Promoting domestic gas exploration and development

Tax, Royalty and Investor Incentives

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Summary

Key findings

- Western Australia is the most energy and gas-dependent economy in Australia. Natural gas supplies half of WA's primary energy requirements. Natural gas also fuels 60% of the State's electricity generation.

- Ensuring greater competition, diversity and security of gas supply is therefore critical for the State's long term economic future.

- Tax and royalty arrangements can play an important role in promoting the exploration and development of gas fields for domestic supply.

- While the existing Commonwealth – State tax and royalty regime that operates in Western Australia does not provide any *deliberate* bias in favour of LNG exports, certain concessions may act as an incentive for large scale LNG development.

- Concessions under the Commonwealth Petroleum Resource Rent (PRRT) regime may act as an incentive for large companies to explore and develop large size petroleum fields in remote offshore locations. Because of the scale of the projects in terms of reserve development and production potential, gas export options have been pursued.

- Many of the smaller gas fields are located on-shore and in coastal waters. These fields are generally not large enough to support an LNG development and as such gas developed from these fields could be directed into the domestic market.

- These petroleum fields are subject to the royalty and excise regime, where royalties are calculated on the wellhead value of the petroleum produced, as opposed to profits. Because of this, producers may incur royalty liabilities for years before fields become profitable. This will impact upon the net present value of the investment.

- This report investigates fiscal incentives which may be implemented to promote domestic gas exploration and development – from smaller inshore or onshore domestic gas fields, or as a domestic gas component of an offshore LNG field.

- The report concludes that there is no single tax incentive which will alone ensure domestic gas supply. A package of incentives should instead be implemented to promote exploration and development of domestic gas fields.

- These incentives include both direct and indirect incentives, and fall within both Commonwealth and State responsibility.

Commonwealth – State grants

- Commonwealth and State grants are one important avenue for supporting companies to explore and develop gas fields for domestic supply.

- Such grants are administratively straight forward to implement, and would support Australia's long term energy security by promoting competition and diversity of domestic gas supply.

- Grants could in particular be used to promote new "frontier" developments and technology, such as greenfield tight gas developments.

- Grants have in the past been provided to support new technology development in the petroleum industry, such as coal seam methane and carbon sequestration.

State royalty concessions

- State royalty concessions could provide important encouragement for domestic gas developments. These include royalty holidays, reducing the royalty rate or rebasing the commodity value for royalty assessment.

- The Alliance proposes a reduction in the royalty rate for domestic gas developments to 5% or the provision of royalty holidays for the first 6 years of a domestic gas project.

- Such concessions can promote the development of domestic gas fields by improving the upfront economics of a project, particularly for tight gas projects.

- Any impact on State revenue could be limited, particularly where the concessions allow the development of a field that might otherwise be uneconomic to develop in its initial stages, which would subsequently generate significant royalties for the State over the long term life of the field.

- Where gas fields involve LNG projects with a potential domestic gas leg, royalty concessions can be provided for the domestic gas component to promote domestic supply.

Increased Commonwealth deductibility for pre-wellhead expenses

- Increased deductibility for pre-wellhead expenses should be provided for domestic gas developments under federal taxation arrangements.

- The Alliance proposes a 175% uplift on expenditure incurred in exploring and developing domestic gas reserves, particularly tight gas where development involves significant pre-wellhead expenses.

- The uplifted tax deduction would be available to companies once the expenditure is incurred, and the companies would not have to develop gas before they received the tax incentive. The impact of this incentive would be to reduce companies' taxable income and may provide an incentive to companies with an existing tax liability.

Commonwealth Flow Through Share Scheme

- A Flow Through Share scheme would provide significant assistance for smaller petroleum companies engaging in domestic gas exploration and development, and who are reliant on the market for risk capital.

- Such a scheme would promote frontier and start-up developments where companies might not otherwise generate a taxable income in the initial project years that would make tax deductions an appropriate incentive.

- By implementing an FTS scheme, these companies would be able to pass these losses through to investors who could use the tax deductions, which could in turn promote equity funding by investors.

Introduction

Western Australia’s domestic gas market

Western Australia is the most energy and gas-dependent economy in Australia. Natural gas supplies half of WA’s primary energy requirements. Natural gas also fuels 60% of the State’s electricity generation. Access to natural gas underpins the State’s manufacturing, processing and mining industries, and the thousands of jobs they represent.

In recent times however the State’s domestic gas market has experienced a serious gas supply shortage. Current and prospective gas users are unable to secure long term gas supplies in substantial quantity. The price of such short term gas that is available has risen dramatically. According to reports of recent contracts, WA wholesale gas prices have risen five-fold over the past 18-24 months. Prices reported for recent gas sales in WA are now around five times Eastern States prices on a delivered basis.

The gas supply shortage and escalating prices are threatening billions of dollars of project developments which are dependent on gas supply for energy. Projects are at risk of going offshore or interstate because of the shortage of gas, or of becoming uneconomic because of escalating energy prices.

A number of projects have also been forced to turn to coal-fired power as their only available option. At current prices, gas is no longer competitive with coal for baseload power generation and most resource processing. This raises serious concerns for Australia’s long term efforts to reduce greenhouse emissions.

Western Australia’s demand for gas will continue to grow. A recent report by Economics Consulting Services concluded the State will require around 1100 TJ/day of gas by 2014-15 to meet new and replacement demand. This includes: 274 TJ/day of replacement gas, 68 TJ/day of resource project grid connected electricity and 783 TJ/day of new mineral and petroleum processing projects. This demand is equivalent to the total size of the existing market for gas.

Around 274 TJ/day of replacement gas will be needed to replace existing contracts as they expire. These include large contracts for gas used in electricity generation, industrial processing and manufacturing. There is no certainty that gas will be available to meet these replacement contracts and that contracts can be automatically rolled-over. Contracts may be tied to fields that are declining and with producers that have no replacement fields in the required timetable. This raises serious issues for the State’s electricity, manufacturing and minerals processing sectors.

While domestic demand for gas has expanded, oil and gas producers continue to focus on exports of liquefied natural gas (LNG). Since its inception, North West Shelf Joint Venture has expanded natural gas exports through the construction of five LNG processing trains, with a further sixth train foreshadowed. By comparison, supply to the domestic market has increased only marginally.

Given the importance of domestic gas supply, recent reports by the Commonwealth – States Joint Working Group on Natural Gas Supply, the Chamber of Commerce and Industry of Western Australia and Synergies Economic Consulting have investigated the barriers to domestic supply of natural gas in Western Australia. These reports have investigated a variety of issues including the impact of current regulations, barriers to competition in the upstream gas supply market, availability of skilled labour and tax incentives to stimulate investment.

Additionally, the Federal Government announced in its May Budget for the 2008-2009 year that a review of the Australian taxation system which examined hurdles faced by remote gas developers would commence.

