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Future Danish Oil and Gas Export

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Abstract

Denmark possesses only a small share of the exploitation rights to North Sea oil and is a minor producer when compared to Norway and the UK. However, Denmark is still an oil exporter and a very important supplier of oil for certain countries, in particular Sweden.

A field-by-field analysis of the Danish oil and gas fields, combined with estimated production contribution from new field developments, enhanced oil recovery and undiscovered fields, provides a future production outlook. The conclusion from this analysis is that by 2030 Denmark will no longer be an oil or gas exporter at all. Our results are also in agreement with the Danish Energy Authority's own forecast, and may be seen as an independent confirmation of their general statements.

Decreasing Danish oil production, coupled with a rapid decline in Norway's oil output, will force Sweden to import oil from more distant markets in the future, dramatically reducing Swedish energy security. If no new gas suppliers are introduced to the Swedish grid, then Swedish gas consumption is clearly predestined to crumble alongside declining Danish production. Future hydrocarbon production from Denmark displays a clear link to Sweden's future energy security.

Key words:
Future Danish oil and gas production, field-by-field analysis, Swedish energy security

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1. Introduction

Norway and the United Kingdom own the largest share of the North Sea oil and have been the driving forces behind North Sea oil production. Denmark owns only a small share of the bounty that was North Sea oil and is a minor producer when compared to Norway and the UK. Denmark produced around 290 000 barrels per day (b/d) in 2008 [1]. Danish domestic consumption is around 190 000 b/d [1], and the country has been self-sufficient in oil since 1997.

From statistics it can be seen that Denmark is also an oil exporter and a very important supplier of oil for certain countries, in particular Sweden. In 2007, Sweden imported nearly 30% of its oil from Denmark, on average 100 000 b/d [2]. This amount is equal to a third of the total Danish oil production, and virtually all their surplus production once domestic needs have been met. Consequently, future Swedish energy security is connected closely to Danish oil production.

1.1 Aim of this study

Danish historical production is investigated alongside future capacity potentials in a similar manner to previous examinations of Norwegian production [3-4]. A field-by-field analysis of existing oil and gas fields is used to determine Denmark's future potential. New field developments are also analyzed along with enhanced oil recovery (EOR) to quantify future contribution to output. Undiscovered oil is estimated and compared with other studies to obtain a reasonable figure for the impact of future discoveries in the Danish North Sea region and their importance for future production. The overall aim is to analyze production behaviour of Danish oil and gas. From this a possible future production profile will be created, where historical experience is applied to future development.

The Danish Energy Authority (DEA) makes forecasts for future oil and gas production for the Danish section of the North Sea [5]. However, a thorough examination of their data and establishment of an independent forecast for comparative purposes could prove beneficial for both planners and policy makers. Consequently, this study also aims to perform an independent review of the DEA forecast to determine if they arrive at a reasonable range or not.

Finally, Swedish dependence on Danish oil and gas is also briefly examined. Future Danish oil and gas production is intrinsically linked to future Swedish energy security, given Denmark’s role as Sweden’s most important oil and gas supplier.

1.2 Methodology

All fields are separately analyzed to determine depletion rate, decline rate, cumulative production and estimated ultimate recoverable resources (URR). Official production data from the DEA [5] is used and past production statistics are taken from the DEA statistics going back to the beginning of the Danish oil era in early 1970s.

The DEA does not use such common terms as “*proved*” and “*additional*” reserves, utilising instead the terms “*ongoing*”, “*approved*”, “*planned*” and “*possible*” recovery [6]. The official URR estimates are calculated by combining the cumulative production and the remaining recoverable reserve, as reported by the DEA [5]. In addition, we also estimate URR of each field through decline curve analysis. Furthermore, discovery year and year of first production for all fields are taken from official DEA material [5].

Unlike Norwegian oil production which is broken down into crude oil, natural gas liquids and condensate by the Norwegian Petroleum Directorate, Danish oil production is only reported as oil. We chose to divide it into two subclasses where the first is oil from giant oil fields, i.e.

those fields with more than 0.5 billion barrels (Gb) of URR or a production of more than 100 000 b/d for more than one year. The definition used here follows established results from other studies [7-9].

Crude oil from smaller oil fields, which are fields not large enough to be classified as giants, is the second subclass. These fields will be called dwarf oil fields as established in a prior study of Norway [3]. However, there is no clear border between giants and dwarfs, as the largest dwarfs might actually be just below the giants, but on the larger scale most oil fields will be small or significantly smaller compared to the giants and therefore the term "*dwarf*" is chosen to illustrate the concept.

When it comes to gas, we apply similar subdivisions. A gas giant is often defined as a field with more than 3 trillion cubic feet of URR, which is equivalent to 84 billion cubic meters (bcm). The Tyra field is just on the verge of being classified as a giant and we will treat it like a giant. All other Danish gas fields are categorized as dwarfs.

1.3 Decline curve analysis

A detailed field-by-field analysis of Denmark is performed using the decline curve analysis methodology. This type of analysis has previously been performed on Norway [3-4] as well as on the world's giant oil fields [9]. Decline curves have also been used for gas fields [4, 10]

The Arps decline curves [11] are simplistic and focused on obtaining expressions with mathematical tractability that could be utilized in a simple and straightforward manner. In the models, it is assumed that the declining production starts a given time t_0, with initial production rate of r_0 and the initial cumulative production Q_0. The production rate at time $t \geq t_0$ is denoted by $q(t)$ and the corresponding cumulative production at the same time is defined by the integral $Q(t) = \int_{t_0}^{t} q(u)du$.

The simplest decline curves are characterized by three parameters, the initial production rate $r_0 > 0$, the decline rate $\lambda > 0$ and the shape parameter $\beta \in [0,1]$. If the production is allowed to continue without end and the integral $Q(t) = \int_{t_0}^{t} q(u)du$ converges as $t \to \infty$ it is possible to calculate the ultimate cumulative production of the decline phase, which can be summed with Q_0 to give the fields estimated URR. Normally production is stopped when the economic/energetic limit is reached, i.e. when keeping the equipment running requires more money and/or energy than it yields. This cut-off point can be denoted $r_c < r_0$ and is found by solving $q(t) = r_c$ with respect to t, where the solution occurs at t_{cut}. By inserting t_{cut} as the upper limit for $Q(t)$, one can now calculate the technically recoverable volume, denoted by V_{rec}.

The key properties of the Arps exponential and harmonic decline curves can be seen in Table 1, while the generalized hyperbolic case is displayed in Table 2. Note that the exponential and harmonic curves only are special cases of general hyperbolic decline. Modification of the shape parameter β can alter the shape of the production rate function and be used to determine what kind of decline curve that is suitable for fitting against empirical data. The value of the decline parameter λ governs how steep the decrease in production will be.

The exponential decline curve is by far most convenient to work with and still agrees well with actual data (Figure 1 and 2). Hyperbolic and harmonic decline curves involve more complicated functions and are, consequently, less practical to utilize. The disadvantage of the exponential decline curve is that it sometimes tends to underestimate production far out in the tail part of the production curve, as decline often flattens out towards a more harmonic and hyperbolic behaviour in that region (Figure 3 and 4).

Table 1. *Key properties of Arps exponential and harmonic decline curves*

	Exponential	**Harmonic**
β	$\beta = 0$	$\beta = 1$
$q(t)$	$r_0 \exp\left(-\lambda(t-t_0)\right)$	$r_0\left[\exp\left(-\lambda(t-t_0)\right)\right]^{-1}$
$Q(t)$	$Q_0 + \frac{r_0}{\lambda}\left(1-\exp\left(-\lambda(t-t_0)\right)\right)$	$Q_0 + \frac{r_0}{\lambda}\ln\left(1+\lambda(t-t_0)\right)$
URR	$Q_0 + \frac{r_0}{\lambda}$	*Not defined*
t_{cut}	$t_0 + \frac{1}{\lambda}\ln\left(\frac{r_0}{r_c}\right)$	$t_0 + \frac{1}{\lambda}\left[\frac{r_0}{r_c} - 1\right]$
V_{rec}	$Q_0 + \frac{r_0 - r_c}{\lambda}$	$Q_0 + \frac{r_0}{\lambda}\ln\left(\frac{r_0}{r_c}\right)$

Table 2. *Key properties of Arps generalized hyperbolic decline curve*

	Hyperbolic
β	$\beta \in [0,1]$
$q(t)$	$r_0[1+\lambda\beta(t-t_0)]^{-1/\beta}$
$Q(t)$	$Q_0 + \frac{r_0}{\lambda(1-\beta)}\left[1-\left(1+\lambda\beta(t-t_0)^{1-\frac{1}{\beta}}\right)\right]$
URR	$Q_0 + \frac{r_0}{\lambda(1-\beta)}$
t_{cut}	$t_0 + \frac{1}{\lambda\beta}\left[\left(\frac{r_0}{r_c}\right)^{\beta} - 1\right]$
V_{rec}	$Q_0 + \frac{r_0}{\lambda(\beta-1)}\left[\left(\frac{r_0}{r_c}\right)^{\beta-1} - 1\right]$

The greatest advantage of decline curve analysis is that it is independent of the size and shape of the reservoir or the actual drive-mechanism [12], thus avoiding the need for more detailed reservoir data. Furthermore, decline curves are more than just an empirical model of field behavior since they also represent physical solutions to reservoir flow equations in various cases [9].

