Submission of the National Competition Council to the CoAG Energy Market Review

APRIL 2002

National Competition Council

Table of contents

Abbreviations

$/GJ	Australian dollars per Gigajoule
$/TJ	Australian dollars per Terajoule
ABARE	Australia Bureau of Agricultural and Resource Economics
ACCC	Australian Competition and Consumer Commission
ANZMEC	Australian and New Zealand Minerals and Energy Council
CoAG	Council of Australian Governments
Code	National Electricity Code
Council	National Competition Council
CPA	Competition Principles Agreement
DNSP	Distribution Network Service Provider
DUOS	Distribution Use of System
EGP	Eastern Gas Pipeline
ESC	Essential Services Commission
FRC	Full retail contestability
GJ	Gigajoule, a unit of measurement for measuring the energy content of natural gas or other energy sources
GPAL	Gas Pipelines Access Laws
GST	Goods and services tax
ICRC	Independent Competition and Regulatory Commission, ACT
IPART	Independent Pricing and Regulatory Tribunal, New South Wales
MSP	Moomba-Sydney pipeline
MWh	Megawatt-hour (a unit of measure for electricity consumption)
National Gas Access	National Third Party Access Code for Natural Gas Pipeline

Code (Gas Code)	Systems
NCP	National competition policy
NECA	National Electricity Code Administrator Ltd
NEM	National electricity market
NEMMCO	National Electricity Market Management Company
NGPAC	National Gas Pipelines Advisory Committee
PC	Productivity Commission
PJ	Petajoule (equal to 1,000,000 GJ or 1,000 TJ)
PSLA	Petroleum (Submerged Lands) Act
RIEMNS	Review into the Integration of Energy Markets and Network Services
RRN	Regional Reference Node
SAIIR	South Australian Independent Industry Regulator
TJ	Terajoule (equal to 1,000GJ)
TNCP	Transmission Network Connection Point
TNSP	Transmission Network Service Providers
TPA	Trade Practices Act 1974
Tribunal	Australian Competition Tribunal
TUOS	Transmission Use of System
UIWG	Upstream Issues Working Group

Overview

This is the submission of the National Competition Council (the Council) in response to the Issues Paper; dated May 2002 issued by the Council of Australian Governments Energy Market Review (the Review).

The Council is currently conducting this year's assessment of progress of Governments in the implementation of National Competition Policy (NCP). The final assessment will be issued after 30th June 2002. Until such time, the Council considers it would be inappropriate to detail any specific areas of concern it may have in the context of this submission. This submission does, however, foreshadow broad areas of policy concern. The Council does anticipate providing the Review with supplementary submissions as its NCP assessment work progresses.

Energy reform under NCP

In 1990, all governments in Australia agreed to a reform process that led to the creation of a National Electricity Market (NEM). Two years later, governments agreed to create its equivalent in the gas industry: arrangements to ensure national free trade in natural gas. Since then, these agreements have been amended in an endeavor to develop and refine a national policy framework for energy reform in Australia. In 1995 CoAG incorporated the electricity and gas reform agreements into the NCP agreements and assessment process.

Electricity reform under NCP

The aim of the electricity reform process was to achieve "a fully competitive market" characterised by:

- non discriminatory access to transmission and distribution networks;
- removal of regulatory barriers for new participants in generation or retail supply;
- removal of regulatory barriers to interstate and/or intrastate trade; and
- the ability for all customers to choose their supplier.

Significant structural reform of the state-owned monopolies was an important component of the reform process and Governments developed the National Electricity Code as the mechanism to deliver a fully competitive market.

The Code was developed to govern, in broad terms, the transition to and operation of the market, including setting the trading rules, network pricing principles, system controls and rules for access to networks. Subsequently, governments agreed to fully implement the market arrangements specified in the Code and to have the Code authorised by the Australian Competition and Consumer Commission (ACCC) and accepted as an access undertaking under the *Trade Practices Act 1974* (TPA).

The electricity agreements tended to be driven by, rather than drive, the development of the Code. Further, the stated objectives of the agreements were ambiguous, particularly in the context of the Code. This meant that reform implementation was related, by and large, to the approval of the Code by the ACCC and related processes, rather than comprehensively subject to the discipline of the assessment of NCP reform implementation and the competition payments. There has been no overarching national policy guidance or co-ordination. The ACCC approval processes, because they are inherently reactive rather than proactive, have been, understandably, a blunt instrument in policy development and implementation. This has placed the ACCC, and to some extent NECA, in a difficult position in, by and large, trying to identify and achieve policy objectives using only the regulatory instruments governments have provided to them.

Gas reform under NCP

While the CoAG gas reform agreements date back to 1992, substantial progress was not achieved until gas reform was rolled into NCP in 1995. In 1994-5 there were some unilateral attempts to introduce state-based access regimes for gas pipelines and some restructuring of publicly owned gas businesses, often with a view to privatisation. In mid-1995, the intergovernmental Gas Reform Task Force (GRTF)[1] was established to develop a uniform national access code for gas pipelines. The work of the GRTF was later handed over to the Gas Reform Implementation Group (GRIG). Final agreement on implementation of the National Gas Access Code was achieved in 1997 and each government passed relevant legislation for the code and attendant rules over the following eighteen months.[2] In accordance with the 1997 agreement, each government sought, or is seeking, certification

---

1 This group, as with GRIG and UIWG, also included representatives from the upstream and pipeline sectors of the industry as well as major gas users.

2 Queensland's legislation became operational in May 2000 and Tasmania's legislation became operational in 2001. A natural gas sector has only recently developed in Tasmania.

of their implementation of the agreed gas laws as an effective regime under Part IIIA.

Since the implementation of NCP in 1995, governments have also individually addressed other obligations under the gas agreements and under general competition policy principles to achieve national free and fair trade in gas. Some of this work has been designed to reduce regulatory and other barriers to competition in gas production, guided by the inter-governmental Upstream Issues Working Group (UIWG). The Queensland, Western Australian and South Australian governments have reformed acreage management and other upstream regulatory arrangements. Other governments are expected to complete reforms in this area in the near future. Governments have also addressed their obligations to provide for contestability in gas supplies down to the household level.

The Council has overseen the implementation of all elements of gas reform under NCP by governments. The Council's assessment process and the discipline of competition payments has been a critical driver in reform implementation in the gas sector.

Policy objectives and development

The experience to date with NCP reform implementation, particularly in relation to the electricity and gas sectors, and the nature of the changes that the Council considers are needed in the NEM policy architecture, suggests that this Review should start with basic principles associated with the role of policy development and implementation in competition policy reform.

The reform process

Any competition policy reform process, including under NCP, involves (or, at least, should involve) several distinct stages: policy development, policy implementation, appropriate regulation of market failure, and more competitive market outcomes. Clearly, there are close relationships between these distinct stages and feedback between the stages is important to test whether settings are appropriate. But equally, it is important to recognise that each stage has a particular role and place in the sequence of events associated with reform. Further, where problems with reform or the need for further changes are identified, each stage of the reform process needs to be analysed to test which stage needs to be addressed. For example, arguments that less pipelines should be covered under the National Gas Code because regulated returns on covered pipelines are too low make little sense.

The need to address competition policy issues in processes distinct from regulation and the particular impacts of competition on businesses and individuals is generally accepted. The Hilmer Review recognised this distinction:

> *Competition policy is not about the pursuit of competition* per se. *Rather, it seeks to facilitate effective competition to promote efficiency and economic growth while accommodating situations where competition does not achieve efficiency or conflicts with other social objectives. These accommodations are reflected in the content and breath of application of pro-competitive policies, as well as sanctioning of anti-competitive arrangements on public benefit grounds.* (Hilmer Review 1993, p.xvi)

Further, the Hilmer Review recognised that policy matters involve broader considerations than administration and enforcement of regulation, and therefore require distinct policy development processes and institutions. In its discussion of developing and applying competition principles in relation to the 'additional policy elements' (regulation reform, structural reform, access to essential infrastructure, competitive neutrality and prices oversight) the review said:

> *These policy elements differ from the competitive conduct rules in significant ways. While prohibitions on market conduct can be defined with some precision, and then administered through administrative bodies or the courts, the additional elements typically involve more difficult policy assessments...The key institutional tasks under these policy elements were shaped accordingly.* (Hilmer Review 1993, p 317)

Consequently, the Hilmer Committee concluded that it was not appropriate for any existing organisation (such as the then Industry Commission or THE ACCC) to provide policy advice to governments at a national level on the additional policy elements that the review had identified. The Committee recommended the creation of the Council to fill this void.

Similarly, the Office of Regulation Review (ORR), in its 1999 *A Guide to Regulation*, also recognised the general principle that policy development should be maintained as a distinct process from regulatory design (policy implementation):

> *While some regulation is necessary and beneficial, there are some cases where it may not be so or where it could be better designed. Regulation should not only be effective, but should also be the most efficient means for achieving relevant policy objectives. In this context, there is a public perception that rule makers too often concern themselves with the issue of effectiveness, ignoring efficiency issues (that is, existing regulation may be effective, but it may not necessarily be the 'best' means for achieving the particular policy goal).*
>
> *Determining whether regulation meets the dual goals of 'effectiveness' and 'efficiency' requires a structured cost-benefit approach to policy development. The relevant problem to be addressed and subsequent policy objective should be identified as a first step in the policy*

> *development process, followed by consideration of a range of options (including no action) for achieving the objective. The benefits of any regulation to the community should outweigh the costs.* (ORR 1999, p. B1)

The Australian Competition Tribunal (the Tribunal) has also recognised the importance of this distinction between policy settings and market outcomes in setting the test for the promotion of competition in relation to decisions on infrastructure to be covered by access regulation under Part IIIA:

> *The Tribunal does not consider that the notion of "promoting" competition in s 44H(4)(a) requires it to be satisfied that there would be an advance in competition in the sense that competition would be increased. Rather, the Tribunal considers that the notion of "promoting" competition in s 44H(4)(a) involves the idea of creating the conditions or environment for improving competition from what it would be otherwise. That is to say, the opportunities and environment for competition given declaration, will be better than they would be without declaration.* (Sydney Airport Case, at 40,775)

This approach to interpretation of the coverage criteria was confirmed in the Tribunal's Eastern Gas Pipeline decision. The Tribunal has drawn a clear distinction between setting the test for coverage of access regulation under Part IIIA including what that test means for the *environment for competition*, and actual market outcomes and the *level of competition* realised. Policy reform is about getting an effective environment for competition, not about the level of competition at any particular point in time.

Competition policy is determined and implemented by governments as part of their responsibilities and subject to the political process. As recognised by the Hilmer Review, this policy process is subject to a wide range of economic and social considerations. Separate processes and institutions are needed to deal effectively with policy matters. The ORR has suggested that policy development and implementation should include explicit consideration of the problem/s being addressed, the objectives of any government intervention, questioning whether regulation is needed and if so, designing effective and efficient regulation. The Tribunal considers that the application of regulation via the Gas Code coverage process is concerned with creating an appropriate environment for competition rather than actual market outcomes.

Once policy is implemented through regulatory processes, it follows that enforcement and/or administration of that regulation by the courts, quasi-judicial bodies or regulators is a further and distinct step in the chain. Last in the chain is the impact on markets of policy development, policy implementation and regulation; that is, the actual market outcomes.

While poor market outcomes may *indicate* that policy settings *may not* be appropriate, ultimately, competition policy issues should be analysed with a view to the long-term environment for competition. Policy changes should not be justified merely by poor market outcomes. The poor market outcomes should be linked to a specific policy weakness, the weakness analysed and remedial policy action taken. For example, the exercise of market power by particular market participants, which is often a normal part of an efficiently operating contestable market, may merely reflect good performance by those participants. Policy adjustments to address this market power may deter competitive behavior rather than encourage it. But the sustained exercise of substantial market power may indicate that the regulatory environment for competition does not sufficiently address market power problems because, for example, a regulator is under resourced.

Three elements that are important to ensure an appropriate separation of policy development and implementation, regulation and market outcomes include:

- policy development requires, as a starting point, clear policy objectives;
- the policy objectives need to be reflected in robust and consistent rules, with an appropriate balance between certainty and flexibility; and
- institutional arrangements need to reflect the split between policy development and regulation.

Reform objectives in energy markets

The role of governments in the energy market reform process is to ensure that the policy development and implementation for energy market reform is appropriate. The first step in this process is to identify and/or confirm the policy objective/s of reform. The current objective of gas reform under NCP is clear: the promotion and facilitation of effective competition in gas markets, including the regulation of natural monopoly gas pipelines where necessary and appropriate to facilitate this end. The objective of the NEM is less clear. This is discussed further below.

The need for robust and consistent rules

It is well recognised that markets do not operate well in an environment of high ‘sovereign risk’; that is, where markets are subject to unpredictable political intervention. This does not mean that the implementation or application of policy should be set in concrete. But it does mean that:

- the policy and rules should be firm; and
- where there is any flexibility in implementation or application (as may be appropriate to adapt to a changing economic environment), that this flexibility is consistent and predictable and subject to an identified range of considerations.

Similarly, the enforcement and administration of regulation should be free of political intervention and subject to robust and consistent rules. Enforcement and administration bodies should be independent, objective and transparent. The trend in Australia towards independent statutory bodies to conduct economic regulation is consistent with this principle.

Thus, clear policy objectives and the separation of policy processes and institutions from regulatory processes and institutions should be reflected in clear and consistent rules for enforcement by independent regulators to provide certainty in markets. This has already been achieved in the gas sector. The changes canvassed in this section and later in the electricity section are designed to achieve the same result in the NEM. Vitally important for effective markets, governments should not be involved in the day to day operation of those markets. The role of governments ends in establishing and maintaining the laws and regulations to create the right environment for effective regulation and markets.

Appropriate institutional arrangements

Just as it is important to recognise the difference between the role of policy from that of regulation in the context of the reform process, it is necessary to ensure that the institutional arrangements set in place to achieve the reforms reflect this difference.

The institutional arrangements need to be appropriate to the objectives to be achieved by not only separating policy development and monitoring from regulatory functions, but also by ensuring that the bodies responsible for each are equipped with the right tools to successfully achieve their roles.

The Council considers that governments have implemented appropriate institutional arrangements for gas reform, but that there has been some confusion of roles in relation to the NEM. As identified above and discussed more fully in the electricity section of this submission, the Council considers that the institutional arrangements for the NEM should include in addition:

- a policy co-ordination forum to identify important refinements to the NEM policy architecture; and

- a process for co-ordinating and monitoring the implementation of the identified policy reform measures that will ensure effective reform implementation.

Summary of key issues

The different approaches to reform implementation under NCP, and in particular, the lack of overarching guidance in policy development and reform implementation in the electricity sector, has meant that there is now more work to be done in electricity reform than in gas. The more complex issues associated with electricity reform, and the NEM, and the generally greater sensitivity of governments to electricity issues, have also been important factors here.

Electricity

Significant progress has been made in the implementation of the electricity reforms as evidenced, most notably, by the disaggregation of utilities and the establishment of the NEM. The implementation of electricity reforms has seen significant benefits accrue both in terms of cost savings and economic efficiencies. ABARE estimated that Australia's gross domestic product by 2010 will be 0.26 per cent ($2.4 billion in 2001 prices) higher than in the absence of reform, with the net present value of benefits of reform between 1995 and 2010 totaling $15.8 billion in 2001 prices (Short et al. 2001, p. 84).

Despite these substantial benefits from the NEM, there have been many critics of electricity reform. The criticisms are made against a background of rising energy costs worldwide (driven by rising oil prices and demand for energy) and the gradual exhaustion of excess electricity generation capacity as demand rises, eroding opportunities for low wholesale electricity prices. Some have suggested that the electricity market is inevitably following the path of problems experienced overseas, particularly the high profile failures in California, and governments should immediately and intrusively re-regulate the industry.

Others have criticised the NEM because there has been an increase in coal-fired electricity generation, exacerbating environmental problems. The Senate Environment, Communications, Information Technology and the Arts Committee recommended that the Council's assessments incorporate benchmarks for the reduction of the greenhouse intensity of power generation (Recommendation 31) (Commonwealth of Australia 2000). As the Senate Committee recognised, however, this is beyond the current scope of the NCP agreements (see Recommendation 30). It is open to governments to introduce policies designed to deal with the social implications of electricity supply and consumption, such as rules or general tax or subsidy measures to correct for the environmental costs of electricity. Indeed, the NEM separation of generation activities from other parts of electricity supply facilitates such policies. Some measures have already been introduced to allow consumers to choose 'green' electricity without impeding the operation of the market.

The NEM is approaching a watershed in its development and decisions made by governments in the near future will determine its future structure and performance. However, the issues arise because of a need to clarify the overarching policy objective of the NEM and refine the market arrangements, rather than overturn them. The overall market framework, which provides for competition between generators and retailers of electricity and shared use of transmission and distribution infrastructure, provides the best opportunity for an efficient electricity industry and competitive prices to consumers in the long run.

Governments have a clear role, from an economic policy perspective, in ensuring that the NEM architecture is and remains appropriate. However, it is also important to retain the independent operation and regulation of the NEM. Governments need to determine between two approaches in deciding what is the appropriate regulatory framework for the NEM.

The first option would be to facilitate competition in electricity generation and retailing only. Regulated networks would not be open to competition. Rather, under this “common carriage” approach, transmission and distribution infrastructure would be managed through a central planning process and/or with regulatory oversight so as to promote competition in electricity generation and retailing. Investment in network infrastructure, including interconnection between regions, would be governed by a net community welfare prudent investment test (rather than more targeted testing of the costs and benefits of the investment). There would be no presumption in favour of investment in generation or unregulated interconnection. This approach is compatible with more regions and better locational pricing of wholesale markets. Indeed, combining wholesale market reforms with the common carriage approach to networks would confer significant benefits, including by assisting decisions about network augmentation (because price differentials between regional wholesale markets would help quantify the overall costs of network constraints). Network pricing could not be used to signal efficient investment in, and despatch of, generators, so other mechanisms would be needed to ensure appropriate incentives.

The second option would be to facilitate competition at all levels of the industry including networks. An aim under this approach (referred to as the “congestion management” approach) would be to provide market signals to market participants for the efficient investment in, and the efficient operation of, electricity generation, retailing, transmission and distribution services. This approach recognises the inter-relationship between augmentation of electricity transmission (and, at least in some respects, distribution) infrastructure and new investment in generation. In short, this approach seeks to provide an integrated set of market signals for the efficient supply of all electricity services.

The current NEM market arrangements are a hybrid of these two approaches. In particular, intra-regional transmission network planning and development is most closely akin to the common carriage approach with the network investment decisions centrally coordinated and taken by the network planner/owner. Inter-regional network planning and development provides for both regulated and unregulated interconnection. The approval process for regulated interconnectors and the role of unregulated interconnectors have characteristics of the congestion management approach. There is a bias against new regulated interconnection (with a ‘beneficiary pays’ and ‘last resort’ set of tests) and proponents of unregulated interconnectors respond to market signals and can offer access on discriminatory terms.

The Council has on a number of occasions expressed concern as to the lack of interconnection and system augmentation to address constraints within the NEM. The Council considers that not only does the hybrid network approach adopted under the Code demonstrate a degree of confusion as to the purpose of the NEM, but also has, to a significant extent, resulted in the development of a regional rather than national transmission network.

In terms of the two approaches set out above, the Council considers that the first approach would likely work more effectively than the current hybrid approach, at least in providing an effective energy market and supply security. This approach would also maximise opportunities to share reserve capacity. However, this approach would risk excessive investment in the grid and may provide poor signals for efficient investment in new generators. In fact, this approach risks inappropriately deterring new investment in generation and unregulated interconnection.

The second approach, while more complex, appears to be feasible and offers the prospect of a more effective and efficient market in the long-term and a reduced reliance on central planning and regulatory oversight. For this reason, the Council supports moves toward the congestion management approach for the NEM.

In the wholesale markets, the choices here are largely a question of the degree of nodal pricing adopted, which in turn largely depends on the size and number of regions under the NEM. At present, there are five regions. The Council sees significant benefit, in terms of more efficient despatch and wholesale pricing, through the introduction of a greater number of regions. The full nodal pricing approach, involving some 340 regions, has particular theoretical appeal. The Council does, however, note NECA's view that significant benefits from more efficient despatch and wholesale pricing can be achieved with an approximate doubling of the number of regions, combined with refinements to improve price signals.

In transmission network pricing under a congestion management approach, the introduction of a greater number of regions will result in price signals that more accurately take into account system constraints and asset utilisation. Such an environment will enable the determination and passing through of more cost reflective transmission network costs as the risk of over-signaling would be diminished. The passing through of cost reflective transmission network charges together with greater accuracy in the wholesale market as a result of a greater number of regions will provide an integrated set of market signals for meeting shortfalls in electricity supply. In addition, network investment and planning would be subject to the same price signals as other forms of meeting demand for electricity, such as new generation and unregulated interconnection. This would deal with current uncertainties and inadequacies in the approval processes for new regulated interconnection.

Pricing distribution network services raises more difficult issues. Nonetheless, prices should be cost reflective between regions, so that prices in one region would reflect the costs within that region, but prices between regions could vary, with CSO subsidies provided to address social concerns, particularly in rural and remote areas. Further, cost reflective pricing within regions appears to offer some benefits in relation to large users, but cost reflective pricing for small users within a region may not justify the cost and effort.

At the retail level, current measures applied in the NEM to isolate retail consumers from wholesale markets should be phased out. These measures impede effective demand management, foreclose opportunities for risk management by retailers and deter entry and competition in retail markets. There should be agreement between governments on the most effective way to rollout full retail contestability. The Council considers that full contestability is an essential feature of the NEM, particularly in order to provide the depth in the market needed to provide for effective competition.

Measures are needed to ensure that systems within the NEM do not act as an impediment to entry in electricity supply in any particular regions. Metering issues are particularly important in this respect: metering standards are needed to ensure compatibility, but no particular metering technology should be mandated. Metering rollout should be governed by consumer needs rather than mandated. Meter ownership arrangements should be designed so as to avoid impeding contestability in electricity supply.

In relation to current institutional arrangements, the Council considers the greatest flaw to be the lack of an effective policy co-ordination, development and implementation forum. Such a body is needed to identify important refinements to the NEM policy architecture. The Review is an important step in that process, at least from the point of view of a one-off policy package for the NEM. The Ministerial Council on Energy with appropriate advice may provide an effective policy development forum. An alternative approach may involve regular reviews under the aegis of the Ministerial Council or CoAG. A discipline on agreed policy implementation is also needed. To date, the Council's assessment process has provided an effective mechanism where governments have set a clear set of guiding principles for reform implementation.

Further, current overlapping responsibilities between institutions under the NEM need to be resolved to help ensure timely and effective policy development and regulation. This would address, at a minimum, those aspects of the NEM that currently lie outside national co-ordination and the scope of those aspects of the NEM currently subject to ACCC approval. Further, the cumbersome Code change process needs to be refined to provide for more timely and effective amendments to the Code.

While some have argued for a single national economic regulator, the Council considers that the case for such a substantial change has not been made out. While there may be benefits such as greater regulatory consistency, resource concentration and heightened development of regulatory expertise there would also be costs through loss of regulatory benchmarking and decreased local knowledge.

Aside from implementing arrangements to address the absence of an effective NEM policy body and current overlapping responsibilities between institutions, discussed above, the Council considers that the current institutional structure appears to be working. Regulatory responsibilities currently within the ambit of jurisdictional regulators, namely distribution networks, licensing and retail have a particular regional rather than national focus. Jurisdictional regulators have the required expertise and experience to regulate such matters. Matters of NEM-wide importance, such as the transmission network, are appropriately regulated by national institutions.

The Council does not consider the risk of regulatory inconsistency between regulators under current arrangements to be high. To date, the regulatory approaches adopted by the different regulators have been largely consistent and in line with underlying Code objectives. To the extent that greater regulatory convergence is desirable, amendment of the rules applied by regulators (for example, the provisions of the Code or State electricity legislation) may be appropriate. Arrangements such as the ACCC's Energy Committee and the Utility Regulators' Forum are appropriate in ensuring overall consistency of approach and sharing of expertise while at the same time allowing for appropriate regional variations in approach.