The Varanus Island emergency, which impacted 30% of the State's domestic gas supply, reinforced the need for greater diversity and security of gas supply for Western Australia.

This study investigates fiscal incentives which may be considered to increase the supply of gas into the Western Australian market and help secure the State's long term energy future.

The DomGas Alliance

The DomGas Alliance was formed in 2006 in response to serious gas supply shortages and includes current and prospective gas users and gas infrastructure investors.

Members include: Alcoa of Australia, Alinta, Burrup Fertilisers, Dampier Bunbury Pipeline, ERM Power / NewGen Power, Fortescue Metals Group, Horizon Power, Newmont Australia, Synergy, Verve Energy and Windimurra Vanadium.

Alliance members represent the majority of Western Australia's domestic gas consumption and gas transmission capacity, including smaller industrial and household users of gas. The Alliance also represents a significant proportion of prospective demand for additional gas supplies.

The Alliance works closely with the State and Federal Governments to promote competition and supply of gas for industry and households in Western Australia.

Objective

This report aims to identify and evaluate fiscal measures which may be used to stimulate exploration and development of domestic gas fields, with a view to increasing the domestic gas supply in Western Australia. It aims to:

- understand the role of fiscal incentives in promoting behaviour;
- review fiscal incentives which have been used to stimulate investment in the resources and energy sector;
- analyse the current taxation and royalty regimes governing the exploration and development of petroleum products in Western Australia; and
- provide key recommendations to Federal and State Government on implementing fiscal measures to promote domestic gas supply.

PART 1 presents general observations about different types of tax incentives and the various types of behaviour which they seek to promote. Broadly speaking, tax incentives either try to promote supply side behaviour or demand side behaviour.

The report builds on this analytical framework to review and assess the range of fiscal options that have been used to stimulate desired activities in the resources and energy sector. This analysis focuses on a number of tax incentives which have historically been available to the resources and energy sector.

The report identifies key features of the incentives, the types of behaviour they seek to promote, and their effectiveness. In addition to domestic fiscal incentives, the report discusses incentives used in overseas markets, and their impact on investor behaviour.

PART 2 analyses the current tax and royalty regimes to determine how incentives interact with petroleum exploration and development in Western Australia. The report examines the different tax and royalty regimes which apply to activities undertaken offshore in Commonwealth waters, or within state boundaries either onshore or in coastal waters. Distortions which create more favourable conditions for export projects, as opposed to domestic projects have been identified by assessing the differing regimes applied to onshore and offshore exploration and development.

PART 3 identifies and evaluates options for tax incentives which may be used to stimulate exploration and development of domestic gas fields. The analysis examines the impact of these incentives on the taxation regime more broadly.

PART 4 provides key policy recommendations for Federal and State Government on implementing tax incentives to promote domestic gas exploration and development.

Part 1 – Existing tax incentives

1. General observations about tax incentives

Various tax initiatives exist to promote behaviour and investment. These include tax credits, tax allowances, tax holidays and reduction in statutory tax rates. A brief overview of the key features of these is provided below.

1.1 Tax credits

Tax credits provide an offset against taxes that are otherwise payable rather than a deduction against taxable income. Tax credits may be a fixed percentage of qualifying expenditure incurred in an income year or a fixed percentage of qualifying expenditure in a year in excess of a base such as a moving average.

1.2 Tax allowances

Tax allowances are deductions against taxable income, that is, they reduce the tax base. Tax allowances provide taxpayers with either faster or more generous deductions for qualifying expenditure. Under a faster deduction tax allowance, such as accelerated depreciation or statutory cap on effective life, taxpayer's write off the cost of qualifying expenditure over a shorter period compared to its economic useful life.

These allowances do not alter the total cost base to be depreciated but increase the present value of the claims by bringing them forward.[1] In contrast, enhanced deductions, such as R&D tax concessions and development allowance, enable taxpayers to claim total deductions on that qualifying expenditure to an amount greater than the actual cost incurred.

1.3 Supply vs. demand side incentives

In setting tax incentive policies, consideration should be given to whether the required behaviour is supply-side or demand-side behaviour. From the information presented above, it appears that supply-side behaviours are promoted with tax allowance incentives, whereas demand-side behaviours are promoted with tax credit incentives.

This finding is consistent with the type of behaviour being encouraged. Supply-side behaviours are behaviours displayed by businesses in their production/ manufacturing capacity, and are linked to the business' output. The use of either tax allowances or tax credits as incentives is appropriate for businesses, as they are currently subject to a flat company tax rate of 30%.

[1] OECD, Corporate Tax Incentives for Foreign Direct Investment No. 4, 2001, p. 27

However, the use of enhanced tax allowances will provide businesses with total deductions greater than the actual cost incurred, and thus tax allowances may be a more appropriate incentive for businesses which have an income tax liability.

Demand-side behaviours are behaviours displayed by end-users of a product or service. Where the demand-side behaviour is targeted at households and individuals, the use of tax credits as incentives provides taxpayers with equal value, regardless of the taxpayer's marginal tax rate.

2. Existing tax incentives used in energy and resources sector to stimulate investment

2.1 Overview

This section identifies tax incentives which have been used in the resources and energy sector to promote certain types of investor behaviour. The incentives described provide a framework of mechanisms used by the Government to promote investment in the resources and energy sector.

Additionally, incentives provided by overseas jurisdictions to promote investment in the resources and energy sector are identified.

2.2 Australian market

2.2.1 Accelerated depreciation of a capital asset / statutory cap on effective life

The Australian taxation system allows for deductions for acquisition of a capital asset as the asset is depreciated over its lifetime. Assets in existence at 21 September 1999 have access to accelerated rates of depreciation, which allows for assets to be depreciated at a faster rate, increasing the amount of a taxpayer's deductions in the earlier years, thus deferring or reducing tax obligations for companies with taxable income.

Assets acquired after 21 September 1999 cannot utilise accelerated rates of depreciation, however many assets have a statutory cap on their effective life. Certain industries have lobbied for, and obtained, statutory caps on the effective lives of assets used in those industries which enable the taxpayers to have greater deductions over a shorter amount of years. An example of such an asset is a gas pipeline, which may have an effective life of 50 years, but a statutory cap of 20 years. The taxpayer can, therefore, depreciate the asset over a 20 year period, allowing for larger proportionate write offs over a shorter period of time.

Accelerated depreciation rates / statutory cap on effective lives of capital assets are used to attract both domestic and foreign investment into particular industries. The taxpayer's cash flow in the earlier years of a project is increased as he/she experiences greater deductions and therefore pays less tax, assuming he/she is tax-paying overall.

This increases the net present value of the taxpayer's investments, as well as the internal rate of return and the likelihood of projects being approved and funded.