Decline curve analysis can also be combined with depletion analysis to determine when a field will reach a maximum rate of production [4, 9]. In the case of Denmark, many operational fields contain both oil and gas. Consequently, a similar production behavior for both oil and gas is feasible. Especially, as of the gas is categorized as associated gas and largely produced as a side product of the more valuable oil extraction. Consequently, the decline curves are seen as generally reliable for obtaining a picture of future production output from a field in the near and medium term after the peak has occurred.

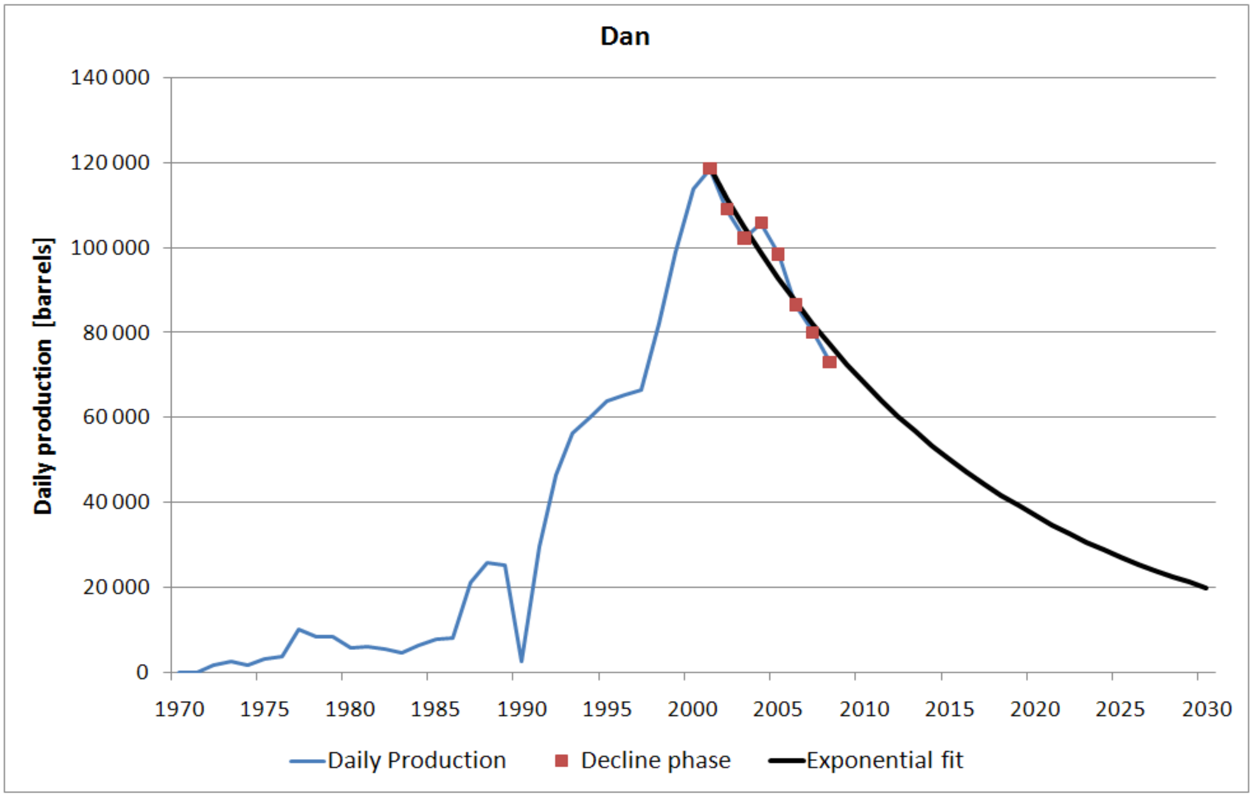

Figure 1: *Exponential decline curve applied to the Dan giant oil field.*

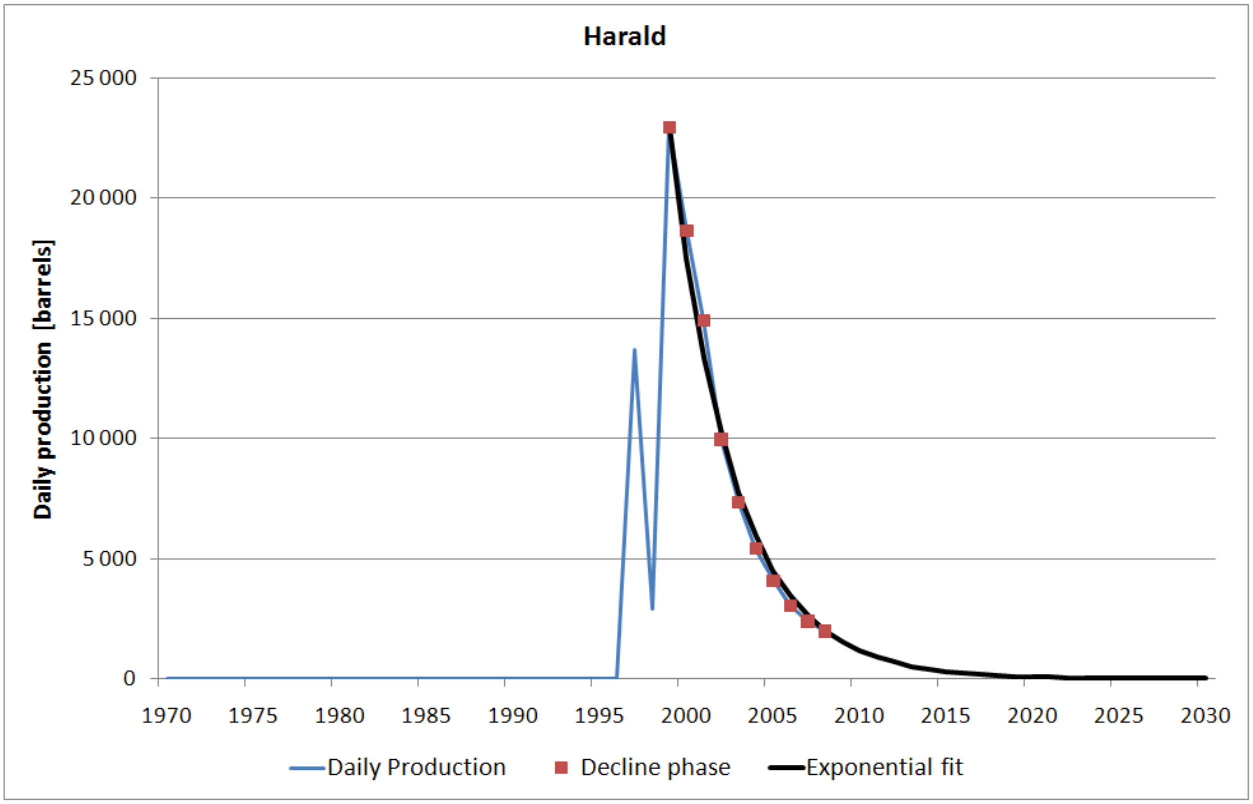

Figure 2: *Exponential decline curve applied to the Harald dwarf oil field.*

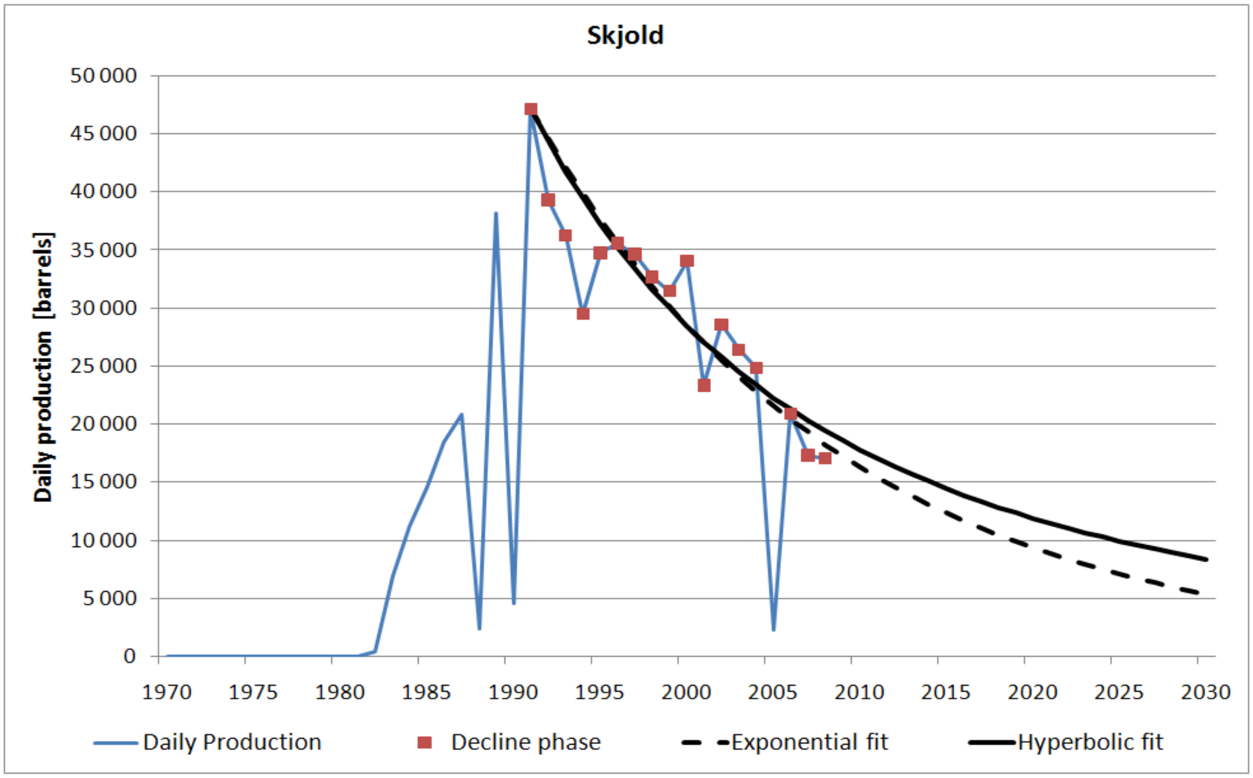

Figure 3: *Hyperbolic and exponential decline curves applied to the Skjold oil field*

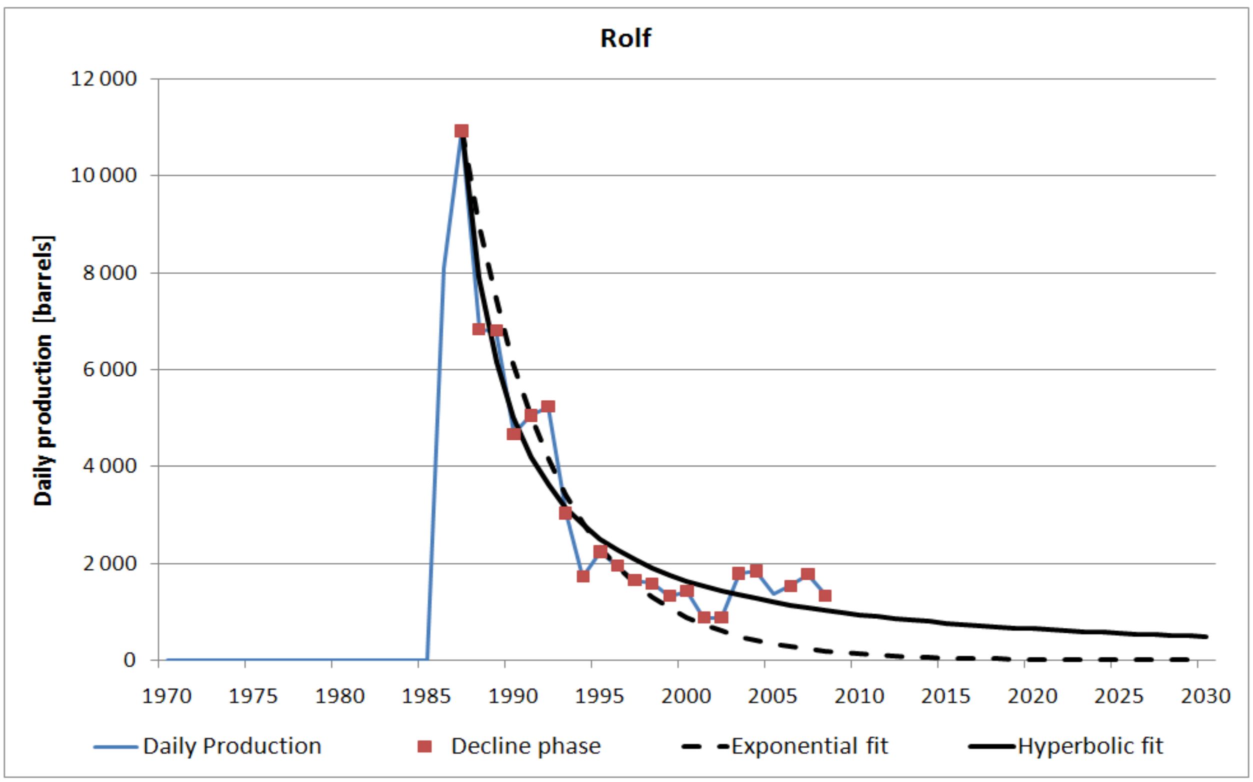

Figure 4: *Hyperbolic decline curves can successfully fit the historical data and provide a more reasonable outlook than the simple exponential curve*

The depletion rate of remaining reserves (referred to as depletion rate in this article) is defined as:

$$d_{\delta t} = \frac{q_t}{R_r} = \frac{q_t}{R_0 - Q_t} \tag{1}$$

Where $d_{\delta t}$ = depletion rate of remaining reserves, R_0 = initially present reserves or ultimate recoverable resources, q_t = production at time t, Q_t = cumulative production up to time t. This value of this parameter prior to the onset of decline has shown to be in strong correlation with future average decline rates [9]. In addition, this parameter is also vital for maximum depletion rate modelling [13, 14]. Campbell and Heapes [15], Mäkivierikko [16] and others use different forms of depletion rate modelling.

2. Distribution of oil

The Danish borders stretches into the southern parts of the North Sea rift system with prolific oil and gas. Upper Jurassic-source rocks, Cretaceous chalk and lower Tertiary sandstones are present and contain various oil-bearing formations, especially chalk and sandstone reservoirs. The chalk reservoirs are known to have low permeability, which affects production.

All of the closed-down, currently producing oil fields and new field developments together contain a URR of 3.1 Gb of oil [5]. The bulk, namely 62%, is concentrated in the three giants called Dan, Gorm and Halfdan, while the remaining oil can be found in dwarf fields. The dominance of a few fields is also mentioned by the World Energy Council [6]. When it comes to natural gas, the situation is similar to that of oil. The only giant field, Tyra, alone holds nearly 40% of the ultimate reserves. The three oil giants together hold almost as much gas as Tyra, making 70% of the Danish gas being concentrated to just four fields. Furthermore, the historical production record of oil and gas production in Denmark shows the importance of the giant fields.

