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A decline rate study of Norwegian oil production

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ABSTRACT

Norway has been a very important oil exporter for the world and an important supplier for Europe. Oil was first discovered in the North Sea in late 1960s and the rapid expansion of Norwegian oil production lead to the low oil prices in the beginning of the 1990s. In 2001, Norway reached its peak production and began to decline.

The Norwegian oil production can be broken up into four subclasses; giant oil fields, smaller oil fields, natural gas liquids and condensate. The production of each subclass was analyzed to find typical behaviour and decline rates. The typical decline rates of giant oil fields were found to be −13% annually. The other subclasses decline equally fast or even faster, especially condensate with typical decline rates of −40% annually. The conclusion from the forecast is that Norway will have dramatically reduced export volume of oil by 2030.

1. Introduction

Norway and the United Kingdom own the largest share of the North Sea oil and have been the driving forces behind the North Sea oil production.

Particularly interesting is Norway as its domestic consumption of oil is only around 200 000 bpd and therefore much of its production can be exported. In fact it is also the world's third largest oil exporter (Aleklett, 2006). The United Kingdom by comparison is a net oil importer and its future production will not be as important for the rest of the world as that of Norway.

North Sea oil was discovered in the 1960s, and the first commercial production started in early 1970s. The oil crisis of 1973 made the North Sea very attractive as it could offset supply cuts by the political will of OPEC nations.

The programme for the development of new technologies got an enormous budget, 11 billion dollars more than the US had spent on the moon landing project (Time Magazine, 1975). The North Sea became the world leading region for production and offshore technology.

All the new technologies that were introduced led to increased production and in the 1990s oil was flowing. In the end of the 1990s some even stated that the world was drowning in oil and the oil price was heading towards 5 US$/barrel (The Economist, 1999).

But suddenly the shock came and the situation changed dramatically. In 1999, the United Kingdom reached its maximum oil production and started to decline. In 2001, Norway peaked at a production of 3.4 million barrels per day (Mbpd) and has been in decline since then. Norwegian oil production in 2007 had fallen to 2.6 Mbpd, 25% less than the peak production. In 2008, Norway cut down its oil production forecast from 2.5 to 2.4 Mbpd, explaining this by maturing fields on the Norwegian continental shelf (Oil & Gas Journal, 2008).

2. Aim of this study

Norway is a major oil exporter and the decline of Norwegian oil will affect all who are dependent on its export. A realistic forecast for the future Norwegian oil production is therefore important. This article will present such a forecast.

Oil production can be divided into crude oil, condensate and natural gas liquids (NGL). This study will present a field-by-field analysis of all Norwegian oil, condensate and NGL production. As the Norwegian Petroleum Directorate makes all field-related data available, Norway is ideal for a detailed field-by-field study.

Extrapolation and estimates of the amounts of oil that remain to be discovered will also be made to provide a reasonable picture of the impact from undiscovered reserves based on the continuation of historical trends.

3. Methodology

All fields will be analyzed separately to determine their depletion rate, decline rate, cumulative production and much more. The official data from the Norwegian Petroleum Directorate

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(NPD) is used. The total oil production is divided into four subclasses. This is to better display the different behaviour and properties of the different oil types and field sizes.

The first subclass is crude oil from giant oil fields, which are fields with more than 0.5 Gb of ultimately recoverable resources (URR) or a production of more than 100 000 barrels per day (bpd) for more than 1 year. The definition used here follows the established results from other studies (Simmons, 2002; Robelius, 2007).

Crude oil from smaller oil fields, which are fields not large enough to be classified as giants, will be the second subclass. These fields will be called dwarf oil fields in this study. It should, however, be noted that there is no clear border between giants and dwarfs. The largest dwarfs also might actually be just below giants, but on the larger scale most oil fields will be small or significantly smaller compared with the giants and therefore the term "dwarf" is chosen to illustrate the concept.

Finally, all condensate and all natural gas liquids (NGL) constitute the last two subclasses. This is a result of NPDs statistics, where they are displayed as separate categories.

The past production is taken from NPDs statistics and goes back to the beginning of the Norwegian oil production in early 1970s. The URR and discovery year of all fields are also taken from official NPD material (Norwegian Petroleum Directorate, 2008).

The overall aim is to analyze the production behaviour of Norwegian crude oil, condensate and NGL. From this a possible future production profile will be created, where the historical experience is applied to future development.

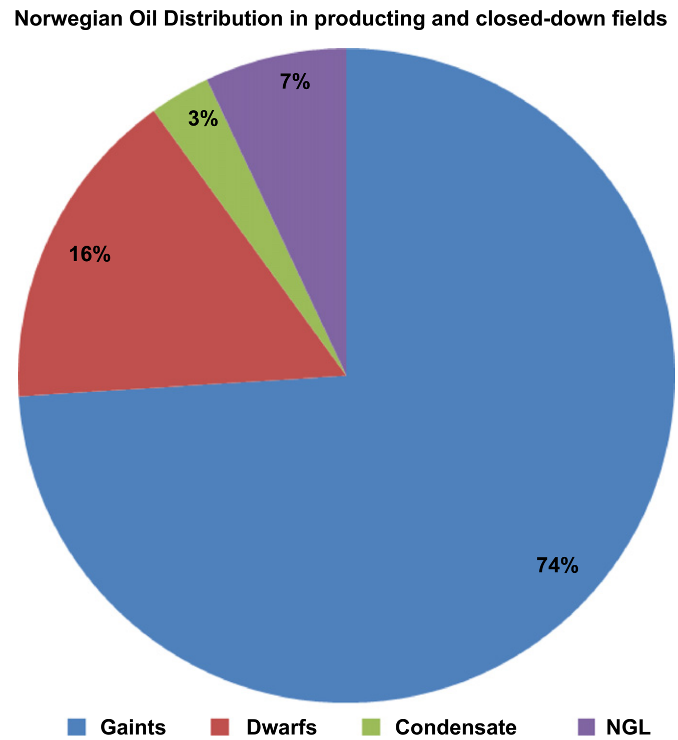

Fig. 1. Distribution of oil from all closed-down and currently producing fields. Most of the oil can be found in giant oil fields, such as Ekofisk and Statfjord. Only a smaller share is found in dwarf oil fields, such as Gyda and Albuskjell. It should also be noted that any NGL and Condensate within giant oil fields are included in the Condensate and NGL classes.

