26 November 2007

Consultative paper prepared by the Policy Advice Division of Inland Revenue and by the New Zealand Treasury

SUGGESTED CHANGES TO THE PETROLEUM MINING EXPENDITURE TAX RULES

1. On behalf of the Minister of Finance and the Minister of Revenue, tax policy officials are consulting with the petroleum mining industry and other interested parties on possible changes to the tax treatment of expenditure incurred on petroleum mining. The suggested changes are designed to remove the uncertainty and disincentives that currently exist with the current rules.

The New Zealand Energy Strategy

2. In 2004, the government announced a series of measures designed to encourage oil and gas exploration in New Zealand, as a result of concerns over the rate of depletion of the Maui gas reserves and a strong belief that new fields are critical to meeting our future energy supply needs. The announcement was followed by the introduction of changes to the petroleum royalty rules aimed at making them even more internationally competitive, in order to stimulate a high level of exploration activity over the next few years. Underlying the changes was the principle that the tax system should not create barriers or obstacles to an increase in exploration. The government also agreed to consider the industry's concerns about the petroleum mining rules, which the industry sees as discouraging sensible investment in oil and gas exploration and development. The suggested changes outlined here aim to respond to these concerns as far as is possible.

3. Earlier this year the government released the New Zealand Energy Strategy, which is clearly focused on ways of responding to two long-term energy challenges. The first is responding to climate change and tackling carbon emissions from energy production and use. The second is delivering secure, clean energy at affordable prices to support economic development, while being environmentally responsible. In relation to gas exploration, the government states that it believes that the current rules and incentives are generally appropriate.

Summary of the suggested changes

4. The suggested changes are to:

- remove the onshore-offshore boundary and allow deductions for development expenditure to occur from the date that the expenditure is incurred;

- allow the industry to elect to amortise development expenditure under either the current seven-year straight-line method or apply a new depletion method;
- allow a deduction for production well expenditure when that expenditure fails to produce an income earning asset; and
- clarify that GST input tax credits are allowed on the costs of restoration associated with a past taxable supply.

Removal of the onshore-offshore boundary

5. The current tax rules treat onshore and offshore development expenditure differently. Onshore development costs are deductible from the date that commercial production starts. Offshore development costs are deductible from the date that the expenditure is incurred. The industry has asked officials to consider the definition of onshore and offshore development in light of recent advances in drilling and production technology.

6. The differences in the treatment of onshore and offshore development were based on the longer lead time, more risk and higher cost of offshore developments relative to onshore developments. The industry also argued that offshore development assets begin deteriorating immediately because of the corrosive marine environment.

7. The original policy of distinguishing between onshore and offshore development was not based on ideal tax policy principles. Instead it was based on a mix of the location of the reservoir and the location of the facilities. Developments in horizontal drilling technology now mean that this boundary is no longer sustainable. Horizontal drilling techniques allow wells to be drilled offshore from an onshore location.

8. The policy concern with any boundary is whether it distorts sensible investment decisions. In the absence of horizontal drilling, offshore development is encouraged over onshore development. This was a problem with the original policy. However, with horizontal drilling the current tax rules may encourage facilities to be located on the seaward side of the high-tide mark, when in the absence of tax they may be located onshore (for oil and gas reservoirs close to New Zealand shores). So long as there is a difference between the tax treatment of onshore and offshore development expenditure there is the chance that investment decisions will be influenced by the tax rules.

9. One option to resolve this problem is to abolish the boundary altogether. This seems to be a sensible approach, although it raises the question of when to start amortising development expenditure.

10. On balance, we suggest removing the onshore-offshore boundary and allowing deductions for development expenditure to occur from the date that the expenditure is incurred. This approach appears more consistent with the government's view that incentives for gas exploration are generally appropriate. It would also remove the uncertainty that exists in the current petroleum mining rules.

The seven-year rule

11. The current rules allow development expenditure to be amortised over seven years on a straight-line basis, an approach that can be concessionary for some projects and penal for others. Income from a gas field with a life of more than seven years may be under-taxed, and, similarly, income from a field with a shorter life may be over-taxed. Income from a gas field that produces the bulk of its production in early years may be over-taxed, while late life producers will be under-taxed.

12. Economic theory suggests that deductions for the fall in value of capital good's should try to approximate an asset's actual decline in value. In this way tax rules do not interfere with the goods' value. In the case of development expenditure, the current rules prescribe a single amortisation rate and may affect the value of such investments.

13. Our suggestion is to allow petroleum miners to elect the amortisation method that applies to petroleum development expenditure. The current seven-year straight-line method would be retained. This approach is a relatively simple option to apply and is already widely understood by the industry. Furthermore, it maintains the current level of concession for gas exploration and development when the expected life of the discovery is greater than the amortisation period. It is therefore consistent with statements in the New Zealand Energy Strategy that the current rules and incentives for gas exploration are generally appropriate.

