Socio-economic aspects of the agreement between A.P. Møller - Mærsk and the state regarding an extension of the Sole Concession for offshore areas in the North Sea

1. Introduction

In September, an agreement was made to extend A. P. Møller - Mærsk's Sole Concession for areas in the Danish sector of the North Sea, and the Danish government has subsequently introduced a motion to approve the agreement in Folketinget (the Danish Parliament), as well as Bills to amend the Hydrocarbon Tax Act and the Subsoil Act.

The Danish state has the right of ownership to Denmark's subsoil. The oil and gas accumulations in the Danish sector of the North Sea are scarce natural resources that are valuable in themselves. As in a number of other countries, the Danish state has chosen to license private companies to carry out oil and gas production activities, and thus benefit from the know-how and technology possessed by the companies. Licences are granted for a long term (typically 30 years), a reflection of the need for long-term investments in oil and gas production activities. The aim is to derive the greatest possible socio-economic benefit from the oil and gas resources in the North Sea. Thus, licence terms and tax rules are designed so that the companies have a financial interest in investing in exploration and technological development, without this leading to major distortions or depriving the state of an appropriate share.

Under the agreement concluded, the state will obtain a considerably larger share of the profit derived from utilization of the Sole Concession in the North Sea. As from 2004, the state will obtain a 20 per cent profit share/state participation, at the same time as an effective hydrocarbon tax scheme is introduced that reduces the investment allowance from 250 per cent to 30 per cent, thus substantially minimizing distortions. Moreover, the cost-effectiveness of production can be optimized by abolishing the field-based tax assessment and so-called gross taxes, such as royalty and the pipeline tariff. To this comes that the agreement (including the compensation provision) will eliminate the existing uncertainties with regard to North Sea activities, so that long-term investments and plans can be made, which is crucial to effective exploitation of the resources. In the Report on the North Sea from October 2003, a more detailed account is given of the individual elements of the agreement.

When evaluating the economy of the agreement from a socio-economic point of view, the following factors must be considered particularly important:

1. The agreement contributes to optimizing exploitation of the resources in the North Sea from a socio-economic point of view.
2. The revenue generated by the agreement for the state.
3. The agreement is robust (sensitivity analyses).
4. The profit from the activities in the North Sea will be distributed fairly between the state and the Concessionaires, considering that the subsoil belongs to the state (profitability analyses).

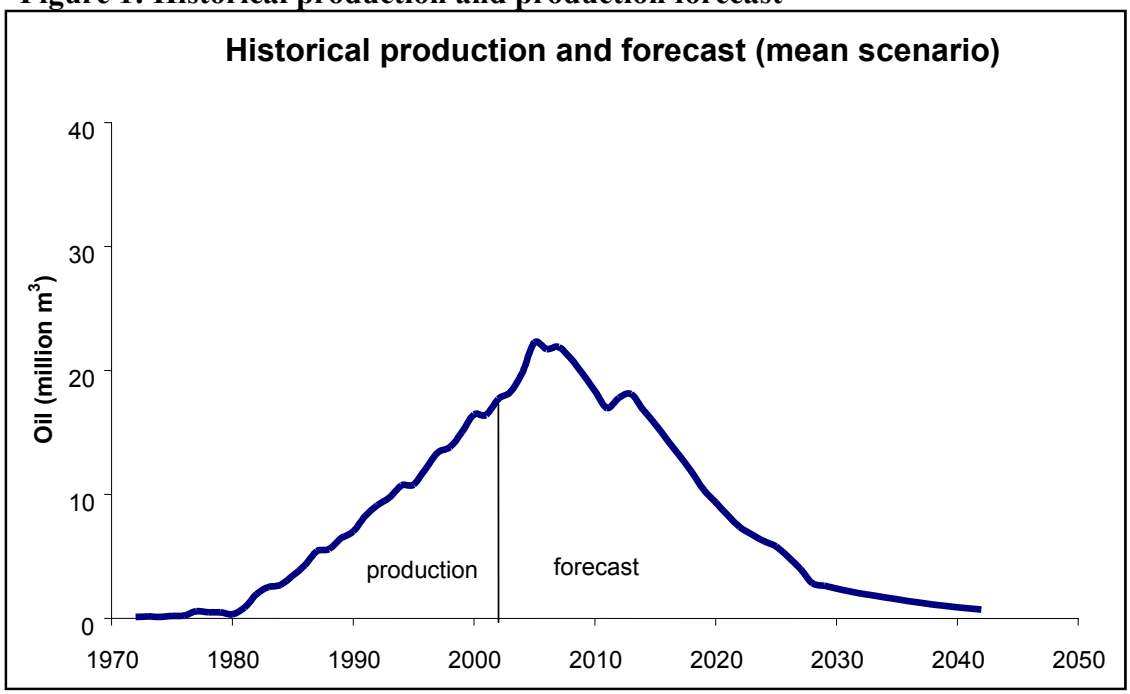
These factors are discussed in more detail below to give a comprehensive view of the agreement from a socio-economic point of view. At the same time, a summary is given of various information and calculations included in answers to questions posed in Folketinget.

2. Oil and gas production in the North Sea

When the search for oil and gas began in the 1960s, scant knowledge about the possibilities of discovering oil and gas in Denmark existed. The first oil discovery was made back in 1966, and oil production was initiated in 1972. However, it was not until the beginning of the 1980s that oil and gas production really got underway. Until then, the activities in the North Sea were relatively limited, both as regards production and investments. Since the beginning of the 1980s, oil production has undergone strong growth, one effect being that Denmark is self-sufficient in oil and gas today. Thus, the development in oil and gas production has far exceeded the expectations from the 1960s.

In the years ahead, production is expected to increase slightly compared to today, but after that, forecasts indicate that the deposits will gradually be depleted, resulting in declining production. By far the largest portion of the remaining resources in the North Sea is thus expected to be produced in the period until 2012 when the existing Sole Concession expires; see Figure 1 below.

Figure 1: Historical production and production forecast



Together with its partners in Dansk Undergrunds Consortium (DUC), A.P. Møller - Mærsk is in charge of the majority of activities in the Danish sector of the North Sea. In 2002, 82 per cent of Danish oil production, viz. 21.5 million m^3, derived from DUC. The corresponding figure for gas production was 7.3 billion m^3, equal to a 92 per cent share.

