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RESPONSE TO A DISCUSSION PAPER FROM THE MINISTRY OF FINANCE ("MoF") REGARDING A PROPOSAL TO LIMIT THE DEDUCTIBILITY OF FINANCE COSTS UNDER THE PETROLEUM TAX ACT ("PTA")

1. INTRODUCTION

This initiative is sponsored by the following companies

- DONG Norge AS
- E.ON Ruhrgas Norge AS
- Faroe Petroleum Norge AS
- Gaz de France Norge AS
- Norwegian Energy Company AS
- Pertra ASA
- Petro-Canada Norge AS
- Premier Oil Norge AS
- Revus Energy ASA
- Talisman Energy Norge AS

Jointly the group of companies that the sponsors represent is in this paper referred to as "Newcomers". As Newcomers they have recently started their activities on the Norwegian Continental Shelf or are considering starting such activities.

Some of the companies listed above are members of OLF. OLF has submitted a separate letter with comments on the proposal. The reason why they also participate in this initiative is that the Newcomers will all be significantly affected in a negative manner by the proposal if implemented in its present form, and wish to provide additional details on the impact of our companies. Although the Newcomers are very different as companies, they represent a uniform group with respect to their activity on the NCS. They chase new opportunities on the NCS that have been created as a result of significant positive changes made by Norwegian authorities during the last years aimed at new entrants. We understand the objective of these changes has been to secure an optimal management of the resources on the NCS. On this basis we are strongly concerned about the signals we perceive the proposal in its present form provide to us as a group.

2. SUMMARY

The Newcomers refer to and support the comments made by OLF in its response to the MoF. We are significantly concerned about the negative impact on the Newcomers.

Cost should be deductible against the same tax rate as income is taxed. If a standardised rule is applied, such rule should allocate all interest cost to the offshore tax regime for a company that only performs upstream activity on the NCS.

Exchange gains and losses on debt should be taxed the same way as the interest cost. As long as functional currency is not allowed for tax purposes and petroleum tax is to be paid in NOK, exchange gains and losses deriving from oil sales and exchange into NOK for tax payment should be taxable/deductible in the offshore (78%) tax regime.

Using RNB forecast for oil price and assumptions close to those applied for the PTA Section 10 neutralisation, the calculated effect for the period 2007 – 2011 is additional tax cost for the six companies in the group that have an existing portfolio in the area of MNOK 485 (NPV) if no new projects beyond what is known by May 2006 are included in the calculations. For the period 2007 – 2013 additional tax cost calculated for the companies is approximately MNOK 610 (NPV). If oil prices go down below the RNB forecasts or additional projects are included, the calculated adverse effect for the companies will increase.

The general picture is that the proposal will have an adverse effect on:

- Exploration projects
- Development projects
- Marginal projects
- Capital intensive projects

On the other side, our work has revealed that the proposal will have a beneficial effect on:

- Mature, producing projects
- Highly profitable projects
- Projects with low initial development costs

The effect is therefore that companies that seek to build a position on the NCS through investing in exploration and development projects, as well as marginal tail end and small fields, will be negatively affected by the proposal.

With lower oil prices than our base case, the proposal will increase the effective tax rate substantially while with higher oil prices the effective tax rate will increase less.

On a generic basis it may be demonstrated that for capital intensive projects and lower oil prices, the tax burden may increase by more than 6 percentage points over the lifetime of the field. This equals a reduction of the after tax value for the company of more than 25%.

On top of this, the MoF has announced that an additional (unspecified) tax increase will be proposed and implemented in order to compensate for an alleged tax reduction for the government as a result of the proposal.

The proposal will increasingly discriminate capital against other resources that are necessary for generating maximum added value from the petroleum resources on the NCS. The effect thereof is that cost before and after tax may change to the extent that a best solution before tax is no longer a best solution after tax. The result is more expensive exploration and development on the NCS, marginal fields that are not developed and potential sub-optimisation that may conflict with a general desire to create maximum wealth from the petroleum resources on the NCS.

Such negative change is contrary to the general message made by Norwegian authorities on numerous occasions when they have promoted the NCS. It is also contrary to the signals we have noticed with respect to changes in the procedures for being accepted as a participant on the NCS and the allocation of licenses to Newcomers as well as to the changes made in the Petroleum Tax Act (“PTA”) during the last years.