14. We also suggest allowing development expenditure to be amortised on a depletion basis. That would allow the cost of the field to be written off over its life and would deal with the industry's concerns by improving the matching of deductions with revenue from oil or gas fields. The depletion method relies on estimates of recoverable reserves in the ground. Development expenditure would be written off as oil and gas reserves are depleted.

15. Information on gas and oil reserves, expectations of the likely value of reserves and the likely cost of bringing reserves to market are factors in the decision whether to invest in production. Exploration and production companies therefore build up a lot of knowledge about reserves in an oil and gas field before committing development expenditure.

16. Oil and gas reserves are typically ranked on the basis of confidence levels. Oil reserves are primarily a measure of geological and economic risk – the probability of oil existing and being producible under current economic conditions using current technology.

17. An example of a reserve ranking system is as follows:

Reserves	*Description*
Proven	Reserves which, on the available evidence, are virtually certain to be technically and commercially producible, meaning they have a better than 90 percent chance of being produced.
Probable	Reserves which are not yet proven, but are estimated to have a better than 50 percent chance of being technically and commercially producible.
Possible	Reserves which, at present, cannot be regarded as probable, but are estimated to have a significant but less than 50 percent chance of being technically and commercially producible.

18. For the purpose of the depletion method, the question is how the reserves should be measured. Using proven reserves may understate the base and result in overly generous amortisation deductions. However, using a combination of proven, probable and possible reserves may overstate the base and result in income being over-taxed.

19. For taxes not to influence investment decisions it is desirable for the reserve base used for amortising development expenditure to be the same as that used to inform the initial investment. For accounting purposes, we understand that accounting standards typically use P90 or proven reserves. However, this may be no more than a reflection of conservative nature of accounting standards and not fully reflect the business investment decision. We also understand that companies tend to base investment decisions on probable reserves (P50, which includes P90 reserves). If this is correct, P50 reserves are likely to be the best reserve base for amortising development expenditure. However, we welcome feedback on this suggestion.

20. Deductions for development expenditure under the depletion method could be computed according to the following basic formula:

A *x* B

where –

A is the amount of development expenditure, less the expected residual value, reduced by the total depreciation deductions allowed in previous tax years; and

B is the proportion that the production of petroleum in that year bears to the estimated total recoverable reserves remaining at the commencement of the year.

21. Although the basic model is simple, it needs to be improved to reflect the dynamic nature of business investment. For this reason, we think that the following matters are worth considering.

22. How should companies account for additional development expenditure over the life of the project? From time to time, over the life of a field, additional development expenditure may be required to keep the oil and gas flowing or bring newly located reserves into production. For the depletion method, we suggest that petroleum miners account for additional development expenditure in the income year directly following the year in which the expenditure was incurred.

23. We suggest a similar approach to increases or decreases in reserves – that is, to lag changes in reserves so that they are counted in the year directly following the year that the reserve's estimate is adjusted. Estimates of reserves may change over the life of an oil or gas field. This may be for external reasons, like a natural disaster. It may also occur because of matters relating to the specific field, such as having fewer reserves than originally estimated.

24. While there is an element of inaccuracy in both these suggested treatments, they have the benefit of being relatively straightforward. It may be possible to design apportionment rules that better reflect the exact timing of additional development expenditure or changes in reserves. However, even a relatively simple apportionment rule may not be justified on the basis of compliance costs. That said, we invite feedback on whether a more complex approach is justified.

25. Based on the preceding considerations, deductions for development expenditure under the depletion method could be computed according to the following formula:

A *x* B

where –

A is the amount of development expenditure, less estimated residual value, plus any additional development expenditure incurred in the prior year, reduced by the total depreciation deductions allowed in the previous years; and

B is the proportion that the production of petroleum in that year bears to the estimated total reserves booked and remaining at the beginning of the year. Adjustments for new reserves or reserve down-grades of P50 reserves will be made at the beginning of the next year. The relevant base is barrel of oil equivalent (to pick up any associated gas reserves).

26. The only remaining question is when the deductions should be allowed. The seven-year amortisation method allows deductions to begin for development expenditure from the date that the expenditure is incurred. However, the depletion method requires production to calculate deductions for development expenditure.

27. In principle, deductions for development expenditure should be amortised as the reserves are depleted. However, this means that deductions for development expenditure would be delayed until production begins. This may or may not be a concern for petroleum miners, depending upon the time taken between incurring development expenditure and first production.

28. An approach to dealing with this concern is to allow petroleum miners to elect to apply the seven-year amortisation method until production begins. The depletion approach could then be applied to the remaining development expenditure at the start of the income year that commercial production begins. The benefit of this approach is that it is more in keeping with the seven-year method and with the government's stated view that the petroleum mining rules are generally appropriate. We welcome feedback on this point.