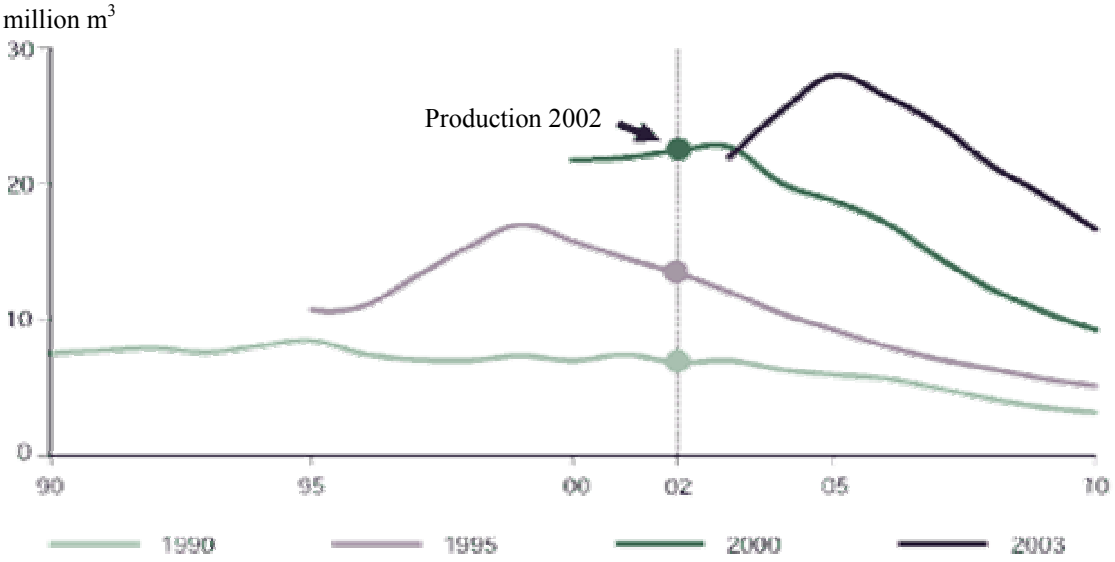
There are two main reasons why so vast resources are produced from the North Sea today: For one thing, investments have continuously been made in developing technology to make it possible to exploit a steadily increasing amount of the oil present in the subsoil. For another, capital has been invested in exploration, with new discoveries continually being made.

The majority of oil discoveries in Denmark to date have been made in very tight chalk layers. When production started from these formations, it was estimated that only very small amounts of oil could be extracted. For example, it was forecast 20 years ago that only about 6 per cent of the oil in the Dan field could be recovered. Since then, new production methods (water injection and horizontal wells) have been developed, which means that an ever increasing share of the oil-in-place can be extracted from the fields today. Therefore, current estimates suggest that more than 26 per cent of the oil-in-place in the Dan field can be recovered.

One method to illustrate the importance of technological development and continuous oil and gas exploration efforts is to compare the production estimates made in the forecasts from 1990, 1995 and 2000 with actual production figures for the relevant years.

The forecast from 1990 estimated 2002 oil production at 6.8 million m^3. The production recorded in 2002 was 21.5 million m^3. Thus, actual production more than tripled the production figure estimated in 1990. The forecast from 1995 estimated the production for 2002 at 13.2 million m^3, i.e. about two-thirds of the actual production recorded in 2002; see Figure 2 below.

Figure 2. Forecasts for the period 1990-2010



2.1 Future oil and gas production

To secure the greatest possible socio-economic benefit from the resources in the North Sea, it is essential to continue improving technology in order to extract increasing volumes of the remaining oil-in-place. Likewise, it is crucial to carry on exploration activity so that new discoveries will continue to be made. Moreover, in step with individual fields being depleted, it is also important to consider how marginal oil reserves are exploited, i.e. whether production continues until the last drop or whether it is discontinued before that.

Naturally, numerous factors determine how technological development, exploration and the exploitation of marginal fields will progress in future. Some of the determining factors are technological advances, oil prices and the dollar exchange rate.

A crucial element is that the agreement will provide a stable framework that eliminates insecurity about the future situation in the North Sea. This is of major importance to the investment climate for North Sea activities, because these investments are very long-term in nature.

Conversely, if no guarantees are given for A.P. Møller - Mærsk's continuation of activities after 2012, it is estimated that the DUC companies will attempt to optimize their short-term proceeds in the period until the Sole Concession expires. In all likelihood, this will mean that DUC will invest less in developing drilling technology, as the investment will have a shorter term to yield a return. Likewise, it must be expected that the relatively cost-intensive investments in new exploration will be minimized, as there will scarcely be time to exploit any new discoveries prior to 2012. Finally, it can be expected that less profitable fields, in which production is upheld today based on expectations for future earnings, will be closed down sooner. A probable consequence is that the remaining oil-in-place in such fields can only be exploited to a limited extent at a later date, because the investments required for resuming production will not be profitable.

The fact alone that the agreement has removed insecurity about the future is thus estimated to have a favourable effect on the future exploration and investment level, and thus on the size of profits.

To this comes that the agreement contains a number of incentives to exploit the remaining resources effectively. Thus, field-based tax assessment will be abolished. This means that income is no longer to be determined separately for each individual field. Instead, an overall calculation of income is to be made for all fields, with total income and expenses being pooled for all fields.

The current tax system means that hydrocarbon tax allowances for marginal fields cannot be transferred to other fields before production from the relevant field is discontinued. All other things being equal, this may prompt an operator to close down a disappointing field prematurely (i.e. before break-even) in order to utilize the allowances by transferring them to other fields that yield a high profit. Moreover, royalty will be abolished, and the pipeline tariff of 5 per cent of the production value will be offset against hydrocarbon taxes until 2012, from which time it will be abolished.

The pipeline tariff is a tax on gross production without any deduction for costs. Royalty and the pipeline tariff have the same effect as costs associated with production and thus also provide an incentive to discontinue production earlier than considered sound from a socio-economic point of view.

Therefore, the state will obtain its future revenue from the following three sources mainly: Profit sharing/state participation, ordinary corporate taxation and hydrocarbon taxation, which is a special form of profit taxation targeted at oil and gas production activities in the North Sea. This means that the state will collect a very large share of its revenue without distorting production and investment decisions.

To serve as a basis for the agreement, analyses were made to show how production will develop in a scenario with an agreement and in a scenario without an agreement. The most important assumptions underlying the analyses are outlined in Box 1 below.

Box 1: Calculation assumptions

Oil price

In all calculations, oil price forecasts are based on projections made by the International Energy Agency, i.e. an oil price of USD 22.355 per barrel today, gradually increasing to USD 36 per barrel in 2042.

Dollar exchange rate

In all calculations, a dollar exchange rate based on the medium-term projections made by the Danish Ministry of Finance has been used, i.e. a dollar exchange rate of DKK 6.95 per USD.

Reserves

The same oil reserves estimates have been used in all the calculations. They are based on the assessment of reserves made by the Danish Energy Authority.

Extension of Sole Concession

In the scenario with an agreement, it is assumed that the term of the Sole Concession will be extended from 2012 until 2042. In the scenario without an agreement, it is assumed that applications for licences will be invited in 2012.

Tax rules

In the scenario with an agreement, it is assumed that the tax rules set out in the agreement will apply, including a reduction of the hydrocarbon tax allowance from 250 per cent to 30 per cent. In addition, the transitional rules laid down in the agreement are assumed to apply, according to which investments already made can be deducted at the rate of 10 per cent per year for up to ten years from the investment was made. In the scenario without an agreement, it is assumed that the present tax rules will apply unchanged until 2042.

