Supporting Information:

Future emissions from oil, gas, and shipping activities in the Arctic

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1. The economy of Arctic

The Arctic covers a huge and sparsely populated area. This vast territory contains valuable natural resources, and the Arctic economies are largely based on resource extraction. Variation in the regional endowments of resources leads to considerable variation in regional GDP (Glomsrød and Aslaksen, 2006, 2009). Due to petroleum and other minerals extraction, Alaska, Northern Canada and Arctic Russia have higher disposable income per capita than their non-Arctic counterparts. Petroleum is the dominate industry in Arctic Russia and is also considerable in Alaska. Arctic Canada has higher revenues from mining (diamonds) than energy production, whereas the fisheries are most important among resource based industries in Faroe Islands, Greenland, Iceland and Arctic Norway. Arctic Finland is the only Arctic region with a substantial manufacturing industry, dominated by the electronics industry.

2. Future oil and gas emissions in the Arctic

2.1. Future oil and gas activities in the Arctic

The potential scale of future petroleum production in the Arctic regions is assessed based on the FRISBEE model of the global energy markets (Aune et al., 2005). The model was previously used for studies of impacts of petroleum industry restructuring (Aune et al., 2010) and globalization of natural gas markets and trade (Aune et al., 2009).

The FRISBEE model builds upon the IHS database (IHS Incorporated, 2009) and describes future supply and demand of oil and gas through elaborate modelling of oil and gas investments and production. It is a recursively dynamic partial equilibrium model accounting explicitly for discoveries, reserves, field development and production of oil and gas. The emphasis is on petroleum markets; however, global markets for coal and electricity are also modelled albeit in less detail. Production takes place in 15 regions and four field categories depending on location onshore/offshore, depth of offshore fields and size of resources. In the Arctic, the model depicts only one field category in Alaska, Arctic Canada, Arctic Norway and Greenland, and two for Arctic Russia (West and East). The process of discovering reserves from the pool of undiscovered resources is determined by expected oil or gas price and the amount of remaining undiscovered resource and field characteristics.

For both oil and gas the model distinguishes between basic up-front investments and later investments in improved oil recovery (IOR) modifying the rate of decline in production after the peak level. In the future, a growing share of crude oil production will come from smaller and offshore fields, probably with higher decline rates. Hence, steadily increasing investments in IOR are needed to keep up production recovery rates. A typical production profile is illustrated in Figure 1.