About 90% of Danish production originates from chalk reservoirs with complex conditions [5]. Only a few countries and companies have developed oil production from such formations, and this has forced the Danish oil industry to obtain the requisite knowledge on exploration and production in challenging formations. Public-private partnership and research collaboration has aided the development of sophisticated technologies and education of specialists. Advanced horizontal drilling techniques and use of water injection have been declared as the main reasons for the increase in recovery factors and production levels witnessed between 1990 and present [5].

2.1 Danish giant oil fields

In total, Denmark has only three giant oil fields - Dan, Gorm and Halfdan (Table 3). All of them are chalk reservoirs and their decline rates agree well with the Norwegian Valhall and Eldfisk giant fields, also consisting of chalk reservoirs [3]. Ultimate recovery of Gorm has varied from year to year in the DEA’s assessment, and passed the verge of becoming a giant in some cases. Therefore, we chose to include Gorm among the giants.

Dan is an anticline structure induced by salt tectonics with low reservoir permeability. A major fault divides the reservoir into two blocks and numerous smaller faults are also present, making conditions complex. Recovery is done from the central part and the flanks by water flooding. Gorm has a similar geology as Dan with numerous faults and production is also maintained by water injection. Furthermore, Gorm serves as an infrastructure hub for surrounding satellite fields and supports them with injection water and lift gas. Better description of the production facilities can be obtained from the DEA [5].

Halfdan is a porous, non-fractured chalk reservoir consisting of a disintegrated structural trap, where the trapped oil and gas have only been able to migrate short distances due to low permeability. This feature ensures a production strategy different from Dan and Gorm, resulting in the use of advanced fracturing techniques known as Fracture Aligned Sweep Technology (FAST) [17-19]. In addition, mineral solubility and downhole scale control have proved to be important, but challenging parameters, for all the three fields [20-23].

The average annual decline of the Danish giants is found to be 6.7%. This is significantly lower than average of the Norwegian giants at 13% [3], but should be seen as a result of the lower depletion rates of Danish fields. This is explained by the generally lower permeability of the Danish chalk reservoirs compared to the sandstone reservoirs that dominate Norwegian giants. Furthermore, one can estimate ultimate recovery from exponential decline curve fits using relations from Table 3.

