(and continuing) market with and without the arrangements ror wnicn autnonsation is sought. As was stated in Re Application by Concrete Carters Association (Victoria) ${ }^{10}$ :
> "The positive side of this weighing process, namely the appraisal of claimed benefits, will commonly depend upon an appreciation of the competitive functioning of relevant markets, with and without the conduct in respect of which authorisation is sought. The negative side of the weighing process depends upon the assessment of competition itself in relevant markets with and without such conduct."

The NEM does not represent a "distinctive, albeit evolving, structure" of each or any existing State or Territory market and it does not represent an existing market in the sense of comprising the potential for close competition ${ }^{11}$.

As a new market, the operation of the NEM under the regulatory environment created by the Code, is not capable of any relevant comparison with respect to competition with each or any of the separate State or Territory markets that now exist. It is submitted that a State or Territory geographic market in which essentially only intra-State competition occurs, cannot represent a true yardstick for the purposes of any analysis under section 90(6) or 90(8).

Interstate trade is presently limited, being based on jurisdictional regulations and the provisions of the Interconnection Operating Agreement ("IOA"). Such interjurisdictional trading is presently limited to opportunity interchange between utilities who are the signatories to the IOA, and to emergency assistance and contract energy transfers (which are described in Schedule 3). It is submitted that electricity trading under the IOA does not amount to a competitive electricity market because, first, no obligation is placed on the parties to take lower cost energy from interstate and secondly, the pricing arrangements relate only to the quantities exchanged and have no broader impact such as will occur in the NEM where inter-regional flows may set the regional reference prices in both the exporting and importing regions. The IOA is therefore not a true yardstick for the purposes of section 90(6) or 90(8).

Accordingly, it is submitted that the introduction of the NEM under the regulatory environment created by the Code, taking into account the pro-competitive public benefits discussed in Chapter 5, must result in a net benefit to the public. There is no anticompetitive detriment to which an examination under sections 90(6) and (8) can attach, as there is no existing and continuing market structure within which competition or any effect or likely effect upon competition can be assessed.

### 6.1.4 Alternative assumptions and analysis

The Code will amount to an arrangement or understanding between the participants (some of whom will be competitors) and:

- the Code may contain exclusionary provisions;

[^0]- giving effect to certain provisions of the Code may incorporate conduct that may constitute third line forcing within the meaning of section 47(6) or (7) of the Act; and
- the Code may contain price fixing arrangements within the meaning of section 45A of the Act.

It is also recognised that for the purposes of section $90(8)$, matters of detriment, including, but not limited to, anti-competitive detriment, are to be examined; as with benefit, detriment to the public is to be seen as detriment to the community generally, although the most important of potential detriments "will normally be the anti-competitive effects" 12 .

If the references in sections 45 and 47 to "lessening of competition" require a comparison between competition in two separate and distinct markets; namely, the existing state and territory markets of the participating jurisdictions, whether viewed individually or collectively, and the NEM, or a comparison within the NEM, with and without the Code, the Code:

- may incorporate conduct that may otherwise constitute the practice of exclusive dealing; and
- may include arrangements that have the purpose or would have or might have the effect of substantially lessening competition.

For the purpose of identifying the main aspects of the Code that may fall within any of the classifications set out above and of demonstrating the net public benefits relating to those aspects, it will be assumed, without derogating from the submission expressed under paragraph 6.1.3:
(a) that the reference in section $90(6)$ to "any lessening of competition" requires a comparison between competition in the two separate and distinct markets, being the existing State and Territory market for each participating jurisdiction and the NEM;
(b) that sections 90(6) and (8) contemplate and require a comparison between competition in the NEM as regulated by the Code and competition in a NEM not regulated by the Code, so that references in this Chapter 6 to any lessening of competition are construed as references to an assessment of competition in the NEM with and without the Code or a particular provision or provisions of the Code (as the context may require); and
(c) in the context of section 90(8), any detriment to the community generally (with emphasis on anti-competitive effects by reference to those two markets) is to be taken into account.

Accordingly, paragraphs 6.2 and 6.3 have been prepared so as to address and deal with each of these assumptions.

[^1]By developing these assumptions, the method adopted in Re 7 Eleven Stores Pty Ltd ${ }^{13}$ may be capable of adaptation:
> "Implicit in the section 90 test for authorisation is the requirement of causation. We seek to establish whether the conduct under scrutiny results or is likely to result in net public benefit. 'This must involve consideration of the circumstances which are likely to prevail in the absence of such conduct'... In the present matter, the relevant circumstances are those that would prevail were the system not to exist ..."

In the present context, by way of analogy, the relevant circumstances are those that would prevail were the NEM and its regulation by the Code not to exist (ie the retention of the current State and Territory markets) or, alternatively, if the NEM were to exist, but not be regulated by the Code.

### 6.1.5 General assessment of a comparison between competition in existing State and Territory markets and in the NEM

Applying assumption (a) in paragraph 6.1.4, since the introduction of the NEM and operation of the Code will introduce new competition and deliver public benefit and net public benefit it is important that the likely shape of the future, both with and without the NEM and the Code, is considered.

The public benefits of the NEM have been discussed earlier in the submission, in paragraph 2.1 and in Chapter 5. Benefits of a single NEM, compared to separate State and Territory markets, include:

- reduction of reserve plant margins by sharing between the generating plants in the participating jurisdictions;
- better capacity utilisation;
- better management of non-coincident peaks;
- better utilisation of economies of scale in generation;
- an increase in competitive pressures, and therefore greater efficiency gains, with an increase in the number of competing generators and retailers;
- consistency of market arrangements across State and Territory boundaries; and
- more extensive reform of the electricity sector in some jurisdictions than would be the case without the national market, and acceleration of proposed State and Territory reforms.

[^2]
### 6.1.6 General assessment of a comparison between competition in the NEM with and without the Code

Applying assumptions (b) and (c) in paragraph 6.1.4, it is important that the functioning of and competition in the NEM with and without the Code is understood.

The unique characteristics of electricity mean that it is not feasible for electricity to be competitively traded in exactly the same manner as other products. In particular, electricity cannot be stored, and demand and supply must be instantaneously matched. Central coordination and market arrangements such as those contained in the Code are necessary to ensure this matching. The market arrangements contained in the Code promote efficiency by:

- merit order dispatch of generators; and
- mimicking the operation of other competitive markets by establishing a competitive price-setting mechanism in the spot market.

Furthermore, because of the natural monopoly characteristics of the network businesses, competition in the NEM would be inhibited without the framework introduced by the Code, which aims to ensure that the wires businesses cannot extract excess profits due to their monopoly status.

### 6.1.7 Lessening of competition and detriment

As set out in paragraph 6.1.2, a lessening of competition may, in certain circumstances, not give rise to any detriment at all, and could even be a positive benefit.

Accordingly, the analysis under sections $90(6)$ and (8) is quite separate from, and must not be confused with, any analysis of a lessening of competition in the context of Part IV of the Act. ${ }^{14}$

Even if, on the basis of the assumptions made under paragraph 6.1.4, a provision of the Code might lessen competition (in the context of any of those assumptions), it is submitted that:
(a) the fact that a provision may lessen competition does not necessarily imply it results in detriment under sections 90(6) and (8);
(b) the provision must be assessed in the context of the Code as a whole and the overwhelming public benefit of the Code as a whole;
(c) a very relevant question is whether the provision that may lessen competition introduces a positive benefit in the context of the Code as a whole and the operation of the NEM as regulated by the Code; and
(d) no question of detriment arising from any lessening of competition in respect of any provision of the Code can be considered or assessed in isolation; detriment (if any) must be assessed in the context of the Code as a whole and what may be seen

[^3]as a potential detriment in isolation, may, indeed, be a positive benefit when construed in the context of the Code as a whole and the operation of the NEM as regulated by the Code.

### 6.1.8 Detriment

Code provisions which potentially lessen competition are analysed in more detail in paragraphs 6.2 and 6.3 below. In some cases it is submitted that there is no clear evidence that a potential lessening of competition causes detriment. For example, paragraph 6.2.1 proposes that, while the Code is a complex document and may thus deter some potential entrants to the NEM, any perceived lessening of competition is unlikely to cause detriment because there will be sufficient competition amongst existing Market Participants and successful new entrants. Furthermore, any party unable to enter the NEM, can gain the benefits of competition because the NEM facilitates retail competition. With retail reform, the opportunity will exist for all end use customers to choose their retail supplier. All contestable customers thus can influence the upstream energy sub-market and can derive the benefits of wholesale competition without needing to operate in the NEM themselves.

Moreover, applying the analysis in paragraph 6.1.7 and, in particular, sub-paragraph (d), it is submitted that no detriment will result or will be likely to result from any lessening of competition that may arise, or may be suggested as being likely to arise in respect of any provision of the Code, when assessed in the context of the Code as a whole. Paragraphs 6.2 and 6.3 argue that those features identified as possibly falling within a provision of Part IV of the Act have been incorporated in the Code for good public benefit reasons. In each case the public benefit arising from the provision outweighs any perceived detriment. Furthermore, given the overwhelming public benefit of the Code as a whole, and the increase in competition it entails, any anti-competitive detriment of any individual provision is well outweighed.

### 6.2 Major issues raised by the ACCC

This paragraph addresses the primary issues raised by the ACCC in its Issues Paper dated March 1996 and its National Electricity Market Code of Conduct - Comments and Issues Arising paper dated May 1996. Further issues raised by the ACCC are addressed in paragraph 6.3, and in Chapter 8 which focuses on the access arrangements.

### 6.2.1 Code Complexity

Code complexity has been raised as a concern in a number of contexts, particularly in submissions to the NGMC on the Code from representative customer groups. Two major concerns have been raised:

- complexity detracts from simplicity and transparency, and therefore adds costs to those who wish to enter and participate in the market. In this context complexity may be seen as a barrier to new entrants and a competitive obstacle to existing participants, particularly smaller ones less well resourced to work with such a comprehensive set of arrangements; and
- complexity of the Code involves a degree of prescription that may remove the incentive and opportunity for participants to arrive at their own bilaterally
negotiated arrangements. In this context complexity may retard innovation and the competitive benefits that result from innovation within a market.

Each of these concerns is discussed below.
(a) Code complexity as a barrier to entry

It is acknowledged that the Code is a complex document particularly for a customer who has no technical experience in the electricity industry. In response to the issue, the following points arise:

- the Code is complex because Chapters 1 to 8 of the Code define the market and access arrangements within the NEM and because Chapter 9 of the Code provides an explanation of the transitional arrangements under which the NEM is to evolve;
- electricity is extremely dangerous, cannot be stored and must be instantaneously delivered and therefore requires a code of arrangements to ensure its safety and reliability. Most of the Code's details primarily affect specialised participants such as generators and network owners and provides "how to" instructions for safety and the accurate measurement of trading relationships;
- in many of its technical schedules to Chapter 5, the Code standardises and documents information requirements and technical standards for persons seeking to establish a connection to the network. These requirements and standards have previously existed in one form or another for connection to the network. Such networks are operated according to good industry practice both in Australia and abroad. In most companies, the technical requirements for connection to a network are arranged by specialists who have the appropriate knowledge and skills to ensure that the customer's or generator's requirements are taken into account in the planning and design of a connection facility. It is important that standards exist to ensure that the impact of one party's connection facility do not adversely affect the quality of electricity received by other network users;
- in Chapter 4, Power System Security, Chapter 5, Network Connection, and Chapter 7, Metering, it has been necessary to specify responsibilities and obligations of various categories of Code Participants as a by-product of restructuring a vertically integrated industry into its competitive and natural monopoly components. It is also important to note that the industry is moving from a public sector monopoly industry structure to one openly and actively encouraging new entrants and private enterprise. It is costly for private companies to operate in an environment where their responsibilities and obligations are entirely left open to negotiation, due to uncertainty and potential disputes. In part therefore the level of prescription in these parts of the Code reduces ambiguity and makes the requirements for entry clearer and less risky to possible new entrants; and
- the level of detail in the Code reduces the existing information asymmetry that exists between well established incumbent Market Participants and new Market Participants and therefore provides a more level playing field for competition.

Chapter 5 of the Code (Version 1.0) has also been re-drafted as part of a Code simplification exercise to reduce its complexity. NGMC representatives worked with the Electricity Users Group ${ }^{15}$ and there were changes made to the following Chapter 5 clauses, namely: 5.2 Obligations, 5.3 Establishing or Modifying Connection, 5.7 Inspection and testing, 5.8 Commissioning, and 5.9 Disconnection and Reconnection.

However, the Code simplification exercise did not go as far as the Electricity Users Group desired based on legal advice from Freehill, Hollingdale \& Page received on 23 May, 1996. A copy of this letter is included in the National Electricity Code Consultations Report. The key point made by Freehills is:
> "We are aware that you [the NGMC] have received considerable public comment about the length and complexity of the Code. Reducing many of its prescriptive provisions may reduce this problem. However it is our view that in many respects, if provisions of the Code are entirely deleted, additional problems will result.

Firstly, whilst we acknowledge that less prescription may mean Code participants are free to negotiate the terms of arrangements they make between themselves, it is also possible, if not likely, that a lack of prescription, may cause uncertainty and unintended loop holes which may lead to disputes. This, in turn, may mean Code participants are subjected to costly delays and expenses at a later stage which could have been avoided if those provisions of the Code had guided them more precisely."

In recognition of the Code complexity concern, the NECA Chairman has stated that NECA is prepared to develop indexes, handbooks and user manuals (as suggested by the ACCC), and other guidance material to ensure that the Code is accessible and more user friendly. It is expected that these materials will be completed early in 1997.

In addition, a Market Liaison Panel has been established to provide a forum for discussing the details of the Code and to develop suitable materials to assist persons operating in the NEM. The Market Liaison Panel is chaired by the NECA Chairman and consists of key stakeholders including generators, large and small customers, Network Service Providers, retailers, and NEMMCO.

This supports an argument that Code complexity is not regarded as anti-competitive. It must be bome in mind that even smaller intending participants are likely to be corporations with the skill, experience and resources sufficient to enable them to readily understand and to absorb the key elements in the Code relevant to their circumstances.

Furthermore, while the complexity of the Code may deter some potential entrants, this is not sufficient to show that detriment has been caused. While it is desirable to minimise barriers to entry, their existence may not substantially impact on the competitive outcome, if sufficiently robust competition occurs amongst those who do overcome any barriers. This submission contends that the complexity of the Code will not deter new entrants to the extent likely to substantially reduce the level of competition in the marketplace.

[^4]For small customers, the Code permits the entry of traders and facilitates retail competition. Both these aspects ensure there are incentives for providing expert advice on energy services to such customers. With retail competition, retailers have an incentive to offer customers the best deal on service and price, and this enables customers to take advantage of competition without becoming directly involved in the wholesale market.

The public benefit of exhaustive treatment of each of the critical subjects in the Code more than offsets the limited difficulty posed by complexity. The Code therefore increases certainty and establishes minimum entitlements to all participants or intending new entrants. A less comprehensive Code would entrench existing information asymmetries that exist between incumbents and new Market Participants.

## (b) Code complexity as a barrier to innovation and competition

It has been further contended that the complexity of the Code involves a degree of prescription that may remove the incentive and opportunity for participants to arrive at their own bilaterally negotiated arrangements. In this context complexity may retard innovation and the competitive benefits that result from innovation within a market.

In response to this concern it needs to be said that the Code does not prohibit bilateral arrangements from being implemented between willing parties. The Code does not prescribe any form of contractual relationship between parties for energy purchasing even though Market Generators and Market Customers are required to sell and purchase energy through the spot market. The only restriction is that contracts between a generator and customer are not directly taken into account in the spot market's central dispatch process. Even this restriction does not preclude innovation in energy contracting arrangements because of the concept of self-dispatch for Scheduled Generators.

The treatment of Code Participant's rights and obligations in the Code is in the public interest because it reduce uncertainties for all participants and assists negotiations between parties. It also addresses the reality of unequal bargaining power between incumbent Network Service Providers and Market Participants, on the one hand, and new participants and Market Customers, on the other.

The Code also explicitly recognises that as the market grows and matures there will be need for revisions of the Code to ensure that it continues to facilitate competition and does not become ossified and constraining. Experience of market operations will indicate where the Code can be usefully simplified or made more flexible, without causing unacceptable uncertainty. The Code change processes have been developed with this requirement in mind.

The Code has already been revised to remove prescriptiveness in some areas, and further review is proposed. For example, Chapter 6 of the Code, governing transmission and distribution pricing, has been substantially revised from earlier, more prescriptive drafts and is to be reviewed by NECA in the near future. Chapter 7, describing metering requirements, is also subject to a review to assess whether arrangements can be less prescriptive, more flexible and allow market-driven responses. The Code will continue to be subject to review as market experience continues, within the strict confines of the Code change process.

### 6.2.2 Market functions of NEMMCO

Another concern is that the provision of services by NEMMCO should be limited to those that are essential to system security, operation of the new market arrangements and the establishment of services that do not now exist and which cannot be expected to develop quickly.

Under the Code, as part of its functions, NEMMCO is required to:

- contract for ancillary services required to ensure power system security which are dispatched via the central dispatch process;
- contract for reserves or provide a last resort direction when the market fails to meet reserve standards established by the Reliability Panel;
- ensure facilities are available for Market Participants to trade in a short term forward market; and
- facilitate an exchange for inter-regional hedge contracts.


## Ancillary services and reserves

The dispatch of ancillary services and the availability of system reserves as centrally coordinated services managed by a Market Operator is critical to the management of power system operations. For example, as part of the mega-brief consultancy program discussed in paragraph 2.3.2, ECC Consultants were asked to review proposals for ancillary services. In their report, ECC Consultants state:
> "As these contractual ancillary services are integrated into the dispatch algorithm, efforts can commence on investigating the feasibility of adding a spot market for such ancillary services to work in conjunction with, or as a replacement for, the contractual ancillary services. However, there is a risk of trying to develop an ancillary services spot market as a total replacement for the ancillary services contractual market in that there would be no assurance of there being enough such ancillary services offered into spot market. ${ }^{16 "}$

## Short-term forward market and inter-regional hedge market

The potential of private sector involvement in sub-markets for short term contracts, interregional hedges, and various other services, is fully recognised by the Code. In fact, nothing in the Code precludes other persons from offering these services to NEMMCO or to other persons. NEMMCO's role is to facilitate these sub-markets. It is vital that these services are available because they enable Market Participants to better manage risk. There would be substantial potential detriment to the operation of the NEM if these submarkets did not develop. Therefore, the establishment of these sub-markets cannot be left to chance in the early developmental phase of the NEM.

[^5]A further discussion of NEMMCO's role in the inter-regional hedge market is contained in paragraph 6.3.8.

The Code also stipulates that if NEMMCO itself operates a short term forward market or inter-regional hedge exchange:

- it must do so in a way which reasonably ensures it uses no advantage derived from its other functions which would not be available to an alternative operator; and
- it must use reasonable endeavours taking into account the surrounding circumstances, to give effect to the objective of recovering the costs of the establishment and operation of the market from Market Participants who trade in that market.

NEMMCO is also required under the Code to ring fence these trading activities by keeping separate accounting records for these trading activities with clear audit trails as provided for in clause 1.11 of the Code.

In considering concerns about NEMMCO's market functions it must be recognised that the Code provides for:

- three year sunset clauses for NEMMCO facilitation role in a short term forward market and inter-regional hedge exchange with reviews by NECA of any future role for NEMMCO;
- a five year sunset clause on NEMMCO's reserve trading activity subject to a review by the NECA's Reliability Panel; and
- further development of a competitive market in the provision of at least some categories of ancillary services.

In any event, should alternative markets become manifest before these sunset clauses become effective, then Code change review processes may be used to amend NEMMCO's roles in these areas.

### 6.2.3 Market Design and "Gaming"

In relation to the spot market the $\mathrm{ACCC}^{17}$ posed the following discussion point:
"Does the proposed trading system provide opportunities for the "gaming" of the market bidding process which could provide an unfair advantage to any participant or class of participant? If so, what are the opportunities and how can they be reduced or eliminated?"

This statement suggests that market design should take into account the ability of Market Participants to act in an anti-competitive manner.

For the purpose of this Submission, a simple definition of 'gaming' can be used; namely that gaming is something which is within the Code's rules, but outside their spirit. Within

[^6]this definition, two sorts of gaming are considered - "loophole gaming" where a weakness in the rules is identified and exploited, and explicit anti-competitive behaviour. Whilst some degree of market power will be required to undertake the latter, loophole gaming is not related to a participant's market power. Consequently the way in which these issues are dealt with may vary as described below. In any event, gaming must not be confused with legitimate market behaviour of testing the market to find out market sensitivities and competitive pressures.

It is submitted that, in the best interests of market efficiency and public interest, that "gaming", "collusion", and other forms of anti-competitive behaviour should be addressed, in order, by:

- market structure;
- market design;
- regulation.

Each of these is discussed below.
(a) Market structure

A major area of concern is the influence market structure has on the ability of players to participate in "gaming" in the market.

The structure of the generation sector in each participating jurisdiction is a matter that is outside the scope of the Code. The governments in the participating jurisdictions have agreed that the generation sector will become competitive and that rules for nondiscriminatory entry to the market should be established.

Major industry restructuring has already occurred in New South Wales and Victoria while South Australia is currently implementing a industry restructuring program. In Queensland an independent task force is currently conducting an industry structure review. Current market shares in the generation sector are shown in the table below.

| Generating Company | Share of Capacity (\%) <br> Excluding Queensland | Share of Capacity (\%) <br> Including Queensland |
| :--- | :---: | :---: |
| NSW: |  |  |
| Pacific Power | 12.6 | 10.3 |
| Delta Electricity | 16.4 | 13.3 |
| Macquarie Generation | 17.9 | 14.6 |
| Snowy Mountains Hydro | 14.4 | 11.8 |
| Victoria: |  |  |
| Loy Yang A | 7.7 | 6.3 |
| Yalloum | 5.6 | 4.6 |
| Hazelwood | 6.2 | 5.0 |
| Gas fired stations | 3.7 | 3.0 |
| Hydro stations | 1.8 | 1.5 |
| Loy Yang B | 3.9 | 3.1 |
| Energy Brix | 0.7 | 0.5 |
| South Australia: ETSA | 9.1 | 7.4 |
| Queensland: |  |  |
| AUSTA Electric |  | 13.4 |
| Gladstone |  | 5.2 |
| Total | 100 | 100 |

Source: NSW Electricity Reform Taskforce
The table shows that in the national market no single generating company currently owns more than $15 \%$ of total generation capacity in the market ( $18 \%$ if Queensland is excluded). Despite the apparent absence of market dominance given the spread of their relative market shares, generators may nevertheless dominate a particular segment of the load curve or a particular region, or may attempt to collude with other generators in setting wholesale prices.

There are a number of factors however which will mitigate the market power exerted by any single generator or a group of generators:

- actual or potential new entrants. The structure of the market is not static. The introduction of the NEM enables the entry of new generators, and this will limit the ability of generators to extract excess profits in the longer run. In recent years innovations in generation technology (such as gas turbines) have increased the efficiency of smaller scale generation and reduced the barriers to entry resulting from economies of scale. The Industry Commission noted in its study of the South Australian industry ${ }^{18}$ that while ETSA Generation holds a position of market power in the South Australian market, it "is vulnerable to entry should it raise its prices too far above incremental cost", though this may take some years;
- transmission and demand side options. These provide competitive pressure on generators, imposing upper limits to the ability of incumbent generators to raise prices, in the longer term;

[^7]- collusive behaviour. The ability to sustain this behaviour in the longer term is difficult as the number of generators increases;
- countervailing market power. While spot market prices are largely determined by the supply side, in the contract market there are large retail companies which balance the market power exerted by generating companies in setting contract prices; and
- national dispatch. The move from regional to national dispatch will allow greater utilisation of the interconnectors to reduce the regional dominance of existing participants.
(b) Market design

The NEM rules are intended to leave Market Participants with as much leeway as possible within the bounds necessary to operate a secure power system and avoid free riding ${ }^{19}$. The market is designed to be economically efficient, devolve decision making down to participant level, and provide the participants with sufficient information to make sound business decisions.

In the market design, the trading rules for the spot market and central dispatch process cannot eliminate or even significantly reduce any market power of a Market Generator. Any Market Generator large enough to profit by withdrawing capacity at the last minute may also, and with less visibility, withhold or overprice capacity in the contracts market. In the short run withdrawing capacity will have more effect on prices if done late in the process, because competitors and Market Customers cannot respond quickly. But such behaviour, if repeated, will induce contracting and other responses such as new entry, by generators or transmission augmentation, that reduce its effectiveness.

The proposed market design, as embodied in the Code, provides a neutral and flexible trading framework. It is submitted that the market design in terms of the spot market and central dispatch process cannot solve market power problems. The best protection is to provide a market design that is based on readily auditable processes for bidding and for merit order dispatch. In addition, the arrangements for the publication of information, including bidding information after the event, to participants and to the public, need to be comprehensive. The net effect of this will be an enhanced capacity for potentially concerned parties to monitor supplier behaviour to identify quickly any activity that may be regarded as an excessive or inappropriate influence on spot prices, or collusive behaviour, and to raise the alarm. The processes are transparent and auditable - thereby enabling ready investigation of complaints by the ACCC as the regulator of general market conduct.

The market design has also focused on permitting new entrants into the marketplace. Any continued removal of capacity from the spot market is likely to induce customers to look to alternative supply options either through contracts with other generators or through

[^8]options such as cogeneration or transmission augmentation. As noted above, this acts as a constraint on the ability of incumbents to abuse positions of market power.

A further major countervailing force in the market is the empowerment of end-use customers through retail competition. Here the freedom of customers to choose their own supplier provides competitive discipline which flows back upstream to retailers and ultimately to generators.

## (c) Regulation

If the market structure that evolves is not sufficiently competitive then there will be a need to adapt the regulation of the market. If gaming opportunities exist then this will most often, and most seriously, be as a consequence of Market Participants being able to use market power. Some limited, loophole gaming may occur which is not related to the exercise of market power. These abuses should be corrected by NEMMCO and NECA through the Code Change process.

The Code Change process is not designed to provide a check to the exercise of market power. This responsibility will lie with the ACCC to impose whatever restrictions it deems necessary to address problems raised by an inappropriate industry structure. Technological change, customer awareness, competitive entry and merger legislation will all enhance contestability in generation and it can be expected that the generation sector will become increasingly competitive.

### 6.3 Aspects of the Code relevant to net public benefit

### 6.3.1 Registration and exclusive trading (Chapter 2)

Chapter 2 sets out requirements for registration and requires exclusive trading of electricity in certain cases. In particular, clauses 2.2.1(a), 2.3, 2.4 and 2.5 require registration of generators, customers and traders respectively and clause 2.10 .1 provides that the registration must be in a form prescribed by NEMMCO. Such provisions could be considered to be:

- exclusionary provisions, as competing participants agree not to trade with unregistered persons;
- exclusive dealing provisions, as participants in the market agree to trade on condition that they will not supply electricity to, or acquire electricity from, unregistered persons; or
- provisions having the purpose or effect of substantially lessening competition. A requirement to be registered before being entitled to trade might be anticompetitive if it creates a barrier to entry to the relevant market. If, for example, significant costs are incurred in becoming registered, or if there is some other difficulty or barrier to becoming registered, competition in the market may be lessened or prevented.

Although the registration requirements may lessen competition in the market by raising barriers to entry not otherwise present, they are an essential element for the orderly
functioning of the market design proposed and are therefore justified on the grounds of the substantial public benefits that arise (see paragraph 5.4 of the Submission).

Furthermore, generators and Network Service Providers need to be bound to the Code (as the National Electricity Law provides) in order to preserve the integrity of the power system and ensure public safety.

Compulsory registration of Market Participants achieves the binding effect of the Code and is also necessary for the adequate functioning of the gross pool market design.

## (a) Generators

The market participation rules for generators distinguish between whether a generator is participating in central dispatch (for system security reasons) or simply participating in the spot market. The generator central dispatch participation rules define minimum requirements for participation to ensure the orderly management of power system operations.

Clause 2.2.1 (a) makes registration of generators compulsory subject to a power by NEMMCO to exempt a generator from registration, and also makes any decision by NEMMCO not to exempt, a reviewable decision in terms of the Code.

Under the Code, generators are required to register with NEMMCO as Scheduled or Non-Scheduled Generators and as Market or Non-Market Generators. The rules for each category are set out below.

## Scheduled Generator (Clause 2.2.2)

Unless otherwise exempted by NEMMCO, a generating unit (or combination of units connected at a common connection point) with a name plate rating of 30 MW or greater is required to be a Scheduled Generating Unit. A Scheduled Generator is required to participate in the central dispatch process operated by NEMMCO. This means the Scheduled Generator must (in accordance with clause 3.8.6):

- notify NEMMCO two days ahead of each trading day of its MW capacity availability profile for the trading day and estimated commitment or decommitment times;
- . notify.NEMMCO one day ahead of each trading day of its MW capacity profile for an intended self dispatch level and an (optional) incremental MW amount for each price band being offered by the Scheduled Generator; and
- provide a dispatch offer which specifies a self dispatch level of more than zero and at least one price band for off-loading below the intending self dispatch level such that the unit may be offloaded if required during an excess generation period.

Generators with generating units with a name plate rating of less than 30 MW may opt to be Scheduled Generators provided they have adequate monitoring and control facilities to support central dispatch.

## Non-scheduled Generator (Clause 2.2.3)

A Non-Scheduled Generating Unit is one which does not participate in central dispatch. A generating unit may be classified as a non-scheduled generating unit if its name plate rating is less than $\mathbf{3 0} \mathbf{~ M W}$ or :

- the primary purpose of the unit is local use and the sent out electricity rarely exceeds 30 MW ; or
- the physical and technical attributes of the unit are such that NEMMCO is satisfied that it is not practicable to participate in central dispatch; or
- the output of the generating unit is intermittent, being generating units whose output is not predictable, such as solar generators, wave turbine generators, wind turbine generators and hydro-generators; and
- NEMMCO has exempted it from the central dispatch process.


## Market Generator (Clause 2.2.4)

A Market Generating Unit is a unit from which the sent out electricity is not purchased in its entirety by the Local Retailer or by a Customer located at the same connection point. A Market Generator must sell all its sent out electricity through the spot market and accept payments from NEMMCO for sent out electricity at the spot price applicable at its connection point. In addition, the Market Generator must purchase all electricity supplied through the national grid to the Market Generator at the spot price applicable at its connection point and make payments to NEMMCO.

## Non-Market Generator (Clause 2.2.5)

A Non-market generating unit is a unit from which the sent out electricity is purchased in its entirety by the Local Retailer or by another Code Participant, in the latter case, where the purchase occurs at the same connection point. A NonMarket Generator is not entitled to receive payment from NEMMCO for electricity sent out at its connection point.

The effect of these provisions is to require a generator who supplies electricity to the market to be registered and to participate in the market as described under the Code. Apart from the exemption arrangements, there is no option for a generator to participate in the wholesale market except in the terms described by the Code, nor to sell (or purchase) electricity except through the spot market, nor to accept (or make) spot market payments other than at the spot price (clause 2.2.4). The corollary, in clause 2.2.5 is that Non-market Generators, those that are not registered or have been exempted from registration, are not entitled to participate in or receive payments through the spot market, or (clause 2.2.3) in NEMMCO's central dispatch operation.

The public interest lies in the registration arrangements outlined in the Code applying to all generators for the purposes of managing power system security and the wholesale market. This is the rationale behind the need to register generators as Scheduled or Non-Scheduled Generators and Market and Non-Market Generators.

As part of the mega-brief consultancy program discussed in paragraph 2.3.2, ECC Consultants were asked to review the MW threshold limits for the orderly operation of the spot market and the power system ECC Consultants state:
"Our recommendation is that Option 3 above ( 30 MW threshold limit but enhanced to address generation greater than 30 MW which does not export 30 MW or more to the system on a normal basis) be pursued. ... However with respect to the 30 MW technical level, we would suggest that the level be kept under review and modified if necessary in response to future developments (ie. installation of numerous 29 MW units may necessitate that units down to the lower level at least to be closely monitored, while actual experience may also allow the limit to be increased.) The 30 MW limit is consistent with similar levels in other pools: all units 50 MW and above require telemetry and automatic generation control in the $20,000+M W$ peak load New England Power Pool ("NEPOOL") in the United States, while all units 100 MW and above have to be submitted to central dispatch in the $48,000+M W$ peak load pool in England and Wales.

We recommend that large on-site units of 30 MW or more, even if not exporting to the system, or exporting less than 30 MW, also be closely monitored unless their associated demand is relayed such that the maximum impact on the system is less than 30 MW . ... but the RSOs [Regional System Operators] need to know the details of this generator for security purposes. Therefore, these units should have to meet the same telemetry requirements as centrally dispatched units and should be required to submit daily indicative schedules of both demand and generation. ${ }^{20 "}$

The process of becoming registered is unlikely to add any level of significant costs to a new entrant in the generation market, relative to the other costs associated with such entry.

It is also important to note that the criteria by which NEMMCO shall determine whether a generator is entitled to an exemption from registration do not rely on any significant level of discretion on the part of NEMMCO. The criteria are set out clearly and fully in clause 2.2.3, especially paragraph (b).

[^9]These arrangements covering Market and Non-Market Generators provide generators with a balance between the needs of commercial certainty and the costs of meeting central dispatch requirements. They also provide customers with the benefits of security of supply.

## (b) Customers

Clause 2.3.1 defines the term "customer", and requires a person who wishes to engage in the activity of directly purchasing electricity from the wholesale market at any connection point to register with NEMMCO as a Market Customer and to register that connection point as one of that person's market connection points. Under clause 2.3.1 (d) a person who engages in the activity of purchasing electricity at any connection point otherwise than directly from the wholesale market may voluntarily register with NEMMCO as either a:

- First Tier Customer (Clause 2.3.2) - when the electricity supplied is purchased by a person at that connection point directly and entirely from the Local Retailer; or
- $\quad$ Second Tier Customer (Clause 2.3.3) - when the electricity supplied is purchased by a person at that connection point other than directly from the Local Retailer or the spot market and that connection point is also classified as a market load of a Market Customer.

These registration requirements are in the public interest because they are required for the orderly accounting of energy purchases from the spot market. For example:

- Market Customers register market loads so that the total pool purchases may be calculated as the sum of market loads plus any temporary consumption at Market Generator connection points.
- Second Tier Customer loads are registered so that the market consumption of a Market Customer (Local Retailer) may be adjusted when a Second Tier Customer purchases electricity from another Market Customer (Retailer). (Note: a distribution network may also be part of a distribution business that has a Retail arm. The market loads for the distribution business would consist of all its connection points at the bulk supply points at the transmission network. When a customer (eg. Second Tier Customer) within the distribution network no longer buys electricity from the Local Retailer, there is a requirement to subtract the Second Tier Customer's load from the total market loads of the Local Retailer to avoid double counting. In addition before this adjustment is made, the new Retailer of the Second Tier Customer is required to register that customer's connection point as one of its market loads. In effect, every Retailer's total consumption becomes the sum of its registered market loads across the interconnected system.)
- First Tier Customer loads are registered on a voluntary basis to cater for those customers who wish to become Code Participants without having to become Market Customers.

The overwhelming public interest lies in having a viable electricity market which satisfies demand instant-by-instant ${ }^{21}$ The viability of the market requires all Market Customers to be registered in order to make energy settlements possible.

## (c) Traders

Clause 2.4 of the Code requires registration with NEMMCO of all persons who wish to trade in the short-term forward and inter-regional hedge markets facilitated by NEMMCO, and precludes parties from so trading unless registered (either as a Trader or as some other category of Market Participant) and except in accordance with Chapter 3 of the Code.

There is public benefit in the development of risk management instruments so that parties may contract to provide for themselves a level of certainty as to future price and generator plant availability. Registration is a threshold requirement for the orderly functioning of this commodity market because of the anonymity of producers and consumers. Registration yields the clear benefit of ensuring that the participants are known and potentially accountable for their behaviour to the market as a whole. Identification of traders, through registration, enables other participants in the market to determine who they are dealing with and to make enquires if they so desire. Initially this will be critical to the integrity of the emerging market for hedges. The benefits arising from the ability of the market to operate effectively are considered to outweigh any potential anti-competitive effects that registration might be thought to produce.
(d) Market Participants

Under clause 2.5 of the Code persons who wish to participate in the NEM as a Market Customer, Trader or Market Generator are required to register with NEMMCO as Market Participants. Market Participants are only permitted to participate in the categories in which they are registered.

In their report to the Victorian Govemment, Putman, Hayes, and Bartlett address the question of mandatory participation in the spot market as a form of exclusive trading:
> "Because the actions of any generator or load connected to the grid can directly affect other connected entities, all connected entities above some de minimus size must participate in the central dispatch process, at least to the extent of providing information and meeting technical standards. All connected entities must also participate in the market, at least to the extent of paying (or being paid) compensation for the system services they use (or provide) and for the costs their actions impose on (or benefits their actions provide to) other connected entities. But if technical and information standards are met and all system services are unbundled and properly priced, independent operations outside the spot market should, in principle, be allowed.

[^10]Ideally, there would be advantage and significant disadvantages to any entity operating outside the market. Any generator, whether or not it regards itself as centrally dispatched, will be able to make offers that allow it to operate without regard to the prices in the market if it chooses; it will just be costly to run when there is cheaper energy available in the market or to be idle when the spot price of energy is very high. Any load with a contract for low-cost energy can operate without responding to spot market prices if it chooses; it is just costly to ignore opportunities to reduce load and resell the contracted power in the market when the price is very high, or to buy extra energy when the price is low. Even if the spot market does not price energy properly, any two parties can contract to protect themselves against spot market prices. If all system services are properly priced, there will be no advantage to operating outside the market.

As a practical matter unbundling and separately pricing each of the system services provided by the monopoly dispatcher and grid is difficult, costly and impossible to accomplish perfectly. There will always be some arbitrary cost allocations and the need for some residual monopoly power to recover these. Allowing traders to opt out of the market may provide incentives for the market to improve its pricing, but will also provide opportunities for powerful interests to seek special treatment. On balance, it is probably preferable to require all traders to belong to the market and help pay its costs, subject to defined appeal procedures and regulatory oversight, rather than allowing traders to threaten to opt out as a way to force the system's fixed costs on others. "22

### 6.3.2 Participant Fees (Clause 2.12 and Chapter 4)

Participant fees will be charged to cover the costs of NEMMCO and NECA. This includes NEMMCO's costs in fulfilling its obligations under Chapter 4 of the Code for power system security. Principles to guide NEMMCO in the establishment of participant fees are set out in clause 2.12. The key elements making up the principles are simplicity, cost recovery, user pays (noted by the ACCC as desirable), and non-discriminatory application. Both NEMMCO and NECA under their company Members Agreements are also required to provide services to Code Participants on a cost effective basis.

Participant fees may lessen competition by creating a barrier to entry. However, this market cannot function without the key central co-ordination functions of NEMMCO and NECA and as such requires a suitable fee structure to cover their operating costs. NEMMCO and NECA provide services to the market as a whole, which benefit all participants (a 'common good'). However, unless these fees are an obligatory part of participating in the market, participants could 'free ride' on these services. Provided the fees reflect the costs of providing NEMMCO and NECA services, then any barrier to entry imposed cannot be viewed as artificial or discriminatory.

[^11]On balance the benefits of a well functioning, centrally co-ordinated market far outweigh the possible reduction in competition that the market fees of NEMMCO and NECA may present.

### 6.3.3 Prudential requirements (Clause 3.3)

Chapter 2 of the Code requires all Market Participants to satisfy the prudential requirements set out in clause 3.3 of the Code. In particular, clauses 2.5.1(c) and 2.5.2 provide that Market Participants - that is, persons registered as customers, traders or generators - may only participate in the markets and trading activities conducted by NEMMCO if they satisfy the relevant prudential requirements and other applicable obligations under the Code, and also any relevant requirements imposed by jurisdictional regulators. These provisions might constitute:

- exclusionary provisions, in that competitors agree not to purchase electricity from or sell electricity to Market Participants unless they satisfy the prudential requirements;
- exclusive dealing provisions, as each participant trades on condition that they will not supply electricity to or acquire electricity from any person who does not satisfy such requirements; or
- provisions substantially lessening competition, if they create a barrier to entry to the electricity market.

Given the characteristics of the proposed NEM, the requirement for Market Participants to satisfy prudential requirements as a condition of participation is seen as essential for the efficient operation of the market and the financial protection of the suppliers to the market.

The proposed market design requires all wholesale electricity to be bought and sold through the spot market. The spot market is a "blind market", with suppliers (generators) being unable to identify a specific purchasing counterparty, and with all purchasers paying the same spot price irrespective of their credit worthiness. Therefore, unlike most other markets, it is not possible for the supplier to undertake the normal credit risk assessment of its customers and set prices and/or terms of payment accordingly.