Gas

Reform of the gas industry under NCP is nearly complete. Some jurisdictions are yet to complete reforms to upstream management arrangements and/or finalise retail contestability. But the Council expects these outstanding matters to be addressed in the near future.

Much of the current debate about gas reform focuses on the application of, and regulation under, the National Gas Access Code (Gas Code). The Council considers that a number of threshold points should be recognised in this debate.

First, the application of the Gas Code to particular pipelines is determined:

- in a process distinct from regulation;
- as a matter of policy;
- according to robust criteria in response to applications for coverage, or revocation of coverage; and
- with appropriate review arrangements by the Australian Competition Tribunal (or state review bodies) to ensure accountability.

Second, the experience to date with these coverage and revocation processes is that the Gas Code currently applies to significantly fewer pipelines, especially transmission pipelines, than anticipated by governments in the 1997 Natural Gas Pipelines Access Agreement.

Third, there appears to be widespread consensus that application of the Gas Code to gas distribution pipelines has been positive in terms of promoting competition in dependent markets, the development of new pipeline infrastructure and the efficiency of energy markets.

Fourth, while there has been criticism of the Gas Code and associated administrative arrangements by transmission pipeline interests, this criticism has coincided with a sharp increase in interest in the exploration and development of gas fields and in the construction of new transmission pipelines. There is interest in the development of gas resources in Bass Strait, the Cooper Basin, the Otway Basin, the Timor Sea and elsewhere. Duke Energy has recently completed a major new pipeline, linking gas processing facilities at Longford in Victoria and consumers in Sydney, Canberra and elsewhere in New South Wales and Victoria. There are competing proposals to build new pipelines linking gas fields in Victoria and consumers in South Australia, and linking gas fields in the Timor Sea to consumers in south-east Australia. Duke Energy is also constructing a pipeline from Longford to Tasmania. Other pipeline proposals include linking gas fields in Papua New Guinea to Queensland and possibly southeast Australia. In the light of this, the proposition that the Gas Code is currently deterring investment in new transmission pipelines appears difficult to sustain.

Fifth, the Gas Code is relatively light-handed regulation of gas pipelines by OECD country standards (for example, see comments about the flexibility of the Gas Code provisions at p.21 of Attachment A to this submission). In its Information Paper on its Exposure Draft of the National Gas Access Code, the GRTF said:

> *The Code is less prescriptive than the National Electricity Code, but also is more detailed than would normally be required to make an undertaking under Part IIIA of the Trade Practices Act. The aim of the Code is to provide sufficient prescription so as to reduce substantially the number of likely arbitrations, while at the same time incorporating enough flexibility for the parties to negotiate contracts within an appropriate framework.* (at p.7)

Sixth, the Gas Code has been in place for about four years and its full application, in particular by finalisation of initial access arrangements, is not yet complete. Many of the impacts are yet to be realised, particularly in terms of increased competition in energy markets

None of this means that the Gas Code, and its current application to gas pipelines, should never change. In fact, it seems likely that as transmission pipeline infrastructure in Australia is developed, and more choices become available to gas producers, retailers and users, fewer pipelines will have substantial market power and the ability to profitably restrict competition in gas markets such that coverage under the Gas Code is appropriate. Further, as the culture of doing business in effectively competitive gas markets becomes entrenched, it may be appropriate to further lighten the level of regulatory intervention in the Gas Code.

But in the context of the current state of development of the gas industry, the Gas Code in its current form appears appropriate and is certainly not fundamentally flawed. Further, as clearly recognised by governments in all the relevant inter-governmental agreements, gas access regulation is a crucial element in the development of a competitive gas industry Australia-wide.

The Council recognises that many criticisms of regulation under the Gas Code are focused not on specific provisions of the Code or the coverage of the Code, but on interpretation of the Code by regulators. The Council has no regulatory role and does not have a mandate undertake analysis of regulators' performance. However, it is the Council's view that, to the extent that any of this criticism might be justified, remedial action should focus directly on identified problems rather than wide-scale change to the Code or coverage under the Code.

The Council considers that gas reform has been one of the success stories of NCP implementation. However, it will be some years before the full impact of this policy reform implementation will be realised. Lags between policy reform and market outcomes are common. However, the evidence to date is that gas policy reform under NCP has already generated substantial activity in the development of new gas production and gas pipelines. Current policy settings have created the environment for effective competition in gas markets.

A long term perspective

The Issues Paper invites submissions on the characteristics of a successful energy market in 2020. The Council has taken a long-term perspective in all its comments in this submission, as is appropriate in all policy debates. Some further comments are provided here specifically with a twenty-year perspective.

Infrastructure development and new technology will be key drivers of developments in both electricity and gas. In fact, emerging technologies in small-scale gas-fired electricity generation may mean fundamental changes in, and possible integration of, gas and electricity markets. Elsewhere, this paper discusses possible trends in gas pipeline development that may have implications for gas and energy markets and regulation. The changes canvassed in this submission in relation to the NEM may, in themselves, drive infrastructure development, which in turn may drive changes in energy markets, and the need for regulation.

Importantly policy development should not cater to a fixed view on what energy markets should look like in the long term, but should recognise that substantial changes are likely to occur and set policy objectives, institutional arrangements and rules that are capable of adapting to the new environment. The Gas Code coverage/revocation process is a good example: the process provides the means to adapt the application of access regulation to the changing characteristics and needs of gas markets. Similarly, the adoption of nodal pricing in transmission services and wholesale markets in electricity will provide a more flexible and adaptive NEM, more capable of meeting the needs of the markets, and the community, over time.

Electricity

Background

The NEM and NCP

Reform of the electricity industry was a key component of the implementation of NCP[3]. More recently CoAG reaffirmed their commitment to the reform process in June 2001, by way of the CoAG Agreement of 8 June 2001 (CoAG 2001).

In considering reforms to the NEM and the electricity industry generally, the Council considers it imperative not to lose sight of both the original aims and objectives that Governments agreed to in the lead up to the adoption of NCP in 1995, and also the objectives and principles agreed to in the June 2001 CoAG Agreement.

It is the Council's view that not only should these aims and objectives serve as a benchmark against which legislative reform and competition payment determinations be assessed, but should also be applied as a central pillar to reinvigorate and re-orientate where necessary, the reform process.

The Council considers the work of the CoAG Energy Market Review, being a review constituted by way of the CoAG Agreement, to be integral in the process of further articulating the means by which these aims and objectives can be effectively advanced. Accordingly, the benchmarks against which governments' progress in implementing electricity reform will be assessed by the Council, will reflect the findings and recommendations of the CoAG review.

NCP electricity reform objectives

As early as 1990, State and Federal Governments demonstrated a commitment to the reform of the electricity sector. This reform commitment

---

3 The intergovernmental agreements that underpin the National Competition Policy are the Competition Principles Agreement, the Conduct Code Agreement and the Agreements to Implement the National Competition Policy and Related Reforms (Implementation Agreement) dated April 1995.

stemmed from a recognition that significant productivity and welfare benefits were to be had from restructuring and reforming the industry so as to make it more competitive.

A number of inter-governmental agreements were entered into to give effect to this reform agenda. The aim was to achieve a “fully competitive market”. The principal objectives of the reform package, which culminated in the establishment of the NEM, include the following (CoAG Darwin 19 Aug 1994, para 2(b)):

- an ability for customers to choose which supplier, including generators, retailers and traders, they will trade with;
- non-discriminatory access to the interconnected transmission and distribution network;
- no discriminatory legislative or regulatory barriers to entry for new participants in generation or retail supply; and
- no discriminatory legislative or regulatory barriers to interstate and/or intrastate trade.

In relation to network pricing, the Governments agreed to principles relating to the recovery of the fixed cost component of network pricing that would encompass common asset valuation methodologies and rates of return as well as cost reflective and uniform pricing methodologies. There was also agreement that customers and generators be charged on a consistent basis, in accordance with their use of network assets and by taking into account the impact of network constraints (CoAG Darwin 19 Aug 1994, para 3 and Hobart 25 Feb 1994, para 2).

The 1994 CoAG agreements set out objectives relating to the efficient provision of services, the responsible development of resources and environmental concerns. Policy principles consistent with these objectives were agreed. These principles included recognition of the importance of competitive energy markets and the need to continuously improve national energy markets, in particular between and among jurisdictions.

The electricity sector reform package predated NCP. The key NCP principles of competitive neutrality, structural reform of public monopolies, the removal of legislative provisions that restrict competition (unless the benefits outweigh the costs), and the establishment of an access regime for significant infrastructure are, however, consistent with and relevant to the implementation of the electricity reform package.

Reforms to date

Reforms to the electricity sector have, to date, included the dismantling of State-owned monopolies, the implementation of a system of third party access to natural monopoly network infrastructure, and the establishment of the NEM to facilitate competition in the wholesale electricity trading market. Retail contestability for medium to large customers has been introduced in all NEM jurisdictions, and for small customers in New South Wales and Victoria.

In the Council's 2001 NCP assessment, the Council noted that while progress against commitments related to the establishment of the NEM and structural reform had generally been good, some aspects of the current market arrangements may be impeding competition in the NEM (NCC 2001b, p.6.5). In particular, the Council noted that sustained large inter-regional differences in electricity prices was inconsistent with the notion of a competitive market, and suggested that existing policy settings may not be appropriate. The Council considered that for the NEM to operate as an effective market, it must:

- provide an environment for strong inter-regional competition, including by facilitating adequate interconnection, embracing national consistency and allowing for market entry and growth in the number of market participants;
- extend the benefits of competition to all electricity consumers;
- be governed by means of an independent and efficient institutional framework; and
- adopt transparent, market-based solutions to addressing market failure and other problems.

In order to address these concerns effectively and to achieve the objectives of NCP and electricity reform, the Council considers it necessary to put in place a package of reform measures that sit within and are consistent with an overarching, clear reform framework. The Council sees the CoAG review as a significant opportunity in which such an overarching framework consistent with NCP policy can be defined and applied in the formulation of specific reforms.

Wholesale market

NEM region boundaries

Current market arrangements

The NEM is currently divided into five regions for the purposes of the wholesale market: New South Wales (including the ACT), Victoria, the Snowy region, Queensland and South Australia. These regions each contain a Regional Reference Node (RRN). In line with current Code requirements that RRN's be located near large load and generation centres, RRN's are presently located near Sydney, Melbourne, Brisbane and Adelaide and in the Snowy Mountain region.

The NEM operates by matching demand and supply at a particular RRN. Generators (other than embedded generators) are connected to the grid at Transmission Network Connection Points (TNCP). Each TNCP is referable to a particular RRN. Generally, this will be the RRN located near the capital of the State in which the TNCP is located.

At each RRN, demand is matched with supply by despatching on the basis of the lowest cost bid in by generators. Generators submit in advance daily bids indicating the volume of electricity they are prepared to produce for a specified price. During the course of a trading day, generators alter availability details by re-bidding. Despatch instructions are issued at five-minute intervals throughout the trading day. Despatch interval price and demand data are averaged over each half-hour period for the purpose of market settlement.

To determine the lowest cost generator for the purpose of despatch, the price bid by the generator, the loss factor (which takes into account the loss in transporting the energy through the network) and system constraints are taken into account.

Each TNCP is given a loss factor, which is generally greater the further away it is from its RRN. The loss factor is a static figure calculated annually as the average marginal loss factor for the previous year[4]. Load losses are, however, dynamic and constantly changing depending upon activity over the grid.

As an example, assume generator A is in southwest Queensland and generator B is in the Hunter Valley area of New South Wales. Both are roughly equidistant from Brisbane. Out of these two generators, the Brisbane RRN would despatch the one with the lowest price adjusted by, in the case of generator A, the loss factor from the TNCP of generator A to the Brisbane RRN, and in the case of generator B, the sum of the loss factors from generator B's TNCP to the Sydney RRN, the Sydney RRN to the Queensland/New South Wales interconnector and from the interconnector to the Brisbane RRN.

System constraints are taken into account in despatch by application of multiple constraint equations. These constraint equations are largely applied on a static rather than dynamic basis.

4 The ACCC is currently considering an application for authorisation of changes to the Code by NECA to move toward a forward looking approach in the calculation of loss factors. (Stage 1 of integrating the energy market and network services, lodged with ACCC on 27 March 2002).

The location of particular consumption loads is not taken into account in determining despatch orders.

There is a different energy wholesale market spot price at each RRN. Generators located in one region that are despatched for another region receive the spot price at their own RRN rather than the (inevitably higher) spot price of the destination RRN. The potential for this difference in price is currently auctioned through settlement residue auction arrangements. These arrangements are used as a mechanism to manage market risk. As NECA noted, they do not, however, provide a complete hedge to market risk. This is because constraints applied to interconnectors can result in price separation and in combination with the reduced flow on the interconnector, can result in insufficient settlements residue to provide a firm contract between the regions (NECA 2000, p. 39).

Market inefficiencies

The Council considers there are two principal problems with the current wholesale market arrangement. The first relates to the static rather than dynamic application of loss factors and system constraints measures, and the second relates to the requirement that loads be referenced to RRNs which may be some distance away from generating units and consumption loads.

As noted above, although loss factors are calculated on the basis of historic annual average loss factors as a static figure, they vary significantly depending upon activity on the grid. NECA referred to work undertaken by NEMMCO that showed that there was a variation of between 1 and 8 per cent between 1999-2000 average marginal loss factors and actual half-hourly loss factors for the selection of TNCPs considered in the study. NECA noted that even with these relatively small variations, the use of actual half-hourly loss factors could alter the despatch order. With the introduction of such dynamic pricing, NECA estimated that the value of the welfare gain resulting from an increase in productive efficiency due to the despatch of more efficient plants was likely to be in the order of $1 million a year. This figure reflected expected static efficiency gains only and did not include dynamic efficiency gains, which were expected to be significantly greater (NECA 2000, p 6).

In relation to system constraints, NECA considers that the structure of the constraint formula means that a preference between local generation and imported generation is sometimes made without reference to market outcomes. Inaccurate system constraint measures can lead to productivity losses as more cost efficient generators may be unnecessarily constrained off whereas higher cost generators are despatched. As the regional price would be set by the more expensive generator in this instance, there would also be efficiency losses as end-use customers in the unconstrained area of the region pay more for their electricity than they otherwise would have in a more refined regional structure (that is, one in which the regions were delineated on the basis of system constraints) (NECA 2000, p 7).

The second issue relates to the referencing of loss factors to RRNs, which may be some distance away from generating units and consumption loads. For example, a generator located near the Brisbane RRN would likely be despatched ahead of a generator located in North Queensland even though they both bid the same price, because the loss factor attributable to the North Queensland generator would be greater. This despatch order does not take into account the fact that there may be a major consumption load centre in North Queensland located near the North Queensland generator. This may lead to pricing that does not reflect the true cost of supply thus leading to market distortions.

Benefits from more efficient pricing

As NECA points out, more efficient despatch would mean the market-clearing price would more closely reflect cost. The increased accuracy in pricing would mean that production and consumption decisions would be more closely aligned resulting in greater allocative efficiencies, thus increasing welfare (NECA 2000, p 6). The improvements in economic efficiency derive from both the more efficient despatch of plant and the market's response to these more efficient price signals.

NECA also notes that its analysis demonstrates that a move to a more refined regional structure would be likely to lead to price reductions to end-use customers. They note that typically, if an existing region were sub-divided, the price in the new region would be lower for most of the time with a more refined structure. This would likely represent a gain for many rural customers, particularly those located near major generating areas, compared to customers in the large load centres.

In the longer term, the price signals from more accurate market despatch and pricing would lead to more efficient investment, both in terms of location and type. Prices would more accurately signal the benefits to society of investing in different options enabling more efficient investment outcomes. NECA estimated that the potential dynamic efficiency gains as a result of improved locational pricing signals would likely be in the hundreds of millions of dollars (NECA 2000, p 6).

The ACCC noted that an improvement in energy market signals would diminish the need for economic signals to be provided through transmission use of system charges (ACCC 2001, p vii). It went on to suggest that such improvements might include the introduction of more regions and full nodal pricing in the spot market.

NECA options for efficient pricing

NECA considers five different options for a refined regional structure. The market model under each option contains a different number of regions. Option one essentially preserves current arrangements with four-five regions, option two has six-eight regions, option three has nine-eleven regions, option four has 10-13 regions and option five is the full nodal pricing model with over 340 regions with a regional reference node corresponding to each TNCP. Option four sets a minimum size for a region of 100MW of generation and consumption load.

Options one and two preserve the backward-looking loss factor calculation albeit with a greater attempt at accuracy in option two. Options three and four adopt forward-looking loss factor approaches, with option four adopting tighter tolerance thresholds for both constraints and variations in loss factors.

NECA concluded that both options three and four would improve locational price signals for more efficient investment. It noted that while the move from option three to four would result in insignificant short term efficiency gains from a NEM perspective, more refined price signals resulting from the increased number of regions would help the location decisions of new investments. NECA estimated that the implementation of option four would result in price reductions for end-use customers, many of whom would be in rural and remote areas, within the NEM to the value of $8.4 million per annum[5]. As NECA's managing director stated in a letter to market participants late last year, this result could be achieved without the need to increase prices elsewhere. NECA further estimated that the reforms would result in productive and allocative efficiency gains of at least $150 million, and dynamic efficiency gains in the order of $500 million to $1 billion, over the next ten years (NECA 2000, p 29).

NECA concluded that the net benefits of option five, full nodal pricing, in the particular circumstances of Australia's transmission network would be arguable. It also pointed to difficulties and risks arising from full nodal pricing associated with largely illiquid markets.

On this basis, NECA recommended that revised criteria for the setting of regions within the NEM be adopted to implement the key elements of options three and four. NECA referred the issue of regional boundaries to NEMMCO for review. NEMMCO in its draft report on the Review of Regional Boundaries, recommended a six-region structure although it noted that such a minimalist approach was appropriate until such time as NECA completes its RIEMS work (NEMMCO 2002, p. 3).

Issues

The Council supports NECA's call for improving market arrangements to ensure greater accuracy in despatch and pricing. As NECA argued, the efficiency benefits to result from more accurate despatch and pricing are considerable.

---

5 NECA estimated the total value of price reductions for New South Wales, Victoria, South Australia and Queensland with the implementation of option 4 would be $1.6m, $0.1m, -$1.8m and $8.4m per annum.

The achievement of such efficiency benefits is consistent with the objectives of NCP. In addition, more accurate despatch would clearly be consistent with the intergovernmental commitment to establish a fully competitive market with no barriers to effective interstate and/or intrastate trade.

The Council finds the theoretical basis of full nodal pricing appealing. In particular, full nodal pricing is able to provide the most accurate price signals leading to, in theory, the greatest allocative and dynamic efficiency gains.

The Council notes NECA's concern relating to market liquidity problems resulting from a large number of small regions. The likelihood of problems arising from any lack of liquidity within smaller regions will depend on the level of concentration of ownership of generation within regions, the likelihood of new entry in generation, transmission constraints between regions and the effectiveness of mechanisms to deal with those constraints, either in a physical sense (thus removing the constraint) or in terms of managing risks associated with the constraint (such as hedge arrangements). The essential question is not merely whether ownership in generation within a region is likely to be concentrated, but the extent to which electricity supplies within a region are likely to be sufficiently contestable to constrain any exercise of market power. An effectively functioning physical trading market (including appropriate and certain processes for transmission system augmentation), and the development of a financial derivatives and risk management markets that would likely follow, may address liquidity concerns arising from an increased number of trading regions. Indeed, there may be possibilities for expanding the settlement residue auction mechanism to manage interregional trading risk, which may operate effectively with smaller trading regions.

While the Council finds full nodal pricing appealing, it sees merit in further consideration of NECA's option 4 in particular, in which the number of trading regions is significantly more than that at present but less than under a full nodal pricing model. It would appear to be logical to set the borders of a trading region on the basis of system constraints and as such, it may be the case that adjacent full nodal pricing regions, not otherwise separated by or likely to be separated by system constraints, may be merged into a single region without distorting the efficient price signals to result from greater locational pricing.

In conclusion, the Council supports the direction of NECA's proposed reforms and would encourage greater locational pricing by moving toward a full nodal pricing model. The Council concurs with the view expressed by Rod Shogren, Commissioner of the ACCC, at the Electricity Supply Association of Australia conference in March of this year that:

> *"The Commission supports the move towards more regions and increasing locational signals. It is simply fatuous to claim we have a true national market while regional boundaries do little more than mark the borders between State-owned transmission authorities."*

Networks

Network pricing

Transmission networks

Current arrangements

As noted above, the intergovernmental agreement in relation to network pricing sought to establish a pricing regime that:

- applied common asset valuation methodologies, rates of return and was uniform;
- was cost reflective; and
- took into account the impact of network constraints.

To a significant extent, measures to give effect to these objectives have been implemented. In the case of transmission network pricing, from 1 January 2003[6], the ACCC will regulate all transmission network pricing within the NEM pursuant to Parts B and C of Chapter 6 of the Code (subject to any continuing Code derogations). This will ensure a high degree of regulatory uniformity in terms of methodology, with Parts B and C being applied to the whole NEM transmission grid, and also to the application of the methodology, with the ACCC being the sole regulator.

The pricing methodology set out in Part B of Chapter 6 of the Code provides for the determination of a revenue cap by the ACCC by applying the CPI-X incentive based formula. Part C sets out the method by which transmission network services providers (TNSPs) derive their network prices from the ACCC determined price cap. Prices are determined by apportioning the revenue cap to cover the cost of assets used to provide entry services, exit services, transmission use of system services (TUOS) and common services.

Entry and exit costs are charged as a fixed annual amount referable to the exit/entry cost for a particular connection point. Common service costs are allocated on a postage stamp basis across all connection points. In the case of

---

6 Currently, the ACCC is required to apply the Victorian Tariff Order when regulating prices for the Victorian transmission network. In South Australia, the South Australian Independent Industry Regulator is responsible for transmission network pricing in SA pursuant to the Electricity Act 1996, the Independent Industry Regulator Act and the Electricity Pricing Order. These derogations to the Code cease on 1st January 2003.

TUOS, 50 per cent of customer TUOS costs attributable to a particular connection point are recovered on a cost reflective basis (referred to as the TUOS usage charge) and 50 per cent on a postage stamp basis across all connection points (referred to as the TUOS general charge).

Issues

Under Part C, only half of TUOS charges attributable to a particular connection point are recovered on a cost reflective basis while the other half is passed on a postage stamped basis. As a general principle, the Council believes that cost reflective pricing will result in the most accurate and transparent price signals necessary for efficient investment. The Council does, however, acknowledge the argument that under current pricing arrangements, cost reflective pricing of 100 per cent of TUOS on a locational basis may result in oversignalling. This is because the Part C pricing approach is based on the determination and allocation of the revenue cap on the basis of asset costs. It does not take into account spare capacity or the need to overbuild the network for system security, and the fact that in mature networks the incremental cost can be lower than the average cost.

The Council believes that as a minimum, the pricing approach under Part C should be refined to take into account such system capacity and system utilisation factors. Such a refined approach would result in more accurate pricing signals as areas of the network needing investment and areas of the network shown as underutilised (possibly demonstrating inefficient overinvestment) are identified through the pricing mechanism. It would also alleviate the current problem of oversignalling thus enabling a more cost reflective pricing approach to be adopted. This would further improve price signals necessary for efficient investment.

The Council notes that Chapter 6 allows the application of a “modified cost reflective network pricing method” (Cl 6.4.3B(c), Sch 6.4(6)). This method effectively sets the proportion of total TUOS to be charged as the TUOS usage charge (that is, on a cost reflective basis) to reflect asset utilisation rather than simply being 50 per cent as is the case under the standard Part C method. This modified method, however, has not yet been tested within the NEM.