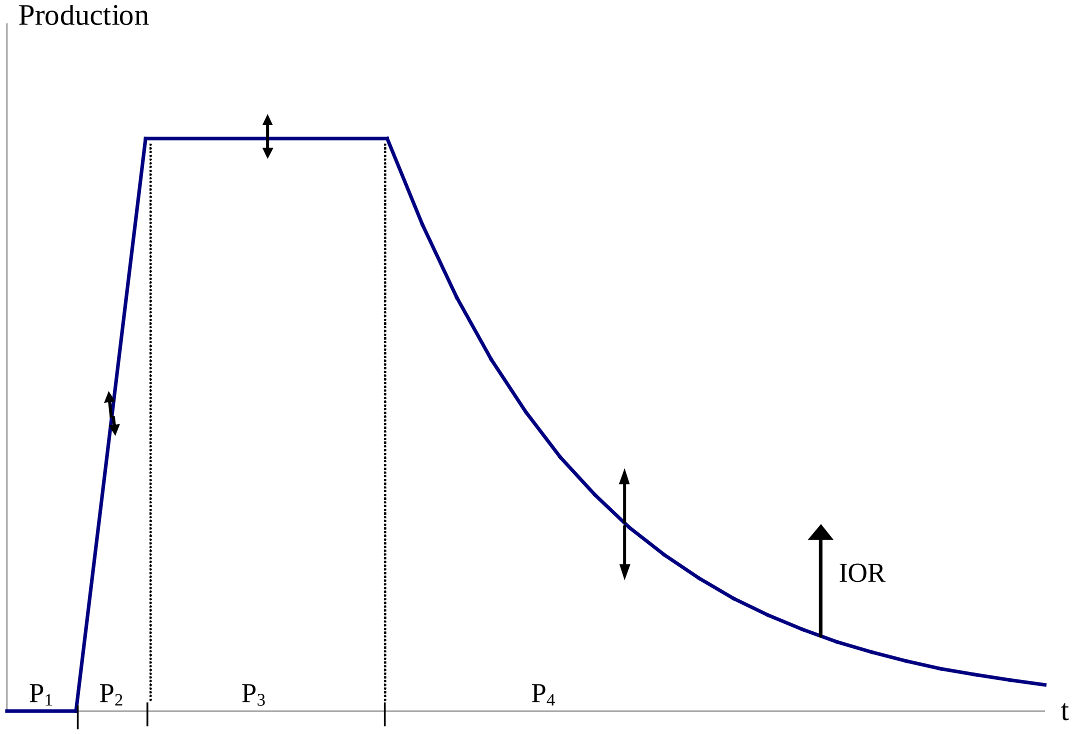

Figure 1: A typical production profile in the FRISBEE model.

For Arctic regions there is one type of field category only in the model, and the time lag from investment decision to maximum plateau production is generally 50-100 per cent longer than in comparable non-Arctic fields in each regions. The initial operational and capital costs are based on the IHS database. Capital and operational costs in new Alaskan fields are assumed to be 50 per cent higher than average costs of existing fields in the database. For Norway, the costs of new fields are set to 50 per cent above the cost level of the most expensive field category. It is assumed that Canada has the same costs as Norway. The cost level in West Arctic Russia is also set to 50 per cent over existing average cost level, whereas costs in East Arctic Russia are doubled. Investment costs are assumed to increase over time as the undiscovered resources are being developed.

The world market price of oil is exogenous in the model. OPEC satisfies the residual demand at the prevailing oil price, determined as the difference between world demand and non-OPEC supply. The fixed oil price assumption implies that total demand and non-OPEC supply are determined independently of each other. Non-OPEC supply responds to the oil price level. If demand rises due to income growth, OPEC will increase supply to cover additional demand and keep the oil price at the preferred level of the cartel. In the gas markets, however, the price is endogenous. Therefore, our description of the demand side will focus on gas.

Demand of gas is modelled in each region for the three industries manufacturing, electricity production and other sectors (including households and services). Demand is driven by growth in GDP and population. Gas demand is a function of the end-user prices of all energy goods, with own price-elasticities for manufacturing and other sectors at an average of -0.3 for the long run and -0.1 in the short run, with low cross-price elasticities. In the long run, gas demand is dependent on income growth with (per capita) income elasticity of 0.6. Exogenous energy efficiency improvement for gas consumption is set to 0.25 per cent per year in OECD countries and 0.50 per cent for the rest of the world.

The model output covers regional supply, demand and trade flows. The version adopted here is specially designed to study the role of Arctic petroleum, which is represented by the five regions Alaska, Northern Canada, Greenland, Arctic Norway and Arctic Russia. Arctic Russia is further divided into West and East Russia, where the latter region is the petroleum provinces from the Sakha region end eastwards (from the Laptev Sea to the Russian part of the Chuchi Sea). The Arctic regional petroleum activity is defined based on AMAP data (IHS Incorporated, 2009). Arctic regions are only producers of petroleum, whereas the demand generated by the small Arctic population of 10 millions is counted together with non-Arctic demand from regions of their corresponding Arctic states.

The global oil and gas industry outside OPEC is modelled as single investors allocating a share of the annual cash flow to field investments by maximizing net present value of returns, based on adaptive expectations of the future oil (exogenous) and gas price development. For oil and gas, respectively, the historic prices over the last six years will gradually be replaced by the exogenous and the endogenous price trajectory. The gas price is endogenously determined in regional markets. The model depicts the gas market as global and integrated, based on factors making international trade more profitable over the last decade. One factor behind this development is the decline in costs of transportation, in particular for LNG, another is higher imports to main consuming areas with declining reserves and associated upwards pressure on the prices. While unconventional oil is included in the model, it only covers conventional gas reserves; hence, recent technological development and cost reduction in shale gas extraction are not taken into account.