4. Distribution of oil

The Norwegian share of the North Sea stretches from the central parts of the North Sea all along the coast up to the Barents Sea. The North Sea and the Norwegian Sea have been the most important areas for production. The Barents Sea is the current frontier region.

All abandoned and currently producing giant and dwarf oil fields, condensate and NGL fields together contain 29.9 Gb of oil (Norwegian Petroleum Directorate (NPD), 2007). The bulk, namely 74%, is concentrated to giant oil fields (Fig. 1).

The historical oil production of Norway shows the extreme importance of the giant oil fields. In fact nearly all Norwegian oil production has come from giant oil fields and it was only in the middle of the 1990s, that smaller crude oil fields, condensate and NGL started to contribute significantly to the total production (Fig. 2).

Norwegian oil output peaked in 2001 and has been in decline since then. This coincides quite well with a plateau production, from 1996 to 2000, from the giant oil fields. Rapid development of dwarf oil fields and increased production of mainly NGL managed to offset a part of the decline from giants, but when more and more giant oil field started to decline the trend became irreversible and the total Norwegian oil production peaked.

It is clear that giant oil fields, which is a small number of fields, have been of great importance for Norway and will continue to be so for the nearest decades. The importance of giant oil fields has also been shown on a global scale (Robelius, 2007).

4.1. Norwegian giant oil fields

In total, Norway have found 17 giant oil fields containing a total of 22.1 Gb crude oil. Some of these fields also contain significant amounts of condensate or NGL but this is treated separately. Statfjord and Ekofisk are by far the largest of the giants, each with more than 3 billion barrels of ultimately recoverable reserves.

By year 2007 only five of the giants were producing more than 100 000 bpd, and Ekofisk, producing around 207 000 bpd, had the highest production of them.

The decline in production of the Norwegian giants has been high. The average decline rate is around −13% per year. Some fields, such as Jotun and Troll, have declined much faster. Eldfisk and Valhall, both with a modest production for a field of their size, have the lowest decline rates mostly because of their chalk reservoirs with low recovery rate (Table 1).

Since the giant oil fields are producing so large volumes, compared with smaller oil fields, it would require an excessive amount of small oil fields to compensate or dampen the effect from the declining giants.

The important fact is that once giant oil fields go into decline it is fast (Fig. 3). The typical decline rates for the Norwegian giants are well above −10% per year. The average decline rate of all giant fields is −13.4% and if weighted against the peak production of every individual field it will be −13.8%. This high decline rate will have a significant impact on the total oil production due to the large contribution from giant oil fields.

This result is also important for the world oil production. As pointed out by other studies a small number of giant oil field accounts for the majority of the world's oil production (Robelius, 2007). The future behaviour of these giants will be of the uttermost importance for the future oil production. By looking at the aggregate decline rate of the Norwegian giant oil fields some light can be shed on the future behaviour of the entire worlds giant oil fields as a group.

Clearly it can be seen that the aggregate decline rate is not constant, but increases with time as more and more old field falls into decline and no new fields are brought into production. This is a clear and fundamental difference compared with a recent study

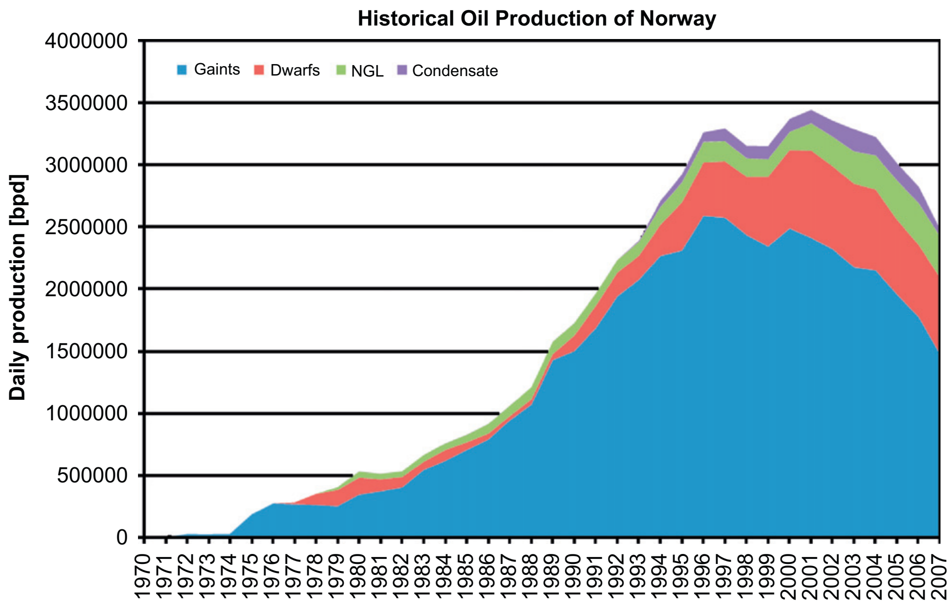

Fig. 2. Historical oil production divided into subclasses. Most of all Norwegian oil production has been from giant oil fields. Since the peak production around 2000 none of the other classes managed to compensate for the decline from the giants. It should also be noted that any condensate and NGL production from giant oil fields are included in the Condensate and NGL classes.

Table 1
The Norwegian giant oil fields

Field name	URR (Gb)	Discovery year	First oil	Top/plateau prod. (bpd)	Peak year	Average decline (%)
Statfjord	3.557	1974	1979	573 908	1995	−14.4
Ekofisk	3.349	1969	1971	284 694	2004	−9.3
Oseberg	2.231	1979	1986	501 917	1996	−14.7
Gullfaks	2.230	1978	1986	529 778	1994	−12.5
Snorre	1.472	1979	1992	234 329	2003	−13.0
Troll	1.467	1979	1990	358 791	2003	−19.6
Valhall	1.300	1969	1982	91 508	1999	−5.8
Heidrun	1.132	1985	1995	231 886	1997	−7.7
Draugen	0.881	1984	1993	204 361	2001	−16.5
Norne	0.857	1991	1997	194 679	2001	−16.1
Eldfisk	0.808	1970	1979	101 243	1980	−3.9
Grane	0.755	1991	2003	217 347	2006	−12.2
Åsgard	0.690	1981	1999	143 372	2001	−9.8
Ula	0.503	1976	1986	126 590	1992	−14.2
Balder	0.387	1967	1991	120 348	2005	−13.9
Brage	0.350	1980	1993	101 131	1997	−14.6
Jotun	0.158	1994	2000	123 482	2000	−29.6

The largest of them were discovered in the 1970s. Jotun, the last of them, was discovered in 1994 and is minute compared to Statfjord. The peak year corresponds to the top production or the end of plateau production depending on actual production profile of the field.

