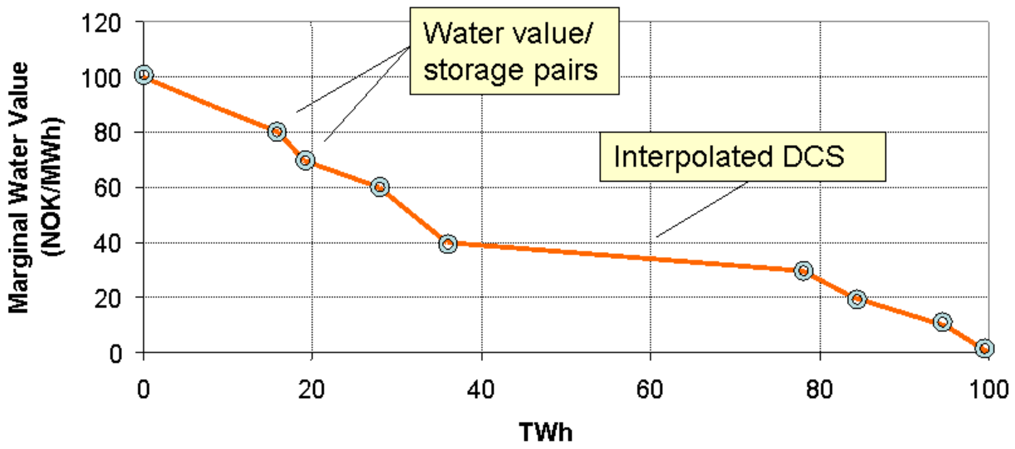
Note that the stochastic nature of the inflow conditions is captured by replacing *f* in the exposition above with a random variable *F*, representing the potential distribution of hydro inflows[34]. This random variable can have the same distribution as the historical inflows; alternatively it can be biased towards dry or wet years to capture, say, a generator's risk adjusted behaviour (e.g. a generator making a conservative assumption of hydro inflow levels in determining operating targets and decisions). For a discrete number of inflows and their corresponding probabilities, the expected marginal value of water for a given storage level is then simply the weighted average of the marginal water values from the corresponding DCS curves at that storage level.

DCS over the model period

As mentioned, the above procedure is in practice conducted for a set of discrete water values, giving a set of discrete water value/storage pairs. Interpolating between these pairs gives the full DCS curve. This curve is illustrated in the figure below.

[34] That is, we have a number of inflows *f*, each with a given probability. Each creates a DCS; the expected DCS is the probability-weighted sum of these DCSs.

Figure A.8.5 Single period DCS for one reservoir (period (t))

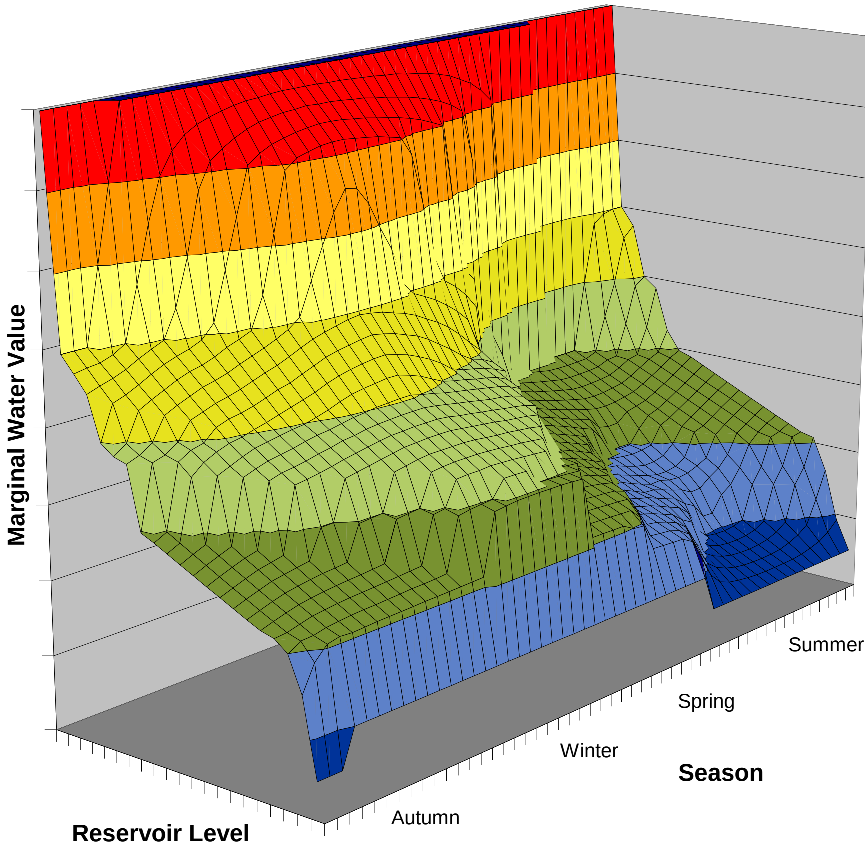


Source: Econ Pöyry

Calculating the end-of-period DCS for each period in the analysis from “end to start” gives marginal water value “surface” over the time horizon of the analysis. Thus, given a period and storage level in the reservoir, the corresponding marginal water value can be read from the graph and used to make a release (generation) decision in that period.