We fail to see the need to rush such proposal through without carefully discussing the impact for the different type of projects and participants on the NCS.

On this basis we feel it is fair to question whether the Norwegian authorities now want to reverse the positive trend in their efforts to facilitate for Newcomers on the NCS.

3. COMMON FEATURES OF NEWCOMERS ON THE NCS

The Newcomers have entered the upstream petroleum activity on the NCS over the last six years. Relative to their size they are very active and are seeking to rapidly expand their business on the NCS, mainly through new exploration activity in mature areas as well as investments in small fields and tail end production. They perform no other activity than upstream exploration, development and exploitation of petroleum on the NCS. They have no onshore income against which to offset cost and losses that are allocated onshore.

Although some of the acreage has been acquired through acquisition of interests in proven reserves and existing production, the only way to make a reasonable return on such investments is to develop and produce beyond the estimates at the time of transfer. Hence, extensive exploration and development cost shall have to be expected for every boe produced in order to obtain the opportunities these companies are seeking when they buy into existing production or proven reserves.

4. THE GOVERNMENT'S INITIATIVES FOR FACILITATING NEWCOMERS' ACTIVITY

Since 2000 a number of new incentives have successfully attracted newcomers to the NCS. As far as tax is concerned, these incentives include:

- Interest adjusted Loss Carry Forward ("LCF") and Uplift Carry Forward ("UCF")
- Annual state payment of the tax value of loss created by exploration costs
- Safeguarding the value of LCF and UCF in case the upstream petroleum activity ceases
- Simplification of the PTA Section 10 procedures

In the preparatory work to the changes in 2001/2002, Ot. Prp. No. 86, the MoF states that the main reasons for these incentives are (page 39):

> *"Forslaget vil øke muligheten for at selskaper som driver særskattepliktig virksomhet vil få utnyttet den økonomiske verdien av fradraget. Dermed vil en kunne oppnå økt grad av likestilling mellom selskaper i og utenfor skatteposisjon. Forslaget vil således bidra til en nedbygging av skattemessige inngangsbarrierer for nye selskaper på sokkelen. Det vises her til at dette har vært en uttalt målsetting som blant annet lå til grunn for petroleumsskatteutvalgets mandat. Samtidig vil forslaget innebære redusert økonomisk risiko knyttet til de investeringer som foretas. Også på denne måten søker departementet å fjerne en mulig skattemessig barriere for at nye selskaper vil søke å etablere seg med virksomhet på norsk sokkel."*

Also non-tax initiatives have been implemented by the authorities, such as

- Actively promoting the NCS towards potential Newcomers
- A pre-qualification process
- A new system for allocation of licenses (APA awards)
- Third party access to infrastructure
- Significant allocation of licenses to Newcomers

The number of new companies on the NCS indicates that the incentives introduced after 2000 have been successful. However, based on the emphasis on attracting Newcomers the current proposal in its present form is a step in the opposite direction. The fact that the MoF is seen to take such step without any discussion of this fact is of grave concern to the Newcomers.

5. EFFECT OF THE PROPOSAL

5.1 Effect on the companies

In order to demonstrate the effects of the proposal on a consistent basis, the companies have engaged the independent consultant SB Finans AS to calculate the effects of the proposal compared with the existing system. The calculations have been carried out for the six companies in the group that have an existing portfolio (DONG Norge AS, E.ON-Ruhrgas

Norge AS, Gaz de France Norge AS, Pertra ASA, Revus Energy ASA, Talisman Energy Norge AS[1]).

A summary of the calculation from SB Finans AS is made in a report dated 14.08.2006 (the Report) that is enclosed as **Attachment A**.