The most effective method of reflecting asset utilisation through price is through greater locational pricing. System capacity constraints and asset utilisation would be reflected through price at a greater number of regional reference nodes than presently, providing the market with more efficient network investment signals. This approach would most comprehensively resolve the current problem of over-signalling, enabling greater cost reflective pricing.

Distribution networks

Current arrangements

Parts D and E of Chapter 6 of the Code deal with distribution network pricing. Part D sets out the way in which the jurisdictional regulator is to determine the revenue cap and/or a weighted average price cap and Part E specifies the way in which the distribution network service provider (DNSP) is to determine service prices on the basis of the revenue cap. Parts D and E follow in broad terms the pricing methodology applied for transmission networks with the jurisdictional regulator setting a revenue price cap on the basis of a CPI-X incentive based formula and the DNSP allocated the revenue cap across assets providing entry, exit, distribution use of system (DUOS) and common services. The Code provides that customer DUOS charges be allocated "…on a cost reflective or other basis agreed with the Jurisdictional Regulator" (Cl 6.13.6(c)(2)).

Chapter 6, however, allows jurisdictions to opt out of the application of Part E and to apply jurisdiction based pricing regimes[7]. Every jurisdiction other than the ACT has expressly opted out of the application of Part E. Every jurisdiction other than South Australia (which applies the Electricity Pricing Order) applies Part D to determine a revenue/price cap.

While jurisdictions have opted out of the application of the pricing methodology set out in Part E, the principles underlying their own methodologies are generally not dissimilar to Part E. For example, the distribution pricing regimes of the jurisdictions generally provide for cost reflective and incentive based pricing.

Issues

The Council is concerned that current distribution pricing restricts the pass through of transmission and distribution network charges on a cost reflective basis. In relation to transmission network charges, the Council concurs with the ACCC's view that it is important that any signals arising from transmission prices are transferred through to end use customers and are not distorted by the distribution pricing arrangements (ACCC 2001, p. vi). Particularly in the case of medium to large customers, the passing through of cost reflective transmission costs would provide locational investment signals. Not only would such signals enable customers to position further investment in cost advantageous locations but also they would provide TNSPs with signals to identify, for example, areas of the network requiring augmentation.

---

[7] Victoria applies the Electricity Distribution Price Determination, New South Wales the Pricing Principles Methodology, Queensland the DNSPs Network Pricing Principles Statements and South Australia the Electricity Pricing Order rather than Part E to determine distribution network prices.

In the case of distribution network charges, the allocation of such charges on a cost reflective basis particularly to medium and large customers would provide even stronger locational investment signals. This is because these charges are significant, typically accounting for approximately 40 per cent of a customer's total electricity bill. The passing on of actual network costs to customers (particularly medium to large customers) would for example, enable them to locate new investment in areas to take advantage of lower network charges or to make network bypass decisions. Efficiency gains resulting from effective locational price signals would be significant.

In the case of small customers and householders, the intergovernmental agreements provide that in view of the complexity of calculating the value of network services used by individual small customers and householders, that distribution system pricing could be calculated using a greater degree of averaging than that required for the transmission network (CoAG Darwin 19 Aug 1994 and Hobart 25 Feb 1994). The value of providing cost reflective locational investment signals for individual customers at this level of the market is questionable.

There are, however, benefits in having the postage stamped network charge within a region more cost reflective. Benefits would include providing the collective group of customers and the DNSP with investment signals such as the need for network augmentation. To achieve this, a greater number of smaller regions would be required. A region would be designed so that the cost of supplying electricity would be roughly the same for all small customers within the region. To the extent that a number of regions share a common network owner, ring-fencing measures would need to be put in place to ensure that actual network costs for a particular region were passed through to that region. Postage stamping of network charges between regions would distort network price signals. This approach of network pricing on the basis of a larger number of smaller regions is consistent with the move toward greater locational pricing discussed above under the wholesale market section of this paper.

To the extent that differences in cost arising from the application of cost reflective pricing methodologies would give rise to social policy concerns, the Council would advocate the use of clear and transparent post facto rebates or subsidies rather than hidden cross subsidies by way of the postage stamping of charges. In this way, social policy objectives can be achieved without distorting market price signals necessary to ensure competitive efficiency gains. This approach was recently adopted by the Victorian Government in the payment of Special Power Payments to subsidise customers for high distribution network costs.

Network investment and planning

Council 2001 Assessment

In its 2001 NCP assessment, the Council expressed its concerns in relation to the approval process for the development of interconnectors (NCC 2001b, p. 6.10). In particular, the Council recognised the inter-relationship between investment in regulated interconnection and investments in unregulated interconnection and /or new generation and the need to get the right balance of incentives for investment in different means of meeting an electricity supply shortfall in a particular region.

Regardless, the Council was concerned that the approval process is too lengthy and the criteria too onerous and/or too exposed to gaming by vested interests. As such, there is concern that the NCP objective of removing legislative and regulatory barriers to interstate and intrastate trade is not being achieved. In addition, the Council considered it desirable that the IRPC be constituted by members of planning authorities rather than transmission service providers, and that a single national body undertake the regulatory role for investments above a certain size (NCC 2001b, p.6.13).

Subsequent reform proposals

NEMMCO

The Interconnector Process Working Group, established by NEMMCO to identify issues that may be impeding the development of transmission network infrastructure within the NEM, issued its report in June 2001 (NEMMCO 2001).

The first key finding set out in the report was that there was a need to agree on the role of transmission networks in the NEM. In particular, whether its role is that of facilitating competition between generators in different regions of the NEM in order to achieve the lowest cost despatch, or whether the network can be designed and operated solely in response to the identified and specific needs of market participants.

If the first role is preferred, a common carriage model, whereby network access is made available on equal regulated terms and network planning and investment is centrally planned rather than market driven, may be most appropriate. If, however, the second approach is preferred, a congestion management model may be appropriate. Under this model, investment is driven by the needs of individual market participants rather than by the needs of the market as a whole. (NEMMCO 2001, schedule 3).

The current NEM arrangements show characteristics of both models. Intra-regional system planning and development appears consistent with the common carriage model as it is essentially centrally planned by the system owner/planner and access is mandated on regulated terms under the Code. In contrast, the nature of unregulated interconnectors in particular, appears more in line with the congestion management model given the opportunities for discriminatory market driven development, access and use.

The Council considers it imperative to determine the overarching policy question of the role of transmission networks within the NEM before considering further refinements to current arrangements under the Code. The Council considers that in broad terms, the common carriage model would better facilitate competition between generators and system security than current arrangements, at least in terms of inter-regional supplies. The model could also be combined with greater locational pricing in the wholesale market.

However, many market participants would regard such a development as a step backward in the direction of structural and market reforms since the start of the NEM. In particular, the common carriage approach would not ensure that the greatest benefit is derived from improved locational and investment price signals that would result from market structure improvements in the wholesale market through, for example, greater nodal pricing. Under the common carriage approach, such price signals could be relied on by the central network planning body to guide investment decisions. Nonetheless, overbuilding of the transmission system would be a likely result, improving supply security but wasting resources and muting signals for efficient investment in generation. Alternatively, under the congestion management approach, market participants would be exposed to the improved locational and price signals and it would be this exposure that would identify the network needs of market participants and as such, direct efficient investment in the network. This approach would appear to be more consistent with the underlying direction of the NEM. Accordingly, the Council considers that arrangements that provide market signals for both generation activities and the transmission network are both feasible and more likely to provide an effective NEM.

This view seems to be in line with the view expressed by the ACCC in the Network and Distributed Resources Code changes determination that it "… has always preferred placing networks within the market rather than outside it" (ACCC 2002, p. 16). The Council notes that the majority of the parties consulted by the Working Group considered that the most effective model at this stage would be one more closely aligned with the common carriage model. This support for common carriage may be explained by uncertainty surrounding the viability and support from governments for the expansion of the number of trading regions to facilitate greater locational pricing.

Other key findings of the Working Group included the introduction of "safe harbour" guidelines to ensure a minimum level of regional interconnectivity, the streamlining of licensing and approval processes, the implementation of national planning arrangements and with it, the establishment of a single national planning body, and the refinement of the regulatory test and the role of the IRPC.

While the Council welcomes moves to streamline and refine current arrangements, it considers it essential that the policy issue of the desirable functional role of the transmission network be resolved. Refinements to the current arrangements can then be directed with this policy objective in mind.

Recent Code changes

The ACCC authorised changes to the interconnector provisions of the Code in February 2002. The effect of the changes was to give greater responsibility for transmission network planning and development to network service providers. Under the approved arrangements, network service providers are responsible for applying the ACCC promulgated regulatory test following market consultation. The role of the IRPC and NEMMCO is limited to that of assessing interconnector applications on technical grounds rather than applying the regulatory test, as was the case prior to the changes. A condition of the approved changes imposed by the ACCC was that parties to network investment proposals are required to take account of the impact of the investment on the NEM as a whole. Disputes as to the application of the regulatory test are to be resolved by a dispute resolution panel and/or by the ACCC.

The Council considers the development of the regulatory test to be a policy matter. The content and nature of the regulatory test goes to the heart of determining the architecture of the NEM: that is, the question whether inter-regional transmission augmentations adhere to a common carriage model or a congestion management model. For this reason, the Council considers it desirable for the regulatory test to be promulgated by a NEM policy body, with the ACCC, as economic regulator, ultimately responsible for applying the test.

As noted above, the Council considers it essential that the design philosophy for the national grid be determined. Appropriate changes to the Code to give effect to such a design philosophy would then follow. Until such time as an appropriate design philosophy is determined, the Council sees value in addressing problems with current arrangements in order to make them more practicable. The current process requires the application of a regulatory test that has a clear bias toward local generation with system augmentation as a last resort. This gives rise to the problem of “gaming” whereby a regulated interconnector proposal already well advanced in the approval process must be reassessed to take into account the effect of new generation projects. This can involve significant delays. In the case of the SNI, the original application for approval was made in 1995 and is still not finalised. This renders the approval process largely ineffective. An example of an alternate approach may be to apply the regulatory test in the light of circumstances at a given point in time. Notice could be given of the assessment cut off date and after this date, any announcement of new generation projects would not be taken into account in assessing the interconnector project.

Retail markets

There are problems with retail markets under current NEM arrangements. State-by-state inconsistencies remain, restraints on the operation of markets reduce liquidity and increase risk for at least some retailers, opportunities for economies of scale and scope are suppressed and many current arrangements impede opportunities for physical and financial hedging by retailers. Further, some NEM refinements discussed above to improve the effectiveness of price signals in the wholesale market and in transmission may increase the risks faced by retailers. These problems vary in nature and magnitude between regions. But there is already some evidence of retailers reducing or abandoning their current and planned activities.

Cost reflective retail pricing

Historically, the cost of supply has had little if any direct bearing on franchise tariffs. The existence of multiple tariffs and the amount at which they were set was, in many cases, a result of the implementation of social policy in an environment where retailers were government owned. This approach, however, does not sit well in the NCP environment and stands in contradiction to the intergovernmental agreement on cost reflective pricing.

Effectively functioning markets provide price signals to moderate both supply-side and demand-side decisions. The market manages and co-ordinates supply and consumption decisions to attain equilibrium and capture the benefits to producers and consumers from trade. In principle, the NEM should adhere to these fundamental market mechanisms, but electricity markets are complicated by the technical requirement to maintain balance between energy (supply) and load (demand) in the system. Equilibrium is attained 'automatically' and necessarily by the system operator rather than purely as a function of market mechanisms. These technical requirements can cloud the consequences of isolating, in whole or in part, demand side decisions from prices in the wholesale market. For an effective and efficient NEM, supply decisions should reflect the needs of consumers while consumers should take full account of the costs of supply in their consumption decisions. Transitional arrangements in the development of an effectively competitive NEM, especially in relation to household consumption, are understandable. But in the long term, attempts to isolate consumers from the wholesale market are likely to impede the effective operation of the NEM.

Consumers, and in particular households, are isolated from wholesale price signals in the NEM in a number of ways. These include retail price caps and the lack of demand management tools for small consumers such as time-of-use meters.

Through vesting contract arrangements and the ETEF, used to support the retail price caps, retailers are protected from variations in wholesale prices.

This removes any incentive for either incumbent or new retailers to expose customers to wholesale price movements or to invest in customer consumption management strategies to reduce the risks associated with exposure to wholesale price variations. In the absence of meters to enable effective demand side management, the possibilities for retailers to adopt customer consumption management strategies to reduce wholesale market risk, are limited. (Issues relating to meters are considered further below).

Small and residential customers, on regulated and/or franchise tariffs are a significant sector of the market, accounting for over a quarter of total electricity consumption in the NEM (Electricity Australia 2000). There are two effects if retail franchise tariffs do not reflect wholesale prices and the network cost of supply.

First, the cost reflective price signals being sent down the supply chain from the wholesale market through to network pricing are muted. Many of the efficiency benefits underlying the NCP cost reflective pricing principle are negated. In particular, there is little relationship between the demand for electricity and the value of electricity services, particularly in peak loading periods. This invariably means an often-difficult central planning role for government in managing demand. For example, in early 2001, faced with an electricity shortage, the Victorian Government imposed mandatory consumption restrictions on Victorian consumers that turned out to be overly restrictive and resulted in Victoria exporting excess electricity to New South Wales.

Second, a consequence of retail tariffs not reflecting the costs of supply is that this sector of the market is unable to send effective price signals to upstream suppliers. In a competitive environment, demand would shift in response to price differentials reflecting the costs of supplying different services; which in turn, would help direct investment decisions and otherwise allocate resources. Even if the market was restructured so that retail prices were cost reflective, effective demand management tools such as time-of-use meters and the ability to shed load in response to high prices (VoLL for example), would be needed in order to enable customers to respond to price signals. Effective upstream investment signals could only be achieved through adequate demand side management mechanisms.

As considered above, the Council supports the expansion of the number of trading regions to facilitate greater locational pricing. It also supports the passing through of cost reflective transmission and distribution network prices for large and medium sized customers but accepts that a degree of network cost averaging within a trading region may be appropriate for small customers. Consequently, small customers in different trading regions would incur network charges reflective of the cost of supply for that trading region. The effect would be that small customer retail tariffs could differ between regions, as they would reflect the cost of supply for that region. The key to getting efficient demand-side responses is ensuring that there are sufficient trading regions to provide effective market price signals.

Although the issue of cost reflective retail tariffs is distinct from the issue of full retail contestability, they are clearly interrelated. By making regulated tariffs more transparent and cost reflective, new retailers operating in a contestable environment will be able to compete for all customers as regulated network supply costs will be passed on to both first tier retailers offering regulated tariffs and new retailers offering contestable terms. This would also address the concern that only low cost customers (often currently relied upon to fund cross subsidies for higher supply cost customers) would benefit from FRC as they are "cherry picked" by new retailers. (This issue is considered further below in the FRC section under the heading "Social policy objectives".)

Accordingly, the Council would encourage jurisdictions to move toward transparent cost reflective regulated tariffs. The Council welcomes the approach adopted by the Independent Pricing and Regulatory Tribunal (IPART) in New South Wales to move regulated tariffs to cost reflective 'target' levels by mid 2004 with network, variable retail and fixed retail costs clearly identifiable.

Full retail contestability

The Council considers implementation of FRC to be an essential component of energy market reform. The ability of customers to choose suppliers and the removal of discriminatory barriers to entry for new retail participants were objectives of the electricity industry reform package agreed by State, Territory and Federal Governments.

Currently, all customers in New South Wales and Victoria are contestable while those consuming more than 200MWh, 160 MWh and 100MWh per annum are contestable in Queensland, SA and the ACT respectively.

Benefits of FRC

In an effectively competitive retail market, the benefits of FRC include the potential for lower retail prices, improvements in service quality, increased product innovation, improved retail efficiency, increased energy use efficiency as demand responsiveness is encouraged and general efficiency as consumer price signals impact on upstream market behaviour.

The full benefits of FRC can only be achieved if the NEM as a whole operates more effectively. This would include, for example, the improvement of wholesale despatch and pricing, the passing on of cost reflective network pricing, and more effective network planning and development arrangements. (These matters were considered above.) To this extent, FRC and its expected benefits can be said to sit at the end of the supply chain. By improving the upstream elements of the market, the full benefits of FRC can be unlocked.

As noted in its 2001 NCP assessment, the Council considers that customers have achieved significant benefits from the opening up of markets to competition. The Productivity Commission estimated that households and industrial users achieved reductions in real electricity prices during the 1990s averaging around 16 per cent.

In the United Kingdom (UK) where FRC has been in place since May 1999, significant consumer benefits have been reported. In January 2001, the UK National Audit Office published a report examining the impact of retail choice for domestic electricity customers. The report concluded that customers who had elected to switch supplier had achieved price and service benefits. On price, it noted that within a year of the introduction of FRC in the UK, domestic customers who changed supplier saved an aggregate 15 per cent of their electricity bills in real terms since the start of competition, half of which was due to competition (resulting from savings in changing retailers, dual fuel discounts and direct debit savings) and half due to reductions in regulated network price caps[8].

Impediments to the full realisation of FRC consumer benefits are considered below.

Tariff regulation

Both New South Wales and Victoria regulate retail tariffs notwithstanding the introduction of FRC. The rationale for such regulation is that until the retail market for small customers is sufficiently mature to ensure competitive outcomes, customers need to be protected from high prices. In addition, regulation is designed to avoid the shock of a sudden price increase in cases where, to date, franchise tariffs had been set at less than the cost of supply.

While the Council understands the rationale behind retail tariff regulation, it is concerned that setting the tariff too low will stifle the development of the retail market and, in particular, the entry into the market of new retailers. As network charges are regulated, the ability of retailers to compete on price (that is, offer cheaper tariffs than the regulated tariff) is dependent on their success in electricity trading and contracting strategies on the one hand, and their ability to cut retail service costs on the other. Margins on the provision of retail services such as billing, the operation of call centres and the provision of other customer services have been low, with Australian regulators allowing retail profit margins in the vicinity of 1.5-2.5 per cent of sales (Office of the Regulator General 2001, p. 31). Accordingly, the setting of tariffs at too low a level can easily erode the headroom required to encourage effective retail competition.

---

8 In the UK, by June 2000 (i.e. a little over a year after the introduction of FRC), the 6.5 million customers who had switched retailers saw their combined bills fall by £299 million since the start of competition (i.e. a 15% reduction in real terms). Office of Gas and Electricity Markets, *"Giving Domestic Customers a Choice of Electricity Supplier"*, Report by the Comptroller and Auditor General, 5 January 2001, page 2.

The setting of retail franchise tariffs at too low a level also impacts on incumbent franchise retailers. In the absence of adequate margins, the commercial viability of franchise retailers is threatened. A recent NEMMCO report commented that the current prudential trading requirements had resulted in "the growing cost of credit support and the tightening of the availability of credit support". (NEMMCO 2001b) The Council recognises there are difficulties in determining appropriate tariff levels, particularly in the absence of accurate and sufficient market information. For this reason, the Council prefers a "light-handed" approach to the regulation of retail tariffs. Ideally, the regulators would be limited to overseeing rather than determining tariffs and would have the power to step in and veto or modify tariffs if considered unacceptably high. Otherwise, the setting of tariffs should be left to market participants.

The Council considers that the regulatory power to veto and modify tariffs should be transitional only, should be reviewed periodically and conclude when the market is able to deliver competitive outcomes. The Council also considers it desirable for the tariff regulator to be an independent regulatory body rather than the Minister. This is particularly important in jurisdictions where industry assets continue to be government owned where conflict of interest issues may otherwise arise.

NEM jurisdictions opting out of FRC

Notwithstanding the commitment of all Governments to give consumers the ability to choose supplier, FRC has only been introduced in New South Wales and Victoria. SA is planning to introduce FRC from January 2003. Even though WA is not a party to the electricity reform agreements, it has indicated its intention to introduce FRC from 2005. Queensland has decided not to implement FRC for the time being believing that the implementation costs for Queensland outweigh the benefits. The ACT has asked its jurisdictional regulator, the Independent Competition and Regulatory Commission to report on the cost/benefit of FRC implementation in the ACT.

The Council is concerned by the impact on the NEM as a whole of jurisdictions such as Queensland opting out of the implementation of FRC. This concern is for the potential impact of such unilateral action by a government on the effectiveness of the NEM as a whole and on individual market participants who have sunk investments in anticipation of a fully contestable national market. The Council is particularly mindful of the intergovernmental agreement not only to eliminate discriminatory legislative or regulatory barriers to entry for new participants in retail supply but also to interstate and/or intrastate trade.

This issue will be considered fully by the Council as part of its NCP assessment for this year. On completion of the assessment, the Council will be in a position to provide the committee with a supplementary submission addressing this concern.

Social policy objectives

An impediment to the introduction of FRC is a perception that only low cost supply customers, mostly urban customers, would benefit from its introduction. This is because low cost customers generally pay more than the actual cost of supply under non-cost reflective regulated tariffs. The overpayment effectively cross subsidises higher cost customers, many of whom live in remote and rural areas.

In an FRC environment where regulated tariffs are not cost reflective but cost reflective network charges are nonetheless passed on to new retailers, those retailers would be able to offer prices to low cost customers below the regulated tariff. They would not, however, be able to do so with high cost customers. This gives rise to concerns that new retailers would only compete for low cost urban customers and that these customers would be “cherry picked” off the regulated tariff thus eroding the cross-subsidising customer base.

This scenario, however, only holds true where network charges (which principally account for supply cost differentials) are passed on inconsistently to customers on regulated tariffs and those on contestable terms and/or where the wholesale market does not work effectively for example, due to inadequate mechanisms to deal with network constraints. With a properly functioning wholesale market and if network charges were passed on consistently to all customers, either on a cost reflective or a postage stamp basis, the possibility for customer cherry picking would be diminished. Rather, first tier and new retailers would be able to compete by passing on lower energy and retail supply costs, such as those associated with billing and the provision of customer services. In this way all customers could potentially benefit from FRC.

The Council recognises social policy concerns relating to the provision of electricity to high supply cost customers. The Council supports the implementation of social policy objectives (such as ensuring rural and remote customers have access to affordable energy) in a clear and transparent manner that does not hide or mute market price signals, as is the case with hidden cross subsidies.

The Council supports the use of rebates to achieve social policy objectives and is encouraged by Victoria’s approach of subsidising rural and regional customers for higher distribution costs through the Special Power Payments. Such a rebate could be paid directly to DNSPs and passed on to customers thereby reducing the rebate scheme’s administrative costs. A network cost rebate scheme would be consistent with other electricity rebate schemes such as those for pensioners, people on life support systems and those requiring drought relief.

Metering

Metering installation type

There has been significant debate on the question of metering in the context of FRC.

One view is that a mass rollout of interval meters recording consumption data on half hourly intervals to mirror wholesale market settlement periods, is required in order to realise the benefits of a contestable market. This would enable real time wholesale price variations to be passed on to customers. Retailers would be able to offer multiple tariffs, which would lead to greater demand responsiveness as customers have price incentives to manage consumption. This in turn assists in managing the risks associated with demand peaks.

Those opposed to a mandatory half-hourly interval meter rollout argue that it is not economic for customers consuming below 160 MWh per annum to have a half-hourly interval meter as the benefits from settling the market a little more accurately would not outweigh the meter installation and data handling costs associated with interval meters. New South Wales and Victoria estimated that a statewide rollout of half-hourly interval meters would cost in the order of $50 million and $33 million respectively (MIG and DNRE 2000. The ongoing cost of processing collected meter data would be expected to be even greater.

In addition, domestic customers are said to be more interested in the simplicity of their metering arrangements than in real time price signals and would be unlikely to be interested in multiple tariff offers. It is argued that even though less accurate, load profiling is adequate for small customers.

The Council believes it is important in considering the issue of metering that the desired purpose of the time of use meter is clearly understood. In particular, a distinction needs to be drawn between metering requirements at the wholesale market settlement level and at the retail level. The metering information required to settle the wholesale market is likely to differ to that needed to accommodate the retail relationship between the individual retailer and customer.