Table 3: *Danish giant oil fields and some characteristic properties. Official URR are taken as reported by the DEA [5] in 2008 for the expected case, while the estimated URR are calculating using decline curve analysis.*

Field name	Official URR [Gb]	Estimated URR [Gb]	Disc. Year	First Oil	Peak Prod. [b/d]	Peak Year	Decline [%]
Dan	0.923	1.077	1971	1972	118 532	2001	6.0
Gorm	0.399	0.496	1971	1981	52 468	1997	8.1
Halfdan	0.608	0.770	1999	1999	104 851	2006	6.1
Total	***1.930***	***2.343***					***6.7***

2.2 Danish giant gas fields

The Tyra field is the only one that can be classified as a gas giant. Similar to the oil giants, it consists of a chalk reservoir created by tectonic uplift where a free gas accumulation is overlying a thin oil zone, necessitating horizontal drilling for proper development [24, 25]. This explains why Tyra is also catalogued as a dwarf oil field. In addition, Tyra contains final processing facilities for gas and oil from the many surrounding fields, making it an important infrastructural hub [5]. The characteristic behaviour of Tyra can be seen in Table 4. About 35% of remaining reserves of gas in the DEA's expected case is located in Tyra [5], so future behaviour of this field will be a key factor for Danish gas production in the coming decade.

Table 4: *The characteristic behaviour of the Danish giant gas field Tyra. NPY stands for "No Peak Yet" and implies that the field has not reached the onset of decline.*

Field name	URR [bcm]	Discovery Year	First Gas	Peak Production [bcm/year]	Peak Year	Average Decline [%]
Tyra	78	1968	1984	2.8	NPY	NPY

2.3 Danish dwarf oil fields

In total, Denmark has 16 dwarf fields (Table 5). Better descriptions of each individual field, their geology and production facilities are given by the DEA [5]. More specialized development studies and other analyses have been made by others [26-30]. Long horizontal wells are frequently used for many fields [31]. The oldest dwarfs were found in the 1960s/1970s and entered production in the early 1980s. The youngest dwarfs were discovered in 2000 and came on stream in 2003.

Most of the dwarfs consist of chalk and/or carbonate reservoirs while only Lulita, Siri, Cecile and Nini are sandstone reservoirs. Generally higher decline rates for sandstone reservoirs compared to chalk and carbonate have been found by the IEA [20] and this agrees reasonably well with the Danish experience. This is motivated by the generally higher permeability that allows for a higher rate of extraction compared to less permeable reservoir types. However, there are examples of chalk reservoirs with higher decline rates than sandstones, explained by differences in production strategies and equipment. Reservoir type should only be seen as a rough rule of thumb for individual field, but it is not surprising that the sandstone reservoirs are among those with the highest decline rates.

Many other dwarf fields generally decline somewhat slower, but still about 10% annually. The average annual decline of all Danish dwarf fields was found to be 15.1%. Similar to Norway [3], the dwarfs are found to decline faster than the giants. This is even the case when the reservoir properties are similar. IEA [20] found field size to be an important parameter for decline and this appears to be the case also in Denmark. In addition, the official ultimate recovery values agree fairly well with our estimates and usually end up lower than the URR estimates from decline curves.

Table 5: *Danish dwarf oil fields and some characteristic properties. The estimated URR have been calculated using decline curves. NPY stands for "No Peak Yet" and implies that the field yet hasn't reached the decline phase of its life.*

Field name	Official URR [Gb]	Estimated URR [Gb]	Disc. Year	First Oil	Peak Prod. [b/d]	Peak Year	Decline [%]
Cecilie	0.006	0.009	2000	2003	5 342	2004	31.2
Dagmar	0.006	0.020	1983	1991	8 185	1991	17.6
Harald	0.057	0.050	1980	1997	22 952	1999	23.8
Kraka	0.038	0.049	1966	1991	8 460	1994	7.4
Lulita	0.006	0.013	1992	1998	3 860	1999	13.4
Nini	0.050	0.048	2000	2003	25 450	2004	25.4
Regnar	0.006	0.006	1979	1993	7 392	1994	11.9
Roar	0.019	0.018	1991	1996	7 358	1997	19.9
Rolf	0.031	0.091	1981	1986	10 924	1987	9.6
Siri	0.075	0.124	1995	1999	36 495	2000	13.3
Skjold	0.333	0.441	1977	1982	47 110	1991	4.5
Svend	0.050	0.096	1975	1996	23 365	1997	10.4
Syd Arne	0.182	0.163	1969	1999	40 855	2005	21.0
Tyra	0.166	0.206	1968	1984	30 120	1994	7.8
Tyra South East	0.053	0.055	1991	2002	10 580	2005	9.1
Valdemar	0.088	-	1977	1993	NPY	NPY	NPY
Total	***1.166***	***1.468***					***15.1***

2.4 Danish dwarf gas field

Besides the giant Tyra field, Denmark also has 8 dwarf gas fields (Table 4). The dwarf gas fields are often dwarf oil fields too, sharing their geology and properties. Consequently, chalk reservoirs are dominant amongst the small gas fields. It should be noticed that Dan, Halfdan and Gorm are both giant oil fields and dwarf gas fields on the same time. The Kraka, Lulita and Svend dwarf oil fields have each produced around 1 bcm of gas over their life, but their gas output are so negligible that they cannot be considered dwarf gas fields.

The most striking fact for this group is the small amounts of remaining reserves. Only Halfdan, Harald, South Arne and Valdemar contain more than 4 bcm of gas left to produce [5]. Halfdan alone has 32% of the remaining gas in DEAs expected case [5], which is approximately as much as Tyra. Gas production from the dwarf gas fields has been uneven, and governed by oil production. Ccsonsequently, few of the fields have displayed a clear peak in gas production yet or alternatively some fields still contain significant shares of their recoverable gas.

Table 6: *The Danish dwarf gas fields. 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 has not reached the onset of decline.*

Field name	URR [bcm]	Discovery Year	First Gas	Peak Production [bcm/year]	Peak Year	Average Decline [%]
Dan	27	1971	1972	NPY	NPY	NPY
Gorm	8	1971	1981	NPY	NPY	NPY
Halfdan	38	1999	1999	NPY	NPY	NPY
Harald	24	1980	1997	NPY	NPY	NPY
Roar	16	1968	1996	2	1997	17.2
Skjold	4	1977	1982	NPY	NPY	NPY
South Arne	9	1969	1999	0.4	2002	20.8
Valdemar	7	1977	1993	NPY	NPY	NPY
Total	***133***					***19.0***

2.5 New field developments

Denmark has four announced or approved oilfields coming on-stream in the future (Table 7). These fields are called Adda, Amalie, Boje Area, and Freja. There is also a small possibility of recovering about 6 million barrels of oil from the gas field Alma, but the DEA is not expecting it [5]. Adda and Freja are sandstone reservoirs, while Boje Area and Amalie are made from chalk.

The new fields contain only a mere 0.03 Gb of oil in an optimistic case and cannot realistically be expected to compensate for the decline in existing oil production due to their small recoverable reserves and expected production levels. The Cecile field is of comparable size and only managed to produce roughly 5000 barrels per day at most for a short period of time (Table 5). In total, this means that at most 20 000 b/d of production additions for a short period can be expected from all the announced new field developments.

Table 7: *The four new oilfields expected to come into production in the near future. These fields are minute compared to the giant fields and several of the dwarfs already in production.*

Field name	URR [Gb]	Discovery Year	Expected First Oil
Adda	0.006	1977	2010
Amalie	0.006	1991	not available
Boje Area	0.006	1982	2011
Freja	0.006	1984	not available
Total	***0.024***		

The DEA has also announced five new gas fields as new gas field developments (Table 8). Amalie and Freja are categorized as planned new gas fields [5], while the other gas fields lack detailed development plans. Elly is a combined chalk and sandstone reservoir. Each of these fields contains only a small amount of gas. In fact, some are so small that they are rounded down to 0 bcm in official DEA statistics.

Table 8: *The four new gas fields expected to come into production in the near future. These fields are minute compared to Tyra and several of the dwarfs already in production.*

Field name	URR [bcm]	Discovery Year	Expected First Gas
Adda	0	1977	2010
Alma	1	1990	2011
Amalie	2	1991	not available
Elly	~1	1984	2011
Freja	0	1984	not available
Total	***~4***		

New field developments for both oil and gas can only be considered small and marginal. These fields will not realistically be able to compensate for much of the decline in existing production. Modernisation, redevelopment and enhanced oil recovery in old fields are likely to have a much greater impact on future production than the new fields waiting to come on-stream.

2.6 Oil and gas exploration

Denmark had already given away the first oil exploration licence by 1935 and actual drilling commenced in 1936 [15]. The first well, in the Danish North Sea, that discovered hydrocarbons was drilled in 1966. This well was also the first oil find in the North Sea and drew attention to the potential of the northern parts of the North Sea to Norway and the UK [15]. The discovery of the giant Dan marked the real beginning of the Danish oil era.