The calculations have been made under the following set of assumptions (page 6 in the Report):

- Oil price: RNB 2006
- Gas price: 25% energy equivalent discount to oil price
- Inflation: 2.5%
- Discount rate
  - Base: 8.0%
  - Low: 3.26 % (5 year Gov. Bond for June 06 + 50 bps, less corporate tax)
- Interest rate debt
  - Base: 5.03 % (5 year Government Bond for June 06 + 100 bps)
  - Low: 4.53 % (5 year Government Bond for June 06 + 50 bps)
- Interest rate cash: 3.78 % (5 year Government Bond for June 2006 – 25 bps)
- Interest rate loss carry forward: 3.26 %
- Exchange rate: NOK/USD: 6.3
- Production and cost profiles for the assets are based on Wood Mackenzie's Energy Vision database (updated per May 2006)
- Period:
  - 5 years
  - 7 years
- Exploration cost: Budgeted cost, average cost horizon 2006 - 2008

The 7 year period is the same period as applied by the MoF when neutralising tax effects in accordance with the PTA Section 10. It is not, however, a realistic assumption that the Newcomers will not enter into new projects during a 7 year period. The reason for the Newcomers to enter the NCS is that they will build up and expand a business here. Hence, during the foreseeable future, these companies will seek new opportunities on the NCS and invest any net positive cash flow on exploration and development. Therefore, assuming a significant addition of new exploration and development cost compared with what is included in the existing projects only, is the most realistic scenario. Since most individual assumptions about new investments in the future may be alleged to be arbitrary, we believe it is a conservative assumption to make that the relative amount of new investments during the first years for most of the Newcomers with an existing portfolio will continue also thereafter. On this basis we have asked SB Finans AS to also illustrate the results for a five year period[2]. This scenario is referred to as Base Case.

The calculations show that the proposal has a significant negative effect on the Newcomers as a group. All the companies can individually demonstrate increased tax costs if the proposal is

[1] Includes both Talisman Energy Norge AS and Talisman Resources Norge Ltd Norwegian branch.
[2] Since hardly any exploration costs are included in the model after 2008, the best illustration would have been to apply only these first years as base case. Some of the companies are, however, not expected to be in a tax paying position these years. This makes the use of a period less than five years inadequate although this will underestimate the calculated effects compared to what is a most likely scenario.

implemented. For the Base Case the calculated tax increase will be in the range of 0.5 - 5 percentage points, the Report page 11. This represents a reduction of after tax profit for the companies in the range of 2 - 20 percent. Even with the very conservative assumptions that are built into the 7 year scenario the calculated tax increase will be in the range of 0.5 – 2.5 percentage points (2 – 10% reduction of after tax profit[3]), the Report page 10.

For the period 2007 – 2011 additional tax cost for the six companies is calculated to be in the area of NOK 485 million on NPV basis (NOK 610 million for the period 2007 – 2013) even if no new projects beyond those known and reported by May 2006 are included. If a reasonable amount of new projects are included, the adverse calculated effect will increase.

The cost of capital for the Newcomers as a group is significantly higher than 4.5 – 5%. For the independent companies a borrowing cost in the area of Libor + 5% (500 base points) is what is seen in practice. This will increase the calculated additional tax resulting if the proposal is implemented. On a company basis this will be very significant, i.e. increase the effective tax rate.

5.2 Generic illustrations

5.2.1 Introduction

Under this section we have provided comments on how we see the proposal in its present form will affect the economics of a typical field during its lifetime (Chapter 5.2.2). Under Chapter 5.2.3 – 5.2.6 we have commented specifically on the effect of the proposal on exploration cost, development cost and small/short life fields respectively.

5.2.2 Field economics

On a generic basis it may be demonstrated that for capital intensive projects and lower oil prices, the tax burden may increase by beyond 6 percentage points over the lifetime of a typical field, resulting in an effective tax rate of close to 84% for the full lifetime of a field ("Exploration Project", ref. page 17 and 23 in the Report).

The general picture is that the proposal will have an adverse effect on:

- Exploration projects
- Development projects
- Marginal projects
- Capital intensive projects

In addition the effective tax rate will increase more over the life time for fields if the oil price goes down and increase less if the oil price increases.

We refer to page 23 – 25 in the Report.

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[3] With an effective tax rate in the area of 75% every 1% percentage point increase in effective tax rate reduces the companies after tax profit with approximately 4 percent. Hence, an increase of effective tax rate by 1.6 percentage points reduces after tax profit by 6.4. percent.

5.2.3 Exploration cost

Since exploration costs are deducted as incurred for tax purposes, such cost will provide no value to the numerator in the formula in the proposal. Hence, to the extent a company is able to obtain loan for financing exploration cost, no interest cost on such financing would be tax deductible against offshore income (78% tax base) according to the proposal.

