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29 August 2008

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The Secretary
Select Committee on Fuel and Energy
PO Box 6100
Parliament House
Canberra ACT 2600

Dear Sir/Madam,

Re: Fuel and Energy

I refer to your letter of 10 July 2008 to Mr Gordon Martin requesting submission to The Senate Select Committee on Fuel and Energy.

Curtin University of Technology is pleased to provide the following submission to the Select Committee on some of the Issues of their enquiry.

Part 1 Summary

This submission makes the following recommendations on the Issues raised in the call for submissions.

Issue 4
The impact of an emissions trading scheme on the fuel and energy industry and related matters

Recommendations

- *Consideration is given to the case for no compensation (and no free emissions permits) being paid to power companies: such payments will undermine the integrity of the concept of the polluter-pays-principle.*
- *Regulatory requirements governing third party access to pipeline networks be reviewed to ensure that competition is not being restricted under the current regulatory environment.*
- *There is an urgent need for all aspects of gas security of supply to be studied in the context of potential major supply disruptions, given the likely major expansion of the gas industry in South East Australia.*
- *Research into CCS technology for large scale sequestration of CO2 from power stations be treated as a public good and funded by the Commonwealth. However, once the process has been shown to be environmentally and financially viable, no further subsidies should be given. The cost of CCS, when the technology is viable, must be borne by the power generators (and ultimately the consumers) if a carbon regime is to retain its integrity.*

Issue 6
Taxation arrangements on petroleum, diesel and gas products
Recommendations

- *Consideration is given to no offset in excise duty be given when carbon pricing impacts upon petrol prices.*
- *Consideration is given to a comprehensive range of environmental taxes ultimately replacing the excise duty on petrol, so that consumers are aware of the social cost of all emissions of pollutants in the transport sector, not just CO2 which is a relatively small component in the total.*

Issue 8
The role of alternative fuels to petroleum and diesel
Recommendation

- *The Commonwealth Government ensures that Geoscience Australia's scientific capability remains commensurate with its strategic resource identification and development mission.*
- *Consideration is given to whether there is a beneficial case for the country from delayed development of oil and gas fields.*
- *The requirements for fallow acreage release are reviewed against a background of international best practice, with the objective of in optimising lease retention strategy that benefits the nation, recognising that both State & Commonwealth jurisdictions are involved.*
- *Consideration is given to providing incentive to both industry and the research sector to develop technologies which improve oil recovery factors – including amendments to the tax legislation to encourage field trials and large scale EOR implementation projects.*
- *Consideration is given to studying the policy of retaining gas in-place to supply domestic markets to fully assess the short- and long-term consequences for Australia.*
- *Consideration is given to a joint evaluation of State and Federal tax regimes to determine whether changes (e.g. deferred tax and royalty regime for tight gas) would enable new gas sources to be brought on-stream.*

Part 2 Commentary

The following commentary is provided in support of these recommendations.

Issue 4
The impact of an emissions trading scheme on the fuel and energy industry and related matters

The principle for establishing a price for carbon, either through emissions trading or a carbon tax, is to restrict emissions of carbon dioxide, and hence environmental damage, to an acceptable level. This is achieved through the marketplace in two complementary ways. First, the price of carbon raises the cost of power generation

and hence electricity prices to the ultimate consumer, thus reducing their demand for electricity and lowering power generation requirements. Second, by raising the cost of power generation using fossil fuels, the price of alternative, lower-carbon, technologies will become more price competitive and hence the preferred option financially for investment in new plant. To the extent permitted by market forces, the cost of carbon would be passed on through the electricity pool to retailers and hence final consumers. The corresponding impact on coal-fired generators would be a decline in their net revenue. Renewable energy generators with negligible carbon footprints will experience net revenue gains, while relative (to coal) low carbon intensity gas generators may also experienced net revenue gains depending upon the extent of the impact on total electricity demand and the position of coal-fired generators in the market.

A recent study by ACIL Consulting for the ESAA concluded that the impact on NEM pool prices was relatively large compared with the resulting reduction in emissions. For $10 and $30 per tonne carbon prices, pool prices would increase by 14% and 53% respectively, with corresponding GHG emissions reductions in 2009-10 of 6.5 mt and 17.8 mt. These amounts are relatively small given the size of the impact on wholesale electricity prices, although the impact on retail prices (in percentage terms) would be considerably lower given that they must also reflect transmission, distribution and retailing charges.

Needless to say, the issue of compensation has arisen as a result of the new carbon pricing regime. The net revenue of Victoria's brown coal generators is going to be particularly adversely affected by the resulting cost impost, particularly at the $30 (and higher) level. However, since there will be winners as well as losers, allocating compensation at the sector level would not be a very effective way of compensating the losers. If, indeed, claims for compensation have any merit at all.