The Council understands that for settlement of the wholesale market, information is required on the amount of electricity consumed for the total customer portfolio of a particular retailer and the time of day consumption profile for that total customer portfolio allowing for a margin of error of no greater than one per cent (CIC 2002). It is not necessary for wholesale market settlement to know the individual consumption load profiles of each customer within a retailer's portfolio. Load profiling together with accumulation metering provides the information necessary for effective wholesale market settlement.

At the retail level, what is needed to encourage effective competition is information to enable customers to manage their individual energy consumption profiles and information to enable retailers to offer and settle multiple tariffs of interest to consumers. This may be achieved without end customers being exposed to wholesale prices in “real-time”. Rather, retailers could set prices ahead of consumption, which differ according to time of day. Indeed, there may be real value in the retailer’s ability to buffer the end user from constantly fluctuating wholesale prices.

The issue is one of information resolution. The Council understands that the objective of enabling greater demand responsiveness and retail market dynamism can be effectively achieved without adversely affecting wholesale market settlement accuracy, with time-of-use meters that record consumption on the basis of six to ten time of day reference points in a month (CIC 2002). For example, time of day reference points can be set to capture consumption data for a morning and evening peak period, a middle of the day moderate period and a night low consumption period. This series of reference points may be varied for weekends and to take account of seasonal consumption pattern variations.

The Council understands that the most significant cost of time-of-use meters is the ongoing data processing cost as opposed to the cost of the meter itself or maintenance and operation costs. The ongoing cost savings of processing, for example, six to ten monthly reference points rather than 1440 monthly reference points, which would result from use of half-hourly interval meters, would be significant. This suggests that the introduction of some form of metering designed to limit data processing costs would be more cost effective (CIC 2002, p.10).

Mandatory/voluntary meter roll out

On the issue of mandatory interval meter roll out, the Council considers that an effectively functioning market, rather than a regulated mandatory roll out, may be the most efficient means of expanding time-of-use meters in the market. This view is consistent with that expressed by the New South Wales Government’s Market Implementation Group and the Victorian Department of Natural Resources and Environment (MIG and DNRE 2000).

The principal reason for this is that not all customers will value or make use of the information provided by time-of-use meters by being prepared to modify energy consumption behaviour in response to metering information and variable tariffs offered by retailers. The cost of supplying, maintaining and operating time-of-use meters for these customers would unlikely outweigh the derived benefits. Time-of-use meters may, however, be an attractive investment choice for those customers that value or are prepared to utilise time-of-use consumption information and take advantage of retailer multiple tariff offers. High-energy users are more likely to find this attractive, because they are more likely to derive significant gains by managing consumption more effectively. However, it is possible that current high energy consumption households, particularly those relying heavily on air-conditioning at peak times, may be cross-subsidised by other customers for their peak use consumption under the load profile. If this is the case, these customers are likely to find time-of-use metering less attractive. Provided any distortions such as these are limited, and with other measures outlined above to help ensure an effective retail market, the Council considers that the use of load profiling and self-selection for metering to be the most efficient way of identifying customers that would benefit from the introduction of time-of-use meters. Such customers would be inclined to take up multiple tariff offers from retailers and may indeed, be prepared to pay an interval meter installation, maintenance and operation fee to access the multiple tariff offers.

Over time, as the cost of meters falls and/or new technologies reduce the cost of interval meters, investment in time-of-use meters may be more attractive. A mandated roll out of interval meters may lock in technology that may ultimately prove to be inadequate. Furthermore, the use of 30-minute settlement periods in the wholesale market may change in the future to, for example, five-minute intervals to reflect bidding. This may render half-hourly interval metering obsolete.

The Council would like to see the development of a retail market structure that would enable the retail market to operate competitively. Through this competitive process, the expectation would be that the right mix of metering installation types and retail marketing opportunities would arise. It is important that the market structure be in place to enable effective competition and this dynamic process to take place.

Other metering issues

On the question of meter ownership, the Council notes that Chapter 7 of the Code (which deals with metering) makes no reference to and sets no requirements in respect of meter ownership. Nor has this issue been dealt with comprehensively by the NEM jurisdictions. The Council would welcome a move to resolve these issues, so as to ensure meter ownership, operation and maintenance does not act as a barrier to entry in the retail market. The Council notes that commercial solutions such as new retailer leasing arrangements or customers entering into long-term retail contracts would be available. The Council considers it essential that metering arrangements be put in place to ensure that the ownership, operation and maintenance of meters does not result in a barrier to effective competition. This may entail the adoption of regulated access measures and/or specific meter ownership vesting arrangements.

The Council welcomes the approaches of New South Wales and Victoria in relation to the provision of metering services. Both States agree that contestability in the metering services market is desirable in the long-term and that the current local network service provider monopoly arrangements are transitional only and will come to an end when the Code derogations cease on 1 July 2004 or earlier if ordered by the Minister.

The Council encourages a move toward contestability in both the provision of metering services (which includes meter installation, operation and maintenance) and the provision of data services (which includes meter reading and data processing) as is currently the case in the UK.

The Council also considers there is significant benefit in the establishment of compatible metering standards across the NEM. Such standards should enable customers to switch retailers with relative ease and ensure that metering arrangements do not act as a barrier to entry in the retail market, especially across jurisdictions.

Institutional arrangements

Current arrangements

The regulatory arrangements covering activities within the NEM are multi-layered and relatively complex.

At the trans-jurisdictional NEM level is NECA and NEMMCO. NECA is the Code administrator and is responsible for monitoring and enforcing compliance with the Code. NECA also considers amendments to the Code and submits proposed amendments to the ACCC for authorisation. NEMMCO operates and administers the wholesale market, and has responsibilities in relation to power system security and network planning.

The ACCC is both the price regulator for transmission networks within the NEM and the body that authorises proposed changes to the Code pursuant to the TPA. In addition, the ACCC promulgates the regulatory test to be applied by NEMMCO in considering an application for the development of an interconnector.

In relation to the electricity sector, the Council is responsible for ensuring implementation of the specific electricity reforms agreed in the context of NCP. It also assesses progress in implementing these specific electricity reforms with a view to making recommendations to the Federal Treasurer as to appropriate levels of competition payments.

At the State level, jurisdictional regulators have responsibilities conferred under the Code as well as State legislation regulating the electricity industry and legislation conferring general powers on the jurisdictional regulator. Generally, this suite of powers confers on the jurisdictional regulator powers in relation to the licensing of industry participants and the setting of licence conditions, and distribution network pricing. Some jurisdictional regulators are also responsible for the setting of retail tariffs for small customers while in other jurisdictions it is the responsible Minister[9]. Jurisdictional regulators also have power to investigate matters referred to them by and make recommendations to the responsible Minister.

Absence of NEM policy body

The Council considers that the most significant gap in the current NEM institutional arrangements is the absence of national oversight of policy direction as distinct from the regulation of the NEM. This policy vacuum has resulted in the stalling of the reform process generally, and in particular, a failure to effectively consider and determine calls for further reform from bodies such as the ACCC, NECA and NEMMCO. Under current arrangements, the instruments provided to these bodies are too blunt to drive continued policy development and implementation, which may be appropriate, given the stated roles of these institutions. But it is not appropriate for governments to maintain this policy deficiency and ignore suggestions from NEM institutions that changes are needed.

The absence of a NEM policy making body has resulted in both NECA and the ACCC effectively making policy determinations and attempting to implement that policy through the Code change process. This approach is not an effective means of developing policy as it limits the reform process to specific, detailed aspects of the Code, often considered in isolation rather than in the context of broader higher level issues. In addition, the fusing of policy making with regulation in an unclear and ad hoc manner is clearly undesirable: this has reflected a policy failure in the NEM rather than any inadequacy in the regulatory arrangements or current institutions. The fusing of policy and regulation risks confusing the important distinction between policy objectives and architecture of the NEM, which is the province of governments ideally agreeing to a common approach, and the economic regulation of the NEM within that policy framework. Ideally, the Code change process should be focussed on the detail of changing the Code to implement clear policy objectives.

An important example of the inappropriate fusion of policy and economic regulation is in the area of network planning. The content and nature of the regulatory test against which regulated interconnector proposals are assessed goes to the heart of determining the architecture of the NEM: that is, the question whether inter-regional transmission augmentations adhere to a common carriage model or a congestion management model. This is essentially a policy matter. However, the test is currently promulgated by the ACCC with broad guidance in the Code (Cl 5.6.5(q)). Application of the test, which is a regulatory function, is carried out by network service providers

9 The relevant Minister has power to regulate retail tariffs for small customers in Victoria and Queensland. In New South Wales, it is IPART and in the ACT it is the ICRC (following Ministerial references in both cases), and in SA, it is the SAIIR.

with the resolution of disputes being the role of the dispute resolution panel and the ACCC. The outcomes of this application are subsequently reconsidered by the ACCC in its capacity as the economic regulator in assessing prudent investments when setting or resetting the cost base for the determination of transmission network revenue caps. For the ACCC to determine policy and subsequently economically regulate interconnectors would appear anomalous. The Council considers it desirable for the regulatory test to be developed by a NEM policy body, with the ACCC, as economic regulator, ultimately responsible for applying the test.

The Council welcomes this Review as a first step towards establishing clear policy objectives and a robust policy and legislative framework for the NEM, including by identifying an ongoing policy development process and appropriate institutional responsibilities. The Council also welcomes the establishment of a NEM Policy Forum of Ministers as foreshadowed by CoAG. The Council considers that it is important that this body operate effectively with adequate and dedicated resources, such as the nomination or creation of an organisation to provide secretariat services. In addition, this forum should have power to direct NECA and NEMMCO to conduct reviews and make recommendations with a view to developing NEM policy. This power would be akin to the power of State Ministers to direct State regulators to carry out reviews and make recommendations. Further, current overlapping responsibilities between institutions under the NEM need to be resolved to help ensure timely and effective policy development and regulatory processes. This would address, at a minimum those aspects of the NEM that currently lie outside national co-ordination, in terms of either policy development or regulation, and the scope of those aspects of the NEM currently subject to ACCC approval.

Single national regulator

The Council notes calls from a number of industry groups including ESAA and the Victorian Minister for Energy and Resources, that a single national economic regulator of the NEM be established in place of jurisdictional regulators. It is argued that the benefits of a single NEM economic regulator would include the following:

- There would be a greater degree of regulatory uniformity within the NEM as the same regulator would be responsible for regulation of the entire NEM.
- Gaps and overlaps in regulatory responsibility would be diminished as the single regulator took regulatory responsibility for all levels of activity.
- The regulatory process would be simplified for industry participants as only one rather than a number of regulators, particularly in the case of cross-border activities, would have jurisdiction.

- The pooling of expertise and the reduction in functional duplication would make the regulator itself more efficient and cost effective.

While the Council recognises these arguments, it considers that the current set of institutional arrangements, in general, works well and that while aspects may need refinement, it does not see the need to abandon current arrangements in favour of a single national economic regulator. This is because of the following:

- The regulatory approaches adopted by the different jurisdictional regulators are largely consistent. For example, the approach taken in distribution network regulation is largely the same across jurisdictions. In addition, there is significant co-operation and consultation between jurisdictional regulators through, for example, the Energy Committee, which includes State regulators, established to advise the ACCC and the Utility Regulators' Forum (which is a co-operative voluntary body the aim of which is to ensure uniformity in regulatory approach).

- Regional regulators are likely best placed to understand regional regulatory issues. Jurisdictional regulators currently have significant expertise and experience in regulating matters of particular jurisdictional concern such as distribution networks and retail tariffs. There is uncertainty as to whether a single NEM regulator would be able to duplicate this degree of regional expertise and experience.

- There is benefit in having some divergence in regulatory approach. It allows for benchmarking between regulators and promotes innovation. As all the jurisdictional regulators are general economic regulators, the experience they gain in regulating other industries may also promote innovation.

- There may be a greater risk of industry capture and a reduced ability to draw on experiences from other regulatory areas with a single national electricity regulator.

For these reasons, the Council considers that on the whole, the current division of regulatory responsibilities between the ACCC and the jurisdictional regulators is appropriate. Matters concerning the NEM as a whole such as the regulation of transmission network pricing and interconnector approvals are appropriately in the regulatory ambit of the ACCC. More localised issues such as distribution networks, retail pricing and licensing, are appropriately within the regulatory ambit of jurisdictional regulators with particular local expertise and experience.

Refinement of current arrangements

While the Council considers the current NEM institutional arrangements are appropriate, a move to streamline the arrangements to improve efficiency would be welcome. In particular, the Council notes the following areas as requiring attention:

- The current Code change process can involve lengthy consideration and consultation by both NECA, through the Code Change Panel, and by the ACCC pursuant to the authorisation process under the TPA. This has resulted in a number of significant Code changes taking up to two years. Streamlining of the Code change process to reduce the duplication in the roles of NECA and the ACCC to give effect to Code changes in a more timely and efficient manner would be desirable.

- Gaps and overlaps in regulatory functions between the different regulators should be identified and addressed. For example, jurisdictional regulators are required under the distribution pricing methodology under the Code to apply a performance incentive pricing methodology approach. Jurisdictional regulators, however, have no express power to set service standard benchmarks. Rather, they have tended to rely on general licence condition powers to enable them to proceed with performance standard benchmarking. Similarly, there may be inconsistencies in requirements, particularly technical requirements between the regulators that may be problematic. Identification and rectification of such inconsistencies would be desirable.

- Co-operative arrangements such as the Utility Regulators' Forum should be encouraged to ensure ongoing consistency and cooperation between jurisdictional regulators.

Competitive neutrality

A key element of NCP reform is competitive neutrality (Clause 3, Competition Principles Agreement). This reform is intended to ensure that significant government owned businesses have no advantage flowing from their ownership.

In the electricity industry, an issue arises as to the application and effectiveness of competitive neutrality reforms. In particular, concern has been expressed as to the effectiveness of competition between Government owned generators themselves and between Government and privately owned generators.

The Council does not suggest that public ownership is contrary to NCP. It does, however, see the need for enhanced rules or protocols about how structurally separated publicly owned generators compete against each other and against privately owned generators in order to ensure effective competition within the NEM. The Council welcomes initiatives designed to enhance competition in areas dominated by publicly owned enterprises. This includes the New South Wales proposal to sell the rights to the output of the three state-owned generators and the retail activities of the four state-owned power retailers.

Gas

Background

The implementation of the agreed gas reform package has been one of the major success stories of NCP. All governments have introduced the key policies outlined by CoAG and the benefits of those reform measures are beginning to be realised through the emergence of more competitive gas markets.

Between 1992 and 1997 CoAG struck a series of agreements designed to create a national gas market characterised by more competitive supply arrangements. In short, CoAG agreed to:

- remove legislative or regulatory barriers to both inter- and intra-jurisdictional trade in gas;
- introduce third-party access rights to both inter- and intra-jurisdictional supply networks;
- introduce uniform national pipeline construction standards;
- increase commercialisation of the operations of publicly-owned gas utilities;
- remove restrictions on the uses of natural gas (for example, for electricity generation); and
- ensure gas franchise arrangements were consistent with free and fair competition in gas markets and third party access.

Consequently, in 1997 Commonwealth, State and Territory Governments signed the Natural Gas Pipelines Access Agreement, under which each jurisdiction agreed to enact uniform gas access legislation incorporating the National Gas Access Code.[10] Each jurisdiction has subsequently enacted a Gas Access Act enacting the Gas Pipelines Access Laws (GPAL) and National Gas Access Code.

CoAG's objectives for national free and fair trade in gas are now largely in place. The only significant outstanding issues remaining are the introduction

---

[10] Tasmania's obligation was postponed to the development of a natural gas industry in that State.

of full retail contestability in all States and Territories and the completion of the review and reform of acreage management legislation.

Gas reform under the NCP has transformed the gas industry in Australia. The introduction of the National Gas Access Code, particularly in relation to gas distribution pipelines, and increased competition in gas exploration, has stimulated gas production and pipeline development proposals and activities. There is unprecedented interest in the development of gas resources in Bass Strait, the Cooper Basin, the Otway Basin, the Timor Sea and elsewhere. A major new pipeline has been completed recently, linking gas processing facilities at Longford in Victoria and consumers in Sydney, Canberra and elsewhere in New South Wales and Victoria. One is currently being laid linking Longford to Tasmania. There are competing proposals to build new pipelines linking gas fields in Victoria and consumers in South Australia, and linking gas fields in the Timor Sea to consumers in south-east Australia. Other pipeline proposals include linking gas fields in Papua New Guinea to Queensland and possibly southeast Australia.

NCP is assisting in stimulating the development of a vibrant and competitive gas industry in Australia. The gas industry is likely to play an increasing role in meeting Australia's energy needs, including because gas is likely to increase its role in electricity generation for environmental reasons. A well-developed and competitive gas industry is vital to Australia's economic and environmental future.

Progress on NCP gas reform has been slower than CoAG envisaged in its early agreements. This is largely because the original timetable was ambitious, with many complex issues needing to be resolved. Though the program is still not completed, the Council expects to be able to sign off on the last of the outstanding issues by its June 2003 assessment.

The Council considers that jurisdictions, through both the CoAG gas reform agreements and the general NCP agreements, outlined a policy for industry-wide reform that was clear and comprehensive. Independent monitoring of the implementation of that policy by the Council through the NCP assessment process has provided a strong incentive to jurisdictions to meet their agreed reform obligations. The combination of the establishment of policy objectives and effective monitoring of progress has supported the successful implementation of national gas reform.

This submission provides the Council's views on the gas reform process both as it has developed over the past ten years and how it should be progressed into the future. The submission examines the reforms in the context of the following three areas of the gas industry:

- the upstream sector;
- regulation of pipeline infrastructure; and
- introduction of fully competitive retail markets.

Reform in the upstream sector under NCP

An efficient gas production sector is essential to ensure that gas sales markets are able to develop and grow. NCP has required governments to examine the regulatory barriers and restrictions on competition that may have impaired the development of an efficient upstream gas sector in the past. The full effects of the changes that governments have been making will take some time to flow through, but there are already positive signs of increased competitive activity.

In 1998 the Upstream Issues Working Group (UIWG) reported to CoAG, identifying three areas that were significant in the development of a more competitive upstream gas sector:

- marketing arrangements used by gas producers;
- third party access to upstream processing facilities; and
- acreage management legislation.

The Council has considered the issues of marketing arrangements and acreage management legislation in the course of its assessments of jurisdictions' progress with the implementation of NCP reforms.

Marketing arrangements

The Council recognises that at times joint marketing arrangements between gas producers may be the most efficient way to market gas. However, there is potential for them to limit competition between producers and reduce competition in the gas sales market. The Council considers that because of the range of factors that need to be considered in determining whether such joint marketing arrangements are in the public interest, authorisation through the TPA constitute the most appropriate process for considering the potential competitive effects of such arrangements.

Authorisation through the TPA allows for an independent assessment of the costs and benefits of joint marketing arrangements through a transparent, public process. Interested parties rights are further protected through access to review mechanisms such as the Australian Competition Tribunal and the Federal Court.

In the course of assessing State and Territories' progress with implementing the NCP gas reform and legislation review obligations, the Council examined State legislation in South Australia and Victoria that provided protection from Part IV of the TPA for particular gas joint marketing arrangements in those jurisdictions. Both States had utilised section 51(1) of the TPA to provide protection rather than have the joint marketing participants seek authorisation of their arrangement under Part VII of the TPA.

While the Council was satisfied, in these two cases, that the jurisdictions had met their obligations under the NCP agreements, it considers, in general, that the authorisation provisions should be utilised rather than section 51(1). The Council is not aware of any jurisdiction introducing new section 51(1) exemptions for joint marketing arrangements.

Access to processing facilities

Production processes are not considered 'services' under Part IIIA and cannot be declared. It is therefore unlikely that gas processing facilities come within the operation of the national access regime. This was recognised in the UIWG report to CoAG, which recommended that States monitor any problems with access to gas processing facilities within their jurisdiction and take action if necessary. Further, gas producers through their industry association, undertook to develop an industry code of practice for third party access to gas processing facilities.

The Council is not aware of any current issues relating to access to existing gas processing facilities. The Council is aware that some new producer entrants are contemplating construction of their own processing facilities rather than utilise existing facilities. This may be the result of unsuccessful access negotiations. Alternatively, it may be that with current technology, gas-processing facilities are economic to develop for new producers.

Acreage management legislation

Acreage management legislation covers the allocation and management of exploration and production rights to natural gas (and other hydrocarbons) on Australian land and in Australian waters. The objective of acreage management policy is to enable the timely and effective discovery and development of the nation's resources and hence allow for the maximisation of the nation's resource wealth.

The allocation of exploration and production rights, and the way in which exploration acreage is allocated and managed, can have important consequences for barriers to entry and the number of and variety of producers – and hence the level of competition – in upstream oil and gas markets.

All jurisdictions are currently engaged in the review and reform of their acreage management legislation, both offshore and on-shore. The offshore legislation, the Petroleum and Submerged Lands Act (PSLA), is being reviewed through a national process, with each State and Territory reviewing their on-shore legislation.

The 1998 UIWG report to CoAG considered that it was important for new entrants to be encouraged to bid for acreage and that maximising the transparency and predictability of the processes used to award exploration acreage is important in achieving this end. The Council has utilised the work of UIWG as well as the ANZMEC Petroleum sub-committee, in assessing jurisdictions' progress with their obligations to review and reform, where appropriate, acreage management legislation.

Restriction on competition

In order to achieve the timely and effective discovery and development of petroleum resources it may be necessary restrict the behaviour of market participants, for example by allocating exclusive rights to explore and develop to particular parties for a period of time.

It is these type of restrictions that NCP reviews are required to assess and reform when the net costs of those restrictions outweigh the net benefits. The Council assesses the adequacy of reviews and government policy responses against NCP principles outlined in clause 5 of the Competition Principles Agreement (CPA).

Council's approach to assessing NCP implementation

In assessing the adequacy of legislation reviews of offshore and on-shore acreage allocation, and governments' responses to those reviews, the Council considers that the UIWG principles set an appropriate framework for acreage management legislation. Where jurisdictions have chosen not to adopt these principles, the Council examines their reasons for not doing so.

In summary, the UIWG principles are as follows:

- legislation and procedures should be sufficiently transparent to give all stakeholders confidence in the integrity of the decisions made in awarding and managing tenements;

- tenement management appeals/audit processes should give confidence to the stakeholders that the procedures used to arrive at decisions were followed to the extent required to give a commercial degree of assurance to the validity of the decision;

- legislation should enable the most appropriate form of application for exploration tenements to achieve maximum exploration effort;

- overall objectives governing the length of tenement term, and renewal and relinquishment requirements, should be whether or not the requirements are likely to maximise exploration effort in the near/medium term. In particular, the requirements should facilitate discovery–led development of markets; and

- legislation should enable the size of tenement on offer to be chosen to balance the need to attract the interest of explorers and the need to facilitate intra– and inter–basin competition. There is also a need to evaluate the size of the tenement against the likely work programs to judge whether or not the program is likely to be effective.

Particular emphasis is placed on the importance of transparency and predictability in the acreage award process.

Current status of the Council's assessments

The Council notes that ANZMEC Ministers have endorsed the national review of the PSLA and the Council is currently awaiting reports on the amendments to Commonwealth, State and Territory legislation based on the report.

With regard to on-shore acreage management legislation, the Council has already received reports on relevant reviews and reform implementation from New South Wales, Victoria and South Australia and has concluded that they meet NCP obligations. The Council is still considering the progress of other jurisdictions.

Regulation of pipeline infrastructure

In February 1994, CoAG agreed to remove impediments to free and fair trade in natural gas. A central element of the reform process has been the development of a National Gas Access Regime (the Gas Regime) which applies to natural gas transmission and distribution pipeline services

The Gas Regime comprises: the Gas Pipelines Access Law (GPAL), which provides the legal framework for the regime; supporting state and territory legislation and regulations; and the National Third Party Access Code for National Gas Pipeline Systems (the Gas Code). South Australia was the lead legislator, with all other jurisdictions enacting the Gas Regime through an application of the South Australian law. Each government agreed to seek *certification* of their Gas Regime as effective under Part IIIA of the TPA.