We have noticed the argument that deducting the exploration cost for tax purposes and capitalising them in the statutory accounts will create a deferred tax liability of 78% of the difference between the values in the two systems. This is, however, not entirely correct since the deduction of cost for tax purposes will create a taxable loss carry forward that generates a deferred tax benefit to the extent the tax value is not to be refunded in accordance with the PTA Sec 3c fifth paragraph. The deferred tax benefit will normally offset a significant part of the deferred tax liability.

The concept whereby the tax value of losses created by exploration cost is repaid annually to the companies has made it possible to partly finance exploration through borrowing. For some of the independent Newcomers, such loan financing constitutes a significant element in the financing of their activity.

Although one could consider to capitalise exploration cost for tax purposes in order to obtain interest deduction, this is not an alternative since the company would then not get a taxable loss caused by exploration cost. Hence, no repayment of tax value to be received from the tax authorities. In addition there may be uncertainty as to whether capitalised exploration cost will qualify as a Tax Base in the proposal.

5.2.4 Development cost

Development costs are for tax purposes depreciated by up to 1/6 (16.67%) each year. An investment of 100 in year 1 will give the Tax Base at each respective year end as shown in Table 1.

Table 1

Time/Year	1	2	3	4	5	6	7
Tax base	83.3	66.7	50.0	33.3	16.7	0	0

The proposal applies the following formula for interest cost to be allocated offshore:

Deductible interest cost = Actual interest cost * (50% * Tax Base) / Average interest bearing debt

Since the interest cost by definition is a result of the interest rate and the loan amount, it is the amount inside the bracket that determines the extent to which interest cost will be deductible against offshore income under the proposal. According to the proposal an oil company shall at the maximum be allowed to loan finance an investment with 50% of the year end written down tax value of such investment:

Table 2

Time/Year	1	2	3	4	5	6	7
Max loan	41.7%	33.3%	25.0%	16.7%	8.3%	0	0

In order to compare the proposal on a general basis with the existing system one needs to make some assumptions. A very simple example for illustration purposes may comprise the following elements:
- development period: 2 years (an average of 1 – 3 years)
- production period: 8 years (the result is not significantly sensitive to applying 4 or 12 years)
- no dividend (net cash flow is applied for new exploration, new development and repayment of loan)[4]
- decommissioning cost is 10% of investment[5]
- all amounts in nominal terms

The results are set out in Table 3. The full calculations are shown in **Attachment B**.

Table 3

Time/Year	1	2	3	4	5	6	7	8	9	10
Max loan	67.0%	54.0%	39.5%	26.3%	13.0%	-0.3	-0.5	-0.8	-1.0	-1.3

A relative comparison between the proposal and the existing system is made in Table 4.

Table 4

Time/Year	1	2	3	4	5	6	7	8	9	10
Proposal	41.7	33.3	25.0	16.7	8.3	0	0	0	0	0
Existing	67.0	54.	39.5	26.3	13.0	-0.3	-0.5	-0.8	-1.0	-1.3
Difference	-25.3	-20.7	-14.5	-9.6	-4.7	0.3	0.5	0.8	1.0	1.3
Prp. as % of existing[6]	62.2	61.7	63.3	63.5	64.1					

The example illustrates the fact that interest cost on the financing of development projects deductible against offshore income will be reduced by approximately (more than) 35% under the proposal compared to the existing regulations. This relative reduction will not change significantly if the production period is shorter or longer, ref the calculations in **Attachment B**.

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[4] For the same reason no significant cash that generates interest income is included.

[5] Having in mind that new field developments are increaslingly based on assets that are easily removed (FPSOs and light seabed installations), this is regarded as a reasonable general assumption on which to build the illustration

[6] Indicates size of tax deductible debt against 78% tax base according to the proposal as a percentage of similar debt under the existing system.

5.2.5 Small projects/marginal fields

Investments related to projects with an expected life time of less than 3 years may be expensed as incurred for tax purposes. Hence, the effect of the proposal will be very similar to that of exploration cost, ref. chapter 5.2.3 above.

