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CO_2-emissions from Norwegian oil and gas extraction

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A B S T R A C T

Emissions from oil and gas extraction matter for the life cycle emissions of fossil fuels, and account for significant shares of domestic emissions in many fossil fuel exporting countries. In this study we investigate empirically the driving forces behind CO_2-emission intensities of Norwegian oil and gas extraction, using field-specific data that cover all Norwegian oil and gas activity. We find that emissions per unit extraction increase significantly as a field's extraction declines. Moreover, emission intensities increase significantly with a field's share of oil in total oil and gas reserves. We also find some indication that oil and CO_2-prices may have influenced emission intensities on the Norwegian continental shelf.

1. Introduction

Although more than 90% of the GHG (greenhouse gas) emissions from fossil fuel use occur downstream when the fuel is combusted, emissions related to extraction also matter for the life cycle emissions of fossil fuels. Moreover, in large oil and gas producing countries, these emissions may constitute large shares of domestic emissions. Both in Canada and Russia oil and gas production and transmission account for more than 20% of domestic GHG emissions [12,22]. In Norway the share of GHG emissions coming from the oil and gas activity on the Norwegian continental shelf constituted 27% in 2013 [33]. Despite a falling trend in overall production of oil and gas in Norway over the last decade, GHG emissions from this activity have not been falling. Hence, there is concern in Norway about these emissions (see e.g. Refs. [23,36]).

At the same time, the emission intensity for Norwegian oil and gas extraction is below the world average. Whereas the world average is around 130 kg CO_2 per ton oil equivalent (toe) [29], the Norwegian average in 2012 was 55 kg CO_2 (see Fig. 1).[1] One reason for the lower emission intensity is the Norwegian CO_2-tax, which was introduced in 1991 [27]. The current CO_2-tax level for oil and gas production is 1 NOK per Sm^3 gas, which translates into about 50 Euro per ton CO_2. This comes in addition to the EU ETS (EU Emission Trading System) regulation, meaning that the oil and gas industry in Norway pays both CO_2-tax and EU ETS price. According to the Norwegian Ministry of climate and environment (2014), the CO_2-tax is likely to have caused the separation and underground storage of the CO_2 content in the gas extracted at the Sleipner field since 1996, and at the Snøhvit field since 2008.

Oil and gas production in Norway takes place offshore, mostly in the North Sea but there are also several fields in the Norwegian Sea and one field in the Barents Sea. Norwegian oil production started up in 1971, and peaked in 2001 at around 200 million Sm^3 (throughout the paper, oil includes crude, NGL and condensates). Since then, oil production has been approximately halved, cf. Fig. 2. The first unit of Norwegian gas was extracted in 1977. Gas production in Norway was moderate until mid-1990's. Then it increased until it peaked in 2012 at almost 120 billion Sm^3 (or 120 million Sm^3 toe). As shown in Fig. 2, in the 16-years period we consider, total petroleum production has been rather constant, but there has been a gradual change from mostly oil production to about equal shares of oil and gas.

Oil and gas extraction is an energy intensive activity. Most of the GHG emissions from Norwegian petroleum production comes from the use of gas turbines that generate electricity. These are located at the platforms offshore, and are less efficient than modern large-scale gas power plants [11]. In 2012, they accounted for 62% of total GHG emissions from Norwegian oil and gas production. The use of diesel accounted for 9% of emissions, flaring, venting and oil

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[1] In addition comes other GHG emissions such as methane – these constitute around 15% of total GHG emissions globally (from oil and gas extraction) but only 5% in Norway. This is partly due to strict restrictions on flaring in Norway. As a comparison, CO_2-emissions from *combustion* of oil are around 3000 kg per toe.

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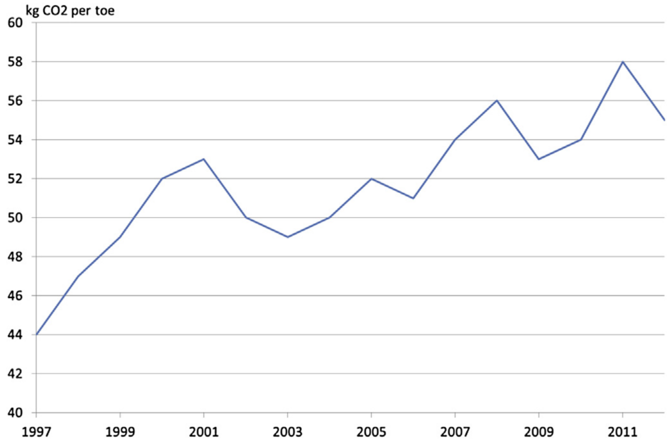

Fig. 1. Development of average CO_2-emissions per unit of oil and gas in Norway from 1997 to 2012. Kg CO_2 per toe. Source: Own calculations based on data from the Norwegian Environment Agency.

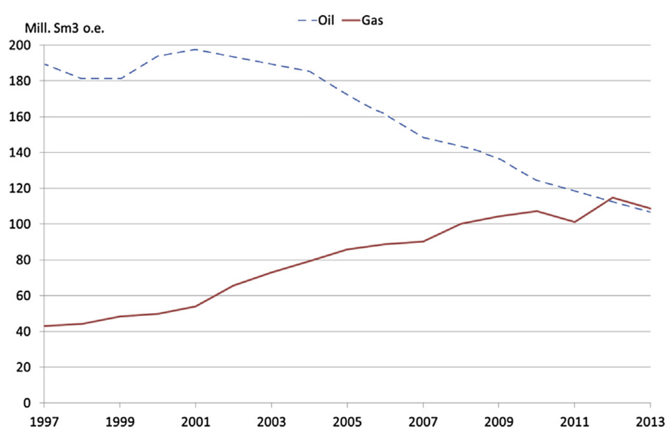

Fig. 2. Development of Norwegian oil and gas production in the period 1997–2013. Million standard cubic meter (Sm^3) oil equivalents. Source: Statistics Norway (http://www.ssb.no/energi-og-industri/statistikker/ogprodre/kvartal).

loading for 11%, while the remaining emissions (18%) come from onshore activity (mostly gas turbines) that are only partly related to specific fields.[2]

In this paper we investigate the driving forces behind CO_2-emission intensities on the Norwegian continental shelf. We employ a unique dataset with annual field data for CO_2-emissions from 1997 to 2012, covering all Norwegian oil and gas fields. These data are combined with annual field data for production of oil and gas (and water), and field data on original reserves, reservoir and ocean depths, and whether the field has access to electricity from the grid ("electrified fields"). We test for the effects of these field characteristics as well as the effects of CO_2-prices, oil prices and time. In particular, we are interested in whether there are significant differences between oil and gas fields, or more precisely, whether the share of oil in a field's reserves or production is of significance for a field's emission intensity. Moreover, we examine how emission intensities develop in the decline phase of the field.