State participation

In the scenario with an agreement, it is assumed that the state will receive a 20 per cent profit share until 2012, after which the state will become a partner with a 20 per cent share. In the scenario without an agreement, state participation from 2012 is assumed.

Gross taxes

In the scenario with an agreement, it is assumed that royalty will be abolished from 2004 and that the pipeline tariff will be offset against hydrocarbon tax until 2012, after which it will abolished. In the scenario without an agreement, it is assumed that royalty will be upheld.

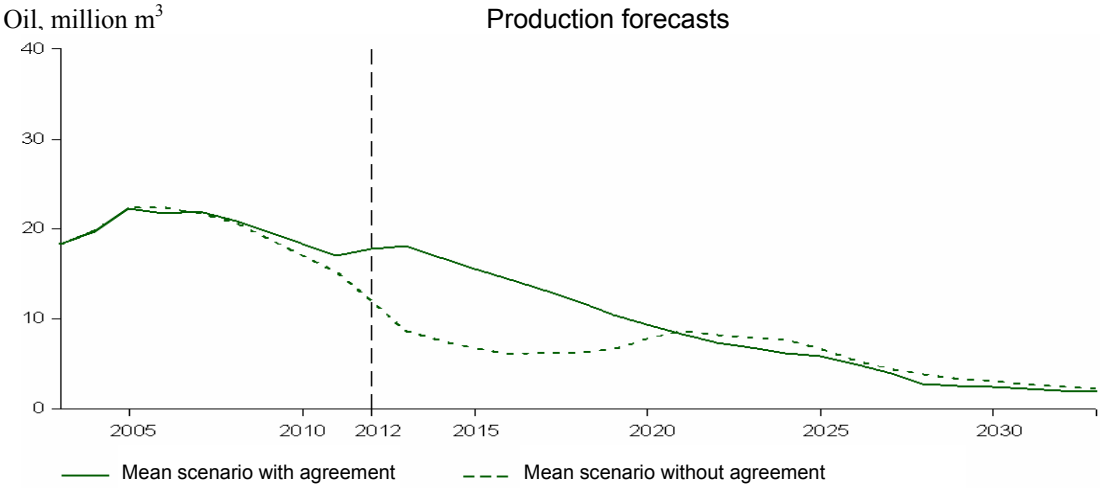
Production, investments and costs

In the scenario with an agreement, a production projection based on empirical data, experience from A.P. Møller - Mærsk's existing fields and other fields not comprised by the Sole Concession has been used to estimate investments and operating costs. In the production scenario without an agreement, the most important difference is that investments will decrease before and after 2012, resulting in insufficient exploration and technological development.

In the scenario with an agreement, it is estimated that the recovery factor will increase by 5 percentage points over the whole period, equal to an annual increase of 0.7 per cent. Moreover, it is projected that production from a new medium-sized discovery will be initiated around 2012. Overall, production is estimated to increase by about 1.2 per cent per year. By comparison, during the period from 1990 to 2003 the combined oil production from specific fields comprised by the Sole Concession increased by an average of 4 per cent per year relative to the oil production forecasts made for these fields in 1990.

In the scenario without an agreement, it is assumed that the lower investment level, particularly around 2012, will slow down technological development to a certain extent, corresponding to an increase in production of 0.5 per cent per year or 3 percentage points over the whole period, combined with an estimated delay in the discovery of a new accumulation; see Figure 3 below.

Figure 3. Estimated oil and gas production with and without an agreement for the period 2004-2012



1) Apart from the estimated production scenario, the various projections are also based on estimated investments and costs. A total outline of investments, production, costs, etc. is enclosed as an appendix.

2) The calculations are based on an oil price of USD 22.355 per barrel in 2004-2010, gradually increasing to USD 36 per barrel in 2042 (2003 prices) and a dollar exchange rate of DKK 6.95 per USD. At the beginning of October 2003, the oil price slightly exceeded USD 27 per barrel.

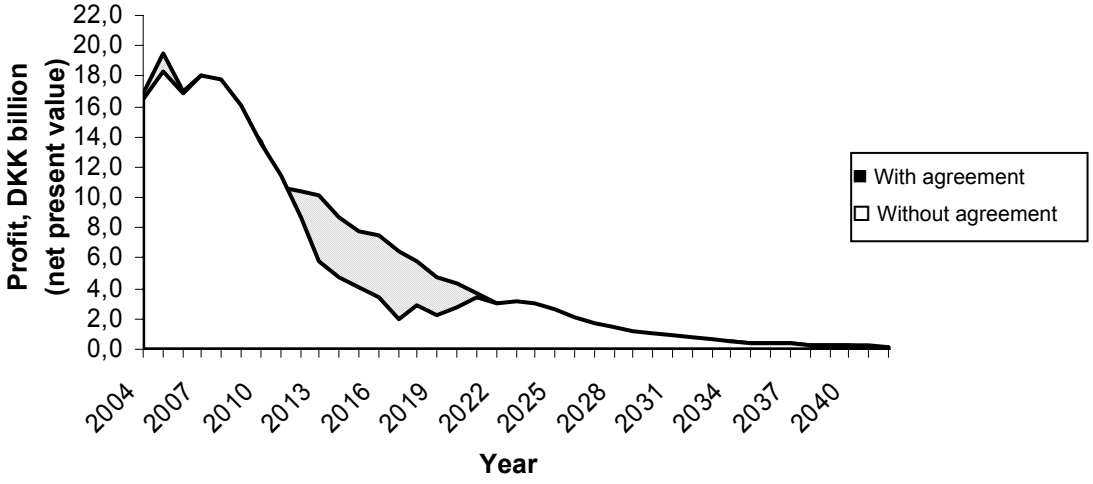
The production projections appearing from the figure indicate the state's mean scenario. The enclosed appendix also shows a high and a low production scenario, based on different assumptions with regard to technological development and the size of new discoveries. For each of these production scenarios, calculations have been made of developments in production with and without an agreement.

2.2 Socio-economic value of concluding an agreement

Based on the production figures shown above in the scenarios with and without an agreement, calculations have been made of the annual profits deriving from oil production under the Sole Concession that are to be distributed between the state and DUC; see Figure 4. The difference in profit between the scenario with an agreement and without an agreement is illustrated by the hatched area between the two curves and amounts to a total of DKK 27 billion (net present value) over the whole period from 2004 to 2042. Ac-

cordingly, the agreement will yield a socio-economic gain of this magnitude due to increased production.

Figure 4: Total annual profits to be distributed between DUC and the state during the period 2004-2042, with and without an agreement



Thus, when assessing the significance of an agreement, it does not suffice to focus merely on how large a profit share the state will receive from production in the North Sea. It is also important to assess whether the agreement contributes to effective exploitation of the oil and gas accumulations in the North Sea. A high profit share for the state, say 70 per cent, will not result in larger state revenues if it leads to a lower investment and production level, and thus less Danish kroner for the state.