Result of Measure

Several gas pipelines and distribution systems have been constructed partly as a result of this measure. A few of these projects include the Eastern Gas Pipeline, Tasmanian Gas Pipeline and Seagas.

2.2.2 Research and development tax concessions

The research and development (R&D) tax concessions enable companies to deduct up to 175% of eligible expenditure incurred on qualifying R&D activities against assessable income.

The R&D tax concession program was introduced in 1986 to encourage Australian industries to improve productivity and competitiveness. Its policy objective was to foster innovation by encouraging research and development activity.

The R&D concession can be claimed across all industries and has been successful in attracting investment and supporting innovation in Australia. A study conducted by the Department of Industry, Tourism and Resources found that the R&D tax concession raised companies' awareness of R&D as an investment option, and that the concession provided a timely return on their R&D investment. [2]

Result of Measure

Although some projects may have been able to take advantage of R&D concessions a specific result of this measure has not been quantified.

2.2.3 Excise exemption on extraction of condensate

In 1977, the Commonwealth Government introduced a concession to allow for condensate, a light form of crude oil to be produced excise free. The purpose of this concession was to facilitate exploration and development of petroleum resources in the mainly gas producing areas in the Cooper Basin and North West Shelf. At the time, these gas fields did not have the same profitability as the oil fields in the Bass Strait, and as such this concession improved the economics of exploring and developing these resources.

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[2] Department of Industry, Tourism and Resources, 2005, *The R&D Tax Concession – Impact on the Firm,* p.6

Result of Measure

The benefits of the concession can be seen in the amount of development of gas fields in the Cooper Basin and the North West Shelf over the last 30 years. The recent 2008 budget announcement by the Commonwealth Government that the concession would be removed was met with strong opposition by the North West Shelf partners.

2.2.4 Excise exemption on production of known reserves on Barrow Island

The Commonwealth waived excise on production of crude oil from Barrow Island, to incentivise continuing production in a mature oil field. To waive the excise and royalty regime, the Western Australian Government introduced a resource rent royalty (RRR), which taxed the profits of the petroleum field. The RRR is calculated as 40% of the profits from the petroleum products sourced from the field.

Result of Measure

Under the existing royalty and excise regime, further production of oil could be uneconomical, and by implementing a profit based tax such as the resource rent royalty, the Government ensured that the tax on oil extraction was responsive to upstream costs.

2.2.5 Fuel tax credits (FTC)

The Fuel Tax Credit ("FTC") scheme was launched on 1 July 2006 and has a current life span stretching into late 2011. The FTC scheme currently allows for claiming of credits for commercial use of diesel and other taxable fuels for specific activities. In July 2008, the eligibility of off-road fuel use was expanded to all fuel uses.

This resulted in three FTC rates:

- for on-road activities (approximately 18c per litre);
- currently ineligible off road activities (approximately 19c per litre); and
- currently eligible off road activities (approximately 38c per litre).

Result of Measure

As a result, new opportunities exist for current and prospective claimants to increase claims, but in turn, the complexity of claims has also risen.

The value of the FTC to businesses is that it allows savings of between 10% and 20% of total fuel costs, at current fuel prices.

2.2.6 Enhanced Project By-Law Scheme (EPBS)

The Enhanced Project By-law Scheme (EPBS) allows eligible goods which are not made in Australia, or which are technologically superior to local goods, to be imported duty free for the duration of the project. The key attributes for these eligible goods include:

- expenditure must be greater than A$10 million; and
- only certain industries (including gas supply industries) are covered by the scheme).

The EPBS requires applicants to develop an Australian Industry Participation Plan (AIPP) to encourage the use of Australian industry in the project and global supply chains.

The EPBS application is made to AusIndustry and this application must be lodged before the eligible goods are imported.

Eligible goods include functional units, procurement/equipment packages, pipes, pipelines, conveyors, flexible flow-lines and stainless steel materials.

Result of Measure

A successful EPBS application will generally result in savings of approximately $50,000 per $1 million of eligible imports, i.e. approximately 1% of total project costs.

2.3 Overseas markets

2.3.1 United States

Historically, the US Internal Revenue Service (IRS) has used tax incentives as a means to promote the production of hydrocarbons through ‘non-conventional sources’. Section 29 of the Internal Revenue Code, established under the Windfall Profit Tax of 1980 a tax credit was established for producing hydrocarbons from non-conventional sources which included:

- Oil produced from shale and tar sands;
- Gas from geo-pressurised brine, Devonian shale, coal seams, tight formations, and biomass;
- Liquid, gaseous, or solid synthetic fuels produced from coal;
- Fuel from qualified processed formations or biomass; and

- Steam from agricultural products. [3]

The tax credit for non-conventional gas provided a $0.50/Mcf incentive for gas produced from non-conventional sources.

Result of Measure

During the period from 1990 to 1999, production of non-conventional gas in the US more than doubled from 2.0TcF to 4.8TcF per year. [4] During the 1990's, the US domestic market benefited from stable and fairly priced gas supplies.

In 2005, there were more than 8,000 producers of natural gas in the US, with some 160 pipeline companies supplying gas to the domestic market.[5] Today, gas produced from non-conventional sources represents approximately 30% of supply to the US domestic market.

2.3.2 Canada

In Canada, certain corporations in the mining, oil and gas, and renewable energy conservation sectors can issue investors with Flow Through Shares (FTS), as a way of raising capital to finance their exploration activities. These FTS are essentially the same as common shares, except that they allow the issuer to pass through its allowable tax deductions to holders of its FTS. The investor is therefore able to claim tax deductions in the exploration company as a personal tax deduction.

The FTS benefit investors as they are able to offset their assessable income with their investment in the exploration company. The FTS also benefit exploration companies as they are able to attract additional funding from investors, by passing through tax losses or tax deductions which the shareholders can use.

In October 2000, a 15% tax credit applicable to eligible grassroots exploration in Canada was introduced, to combat the downturn in mineral exploration during the 1990s.

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[3] Energy Information Administration, *Analysis of Five Selected Tax Provisions of the Conference Energy Bill of 2003*, www.eia.doe.gov/oiaf/servicerpt/ceb/fuel.html (accessed 30/07/2008)

[4] Perry, Kent. F, *rationale for Section 29 Non-Conventional Gas Tax Credit Extension*, Gas Technology Institute, http://media.godashboard.com/gti/1ResearchCap/1_5EandP/1_5_1_AreasOfRsch/Section29StudyUnconvenGas.pdf (accessed 06/08/2008)

[5] http://www.naturalgas.org/business/industry.asp

Result of Measure

There is much evidence to support the notion that the tax credit and the FTS scheme has been successful in stimulating resource exploration in Canada. Expenditure on exploration increased from $300 million in the late 19990's, to approximately $1.7 billion in 2006.[6] Canada remains the number one destination for resource exploration expenditure in the world.