For this reason, the centrally co-ordinated prudential requirements have been structured to effectively place each purchaser at a common level of credit worthiness to provide suppliers with an appropriate level of confidence in the NEM. Without this confidence, the suppliers to the market would have no choice but to include a risk component in their prices for electricity to compensate for the reduced and uncertain credit quality of their unknown counterparts thereby raising prices and reducing customer benefits.

NEMMCO will perform a market clearing role as a principal to each trade in the spot market, but with limited recourse such that it is only required to pay to suppliers up to the total amount collected by it from purchasers in respect of spot market trades in any billing period. If there is ultimately a shortfall in NEMMCO's recovery from any purchaser, then that shortfall is to be pro-rated across the suppliers. If, instead, NEMMCO were to be liable for this risk, it would necessitate NEMMCO being established with a significant capital base to support it. This is clearly not desirable as NEMMCO's only source of
income is from the Market Participants. By accepting a pro-rated share of any shortfall, the suppliers (generators) are implicit providers of the market's capital backing.

In order to reduce the risk of any shortfall occurring in the event of a payment default, the structure of prudential requirements is set out in clause 3.3 of the Code and provides for the following:

- Market Participants will be required to provide and maintain "unconditional guarantees" to NEMMCO for an amount equal to their "Maximum Credit Limit" which will be set for each Market Participant by NEMMCO on the basis of the Participant's expected maximum ("reasonable worst case") exposure, to be determined in accordance with clause 3.3.8 and principles specified in Schedule 3.3. of the Code. This will effectively bring all Market Participants up to at least the same credit level.
- NEMMCO will have the power to "mark to market" at any time and issue calls on Market Participants to provide additional collateral if the Maximum Credit Limits are, or are expected to be exceeded.
- The "unconditional guarantees" will not need to be provided from an entity which meets the Acceptable Credit Criteria. The Acceptable Credit Criteria require that each such entity:
- either be a bank under the prudential supervision of the Reserve Bank of Australia, or be an Australian State, Territory or Federal Govemment; and
- carries a short term credit rating of at least P1 (Moodys) or A1 (Standard and Poors) or equivalent; and
- has not provided a total of "unconditional guarantees" in excess of a "concentration risk level" to be determined by NEMMCO.
- Market Participants that are also entities that meet the Acceptable Credit Criteria will not be required to provide "unconditional guarantees".
It is considered necessary to limit the method of providing collateral to unconditional bank guarantees, as credit ratings alone are not viewed as providing sufficient liquidity or surety, and even cash may not provide sufficient security in the event of insolvency.

The process undertaken by the NGMC in arriving at the proposed prudential requirements structure was as follows:

- In 1995 the NGMC commissioned a very comprehensive study and report by a consortium of Condell Vann \& Co. and Corrs Chambers Westgarth, addressing the need for and proposed structure of prudential requirements arrangements for the NEM.
- Following publication of the Condell Vann/Corrs Chambers Westgarth report, in December 1995 the NGMC established an expert panel to review the findings of the report, conduct a process of consultation with participants and stakeholders and develop detailed plans for implementation. This Panel comprised high level
executives with extensive expertise in financial markets and representatives from treasury/financial management areas of both generator and retail Market Participants.
- The panel produced a summary report of its recommendations and held well attended seminars in both Melbourne and Sydney in March 1996 to present and discuss the implications of its proposed approach.
- Following the seminars the Panel received and considered a number of written submissions before finalising the arrangements set out under clause 3.3 of the Code.

It should be noted that any cost implied by the requirement to provide guarantees is not a new cost imposed only for this market. All sales of goods involve a cost (almost always implicit) to cover the credit risk exposure to the counterparty to the transaction. The nature of the spot market, as discussed above, requires a known credit risk level to be set which suppliers can price around and, thus, makes explicit something which in most other markets exists but is hidden.

The requirement for guarantees passes the costing of this credit risk to the banking sector, where this pricing forms a major part of its commercial practice and should, therefore, result in the best possible pricing for the cost of the credit risk.

The proposed arrangements do not discriminate in any way. The Maximum Credit Limit and amount of the required guarantee will be determined by NEMMCO for each Participant by a consistent methodology to be developed and published by NEMMCO in accordance with the principles set out in clause 3.3.8 and Schedule 3.3 The size and cost of a guarantee will, therefore, be dependent on the way in which the Market Participant operates and trades in the market and the overall assessment of its credit worthiness by the provider of the guarantee. Where guarantees are provided by a participating jurisdiction to a Market Participant, the participating jurisdictions have agreed to provide the guarantee on a commercial basis consistent with the cost of guarantees from the private sector in accord with agreed competitive neutrality provisions of the national Competition Principles Agreement.

As the spot market is a blind trading market, its viability depends upon Market Participants meeting appropriate prudential requirements. There will be no externally or Code-based limits on the size of the exposure or the amount of trading that any participant may engage in, other than the limits set by each participant for itself. Each Market Participant determines their level of prudential requirements by their intended trading volume. It is considered that this method of calculating prudential requirements calculated for Market Participants is a reasonable balance between the necessity to cover potential defaults without raising unnecessary entry barriers.

### 6.3.4 Network Loss factors ( Clause 3.6)

The provisions in clause 3.6.1-3 require the calculation of inter-regional, intra-regional and distribution loss factors, and the use of such factors as price multipliers. The market in its treatment of network losses needs to provide economically efficient locational price signals to ensure that:

- the central dispatch process properly takes account of network losses to achieve the most economic outcome for the power system as a whole;
- new investment associated with both electricity generation and consumption reflects the true value of that investment in any location within the market area; and
- the right balance is achieved between investment in generation, demand side measures and/or the main transmission network.

At the same time, it is important that this be achieved in a way which provides for adequate price discovery in the market and does not inhibit bilateral trading between participants.

To the extent that loss factors result in the averaging of losses across a region, they may create cross-subsidies from those whose actual losses are low to those whose actual losses are high. As such, these provisions may be:

- price fixing arrangements, to the extent that participants are employing formulae which may have the effect of fixing or controlling the price of electricity in a region; or
- anti-competitive arrangements, in that the existence of the cross-subsidies substantially lessens competition in a region.

It is important to note that in the Code the averaging of losses will only occur in the low voltage distribution network where it is not economically feasible to develop dynamic marginal loss factors for each distribution connection point. Even if it were technically feasible, the overall costs of doing so would outweigh any benefits flowing from applying marginal loss factors to each individual customer.

The key components of the Code provisions with regard to the treatment of network losses are bound together with the criteria by which regions in the NEM are defined. The difference between inter-regional and intra-regional losses are that:

- inter-regional transmission losses between the regional reference nodes will be calculated on a dynamic basis in the central dispatch process using a load flow/losses equation estimated by NEMMCO annually;
- intra-regional losses between a transmission connection point and the regional reference node will be represented as pre-defined marginal loss factors that reflect the marginal losses incurred at various generation and load centres in moving energy from generation to loads under "average" conditions. (These locational loss factors are calculated by NEMMCO using standard load flow models using actual generation and load flows for the previous financial year.);
- generator and scheduled loads offers and bids will be adjusted by a combination of inter-regional factors (calculated dynamically) and intra-regional loss factors and this will ensure that generators or loads are dispatched in merit order taking into account network losses; and
- distribution losses (from the transmission connection point to the end user connection point) are represented by average rather than marginal loss factors. If
in NEMMCO's opinion the calculation of a distribution loss factor for an embedded generator would significantly affect the central dispatch of generation, NEMMCO may require the Distribution Network Service Provider to calculate the distribution loss factor in a similar manner to intra-regional loss factors.

This approach to the treatment of network losses was recommended by Putman, Hayes, and Bartlett in their report to the Victorian Government. ${ }^{23}$

There is a public benefit, through reduced administration costs, and certainty, in the arrangements for averaging distribution losses in a region. The extent of averaging envisaged in the Code is limited and has no material impact on competitive outcomes in the spot market. The alternative of measuring losses at every point within a network would be administratively unworkable and prohibitively expensive.

### 6.3.5 Projected Assessment of System Adequacy (PASA - Clause 3.7)

It has been contended that competition in the market could be lessened by the collection and publication of PASA information through the potential for that information to be misused to manipulate spot prices. It is submitted below that such lessening of competition is unlikely to occur and to the extent that it may, any such effect will be clearly outweighed by the benefits of the widest possible dissemination of PASA information.

Collection and publication of PASA information for periods up to two years in advance will provide good information on consumption, production and investment behaviour on the part of all Market Participants. Where periods of projected inadequacy of electricity supply are identified, generators may decide to expedite the commissioning of additional generation capacity, or to defer for that period maintenance that would take generation units out of production. Similarly, periods of projected inadequacy might well assist Market Customers to plan for reducing demand or for taking out various forms of hedge against the shortages and higher prices likely to result. A market without information about adequacy levels will be limited in the way it manages risks and hamesses the resources at its disposal. It will, in fact, be limited to rely on very short term and potentially very costly measures to guarantee supply in the event that inadequacy becomes a clear and present risk.

Against these benefits the risk of any participant or set of participants using PASA information to manipulate market outcomes is both remote and limited. Participants can only manipulate market outcomes to the extent to which they have market power. If PASA-type information was not made generally available to all Market Participants, there would be a distinct risk that it would be available, albeit in a less complete and less systematic form, only to a few. In that case the risk of information asymmetry leading to market power, and to the possibility of manipulation of market outcomes, would be of real concern. However, that is not the arrangement proposed by the Code.

Maintenance outages of generating plant were previously subject to a centrally coordinated process with significant care being taken to ensure that an adequate reserve margin was maintained between the forecast demand and the plant expected to be

[^12]available for service. Outages were co-ordinated centrally to ensure that the most important outages received priority. Even in the centrally co-ordinated process, not all desired outages were accommodated, and some planned outages had to be deferred or cancelled. If insufficient opportunities are made for generation maintenance, the reliability of the generators will deteriorate, putting system security at risk. It is important to note that in most cases, generating plant cannot be recalled to service at short notice after a major maintenance outage commences because of the extent of plant disassembly involved.

The PASA process is designed to allow Market Participants to make their own commercial decisions as a substitute for the centralised maintenance co-ordination process. One of the key market design principles has been to decentralise decision making processes, wherever possible, to the participants themselves. In order to achieve this, particularly for the scheduling of maintenance and commitment/ decommitment of plant, it is a prerequisite that sufficient data is made available to all participants on which to base these potentially critical commercial and operational decisions. For participants to determine appropriate outage times for their plant, they need to form a view on three fundamental factors over the planning period - the forecast system demand, the reserve requirement to be imposed for reliability of supply, and the amount of generating plant already planned to be out of service. The PASA process enables a reasonable view to be formed by all participants on these factors.

The ACCC has suggested that NEMMCO should monitor the use of PASA information to detect possible anti-competitive uses. This policing role is not a specific function of NEMMCO and NEMMCO will not have the resources to undertake such functions. It is accepted, however, that NEMMCO, along with other industry participants, will have a capacity to observe the way PASA information appears to be used, and to take action it believes to be consistent with good corporate practice. Because NEMMCO will not be claiming any high degree of expertise in trade practices issues, appropriate action may include referring matters on occasion to the ACCC.

The ability to uncover abuses of market power will depend on access to sufficient data from the spot market and the financial sub-markets. Whilst NEMMCO can monitor activity within the spot market it can only consider actions in isolation. This will only give a limited picture of participants' behaviour.

The monitoring of behaviour in the spot market is a contentious issue. It is submitted that the balance of the argument is to publish as much data about the market as possible. Not only will this increase market efficiency, but it will allow Market Participants to monitor each others' behaviour, thus aiding detection of anti-competitive behaviour. In this respect reference should be made to the TransGrid Paper entitled Analysis of Pool Pricing set out in Schedule 13, the report by St Clements Services entitled Electricity Market Transparency set out in Schedule 14 and the paper entitled Importance of information disclosure - Summary of the NASDAQ case set out in Schedule 15.

The question of responsibility also arises. If Market Participants are not to be given access to market information on the grounds that this would facilitate gaming, there are no assurances that Market Participants are being adequately protected. This is especially important in areas where Market Participants may have detected gaming themselves if information was released to the market, but in the absence of such data have incurred
losses. If reacting to gaming behaviour is not possible for participants, the market is likely to produce sub-optimal outcomes.

### 6.3.6 Spot Market determination of spot prices and compulsory nature of the market

 (Clauses 3.8 and 3.9)The wholesale trading arrangements which determine the price for electricity are set out in Chapter 3 of the Code. The market is intended to set the competitive price for electricity through a process of:

- bidding by generators;
- demand side bidding; and
- rebidding.

Chapter 3 also sets out the manner in which the spot price is set, including the treatment of:

- dispatch and determination of the merit order (including implications for new generators, if any);
- regional spot prices;
- network losses and constraints;
- self commitment; and
- maximum and minimum prices.

In particular, clauses 3.8 and 3.9 of the Code require that all electricity supplied and used by Market Participants must be transacted through the spot market and at the spot market price. These provisions may be considered to be:

- exclusionary provisions, as competing participants agree not to trade with other persons except through the spot market;
- exclusive dealing provisions, as Market Participants agree to trade on condition that they will not supply electricity to, or acquire electricity from, unregistered persons;
- price fixing provisions, because participants are agreeing that a particular pricing mechanism will be used to determine prices to be charged for such generation and load; or
- provisions having the purpose or effect of substantially lessening competition, in that the requirement to trade through the spot market or to trade at particular prices creates barriers of entry to, or lessens competition in, the electricity market:

In assessing any potential detriment of the proposed spot market constituted by any lessening of competition, the objective should be to assess what would result if it were feasible for generators, consumers and others to come together in a more conventional
market to set the terms and conditions for the trading of the electricity (including pricing). The central dispatch/spot market process should be viewed as a necessary facilitator of the trading process, not the determinant of the outcome.

It is submitted that a competitive spot market with a common clearing price is the simplest and most efficient means of balancing supply and demand for electricity at any point in time. An electricity spot market can work much like any other wholesale market in which buyers and sellers make offers, determine the prices at which supply equals demand, and trade the product at those prices. Some special market arrangements are needed to deal with the unique characteristics of electricity but these arrangements are different only in degree from those functioning in other commodity markets. Thus a spot market should be viewed as a necessary facilitator of competitive trading in electricity which is required because of the unique characteristics of electricity as a product. This facilitation role does not lessen the competition that will occur in the NEM.

It is important in this context to refer to the comments made by Putman, Hayes, and Bartlett in their report to the Victorian Government, on the competitive benefits of a spot market for electricity:
> "The wholesale electricity market, like any well-functioning commodity market, will include diverse commercial and financial arrangements, including contracts of various types and duration, vertical integration (where allowed), joint ventures, short-term trading, etc. At the core of these commercial arrangements will be a spot market in which physical electricity is priced and traded. This electricity spot market will be technically complex but will be invisible to most consumers, just as the technically complex wholesale markets in petroleum and government securities are invisible to most buyers of petrol and banking services.

A spot market in physical electricity has two principal functions.
(a) Maintain Efficient Short-Term Operations or Dispatch

A spot market coordinates short-term operations of separately owned entities to assure that demand is met economically and reliably given the production facilities actually available on the day, largely independent of longer-term contract arrangements.

## (b) Facilitate Longer-Term Contracting and Competitive Entry

A spot market reduces the risks of contracting by allowing contracting parties to buy and sell "overs and unders" to meet their obligations at least cost/highest profits, thereby facilitating entry by undiversified competitors, each of which can compete in the specific activities it does best without needing to be a self-contained, fullservice producer.

Discussions of electricity spot markets usually focus on the first of these two objectives, maintaining efficient and reliable operations or dispatch. This focus is understandable, given the traditional central
control of system operations and the difficulty or even impossibility of designing a spot market that will mimic the operations of a technically oriented dispatch process. But the purpose of a spot market is not primarily to improve or duplicate the dispatch of given plants with given cost characteristics meeting given demand in the short run: it is to allow market forces to determine the amount, mix and demand, in the long run. A well-designed spot market/dispatch process will maintain or even improve short-run efficiency and reliability, albeit probably with more price-induced load management and less reserve capacity than is traditional. But even if a spot market appears to reduce short-run dispatch efficiency to some extent, this can be a small price to pay for the benefits of competition in the longer run, where the largest cost savings are expected. "24

It is submitted that the mechanisms to establish spot prices mimic those in traditional markets (the interplay of supply and demand). It is further submitted that the central coordination is an essential element required by the need to balance supply and demand on an instant-by-instant basis. As such, pricing under the spot market, and the mandatory participation in that market produces a competitive outcome. The public benefits of market efficiency and equitable treatment of participants delivered through this mechanism far outweigh any perceived detriment arising from any lessening of competition.

### 6.3.7 Determination of price cap and floor

In the context of the spot market, the price cap and price floor may amount to price fixing under section 45A of the Act.

## (a) Price Cap (Clauses 3.9.4 and 3.9.5)

In an ideal market, a price cap would not be necessary. Such a market would include a large number of participants, both buyers and sellers, all indicating the price thresholds at which they were prepared to buy or sell. Participants will also each have the capability to ensure that they did not buy or sell in the event that the market clearing price did not meet the price threshold they had previously indicated.

In the context of an electricity market, this would require all generators and wholesale buyers to have the physical capability to control their generation or purchase at all times to match their indicated intentions in the form of bids and offers into the spot market. This is simply not practical for the following reasons:

- many generators have physical constraints which limit their ability to respond instantaneously to changes in market price - the national market provides for this by allowing these generators to run "out of merit" in which case they are unable to set the price in the market;

[^13]- very few wholesale purchasers have the capability to directly control the amount of demand they are taking from the market at any point in time; almost all wholesale purchases are made by retailers who do not have the real time load monitoring and the remote load control system in place which would allow them to directly manage (or allow the market operator to directly dispatch) their wholesale purchases - the national market recognises this limitation by making it purely optional for wholesale purchasers to participate directly in the bidding, scheduling and dispatch processes associated with the spot market.

With demand side participation in the scheduling and dispatch process being purely optional, there is no guarantee that the spot market will physically clear at all times. Under these circumstances, the market operator must have the authority to direct customer load to be cut off when necessary to protect the integrity and security of the power system. NEMMCO is provided with these powers in Chapter 4 of the Code.

As far as the spot market is concerned however, the wholesale purchasers whose load has been interrupted will not have submitted a dispatch bid indicating a bid price at which it would be prepared to have that load interrupted. Instead, the Code sets the price at such times to a specified maximum amount, VoLL (the Value of Lost Load).

Due to information asymmetries and technology shortcomings for Market Customers (such that most customers cannot respond in a timely fashion to changes in wholesale prices), there is no practical alternative under the current market design to imposing a price cap. This leaves open the issue of the level of the cap. There is no single theoretically correct level of VoLL. Every user of electricity places their own specific value on electricity use and usually this will depend upon what the electricity is being used for, what period of notice would be given before supply is interrupted, and how long supply may be unavailable. The codified value of VoLL therefore is a necessarily simplified surrogate to use in place of the potential wide range of possible values which affected customers would apply given the opportunity to do so.

If the level of VoLL is set too low, it will materially impact on the overall level of power system reliability. It would discourage investment in new (and possibly encourage mothballing of existing) high operating cost peaking plant which provide essential reserves for the overall market.

On the other hand, if VoLL is set too high, it would substantially increase the risks associated with the occurrence of such high prices and would probably result in over-investment in reserve plant and voluntary load interruption schemes, and the costs of these would ultimately impact on market prices which customers have to pay.

The level of VoLL proposed in the Code, which is consistent with the value currently in use in the England/Wales market, strikes a balance between these two
conflicting needs. However, the Code also proposes that NECA conduct a review of the level of VoLL one year after market commencement.

## (b) Price Floor (Clause 3.9.6)

If a period of excess generation is forecast, there is a physical requirement to reduce the supply of generation to the power system to avoid a system collapse. To solve this problem without direct intervention by NEMMCO, the Code prescribes a pricing mechanism whereby Scheduled Generators submit off-loading prices to reduce their output potentially to zero if required. Those Scheduled Generators still generating will be exposed to negative prices and will pay NEMMCO their dispatched MW times the negative pool price. This pricing mechanism will send a strong signal to all Scheduled Generators to avoid a period of excess generation. It will also allow the market to resolve the excess generation problem rather than have NEMMCO resolve it in some arbitrary manner.

Under clause 3.9.6 of the Code, during periods of excess generation:

- spot prices are constrained to be not less than zero for Market Customers; and
- Scheduled Generators are obliged to submit negative price bids to enable them to continue to generate electricity during such periods.

Therefore there is in effect no floor price for Market Generators. The principal arguments in support of these arrangements are set out below.

## Limited Capability for a Demand Side Response

The number of customers who would be able to respond to negative pool prices in real time (or with short lead time, say one to two hours) would be limited to those who would have direct exposure to pool price together with the ability to increase their consumption (it should be recognised that vast majority of customers who elect to have pool price exposure would have the ability to reduce consumption in response to higher pool prices rather than increase consumption at low or negative pool prices which would be expected to occur for limited periods at night time and on weekends when many such customers are not using large amounts of electricity). Therefore a negative pool price to customers, in the short term, may only have a limited impact in increasing demand to avoid the excess generation problem.

## A Generator Problem

An excess generation condition means that even when the price in the market has fallen to zero, collectively the generators are still unwilling to reduce their output to match the customer demand at that zero price even though generation must be reduced to avoid a system collapse. While the reasons for this situation may be quite varied, in general this will be the result of inter-temporal constraints associated with the operation of the generator which discourage the generator from any further reductions in output. As stated earlier however, it is extremely
unlikely that increases in demand can occur which might contribute to solving the excess generation condition in the short term.

Essentially it must be solved by generator action. And if the generators do not respond, NEMMCO will have no choice but to intervene in the market and reduce the level of generation until it matches the level of demand with sufficient negative regulating reserve capability to protect the integrity of the power system. Therefore it is important that the commercial drivers in the market provide maximum incentive to the generators to reduce their output at these times. Allowing the pool price for generators to be less than zero while pegging the pool price to customers at zero maximises this incentive. It ensures that contracted generators will not receive difference payments under their contracts from customers which simply offset the payments to the pool resulting from the negative pool input price. Therefore all generators, not just those which are uncontracted, will pay a penalty for continuing to generate.

For example, assume the spot market price is allowed to go negative to $\$$-20/MWh for both customers and generators and a generator has a 2 way hedge contract at a strike price of $\$ 30 / \mathrm{MWh}$ with a Market Customer for 100 MW . The difference payment from the Market Customer to the Generator would be:

$$
\begin{aligned}
& =(\text { Strike Price }- \text { Pool Price }) \times \text { Contract MW } \\
& =(\$ 30 / \mathrm{MWh}-\$-20 / \mathrm{MWh}) \times 100 \mathrm{MW} \\
& =\$ 5,000
\end{aligned}
$$

If the generator maintains an effective spot market input of 100 MW , the net position of the generator would be:

$$
\begin{aligned}
& =\text { Pool Income }+ \text { Difference Payment from Customer } \\
& =\$-20 / \mathrm{MWh} \times 100 \mathrm{MW}+\$ 5,000 \\
& =\$ 3,000
\end{aligned}
$$

The effective price to both parties is the strike price in the contract and the generator is protected from the negative price to the extent to which it is contracted.

It is clear from the above example that for the generator with an objective of maximising its short term position, the incentive is to off-load and not to consider its contract position when deciding to maintain or reduce output levels. However, in a market with diverse ownership and management many factors will influence decisions and the extent to which heavily contracted generators will or will not react to spot market prices is unclear, particularly if both generators and customers receive/pay the same spot market price.

If the spot market price to customers is limited to at least zero then the net position of the generator that continued to generate would be:

$$
=\text { Pool Income }+ \text { Difference Payment from Customer }
$$

$$
\begin{aligned}
& =\$-20 / \mathrm{MWh} \times 100 \mathrm{MW}+(\$ 30 / \mathrm{MWh}-\$ 0 / \mathrm{MWh}) \times 100 \mathrm{MW} \\
& =\$ 1,000
\end{aligned}
$$

However, the net position of the generator that reduced its output to zero would be:

$$
\begin{aligned}
& =\$-20 / \mathrm{MWh} \times 0 \mathrm{MW}+(\$ 30 / \mathrm{MWh}-\$ 0 / \mathrm{MWh}) \times 100 \mathrm{MW} \\
& =\$ 3,000
\end{aligned}
$$

Therefore by setting the spot market price to customers at zero provides an incentive to some generators to reduce their output to zero.

Under a negative spot market price, Market Customers may also face increased risk if they were over contracted, because they would then face payments to generators without an offsetting revenue stream.

Maximising the incentive for all generators by allowing a negative price to generators with a floor of zero to Market Customers will result in excess generation periods occurring less frequently than would otherwise be the case and also ensure that, when they do occur, there is less need for NEMMCO intervention. This is clearly in the public interest.

## Prudential Risk and Market Complexity

While it is not a key consideration in deciding the public benefit of the proposed arrangements, an added benefit of the floor price is that, for parties to a bilateral contract which references the pool output price, the maximum difference payment a purchaser will ever have to make under the contract will be limited to the strike price of the contract. If the reference price for the contract could be less than zero without any limit, it would create another complex set of risk management issues which participants will have to address. The price cap and floor arrangements are an essential feature of the market as long as there is no compulsory demand side bidding with the physical systems in place to enable every Market Consumer to be dispatched (that is probably decades away). The arrangements also recognise the entities best able to adjust to these pool conditions. The benefits of these limitations to full price flexibility, by reducing the transactions costs of operating in the market, exceed any supposed benefits from such flexibility.

The price floor provides key.incentives to generators while protecting customers, while the price cap (of VoLL) gives protection to both sides of the market during the period in which the market is developing.

### 6.3.8 Inter-regional hedges (Clause 3.11)

Clauses 3.2.7, 3.65, 3.11, 3.11.1(e) and (g), 3.11.3 and 3.12 relate to inter-regional hedging.

These clauses may involve sections 45 A or 47 of the Act for the following reasons:

- NEMMCO has access to settlement surpluses to underwrite hedges whereas independent offerors do not (this may lessen competition);
- NEMMCO has an obligation to set a reserve price for its hedges (this may be price fixing);
- NEMMCO has the ability to contract with Network Service Providers and/or Ancillary Service Providers which can significantly affect the capacity of interconnectors and therefore regional pool price differences. The knowledge that NEMMCO has this power may affect the degree to which other parties will contract to provide equivalent hedges (this may lessen competition); and
- NEMMCO may engage in secondary trading in inter-regional hedges (IRHs), even where it is the entity that establishes and administers the exchange. If NEMMCO were to use information gained from its special position in the market in its secondary trading, this would affect the confidence that other parties have in the market (this may be anti-competitive). Likewise, if NEMMCO obtained special treatment from the exchange administrator, this would also affect the confidence that other parties have in the market (this may lessen competition).
(a) The need for IRHs


## Price differences between regions

The south east Australian electricity network is distributed over a wide area. Transport losses (the loss of electrical energy incurred during the act of transport) and constraints (limitations on transport capacity) need to be taken into account not only in the dispatch of electricity but in setting the spot price in order to achieve efficient and equitable outcomes. Hence the spot market is to be set up as a number of linked, geographical price regions and the dispatch algorithm, which determines the dispatch of electricity and the price, and which attempts to maximise the benefits of trade in the spot market, is to take inter-regional losses and constraints into account. ${ }^{25}$ The algorithm will calculate a spot price at each regional reference node separately. Thus:

- inter-regional flows of electricity will occur from lower to higher priced regions;
- as losses occur-when electricity is transported from one region to another, prices in the destination region should be higher than in the source region. To ensure that benefits of trade are maximised, the price difference must be based on marginal rather than average losses ${ }^{26}$;
- likewise, if electricity transported into a region is limited by a constraint, prices in the destination region (in which the electricity which would have come from the inter-regional source must be replaced with higher cost

[^14]generation or demand side options) will be higher than in the source region.

## Settlements residues

Transport of electricity from a lower to a higher priced region can give rise to excess revenues in the spot market. For reasons discussed below, these remain initially with NEMMCO as settlements residues.

This excess revenue arises as follows. NEMMCO receives all payments for electricity purchased through the spot market. It also makes payments for all electricity supplied into the spot market. Where there are price differentials between two regions, and electricity is transported from one region to another, electricity will be paid for by NEMMCO at one price (in the lower price region) and, net of losses, sold by NEMMCO at another price (in the higher price region).

Consequences of spot market design
Consequences of this spot market design thus include the following:

- large inter-regional differences in spot prices can arise; and
- settlements residues can appear in the spot market when electricity flows from lower to higher priced regions.


## Trading in the NEM

Although electricity is purchased and sold in the NEM in accordance with the spot market procedures, it is likely that wholesale market participants will, for purposes of improving cash flow certainty and/or profit, enter into forward contracts after which, financially, they will be in the net position that they would have been in had they physically sold electricity bilaterally.

As well as generally reducing financial risks, such forward contracts, or contracts for differences, can, under some circumstances, also create risks for the parties. For example, if a generator is subject to a firm contract under which the generator effectively sells a retailer electricity, the generator will be exposed to the risk of making difference payments without corresponding revenue if the generator is not able to generate (or otherwise earn pool revenue).

It is intended that, in the NEM, generators and retailers from all regions will be able to trade with each other on an efficient and non-discriminatory basis.

This enhances competition in the wholesale market in each region by increasing the number of players and by increasing the choice of generation and customer types. It also assists in the process of retail deregulation, allowing contestable customers a wider choice of counterparties from whom they can purchase their energy.

It also creates benefits in the spot market. The benefits of trade realisable through the spot market are maximised if both the quantities and locations of generating capacity committed to being present in the spot market are optimal, with
equivalent forward planning considerations applying on the demand side. Participants' contracted positions should have a strong commercial influence on their forward planning decisions, including generating unit commitment. Thus it will be important to ensure that efficient forward trading can occur right across the NEM, so as to provide a market-based mechanism for co-ordinating plant management decisions and hence enable the full benefits of trade available from the NEM to be unlocked.

However, a generator generating in its own region will not be earning the spot market price applying in some other region. If the generator enters into a forward contract with a retailer in the other region under which payments are made based on the spot market price in that region, then where such differentials occur the generator suffers an exposure to the inter-regional spot price difference.

Thus a participant (the generator in the above example) can face additional risks when contracting across regional boundaries. In principle, a participant could obtain relief from the additional risk by purchasing an inter-regional hedge (IRH). Under such a contract it would expect to be in a similar position that it would have been in had it sold electricity in its own region. The residual exposure would be comparable with that incurred through contracting with a participant in the same region.

## Desirability of IRH products

It can therefore be argued that parity between inter and intra-regional trade would be achieved if IRHs were available to participants at efficient prices. Participants could then choose to purchase such a hedge or to carry the risk themselves, or manage it another way. As discussed below, electricity transporters are in principle natural providers of IRHs. ${ }^{27}$ Efficient prices for IRHs can therefore be construed to be those which could be expected to apply given open competition between electricity transporters. At the start of the NEM, electricity transport is to be a fully regulated monopoly. However, the Code's IRH provisions are designed to emulate outcomes that might be expected to prevail given competition in transport.

## Transport and interconnector owners

If interconnector owners were direct participants in the spot market, competing to transport electricity between regional reference nodes, ${ }^{28}$ the settlement surpluses that arose would presumably be paid to the interconnector owners in accordance with the transport service provided. Through their entitlement to the settlement surplus plus their general ability to manage the availability of their interconnectors, the interconnector owners would be well placed to be "natural" providers of hedging against inter-regional price differences and thus facilitate

[^15]inter-regional trading. ${ }^{29}$ Given effective competition amongst transporters, efficient inter-regional trading (ie a level of trading that maximises benefits arising from the NEM) might be expected to evolve without the need for any specific Code provisions. Parity in inter-regional trade would be achieved naturally through market forces.

However, although the Code has provision for the possible future evolution of non-regulated interconnectors, once registered all existing network businesses are to be treated as regulated monopolies. This approach is dictated by the present impracticality of setting up competition in the provision of transport services. A monopoly Network Service Provider whose revenue was based on the settlement surpluses could, furthermore, have an incentive to inefficiently manage the availability and losses on the interconnector in a way which enhanced that surplus. It is considered that this should be prevented by the market design and regulatory guidelines.

As a result, the inter-regional settlement surpluses remain as residues after spot market settlement, and do not automatically pass to parties who might be considered to be primarily entitled to them and who would be likely to compete as natural providers of inter-regional hedging.

## Consequences of the lack of natural IRH providers

In the absence of natural providers of hedging, inter-regional contracting in electricity would almost certainly be inhibited and the efficiency of the NEM significantly impaired.

## Secondary trading

It is desirable that any party that enters into IRHs has the capacity to manage its risks by trading out of and back into that contract position. Such secondary trading should, in principle, occur whenever parties have matched bargaining positions and it is not part of the market structure to create such matched positions. However, and especially during the period when the market is immature, there is a need to facilitate such secondary trading, to enable the maximum number of trades. Failure to ensure this will lead to a loss of value in the IRH package, as parties will be less able to manage their risks, and this may reduce their initial purchases and sales of IRHs (with a concomitant reduction in inter-regional trading and despatch).
(b) Code provisions relating to IRHs

In recognition of the potential impairments of market efficiency outlined above, the Code:

- makes arrangements which are intended to emulate the theoretical outworkings of a fully competitive market and thus (if the emulation is reasonably successful) safeguard the efficiency of the NEM and ensure parity in the inter-regional trading;

[^16]- for this purpose, assigns the inter-regional settlement surpluses to NEMMCO in the first instance and requires NEMMCO to manage them (through, for example, using them to help underwrite the risks associated with issuing inter-regional hedges);
- also for this purpose, requires NEMMCO to issue inter-regional hedges at reserve prices intended to emulate the theoretical outworkings of a fully competitive market;
- requires NEMMCO to negotiate with Network Service Providers and Ancillary Services Providers on the capacity of inter-connectors; and
- requires NEMMCO to facilitate a secondary trading exchange, although it limits NEMMCO's role in this respect to the first three years of the operation of the NEM, when, it is considered, the market will be in an sufficiently mature position to create an exchange for itself, or to take over the operation of NEMMCO's exchange.


## NEMMCO to receive settlements surpluses

The mere fact that NEMMCO offers IRHs does not, of itself, constitute a breach of the Act. It may, however, be considered that since NEMMCO has access to the settlement surpluses NEMMCO will be able to write IRHs more confidently than other parties, and at lower prices. In fact, as discussed below, NEMMCO's prices are regulated at the reserve price. Furthermore, giving NEMMCO access to the settlement surplus is necessary in order to ensure its ability to write the IRHs. It is shown below that if NEMMCO does not write the IRHs at market inception, substantial detriment may result. Vesting the surpluses in NEMMCO removes such detriments by ensuring that NEMMCO is able to offer IRH at market inception. In other words, vesting the settlements surpluses in NEMMCO ensure that all the benefits of having IRHs will exist at market inception.

It should be noted that the Code merely provides that NEMMCO has power to initiate IRHs. It does not preclude the provision of IRHs by other entities should private players be capable of efficient provision of suitable instruments. The Code is no impediment to these instruments and NEMMCO's facilitation role will also be no impediment.

It should also be noted that NEMMCO must return annual surpluses accruing from the settlements residues and inter-regional hedging activities to the appropriate transmission Network Services Providers to be used to reduce Transmission service prices. Competing, non-regulated interconnection businesses, on the other hand, would be entitled to retain these amounts. This would be inequitable in the case of regulated businesses that are fully funded through regulated charges.

## Reserve price

NEMMCO is required to set a reserve price for IRHs. This may be considered to be price fixing. The price is that required to minimise the difference between payments under the IRH and receipts for the IRH. This price is expected to
approximate that applying in a contestable market. This protects the ultimate receivers of settlements residues. The reserve price also helps ensure that NEMMCO's trading in inter-regional hedges does not unfairly under-cut other potential providers of similar products. It also ensures that the settlements residue is not alienated at an inappropriate low price.

It must be emphasised that the reserve price is, as the name suggests, a minimum price only. If the market for IRHs clears at a higher price due to the intensity of competition, then that higher price will apply.

## Arrangements with Network Service Providers and Ancillary Service Providers

The Code provides that Network Service Providers will negotiate with NEMMCO in good faith to reach agreement on:

- reasonable capacity profiles for the interconnector; and
- reasonable compensation arrangements to apply when the interconnector does not meet the agreed capacity profiles.

NEMMCO is also empowered to enter into contracts with Ancillary Service Providers for the purpose of maintaining interconnector capacity.

These provisions are intended to help ensure that assets and services relating to inter-regional transport are managed in a cost effective way that responds to demand for inter-regional transport. Each contract is to be used as a risk device. It is therefore a response to the level of IRHs sold by NEMMCO, or the demand for IRHs. These sales therefore provide a signal for the management of interconnector capacity.

It could be argued that giving NEMMCO specific access to the Network Service Providers could have anti-competitive effects. Network Service Providers are not compelled by the Code to negotiate with other providers of IRHs.

However, it should be emphasised that the Code does not prohibit other offerers of IRHs from negotiating such contracts, and, indeed, there is a positive incentive on such other providers to do so. This is the product of negotiation between these providers and the Network Service Providers. It is also noteworthy that the information as to the capacity profile negotiated by NEMMCO is available to all. Furthermore, the public benefits arising from market efficiency in the management of the physical assets outweigh any potential detriment.

## Secondary trading

The Code requires NEMMCO to ensure that an IRH Exchange is established at market commencement. As stated above, such an exchange is needed if the full benefits of the package are to be realised.

It is intended that NEMMCO will conduct the exchange itself only if it considers that an efficient exchange would not otherwise arise.

As NEMMCO is the primary issuer of IRHs at market start, it is essentially for NEMMCO to be able to engage in secondary trading in order to manage its risks by trading into and out of positions. If it were unable to do so, this would affect liquidity in the market and thus prevent other parties from managing their risks appropriately. It might also result in NEMMCO only offering conditional instruments, which may be less effective for the purposes of market users. This would constitute a loss of public benefit in the package.

It may be argued that NEMMCO has a special position in the market which will give it access to information that will allow it to trade on better terms than other participants. This would lead to a loss of confidence in the secondary market, with anti-competitive effects. In fact, however, NEMMCO must, under clause 8.5.6(c), only trade on the basis of information known to the whole market. This argument therefore has no force.

It may also be argued that if NEMMCO conducts the exchange it will unduly advantage itself when it participates as a trade in the exchange. In other words, it is argued that NEMMCO will have a conflict of interest. This would, again, lead to a loss of confidence in the secondary market, with anti-competitive effects. In this case, however, under clause 3.11.2(c), NEMMCO is compelled to ensure that it obtains no benefit from its dual role. This argument therefore also has no force.

It is also relevant that, under clause 3.11.1(1), NEMMCO does not retain any profits from secondary trading, but must distribute them via Network Service Providers. Its incentive to eam profits from such secondary trading must therefore be doubted. It is more likely to use the exchange to mitigate its risks.

## (c) Summary of public benefit of IRH code provisions

Accordingly, NEMMCO is empowered or obligated by the Code to:

- have access to inter-regional settlements residues for the purpose of managing risks in relation to inter-regional hedges, in direct analogy to the way that spot market settlement surplus could be expected to be utilised by competing, non-regulated transporters;
- offer inter-regional hedges for sale at a reserve price that attempts to emulate what might be expected to prevail in a competitive market;
- negotiate arrangements with Network Service Providers that assist in the management of risks associated with the unavailability of interconnection capacity, indirect analogy to the way that competing, non-regulated transporters could be expected to co-optimise their asset managements and trading opportunities;
- negotiate the provision of ancillary support services, and appropriate compensation in the event that interconnection capacity is reserved for the cross-region provision on ancillary services in direct analogy to the way that non-regulated transporters would be expected to recruit support services and to seek to ensure that their assets were utilised for market value services; and
- to ensure that an IRH exchange is established to facilitate trade in IRHs, and on which it may participate to manage its risks, in a manner analogous to the trading in which it would engage in a competitive market with full, equal information, and where no party in the exchange receives special treatment from the exchange.

It is argued that this package of arrangements provide a practicable, low-risk approach to promoting the availability of inter-regional hedges at efficient prices (neither inflated nor subsided). This should in turn promote the efficient integration of regional electricity markets into a NEM that delivers all the benefits potentially available from such integration. Providing for NEMMCO to make these facilities available at market commencement ensures that they will be available from this time, while the rules governing NEMMCO's conduct ensures that more efficient providers of such facilities will be able to replace NEMMCO whenever they are able to do so (including at market commencement).

Although the turnover in inter-regional hedges will probably be only a few percent of the turnover in the NEM, the inter-regional hedges are expected to be an important catalyst to release the main benefits of the NEM.
(d) Integrity of arrangements for NEM start

It should be emphasised that the IRH arrangements set out in the Code are, however, part of a total package. The provisions as to origination should not, for example, be viewed in isolation from the provisions as to secondary trading. All aspects of the package are closely interdependent. It is not possible to delete one aspect of the package without having a potentially significant detrimental effect on the whole.