The Gas Regime works by applying the Gas Code to all covered pipelines. The Gas Code establishes the mechanisms and principles under which pipeline operators will offer access. The Gas Code has a number of core elements:

- coverage criteria;
- access arrangements;
- ring fencing;

- dispute resolution; and
- appeals.

The National Gas Code is operational in all jurisdictions. The regime has been certified as an effective access regime under Part IIIA of the TPA in all States and Territories other than Queensland and Tasmania. The Council is still considering the Queensland Government's application for certification and has released a draft recommendation not to certify the regime as effective. This is discussed further in the section on derogations and transitional arrangements. The Tasmanian Government has not yet applied to the Council for certification, but intends to do so in the near future.

Part IIIA and clause 6 of the CPA outline both the principles for identification of infrastructure services where regulation is appropriate and the principles for designing access regimes to effectively regulate those identified services. The Council considers, in essence, that the requirements for certification as an effective access regime are:

- appropriate coverage of services;
- appropriate treatment of interstate issues;
- an effective model to facilitate access and competition, including scope for commercial negotiation underpinned by an independent regulatory framework;
- independent and binding dispute resolution; and
- appropriate guidance to the arbitrator and regulator.

The Council considers that the National Gas Code meets these requirements. The National Gas Code requires service providers to develop and have approved access arrangements for covered pipelines. Access arrangements must meet the requirements of the Code in addressing issues such as pricing, information provision, trading and queuing policies. However, the Code's requirements allow service providers considerable discretion in how to structure their access arrangements and the approaches they can take in addressing the requirements. This flexibility, combined with parties ability to negotiate outside an access arrangement, means that the National Gas Code is more light handed in its regulation of gas pipelines than regimes in countries such as the United States and is also more light handed than other regulatory regimes in Australia.

The Council recognises that the application of the Code inevitably imposes costs and burdens on service providers and it is necessary to ensure that this imposition does not hinder the efficient development and operation of gas pipeline services. It is therefore necessary to ensure that the requirements of the Code are the minimum necessary to deliver its stated objective and that those requirements are being applied consistently with the objective.

The objective of the Code is to establish a framework for third party access to gas pipelines that:

(a) facilitates the development and operation of a national market for natural gas; and

(b) prevents the abuse of monopoly power; and

(c) promotes a competitive market for natural gas in which customers may choose suppliers, including producers, retailers and traders; and

(d) provides rights of access to natural gas pipelines on conditions that are fair and reasonable for both Service Providers and Users; and

(e) provides for resolution of disputes.

While the Code has now been in operation for four years in some jurisdictions, it is only now that the regulators are concluding the first round of access arrangements for some pipeline services. The finalisation of the first round of access arrangements has been a resource intensive and complex process as service providers, users, regulators and other interested parties have had to understand the requirements of a new regulatory system. For many service providers, the application of the Code was the first time they had been subject to economic regulation and required significant adjustments to how they operate their business and the information they now need to provide to regulators and users.

The Council would expect that while the second round of access arrangements will have their own particular issues, there should be a greater understanding of the requirements of the Code and the processes should be less complex, more timely and less onerous.

However, the Council does consider that monitoring of the Code through both the NGPAC process and through a comprehensive review, is important to ensure that the Code and its application are meeting the objective identified by CoAG. The Council supports a review of the Code, against its objectives, once the first round of access arrangements is complete and there has been some experience of second round processes. Further, any review should also be able to take account of Government response to the PC's review of the national access regime, under which the Code sits.

Criteria for coverage under the National Gas Code

Experience to date shows that the coverage criteria in section 1.9 of the National Gas Code have confined access regulation to fewer gas pipelines than originally envisaged by governments. Furthermore, the current wording is subject to significant authority through the Australian Competition

Tribunal's (the Tribunal) decisions in the *Sydney Airports case*[11] and the *Duke Eastern Gas Pipeline case*[12].

Interpreting the coverage criteria

When considering the coverage criteria, the appropriate test for the Council is that it must be "affirmatively satisfied" of the matters set out in the coverage criteria.[13]

In interpreting the coverage criteria, the Council uses general principles of statutory interpretation and accords primacy to the language of the Gas Access Acts and the National Gas Access Code. The Council has regard to the following additional matters in interpreting the legislation:

- the Tribunal's recent decision in the *Duke Eastern Gas Pipeline case*, and the decisions of the Tribunal in relation to applications for declaration under Part IIIA of the TPA. The decisions under Part IIIA are relevant because the words of the declaration criteria in sections 44G(2) and section 44H(4) of the TPA raise for consideration the same issues as those raised by the coverage criteria. The declaration criteria have been considered by the Tribunal in the *Australian Union of Students case*[14] and the *Sydney Airport case*[15] ;

- the purpose sought to be achieved by enacting the Gas Access Acts of New South Wales, South Australia, Queensland, ACT, and the Commonwealth.[16] Reference is made to the preambles to each of the Gas Access Acts to determine this purpose;

- pursuant to section 10.5 of the National Gas Access Code, the Council has regard to the introduction and overview to section 1 of the National Gas Access Code:

  - where the meaning of the provision in section 1 appeared clear, to confirm the ordinary meaning conveyed by the text of the provision; or

  - where the Council considers the provision was ambiguous or obscure, or the ordinary meaning would lead to a manifestly absurd or unreasonable result, to determine the meaning of the provision.

The Council agrees with the Issues Paper's statement that the Tribunal's decisions in the EGP and Sydney Airports cases have clarified that coverage

---

11 *Sydney International Airport; Re Review of Declaration of Freight Handling Facilities* (2000) ATPR 41-754.

12 *Duke Eastern Gas Pipeline Pty Ltd* (2001) ACompT 2.

13 *Sydney Airport case* at paragraphs 23, 100, 189, 206, 208, 212, 216, 217, 219.

14 *Re Australian Union of Students* (1997) ATPR 41-573.

15 *Sydney International Airport* (2000) ATPR 41-754.

16 Section 33, *Interpretation Act, 1987* (New South Wales); section 15AA, *Acts Interpretation Act, 1901* (Commonwealth).

is only available in relation to the services of natural monopoly infrastructure where that natural monopoly has sufficient market power in a dependent market to affect competition. In the case of natural gas pipelines, the focus of a coverage/revocation process will often be on the question of whether a particular pipeline has sufficient market power to potentially hinder competition in a dependent market. The Council's experience has been that most natural gas pipelines in Australia are natural monopolies, though as natural monopoly is a dynamic concept, this may not always be the case.

In the course of considering the application by EAPL for revocation of coverage of the Moomba to Sydney pipeline under the National Gas Code, the Council requested Professor Janusz Ordover and Dr William Lehr to consider the questions of natural monopoly and market power in the Australian gas pipeline industry. Professor Ordover and Dr Lehr's work provides a framework for analysing these questions on an individual pipeline basis. The framework is consistent with approach taken by the Tribunal in the EGP case and has been adopted by the Council in recent coverage and revocation recommendations. A copy of Professor Ordover and Dr Lehr's paper is at Attachment A.

The coverage criteria in section 1.9 of the National Gas Code do outline an appropriate test for identification of the natural gas pipelines that should be regulated. The coverage and revocation processes provide the opportunity for interested parties to test whether regulation is appropriate in the case of a particular pipeline. Schedule A of the National Gas Code identified pipelines that Governments considered, at the time of the development of the Code, to meet the criteria in section 1.9. However, as the gas industry has developed and as understanding of the criteria has expanded, issues have arisen as to whether the pipelines on Schedule A continue to meet the criteria.

To date the Council has received 20[17] applications for revocation and one application for coverage of a new pipeline. A table outlining all revocation and coverage applications is at Attachment B. Of the 18 completed applications for revocation, the Council has recommended that all but three be revoked. The decision-makers have accepted the Council's recommendation in all these matters, consequently there are now 15 fewer pipelines regulated under the National Gas Code. This is to be expected as the gas industry develops and more gas sales markets are linked with a wider variety of gas production sources through more transmission pipelines.

In fact, it seems likely that as transmission pipeline infrastructure in Australia is developed, and more choices become available to gas producers, retailers and users, fewer pipelines will have substantial market power and the ability to profitably restrict competition in gas markets such that coverage under the Gas Code is appropriate. Further, as the culture of doing business in effectively competitive gas markets becomes entrenched, it may

[17] This counts the EAPL initial application for revocation of three pipelines in the MSP system as one application and the subsequent EAPL application for revocation of two pipelines in the MSP system as another one application.

be appropriate to further lighten the level of regulatory intervention in the Gas Code.

But in the context of the current state of development of the gas industry, the Gas Code in its current form appears appropriate and is certainly not fundamentally flawed. Further, as clearly recognised by governments in all the relevant inter-governmental agreements, gas access regulation is a crucial element in the development of a competitive gas industry Australia-wide.

Regulatory certainty

While the Council considers the National Gas Code has considerable flexibility and is capable of providing certainty to service providers, there are additional regulatory mechanisms that could be included to enhance certainty, particularly for new investment. The Council discussed these in its submissions to the PC review of Part IIIA, but considers the discussion is also relevant to the National Gas Code.

Access Holidays

Where new infrastructure projects are expected to be only marginally profitable (allowing for risk), any diminution of expected returns as a result of exposure to access regulation may deter investment. In some cases, the project may simply not proceed. In others, investment may be delayed until such time as demand has increased by a sufficient amount to pay the expected access 'tax'. To counter these sort of impacts on marginal projects, it has been suggested that the concept of "access holidays" be introduced. This would mean, in effect, proposed projects which were expected to be only marginally profitable would be exempt from coverage for a designated period, thereby providing the owner with the opportunity to recoup capital costs free of the threat of access. In many respects, an access holiday would be akin to a patent.

The certified access regime for the Tarcoola to Darwin rail link appears to have some of the attributes of an access holiday. In particular the pricing rules – while providing an incentive for third parties to use the facility where they can provide the service more cheaply than the incumbent – permit the incumbent to retain most of the profit attaching to the use of the line.

The Council considers it fundamentally important that access regulation not deter or delay efficient investment in infrastructure. The consequences of under-investment are significant and accordingly, economic efficiency is most likely to be achieved by erring on the side of over, rather than under, compensation of service providers. That said, the balancing process is a difficult one and users and infrastructure owners are likely to have strongly opposing views.

The Council considers that these issues are most acute in relation to new investment, whether that be the development of entirely new projects or new investment which expands the range of services that can be provided by existing infrastructure.

The PC has canvassed the idea of access holidays to counter the potentially 'chilling' effect of access regulation on new investment. Regulation of greenfields investments is a contentious issue and the principle of access holidays has attracted considerable interest. If access holidays were to be introduced a number of issues would need to be addressed, including the difficulty in identifying relevant investments and the risk of gaming by infrastructure owners.

The Council would be concerned if the determination of whether an access holiday would be available were based on an *ex ante* assessment of profitability of any particular project. For example, if a project was likely to earn normal returns, it could indicate that market power could not be exercised in a dependant market; in which case, coverage would not be appropriate. Conversely, if high returns are doubtful because a project is not efficient, it is unclear why favoured treatment is warranted.

It is important to distinguish whether the issues that are addressed in considering whether to grant an access holiday are questions of coverage or questions of appropriate regulation.

If the issues relate to whether the provider of a marginal project would have market power in the downstream market, or whether the cost of regulation of a particular service might be too high and contrary to the public interest, they would appear to go to the criteria for coverage. If this were the case, arguably they would be best dealt with through a binding ruling approach (discussed below).

However, if the issues regarding the grant of an access holiday were regulatory in nature, then some form of qualified (perhaps even 'null') undertaking would appear to be the right approach; for example, the case of major infrastructure investments where returns are subject to uncertain demand, with the possibility of blue sky returns as one possible outcome, but a material risk of failure as another. In this case, an application for coverage would be likely if returns turn out to be high. *Ex ante*, eliminating the possibility of high returns could make the project commercially unviable and deny the community what may have been a socially desirable investment.

The Council also considers that for a system of access holidays based on an initial threshold of contestability of the project, there may be some role for prices monitoring during the period of that access holiday.

An alternative to access holidays is to enable an independent regulator to factor in all the risks associated with greenfield investments through the regulatory process. The ACCC adopted this approach in its decision on the Central West Pipeline. Similarly, the Council took account of greenfields issues in its approach to the NT/SA Rail certification.

Under the National Gas Code it is possible for a service provider to submit an access arrangement for a pipeline that is not yet covered. This is akin to the undertaking process in Part IIIA. The Council considers that pipeline companies could use this mechanism to achieve regulatory certainty prior to an investment being made. The Council is aware that some service providers have questioned whether a regulator, under the Code as currently drafted, could accept a pre-investment access arrangement. If such impediments were identified, the Council would support amendments to the Code to ensure that pre-investment access arrangements can be considered and accepted under the Code.

Binding rulings

There is currently a procedure for advance advisory opinions under the National Gas Code. The relevant provisions are as follows:

> *1.22 A Prospective Service Provider may request an opinion from the NCC as to whether a proposed Pipeline would meet the criteria for Coverage in section 1.9.*
>
> *1.23 The NCC may provide an opinion in response to a request under section 1.22 but the opinion does not bind the NCC in relation to any subsequent application for Coverage of the Pipeline.*

To date one application for an advance ruling has been made to the Council. In that case the Council's advice was that, on the basis of the information supplied by the prospective service provider, it was unlikely that the pipeline would become covered. The supplied information included that:

- the pipeline would be only 4.5 km in length;
- it was being built to an optimal size for the customer it was to service; and
- there were other pipelines that may have been able to provide substitute services to potential third party access seekers.

Under the Gas Code, the advance ruling is not binding on the Council, and as a result it is more appropriately described as an advisory opinion.

The Council's capacity to give a binding ruling would be affected by the information available to the Council, including information gathered through any public process. It would be appropriate for any binding ruling process to be conducted in a similar way to an application for coverage. It might include a process for the Council to recommend revocation of the binding ruling if there was a material change in circumstance or if the service provider purposively or negligently misled the Council in the information provided. Any such revocation should be subject to a merit review to the Tribunal.

One context in which a binding ruling process may have been helpful was in regard to access to the proposed Tarcoola to Darwin rail-track. In that case, competition in downstream markets from road haulage raised a very real question as to whether the project would satisfy declaration criterion (a). However the NT and SA Governments considered that the threat of potential declaration obliged them to establish an access regime and seek its certification. It would not have been appropriate for the Council to refuse certification on the grounds that clause 6(3) was not met when there was no other mechanism for providing the Governments with the certainty they sought.

The Council sees the binding ruling process having particular application in situations where:

- it is unlikely that the infrastructure will have natural monopoly characteristics and, as a consequence, it is unlikely that criterion (b) will be satisfied; or

- the market conditions are such that it is unlikely that criterion (a) will be satisfied, for example, because the infrastructure owner is not likely to possess market power.

The fundamental advantage of a binding ruling is that it involves consideration of the relevant issues at the time the investment is made. Even if the Council were unable to reach a firm view on one of the criteria, the process and the views reached in relation to the other criteria may nonetheless provide a much greater degree of certainty to an infrastructure owner than would otherwise be available. Given the recent complaints about levels of uncertainty attendant on infrastructure investment, any mechanism that promotes certainty is likely to be efficiency enhancing.

Prices monitoring as an alternative to coverage

As was submitted to the PC review, the Council supports the provision of prices monitoring as an alternative to declaration/coverage where there is some doubt whether:

- an essential facility has scope to extract monopoly profits; or

- the benefits of applying coverage to constrain an essential facility's market power exceed the costs of regulation.

Market power problems associated with natural monopoly can vary by degree. The availability of prices monitoring as an alternative to coverage would mean that coverage would not be imposed in some marginal cases where the criteria for coverage are met but where competition may emerge in a dependent market despite the market power of a natural monopoly service provider. Prices monitoring of the service provider would facilitate the appropriate oversight.

For these reasons, the Council would consider it appropriate for prices monitoring to be considered in response to an application to cover or revoke a pipeline service. Thus, in response to an application, a recommendation could be made, as appropriate according to the respective criteria, to:

- cover the pipeline service;
- declare the pipeline service for prices monitoring for a period of time; or
- not cover the pipeline service.

The Council considers that a decision to impose prices monitoring should be quite separate from the conduct of prices monitoring for a particular business. While the former is a policy matter, the latter constitutes the administration of specific regulation. The Council also considers that the two functions (imposing prices monitoring and conducting prices monitoring) should be the responsibility of separate agencies. The consideration of whether prices monitoring is appropriate involves different questions, information and skills compared to the application of prices monitoring. Separation of these policy and regulatory functions avoids problems associated with a regulator determining its own jurisdiction and imposes few, if any, costs of inconsistency or overlap between the responsible organisations. This is consistent with the views expressed in the PC's Draft Report on the Review of the Prices Surveillance Act 1983.

Transitional arrangements and derogations

A number of access regimes submitted to the Council have included transitional arrangements and/or derogations which constrain the operation of the regime in some way. These constraints can have implications for the effectiveness of the regime.

Transitional arrangements are timetables to phase in the availability of access for different classes of customer. The Council accepts that transitional arrangements can provide a breathing space to help parties adjust to the realities of a fully competitive market. Conversely, they create delays in competitive arrangements, and may impose price penalties on consumers who would otherwise be contestable at an earlier stage. For this reason, while an effective regime may incorporate transitional arrangements in response to demonstrated public policy issues, the arrangements should be phased out as early as possible.

In the National Gas Regime, for example, contestability for different classes of customer is being phased in over several years. The policy objectives are to allow household contestability issues such as metering to be resolved, and to allow for cross-subsidies between customer groups to be unwound. Governments argued that a staged reduction of cross-subsidies would cushion price shocks that might otherwise have a negative impact on markets and social policy concerns.

Derogations are modifications, variations or exemptions from the application of an access regime. For example, a derogation may seek to exempt a particular facility from an access regime's pricing principles. Clause 12.2 of the 1997 Gas Agreement emphasises that derogations are to be limited to those essential to the 'orderly introduction of competitive arrangements' with the aim of creating a 'competitive natural gas market characterised by access to all gas consumers and all producers in all States and Territories'. Except for changes in contestability timetables *(discussed below)*, jurisdictions have not legislated derogations beyond those agreed in annexes H and I.

In considering a derogation in the context of a certification application, the Council assesses the anti-competitive effect of the arrangement against the overall public benefit. Issues for the Council include:

- the effect the derogation will have on the operation of the access regime, including effects on regulatory processes and dispute resolution, and ramifications for compliance with the clause 6 principles;
- effects of the derogation on competitive outcomes in markets reliant on the infrastructure service;
- the length of time the derogation will be in place; and
- public policy matters such as sovereign risk issues.

In general, the Council will not recommend certification in respect of services that are subject to a total derogation, unless these services are covered by an *alternative* effective regime.

As an example, the Council has considered two access regimes in which derogations raised significant issues:

- in the case of the Western Australian Gas Regime (WA Gas Regime), the Council was not convinced of the policy merit of a number of derogations affecting major pipelines, and was unable to convey a certification recommendation to the Minister until the derogations had expired; and
- in the case of the Queensland Gas Regime, the Council considered derogations affecting major pipelines to be sufficiently material that it was unable to view the Queensland Regime as a consistent application of the National Gas Pipelines Access Code (National Gas Code). The Council assessed the Queensland Gas Regime as a 'stand alone' access regime against the clause 6 principles.

The Council released its draft recommendation in respect of effectiveness of the Queensland Gas Regime in December 2001. The draft recommendation outlines significant concerns about the effectiveness of the Queensland Regime as it applies to the services of four derogated pipelines. The derogations go to the key 'effectiveness' criteria of regulatory independence and information provision. The length of the derogations go beyond what might be considered a reasonable transitional period.

Governance and institutional arrangements

Current arrangements

Under the National Gas Access Regime an application for coverage or revocation of coverage of a pipeline is made to the Council. The Council then makes a recommendation to the Decision-maker. The Decision-maker under the National Third Party Access Code for National Gas Pipeline Systems (the Code) is the 'relevant Minister' as defined by the Gas Pipelines Access Law, and varies with the type of pipeline and jurisdiction involved.

Decisions concerning the coverage of a pipeline are subject to both administrative and judicial review. For transmission pipelines, the Australian Competition Tribunal (the Tribunal) is the administrative appeals body in all jurisdictions except South Australia and Western Australia (where the relevant bodies are the SA Gas Review Board and WA Gas Review Board respectively). The Federal Court is the judicial review body in all jurisdictions except Western Australia, where the Supreme Court is the judicial review body. For distribution pipelines, the Tribunal is the administrative appeals body in all jurisdictions except Queensland (Qld Gas Appeals Tribunal), South Australia (SA Gas Review Board) and Western Australia (WA Gas Review Board). The Federal Court is the judicial review body in all jurisdictions except Queensland (Supreme Court) and Western Australia (Supreme Court). Arrangements in Tasmania are yet to be determined.

The ACCC is the relevant regulator for transmission pipelines in all jurisdictions except Western Australia. The relevant regulator for distribution pipelines is the local independent regulatory agency, except in the Northern Territory where the ACCC is also the regulator of distribution pipelines.

Decisions by the regulator concerning the imposition of an access arrangement for transmission pipelines are subject to administrative review by the Tribunal and judicial review by the Federal Court in all jurisdictions except Western Australia (where the WA Gas Review Board is the administrative appeals body and the Supreme Court is the judicial review body). For distribution pipelines, the Tribunal is the administrative appeals body for all jurisdictions except Victoria (ORG Appeal Panel), Queensland (Qld Gas Appeals Tribunal), South Australia (SA Gas Review Board) and Western Australia (WA Gas Review Board). The Federal Court is the judicial review body for all jurisdictions except Queensland (Supreme Court) and Western Australia (Supreme Court).

The Regime provides that where a prospective user and service provider cannot agree on access to a pipeline service, either party may refer the dispute to the relevant regulator. If the relevant regulator agrees that there is a dispute, it must arbitrate on the matter. The arbitrator under the Code is therefore the relevant regulator.

Applications for judicial review of an arbitrator's determination would be made to the Federal Court in all jurisdictions except Western Australia, where applications would be made to the Supreme Court, and South Australia in the case of distribution pipelines (Supreme Court). Tasmania is the only jurisdiction that provides for review of an arbitrator's determination (for transmission pipelines only); the Tribunal would be the appeals body.

Several other bodies have been set up under the Regime to facilitate its operation.

- The National Gas Pipelines Advisory Committee (NGPAC) comprises a panel of government, regulators, industry representatives and major gas users. Its responsibilities include reviewing the operation of the Code, advising Ministers on the interpretation of the Code, and making recommendations to Ministers on possible Code changes.

- The Code Registrar maintains the Code, keeps a public register describing each pipeline covered by the Code, and holds documents provided to it by participants in the regime.

National and State regulators

The Council considers that for infrastructure services with national characteristics – such as electricity and gas transmission and interstate rail services – a single generic national regulator is likely to deliver the most efficient outcomes.

At the same time, a general economic regulator operating at the State level, across several industries, can be an appropriate framework for dealing with state-specific infrastructure such as gas and electricity distribution networks. This framework allows for alternative approaches to be tested, promoting innovation and benchmarking.

The Gas Code structure combines these two approaches in an appropriate way with the ACCC as national regulator of transmission pipelines and the State based regulators responsible for the distribution networks. Further there are mechanisms within the Code and practices adopted by Australian regulators to ensure that there is dialogue and consistency between regulators. These mechanisms include:

- NGPAC;

- the Energy Committee of the ACCC; and

- the Utility Regulators Forum, which has been active in promoting regulatory consistency.

Further, the current structure provides for consistency of regulatory outcomes, to the extent possible under the current regimes, between the gas and electricity sector. In most jurisdictions the same regulators deal with gas and electricity issues, with the ACCC being responsible for electricity transmission.