The tax credit for grassroots exploration, in conjunction with FTS, has increased the percentage of exploration spending by junior companies compared with senior companies. In 1998, junior company spending was less than 30% of total exploration expenditure, by 2004, that percentage has increased to 49%, a total of $531 million spent on exploration by junior companies.[7]

The relative importance of junior company spending versus senior company spending is perhaps the most outstanding feature of the current upward trend. After falling below the 30% level in terms of exploration expenditure both for 1998 and 1999, junior company expenditures gradually accounted for larger shares of total spending in the 2000-2003 period. In 2004, junior spending jumped to $531 million and represented 49% of amalgamated junior and senior expenditures. This proportion is expected to keep growing in 2005 with junior spending intentions amounting to 54% of the total for that year.

In percentage terms, the anticipated $606 million in junior company spending for 2005 would surpass even the levels of 1987 and 1988, which previously represented the best performance on record for the relative importance of junior mining companies in the Canadian exploration and deposit appraisal sector.

2.3.3 Russia

Russia has the world's largest natural gas reserves, and is a significant exporter to Europe and the Confederation of Independent States. Recently, Russia has begun to prioritise domestic supply of gas over exports. This domestic prioritisation is achieved through subsidised pricing for gas supplied to the domestic market. Gas producers are able to claim the domestic-export price differential as an allowable deduction against taxable income. Additionally, projects which produce sufficient amounts of gas, can pay taxes through royalty-in-kind payments, i.e. transfer of gas to the state for supply to the domestic market.[8]

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[6] Prospectors and Developers Associate of Canada, PDAC's position on Canada's 'super' flow-through program, http://www.pdac.ca/pdac/advocacy/financial/flow-through.html (accessed 06/08/2008)

[7] Natural Resources Canada, http://www.rncan-nrcan.gc.ca (accessed 06/08/2008)

[8] McLennan Magasanik Associates, *Report to the Joint Working Group on Natural Gas Supply: Natural Gas in Australia,* 2007, p.113

Result of Measure

The result of this measure is expected to be positive in terms of directing gas supply to the domestic market in Russia.

2.4 Conclusion

Various types of tax incentives have been used both domestically and in overseas markets, to promote behaviour and investment in the resources and energy sector. The Commonwealth Government has demonstrated a desire to stimulate petroleum exploration and development through concessions provided under the PRRT and excise regimes. Similarly, through the R&D tax concession, the Commonwealth has demonstrated its acknowledgment of the importance that Australian industries invest in innovation.

Examples from overseas markets demonstrate how governments have dealt directly with issues such as prioritising domestic gas supply, ensuring the diversity of domestic supply, and the continued exploration of reserves.

Part 2 – Review and assess the tax and royalty regimes

1. Introduction

This section analyses the existing tax and royalty framework for petroleum exploration and development in Western Australia. The royalty, excise, RRR and PRRT regimes are compared, with a view to analysing any distortions between the different regimes which may favour investment in large scale export focused projects.

2. Overview of tax and royalty framework

The Commonwealth, State and Territory Governments levy taxes and royalties on petroleum products which are extracted from Commonwealth and State or Territory lands. These taxes and royalties are levied to ensure that the people of Australia who own the land which the companies are exploiting for commercial gain, are adequately compensated.

Broadly, if a hydrocarbon field is located in a Commonwealth area (defined as outwards of three nautical miles from the territorial sea baseline) it will be subject to the PRRT regime, which is levied by the Commonwealth Government. If a hydrocarbon field is located in State or Territory areas (on-shore or in coastal waters) it will be subject to petroleum royalties collected by the State or Territory, and a crude oil excise collected by the Commonwealth Government. The PRRT regime does not overlap with the royalty and excise regimes.

In Western Australia there are two exceptions to this arrangement, namely:

- Barrow Island, an on-shore field which is subject to a resource rent royalty (RRR) which is shared by the Commonwealth and Western Australian Governments; and

- North West Shelf exploration permits WA-1-P and WA-28-P, off-shore fields, which are subject to petroleum royalties and crude oil excises collected by the Commonwealth Government.

These royalties, taxes and excises are discussed in greater detail below.

3. Petroleum Resource Rent Tax

PRRT applies to all projects in Commonwealth waters (with the exception of North West Shelf Exploration permits WA-P-1 and WA-P-28 in Western Australia as mentioned above).

PRRT applies to all marketable petroleum commodities, which includes:

- Crude oil;
- Condensate;
- Sales gas;
- Natural gas;
- Liquefied petroleum gas (LPG); and
- Ethane.

PRRT does not apply to value-added products such as liquefied natural gas (LNG), though its feedstock attracts PRRT.

PRRT is an economic rent which taxes the profits of petroleum production in Commonwealth areas. PRRT is assessed at a rate of 40% of taxable profits of a petroleum project, after allowing for deductions including exploration expenditure, and project development and operating expenses.

Companies can carry forward un-deducted expenses, to offset against future PRRT assessable receipts. These un-deducted amounts can be carried forward at compounding rates which are set annually. The compounding rate for undeducted exploration expenditure is, in some cases (depending on when it was incurred) equal to the long term bond (LTB) rate plus 15%, while the compounding rate for other operating expenses is equal to the LTB rate plus 5%.

Additionally, a concession allows for un-deducted exploration expenditure to be transferred to another company under common ownership with a PRRT paying project (or between projects of the same taxpayer) where certain conditions are satisfied.

A further concession introduced by the Government in May 2004, allowed for a 150% uplift on PRRT deductions for certain eligible expenditure in designated frontier areas. This concession was designed to encourage exploration and development of remote fields, which were generally located at least 100km from a developed field. This concession was in place until July 2008, and many of the designated frontier areas were located off the coast of Western Australia.

All payments of PRRT are deductible for income tax purposes.

4. Resource rent royalty

In 1990 a resource rent royalty (RRR) was applied to petroleum production from the mature field at Barrow Island, after the Commonwealth agreed to waive the crude oil excise. The royalty from Barrow Island petroleum production is shared between the Federal Government (75%) and Western Australian Government (25%).

RRR is assessed in a similar method to PRRT (i.e. economic rent based on profit), with the key difference being that exploration deductions are limited to the year preceding the introduction of the RRR (1990).