3. The state's profit share

With the agreement and based on the mean production scenario, the state will receive, until 2042, an average share of just over 60 per cent of profits from the oil and gas produced under the Sole Concession. Historically, the state share has fluctuated quite considerably, but has averaged about 47 per cent. In recent years, however, it has been down to a mere approx. 40 per cent. Thus compared to the historical share, the tax regime will be tightened considerably.

Although comparison with the historical distribution of the profit may give an idea of the tightening that will follow from the agreement, it would be more realistic to make the comparison with the profit distribution that would result from continuing with the present rules. This is not an easy task, however. The most difficult problem is estimating revenues from the hydrocarbon tax. History shows that hydrocarbon taxation has little or no effect. The companies have been liable to hydrocarbon tax only in rare years, and state revenues from hydrocarbon tax since its introduction in 1982 total less than DKK 1 billion.

For this and other reasons, the Hydrocarbon Tax Committee estimated, in an appendix to its report from 2001, that the DUC companies would only have to pay hydrocarbon tax at an oil price of USD 30 per barrel. In a calculation example, the Committee found the

state share of the profit over the period 2000-2012 to be 36 per cent with the present rules and the above-mentioned price level.

The production forecasts shown above include investments based solely on technical engineering calculations. For example, no allowance is made for the optimum solution from a corporate economy point of view, in light of a 250 per cent hydrocarbon allowance. Hydrocarbon tax payments are thus estimated to total DKK 25 billion. But it is very uncertain that revenues of that magnitude will accrue from hydrocarbon tax. Thus, one of the conclusions made in a memorandum dated 25 October 2000 from the Danish Ministry of Taxation is that "this will provide an incentive for financially rational companies to make sufficiently large investments to ensure that, no matter how high the oil price and how large their oil discoveries, only a situation of exceptionally favourable conditions can make them briefly liable to hydrocarbon tax".

Assuming full hydrocarbon tax payments in the period ahead, the state share will average 45 per cent under the present rules up to 2012 and about 53 per cent over the entire period 2004-2042. Depending on the assumptions with regard to future hydrocarbon tax payments, the anticipated state share of the profit with the present rules will thus fluctuate between 36 per cent and 53 per cent.

Provided that the companies will be liable to full hydrocarbon tax in future, the anticipated added state revenue with the agreement compared with the present rules will be DKK 31 billion in net present value terms over the entire period; see Table 1.

Table 1: Comparison between revenue with the present rules and with the agreement

DKK billion, net present value 2004-2042	**Present rules[1)]**	**Agreement**
Profit share / state participation	11.2	42.5
Oil pipeline tariff.....	10.1	6.9
Royalty	14.2	0.0
Corporate tax	42.1	49.4
Hydrocarbon tax	24.8	34.6
Total	**102.4**	**133.4**

Note: The figures indicating the hydrocarbon tax under the agreement are after set-off of the oil pipeline tariff.

1) Including change of operator, introduction of 20 per cent state participation and abolishment of royalty payments in 2012. The present tax system is assumed to be upheld throughout the period.

In light of the uncertainties associated with the hydrocarbon tax, the table below shows a comparison between state revenues under the agreement and under the present rules, based on different assumptions with regard to future hydrocarbon tax payments. As it appears from the table, the additional state revenue is expected to be at least DKK 31 billion with the agreement.

Table 2: Comparison between state revenue with the agreement and with the present rules, based on different assumptions with regard to hydrocarbon tax payments

	DKK billion net present value 2004-2042
Agreement	133
Agreement without socio-economic benefit (increased production)	112
Present rules with full hydrocarbon tax payments (DKK 25 billion)	102
Present rules, but without hydrocarbon tax payments	77

Note: In order to avoid hydrocarbon tax liability, the companies will have to make investments that reduce their profit. No allowance is made for such investments in the calculations, and the DKK 56 billion can therefore not be taken as an expression of the maximum additional revenue that will be generated with the agreement as against under the present rules.

The present rules and the agreement may also be compared on a historical basis, i.e. by assuming that the agreement had been entered into in 2001 and comparing the revenues actually received by the state in the period 2001-2003 with those that would have been generated under the agreement, using historical figures for production, investments, etc. Such calculations show that the state would have received DKK 7.3 billion more with the agreement between 2001 and 2003 than it actually received over the same period, which, on an annual basis, is close to the additional revenue that the agreement is expected to create in future; see the report submitted to Folketinget.

3.1 Comparison with other tax models

In addition to a comparison with the present rules, the agreement has also been compared with the so-called neutral tax model proposed by the Hydrocarbon Tax Committee for *new* licences. The idea of this proposal is to abolish the hydrocarbon allowance and replace it with an allowance for return on equity, and to allow tax losses to be carried forward with interest, sold, and their tax value to be disbursed eventually. The Hydrocarbon Tax Committee further recommended eliminating royalty and the oil pipeline tariff by offsetting such payments against the hydrocarbon tax and abolishing field-based tax assessment to increase the incentives to exploit marginal fields.

The agreement between the Danish government and A.P. Møller - Mærsk entails a substantial reduction of the hydrocarbon allowance (from 250 per cent to 30 per cent). Furthermore, it abolishes royalty, the oil pipeline tariff and field-based tax assessment. So, the agreement does not differ significantly from the recommendations in the Hydrocarbon Tax Committee's report. The most important difference is that the agreement provides for the government to share in the profit from the existing Concession already from 2004. The enclosed appendices contain a more detailed comparison between the Hydrocarbon Tax Committee's recommendations and the agreement.

The Hydrocarbon Tax Committee took no position on the tax rate issue. It appeared from the Committee's report that the tax rate is a political decision. A comparison between the neutral tax model and the agreement must therefore be based on an assumed tax rate.

The Hydrocarbon Tax Committee did not consider transitional rules either, since its recommendations applied to new licences only. This means that it did not deal with how a

new tax regime was to treat earlier investments made for tax purposes. The background for introducing transitional rules is that previous investments were made in reliance on the present tax rules. Moreover, accumulated losses can only be eliminated by agreement between the parties involved.

Furthermore, the Hydrocarbon Tax Committee did not take a stand on profit sharing/state participation under the existing Concession/licences, since all its calculations related to new licences only. To allow comparison between the neutral tax model and the agreement, two different calculations were therefore made, based on different assumptions with regard to tax rate and state participation. In both, the interest rate for the allowance for normal return on equity is set at 3 per cent.

The first calculation uses the tax rate (52 per cent) and the transitional rules provided for in the agreement and assumes state participation from 2012. It is also based on the production scenario expected to follow from the agreement. The calculation shows that, compared with a neutral tax model, the agreement will generate an extra DKK 3 billion state revenue in net present value terms for the entire period 2004-2042.