Retail Markets

Full and effective customer choice

Jurisdictions have provided in annex H of the 1997 Gas Agreement for the progressive introduction of contestability for all gas consumers. Annex H has been modified by agreement of all jurisdictions since the 1997 Gas Agreement. The introduction of full retail contestability is important to realise the benefits of competition in the gas sector. The introduction of full retail contestability, to promote competition effectively, requires more than the removal of legal barriers. Effective introduction of full retail contestability requires jurisdictions to implement a package of business rules covering such matters as:

- processes for measuring gas use (whether through metering or other processes);
- protocols for transferring customers from one gas supplier to another;
- consumer protection requirements; and
- safety requirements and gas specification requirements to be met before interconnection can take place.

Most of the legal removal of barriers to competition occurred with the enactment of the GPAL including the National Gas Access Code (although some barriers may remain). The business rules must make it practical for customers to select from among suppliers, thus promoting competition among suppliers to secure customers. This process of supplier selection has promoted effective competition in other network industries such as telecommunications.

Jurisdictions have experienced significant difficulties in introducing effective full retail contestability in accordance with their contestability timetables. Some have announced deferrals of up to 12 months for smaller customer sizes. Difficulties relate to such matters as:

- the introduction of information technology systems to handle customer billing and transfer; and
- the choice and costs of a method of metering (that is, how to measure use by smaller customers cost effectively).

One particular implementation issue is the need for full retail contestability business rules to accommodate convergence among jurisdictions and with the electricity industry. The parties selling gas to consumers, particularly small consumers, are generally utility retailers that are in the business of selling gas, electricity and sometimes other utility services. These suppliers generally wish to operate in a number of different States and Territories and offer a number of different utility services to achieve efficiencies of scale and scope. To promote effective competition, States and Territories need to introduce business rules that are similar across jurisdictions and similar across the gas and electricity industries. Without similar rules, retailers will face higher costs (which they will need to recoup from consumers) or will be discouraged from entering more than one State or Territory, limiting consumer choice and competition.

Jurisdictions need to ensure that their introduction of new arrangements for full retail contestability does not create barriers to free and fair trade in gas among jurisdictions. They may need to coordinate the introduction of full retail contestability to ensure different contestability rules do not impede interstate trading in gas.

The Council considers that it is important for jurisdictions to introduce rules for full retail contestability as soon as possible in keeping with the 1997 Gas Agreement. The Council will consider jurisdictions' progress more fully in the NCP assessment in 2002. This will be after the date of 1 September 2001 nominated in the 1997 Gas Agreement as the date by which access for all customers and suppliers was contemplated. The Council also notes that all jurisdictions anticipated implementation of full retail contestability by 1 July 2002 under annex H. The Council expects that jurisdictions will have had sufficient time by July 2002 to tackle most, and in some cases all, of the obstacles that have delayed the implementation of full retail contestability.

Social policy objectives

The introduction of FRC will expose all customers to the full cost of the service they purchase. This exposure ensures that the service is utilised in the most efficient manner, which provides for a net community benefit. However, Governments are often concerned that it may not be fair for some customers to be required to pay the full cost. This may be because they are disadvantaged through limited income or because the cost of providing the service is higher for them than for other consumers.

It is entirely appropriate for Governments to determine that these consumers should be subsidised in their use of the service. The Council considers that the most appropriate and least distortionary way for this to occur, is for Governments to directly fund these subsidies to consumers. While the method of payment of the subsidies can vary, it should not be used to favour a particular service provider, but should be paid in a way that enables the customer to choose their provider and to still access the subsidy. As discussed in the electricity section of this submission, a customer rebate scheme is likely to meet these objectives.

Attachment A

Should Coverage of the Moomba-Sydney Pipeline be Revoked?

Janusz A. Ordover

New York University

and

William Lehr

MIT

November 22, 2001

Introduction

The National Competition Commission (NCC) is considering whether to revoke coverage of the Moomba-Sydney Pipeline (MSP) under the Gas Act.[18] The MSP is the only pipeline system currently delivering gas from the Cooper Basin production fields to markets in New South Wales (NSW) and the Australian Capital Territory (ACT) in south east Australia. The MSP is owned by the East Australian Pipeline Limited (EAPL), which is the trustee of the Australian Pipeline Trust. The Australian Gas Light Company (AGL) owns 30% of the Australian Pipeline Trust and is a major gas retailer in ACT and NSW and its subsidiary, Agility Management Pty Limited is the physical operator of the pipeline.

---

[18] Coverage of a pipeline under the *National Third Party Access Code for Natural Gas Pipeline Systems* imposes a regulatory regime that requires the pipeline operator to submit to the ACCC an arrangement for third party access, imposes disclosure requirements upon the pipeline operator, and puts in place an access dispute arbitration process. Hereafter, we refer to the Code and the other relevant legislation such as the *Gas Pipelines Access Law* and the *Natural Gas Pipelines Access Agreement 1997* collectively as the "Gas Act."

Prior to 1998, the MSP accounted for almost all of the natural gas delivered into the NSW and the ACT retail markets.[19] Because of the lack of alternative sources of natural gas transport to the retail markets in southeast Australia, the MSP was subject to coverage under the Gas Act provisions, which impose third party access requirements. However, no access arrangements for the MSP are currently in place under the Gas Act provisions.

In 1998, the previous owners of the MSP and the owners of a spur from the Victorian pipeline system jointly constructed the Interconnect pipeline to link the Victorian pipeline system to the MSP, thereby introducing another source of natural gas transport into NSW and the ACT. In 2000, the Eastern Gas Pipeline (EGP) began operation, providing a source of natural gas transport from the major production fields in the Gippsland Basin to the retail markets in NSW/ACT. The EGP is owned by Duke Eastern Gas Pipeline Pty Limited and DEI Eastern Gas Pipeline Pty Limited and is operated by Duke Australia Operations Pty Limited (collectively Duke).

In January 2000, AGL Energy Sales & Marketing Limited, a related body corporate of AGL, petitioned the National Competition Commission (NCC) to subject the EGP to access coverage.[20] On 3 July 2000, the NCC made a recommendation to the Minister for Industry, Science and Resources (Minister) that the EGP should be covered and in October 2000 the Minister determined that the EGP should be covered.[21] Duke appealed the decision to the Australian Competition Tribunal (Tribunal) which revoked coverage in May 2001.[22] This prompted EAPL to apply to the NCC to revoke coverage of the MSP, which initiated the current proceeding. Meanwhile, in December 2000, the ACCC issued a draft order for access regulation of the MSP that calls for prices that are approximately 40% below current MSP rates.[23] This draft order is in abeyance until the current revocation proceeding is concluded.

The purpose of this memorandum is to provide advice to the NCC with respect to two important questions:

---

19 In 1997, 95% of the natural gas consumed in New South Wales as supplied via the MSP (see page 27 of *Final Recommendation: Application for Coverage of the Eastern Gas Pipeline (Longford to Sydney)*, National Competition Council, June 2000).

20 For a pipeline to be subject to access coverage the Minister must be satisfied that each of the four criteria set forth in Section 1.9 of the *National Third Party Access Code for Natural Gas Pipeline Systems* are satisfied. The relevant criteria are cited in Section II below of this memorandum.

21 See *Decision on Coverage of Parts of the Moomba to Sydney Pipeline System by Minister Nick Minchin*, 16 October 2000.

22 See *Duke Eastern Gas Pipeline Pty Ltd* [2001] ATPR 41-821.

23 EAPL proposed $0.708/GJ while the ACCC proposed $0.43/GJ. See *Draft Decision Access Arrangement by East Australian Pipeline Limited for the Moomba to Sydney Pipeline System*, Australian Competition and Consumer Commission (ACCC), December 19, 2000.

First, given that the MSP presently is a natural monopoly in the provision of transportation services between Moomba and Sydney, what are the relevant economic criteria that should be used to determine whether that pipeline possesses market power in the provision of transmission services, and if it does, whether the pipeline has both the incentive and ability to exercise that power in the downstream market for gas sales?

Second, based on the economic framework described above and a review of circumstances pertaining to the relevant markets in Australia, does the MSP possess substantial market power in the retail markets for gas sales in the NSW/ACT?

Criteria for Coverage Under the Gas Act: An Economic Assessment

Criteria for Coverage Under the Gas Act

To justify coverage of a pipeline under the Gas Act, it is necessary to show that all of the following four conditions are met:[24]

> "(a) that access (or increased access) to services provided by means of the Pipeline would promote competition in at least one market (whether or not in Australia), other than the market for the services provided by means of the Pipeline;
>
> (b) that it would be uneconomic for anyone to develop another Pipeline to provide the services provided by means of the Pipeline;
>
> (c) that access (or increased access) to the services provided by means of the Pipeline can be provided without undue risk to human health or safety; and
>
> (d) that access (or increased access) to the services provided by means of the Pipeline would not be contrary to the public interest."

The advice which has been sought from us is relevant to the first and second criteria. We have not been asked to address any matters affecting criteria (c) and (d), and therefore, the balance of our comments will focus solely on the first two criteria. As will be clear shortly, it is easier if we address the first two criteria in reverse order.

Economic Assessment of Criterion (b)

Economic assessment of criterion (b) hinges on the meaning of the term "uneconomic" and the phrase "the services provided by means of the pipeline." Regarding the first term, there are three possible interpretations. The first

[24] See Section 1.9 of the *National Third Party Access Code for Natural Gas Pipeline Systems*.

interpretation relies on the concept of minimum viable scale. Minimum viable scale is the scale of operations that the entrant must attain in order to recover all of its forward-looking costs, given the current rates charged by the incumbent.[25] Under this interpretation, entry is "uneconomic" if the entrant is not able to recover all of its forward-looking costs for any level of output that it can conceivably capture, given that it is constrained to charge no more than the incumbent. Put another way, entry is uneconomic if the minimum viable scale exceeds the amount of business that the entrant can expect post-entry. It is possible that current rates are sufficiently above economic costs for entry to be profitable and yet such entry may be inefficient (higher cost).

More generally, the entrant likely anticipates the impact of entry on post-entry competition and thus expects that current rates will fall. Under this second interpretation, entry is uneconomic if it is unprofitable for the entrant after taking account of the expected intensification of post-entry competition. Evaluating whether entry is "uneconomic" in this context depends in part on ones (or the rational entrant’s) expectations about how competitive the market will prove to be after entry, which leaves the outcome ambiguous.

The third interpretation which seems most appropriate in the present situation is to focus solely on the costs of serving a given volume of demand. From this perspective, criterion (b) is satisfied if it would be economically inefficient for two or more pipelines to provide the volume of services offered by the pipeline under consideration. Thus, criterion (b) is satisfied if the total cost of serving a given level of output is lower if the output (in this case, gas transport services) is provided by a single pipeline rather than by two or more pipelines.[26] If this is the case, then the incumbent pipeline is a natural monopoly and competition between two or more pipelines offering the same services would be inefficient.[27]

Two remarks regarding this last interpretation of the "uneconomic" criterion are proper. First, whether entry is inefficient from a cost perspective depends on the target level of output. Thus, if demand for the service were to double from the current level, for example, there might be no cost penalty for having more than one firm providing the relevant service. Second, just because the provision of the service is a "natural monopoly," it does not mean that the incumbent is necessarily sustainable against a

---

25 See, for example, Section 3, United States Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines*, Revised 1997.

26 Formally, a provision of a particular product or service is a natural monopoly if, over the entire relevant range of outputs, the firms’ cost function is *subadditive*. A cost function C(q) is subadditive at q if it is always cheaper to produce a vector of outputs, q, in a single firm then by partitioning the output among two or more firms. For further discussion of these technical characteristics, see Sharkey, William, The Theory of Natural Monopoly, Cambridge University Press: Cambridge, (1982) and W J Baumol, J C Panzar, and R D Willig, Contestable Markets and the Theory of Industry Structure, HBJ Publishers: New York (1982).

27 This interpretation of criterion (b) seems to be the one adopted by the Tribunal in the EGP decision at paragraphs 64 and 137 (see *Duke Eastern Gas Pipeline*, note 22, *supra*). The Tribunal stated at paragraph 137, "The test is whether for a likely range of reasonably foreseeable demand for the services provided by means of the pipeline, it would be more efficient, in terms of costs and benefits to the community as a whole, for one pipeline to provide those services rather than more than one."

competitive incursion by a new firm. Consequently, profitable entry can occur into a monopolistic market, even if such entry would raise the total costs of production, as we note later.

Interpreting the second part of criterion (b) is much easier. The services provided by the MSP are the transport of natural gas from the production fields in the Cooper Basin to the retail markets in NSW and the ACT. In the short term, when the capacity is fixed, these services include the transport of any volume of gas from zero up to the capacity of the pipeline. Over the longer-term, when it is possible to expand capacity by adding additional compressor stations, the services may include the transport of gas in any volume up to the pipeline's maximum potential capacity. For another pipeline to provide the services offered by the MSP, it would have to transport natural gas between the Cooper Basin fields and the NSW/ACT markets.

Therefore, evaluating criterion (b) amounts to a determination of whether the MSP is a natural monopoly, which turns on the characteristics of the cost function associated with meeting any level of demand up to either the maximum potential capacity of the MSP or the maximum demand that the MSP pipeline might be called upon to serve, whichever is smaller. Note that this approach does not address the question of industry structure or market power, which are logically separate issues. For the determination whether the MSP is a natural monopoly in the provision of the transportation service between Moomba and Sydney (or any points in between), it is irrelevant that there are other pipelines between other sources of gas production and the retail markets in NSW and the ACT.

Indeed, as already noted, even natural monopoly does not assure that all of the demand is served by a single firm. Not all natural monopolies are sustainable against cream-skimming entry (*i.e.*, entry that seeks to serve only a portion of the market). For a particular combination of costs and market demand, entry on a scale smaller than the size of the market may be profitable, even though the cost of meeting total demand when it is supplied by multiple firms is higher.[28] Such inefficient entry is more likely the more restricted (by regulation, for example) is the incumbent firm in its ability to respond to market incursions and the more its prices deviate from economically efficient levels (due to cross-subsidies, for example).

The costs of constructing and operating a pipeline are largely sunk and fixed. Variable operating costs constitute a relatively small share of the total costs. For this reason, it seems plausible to expect that constructing and operating two (or more) point-to-point pipelines, each carrying only a share of the gas currently carried by the MSP would be "uneconomic", as we interpret criterion (b). Therefore, given the current and anticipated state of demand, it is reasonable to conclude, on cost criteria alone, that the MSP is a natural monopolist in the provision of transportation services for natural gas between

---

28 If the cost function is supportable (*i.e.*, there exists a price, p, such that p*q = C(q) but for any other q' that is smaller than q, the product p*q' is less than or equal to C(q), where C(q) is the cost of producing the output vector q), then small scale entry against a natural monopoly whose costs are subadditive for all levels of output up to its capacity cannot occur. In a single product case, global economies of scale are sufficient to assure supportability and subadditivity are both satisfied and that the natural monopoly producing q is sustainable (see Sharkey, note 26, *supra*, pages 84-94).

Moomba and Sydney. Furthermore, we do not think that the threat of cream-skimming entry is likely given the costs of building a competing pipeline to run from Moomba to Sydney and the potential for expanding the existing MSP pipeline at relatively low incremental cost.

The conclusion that criterion (b) is satisfied is bolstered by consideration of the relationship between forecasted demand, production reserves in the Cooper Basin, and the potential capacity of the pipeline (see Exhibit 1).[29] Taken together, these data indicate that the MSP is likely to be able to meet the relevant retail demand in NSW and the ACT retail markets and that the Cooper Basin reserves are not so large as to warrant construction of a second pipeline during the expected remaining lifetime of the MSP.[30] To the extent that the MSP has excess capacity today or is likely to have excess capacity in the future, the costs of serving the forecasted gas demand by two or more pipelines would be even higher.

Criterion (b) is a necessary (but not a sufficient) condition to justify coverage. When this condition is met, the total cost of transporting gas is minimized (and the goal of economic efficiency is served) when the activity is undertaken by one firm rather than by two or more firms. In the instant case, firms demanding transportation of natural gas between the production fields in Cooper Basin and the retail markets in NSW/ACT could not efficiently develop another pipeline that could compete with MSP without the overall cost of gas transport increasing. Such wasteful duplication of assets would engender inefficiencies to the detriment of the consuming public. Therefore, when criterion (b) is satisfied, it is efficient for firms wishing to ship gas between Cooper Basin and the NSW/ACT retail markets to avail themselves of the services provided by the MSP rather than constructing another pipeline. Coverage, if mandated, assures third parties access to the MSP.

Whether mandating coverage is desirable from the perspective of promoting competition in either the upstream or downstream market hinges on the evaluation of criterion (a), and is not a direct concern in the determination of whether criterion (b) is satisfied. The finding that criterion (b) is satisfied and that the MSP is likely to be a

---

29 We note that there are several potential projects referred to by the Tribunal in the EGP decision which involve the delivery of gas to Australia from offshore sources namely the Timor Sea and Papua New Guinea. Some proposals for the development of these offshore gas sources contemplate using Moomba as a hub for delivery on to Sydney. For example, the proposal for the Timor Sea gas involves an undersea pipeline to Darwin, construction of a pipeline from Darwin to Moomba, and then utilization of the Moomba to Sydney pipeline for delivery to the NSW/ACT markets. Based on the material we have reviewed, none of these proposals is sufficiently advanced to be taken into account under criterion (b).

30 As Exhibit 1 makes clear, there is ample room to expand the capacity of the EGP and MSP such that they could separately or together address the growth in demand for natural gas in the NSW/ACT markets. Moreover, each has sufficient additional reserves in the associated upstream market so that either or both could expand its transport services above current levels either to respond to a shift in current market demand (perhaps in response to an attempt by one or the other pipeline seeking to raise prices above competitive levels) or to accommodate additional demand in the downstream retail markets.

sustainable natural monopoly, has implications for the assessment of coverage under criterion (a). First, it eliminates consideration that entry by another pipeline between Moomba-Sydney will offer effective competition to the MSP for pipeline services. Second, the finding of natural monopoly leads to the presumption that the MSP may be able to convert its technological and incumbency advantage (deriving from the characteristics of pipeline costs) into significant market power in either the upstream or downstream market. Before considering criterion (a), however, we will explain the concept of market power and its relationship to the promotion of competition.

Market Power

In economics, market power is defined as the ability to profitably raise prices above marginal cost. Any firm – other than a firm operating in a perfectly competitive market – can have, in principle, some ability to raise price above marginal cost: all that is required is that the firm faces a downward-slopping demand curve. Indeed, under some cost conditions, pricing at marginal cost would ruin the firm and is thus a precondition for financial viability.[31] Regulatory concerns arise only if the firm possesses significant and durable market power leading to prices that substantially deviate from proper economic costs and which generate persistent supracompetitive returns. When a firm possesses substantial and durable market power, it is often said to possess "monopoly power." Additionally, a firm with market power may have both an incentive and ability to engage in market strategies designed to protect its monopoly profits and power to the detriment of competition and consumers.[32]

The existence of effective competition precludes the ability profitably to exercise monopoly power, and therefore, a finding that effective competition exists in a market is usually taken to be equivalent to a finding that no firm in that market possesses substantial market power. In the presence of effective competition, prices are driven towards economic costs and resources are allocated efficiently.

– *Applying an appropriate standard*

In the real world – as opposed to the theoretical construct of perfect competition – most firms have some degree of market power (i.e., some degree of discretion over price).[33] Indeed, generally firms seek to gain advantages in the marketplace that will result in attaining some level of market power. Moreover, firms may acquire market power through means that are wholly

---

[31] For example, marginal cost pricing will fail to recover total costs if there are substantial fixed costs.

[32] Of course, firms generally strive to protect or enhance their market positions. Such quest for profits and market share is, indeed, an engine of competition and should not be discouraged. See, for example, Jeffrey Church and Roger Ware, Industrial Organization, Irwin/Mc-Graw Hill, Boston (2000).

[33] On the divergence between the theoretical ideal of perfect competition and real world markets, see for example, Dennis Carlton and Jeffrey Perloff, Modern Industrial Organization, Harper-Collins: New York, 1990, pages 92-94; Alfred Kahn, The Economics of Regulation, MIT Press: Cambridge, 1988 (reprint edition, original John Wiley & Sons, 1970), volume II, pages 44, 114.

consistent with the process of effective competition (for example, through innovation, superior customer service, or operating efficiency). Therefore, a useful framework for assessing market power needs to be sufficiently nuanced to distinguish between the possession of *any* market power which is consistent with effective competition and the possession of *substantial* market power which is not.

Once one appropriately abandons the standard of perfect competition as a benchmark for assessing how well the market performs, one must accept that there may be systematic deviations from that standard in terms of structure (*e.g.*, potentially concentrated market shares), behaviour (*e.g.*, evidence of some control over prices), and outcomes (*e.g.*, systematic deviations from marginal cost pricing). Structural characteristics may portend the existence of market power, but, if the firm or firms with market power do not have the ability to use that power to harm the competitive process, then that firm or those firms do not have a *substantial degree of market power*. In such a case, the market may be deemed to be effectively competitive.

– *Market definition*

The first step in determining whether a firm has market power is to identify the relevant market in which power is to be gauged. The mere fact that a firm may have a large market share in a putative market is potentially irrelevant to the issue of market power, if the market is improperly specified. In the present context, there are two relevant markets in which market power and its potential impact on competition needs to be assessed. These are: (1) the "upstream" market for natural gas production; and, (2) the "downstream" market for retail sales of natural gas.[34]

Markets are defined with respect to both product and geographic boundaries. Generally, if consumers regard two products as close substitutes for one another, then they are regarded as being in the same market. If two goods are viewed as very poor substitutes for each other (or are clearly unrelated goods), then they are in separate markets. Assessing the extent to which goods are substitutes for each other requires an examination of the responsiveness of consumers to changes in the relative prices of the goods under consideration, as we shall explain in detail below.

A proper market definition inquiry begins with the narrowest set of products (services) and geographic areas feasible and asks the question,

[34] There are also the downstream markets for local gas distribution and wholesale sales of natural gas. We are assuming that the downstream market for local gas distribution is a natural monopoly that is regulated and will not address the impact of potential market power over long haul pipeline services on local distribution competition. Furthermore, our analysis of the markets for natural gas consumption is not sufficiently detailed to distinguish between wholesale and retail trade. Similarly, we also have not tried to separate out the potentially disparate effects of market power on different classes of end-users (*i.e.*, large commercial, small to medium commercial, and residential customers).

whether a hypothetical monopolist over that set of products (services) could profitably raise prices by a small but significant and non-transitory amount.[35] If the answer is "yes," then the relevant market has been identified. If, however, in response to the price increase a sufficient number of consumers would switch to alternative services/products to render the hypothesized price increase unprofitable, then the market must be expanded to include those services to which consumers would switch, and the exercise is repeated. This exercise continues until the smallest set of products (services) and geographic areas is identified such that a "hypothetical" monopolist over these products (services) likely could impose a small but significant non-transitory price increase. From this perspective, then, the relevant market is comprised of a group of products and a geographic area in which a sole supplier could exercise market power.

Two goods are in the same market when they are good substitutes for each other. Two goods are deemed substitutes if an increase in the price of one leads to an increase in the demand for the other (*i.e.,* the cross-price elasticity of demand is positive).[36] Hence, the relevant market should include all those products that are close substitutes for the product in question and exclude those products which are either not substitutes or very weak substitutes for the product in question. Unfortunately, it is often not a trivial matter to obtain with econometric methods statistically meaningful estimates of all the pertinent cross-elasticities of demand. Moreover, even when such cross-elasticities can be estimated, there is still a threshold question of what is the proper cut-off for inclusion of the product in the relevant market.[37]

With a commodity product like natural gas, the basis for discriminating among different sources of supply depends on the terms of availability and the price. There are a number of reasons why one may observe a wide dispersion in gas prices in both upstream and downstream markets. In the upstream market, there may be substantial differences in the costs of extracting or processing gas from different production sources. In the downstream market, what matters is the delivered price of gas which will vary depending on the location of an end-user because of transport costs and because of the terms under which gas is provided to or consumed by the end-user (*e.g.,* average and peak consumption, guaranteed or as-available delivery

---

[35] See, for example, United States Department of Justice and Federal Trade Commission, *Horizontal Merger Guidelines*, April 2, 1992.