The essence of the provisions is to ensure that IRHs are available at market inception in sufficient quantity, and at such prices, as will allow the integration of trading in the participating jurisdictional markets. For the reasons set out above, there is a significant risk that the non-availability of such hedges will result in the NEM being limited to state based markets. This will reduce the full national benefits of electricity reform emerging.

## Private provision of IRH facilities

Other more market-based arrangements are possible. For example, settlements residues might be passed directly to the appropriate end recipients ${ }^{30}$ in anticipation that those recipients might then compete to provide inter-regional hedging. However there are significant risks that these products will not develop at market inception due to high transaction costs, free-rider problems and lack of certainty regarding year by year entitlements. Even if more market-based facilities do develop there is a significant risk that they will not provide IRHs in significant quantities to enable an appropriate level of interstate trade, or at prices which will make interstate trade realistic. Consequently, there is a danger that the catalytic role of inter-regional hedging would not be effectively performed and the main benefits of an integrated NEM would not eventuate. The risks would seem to far

[^17]outweigh, at least at the start of the NEM, the anti-competitive detriment which arises from retaining a residue-management role within NEMMCO.

Similarly, given the complexity of the arrangement needed to facilitate secondary trading, there is a possibility that no agency will come forward to provide a secondary trading exchange at market commencement. The consequences are significant, as the liquidity and efficiency of secondary trading is a significant consideration for those contemplating entering into IRHs. The risk exists that, without a secondary trading exchange in place, the full benefits of interregional trade will not be realised at market commencement. NEMMCO's role is designed to ensure that this market failure does not occur. NEMMCO must be able to engage in such secondary trading and every effort is made to ensure that, if it provides the exchange, it does not obtain any undue benefits from the dual role. The consequences of the exchange not being in place create public detriments which outweigh any adverse consequences of any failure of the efforts to avoid a conflict of interest.

It is acknowledged that some of the provisions of the Code described above have the potential to be a barrier to other providers of IRHs or IRH exchanges, but the cost of a failure to provide IRHs or an IRH exchange is likely to be a number of orders of magnitude larger than the benefits of additional, competitive IRH participation at market inception.

Furthermore, the fact that there may be some barriers to entry does not, by any means, imply that the Code has the automatic consequence of precluding other originators of, or traders in IRHs, or other exchanges. The Code provisions seek to ensure that NEMMCO will provide IRHs at a price reflective of a competitive market. The other providers of IRHs would, at best, be in the same position if a liquid, competitive market in these products existed, in any case. As such, some level of private participation is expected and this will grow over time. In addition, the provisions of Code review of the IRH facilities in NEMMCO provide a method whereby market participants concerned at any adverse effects of the Code over the long term can amend these provisions to allow alternative structures to emerge.
(e) Summary of rationale and expected benefits of IRHs

In summary, it is argued that:

- The availability of inter-regional hedges at efficient prices will be an important catalyst to realising the benefits of an integrated NEM.
- In the absence of the proposed IRH arrangements, in an electricity market in which transport services were competitively provided, interconnector owners would compete to arbitrage between the regional nodes of the spot market. Settlement surplus would go directly to interconnector owners and no inter-regional residues would remain after settling the spot market.
- The interconnector owners' access to spot market settlement surpluses and their ability to manage interconnector availability risks would make them natural providers of inter-regional hedging in net amounts up to the
capacity of the interconnectors. An efficient inter-regional hedging market and, consequently and more significantly, an efficient, integrated electricity market could then be expected to arise without further intervention.
- However inter-regional electricity transport is to be a regulated monopoly. Consequently, the availability of efficiently-priced inter-regional hedging cannot be expected to arise automatically. In its absence, a NEM would tend to degenerate towards isolated regional markets, with consequent loss of public benefit through reduced economic efficiency and inequality of access.
- The Code therefore contains provisions which are intended to emulate the outworkings of a competitive electricity transport market and ensure that efficiently priced inter-regional hedges are available to Market Participants from market inception, thereby unlocking the main benefits of an integrated NEM.
- The Code also ensures the availability and efficiency of secondary trading arrangements.
- The arrangements present a low risk solution that is currently feasible to implement.


### 6.3.9 Ancillary services (Clause 3.13)

NEMMCO will register Network Service Providers (and thereby allow Network Service Providers to deal with it and other Code Participants) to ensure that each Network Service Provider includes in its connection agreements with generators an obligation on the connected party to provide certain ancillary services (clause 3.13). Such a requirement might be held to be:

- an exclusionary provision, in that competitors agree not to obtain network services from persons unless they comply with the requirement to acquire such ancillary services;
- an exclusive dealing provision, as participants trade on condition that one or both of them will not acquire network services from a non-complying Network Service Provider;
- a third line forcing provision (which is a form of exclusive dealing), in that NEMMCO is supplying services to Network Service Providers on condition that they obtain ancillary services from Code Participants; or
- a provision substantially lessening competition, if the requirement creates a barrier to entry to or lessens competition in the generation market.

The rationale behind the Code arrangements for ancillary services is discussed in detail in paragraph 3.4.4 of this Submission. In summary, the conditions for connection in Chapter 5 of the Code for generators (Schedule 5.2) and customers (Schedule 5.3) define the details of requirements and conditions which must be satisfied as a condition of
connection to the power system. These include the provision of measures to protect the quality of supply of electricity to other network users. Such measures may take the form of:

- limits on reactive power demands of customers;
- facilities to disconnect load blocks in the event of severe low power system frequency;
- protective devices to disconnect malfunctioning or faulty plant;
- suppression of harmonic distortion of power supply waveforms; and
- facilities to automatically control a generating unit's active and reactive power outputs.

Maintaining the quality of supply of electricity to all network users is important. The resultant public benefit of such quality of supply through the requirement that network users be forced to provide ancillary services through connection agreements will outweigh any potential anti-competitive detriment arising from such a restriction because of the common good nature of ancillary services. Without this requirement there would be an inherent weakness in the market with an under-provision of such ancillary services, as some users would not bear the full costs of their actions.

### 6.3.10 Market Intervention by NEMMCO (Clause 3.14)

NEMMCO is authorised, and in some cases required, to engage in reserve trading and to issue directions to Code Participants to take necessary actions to maintain a reliable operating state (Clause 4.8.6) or maintain power system security (Clause 4.8.10). Such requirements could be an anti-competitive arrangement in that NEMMCO's intervention could substantially lessen competition in the market for generation. (Note: paragraph 3.4.3 of this Submission explains in detail the key concepts being discussed here.)

The requirement for NEMMCO to fulfil this role of contracting for reserves is seen as a transitional measure until confidence is gained in the ability of the market-based signals to deliver adequate system reserves and reduce the risk of involuntary load shedding.
NEMMCO reserve trading activity has a five year sunset clause.
NEMMCO's powers of direction include two provisions:

- as a last resort option if commercial reserve trading negotiations fails to address a projected lack of reserve condition, Clause 4.8.6 allows NEMMCO to intervene to direct Scheduled Generators or Market Customers to make plant available to address the lack of reserve problem;
- Clause 4.8 .10 which is also in the National Electricity Law (Section 76) provides NEMMCO with the powers of direction to maintain public safety and power system security.

NEMMCO's power to intervene in response to a projected lack of reserve condition is also a safety net provision in the Code. Like NEMMCO's reserve trading activity, this intervention power also has a 5 year sunset clause.

The reserve trading and intervention arrangements include Code provisions that require NEMMCO to operate within strict guidelines to minimise the distortion to the market by this intervention. For example:

- where NEMMCO indicates that a projected lack of reserve condition exists in the short or medium term PASA, NEMMCO may publish a declaration that it requires additional information (on plant status and planned outages) to assess the latest practicable time at which it would need to intervene. (Clause 3.14.2)
- the date of estimated market intervention is published by NEMMCO and NEMMCO is also required to publish a declaration that it has entered the market to negotiate reserve contracts. NEMMCO is not to enter into contracts with plant that has submitted dispatch offers or bids or is likely to submit them. (Clause 3.14.5(b))
- when plant under a NEMMCO reserve contract is dispatched or a direction is issued, NEMMCO is obligated to determine spot prices at a value which NEMMCO considers would have applied if the reserve plant had not been dispatched or the direction had not been issued. These trading intervals are to be known as intervention price intervals (Clause 3.9.3)
- NEMMCO is also obligated to compensate any Scheduled Generator or Market Customers during intervention price intervals based on a determination made by an independent expert appointed by NEMMCO. (Clause 3.14.11)
- NEMMCO is to intervene in a manner that minimises total costs to customers according to guidelines developed by the Reliability Panel. (Clause 3.14.11)

The effect of reserve trading on generation is multi-faceted. NEMMCO must ensure contracts with generators and interruptible loads are in place to deliver appropriate reserves. To the extent that capacity has been contracted with NEMMCO for reserves it is not available to be bid into the market in the normal course. This should not be a significant problem in the short term, given the excess capacity that exists in Victoria and NSW, and given that the State systems that the NEM will replace have reserve levels built into their planning and operation. If there is a medium or longer term problem with reserves and the effect they might have on generation capacity for trading in the pool, then PASA and other information made available to the market will serve as a signal for new investment.

Given the immaturity of the market in its initial years, this transitional safety net feature is regarded as being in the public interest to avoid the potential risk of market failure and involuntary shedding. Hence the arrangements for facilitated delivery of such services by NEMMCO on a last resort basis provide public benefits which exceed any detrimental effects which might accrue to some Market Participants. Customer confidence in the market will be weakened if involuntary load shedding occurs because of a lack of reserves and if NEMMCO did not act to prevent it.

It is important that NEMMCO's intervention power in clause 4.8.6 to "keep the lights on" be recognised as a last resort and transitional power only. Otherwise it will threaten the long term effectiveness of the market. If Market Participants come to think that NEMMCO has an obligation to supply (which it does not under the National Electricity

Law or the Code) and that each of them will pay some share of the costs of NEMMCO provided reserve capacity no matter what they do to individually to protect themselves, they will stop acting for themselves; the market will collapse, and NEMMCO (or some other agency) will have to step in to re-establish a monopoly with an obligation to supply. The Code recognises this complex problem and deals with it by establishing the Reliability Panel to operate independently of NEMMCO to determine the power system security and reliability standards and the criteria for intervention by NEMMCO. These standards are to be subject to a public consultation process administered by the Reliability Panel.

Thus this role of NEMMCO is essentially a market based mechanism required to eliminate the prospect of a return to the command and direction approaches of the past vertically integrated monopolies. The benefit to the economy through continuous supply of quality electricity far outweigh any anti-competitive detriment which might be argued exists through NEMMCO's final intervention powers.

### 6.3.11 Information requirements (Clause 3.15, Chapters 4 and 5, Clause 8.6)

The Code regulates the sorts of information that must be made available by Code Participants, both to the public, and to other Code Participants, NEMMCO and NECA. These include requirements relating to:

- information published by NEMMCO, including $\left(\right.$ PASA $\left.^{31}\right)$, bid, price and quantity information and information required for system planning;
- information to be provided by generators;
- information to be provided by other Market Participants;
- information to be published by Network Service Providers;
- use of the information for market trading activities; and
- use of the information for operation of the system.

The information disclosure requirements defined in clause 3.15 , Chapters 4 and 5 , and clause 8.6 of the Code have been designed based on the following principles:

- information is only withheld if it is "confidential information" (such as commercially sensitive information);
- where necessary, "confidential information" is aggregated for publication;
- information disclosure supports the pursuit of market efficiency and is consistent with "light handed" regulation;
- information disclosure removes an advantage that most large market participants would otherwise enjoy over small market participants and increases the prospects of attracting new entrants to the market; and

[^18]- information disclosure empowers Market Participants to monitor market behaviour and thereby should assist in deterring gaming by Market Participants.

The table below summarises the major information disclosure provisions of clause 3.15 and provides further details on the rationale for providing the information. The information in clause 3.15 .4 is provided to Market Participants because they are participating in the market. Under clause 3.15 .9 of the Code, persons who are not Code Participants may obtain any market information NEMMCO is required to publish on a user pays basis.

| Information Disclosure | Rationale |
| :---: | :---: |
| 3.15.3 Standing data: <br> - list of Market Participants and NSPs <br> - registered bid and offer data plus technical data on shared transmission and distribution network impedances and operating procedures and practices for transmission or distribution networks <br> - details of exemptions from central dispatch or special generation or loads aggregation approved proposals <br> - annual update of intra-regional and distribution loss factors <br> - annual Statement of Opportunities | - provides new entrants with list of competitors <br> - improves transparency of Code Participants' actions and increases accountability to customers and generators <br> - improves market transparency <br> - provides important locational signals to new entrants <br> - provides important investment signals to both existing and new entrants |
| 3.15.4 Spot market <br> - weekly medium term PASA <br> - daily short term PASA <br> - daily pre-dispatch schedule and forecast spot prices for following day <br> - actual dispatch prices and regional reference prices <br> - advice to a generator and Network Service Provider when a generating unit has been constrained off in central dispatch <br> - daily details of final dispatch offers and bids and actual availabilities for generating units and loads for the previous trading day <br> - daily details of dispatched generation and loads by generating unit or load for the previous day <br> - daily any operational irregularities for the previous day | - assists Market Participant decentralised decision taking to balance supply and demand in response to forecast conditions and prices <br> - provides clearing prices to market <br> - enables generator and NSP to settle any compensation provisions in a contract between the parties <br> - improves market transparency and empowers Market Participants to monitor market behaviour |
| 3.15.5 Short term forward market <br> - details of STFM trading based on the form of the market (daily after trading is completed) | - all financial derivative or share markets provide basic trading results to participants to improve market efficiency by providing pricing signals |
| 3.15.6 Inter-regional market <br> - annual details of NEMMCO's activities in trading inter-regional hedge contracts | - all financial derivative or share markets provide basic trading results to participants to improve market efficiency by providing pricing signals <br> - provides accountability for NEMMCO's activities |
| 3.15.7 Ancillary services contracting by NEMMCO <br> - annual details of the costs incurred in contracting for ancillary services as well as an aggregate summary of the services purchased in the previous year and planned purchases for the following year | - provides accountability for NEMMCO's activities to Market Participants |
| 3.15.8 Reserve trading by NEMMCO <br> - a report to Market Participants when NEMMCO's reserve plant is dispatched as soon as practicable thereafter <br> - annual details of NEMMCO's reserve trading activity | - improves market transparency and NEMMCO's accountability |
| 3.15.9 Public information <br> - daily information to the public on spot prices, power system load by region, inter-regional power flows, any network constraints and STFM trading results <br> - annual Statement of Opportunities (at cost) <br> - any market information NEMMCO is required to publish is available to the public on a fee basis | - improves market transparency and NEMMCO's accountability |
| 3.15.10 Market audit <br> - annual audit report of NEMMCO's market operations provided to Market Participants on request | - improves market transparency and NEMMCO's accountability |

The ACCC has expressed reservations about the extent of the release of market information to participants with a particular concern about the potential for the publication of individual price and quantity bid information to assist in tacit collusion between competing generators. As a general principle it is submitted that all information regarding the spot market should be available to those within and outside the market unless the release of such data would be prejudicial to one party or sector within the market.

The main reasons clause 3.15 .4 of the Code provides the release of details of final dispatch offers and dispatch bids, actual availabilities and dispatched levels of generating units and scheduled loads for the previous day are set out below.

Market efficiency will require a high level of information. In the spot market, prices will be primarily determined by the interaction of generator bids, the scheduling program, the level and profile of demand, plant availability, demand side bidding and any physical limitations on the system. Spot prices will be volatile and Market Participants will hedge the risks associated with wide price variations in a number of secondary markets. In these markets, risk premiums will be passed on to each party according to their willingness to take risk and according to their perceptions of future spot market and contract prices. Any asymmetry of data provision between contracting parties is likely to advantage one side against the other. In a market where customers are primarily price takers in the spot market it is important that they can understand the way in which prices are set in the spot market, and analyse the drivers of spot market price. If they are unable to do this they may well end up paying higher risk premiums or option prices for contracts or may be led to enter contracts with a strike price higher than might otherwise be the case.

When market power is an issue, new entrants will be deterred if they are unable to assess the risks associated with market entry. For example, a new entrant in retailing would want to understand all the drivers of spot price, and in particular the way in which generators can affect price. This assessment would be impaired by not releasing data on generators bidding, or by ignorance of what generation was capable of competing. This point relates both to the PASA data, and other market information. An example of the information required to properly analyse spot prices based on the NSW State Market is given in Schedule 13.

In relation to bid information, if denied reasonable access to this information after dispatch, retailers will be unable to construct a bid price function and therefore will be unable to model the relationship between load and price. This will significantly increase risk and will result in the retailers effectively operating blindly in the market.

It is also submitted that most existing industry participants are already aware of the current long run and short run generation costs by type of technology. This knowledge already provides an opportunity for tacit collusion between generators whether or not bids are published. This being the case, it can be argued that the publication of bids is one of the major checks available to retailers and customers to detect potentially anti-competitive behaviour by generators.

In their report, ECC Consultants made the following comments regarding the impact of market information on the transparency and auditability of the spot market:
> "The Code (version 0.9 of Chapter 3) does not indicate the disclosure of the actual $M W h$ output of individual units (or notional units) for each $1 / 2$ hour
trading period. We would expect at least some participants to request such data and we support the disclosure of such data to create a level playing field for all participants. If such data is not disclosed to all participants, it can still be fairly accurately estimated given the final offer/re-offer and bid/re-bid data, but only the larger participants will have the resources to develop such estimates.

We support the current information disclosure requirements of the Code as far as they go and would recommend expansion to include actual unit or notional unit outputs. In general, we believe that all information should be disclosed unless it can be shown that the disclosure of such information can have a significant detrimental impact on an individual participant or which will negatively impact the development of a truly competitive market. ${ }^{132}$

The difficulties and economic penalties for the whole market if generators are denied bid information have already been described to the ACCC in the course of the NSWEM authorisation application. ${ }^{33}$ Those considerations apply equally to the NEM. When a generator considers taking plant out of service for maintenance, it must manage a range of risks, having regard to its contract situation. Sufficiently reliable information on what is likely to occur in the market is needed by the generator. Even with information on expected system reserves, expected plant movements, historical price information and expected available generation, there will still be a significant level of uncertainty and hence risk for generators. Generators, in the absence of sufficient information, would have to adopt strategies such as:

- carrying unnecessary spinning reserve which, in turn, will decrease the efficiency of operation of the total system and increase overall costs;
- pass on to customers the costs of increased risk; and
- put in place insurance schemes, again at industry and customer expense.

Gaming is less likely if the behaviour of Market Participants is open to scrutiny. Detection of behaviour such as gaming or collusion will be increased through greater transparency and this leads to:

- peer pressure to desist;
- reporting to regulatory authorities to take any appropriate action;
- wider public pressure to desist; and
- other participants retaliating, perhaps by replicating the behaviour and eroding the advantage gained.

The disclosure and publication arrangements in the NEM build on the England and Wales experience. In Schedule 14 of the Submission, a report prepared by St. Clements Services

[^19]entitled Electricity Market Transparency discusses the benefits to market efficiency of information disclosure in the UK market. The St. Clements Services report states that in the UK market:
> "In most cases, the actual market abuse was detected by market players who were able to identify the abuser from the data available in the market" ${ }^{34}$

The St Clements Services' specific example cited in the case study is the reduction in market abuse for generators gaming under generation payments under the pool rules.

The report also cites the following benefits from disclosure of all data and information having a direct bearing on pool payments and pool prices including:

- allows more comprehensive price analysis;
- allows more rational behaviour by market players;
- reveals the ability to set price of key market players;
- in the longer term allows new entrants to make more informed and, hence rational, decisions and reduces barriers to entry;
- is useful to new generator entrants in their comprehension of the market; and
- is useful for both generators and retailers in understanding the operation of a complex competitive market.

St Clements Services also state that it is preferable for markets to be designed such that they do not require a large degree of regulatory control. This will reduce the uncertainty of regulatory intervention; thereby encouraging new entrants. St Clements Services further state that risk of collusion between existing participants can deter new entrants and increase regulatory uncertainty. However in a transparent market such collusion can be detected by both existing and new entrants who are able to highlight such collusion and bring it to the attention of the regulator. St Clements Services concludes by stating that market transparency through maximum information disclosure allows market players to improve market efficiency by reducing market abuse, enhancing market comprehension, and delivering self regulation.

Schedule 15 cites further evidence from the US on the importance of information disclosure in the "NASDAQ" case. NASDAQ is one of the three major stockmarkets in the US and is best known for its listings of speculative, technology, and computer stocks. In May, 1994 two academics undertook a study which suggested that dealers on the NASDAQ were colluding to maintain artificially high spreads on the shares they traded. The study was conducted using publicly available information about the market. As a result of the study, investigations were instituted by the US Department of Justice and the SEC. The SEC estimated that investors in NASDAQ stocks had lost millions of dollars in recent years as a result of price fixing. The NASDAQ case offers further evidence of the benefit of substantial disclosure of bidding and transaction information in detecting

[^20]patterns of conduct that are inimical to competition, and adding the resources of vigilant third parties in this regard to those of the regulator. (This case study also reinforces the importance of clause 3.15 .9 in providing information to non-Code Participants for academic research or to assess opportunities for new entrants.)
In addition to bidding and dispatch information, disclosure of information from generators and other Market Participants and from Network Service Providers on network constraints and operating circumstances as provided for in clause 3.15 .4 of the Code is necessary to enable NEMMCO to make timely and informed decisions about dispatch, reserves, load shedding and other system security and operational matters. There is a clear public benefit in enabling NEMMCO to do this. There is a further public benefit in ensuring that such information is available to participants and other interested parties in sufficient detail and good time to enable efficient market responses. An informed market will be able to function effectively and efficiently in clearing short term constraints in ways best calculated to serve customer and end user interests. For example, information about nonavailability of specific generation plant because of maintenance requirements will provide the market with signals to encourage increased output from other generating plant. It may also signal opportunities for increases in prices bid, and, at the same time, encourage demand side initiative to reduce load.

This Submission has already dealt with PASA and other system planning information at paragraph 6.3.5 above. Each of the other issues raised by the ACCC is covered below -

- Necessity and Public Benefit: The information requirements set out in the Code are based on the assessment of reasonable necessity derived from the experience gained in other electricity markets, including the England and Wales Pool, and, particularly, the Victorian Pool. In relation to the England and Wales pool in 1993, OFFER said:-
"As with my previous Reviews, it has not proved at all straight-forward to trace the causes of the Pool price changes which are the subject of this Statement. This complexity and lack of transparency makes it difficult to identify which of the causes are a matter of concern, and where remedial action is appropriate. It also engenders suspicion, and discourages new participants from entering the market.
"It is important that market participants and other interested parties have as much information available to them as possible to enable them better to understand and analyse the Pool. I have consistently pressed the Pool to make information widely available. To some extent the Pool has responded. Most price information that is made available to all Pool members is now made available publicly.
"However, there is additional relevant information which is not presently made available to Pool members or publicly. NGC Pumped Storage Business said that the 'commercially confidential' classification of some data submitted by generators in their daily offer makes it almost impossible for individual Pool members properly to understand the interactions that lead to the setting of Pool prices." ${ }^{35}$
- Technology Acquisition Costs: The costs of acquiring technology needed to process and supply information to NEMMCO are relatively insignificant

[^21]compared to the costs required to participate as a Market Generator or as a Market Customer, and are not of an order likely to have any effect on limiting competition or new entry.

- Lower Cost Alternatives: The Applicants are not aware of lower cost alternatives which provide similar or equal functionality. NEMMCO is charged with the responsibility of ensuring, on an on-going basis, that the processes supporting the market and its operation are effective and efficient. This authority will enable NEMMCO to take advantage of new developments and innovation in future that might reduce market transaction costs and improve efficiency. Insofar as any part of the Code might become a constraint, this can be readily dealt with through the Code Change procedures.
- Flexibility in Technological Requirements: It is submitted that market participation would not be assisted by flexibility in the technological requirements for information collection and transfer as this will increase the cost of information systems and data communications to support the market. In addition, these costs are unlikely to be significant or a barrier to market entry.
- Adequacy of Information Availability: It is submitted that the measures proposed in the Code for making information available are adequate.
- Effect of Aggregation and Detail on Competition: The detail of information that is to be made available is extensive. This level of detail will enable customers intending to enter the market directly to have access to substantial information about generators and their market behaviour to determine how they might wish to contract and with whom for the supply of electricity. On the supply side, the level of detailed information will provide the fullest disclosure of information available to enable sensible decisions to be made about investment, refurbishment and maintenance. The relative certainty of the basis for these investment decisions, which relate to substantial capital invested over the long term, will improve the efficiency of the market and lower the costs of risk that will be passed on to shareholders and customers.

In conclusion, it is submitted that the collection and flow of information set out in the Code encourages competitive pressures in the trading of electricity, and promotes efficient investment decisions and system security. It is also submitted that the collection of the information set out in the Code is required to enable NEMMCO to make appropriate decisions in relation to the operation of the market and the system, and that publication will ensure the integrity of the processes so served. It also addresses the information asymmetry that would otherwise advantage some participants to the detriment of others.

As well, the timing of the publication is critical to minimising any risk of collusive behaviour. Of most importance in this context is the publication of final dispatch offers and loads for the previous day. As such this information cannot be used in rebidding or availability adjustment. This tends to limit the adverse effects of any misuse of market information while at the same time ensuring customers are fully informed. Consequently the overriding benefit is to have a well informed market where no individual player can extract benefits at the expense of others because of information asymmetry.

### 6.3.12 Force Majeure and Market Suspension (Clause 3.16)

Clause 3.16 empowers NEMMCO to intervene in the market to either invoke an administered price cap or suspend the market. Such arrangements may be regarded as price fixing provisions.

Under clause 3.16 .2 of the Code, NECA is to develop and publish a schedule to define force majeure and material force majeure events which, if not rectified within 24 hours, would cause NEMMCO to invoke an administered price cap in the affected region(s). It is also the responsibility of NECA to establish a schedule of price caps for each region.

Under clause 3.16.4, NEMMCO may declare the spot market to be suspended in a region when:

- the power system has collapsed to a "system black";
- a Government has invoked its emergency services legislation and instructed NEMMCO to suspend or operate the market in a manner contrary to the dispatch process set out in the Code; or
- the NEMMCO Board considers that it is has become impossible to operate the spot market in accordance with the provisions of the Code.

If the circumstances set out above occur in a region or regions, NEMMCO may suspend the market. In all cases the market shall, as far as possible continue to be operated in accordance with the normal PASA and dispatch procedures, or the most recent predispatch schedule if it is still valid, with prices set accordingly - subject to the administered price cap.

If in NEMMCO's opinion it is not possible to follow the normal dispatch/pricing process and there is no valid pre-dispatch schedule, then the administered price cap shall apply. If the price cap is reached in any region then prices in all other regions connected to that region via unconstrained interconnectors shall be determined relative to that region by the application of loss factors based on the actual flows.

If this approach leads to generators being dispatched at a price below its bid or offer price then those generators may claim compensation up to a limit determined by the difference in the administered price and the price in the generator's dispatch offer. Under clause 3.16.6 of the Code, such claims are to be processed and determined by NECA's Dispute Resolution Panel. The compensation payments are to be funded through a uniform levy on Customers in the affected regions.

Under the above arrangements, there is a need to link prices between interconnected regions if the market is suspended or an administered price cap invoked in one or more regions. Without this, NEMMCO could become exposed to price differences where flows are from a region operating normally but at a high price to a suspended region with a lower price cap in place. Thus, while the market may only be effectively suspended in one region, the price impacts may flow across the entire interconnected system.

The application of an administered price cap under market suspension or for certain defined material and sustained force majeure events is viewed as being essential for

Market Participants to manage their contract risks, at least until the market evolves sufficiently for alternative commercial risk management strategies to be developed. Alternative individual-by-individual contracts would impose high transactions costs on the market and is unlikely to lead to a significant level of coordination to result in a smoothly operating response to force majeure events.

The above arrangements are in the public interest because they provide an auditable process by which NEMMCO, NECA, and participating jurisdictions are to be held accountable for market intervention. Such intervention should only occur when the power system cannot be operated under the market rules to maintain power system security. In this context, it is important to note the recommendation made by William M. Mercer and Clayton Utz in their mega-brief consultancy report, Market Suspension Criteria and Pricing:
> "In summary, it is suggested that a clear approach to market suspension be set out in the Code of Conduct which is co-ordinated by NEMMCO. Given the extremely limited circumstances in which market suspension is likely to occur, a highly pragmatic approach is suggested. More sophisticated approaches could be adopted but the added complexity does not seem warranted at this time."36

### 6.3.13 Costs on participants of complying with NEMMCO directions (Clause 4.3.4 and 4.8)

Clause 4.3.4 and 4.8 of the Code contains provisions requiring participants to comply with directions of NEMMCO or to assist NEMMCO in fulfilling its responsibilities under the Code, particularly with respect to system security and frequency control, without providing for such participants to recover costs incurred in so acting except as provided for in clause 3.14 of the Code for Scheduled Generators or Market Customers.

Such provisions could be considered to be anti-competitive to the extent that the increased cost of participation in the NEM creates a barrier to entry.

Without provisions for ensuring system security, and the reliability of the system within operational constraints, there can be no electric power system of the type on which consumers and participants have traditionally relied. System security arrangements in the hands of a nominated agency are therefore a practical necessity. Such arrangements involve costs that, as in any other market, must be recovered from the Market Participants, and, through them, from the end use consumers. The issue, then, is not whether costs are recoverable from participants, but whether they are recovered in a fair, equitable and transparent manner having regard to objectively determined and relevant criteria.

It is possible that, in complying with NEMMCO directions, a participant may not be compensated either at all or fully for the costs incurred in compliance with the directions. In deciding whether to become a registered participant any person will need to assess these and other risks of being in the electricity supply industry and take appropriate measures to reduce the risk of unacceptable levels of financial exposure. Such measures can include hedging within the market and insurance outside it. It needs to be recognised that the wholesale electricity market described by the Code involves substantial players, rather than involuntary end consumers without resources or knowledge.

[^22]
### 6.3.14 Interruptible load requirements (Clause 4.8.9)

Clause 4.8.9 of the Code provides that a region must provide interruptible load to a specified level before they are able to accept a lower level of security for part of the power system. As such, this clause may be held to be a provision substantially lessening competition if the costs it imposes on participants create a barrier to entry to the NEM.

In the arrangements set out in clause 4.8.9, a participating jurisdiction acting on behalf of its customers or a group of Code participants in a geographic area may elect to accept a lower standard of reliability than other electricity consumers. This arrangement would be established in the power system security and reliability standards set by the Reliability Panel. In this situation, when there is shortage of supply, these customers will automatically be shed first in response to contingency events on the power system to maintain a satisfactory operating state. Through this arrangement, customers are being given a choice to forego electricity consumption to reduce their contribution to payment for reserve plant in the system.

The power system security and reliability standards which will govern the market will be determined by the Reliability Panel. Because of the "common good" nature of system security and reliability, and the consequent capacity for Market Participants to adopt a "free ride" approach, unstructured competitive processes are unlikely to provide an adequate level of system security and reliability. Consequently the participating jurisdictions have established processes in the Code to determine the reliability standards for the power system as a matter of public policy.

The balance is thus between the public benefit of system security and the constraints on individual action which the reliability standards impose. It is submitted that the broader benefits to the market as a whole and through it to all end use customers warrants the central determination of reliability standards by the Reliability Panel.

### 6.3.15 Technical standards in the Code (Chapters 4 and 5)

The Code prescribes minimum technical standards for equipment connected to the system. The effect on competition in the market may vary depending on whether the standards apply to:

| - | generators; |
| :--- | :--- |
| - | transmission networks; |
| - $\quad$ distribution networks; and |  |
| - $\quad$ customers. |  |

These arrangements may be considered to be:

- exclusionary provisions, as competing participants agree not to trade with other persons except where they satisfy the technical requirements;
- exclusive dealing provisions as each participant only deals with others involved in NEM where they satisfy such requirements; and
- provisions substantially lessening competition, if they create barriers to entry to the NEM.

The specification of technical standards for equipment connected to the network has been designed to ensure that from a participant's perspective a clear and unambiguous framework is established within which they can negotiate with Network Service Providers on the terms and conditions for a connection facility and at the same time ensure the integrity of the network to provide the quality of service required by other users.

Schedule 5.1 of the Code has been defined to establish the performance standards to be maintained by the power system when Network Service Providers design connection facilities for customers and generators. These performance standards are also to be maintained by the Network Service Providers as they design augmentations to the transmission and distribution networks to service an increase in customer loads or new generation plant.

In a similar manner the conditions for connection for generators in Schedule 5.2 and for customers in Schedule 5.3 reflect the unique physical differences involved in supplying electricity to a network and consuming electricity from a network.

It is important to note that the conditions for connection for a generator have been specified in a manner to remove any bias against altemative generation technology provided that the alternative is safe for public use.

As stated in paragraph 3.4.7, NEMMCO, the System Operators, and Network Service Providers have a joint technical responsibility to ensure that the power system, as it grows in capacity and expands geographically, maintains the standards of service specified in Schedule 5.1 and in the definition of satisfactory operating state defined in Chapter 4 of the Code.

These technical standards, despite their different impacts on suppliers and customers operate in the public interest because without them the power system will not operate safely to convey electricity to customers to an acceptable technical quality of supply. These standards are similar in their economic effect as those applied to many markets. The standards help establish a degree of confidence in the quality of the commodity and in so doing reduce the transaction costs of supplying and purchasing electricity both at the wholesale and retail level.

It is submitted that because the standards apply uniformly throughout the NEM they do not discriminate against, nor do they present a barrier to entry for any participant. In addition, where these standards may be considered to represent a barrier to entry there are adequate dispute resolution procedures involving either NECA or a jurisdictional regulator as appropriate to resolve the matter. Clause 8.4 of the Code describes the process for a party to seek a derogation from the Code.

Not all existing facilities connected to the networks in participating jurisdictions comply with minimum technical standards in Chapter 5 . These differences arise because:

- technology and technical standards have changed over 40 years;
- it has not made commercial sense for an existing facility to upgrade its facility when the current facility is not compromising the quality of electricity received by other users.

The public interest of customers and generators would not be served by an arbitrary requirement to upgrade existing facilities to new technical standards when there is no appropriate financial incentive to do so. Specific examples of these derogations are identified in Chapter 9 of the Code.

However clause 5.2 of Chapter 5 does provide that when an existing facility is not compliant with the minimum standards for connection and there is measurable impact on the quality of service received by other network users, then regardless of any prior connection agreement, the owner of the existing facility is obligated to enter into negotiations with Network Service Provider to whom they are connected to correct the problem. It is submitted that the benefits from enforcing an upgrade to comply with the Code in extending the quality of the service of the electricity system to a wider range of users exceeds any negative impact on the individual firm which might be required to upgrade its facilities to conform with the Code.

### 6.3.16 Access undertakings (Chapter 5)

As part of the registration requirements, clauses 2.6(b) and 5.2.3 require all Network Service Providers to give an access undertaking for their network services in accordance with the terms of Schedule 5.8 of chapter 5. In essence, the National Electricity Law requires all those who control, own or operate interconnected electricity networks to register with NEMMCO, unless exempted by NEMMCO from that requirement. This is intended to enable all such Network Service Providers to be bound to the terms of the Code and, in particular, its access provisions. It also ensures that consistent with the submission of the relevant portions of the Code as an industry access code under the Act, Network Service Providers must also give an undertaking with the ACCC to comply with that code.

It is recognised, however, that not all those who might provide network services should be compelled to register with NEMMCO and hence observe the Code. There are likely to be a variety of appropriate exemptions for which NEMMCO will need to produce guidelines and they are likely to cover such things as small electricity distribution arrangements of a kind which already attract exemption from State based regulatory arrangements.

It is submitted that there is a public benefit from all providers of network services being covered by a common access undertaking, although the terms and conditions incorporated into the undertaking which is given may vary, depending on applicable jurisdictional arrangements. Nevertheless, because the interconnected network can be considered as a "single" national grid, irrespective of the ownership of individual network assets, there are advantages to those seeking access to face a common access arrangement. The advantages of this include the promotion of locational decision making on factors which reflect the true costs of connection. This helps minimise the aggregate costs to end-users operating across a number of jurisdictions.

It is submitted that the public benefit of a national access regime covering the national grid outweigh any possible detriment caused by the imposition of standards for access and the reduction in flexibility that any individual Network Service Provider might desire to
exercise. That said it must be borne in mind that there is no restriction on the ability of Network Service Providers to increase the quality of service or reduce the network costs it imposes on its customers.

### 6.3.17 Compliance with the Code to establish a connection to a network (Clause 5.3.7)

Clause 5.3.7 provides that a Connection Applicant who wishes to accept an offer to connect made by a Network Service Provider must agree to be bound by the relevant provisions of the Code. Such a provision could be considered to have the purpose or effect of lessening competition.

Parties seeking access to a network are required to be bound by the relevant provisions of the Code because the Code provides the framework for ensuring the safe and reliable operation of a network to convey electricity. Clause 5.2.1 states that all parties, including Network Service Providers, Generators, and Customers must maintain and operate all equipment that is part of their facilities in accordance with the Code, applicable regulatory instruments, good electricity industry practice, and applicable Australian Standards. It is submitted that there is a public benefit from having all parties, including parties seeking access to a network, agree to comply with a Code which provides the framework for the safe and reliable operation of the power system.

That said it must be borne in mind that clause 5.3.7 imposes no restriction on the ability of Network Service Providers to increase the quality of service or reduce the network costs it imposes on its customers.

### 6.3.18 Generator Access (Clause 5.5)

The provisions in Chapter 5 that relate to access arrangements for generators (clause 5.5) could be argued as providing an exclusive dealing arrangement, particularly as Network Service Providers are required to negotiate in good faith to provide compensation in the event that the Generator is constrained-off because the level of service and capability of the network is not consistent with the terms of the connection agreement. Similar compensation obligations are not imposed upon Network Service Providers by the Code with respect to customer connection or other Network Service Provider connection arrangements. However, the Code does not preclude such compensation arrangements being negotiated between Network Service Providers and customers and other Network Service Providers.

In the NEM, there will be a single spot price for each region. In the event that a transmission constraint occurs between the generator and the reference node within a region, a generator may be constrained-off. In other words, despite the fact that it makes a bid which would place it in the merit order, local transmission constraints prevent it being dispatched at the level of its bid, and a higher price generator not subject to the network constraint is dispatched in its place. Where the constrained-off generator has contracts for differences with customers in the energy market it will be exposed to financial losses for this event.

A major concern for generators arises from the possibility that such an outage could coincide with a high pool price incident in the energy sub-market. This would expose generators with contracts for differences in the energy sub-market with very high difference payments.

For example a 500 MW generator with a contract strike price of $\$ 50 / \mathrm{MWh}$ and with a pool price at $\$ 200 / \mathrm{MWh}$ would experience a revenue loss of around $\$ 100,000$ per hour of constrained-off operation. If the pool price was at VoLL, $(\$ 5,000 / \mathrm{MWh})$ the 500 MW generator could experience a revenue loss of some $\$ 2.5$ million per hour.

The compensation provisions in clause 5.5(f) are to enable the generator and the Network Service Provider to come to an appropriate risk sharing arrangements. In the example above, if the pool price is at $\$ 200 / \mathrm{MWh}$ the customer would receive a payment from the generator of some $\$ 75,000$ instead of paying a net amount of $\$ 25,000$ if it was not constrained-off, a benefit of $\$ 100,000$ per hour of constrained-off operation. In the event the price went to VoLL, the customer that is constrained-off would benefit by some $\$ 2.5$ million per hour.

Therefore compensatory arrangements applying to generators are neither necessary nor applicable to energy customers. It is submitted that this arrangement provides public benefit because energy customers and generators are provided with incentives to behave in an appropriate manner to maintain a secure power system at the same time as they are provided with economic signals to which they can each sensibly respond.

### 6.3.19 Augmentation and development of new transmission networks (clause 5.6)

Chapter 5 of the Code specifies the principles and procedures to be followed by Network Service Providers in planning and augmenting transmission networks. Augmentation may be required in response to a request for connection. It may also be required as a response to changes in long term load forecasts. These arrangements have been described in detail in Chapter 4 of the Submission. They are also assessed as part of the industry access code in Chapter 8 of the Submission.

Under Clause 5.6 of the Code, NEMMCO and an Inter-Regional Planning Committee is to review proposed augmentations to transmission networks whether they are justified according to a net customer benefit criterion. If the proposed augmentation is determined to be justified, then under clauses $5.6 .5(\mathrm{~m})$ and (o) NEMMCO may request a Network Service Provider to arrange for the augmentation to proceed, and the cost of the relevant assets are to be included in the determination of the revenue cap of the Transmission Network Owner in accordance with Part B of Chapter 6. These provisions may be considered to be anti-competitive arrangements under the Act.

It is submitted that the public benefits of these provisions outweigh any perceived detriment for the reasons set out below.