In the next section we review previous literature relevant to our study. In Section 3 we present our empirical approach, including a discussion of explanatory variables and the empirical model, and then present the data we use. In Section 4 we display and discuss the empirical results, as well as the results from some robustness and alternative estimations, and discuss policy implications. In the last section we conclude.

2. Previous literature

To our knowledge, similar studies have not been undertaken before, neither for Norway nor other countries, probably because of the uniqueness of the Norwegian emissions data associated with oil and gas production. There exist some related studies, though. The International Association of Oil and Gas Producers publishes every year regional GHG and CO_2 emission intensities for different regions of the world, based on reported data from its member companies [29]. Rahman et al. [31] quantify the GHG emissions from crude recovery of five selected North American crudes, using information about energy use and process fuel shares. They find large differences in emission intensities between the different crudes, ranging between 3.94 and 23.85 g CO_2 per MJ, which corresponds to, respectively, 165 and 1000 kg CO_2 per toe (most of the crudes were in the lower range though – only one was above 240 kg CO_2 per toe). Brandt and Unnasch [6] calculate energy efficiency and GHG emissions of thermal enhanced oil recovery, both for generic cases and for 19 California-specific projects, whereas Jaramillo et al. [17] analyze life cycle emissions of enhanced oil recovery for five different projects in North America. Brandt [5] analyses energy efficiency of oil production in 306 Californian oil fields over a 50-years period, whereas Brandt [4] examines GHG emissions from oil shale extraction in the Green River formation. Bergerson et al. [1] quantify life cycle emissions associated with two different extraction processes for Canadian oil sand. Oil sand production is more energy intensive than conventional oil production, leading to high GHG emission intensities (cf. [8]). Betancourt-Torcat et al. [2] model the effects of mitigation strategies to reduce GHG emissions from Canadian oil sands operations. Olateju and Kumar [30] assess hydrogen production from wind energy as a mean to reduce GHG emissions from oil sands in Western Canada. Klokk et al. [19] study how CO_2 deposited in oil reservoirs can be used for enhanced oil recovery on the Norwegian continental shelf.

There are a number of studies that analyze GHG emissions from other types of energy production, or from energy use in different sectors. Li et al. [20] examine GHG emissions from a coalfield in China, considering CCS (carbon capture and storage) as a way to minimize emissions while simultaneously ensuring workforce safety. Davison [9] assesses three different CCS technologies that can be used in electricity generation, looking into both emissions, costs and performance. Rootzén and Johnsson [32] analyze the prospects for CO_2 emissions abatement in the Nordic carbon-intensive industry, also focusing on CCS options, while Szklo and Schaeffer [35] and Johansson et al. [18] examine options to reduce CO_2-emissions in Brazilian and European oil refineries, respectively. Jaramillo et al. [16] and Garg et al. [15] consider life cycle GHG emissions of, respectively, liquid transportation fuels derived from coal and natural gas, and oil used in the transport and household sectors in India.

3. Empirical approach and data

3.1. Empirical approach

During the period 1997–2012, the average emission intensity of Norwegian oil and gas extraction increased by more than 20% (see

[2] Flaring is the controlled burning of natural gas produced in association with oil in the course of oil and gas production operations. Venting is the controlled release of unburned gases directly into the atmosphere [28]. Data source for Norwegian GHG emissions: http://ssb.no/en/natur-og-miljo/statistikker/klimagassn.

Fig. 1), and the aim of this paper is to empirically investigate the driving forces behind fields' emission intensities. Here we will first discuss possible explanatory variables, and then present our empirical model.

Many of the fields on the Norwegian continental shelf are currently in the decline phase. When production decreases from a field's peak level, this is often associated with increased production of water (as a waste byproduct), at least for oil fields ([37]; p. 5), which implies that more energy is needed per unit extraction. Moreover, the natural pressure in the reservoir declines as the oil and gas are extracted ([10]; p. 21), which also means that more energy is needed ([26]; p. 47). Hence, we should expect that the emission intensity increases as a field's production falls from its peak level. As an illustration of this hypothesis, Fig. 3 shows the development of the Ekofisk field, which is one of the major oil and gas fields in Norway. It was the first field on the Norwegian continental shelf and is expected to continue producing until around 2050 [25]. Whereas the emission intensity was around 40 kg CO_2 per toe while production was around its peak level, it has increased to 90 kg in 2012 when production was slightly below 50% of its peak level. At Ekofisk, as well as other major oil fields like Statfjord and Gullfaks, production is currently dominated by water. For instance, at Ekofisk twice as much water was produced as oil in 2012 (measured in volumetric units). Thus, it is also relevant to examine whether a field's water production has significant effects on its emission intensities.

By comparing Figs. 1 and 2, we notice that the share of gas in total petroleum extraction has increased while the emission intensity has gone up during our estimation period. This might suggest that gas production is more emission intensive than oil production. On the other hand, as oil reservoirs often contain more water than gas reservoirs ([37]; p. 5), this may suggest that more energy is needed to extract oil than gas. Further, more heat is required to separate oil, gas and water from an oil well stream compared to a gas well stream. Moreover, as natural gas is lighter than air, it will naturally rise to the surface of a well. Consequently, less lifting equipment and well treatment are typically needed for gas reservoirs compared to oil reservoirs ([10]; p. 21). Thus, we examine whether the share of oil in a field's overall oil and gas reserves, or in its running oil and gas production, has influence on its emission intensity.

Oil and gas producers are likely to respond to price changes. In particular, the price of CO_2 should be of importance when they assess investments and other efforts to reduce emissions. Thus, as mentioned in the introduction, we should expect a negative relationship between the CO_2-price and the emission intensity. The CO_2-price facing Norwegian oil and gas producers declined by more than 50% from late 1990's to 2012 (in real terms). This is partly because the nominal CO_2-tax was reduced by more than 20% from 1999 to 2000, and partly due to lower than expected CO_2-prices in the EU ETS in 2009–2012. Hence, the incentives to cut emissions were reduced during our estimation period.