In summary, there are three ways to increase the scale of production. First, the oil companies might raise production above the pre-specified production profiles in all phases of ongoing production. Second, they may invest in new fields with the specific production profiles. Finally, there is the option to invest in IOR, which increases the reserves and lifts the production profile in the decline phase. In the absence of constraints on investments, all three options will be used so that the marginal rates of return are equal.

2.2. Gridding of the oil and gas data

The FRISBEE model gives oil and gas production in 2030 and 2050 for the East Russia, West Russia, Alaska, Arctic Canada, and Arctic Norway. This section describes how the FRISBEE regional output is distributed over a 1x1 degree grid. The gridding is based on data provided by IHS (IHS Incorporated, 2009) and USGS (Gautier et al., 2009). The IHS data contains gridded data on historic oil and gas production, estimated resources, and additional data such as stage of production, on/off-shore, and so on. The USGS Arctic appraisal contains estimates of undiscovered resources in the Arctic.

The gridding is performed in a three step process: first, average cumulative extraction rates are estimated for each field; second, the fields operating in each year are determined; and third, the total extraction in each region is scaled to match the FRISBEE output.

2.2.1 Step 1: Average cumulative extraction rates

In the first step, the average cumulative extraction rates (cumulative production divided by years in production) for each field are determined using either historic production data or reserve size for the fields not currently in production using the IHS data (IHS Incorporated, 2009). Using the cumulative production data we estimated the "Average Annual Extraction" for all fields with non-zero historic production. For mature fields, this estimate is probably a reasonable estimate. For fields in the early stages of production, this estimate is probably inaccurate as average production will be unrealistically low. We considered using the maximum production in the historic period but this was found to be overly optimistic in later parts of the analysis. To account for fields with unrealistically low average production due to the early phase of extraction we estimated the average extraction based on the estimated reserves and a field "lifetime" of 31 years. The lifetime is idealized, somewhat arbitrary, and specific to our method. The only constraint on the lifetime are that it lies between 30 and 50 years to be consistent with our time periods of 2004 (2000), 2030, and 2050. We chose the lower end of the scale as it agrees best with the historic production data and to raise average production levels to obtain consistency with fields with good production data and fields without production data. For the USGS undiscovered resources data we assumed a recovery factor of 30% for oil and 50% for gas. We scaled these factors by the "Assessment Unit Probability" to adjust for the probably of the undiscovered resources (Gautier et al., 2009). The "lifetime" of the USGS resources was taken as 60 years to account for different production in different parts of the resources over a longer time scale. Based on the average and estimated extraction data we back calculate the remaining lifetime of the field based on the remaining reserves and the maximum possible extraction rate. Based on our lifetime assumption, this means that the maximum lifetime will be 31 years which lies between 30-50 years which is consistent for the purpose of our analysis.

2.2.2 Step 2: Fields in operation

In the second step, using information on the current stage of development in each field (IHS Incorporated, 2009), fields are selected that are in operation in either 2030 or 2050.

Production occurs at a grid point in 2030 if:

- BOTH, if the field has a "lifetime" greater than 30 years. We intentionally take this greater then 26 (=2030-2004) years to account for small production at the end of the lifetime.
- AND the field is producing in 2004 OR IHS categorizes the field as "Waiting Development Approval" OR "Under Development"

Production occurs at a grid point in 2050 if:

- EITHER, the field was in operation in 2030 AND has a "lifetime" greater than 25 years. As for 2030, we intentionally take this greater then 20 (=2050-2030) years to account for small production at the end of the lifetime.
- OR IHS categorizes the field as "Appraisal" OR "Discovery". Here we assume that the development time means that the fields will not be in production in 2030, but will be in production in 2050. This just shifts the data for gridding from 2030 to 2050.
- OR the regions in the USGS undiscovered resources. Since the USGS regions are large, we located production in the most feasible locations for transportation purposes.