Areas in the Danish North Sea have been offered to those companies that have displayed and interested in a system of licensing rounds, similar to the Norwegian licensing system. Thus far six licensing rounds have been held, with the latest in 2005/2006 [5]. In total, about 180 exploration boreholes have been drilled [15]. Exploration drilling reached a maximum in 1985 with fourteen holes drilled, but nowadays exploration drilling has decreased to no more than one or two holes per year [15], thus indicating maturity and low expectance of major new discoveries. During the period 1963-2008, the cumulative exploration costs have been over 4 billion euro and about 12% of the total investments in the Danish petroleum sector [5].

The historical discovery trends are shown in Figure 5. The amount of new fields found has remained more or less constant since the late 1960s, although the discovered volumes have decline significantly. This is primarily a result of smaller reservoirs.

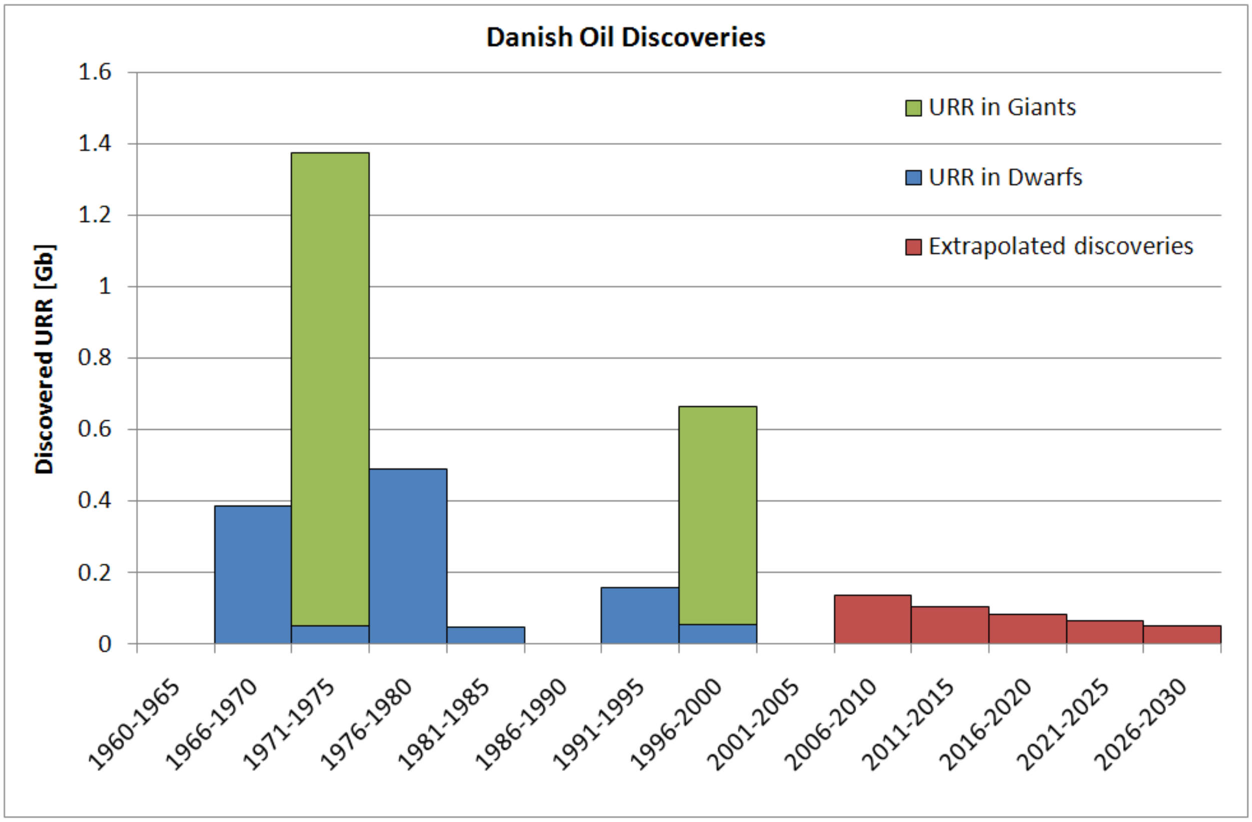

Figure 5: *Danish discoveries in terms of URR. The discoveries of giant fields can be clearly seen and towers tall above the dwarf discoveries.*

It is still possible to discover more in the Danish North Sea and this can be estimated by a number of different techniques. Campbell and Heapes [15] places Denmark's ultimate reserves at 3.5 Gb using creaming curves, thus leaving little room for future discoveries in the Danish region of the North Sea. The DEA [5] is expecting possible future discoveries of 0.1 Gb in their low estimate and 0.16 Gb in the expected scenario, while the discovery potential is placed at 0.4 Gb. This study also uses logarithmic extrapolation of the discovery trend to estimate future discoveries, as done in other studies [3]. However, it should be noted that poor statistics make any trend extrapolation uncertain. In total, we find that up to 0.4 Gb of new discoveries are to be made in Danish North Sea until 2030 (Figure 5).

Alternatively, a logistic fit can be applied to the cumulative discoveries in order to estimate the ultimate reserves (Fig 6). Logistic curves and similar curves have been used in a long array of studies as a means to determine future production, and ultimate production [32-36]. Cumulative production must equal the ultimate reserves when time goes towards infinity, and consequently, logistic models can be used to model both production and discoveries. Using this method, slightly below 3.5 Gb is also obtained as ultimate reserves.

In total, we can assume that the ultimate reserves of Denmark are close to 3.5 Gb, which is in good agreement with other studies. Furthermore, we stress that most of the new discoveries would be located in small reservoirs, making development more expensive and challenging. Undiscovered fields are assumed to be dwarfs and follow production curves similar to that of dwarf fields already in production.

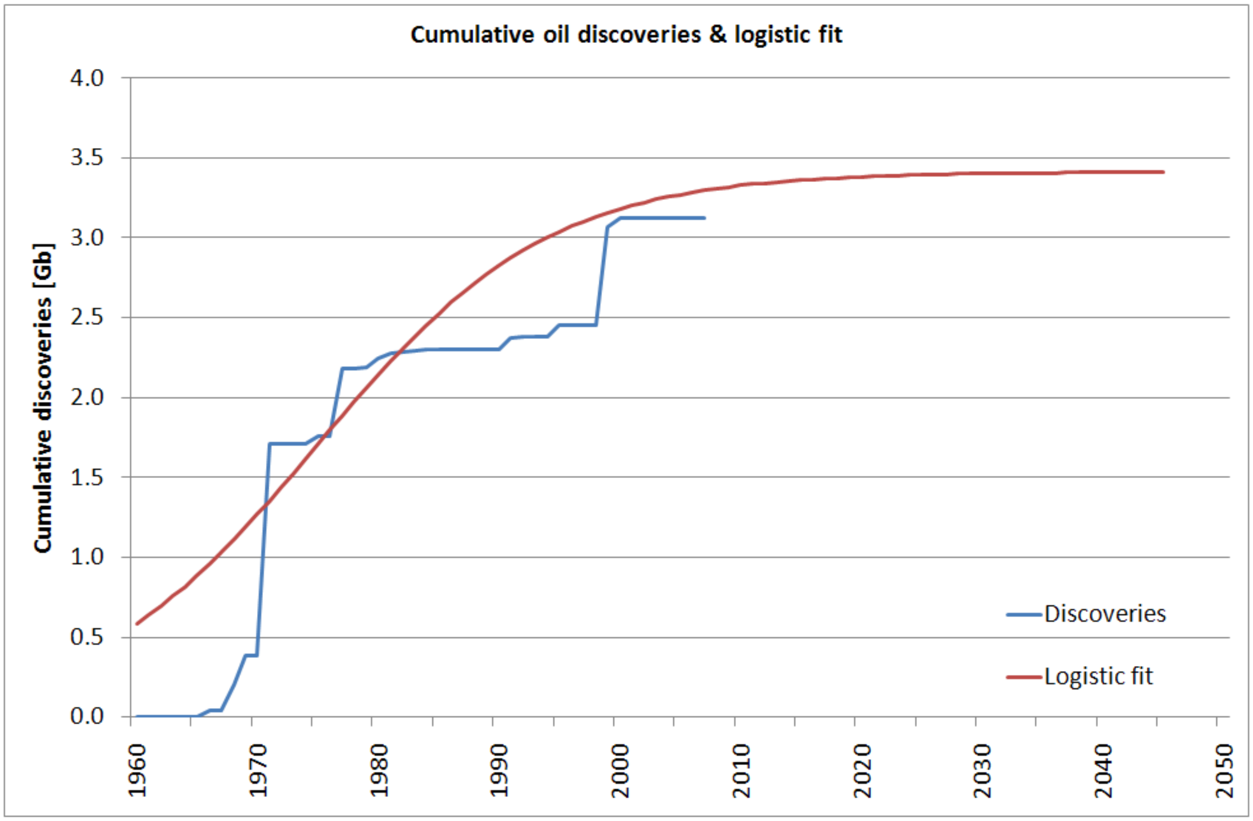

Figure 6: *The cumulative oil discoveries of Denmark together with a logistic fit. The cumulative discoveries seem to flatten out slightly below 4 Gb, in agreement with the logarithmic extrapolation technique.*

Historical discoveries of gas in the Danish North Sea, together with an extrapolation, can be seen in Figure 7. The logistic fit provides similar outlook and gives room for around 40 bcm of new discoveries (Figure 8). This is significantly more optimistic than the DEA's own forecast [5], which gives 8 bcm in the low case and 17 bcm in the expected case.