The Inter-Regional Planning Committee, comprised of NEMMCO, transmission system planners, and other experts nominated by NEMMCO, is being established to ensure that changes to transmission networks are coordinated to maintain the network performance standards specified in Schedule 5.1 of the Code. This cooperation between monopoly service providers is essential to properly plan and enable expansion of the power system's transmission networks to provide transmission services to new generators and customers seeking access. In the absence of a coordinated transmission planning process, the quality of supply to existing and new Network Users cannot be maintained.

It is also important to note that the planning reviews are conducted by the Inter-Regional Planning Committee via a public consultation process. Under the process, NEMMCO and
the Inter-Regional Planning Committee are obligated to publicly assess the technical and economic effects of the proposal using the primary criterion of maximising net benefits to customers. In assessing an augmentation proposal, the Inter-Regional Planning Committee is also obliged to consider the implementation of demand side measures or generation investments proposed by existing or intending Code Participants. NEMMCO's determination can be independent of the views of Inter-Regional Planning Committee members and any determination by NEMMCO may be reviewed by the National Electricity Tribunal if a party wants it reviewed.

The Code also does not provide NEMMCO with any authority to ensure that the proposed augmentation takes place.

The perceived detriment of these provisions is also minimal because there is nothing to stop a Network Service Provider speculating on an augmentation, by building it without reference to these provisions, and subjecting it to the tests of the Regulator.

It is submitted that these network planning arrangements provide a public benefit as they:

- provide for an objective review of the net benefit of the proposed investment to be undertaken by an independent party (NEMMCO and the Inter-Regional Planning Committee) which has no commercial interest in the outcome;
- provide for all parties affected by the proposed investment to have input into a comprehensive and transparent review process prior to any investment decision being made;
- provide for a further independent review by the National Electricity Tribunal of NEMMCO's determination if a party wishes the decision to be reviewed; and
- seek to ensure that where the Inter-Regional Planning Committee's process leads to a determination that the augmentation is of net benefit to customers, the Network Owner does not unduly bear risk associated with an investment made as a result of that process.

It has also been suggested that augmentations constructed pursuant to clause 5.6 and following should be subject to regulatory review despite the potential review role given to the National Electricity Tribunal. The Code essentially provides three ways in which network augmentation decisions are made:

- through contracts between users and network service providers. In this case the provisions of the contract, and the sharing of risk implied by the contract, should apply. Regulatory review should not redistribute agreed risk sharing by the contracting parties;
- through investments made by the Network Service Provider on their own assessment. The Code provides for these to be subject to regulatory review, using deprival value as the preferred asset valuation approach. In this case the network owner takes the decision to invest, and therefore appropriately bears the risk of stranded assets; and
- through investments which are approved by the Inter-Regional Planning Committee. This approach uses net customer benefit as the primary criterion by which to judge potential investment in the network. In essence, it creates a contract between customers as a whole and the network owner, and in these circumstances it is not appropriate that the network owner, who has not taken full responsibility for the investment decision, should be exposed to the full risk of stranded assets.

It is recognised that efficiency incorporates the efficient use of the existing network. However, it must be recognised that dynamically efficient investment in the network will not occur if investors are faced with excessive regulatory risk, or will only occur if high returns are available to compensate for the risk.

It is submitted that the Code effectively balances the interests of different parties in its treatment of network augmentation. It recognises the economies of central information collection and network planning, and attributes the risk of stranded assets to those parties who make the investment decision (or, in the case of customers as a whole, on whose behalf the decision is made). The proposed national approach to transmission planning via NEMMCO will help to ensure that access to both upstream and downstream markets via transmission networks is assessed consistently from a national rather than a regional perspective.

### 6.3.20 Maximum charges and pricing rules (Chapter 6)

Parts B, C, D and E of Chapter 6 of the Code contain provisions for fixing and allocating maximum and minimum charges for network services. Such provisions might amount to:

- price fixing arrangements, in that participants are operating in accordance with an understanding which fixes or maintains the prices for electricity and related services; or
- anti-competitive arrangements, to the extent that competition is reduced because of the level at which prices are fixed or maintained.

The terms and conditions for access to transmission and distribution network are determined on the basis of the industry access code to be approved by the ACCC. The public benefits case for the industry access code are discussed in Chapter 8 of this Submission.

### 6.3.21 Lack of price regulation for certain services (Chapter 6)

Chapter 6 of the Code provides for transmission and distribution services to be excluded from the regulatory cap arrangements where in the judgment of the appropriate regulator there is a reasonable expectation that those services can be provided on a contestable basis.(clause 6.2 .4 (f) specifies this exclusion for transmission services while clause 6.10.4 (b) relates to distribution services.)

However, these other services are not dealt with in any detail because the degree of contestability may vary by jurisdiction or within a jurisdiction from a practical point of view. Thus, there is full specification of the pricing regime that applies to certain services but little or no specification of the pricing regime that applies to other services which is at
the discretion of the appropriate regulator. The omission of these provisions might be held to be anti-competitive, to the extent that competition in the market for both the regulated and the unregulated service is lessened:

- by the duties and restrictions imposed in relation to certain services, leaving other services unregulated and, therefore, subjected to lower costs on the provision of those services; or
- by the need for parties to bring about changes to the Code before they may obtain the services which are not addressed by Chapter 6.

The terms and conditions for access to transmission and distribution network services are determined on the basis of the industry access code to be approved by the ACCC. The public interest case for the industry access code is discussed in Chapter 8 of this Submission.

### 6.3.22 Outsourcing by Network Service Provider (Chapter 6)

It has been commented that the incentive based revenue/price regulation regime set out in Parts B, C, D and E of Chapter 6 of the Code focuses on the case where the assets used to provide a particular network service are owned by the Network Service Provider, and that the Code contains no recognition that the Network Service Provider can outsource the provision of certain services which it then on-supplies. It has been further suggested that this constitutes an anti-competitive arrangement (section 45 of the Act) and an exclusionary provision.

There are many areas in which the Code specifies the obligations that participants undertake, and in most of these it is a matter for the participant to determine, within any constraints or guidelines inherent in the Code itself, how to discharge its obligations and conduct its business. The Code is not intended to be exhaustive on matters which are not material or relevant to the operation of the NEM. Whether a participant, such as a Network Service Provider, outsources or contracts out some functions is immaterial, provided the responsibility remains with the registered participant. For this reason no recognition about outsourcing and contracting out is needed in the Code.

### 6.3.23 Cross-subsidisation of services (Chapter 6)

Some provisions allow for the allocation of common costs for one type of service in such a way as may cross-subsidise the provision of another type of service. In particular, corporate and overhead costs are included as part of operating and maintenance costs in the determination of an annual revenue requirement for transmission network owners. It has been commented that there is potential, with excessive or even full allocation of common costs for prescribed services to cross subsidise the provision of non-prescribed services, and, further, that this could amount to:

- price fixing arrangements, in that participants are operating under an arrangement which has the effect of fixing or controlling the price for services; or
- anti-competitive arrangements to the extent that the cross-subsidy substantially lessens or prevents competition in the market for either type of service.

A similar issue exists in relation to Distribution Network Service Providers and their common and overhead costs.

The treatment of these costs and any potential cross subsidies is a matter for determination by the appropriate regulator as provided for in the industry access code to be approved by the ACCC. The public benefits case for the industry access code are discussed in Chapter 8 of this Submission. It should be noted that, in recognition of the complexity of this area and the rapid development of knowledge and experience throughout the world, these parts of the Code are subject to early review.

### 6.3.24 Allocation of Revenue Requirements to More than One Transmission Network Owner (Chapter 6)

The arrangements in clause 6.3.2(b) for the appointment of a coordinating Network Service Provider in a region served by more than one transmission network owner, and the allocation of the aggregate annual revenue requirements may be:

- price fixing arrangements; and
- anti-competitive arrangements.

The thrust of the determination of transmission revenue requirements in Chapter 6 is to establish suitable recompense for assets necessarily employed and for the recovery of fair operational and maintenance expenses while providing incentives for efficient investment and operation of the network. Consequently, if within a region there is more than one owner of transmission assets employed to provide network services, the revenue requirement for the whole region needs to be allocated in a transparent and agreed manner relative to the revenues involved.

There must be some doubt as to whether a fully transparent and clear arrangement for determining revenue requirements under these highly regulated circumstances could be considered to be a price fixing arrangement. The approval of an annual revenue requirement by an independent regulator and the further approval of the methods by which the annual revenue is allocated as costs to individual connection points or customers are required because of the natural monopoly characteristics of the networks. The very nature of the networks as natural monopolies, eliminates the prospect of competition as a benchmark for pricing and control of monopoly power.

### 6.3.25 Prudential requirements for network services (Clauses 6.6 and 6.15)

Clauses 6.6 and 6.15 of the Code set out the prudential requirements for network services that a Network Service Provider may impose on a generator or customer. These provisions might constitute:

- exclusionary provisions, in that parties will not receive network services unless they satisfy the prudential requirements;
- exclusive dealing provisions, as each participant trades on condition that they will not supply electricity to or acquire electricity from any person who does not satisfy such requirements; or
- provisions substantially lessening competition, if they create a barrier to entry to the electricity market.

The requirement for prudential requirements is intended to allow the Network Service Provider to manage the financial risks associated in network assets for a party seeking connection. The Network Service Provider may require a generator or customer to make capital contributions, pre-payments, or financial guarantees for connection services and/or network services. The requirement for these and their treatment are negotiated between the parties and included in the connection agreement.

There are safeguards in the Code to prevent any double counting which might arise by including in the Network Service Provider's asset base the value of assets paid for by network users.

It is submitted that these provisions provide a public benefit because they protect the legitimate business interests and investments of the Network Service Provider. The interests of the party seeking access are protected by the right to dispute an offer which is not considered fair and reasonable and to seek to have the dispute resolved by the appropriate regulator.

### 6.3.26 Metering Standards (Chapter 7)

## (a) Compliance with metering installation standards

Clause 7.1.4 places an obligation on Market Participants to ensure that each of its market connection points has a metering installation that complies with the standards laid down in the Code and which is registered with NEMMCO. Participation in the market in respect of any connection point is dependent on such compliance, or on an exemption by NEMMCO from such compliance.

Requirements to install metering of a particular standard may be:

- exclusionary provisions, in that competitors agree not to purchase electricity from or sell electricity to a person unless they have such metering;
- exclusive dealing provisions, as participants trade on condition that one or both of them will not supply electricity to or acquire electricity from a person unless they obtain such metering; or
- provisions substantially lessening competition, if they create a barrier to entry to:
(a) the electricity market - in that Market Participants incur a cost in purchasing such metering; or
(b) the market for meters - in that those who supply meters of a lesser standard are excluded from supplying to wholesale electricity Market Participants.

An electricity supply market requires reliable metering to determine usage and to serve as a basis for financial settlement and management of both usage and
delivery by customers and other Market Participants. The central role that metering has in the operation of the market means that it must meet recognised standards upon which all participants can rely. The standards in the Code document those requirements in a transparent and unambiguous manner. Otherwise, confidence in the market would be undermined and the performance of the financial settlement system subject to doubt. It is submitted that any possible detriment to the public from the requirements to comply with the standards for metering in the Code is minimal. In particular, the benefit from the development and operation of the NEM which requires confidence in the metered information far outweighs any perceived detriment to the public from a requirement to meet the metering standards of the Code.

## (b) Standards for revenue and check metering installations

Clause 7.2.5(a) places an obligation on the nominated responsible person for each connection point to ensure that revenue metering installations and check metering installations are provided and installed in accordance with the standards set out in Schedule 7.2 of the Code. As with clause 7.1.4 above, this provision could be regarded as being:

- an exclusionary provision;
- an anti-competitive arrangement; and
- exclusive dealing.

The public benefit argument set out in relation to clause 7.1 .4 also applies here, namely that the integrity of the metering arrangements are so critical to the operation of the market, that they must be specified sufficiently to enable all Market Participants to justifiably rely upon them. It makes little sense to set out standards and attendant obligations without also nominating a person who is responsible for discharging those obligations in respect of each connection point.

## (c) Components in metering installations

The components and requirements of a metering system, as specified in clause 7.3.1, might be considered to be:

- exclusionary provisions, in that when combined with other Code provisions including clause 7.1.4, competitors agree not to purchase electricity from or sell electricity to a person unless they have such metering installations;
- exclusive dealing provisions, as participants trade on condition that they will not supply electricity to, or acquire electricity from a person, unless they have such metering; and
- provisions substantially lessening competition to the extent they may create a barrier to entry to the NEM or the market for meters.

The public benefit in such a level of detailed prescription is that the industry's experience about the minimum working requirements in a metering system are set out in a clear and transparent manner, and there is nothing about the specification that could reasonably be regarded as discriminatory. All of the specifications are necessary for the proper functioning of a low cost, automated, modern metering system. These minimum standards contribute to the benefits expressed above on the requirements to comply with the standards on metering.

The metering installation provisions in the Code are intended to be technology neutral - this being a matter of considerable public benefit.
(d) Metering communication links

Clause 7.3.5 requires each metering installation to have an associated communications link which is connected to the public telecommunications network, together with a modem. As such, the provisions of clause 7.3.5 may be:

- exclusionary provisions;
- exclusive dealing provisions; or
- provisions that substantially lessen competition;
on the basis as described in paragraph (c) above.
As already noted, there is public benefit in having a viable market, and that must be a market served by a modern reliable and low cost metering system. Such a system needs to be accessible via telecommunications means for remote polling of metering data.
(e) Accuracy levels and time limits

The requirements in clause 7.11 on metering accuracy levels, and the time limits for rectifying a meter outage or malfunction may be considered to be anticompetitive, exclusionary or exclusive dealing for the reasons noted in paragraph (c) above.

In fact, given the design of the market, with determination of the spot price every 30 minutes, it will be necessary to poll the meters and to take readings every 30 minutes. The other standards in the clause reflect the collective experience of the industry on availability and repair times.

A cost benefit analysis of the accuracy requirements for metering installations specified in Schedule 7.2 of the Code was prepared by the NGMC and is provided in Schedule 16 of this Submission. This cost benefit analysis indicates that the accuracy of metering installations should be based on a minimum of "maximum allowable errors" which vary with loads having an annual energy throughput of:

- greater than $1,000 \mathrm{GWh}$;
- between 100 GWh and less than 1000 Gwh ; and
- less than 100 GWh .


## (f) Inspection and test requirements

The metering accuracy, inspection and test requirements set out in Schedule 7.3 reflect the collective wisdom and experience of the industry in relation to the technical issues involved.

### 6.3.27 Use of meters (Chapter 7)

Clause 7.3.1(d) contains provisions preventing metering installations from being used for purposes other than the metering of wholesale electricity supplies unless that further use does not interfere with the Code usage or infringe on the requirements of the Code. Such provisions may be considered as:

- exclusionary provisions, as competitors agree not to give access to meters to third parties;
- exclusive dealing provisions, as participants trade on condition that neither party will give access to meters to third persons; or
- provisions substantially lessening competition, to the extent that competition in markets which might use the metering installation is substantially reduced or prevented.

The use and reliability of metering installations is critical to the integrity of the NEM and in particular, to the settlement of payments for electricity trades through the NEM. Any use of meters for purposes other than the NEM may compromise the NEM arrangements. Accordingly, it is submitted that the Code requirement as to the use of metering provides a public benefit because it ensures that settlement of the spot market is to an agreed standard.

### 6.3.28 Licensed metering providers (Clause 7.4 and Schedule 7.4)

Clause 7.4 and Schedule 7.4 also contains provisions compelling parties to use only licensed metering providers, and, likewise, confining the extent to which persons may perform such metering work. Such provisions could be considered to be:

- exclusionary provisions, to the extent that competitors agree only to acquire metering services from particular persons;
- exclusive dealing provisions, to the extent that participants trade under the restriction that metering services only be acquired from licensed metering providers;
- third line forcing provisions (which is a form of exclusive dealing), in that generators supply electricity to retailers on condition that they then acquire metering services from particular persons, being metering providers licensed by NEMMCO; or
- provisions substantially lessening competition, to the extent that competition for metering services is substantially lessened or prevented.

Argument has already been advanced on the public benefit associated with reliable metering if the market is to function properly. The integrity of the metering system depends, amongst other things, on the reasonable quality of the persons who operate in the capacity of metering providers. The real issue is not whether it is acceptable to require metering providers to be registered and to be qualified, but whether the processes and standards involved are excessive in relation to the limitations that might exist from having no requirement for meter providers to be licensed. This Submission contends that they are not.

The public benefit in the market and the reliance on the integrity of the metering system requires that competent metering providers perform metering work appropriate to their qualifications. The categories of registration and the competency gradations associated with each reflect divisions that are meaningful and traditional within the industry. The Code is therefore attempting to reflect the industry's understanding of best practice, rather than to create new divisions and distinctions.

Rather than specify particular courses or qualifications that may be available from educational institutions, the Code sets out the knowledge and competency requirements that the industry considers should apply. This leaves it open for individuals to present to NECA evidence of new ways in which competency might be demonstrated, and increases the possibilities for entry of new providers into the industry.

### 6.3.29 Participant reporting requirements (Chapter 8)

Under clause 8.7.2(d), NECA may establish additional or more onerous reporting requirements and monitoring standards which do not apply to all Code Participants. Such provisions could be considered to be:

- exclusionary provisions, as competitors agree to supply to or purchase from such Code Participants only to the extent that they meet those standards or requirements;
- exclusive dealing provisions, to the extent that participants trade on condition that they will not supply electricity or other services to, or acquire electricity or other services from, Code Participants who do not meet those standards or requirements; or
- provisions substantially lessening competition, to the extent that:
(a) the additional cost of meeting the standards or requirements constitutes a barrier to entry into the NEM; or
(b) an uneven application of requirements or standards reduces competition in the NEM.

It is not the intention of the clause that NECA should exercise this discretion in any way which would give a competitive advantage to one party over another. The purpose of the clause is to enable NECA to take into account the various circumstances that might dictate a more rigid or onerous reporting arrangement for participants in one set of circumstances which would not apply to participants whose circumstances are different. The provision makes it clear that some judgment would be expected of NECA in determining special
reporting and monitoring arrangements without being required to apply the same arrangements universally to all participants with the general increase in overall industry compliance costs.

The public benefit in NECA having and exercising reasonable discretion in determining arrangements which do not have to apply universally to all Code Participants is in the containment of costs of Code participation.

### 6.4 Impact of the NEM on the Retail Market

While the primary focus of the Code is the NEM, it is also important to consider its impact on other markets, particularly the retail market in terms of any lessening of competition in those markets. In fact, the NEM will have a highly pro-competitive impact on the retail market.

Competition in the wholesale market is vital in order to derive the full gains which can flow from retail competition. Generation costs represent around $60 \%$ of total delivered costs. If there is no wholesale competition, retailers have far less opportunity to drive their costs down and gain a competitive advantage because they would all be sourcing their energy at the same price.

The NEM requires the unbundling of electricity supply into its component parts generation, network services and retail supply. This unbundling enables the introduction of competition at both the wholesale and retail level.

The access provisions of the Code facilitate competition in the retail electricity market by enabling trade in electricity across the transmission and distribution networks.

Retail competition is also enhanced by the capability of retailers to manage their risks through the financial sub-markets facilitated by the Code. Without the ability to effectively manage financial exposures many potential retailers (particularly small ones) would find the risks of retail market operations too great.

Similarly, the gains from wholesale competition will be enhanced with retail competition, as retailers who are operating competitively will have an incentive to seek out the lowest cost energy from the spot market or through power contracts. This is an improvement on the previous arrangements where there was little incentive to limit "pass through" of generator cost increases to captive, franchise customers.

### 6.5 Conclusion on the net public benefit

Chapter 5 noted that, first and foremost, the creation of the NEM introduces competition where there is currently no market, and net public benefits will result. Within the new competitive arrangements, some provisions of the Code may fall within Part IV of the Act. This Chapter has identified the more significant instances of potential anti-competitive arrangements and conduct embodied in the Code. This Chapter, however, has demonstrated that each such provision has been developed in recognition of its public benefits. Moreover, any perceived detriment which may result from these provisions is outweighed by the overall benefits which result from introducing a competitive NEM.

## 7. AUTHORISATION OF JURISDICTIONAL DEROGATIONS

### 7.1 Background and Purpose

### 7.1.1 Introduction

Chapter 9 of the Code sets out, for each participating jurisdiction (with the exception of Queensland), which parts of the first 9 Chapters will not apply with respect to Code Participants in their jurisdictions.

Most of these "derogations" are for the "transitional" period ending either on 1 July 1999 or 31 December 2000. When expiring at this time, their purpose is generally to avoid "price shocks" or similar market disturbances which might otherwise arise with the sudden application of the provisions of the Code.

These provisions are to be distinguished from individual derogations which may be sought by any Code Participant under the provisions of Chapter 8. The derogations in Chapter 9 are jurisdictional exemptions which apply to Code Participants because of exemptions specified by a jurisdiction, not by Code participants as such.

The provisions of Chapter 9 are not subject to the Code change process set out in Chapter 8. Additions to a Chapter 9 provision by a jurisdiction necessitate consultation with other jurisdictions but are otherwise subject only to approval by the ACCC.

### 7.1.2 Nature and Purpose of Chapter 9 Derogations

These derogations refer directly to other parts of the Code and create specific exemptions to those provisions for a jurisdiction.

Each of the participating jurisdictions--New South Wales, Victoria, South Australia and the ACT have included derogations of this type.

Queensland, while supporting the Code, is not yet in a position to document the extent to which it will apply the Code, at least for the transitional period to the end of the year 2000. Queensland is expected to be able to do so shortly.

The effect of a jurisdictional derogation from the Code is to change what would otherwise have been the outcome of the application of a particular Code provision to a Code Participant operating within the jurisdiction.

The derogations perform several functions which are largely common to the jurisdictions-:

- Local determination of transmission access arrangements and pricing: this is to recognise the transitional pricing and regulatory regime established as part of the reform and restructuring of the electricity supply industry ("ESI") in each participating jurisdiction. These arrangements provide continuity of the price arrangements for network owners and customers and certainty for the pricing arrangements established in each participating
jurisdiction. By 1 January 2001, all participating States and Territories will adopt the regulation and pricing principles of the Code and responsibility for regulation of transmission prices will have passed from the jurisdictional regulators to the ACCC.
- Local determination and application of distribution pricing until at least 1 July 1999: the same rationale applies as that for transmission pricing. By 1 January 2001, all jurisdictions will have adopted the regulation and pricing principles of the Code, however, jurisdictional regulators will continue to regulate distribution access and pricing.
- Local determination of intra-regional loss factors: the calculation of these amounts is integral to the determination of network prices and hence needs to be jurisdictionally based during the transition period (subject to NEMMCO determining these factors for those participating in the wholesale market).
- Jurisdictional regulators: Chapter 6 requires all jurisdictions to appoint their own jurisdictional regulator to administer distribution network pricing.
- Customer thresholds: the Code does not determine the eligibility of customers to trade in the wholesale market. These derogations describe how the jurisdictions determine who these customers are.
- Transitional metering provisions: these provide a transitional period for metering to reach the standards set by the Code.

The purpose of Chapter 9 is to define clearly which parts of the Code are not to apply and for how long this will continue. These arrangements need to be taken into consideration by the ACCC in considering authorisation of the Code and acceptance of its relevant provisions as an access undertaking because Chapter 9 is part of that Code and hence constitutes a description of the arrangements for which approval is being sought.

Chapter 9 derogations provide continuity and a transition for state arrangements and price determinations established before the national market; in some cases arrangements were determined well before details and impacts of the national Code were known. In providing a transitional period, the Chapter 9 derogations have regard to the legitimate business interests of providers who have given undertakings in regard to jurisdictional based arrangements where changes to those arrangements would have a significant and deleterious commercial impact. The interests of the public are served as jurisdictional arrangements provide a transition to the application of Code principles which otherwise may have a serious social and economic impact. The jurisdictional arrangements also provide certainty in relation to the pricing arrangements and undertakings of some governments established as part of the reform and restructuring of the ESI in each jurisdiction.

### 7.1.3 Derogations extending beyond the transitional period

Some of the exemptions sought by the jurisdictions apply beyond the transitional period identified in the COAG communiqué of February 1994.

In Victoria's case, a period ending on 31 December 2000 is generally required with respect to network pricing and access provisions in order to match the terms of the Victorian Tariff Order which currently govern the pricing and provisions of networks located within Victoria.

Victoria has specified in its derogations a variety of currently existing plant which, because of its age, is unable to match the recently formulated technical requirements of the Code. Like exemptions will be required by some of the other jurisdictions.

Victoria's Tariff Order makes specific provision for distribution pricing beyond the transitional period. Such arrangements address rural and urban network pricing and incentive-based regulation. Victoria's distribution companies were sold to private buyers on the basis of these provisions and require continuity of application for the determination of distribution pricing beyond the transitional period.

Victoria and New South Wales have long-term electricity supply arrangements that were well in place before the detailed proposals for the national market.

These arrangements must necessarily remain for the life of the contracts in which they are set out.

### 7.2 Jurisdictional Provisions

Set out below is an analysis of the specific derogations of each jurisdiction, including a description in terms of the public benefit arising from the derogation as against any perceived detriment in the context of the whole Code.

### 7.2.1 New South Wales

## (a) Introduction

New South Wales has included a number of derogations in Part B of Chapter 9 of the Code. The derogations are designed to accommodate the objectives and policies referred to in clause 9.10 of the Code. Broadly speaking the objectives of the arrangements reflected in the New South Wales derogations are to:

- regulate the categories of persons who are eligible to participate as customers in the national wholesale electricity market;
- preserve the rights and obligations of parties under existing power supply agreements until those agreements expire;
- provide for a continuation of current transmission network and distribution network pricing arrangements until those arrangements expire; and
- provide for a body nominated by the New South Wales Government (IPART) to determine any disputes relating to access, connection and use of transmission and distribution networks for periods corresponding to the New South Wales network pricing regulatory periods.

Set out below in paragraph 7.2.1(b) is an overview of the New South Wales derogations contained in Part B of Chapter 9 of the Code. In paragraph 7.2.1(c) there is an assessment of those New South Wales derogations that may breach the Act including details of the public benefits and any detriments associated with those provisions of the New South Wales derogations.
(b) Overview of the New South Wales Derogations

## Chapter 1 - Introduction and Code Supervision

There are no New South Wales derogations in respect of Chapter 1.

## Chapter 2 - Code Participants, Registration and Cross Border Networks

Clause 9.11.1 of the Code contains definitions for specified words and expressions used in the New South Wales derogations which are not defined in Chapter 10 of the Code.

Only holders of retail suppliers licences issued under the Electricity Supply Act 1995 (New South Wales) and persons declared by the New South Wales Minister for Energy under section 92 of the Electricity Supply Act 1995 (New South Wales) to be "non-franchise customers" will be eligible to register as "Customers" for the purposes of the Code (clause 9.12.1).

Clause 9.12.2(a) deems specified New South Wales generators to be "Market Customers" in relation to electricity supplied by those generators under certain specified long standing power supply agreements.

Paragraphs (b) and (d) of clause 9.12 .2 go on to provide that these generators will not be required to comply with a requirement of the Code if:

- complying with requirements under the Code would place the generator in breach of its power supply agreement; or
- if the generator requires the cooperation of the counterparty to the power supply agreement in order to comply with the relevant

Code requirement and the counterparty lawfully refuses to cooperate with the generator.

Paragraph (j) of clause 9.12 .2 provides, however, that paragraphs (b) and (d) do not affect the key obligations of these generators to make payments under the Code in respect of participant fees, prudential requirements or settlement amounts.

Under clause 9.12.3, where a transmission network or distribution network situated in New South Wales is considered to be a continuation of a network situated in another participating jurisdiction, then with the consent of the relevant Ministers, the network in New South Wales may be deemed to be entirely in the other participating jurisdiction in terms of regulation including any transitional arrangements of the other participating jurisdiction. The reverse also applies to networks in other participating jurisdictions that involve a continuation of a New South Wales network.

## Chapter 3 - Market Rules

A body nominated by the New South Wales Government or, if no such body is appointed, NEMMCO, will:

- until 30 June 1999, set all intra-regional loss factors to apply to Market Customers (but not generators or scheduled loads) in respect of electricity transmitted through transmission networks situated in New South Wales (clause 9.13.1); and
- until 31 December 2000, set all loss factors to apply to Market Customers (but not generators or scheduled loads) in respect of electricity distributed through distribution networks situated in New South Wales (clause 9.13.2).

Clauses 9.13.1(d) and 9.13.2(d) provide mechanisms by which:

- in the case of transmission loss factors set by New South Wales there should, in an aggregate sense, be an outcome that equates to that which would have applied if there were no derogations; and
- in the case of distribution loss factors either NECA or a Code Participant may request, if it considers that a factor set will have a material adverse effect on the operation of the market of a participating jurisdiction outside New South Wales, that the relevant New South Wales body give further consideration to the factor set by taking into account the material adverse effect and policy considerations for determining such factors otherwise than in accordance with clause 3.6.3.


## Chapter 4 -System Security

Clause 9.14.1 provides that the Network Operating Procedures (New South Wales) and the System Operating Procedures (New South Wales) developed and published by TransGrid under the New South Wales Wholesale Electricity Market Code will, with the necessary changes, be the regional specific operating procedures to apply in respect of operations of the network situated in New South Wales.

## Chapter 5 - Network Connection and Access Disputes

The New South Wales Independent Pricing and Regulatory Tribunal ("IPART") will be the body responsible for determining disputes, to the exclusion of the dispute resolution procedures set out in Chapter 8 of the Code, in relation to:

- access to;
- connection to;
- use of; or
- transmission network service pricing for,
the transmission network situated in New South Wales where the relevant dispute arises on or before 30 June 1999 (clause 9.15.1).

IPART will also be the body responsible for determining disputes, in relation to:

- access to;
- connection to;
- use of; or
- distribution network service pricing for,
distribution networks situated in New South Wales which, if the dispute arises before 31 December 2000 will involve the application of Part 4A of the IPART Act, whilst disputes thereafter will be governed by the dispute resolution mechanisms set out in Chapter 8 of the Code, but with IPART acting as the dispute resolution adviser and panel (clause 9.15.2).


## Chapter 6 - Network Pricing

IPART will, until 30 June 1999, regulate transmission network service pricing ("TNSP") for transmission networks situated in New South Wales under the provisions of IPART Determination No 2.1 of 1996. Thereafter, TNSP in New South Wales will be regulated by the ACCC under the provisions of Chapter 6 of the Code.

Distribution network service pricing ("DNSP") for distribution networks situated in New South Wales will be regulated by IPART until 31 December 2000 under the following regulatory arrangements:

- the IPART Act;
- IPART Determination No 2.2 of 1996; and
- any further Determination issued by IPART in respect of DNSP and covering the period following 30 June 1999.

From 1 January 2001 DNSP will be regulated by IPART as jurisdictional regulator for New South Wales under the provisions of Chapter 6 of the Code. As noted in clause 9.10.2(a) of the New South Wales Derogations, in principle, the New South Wales Government supports the national regulation of both distribution and transmission networks to commence from 1 July 1999, but has emphasised that a satisfactory regulatory framework should be agreed and put in place.

## Chapter 7 - Metering Code

There are no derogations for New South Wales in respect of metering other than those which will apply to all participating jurisdictions and which are set out in Schedule 9A of Chapter 9 of the Code.

## Chapter 8 - Administrative Functions

There are no derogations for New South Wales in respect of Chapter 8 other than those outlined above in respect of Chapter 5.

## Chapter 10 - Glossary

The definition of "Transmission Network" is to be replaced by the following definition:
"Any electricity power lines and associated equipment and electricity structures situated in New South Wales and declared by the Minister for Energy under section 93 of the ES Act to be a transmission system."
(c) Reasons for and Public Benefits of New South Wales Derogations

This section of the submission summarises the effect of each of the proposed New South Wales derogations and the reasons why the State of New South Wales Government has requested the relevant derogation.

## Public Benefit Argument

The effect of the derogations is to provide a transition from the current arrangements to the full competition which is the aim of the New South Wales Govermment. Any exclusionary provisions or lessening of
competition is relative to the end point of the transition. When viewed as a whole with other transitional arrangements, they represent an opening up of the market compared with current arrangements.

The arrangements proposed are necessary to ensure that there is a realistic, orderly transition to full competition. Phasing in of contestability allows the Government to target customer information and education programs to progressively larger groups of customers and provides retailers time to develop and refine their marketing systems and strategies. The derogations also recognise the sanctity of existing contractual arrangements which are to be preserved for the periods of those contracts. The derogations in New South Wales also allow for the progressive installation of new metering, data communications systems and other market infrastructure.

## New South Wales Customer Eligibility (9.12.1)

The Code contemplates that only a limited class of persons will be eligible to register as "Customers" under the Code (see clause 2.3.1(e)). In the case of New South Wales all licensed retailers will be entitled to be so registered and thereby be eligible to purchase electricity directly through the wholesale pool. In addition, over time (see the tables below) all New South Wales businesses and individual consumers will be eligible to purchase electricity either directly through the wholesale pool or from a retailer of choice. By limiting customer eligibility in this way it could be said that clause 9.12.1 comprises:

- exclusionary provisions, as competing participants have made an arrangement (as reflected in clause 9.12.1) whereby they agree not to trade with persons with connection points in New South Wales that are not eligible to be registered as customers;
- exclusive dealing provisions, as Code participants (including generators, NEMMCO and traders) agree to trade on condition that they will not supply electricity to New South Wales persons who are not entitled to be registered as customers; or
- provisions having the purpose or effect of substantially lessening competition - in the sense that only licensed retailers will be entitled to participate as retailers in New South Wales and in the sense that not all New South Wales customers will immediately be entitled to choose from whom they purchase electricity (either directly through the pool or from a non-local retailer).

TIMETABLE FOR CUSTOMERS BEING ABLE TO CHOOSE AN ELECTRICITY SUPPLIER

| Site threshold | Approximate <br> annual power <br> bill | Date of <br> eligibility | Number of <br> eligible <br> sites | Examples |
| :--- | :--- | :--- | :--- | :--- |
| $>40 \mathrm{GWhpa}$ | $>\$ 2,000,000$ | 1 October 1996 | 47 | Large metropolitan hospital <br> Heavy manufacturing plant |
| $>4 \mathrm{GWhpa}$ | $>\$ 250,000$ | 1 April 1997 | 660 | Multi-storey office block <br> Food processing plant <br> Supermarket |
| $>750 \mathrm{MWhpa}$ | $>\$ 75,000$ | 1 July 1997 | 3,500 | Engineering workshop <br> $>160 \mathrm{MWhpa}$ |
| $>\$ 16,000$ | 1 July 1998 | 10,800 | Fast food restaurant <br> Bakery |  |
| $<160 \mathrm{MWhpa}$ | $<\$ 16,000$ | 1 July 1999 | $2,700,000$ | Service station |

BREAKDOWN OF SITE NUMBERS BETWEEN METROPOLITAN AND RURAL DISTRIBUTORS

| Site Threshold | Number of sites |  |  |
| :--- | :--- | :--- | :---: |
|  | Distributors | Rural |  |
|  | Metropolitan |  |  |
| $>4 \mathrm{GWh} \mathrm{pa}$ | 580 | 80 |  |
| $>750 \mathrm{MWh} \mathrm{pa}$ | 2,900 | 600 |  |
| $>160 \mathrm{MWh} \mathrm{pa}$ | 8,700 | 2,100 |  |
| All | $2,050,000$ | 650,000 |  |

## Preservation of Specified Power Supply Agreements (9.12.2)

This derogation relates to a number of long-standing power supply agreements entered into by the then Electricity Commission of New South Wales (now known as Pacific Power) and the following parties:
(a) Tomago Aluminium Company Pty Ltd (and others) agreement dated January 1991 under which Pacific Power (and now Macquarie Generation) has agreed to supply electricity to Tomago for use at a smelter site in the Hunter Valley (New South Wales).
(b) Capral Aluminium Ltd - agreements dated March 1966 and June 1993 under which Pacific Power (and now Delta Electricity) has agreed to supply electricity to Capral for use at Capral's aluminium smelting works at Kurri Kurri (New South Wales).
(c) Australian Iron \& Steel Pty Ltd. - agreement dated March 1955 under which Pacific Power (and now Delta Electricity) has agreed to supply electricity to Australian Iron \& Steel for use at its hot and cold strip mill and tin plate plant at Port Kembla (New South Wales).
(d) Broken Hill Proprietary Company Ltd - agreement dated August 1959 under which Pacific Power (and now Delta Electricity) has agreed to supply electricity to BHP for use at its iron and steel works in Newcastle (New South Wales).

As part of the restructuring of the New South Wales generation sector in March 1996, Pacific Power's rights and obligations under the agreements referred to in paragraphs (b), (c) and (d) above were transferred to First State Power (now known as Delta Electricity), effective from 2 March 1996, by way of Ministerial Vesting Orders made under the Energy Services Corporations Act 1995. Similarly, effective from 2 March 1996, Pacific Power's rights and obligations under the agreement referred to in paragraph (a) were transferred by Ministerial Vesting Order to Macquarie Generation.

Under each of these power supply agreements, the relevant generator is effectively performing the role a Market Customer would perform under the Code. That is to say, under these agreements the relevant generator has contracted directly with these end use customers to supply electricity on agreed terms.

In recognition of this fact, and the fact that all of these agreements were entered into before the commencement of the compulsory market arrangements embodied in the Code, it is considered appropriate to
continue to recognise the ongoing rights and obligations imposed on the respective generators under these Agreements by:
(a) deeming each generator to be a "Market Customer" in respect of electricity supplied under the relevant power supply agreement; and
(b) relieving the generator from complying with a requirement of the Code if:
complying with the Code requirement would place the generator in breach if its power supply agreement; or
the generator requires the cooperation of another party to the agreement in order to comply with the relevant requirement and that party refuses to cooperate with the generator.

The effect of derogation (a) is that the supplying generator will be treated as if it is effectively selling through the pool all electricity it supplies under the supply agreement and then purchasing that electricity as a Market Customer for re-supply to the end use customers. That is to say, the generator will receive the pool price for the electricity it supplies in its capacity as a generator and will pay the pool price for the electricity it purchases from the pool for re-supply under the power supply agreement. Over and above this, the generator will also receive from the relevant end use customer the relevant contract price agreed in the power supply agreement.

It should also be noted that these derogations do not, in any respect, impose any exclusive supply rights on the relevant supplying generator. If the end use customer is eligible to register with NEMMCO under the Code as a Customer, it may choose, subject to any constraints or remedies in the relevant power supply agreement, either to::

- register as a Market Customer and purchase electricity through the pool for use at the premises covered by the relevant Power Supply Agreement; or
- purchase its electricity requirements from a retailer other than its local Participant Retailer.

In addition to the abovementioned points, it should also be noted that if a generator utilises either clause 9.12.2(b) or (d) to excuse itself from complying with a relevant requirement of the Code, the generator will be required to notify NECA of the relevant non-compliance (clauses 9.12.2(c) and (e)). In addition, at the end of each quarter, NECA will be required to prepare a report for the previous quarter, and make it available on request to all Code Participants and Participating Jurisdictions, summarising:

- those acts or omissions of generators constituting non-compliance with any Code Requirement as disclosed in written notices received by NECA under paragraphs (c) or (e); and
- an assessment by NEMMCO of the effect that those acts or omissions have had on the efficient operation of the market (clause 9.12.2(k)).

The purpose of these provisions is to ensure that there is adequate transparency in the application of the exemptions set out in clauses 9.12.2(b) and (d).

The derogations merely preserve the status quo in relation to existing power supply contracts. It is considered to be in the public interest that new market arrangements should not overtum private contractual arrangements entered into in good faith well before commencement of the national market. There are no detriments that arise from the derogations.

## Loss Factors (9.13)

New South Wales (like the other participating jurisdictions) has maintained regulatory control over the determination of network loss factors for a transitional period. Given that loss factors are an integral part of the arrangements embodied in the Code that determine the amounts ultimately receivable and payable for electricity generated and used in the wholesale electricity market, the determination of loss factors might amount to an arrangement that has the purpose, or has or is likely to have the effect, of fixing or controlling the price for electricity traded through the wholesale market.

Under Chapter 6 of the Code, the regulation of transmission network service pricing ("TNSP") will remain the responsibility of each participating jurisdiction until 30 June 1999. Thereafter, regulation of TNSP will pass to the ACCC and the then existing pricing provisions set out in Chapter 6 of the Code will be applied by the ACCC.

One of the main reasons for the decision to leave regulation of TNSP with each participating jurisdiction until 30 June 1999 was to assist with the smooth transition to the National Market through avoiding, at least in the short term, any unexpected "price shocks" to customers (particularly rural customers) which could potentially result from a sudden shifting of TNSP from a state based system to a national system.

The New South Wales Government similarly wishes to avoid any initial price shocks to New South Wales customers which may result from allowing NEMMCO to set intra-regional transmission loss factors with effect from the commencement of the Code. The New South Wales Govemment is particularly concerned, in this regard, with the position of end use customers in remote rural areas of New South Wales. Accordingly, the purpose of the derogation in clause 9.13.1 is to provide for a body nominated by the New South Wales Government to set, until

30 June 1999, intra-regional loss factors to apply to Market Customers (but not generators or scheduled loads) in respect of electricity transmitted through transmission networks situated in New South Wales.