The USGS undiscovered resources are only used in 2050 and we do not assume that all undiscovered resources are useable. Wood Mackenzie analyzed the "least developed basins in the Arctic and examine which of these has the most to offer explorers" (Murray, 2006), and we used this to remove some of the USGS undiscovered resources from the analysis:

- North Greenland removed due to extreme weather
- East-central Greenland removed due to low prospects
- Hope Basin removed due to low prospects
- North Chukchi Sea removed as it is gas-prone with insufficient resources for a pipeline or LNG in ice conditions
- North Kara Sea removed due to tough ice conditions, gas prone, and far from markets
- East Siberian Sea removed due to tough ice conditions, gas prone, and far from markets
- We additionally took out similarly located areas with similar characteristics
    - Lomonosov-Markarov
    - Vilkitskii Basin
    - Eurasia Basin
- We retained north-east and west Greenland as they have potential and are being promoted
- Even though the Laptev Sea has tough ice conditions, gas prone, and far from markets, we retain it due to its the potential

2.2.3 Step 3: Scaling to match FRISBEE output

In the third step, the estimated extraction rates in 2030 and 2050 are then scaled so that the regional output matches the FRISBEE model output. That is, the gridded data is used as a proxy for the location of the FRISBEE extraction. The USGS data on undiscovered resources (Gautier et al., 2009) are incorporated in the 2050 estimates. Greenland is not included in the FRISBEE results and the output is estimated using the estimated field size (IHS Incorporated, 2009;Gautier et al., 2009).

2.3 Oil and gas emission factors

For Norway the defaults are from Statistics Norway are obtained by dividing the total emissions in Norway from oil and gas production (Statistics Norway, 2010a) with the oil and gas output (Statistics Norway, 2010b). The emissions cover stationary combustion (natural gas in turbines, flaring, diesel combustion, gas terminals) and process emissions (venting, leaks, oil loading at sea and onshore, gas terminals). The pollutants covered are CO_2, CH_4, N_2O, SO_2, NO_x, NMVOC, CO, NH_3, and PM. The average emission intensity was determined for the period 2000-2006, however, NMVOC was based on the 2006 value as it has changed rapidly from 2000-2006 due to the implementation of the Gothenburg Protocol (UNECE, 2005).

For Russia we use the UNFCCC Russian GHG Inventory for 2009 (Russian Federation, 2010, Table 1s) to derive emission factors per Mtoe. There is good agreement between the OGP (Oil and Gas Producers, 2009) estimates and the UNFCCC inventory, except for CH_4. For CH_4, the GHG inventory includes leaks from pipelines and for consistency with other regions, we do not consider this. The GHG inventory does not have PM estimates and we use a default of 50g/toe which lies between the estimates for Alaska, and Norway and Canada.

For Canada we estimate emission factors using the Canadian Association of Petroleum Producers database for the year 2000 (CAPP, 2004) and the oil and gas output (IHS Incorporated, 2009) in the Northwest and Yukon Territories. Comparisons were made with the National Pollutant Release Inventory (Environment Canada, 2010) and reasonable agreement was found where there was overlap.

Alaskan emissions are estimated from a variety of sources. The Alaskan GHG Inventory has an estimate of 24.77 Mt CO_2-eq for the oil and gas industries in Alaska. The Trustees for Alaska (Trustees for Alaska, 2010) compiled estimates from a variety of sources for the oil and gas industry on the North Slope with emissions of 41.8 Mt CO_2, 114 kt CH_4, 2.7 kt NMVOC, 1.5 kt SO_2, 56.4 kt NO_x, 11.6 kt CO, and 6.2 kt PM. A report (Russell et al., 2006) estimated NO_x emissions in 2002 of

46.7 kt NO_x. A National Academies report (Orians, 2003) has estimates of 7.3-41.8 Mt CO_2, 24 kt CH_4, 2.4 kt NMVOC, 1.3 kt SO_2, 70 kt NO_x, 11 kt CO, and 5.4 kt PM. Based on these sources we estimate the emissions as 24 Mt CO_2, 100 kt CH_4, 2.5 kt NMVOC, 1.4 kt SO_2, 55 kt NO_x, 11 kt CO, and 6 kt PM. Emission factors are estimated together with the oil and gas output (IHS Incorporated, 2009). Due to lack of data, the emission factor for N_2O is taken from the OGP (Oil and Gas Producers, 2009) estimates for the United States.