The figure below illustrates 52 different DCS curves over a complete year for an example reservoir. Note the development of the water values for given storage levels over the different weeks and seasons, reflecting such factors as demand levels, thermal plant availability, and inflow levels.

Figure A.8.6   Example of the 52 different DCS' for a single year



Source: Econ Pöyry

Simulation Module (market clearing)

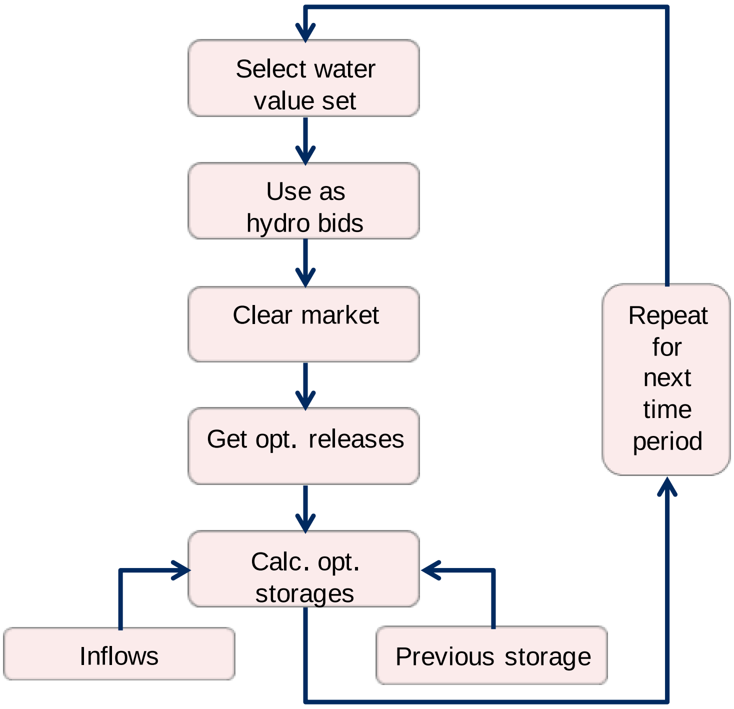
In the simulation module prices are found where demand equals supply for each zone adjusted for trade between the zones. The hydro power bid their production according to their water values as described in the section below.

The simulation module calculates the optimal solution for one week at a time. This allows the modelling of start/stop costs and ramping restrictions on plant operation over a weekly period. In the model, costs of starting up new units is assessed by introducing a variable for each technology that specifies how much of the installed capacity that is currently online. A start-up cost is added when this capacity is increased (from one time step to the next). Furthermore, units operating in partload are penalized due to the lower efficiency of operating in this point. Hence, if less power is needed, e.g. during night, capacity will be taken offline if the increased costs of running the units in part-load is bigger than the costs of starting up the unit later on, when more capacity is needed again. But to know which cost is bigger, the model must see some time ahead. Therefore the whole week is optimised at the same time.

Hydro power in the simulation module

You start out the simulation by deciding a starting storage on the reservoirs. By using the curves constructed in the rule module (the DCR and DCS), BID finds the water value for this storage level from the DCS curve, and the corresponding level of preferred release from the DCR curve. This is bid into the market and the market is cleared. The release takes place, and based on the previous storage, the release and inflow, the new storage is calculated. This is repeated each period of analysis. The figure below shows this loop.