5. Petroleum royalties and crude oil excise

In Western Australia, petroleum royalties and crude oil excises apply to all projects in coastal waters (within three nautical miles of the territorial sea baseline), on-shore areas, and the North West Shelf (exploration permits WA-P-1 and WA-P-28). Crude oil excises are levied by the Commonwealth, and royalties are levied by the Western Australian Government.[9]

5.1 Petroleum royalties

Royalties are assessed as a percentage of the wellhead value of petroleum production (between 10% and 12.5%). Royalties therefore, are not responsive to pre-wellhead expenses such as exploration and drilling expenditure, and producers will incur royalty liability once production commences. To calculate the wellhead value of production, producers generally apply a ‘netback’ approach, which allows them to deduct certain expenses from the sales value, including:

- crude oil production excise (Commonwealth royalties only);
- a proportion of the platform costs;
- certain processing and transportation costs;
- interest on depreciated value of capital items; and
- specified depreciation and operating expenses.

5.2 Crude oil excise

Crude oil produced on-shore, in coastal waters, and in the North West Shelf, is subject to an excise levied by the Commonwealth Government. The Commonwealth Government applies an excise on crude oil production in areas where PRRT does not apply (i.e. on-shore, coastal waters, North West Shelf).

[9] Some royalties, such as those from the North West Shelf, are shared between the Commonwealth and Western Australian Governments.

The first 30 million barrels of oil produced from a field are excise free, and historically, condensate, a light crude oil produced from gas fields, has been excise exempt. Currently, no on-shore fields are large enough to pay the crude oil excise.

The marginal excise rates for crude oil vary depending on when the oil was discovered. “New’ oil, discovered after 18 September 1975, has a top marginal excise rate of 30%, which is lower than the top marginal rate for “Old” oil, which is 55%. Companies calculate their crude oil excise liability by applying the relevant crude oil excise rate to the volume weighted average of realized free onboard price (VOLWARE price).

6. Historical framework

To understand the current tax and royalty framework which applies to petroleum exploration and development in Western Australia, it is helpful to have an appreciation of the historical amendments which have been made in response to requests from industry groups, or to promote certain types of investor behaviour.

In 1990, the Commonwealth Government waived the excise on crude oil produced from Barrow Island and entered into the Barrow Island Royalty Variation Agreement Act 1982 between Commonwealth, Western Australia, and the producer.

At the time, Barrow Island was a mature oil field, and under the prevailing royalty and excise regime, economic production could have ceased. To ensure optimal recovery of oil, the Government waived the crude oil excise, and entered into an agreement whereby a RRR was applied at a rate of 40% to the profits of the project, and shared between the Commonwealth and Western Australian State Government.

Since its introduction in 1987, the PRRT regime has seen a number of concessions introduced which have facilitated the viability of large scale projects developed in remote off-shore areas. In 1991 an amendment was passed to allow for undeducted exploration expenditure incurred after 1 July 1990 to be transferred to other PRRT paying projects under common ownership. This promoted the investment of large multinationals in a number of offshore projects, by facilitating companies to maximise the net present value of their investments, by reducing their overall PRRT liabilities.

As a further concession afforded to PRRT deductions, exploration expenditure in designated frontier areas was eligible for a 150% uplift. This concession was introduced in May 2004, and lasted until July 2008. Up to 20% of the offshore acreage areas each year could be designated as frontier areas, and a number of these areas were located in remote areas off the coast of Western Australia.

Additionally, amendments have been made to the PRRT legislation to calculate the appropriate transfer price for gas which is converted into LNG through integrated gas to liquid projects. These amendments were first announced in October 2001, and further amended in 2005, to provide taxpayers with a prescriptive formula as to how to calculate their transfer price, in the absence of arm’s length sales to a downstream operation.

Legislative amendments allowed the Commissioner of Taxation to apply a gas transfer price formula to calculate the PRRT payable on upstream gas production which was converted to LNG, in the absence of arm's length sales of the upstream gas.

In 2005, the Petroleum Resource Rent Tax Assessment Regulations were introduced to provide taxpayers with a framework to calculate their PRRT liability, where their upstream gas is converted to LNG, and where there is an absence of an arm's length sale of the gas.

7. Revenue

A review of the revenue sourced by the State and Commonwealth Governments has been provided to put into context the impact of any potential concessions. In the 2005-06 financial year Western Australian royalty receipts from petroleum and gas production, was equal to approximately $678.8 million dollars. In the 2005-06 year, the Commonwealth Government received from petroleum production onshore and offshore in Western Australia: [10]

- Approximately $804 million in PRRT receipts;[11]
- Approximately $291 million in crude oil excise receipts; and
- Approximately $373 million in royalties. [12]

8. Conclusion

The tax and royalty regime which operates in Western Australia does not appear to provide any *deliberate* bias in favour of investors pursuing large scale LNG projects. Companies will be subject to either the PRRT or royalty and excise regime, dependent on whether PRRT or a royalty regime applies to a particular petroleum field, which is determined by where that field is located, not the end consumer to which the petroleum field supplies.

Certain concessions which are provided under the PRRT system, may however act as an incentive for companies to explore and develop new fields located offshore in Commonwealth waters. As described above, PRRT is levied on the super profits (as the regime permits for compounding to recognise the timing and risk of the exploration expenditure incurred) of a petroleum project, and as such expenditure spent on exploring and developing a petroleum field reduces a company's PRRT liability.

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[10] ABS, *Western Australian Statistical Indicators, Mar 2007: Feature Article 1: The Resources Industry in Western Australia 2001-02 to 2005-06*

[11] Estimated by ABS based on 40% of total Australian PRRT

[12] Commonwealth royalties include North West Shelf Royalty, Resource Rent Royalty, and Internal Waters Royalty

Furthermore, concessions afforded to larger companies, or group companies, allow them to transfer these undeducted expenditures between projects or between companies, to minimize overall PRRT liability. This concession attracts large companies and groups of related companies, who have the capital and infrastructure to support exploring and developing multiple fields.

Furthermore, the exploration expenditure 150% uplift concession incentivises companies to explore and develop remote ‘frontier’ fields, located a substantial distance from existing infrastructure. Similarly, this concession is in practice only able to be utilised by large companies, with substantial amounts of capital and infrastructure. These fields are too large and too remote from existing infrastructure to be developed for the domestic market alone and tend to be developed with a focus on the LNG export market.

Many of the smaller gas fields are located on-shore and in coastal waters. These fields are generally not large enough to support an LNG development and as such gas developed from these fields could be directed into the domestic market. These petroleum fields are subject to the royalty and excise regime, where royalties are calculated on the wellhead value of the petroleum produced, as opposed to profits. Because of this, producers may incur royalty liabilities for years before fields become profitable. This will impact upon the net present value of the investment.

Concessions provided under PRRT may act as an incentive for large companies to explore and develop large size petroleum fields in remote offshore locations. Because of the scale of the projects in terms of reserve development and production potential, gas export options have been pursued.

Part 3 – Identification of appropriate incentives

1. Overview

Based on the review of the incentives which have been used in the resources and energy sector to promote behaviour, and the review of the current tax and royalty framework for gas exploration and development in Western Australia, the report has identified a number of alternative incentives to promote the development of gas fields to supply the domestic market.