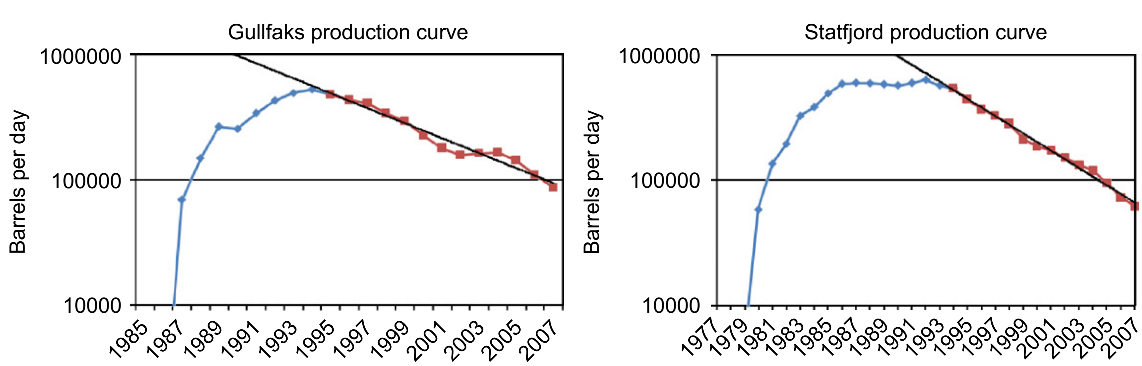

Fig. 3. The production profiles of the two giant fields Gullfaks and Statfjord in a logarithmic plot with a fitted line to show the virtually constant decline. The annual decline in the post peak section varies from −23% to +3% for Gullfaks, but the average decline becomes −12.5% and the median value is −13.0%. For Statfjord the annual decline varies from −24% to −4%, with an average decline of −14.4% and a median value of −13.2%.

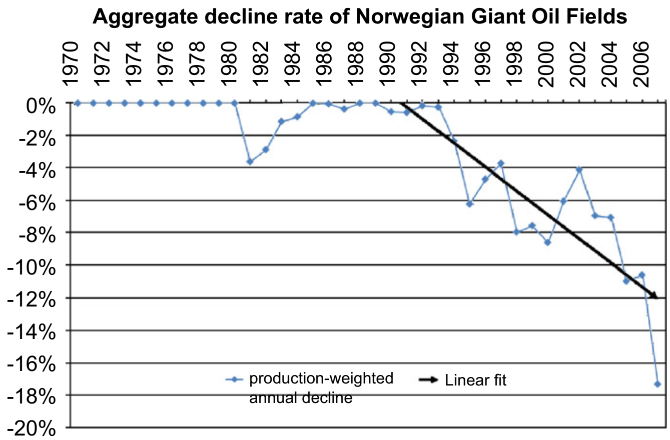

Fig. 4. Aggregate decline rate of Norwegian giant oil fields. The annual decline rates of each field were weighted using the annual production to construct the aggregate decline rate of the giant oil field group. The giant oil fields started to decline in 1991 and since then the aggregate decline rate have been growing by roughly 1% annually. As no new giant oil fields were brought into production the aggregate decline rates slowly approaches the decline rate of individual giant oil fields. Only by adding new fields can the aggregate decline rate be held low.

on aggregate decline rates, claiming that it will be constant (Cambridge Energy Research Associates, 2007) (Fig. 4).

4.2. Norwegian dwarf oil fields

Norway has a significant number of smaller oil fields, in total 41 in production or closed-down. Together they account for 4.71 Gb of crude oil in URR, but compared with the giants they are small in both reserves and total production.

A total of eight fields have been abandoned, once all recoverable oil has been extracted. Vest Ekofisk and Albuskjell are the two largest of these closed-down fields with URRs of 0.077 and 0.047 Gb, respectively. They peaked at a production of 66 000 and 25 000 bpd, respectively. The remaining 34 dwarf fields are still in production. Kristin is currently the largest producer at 73 000 bpd, but most of the dwarfs lie at a much lower production.

The typical life span, namely the time the field is increasing its production or remaining on plateau, of a dwarf field is also much shorter than for a giant oil field. Therefore a very large number of dwarfs are needed to replace just one giant. This was also pointed out by others (Robelius, 2007).

The mean decline of the Norwegian dwarf oil fields is −21.3% and if weighted against the peak production of individual fields it will be −18.1% (Table 2). The historical data thereby shows that small oil fields declines faster than giants. Dwarf oil fields that have not reached their peak yet are assumed to decline with the average mean decline rate once they end their plateau phase.

5. Condensate production

Condensate corresponds to the heaviest components of natural gas and is partially liquid at normal pressures and temperatures. Norway has a total of 17 fields producing condensate with a combined URR of 0.868 Gb. Often the condensate is associated gas in oil fields and in many cases the production is low. Sleipner Öst has the largest recoverable volumes of condensate with an URR of 0.22 Gb, and it peaked in 1999 at a production of 53 000 bpd.

A total of 35 new fields with recoverable amounts of condensate, some are PDO-approved while others are in the early planning stages, are expected to come online in the future. Many of them only contain a few million barrels. The total URR from all the new condensate fields will be 0.35 Gb.

The decline rates of condensate production are very high. The mean decline from all Norwegian condensate is −35.5% and it becomes −37.7% when weighted against the peak production of individual fields. This shows that condensate production basically disappears after a few years (Table 3).