The second calculation is based on a 70 per cent tax rate and the same transitional rules as in the agreement, but it assumes no state participation and uses the same production scenario as without the agreement. It would hardly be possible to introduce a neutral tax system involving 70 per cent hydrocarbon tax through an agreement. The production scenario without an agreement therefore seems more realistic. With a hydrocarbon tax rate of 70 per cent it would be difficult also to demand 20 per cent state participation in connection with a change of operator in 2012. A total tax load of this magnitude would probably make it difficult to attract operators.

Overall, the calculations show that the neutral tax model would provide lower revenues in net present value terms over the entire period than the agreement concluded; see Table 3.

Table 3. State revenue for the period 2004-42 with the agreement and with neutral taxation in DKK billion net present value (2003), and a 52 per cent tax rate.

	State revenue 2004-2042, DKK billion net present value
Agreement	133
Neutral tax (52 per cent), with state participation after 2012 with the production scenario assumed under the agreement	130
Neutral tax (70 per cent), without state participation, with a production scenario without an agreement	122

It is not known whether other countries have used a neutral tax regime in their oil industry. Norway has considered a neutral tax model, but without adopting it. It is therefore an unproven regime, and there is no experience with its effects and administration. Furthermore, a neutral tax model like the one proposed by the Hydrocarbon Tax Committee is not consistent with EU rules on state aid. In contrast, the existing hydrocarbon tax model is known and proven. This factor should, of course, also be taking into consideration when evaluating whether the neutral tax model is preferable to the agreement.

4. Sensitivity analyses

The agreement aims to ensure that the state derives a higher and more stable share of the profit from the North Sea resources. A number of sensitivity calculations have therefore been carried out, based on different assumptions as to oil price, dollar exchange rate and production; see Table 4 below.

The agreement is designed such that the effective tax rate decreases if production decreases. Conversely, the effective tax rate increases with increasing income from North Sea activities. This is to provide an incentive to continue production, even if recoverable oil reserves should turn out to be smaller than expected, or oil prices should fall dramatically.

The lowest state share shown in the sensitivity calculations is an average of 56 per cent over the entire period at an oil price 20 per cent below the level assumed in the calculations. Conversely, the state share increases to 63 per cent if the oil price increases by 20 per cent.

Table 4. Sensitivity calculations for state revenue (state share shown in brackets)

DKK billion	2004	2005	2006	2007	2008	Annual average 2004-2012	2004-2012	2013-2042	2004-2042
	---------- DKK billion 2003 prices ----------						DKK billion net present value		
1. Agreement based on state's mean scenario*)	**9.8**	**11.9**	**11.4**	**11.9**	**11.8**	**10.6 (57%)**	**80 (57%)**	**54 (66%)**	**133 (61%)**
Sensitivities to changed production									
2. As 1, but low production scenario	9.8	11.9	11.5	11.3	10.6	9.6 (56%)	73 (56%)	25 (65%)	98 (58%)
3. As 1, but high production scenario	9.8	11.9	11.2	11.9	11.6	11.4 (58%)	85 (58%)	80 (67%)	165 (62%)
Sensitivities to oil prices									
4. As 1, but oil price minus 20% (2004-10: 17.9 USD/barrel)	6.2	7.9	7.5	8.0	8.0	7.1 (52%)	53 (52%)	40 (64%)	93 (56%)
5. As 1, but oil price minus 10% (2004-10: 20.1 USD/barrel)	8.0	9.9	9.5	9.9	9.9	8.9 (55%)	66 (55%)	47 (65%)	113 (59%)
6. As 1, but oil price plus 10% (2004-10: 24.6 USD/barrel)	11.6	13.9	13.4	13.9	13.7	12.4 (59%)	93 (59%)	61 (67%)	154 (62%)
7. As 1, but oil price plus 20% (2004-10: 26.8 USD/barrel)	13.4	15.8	15.3	15.8	15.6	14.1 (61%)	106 (61%)	68 (67%)	174 (63%)
8. As 1, but oil price of USD 50/barrel in 2004-10 (from then onwards gradually increasing)	31.9	36.5	35.5	36.2	35.3	32.5 (67%)	244 (67%)	140 (70%)	384 (68%)
9. As 1, but oil price of USD 100/barrel in 2004-10 (from then onwards gradually increasing)	71.9	80.9	79.1	80.1	77.7	71.9 (70%)	541 (70%)	297 (72%)	838 (71%)

Note: A 10 per cent change in the dollar exchange rate will have the same effect on state revenues as a 10 per cent change in the oil price. A 10 per cent higher dollar exchange rate corresponds to a dollar exchange rate of 7.65 (instead of 6.95). Historically, the oil price has experienced far larger relative fluctuations than the dollar exchange rate.

*) Mean state assumptions, including an oil price of: 22.355 USD/barrel in 2004-10, gradually increasing from then onwards to USD 36/barrel in 2042 (2003 prices); a dollar exchange rate of 6.95; mean production scenario. At the beginning of October 2003, the oil price exceeded 27 USD/barrel.

5. Does the state get a sufficient share of the profit?

Oil and gas production generates a profit that consists of normal profit and supernormal profit – the economic rent. Various models have been designed for the most appropriate tax treatment of the economic rent. They include state participation, state outsourcing and hydrocarbon tax. The countries producing oil in the North Sea have chosen different models. Like most other countries, Denmark has opted for a "hybrid model" where state revenues are captured using instruments that target the economic rent directly (hydrocarbon tax, state participation, royalty) and supplement the instruments for targeting the remuneration of capital in general, i.e. corporate tax.

With the agreement, the state will continue to collect revenue using a variety of instruments, some of which are intended for taxing capital and others designed specifically to

tax the economic rent. However, the situation has changed significantly as compared to before the agreement, since the state collects a far larger proportion of the revenue using instruments targeted directly at the economic rent, for example, through state participation and effective hydrocarbon taxation.

With the agreement, consensus has also been reached that the economic rent must be distributed in future with a considerably larger share accruing to the state. On the other hand, it is also obvious that the DUC companies are entitled to normal remuneration, including a risk premium, of their capital investments in the North Sea.