We did not find emission factor estimates for BC or OC in the Arctic and based our estimates on shares of particulate matter (Bond et al., 2004) (PM). BC and OC emissions vary significantly with technology (Bond et al., 2004) and technology for oil and gas extraction varies from gas turbines to diesel generators. In the absence of better information, we assume that each region has a 50-50 split between gas turbines and diesel generators. Based on Table 5 in Bond *et al.* (2004) we estimate BC and OC emission factors as a share of PM based on middle/light distillate from generators and natural gas.

3. Shipping emissions

3.1 Transit shipping model

A deterministic model has been developed to calculate vessel speeds and fuel consumption as a function of sea ice conditions. The future Arctic transit shipping activity level, specifically, the number of ship passages, is determined by jointly assessing the volume of global seaborne trade and the attractiveness of selecting the Arctic transit route as opposed to traditional sea routes (e.g. via Suez) for container trade between eastern Asia and Europe. The model has the following basic steps:

- Calculate transit times and fuel consumption on potential Arctic routes compared to the Suez route.
- Calculate the economic viability of potential Arctic routes by comparing costs against the Suez route.
- Project potential amount of cargo that may be transported in 2030 and 2050 for the most favourable Arctic route on commercial terms.
- Calculate the number of transits in 2030 and 2050, based on projected amount of cargo.
- Calculate ship emissions, based on number of transits, fuel consumption factors and emission factors.

The attractiveness of transpolar shipping is evaluated by considering two different scenarios (year-round and part-year operation) for container shipping between defined hubs in Asia (Tokyo, Hong Kong or Singapore) and Europe across the Arctic, both based on independently operating vessels (i.e. no ice-breaker escort). The first Arctic scenario consists of a fleet of identical 5000 TEU double-acting container vessels (as described in Arpiainen and Kiili, 2006) operating a liner service that transits the Arctic throughout the year. The second Arctic scenario consists of a fleet of identical, ice-classed 6500 TEU container vessels with bulbous bows, operating a liner service that transits the Arctic during the summer, when the ice cover is at its minimum, and uses the Suez Canal the rest of the year. The length of the summer season varies according to ice conditions.

The concept of the model developed to calculate emissions from ships operating independently (i.e. without ice-breaker escort) in the Arctic is presented in Figure 2. The top-level results from the model are geographically gridded values for emissions to air of various pollutants given in kilograms. These emission values are derived from similarly gridded fuel consumption values using constant factors that relate the mass of fuel consumed to the mass of pollutants emitted to air (the emission factors given in the main text). The gridded fuel consumption is calculated by multiplying the traversed distance with the amount of fuel consumed per unit of distance and the number of passages. The fuel consumed per unit of distance traversed is calculated from modelled ice conditions and ship-specific ice-performance curves along with specific fuel consumption (the ratio of the mass of the fuel consumed to the resulting power produced by the engine) values.

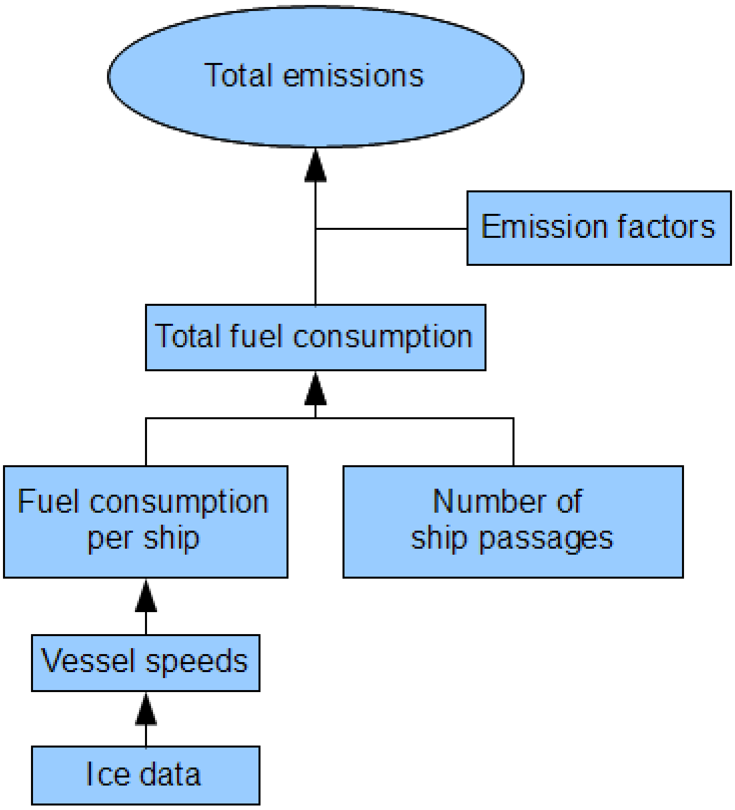

Figure 2: Model concept used to calculate emissions from ice data, ship parameters and number of passages.