It should be noted that the few data points that exist makes any extrapolation uncertain and the results should be seen as an educated guess. However, recent exploration wells have discovered the Svane structure, a deeply located high pressure high temperature reservoir filled with coal-derived gas from underlying carboniferous layers that may prove to be a significant field [5]. Due to complex reservoir conditions and great depth, the Svane structure is still being evaluated. If it proves to be commercially feasible, it will be expected to come on stream beyond 2020 at earliest. In order to be optimistic, we use 40 bcm as an estimate for future gas discoveries in Denmark.

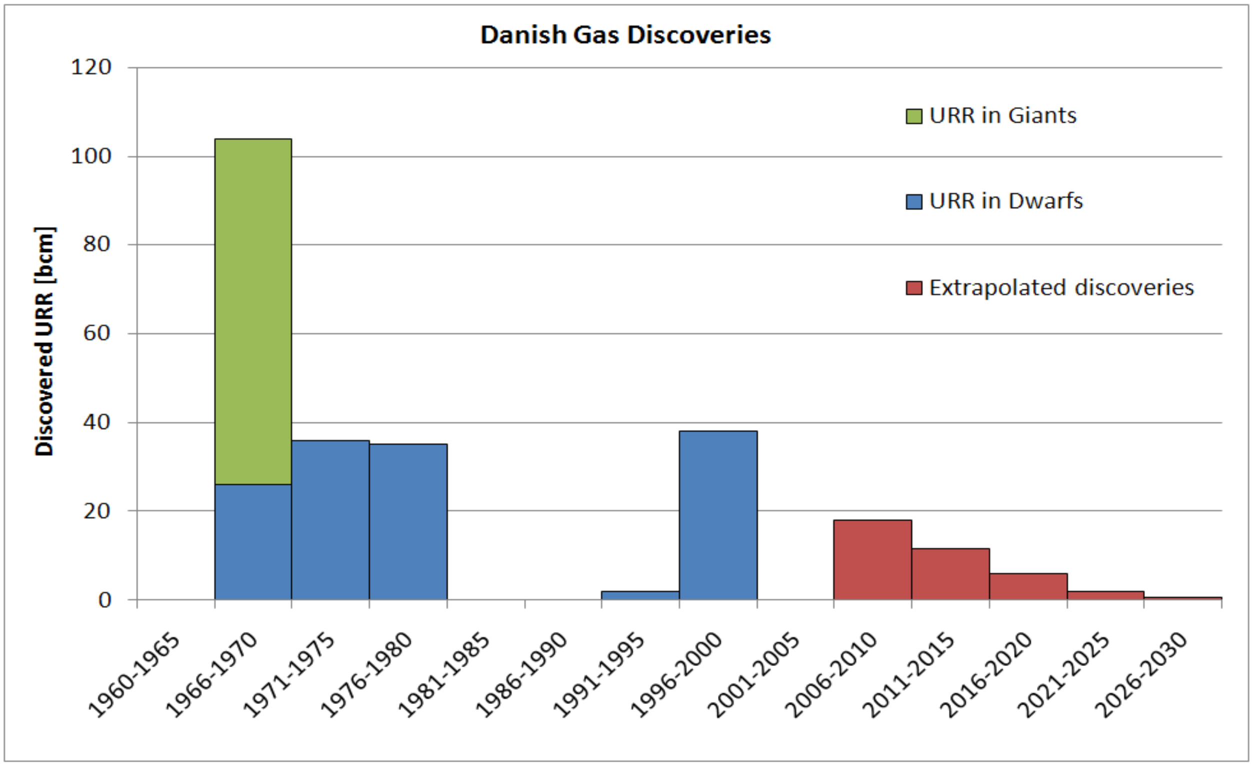

Figure 7: *The Danish gas discoveries. Tyra is the only gas giant that has been discovered in Danish North Sea since 1960s. Periods of no discoveries at all has occurred in several cases.*

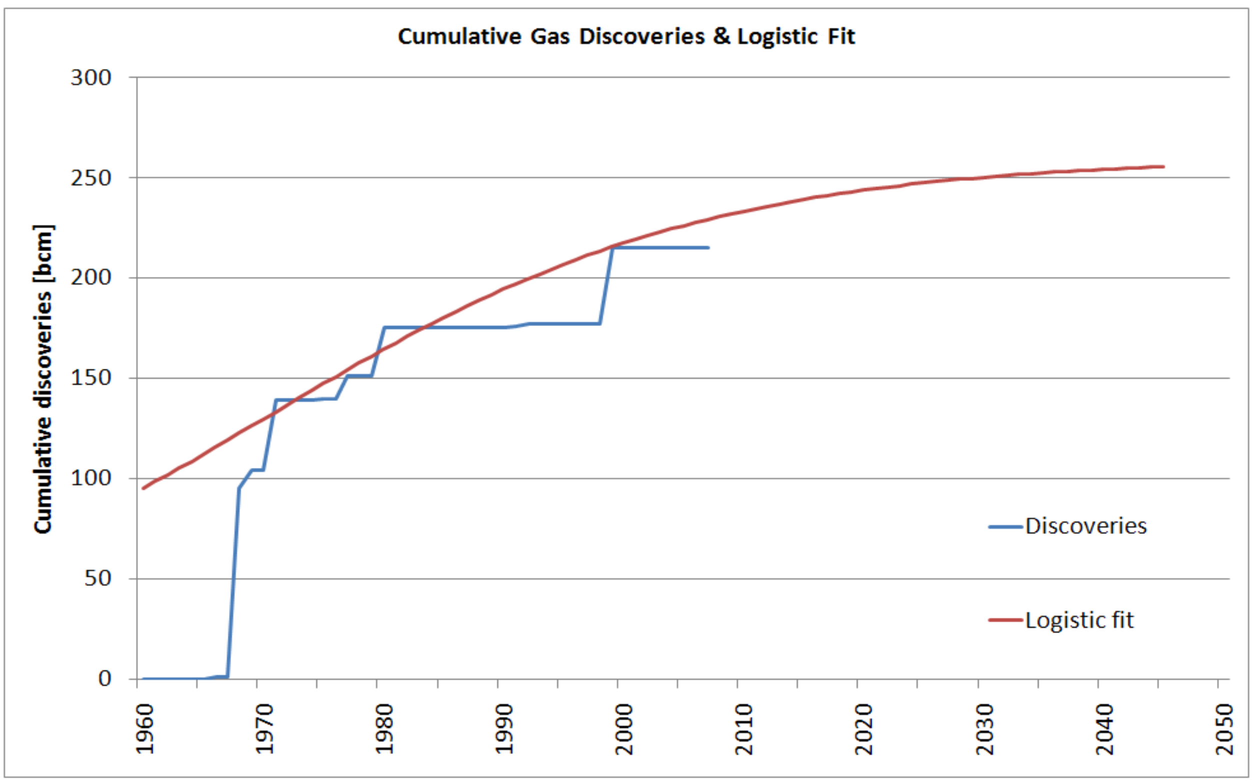

Figure 8: *The cumulative gas discoveries of Denmark together with a logistic fit. The cumulative discoveries seem to flatten out around 250 bcm, providing room for new discoveries of 40 bcm.*

2.7 Enhanced oil recovery

The average recovery factor is roughly 20 % and enhanced oil recovery (EOR) is seen as a future possibility to enable more oil to be recovered [5]. The Danish Siri field has been subjected to EOR, but only due to limited amount of gas and gas compressor restrictions [37]. However, no major EOR projects are currently present in Denmark but the DEA has performed extensive literature studies and screenings for determining future potential in joint venture with Maersk and the Danish North Sea Fund [38]. Their conclusion is that CO_2 injection is the only proven EOR-technology feasible in Danish fields [5].

EOR does offer a way of producing more oil, but when can that oil be expected to come on-stream? Neither EOR developments are ongoing nor has the DEA received any applications from field operators. However, the DEA are aware that the oil companies are doing internal feasibility studies [39]. As a result, we expect significant EOR contributions first around 2020 or beyond. Consequently, EOR will not play any significant part in the Danish oil production in the nearest decade. Beyond 2020, production volumes could be a minor contributor to future Danish oil production, but this will not likely be able to offset overall decline in production and only dampen the descent to some extent.