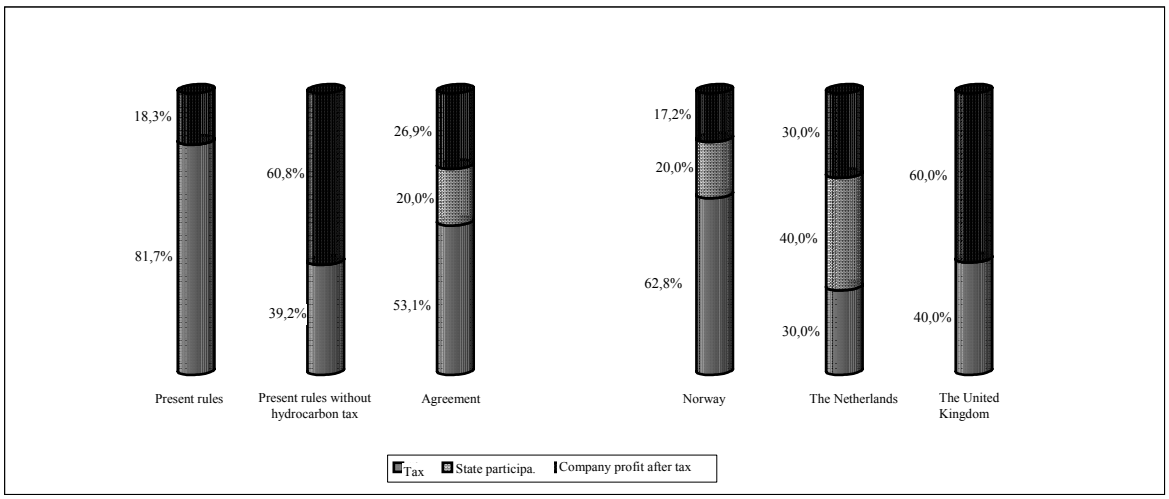
Whether the state share is sufficiently large is a matter of political judgement. As a basis for such judgement, it might be relevant to illustrate, on the one hand, A.P. Møller - Mærsk's profitability under the agreement, and on the other hand, to view the agreement in an international perspective. It should be emphasized, however, that evaluating the company's profitability is associated with major uncertainties.

5.1 The situation in the other North Sea countries

Under the present rules, the Sole Concessionaires are subject to an overall marginal tax rate (the aggregate rate of state taxes and fees, etc., payable out of each extra Danish krone earned) of nearly 82 per cent when in hydrocarbon tax position, as opposed to an aggregate marginal tax rate of about 39 per cent when not.

The agreement provides for an overall marginal tax rate of about 73 per cent, including the state's profit share, when hydrocarbon tax becomes payable. At the international level, this compares with an overall marginal tax rate in Norway of just under 83 per cent, about 70 per cent in the Netherlands and about 40 per cent in the United Kingdom; see the figure below.

Figure 5. Marginal tax rate applying to DUC under the present rules and under the agreement, as well as in other North Sea countries



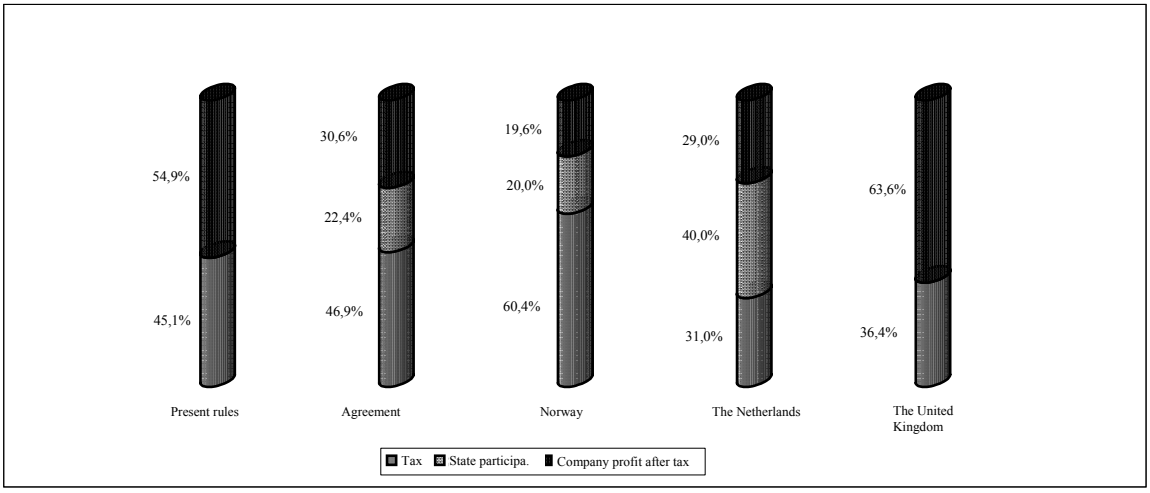
Note. The state participation share also includes tax paid by the state-owned company to the state. In Norway, the rate of state participation varies with each licensing round. The calculation therefore assumes 20 per cent state participation.

In cases where no hydrocarbon tax is payable, the overall Danish marginal tax rate under the present rules is comparable to the overall UK marginal tax rate and considerably lower than the rates in both Norway and the Netherlands.

With the agreement, the overall marginal tax rate is somewhat below the Norwegian level, at the same level as the Dutch and considerably above the UK level.

But the marginal tax rate does not say anything about the actual tax load. The average tax rate is a far better indicator. It illustrates the relationship of taxes paid to income earned. Model calculations show that, once the transitional rules have been phased out, the average tax rate for model fields in Denmark will change from about 45 per cent under the present rules to about 70 per cent under the agreement. This tax level is the same as in the Netherlands, i.e. about 70 per cent, and just below the level in Norway where the average tax rate is about 80 per cent. Again, British rates are considerably lower, the average rate being only about 36 per cent; see the figure below.

Figure 6. Model field calculation of the average tax rate applying to DUC under the present rules and under the agreement, as well as in other North Sea countries



Note. The model fields reflect anticipated future discoveries in Danish territory.

Thus, compared to the other countries operating in the North Sea, the agreement seems to bring the Danish tax rate to the same level as the Dutch, but slightly below the Norwegian level. In this connection, it is important to remember that the Norwegian fields are typically larger, and that the cost of recovering the oil is lower. It is therefore natural that Norway should be able to maintain a slightly higher tax rate.

5.2 The profitability of North Sea operations

Calculating profitability on North Sea operations is difficult and associated with major uncertainties. Analyses made for the period 1962-2003 show a nominal rate of return between 17 per cent and 18 per cent, depending on the assumptions concerning the value of DUC's assets at end-2003. In real terms (i.e. adjusted for inflation), the return was about 11 per cent and the so-called risk premium about 6 per cent. The risk premium is a measure of the added return on a given activity that exceeds the return obtainable on a safe investment, such as government bonds.

However, looking at the return for the entire period 1962-2003 does not give a true picture. Thus, the first 20 years were characterized by very low levels of production and investment. Furthermore, the tax regime applying to North Sea activities during the first 20 years was considerably different, since hydrocarbon tax was not introduced until 1982. A comparison between historical and future rates of return must therefore be based on a period with a reasonably comparable production scenario and tax system. The period 1982-2003 therefore seems an obvious choice; see Figure 1 above.

Between 1982 and 2003, the nominal return was between 18 and 19 per cent, the real return between 15 per cent and 16 per cent, while the risk premium has been calculated at about 8 per cent.