[36] The cross price elasticity of demand between good 1 and good 2 is equal to the percentage increase in the demand for good 1 when the price for good 2 increases by one percent, holding other prices constant. If this is positive, then the goods are substitutes; if negative, the goods are complements (see Pindyck, Robert and Daniel Rubinfeld, Economics, Third Edition, Prentice Hall: Englewood Cliffs, NJ, 1995, page 31).

[37] For example, wine is a substitute for beer, but we expect that the cross-price elasticity of demand for beer relative to wine to be much smaller than the cross-price elasticity between different brands of beer. The choice of what constitutes the appropriate cut-off level for identifying whether two goods are substitutes for the purposes of defining the relevant market will affect the dimensions of the market under consideration.

commitments, etc.). Moreover, the price and the terms for availability may differ systematically based on the type of customer (*e.g.*, large commercial vs. residential consumers).[38]

The time horizon of the analysis may also impact how broadly the market is defined. With a longer horizon, the ability of users to substitute to other sources of supply in response to a price increase is likely to be greater, implying more elastic demand and higher cross-elasticities. For example, with a sufficiently long horizon, end-users can switch to alternative fuels (*e.g.*, oil) or sources of power (*e.g.*, electricity) in response to an increase in the price of natural gas, even if in the short-term such switching may be limited.[39] The time horizon is also relevant for assessing the impact of long-term contracts, which can also account for substantial variation in delivered prices.[40] Finally, the existence of storage facilities or inventories may make it possible to substitute between current and future demand for natural gas.

All of these factors need to be taken into account in defining proper markets in which market power is to be assessed. These factors also complicate the definition of the relevant "price." However, these difficulties are not of such magnitude as to undermine sound public policy. Still, it is essential that the regulator makes clear the criteria used for inclusion or exclusion of the various services and products in the pertinent markets so as to assist all the parties in understanding the principles that underpin the ultimate decision regarding the need for coverage (or the lack thereof).

Economic Assessment of Criterion (a)

Criterion (a) calls for an assessment whether coverage of the pipeline would "promote competition" in "at least one" market other than the one for pipeline services. This test has been described by the Tribunal in the following way:

---

38 Discrimination in the price or terms of availability may reflect differences in the underlying costs of serving different classes of customers or may reflect Ramsey pricing. For example, large commercial customers may require less customer service than residential customers (implying a lower cost to serve); or large commercial customers may have more stringent peak demand requirements than residential customers (implying a higher cost to serve). Alternatively, these differences may be due to the abuse of market power. Without considering the conditions under which the discriminatory practice arises, it is not possible to conclude from the observation of heterogeneous pricing and availability terms that there is substantial market power or that the public interest is being harmed.

39 Moreover, the ability of different classes of consumers may vary systematically in their ability to substitute among alternative sources of supply. For example, large commercial customers are likely to be more readily able to switch to alternative sources of supply than are residential customers. Therefore, if demand is segregated on the basis of customer type, one may identify market boundaries differently.

40 This variation may be the result of discounts or premiums for longer-term commitments or because of changes over time (*e.g.*, differences in *ex ante* expected prices and current spot rates).

"The Tribunal does not consider that the notion of "promoting" competition... requires it to be satisfied that there would be an advance in competition in the sense that competition would be increased. Rather, the Tribunal considers that the notion of "promoting" competition ... involves the idea of creating the conditions or environment for improving competition from what it would be otherwise. That is to say, the opportunities and environment for competition given [coverage], will be better than they would be without [coverage]."[41]

Following this interpretation, we understand criterion (a) to be focusing on whether coverage would reduce impediments to entry in either the upstream market for the production of natural gas or the downstream markets for the delivery and sale of natural gas to end-users.

A reduction in entry barriers in either an upstream or downstream market need not automatically induce new entry. Because of other market frictions, entry may be slow in coming. Hence, criterion (a) cannot be taken to mean that coverage would rapidly induce entry relative to the no-coverage benchmark. Rather, we take the criterion to mean that coverage is justified if imposition substantially increases the overall competitive conditions in relevant market(s), including the likelihood of entry. Here, it is important to point out that the mere reduction in impediments to entry could stimulate competition among incumbent firms as the enhanced threat of entry forces the incumbents to act more competitively on all dimensions that matter to consumers (which includes price, conditions of sale, service, and so on). Interestingly, it is conceivable that criterion (a) might be satisfied if it were found to lower entry barriers in at least one market, while increasing entry barriers in another.[42] In any case, since the pipeline "connects" two separate markets – the upstream production market and the downstream retail market -- it is necessary to evaluate the ability of the incumbent pipeline to exercise significant market power at least in these two distinct markets. For example, it is conceivable that the incumbent may not be able to exercise market power in one of the markets but be able to exercise market power in the second of the two markets. As we shall see, such a possibility cannot be excluded on merely theoretical grounds.

In the present context, transport facilities between upstream natural gas wells and downstream retail markets are an essential component in the natural gas value chain. Without a way of delivering gas from the well-head to end-users in downstream retail markets there would be no reason to extract the gas and there would be no way for end-users to obtain the gas. If a pipeline is a bottleneck facility, potentially it can adversely affect competition in the downstream and upstream markets, as indicated in criterion (a). For example, by overcharging for gas transport, it may reduce the number of

---

[41] See *Review of Declaration of Freight Handling Services at Sydney Airport* (2000) 22 ATPR 41-754.

[42] In this hypothetical circumstance, it still would be necessary to satisfy criterion (d), which requires that coverage be in the public interest.

active firms in either market; or it may use the terms and conditions of access to the pipeline to disadvantage some firms and advantage others.[43]

There are two plausible reasons why the pipeline with latent monopoly power over transport might use this to impact competition in upstream or downstream markets. First, it may seek to do this to exploit and protect its monopoly position in the market for pipeline services. Second, insofar as it is (or plans to be) vertically integrated, it may seek to extend, protect, or exploit whatever market power it may have in either upstream or downstream markets.

To evaluate these competitive dangers, it is necessary to consider the competitive conditions in the upstream and downstream markets. For example, if the pipeline has a subsidiary operating in the downstream market, the pipeline may seek to use its control over transportation facilities to disadvantage its downstream rivals. Whether the pipeline could be effective in such a strategy will depend on the strategic alternatives available to the pipeline's downstream rivals (*e.g.*, the opportunity to switch to gas supplied by the EGP or the Interconnect would reduce any potential anticompetitive impact from discrimination by the MSP).

– *Ability and Incentive to Abuse Market Power*

In this section, we discuss the incentive and methods by which a pipeline with market power over pipeline services may seek to exploit its power to affect the conditions for competition in upstream or downstream markets.

– *Ability to charge monopoly prices for transport services*

First, absent coverage or any other form of price regulation, the MSP may be able to set prices for transport services that substantially exceed its forward-looking, long-run economic costs.[44] This would have the effect of increasing the delivered cost of gas in the NSW/ACT markets, which would, in turn suppress demand for upstream production from the Cooper Basin. As we discuss further below, this appears to be the case under the current MSP tariffs.[45]

If aggregate demand for natural gas at a particular location (say, Sydney) is relatively inelastic at current prices, and because transport costs

---

[43] There is no certainty that the incumbent pipeline may engage in conduct that would be harmful to competition. It is well-known that a monopolistic supplier of an input may earn maximum profits if the downstream industry into which it sells the input is perfectly competitive.

[44] The current prices charged by the MSP are not subject to regulation given the current status of the access undertaking submitted to the ACCC.

[45] Although the MSP is currently covered, there is no access arrangement in force because the one proposed by the ACCC is in abeyance pending resolution of the current proceeding. Therefore, the current tariffs are not subject to price regulations.

represent only about 10% of the delivered cost of natural gas,[46] the reduction in demand for pipeline services from a price increase is likely to be small. However, this does not mean that demand elasticity facing a given pipeline is per force also low. The elasticity of demand for a given pipeline's transport services depends not only on the ability of customers to switch to other fuels but, also, on the ability to switch to other suppliers of gas. If the ability of end users to shift demand to other sources of natural gas away from MSP is also small at a "competitive" price,[47] then a price increase above that level would likely be profitable for the MSP. Indeed, as we discuss further below, the ACCC's draft access decision suggests that current rates are substantially above the pertinent economic costs.[48]

An increase in the prices for transport services above this benchmark competitive level could be partially offset by reduced margins earned by both upstream gas producers and downstream distributors.[49] Less than a full pass through of transport costs to end-users attenuates the reduction in demand associated with a price increase for pipeline services. Stated another way, the willingness of other economic actors to absorb some of the overcharge reduces the elasticity of demand for transportation services faced by MSP and thus enhances the incentives to elevate prices.

The incentive to elevate prices may be further reduced if the MSP is able to charge differential prices for transport depending on the source of the gas or its ultimate destination. That is, if it is able to price transport services differently to users based on their willingness-to-pay.[50]

The combination of lower upstream and downstream margins from above-competitive transport rates, will tend to reduce incentives to invest in both upstream and downstream markets and therefore could have an adverse effect on competition in both of these markets.

None of the above automatically implies that just because MSP is a natural monopolist in the provision of transport between Moomba and Sydney, it can set

[46] Transmission costs accounted for approximately 10% of the delivered price of gas to residential customers, while local distribution accounted for between 40-50% of the delivered price. The share of the delivered price that is due to transmission is higher for large commercial customers who draw gas from the transmission network and do not pay local distribution or retailing charges (see *Final Recommendation Application for Coverage of Eastern Gas Pipeline (Longford to Sydney),* National Competition Council, June 2000, page 26.

[47] Here, by a competitive price, we mean a price that earns MSP a normal rate of return (corrected for risk) and no more. We are not implying that this is the proper price benchmark against which prices in other industries must be gauged.

[48] See *Draft Decision Access Arrangement by East Australian Pipeline Limited for the Moomba to Sydney Pipeline System*, ACCC, December 19, 2000.

[49] The extent to which higher transport rates would be absorbed depends on the various elasticities of demand and supply along the gas production and distribution chain.

[50] Importantly, differential pricing of transport is likely to be efficient since pipeline costs are largely fixed. When fixed costs are high, marginal cost pricing is not feasible. Instead, second-best (or Ramsey) pricing is socially preferred.

prices at the "monopoly level," meaning price without regard to the market. The MSP's ability to monopoly price is potentially constrained by competition in upstream or downstream markets. Regarding the upstream markets, if gas producers can sell their gas to other retail markets via other pipelines, they will refuse to sell gas to MSP unless they earn the same return on the marginal unit of gas shipped to Sydney (or ACT) as they earn on shipments to other locales. This type of competition will constrain MSP's ability to set transport prices substantially above economic costs, even if MSP remains a monopolist with respect to transport between Cooper Basin and the markets in NSW/ACT. Regarding the downstream markets, if there are other sources of natural gas supply to the retail markets in NSW/ACT then MSP cannot overprice transport since this would render the gas shipped over it uneconomic. As noted, this ability of consumers to switch to gas from other sources also constrains the MSP's ability to set transport prices substantially above economic costs.

Source and/or destination competition is an effective constraint on MSP, if there is sufficient independent capacity to absorb gas output on pipelines going to other destinations and if there is sufficient volume of gas output from other sources to which consumers can divert their demand in the face of elevation in price of the gas delivered over MSP. If these conditions are met, a substantial price increase above the competitive level will likely be unprofitable. This is so, despite the fact that the pipeline (here the MSP) is actually a natural monopoly over transport from the Cooper Basin to NSW and ACT.

– *Ability to engage in explicit or implicit price collusion*

If the MSP faces only limited competition in either upstream or downstream markets, then it is possible that market participants will be able jointly to implement above-competitive prices through explicit or implicit coordination.

There are two important questions to address in this context: first, whether collusion between pipelines is a reasonable concern in the Australian context; and, second, whether requiring asymmetric coverage of the MSP pipeline would reduce the likelihood that collusion would be successful.

We have not undertaken an independent inquiry as to whether collusion among the pipelines is either likely or feasible. However, we note that the number of pipelines serving the NSW/ACT retail markets is small and is likely to remain so for the foreseeable future. Each pipeline is likely to have substantial latent market power in its relevant pipeline service market (by the same reasoning as was used to justify the conclusion that the MSP is a natural monopoly) and thus may not be adequately constrained by other pipelines that compete with it in the source (gas field) market. Thus, based on these plausible facts, public policy concerns regarding coordinated pricing cannot be dismissed out of hand.

It is critical to note that the ability to sustain a collusive outcome does not depend solely on the number of competing pipelines. Indeed, there are many markets with a small number of participants that are effectively competitive. Other market characteristics also impinge on the ability of firms to charge prices that significantly exceed competitive levels. For example, if each of the pipelines has excess capacity and if it is relatively easy to price discriminate so as to offer deals to potential customers that are unlikely to be observed by the competitor pipeline then price coordination may not be sustainable. Long-term contracts and large-scale purchases are also thought to hinder cooperation.

Some have argued that coverage of the MSP actually enhances the pipeline owners' ability to sustain a collusive outcome because the disclosure requirements associated with third party regulated access make pricing transparent.[51] While this criticism of regulation is well-founded, it ignores the effect of regulation on constraining prices to cost-based levels. By constraining prices, regulation sets a benchmark for unregulated prices that can be used by buyers in negotiations with the unregulated pipeline(s). This could have a salutary effect on the overall prices. On the other hand, the requirement to price according to public tariffs tends to rigidify prices since the regulated firm cannot readily take advantage of a secret discount or surprise when deciding on a price reduction. Abstracting from the well-known costs and inefficiencies associated with regulation in general, we believe that coverage on balance would not facilitate collusion.

– *Other incentives and opportunities to distort competition in adjacent markets*

A pipeline with monopoly power over transport may seek to leverage its market power into either upstream or downstream markets. The potent paradox is that the more tightly is the pipeline regulated in the provision of its monopoly service (here transport of natural gas), the stronger are the incentives to adopt business strategies aimed at extending this market power to the unregulated adjacent markets, such as upstream production or downstream retail distribution. The rationale here is plain: since the pipeline cannot earn its full monopoly return on the "bottleneck" activity, it will strive to capture that return in some other activities. The net effect may be more harmful to overall efficiency and competition than the alternative regime where the pipeline is allowed to capture some of the potential return for the provision of its transportation service. Alternatively, pursuing the public policy goal of preventing or deterring such "leveraging" could lead to additional regulatory constraints on the pipeline and the concomitant regulatory burdens, costs, and inefficiencies. There are, frankly, no easy trade-offs in this area. However, to the extent that competition in the source and destination markets is at least reasonably effective, the concerns with anticompetitive leveraging (hence the need for active regulation) are commensurately lessened.

The value of pipeline services is directly linked to the value of upstream production in the Cooper Basin and the retail markets in NSW/ACT. That is, the pipeline is a co-specialized asset. If there are

[51] See "Report in Support of Application to the National Competition Council for Revocation of Coverage of the Moomba-Sydney Mainline and the Dalton-Canberra Lateral Pipeline," Network Economics Consulting Group (NECG), August 2001, page 24.

inadequate reserves or production from Cooper Basin or if demand for natural gas in downstream markets is inadequate, then the value of the MSP will be adversely affected since it is only useful for transporting gas between these two markets. To the extent that such strategies are available, the MSP will have an incentive to deploy them in order to enhance the value of its assets. These may be either pro-competitive or anti-competitive in either the upstream or downstream market, depending on the circumstances. For example, if the MSP has no ownership interests in either upstream or downstream markets and if the MSP has excess capacity, it may be inclined to promote increased competition in upstream and downstream markets to reduce margins (and prices) in both markets and to increase incremental demand for pipeline services. If the MSP has excess capacity, stimulating incremental demand for MSP services is likely to be quite profitable because variable costs are low (*i.e.*, most of the costs are fixed or sunk) and promoting competition in upstream and downstream markets will have the expected effect of reducing upstream and downstream prices, creating a larger opportunity for the MSP to earn profits on the provision of its pipeline services.

Alternatively, if the MSP has ownership interests in either upstream or downstream markets, it will have an incentive to discriminate in favor of its affiliate. This discrimination may take a number of forms, including charging lower prices for transport services or offering such services on unequal and inferior terms to non-affiliates in either the upstream or downstream market. As we noted, such discriminatory incentives are more potent the more constrained is its ability to charge profit-maximizing prices for transport. Moreover, such discrimination need not lead to an overall reduction in economic efficiency and result in harm to consumers. For example, by advantaging its affiliate(s), the vertically-integrated incumbent may put enhanced competitive pressures on its stand-alone competitors in the upstream or downstream markets.

In fact, the owners of the MSP do have substantial ownership interests in both the upstream and downstream markets. In the downstream market, AGL, which is a major owner of retail and local gas distribution facilities in NSW and the ACT, has a direct ownership and management role in the operation of the MSP. The pipeline is owned by the Australian Pipeline Trust, of which AGL holds 30% of the units; AGL owns 50% of Australian Pipeline Limited which is the trustee and manager for the Trust; and AGL's wholly owned subsidiary Agility Management Services which is responsible for managing the actual operation of the pipeline. In the upstream market, the EAPL and another AGL wholly-owned subsidiary, AGL Wholesale Gas Limited, are parties to a 30-year agreement to purchase gas from the South Australian Cooper Basin Unit Producers (SACBUP), which is the consortium of producers that control natural gas production in Cooper Basin.

The MSP's major ownership interest in the downstream market as set out above creates natural incentives competitively to advantage its affiliate. However, it must be recognized that the technical aspects of gas transport (such as the need to balance the network and control injections into and withdrawals from the pipeline) can cause the pipeline owner to favor its affiliates for reasons that have nothing to do with the incentives as described above but, rather, for reasons that are firmly grounded in pipeline economics. When such discrimination arises as a consequence of the efficiencies of vertical integration, overall efficiency would be harmed if the integrated pipeline could not extend preferential benefits to its affiliates.

– *The upstream market*

With respect to the upstream market, the appropriate question to ask is whether there are gas producers over which the MSP might potentially exercise monopsony power. This naturally focuses attention on the producers in the Cooper Basin that use the pipeline in Moomba to deliver their gas to the NSW/ACT markets. The ability of the MSP to exercise monopsony power over these producers depends on the market power of these producers and the range of options facing the Cooper Basin for delivering their gas to retail markets that do not depend on the MSP. Because the MSP is the only pipeline between Moomba and Sydney, this means options for delivering the gas via other pipelines to retail markets other than the NSW/ACT. At the same time, as noted above, MSP has no alternative use for its pipeline but to transport gas to NSW/ACT. This creates a setting in which there is potentially bilateral market power (*i.e.*, market power both on the sell and the buy sides of the "market").

If there are many options available to the producers for selling their gas into other retail markets, then the MSP will not have any monopsony power in the upstream market.[52] The MSP will not be able to lower the price it pays to upstream producers, or equivalently, increase the price it charges producers for transporting their gas to downstream retail markets in order to earn supracompetitive profits.

In gauging the strength of this competition, it is important to examine the available capacity on these alternative pipelines as well as the retail prices of gas in the destination markets of these pipelines. If the aggregate capacity of these pipelines is small relative to total output of the gas field, the concern that transport to NSW/ACT may be overpriced is not necessarily obviated. For example, the dominant pipeline may "allow" its smaller rivals to bid for all the output that they can profitably take and then charge a supracompetitive rate for transporting the remaining share of gas output.

We understand that a substantial amount of gas from Cooper Basin is currently delivered to Adelaide via the Moomba-Adelaide pipeline, but that

[52] It will be recalled that monopsony power (or buyer power) results from increasing marginal costs of obtaining supply of the input (here, natural gas). There is also a possibility that the firm with buyer power may attempt to extract quasi-rents from gas producers who may have sunk substantial costs into the development and operation of the wells. Over the long-run, it is not possible for the buyer to extract such quasi-rents since the strategy leads to the exit of suppliers from the relevant market.

pipeline is at capacity. Generally, pipeline capacities can be expanded but it takes time as well as financial resources. We have no information that would enable us to opine on how likely such expansion is over the time horizon that is relevant to the decisions under the Gas Act. Nonetheless, the possibility of expansion by the pipelines serving the Cooper Basin must be taken into account when examining the market power of MSP and thus the need for coverage. In addition, one need also examine the likelihood of entry during the relevant decision horizon.[53] However, over the short term, when such an expansion in capacity is not feasible, it appears that alternative outlets for the sale of Cooper Basin gas are limited, which suggests the potential for the MSP to exert monopsony power.

The ability of the MSP to exert monopsony power also depends on the market power of producers. If producers have market power, then the ability of the MSP to exercise monopsony power will be constrained without coverage. Producers' market power depends on the availability of alternative outlets for gas as well as on their ability to "bargain" jointly with the MSP. To the extent that there is a danger of collusion among the incumbent gas producers and the MSP, coverage may lower entry barriers upstream by reducing the ability of the upstream incumbent gas producers to collusively foreclose access to the MSP. Of course, if there are other entry barriers into gas development in the Cooper Basin, then coverage may be of lesser importance to upstream competition.

We understand that current Cooper Basin production is under the control of a single consortium. Since this is the only gas that can use the MSP pipeline, it seems reasonable to presume that the consortium may have substantial bargaining power when negotiating with the MSP for pipeline services. However, absent coverage, the consortium might be able to foreclose entry of new producers by signing a favorable long term contracts with the MSP.

– *The downstream market*

Downstream competition is also an important constraint on the MSP's market behaviour. Downstream, the focus is on the geographic markets that are served by distribution networks that currently purchase, or could purchase, gas delivered via the MSP. Identifying the appropriate downstream retail market or markets, is more complex than for the upstream market since it is possible that the downstream market may be effectively segmented either on the basis of end-user location or customer type. If this is the case, then it may not be possible to treat the NSW/ACT as a single market, but rather as a collection of separate geographic or customer markets. For example, some regional markets may only be served by the MSP and the ability to deliver gas via alternate pipelines or by some other means may be quite limited for the foreseeable future. Those areas within NSW and the ACT for which the MSP is the only feasible source of supply may benefit from

---

[53] Pipeline entry and expansion can be facilitated by the ability of the pipeline to secure supply by means of long term contracts.

coverage if it leads to lower transport prices and assured access to the pipeline. Of course, insofar as the MSP exercises monopoly power in the provision of gas transport service to these areas, it creates incentives for other pipelines to create "spurs" that might reach the monopoly service areas.

Furthermore, in downstream retail markets, it may be necessary to examine competitive alternatives that are available to different classes of users. The competitive alternatives available to large commercial, small commercial, and residential customers may be systematically different. For example, different classes of gas customers may be differentially able to substitute to alternative sources of supply in the face of a price increase in delivered gas. It is the customers with the most inelastic demand who may benefit the most from coverage.

Of course, if the MSP is not able to set differential prices for transport destined for different categories of buyers and located in different areas, the issue of segmentation is moot. That is, absent the ability to set differential prices for transport, it may be reasonable to treat the NSW/ACT as a single market. We have not seen any data that suggests that a more fine grained segmentation of the market is warranted, but additional data might suggest that it is necessary to consider additional definitions of what constitutes the relevant downstream market for MSP services.

Irrespective of the actual delineation of the proper geographic market, the inquiry should focus on the availability of natural gas to the customers located in the relevant market from sources other than the Cooper Basin. Thus, even if MSP is the only pipeline capable of transporting gas from the Cooper Basin to NSW, say, this does not mean that the only natural gas available to customers in NSW can be sourced from the Cooper Basin. If the competition for gas customers in NSW is intense because there is significant pipeline capacity that can be deployed to deliver gas to NSW, then MSP will not be able to overprice transport without risking a significant diminution in demand for Cooper Basin gas and thus for its own transportation services.