APPEA has recently advocated that LNG projects are needed to underpin high cost offshore projects, allowing infrastructure to be built which can enable domestic gas to be supplied at a relatively low cost[13]. This approach assumes that domestic gas fields can be developed alongside large scale LNG projects, and can utilise the infrastructure developed for the LNG projects, to deliver gas to the Western Australian market. Given the significant infrastructure which would need to be developed, and the timing for commissioning such infrastructure, this approach might not be optimal for addressing the domestic gas supply shortage in the short to medium term.

Accordingly, an option for increasing the domestic gas supply is to focus on developing smaller fields which are not large enough to support LNG production. These fields could therefore be developed specifically to supply gas into the domestic market.

The tax incentives which have been identified focus on targeting the exploration and development of gas reserves located close to existing infrastructure either onshore or in coastal waters. Reasons why these reserves may not have already been developed may include:

- Size of the known reserves and potential size of unknown reserves;
- Inability of smaller companies to raise capital to explore and develop marginal fields;
- Difficulties associated with extracting the gas (i.e. tight gas reserves)
- Economics of exploring and developing the smaller fields under the current royalty regime.

Accordingly, the fiscal incentives which have been identified focus on addressing the facilitation of exploration and development of gas fields located either onshore, or in coastal waters, close to existing infrastructure.

[13] APPEA, 2007, *APPEA's Natural Gas Strategy: Presentation to the Australian Institute of Energy, Canberra*

The incentives are aimed at enticing new entrants in the upstream gas market, with a view to diversifying the supply of natural gas amongst a number of competitors, and a number of different reserves.

These incentives may be direct incentives, and specifically target the development of gas fields either onshore or in coastal waters, or the incentives may be indirect incentives, with broader application to petroleum development in general but still aiming to facilitate the development of domestic gas fields.

2. Incentives provided by the State Government under the royalty framework

There are a number of incentives which the Western Australian Government can provide under the royalty system, which could serve to promote the exploration and development of domestic gas fields. These incentives may either be direct or indirect incentives as described above, and their impacts can be quarantined from different industries, and from different States and Territories of Australia.

2.1 Royalty holidays

Under the current framework in Western Australia, companies which explore and develop gas fields onshore or in coastal waters, incur a royalty liability as soon as they commence producing the gas. Accordingly, companies may incur a royalty liability before they earn an economic profit. These royalties are deductible for income tax purposes. However for companies with carried forward losses, royalty deductions will only serve to increase their losses, which adversely impacts cashflows.

Royalty holidays offered by the State Government for the development of specific domestic gas fields will help to promote the development of these fields, by improving the upfront economics of a project. These royalty holidays are classified as a direct incentive as they can be specifically targeted towards the development of domestic gas fields.

Many smaller companies cannot sustain ongoing periods of losses, as they have limited access to finance. If they are not members of a tax consolidated group, these losses cannot be transferred to another group entity. Accordingly, these companies may need to earn profits within the first three years of the exploration and development of a petroleum field.

This could be achieved through royalty holidays, which would increase their cash flow by 10% (for illustrative purposes assuming a 10% royalty rate) of the wellhead value of hydrocarbons produced while they have carry forward losses, and by 7% of the wellhead value of hydrocarbons after they incur an income tax liability.

These returns would be factored in when modelling the economic feasibility of a project, and may help in pushing projects economically over the line.

Options for implementation

The incentive could be offered through either of the following means:

- as a more formal and uniform incentive built into the legislative framework (e.g. by way of regulations issued based on a legislated royalty holiday scheme for qualifying activities introduced into the *Petroleum and Geothermal Energy Resources Act 1967*); or

- more commonly, on a case-by-case basis (upon application) by way of a cash reimbursement / refund of the royalty paid by the eligible producer up to a specified number of years or volume of production (which may be agreed individually with the Minister for Energy and Resources, based on guidelines set out within a State Government royalty holiday scheme established and administered say by the Department for Industry and Resources).

2.2 Rebasing commodity value for royalty assessment

Currently royalties are assessed on the wellhead value of petroleum. The State Government could provide an incentive to companies to develop gas fields onshore and in coastal waters, by rebasing the value of the petroleum on which the royalty is calculated. This value could be rebased annually to a fixed price, or could be a modification of the current methodology, to be responsive to pre-wellhead expenditures such as exploration and drilling costs.

This incentive would be an indirect incentive as it would apply to the all petroleum developed onshore and in coastal waters of Western Australia. Given the number of marginal gas fields located onshore in Western Australia, this incentive could promote the development of gas fields for the domestic market.

Options for implementation

This measure can be formally implemented through an amendment to the *Petroleum and Geothermal Energy Resources Act 1967* to:

- redefine the meaning of the term “assessable well-head value” for petroleum produced;

- redefine the methodology for determining the “assessable well-head value” of petroleum produced, by reference to the rebasing or indexation methods outlined above; and / or

- introduce a specific provision on allowable deductions for eligible pre-well head expenditures such as exploration and drilling in certain defined onshore or offshore (coastal) gas fields.

Alternatively, the Minister for Energy and Resources may approve (on a case-by-case basis), an agreed methodology with the permit holder, lessee or licensee, for determining the assessable value of the well-head petroleum produced which takes into account the matters noted above (as provided for currently under section 145 of the *Petroleum and Geothermal Energy Resources Act 1967)*. However, for the process to be transparent, an established framework of guiding principles should be published (e.g. to define the eligible or qualifying onshore or offshore (coastal) projects or onshore petroleum exploration and recovery areas).

3. Incentives provided under the Commonwealth Taxation System

A number of incentives can be provided under the Commonwealth taxation system, to incentivise the development of domestic gas fields in Western Australia.

3.1 Reduction in statutory cap on effective life of upstream gas assets

The study undertaken by APPEA, has found that Australia's capital depreciation write-off periods of 15 to 20 years are less favourable than the five to ten year periods offered by many competing jurisdictions in the Middle East. [14] By reducing the statutory cap on effective life of capital assets used in upstream gas developments, this could enable assets to be depreciated at a faster rate, and would increase companies' cash flows in the early years of a project.

This incentive is an indirect incentive as it would apply across all States and Territories of Australia. The impact on other industries however would be quarantined, as the changes to the statutory cap on effective life could be limited to upstream gas assets.

For smaller companies investing at shorter term projects for the domestic market, this increase in depreciation rates would increase their cash flow in the early years of a project (assuming they are tax payable), increasing the net present value of their investment.

Options for implementation

The above measure will require a legislative amendment to the statutory capped life table for the oil and gas industry in subsection 40-102(5) of the *Income Tax Assessment Act 1997*.