Profitability calculations must be based on various assumptions regarding the value of DUC's assets – the so-called terminal value, i.e. the value of equipment, know-how, etc., that form the basis for North Sea production. The assumed value of DUC's assets is a highly important parameter in calculating the anticipated future return from the North Sea activities. At end-2003, it is expected that DUC's asset mass will be booked at about DKK 30 billion, and that its investments will total about DKK 80 billion (2003 prices).

The financial statements prepared by the DUC companies do not include all investment outlays for research, exploration and development. Nor do they include the value of know-how developed, for example, on horizontal wells and the technological advances made in this connection. Add to this that, naturally, the value of the assets should be judged in the perspective of the potential future income they may generate.

On the other hand, it is also obvious that the value of the assets hardly equals the overall value of the investment input. Some of these investments are of an earlier date, and are unlikely to have the same value today. The value of the assets will therefore be more than DKK 30 billion, but less than DKK 80 billion. Based on the information provided in financial statements etc., the best estimate of the terminal value of the assets is about DKK 60 billion. Based on this estimate, the anticipated nominal return for the period 2004-2042 will be 11 per cent to 12 per cent and the real return between 9 per cent and 10 per cent – considerably less than over the period 1982-2003; see Table 5.

In estimating the future risk premium, a number of uncertainties other than those relating to the terminal value are associated with determining the risk-free interest rate. Historically, the risk-free interest rate varied between 5 per cent and 20 per cent in the period 1962-2003. There is thus a certain probability that the risk-free interest rate will continue to vary considerably also in future.

According to economic projections, however, the risk-free interest rate is expected to stay at an average of about 5 per cent throughout the period 2004-2042. Taking this as a point of departure, the future risk premium may be estimated at just under 7 per cent, i.e. lower than the risk premium accruing to the DUC companies between 1982 and 2003, during which period oil production really got underway. This is an appreciable reduction, also compared with the risk premium obtainable without an agreement, which is assumed to be about 9 per cent for the period 2004-2042.

Table 5. Rates of return and risk premiums for DUC 1962-1981, 1982-2003 and 2004-2042.

Period	Return (nominal)	Average Inflation	Return (real)	Risk premium
	---------- per cent ----------			
1962-1981	16-17	8	5-6	Approx. 3
1982-2003	18-19	3	15-16	Approx. 8
2004-2042	11-12	2	9-10	Approx. 7
2004-2042 (without agreement)	*12-13*	*2*	*10-11*	Approx. *9*

Note: The anticipated return for 2004-2042 without an agreement is based on a scenario where DUC is assumed to continue under the present terms up to 2012 and subsequently, after applications for licences have been invited**,** continue up to 2042 under the terms applying to all other licences. The calculations are based on a terminal value at end-2003 of DKK 60 billion. Anticipated returns and risk premiums for 2004-2042 will typically fall by 0.2-0.3 percentage point, ignoring cash flows occurring after 2025. Due to the discounting method used, there is no simple relationship between nominal return, inflation and real return in the period 1962-1981.

It is difficult to determine whether a risk premium of 7 per cent will meet general expectations in the oil industry. Thus, risk premiums vary considerably from company to company and also reflect the conditions under which the oil is produced. For example, if the oil is difficult to extract, the risk premium will be higher. Moreover, the future risk premium is based on the assumption that DUC will make a new discovery and ensure efficient technology development. However, it is estimated that a 7 per cent risk premium will be within the oil industry's expectations for the future, provided that production conditions remain unchanged.

DONG A/S has explained that in cases where DONG has purchased or made an offer to purchase oil fields or recommended increasing one of its existing shares, the company has used an evaluation criterion of 10 per cent real return after tax (nominally about 12.2 per cent) to determine whether such purchase or increase was commercially interesting. Assuming an average risk-free interest rate of just under 5 per cent for the period 2004-2042, it may therefore be concluded that DONG will, implicitly, demand a risk premium of at least 7 per cent for the period 2004-2042.

Conclusion

With the agreement, the government aims to strike a balance between, on the one hand, securing a reasonable profit share for the state and, on the other hand, maintaining profitability for the companies that carry out exploration and production in the North Sea, in order to ensure the industry's continued interest in investing in exploration, technology development and production. The agreement therefore aims to:

- Utilize the remaining North Sea resources more efficiently, in order to contribute to an increased socio-economic return on investments in the North Sea
- Raise a considerably larger state revenue than possible under either the present rules or alternative tax models
- Create a robust solution with a far more stable tax base
- Ensure that the future return on the North Sea activities is consistent with general industry expectations.

Appendices

Appendix 1A.

Oil Production, million m^3, 2004-2042

Year	With agreement			Without agreement		
	Low scenario	Mean scenario	High scenario	Low scenario	Mean scenario	High scenario
2004	20	20	20	20	20	20
2005	22	22	22	22	22	22
2006	22	22	22	22	22	22
2007	21	22	22	22	22	22
2008	19	21	21	21	21	21
2009	17	20	21	19	19	19
2010	15	18	22	17	17	17
2011	13	17	22	15	15	15
2012	12	18	22	11	12	12
2013	10	18	21	8	9	9
2014	9	17	21	6	8	8
2015	8	16	22	5	7	7
2016	7	14	20	4	6	6
2017	6	13	20	4	6	6
2018	5	12	19	4	6	8
2019	4	10	17	4	7	10
2020	4	9	16	3	8	10
2021	3	8	14	3	9	10
2022	3	7	13	2	8	11
2023	3	7	12	2	8	12
2024	2	6	11	2	8	12
2025	2	6	10	2	7	11
2026	1	5	9	1	6	10
2027	1	4	8	1	4	9
2028	1	3	7	1	4	8
2029	1	3	6	1	3	7
2030	1	2	5	1	3	6
2031	1	2	4	0	3	6
2032	1	2	4	0	2	5
2033	1	2	4	0	2	5
2034	0	2	3	0	1	4
2035	0	2	3	0	1	3
2036	0	1	3	0	1	3
2037	0	1	2	0	1	3
2038	0	1	2	0	1	3
2039	0	1	2	0	1	2
2040	0	1	2	0	1	2
2041	0	1	2	0	1	2
2042	0	1	1	0	1	2

Appendix 1B.