6. Natural gas liquids (NGL)

The Norwegian Petroleum Directorate classifies NGL as butane+ethane+isobutane+propane+LPG+gasoline+NGL mix. NGL is a valuable by-product from natural gas processing and is hence not produced directly at the field, but rather at centralized gas treatment plants. In total, 45 Norwegian fields have been producing NGL. The total URR of NGL is 2.1 Gb with an additional 0.24 Gb from new field developments.

The NGL production was more than doubled from 2000 to 2007. To a great extent the production increase came from giant fields, such as Åsgard and Oseberg, which had compensated less crude oil production with increased amounts of NGL.

The mean decline of Norwegian NGL is −19.5% annually, but this is slightly lowered to −15.6% when weighted against peak production of NGL fields. The conclusion from this is that NGL declines slower than condensate, but the reason for this are the modest production levels as NGL falls out naturally as a by-product (Table 4).

7. New field developments

A number of new dwarfs are expected to come into production in the near future. The Norwegian Petroleum Directorate lists all undeveloped fields according to how far the development plan has come.

In total, eight dwarf fields have got their plan for production and operation (PDO) approved and are expected to come on-stream in a few years. Alvheim and Tyrihans are the two largest of these fields, both containing around 0.2 Gb of oil.

Ten new dwarfs are in the planning stage, and will be expected to come online between 2012 and 2018. A total of 13 new dwarfs is classified as "development likely but not clarified". These are assumed to come online after 2017. Six new oil discoveries from 2007 will also included in the new field developments.

The production from new fields developments are modelled by assuming that each new field will follow a similar production profile as some of the old fields. This means for instance that the new Volve field, with and URR of 0.092 Gb, will behave approximately as the old Varg field, with an URR of 0.095 Gb.

This is of course a crude simplification as the geology and other properties of the fields might be very different, but it provides a reasonable assumption for the future production profiles. This might also be an optimistic assumption, as the older fields generally were less complicated to develop than the fields that will be brought into production in the future.

A number of new fields that will be producing condensate and NGL are also expected to be brought on-stream in the future. These are modelled in the same way as the dwarf oil fields.

8. Undiscovered oil

Norway has maintained an active exploration programme licensing the more attractive areas first. The discoveries are published by the Norwegian Petroleum Directorate and the trends

Table 2
The Norwegian dwarf oil fields

Field name	URR (Gb)	Discovery year	First oil	Top/plateau prod. (bpd)	Peak year	Average decline (%)
Tordis	0.406	1987	1994	70 914	2003	−6.9
Vigdis	0.358	1986	1997	88 030	1999	−4.8
Vesslefrikk	0.353	1981	1990	70 107	1996	−11.2
Oseberg Sör	0.309	1984	2000	70 136	2006	−22.1
Gullfaks Sör	0.301	1978	1995	NPY	NPY	NPY
Statfjord Nord	0.265	1977	1995	68 885	2000	−15.0
Gyda	0.243	1980	1990	65 622	1994	−12.5
Oseberg Öst	0.235	1981	1999	65 699	2001	−27.2
Statfjord Öst	0.235	1976	1994	72 985	1998	−12.3
Kristin	0.212	1997	2006	NPY	NPY	NPY
Visund	0.175	1986	1999	NPY	NPY	NPY
Njord	0.151	1986	1997	67 567	2000	−15.9
Tor	0.150	1970	1978	77 993	1979	−6.4
Fram	0.132	1992	2003	50 622	2004	−23.6
Kvitebjörn	0.113	1994	1990	NPY	NPY	NPY
Yme	0.099	1987	1994	33 941	1998	−44.4
Varg	0.095	1984	1998	29 943	2000	−7.3
Murchison	0.086	1979	1981	49 328	1984	−10.4
Sygna	0.080	1996	2000	43 936	2001	−26.2
Vest Ekofisk	0.077	1970	1977	66 291	1978	−20.3
Embla	0.071	1988	1993	24 397	1994	−11.5
Urd	0.066	2000	2005	35 232	2006	−58.6
Hod	0.065	1972	1990	26 297	1991	−13.3
Heimdal	0.057	1972	1990	NPY	NPY	NPY
Tambar	0.054	1983	2001	29 749	2002	−13.9
Glitne	0.052	1995	2001	37 172	2002	−25.6
Albuskjell	0.047	1972	1979	24 575	1981	−19.7
Ringhorne Öst	0.040	2003	2006	NPY	NPY	NPY
Fröj	0.035	1987	1995	30 643	1996	−37.0
Edda	0.031	1972	1979	21 716	1980	−6.5
Huldra	0.031	1982	2001	20 378	2003	−37.7
Mikkel	0.029	1987	2006	NPY	NPY	NPY
Gimle	0.028	2004	2005	NPY	NPY	NPY
Tommeliten Gamma	0.025	1978	1988	13 526	1989	−22.3
Tune	0.020	1996	2002	19 631	2003	−37.2
Cod	0.018	1968	1977	8013	1980	−14.5
Skirne	0.013	1990	2004	5116	2005	−15.2
Vale	0.011	1991	2002	NPY	NPY	NPY
Lille-Frigg	0.009	1975	1994	7527	1995	−45.0
Blane	0.005	1989	2007	NPY	NPY	NPY
Mime	0.003	1982	1990	2797	1991	−36.1
Enoch	0.002	1972	1979	NPY	NPY	NPY

The largest of them are almost giants while the smallest only contains a few million barrels of oil. The peak year corresponds to the top production or the end of plateau production depending on actual production profile of the field.NPY stands for "no peak yet" and implies that the field yet haven't reached the decline phase of its life.

Table 3
Statistics for Norwegian condensate producing fields

Field name	URR (Gb)	Discovery year	First oil	Top/plateau prod. (bpd)	Peak year	Average decline (%)
Sleipner Öst	0.220	1981	1993	53 938	1999	−20.8
Sleipner Vest	0.186	1974	1996	44 659	2001	−5.2
Ormen Lange	0.139	1997	2007	NPY	NPY	NPY
Snöhvit	0.114	1984	2007	NPY	NPY	NPY
Åsgard	0.110	1981	2000	74 593	2003	−19.4
Sigyn	0.035	1982	2003	16 982	2005	−16.8
Troll	0.028	1979	1999	26 057	2003	−70.3
Kristin	0.013	1997	2005	32 768	2006	−100.0
Mikkel	0.013	1987	2003	13 100	2005	−30.0
Frigg	0.003	1971	1977	835	1981	−14.2
Odin	0.002	1974	1984	401	1992	−63.2
Statfjord	0.001	1974	2004	1161	2004	28.4
Fröj	0.001	1987	1977	470	1981	−69.3
Lille-Frigg	0.001	1975	1994	111	1996	−44.6
Nordöst Frigg	0.001	1974	1983	200	1990	−47.3
Öst Frigg	0.001	1973	1988	212	1992	−46.5
Murchison	0.000	1976	1983	8	1984	−8.3

Most of them are very small in terms of ultimately recoverable reserves. NPY stands for "no peak yet" and implies that the field yet haven't reached the decline phase of its life.