The values for specific fuel consumption used in this study are given in Table 1. The present specific fuel consumption value is taken from Buhaug et al. (2009). The future specific fuel consumption values are reduced from the present by 5 % in 2030, and 10 % in 2050, in keeping with the methodology of Eide et al. (2007), to reflect the IPCC A2 scenario.

Table 1: Present and assumed future specific fuel consumption for slow-speed internal combustion engines running on residual fuel oil (adapted from Buhaug et al., 2009;Eide et al., 2007), assuming the IPCC A2 scenario).

Year	**Specific fuel consumption [g/kWh]**
Present	175
2030	166
2050	158

3.2 Transpolar shipping routes

Four different sea routes across the Arctic Ocean have been investigated in this study. After evaluating each route with respect to the transit time, fuel consumption, ice conditions, uncertainties in tax regimes etc., a single route was selected for the purpose of modelling transpolar shipping. Transit through the Northwest passage is considered unlikely during the next few decades (Wilson et al., 2004) and have not been considered in this study.

The four prospective routes across the Arctic are presented in Figure 3. Route 1 is close to the traditional Northern Sea Route, passing largely within Russian territorial waters. Route 2 is a modified version of the first that avoids some of the shallow areas, and is thus more appropriate for larger ships. Route 3 is designed to lead vessels mostly outside of the Russian Exclusive Economic Zone (EEZ), whereas Route 4 cuts directly across the North Pole. Calculations of transit times and fuel consumption for the different Arctic routes show that route 2 is the most suitable route for 2030, with route 3 a close second. For 2050 route 3 is the most suitable regardless of any fee considerations. Due to the currently untenable and future uncertain fee level associated with route 2 we have chosen to use route 3 for both 2030 and 2050 in this study.