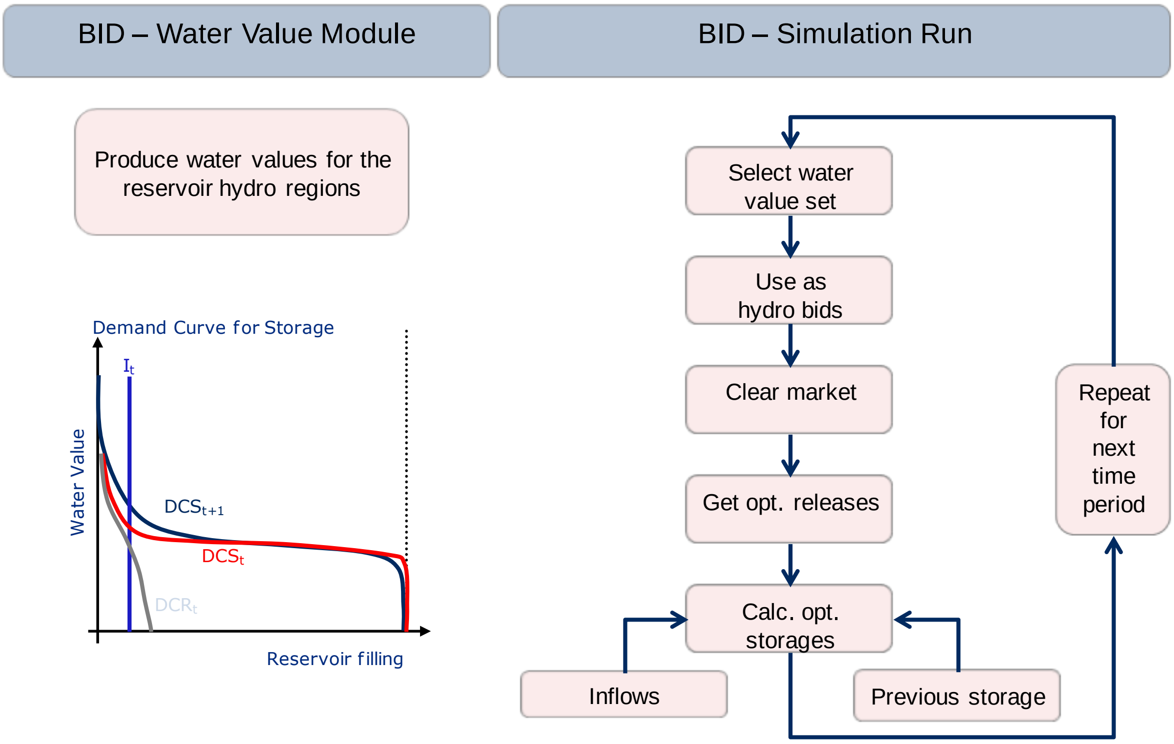
Figure A.8.7 BID simulation module structure



The simulation is regional and includes (elastic) demand, hydro plant (bidding in at their water value) and a non-hydro generation plant set. In a given period, given the thermal plant costs, the marginal water values, the market structure (such as cross border capacities and any intra-temporal constraints) and demand curve, the model minimizes the system costs. Minimizing the system cost is equivalent to obtaining the most economic efficient solution. From the market solution, prices, generation levels, demand levels, trade levels and so forth can be obtained.

How the rule module and the simulation module are combined is shown in Figure A.8.8.

Figure A.8.8 The rule module (the calculation of the DCR and DCS) and the simulation module (the market clearing)



The multi-period simulation process is as follows. First, a series of inflows to each reservoir in the model is generated (using for example statistical methods based on historical inflow distributions, or an actual historical inflow series) for a desired time horizon of the study. Starting at the first period of the time horizon and a beginning storage level (and hence water value from the DCS) for each reservoir, the market clearing model is solved and market prices, generation levels, and so on are obtained for the period. The storage levels in the reservoir are adjusted by the inflows for the period less water released, and the process is repeated sequentially for each period of the analysis. In this way the behaviour of the market, including the operation (and hence storage trajectories) of the hydro reservoirs can be simulated, and the effectiveness of the storage conservation measures assessed within the simulated market environment. A key element of these simulations is that the hydro operators in the simulations do not know what the future inflows will be, but rather base their decisions on their current storage levels, market structure, and potential future hydrological conditions. This avoids the problem of assuming perfect model foresight.

By conducting the simulation for a large number of inflow series, the distribution of the above results (rather than just point estimates) can be obtained. Alternatively, certain inflow structures, such as dry years or wet years, can be constructed and the market analysed under such inflow scenarios.

Extensions

BID extends the standard SDP approach in the following key ways:

Clearly, in a multi-reservoir multi-region model, the value of water in a given reservoir is a function not only of the storage in that reservoir, but of the storage in all the other reservoirs, as well as (implicitly) the transmission system and consequent levels of congestion in the network. In BID, the DCR and DCS curves for each reservoir are extended to incorporate the other reservoirs; that is, the water value is a function of the storage level in the reservoir, and the summed storage levels in all the other reservoirs.

At any given point in time, the hydro generators are able to predict to some extent future inflow levels, based on recent inflows, weather forecasts, snowpack levels, and so on. The accuracy of the prediction degrades with time; that is the inflows for next week can be predicted more accurately than inflows for next month. In addition, the accuracy is a function of the time of year; for example, snow pack levels may be measured in advance to give a good expectation of spring inflows. Clearly, the DCS is a function of the accuracy of the inflow forecasts, and the calculation of the DCS in BID is extended to capture this "forecastability". Further the DCS is recalculated for each time period to capture the effect of changing forecasts as each future period gets closer and closer.

Within a given region, there are multiple hydro plants, each having different capacities, reservoirs, operational features, and relative storage levels in a given period. Thus whilst the water value (DCS) structure may be essentially the same for each reservoir in a region, the water value for each reservoir may differ from the "average" water value from that regions DCS, reflecting different amounts of water in storage in each reservoir. As discussed above, the goal of BID is not to model the technical aspects of each plant individually, but rather to model the economic effect of the technical aspects. In general, the storage levels for the reservoirs in a given region will be distributed around an average relative storage level (i.e. how full the reservoir is in percentage terms). Rather than take just one water value (and thus a single bid for all the hydro in a given region) for the region based on this average relative reservoir level, BID samples several reservoir levels and thus the corresponding water values from this (user defined) storage level.

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