Table 4
Data for Norwegian NGL producing fields

Field name	URR (Gb)	Discovery year	First oil	Top/plateau prod. (bpd)	Peak year	Average decline (%)
Statfjord	0.225	1974	1985	30 329	1996	−2.3
Sleipner Öst	0.221	1981	1995	44 311	1999	−14.1
Åsgard	0.213	1981	2000	NPY	NPY	NPY
Ekofisk	0.194	1969	1971	21 252	1991	−3.6
Troll	0.162	1979	1998	NPY	NPY	NPY
Norne	0.128	1991	2001	4173	2005	−13.4
Sleipner Vest	0.128	1974	1996	26 940	2002	−7.7
Oseberg	0.092	1979	2000	NPY	NPY	NPY
Snorre	0.068	1979	1992	18 806	2001	−28.4
Eldfisk	0.064	1970	1979	11 223	1989	−5.9
Gullfaks Sör	0.064	1972	1990	NPY	NPY	NPY
Valhall	0.053	1969	1982	7533	1990	−3.6
Gullfaks	0.044	1980	1990	9005	1994	−0.5
Kristin	0.042	1997	2005	NPY	NPY	NPY
Ula	0.041	1976	1986	10 383	1993	−12.2
Visund	0.041	1986	2005	NPY	NPY	NPY
Mikkel	0.036	1987	2003	NPY	NPY	NPY
Draugen	0.035	1984	2000	14 731	2001	−13.9
Sigyn	0.034	1982	2003	13 212	2005	−12.5
Gyda	0.031	1980	1990	8285	1994	−12.8
Gungne	0.028	1982	1996	8174	2003	−9.8
Tordis	0.024	1987	1994	6407	2002	−23.1
Statfjord Öst	0.023	1976	1978	5801	2005	−12.6
Vest Ekofisk	0.021	1970	1979	7020	1980	−13.4
Vigdis	0.021	1986	2003	NPY	NPY	NPY
Brage	0.020	1980	1993	3915	1998	−2.6
Tor	0.020	1970	1979	5114	1983	−8.1
Kvitebjörn	0.019	1982	1990	16 273	2006	−82.8
Vesslefrikk	0.018	1981	1990	5061	1996	−12.0
Albuskjell	0.017	1972	1979	5090	1983	−17.3
Heidrun	0.013	1985	2001	3225	2004	−20.1
Statfjord Nord	0.012	1977	1995	3986	2005	−43.2
Tommeliten Gamma	0.009	1978	1998	3687	1990	−15.8
Embla	0.009	1988	1993	1933	1994	−6.5
Cod	0.008	1968	1979	2519	1983	−13.2
Fram	0.008	1992	2007	NPY	NPY	NPY
Murchison	0.006	1979	1983	3926	1984	−30.2
Hod	0.005	1972	1990	1760	1991	−16.0
Blane	0.004	1989	2007	NPY	NPY	NPY
Edda	0.003	1972	1979	1699	1980	−9.7
Tambar	0.003	1983	2001	1752	2002	−11.8
Tune	0.003	1996	2002	925	2004	−24.8
Huldra	0.002	1975	2001	1040	2002	−22.6
Gimle	0.001	2004	2005	431	2005	−80.4
Mime	0.000	1982	1990	228	1991	−40.2
Urd	0.000	2000	2005	366	2006	−53.9

Just as for condensate most of the fields are small in both terms of URR and production.NPY stands for "no peak yet" and implies that the field yet haven't reached the decline phase of its life.

are clear. To summarize one can say that the Norwegian continental shelf is a mature region, where most of the fields and promising structures already have been found. Few uncharted regions remain and the geology is generally understood to a large extent.

The peak of giant oil field discovery was in the early 1980s and there have been no new giant found since 1994. The undiscovered amounts of oil in both giant and dwarf fields, condensate and NGL were estimated using a logarithmic extrapolation technique of the historical discovery trends in both URR and number of fields (Figs. 5–8). This method is similar to the one used in another study (Aleklett, 2007).

In total, about 2 Gb of undiscovered oil is included in this study. This makes the ultimately recoverable reserve for Norway in this study close to 35 Gb by 2030. Different assessments of the Norwegian URR have been performed by various studies. Both parabolic fractal evaluation and creaming curves were found to yield an URR of 36 Gb of oil (Laherrere, 2008). Other assessments have yielded an URR of around 33 Gb (Campbell, 2008). So the URR value of Norway here is well in line with other studies (Fig. 5).

The Norwegian Petroleum Directorate gives an estimate based on a probability distribution and also explicitly mentions the uncertainty in all estimates of undiscovered resources. A total of 4 Gb is assumed with P90 and 16.6 Gb with P10, this gives a mean value of 9.6 Gb Norwegian Petroleum Directorate (NPD), 2007. Somewhat optimistic compared with other studies.

The discovery of dwarf oil fields peaked in the 1990s and has been in decline since then, despite new exploration efforts and introduction of new technology. Discovery of condensate also reached its maximum level in 1990s. NGL discoveries peaked around the same time as condensate and dwarf oil fields.