5.2.6 The additional after tax cost for exploration and development

The proposal will result in all interest cost related to exploration activity being allocated onshore (28% tax regime). Further, the interest cost on development projects being deductible in the 78% tax regime will be reduced by up to approximately 35%. For small projects/marginal fields with expected lifetime less than three years, the result will be very similar to that for exploration cost.

Since the Newcomers do not have any onshore income[7] against which to offset such cost, only 50% of the onshore loss (interest cost) may be re-allocated offshore and deducted against the 28% tax base.

For the 50% of the loss that remains onshore, no interest will apply on the loss carried forward. In addition, a Newcomer will have no prospect of generating significant income onshore within a reasonable time, ref. the footnote above.

The effect of this is that a significant part of interest cost resulting from loan financing of exploration and development projects may only be deducted against an effective tax rate of 14%.

The additional cost for exploration and development projects respectively, may be illustrated as follows:

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[7] Positive cash flow from operations or shareholder contribution will be used to finance expanding activity (exploration and development) and repay debt. Exchange gains must be assumed to be offset by losses over time.

Table 5

Project	**Exploration Project & "Small Fields/Short Time Projects"/Marginal Projects**	**Development Project**
Cost	100	100
Cost after tax (nominal value)	22	7
Loan financing	50%	50% (average, see Table 3)
Loan period	1.5 year	5 years
Interest rate	5%	5%
Interest cost	2.5	2.5
Tax value 78%	1.96	1.96
Tax value 14%	0.35	0.35
Net difference (one year)	1.6	1.6
Net Difference (1.5 year)	2.4	
Net Difference (5 years)		8
35% of Net Difference		2.8

The illustration in Table 5 indicates that cost of exploration will increase by approximately 2.4% of total cost while development cost will increase by approximately 2.8% of total investment. This increase in cost is made up of additional tax if the proposal is carried through. Since this is an after tax cost, the amounts shall have to be compared with the after tax cost of exploration cost (100 – 78% = 22) and development cost (100 – 78% - (50% * 30) = 7) respectively.

For exploration cost the proposal implies an increased tax that may be in the area of 10% of the after tax cost of the investment if the proposal is carried through. For development cost the proposal implies an increased tax in the area of up to 35% of the after tax cost of the investment on a nominal basis. Assuming that uplift compensates for the time delay on a Net Present Value basis, it may be argued that the proposal will increase the after tax cost for exploration and development with approximately 10%.

We appreciate the fact that these calculations are very rough and that the assumptions as such may be argued. They do, however, illustrate the point that the proposal from the MoF in its present form will increase the after tax cost of exploration and development significant. For that purpose we consider the calculations sufficient.

6. MAIN COMMENTS ON THE PROPOSAL

The experience with the PTA Section 3d has been that the way it has been interpreted it has resulted in unjustified allocations of significant amounts of net financial cost onshore for companies that are only performing upstream activity on the NCS. On this basis many of the Newcomers have been looking forward to a change in the regulations for allocation of financial items between onshore and offshore.

Hence, the Newcomers are not negative to a new proposal as such, but modifications need to be done in the proposal from the MoF in order to secure that a standardised rule to a better extent reflects the reality under which it is to operate. In this respect we welcome the initiative for modifications indicated by OLF/Econ, though we have not yet evaluated the impact on the Newcomers.

The proposal in its present form will reduce even more the possibility to deduct financial cost and thereby impose a significant increase in tax burden on the Newcomers in general. The result being that exploration and development projects become significantly more expensive after tax. The proposal as it stands will work in the opposite direction of the government's recent initiatives to facilitate new activity and attract new companies on the NCS for Newcomers.

Since the Newcomers are only engaged in upstream activity on the NCS, the argument of financing onshore (other) activity is not relevant for these companies.

Capital is a resource that is needed in order to create value (income) from petroleum projects on the NCS just like technical and human resources are also necessary. We fail to see the rationale for discriminating certain types of resources for tax purposes. The effect thereof is that cost before and after tax may change to the extent that a best solution before tax is no longer a best solution after tax. The result is more expensive exploration and development on the NCS, marginal fields that are not developed and potential sub-optimisation that may conflict with a general desire to create maximum wealth from the petroleum resources on the NCS.