The prices of oil and gas are important for the profitability of oil and gas producers, and are likely to affect their decisions. Higher prices give companies more incentives to also develop marginal fields, i.e., fields with limited profitability. One possible reason for limited profitability could be that more energy is required to extract the oil and gas from the reservoir. Higher prices may also give companies incentives to delay termination of producing fields, e.g. by investing in IOR (Improved Oil Recovery) or EOR (Enhanced Oil Recovery) measures, which often implies higher emissions per unit extracted due to more energy demanding activities ([6,26]). The North Sea is a mature oil and gas province now, and there has been a gradual shift from large and easily accessible fields towards smaller and more marginal fields during the last 15–20 years. Over this period, the oil price tripled (in real terms). To what extent the oil price increase has influenced the development of the marginal fields is difficult to say. It seems natural, however, to test whether the oil price has affected the emission intensities on the Norwegian continental shelf.

Although there has been a shift towards more marginal fields, technological improvements could mitigate the so-called depletion effect, e.g. if operations become more energy-efficient over time (see Ref. [21] for an analysis of this issue based on oil extraction costs worldwide). Thus, we examine whether there is a significant time trend, or if the start-up year has an influence on a field's emission intensity. Fig. 4 shows the emission intensity of individual fields over the period 1997–2012, combined with the start year of production. We notice large differences across fields. However, since none of the fields both started and terminated production during this period, we do not have data for the full life cycle emissions of any of the fields. Thus, the figure will probably overestimate life cycle emissions of older fields that had reached the decline phase in 1997, and underestimate emissions of newer fields that were still around peak level in 2012.

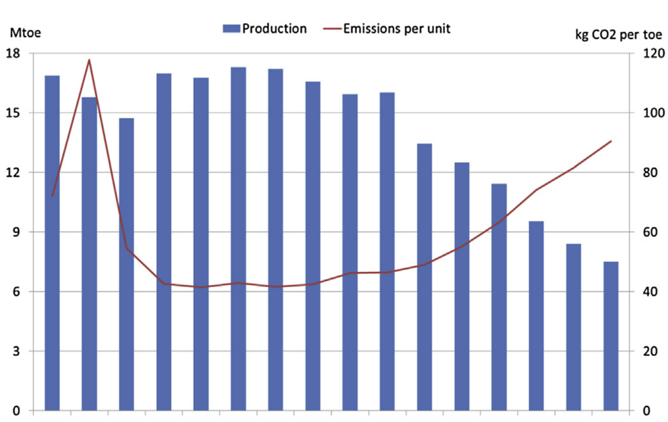

Fig. 3. Total production of oil and gas (Mtoe), and emissions per unit (kg CO_2 per toe), at the Ekofisk field in the period 1997–2012. Source: Own calculations based on data from the Norwegian Environment Agency and The Norwegian Petroleum Directorate.

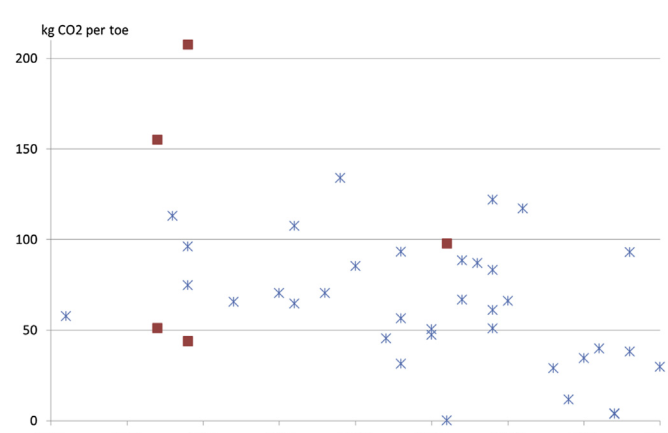

Fig. 4. Emission intensity for individual fields in the period 1997–2012, combined with the start year of production at the field. Red squares indicate fields with production terminated before 2012. Source: Own calculations based on data from the Norwegian Environment Agency and The Norwegian Petroleum Directorate.

Three fields have close to zero emissions (two of them overlap in the figure). These fields use electricity from the grid, and hence have very small direct emissions. These are Troll I, Ormen Lange and Snøhvit, which are large fields producing gas only. Gjøa, which produces both oil and gas, is also electrified but has higher emission intensity so far due to recent start-up (2010). Indirect emissions from electricity input are not accounted for in the statistics, and thus not in our study either. Thus, we should expect a negative relationship between electrification of a field and its emission intensity.

According to NHO/OLF [24]; smaller fields have historically had higher emission intensities than larger fields on the Norwegian continental shelf. We therefore examine this in our empirical model. We also investigate whether ocean depth or reservoir depth are of importance for a field's emission intensity. According to Brandt [5]; there tends to be a positive relationship between depth and energy consumed when drilling a well.

This completes our discussion of potential explanatory variables, which consist of both technical and economic variables. When constructing our empirical model, we log-transform the dependent variable and some of the explanatory variables (cf. e.g. Ref. [13]; p. 57). We do not transform, however, the share variables (nor the time trend, the start year, and dummy variables). The log-transformation implies that the estimated parameters β_i have an intuitive interpretation as elasticities, that is, a one percent increase in the explanatory variable leads to an increase in the dependent variable of β_i percent. For the share variables, an increase in the explanatory variable of one *percentage point* leads to an increase in the dependent variable of approximately β_i percent (more precisely, a *unitary* increase in the explanatory variable leads to a multiplicative increase in the dependent variable of $e^{\beta i}$).

Thus, we consider the following empirical model for the emission intensity, *em_int*, where *i* and *t* denote respectively field and year and log denotes the log-transformation:

$$\begin{aligned}\log(em\_int_{it}) &= \beta_0 + \beta_{1a} prod\_share_{it} + \beta_{1b}(prod\_share_{it})^2 + \beta_{1c}(prod\_share_{it})^3 + \beta_2 gasres\_share_i \\ &+ \beta_3 gasprod\_share_{it} + \beta_4 \log(res\_size_i) + \beta_5 \log(res\_depth_i) + \beta_6 \log(w\_depth_i) + \beta_7 water_{it} \\ &+ \beta_8 \log(carb\_p_t) + \beta_9 \log(oil\_p_t) + \beta_{10} D\_elect_i + \beta_{11} start\_year_i + \beta_{12} time_t + c_i + u_{it}\end{aligned}$$

The first variable on the right-hand side is annual production as a share of the field's historic peak production (*prod_share*). As this variable is of particular importance (see the empirical results in the next section), we include both a second and a third order term in addition to the linear term. The other right-hand side variables are respectively the share of gas in the field's original reserves (*gasres_share*), the share of gas in the field's running production minus the share of gas in original reserves (*gasprod_share*), original reserve size (*res_size*), reservoir depth (*res_depth*), ocean depth (*w_depth*), water produced as a share of peak oil and gas production (*water*), CO_2-price (*carb_p*), oil price (*oil_p*),[3] dummy for electrified fields (*D_elect*), first year of extraction (*start_year*) and time trend (*time*). β_j (j = 0,1a,…,11) are unknown parameters, c_i are unobservable random field-specific effects, while u_{it} are genuine error terms. We assume that both c_i and u_{it} are normally distributed with zero expectation and with variances σ_c^2 and σ_u^2, respectively. All empirical results are based on maximum likelihood estimation.