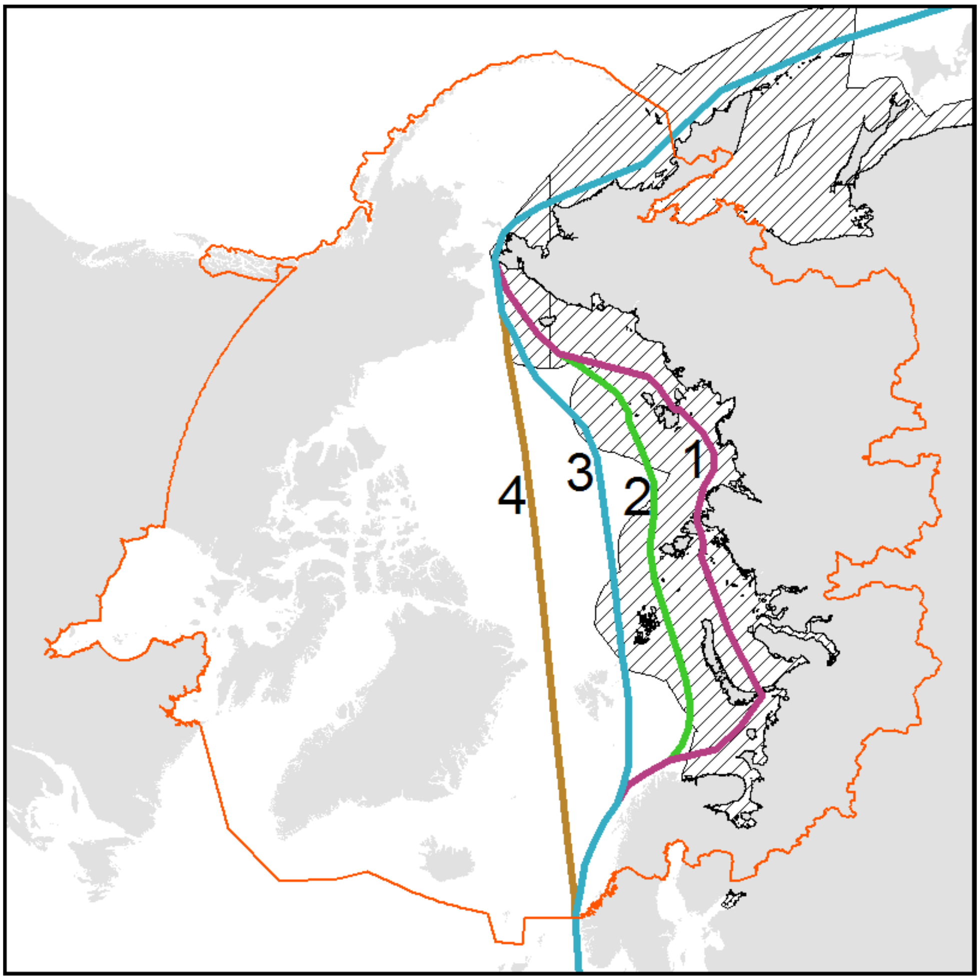

Figure 3: Arctic transit routes used in this study. The Exclusive Economic Zone of the Russian Federation (source: Vlaams Instituut voor de Zee (VLIZ), 2009) is shown with diagonal hatching. The AMAP Arctic boundary used in this work is shown with a solid orange line.

3.3 Emission factors

The current NO_x requirement (Tier I: Ships built between 1 January 2000 and 1 January 2011) for ships with engines below 130 RPM is to emit less than 17 g/kWh. For Tier 2 vessels (built after 1 January 2011) the corresponding requirement is 14.4 g/kWh. Vessels operating in Emission Control Areas (ECA), will additionally be subject to Tier 3-regulations (vessels built after 1 January 2016) which require that emissions be limited to 3.4 g/kWh. Whether the Arctic will be designated an ECA remains an open question, and in this study we assume that it will not be.

Based on the emission factors (Table 4, main document) and the current average specific fuel consumption (Table 1) we calculate the current average emission of NO_x to be 16.5 g/kWh. Meeting the requirements of Tier 2 would thus require an improvement of approximately 13 % (and a 79 % improvement to match the requirements of Tier 3). A simplified calculation which assumes an average lifetime of a vessel is 30 years, and that the fleet is of constant size and is continuously renewed, gives a required fleet average reduction of 8.7 % in 2030 and 13 % in 2050 compared to today's emission levels. Since the specific fuel consumption (SFC) is set to improve 5 % from the current value to 2030, and 10 % from the current value to 2050 (see Table 1), this translates to a necessary emission reduction factor of 3.9 % in 2030 and 3.3 % in 2050 for NOx. These modest reductions are a result of previous efforts to limit the NO_x-emissions from shipping, which up to now has been the main focus of emission reductions in the industry since no other pollutants have been regulated internationally, though SO_x and PM have been regulated regionally (Eyring et al., 2005). We assume that these NO_x-reductions come about by modification and/or tuning of the engine which does not impact emissions of other pollutants or the fuel efficiency in any significant way.

MARPOL 73/78 Annex VI originally stated that the sulphur content of any fuel oil used on board ships shall not exceed the following limits (all percentages by mass, applicable to non-ECAs):

- 4.5 % prior to 1 January 2012
- 3.5 % on and after 1 January 2012
- 0.5 % on and after 1 January 2020

The amended version of Annex VI states that any technology or operational measure which is at least as effective as switching to low-sulphur fuel in reducing SO_x-emissions may be implemented in lieu of switching fuel. We have, however, based our calculations of reduction factors on the assumption that the prescribed emission reduction will be achieved by fuel-switching alone, as the mix of measures that will be implemented are difficult to predict. This assumption should not impact the reduction factor for SO_x to any great extent (but may impact other pollutants). According to data published by DNV (Det Norske Veritas, 2005), the current average sulphur content is 2.46 %. After 1 January 2020 the sulphur content should be no more than 0.5 %, or 20 % of the current average. We assume that the SO_x emissions will be reduced by the same factor as the sulphur content of the fuel, thus the emission reduction factor for SO_x will be 80 %. According to report published by Entec UK (Entec UK Limited, 2005), switching from fuel with 2.7 % sulphur content to fuel with 0.5 % sulphur content will reduce SO_x-emissions by about 80 % and PM-emissions by about 20 %. Corbett et al. (2010) reports that field measurements of emission factors indicate no statistical correlation between switching to low-sulphur fuels and the emission factor for BC, while OC and SO_x are correlated. Since OC may be considered a subspecies of PM we will assume the same reduction percentage for OC as for PM. The following tables summarise the emission factors that have been used for both years considered in this study.