In our future outlook, EOR is assumed to improve recovery in each field by 10%. This results in an additional 0.3 Gb of oil from existing fields. Furthermore, we assume that 80% of the Danish fields will be subjected to EOR measures from 2015 to 2030. Typical depletion rates in Danish fields are 6-10% at peak and if this is also applied to EOR using a depletion rate model approach [9, 14], resulting reasonable production levels would be in the order of 40 000-50 000 b/d by 2030.

3. Future outlooks

The Danish North Sea is by all standards a mature oil producing region with the largest and most promising discoveries already made and developed. The onset of decline has already been reached in several of the key producing fields, namely the giants. The peaking of the giants has been shown to be a good indicator for the peaking of an entire region [8] indicating that Denmark has passed peak levels and faces a continued declining production in the future.

3.1 Danish production forecasts

A field-by-field analysis of Danish oil fields, combined with estimated production contribution from new field developments and undiscovered fields, gives a future outlook as shown in Figure 9. Most of the fields are already in decline and have been modelled using decline curves. The conclusion is that by 2030 Denmark will be only producing around 120 000 b/d, even if new field developments, enhanced oil recovery and undiscovered fields are included.

An outlook for future Danish gas production can be seen in Figure 10. This forecast has been performed using the same model and parameters as with Norwegian gas fields in the North Sea [4]. The forecast must be considered as optimistic and should be regarded as a high case forecast since the rate of gas discoveries in the Danish part of the North Sea has so far been disappointing. No enhanced recovery is assumed to gas production. For operational fields the forecast gives a similar outcome as existing forecasts at the DEA [5].

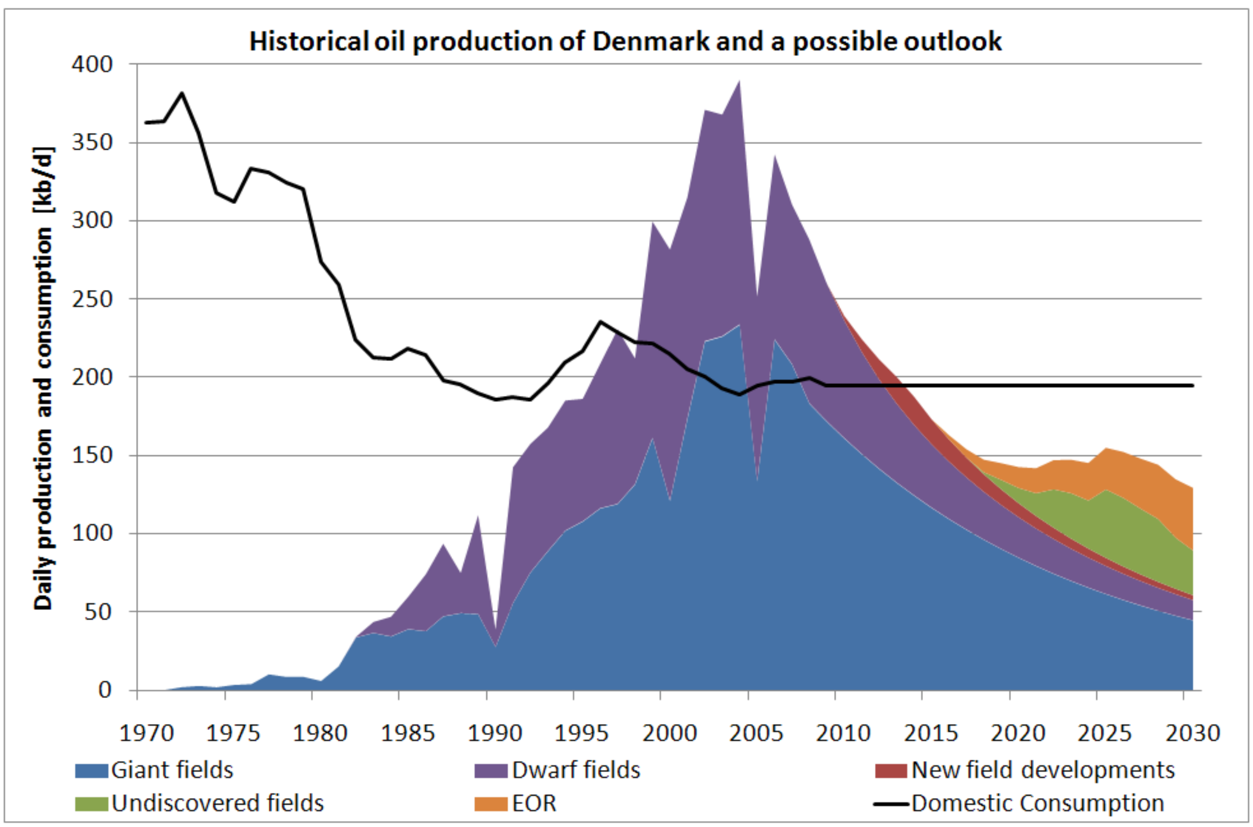

Figure 9: *Possible future outlook for the Danish oil production. Future behavior of the giant fields will be the key factor for determining future Danish oil production as nothing can offset their decline.*

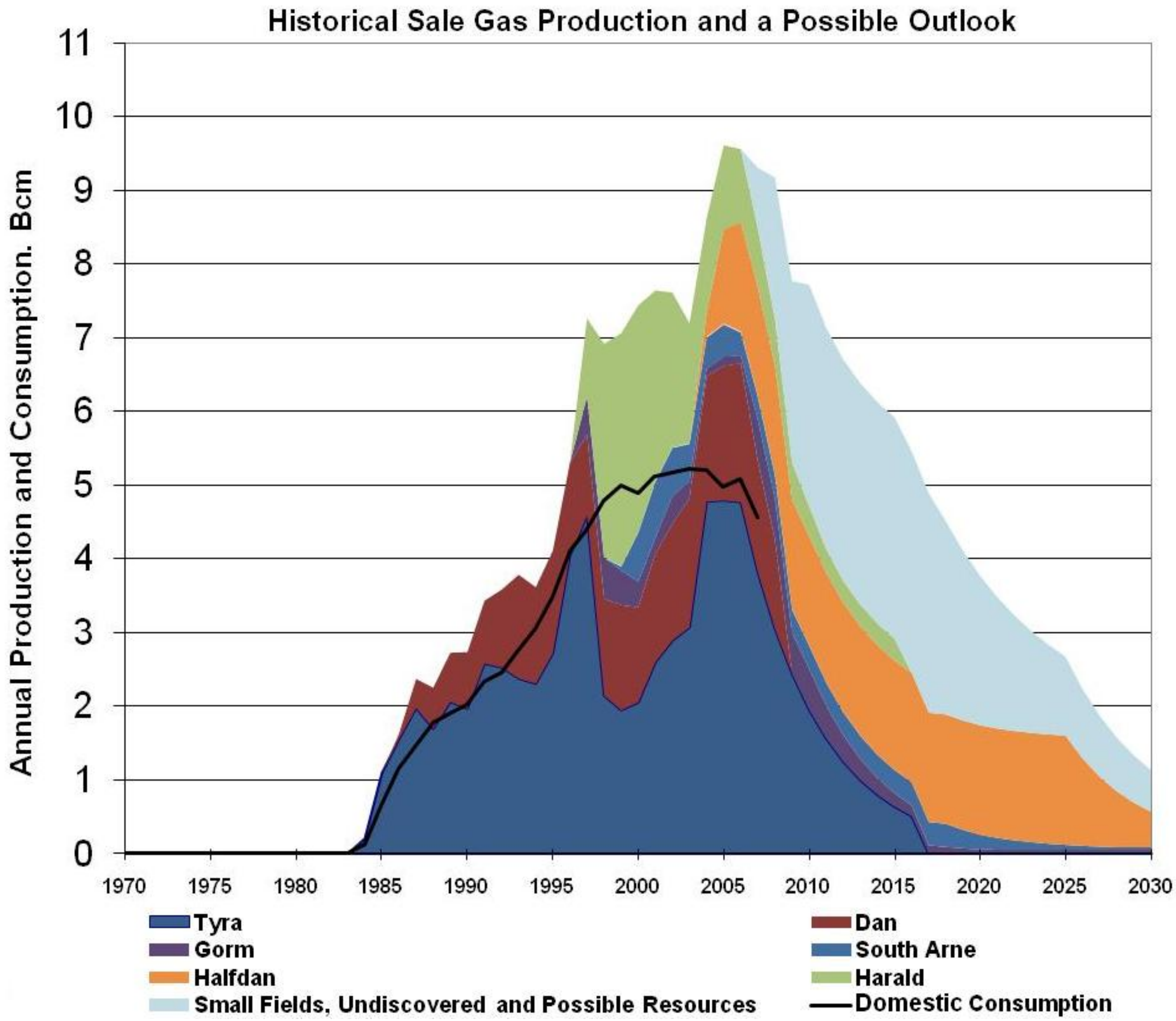

Figure 10: *A future outlook for the Danish gas production. Tyra will remain as an important field for the next years, but will face a steep decline. Halfdan is the dominating gas producing field in the future together with small fields, undiscovered and possible resources. The undiscovered and possible resources are based on the DEA's own estimate.*

4. Comparison with the DEA forecast

The DEA publishes a short-term 5 year outlook and a long-term 20 year outlook for the Danish oil and gas production [5]. In both cases, oil production is expected to continue to decrease. Reduced expectations for Dan and Halfdan production explain a 19% reduction compared to the 2007 forecasts. Danish oil consumption has been steady at roughly 190 000 b/d since 1985 and is expected to remain at that level until 2030.