For reasons similar to those relating to transmission loss factors, the New South Wales Government also wishes to maintain control over distribution loss factors which will apply to Market Customers in New South Wales until 31 December 2000. The derogation in clause 9.13.2 accordingly provides for a body nominated by the New South Wales Government to set these loss factors, and to take into account any resulting material adverse effects on other markets and the policy considerations for determining those factors set out in clause 9.13.2(d) of the Code when so requested by NECA or a Code Participant.

## New South Wales Power System Operating Procedures and System Operating Procedures (9.14.1)

The Network Operating Standards (New South Wales) ("the New South Wales Standards") have the same general effect as the Schedules to Chapter 5 of the Code. The New South Wales Standards set out the requirements upon participants to ensure that equipment connected to the network is safe and that the activities of any participant do not jeopardise the network as a whole or the reliability or quality of network service to other participants. In the event that there is any discrepancy between the Code and the New South Wales Standards, the latter shall prevail.

In addition to the New South Wales Standards, New South Wales will adopt the System Operating Procedures (New South Wales) (the "New South Wales Procedures") applying in New South Wales immediately before Code commencement, after consultation with NEMMCO. The New South Wales Procedures and the New South Wales Standards will form the regional specific power system operating procedures as contemplated by the Code (clause 4.10.1(b)).

The New South Wales Procedures are designed to ensure that the interconnected New South Wales network is operated in a safe and reliable manner. In particular, the New South Wales Procedures are designed to recognise the need to minimise the risks of damage to persons and property, whilst maintaining a high degree of reliability in the ability of the interconnected New South Wales power system to deliver electricity to end use customers in a useable form.

To the extent that any arrangements contained in the Network Operating Standards (New South Wales), and the System Operating Procedures (New South Wales) substantially lessen competition (and it is not conceded that the New South Wales Standards and.New South Wales Procedures have any such effect) it should be recognised that their provisions are designed to ensure that the interconnected New South Wales network operates in a safe and reliable manner.

## Network Access Disputes (9.15.1 and 9.15.2)

Given that, under Chapter 6 of the Code, transmission network service pricing ("TNSP") is to be determined at the state level until 30 June 1999, it is considered appropriate that disputes in relation to access to, connection to, use and pricing of transmission networks which arise on or before 30 June 1999 also be dealt with at the jurisdictional level by the same body which is to have oversight of TNSP during that period (being IPART in the case of New South Wales). It is anticipated that many of the disputes which will arise will relate to network service pricing, and accordingly the New South Wales Govemment considers it appropriate for the body which will regulate network pricing in New South Wales, namely IPART, to be also responsible for determining connection and access disputes in New South Wales.

As indicated in relation to transmission access and connection disputes, the New South Wales Govemment considers that there is a need to ensure that the party responsible for distribution network pricing (IPART) is also responsible for the settling of distribution connection and access disputes which in a large part can be expected to revolve around pricing issues. The body responsible for regulating distribution network pricing in New South Wales will be IPART (see below).

The provisions regulating transmission and distribution access and connection disputes are not anti-competitive and are not considered to involve a breach of Part IV of the Act.

## Network Pricing (9.16)

New South Wales' transmission network service pricing derogation is consistent with the express provisions in Chapter 6 of the Code to the effect that:

- New South Wales will appoint a regulator to be responsible for the regulation of TNSP prior to 1 July 1999; and
- on and from 1 July 1999 the ACCC will become the authority responsible for regulating TNSP in New South Wales in accordance with the principles specified in Chapter 6 of the Code.

In this regard, IPART Determination No 2.1 of 1996 (as amended or supplemented from time to time) will apply to regulate TNSP in New South Wales until 30 June 1999.

In relation to distribution network service pricing, the New South Wales Government intends that IPART continue to regulate distribution network service pricing ("DNSP") for New South Wales in accordance with IPART's determinations, including the current determination, Determination No. 2.2 of 1996. The New South Wales Government believes that it is logical for IPART to retain its role in distribution network pricing while there continues to be a New South Wales franchise
market subject to IPART regulation. While the timing for declaration of all customers as non-franchise has not been finally settled as yet, DNSP is to be set by IPART until 31 December 2000. This will provide consistency in the regulatory arrangements.

As noted in clause 9.10.2(a) of the New South Wales Derogations, in principle, the New South Wales Govemment supports the national regulation of both transmission and distribution networks to commence from 1 July 1999 but has emphasised that a satisfactory framework should be agreed and put in place by that date.

The derogation contained in clause 9.18 .1 relates to the ability of New South Wales to regulate network pricing. Under this New South Wales derogation, the definition of "Transmission Network" in Chapter 10 of the Code will be excluded and replaced by a definition to the effect that in New South Wales the transmission network will be "any electricity power lines and associated equipment and electricity structures situated in New South Wales and declared by the Minister for Energy under section 93 of the Electricity Supply Act to be a transmission system". The purpose of this derogation is to ensure that some flexibility is maintained by the New South Wales Government with respect to the distinction between a transmission and a distribution network for regulatory purposes.

### 7.2.2 Victoria

## (a) Public Benefits

Part A of Chapter 9 of the Code sets out the transitional arrangements for Victoria. The provisions of Part A are explained in detail in paragraph 7.2.2(d).

The principal objective of Part A is to facilitate the transition from the existing regulatory structure in Victoria to the regime contemplated by the Code. The transitional arrangements are necessary to ensure that there is a realistic, orderly and managed transition to the competitive national electricity market. The arrangements are designed to ensure that consumers and investors are not disadvantaged, that existing rights and investments are not undermined, and that the benefits from the reform to date are not lost in the movement to the NEM.

The existing Victorian regime resulted from a series of reforms after 1993, which are summarised in paragraph 7.2.2(b). There are some differences between what is proposed in the NEM and the current arrangements in Victoria. There has been a high degree of public acceptance in Victoria of its industry reforms, including the long term arrangements put in place to address Victoria's transition into a competitive electricity market. Some of these arrangements are the subject of derogations set out in Part A of Chapter 9 of the Code.

If the Code did not include appropriate transitional arrangements, then investors and consumers who have made decisions on the basis of the
existing Victorian regime would be disadvantaged and the credibility of the NEM would be adversely affected.

Other objectives of the transitional arrangements for Victoria are:

- to ensure that certain arrangements for reform of the Victorian ESI implemented under the Electricity Industry Act 1993 (Vic) continue after the Code commencement date;
- to enable the State and its agencies to perform its obligations under existing contracts particularly those relating to the Loy Yang B Power Station, and the Portland and Point Henry Smelters;
- to provide certain specific derogations from technical standards set out in the Code for Code Participants in Victoria; and
- where required by the Code, to nominate the regulatory arrangements applicable in Victoria.
(b) Background: Victorian Reforms

The current Victorian market and regulatory structure dates back to 1993 and the reform of the Victorian ESI. Before the reform, the industry was controlled by the State-owned monopoly utility, the State Electricity Commission of Victoria ("SECV"), with some distribution and retail functions carried on by the municipal electricity undertakings. Since 1993, consistent with the COAG principles, the reform process has achieved vertical and horizontal disaggregation of the industry.

To lock in the benefits of reform and ensure that the improvements in dynamic and allocative efficiency continue to flow from reform, Victoria has taken the further step of privatising three generating companies and all five distribution business. While private shareholders will derive additional value from the industry, the effective regulatory regime established by Victoria and the competitive industry structure will ensure this value is equitably distributed between shareholders and customers. Continuance of these arrangements will ensure certainty for investors, an appropriate transition to the national regime and security for franchise customers.

The reform process in Victoria has adopted the following principles:

## - Increasing Economic Efficiency - The Introduction of Competition

Economic efficiency within the industry has, under the reformed structure, been increased in a number of ways. Firstly, through competition between existing generators in the wholesale market (both in the pool and contract markets) and amongst retailers for those customers which are contestable. Secondly, through the facilitation of the multiple ownership of transmission and
distribution assets (this has also been achieved through the separation of VPX's and PowerNet's functions). Thirdly, by requirements on the monopoly elements of the industry to open many of their activities that were formally regarded as monopoly activities to competitive tendering.

Increasing economic efficiency in generation and retail results from competitive pressures on the businesses in those markets whilst regulation of the monopoly areas under the Tariff Order exerts downward pressure on costs. The reforms provide for new entry, particularly generation and retail by ensuring competitive neutrality between incumbents and new entrants. This is also reflected in the market and regulatory structure which allow for reducing barriers to entry and the existing non-discriminatory provisions which exist in Victoria.

- Customer Benefits

The reforms have aimed at lowering prices to customers, maintaining standards of service and safety whilst increasing customer choice. At present, customers with an annual load of 750 MWh or more ("contestable customers") may choose their retailer from any of the retailers competing in Victoria and by the year 2001 all customers in Victoria will be able to freely choose their retailer. The experience to date of those customers now able to choose their retailer is that approximately half are now purchasing their electricity from a retailer other than their host retailer. Additionally retailers have begun to offer a range of innovative services and products in response to customer needs and it is anticipated that these this will continue.

For contestable customers, the choice is not only between purchasing from competing retailers, or indeed becoming pool participants themselves, but also encompasses opportunities to develop their own sources of power or alternative technologies, including demand management and schemes to improve energy efficiency. Customers are able to exercise choices as a result of the reform process.

## - Cost Reflective and Transparent Pricing

This principle is implemented primarily by the Tariff Order. Tariff reforms are being introduced gradually, over a transitional period up to the end of 2000 with some extending beyond that date. The Tariff Order provides price stability to customers thereby avoiding price shocks during the transition. In particular Maximum Uniform Tariffs ("MUTs") apply to the sale of electricity to franchise customers (i.e. customers other than contestable customers) and are structured on a CPI-X basis, with customers benefiting from price reductions in real terms. It is an important
regulatory principle that price controls such as CPI-X are allowed to run for their duration once set as this allows the regulated businesses to act in response to these caps. This principle is also designed to provide for some certainty for customers, competing retailers and investors. It also provides for the gradual unwinding of historic anomalies which distort commercial incentives and economic signals for new investments and for the operation of existing assets.

## Maintaining Safety Standards

As part of the industry restructuring process, Victoria has created an independent Office of the Chief Electrical Inspector responsible for electrical safety from generation through to end use. This has been achieved through various regulatory instruments and there is close monitoring of compliance by the Office of the Regulator-General ("the Regulator-General"). The Regulator-General has (or is introducing) minimum safety standards for all sectors and will be introducing increased flexibility as to how industry can meet these standards.

## - Maintaining Service Standards

In a fully deregulated market, there exists the potential for standards of service and quality to be compromised. Therefore during the reform process, Victoria has sought to ensure that existing standards are maintained or enhanced as a key tenet of the privatisation and industry reform.

## - Independent Lighthanded Regulation

Victoria has adopted a "light-handed" model of regulation in all industry sectors.

This has been achieved in the monopoly areas through the licences (for access and some elements of pricing) and the Tariff Order (for network pricing), with regulation by the Regulator-General. The introduction of competition where possible also mitigates the need for interventionist forms of regulation.

The Regulator-General is established as a separate body under its own Act, with responsibility for regulatory oversight of a number of utility industries.

## - Commercial Investment Decisions and Risk Allocation

The Victorian reforms have introduced commercial incentives and capital market disciplines into an industry which was previously able to rely on both its monopoly position and, in some instances, Government support. The new structure has placed the risk for new investment decisions, and other commercial decisions, with
the individual companies and capital will only be committed if it can earn a commercial return. The reform process has sought to allocate risk to those in a position to manage the risk appropriately. Effective competition and regulation mean that the risks associated with poor investment decisions cannot be passed through to customers.

These principles of Victorian reform continue to be applied as part of an ongoing process. Consequently, it is possible that some of the areas in which Victoria has included transitional provisions will be resolved prior to the Code coming into effect.

## (c) Outline of the Transitional Provisions

The transitional provisions fall into two broad categories, as outlined in general terms below. The outline is followed in paragraph 7.2.2(d) by a detailed explanation of each of the provisions in Part A of Chapter 9.

## Category 1: Transitional Arrangements up to December 2000

The first category of provisions are intended to ensure that, where necessary, arrangements for reform of the Victorian electricity supply industry implemented under the Electricity Industry Act 1993 (Vic) continue after the Code commencement date for as long as is required to achieve a successful transition from the established Victorian regulatory structure to the Code.

Into this first category fall the provisions that nominate interim regulatory arrangements for network pricing and access, as required by the Code. Victoria is nominating its existing regulatory instruments to apply during the transitional period. The Regulator-General will continue to regulate network access and pricing under the Tariff Order and the licences in order to provide certainty for those investors that bought the now privatised generators and distributors, and to avoid price shocks for customers in the transitional period.

Also in this category are the Industrial Relations Force Majeure (IRFM) provisions. The Code contemplates that price caps will apply during force majeure events. In Victoria, under the VicPool Rules, if certain IRFM events occur, then a price cap applies. The IRFM provisions were implemented in 1996 to provide pricing certainty for franchise customers for as long as the MUTs apply. The IRFM arrangements have been included in Chapter 9 of the Code, and will cease to apply when the MUTs expire and all customers become contestable.

## Category 2: Longer Term Arrangements

The second category of provisions have a longer term effect and these fall into three sub-categories.

First, the provisions relating to the Power Traders enable the State and its agencies to perform their take or pay obligations under long term contracts primarily relating to Loy Yang B Power Station and the Portland and Point Henry Smelters entered into before the 1993 reform process commenced. This enables the wholesale and retail market arrangements to remain largely unaffected by these contracts and isolate any detrimental effects of imposing them in the competitive markets.

Secondly, some provisions in Chapter 9 ensure that structural reforms in Victoria, such as the separation of transmission ownership from control, the access and pricing principles, and privatisation of the industry can be successfully integrated into the national market.

Thirdly, derogations from technical standards set under the Code, already in place in the Victorian industry, are reflected in Chapter 9.
(d) Part A of Chapter 9: Details of the Provisions

A detailed explanation of each of the provisions of Part $A$ is set out below.
Clause 9.3.2 Definition of Network Service Provider
The table specifies in the case of a number of clauses of the Code, whether the term "Network Service Provider" should be interpreted as $V P X$, PowerNet or both.

The separate roles of VPX and PowerNet in relation to the Victorian transmission network is unique in Australia. VPX is responsible for operating and planning the Victorian transmission network. PowerNet owns and maintains the electricity transmission assets. In order to have access to the transmission network, it is necessary to negotiate a use of system agreement with VPX and a separate connection agreement with PowerNet (or other grid owner).

The distinction between VPX and PowerNet is an important part of the Victorian reforms, in order to:

- achieve efficiency gains in the operation and maintenance of the network, through appropriate pricing strategies and competitive tendering of augmentation work. Competitively sought assets receive a regulated rate of return, however the asset value is determined by the competitive process. This has the advantage of facilitating light-handed regulation - VPX determines requirements and, subject to approval, decides on who carries out the work;
- minimise the potential for over-investment in transmission networks by separating the person making investment decisions from the asset owner and providing information about investment opportunities/options to the public;
- facilitate multiple ownership of transmission assets, whilst ensuring that the network is developed in an efficient manner, e.g. by avoiding the duplication of assets.

It is contemplated that, over time, there may be other owners of transmission network assets in Victoria. However, any new grid owner will be required to enter into similar arrangements with VPX as PowerNet has, ensuring secure and safe operation of the network by a single operator whilst allowing competing network owners and service providers.

As the Code does not draw a distinction between Network Service Providers that provide only connection services (in Victoria, PowerNet), and those that provide only use of system services (in Victoria, VPX), it is unclear in some cases (as indicated in the table in clause 9.3.2) whether references to the Network Service Provider in the Code should be interpreted as VPX or PowerNet or both.

Part A of Chapter 9 seeks to clarify these issues. In the national market, VPX will retain the function of operating the transmission network in Victoria and will retain responsibility for planning of the transmission network within the framework established under the Code.

## Clause 9.4.1 Customers

## If a person is a non-franchise customer in Victoria then they may become a customer for the purposes of the Code.

Clause 2.3.1(d) of the Code requires each jurisdiction to nominate the persons that may register as a Customer under the Code. The timetable in place in Victoria provides for all customers in Victoria to become contestable by 2001 (see the Electricity Industry (Non-franchise Customers) Regulations 1995). That timetable is to be followed for the purposes of the Code and ensures that there is progressive and comprehensive deregulation of the retail market.

## Clause 9.4.2 Loy Yang B

## The Loy Yang B Trader is the Generator in relation to Loy Yang B power station.

Among the transitional issues raised as part of the Victorian reform process were the State's long term obligations under various contracts. To enable the State to implement the reform process within the framework of those contractual relationships without distorting the operation of the wholesale electricity market, four separate "traders" were established within the SECV to manage the contractual arrangements and to trade the energy relating to them through the Pool. One of the four traders was responsible for each of:

- Victorian entitlement from the Snowy Mountains Hydro-Electric Scheme;
- the Victorian entitlement under the Interconnection Operating Agreement between New South Wales, Victoria and South Australia;
- the arrangements with the owners of the Portland and Port Henry smelters; and
- the arrangements with the owners of Loy Yang B power station.

Clause 9.4.2 of Chapter 9 enables Victoria to comply with the long term obligations arising out of the sale of Loy Yang B power station in 1992. The transitional arrangements provide for the SECV to be the person that must register in respect of the generating units at Loy Yang B power station, and exempts the owners of the power station from the requirement to do so. SECV is a State owned body and the party to the long term take-or-pay contract ("PSA") with the owners of the power station.

In this way, SECV (through the Loy Yang B Trader) is effectively interposed between the owners of the Loy Yang B power station and the NEM in a manner which is consistent with the Code. This enables the energy generated by the Loy Yang B power station to be traded into the market without having to renegotiate the pre-existing contracts or replicate the features of the existing contracts (which include capacity payments) in the structure of the NEM. The energy is traded on a competitive basis, ensuring that the energy from the Loy Yang B Trader is scheduled on exactly the same competitive basis as other generators. These provisions will continue until the termination of the last of the relevant contracts (due in approximately 2025).

## Clause 9.4.3 Smelter Trader

## Smelter Trader is the Generator and the Market Customer in respect of the Portland and Point Henry Smelters, and Anglesea Power Station.

SECV also has long term supply arrangements with Alcoa of Australia for the Portland and Point Henry Smelters. These arrangements also deal with the operation of the Anglesea power station as part of the Victorian system. To enable Victoria to comply with the long term obligations arising out of these arrangements, the transitional arrangements provide for the SECV to be the person entitled to register under the Code:

- as the person buying the energy required to be supplied under the Smelter agreements; and
- as the generator in respect of the generating units at the Anglesea power station, and therefore exempts the owners of the Smelters' Anglesea power station from the requirement to do so. This is for the same reasons as apply in the case of the Loy Yang B arrangements (see 4.3 above).


## Clause 9.4.4 Power Traders: Compliance


#### Abstract

A Power Trader (Loy Yang B Trader and Smelter Trader) is not required to comply with the Code if the relevant agreement prevents it from doing so. It must report to NECA about non-compliance. NECA must report to Market Participants.


The PSA and the Smelter Agreements contain a number of provisions that relate to the technical performance required of the power stations. These were negotiated before the relevant chapters of the Code were prepared. In some respects the rights of SECV under the PSA and the Smelter Agreements are not consistent with the requirements of the Code. Where SECV would be in breach of one of these agreements if it complied with the Code, or has no right under the relevant agreements to ensure compliance with a particular provision of the Code, then SECV is relieved of its obligations under the Code.

There are protections to ensure that the provision is not abused, including a requirement to report to NECA and to use reasonable endeavours to persuade the counterparty to the relevant agreement to comply with the relevant Code provision. NECA is also required to report to other Market Participants in order to provide a transparent mechanism for full disclosure of any breaches.

## Clause 9.4.6 Cross Border Networks

Networks that are the continuation of a network interstate may be declared part of that interstate network.

In several isolated instances transmission or distribution networks cross interstate borders. This derogation allows the Minister to declare that a part of a network is part of the interstate network. This aims primarily to simplify administration of the Code.

## Clause 9.5.1 and 9.5.2 Loss Factors

A body appointed by the State will determine intra-regional loss factors and distribution loss factors that apply until 2001.

The determination of loss factors influences the amount that end users pay for their electricity. To avoid price shocks to rural customers, and for so long as the MUTs exist, the loss factors will be determined by a body nominated by the State.

### 9.5.3 Victorian Region

Victoria is one region for the purposes of the Code until 31 December 2000.

To ensure that the effect of the Victorian IRFM arrangements will be confined to Victoria as intended, Victoria will be one region during the transitional period.

## Clauses 9.5.4 to 9.5.5 IRFM

An IRFM Event is a force majeure event for the purposes of clause 3.18 .3 and NEMMCO must invoke an administered price cap in accordance with the IRFM provisions in Schedule 9A1. Other Market Participants must also comply with Schedule 9AI.

The Code provides for force majeure provisions to be developed for each jurisdiction. Under Part A of Chapter 9, the Industrial Relations Force Majeure ("IRFM") arrangements already in place in Victoria have been identified for this purpose.

The IRFM arrangements were put in place by amendments to the VicPool Rules and agreements between SECV and the Victorian generators in 1996. The purpose of these IRFM arrangements is to prevent or minimise the pass-through to franchise customers of the financial effect of certain kinds of labour disputes (called "IRFM events") which affect the industry (particularly generation or transmission). During the transition to a fully competitive retail market, the IRFM provisions help stabilise electricity prices for franchise customers if there is industrial action.

The potential for there to be a pass through (in the absence of the IRFM provisions) comes about in the following way:

- the MUTs for franchise customers set under the Tariff Order are the maximum price at which distributors can sell electricity to franchise customers. This presents a risk for distributors, as they must not sell electricity to franchise customers above the maximum prices, but must buy it at the spot price from VicPool. The spot price is potentially volatile;
- to hedge against this risk, as part of the reform process, the distributors and generators entered into hedging contracts (known as the vested hedging contracts) in respect of franchise load. The vested hedging contracts take the form of contracts for differences, under which either party may be required to make a difference payment to the other, depending on whether spot prices are above or below corresponding strike prices in the vested hedging contracts. The strike prices were set by reference to the MUTs;
- under the terms of the vested hedging contracts, the generators are entitled to relief from their obligation to make a difference
payment to the extent of any capacity lost by reason of a Force Majeure Event (which could, in some circumstances, include an industrial dispute). The Tariff Order recognises that this presents a risk to distributors, as it leaves the distributors exposed to the Pool price on a portion of the electricity they are selling to retail customers. To address this risk, the Tariff Order provides for pass-through of the financial effect of the force majeure event under the vested hedging contracts to the distributors' franchise customers. The pass-through is regulated by the Regulator-General.

In the period after the initial reforms were implemented, it became apparent that industrial disputes arising as a result of the reform process could lead to significant and irregular pass-throughs to franchise customers. The VicPool rules were therefore amended to protect franchise customers. In summary, the Victorian IRFM arrangements have the following features:

- a Pool price cap applies if an IRFM event results in an aggregate capacity reduction across all generating units affected of 550 MW or more for 24 hours (not necessarily consecutive); and
- the price cap is equal to the vested hedging contract strike price plus $\$ 40 \mathrm{MWh}$;
- generators with bid prices above the price cap are entitled to an uplift, calculated to cover their actual costs of generating plus a small capacity payment (but capped at the lesser of their bid price and an amount equal to $\$ 240 / \mathrm{MWh}$ (as escalated) above the price cap). The portion of this uplift attributable to the franchise load is paid by SECV and the portion attributable to the non-franchise load is paid by the DBs ; and
- generators have agreed not to claim force majeure relief under the vested hedging contracts in relation to an IRFM event affecting their power station.

This effectively shares the risk of an IRFM event between generators, the distributors and the government.

The Victorian IRFM arrangements cease to apply at the end of 31 December 2000.

The purpose of Schedule 9A1 is to preserve the existing Victorian IRFM arrangements until 31 December 2000. The arrangements are to be reviewed by NEMMCO within six months of market commencement.

## Clause 9.5.8 Loy Yang B Uplift

NEMMCO calculates and collects the LYB Uplift Payment in respect of electricity supplied in Victoria (as well as the costs of doing so).

A levy is payable by Pool Customers under an Order in Council made under section 158B of the Electricity Industry Act 1993 and the VicPool Rules. The purpose of this levy (known as Loy Yang B uplift) is to recover $51 \%$ of any loss the SECV may make as a result of purchasing electricity under the PSA pricing arrangements and on-selling it at the market spot price. The levy is currently collected by VPX and paid to SECV.

The purpose of clause 9.6 .6 is to preserve the existing Victorian arrangements after the implementation of the NEM. Under this clause, the levy will only apply to electricity supplied to Victorian customers and the costs of collection will be borne by Victorian customers. The Loy Yang B Uplift will be collected on an equitable basis from all consumers in Victoria as it will be paid in respect of all electricity purchased through the NEM and referable to Victorian loads.

The collection of this levy is an integral part of the arrangements put in place in Victoria for the restructuring of the electricity supply industry in 1994-95.

## Clause 9.6 Operations on the Networks

## The System Operating Procedures and nomenclature standards in use under the System Code apply from market commencement until amended in accordance with the Code.

Under the Code, operating procedures and nomenclature standards are to be developed. For transitional purposes, existing system operating procedures and nomenclature standards remain in place after the commencement date, subject to change in accordance with the Code.

## Clause 9.7.1 Regulation of Transmission Network Connection until 2001

## The Regulator-General regulates transmission network connection until 2001.

Chapter 6 contemplates that the Code provisions relating to network pricing will take effect at the end of a transition period. The transition period for Victoria ends on 31 December 2000, the date specified by the existing Victorian Tariff Order as the end of the first pricing period.

The Tariff Order was put in place for the restructuring of the industry in Victoria and prior to the recent privatisations. The access regime is explained in detail in Chapter 8. While the pricing principles in the Tariff Order apply, the access regime on which they are based should continue.

Accordingly, the Regulator-General is to regulate transmission network and access connection until 2001. In doing so, the Regulator-General will apply the provisions of the existing transmission licences, which specify requirements for providing connection and access to transmission networks in Victoria.

## Clause 9.7.2 Application for Connection after 2001

A Connection Applicant deals with VPX in relation to transmission use of system, and deals with PowerNet (or other Transmission Network Owners) in relation to connection services.

After 2001, some provisions in Part A of Chapter 9 will continue to apply to the regulation of connection to a transmission network in Victoria. This is because, as outlined above, VPX and PowerNet have separate roles in relation to the Victorian transmission network. A person seeking connection to and use of the Victorian transmission network would need to apply to both VPX and PowerNet in some circumstances and would need to enter into a connection agreement (as defined in the Code) with each of them.

Clause 9.7.3 Regulation of Distribution Network Connection until 2001

The Regulator-General regulates distribution network access until 2001.
For the same reasons outlined above in relation to transmission access, the transitional arrangements provide for the Regulator-General to regulate connection to Victorian distribution networks by applying the terms of the Victorian distribution licences until 31 December 2000. The conditions of the distribution licences specify requirements for providing connection to, and use of, distribution networks in Victoria.

## Clause 9.7.4 Regulation of Distribution Network Connection after 2001

## The Regulator-General regulates distribution network access until he/she ceases to regulate distribution network pricing.

After 2001, the Regulator-General will be responsible for regulating the pricing of distribution services in Victoria under the applicable Code provisions, as the jurisdictional regulator for Victoria.

Victoria believes it is inappropriate to divide responsibility for regulating the price of distribution services and the terms and conditions on which access to distribution services must be provided between State regulators and the national regulator. This is for the following reasons:

- it is axiomatic that the pricing of access and the terms and conditions on which access is provided are inextricably linked. The level at which prices are set will depend on the risk allocation
implicit in the terms and conditions of access. If one regulator is regulating the pricing of access and another regulator is regulating the terms and conditions of access, then the regulated entity may well "play-off" the two regulators; and
- the distribution network pricing regime will necessarily make certain assumptions about the efficiency gains that a distribution business may achieve in providing access to or in augmenting its network; and
- access to, and augmentation of, a distribution network involves numerous customers and a multitude of transactions possibly giving rise to issues which may well not be of a magnitude appropriate for the national regulator to resolve.

To ensure that there is only one regulator for both distribution access and distribution pricing, the transitional arrangements provide for the Regulator-General to continue to regulate distribution access as well as distribution pricing from 1 January 2001, but applying the terms of Chapter 5 (which are to be approved by the ACCC) and not a Victorian specific access regime. The provision ceases to apply if there ceases to be a Jurisdictional Regulator for distribution pricing for Victoria.

## Clause 9.7.5 Technical Requirements - Network Service Providers

## VPX's and PowerNet's connection related obligations are modified.

Clause 9.8.5 of Part A of Chapter 9 sets out some technical derogations for VPX and PowerNet in respect of the Victorian transmission network. The derogations are included to clarify their obligations under the Code, and reflect the existing technical design limitations of the transmission network.

## Clause 9.7.6 Technical Requirement - Generators

## The connection related obligations of Generators (technical requirements related to facilities and quality of electricity delivered into the system) are modified as set out in Attachment 9A3.

The technical requirements for generating units in the Code have been prepared on the basis of what would be expected of a generating unit in today's environment. Many existing generating units do not comply with the technical requirements specified in the Code. Part A of Chapter 9 contains some specific derogations for particular generators in relation to the technical connection related obligations under the Code. These are to take into account known technical and design limitations of generating units and other facilities. It is appropriate to deal with these now to:

- recognise that the likely cost of requiring plant modification to meet the standards in the Code exceeds any potential gains in terms of system security or operation of the market. In most cases,
the system has operated for many years safely and efficiently without the relevant plant complying with the requirement;
- provide information to market participants and others at Code commencement about the known technical limitations of plant; and
- provide certainty for generators (and potential purchasers of Victorian generating assets) by including the derogations at Code commencement rather than requiring them to use the Code derogation process. This is also a pragmatic approach aimed to avoid unnecessary repetition of the process that lead to the inclusion of equivalent derogations under the Victorian System Code.


## Clause 9.7.7 Certain augmentation works exempt

The augmentation works referred to in the Tariff Code are not subject to the Code processes.

Where augmentation work has already been taken into account in calculating PowerNet's charges under the Tariff Order, the procedures that apply to augmentation under the Code do not apply.

## Clause 9.8.1 Appointment of Jurisdictional Regulator

## The Regulator-General is the Jurisdictional Regulator for Victoria.

Clause 6.2.1(c) of the Code requires each jurisdiction to appoint a Jurisdictional Regulator for transmission network pricing for the interim pricing arrangements. As discussed above, the Jurisdictional Regulator for Victoria is the Regulator-General.

## Clause 9.8.2 Extension of the transitional period for Victoria

The transitional regulatory arrangements in Victoria cease in 2000 (not 1999).

Chapter 6 of the Code provides for transitional arrangements for transmission network pricing to apply until the end of a transitional period. The transitional period for Victoria ends on 31 December 2000, consistent with the first review period under the existing Victorian Tariff Order put in place on the restructuring of the Victorian electricity supply industry (in 1994-1995). The Victorian distributors were privatised on the basis of the pricing regulation contemplated by the Tariff Order during that first review period.

Clause 9.8.3 Transmission Network Pricing from 1 January 2001

After 31 December 2000, the provisions of Chapter 6 of the Code will apply to transmission and distribution pricing in Victoria, with some minor exceptions.

In relation to transmission pricing, certain equalisation adjustments put in place by the Tariff Order will continue until 30 June 2020 (as contemplated by the Tariff Order). These equalisation adjustments apply to use of system fees payable by distribution companies. The purpose of the equalisation adjustments is to provide a smooth transition to fully cost reflective pricing and to recognise historic property rights. During the period 1 January 2001 to 30 June 2020, the equalisation adjustments are gradually reduced in accordance with a mechanism set out in clause 9.9.3.

## Clause 9.8.4 Jurisdictional Regulator

## The Regulator-General is the Jurisdictional Regulator.

Clause 6.13.1(b) of the Code requires each jurisdiction to nominate a Jurisdictional Regulator for distribution network pricing. As discussed above, in Victoria, the Jurisdictional Regulator is the Regulator-General.

Clause 9.9.5 Distribution Network Pricing prior to 1 January 2001
The Tariff Order regulates distribution network pricing until the end of 2000.

The Tariff Order, put in place for the restructuring of the Victorian electricity supply industry will regulate network service pricing until the end of 2000, consistently with the first review period under the Tariff Order. The Victorian distributors were privatised on the basis of the pricing regulation contemplated by the Tariff Order during that first review period.

Clause 9.9.6 Distribution Network Pricing after 1 January 2001

> The Regulator-General must choose the price capping option for economic regulation, and apply the principles in clause 5.10 of the Tariff Order.

Clause 6.13.3 of the Code allows the Jurisdictional Regulator to choose one of a number of options for the regulation of distribution network pricing after the end of the relevant transition period (i.e. after 31 December 2000 in the case of Victoria). Part A of Chapter 9 requires the Regulator-General to use the explicit price capping method. This is for consistency with the current Victorian arrangements (as outlined in the Tariff Order).

Clause 5.10 of the Tariff Order contains a number of continuing provisions which the Regulator-General is required to apply in regulating distribution network pricing after the year 2001. The effect of these
provisions is preserved in clause 9.9.6 of Part A of Chapter 9. These provisions require the Regulator-General, amongst other things:

- to utilise price based regulation adopting a CPI - X approach and not rate of return regulation - hence the requirement that the Regulator-General use the explicit price capping method after 31 December 2000; and
- in determining the value of the fixed assets which were allocated to the distribution companies as at 1 July 1994 on the disaggregation of the electricity supply industry, to use the asset values set out in clause 5.10 of the Tariff Order (adjusted to take into account inflation and depreciation and for disposals); and
- to have regard to the need to:
- provide each distribution company with incentives to operate efficiently; and
- ensure a fair sharing of the benefits achieved from efficiency gains between customers and the distribution companies; and
- ensure appropriate incentives for capital expenditure and maintenance in the distribution companies' distribution systems; and
- have regard to the level of executive remuneration in each distribution company by reference to any relevant interstate and international benchmarks for such remuneration; and
- to set the price controls for a period of not less than 5 years.


## Clause 9.9 Transitional arrangements for Metering

> A range of provisions include a requirement that metering equipment reach Code standard within 5 years, and Metering Providers apply for registration within 6 months.

In general, the transitional arrangements for metering provide a timetable for participants to:

[^23]
## Schedule 9A1.1 IRFM Events

If there is an IRFM Period, a price cap applies. Generators are entitled to compensation from NEMMCO. SEC and Retailers must in turn pay NEMMCO.

Schedule 9A1.1 is largely based on the provisions in the Pool Rules for an administered price cap during an IRFM period, for payment of the IRFM uplift to generators and for collection of the uplift from SEC and from other Market Participants. The arrangements come to an end at the end of 31 December 2000. See comments above.

## Schedule 9A2 LYB Uplift

The LYB Uplift payment is calculated by NEMMCO and paid by Market Participants on the basis of electricity supplied in Victoria.

Schedule 9A2 sets out the manner in which the Loy Yang B Uplift payment is calculated. It is based on the equivalent provisions in the VicPool Rules. The LYB Uplift payment is only payable in respect of electricity that is sold for end use in Victoria. See comments above.

## Schedule 9A3 Derogations granted to Generators

## Where specified in the Schedule, the requirements of Schedule 5.2 of Chapter 5 of the Code are modified for a generating unit.

Schedule 9A3 sets out certain technical derogations for existing Victorian generating units. The derogations are based on those in Attachment 12 of the Victorian System Code, which were prepared following a detailed due diligence exercise in Victoria following the restructuring of the industry and were approved by the Regulator-General. They reflect pre-existing technical or design limitations. See comments above.

### 7.2.3 South Australia

(a) Introduction

South Australia has included a number of derogations in Part D of Chapter 9 of the Code. The derogations are designed to accommodate the following objectives and policies:

- to manage the introduction of competitive electricity pricing and cost reflective network pricing with the intention of separating competitive and regulated pricing and avoiding distortions in generation and retail competition;
- to provide for the registration of ETSA Power Corporation and ETSA Corporation as the Generators in relation to nominated generating systems and units; and
- to provide for specific derogations from technical standards set out in the Code for some Code Participants in South Australia.

Set out below in paragraph (b) is an overview of the South Australian derogations contained in Part D of Chapter 9 of the Code. In paragraph (c) there is an assessment of those South Australian derogations which may breach the Act including details of the public benefits and any perceived detriments associated with those derogations. In considering the following material, it should be noted that definitions have been included in Part D for terms used in that Part of Chapter 9 of the Code that are not defined in the glossary in Chapter 10 of the Code.

## (b) Overview of the South Australian Derogations

Chapter 1 - Introduction and Code Supervision
There are no South Australian derogations in respect of Chapter 1.

## Chapter 2 - Code Participants, Registration and Cross-Border Networks

## Registration as a Generator

Clause 9.26 .1 of Chapter 9 provides for the registration of ETSA Power Corporation as the Generator with respect to the generating system and associated generating units comprising the Osborne co-generation project. Similarly, ETSA Corporation is deemed to be the Generator in relation to the generating system and associated generating units comprising the Northern Power Station.

In relation to the Osborne co-generation project, it should be noted that the commercial arrangement for that project was negotiated prior to the finalisation of the Code. Whilst the Osborne agreement requires the parties to comply with the obligations set out in the Code, it was specifically agreed that ETSA Power Corporation should be the entity responsible under the terms of the Code for ensuring compliance with the generation provisions of the Code. In particular, the terms of the Osborne agreement do not involve any provisions which conflict with the Code requirements for Generators.

The Northern Power Station agreements were negotiated and entered into a number of years ago before the possibility of a NEM was contemplated. The financial leasing and ownership arrangements contained in those agreement presume that ETSA Corporation is responsible at law for all operational matters relating to Northern Power Station. The terms of the Northern Power Station agreements do not involve any provisions which would be in conflict with the Code requirements for generators.

## Registration as a Customer

Clause 2.3.1(e) provides that a person may not classify its electricity purchase at any connection point unless that person satisfies the requirements of the participating jurisdiction in which that connection point is situated so that the person is permitted to purchase electricity in the spot market in relation to that connection point. Clause 9.26 .2 of Chapter 9 notes that the South Australian requirements in respect of clause 2.3.1(e) will be contained in regulations made under the Electricity Act. At this stage, no regulations have been prepared.

## Cross Border Network

Under clause 9.26.3, where parts of a transmission network or a distribution network situated in South Australia are considered to be a continuation of a network situated in another participating jurisdiction, then with the consent of the relevant ministers, those parts of the network in South Australia may be deemed to be entirely in the other participating jurisdiction for the purpose of determining what provisions govern its regulation (including any transitional arrangements of the other participating jurisdiction). The reverse also applies to networks in other participating jurisdictions that involve a continuation of a South Australian network.

## Chapter 3 - Market Rules

A body nominated by the South Australian Government or, if no such body is appointed, NEMMCO will set until 31 December 2000:

- all intra-regional loss factors to apply to market customers (other than loss factors relating to a connection point in respect of which the customer has registered a scheduled load) for the transmission of electricity through a transmission network situated in South Australia (see clause 9.27.1); and
- all distribution loss factors to apply to market customers (other than loss factors relating to a generator or to a connection point in respect of which the customer has registered a scheduled load) for the distribution of electricity through a distribution network situated in South Australia (see clause 9.27.2).

Clause 9.27.1(d) and 9.27.2(d) provide mechanisms by which:

- in the case of intra-regional loss factors set by South Australia there should (in an aggregate sense) be an outcome that equates to that which would have applied if there were no derogations; and
- in the case of distribution loss factors either NECA or a Code Participant may request, if it is considered that a particular factor will have an adverse effect on the operation of the market of a participating jurisdiction outside of South Australia, the relevant

South Australian body to give further consideration to the determination of that loss factor, taking into account the material adverse effect and policy considerations for determining such factors otherwise than in accordance with clause 3.8.3 of the Code.

## Chapter 4 -System Security

There are no South Australian derogations in respect of Chapter 4.

## Chapter 5-Network Connection

The primary purpose of the derogation set out in clause 9.28 is to ensure that the Code requirements relating to network connection are not applied to Code Participants retrospectively (in circumstances where the same requirements were considered to be unnecessary for the safe and secure operation of the system prior to the commencement of the Code) unless there is adequate justification for the application of those requirements to the relevant Code Participants after taking into account the cost to those Code Participants of complying with those requirements.

In general, South Australia proposes to use the provisions of the Code allowing a Code Participant to seek exemptions from NEMMCO in respect of particular requirements in order to resolve any issues in this area. However, in the case of the power stations nominated in Schedule $9 \mathrm{E}(1)$ of Chapter 9 of the Code, the specific derogations relating to plant technical characteristics have already been identified as necessary.