29. We have also considered the idea of allowing petroleum miners to elect to apply either the depletion method or the seven-year rule to amortising an item of development expenditure in the same field. While such an approach might increase the accuracy of amortisation deductions, it would also increase complexity. For example, it is likely that special rules will be required to ensure the correct outcome occurs when short-lived and longer-lived petroleum mining assets are used together. The concern is that petroleum miners may seek to gain an advantage by amortising longer-lived assets at rates that are faster than seven years. The suggestion is therefore to require petroleum miners to elect either the seven-year or the depletion method for amortising development expenditure in a field.

30. We invite submissions on these options and approaches.

Failed production well expenditure

31. Exploration and production companies want to be able to deduct, for example, the costs of failed production wells as and when the situation arises. Industry advice is that, from time to time, production-drilling results in dry, or unsuitable wells. Sometimes production wells just stop producing.

32. In most cases, a tax deduction should be allowed for the fall in value of an asset. Assets that can no longer be used in an income-earning process often only have a residual scrap value. However, in the case of failed petroleum production wells, the expenditure has to be written off over seven years unless the petroleum mining asset is sold or the relevant petroleum licence is relinquished.

33. The industry argues that the current rule is overly restrictive and, as a result, ties up investment capital. It argues that there are strong commercial drivers for not relinquishing the petroleum license. If a company does, it must forgo immediate deductions for failed production wells, thus tying up scarce investment capital in unproductive assets. The industry also notes that other taxpayers can claim an immediate deduction for the remaining value of an asset once they determine that it is no longer of use to the business.

34. Before commenting further, it is important to put the seven-year rule in context. Firstly, it is symmetrical to deny a deduction for wells that have a life of less than seven years if the rules allow wells with economic lives in excess of seven years to be amortised over seven years. Next, allowing a deduction for petroleum mining assets when they are sold for a loss is symmetrical with taxing any gains made from the sale of these assets. Finally, allowing a loss when a petroleum licence is relinquished is a final square-up.

35. We think it is difficult to justify a move away from the current treatment for development expenditure amortised under the seven-year rule if an asset happens to have a life shorter than seven years. The seven-year rule is an on- average approach to amortising development expenditure. It is concessionary if the petroleum mining asset has a life of more than seven years and penal if its life is shorter. Allowing a deduction for petroleum mining assets that are scrapped before seven years is clearly a concession if nothing is done about assets that live longer than seven years.

36. Such an argument, however, does not apply to failed production drilling or wells that are scrapped under the depletion method.

37. We suggest allowing a deduction for expenditure on production wells that fail to produce an income-earning asset. For example, the costs of a dry production well would be deductible in the year that the well is plugged and abandoned. Petroleum miners who use a depletion method of amortising development expenditure would be allowed a deduction if the asset is scrapped or plugged and abandoned, since the depletion method is based on the economic life of the asset. Any remaining tax book value, less recoveries, would be deductible in the year that the asset is scrapped or abandoned.

38. We welcome feedback on these suggestions.

GST and site restoration expenditure

39. The original policy intent was to allow start-up and cessation costs to be eligible for GST input tax credits, although the current law may not fully reflect this intention. The Commissioner of Inland Revenue has reached a preliminary view that the current GST rules do not allow input tax credits to be claimed if the costs are incurred long after a taxable activity has ceased. This may create problems for taxpayers who are legally required to incur site restoration costs relating to a prior taxable activity many years later.

40. Site restoration costs can be incurred for a number of years after the activity has ceased. Resource consents can impose monitoring obligations for periods of up to 20 years following site restoration. The suggestion is to clarify that GST input tax credits are allowed on the costs of restoration associated with a past taxable supply. This is consistent with the original policy intent and would deal with the industry's concern.

Application date

41. We suggest that the changes apply to petroleum mining expenditure incurred on or after 1 April 2008.

How to make a submission

42. The suggested changes are intended to reduce barriers and obstacles to sensible investment in oil and gas exploration and development. We would appreciate receiving any comments you have on the proposal by 17 January 2008.

43. They should be forwarded to:

    Petroleum mining project
    C/- Deputy Commissioner, Policy
    Policy Advice Division
    Inland Revenue Department
    P O Box 2198
    Wellington
    New Zealand

    If making a submission in electronic form please put 'Petroleum mining project' in the subject line. The electronic address is:

    policy.webmaster@ird.govt.nz

44. Please note that submissions may be the subject of a request under New Zealand's Official Information Act 1982. The withholding of particular submissions on the grounds of privacy, or for any other reason, will be determined in accordance with that Act. If there is any part of your submission which you consider could be properly withheld under that Act (for example, for reasons of privacy), please indicate this clearly in your submission.