We notice from the model specification that there are three variables that vary over both field and time, i.e., *prod_share*, *gasprod_share* and *water*. Six of the variables are field-specific but time invariant, while three of the variables vary over time only. With many relevant variables, some of which are somewhat (positively or negatively) correlated, we have tested a number of model variants that retain only a subset of the variables in the model specification above. The main model, with results presented in Table 2 in Section 4, has been chosen mainly based on the p-values of the parameter estimates of the variables, but we have also kept some variables that we find particularly interesting.

On the other hand, two of the variables are omitted a priori from the main model. First, we do not include the variable *D_elect* since we omit the four electrified fields from the dataset in this case. The reason is that the (log-transformed) left-hand side variable approaches minus infinity when the emission intensity goes towards zero (one of the fields had zero emissions in five years). Thus, instead we perform a separate estimation where we include these fields but set a lower bound on their emission intensity equal to 1 kg CO_2 per toe (i.e., 1% of the mean value, cf. Table 1 in Section 3.2). Second, we omit the variable *water* in the main model, as the volume of water produced at a field tends to increase as the volume of oil production drops, and we are particularly interested in how the emission intensity is changed when production declines from its peak level (i.e., *prod_share*). Thus, instead we perform a separate estimation where we consider the effects of *water*. At the end we discuss the results of some alternative model variants, too.

In the estimations we have also considered models with fixed effects in addition to models with random effects. A model with fixed effects has less strict requirements, but does not allow estimation of the effect of time invariant variables that are of special interest to us. Thus, both model types have its advantages and disadvantages. As the Hausman test shows no significant difference between the two model types, and the estimated parameter values of the most important two-dimensional variable *prod_share* are very similar, we choose to focus on the random effects model.

3.2. Data

We use a dataset of annual CO_2-emissions at individual fields in Norway. Other GHG emissions (e.g. methane – CH_4), accounting for about 5% of total GHG emissions, are not included in the dataset. The dataset has been made available to us from the Norwegian Environment Agency. In order to calculate emissions per unit extraction, we combine the emission data with data for annual production of oil (crude, NGL, condensates) and gas at the field level, obtained from The Norwegian Petroleum Directorate.[4]

[3] An additional explanatory variable could be the Norwegian export price of natural gas. However, European gas prices have traditionally followed the oil price with a few months lag. Thus, it seems better to only include the price of oil in the estimations.

[4] We have excluded 12 observations relating to fields' first year of production, if production that year constituted less than 20% of peak production. The reason is that emission intensities could be influenced by drilling or other activities during the start-up year but before start of production.

Table 1
Summary statistics for the dataset with 452 observations. Electrified fields excluded.

Variable name	Description	Unit	Mean	St. dev.	Min	Max
em_int	Emission intensity	Kg CO_2 per toe	90.5	68.2	7.51	675
prod_share	Production level. Share of peak annual production for the field	Share	0.49	0.31	0.03	1
gasres_share	Share of gas in the field's original reserves	Share	0.21	0.24	0	1.00
gasprod_share	Share of gas in the field's production, minus $gasres\_share_i$		−0.03	0.11	−0.53	0.32
res_size	Size of original reserves	Mill. Sm^3 oe	188	195	7.18	763
res_depth	Reservoir depth	Meter	2668	760	1360	4850
w_depth	Ocean depth	Meter	171	104	66	380
water	Produced water (Sm^3) as a fraction of peak annual oil and gas production (Sm^3 oe)	Ratio	0.35	0.42	0	1.61
carb_p	Total CO_2-price	NOK_{2012} per ton CO_2	431	94	265	654
oil_p	Crude oil price brent blend	NOK_{2012} per barrel	427	155	150	650
start_year	Start-up year	Year	1991	8.9	1971	2008
time	Time trend	Year	8.99	4.54	1	16
accp	Accumulated production as a share of original reserves	Share	0.61	0.26	0.02	1.01[a]
D_Statoil	Dummy variable for fields operated by Statoil	0 or 1	0.62	0.48	0	1

[a] The maximum level of accumulated production marginally exceeds the size of original reserves for some fields, which is likely due to reserve additions after production started.

The dataset covers all oil and gas production in Norway. However, as several oil and gas fields are located in the same area, they are often connected as extraction at smaller satellite fields are managed from a larger field nearby. Hence, in the emission dataset several fields are aggregated. Whereas there are 74 individual fields with separate production data, for 33 of these we do not have separate emission data. Emissions from these fields are instead included in the emission data for the remaining 41 fields, which constituted 86% of total oil and gas production during the 16-years period we consider. In Table A1 in the Appendix we list how each of the 74 fields are allocated to the 41 main fields that constitute the observational units in our dataset. When calculating emission intensity for a field in a given year, we use the sum over all the connected fields of both emissions and production. For other field-specific variables such as reserve size, share of gas in original reserves, reservoir depth and production level as percentage of peak production level, we only use data for the main field, however. As a robustness check, we do a separate estimation for the 25 fields that do not have any connected fields.

Field data for reserve size, reservoir depth and ocean depth have been taken from the Norwegian Petroleum Directorate [25]. Field data on production of water is also received from NPD. Data for the crude oil price Brent Blend are taken from the EIA (www.eia.gov) and translated from nominal USD prices into NOK_{2012} prices using annual exchange rates from the Central Bank of Norway [7] and a producer price index for manufacturing from Statistics Norway [34]. The same procedure has been applied to CO_2-prices, which are obtained from the Norwegian Ministry of Finance.

An overview of the variables is presented in Table 1, together with mean values, standard deviations and min./max. values. The table also displays summary statistics for two additional variables that we come back to later. Empirical correlations between the variables are presented in Table A2 in the Appendix.