The DEA expects the contribution from existing and discovered reserves to allow Denmark to be self-sufficient up to 2018. In our forecast (Figure 9), self sufficiency ends in 2015 and could possibly be extended to 2018 if domestic oil consumption is reduced somewhat. In essence, our analysis arrives at similar conclusions as the DEA and may be seen as a verification of their study. Our natural gas forecast (Figure 10) also gives reasonable agreement with the DEA projection for the contribution from reserves and the end of gas self sufficiency is possibly only a decade away.

However, the DEA places high expectations on technological development and contributions from exploration, which are supposed to maintain Danish oil production at slightly less than 195 000 b/d until 2030. In comparison, we regard those factors as less potent and only capable of providing much smaller contributions than the DEA projects. According to our analysis, such a major contributions from new explorations are unlikely, and the long-term outlook presented by the DEA [5] should be regarded as very optimistic. In both cases, the Danish oil and gas exports are likely to cease well before 2030, with significant consequences for Danish oil and gas export possibilities.

The declining oil and gas production in Denmark would mean changes in the national economy, since a source of state revenue would wither away. The hydrocarbon export income can be described as having a marked effect on the central governments surplus [5]. Also employment would be affected, so finding proper mitigation strategies is essential for the Danish government and the DEA.

4.1 Sweden's energy security

Cheap imported oil was an essential building block for the Swedish prosperity after the Second World War. In 1970, nearly 80% of the total Swedish energy supply came from oil [40]. At this time, Sweden was among the most oil dependent countries on Earth. In the wake of the subsequent oil crises of the 1970s, Sweden started to reduce its dependence on imported oil. Oil was largely phased out from industry, residential and service sectors [40]. Increased biomass utilization, governmental policies and measures, combined with increased oil prices dramatically transformed the Swedish energy sector [16]. Nuclear power and renewable energy sources were introduced on a larger scale and reduced the share of oil to only 30% by 2005 [31]. However, oil is still a large part of the Swedish energy mix, especially in transportation where there are few signs of decreased petroleum product dependence. Swedish oil import for recent years can be seen in Figure 11. More in-depth discussion, especially regarding Russia, can be found in Mäkivierikko [16].

In 1985, natural gas was introduced on the west coast of Sweden and all gas comes from the Danish region of the North Sea [41]. About 30 municipalities are using natural gas and the distribution system is currently being expanded with gas being introduced in to new parts of Sweden as a part of the energy system. The gas pipeline network goes from Trelleborg to Gothenburg, with branches to numerous smaller cities along the way. However, natural gas is only a small part of Swedish energy supply, accounting for 2% of total energy consumption [42].

Decreasing Danish oil production in the future combined with the continued decline of Norway [3], will unavoidably force Sweden to import oil from more distant markets in the future. This also means less security, since several of the potential oil exporters are politically problematic. Swedish gas security is also clearly predestined to follow the decline in Danish production, if no new gas suppliers are introduced to the Swedish grid. However, we conclude that the fate of Swedish natural gas is more dependent on political actions than anything else based on the marginal importance of natural gas in the Swedish energy supply.

Both our production outlooks for Denmark (Figure 10 and 11) and the DEA forecasts will result in a severe reduction of Sweden's energy security. The decline of North Sea oil and gas production should not be taken lightly by Swedish planners and policymakers.

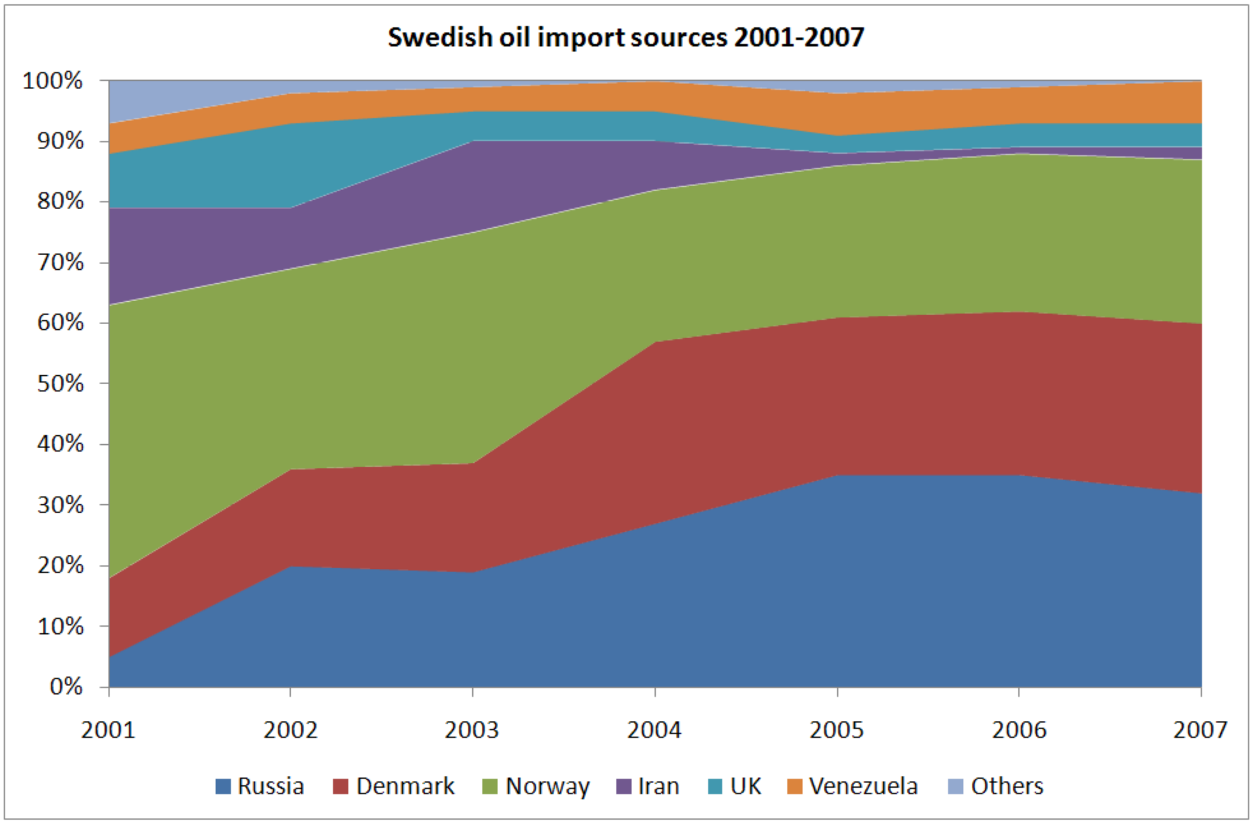

Figure 11: *Swedish oil import 2001-2007. The dependence on Russia has increased significantly, while imports from Norway have decreased, coinciding with the declining Norwegian production. Source: [2, 16]*

5. Conclusion

Closer inspections of Denmark's oil production reveal a significant dependence on just a few fields, namely the giants. Using decline curve analysis, we can project possible production trajectories of each field into the future. Based on both logarithmic trend extrapolation and logistic curve fitting, we estimate future discoveries to roughly 0.4 Gb of oil and 40 bcm of natural gas. This is in agreement with both the DEA estimates and other studies. However, expected production volumes from such volumes are too small to provide any significant change to the overall production. The lack of planned EOR projects is problematic and even if EOR developments are pursued, we do not believe that it would be able to do much more than dampen the overall decreasing production to some extent. Our findings indicate that Danish oil production will continue its decline and that no new field developments, new exploration or enhanced oil recovery will be able to offset the decline in existing production.

Our outlooks provide the same general pictures as the DEA, even though there are some differences regarding contribution from technical progress and exploration. However, those differences do not change the fact that both outlooks foresee the end of Danish oil and gas self-sufficiency within a decade at most. We can only state that the DEA has performed well and provided reasonable forecasts.

In the near term, Sweden will be forced to abandon reliable neighbouring countries as prime oil suppliers and move towards increased dependence on Russia or more distant countries. Sweden is only importing a tiny fraction of Russian oil exports and can probably increase its share of Russian oil to compensate for the decline in North Sea imports. However, increased energy dependence on Russia will lead to more complicated national security situation for Sweden. Principally, Russia has been seen as a traditional security risk in Swedish security policy doctrines. Increased dependence on Russian oil is, therefore, a politically questionable solution to Sweden's future energy supply. The rapid decline of Danish hydrocarbon extraction brings a major change to Sweden and its import possibilities. This calls for responsible planning and development of sound mitigation strategies.

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