Status of Pipeline Service Competition in South East Australia

Ultimately, if the MSP faces effective competition in both the upstream (*i.e.,* Cooper Basin producers can sell their gas to other retail markets not served by the MSP) and the downstream market (*i.e.,* there are substitute sources of gas supply to the NSW/ACT retail markets that do not depend on the MSP), then the MSP will not be able to effectively exploit its presumed monopoly power in the provision of pipeline services between Cooper Basin and NSW/ACT. If this is the case, then coverage which would limit the potential for the MSP to abuse its notional market power would not improve conditions for competition in the upstream or downstream markets.

Is MSP engaging in monopoly pricing?

One of the best indicators of whether the MSP is able to effectively exploit its natural monopoly in the provision of pipeline services to the pertinent group of customers is whether current prices are substantially above long-run economic costs, which is the level that they should attain in the presence of effective competition. While there is disagreement among the participants to this inquiry as to what constitutes an appropriate estimate of economic costs, the ACCC's draft access order[54] calls for rates that are as much as 40% below current levels by some accounts.[55] Moreover, there is evidence that prices have fallen since the EGP began operation, which implies that the MSP's pre-EGP margins were even higher. If one assumes that the ACCC's estimates are accurate to within plus or minus 10 percent of the true level of economic costs, then this suggests that competition in the source and destination markets has not been -- and is not currently -- sufficiently potent to keep prices at levels that one would expect in effectively competitive markets.

Nonetheless, we must caution that "competitive" prices are notoriously difficult to estimate in network industries characterized by significant fixed costs and low variable costs. Furthermore, since a substantial share of the costs faced by MSP are sunk or fixed, if competition were robust, it is possible that prices might fall below long-run average costs in the short-run. In the long-run, firms must be able to recover their costs to remain viable. Consequently, over a sufficiently long planning horizon, prices must average out at levels that ensure recovery of full costs, including the cost of capital. If prices fall below such level for a sufficiently long time, investment in pipeline infrastructure will be deterred.

Structural features and prospects for effective competition

Focusing on the downstream market, there are a number of market features that bear on the assessment of the likelihood of effective competition in that market.

– *Commodity product*

Natural gas is a commodity product. This means that consumers generally regard gas from different sources of supply as close substitutes and should be willing to switch among providers based on relatively small differentials in price. This increases the likelihood that effective competition from substitute sources of supply will constrain the ability of the MSP to exercise monopoly power.

Empirically, the ability of alternative sources of supply to offer effective competition would be supported by a finding that there is a high cross-price elasticity of demand associated with pipeline services offered by

---

54 See *Draft Decision Access Arrangement by East Australian Pipeline Limited for the Moomba to Sydney Pipeline System*, ACCC, December 19, 2000.

55 See "Report in Support of Application to the National Competition Council for Revocation of Coverage of the Moomba-Sydney Mainline and the Dalton-Canberra Lateral Pipeline," Network Economics Consulting Group (NECG), August 2001, page 39.

the MSP, EGP, or Interconnect; or in the delivered gas-prices for gas provided by the different pipelines in the NSW/ACT retail markets; or (less useful) in the well-head prices of gas produced in the Cooper or Gippsland Basins. While it seems plausible that the cross-elasticities are high, we are unaware of any empirical studies that provide a firm basis for gauging the size of the relevant cross-price elasticities.[56]

– *Long term contracting*

Although the majority of gas is sold under long term contracts in both the upstream and downstream markets, we do not believe that these are likely to have a significant effect on the ability of alternative sources of supply to compete. First, the lifetime of the typical contract is relatively short compared to the horizon of entry decisions into upstream production or downstream retail markets. Second, *ex ante* anticipation of future pricing behaviour ought to be reflected in current long term contracts and so dynamic competition among the pipelines in the market for long-term transportation contracts should also act as a constraint on current pricing. Third, upstream producers' or downstream retailers' entry incentives depend, among other factors, on the sufficient availability of demand for gas[57] and on the availability of sufficient transport capacity on alternative pipeline networks. If the marginal purchasers of service from the MSP have ample alternatives open to them, the MSP's ability to elevate prices above the competitive level would be significantly limited. Fourth, the prospects of capturing future demand and potential competition from future sources of supply ought to increase the volume of uncommitted demand available to upstream gas producers or downstream retailers interested in competing in the market. Fifth, the ability of entrants to pre-contract for demand prior to investing lessens the risk associated with the recovery of sunk investments and tends to lessen impediments to entry.

Based on the information we have seen to date, it appears that despite long-term contracts, there is (and there will be) a sufficient amount of uncommitted demand so that effective gas-on-gas competition is likely to be feasible.

– *Sunk costs*

Because the costs of constructing a pipeline are largely sunk, it is unlikely that the MSP could succeed in inducing exit of whatever pipeline alternatives that may exist. In particular, this means that it is unlikely that the MSP could eliminate the capacity provided by the EGP to the market and reduces the likelihood that the MSP would pursue predatory pricing to harm

---

[56] We have seen the comments made in the Tribunal's decision in relation to the EGP on cross-price elasticities and the evidence of Mr. Ergas from which it appears that comment is derived. In our opinion, the material does not provide a sufficiently reliable empirical basis upon which to determine quantitative magnitudes of the pertinent cross-price elasticities.

[57] That is, demand which is not under long-term contracts.

existing competitors. However, the MSP may be able to deploy strategies that might deter the construction of competing facilities (*e.g.* via excess investment in committed capacity to signal to potential competitors the ability to compete aggressively in the market for pipeline services should additional competitors seek to enter).

Additionally, inasmuch as firms in the upstream and downstream markets have made sunk investments, the MSP may attempt to expropriate some of the quasi-rents associated with these investments. The threat of such *ex post* expropriation could distort entry and expansion incentives. The ability to engage in such opportunistic behaviour is constrained by competition among pipelines for gas at the source and by the ability of downstream firms to obtain gas from other sources of supply. Indeed, as always, it is the forces of competition that attenuate the risks of expropriation of rents and quasi-rents. Moreover, insofar as either the upstream producers or downstream retailers have countervailing market power, the concerns about rent extraction are further reduced.

Coverage may reduce the risk of anticompetitive behaviour associated with the threat to expropriation of sunk costs by constraining prices and the scope of feasible contracts for transport. While these effects may be salutary, restrictions on feasible contracts and on the ability of parties to freely negotiate transport arrangements also reduce the ability of market participants to respond to changing market conditions and could lead to inefficiencies. It is our understanding that there is nothing in the Gas Code which restricts the ability of parties to negotiate gas transport arrangements on any terms that they wish including negotiating at prices above the level of the reference tariff and there can be an incentive for a customer to do so in order to obtain certainty benefits deriving from a long term contract.[58] In this regard, the Gas Code does not prescribe the prices that the pipeline must charge but once an access arrangement is in place it does, in effect, set a benchmark price which parties will, inevitably, have regard to in their negotiations. From this perspective, then, the usual concerns with regulatory pricing rigidities are lessened as are the standard concerns with the inefficiencies that may result from even the best-intentioned regulations.

– *Excess capacity*

There is evidence that every pipeline that competes for delivery of gas to the NSW/ACT markets is expected to have excess capacity during the next 10 to 15 years. As data in Exhibit 1 shows, there appears to be substantial excess capacity and reserves available to deliver natural gas from the Cooper and Gippsland Basins into the retail markets in NSW and the ACT. Taken together, this evidence suggests that competition between the EGP and MSP pipelines may offer an effective constraint on the MSP's ability to exercise monopoly power.

---

[58] However, to the extent that the reference tariff is not adjusted to reflect changing market conditions, coverage may create inefficiencies in the negotiated arrangements for transport.

As one caveat to this conclusion we note the possibility that peak capacity constraints may attenuate competition in the downstream market(s). While a possibility, we are not aware of any reason to believe that this is likely to be a substantial factor over the relevant decision horizon.

The availability of pipeline capacity in the upstream market could be more of an issue. Although the Cooper Basin gas is being sold into other retail markets (demonstrating at least the potential for redirecting gas to other markets in response to a hypothetical increase in the price of pipeline services by the MSP), it appears that capacity on the most important alternative route, the Moomba-Adelaide pipeline, is likely to be constrained.[59] This means that the MSP may have monopsony power with respect to the residual production from the Cooper Basin field.

– *Inelastic market demand*

Evidence that the market demand for natural gas is relatively inelastic means that price increases, if feasible, are likely to be quite profitable. This increases the risk from and the incentives for monopoly pricing (or, collusive oligopoly pricing). Furthermore, since pipeline services represent only a portion of the overall delivered cost of gas (while remaining an essential component), we would expect the market demand for pipeline services to be even more inelastic.

While the market price elasticity of demand is important, what is really relevant is the elasticity of derived demand for pipeline services offered by MSP. If there are available substitutes with a high cross-price elasticity of demand, then the own-price elasticity of demand for MSP services may be high. This would make a unilateral price increase by the MSP unprofitable.

– *High fixed costs, low incremental cost of pipeline services*

Pipeline services are characterized by high fixed costs (associated with the pipeline itself) and rather low marginal (or incremental) cost of transport (at least as long as there is available capacity). This means that, up to capacity, the pipeline would find it incrementally profitable to transport additional gas even at a price that may be below long run average costs. It also means that price competition between the MSP and EGP could be quite aggressive, especially in the short-term. This is because the pipelines will ignore their sunk and fixed costs when setting prices. As a result, prices may fall below the level needed to sustain long-term viability.

Opponents of coverage of the MSP have argued that this cost structure also reduces the risk that the MSP might abuse any monopsony power it may have to limit access to the pipeline since its profits are likely to be maximized

[59] See Australian Competition and Consumer Commission 2001, Final Decision, Access Arrangement proposed by Epic Energy South Australia Pty Ltd for the Moomba to Adelaide Pipeline System, September at pp 48, 129, 171, 174, 186 and 188.

if it maximizes throughput.[60] This does not necessarily follow. If the MSP has monopsony power in the upstream market but faces effective competition in the downstream market (*i.e.*, the MSP takes prices as given in the downstream market), then its incentive to exercise monopsony power (by lowering the effective price it pays upstream producers) is reduced relative to the scenario where it also has downstream market power. However, this does not mean that such incentive is non-existent. And neither does it mean that low decremental costs (i.e., costs that MSP would avoid if it were to cut back on throughput) per force render the exercise of monopsony power unprofitable.

A similar logic also applies to the downstream end. Just because marginal costs are low, does not mean that the optimal pricing strategy is to fill the pipe to capacity. It is true, however, that low marginal costs and high fixed costs create incentives towards high levels of throughput.

In sum, coverage that restricts the MSP's ability to engage in monopoly pricing or exploitation of monopsony power may be expected to constrain prices for the critical input which might make entry more profitable (or less difficult) at the upstream and downstream levels.

Conclusions

This memorandum addresses the first two of the four criteria that must be satisfied to justify continued coverage of the MSP under the Gas Act. Our discussion shows that criterion (b) can be reduced to the examination of costs associated with the transport of gas between two points. We note that given the projected volumes of natural gas being shipped from the Cooper Basin to NSW and the ACT, it would be inefficient to construct a second pipeline. This suggests that pipeline-on-pipeline competition on that route is not likely to materialize. Hence, the MSP meets criterion (b).

Criterion (a) is more difficult to interpret, in our view. It asks whether coverage of the pipeline would reduce entry barriers in at least one upstream or downstream market. We take the relevant upstream market to be the production of natural gas in the Cooper Basin and the relevant downstream market to be the NSW/ACT retail market. Coverage may lower such barriers insofar as entry incentives are related to the rates for transporting gas and other elements of transport contracts that would be affected by coverage. Thus, if for example, coverage lessens the opportunities for anticompetitive differential treatment of firms that compete with the subsidiaries of the pipeline, the effects of coverage on competition may be quite salutary.

This does not mean that direct regulation is necessarily the rational policy response to the potential danger of abuse of market power. First, as is

---

60 See "Report in Support of Application to the National Competition Council for Revocation of Coverage of the Moomba-Sydney Mainline and the Dalton-Canberra Lateral Pipeline," Network Economics Consulting Group (NECG), August 2001, page 13.

well known, regulation has its own costs and inefficiencies. Thus, the potential risks of removing coverage must be weighted against the benefits of lessening regulatory burdens. Second, there are a number of market factors that may constrain the ability of the MSP to exercise monopoly power over transport prices, despite the fact that the MSP has a natural monopoly in the provision of transport services between Moomba and Sydney. For example, competition in the upstream and downstream markets from substitute sources of demand (pipelines to other markets) or supply (gas from other sources of supply transported to the NSW/ACT markets) may be sufficiently potent to substantially restrict the ability of MSP to set rates that generate significant economic profits over a long haul. Third, high-volume long-term contracts and excess capacity (as well as other features of the market) may lessen the risk of coordinated pricing between the MSP and other pipelines. Admittedly, though, inelastic demand for natural gas tends to enhance such incentives. Fourth, general prohibitions against abuse of dominance can be sufficient to prevent the MSP from engaging in business strategies that harm non-integrated rivals to the ultimate detriment of competition and consumers.

In light of the limited evidence available (*e.g.,* a lack of good empirical evidence of the cross-price elasticity of demand for services from different pipelines or evidence that the consumers are actively moving demand among sources of gas supply in response to fluctuations in prices), however, it is premature to conclude whether these structural features are, on balance, consistent with a finding of effective competition.

Moreover, if one accepts the ACCC's estimates of the economic costs of providing transmission services as correct, the fact that these are much below the level of current tariffed rates, suggests that the MSP is apparently able to exercise substantial pricing power. To the extent the MSP is vertically integrated into upstream or downstream services (and it appears that the MSP is extensively integrated into downstream markets via the AGL), there is also a public policy concern that it may engage in business strategies that could disadvantage non-integrated rivals. Maintaining coverage may lessen MSP’s ability to deploy such strategies, but it is not without countervailing costs.

We have not engaged in a full-blown study that would enable us to opine whether the MSP meets the test for imposing coverage (or removing coverage) under the Gas Act. Our mandate has been narrower than that: we strived to offer some guidance regarding the possible interpretation of criteria (a) and (b) for imposing coverage. However, based on the limited data we have seen, we tentatively conclude that the case for removing coverage of MSP is not compelling. Plainly, MSP meets criterion (b). There is also evidence, albeit much less compelling, that MSP possibly meets criterion (a).

As stated at the beginning of this paper, it is not part of our role to make an assessment as to whether or not coverage is desirable and, in particular, we have not been asked to consider criterion (d). We would note that as a matter of policy it is important to recognize that regulation has its own costs and should not be mandated when the potential benefits from regulation are small relative to the inefficiencies and other burdens that regulation engenders.

Exhibit 1: Pipeline Capacities, Reserves and Demand

Average and Peak Current and Potential Capacity

	Annual Current Capacity (PJ/a)	Annual Potential Capacity (PJ/a)	Peak Current Capacity (TJ/d)	Peak Potential Capacity (TJ/d)
MSP	170[61]	292[62]	470[63]	800[64]
EGP	44[65]	110[66]	120[67]	300[68]
Interconnect	6.3[69]	70[70]	17.6[71]	
Total	210	402	531	1,100

Gas Reserves[72]

Reserves	Reserves (PJ)	Production (1999) (PJ/a)	Reserves (Years)
Cooper Basin	5,264	226.8	23
Gippsland Basin	8,084	201.4	40

---

61 See EAPL Access Arrangement Information provided to the ACCC, May 1999.

62 See EAPL Submission Number 2 to the National Competition Council in support of revocation of coverage of the MSP.

63 See EAPL Access Arrangement, note 61, *supra*.

64 See EAPL Submission Number 2, note 62, *supra*.

65 See *Duke Eastern Gas Pipeline Pty Ltd* [2001] ATPR 41-821 at 43,065.

66 ACCC Draft Decision on EAPL Access Arrangement, December 2000, p7.

67 See EAPL Access Arrangement, note 61, *supra*.

68 See EAPL Submission Number 2, note 62, *supra*.

69 See *Duke Eastern Gas Pipeline*, note 65, *supra*.

70 NCC EGP Final Recommendation, footnote 18. This is lower estimate provided by EAPL of potential capacity.

71 See *Duke Eastern Gas Pipeline*, note 65, *supra*.

72 See Australian Gas Association, Gas Statistics Australia 2001, September 2001.

Gas Demand in NSW[73]

	2000	2014
Demand (PT/a)	110	211

[73] See *Duke Eastern Gas Pipeline*, note 65, *supra.*

Attachment B

SUMMARY OF APPLICATIONS FOR COVERAGE AND REVOCATION OF COVERAGE OF PIPELINES UNDER NATIONAL GAS CODE

AS AT 16 APRIL 2002

Applicant	Pipeline	Decision sought	Council Recommendation	Minister's Decision
Southern Cross Pipelines (March 1999)	GGTP to Mt Keith Power Station (WA)	Revocation	To revoke coverage (June 1999)	To revoke coverage (July 1999)
Southern Cross Pipelines (March 1999)	GGTP to Leinster Power Station (WA)	Revocation	To revoke coverage (June 1999)	To revoke coverage (July 1999)
Southern Cross Pipelines (March 1999)	Kalgoorlie to Kambalda (WA)	Revocation	Not to revoke coverage (June 1999)	Not to revoke coverage (July 1999)
Southern Cross Pipelines (March 1999)	GGTP to Kalgoorlie Power Station (WA)	Revocation	To revoke coverage (June 1999)	To revoke coverage (July 1999)

Applicant	Pipeline	Decision sought	Council Recommendation	Minister's Decision
SAGASCO South East (May 1999)	Tubridgi Pipeline (WA)	Revocation	Not to revoke coverage (July 1999)	Not to revoke coverage (August 1999)
Boral Energy Resources (May 1999)	Beharra Springs Pipeline (WA)	Revocation	To revoke coverage (July 1999)	To revoke coverage (August 1999)
Robe River Mining Company (June 1999)	Karratha to Cape Lambert Pipeline (WA)	Revocation	To revoke coverage (Sept 1999)	To revoke coverage (Sept 1999)
Epic Energy SA (December 1999)	South East Pipeline System (SA)	Revocation	To revoke coverage (March 2000)	To revoke coverage (April 2000)
AGL Energy Sales and Marketing (January 2000)	Eastern Gas Pipeline (Longford to Sydney)	Coverage	To cover (June 2000)	To cover (October 2000)
East Australian Pipeline Ltd (now Australian Pipeline Trust) (April 2000)	Moomba to Sydney Pipeline System (main trunk line from Moomba to Wilton)	Revocation	Not to revoke coverage (September 2000)	Not to revoke coverage (October 2000)
East Australian Pipeline Ltd (now Australian Pipeline Trust) (April 2000)	Young to Culcairn lateral (NSW)	Revocation	Not to revoke coverage (September 2000)	Not to revoke coverage (October 2000)

Applicant	Pipeline	Decision sought	Council Recommendation	Minister's Decision
East Australian Pipeline Ltd (now Australian Pipeline Trust) (April 2000)	Dalton to Canberra lateral (NSW and ACT)	Revocation	Not to revoke coverage (September 2000)	Not to revoke coverage (October 2000)
Envestra (April 2000)	Palm Valley to Alice Springs pipeline (NT)	Revocation	To revoke coverage (July 2000)	To revoke coverage (July 2000)
Envestra (April 2000)	Alice Springs distribution system (NT)	Revocation	To revoke coverage (July 2000)	To revoke coverage (July 2000)
Dalby Town Council (August 2000)	Dalby distribution network	Revocation	To revoke coverage (October 2000)	To revoke coverage (November 2000)
Peabody Moura Mining Pty Ltd (August 2000)	Peabody – Mitsui Gas pipeline (Qld)	Revocation	To revoke coverage (October 2000)	To revoke coverage (November 2000)
Oil Company of Australia (August 2000)	Kincora to Wallumbilla pipeline (Qld)	Revocation	To revoke coverage (October 2000)	To revoke coverage (November 2000)
Oil Company of Australia (August 2000)	Dawson Valley pipeline (Qld)	Revocation	To revoke coverage (October 2000)	To revoke coverage (November 2000)
Envestra Ltd (May 2001)	Mildura pipeline	Revocation	To revoke coverage (August 2001)	To revoke coverage (September 2001)
Envestra Ltd (May 2001)	Riverland pipeline (SA)	Revocation	To revoke coverage (August 2001)	To revoke coverage (September 2001)

Applicant	Pipeline	Decision sought	Council Recommendation	Minister’s Decision
CMS Gas Transmission Australia (October 2001)	Parmelia pipeline (WA)	Revocation	To revoke coverage (February 2002)	To revoke coverage (March 2002)
East Australian Pipeline Ltd (now Australian Pipeline Trust) (June 2001)	Moomba to Sydney Pipeline System (main trunk line from Moomba to Wilton)	Revocation	Draft recommendation to retain coverage (December 2001). Final recommendation still being considered (due June 2002)	
East Australian Pipeline Ltd (now Australian Pipeline Trust) (June 2001)	Dalton to Canberra lateral (NSW and ACT)	Revocation	Draft recommendation to retain coverage (December 2001). Final recommendation due June 2002.	
Roma Town Council (February 2002)	Roma distribution system	Revocation	Draft recommendation to revoke coverage (March 2002). Final recommendation due April 2002	

References

ACIL Consulting Pty Ltd (ACIL) 2000, *Report to the Petroleum (Submerged Lands) Review Committee*, April

Australian Competition and Consumer Commission (ACCC) 2001, *Determination on applications for authorisation of amendments to the National Electricity–Code - Network pricing and market network service providers*, September

CIC Global (CIC) 2002, *Involving End Users*, April

Council of Australian Governments (CoAG) 2001, *Commonwealth/State Agreement on Energy Policy*, 8 June

Electricity Australia 2000, *Electricity Supply Association of Australia Figures 1998-1999*

Hilmer Review (Independent Committee of Inquiry into National Competition Policy) 1993, *National Competition Policy*, AGPS, Canberra, August.

National Electricity Code Administrator (NECA) 2000 (RIEMNS 2000), *The Scope for Integrating the Energy Market and Network Services – Volume 1 Draft Report*, October

National Electricity Market Management Company Ltd (NEMMCO) 2001, *Interconnector Development in the NEM: A Report by the Interconnector Process Working Group*, June

National Electricity Market Management Company Ltd (NEMMCO) 2001b,, *Consultation Paper, NEM Prudential Framework - Options for Improvement*, 31 December 2001

National Electricity Market Management Company Ltd (NEMMCO) 2002, *Review of Regional Boundaries*, April

National Competition Council (NCC) 2001a, *Assessment of Governments' Progress in Implementing the National Competition Policy and Related Reforms: June 2001*, AusInfo, Canberra.

National Competition Council (NCC) 2001b, *Framework for the Third Tranche Assessment of Governments' Progress with Implementing National Competition Policy and Related Reforms*, AusInfo, Canberra.

National Competition Council (NCC) 2001c, *Legislation Review of Clause 6 of the Competition Principles Agreement and Part IIIA of the Trade Practices Act 1974: Submissions to the Productivity Commission*, January and June

New South Wales Market Implementation Group (MIG) and Victorian Department of Natural Resources and Environment (DNRE) 2000, *Submission to ACCC on Proposed changes to National Electricity Code to facilitate full retail competition,* 11 October 2000.

ORR (Office of Regulation Review) 1999, *A Guide to Regulation*, Second Edition, AusInfo, Canberra.

Office of the Regulator-General 2001, *Special Investigation, Electricity retailers' proposed price increases, Final Report*, December

Ordover J & Lehr W 2001, *Should coverage of the Moomba-Sydney pipeline be revoked?*

Productivity Commission (PC) 2001a, *Review of the Prices Surveillance Act 1983*, Draft Report, Canberra, March.

Productivity Commission (PC) 2001b, *Review of the National Access Regime*, Position paper, Canberra, March.

Short C., Swan A., Graham B. and Mackay-Smith W. 2001, Electricity reform: the benefits and costs to Australia, ABARE paper presented at the Outlook 2001 Conference, Canberra, 27 February – 1 March.

Upstream Issues Working Group (UIWG) 1998, *Report of the UIWG to ANZMEC and CoAG*, December