The dataset is an unbalanced panel, as several of the fields do not produce throughout our time period. 16 of the 41 fields started up after 1997, 5 terminated production before 2012, while 20 produced the entire time period.

4. Empirical results

4.1. Main model results

Table 2 shows the results obtained when estimating the main model. The first variable in the table is *prod_share*, i.e., a field's production level as a share of its historic peak production. When we include only the linear term of this variable, its parameter estimate is highly significant (p-value below 0.01) with a negative sign — hence, emission intensities increase significantly as extraction from

Table 2
Estimation results. Main model with random effects.

Variable	Estimated parameter value	t-Value
prod_share	−4.18***	−6.52
$(prod\_share)^2$	3.63***	2.81
$(prod\_share)^3$	−1.30*	−1.66
gasres_share	−0.77***	−2.71
gasprod_share	−0.42**	−2.49
log (*carb_p*)	−0.13	−1.21
log (*oil_p*)	0.089	1.55
Constant	5.85	6.28
σ_c^2	0.189	
σ_u^2	0.073	
Log-likelihood value	−112.408	
No. of obs.	452	
No. of obs. units	37	

*Significant at 10% level ($p < 0.10$), **Significant at 5% level ($p < 0.05$), ***Significant at 1% level ($p < 0.01$).

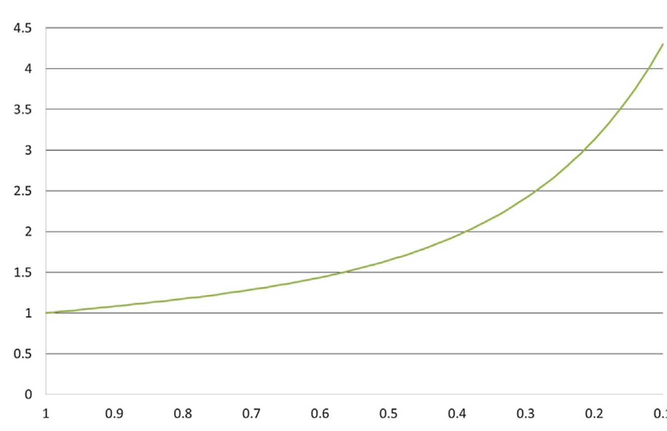

Fig. 5. Illustration of the relationship between production level (as a share of peak production) and emission intensity (normalized to one at peak production). Source: Estimation results in Table 2.

a field declines. To get a more precise picture of how it affects emissions per unit, we have included also the second and third order terms of this variable in the main model. Fig. 5 shows how emissions per unit change as production declines from its peak level, according to the estimation results in Table 2. The emission intensity is normalized to one at peak production, and then the estimated parameters in Table 2 are used to derive how the emission intensity depends on the production level (assuming all other things being equal). When comparing with the development at the Ekofisk field in Fig. 3, we see a similar pattern. A similar pattern is also seen in Fig. A1 in the Appendix, where we have constructed a corresponding figure based on observed data for annual production and emission intensities for the five biggest non-electrified Norwegian fields. Fig. 5 suggests that the emission intensity increases substantially as production declines, and rises particularly rapidly when production is more than halved. Moreover, *total* CO_2-emissions at the field fall only slightly as production falls. Based on the estimation results in Table 2, total emissions are on average reduced by 30% when the field produces 75% below its peak level.

As pointed to in Section 3.1, one important reason for the increased emission intensity as production decreases, is that lower extraction is often linked with increased production of water, especially for oil fields ([37]; p. 5). Thus, total liquid production may be quite unchanged, while energy use per output of oil (and gas) increases. We return to this issue below when we include water production as an explanatory variable in the empirical model. Moreover, as the natural pressure in the reservoir gradually drops as the oil and gas are extracted, production will eventually decrease and emissions per unit extraction go up ([26]; p. 47). In some cases, the operator may instead increase the energy use in order to keep up the production level. Then the relationship between production level and emission intensity will be different than if energy use is kept unchanged. The emissions data do not suggest that increasing the energy use is a common strategy, however. Nevertheless, we test an alternative model specification below where accumulated production (as a share of original reserves) is included as a potential explanatory variable.

The significant, negative parameter estimate of *gasres_share* suggests that emissions per unit increase with the share of oil in the field's original reserves. Given the estimated parameter value in Table 2, a field with only oil has twice as high emission intensity as a field with only gas ($e^0/e^{-0.77} = 2.16$, where -0.77 is the estimated parameter value for *gasres_share*, which goes from 1 to 0 when comparing “only gas” with “only oil”). Note that this result is obtained without including the four electrified fields, which are predominantly gas fields (cf. Section 3.1). Thus, on the Norwegian continental shelf, gas fields have significantly lower emissions than oil fields. The estimated parameter attached to the variable *gasprod_share*, which denotes the share of gas in the running extraction minus the share of gas in original reserves, has the same sign as *gasres_share*, suggesting that extracting oil from the reservoir is more emission-intensive than extracting gas. One could ask whether this is simply because gas is extracted before oil. However, since we control for production as a share of peak production, such an effect should be captured by that variable. Moreover, there is no clear pattern as to which of the two fossil fuels is extracted first – this varies between the fields.

One reason for the higher emission intensity for oil fields may be that there are more water in oil fields than in gas fields, increasing the energy demand per unit oil and gas extracted ([37]; p. 5). Increased water production also implies more energy use related to processing.

An additional reason could be that oil extraction usually generates more profits than gas extraction: First, oil prices tend to be substantially higher than gas prices – during our estimation period the average oil price was around 50% higher than the European gas price [3]. Second, gas extraction may require costly investments in pipeline infrastructure in order to be able to transport the gas to the customers. Thus, when comparing two otherwise identical oil and gas fields, the oil field will usually generate more profits than the gas field, and hence is more likely to be developed. Furthermore, there will tend to be a positive relationship between energy intensity and unit production costs across fields. First of all, energy use is costly by itself – unburned natural gas can be sold and generate more revenues. Moreover, higher water production will tend to increase both energy intensity and unit costs, and the same may hold for lower reservoir pressure (as less oil and gas are extracted for a given effort). According to Brandt [5]; “much of this increased cost and difficulty is due to larger energy demands for extraction and refining.” Thus, in total this may suggest that the average developed oil field could require more energy per unit production than the average developed gas field.