Recommendation

> *It is recommended that consideration is given to the case for no compensation (and no free emissions permits) being paid to power companies: such payments will undermine the integrity of the concept of the polluter-pays-principle.*

Impact on Fuel (Gas)

The proposed introduction of carbon pricing has led to a move towards greater use of gas for future power generation requirements. Gas turbines and/or hydro have always been regarded as the preferred technologies for meeting peak demand, but the efficiency and lower carbon emissions associated with Combined Cycle Gas Turbine (CCGT) plant has raised that technology as a commercially viable alternative to coal. Gas-based power generation technologies have a lower capital cost and shorter construction time than coal-fired plants. In addition, they can be built in modular form, expanding by small increments to meet increases in demand. Thus capital outlay is lower than for coal and a revenue stream commences earlier. With discount rates in the private sector significantly higher than those for public sector corporations, these factors explain the appeal of gas. On the downside, gas has traditionally been a more expensive fuel than coal and hence the predominance of coal generation technologies in the NEM. However, the adoption of carbon pricing will

offset this fuel cost advantage, albeit to an unknown degree at present, provided the cost of gas does not rise in response to higher demand to more than off-set any competitive gain.

Without a delivery infrastructure gas is "stranded". Even with a local pipeline infrastructure, the resource may be stranded locally due to the limited volumes that can be recovered. In other words, it may not be able to command world parity pricing. At present this accounts for the much lower cost of natural gas in the Eastern states, in contrast to Western Australia which is currently reliant for additional requirements on the North West Shelf producers where netback1 LNG export prices have placed a lower bound on the price of future supplies of domestic gas. Export LNG prices tend to be linked to international oil prices because of the long-term nature of the contracts.

Over the past decade, Australia's gas resources have been extended by the rapid development of coal seam gas, generally referred to as coal seam methane (CSM). Although regarded as a major hazard in coal mining and traditionally vented to the atmosphere2, modern technology has enabled CSM to now be regarded as a valuable energy resource. Geoscience Australia3 estimate that Australia's CSM reserves (predominantly in Queensland) at year-end 2006 to be 4642 PJ, based upon the published reserves of CSM operating companies. Whilst these CSM reserves may appear relatively modest, it must be remembered that a comprehensive CSM resource evaluation has yet to be undertaken. However, for the same date, Wood MacKenzie has estimated the total 2P4 gas resource of Eastern Australia at 13,980 PJ.5 Approximately 23 years of forward production at current rates.

There are currently three publicly announced plans for constructing LNG export terminals in Gladstone using Queensland's CSM gas as feedstock. If these planned investments come to fruition it could be expected that international LNG prices would place significant upward pressure on Queensland's domestic gas prices. However, in the near term, CSM producers are likely to monetise their resource domestically in order to obtain a revenue stream to support any expansion into the high upfront capital cost LNG industry. Unlike their North West Shelf counterparts they cannot benefit from the high value liquid hydrocarbons that are generally associated with natural gas and provide a significant revenue stream early in the project life-cycle.

Alternative gas supply options that would be technically, but not commercially, viable at present would be either a long-distance pipeline providing the eastern states with gas from the North West Shelf or Papua New Guinea; or importation of LNG. Wood MacKenzie has estimated delivered costs at $8/GJ and in the range $10-13/GJ,

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[1] The netback price is the price at which LNG producers would be getting the same return on domestic gas sales as for LNG, taking into account the relevant infrastructure required to produce the two products.

[2] With a warming potential 21 times higher than carbon dioxide, methane is a highly intensive greenhouse gas.

[3] Wood Mackenzie, Expert Report for the *Inquiry into Electricity Supply in NSW.*

[4] 2P resources refers to both proven and probable reserves, and represents the industry's expected volume of gas that can be produced and sold. It is general industry practice in Australia to contract based on 2P gas reserves volumes.

[5] Wood Mackenzie, Expert Report for the *Inquiry into Electricity Supply in NSW.*

respectively, for these options.6 They concluded that "it is unlikely that the Eastern Australian market would require this sort of supply before 2020".

Gas is delivered by high pressure pipeline from the fields to designated points (known as city gates) for subsequent delivery to industrial and residential consumers via lower pressure distribution grids. These pipelines have permitted the rapid expansion of gas availability to NSW and Queensland, and a number of new pipeline developments are planned to link the CSM resources in these two states with the major centres of demand. However, an on-going concern is the issue of third party access to pipeline networks and regulated tariffs.