The extrapolated discovery values of URR and number of fields are transformed to a reasonable number of fields with suitable size. The undiscovered fields are assumed to be brought into production with similar delay, between discoveries to first oil production, as already existing fields. This delay is typically 5–10

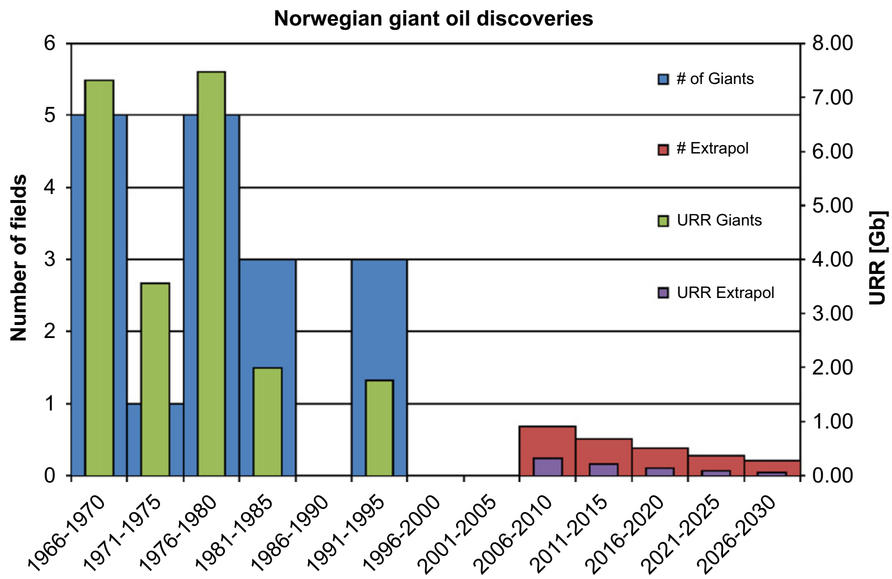

Fig. 5. Extrapolation of the undiscovered amounts of giant oil fields in Norway with respect to both URR and number of fields.

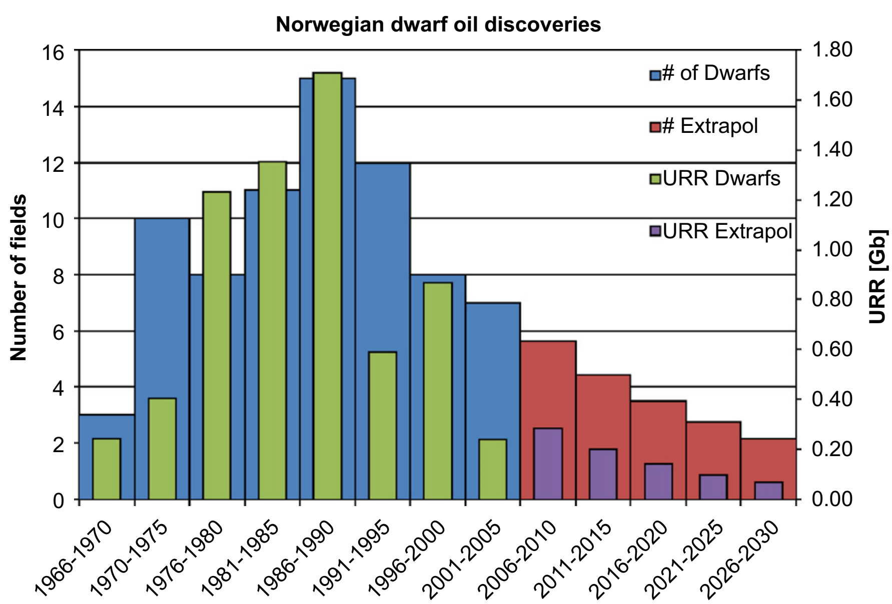

Fig. 6. Extrapolation of the undiscovered amounts of dwarf oil fields in Norway with respect to both URR and number of fields.

years. Most of the undiscovered fields will therefore come online around 2020.

The production from the undiscovered fields is modelled in the same way as the new field developments and thus assumed to follow the behaviour of already existing fields of similar size.

9. Forecast

The future oil production of Norway is forecast by a field-by-field analysis. All fields in decline phase are expected to continue their decline with typical decline rates for their subclass.

Production from new field developments is assumed to start according to official statements. In some cases no official start-up dates are available and for these fields typical delays between discovery to first oil. The production profiles of both undiscovered fields and new field developments are assumed to mimic the behaviour of already existing fields of similar size (Figs. 9 and 10).

The future Norwegian oil production will be very dependent on undiscovered fields. The current fields that can be found in different categories within the new field developments are all quite small and will be unable to do anything else than slightly decrease the overall decline of oil production. The most important factor the future Norwegian production is the development of the giant oil fields and how fast they decline.

Much hope must be placed on the Barents Sea. This region is less than fully explored so it might offer a few more new giants, especially when it comes to gas. However, the geology of the Barents Sea is generally unfavourable. Partly this is due to the large vertical movements of the crust under the weight of

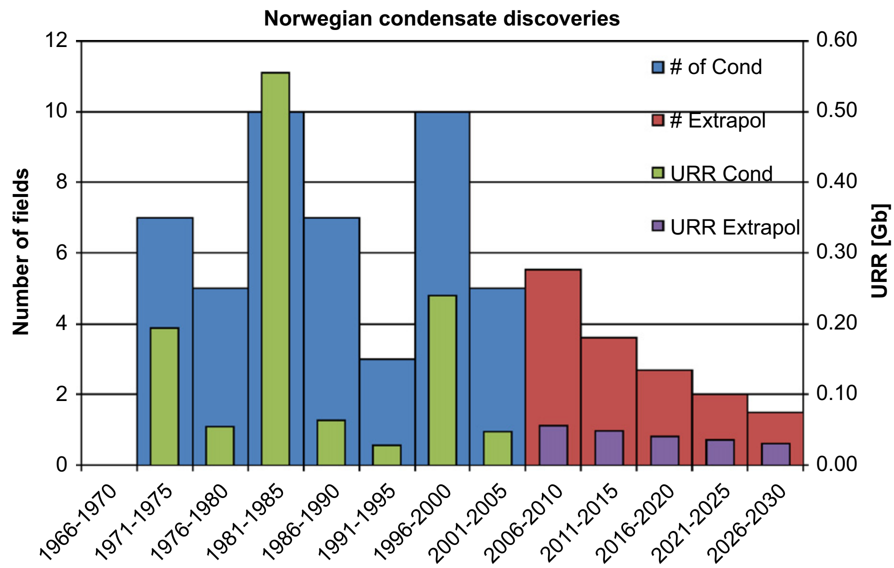

Fig. 7. Extrapolation of the undiscovered amounts of condensate in Norway with respect to both URR and number of fields.