Another explanation could be that Norwegian gas fields are on average bigger than oil fields in terms of reserves. According to NHO/OLF [24]; smaller fields have historically had higher emission intensities than larger fields on the Norwegian continental shelf. However, when we control for reserve size in our estimations, it does not enter significantly and it does not affect the estimated parameter value (or significance level) of *gasres_share* notably (we return to the reserve size below).

The two last variables in Table 2 are the prices of CO_2 and oil (both log transformed). We notice that both prices enter with the expected sign, but the parameter estimates are not significant. However, the estimate of the oil price is almost significant at 10% level with a p-value of 0.12, while the p-value of the estimate of the CO_2-price is 0.23. Hence, both of these prices may have had some effects on the emission intensities. The CO_2-price was halved (in real terms) during the estimation period, reducing the incentives to install more energy-efficient turbines and increasing the incentives to continue extracting even if emissions per unit increase significantly. On the other hand, the oil price tripled in real terms, increasing the incentives to extend extraction and invest in IOR and EOR projects, even if energy use (and other costs) per unit increases ([6,26]). If we make use of the estimated parameters, and the price changes from 1997 to 2012, the estimation results indicate that both the CO_2-price decline and the oil price increase may each have led to about a 10% increase in the emission intensities in this period. However, these calculations are of course uncertain and should therefore be interpreted with caution.

If we include a time trend in the estimation, the two prices enter less significantly (the sign of the estimates is the same). The parameter estimate of the time trend is also insignificant then, but becomes highly significant (with a positive sign) if we exclude the two prices. As explained before, a positive time trend could be due to the depletion effect, i.e., that there is a gradual shift from easily accessible fields to more costly and thus marginal fields. However, if we replace the time trend with *start_year*, i.e., the field's first year of production, this variable does not enter significantly whereas the two prices have very similar effects as in the main model (both with respect to estimated parameter values and t-values). The likely reason for the differing estimation results when a time trend is included is that the time trend is correlated (positively/negatively) with the two prices, and the prices are also negatively correlated with each other, cf. Table A2 in the Appendix. Thus, whereas all these three variables point to an increase in the emission intensity during the estimation period, it is difficult to pin down the exact effect of each of them.

Although the empirical evidence of a CO_2-price effect is somewhat weak, the relatively low emission intensities related to oil and gas production in Norway suggest that the CO_2-price has been

Table 3
Estimation results. Alternative models with random effects.

Variable	Estimated parameter value	t-Value	Estimated parameter value	t-Value	Estimated parameter value	t-Value
prod_share	−4.43***	−6.895	−4.33***	−6.89	−6.80***	−8.88
$(prod\_share)^2$	4.31***	3.295	3.94***	3.14	7.40***	4.84
$(prod\_share)^3$	−1.73**	−2.177	−1.46*	−1.94	−3.10***	−3.39
gasres_share	−0.67**	−2.359	−0.99***	−3.01	−1.52***	−3.22
gasprod_share	−0.39**	−2.317	−0.44***	−2.63	−0.17	−0.92
log (*carb_p*)	−0.13	−1.171	−0.13	−1.23	0.04	0.35
log (*oil_p*)	0.05	0.771	0.10*	1.77	0.04	0.55
water	0.16***	2.718				
D_elect			−2.28***	−6.61		
Constant	6.02	6.497	5.85	6.56	5.76	5.40
σ_c^2	0.19		0.27		0.33	
σ_u^2	0.07		0.07		0.05	
Log-likelihood value	−108.74		−121.75		−27.79	
No. of obs.	452		480		241	
No. of obs. units	37		41		25	

*Significant at 10% level ($p < 0.10$), **Significant at 5% level ($p < 0.05$), ***Significant at 1% level ($p < 0.01$).

important in a longer perspective. In general, it is difficult to estimate long-term effects of the CO_2-price, such as installing more energy-efficient turbines or CO_2-storage. The CO_2-tax was introduced as early as 1991. Hence, an estimation study based on adding data also before 1991 could possibly have shown more significant effects of the CO_2-price, but such data are not readily available.

As emission intensities to some degree are influenced by investment decisions, lagged oil and CO_2-prices could be as relevant explanatory variables as current prices.[5] Hence, we have performed several estimations with different variants of lagged prices. The signs of the estimated parameter values are consistently positive for the oil price and negative for the CO_2-price, but the significance levels vary from below 5% (for both prices, but not simultaneously) to insignificant levels. Hence, we maintain the main model in Table 2, which gives a fairly good representation of the estimated effects of the two prices.

We have run a number of estimations in addition to the one we have presented in this section, and which we have referred to as our main (or preferred) model. In the next section we comment and present the results of some of them.

4.2. Robustness and alternative estimation models

In the empirical model put forward at the beginning of Section 4, we included 12 separate variables, whereas in the main model we only retained 5 of these. The results of including all variables in the empirical model except *water* and *D_elect* (which we return to below) are shown in Table A3 in the Appendix. We notice that the results related to the variables *prod_share*, *gasres_share* and *gasprod_share* are very similar to the main model results, both with respect to estimated parameter values and their significance levels. The two price variables enter with the same sign as before, but the parameter estimates are insignificant as the time trend is also included (cf. the discussion above). We see from the table that there is no effect of reserve size in this estimation, which is contrary to what NHO/OLF [24] has suggested. The estimate of reservoir depth has the expected sign, i.e., emissions per unit increase with higher depths, but it is not significant. The estimate of ocean depth has the opposite sign of the reservoir depth estimate, but is even less significant. As already mentioned, the start year of production for a field has no effect according to this estimation – this is also the case if we exclude the time trend from the model.

As mentioned before, oil fields in the decline phase will often produce water alongside the oil, and this is likely to increase emissions per unit oil (and gas) extracted. Thus, in a separate estimation we have added *water* to the empirical model. The estimation results are shown in the first column of Table 3. We see that water production has a significant, positive effect on the emission intensity. The size of the estimated parameter value indicates that if an oil field produces as much water as its peak oil production (both measured in Sm^3), emissions per unit of oil increase by around 15%. The parameter estimates of the other variables are only slightly changed (the combined effect of the *prod_share* terms are slightly stronger than in the main model – this can be seen by drawing a figure similar to Fig. 5).

When including the fields that use electricity from the grid, the dummy *D_elect* for these fields becomes highly significant with a negative parameter estimate, cf. column 3 of Table 3. This is as expected – the average emission intensity for these observations is less than 5 kg CO_2 per toe, compared to 90 kg CO_2 per toe for the remaining observations. The estimates related to the other variables are only slightly changed – the qualitative results are mostly the same. The main difference is that the oil price now enters significantly at the 10% significance level.