Recommendations

It is recommended that:

1. *Regulatory requirements governing third party access to pipeline networks be reviewed to ensure that competition is not being restricted under the current regulatory environment.*
2. *There is an urgent need for all aspects of gas security of supply to be studied in the context of potential major supply disruptions, given the likely major expansion of the gas industry in South East Australia.*

Impact on Technology

The impact of carbon pricing on the generation technology mix clearly depends upon the marginal cost of abatement of the various options open to the generators in combination with the industry-wide emissions cap (and its future trajectory) imposed by the Commonwealth. In the short term, the choice of abatement measures with a short lead time is rather limited, therefore abatement will largely occur as a result of fuel switching to low emission intensity gas plant. In the EU ETS, for example, there have been some unexpected fuel switches within coal (from lignite to hard coal) and a higher demand for biomass.

In the long run, abatement will have to increase significantly to reflect tighter emissions caps. This may be reflected in:

- a marked increase in the level of renewable generation;
- conversion of integrated gasification combined cycle (IGCC) coal plant to include pre-combustion carbon capture and storage (CCS);
- change in the dispatch order of existing plant; and,
- limited retirement of some old coal fired plants in the NEM.

Throughout this timeframe, however, significant increases in the (real) price of electricity may encourage energy efficiency in end-use thus reducing the growth of demand below what it would have been in the absence of a carbon price.

The role of carbon capture and storage (CCS) in combating climate change is currently widely debated. In simple terms, carbon dioxide is captured from fossil fuel power plants (and potentially other major sources of emissions) and then put into long-term storage in deep geological formations instead of releasing it into the atmosphere. The separate elements of capture, transport and storage of carbon dioxide

[6] Wood Mackenzie, Expert Report for the *Inquiry into Electricity Supply in NSW.*

have all been demonstrated, but the integration into a complete CCS process has not been achieved to date. Technology for large scale capture of CO_2 is already commercially available and fairly well developed. Although CO_2 has been injected into geological formations for various purposes, the long term storage of CO_2 is a relatively untried concept. Therefore it is unclear when this technology will be available in delivering significant CO2 sequestration.

CCS applied to a modern conventional power plant could reduce CO_2 emissions to the atmosphere by approximately 80-90% compared to a plant operating without CCS. However, capturing and compressing CO_2 requires significant amounts of energy and would increase the fuel needs (and hence fuel costs) of a coal-fired plant with CCS by about 30%. In addition, pipeline transport of CO_2 to the site of storage would be required. Unit (i.e. \$/tonne CO_2) transportation costs are heavily dependent on quantities and, to a lesser extent, the distances involved. Not surprisingly, therefore, indicative costs for coal plant with CCS vary widely, with the IEA quoting a range of from US\$40 to US\$90 per tonne of CO_2 captured and stored depending on the power plant fuel and the technology used. It anticipates that costs could fall below US\$25 per tonne of CO_2 captured for coal fired plants by 2030 with sufficient R&D support. This amounts to approximately US\$0.01 to US\$0.02 per kWh in 2030 for capture, transport and storage.[7]

This relatively optimistic projection for CCS suggests that it will be a relatively low cost future option for mitigating CO_2 emissions, especially in countries such as Australia that have access to significant reserves of cheap coal for power generation. A carbon price will be essential for the widespread deployment of CCS, in the absence of other significant commercial benefits flowing from the technology (such as enhanced oil recovery). CCS may also render coal-to-liquids technology economically viable in the presence of high oil prices.

Recommendation

> *It is recommended that research into CCS technology for large scale sequestration of CO2 from power stations be treated as a public good and funded by the Commonwealth. However, once the process has been shown to be environmentally and financially viable, no further subsidies should be given. The cost of CCS, when the technology is viable, must be borne by the power generators (and ultimately the consumers) if a carbon regime is to retain its integrity.*

Issue 6
Taxation arrangements on petroleum, diesel and gas products

The excise duty on petrol and diesel is currently \$0.38143 per litre if used in transport (other than aircraft). This duty pre-dates concerns over emissions of CO_2, and thus has more of a revenue raising, as opposed to environmental, objective. GST is payable on this duty, making the total "tax" just under 42 cents per litre (plus the GST on the fuel itself).

[7] IEA, *Energy Technology Perspectives 2006*, OECD/IEA, Paris.

The proposed introduction of carbon pricing in 2010, via an emissions trading regime, has led to calls for a corresponding offset in the excise duty and/or the GST on the excise duty. This would effectively leave petrol prices unchanged. Leaving aside the mechanics of how that could actually be achieved in practice, there is a sound argument for additional environmental taxes on transport fuels to reflect the external deleterious impacts of the transport sector.