## Chapter 6 - Network Pricing

## Jurisdictional Regulator

For the purposes of clauses 6.2.1(c) and 6.10.1(b) of the Code, the South Australian Government will nominate a jurisdictional regulator. It is currently proposed that the South Australian Government will nominate a Pricing Regulator under the terms of legislation which will be developed early next year. That Pricing Regulator will be the jurisdictional regulator for the purposes of these provisions.

## Transmission Network Service Pricing

The South Australian Government will determine the pricing structure and regulation procedures and the jurisdictional regulator will regulate network service pricing for transmission network situated in South Australia during the transition period ending on 31 December 2000.

The 31st of December 2000 was chosen as the earliest date for the transfer of this function to the ACCC to allow sufficient time (in view of the likely commencement date for the NEM) for participants in the South Australian electricity industry to prepare and adjust for a nationally regulated system of transmission network service pricing.

South Australia will follow the general principles set out in the Code for establishing overall transmission revenue requirements and for allocating those revenue requirements to transmission connection points. Accordingly, clause 9.29 .2 has two basic objectives. They are:

- during the transition period the various detailed decisions to be taken in respect of the application of the Code's general principles are to be determined by the South Australian Government; and
- the detailed transmission pricing arrangements in South Australia are to be consistent with the South Australian Government's policy for customer electricity prices during the transition period.

To satisfy the second objective, it will be necessary to use one or more of a number of possible measures in applying the general Code principles and translating connection point revenue requirements to actual customer prices to give acceptable price outcomes from the South Australian Government's perspective. Clauses 9.29 .2 (b) to (f) identify possible measures which may be utilised, during the transition period, to achieve the South Australian Govemment's policy outcomes. The initial detailed pricing structure and regulation procedures for transmission service pricing in South Australia are currently being developed together with the measures which are to be utilised to give effect to that structure and those procedures.

It should also be noted that following the completion of consideration of the initial pricing structure and regulation procedures for transmission network service pricing later this year, the South Australian Government may wish to include in part D of Chapter 9 , a specific derogation(s) to apply after 31 December 2000 to take account of its future policy objectives in relation to customer electricity prices. At this stage, it is not possible to indicate the nature, or the likely impact, of that derogation.

## Distribution Pricing

Clause 9.29.4 makes it clear that the South Australian Government will, during the transition period, determine how the general principles of distribution network service pricing set out in Chapter 6 will be applied in South Australia to take into account the specific criteria and methodologies developed by the South Australian Govemment in this area. The jurisdictional regulator for South Australia will be responsible for regulation of distribution network service pricing and the application of the relevant principles. Once again, broadly speaking, the South Australian pricing principles will be consistent with the principles for the determination of distribution prices and the principles required for approved new network investment specified in Chapter 6 of the Code.

As such, the derogation set out in clause 9.29 .4 is primarily a clarification rather than a variation from Chapter 6 of the Code. However, South Australia will not be following all of the more detailed specific
requirements for distribution pricing set out in Chapter 6 during the transition period.

At this stage, there is only one distribution business in South Australia. If this business were to be split into two or more new businesses, at some time in the future, clause 9.29.4(c) provides for the possible use of mechanisms to manage the pricing implications of that split. The intent of this provision relates to the allocation of existing distribution asset costs and it is not envisaged that it would have any implications relating to new asset requirements or future investment decisions.

## Chapter 7-Metering Code

There are no derogations for South Australia in respect of metering other than those which will apply to all participating jurisdictions and which are set out in Schedule 9F of Chapter 9 of the Code.

## Chapter 8 - Administrative Functions

There are no derogations for South Australia in respect of Chapter 8.

## Chapter 10-Glossary

There are no derogations for South Australia in respect of Chapter 10.
(c) Reasons for and Public Benefits of South Australia's Derogations

This section of the Submission summarises the effect of each of the proposed South Australian derogations and the reasons why the South Australian Government has requested those derogations.

## Public benefit argument

The effect of the derogations is to provide a measured and acceptable transition from the current South Australian arrangements to the arrangements envisaged by the NEM. Accordingly, any impacts of the derogations mainly apply in the transition period. When viewed as a whole, with the transitional arrangements for each of the other participating jurisdictions, the South Australian derogations clearly represent an opening up of the market compared with the current arrangements in South Australia.

As noted above, the transitional arrangements are necessary to ensure that there is a realistic, orderly and manageable (from South Australia's point of view) transition to the NEM. The phasing in of contestability allows the Government to manage impacts on participants in a workable manner. It is also important that the South Australian derogations recognise the terms of existing contractual arrangements and preserve those arrangements during the terms of those contracts.

## South Australian customer eligibility (9.26.2)

The Code requires customers to satisfy the requirements of participating jurisdictions before they are eligible to register as "Customers" under the Code (see clause 2.3.1(e)). In South Australia's case, all customers with peak demands above 5MW will be eligible to register as customers upon commencement of the NEM in South Australia. The South Australian Govemment is currently finalising its timetable for opening up the SA Market beyond this threshold. The timetable developed by the South Australian Government will ensure that there is a realistic, orderly and manageable transition to customer participation in the NEM and increased contestability for supply of electricity to customers.

## Registration as a generator (9.26.1)

It is not considered that this derogation will have any anti-competitive detriments. It merely preserves the current status of these pre-existing arrangements. It is considered to be in the public interest that the new market arrangements should not overturn private contractual arrangements entered into in good faith well before the commencement of the NEM.

Loss factors (9.27)
South Australia (like the other participating jurisdictions) has maintained regulatory control over the determination of network loss factors for a transition period. The determination of loss factors will influence the price of electricity traded in the wholesale market.

The primary reason for retaining regulatory control in South Australia during the transition period is to ensure and assist in a smooth transition to the NEM through the management of any price impacts on customers (particularly rural customers) which could potentially result from the immediate application of the provisions in the Code dealing with loss factors. Without this requirement, end use customers in some locations could be exposed to substantial and relatively sudden price increases.

The 31st of December 2000 was chosen as the end date for the transition period in South Australia to ensure that there is sufficient time for South Australia to manage and complete its transition to the NEM arrangements.

South Australia does not believe that the provisions of clauses 9.27.1 and 9.27 .2 will have any significant competition implication or related identifiable overall cost implications. As these provisions do not affect the loss factors applied to market generators, they have no impact upon the prices received by those generators or competitive merit order dispatch. Similarly, since the loss factors applied to customers, and hence the price of energy at their respective connection points, apply irrespective of who purchases the electricity from NEMMCO, the loss factors will have no impact on competition between retailers or the relative merits of wholesale and retail purchasing.

It is possible that the provisions of the Code relating to losses could have implications for future investment decisions in remote areas of South Australia. If the South Australian Government considers, upon conclusion of its current review in relation to loss factors, that some form of derogation in relation to intra-regional loss factors and distribution loss factors beyond the end of the transition period is necessary for the benefit of consumers of electricity in South Australia, full details of that derogation and appropriate arguments in support, will be provided to the ACCC.

## Network Pricing (9.29)

South Australia's transmission network service pricing derogation is broadly consistent with the provisions of Chapter 6 of the Code in that:

- each participating jurisdiction will appoint a regulator to be responsible for the regulation of transmission network service pricing during the transition period; and
- from the end of the transition period, the ACCC will become the authority responsible for regulating transmission network service pricing within South Australia in accordance with the principles set out in Chapter 6 of the Code.

The other provisions in clause 9.29 provide for the use of measures to manage the introduction of network prices during the transition period which are similar to those used by the other participating jurisdictions. They are necessary to ensure that price impacts on customers will be manageable.

South Australia submits that its transitional arrangements relating to transmission network service pricing will not have any identifiable impacts on competition in generation or retailing. In the case of customers, the transmission network charges at a particular connection point will apply irrespective of who is purchasing the electricity and those charges will be independent of energy trading arrangements. In the case of generators, transmission network charges are limited to "entry" costs (including augmentation if needed) and possible "firm access" requirements, both of which are not related to the derogations set out in part D of Chapter 9 of the Code.

As noted above, South Australia has chosen 31 December 2000 as the end date for its transition period to ensure that there is sufficient time for South Australia to manage and complete its transition to the NEM arrangements, particularly in view of the probable commencement date of the Code.

South Australia has foreshadowed in its derogation relating to transmission network service pricing, that upon completion of the current review of this matter it may wish to include in Part D of Chapter 9, a specific derogation to apply after 31 December 2000. This derogation if considered necessary by South Australia will take account of future policy
objectives in relation to customer electricity prices in South Australia. At this stage it is not possible to indicate the nature or the likely impact of any such derogation. If it is determined that a further derogation is necessary, full details of the derogation and the reasons why it is necessary will be provided to the ACCC.

### 7.2.4 Australian Capital Territory

The derogations of the ACT apply only to network connection and pricing determinations.

The size of the Territory and the fact that the ACT's distribution networks exist as an integral part of the interconnected New South Wales system, means that the ACT jurisdictional regulator should probably adopt practices consistent with other jurisdictions so as to reduce costs and facilitate adequate comparisons. It is likely that the regulator will enter into consultancy arrangements with interstate regulatory bodies for this purpose.

It is the intention of the ACT, beyond 1 July 1999, to apply the Code arrangements.

The ACT has adopted similar transitional derogations for the determination of disputes about access and connection to networks to those adopted by New South Wales.

## 8. ASSESSMENT OF INDUSTRY ACCESS CODE

"The industry access code' application form and the related parts
of the Submission, particularly this Chapter 8 and Chapter 4 , are
submitted to the ACCC in draft form. Amendments to Part IILA of
the Act in relation to access codes' have not yet been passed by
the Commonvealth Parliament. Accordingly the access code
application, this Chapter 8 and the related parts of the Submission
(the 'Access Code Submission Material') are provided to the
ACCC on an informal basis for the purpose of giving greater
opportunity for the ACCC and interested parties to give immediate
consideration to the access provisions of the Code and the Access
Code Submission Material The Access Code Submission Material
has been prepared on the basis and assimption that the proposed
amendments to Part IIIA of the Act will be passed in the form of the
Trade Practices Amendment (Indistry Access Codes) Bill l996.
When Part III of the Act is amended to incorporate provisions
dealing with 'access codes': a formal application, together with the
relevant parts of this Submission, taking into account statutory
requirements and relevant facts and circumstances prevailing at
that time, will be delvered to the ACCC for consideration".

### 8.1 Introduction

The Code contains (and incorporates by reference) provisions enabling Code Participants to seek and obtain access to the electricity networks in participating jurisdictions. These electricity networks within the participating jurisdictions (the "national grid") include transmission networks (generally, high-voltage networks) and distribution networks (lower voltage networks). The services provided in respect of the national grid are provided by Network Service Providers (the "network services") (as defined in the Code), and involve transmission and distribution services as described below.

The provisions of the Code which relate to access to network services are principally contained in:

- Chapter 4 (Power System Security);
- Chapter 5 (Network Connection);
- Chapter 6 (Network Pricing);
- $\quad$ Chapter 7 (Metering);
- Chapter 8 (Administrative Functions); and
- Chapter 9 (Transitional Arrangements).

These Chapters, together with relevant parts of Chapters 1,2,3 and 10 and such rules applying in the participating jurisdictions as must be complied with in relation to access to
network services (by virtue of Schedule 5.8 and Chapter 9 of the Code and found within "applicable regulatory instruments" as defined in the Code), are submitted to the ACCC for acceptance as an industry "access code" in accordance with section 44ZZAA of the Act, (referred to in this Submission as the "industry access code").

By gaining access to the national grid, Code Participants can be supplied with the following types of network services:

- transmission services - the conveyance of electricity by a high voltage transmission system together with associated technical support services, such as voltage and frequency control; and/or
- distribution services - the conveyance of electricity by a lower voltage distribution system together with associated technical support services, such as voltage and harmonics control.

However, due to the fact that the various participating jurisdictions already have their own operational electricity industry, some elements of which may not yet have been brought into line with the arrangements proposed for the national electricity market, it is necessary for each of the participating jurisdictions to gradually implement transitional arrangements towards the introduction of the competitive national market, in which State and Territorial boundaries no longer separate the electricity industries of each.

The intention of these transitional arrangements is that they should minimise the impact of transition towards the national market on all Code Participants, especially consumers of electricity. The effect of the transitional arrangements is that, in some cases, certain provisions of the Code do not become operational in one or more participating jurisdictions until some future specified date. The provisions of the transitional arrangements for each participating jurisdiction are set out in Chapter 9 of the Code as follows:

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- Part A - Victoria;
- Part B - New South Wales;
- Part C - Australian Capital Territory;
- Part D - South Australia; and
- Part E-Queensland
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Chapter 4 of the Submission provides a description of the proposed industry access code. It should be reviewed prior to this Chapter. The purpose of this Chapter is to provide a detailed assessment of the industry access code pursuant to the criteria required under Part IIIA of the Act.

Each participating jurisdiction currently has arrangements which govern access to its electricity networks. Some of these arrangements will gradually disappear during the transitional period, but others will remain as continuing jurisdictional access requirements.

Few jurisdictional and specific access arrangements involve departures from the Code beyond the transitional periods nominated by the participating jurisdictions. To the extent
they do so, they are described in Chapter 9 of the Code and explained in Chapter 7 of this Submission.

All of the paragraphs of this Chapter, except 8.5, address arguments in support of the access arrangements set out in the Code itself in terms of the criteria to be used to assess access codes under proposed section 44ZZAA(3) of the Act.

The totality of jurisdictional access arrangements (including, pursuant to clause 5.2.3(c) and Schedule 5.8 of the Code, "applicable regulatory instruments" of a jurisdiction) is described in Chapter 4 and Schedules 7 to 11 of this Submission. The adequacy of those particular jurisdictional access arrangements in terms of the statutory criteria for acceptance of an access code for an industry body under proposed section 44ZZAA(3) of the Act is argued in paragraph 8.5 of this Submission.

### 8.2 Requirements for an industry access code under Part IIIA of the Trade Practices Act

### 8.2.1 Legislative right for third parties to obtain non-discriminatory access

Part IIIA of the Act creates a legislative right for third parties to obtain non-discriminatory access on reasonable commercial terms to services provided by facilities where:

- duplication of the facility is not economically viable;
- access to the facility is necessary in order to permit effective competition;
- the facility is of national significance; and
- the safe use of the facility by the person seeking access can be ensured at an economically feasible cost.

Under Part IIIA, access to a service provided by such facilities may be regulated in one of three ways:

- Declaration of service: the relevant Minister may declare the service as being subject to the provisions of Part IIIA. This declaration is based on a recommendation by the National Competition Council in terms of the declaration criteria specified in Part IIIA. Any dispute over access to a declared service not resolved in commercial negotiations can be subject to compulsory arbitration by the ACCC; or
- Acceptance of access codes and undertakings: providers of essential facility infrastructure services which are likely to be the subject of future declarations by the Minister, may either arrange for an industry body to submit to the ACCC an "access code" for acceptance by the ACCC or submit an undertaking to the ACCC for acceptance. Once an access code is accepted by the ACCC service providers may give the ACCC undertakings specifying the terms and conditions on which access will be provided in conformity with the access code. Once such access undertakings are given to the ACCC the services concemed cannot be declared under Part IIIA; or
- Certification of an "effective access regime": a State or Territory government may establish an access regime and apply to the National Competition Council for a recommendation that the Commonwealth Minister register the regime as "an effective access regime" for the purposes of Part IIIA. The services the subject of a certifed effective access regime cannot be subject to a Ministerial declaration under Part IIIA.


### 8.2.2 Criteria for assessment of industry access code

The proposed section 44ZZAA (dealing with access codes prepared by industry bodies), sets out the matters that the ACCC will be required to consider when evaluating a code and determining whether the code should be accepted as an access code. Section 44ZZAA(3) relevantly provides as follows:
"The Commission may accept the code, if it thinks it appropriate to do so having regard to the following matters:
(a) the legitimate business interests of providers who might give undertakings in accordance with the code ("Criterion 1")
(b) the public interest, including the public interest in having competition in markets (whether or not in Australia) ("Criterion 2")
(c) the interests of persons who might want access to the service covered by the code ("Criterion 3"); ...
(f) any other matters that the Commission thinks are relevant ("Criterion 4")

The numbered criteria have been included by the applicant for ease of reference in the balance of this Chapter of the Submission. The individual criteria are assessed against the various aspects of the industry access code described below.

Before analysing the proposed rules of access against the relevant statutory criteria it is relevant to note that:

## (a) Criterion 2 - concept of "public interest"

The concept of "public interest" is not defined in the Act. The Industry Commission's paper entitled Implementing the National Competition Policy: Access and Price Regulation (published in November 1995) suggested that the key consideration to be taken into account when assessing the public interest should be economic efficiency. The "public interest" factors relevant appear to be:

- promotion of competition;
- fostering business efficiency;
- promotion of cost savings in industry and the consequent containment or reduction of prices at all levels in the supply chain; and
- provision of better information to consumers and business.

In the circumstances it is submitted that the concept of public interest is analogous to the concept of public benefit discussed in paragraph 5.4 of this Submission and that the discussion of public benefit in the context of the code in paragraph 5.5 can be applied to the concept of public interest for the purposes of Criterion 2 in section 44ZZAA(3) of the Act. Accordingly, the discussion in paragraph 5.5 should be taken to be incorporated into, and form part of, the submissions made in this Chapter 8 in respect of Criterion 2.

## (b) Criterion 4 - other matters considered relevant by the ACCC

The ACCC has not publicly indicated the "other matters" that it will take into account when assessing an industry access code. The ACCC has, however, indicated the types of matters that it might take into account when assessing individual access undertakings, including:

Matter 1: economic efficiency, including efficient resource allocation
Matter 2: market transparency and appropriateness of the proposed access pricing and terms and conditions

Matter 3: equity considerations, including non-discrimination between like access seekers

Matter 4: the extent and significance of any barriers to entry in related markets including the promotion of competition in upstream and downstream markets

Matter 5: any operational and technical constraints imposed on market participants
Matter 6: adequacy of information disclosure requirements on the provider to meet the needs of potential third parties

Matter 7: whether dispute resolution principles and procedures specified in the industry access code are adequate to meet the needs of users and providers

Given that a consideration of the merits of an individual access undertaking is likely to be analogous to a consideration of the industry access code, this Submission proceeds on the assumption that the additional matters noted above may be considered by the ACCC.

It should be noted that if the ACCC has any additional criteria which it would like addressed that are not covered in this Submission, further material can be provided.

### 8.3 Form of industry access code

### 8.3.1 Introduction - industry access code

The rules for access to network services described in paragraph 8.1 are submitted to the ACCC for acceptance as an access code. Should the ACCC accept the industry access code in accordance with section 44ZZAA, each provider of network services will be required to give an access undertaking under Schedule 5.8 of the Code which will be in accordance with and no broader than the industry access code.

Therefore, it is submitted that in accordance with the proposed section 44ZZA(4A), the ACCC will be entitled to accept that undertaking without complying with section $44 Z Z A(4)$ as it will be satisfied that that undertaking is in accordance with the industry access code.

### 8.3.2 Period of Access Code

The proposed expiry date for the industry access code is 31 December 2010.
Network Service Providers who are registered by NEMMCO at the commencement of the operation of the Code nominate 31 December 2010 as the proposed expiry date of their access undertakings. Paragraph 1.5 of this Submission discusses the rationale behind this expiry date.

Network Service Providers who become registered by NEMMCO at a later date will also provide undertakings as specified in the Code at the time of registration by NEMMCO.

### 8.3.3 Existing access arrangements

The existing jurisdictional access arrangements are described in Schedules 7-11 of this Submission. Parts of the jurisdictional access arrangements will continue to operate as part of the NEM access regime following commencement of the market and the merits of those parts which do continue are discussed in paragraph 8.5.

### 8.4 Satisfaction of the criteria in section 44ZZAA(3) and other relevant matters

### 8.4.1 Introduction

This paragraph 8.4 examines the effectiveness of the rules regulating access to network services set out in Chapters $1-8$ and 10 of the Code. Paragraph 8.5 examines the balance of the access rules comprising the industry access code, being the specific jurisdictional access arrangements that will continue to apply following commencement of the NEM. . To facilitate this examination, the basic provisions of the industry access code will be examined separately against those criteria which are relevant to the industry access code provisions. The main provisions of the industry access code are as follows:

- connection requirements (detailed in Chapter 5 of the Code);
- network planning and augmentation (detailed in Chapter 5 of the Code);
- transmission revenue regulation (detailed in Part B of Chapter 6 of the Code);
- transmission pricing structure (detailed in Part C of Chapter 6 of the Code);
- distribution regulation and network pricing (detailed in Parts D and E of Chapter 6 of the Code); and
- dispute resolution and enforcement of the industry access code (Chapter 8 of the Code and National Electricity Law).


### 8.4.2 Assessment of the connection requirement provisions of the industry access code

## Overview

Clause 5.1.2(a) of the Code states that Chapter 5 of the Code provides the framework for connection to a transmission network or a distribution network and access to the networks forming the national grid and has the following aims:

- to detail the principles and guidelines governing connection and access to a network;
- to establish the process to be followed by a Code Participant to establish or modify a connection to a network;
- to address the Connection Applicant's reasonable expectations of the level and standard of power transfer capability that the network should provide; and
- to establish processes to ensure ongoing compliance with technical requirements of this Chapter of the Code to facilitate management of the national grid.

Chapter 5 provides a set of procedures for those seeking connection and for Network Service Providers to process connection applications. It needs to be recognised that arrangements and procedures for connection to transmission and distribution networks have existed for many years but these differ between jurisdictions and between Network Service Providers. One objective of these provisions is to provide a common set of procedures for connection to simplify entry for parties seeking access.

Clause 5.2 of the Code sets out the obligations on Network Service Providers to provide an access undertaking to the ACCC in accordance with the industry access code. Under these arrangements the Network Service Providers are to make their networks available for connection and must operate their networks in accordance with system performance and quality of supply standards defined in Schedule 5.1.

Clauses 5.3 and 5.4 set out the rights and obligations on generators and customers respectively to maintain and operate equipment that is connected to the network in accordance with relevant laws, the Code and good industry practice. The connection requirements applying to generators and customers are defined in Schedules 5.2 and 5.3 respectively. Schedule 5.1 specifies the requirements for connection of a network to another network.

The major principle of the connection requirements provisions is that a party is to be provided physical access to a transmission or distribution network on a fair and reasonable basis provided that the connection arrangements do not materially or adversely affect the levels of service and quality of supply to other network users.

Criterion 1: the legitimate business interests and investments of the service provider
The connection requirement provisions impose certain obligations on the service provider, with regard to minimum levels and standards of network performance and customer service. Generally speaking, the network performance standards in the Code reflect a continuation of pre-existing standards applying to the meshed or shared network (a "natural monopoly"), and which therefore apply uniformly to all parties connected to that network. Clause 6.2.4(c)(2) requires the regulator to take these performance standards into account when determining a revenue cap to apply to these natural monopoly services.

Chapter 5 provides for negotiation between the access seeker and the service provider on terms and conditions relating to any aspect of the service which can be varied without adversely affecting the levels and quality of supply to other network users.

To protect the legitimate business interests and investments of the Network Service Provider, Chapter 5 of the Code provides that the Network Service Provider:

- must co-ordinate the design aspects of equipment proposed to be connected to its networks with those of other Network Service Providers in accordance with clause 5.4 in order to seek to achieve power system performance requirements in accordance with Schedule 5.1;
- is not obligated to effect an extension of the power system unless that extension is required to effect or facilitate the connection of a party which is the subject of a connection agreement in accordance with clause 5.3.6;
- must together with other Network Service Providers, arrange for and participate in planning and development of their networks and connection points on or with those networks in accordance with clause 5.6;
- must permit and participate in inspection and testing of facilities and equipment in accordance with clause 5.7;
- must permit and participate in commissioning of facilities and equipment which is to be connected to its network in accordance with clause 5.8;
- may disconnect a party in accordance with the provisions of the party's connection agreement;
- may disconnect a party in an emergency in accordance with clause 5.9;
- may impose prudential requirements on a party seeking connection in accordance with clause 6.6 for transmission networks and clause 6.15 for distribution networks.

It is considered that the connection requirement provisions do not unduly impinge upon the legitimate business interests and investments of the Network Service Provider.

## Criterion 2: the public interest, including the public interest in having competition in markets (whether or not in Australia)

As stated in paragraph 6.3 .15 of this Submission, the Code prescribes minimum technical standards for equipment connected to the system. The effect on competition in the market may vary depending on whether the standards apply to:

- generators;
- transmission networks;
- distribution networks; and
- customers.

The specification of technical standards for equipment connected to the network are designed to ensure that from a participant's perspective a clear and unambiguous framework is established within which they can negotiate with Network Service Providers on the terms and conditions for a connection facility and at the same time ensure the integrity of the network to provide the quality of service required by other users.

It is important to note that the conditions for connection for a generator have been specified in a manner to remove any bias against altemative generation technology provided that the alternative is safe for public use.

These technical standards despite their different impacts on suppliers and customers operate in the public interest because without them the power system will not operate safely to convey electricity to customers to an acceptable technical quality of supply. A power system that meets quality of supply and technical safety standards is in the public interest.

In addition, competition in the provision of connection services is addressed clause 5.3.4 of the Code which provides that a party seeking connection may submit applications to connect to more than one Network Service Provider in respect of facilities to be provided that are contestable.

Criterion 3: the interests of persons who may require access to the service
The Code seeks to protect the interests of persons who may want to physically connect to transmission or distribution network to convey electricity through the following provisions:

- clause 5.3 .2 of the Code ensures that any party wishing to lodge a connection enquiry may be assured that the Local Network Service Provider is bound to process the enquiry;
- clause 5.3 of the Code sets out the procedures to followed by a party seeking to establish or modify connection to a network. These procedures cover:
- information to be provided by the party seeking connection;
- the identification of a connection co-ordinator to liaise as appropriate with other Network Service Providers that may be impacted by the proposed connection;
- information to be provided in response by the Network Service Provider;
- requirements on Network Service Provider to liaise with other affected Network Service Providers;
- provision by the Network Service Provider of a work program for the connection;
- requirement on the Connection Applicant to pay an application fee;
- requirements on a Network Service Provider to respond within a specified time period;
- requirement on a Network Service Provider to provide an offer to connect specifying equipment performance, extent and cost of works, impact on network service charges and effect on power transfer capability;
- steps to follow to finalise the connection agreement; and
- maintaining the confidentiality of information provided by a Connection Applicant.

The Network Service Provider and Connection Applicant may negotiate with each other in respect of the provision of connection and any other matters relevant to the provision of connection.

The parties may seek to vary the terms and conditions from those contemplated by this Code where relevant considerations such as geographic factors make variation necessary or desirable provided that any such conditions are reasonable and are explicitly identified in the offer to connect.

The interests of the party seeking access is also protected because according to Schedule 5.1 of the Code, a Network Service Provider must:

- fully describe the quantity and quality of network services which it agrees to provide to a person under a connection agreement in terms that apply to the connection point as well as to the transmission or distribution system as a whole;
- ensure that the quantity and quality of those network services are not less than could be provided to the relevant person if the national grid were planned, designed and operated in accordance with the criteria set out in this Schedule 5.1 and recognising that levels of service will vary depending on location of the connection point in the network; and
- to the extent that this Schedule 5.1 does not contain criteria which are relevant to the description of a particular network service, the Network Service Provider must describe the network service in terms which are fair and reasonable.


## Matter 2: market transparency and appropriateness of the proposed access pricing and terms and conditions

## Matter 3: equity considerations, including non-discrimination between like access seekers

These matters are addressed jointly.
The connection requirement provisions have been developed based on the principle of commercial negotiation of connection services terms and charges as being synonymous with the concept of "light handed regulation". It is important that the Network Service Providers and parties seeking to establish connection negotiate a connection agreement that meets the needs of the Connection Applicant without adversely or materially affecting the levels of service and quality of supply received by other network users. Regulatory intervention should only be required in the event of an access dispute or where a party believes they have been discriminated against.

The terms and conditions for connection are addressed in the following Code provisions:

- responsibility for the planning and design of connection assets will be essentially driven by the customers who are receiving the service. Most decisions can be made by them with respect to the level of service including the capacity of the transmission or distribution network without impacting on other participants. (Clause 5.4)
- where affected participants are in a position to consider the longer term implications of changes in their loading without the need for sophisticated pricing signals to be provided, it is sufficient to allocate the costs of providing the connection service to the dedicated receivers of that service. (Clause 6.4.2)
- any augmentation of dedicated connection assets would take place only at the request of the connected participant. The additional service would be covered under a long term contractual relationship between the Network Service Provider and the connected party and it is likely that it would take the form of a "take or pay" contract. This form of the contract is not specified in the Code but the Code recognises that any such arrangements fall outside the specific provisions of the cost allocation in the Code. (Clause 5.3)
- existing connection assets are treated in the same manner as new assets. The total cost of providing these assets is fully allocated to the relevant participants and the risk allocation would be specified in contracts established between the parties at the time of vesting. (Clause 6.4.2)
- the charges for connection provided by existing equipment are calculated from the annual costs of the equipment which is installed at the sub-station. The annual cost of individual network elements is determined by allocating the total revenue requirement of the connection asset categories assets on a pro rata basis with their deprival value. (Part C of Chapter 6)
- the network owner will need to itemise the plant recovered under connection charges. This could take the form of a sub-station layout diagram, with allocation to network or connection assets clearly marked. (Schedule 5.6).

These arrangements are considered fully consistent with the intent of providing an efficient and equitable access regime. The participants have full control over the planning decisions with knowledge of the price associated with provision of additional network service. They are able to make appropriate trade-offs between cost and the performance and reliability of the network service provided.

New entrants can seek access to a transmission or distribution network and will be able to obtain access at defined (fair and reasonable) prices which accurately reflect the cost of providing the necessary assets to allow connection at the specified capacity and level of performance.

Chapter 6 of the Code therefore provides connection (entry and exit) services to be defined as separate services with costs allocated to these services recovered directly from the affected participants.

## Matter 5: any operational and technical constraints imposed on market participants

The Code prescribes extensive minimum technical requirements on a party seeking connection to a transmission and distribution network and operational requirements on the party after connection has been established. These requirements include:

- compliance with Schedule 5.1 for conditions for connection of two networks
- compliance with Schedule 5.2 for conditions of connection of a generator
- compliance with Schedule 5.3 for conditions of connection of a customer
- compliance with the Chapter 5 provisions for:
- Clause 5.7 Inspection and testing
- Clause 5.8 Commissioning
- Clause 5.9 Disconnection and Reconnection
- compliance with the metering provisions of Chapter 7 if the party seeks to participate in the wholesale market as a Market Participant
- compliance with the obligations of Code Participants for power system security in Chapter 4 including:
- Clause 4.8 Power System security operations
- Clause 4.9 Power Systems security related market operations
- Clause 4.10 Power system operating procedures
- Clause 4.11 Power system security support

Under Schedule 5.6 of the Code, a party seeking connection must enter into legally binding and enforceable connection agreements with the Network Service Provider(s) which must require the parties to abide by and comply with the Code particularly the relevant provisions described above depending upon whether the party seeking connection is a network, generator, or customer.

These technical and operational requirements are consistent with good electricity industry practice and applicable Australian Standards. They also are essential to the Network Service Provider's ability to meet the network performance requirements in Schedule 5.1 of the Code and the ability of NEMMCO, Network Service Providers, and System Operators to fulfil their power system security responsibilities and obligations in accordance with clause 4.3 of the Code. A power system that meets quality of supply and technical safety standards is the public interest.

## Matter 6: adequacy of information disclosure requirements on the provider to meet the needs of potential third parties

Chapter 5 of the Code provides for extensive information disclosure requirements to assist the Network Service Providers to meet the needs of potential third parties. These provisions include:

- preliminary information to be provided for an connection enquiry (Schedule 5.4);
- joint information disclosure requirements for preparing an application for connection (Clause 5.3.3) including Schedule 5.5 Technical Details to Support Application for Connection and Connection Agreement;
- consultation with other affected Code Participants when processing an application for connection (Clause 5.3.5);
- restrictions on the disclosure of information used to establish a connection under clause 5.3 (Clause 5.3.8);
- information requirements for the design of connection equipment (Clause 5.4);
- information disclosure requirements inspecting and testing a Code Participant's facilities (Clause 5.7);
- information disclosure requirements when commissioning a Code Participant's facilities (Clause 5.8); and
- information disclosure requirements when a Code Participant's is either disconnected or reconnected to a transmission or distribution system.

These information disclosure provisions have been designed to ensure that:

- the party seeking connection is fully aware of the information that is required to enable connection to be established
- the Network Service Provider can provide access to a transmission or distribution network without materially or adversely affecting the levels and quality of service received by other network users.


### 8.4.3 Assessment of the network planning and augmentation provisions of the industry access code

## Overview

Chapter 5 of the Code specifies the principles and procedures to be followed by Network Service Providers in planning and augmenting networks. In developing these provisions the proposed model is one of light handed regulation which relies upon public consultation, mandatory consideration of supply and demand side options to alleviate network constraints, competition between network service providers and/or owners wherever this is feasible, and a primary evaluation criterion of net customer benefit. The proposed arrangements recognise that:

- certain aspects of network service provision can readily be made the subject of competition; however
- the network pricing model proposed in Chapter 6, coupled with the proposed treatment of network loss and constraint costs in the National Electricity Market design imply that network augmentation decision-making largely remains a naturally monopolistic function.

In recognition of the "naturally monopolistic" nature of the augmentation investment decision, and the potential conflict of interest faced by a decision-maker whose income may ultimately depend on the value of assets under ownership, Chapter 5 proposes the establishment of a comprehensive consultation and review process to ensure that the interests of Network Users are fully protected in any network augmentation decision. This process is subject to regulatory oversight, but does not involve the regulator in the network planning decision itself.

The Code aims to provide an environment which fosters an efficient level of investment in transmission and distribution networks.

The Code provisions for the planning and development of the network recognise the need to provide information to existing and potential network users to enable them to make informed choices regarding their interaction with the network and the market. For a network, individual users are unable to plan the network completely since individual decisions with respect to different levels of performance would impact on other users, that is, there are externalities associated with network use. These arrangements are based on the need to coordinate this activity to ensure appropriate outcomes for participants and also recognise the different governance arrangements with respect to network planning in each participating jurisdiction.

Criterion 1: the legitimate business interests and investments of the service provider
Criterion 2: the public interest, including the public interest in having competition in markets (whether or not in Australia)

Criterion 3: the interests of persons who may require access to the service
Matter 4: the extent and significance of any barriers to new entry in related markets including the promotion of competition in upstream and downstream markets

## Matter 6: adequacy of information disclosure requirements on the provider to meet

 the needs of potential third partiesThese criteria and matters are addressed together.
Under Chapter 5 of the Code, there are four processes by which a network augmentation may be initiated namely:

- in response for an application for connection or to modify an existing connection (Clause 5.3) by a generator or a customer;
- $\quad$ as part of the annual planning review of networks in a region (clause 5.6.2);
- as part of the annual planning of the power system's transmission networks (clause 5.6.5); and
- as part of the special access conditions for parties seeking to establish new interconnectors (clause 5.6.6).

All four processes have the same common provisions which have the effect of:

- protecting the legitimate business interests and investments of the service provider;
- protecting the public interest, including the public interest in having competition in markets (whether or not in Australia);
- protecting the interests of persons who might want access to the service;
- reducing barriers to new entry in related markets including upstream and downstream markets; and
- providing adequate information disclosure requirements on the provider to meet the needs of potential third parties.

These processes and their common provisions are discussed below.

## Augmentation associated with a party seeking access

Under clause 5.3 .5 of the Code when preparing an offer to connect the Network Service Provider is obliged to consult with NEMMCO and other Code Participants with whom it has connection agreements, if the Network Service Provider believes the terms and conditions of those connection agreements will be affected by the party seeking connection. The Network Service Provider is to determine:

- the performance requirements for the equipment to be connected;
- the extent and cost of augmentations and changes to all affected networks;
- any consequent change in network service charges; and
- the possible material effect of this new connection on the network power transfer capability including that of other networks.
In finalising the connection agreement, the party seeking access is to pay for its connection facilities plus any proportion of the augmentation costs that is attributed to that party under the network pricing methodology endorsed by the appropriate regulator. The balance of any augmentation costs are to be recovered from other network users using the same network pricing methodology.

The information disclosure requirements for a party seeking connection have already been discussed in paragraph 8.4.2.

## Augmentations associated with annual planning reviews of the networks within a region

Clause 5.6 .2 of the Code provides for an annual planning review to be conducted by the Transmission Network Service Provider in conjunction with each Distribution Network Service Provider connected to the transmission network within each region. As part of the planning review process, the Network Service Provider is to:

- issue a report to all affected Code Participants of any relevant technical limits the transmission or distribution system will exceed over the next five years for distribution networks and ten years for transmission networks based on an extrapolation of the load forecasts provided by Code Participants in accordance with clause 5.6.1;
- consult with affected Code Participants and interested parties on the possible options to address the projected limitations of the relevant transmission or distribution system; and
- carry out economic cost effectiveness analysis of possible options to identify the option that maximises net benefit to Customers over a period of at least fifteen years. The range of options is to include a comparison of network augmentation, generation and demand side options.

Following the consultations with the affected Code Participants, the Network Service Provider must prepare a report that is to be made available to affected Code Participants and interested parties which:

- includes assessment of all identified options;
- includes details of the Network Service Provider's preferred proposal;
- summarises the submissions from the consultations; and
- recommends the action to be taken.

A proposal likely to increase the use of system charges of a Code Participant by more than $2 \%$ at the date of the next price review may be disputed by that Code Participant and if agreement cannot be reached in negotiations with the Network Service Provider, then the matter is to be resolved by NECA using the dispute resolution procedures of Chapter 8 for
transmission networks. For distribution networks such disputes will be managed by the Jurisdictional Regulator. The 2\% threshold is to provide Network Users with some protection from unreasonable price shocks.

After a period of review, the agreed or determined cost of the augmentation is included for revenue determination purposes in the asset base of the relevant network service provider and is recovered through use of system charges.

## Augmentations associated with annual planning reviews of the power system's transmission networks

Under clause 5.6 .3 of the Code, NEMMCO must establish an Inter-regional Planning Committee whose functions are to:

- assist NEMMCO in the preparation of the statement of opportunities in accordance with clause 5.6.4;
- undertake an annual planning review of the power system in accordance with clause 5.6.5;
- assess all applications to connect made by Connection Applicants seeking to establish new interconnectors between regions in accordance with clause 5.6.6.

The Inter-regional Planning Committee, comprised of NEMMCO, transmission system planners, and other experts nominated by NEMMCO, is being established to ensure that changes to transmission networks are coordinated to maintain the network performance standards specified in Schedule 5.1 of the Code. This central coordination by NEMMCO is essential to properly plan and enable expansion of the power system's transmission networks to provide transmission services to new generators seeking access upstream in the generation market and new customers seeking access downstream in the supply market. In the absence of a coordinated transmission planning process, the quality of supply to existing and new Network Users cannot be maintained.

In the annual planning review, the Inter-regional Planning Committee must:

- identify the magnitude and significance of future network losses and constraints on power transfers within and between regions and identify and assess options for the reduction or removal of future network constraints and reduction in network losses including the construction of new transmission lines between regions, or the implementation of demand side or generation investments by Code Participants or other persons;
- develop and publish a program for the periodic review of options for the removal or reduction of each network constraint as soon as practicable based on the most recent assessment of augmentation options;
- consider any transmission system augmentation proposals submitted voluntarily by a Transmission Network Service Provider to determine whether it is of net public benefit;
- must call for and receive submissions from Network Service Providers, Code Participants, other interested parties and relevant participating jurisdictions for the assessment of particular augmentation options;
- assess the economic and technical effects of the augmentation options using the primary criterion of maximising net benefits to customers based on the premise that all transmission systems are to be planned and operated as if they form a single power system; and
- must report on the methodology used for its assessment and it must make recommendations to NEMMCO on its assessment of the costs and benefits of augmentation options to remove or reduce network constraints or losses.

The planning arrangements are structured under clause 5.6 .5 for NEMMCO to act in the public interest if it believes that further analysis is required to determine whether an augmentation is justified. NEMMCO may commission an independent analysis the costs of which are to be paid by NEMMCO and included in the calculation of Participant fees.

The Code also prescribes how a justified proposal is to proceed. It is important to note that the Code strictly limits NEMMCO's role to making determinations only. NEMMCO is not permitted to call for tenders to invest in network assets. The process is:

- the Network Service Providers whose networks would require augmentation may arrange for the augmentation project to be undertaken and the cost of the relevant assets are to be included in the determination of the revenue cap in accordance with Part B of Chapter 6; or
- if the relevant Network Service Provider declines to arrange for the augmentation to be undertaken, NEMMCO must mediate and liaise with the relevant Jurisdictional Regulator to resolve the dispute.