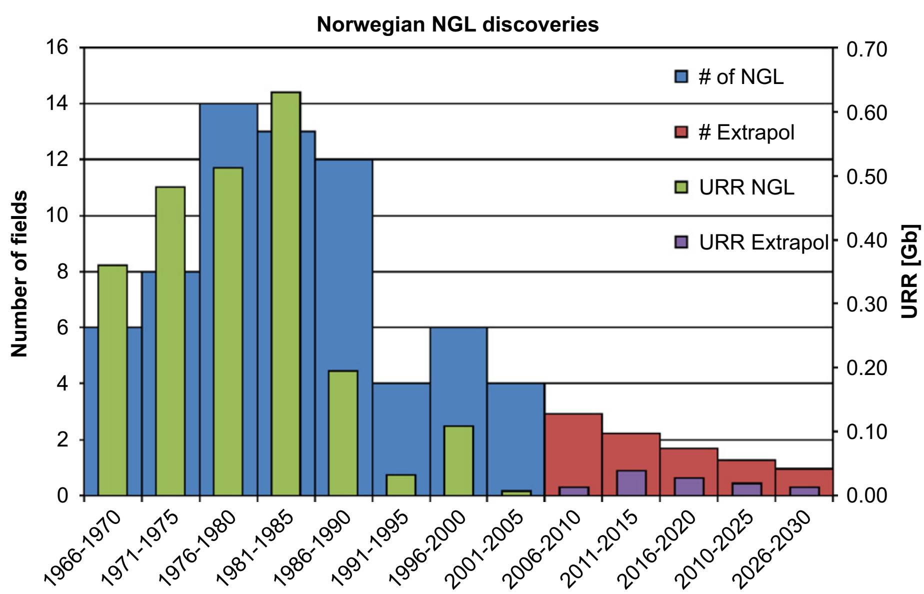

Fig. 8. Extrapolation of the undiscovered amounts of NGL in Norway with respect to both URR and number of fields.

the fluctuating ice caps during the previous ice ages that had pushed source-rocks below the oil window and destroyed seal integrity.

Finding more oil fields and bringing them into production is essential to dampen the decline from existing fields. Unless new discoveries are made Norway will barely be self-supplying with oil by 2030.

In this forecast the total oil production of Norway will be around 500 000 bpd in 2030. By including enhanced oil recovery (EOR) it will probably be possible to increase this a bit. A more comprehensive field-by-field study of proposed projects and future potentials are needed to provide a more reasonable picture.

By assuming a 10% increase in overall recovery from EOR an additional 3.5 Gb of oil can be squeezed out from the Norwegian continental shelf. If this assumed to be evenly distributed over the next decades the total oil production might be 100 000 bpd or even more than in the forecast above. However, a more detailed study is needed to determine the potential and future impact from EOR in Norway.

In 2008, the domestic Norwegian oil consumption was 226 175 bpd. By applying a 1% annual increase in the oil consumption, which is reasonable for a continued economic growth, the domestic oil consumption in 2030 will be 281 524 bpd.

By subtracting the domestic consumption from the total production a rough estimate of the export can be found. Only around 200 000 bpd will be available for export in this case. This is a dramatic decrease from today's export volume well over 2 Mbpd.

10. The oil fund of Norway

The Norwegian government has been wise in understanding that the oil will run out with time and that the wealth it brings

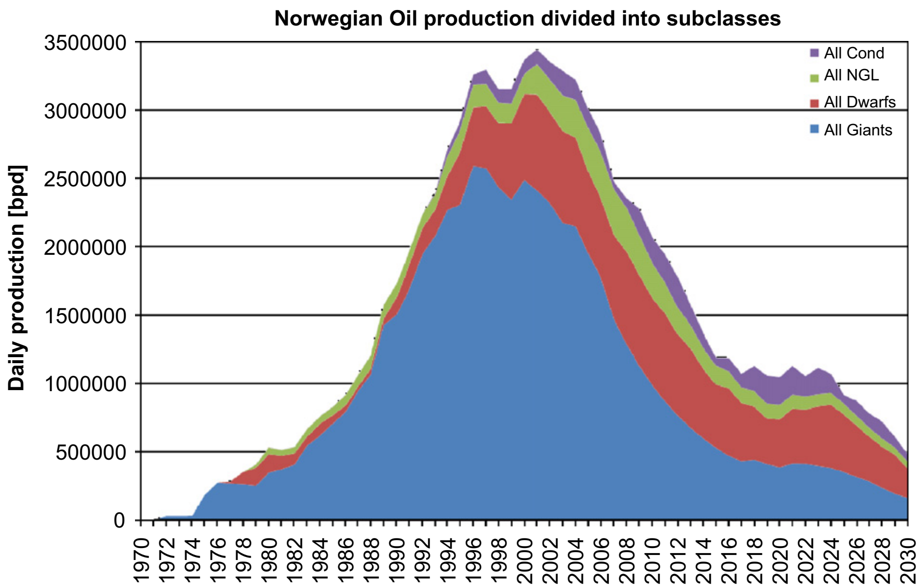

Fig. 9. Future Norwegian oil production divided into subclasses. Giant oil fields will continue to be very important, but their share will diminish with time. NGL and condensate will remain as minor contributors even in the future.