As a robustness check, we have estimated the main model for the fields that do not have any connected fields, cf. Table A1 in the Appendix for the identification of these fields. This shrinks the number of fields from 41 to 25, and the number of observations is almost halved. The estimation results are shown in the fifth column of Table 3. By drawing a figure similar to Fig. 5, we find that the joint effect of the three *prod_share* terms are somewhat stronger than when using the full sample (without electrified fields). This is also the case for the share of gas in original reserves – the estimated parameter of *gasres_share* is twice as high and the t-value has increased as well (see the sixth column of Table 3). On the other hand, the three other variables do not enter significantly, and the sign of the estimate of the CO_2-price has changed.

Next, we examine whether there are significant differences in emission intensities between fields operated by the state-dominated company Statoil and other companies. Statoil operates 23 of the 41 main fields, cf. Table A1 in the Appendix. Although Statoil is a commercial company, it could be the case that it is more concerned about its GHG emissions than other oil and gas companies, e.g. due to the Norwegian state dominance. Statoil was fully owned by the Norwegian state until 2001, when it was partly

[5] Expectations about future oil prices could also matter, e.g. with respect to development of new fields. Price expectations are often driven by current and historic prices, however.

privatized and listed on the Oslo Stock Exchange and the New York Stock Exchange. Since then the state's share has varied, but since 2009 the share has been 67%. When including a dummy for Statoil-operated fields into the main model, we do not find any significant effect. Moreover, the sign of the estimated parameter is the opposite of what we could expect. The results are displayed in Table A3 in the Appendix.

As briefly mentioned above, an alternative explanatory variable for the emission intensity could be accumulated production at the field level (as a fraction of original reserves). As the field's resources are extracted, it may gradually become more energy demanding to extract the remaining resources. In the main model this is indirectly incorporated through the variable *prod_share*, as it is a clear correlation between accumulated production and the level of production at the field level, especially in the decline phase (see e.g. Fig. 3 for the Ekofisk field). When including this variable in addition to the ones in Table 2, the estimated parameter value has the expected (positive) sign, but it is far from significant. This is probably due to the high correlation between this variable and *prod_share* (the empirical correlation is −0.69, cf. Table A2 in the Appendix). The latter variable still enters very significantly, and the results for this and the other variables are not much changed compared to the main model. If we exclude *prod_share*, however, accumulated production becomes highly significant with a positive estimated parameter value, see Table A3. The empirical results for the other variables change quite a lot. The share of gas in original reserves is no longer significant, while the parameter estimate of the share of gas in production is more significant than in the main model (and the estimated parameter value is larger). Finally, the carbon price and the oil price enter highly significantly at respectively the 1% and almost the 1% level, with much larger estimated parameter values than before. However, given the robustness of the *prod_share* variable in all the estimations undertaken, we do not consider this model variant as good as the main model. That is, the production level, as a fraction of peak production, seems to be a more suitable explanatory variable for the emission intensity than accumulated production.

4.3. Policy implications

From a policy perspective, our results may give some insights into how CO_2-emissions from Norwegian oil and gas production could be reduced (see also the discussion in Ref. [14]). A cost-effective way to reduce emissions would be to increase the CO_2-price. This has been done after 2012 – the Norwegian CO_2-tax was increased substantially in 2014. A more direct regulation could involve requirement of field termination when production falls below a certain threshold. This could however risk foregoing substantial profits. Alternatively, the government could be more restrictive when giving permissions to large IOR and EOR projects, as these projects usually imply higher emission intensities than the average extraction of oil and gas on the Norwegian continental shelf. The same goes for the development of marginal oil fields that often require much energy use per extracted unit. Finally, requiring electrification of more fields will reduce emissions from oil and gas production. All these direct regulatory approaches are likely to be less cost-effective than CO_2-prices, however.

5. Conclusions

CO_2-emissions per unit oil and gas production in Norway vary substantially across fields and over time. In this paper we have investigated empirically the driving forces behind the emission intensities of Norwegian oil and gas extraction, using field-specific data for the period 1997–2012.

Our first conclusion is that emissions per unit extraction increase significantly as a field's extraction declines. The emission intensities rise quite rapidly in the decline phase according to the estimations. A number of robustness tests suggest that the quantitative illustration in Fig. 5 provides a good indication of how emissions per unit increase as a field's production decreases from its peak level. According to the estimation results, a field producing 20% of peak level has about three times higher emission intensity than in the peak phase.

Our second conclusion is that a field's emission intensity increases significantly with the share of oil in the field's original oil and gas reserves. This result is obtained even though we have excluded the electrified fields, which are mostly gas fields, from the estimations. We also find that the emission intensities increase with the share of oil in the field's running production (after controlling for the share of oil in original reserves). Thus, extracting oil is associated with higher emissions per unit than extracting gas on the Norwegian continental shelf. This conclusion is strengthened when we take into account the very low emission intensities from the electrified fields.

We also find some indication that oil and CO_2-prices may have influenced emission intensities on the Norwegian continental shelf. The real oil price tripled during our estimation period, while the real CO_2-price was approximately halved. A higher oil price gives more incentives to extend extraction and invest in IOR and EOR measures, while a lower CO_2-price gives fewer incentives to reduce emissions. Both these prices influence the emission intensity with the expected sign according to the estimation results, but they do not enter significantly (the oil price is almost significant at 10% level in our main model). Thus, these results should be interpreted with caution. As both oil and CO_2-prices probably have stronger impacts in the longer term (i.e., more than one year), it is generally difficult to uncover the effects on emission intensities of these price changes.

Neither the size of reserves nor the reservoir or ocean depths showed significant effects on the emission intensities. This was also the case for the fields' start-up year. On the other hand, water production and the dummy for electrified fields were highly significant when included into the model.

An extension of this study could be to make projections of CO_2-emissions from Norwegian oil and gas production based on the estimated parameters and projections of oil and gas production at the field level (and oil and CO_2-prices). Such a projection could give an indication of the future development of CO_2-emissions for a major sector and emission source in Norway. Another extension could be to consider data also prior to 1997. Although emissions data are not readily available, some field-specific data on energy use exist and could be used to calculate proxy data for emissions. Finally, in our estimation we have only considered CO_2-emissions, which currently account for 95% of total GHG-emissions from Norwegian oil and gas extraction. A possible extension could be to consider other GHG-emissions as well, particularly methane emissions.