If NEMMCO determines that an augmentation is not justified, then the relevant Network Service Provider may itself undertake, or arrange for the augmentation project to be undertaken and, to the extent that the augmentation will provide regulated services, the cost of the relevant assets are to be included in the determination of the revenue cap in accordance with Part B of Chapter 6. It should be noted that any augmentation investment made by the Network Service Provider which is not the subject of a take or pay contract, or which has not been determined as being of net benefit to customers by the Inter-regional Planning Committee will be subject to periodic asset revaluation for revenue determination purposes. In other words, the relevant Network Service Provider bears the stranded asset risk on any such investments.

A determination by NEMMCO that an augmentation is or is not justified is a reviewable decision if a party wants it reviewed by the National Electricity Tribunal.

It is submitted that these arrangements are in the public interest as they:

- provide for an objective review of the net benefit of a proposed investment to be undertaken by an independent party (NEMMCO's Inter-regional Planning Committee) which has no commercial interest in the outcome;
- provide for all parties affected by the proposed investment to have input to a comprehensive and transparent review process prior to any investment decision being made;
- seek to ensure that where the Inter-regional Planning Committee's process leads to a determination that augmentation is of net benefit to Participants, the network owner which executes that augmentation does not unduly bear risk associated with an investment decision made as a result of that process.

The last point noted above is an important feature of the arrangements. It results in efficient risk allocation, as the Network Service Providers which will implement the determinations of the Inter-regional Planning Committee (IPC) will not bear the "stranded asset risk" ${ }^{1}$ associated with investment decisions beyond the control of those service providers. In effect, the "stranded asset risk" is bome by the Network Users, who are fully and formally consulted during the IPC decision consultation and review process as specified in Chapter 5.

The objectives of the arrangements are therefore:

- to ensure, through a process of comprehensive review and consultation with the Network Users (who in effect underwrite the market risk on the investment), that at the time of the augmentation investment decision being taken, that decision is optimum;
- to provide, through efficient risk allocation and through minimisation of the Network Service Provider's cost of capital, an environment in which investment decisions may be readily executed at least cost to the Network User; and
- to ensure the overall cost of transmission network augmentation is minimised, thereby minimising the cost of transmission across the national grid, and maximising opportunities for trading electricity.


## Applications to establish new interconnectors across regions

The Code provisions for parties seeking access to connect interconnectors between regional networks have been drafted based on the following principles:

- the Code should not be overly prescriptive on the arrangements for new interconnectors to permit parties to develop commercial arrangements that suit their needs and where such arrangements conflict with the Code they will be required to go through the Code change processes administered by NECA;
- customers should not be required to pay for costs of augmentations to support access for new interconnectors when it is independently determined by the public consultation process outlined in Chapter 5 that customers receive no net benefit for these augmentations;

[^24]- a party establishing an interconnector must agree to be bound by the industry access code other than the transmission service regulation and pricing arrangements in Chapter 6 of the Code;
- network pricing regulation of an interconnector will be dependent on whether the interconnector can be demonstrated by the Inter-regional Planning Committee to be of net benefit to Customers.

The interest of Customers is protected by the following provisions in clause 5.6.6:

- Clause 5.6 .6 (a) requires all proposals for new interconnectors to comply with the access arrangements in Clause 5.6.6;
- Clause 5.6 .6 (b) provides that the Inter-regional Planning Committee must undertake a review of all applications to establish new interconnectors in order to assess the application to connect and determine:
(i) the performance requirements for the equipment to be connected;
(ii) the extent and cost of augmentations and changes to all affected networks;
(iii) any consequent change in network service charges for other Network Users subject to clause 5.6 .6 (c),(d),(e) and (f); and
(iv) the possible material effect of this new connection on the network power transfer capability including that of other networks.
- Clause 5.6 .6 (c) provides that the interconnector proposal must be subject to a review of the economic and technical effects of the proposed interconnector in accordance with clause 5.6 .5 (public consultations) to determine whether there is a net benefit to Customers based on a premise that all transmission systems are to be planned and operated as if they form a single transmission system.
- Clause 5.6 .6 (d) provides that if NEMMCO determines that the proposed interconnector is justified, then the proposed interconnector may, with the consent of the Connection Applicant, be deemed a regulated interconnector that will be subject to transmission network regulation and pricing in accordance with Chapter 6 of the Code. In this event, the costs of augmentations to other affected networks are to be included in revised network service charges for other network users determined in accordance with Chapter 6 of the Code.
- Clause 5.6 .6 (e) provides that if the Connection Applicant proceeds to establish the new interconnectors, it must comply with the determinations of the Inter-regional Planning Committee with regard to the performance requirements of equipment to be connected.
- Clause 5.6 .6 (f) provides that if the Connection Applicant does not make a request under clause 5.6.6(c),or having made a request, does not consent to the interconnector becoming a regulated interconnector in clause 5.6.6(d), or NEMMCO determines that the proposal is not justified, then the interconnector
will be deemed to be a non-regulated interconnector. In this event, the Connection Applicant must:
(i) establish connection agreements with all affected Network Service Providers where augmentations are required to their networks to support the connection and pay for the augmentations and on-going operations and maintenance costs associated with the augmented network assets;
(ii) register with NEMMCO as a Market Participant;
(iii) agree to satisfy all obligations of a Network Service Provider under the Code in relation to that interconnector other than the transmission service regulation and pricing arrangements in Chapter 6 of the Code; and
(iv) apply to NECA in accordance with clause 3.12 to determine the rules that will apply in terms of the Connection Applicant's participation in the market as a Market Participant in relation to that interconnector.

The rights of the party seeking access are taken into account in clause 5.6 .6 (h) under which a determination by NEMMCO with respect to the establishment of an interconnector is a reviewable decision.

## Matter 1: economic efficiency, including efficient resource allocation

The effectiveness of the network planning process in terms of achieving economic efficiency and efficient resource allocation will be dependent on the extent to which network prices provide locational price signals. Network prices should provide signals to optimise the cost of network development in order to minimise the cost of development and operation of the NEM.

This will depend on the network pricing methodology adopted for either transmission or distribution networks. As both Part C - transmission pricing and Part E-distribution pricing are subject to review by NECA and the ACCC, an assessment of this matter will have to await the outcome of those reviews.

Until then, it is submitted that the transitional arrangements for network pricing in each participating jurisdiction strike a balance between pure economic efficiency considerations and the objective of non-discriminatory pricing.

### 8.4.4 Assessment of the transmission revenue regulation provisions of the industry access code

## Overview

Part B of Chapter 6 of the Code outlines the principles, objectives, mechanisms and information disclosure requirements of the regulatory regime to apply to transmission revenue.

Clause 6.2.1 outlines the proposed regulatory arrangements to apply to transmission pricing in the NEM. These arrangements provide ultimately for the regulation of access to transmission system to be administered by a single national regulator.

Clause 6.2.2 sets out the objectives of the transmission revenue regulatory regime to be administered by the ACCC. The key objectives include achievement of the following outcomes:

- an efficient and cost-effective regulatory environment;
- an incentive-based regulatory regime which provides an equitable allocation between service users and service providers of efficiency gains the ACCC expects the service providers to achieve;
- provision, on a prospective basis, of a fair and reasonable rate of return to service providers assuming efficient investment and efficient operating and maintenance practices;
- prevention of monopoly rent extraction by service providers;
- an environment which fosters an efficient level of investment within the transmission sector and upstream and downstream sectors;
- an environment which fosters efficient use of existing infrastructure;
- reasonable recognition of pre-existing policies of governments regarding transmission asset values, revenue paths and prices;
- promotion of competition in upstream and downstream markets and promotion of competition in the provision of network services where economically feasible;
- reasonable regulatory accountability through transparency and public disclosure of regulatory processes and the basis of regulatory decisions;
- reasonable certainty and consistency over time of the outcomes of regulatory processes and recognition of the adaptive capacities of Code participants in the provision and use of transmission network assets;
- reasonable and well defined regulatory discretion which permits an acceptable balancing of the interests of service providers, service users and the public interest, as required of the ACCC under the provisions of Part IIIA.

Clause 6.2.3 sets out the principles for regulation of transmission pricing. The key principles are:

- concerns over monopoly pricing in transmission will, wherever possible, be addressed through the introduction of competition; but
- where there is no practicable scope for competition, the maximum revenue which a network owner can recover is to be subject to independent regulation.

These principles are intended to ensure the achievement of effective "light handed" regulation and provide controls to safe-guard consumers from the exploitation of monopoly power.

Clause 6.2 .4 sets out broadly the form and mechanism of the revenue cap to be applied to network owners. A "CPI minus X" regime, or some other incentive-based variant is proposed. Reviews of revenue controls will occur at five-yearly intervals. The clause identifies the key considerations to be taken into account by the ACCC in determining the revenue cap.

Clause 6.2.5 provides for the establishment by the regulator of an information disclosure regime to apply to regulated service providers. The purposes of the information disclosure regime are to enable the regulator to:

- monitor compliance of the service provider with the revenue cap; and
- gather information on the performance of the regulated entities to be used as input for decisions regarding future revenue cap levels.

Clause 6.2.6 provides for the disclosure of reasonable information by the ACCC as to the basis of its regulatory decisions under Part B of the Code.

Criterion 1: the legitimate business interests and investments of the service provider
C1(a) Cost structure of the transmission sector and implications for regulatory design

The cost structure of the transmission sector and the implications of this for regulatory design were considered in drafting the proposed regulatory arrangements to apply to transmission revenue.

Transmission is highly capital intensive. Asset-related costs comprise approximately 75\% to $80 \%$ of the total annual revenue requirement of a typical transmission utility. Transmission assets are very long-lived (with depreciable lives averaging 40 to 50 years), but have little or no value in alternative use.

Taking into account the particular characteristics of the transmission sector, clause 6.2.2(b) of the Code requires the ACCC to administer "an incentive-based regulatory regime which:

- provides an equitable allocation between Transmission Network Users and Transmission Network Owners and/or Transmission Network Service Providers (as appropriate) of efficiency gains reasonably expected by the ACCC to be achievable by the Transmission Network Owners and/or Transmission Network Service Providers (as appropriate); and
- provides for, on a prospective basis, a sustainable commercial revenue stream which includes a fair and reasonable rate of return to Transmission Network Owners and/or Transmission Network Service Providers (as appropriate) on efficient investment, given efficient operating and maintenance practices of the Transmission Network Owners and/or Transmission Network Service Providers (as appropriate)"

Achievement of the objective outlined in clause 6.6.2(b)(2) is clearly in the business interests of the service provider. However, taking into account the longevity of the assets
and the high sunk costs involved, achievement of this objective is also regarded as being in the public interest. This is because it provides a signal to capital markets that there is a reasonable prospect of earning appropriate returns on future new investment in the network. This, in turn ensures that the grid owners will be able to raise capital at a reasonable cost, in order to maintain and expand the capability of the grid in accordance with the requirements of the users.

It is submitted that the revenue capping arrangements provide the ACCC with an approach enabling the revenue cap to be set at a level which:

- delivers the maximum amount of consumer benefit (in the form of the lowest possible prices) over the regulatory control period; whilst
- ensuring that the owner has strong incentives to earn a normal commercial rate of return by striving toward best practice in operations and maintenance costs and capital investment.

Given these considerations, it is further submitted that the revenue capping arrangements provide the ACCC with an approach enabling it to strike a reasonable balance between the legitimate business interests of service providers and the interests of customers.

C1(b) Shareholder value implications for network owners of periodic application of deprival valuation

Clause 6.2.3(d)(4) states:
"The regulatory regime to be administered by the ACCC must be consistent with the objectives outlined in clause 6.2 .2 and must also have regard to the need to:

> provide a fair and reasonable risk-adjusted cash flow rate of return to Transmission Network Owners and/or Transmission Network Service Providers (as appropriate) on efficient investment given efficient operating and maintenance practices on the part of the Transmission Network Owners and/or Transmission Network Service Providers (as appropriate) where:
(i) assets created at any time under a take or pay contract are valued in a manner consistent with the provisions of that contract;
(ii) assets created at any time under a network augmentation determination made by NEMMCO under clause 5.6.5 are valued in a manner which is consistent with that determination;
(iii) subject to clauses 6.2.3(d)(4)(i) and (ii), assets (also known as "sunk assets") in existence and generally in service on 1 July 1999 are valued at the value determined by the Jurisdictional Regulator or consistent with the regulatory asset base established in the participating jurisdiction provided that the value of these existing assets must not exceed the deprival value of the assets and the ACCC may require the opening asset values to be independently verified through a process agreed to by the National Competition Commission;
(iv) subject to clauses 6.2.3(d)(4)(i) and (ii), valuation of assets brought into service after 1 July 1999 ("new assets"), any subsequent revaluation of any new assets and any subsequent revaluation of assets existing and generally in service on 1 July 1999 is to be undertaken on a basis to be determined by the ACCC and in determining the basis of asset valuation to be used, the ACCC must have regard to:
a) the agreement of the Council of Australian Governments of 19 August 1994, that deprival value should be the preferred approach to valuing network assets;
b) any subsequent decisions of the Council of Australian Governments; and
c) such other matters reasonably required to ensure consistency with the objectives specified in clause 6.2.2; and
(v) benchmark returns to be established by the ACCC are to be consistent with the method of valuation of new assets and revaluation, if any, of existing assets and consistent with achievement of a commercial economic return on efficient investment."

The periodic application of deprival value, as suggested in clause 6.2.3(d)(4)(i), increases the uncertainty of investment returns to service providers, particularly where the revenue cap set by the ACCC reflects changes in asset replacement costs and technologies (including technologies which enable network substitution or bypass). Schedule 17 provides a description of the rationale of the deprival value method. It is submitted that this is in the public interest, given that the basic purpose of undertaking periodic deprival value revaluations is:

- to ensure that prices for monopoly services reflect the cost of efficient new entrants to the market (thus ensuring efficient and equitable prices); and
- to provide incentives to monopolists to undertake adequate analysis of the uncertainty associated with future changes in technology, and electricity supply and demand before making an investment decision (thus ensuring that the grid company faces incentives to invest in an optimum manner).

The periodic application of deprival value is intended to provide an artificial means of imposing the discipline of contestable markets on monopolists. Provided the estimated cost of capital reflects the risks inherent in such arrangements, the arrangements should not pose an undue threat to the legitimate business interests or investments of the service provider. (Clause 6.2 .3 (d)(4) states that the transmission revenue regulatory regime to be administered by the ACCC shall have regard to the need to provide a fair and reasonable risk-adjusted cash flow rate of retum to the transmission network owner.) Furthermore, clauses $6.2 .3(\mathrm{~d})(4)$ (i) and (ii) provide for assets to be valued so as to prevent the network owner or service provider bearing "stranded asset risk" where some other party or parties were involved in making the investment decision, and should therefore bear the risk of that asset being "stranded".

The industry access code takes into account the investments of the service provider, through clauses $6.2 .2(\mathrm{~g})$ and $6.2 .3(\mathrm{~d})(4)$. These clauses provide for the recognition by the ACCC of pre-existing policies of governments regarding transmission asset values, revenue paths and prices. An important element of government policy in this regard is the agreement of the Council of Australian Governments that deprival value should be the preferred approach to valuing network assets for revenue determination purposes. It is submitted that these provisions seek to ensure fair and reasonable continuity of asset values for (revenue determination purposes) in the transition to regulation of transmission revenue by the ACCC. For the reasons set out in paragraph 11(e) below it is considered that reasonable continuity of asset values during and after this transitional period is in the public interest.

## C1(c) Protection of the legitimate business interests of the service provider where the service provider is required or directed to augment the network

In some situations, the risk associated with periodic application of deprival value for revenue determination purposes may be reallocated by means of a contract. A typical example of such an arrangement would be a long term take-or-pay contract between a Distributor and a Network Service Provider for connection services, or between a Network Owner (e.g. PowerNet) and a Network Service Provider (e.g. VPX) in respect of shared network services. Under such a contract, the present value of contract payments to be received by the asset owner fixes the value of the asset. From the perspective of the owner of the asset, one key reason for entering into long term contracts of this type is to mitigate market (i.e. asset utilisation) risk and other risks which can lead to changes in the revenue earning capability of assets.

If assets covered by such contracts were to be optimised and re-valued on an on-going basis for revenue determination purposes by the ACCC, the revenue earning capability of such assets could vary from that originally agreed between the two parties to the contract. Such an outcome would distort the allocation of risk agreed between the two parties and would not be acceptable to either party. It is submitted that this is not in the public interest for the following reasons:

- the Network Owner, even if it is shown to be an efficient asset constructor and manager, faces the risk of financial penalty because of a sub-optimum decision made by some other party which is totally beyond the control of that particular Network Owner.
- the risk associated with regulatory re-determination of agreed contracts would cause commercial Network Owners to either cease constructing any further transmission assets, or alternatively, place high risk premiums on any future investment. This could lead to capital constraints (and consequential under-investment in the network) or an increase in the cost of capital faced by Network Owners (and a consequent increase in network charges).

For these reasons, clauses 6.2.3(d)(4)(i) and (ii) provide for certain assets to be valued for revenue determination purposes by the ACCC in a manner consistent with the provisions of any relevant take-or-pay contract or network augmentation determination made by NEMMCO pursuant to clause 5.6.5. In effect, these clauses provide for the recognition by the ACCC of the allocation of "stranded asset risk" inherent in any relevant take-or-pay contract or NEMMCO augmentation determination. These provisions are aimed at
ensuring that the Network Owner or service provider does not bear "stranded asset risk" where some other party or parties have agreed to bear that risk.

## Criterion 2: the public interest, including the public interest in having competition in markets (whether or not in Australia)

C2(a) Flexibility of arrangements to permit ACCC to develop and apply its own definition of "public interest"

Clause $6.2 .2(\mathrm{k})$ states that the transmission revenue regulatory regime to be administered by the ACCC shall provide reasonable and well defined regulatory discretion which permits an acceptable balancing of the interests of service providers, service users, and the public interest. This accords with the requirements imposed on the ACCC under Part IIIA. Given that "public interest" is not defined in the Act, this provision of the Code is considered highly desirable, as it provides the ACCC with considerable flexibility to develop and apply its own working definition of "public interest".

## C2(b) Promotion of Competition

Promotion of competition is identified in the Code as a key principle for the regulatory regime to be applied to transmission revenue. Clause 6.2.3(a) states:
"Concerns over monopoly pricing in respect of the transmission network will, wherever possible and practicable, be addressed through the introduction of competition in the provision of transmission services."

There are significant benefits to be derived from increasing the level of competition for the right to execute and own transmission augmentation projects and for the performance of on-going asset maintenance. The August 1993 report by the Independent (Hilmer) Committee of Inquiry into National Competition Policy stated that:
"The 'first best' solution [to monopoly pricing problems] is to address the underlying cause of monopoly pricing by increasing the contestability of the market. This might be achieved by removing or reducing regulatory barriers to entry; [or] restructuring public monopolies". ${ }^{2}$
"The Committee recommends that concerns over monopoly pricing be addressed primarily through appropriate regulatory and structural reform to enhance competition..." ${ }^{3}$
"From a competition policy perspective, structural reforms will be particularly relevant where traditional monopoly markets are being opened to competition, and it is desired to ensure that effective competition can be established with minimal need for ongoing regulatory supervision. "4

Clauses 6.2.3(a) and 6.2.4(f) provide for contestability in the provision of new network services. These arrangements are aimed at diminishing the "natural monopoly" status of

[^25]incumbent regional network owners by providing for the possibility of a competitor of the incumbent to own and/or operate network assets in the incumbent's territory.

The Competition Principles Agreement executed by the States and Territories on 11 April 1995 specifies a competitive neutrality policy and principles for the structural reform of public monopolies which principles are consistent with the Hilmer recommendations cited above. Clause 4(1) of the Competition Principles Agreement leaves the determination of matters relating to structural reform of public monopolies very much at the discretion of the owners of those monopolies by stating "Each party is free to determine its own agenda for the reform of public monopolies."

## C2(c) Fostering Business Efficiency, Promotion of Cost Savings and Consequent Containment or Reduction of Prices

Clause 6.2.2(b) provides for the creation of an incentive-based regulatory regime. Such a regime provides for, on a prospective basis, a fair and reasonable return to service providers assuming efficient investment and efficient levels of operating and maintenance costs. It is emphasised that:

- these arrangements require the ACCC to provide for what it considers to be an "efficient" level (not the actual level) of operating costs in the revenue cap;
- the ACCC has considerable discretion in determining its own estimate of efficient operating costs to be provided for in the revenue cap; and
- when the deprival value method is used to determine asset values this means that a return is only earned on assets which are "optimum" (having regard to present and reasonable future levels of customer need) and which are valued at the lower of minimum efficient replacement cost and value to the consumer.

Clause 6.2.4(b) provides for 5-yearly regulatory reviews of the revenue cap.
The establishment of 5 -yearly revenue caps creates clear incentives for network owners to maximise efficiency in both operations and capital expenditure. Once the revenue cap is determined by the ACCC based on its estimates of the potential for efficiency gains in the regulated enterprise, the managers of that enterprise have a clear incentive to maximise shareholder value during the regulatory control period by reducing their costs below the assumptions used to determine the cap. This incentive-based regime will foster efficiency and promote cost savings within the transmission sector. Incentive based regulation has resulted in substantial efficiency gains in a range of industries in the UK.

In order to apply appropriate cost pressures via the revenue cap, the ACCC will need reliable and detailed cost and operational information. Clause 6.2 .5 provides for an information disclosure regime under which the ACCC may require a regulated entity to provide certified financial statements and any other information the ACCC reasonably requires to perform its regulatory functions.

The revenue capping arrangements will also ensure that prices reflect the efficiency gains and cost savings reasonably considered by the ACCC to be achievable by service providers. Under Clause 6.2 .2(b) the regulatory regime is required to equitably allocate the efficiency gains between service providers and service users. The information
disclosure regime provides the ACCC with an effective means of monitoring the service provider's compliance with the revenue cap so that service users benefit from the associated cost and price containment.

## C2(d) Provision of Better Information to Consumers and Business

The information disclosure requirements on the regulated entities and the ACCC (under clauses 6.2 . 5 and 6.2 .6 respectively) is expected to ensure the provision of appropriate and timely information to both consumers and businesses. Clause 6.2 .5 provides the ACCC with considerable discretion in determining the information to be obtained from service providers.

## C2(e) Level of risk borne by service providers and the associated returns to service providers

Efficient resource allocation is facilitated where:

- the risks of a particular activity are bome by that party best able to manage that risk; and
- the rate of return expected (and achievable) by the risk taking party is commensurate with the risk borne by that party.

While Schedule 6.1 of the Code sets out the parameters within which WACC is to be determined, the ACCC is the ultimate judge of business risk (and therefore a fair and reasonable WACC) of the service providers. The level of discretion provided to the ACCC by Schedule 6.1 will enable it to ensure that the rate of return earned by service is commensurate with the risk bome.

Criterion 3: the interests of persons who may require access to the service

## C3(a) Independent regulation and customer involvement in revenue capping process

Part B of Chapter 6 provides for an independent authority (namely, the ACCC) to ensure that there is an appropriate balance between the interests of service providers and service users in determining a revenue cap for the service provider. Clause 6.2 .5 provides the ACCC with powers to obtain all necessary information it requires to reach a revenue cap or related determination. Furthermore, clause 6.2.4(b) provides the ACCC with considerable discretion in determining the process for setting revenue caps, and the involvement of the stakeholders (e.g. customers) in that process.

C3(b) Right of "bypass"
The Code neither encourages nor discourages bypass; it simply permits it. The Code seeks to ensure that the transmission pricing and regulatory arrangements do not unduly encourage new investment in facilities which substitute for or duplicate existing facilities, where the incremental cost of the new facilities is greater than the avoided incremental cost of existing facilities. In the context of Part B of Chapter 6, a proposed mechanism to achieve this is the application of the deprival value methodology.

This approach is intended to ensure that bypass of existing networks only occurs where bypass is in the public interest (i.e. where bypass is the least-cost option from a total societal perspective). It is considered unnecessary for the Code to explicitly mandate bypass; any network owner who does not match the cost of a legitimate bypass altemative (by reducing network charges) runs the risk of driving the customer off the network and suffering a consequent loss of revenue. In other words, normal commercial processes, rather than an explicit regulatory obligation should provide users with ample negotiating leverage where a truly economic bypass alternative exists. The relevant parts of the Code have been drafted to state that transmission prices are maximum prices and that users may negotiate lower prices.

## C3(c) Capital contributions by customers

The Code is not intended to, nor does it, expunge pre-existing contractual obligations of parties in relation to capital contributions.

Clause 6.6 .2 of the Code states that where a network owner receives a capital contribution in respect of an asset, the value of the asset for revenue determination purposes will be reduced by the amount of capital contribution received. This ensures that network owners are unable to charge customers twice for the same assets. Any "double charging" by Network Owners would be in breach of the Code.

C3(d) Increases in transmission revenue due to application of deprival value method
Where the rate of inflation exceeds the real rate of decline in transmission asset replacement costs, there may be an increase in the depreciated value of assets in nominal or money terms. The deprival value of assets is stated at all times in real terms (i.e. including the effects of general price rises, or inflation). Thus, the required rate of return, or Weighted Average Cost of Capital as defined in Schedule 6.1 of the Code, is also measured and stated in real terms. This ensures that the effects of inflation on asset values, revenue requirements and the cost of capital are provided for in an appropriate and consistent manner, and in a manner which does not result in "double charging" for any effects of cost/price escalation.

## Matter 1: economic efficiency, including efficient resource allocation

## M1(a) Efficient use of existing infrastructure

Please refer to the discussion under the subheading 3(b) Right of "bypass" in the section examining Criterion 3.

## M1(b) Neutrality between existing and new technologies

Clause 6.2.3(d)(2) states that: "The regulatory regime to be administered by the ACCC must ... have regard to the need to create an environment in which generation, energy storage, demand side options and network augmentation options are given due and reasonable consideration".

Furthermore, the determination of transmission revenue requirements has regard to the deprival value of assets among other factors. A key objective of the deprival value methodology is to ensure that the impacts of new technologies (in the network sector and
in substitute sectors such as distributed generation) are taken into account in the valuation of assets for revenue purposes. The "economic value test" provides a cross-check of network asset values against the cost of bypass options. Where the cost of the bypass option is cheaper, the existing network asset value and its associated revenue requirement are reduced accordingly. This ensures efficient utilisation of existing network resources.

Irrespective of the length of the planning horizon applied, NEMMCO is required under clause 5.6 .5 of the Code to assess options for the reduction of network constraints and transmission losses. These options include the construction of new transmission lines or the implementation of demand side or generation investments by Code participants or any other person. NEMMCO's assessment must aim to maximise net benefits to customers. In practical terms this means, that if the cost of new technologies (such as distributed generation) is lower than the cost of traditional supply side network investment in alleviating a network constraint then NEMMCO is bound to select the least cost option. Thus, the Code does not provide a bias for or against any particular technology or option.

## M1(c) Neutrality between supply and demand side options

As discussed in M1(b) and according to clause 6.2.3(d)(2) the regulatory environment created gives due and reasonable consideration to generation, energy storage, demand side measures and traditional network options.

## M1(d) Incentives for efficiency under the revenue capping approach

The threat of future optimisation of assets values (through possible reductions in revenues) provides an effective commercial incentive on network owners to make efficient investment decisions. Where a network owner wishes to avoid this risk, it will be required to either obtain NEMMCO approval under clause 5.6 .5 or to negotiate with some other party to accept the risk (via a long term take-or-pay contract). Chapter 5 of the Code provides for consultation, scrutiny and review of NEMMCO approved grid investment decisions by the participants who ultimately underwrite the stranded asset risk of those decisions.

The regulatory arrangements provide strong incentives on network owners to achieve efficiency gains. The extent to which these savings are passed on to users depends on the extent to which the ACCC's revenue cap settings reflect the full potential for prospective efficiency gains. Further discussion of this issue is presented above in paragraph C2(c): Fostering Business Efficiency, Promotion of Cost Savings and Consequent Containment or Reduction of Prices.

## Matter 2: market transparency and appropriateness of the proposed access pricing and terms and conditions

## M2(a) The ideal of "light handed regulation" and the suitability of revenue control

During the Code consultation process, it became evident that some respondents regard commercial negotiation of access terms and charges as being synonymous with the concept of "light handed regulation". These respondents expressed a preference for minimal regulatory involvement in the setting of transmission access terms and charges. In other cases, respondents stressed a preference for a prices surveillance approach, rather than an approach based on price or revenue capping.

In developing the proposed industry access code, the natural monopoly characteristics of the transmission sector have been taken into account. These characteristics suggest that commercial negotiation of terms and conditions for access to existing facilities is unlikely to lead to timely and efficient outcomes.

The August 1993 Report by the Independent Committee of Inquiry into National Competition Policy and the November 1995 Industry Commission paper Implementing the National Competition Policy: Access and Price Regime were studied prior to the drafting of Part B.

The report of the Hilmer Committee clearly favoured the adoption of "light-handed" regulatory approaches, rather than explicit price or revenue control. However, the Industry Commission states:
"The new national competition policy is designed to establish processes and institutions to encourage competition throughout the economy. It aims, in part, to bring a sharper competitive focus to those activities currently sheltered from international and domestic competition.

However, in some areas the conditions for workable competition may be absent, either in the long-term or while the structural and regulatory reforms necessary to promote competition are put in place. In these circumstances, there remains a residual role for price-based regulation within the national competition policy framework. "s

Prices surveillance is inappropriate where the service is founded on an essential facility with substantial monopoly characteristics in an immature market with powerful incumbents. Taking these considerations into account, Part B of the Code prescribes a revenue capping approach where pro-competitive and structural reforms alone are not a practicable or adequate to address the problems of monopoly pricing in the transmission sector .

The rationale for this Submission's position on this issue has been provided separately to the ACCC in a paper entitled Submission to Australian Competition and Consumer Commission on the subject of transmission revenue regulation (Part B of Chapter 6 of the Code) dated 5 July 1996.

## M2(b) Transparency of revenue capping process

Clause 6.2.4(b) provides a high level of transparency: " $A$ description of the process and timetable for re-setting the revenue cap must be published by the ACCC at a time which provides all affected parties with adequate notice to prepare for, participate in, and respond to that process, prior to the commencement of the regulatory control period to which that revenue cap is to apply. The revenue cap re-setting process must provide all affected parties with a reasonable opportunity to prepare for, participate in, and respond to that process."

[^26]Clause 6.2.5 of the Code provides the ACCC with ready access to all of the information it reasonably requires to administer the regulatory arrangements. The clause therefore provides the ACCC with considerable discretion in specifying the content and form of information to be disclosed to it by regulated entities.

## M2(c) Effectiveness of regulatory arrangements in eliminating capitalised monopoly rents

It is suggested that capitalised monopoly rents can be manifested in a number of forms, including:

- investment in excess capacity (stranded assets);
- inefficient construction or gold-plating (and therefore excessive historic cost) of the 'optimum level' of required capacity;
- valuation of assets at levels above deprival value but below consumer value (resulting in monopoly rent-taking).

The proposed deprival value approach captures both of the first two inefficiencies and removes them from the value of the existing asset base by applying best practice design and construction techniques in the costing of the optimised network. In the case of the third point, the deprival value method is deliberately aimed at ensuring such an outcome does not occur. Schedule 17 provides a more detailed discussion of the rationale for deprival value and its effectiveness in eliminating capitalised monopoly rents.

Clause 6.2.3(d)(4)(iii) provides that the ACCC may require the opening asset values (at the commencement of the national regulatory arrangements) to be independently verified through a process agreed to by the National Competition Commission. This provides additional safeguards against the capitalisation of monopoly rents.

## M2(d) Appropriateness of asset valuation approach in determining revenue requirements

The arrangements in clause 6.2.3(d)(4)(iv) of the Code provide for an appropriate rate of return to be earned by an efficient service provider on both sunk (existing) and new assets valued in a manner which is:

- equitable, in terms of wealth distribution effects between network owners and users; and
- efficient, in terms of the long-run cost reflectivity of the revenue requirements derived.


## M2(e) Use of deprival value leading to "inflated asset values" and excessive revenue requirements

The results of empirical studies conducted within Victoria were provided to the ACCC in a document dated 5 July 1996, entitled: Submission to Australian Competition and Consumer Commission on the subject of transmission revenue regulation (Part B of Chapter 6 of the Code). The empirical study suggests that application of current cost asset
values to existing assets in the determination of future revenue requirements would not result in "inflated asset values".

COAG has supported the deprival value approach on the understanding that:

- it is equitable, in that revaluation of existing assets in accordance with the deprival value approach would not result in over-valuation, having regard for the contribution to sunk costs already made by past and present customers; and
- it does not compromise the achievement of economic efficiency as the approach reduces the revenue requirements of existing assets to minimum efficient levels (refer to Schedule 17 for evidence).

The Code provides that the ACCC shall have regard to the application of deprival value as a ceiling in determining revenue requirements. Owner govemments may elect to adopt lower asset values should they so wish.

## M2(f) Consistency of proposed asset valuation approach with "normal commercial practice"

A key principle of Part B of Chapter 6 is that network owners should have a reasonable prospect of earning an appropriate commercial return on assets, but only given efficient investment in, and operation of, the network business. It is suggested that this fundamental objective is the basis of all "normal commercial practice". It is asserted that achievement of this basic objective is in the public interest in that it provides appropriate signals to public and private sector investors to continue to make capital available for the maintenance and expansion of existing network facilities to meet the demands of users.

## M2(g) Validity of deprival value of assets in light of sale prices achieved in recent privatisations

A high level of consistency between the definition of deprival value, and the discounted cash flow value of network assets is an intended outcome of the regulatory arrangements in Part B of Chapter 6 of the Code. These arrangements are intended to ensure that in the event of privatisation, the values paid by private investors to acquire those assets have no influence over the future regulated revenue requirements of the relevant business.

## Matter 3: equity considerations, including non-discrimination between like access seekers

The prime "equity consideration" in respect of the proposed revenue regulatory arrangements is the extent to which those arrangements provide an equitable starting point, in terms of the revaluation of existing assets, for revenue determination purposes.

It is possible that in some cases, the application of current cost asset values in network revenue determination may lead to increases in network tariffs that are politically unacceptable to owner governments. This is likely to be the case where network tariffs have in the past been set at levels substantially below full cost. In such cases, it is assumed that the relevant owner govemment(s) will institute appropriate transitional arrangements, which may include re-valuing assets for revenue determination purposes to levels below their deprival value,
and directing the entities they own not to seek or apply a higher revenue amount. The Code does not preclude owner governments from taking such action. Such action can, and should, be achieved without compromising regulatory independence.

Matter 6: adequacy of information disclosure requirements on the provider to meet the needs of potential third parties

Please refer to arguments advanced in paragraphs C2(d) and M2(b), in relation to the adequacy of information disclosure requirements on the service provider.

## Criterion 4: any other matters that the ACCC thinks are relevant

The Issues Papers published by the ACCC in March and June 1996 have been examined to identify any other matters likely to be considered relevant by the ACCC. These are discussed below.

## C4(a) Efficiency and access benefits

In its March 1996 Issues Paper, the ACCC posed the following question:
"What network efficiency and access benefits are expected to result from the three staged process for determining network prices?"

In response, the ACCC is advised that under the proposed three staged ${ }^{6}$ approach:

- network usage prices are set at a level which maximises the contribution to network owners' reasonable and efficient (that is, optimum and not gold-plated) costs including sunk costs.
- network owners are provided with sufficient cash flow to enable maintenance and expansion (where required by network users) of existing infrastructure operating capability over the longer term.
- specific controls are put in place (via the application of the deprival value method) to minimise the risk of inefficient substitution or "bypass" of the grid by users in response to CRNP price signals.
- regulatory arrangements are specifically designed to protect the consumer from abuses of monopoly power by the network owners, and to diminish any advantage accruing to network owners through 'information asymmetry'.

Thus, CRNP provides, by a simple pricing structure which is readily compatible with the structure of existing electricity tariffs, a price signal which will:

- when combined with the proposed treatment of loss, ancillary services and constraint costs in the national market design, lead to minimal, if any, distortion of consumption in the short run;

[^27]- provide reasonably stable and predictable signals for efficient investment on the supply and the demand sides of theNEM; and
- provide capital markets with a comprehensible signal that there is a reasonable prospect of earning appropriate returns on future new investment in network assets.

C4(b) Promotion of competition and efficiency; balancing competing interests
In its March 1996 Issues Paper, the ACCC posed the following question:
"To what extent is this network pricing methodology likely to be in the interests of network operators and NEM participants and to promote competition and economic efficiency in the NEM?"

In response, the ACCC is advised that the regulatory arrangements seek to:

- strike a reasonable balance between the conflicting interests of Network Owners and Network Users;
- minimise undue regulatory risk, thereby enabling transmission entities (whose costs are $80 \%$ capital related) to raise capital ;
- provide the lowest possible transmission charges, without depriving network owners of reasonable opportunities to earn an appropriate return;
- maximise opportunities for competition and trading across the national grid (through the minimisation of transmission charges); and
- provide for introduction of competition into the provision of transmission network service wherever this is practicable and economic.


## C4(c) Appropriateness of revenue capping

In its March 1996 Issues Paper, the ACCC posed the following question:
"Is revenue capping the most efficient method of economic regulation to ensure efficient operation and pricing of network services and to ensure effective access for NEM participants?"

In response, it is considered that the natural monopoly characteristics dictate the need for explicit revenue capping. This is necessary to protect the interests of "captive" grid users who have no alternative but to purchase transmission network service from the regional incumbent. However, there are alternatives to revenue capping being considered elsewhere: for instance, there has been some discussion in recent US. and UK. literature of 'sliding scale approaches', 'sharing mechanisms' and other forms of incentive-based regulation. Given these considerations, clause 6.2 .4 states: "Economic regulation is to be of the CPI - X form, or some incentive-based variant of the CPI - X form which is consistent with the objectives and principles outlined in clauses 6.2.2 and 6.2.3." Clause 6.2.4 thereby provides the ACCC with considerable flexibility and discretion in the development and application of incentive-based regulatory alternatives to revenue capping.

The rationale for application of incentive-based revenue regulation is outlined in greater detail in a document entitled Submission to Australian Competition and Consumer Commission on the subject of transmission revenue regulation (Part B of Chapter 6 of the Code) dated 5 July 1996.

## C4(d) Regulatory flexibility and discretion

In its June 1996 Comments and Issues Arising paper, the ACCC stated:
"Estimation of other elements of the revenue requirement would also be improved by providing the regulator with sufficient flexibility to consider a range of financial and market indicators in satisfying itself that the revenue requirement estimate is soundly based".

The Commission therefore considers that flexibility of approach to estimation of the revenue requirement (which may include alternative methodologies and a range of relevant indicators), should be available to the regulator to ensure that "best practice" methodologies are applied and that in practice price caps are consistent with the objectives of regulating monopoly Network Service Providers."

The ACCC made these comments in response to version 1 of the draft Code. Version 2 of Part B of Chapter 6 of the Code now contains a much lower level of prescription of regulatory processes and methods than version 1. Importantly, clause 6.2 of version 2 of the Code states:
"This Code does not limit or prescribe the methodologies to be applied by the ACCC in exercising its regulatory powers under the Trade Practices Act and this Code, except to the extent that those methodologies must be consistent with the objectives, principles, broad forms and mechanisms, and information disclosure requirements described in clauses 6.2 .2 to 6.2.6 inclusive of this Code."

The Code now provides the ACCC with wide discretion on matters relating to the method of revenue regulation. In addition, the Code also provides the ACCC with considerable discretion with respect to outcomes which it might consider to reflect an appropriate balance of the interests of the network owner, those seeking access and the general public.

C4(e) Valuation of "sunk" assets: continuity of asset values from one regulatory control period to the next

In its March 1996 Issues Paper, the ACCC asked:
"Will the valuation methodology be neutral as between existing assets and the progressive valuation of new assets to be included in the asset base?"

The neutrality or consistency between valuations of pre-existing and new assets is a key aim of the regulatory arrangements as specified in Part B of Chapter 6. This is considered to be in the public interest for the following reasons:

- it avoids the possibility of 'price shocks' occurring when pre-existing aging assets are replaced with new ones. This is in the public interest as price shocks may be seen to be inequitable. They may also lead to distortions in consumption and
investment signals within the transmission networks that form the power system and upstream and downstreammarkets; and
- it reduces the complexity associated with regulation under a regime in which identical pre-existing assets and new assets are ascribed different values. Such regimes exist in the United Kingdom in electricity and more notably in water. These regimes necessitate complex, undesirable and counter-intuitive 'fixes' such as application of different rates of return to otherwise identical assets.

The deprival value methodology proposed in the Code will be neutral as between existing assets and new assets to be included in the asset base for revenue determination purposes. This should provide for consistent financial and operational performance measurement, and enables more effective benchmarking of service providers.

Given the avoidance of price shocks and the neutrality between existing and new assets is the intent of Clause 6.2.3(d)(4) and given that Clause 6.2.3(d)(4) does not in any way constrain the ability of the ACCC to apply the deprival value method at each 5-yearly regulatory control review in order to disqualify a service provider from recovering a retum on inefficient investment, it is submitted that the ACCC concem is met.