3.2 Incentives for production of non-conventional gas

Western Australia has a number of significant onshore and offshore tight gas reserves, and it has been estimated that these reserves could contain gas resources of as much as 7 TcF. Many of these reserves are located onshore close to existing infrastructure, and could develop gas for the domestic market.

[14] APPEA, 2008, *2008-09 Pre-Budget Submission,* p.9

The current costs and risks associated with development of tight gas operate as a significant economic barrier to it becoming a significant source of gas to the domestic market. However due to the location of significant onshore reserves of tight gas, it has the potential to be a significant source of domestic gas supply.

A number of onshore tight gas fields are located close to recognised markets or existing pipelines. Development of these reserves would enable domestic gas to be supplied without a significant investment in infrastructure that may otherwise be required to transport the gas to market.

Tax incentives could therefore be provided to incentivise companies to invest and develop tight gas, which would help to improve the economics of the projects. These same incentives could also be applied to encourage conventional inshore and offshore domestic gas developments.

Two indirect incentives could be introduced to promote the development of tight-gas fields:

1 **Provision of a tax credit based on quantity of tight gas developed**

A tax credit based on production volume of tight gas, would enable companies to claim a credit against their income tax liability. This credit would help to compensate companies for the costs associated with extracting tight gas. Because the credit would be based on production quantity, companies would be incentivised to extract and develop the gas, in order to gain the credit. For the credit to be beneficial, the company would need to have an income tax liability. Therefore, a tax credit may not be successful in promoting companies to engage in high risk tight gas exploration, if they believe the likelihood of developing the gas and receiving the tax incentive is remote.

Options for implementation

As a measure unique to Western Australia, the incentive would more likely than not be provided by way of a cash reimbursement / refund of the federal income tax paid by the eligible taxpayer where the eligibility criteria are satisfied, as set out in the guidelines for a State Government “tight gas” tax credit or tax offset scheme, established and administered by the Department for Industry and Resources.

2 **Increased deduction for pre-wellhead expenses associated with tight gas development.**

A 175% uplift on expenditure incurred in exploring and developing tight gas reserves would help to improve the economics of tight gas development. The uplifted tax deduction would be available to companies once the expenditure is incurred, and the companies would not have to develop gas before they received the tax incentive. This tax incentive would act in a similar fashion to the current R&D tax concession, which explicitly excludes exploration and drilling activities as being eligible for the concession.

The impact of this incentive would be to reduce companies' taxable income, and may therefore be more attractive to companies with a tax liability.

This incentive should also be extended to other domestic gas developments, such as inshore or offshore conventional gas fields.

Options for implementation

Any changes to the federal tax system will require legislative amendment to the Commonwealth *Income Tax Assessment Act, 1997* (for example, Division 40) as it affects the federal income tax liability of taxpayers and could be considerably challenging to justify from an overall horizontal equity perspective.

As an alternative, a tax credit or rebate similar to the tight gas tax credit incentive discussed above could be introduced by the State Government to provide a cash rebate, whereby the amount of the tax credit will be based on 175% of the eligible tight gas exploration and development expenditure incurred by the taxpayer in a given year.

4. Concessional cash grants

Another option available to both the State and Commonwealth Government is the provision of cash grants to promote the exploration and development of gas fields for domestic supply.

Cash grants can be targeted towards development of fields suitable for domestic gas supply. Grants can be made available to all companies which satisfy certain eligibility requirements, or could be negotiated with individual companies on a project by project basis. Both the Commonwealth and State and Territory Governments have used grants to promote investment from industry.

The advantages of providing companies with cash grants as opposed to tax or royalty incentives previously mentioned include:

- Companies receive upfront financing. This may make grants an attractive incentive for smaller companies with inadequate access to the types of debt or equity financing available to large multinationals.

- Can be targeted so as to promote the exploration and development of fields suited to domestic gas supply.

- They are administratively straightforward to implement. By providing grants, the Western Australian Government can improve the economics of exploring and developing gas fields onshore or in coastal waters, without making amendments to the royalty regime.

Additionally, the provision of cash grants for exploring or developing gas fields in Western Australia could attract domestic and international investment.

Options for implementation

As noted, schemes for the provision of cash grants could be implemented at the State and/or Commonwealth Government levels without necessarily introducing new legislation or a legislative amendment.

Cash grants provided under an un-legislated scheme will be ultimately at the discretion of the Minister for Energy and Resources (which can be more flexible to take into account the circumstances of the explorer/producer and the project), whereas legislated schemes will, by their nature, be more rigid and uniform in their application.

For transparency, a broad set of guiding principles should be published by the relevant government body outlining the eligibility criteria and the quantum of the cash grants (including a scale, if the grants vary with the activity / spending level) for un-legislated schemes.

5. Flow through share schemes

Tax incentives which increase allowable deductions will only benefit companies which have taxable income. Therefore, tax incentives which increase allowable deductions, may not promote the desired behaviour in smaller companies bearing the exploration risk. For these companies, the payback period for their investment, even with additional tax deductions, may be too far into the future to make the project viable.

By implementing an FTS scheme, these companies would be able to pass these losses through to investors who could use the tax deductions, which could in turn create interest in FTS companies by this class of investor.

The FTS scheme could operate in a similar fashion to the one in Canada. Only certain designated exploration expenses could be passed through as tax deductions to shareholders, which would in turn finance either further exploration or development activities.

Option for implementation

Following the Canadian model, the above measure will require a legislative amendment to insert a specific allowable deduction provision within Division 25 of the *Income Tax Assessment Act 1997* that allows a tax deduction to eligible investors (shareholders) for the cost of acquiring shares in exploration companies which spend the proceeds from the sale of those shares entirely on designated exploration expenses (as defined).

An FTS scheme could be quarantined to smaller independent companies engaging in petroleum exploration of resources amenable to domestic gas production. This would limit the scope of any scheme while promoting Australia's long term energy security through domestic gas development.

6. Conclusion

There is no single tax incentive which is likely to promote singularly the exploration and development of domestic gas fields. Investors may be attracted to improvements in their short term cash flows, increases in their allowable deductions, or access to new avenues for financing. It is therefore prudent to consider a package of incentives, which, working in conjunction with each other, may promote the exploration and development of domestic gas fields and which may appeal to investors with various tax profiles.

Direct incentives which can be offered by the State Government, such as royalty holidays, and upfront cash grants, should be considered to encourage smaller companies to explore and develop domestic gas fields (including tight gas fields). Particular incentives can be offered on a case by case basis, and can be targeted towards investor profiles and specific gas fields.

Rebasing the commodity value upon which royalties are calculated will make onshore and coastal areas in Western Australia more attractive places for investment. Given that the size of many fields located either onshore or in coastal waters make them unable to support an LNG project, these fields could supply the domestic market. However this incentive would incur additional time to implement compared to direct incentives, as it would require amendments to state legislation.