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Appendix

Table A1
Overview of main fields and connected fields.

Main field name	Connected field name(s)	No. of obs.	Start year
Albuskjell		2	1979
Alvheim	Vilje, Volund	5	2008
Balder	Jotun	13	1999
Brage[a]		16	1993
Cod		2	1977
Draugen		16	1993
Edda		2	1979
Ekofisk		16	1971
Eldfisk	Embla	16	1979
Frigg		8	1977
Gjøa[b]	Vega	2	2010
Glitne[a]		12	2001
Grane[a]		9	2003
Gullfaks[a]	Gimle, Gullfaks Sør, Tordis, Visund Sør	16	1986
Gyda		16	1990
Heidrun[a]		16	1995
Heimdal[a]	Atla, Huldra, Skirne, Vale	14	1985
Kristin[a]	Tyrihans	7	2005
Kvitebjørn[a]		8	2004
Njord[a]		15	1997
Norne[a]	Alve, Marulk, Urd	15	1997
Ormen Lange[b]		5	2007
Oseberg[a]	Tune	16	1988
Oseberg Sør[a]		13	2000
Oseberg Øst[a]		14	1999
Ringhorne Øst		7	2006
Sleipner Vest + Øst[a]	Gungne, Sigyn	16	1993
Snorre[a]	Vigdis	16	1992
Snøhvit[a,b]		5	2007
Statfjord[a]	Statfjord Nord, Statfjord Øst, Sygna	16	1979
Tor		16	1978
Troll I[a,b]		16	1996
Troll II[a]	Fram	16	1995
Ula	Tambar, Olsevar	16	1986
Valhall	Hod	16	1982
Varg		14	1998
Veslefrikk[a]		16	1989
Visund[a]		13	1999
Volve[a]		5	2008
Yme		5	1996
Åsgard[a]	Mikkel, Morvin, Yttergryta	13	1999

[a] Main field operated by Statoil.
[b] Electrified field.

Table A2
Empirical correlation matrix based on 452 observations (electrified fields excluded).

	em_int	*prod_share*	*gasres_share*	*gasprod_share*	*res_size*	*res_depth*	*w_depth*
em_int	1						
prod_share	−0.599	1					
gasres_share	−0.011	−0.051	1				
gasprod_share	−0.056	−0.060	−0.106	1			
res_size	−0.196	0.178	0.007	0.177	1		
res_depth	0.067	−0.010	0.316	−0.138	0.030	1	
w_depth	−0.182	0.237	−0.031	−0.192	−0.009	−0.089	1
water	0.277	−0.192	−0.463	0.132	−0.058	−0.331	0.042
carb_p	−0.244	0.214	0.073	−0.122	0.039	−0.018	−0.060
oil_p	0.235	−0.229	−0.068	0.177	−0.044	0.031	0.056
start_year	−0.114	0.328	−0.163	−0.074	−0.496	−0.032	0.418
time	0.252	−0.249	−0.067	0.194	−0.049	0.026	0.058
accp	0.395	−0.688	0.051	0.371	0.102	−0.045	−0.336
D_Statoil	−0.014	0.107	0.112	0.030	0.132	−0.060	0.540

	water	carb_p	oil_p	start_year	time	accp	D_Statoil
water	1						
carb_p	−0.321	1					
oil_p	0.306	−0.812	1				
start_year	0.162	−0.241	0.242	1			
time	0.318	−0.889	0.913	0.251	1		
accp	0.247	−0.270	0.290	−0.539	0.341	1	
D_Statoil	0.101	−0.090	0.087	0.399	0.093	−0.161	1

Table A3
Estimation results. Alternative model variants with random effects

Variable	Estimated parameter value	t-Value	Estimated parameter value	t-Value	Estimated parameter value	t-Value
prod_share	−4.07***	−6.14	−4.24***	−6.59		
$(prod\_share)^2$	3.49***	2.66	3.72***	2.87		
$(prod\_share)^3$	−1.22	−1.55	−1.34*	−1.71		
gasres_share	−0.81**	−2.57	−0.78***	−2.76	−0.27	−0.83
gasprod_share	−0.47***	−2.68	−0.42**	−2.47	−1.21***	−5.17
log (*res_size*)	0.004	0.06				
log (*res_depth*)	0.15	0.54				
log (*w_depth*)	−0.03	−0.18				
log (*carb_p*)	−0.04	−0.29	−0.13	−1.17	−0.48***	−3.16
log (*oil_p*)	0.04	0.53	0.09	1.51	0.21**	2.56
start_year	0.001	0.14				
time	0.01	1.17				
accp					0.77***	4.85
D_Statoil			0.13	0.90		
Constant	1.67	0.08	5.78	6.18	5.51	4.28
σ_c^2	0.19		0.19		0.24	
σ_u^2	0.07		0.07		0.14	
Log-likelihood value	−111.53		−112.01		−247.29	
No. of obs.	452		452		452	
No. of obs. units	37		37		37	

*Significant at 10% level ($p < 0.10$). **Significant at 5% level ($p < 0.05$). ***Significant at 1% level ($p < 0.01$).

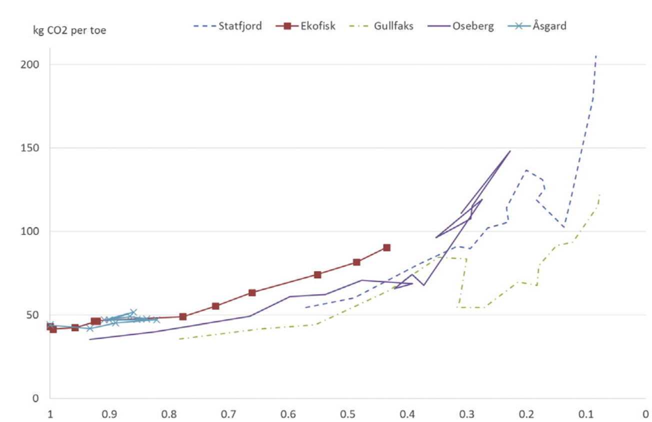

Fig. A1. Relationship between annual production level (as a share of peak production) and emission intensity for the five biggest non-electrified Norwegian fields.
Note: We have omitted observations before peak production is reached. The annual observations are connected in the figure so that year t is connected to year $t-1$ and year $t+1$. Typically, production drops and emission intensity rises as time goes by (but not always).

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