Investments, DKK million, 2003 prices, 2004-2042

	With agreement			Without agreement		
Year	Low scenario	Mean scenario	High scenario	Low scenario	Mean scenario	High scenario
2004	4260	4260	4260	4760	4760	4760
2005	3506	3506	3506	4756	4756	4756
2006	4633	4883	4883	5633	5633	5633
2007	2653	2903	2903	2903	2903	2903
2008	2000	2250	3600	1500	1500	1500
2009	1000	1500	2500	250	250	250
2010	500	1000	1250	0	0	0
2011	250	2600	1500	0	0	0
2012	0	1750	1500	0	0	0
2013	0	2000	3850	0	125	125
2014	0	2000	3750	0	125	125
2015	0	2000	3000	0	125	125
2016	0	1000	3000	0	250	250
2017	0	1000	3000	0	250	1600
2018	0	500	2500	0	500	1375
2019	0	500	1500	0	1850	625
2020	0	250	1250	0	1750	1125
2021	0	250	750	0	1000	2600
2022	0	250	750	0	1000	2000
2023	0	0	250	0	500	1000
2024	0	0	250	0	500	1000
2025	0	0	250	0	250	1250
2026	0	0	0	0	250	1250
2027	0	0	0	0	125	1125
2028	0	0	0	0	125	625
2029	0	0	0	0	125	625
2030	0	0	0	0	0	250
2031	0	0	0	0	0	250
2032	0	0	0	0	0	125
2033	0	0	0	0	0	125
2034	0	0	0	0	0	125
2035	0	0	0	0	0	0
2036	0	0	0	0	0	0
2037	0	0	0	0	0	0
2038	0	0	0	0	0	0
2039	0	0	0	0	0	0
2040	0	0	0	0	0	0
2041	0	0	0	0	0	0
2042	0	0	0	0	0	0

Appendix 1C.

Operating costs, DKK per m^3*, 2003 prices

Year	With agreement			Without agreement		
	Low scenario	Mean scenario	High scenario	Low scenario	Mean scenario	High scenario
2004	97	97	97	98	98	98
2005	101	101	101	104	104	104
2006	110	110	110	113	113	113
2007	115	114	114	117	117	117
2008	121	119	121	121	121	121
2009	131	130	132	130	130	130
2010	145	144	144	143	143	143
2011	164	166	163	161	161	161
2012	191	194	191	191	190	190
2013	188	192	193	172	173	173
2014	186	194	196	174	175	175
2015	188	200	201	180	181	181
2016	192	206	209	187	189	189
2017	196	212	215	193	196	202
2018	201	218	222	199	205	211
2019	213	230	235	212	223	221
2020	229	244	250	229	243	240
2021	251	265	272	251	265	267
2022	282	294	300	282	298	298
2023	283	291	297	283	297	297
2024	284	291	296	284	298	298
2025	290	294	300	290	303	305
2026	297	300	304	297	310	312
2027	303	305	308	303	318	319
2028	310	311	313	310	321	325
2029	322	323	325	322	333	338
2030	339	339	341	339	346	353
2031	362	362	363	362	366	373
2032	392	392	393	392	397	402
2033	393	393	393	393	396	401
2034	394	394	395	394	398	402
2035	400	400	400	400	403	407
2036	407	407	407	407	408	411
2037	413	413	413	413	413	416
2038	420	420	420	420	420	421
2039	432	432	432	432	432	434
2040	449	449	449	449	449	450
2041	472	472	472	472	472	472
2042	502	502	502	502	502	502

*) including financial costs. When multiplying unit costs by the gas volumes produced (which are stated in '000 m^3), such gas volumes must be divided by 1,000.

Appendix 2:

How closely does the agreement follow the Hydrocarbon Tax Committee's recommendations?

The Hydrocarbon Tax Committee's terms of reference were to submit proposals for updating the Danish hydrocarbon tax system to minimize its distorting effects.

In 2001, the Hydrocarbon Tax Committee recommended a neutral tax regime. The Committee submitted a framework model for new licences, but the Committee's report does not contain any proposal that is directly applicable to the existing Concession/licences. In order to use the framework model for the existing Concession/licences, a number of specific problems would have to be solved.

Firstly, appropriate transitional schemes would have to be worked out to ensure that existing rights, such as the right to utilize accumulated, but still unused tax allowances, would not be affected in a way that would conflict with other considerations, for example, the Danish Constitution.

Secondly, the hydrocarbon tax rate would have to be fixed at a level bearing a reasonable relation to the extension of the tax base. The Hydrocarbon Tax Committee explicitly refrained from taking a position on this political issue. The Committee's calculation examples necessarily contain a number of purely calculation technical assumptions, for example, about the hydrocarbon tax rate, but these assumptions are not in the nature of an actual proposal.

Thirdly, it had to be clarified whether the model might cause any specific problems with respect to EU rules, for example, whether the EU Commission would permit disbursement of the tax value of losses carried forward, or whether this would be regarded as state aid.

Although the agreement includes elements of a neutral tax regime and therefore also considerably reduces the so-called distortion loss, it cannot be described as a truly neutral tax system. The table below shows the tax elements under the agreement and under a neutral tax regime, respectively.

Table. Elements of the hydrocarbon tax system of the agreement and of the neutral hydrocarbon tax model

Agreement	Neutral hydrocarbon tax model
• Special hydrocarbon allowance to be reduced to 30 per cent overall.	• Special hydrocarbon allowance of 250 per cent overall to be abolished and replaced by a new allowance for return on equity capital.
• Oil pipeline tariff to be eliminated in practice by set-off against the hydrocarbon tax and to be formally abolished after 2012. Royalty to be abolished from 2004. Tax-base deductions no longer to be allowed.	• Gross taxes (oil pipeline tariff and royalty) to be eliminated in practice by set-off against the hydrocarbon tax. Tax-base deductions no longer to be allowed.
• Hydrocarbon tax rate to be reduced from 70 per cent to 52 per cent.	• Hydrocarbon tax rate?
• Pay-back rule to be abolished.	• Pay-back rule to be abolished.
• No time limit for loss carrying-forward.	• Losses to be carried forward with risk-free interest after tax and to be tradable
• Field-based tax assessment to be abolished.	• Field-based tax assessment to be abolished.
• Transitional rules for hydrocarbon allowance and loss treatment.	• No transitional rules for hydrocarbon allowance and loss treatment.
• Tax value of removal costs associated with decommissioning the last fields to be disbursed when production is discontinued, up to a maximum equivalent to the hydrocarbon tax paid.	• Tax value of losses to be disbursed eventually.
• Compensatory scheme.	• Possible inclusion of a proviso allowing the Concessionaires/licensees to shift taxes back onto the state (by a set-off).

There are four main differences between the agreement and the neutral hydrocarbon tax model.

Firstly, the agreement carries on the hydrocarbon allowance at an overall rate of 30 per cent and does not replace it by an allowance for return on equity. This is because it has been a major concern in the agreement to ensure continued exploration, and thus the 30 per cent hydrocarbon allowance for (capitalized) exploration costs also applies to companies that have not yet made any discoveries.

Secondly, the agreement does not allow losses to be carried forward with risk-free interest, which means that they lose their tax value over time. However, this is no different from the general tax treatment of losses.

Thirdly, the neutral hydrocarbon tax system introduces an allowance for the return on equity. The agreement does not provide for this allowance.

Finally, the neutral hydrocarbon tax regime provides for eventual disbursement of the tax value of losses. Under the agreement, disbursement is limited to the tax value of the removal costs associated with decommissioning the “last” fields, up to a maximum of the hydrocarbon tax paid.

So, it all comes down to just three differences of nuance, and the hydrocarbon tax system provided by the agreement is thus highly comparable to, though not identical with, a neutral tax regime.