The logic flaw in the proposal may easily be illustrated by an example. If the oil company acquires a "turn key" asset, the finance cost during the building period will be included in the purchase price. As such, the cost will be included in the asset cost that is either expensed as incurred or capitalised and depreciated (including uplift). Under both alternatives the asset cost will be allocated 100% offshore. The same will apply to the cost if the asset is leased even though a charter hire will include the full cost of capital. If instead the oil company decides to produce the asset itself (i.e. pay during design and production), the price for the asset will be lower, but the interest cost will only to a small extent be tax deductible against the 78% tax base. In addition to allocating all finance cost offshore, the "turn key" alternative will generate a larger tax base that attracts additional interest cost to the offshore regime compared to the alternative of the oil company financing the building of the asset itself through loan. Having in mind the extent to which the upstream activity on the NCS is technology driven, this difference is not necessarily sensible.

In addition to the problems created by discriminating certain types of resources (finance cost) for tax purposes, a main point is that if income is to be taxed at 78%, then the cost necessary to generate such income must be tax deductible against the same rate. What we have experienced with the introduction of the PTA Section 3d in its present shape is that cost which is incurred in order to generate petroleum revenue (taxed at 78%) is partly allocated onshore in an effective 14% tax regime (one half of 28% that is returned offshore). From what we read in the preparatory papers to the PTA Section 3d, we do not believe that this was the original intention of the authorities. Due to an incomplete law text and its particularly strict interpretation by the OTO and the Oil Taxation Board, allocation onshore of significant net financial cost has been the result. Now the MoF through its proposal is seen to go even further along this line. Modifying this along the lines indicated by OLF/Econ, may, however, be a way to remedy this problem.

The fact that any interest cost allocated to onshore activity is only deductible by 50% in the upstream 28% basis is particularly negative. Newcomers will not have any onshore activity that may be consolidated with the “surplus” interest deductions.

Even if 100% of the loss onshore were allowed to be deducted against the 28% tax base offshore, the result would only be marginally improved. The main effect is the reduction from 78% to 28%. In addition the risk reducing elements specifically designed for Newcomers in the PTA Section 3c does not apply to onshore income.

Also the fact that any currency exchange gains and losses are proposed to be an onshore element and thereby separated for the interest cost will introduce an increased element of risk that is not acceptable to the Newcomers. This may result in the companies ending up with substantial costs that are effectively non-deductible within a reasonable time horizon. For independent companies, this risk will clearly be an element that makes loan financing more expensive and potentially more difficult to obtain. Banks are generally not concerned with potential upside, but rather critical against potential downside in a project when lending money.

7. CONCLUSIONS

We understand the MOF sees a need to change and improve current legislation. It is the wish of the Newcomers to have a transparent tax regime that provides incentives for optimal management of NCS petroleum resources.

Cost should be deductible against the same tax rate as income is taxed. If a standardised rule is applied, such rule should allocate all interest cost to the offshore tax regime for a company that only performs upstream activity on the NCS. Therefore the proposed formula has to be significantly improved.

Exchange gains and losses on debt should be taxed the same way as the interest cost. As long as functional currency is not allowed for tax purposes and petroleum tax is to be paid in NOK, exchange gains and losses deriving from oil sales and exchange into NOK for tax payment should be taxable/deductible in the offshore (78%) tax regime.

Any cost related to the upstream activity that is not tax deductible against the 78% tax rate, should not be allocated onshore, but rather to the 28% tax base in the offshore system. in order to avoid cost related to the offshore activity ending up as (effectively) non-deductible cost onshore and to benefit from the risk reducing elements in the PTA Section 3c.

The proposal in its current form have clear negative effects for the Newcomers and work in the opposite direction of recent initiatives by the Government to increase activity on the NCS and invite new entrances.

Therefore we can not accept the proposal in its current form. It needs modification.

Yours sincerely,

Geir Hjellvik, Revus Energy ASA, on behalf of the companies

DONG Norge AS	______________________________
E.ON Ruhrgas Norge AS	______________________________
Faroe Petroleum Norge AS	______________________________
Gaz de France Norge AS	______________________________
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Talisman Energy Norge AS	______________________________

Enclosure: Attachments A and B