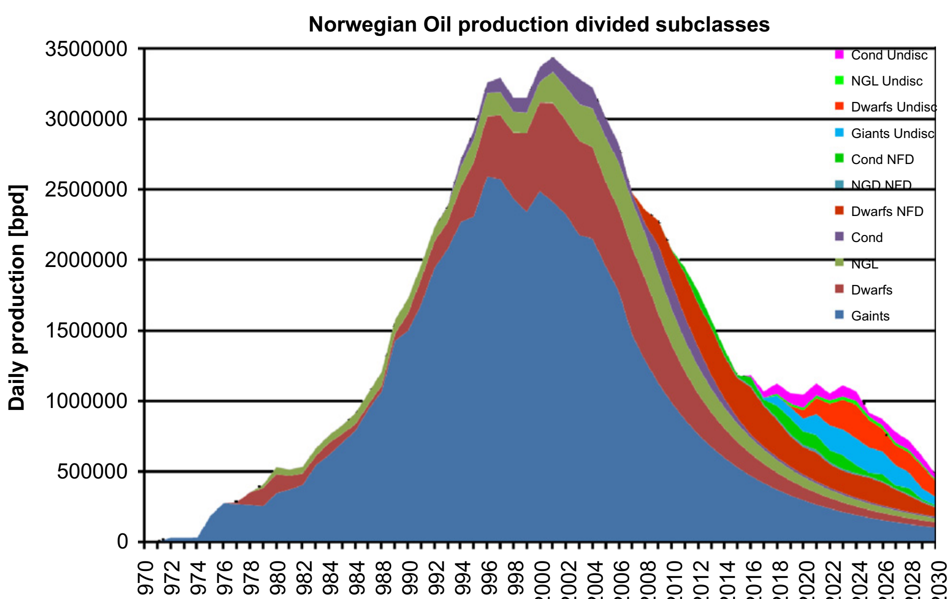

Fig. 10. A possible future oil production of Norway divided into more subparts. Undiscovered giants, dwarfs and condensate will be able to decrease the decline for a moment before the decline starts again. High hopes must therefore be placed on the not fully explored the Barents Sea. Discoveries of new giant fields and new dwarf fields are essential for the future of Norwegian oil production.

must be saved for future generations. This has been done by investing the revenue from oil export in a fund originally referred to as *the petroleum fund of Norway*. In 2006, the name was changed to The Government Pension Fund.

The fund is managed by the Norwegian Central Bank and follows a set of guidelines, including ethical norms for investments, set up by the Norwegian Ministry of Finance. The funds capital is invested in bonds and equities in accordance to the guidelines. Since 1998 the fund has been allowed to invest 50% of its portfolio in the international stock market.

Also the Norwegian government have been very reluctant to use petroleum revenues in the state budget, based on the belief that increased spending will lead to higher inflation and perhaps even an overheated economy. Looking back at history this have been a wise strategy have in many ways managed keep Norway free from "the Dutch disease", which struck the Netherlands after their discovery of natural gas in the 1960s (The Economist, 1977).

The oil fund is now the largest pension fund in the world with a total value of over 2000 billion Norwegian crowns, which corresponds to over 400 billion US dollars. The fund owns more than 1% of the entire European stock market (International Herald Tribune, 2008).

The financial turmoil has recently taken a serious toll of the oil fund and some analysts estimate the total losses over the first quarter of 2008 to more than 100 billion Norwegian crowns (Aftenposten, 2008), (Dagbladet, 2008). Further instability can potentially cause even more losses. In the light of peak oil and the stagnant world oil production the future development of the stock market should be re-examined. Historically, the economic growth of the world has been tightly linked to increased oil consumption. Strong reaction in prices and economic upheaval are possible when it reaches peak production (Hirsch, 2008; Deutsche Bank, 2004).

Others point out that the access to cheap fossil energy has built up the enormous wealth of the modern world, and when cheap and abundant largely oil-based energy no longer exists tomorrows economic expansion will not occur (Campbell, 2006). What will happen to the stock markets after peak oil is hard to determine, but value papers, bonds and equities risk following the world economy downwards when oil production no longer can satisfy demand or soar to new record price levels.

The peak production of Norway coincided with very low oil prices in the end of 1990s and beginning of 2000s. The export also peaked around the same time, effectively meaning that Norway sold its precious oil at the worst possible time.

In 2006, the oil production had dropped 20% from the peak level of 2001 and on the same time the revenues from oil export had more than doubled. In retrospect, Norway might have profited more if it had postponed some of its production to maximize future revenues from oil export.

When looking into the future in the light of a coming global peak in the oil production, it is only reasonable to assume that oil prices will continue to remain at a high level and perhaps even increase to new record levels. A more long-term strategic thinking when it comes to oil production will be needed to wisely handle the natural wealth from the oil resource. Saudi Arabia recently declared their intentions to leave some oil finds untapped to preserve oil wealth for future generations (Reuters, 2008). So it might be a good idea to re-evaluate the production policy and think more about what kind of investments that is best to secure wealth for the future Norwegian generations.

To conclude one can say that maximizing production in the short term might not be the best choice for the future. A production profile that is more kept back and saves oil for the future can be better choice for Norway. After all oil in the ground is a physical asset with a real value while bonds and equities are financial assets, with a value only valid within the system that created them. A barrel of oil contains 6.12 GJ of energy and that has a value independent of speculation, financial instabilities and similar.

11. Conclusion

The Norwegian oil production has been dominated by giant oil fields, both in production and in terms of URR. Dwarf oil fields, NGL and condensate only account for minor shares of the total oil supply.

Based on the historical production profiles of Norwegian fields typical decline rates were found for all subclasses. Giant oil fields decline slower than the other subclasses, but still at a decline rate of more than -10% annually. The aggregate decline rate of the giant oil fields was found to increase with time, thus challenging the conclusion of the recent CERA-study (Cambridge Energy Research Associates, 2007).

Dwarf oil fields, NGL and condensate were found to decline even faster, in particular condensate with an annual decline rate of almost -40%. Decline rates well over -15% can be found for these subclasses.

The rapid decline rates found should be taken very seriously, as they imply that oil production could go down very fast in a region. The role of technology is an important factor here, as much production technology have been aimed at prolonging plateau production or increasing depletion, which results in a rapid decline. The new fields that will be brought on-stream in the near future are small and will not be able to compensate for the decline of the old giant fields.

The conclusion from the forecast is that Norway will barely be an oil exporter by 2030, with only a few hundred thousand barrels of oil available for export in the best case. This will have dramatic consequences for the Norwegian economy and for the world, as Norway presently is the world third largest oil exporter.

By using Norway, which openly displays all its production data, a comprehensive and detailed picture of the actual production behaviour can be created. This is of great importance to better understand the future behaviour of other regions and how fast the decline will be after the moment when the world reached peak oil.

Regarding the future the current oil production policy should be re-assessed. With the increasing oil shortage imposed by peak oil and the risk of an unstable financial market the current investment might not be the optimal. Keeping oil in the ground and having a more moderate oil production policy may be a better way of ensuring the future wealth of the Norwegian people.

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