To maximise the impact that income tax incentives would have on exploration and development of domestic gas fields, an FTS scheme could be introduced, to ensure investors of various tax profiles could take advantage of the incentives. These indirect incentives, such as faster depreciation of upstream gas assets, and concessions for tight gas development, may result in additional tax deductions or tax credits. To increase the cash flow of exploration companies, these deductions or credits must be able to be passed through to investors, who can actually utilise the tax saving. An FTS scheme will ultimately make any incentives provided under the income tax system more attractive, as they will benefit a broader range of taxpayers.

Another alternative to encourage domestic gas supply is to alter the state royalty system so that royalties are levied on petroleum profits (similar fashion to PRRT). If royalties were levied on profits, possible incentives such as allowing companies to offset costs against income from other projects could be considered. This report has not considered any large scale changes to the royalty regime (such as levying royalties on profits) as it has focussed on identifying incentives which could be provided under the existing royalty regime.

Part 4 – Recommendations

1. Overview

Based on the review of the incentives which have been used in the resources and energy sector, the Alliance recommends that a range of fiscal measures be implemented by the Federal and State Government:

- Commonwealth and State grants for new or frontier domestic gas developments;

- State royalty concessions for domestic gas developments;

- Increased Commonwealth deduction for pre-wellhead expenses associated with domestic gas developments; and

- Commonwealth Flow Through Share scheme for smaller petroleum companies engaging in domestic gas exploration and development.

2. Commonwealth – State grants

Commonwealth and State grants are one important avenue for supporting companies to explore for and develop gas fields for domestic supply.

Such grants are administratively straight forward to implement, and would support Australia's long term energy security by promoting competition and diversity of domestic gas supply.

Grants could also be used to promote new "frontier" developments and technology, such as greenfield tight gas developments. Grants have in the past been provided to support new technology development in the petroleum industry, such as coal seam methane and carbon sequestration.

3. State royalty concessions

State royalty concessions could provide important encouragement for domestic gas developments. These include royalty holidays, reducing the royalty rate or rebasing the commodity value for royalty assessment. Such concessions can promote the development of domestic gas fields by improving the upfront economics of a project, particularly for tight gas projects.

Any impact on State revenue could be limited, particularly where the concessions allow the development of a field that might otherwise be uneconomic to develop in its initial stages, which would subsequently generate significant royalties for the State over the long term life of the field.

The Alliance proposes a reduction in the royalty rate for domestic gas developments to 5% or the provision of royalty holidays for the first 6 years of a domestic gas project.

Where gas fields involve LNG projects with a potential domestic gas leg, royalty concessions can be provided for the domestic gas component to promote domestic supply.

4. Increased Commonwealth deductibility for pre-wellhead expenses

Increased deductibility for pre-wellhead expenses could be provided for domestic gas developments under federal taxation arrangements.

The Alliance proposes a 175% uplift on expenditure incurred in exploring and developing domestic gas reserves, particularly tight gas where development involves significant pre-wellhead expenses.

The uplifted tax deduction would be available to companies once the expenditure is incurred, and the companies would not have to develop gas before they received the tax incentive. The impact of this incentive would be to reduce companies' taxable income and may provide an incentive to companies with an existing tax liability.

5. Commonwealth Flow Through Share Scheme

A Flow Through Share scheme would provide significant assistance for smaller petroleum companies engaging in domestic gas exploration and development, and who are reliant on the market for risk capital.

Such a scheme would promote frontier and start-up developments where companies might not otherwise generate a taxable income in the initial project years that would make tax deductions an appropriate incentive.

By implementing an FTS scheme, these companies would be able to pass these losses through to investors who could use the tax deductions, which could in turn create interest and equity funding by investors.

Appendix

Quantitative impact of alternative fiscal incentives

To quantify the impact that fiscal incentives can have on domestic gas field developments, two quantitative models were examined:

- a near-to-shore conventional gas field; and
- an on-shore tight gas field.

The impact of alternative incentives has been calculated in terms of the net present value (NPV) of after tax cash flows which the projects are expected to yield over a 10 and 20 year period.[15]

The base case scenario represents the current fiscal and taxation regime, in which no incentives are offered. These projects forecast marginal returns over a 10 and 20 year period, to reflect the situations often facing potential investors in domestic gas fields.

The impact of the alternative tax, royalty and investor incentives on the NPV of the projects over a 10 and 20 year period are shown in the Table 1 below.

Table 1. Results of scenario modelling

	Scenario	Near-shore DomGas project				Onshore tight gas project			
		NPV of 10 years of after tax cash flows ($M)	% impact of incentive on NPV	NPV of 20 years of after tax cash flows ($M)	% impact of incentive on NPV	NPV of 10 years of after tax cash flows	% impact of incentive on NPV	NPV of 20 years of after tax cash flows	% impact of incentive on NPV
1	Base case (no incentives)	55.96	*na*	$18.52	*na*	$70.31	*na*	$119.76	*na*
2	Reduce royalty rate to 5%	89.79	*60.46%*	$57.14	*208.56%*	$91.48	*30.12%*	$144.13	*20.35%*
3	Royalty holiday until 2015	101.08	*80.64%*	$63.64	*243.68%*	$97.11	*38.13%*	$146.57	*22.38%*
4	Rebase commodity value for OPEX and depreciation	59.70	*6.69%*	$22.26	*20.21%*	$84.50	*20.19%*	$135.69	*13.30%*
5	Resource Rent Royalty (40%)	-70.84	*-226.60%*	-$101.75	*-649.45%*	-$0.33	*-100.47%*	$35.41	*-70.43%*
6	Uplift in pre-well head expenses (175% allowable tax deduction)	79.03	*41.23%*	$41.59	*124.60%*	$73.60	*4.68%*	$123.05	*2.75%*
7	Reduce statutory cap on effective life of pipeline to 10 years	60.48	*8.07%*	$22.63	*22.21%*	$71.24	*1.32%*	$120.93	*0.97%*
8	Provide 3 year cash grant to offset CAPEX	79.18	*41.49%*	$41.73	*125.37%*	$73.96	5.19%	$123.41	*3.05%*

15 A discount rate of 15% was used to calculate the net present value of future after tax cash flows

As demonstrated by the results, incentives such as reducing the royalty rate to 5% or providing a royalty holiday for the first 6 years of the projects have the greatest impact on the NPV of these projects over a 10 and 20 year period.

In these models, introducing a resource rent royalty has the effect of reducing the NPV of the projects, due to the significant revenue which the fields generate at the height of their production, relative to their costs.

Other fiscal incentives (such as rebasing commodity value for royalty assessment, providing increased deductions for eligible expenditure, allowing for quicker depreciation of capital assets or providing cash grants) all help to improve the NPV of the expected returns from the project.