The ExternE study, undertaken by the European Commission, has valued the damages arising from the transport sector from combustion emissions other than CO_2 at far higher levels than for CO_2 itself (the reverse is true for the stationary power sector). Although any off-setting reduction in excise duty may be politically popular in the context of carbon pricing, a more extensive range of environmentally-based taxes should be considered as a replacement for excise duty. Of course, non-combustion damages from the transport sector are also important (e.g. accidents, congestion, etc.). These also go largely unpriced (although some are covered by insurance policies).

Recommendations

It is recommended that consideration be given to:

1. *No offset in excise duty be given when carbon pricing impacts upon petrol prices.*
2. *Consideration is given to a comprehensive range of environmental taxes ultimately replacing the excise duty on petrol, so that consumers are aware of the social cost of all emissions of pollutants in the transport sector, not just CO_2 which is a relatively small component in the total.*

Issue 7

The role of alternative fuels to petroleum and diesel

Please refer also to our submission to Issue 4.

Compressed Natural Gas

A number of countries are on the point of sanctioning greater use of Compressed Natural Gas (CNG) in commercial applications. In Australia, large-scale industrial and/or power generation options for CNG as an alternative to diesel has received little or no attention.

Hydrogen

Until hydrogen generation from renewable energy sources can be achieved economically, and at scale, and also can be made widely accessible, then use of hydrogen is as an alternative energy fuel is not seen as a viable near-term option.

Currently hydrogen for pilot trials is primarily derived from natural gas, which generates concomitant greenhouse gas by-products. As well as this environmental issue, the low energy density of hydrogen compared to petroleum products limits its effectiveness as an alternative to current petroleum-based transport fuels.

Issue 8

The domestic oil/gas exploration and refining industry

Domestic Exploration – Point 1

The importance of Geoscience Australia's (GA's) pre-competitive role in identifying new prospective exploration acreage, and then engaging industry to explore it, appears not to be matched by the resources allocated to it.

Continued under-resourcing of GA will damage both the Commonwealth's and States' ability to ensure that Australia remains internationally competitive in attracting and retaining local & international exploration investment. An example of this under-resourcing is GA's seemingly restricted capability to perform a comprehensive resource quantification of national Coal Seam Methane potential.

Recommendation

It is recommended that the Commonwealth Government ensures that Geoscience Australia's scientific capability remains commensurate with its strategic resource identification and development mission.

Domestic Exploration/Development – Point 2

It is noted that there are some 93 discovered oil and gas exploration and production fields shut-in within the State of WA alone. At now-prevailing prices, some of these might be developed economically. Existing operators are, however, asking to defer their development for various reasons.

Recommendations

It is recommended that consideration is given to an enquiry into:

1. *Whether there is a beneficial case for the country from such delayed development.*
2. *Review fallow acreage release requirements against a background of international best practice, with the objective of in optimising lease retention strategy that benefits the nation, recognising that both State & Commonwealth jurisdictions are involved.*

Domestic Exploration/Development – Point 3

Recovery practices for Australian oil fields typically leaves 65% of known oil in the reservoir. Improving oil recovery factors using Enhanced Oil Recovery (EOR) techniques will contribute to Australia's greater self-sufficiency in oil production.

Recommendation

It is recommended that consideration to be given to providing incentive to both industry and the research sector to develop technologies which improve oil recovery factors – including amendments to the tax legislation to encourage field trials and large scale EOR implementation projects.

Domestic Exploration/Development –Point 4

The policy of the current WA state government is that offshore gas operators with onshore processing plants located within the State are required to retain a percentage of gas in-place to supply the domestic gas market (the domgas market). Whilst the objective of this policy – ensuring that industry in not starved of gas in the face of gas exports – is not disputed, the potential issues loom of free-market distortion, of unnecessarily increased development costs and, consequent, of sub-optimal resource development.

Recommendation

It is recommended that this policy is studied to fully assess the short- and long-term consequences for the State and for Australia.

Domestic Exploration/Development –Point 5

Noting that diversity of gas supply is generally seen as beneficial (particularly in WA, but also elsewhere in Australia) and that discovered onshore low permeability ('tight or 'unconventional') gas resources are significant, is greater co-ordination of Federal and State policies necessary?

Recommendation

It is recommended that consideration be given to a joint evaluation of State and Federal tax regimes to determine whether changes (e.g. deferred tax and royalty regime for tight gas) would enable new gas sources to be brought on-stream.

Mark H Woffenden
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Resources and Chemistry Precinct