3.3 Transit model sensitivity

We investigated the transit model sensitivity to the fuel price and the length of the sailing season, as these are the two most important parameters in the cost calculations. To compare the two different alternatives for transit shipping across the Arctic we calculated the cost per TEU transported from each hub for 2030 and 2050, and compared these with the cost for regular all-year Suez Canal freight. Figure 4 and Figure 5 show the results for the route between Tokyo and Rotterdam for the years 2030 and 2050, respectively. The figures show that significant perturbations of the most likely fuel cost and navigation season length are required to make the cost difference negative, hence we regard the positive results for the Tokyo hub as robust.

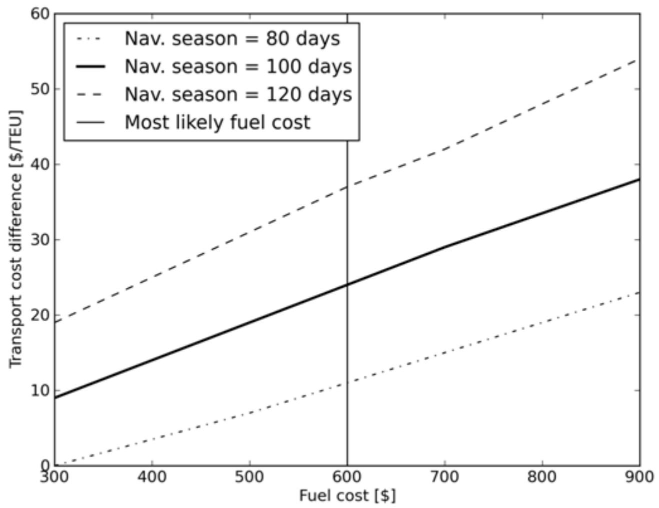

Figure 4: Transport cost difference in $/TEU from Tokyo to Rotterdam for the part-year Arctic route relative to the regular Suez route in 2030. Most likely fuel cost is shown with a solid vertical line, while the most likely season length is shown with a thick solid line. Positive cost difference means that the Arctic alternative is cheaper.

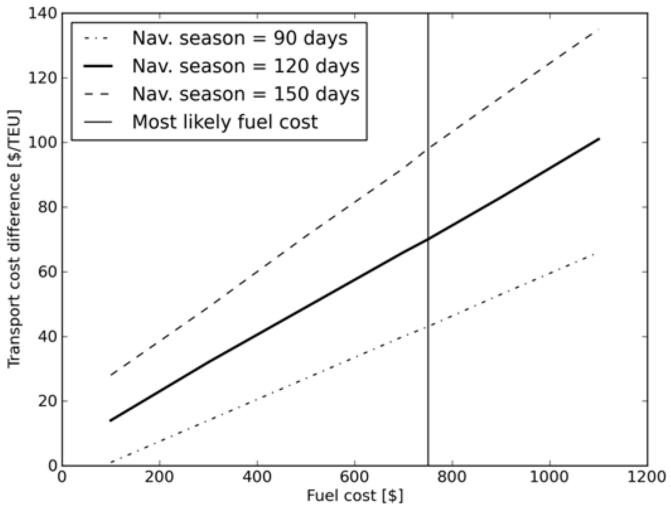

Figure 5: Transport cost difference in $/TEU from Tokyo to Rotterdam for the part-year Arctic route relative to the regular Suez route in 2050. Most likely fuel cost is shown with a solid vertical line, while the most likely season length is shown with a thick solid line. Positive cost difference means that the Arctic alternative is cheaper.

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