## C4(f) ACCC concerns regarding possible over-valuation of assets using deprival value

In its paper of June 1996 entitled National Electricity Market Code: Comments and Issues Arising, the ACCC commented that:
"Strict adherence to the ODV asset valuation approach may tend to"over value network assets, and so result in excessive prices and rates of return. For example, simulations conducted by the Independent Pricing and Regulatory Tribunal of New South Wales suggest that using ODV without regard to other market and financial indicators of asset values may overvalue existing assets considerably, resulting in excessive rates of return and an initial rate shock for users."

It is considered that in most cases, the low historic returns earned by electricity utilities suggest that revaluation of existing assets to deprival value is unlikely to result in over-valuation, and excessive prices and rates of return. This is an empirical question to be analysed and resolved by owner governments in the context of structural reform of their electricity industries.

In August 1994, COAG supported the application of deprival value in the determination of revenue requirements on existing network assets. Where an owner government's empirical studies suggest that application of deprival value in its particular case may result in 'rate shock', then that government may adopt asset values below deprival value for revenue determination purposes (and direct the entities they own to set revenue requirements accordingly). This decision can be readily implemented by the owner government within the context of the regulatory arrangements set out in the Code. The independent regulator need not be involved in this process, but it is possible that the regulator could agree with the relevant owner govemment to execute its regulatory functions in a manner which takes into account the decisions of owner governments to set revenue requirements below the level implied by the deprival value of assets. Jurisdictions
were informed of the need to conduct these empirical studies prior to the endorsement of deprival value by COAG in August 1994.

### 8.4.5 Assessment of the transmission pricing structure provisions of the industry access code

## Introduction

Chapter 6 of the Code sets out the transmission pricing arrangements for connection and access to the National Grid. They complement the technical terms and conditions together with the administrative arrangements for augmentation of the transmission system which are set out in Chapter 5.

The pricing arrangements outlined in Part C of Chapter 6 are based on the framework and principles which have been agreed by COAG for the role of the transmission network in the NEM and the objectives to be achieved by the basic pricing methodology.

The Code now submitted to the ACCC for consideration includes provision for a review of the transmission pricing arrangements to be conducted and completed by NECA within 12 months of the ACCC's initial acceptance of the industry access code (refer to clause 6.1 .6 of the Code).

In addition it must also be recognised that pricing arrangements which broadly reflect some of the principles set out in Part C of the Code are in place in Victoria and New South Wales and participants are gaining familiarity with and understanding of the signals provided. Of particular concern are those participants who will be making long term decisions in the interim period based on the current signals if these are likely to change in the future.

While the Code foreshadows a review of Part C of Chapter 6, it is important to note that Part C of the Code has been developed to meet the objectives set for the operation of the NEM. The development of the pricing proposals set out in Part C of Chapter 6 of the Code has been based, in part, on the advice of overseas consultants with detailed knowledge and experience of the England and Wales and New Zealand approaches, and the more recent developments in the USA.

## Overview of transmission pricing arrangements in Part C

The transmission pricing arrangements are critical to the NEM. They provide the commercial basis for open access to the natural monopoly transmission networks and are an essential component in allowing participants to trade freely in the energy sub-market.

Network pricing which improperly allocates costs for participants could lead to significant distortions in the energy sub-market. Power stations and major load could be encouraged to locate without regard to the costs on existing users, and the possible need for and cost of new transmission when spare capacity may be available elsewhere.

While recognising that no pricing method can exactly reflect the costs to individual participants, greater cost reflectivity minimises the level of cross subsidy between customer groupings. Cross subsidisation may not be in the public interest to the extent that it encourages over use of the system in certain areas, and under use in others; each
with a negative impact on economic efficiency. For example, uniform electricity pricing has tended to encourage development of central power generation facilities to supply remote areas when local generation may well have provided a more efficient lower cost solution.

If pricing is not consistent between areas there are likely to be restrictions on the development of a competitive electricity market between these areas. For example interstate trade in electricity may be limited if individual network owners were to price long distance transmission differently.

The transmission pricing proposal outlined in Part C of Chapter 6 of the Code has the following major features:

- connection charges are to be determined through commercial negotiation and should be directly related to the facilities requested by the Connection Applicant, except for existing connection facilities prior to market commencement, where charges are to be regulated;
- maximum use of system prices for the network are determined by the Network Service Provider by allocating an aggregate annual revenue cap set by the appropriate Regulator in a cost reflective manner;
- the transmission pricing arrangements provide a long run marginal cost (LRMC) based pricing signal to allow participants to gauge the impact of their behaviour on future network costs and make appropriate economic decisions;
- prices are published in advance and are independent of any energy sub-market contracts. Participants are able to trade with a knowledge of the transmission charges in the medium term. Participants are treated equally, with participants at the same location and requiring the same level of service paying the same transmission price regardless of their status, e.g. whether franchised or non-franchised customers, new or existing customers etc., subject to negotiation away from published maximum prices.

The transmission pricing arrangements have been developed to form a consistent part of the overall NEM arrangements. There are a number of aspects which must be considered along with the pricing arrangements when assessing the ability of the transmission aspects developed to support the NEM.

The transmission pricing and regulatory arrangements should therefore be regarded as one part of an integrated package that is aimed at meeting the overall objectives of the NEM as a whole.

## Criterion 1: the legitimate business interests and investments of the service provider

The legitimate interests of the service provider are provided for by the regulatory arrangements outlined in Part B of Chapter 6 and discussed above in paragraph 8.4.4.

Criterion 2: the public interest, including the public interest in having competition in markets (whether or not in Australia)

## Criterion 3: the interests of persons who may require access to the service

These two criteria are treated together.
The proposals for transmission network pricing as set out in Part C of Chapter 6 of the Code have been developed to provide access to the transmission network on a non discriminatory basis. This implies a common approach for all participants, no matter where they are located or whether they participate as traders in the NEM. Prices at different locations may differ, because of the different costs associated with use of the network or because of the demands placed on critical parts of the transmission system at different times.

The network pricing proposals have also been developed to complement the electricity market design proposals in encouraging and facilitating the development of an efficient competitive electricity market. In particular the transmission pricing regime will not distort the energy sub-market since it will only introduce signals which are related to the use of the network.

The Market Participant's choice of contractual arrangements or dependence on the spot market will not affect generation dispatch and the flows in the network under the proposed market structure. Thus the network price does not depend upon the particular arrangements adopted by Market Participants for the hedging of electricity price risk. The maximum network prices will be published in advance allowing all users to participate in the energy sub-market and develop energy contracts and allowing new participants to enter the market with knowledge of the published network prices.

The interests of persons seeking access is best served by non-discriminatory arrangements which place the network customers on par with their competitors and with network pricing which does not distort location signals.

## Matter 1: economic efficiency including efficient resource allocation

Transmission prices should provide signals to optimise the cost of network development and operation in order to maximise the net benefit to NEM participants as a whole.

As noted elsewhere in this submission, aspects of network pricing are closely linked with the market design proposals. The inclusion of constraint costs and marginal losses through the energy market (as provided for in Chapter 3 of the Code) is an important component of providing all the signals necessary to enable transmission system augmentation to be assessed on a proper economic basis.

With regard to the specific structure of transmission prices, COAG has agreed that charges for EHV transmission networks in principle should be cost reflective. Cost reflective network pricing is considered to be in the public interest as it ensures that economic use is made of the existing network taking into account the long term costs of any augmentation necessary to meet continued growth.

The principle of cost reflectivity requires that network pricing is based on the resource consumption in the provision of network services. Since the cost of provision of transmission service predominantly involves capital costs associated with provision of assets, the resource requirements are mainly asset-related capital costs. The price for each participant is therefore influenced by the location of that participant in the network relative to generation injection points, and the assets employed in providing network service.

The transmission pricing arrangements outlined in the Code foster market outcomes which mimic competition. Because structural reform does not overcome the natural monopoly character of the network the Code establishes an incentive based regulatory regime which is directed at producing pricing outcomes that are commensurate with market based prices.

## Matter 2: market transparency and appropriateness of the proposed access pricing and terms and conditions

Clause 6.5.7 requires Transmission Network Service Providers to publish their tariffs (determined in accordance with Part C of Chapter 6) annually. The detailed description of the cost allocation and pricing calculations set out in Part C provide for a very high level of transparency.

The question of appropriateness of the proposed pricing approach is one to be determined by the review to be facilitated by NECA, pursuant to clause 6.1.6.

## Matter 3: equity considerations, including non-discrimination between like access seekers

Fair and reasonable access will be fostered in the following ways:

- clear pricing objectives to promote equity and price stability;
- an incentive based regulatory regime that is predicated on a equitable sharing of the prospective gains from efficiency improvements in business operation;
- non discriminatory access to the network.

Matter 6: adequacy of information disclosure requirements on the provider to meet the needs of potential third parties

The information disclosure requirements on the regulated entities and the regulators will ensure the provision of appropriate and timely information to both consumers and business. The regulators will have considerable discretion in determining the information to be obtained from service providers.
8.4.6 Assessment of the distribution regulation and pricing provisions of the industry access code

## Introduction and statement of rationale

Part D of Chapter 6 of the Code applies to the regulatory requirements in respect of the general level of distribution service prices and/or the aggregate annual revenue requirement for distribution services.

The arrangements specified in Part D:

- set out the principles which will be applied in economic regulation of distribution service pricing ;
- provide for the formulation of national guidelines by which those principles may be applied; and
- establish a regime where participating jurisdictions apply national Code principles in a manner consistent with prevailing conditions in the jurisdiction.

The Code details broad objectives and principles which are used by the relevant jurisdictional regulator to develop detailed regulatory regimes applicable to each Distribution Network Service Provider. To the extent that distribution networks have common characteristics and cost drivers, the regulation in each jurisdiction are likely to be similar. However, where different cost drivers or different industry characteristics exist, specific Network Service Provider regulation may evolve.

The Code establishes a flexible approach to network pricing to individual customers and represents the second stage (i.e. notional guidelines) of the process detailed above. Part E of the Code represents one cost allocation method which can be applied to determine Network Service Provider prices.

## A Consistent Approach to distribution pricing and regulation

The broad principles detailed in the Code and inherent in the development of national guidelines will ensure that any benefits associated with national consistency are achieved.

Given that distribution pricing is only applicable to a specific distribution region there is no economic benefit in the rigid application of a prescriptive national regime. In fact, the imposition of a prescriptive national regime may reduce economic efficiency through the application of inappropriate regulation to any particular Network Service Provider. Further, a prescriptive national regime could potentially limit any innovation the Network Service Providers or regulators may initiate.

## Justification for the Jurisdictional Regulator

Jurisdictional Regulators are required to take account of the various state based issues related to distribution pricing.

Different jurisdictions have different arrangements already in place which impact on distribution pricing. For example:

- long term transitional arrangements directed at price stability and avoidance of price shock to customers;
- the privatisation of some distributors prior to the commencement of the NEM.

Jurisdictional regulators are necessary to support these existing arrangements.
Jurisdictional regulators only have control over networks which are effectively intra-state monopolies.

Distribution pricing is related integrally to customer service standards and quality of supply requirements imposed on the Network Service Provider. Such standards are uniform across the network and relate to all levels of customers from the largest customer down to the smallest domestic customer. Such service/quality standards are established by jurisdictions. As such, it is imperative that those jurisdictions control the pricing aspects associated with meeting these standards.

It is therefore submitted that there is no loss of economic efficiency associated with having jurisdictional regulators of network prices for distribution services, provided that those regulators operate to a common set of principles and prices are presented to customers in a similar form. Given the monopoly nature of distribution networks, the fact that prices are calculated under different regimes on either side of a jurisdictional border is considered to be highly unlikely to have any impact on competition.

## Form of Regulatory Controls

The regulatory arrangements proposed in the Code for distribution pricing result in control of a Network Service Provider's charges at 2 levels:

- a control on the overall revenue or average price that the Network Service Provider earns for Network Services.
- controls on the individual tariffs that the Network Service Provider charges to individuals or groups of customers.

The overall revenue control/price control is structured so that the regulator puts in place a control regime for minimum periods of three years, thereby giving the Network Service Provider regulatory certainty over this period. This establishes an incentive to improve efficient and overall performance through profit maximisation.

The distribution pricing regime requires Network Service Providers to publish regulator-approved customer tariffs. These tariffs represent the maximum that the Network Service Provider can charge and allow negotiation beneath this tariff where commercial incentives drive such negotiation.

This published tariff regime establishes a clear and simple access regime for all customers and retailers with the form of distribution tariffs being similar across all Network Service Providers covered by the Code.

Network tariffs to individuals or groups of customers across each Network Service Provider's network are to be developed by individual Network Service Providers and submitted to the jurisdictional regulator for approval. The tariffs must fit within broad principles of economic efficiency and equity.

Such an approach allows Network Service Providers to develop innovative pricing solutions within a "light handed" regulatory oversight of monopoly network activities.

## Principles of Distribution Pricing

The NEM is structured to achieve a competitive environment. To the extent that competition does not exist in some natural monopoly elements such as distribution, regulated pricing regimes are defined in the Code.

The Distribution Pricing regime outlined in the Code has been designed to achieve the following objectives:

- economic efficiency in the use and the development of the distribution network;
- equity between customers and Network Service Providers;
- non discriminatory access;
- provide a commercial return on efficient network investment;
- transparent pricing;
- price stability;
- administrative simplicity;
- incentive for efficient investment in distribution networks.

It is recognised that some of the objectives may conflict and that it is impossible to design a pricing regime which satisfies all the objectives all the time. In practice, the form of the pricing regime will ultimately depend on the relative weighting placed on each specific objective. It can be argued that this weighting of objectives is further support for the national/jurisdictional model detailed in this Code. For example, as the jurisdictions are all at different points in the reform process it may be more appropriate for one jurisdiction to heavily weight price stability whereas a more advanced jurisdiction may increase the weight on economic efficiency.

## Pricing to Individual Customers (Part E of Chapter 6)

Following extensive consultation and the review set out in clause 6.1.6 of the Code, an even more flexible approach to network pricing to customers may be developed.

A flexible approach offers the following benefits:

- it maximises economic efficiency as the cost allocation process applied to set prices can be better matched to the underlying business cost drivers and physical characteristics;
- it enhances customer resource allocation decisions through more accurate price signals to customers;
- it reduces the likelihood of price distortions and minimises any customer cross subsidies which may evolve from inappropriate cost allocation models;
- it fosters innovative and competitive pricing directed at meeting customer needs and wants; and
it promotes investment efficiency and improved asset utilisation by providing the correct price signals to businesses.

It is often asserted that a possible barrier to entry is created if the cost allocation process is not clearly prescribed and mandated. The barrier to competition is said to be created through the customers not being able to easily decipher or compare Network Service Provider charges. This market information issue is overcome since each Network Service Provider is required to publish an approved set of maximum charges, in a consistent and easily understood format, which is freely available to all prospective users. This process effectively enhances competition as it encourages better price comparison.

Part E has been provided as one possible cost allocation methodology that could be applied in developing Network Service Provider charges. A full and detailed review of Part E be completed within 24 months of the Code's acceptance by the ACCC. This review will be facilitated by NECA and will involve Federal and State regulators as well industry experts and customers. The terms of reference for the review are detailed in section 6.1.6 of the Code.

## Assessment of Regulation of Network Pricing for Distribution Systems

## Criterion 1: the legitimate business interests and investments of the service provider

The regulatory regime seeks to achieve the following objectives:

- the provision of incentives to Network Service Providers to seek to maximise efficiency of their operations and capital investment;
- the provision to the Network Service Provider users of a reasonable share of the financial benefits flowing from the achievement of efficiency improvements by the Network Service Provider; and
- the provision to Network Service Providers of an income stream which has a reasonable probability of delivering them a normal rate of return on efficient investment, after providing for efficient levels of operating and maintenance costs.

Achievement of the third objective is clearly in the business interests of the service provider. However, taking into account the longevity of the assets and the high sunk costs involved, achievement of the third objective is also regarded as being in the public interest as it provides a signal to capital markets that there is a reasonable prospect of earning appropriate returns on future investment in the network.

It is clear that the proposal detailed in the Code adequately protects the legitimate business interests of the Network Service Provider.

Criterion 2: the public interest, including the public interest in having competition in markets (whether or not in Australia)

Part D promotes economic efficiency as it establishes an incentive based regulatory regime which accommodates the specific characteristics of all Network Service Providers.

The incentive based regulatory regime provides for, on a prospective basis, a fair and reasonable return to service providers on efficient investment and efficient operating and maintenance costs. In addition the framework provides flexibility to the regulator to accommodate the particular cost structure characteristics of particular distributors.

Competition and the public interest is promoted through the emphasis on the introduction of contestability and the multi-tiered approach to regulation. First, structural reform is preferred where possible. Second, each jurisdictional regulator is required to apply a competition and a regulatory efficiency test to determine the type and form of the regulation which is to be applied to specific Network Service Provider service. For example, monopoly services not subject to any competition, are subject to a higher degree of scrutiny and regulation than those services which face effective competition. This approach is consistent with the Hilmer recommendations and the general thrust of competition policy reform.

The approach to regulation ensures that the most efficient and appropriate form of regulation is applied to the specific Network Service Provider .

The effectiveness of this regime in fostering efficiency and promoting cost savings will depend largely on the cost pressures applied by the regulators. It is contingent on access to reliable and detailed cost and operational information from the regulated entities. Such information disclosure is adequately provided for in section 6.10.6 of the Code.

Criterion 3: the interests of persons who may require access to the service
The Code adequately addresses the interests of those persons wishing to access the Network Service Provider service. First, the national guidelines will ensure that the network prices for distribution services will be consistent and easily understood. This will ensure that all service users will have full, easily understandable and comparable information of the services provided and the costs of each service.

Second, the jurisdictional regulators will develop guidelines or rules for the determination of the annual aggregate revenue requirements and minimum levels of service and access standards and conditions. In line with the guidelines each Network Service Provider will produce and submit to the regulator a set of tariffs and conditions for access to and use of the distribution network.

Third, an incentive based regulatory regime is proposed which is directed at producing pricing outcomes that are commensurate with market based prices.

Finally, the Code states that where a Network Owner receives a capital contribution in respect of an asset, the value of the asset for revenue determination purposes will be reduced by the amount of capital contribution received. This ensures that network owners are unable to charge customers twice for the same assets. Any "double charging" by Network Owners would be in breach of the Code.

## Matter 1: economic efficiency including efficient resource allocation

The Code establishes an incentive based regulatory regime which is directed at producing pricing outcomes that are commensurate with market based prices. The objectives of the regulatory environment promote:

- a reasonable balance between the interests of Network Owners and Network Users;
- a minimisation of undue regulatory risk, thereby enabling Network Service Providers to raise capital at the minimum possible cost;
- the lowest possible network prices without depriving Network Service Providers of reasonable opportunities to earn a fair rate of return;
- correct price signals to users which will lead to appropriate customer and business investment decisions.

Matter 2: market transparency and appropriateness of the proposed access pricing and terms and conditions

The participating jurisdictions have chosen to pursue the option of ACCC accepting an industry access code, as a means of minimising regulatory uncertainty and dispute resolution costs.

In addition the Network Service Providers will be required to submit their specific tariffs and charges to the jurisdictional regulator for approval. The form of the tariffs and charges will be consistent with the jurisdictional regulatory guidelines and any Commonwealth guidelines and principles.

## Matter 3: equity considerations, including non-discrimination between like access seekers

Fair and reasonable access (or equity of access) will be fostered by:

- clear pricing objectives to promote equity and price stability;
- an incentive based regulatory regime that is predicated on a equitable sharing of the prospective gains from efficiency improvements in business operation;
- flexibility for the devolvement of cost reflective pricing; and
- non discriminatory access to the network.

Matter 6: adequacy of information disclosure requirements on the provider to meet the needs of potential third parties

The information disclosure requirements on the regulated entities and the regulators will ensure the provision of appropriate and timely information to both consumers and business. The regulators will have considerable discretion in determining the information to be obtained from service providers.

### 8.4.7 Assessment of dispute resolution and enforcement provisions

## (a) Dispute Resolution

Clause 8.2 of the Code relates to dispute resolution. This clause applies to any dispute which may arise between Code Participants as to:

- the application or interpretation of the Code;
- any matters in respect of which a contract provides that dispute resolution procedures in the Code are to apply;
- any failure to reach agreement on a matter where the Code requires agreement;
- augmentation of a network; or
- the payment of moneys under or concerning any obligation under the Code.

It is intended that the dispute resolution procedures should:

- be guided by market objectives and code objectives in the Code;
- be simple, quick and inexpensive;
- preserve or enhance the relationship between the parties to the dispute;
- take account of the skills and knowledge that are required for the relevant procedure;
- observe the rules of natural justice; and
- place emphasis on conflict avoidance and encourage resolution of disputes without formal legal representation or reliance on legal procedures.

However, if the dispute resolution procedures do not bring about a settlement of the dispute, Code Participants are free to pursue other options to resolve disputes between them.

Under clause 8.2, each Code Participant must adopt and implement a dispute management system of its own. This dispute management system is to meet the criteria determined by NECA in consultation with Code Participants.

If a dispute arises, the parties must firstly refer the dispute to their own dispute management system. Failing resolution, the dispute can be referred to a dispute resolution adviser appointed by NECA. This adviser may refer the dispute to a dispute resolution panel established by the adviser in accordance with clause 8.2.6 of the Code.

## (b) Enforcement

Under section 9 of the National Electricity Law, a person must not engage in the activity of owning, controlling or operating:

- a generating system that supplies electricity to a transmission or distribution system; or
- a transmission or distribution system that is used to convey, and control the conveyance of, electricity to customers (whether wholesale or retail) and is connected to another such system,
unless the person is registered by NEMMCO as a Code Participant in relation to that activity or is the subject of a derogation under the Code.

Likewise, a person (other than NECA or NEMMCO) must not engage in the activity of administering or operating a wholesale market for the dispatch of electricity generating units or loads unless the person is authorised to engage in that activity under the Code.

Finally, a person must not engage in the activity of purchasing electricity from a person who administers or operates a wholesale market for the dispatch of electricity generating units or loads unless the purchaser:

- is registered by NEMMCO under the Code as a Code Participant in relation to that activity; or
- is the subject of a derogation under the Code.

Under the Code, each Code Participant which is registered with NEMMCO is bound by the Code.

The National Electricity Law establishes a tribunal to deal with breaches. If NECA considers that a Code Participant has breached a provision of the Code, NECA may apply to the National Electricity Tribunal for an order under Part 5 of the National Electricity Law. The National Electricity Tribunal must declare whether or not the Code Participant is in breach of the Code and can make orders requiring the Code Participant to pay a civil penalty, or impose a requirement on the Code Participant to cease the act which constitutes the breach of the Code or to take action to remedy a breach of the Code or implement a specified program for compliance with the Code, or any combination of these. In addition, the registration of the Code Participant may be suspended.

An order of the National Electricity Tribunal for payment of a civil penalty may be registered in a court having jurisdiction for the recovery of debts up to the amount of the civil penalty and proceedings for enforcement of an order registered in the court may be taken as if the order were a judgement of the court.

These provisions are given statutory force under the National Electricity Law being enacted in each participating jurisdiction.
(c) Matter 7: Whether dispute resolution principles and procedures specified in the industry access code are adequate to meet the needs of users and providers.

The dispute resolution procedures set out in clause 8.2 of the Code were designed with the object of being consistent with the relevant requirements of the Competition Principles Agreement (the "Agreement"). It is expected that the ACCC may well consider such requirements under the Agreement when assessing the acceptability of the Code's dispute resolution provisions. Accordingly, the key features of the dispute resolution procedures are assessed below against the relevant requirements set out on the Agreement, namely:

- the Code dispute resolution procedures provide a right to negotiate access which is backed up by an enforcement process in the event that parties are unable to reach
agreement (see clause 8.2.1(a)(3) and the balance of clause 8.2 of the Code, and compare clause 6(4)(c) of the Agreement);
- where the Network Service Provider and the person seeking access are unable to agree on the terms and conditions of access, the Code provides that the matter may be referred for resolution to the dispute resolution panel - being a body which is independent of the disputing parties (see clause 8.2.1(a)(3) and 8.2.6 of the Code and compare clause 6(4)(g) of the Agreement); and
- the resolution of any dispute determined under the Code's dispute resolution procedures is binding on the parties to the dispute, subject to the parties' rights to refer questions of law for determination by a court of competent jurisdiction (see clauses 8.2.1(f) and (g), 8.2.9 and 8.2.11 of the Code and compare clause 6(4) (h) of the Agreement).

While the Code is not prescriptive in this respect, it is envisaged that in respect of access disputes the Code dispute resolution procedures would otherwise be applied in a manner that is consistent with the Agreement. In particular:

- in deciding any terms and conditions for access, the dispute resolution body would be expected to take into account the matters referred to in clause 6(4)(i) of the Agreement;
- the dispute resolution body would explore the possibility of compensation before impeding the existing right of a person to use the network (see clause 6(4)(1) of the Agreement); and
- the dispute resolution body would require access to financial statements and other accounting information pertaining to Network Services (see for example clause 8.2.6(g) and (h) and compare clause 6(4)(0) of the Agreement).


### 8.5 Jurisdictional Access Arrangements

### 8.5.1 Introduction

In Chapter 9 of the Code, reference is made only to those derogations of jurisdictions which evince a departure from the provisions of the Code, either for the transitional period (up to 31 December 2000) or, in a small number of instances, for periods beyond that date.

To the extent that these arrangements comprise part of the industry access code for which acceptance is being sought through this Submission, arguments in support of those arrangements in terms of the access code criteria under proposed amending section 44ZZAA are set out below for the jurisdictions. However, the remarks for Queensland are general and separately dealt with as that State has yet to determine the changes it wishes to make to its industry and regulatory arrangements. The ACT arrangements are not separately argued and those for New South Wales will apply for ACT , where relevant.

In addition to the text of the Code and the specification of any jurisdiction's departure from the provisions of the Code (Chapter 9), each jurisdiction also has access arrangements under "applicable regulatory instruments" which are not comprised in the text of the Code, but which are included within it pursuant to clause 5.2.3 of the Code and
the undertaking required of Network Service Providers under Schedule 5.8 to Chapter 5 of the Code. These provisions have the effect of including in the Code access arrangements, a jurisdiction's "applicable regulatory instruments", being a range of jurisdictional laws and other arrangements specified, for each jurisdiction, in the definition of the expression in Chapter 10 of the Code.

Arguments are likewise set out below in support of these laws and arrangements of the jurisdictions in terms of the access code criteria under proposed amending section 44ZZAA. Queensland and the ACT are again treated generally for the same reasons as set out above.

### 8.5.2 Assessment of New South Wales electricity industry AccessArrangements

## (a) Introduction

The arguments supporting acceptance of the Code as an industry access code are presented earlier in this Chapter 8. This paragraph focuses on those parts of the New South Wales access arrangements which are State-based. In some instances the New South Wales arrangements are transitional, falling away as the Code is introduced. In other respects, predominantly aspects of retail market access, State-specific arrangements will continue to form an integral part of the access arrangements for the foreseeable future.

As noted in Schedule 8 to the Submission, the New South Wales access arrangements have been developed based on the following principles:

- introducing competition where possible;
- minimising the barriers to entry to the marketplace;
- separation of monopoly and competitive businesses;
- regulation of monopoly services;
- allowing parties to negotiate on terms and conditions; and
- ensuring effective procedures to resolve access and pricing disputes.

This section describes how, consistent with these objectives the New South Wales arrangements meet the criteria used by the ACCC to assess accesscodes.

## (b) Entry to the wholesale market

When the Code is introduced, NEMMCO will determine who is registered for participation in the wholesale market. The arguments in support of the Code registration provisions have been described in Chapter 6.

## (c) Entry to the Retail market

The New South Wales Minister for Energy is responsible for issuing retail licences in New South Wales?

Clear, non-discriminatory criteria have been established to assess applicants. In order to become a licensed retailer, applicants must:

- be a distinct legal entity;
- meet the prudential requirements of operating in the wholesale market; and
- demonstrate that they have the ability to operate a viable business.

The licence requirements are applied in a non-discriminatory manner across all potential and actual licence holders. Licence conditions have only been introduced where there are clear public benefit reasons for so doing. For example:

- customer protection measures - these measures include:
- price regulation (through IPART determinations);
- required contract provisions; and
- dispute resolution mechanisms,
for customers who have no right to choose their retailer (ie franchise customers) and all users of distribution services;
- environmental conditions - these are statutory conditions detailed in the Electricity Supply Act which require the formulation of plans and strategies to reduce the level of greenhouse gas emissions. The Minister has been conscious of the need to encourage new entry to the retail market, and has not required these strategies as a pre-requisite for obtaining a retail licence. Environmental plans and strategies are required to be developed in the period following licence approval;
- conditions planning purposes - to ensure business separation of monopoly services;
- information and technical requirements - conditions which are required to ensure that technical requirements are met in the electricity system, and that information is made available for regulatory purposes. These are required in order to ensure the safety of the integrated network, and for effective economic regulation.

The Minister will also take into consideration the market power of a licence applicant, and the effect on competition, in deciding whether to grant a retail licence. These factors are clearly consistent with the objectives of the Act.

[^28]The licence application procedure is a transparent process which involves advertising an application and inviting public submissions. The Minister publishes a report which summarises the substance of submissions and advises the decision on the licence application. Normal administrative law rights of review apply.

New South Wales and other States are actively discussing options to harmonise the licensing process across States.

Based on the arrangements and rationale described above it is submitted that the New South Wales access arrangements relating to entry into the New South Wales retail market meet the statutory criteria for an access code.

It is through a combination of the obligations imposed on:

- a distributor under section 34 of the Electricity Supply Act;
- a retailer to sell under the Electricity Supply Act and its licence; and
- a retailer to supply electricity under the provisions of customer supply contracts which customers enter into with their retailer;
that customers in New South Wales gain the benefits of the right to use the system.
(d) Connection and Use of System

Connection arrangements for Code Participants are described in paragraph 8.4 above. Connection and access arrangements for retail customers who are not Code Participants will continue to be govemed by the Electricity Supply Act when the Code is introduced. The Electricity Supply Act and associated regulations ensure that:

- New South Wales distributors must provide connection to the network, and ensure that customers are protected from the abuse of monopoly power;
- New South Wales distributors must supply electricity to their local customers through their network; and
- New South Wales retailers must enter into customer supply contracts, with retail customers and such customers will thereby gain the benefit of the right to use the system through customer supply contracts with their retailer.

The Electricity Supply Act also enshrines the freedom of retail customers to negotiate a customer connection contract with their distributor if they prefer to deviate from the standard form contract.

Consistent with the intention to introduce competition where feasible, customers may choose who supplies their connection services, as long as they are technically
proficient. Moreover, over time customers will be entitled to choose from whom they purchase their electricity.

## (e) Network Pricing

Transmission and distribution pricing are currently regulated by IPART. The principles underlying IPART's activities reflect in essence the requirements of Part IIIA of the Act. IPART must balance the interests of network operators and users, ensure that customers are protected from abuses of monopoly power and promote competition and efficiency.

The principles for transmission pricing will be governed by the Code from 1999, which has been discussed in Chapter 7. Distribution pricing will continue to be regulated by IPART, under its own Act until 1 January 2001, and then under the Code arrangements.

These transitional arrangements allow for reasonable recognition of pre-existing New South Wales policies relating to asset values, revenue paths and prices. Support for these transitional arrangements is also implicit from the requirement under the Code to review network pricing methodology.

The criteria used by IPART in making its price determinations incorporate the principles of the Act (including Criteria 1, 2 and 3), and include:

- the cost of providing services, and an appropriate rate of return (legimate business interests of network operators);
- the protection of consumers from abuses of monopoly services in terms of prices, pricing policies and standards of services (interests of network users);
- the need for greater efficiency, and a range of other environmental and social factors (the public interest).


## (f) <br> Arbitration of access disputes

The New South Wales access arrangements relating to access dispute resolution have been framed to ensure they meet the requirements of the Act. The IPART Act was amended in 1995 in light of the Competition Principles Agreement, and arbitration of access disputes under that Act must take these principles into account. The IPART Act also enforces the decisions of the arbitrator.

IPART will continue to deal with transmission access disputes until 1999, when responsibility for transmission pricing is transferred to the ACCC and the provisions of the Code apply to both network pricing and access disputes.

New South Wales has derogated from the Code for distribution access disputes. In relation to distribution access disputes arising on or before 31 December 2000, such disputes will be determined by IPART applying Part 4A of the IPART Act. Disputes arising thereafter will also be determined by IPART but under the provisions of Chapter 8 of the Code.

Given that distribution pricing will continue to be regulated by IPART until 1 January 2001, and there is a close relationship between network pricing and network access, New South Wales believes it is appropriate for IPART to continue acting as the dispute resolution arbiter.

As noted in Chapter 7 of the Submission, the New South Wales Government supports the national regulation of both transmission and distribution networks from 1 July 1999, but has emphasised that a satisfactory regulatory framework should be agreed and put in place.

### 8.5.3 Assessment of Victoria's electricity industry access regime

## (a) Introduction

The regulatory instruments applicable to Victoria's electricity industry (referred to in the Code definition of "applicable regulatory instruments") contain provisions enabling industry participants to seek and obtain access to electricity networks in Victoria. These electricity networks may either be transmission networks (generally high voltage networks) and distribution networks (lower voltage networks) within Victoria. The wires which transport electricity from generators to end use customers, including both the transmission and distribution networks, are considered to be a natural monopoly. They are also considered to be services which are susceptible to declaration under Part IIIA of the Act.

Victoria's applicable regulatory instruments include:

- the Electricity Industry Act 1993 (Vic);
- the Office of the Regulator-General Act 1994 (Vic);
- all regulations made and licences issued by the Office of the Regulator-General ("the Regulator-General") under the Electricity Industry Act;
- all regulatory instruments applicable under the licences; and
- the Tariff Order,
to the extent that those regulatory instruments regulate or contain terms and conditions relating to access or connection to a network, the provision of network services, network service pricing or augmentation of a network.

The industry access code submitted to the ACCC pursuant to section 44ZZAA of the Act includes these regulatory instruments.
(b) Interaction with the Code

While the National Electricity Code is being submitted as an industry access code in respect of all States, Victoria initiated the introduction of competition into its electricity supply industry.

To introduce competition in the electricity supply industry Victoria implemented new access arrangements in 1994, prior to the proposed amendments to the Act pursuant to which the ACCC will be able to accept an industry access code, the introduction of Part IIIA itself, and indeed, prior to the establishment of the ACCC. The Victorian access arrangements are part of Victoria's competitive electricity industry. In addition, the privatisation of the distribution businesses and the generators is creating an even greater degree of competition.

As a result, while Victoria will achieve implementation of the National Electricity Code by 2001, the transitional arrangements designed to manage the transition from the current operating environment to that of the national electricity market will result, in some cases, in:

- certain provisions of the National Electricity Code not becoming operational until 2001; and
- some Victorian arrangements remaining in place until after 2001.

Upon registration with NEMMCO, each Network Service Provider in Victoria will submit to the ACCC an access undertaking (pursuant to Section 44ZZA of the Act) in the form set out in Schedule 5.8 of the National Electricity Code. This undertaking provides that the Network Service Provider will maintain and make available its networks for access in accordance with:

- applicable regulatory instruments including, but not limited to, the Act;
- the requirements of the Code; and
- good electricity industry practice and applicable Australian Standards.

In Victoria, applicable regulatory instruments means (as defined in the Code):
"all laws, regulations, licences and codes from time to time applying to Code Participants including those applicable in each participating jurisdiction as listed below, to the extent that they regulate or contain terms and conditions relating to access or connection to a network, the provision of network services or augmentation of a network"

- the Electricity Industry Act 1993 ("EI Act");
- all regulations made and licences ("Licences") issued under the EI Act;
- the Office of the Regulator-General Act 1994 ("ORG Act");
- all regulations, anddeterminations made under the ORG Act;
- all regulatory instruments applicable under the Licences; and
- the Tariff Order made under section 158A of the EI Act."

Throughout this part of the Submission, these regulatory instruments, insofar as they seek to regulate access to Victorian electricity networks, are referred to as "Victoria's access arrangements".

Network Service Providers who are licensed by the Regulator-General at the date of this undertaking will nominate 1 December 2010 as the proposed expiry date of the undertaking. The rationale behind this expiry date is discussed below.

Network Service Providers who may become registered with NEMMCO at a later date will also provide undertakings as specified in the Code at the time of registration with NEMMCO.

This process avoids unnecessary duplication of public consultation in a network industry and ensures coherent industry-wide access arrangements within Victoria.
(c) Satisfaction of the criteria in section 44ZZAA(3)

This part of the Submission examines Victoria's access arrangements against the criteria described in paragraph 8.2.2.

To facilitate this examination, Victoria's access arrangements have been divided into the following categories:
(i) connection requirements;
(ii) network planning and augmentation;
(iii) transmission revenue regulation and transmission pricing structure;
(iv) distribution revenue regulation and distribution pricing structure;
(v) dispute resolution procedures;
(vi) enforcement procedures; and
(vii) procedures for the transition to theNEM.

This examination focuses on the impact of the relevant regulatory instruments in each category to the satisfaction of the stated criteria for that category. In addition, Victoria's access arrangements when considered as a whole comply with the criteria in section 44ZZAA of the Act for the acceptance of an access code. The interdependent instruments which go to make up Victoria's access arrangements have been the avenue through which Victoria has achieved the introduction of competition into a previously sheltered area of the economy and achieved positive economic outcomes of allocative, productive and dynamic efficiencies. Broadly considered, Victoria's access arrangements achieve the necessary balance between the commercial interests of Network Operators and those of businesses seeking to enter and compete in upstream and downstream markets. Per se, and as arrangements which are broadly transitional, Victoria's access arrangements achieve the objectives of the national access regime encompassed in Part IIIA of the Act.

## (i) Assessment of the connection requirement provisions of Victoria's access arrangements

## Overview

## Regulation of connection access and connection charges

The rights and obligations of both the owners of network assets (ie PowerNet Victoria ("PNV") and the Victorian distribution businesses) and network users with regard to connection, related charges and disputes are set out in the relevant licences, codes and guidelines issued by the Regulator-General.

Section 158 of the Electricity Industry Act 1993 confers on the Regulator-General power to regulate prices in respect of:

- charges for connection to, and use of, any distribution system; and
- charges for connection to, and use of, the transmission system,
in accordance with the Tariff Order made under section 158A of the Electricity Industry Act.

The Regulator-General must exercise these powers in a manner consistent with its objectives under the ORG Act and the EI Act.

The Regulator-General's objectives under section 7 of the ORG Act are:

- to promote competitive market conduct;
- to prevent misuse of monopoly or market power;
- to facilitate entry into the relevant market;
- to facilitate efficiency in regulated markets; and
- to ensure that users and consumers benefit from competition and efficiency.

Its objectives under section 157 of the EI Act are:

- to promote competition in the generation, supply and sale of electricity;
- to ensure the maintenance of an efficient and economic system for the generation, transmission, distribution, supply and sale of electricity;
- to protect the interests of consumers with respect to electricity prices and the safety, reliability and quality of electricity supply; and
- . to facilitate the maintenance of a financially viable electricity supply industry.

As part of the transition to full competition, Victoria's electricity consumers are currently classed either as "contestable customers" or as "franchise customers". Since 1 July 1996, all customers whose electricity load level exceeds 750 MWh per year have been contestable customers. From 1 July 1998, customers whose electricity load level exceeds

160 MWh per year will also become contestable customers, and from 1 January 2001 all customers will be contestable customers. Opening the retail market for electricity in this manner has lessened the impact of deregulation on industry participants, customers and regulators alike by ensuring that competition is introduced in orderly, manageable stages.

Victoria's electricity industry is regulated through a licensing regime under the EI Act and the ORG Act. Victoria and other jurisdictions are presently actively discussing options to harmonise the licensing process across the jurisdictions.

Under the terms of its transmission licence, PNV is obliged to:

- make an offer to connect generators, distributors or contestable customers to the system on request, consistent with the EI Act and the Tariff Order;
- comply with the regulatory requirements in relation to connection and transmission charges, including the revenue and price caps on PNV connection charges to generators and customers, including distribution businesses, and its charges to VPX for use of the grid; and
- submit to the Regulator-General for approval a statement of all other transmission charges (including the maximum charge for services and the principles and methodology for setting such charges) which are not already covered by the Tariff Order.

Under the terms of their distribution licences, the distribution businesses are obliged to:

- make offers to connect their distribution systems to the electrical installations of customers or embedded generators, on request;
- provide offers of connection services to another distributor to facilitate the distribution of electricity by the other distributor (eg power transfer capability services and reactive capacity at different points of connection);
- comply with the regulatory requirements in relation to connection and distribution charges;
- comply with accounting requirements designed to ensure transparency of pricing and the separation of distribution and retail functions within the distribution businesses;
- submit to the Regulator-General for approval a statement of all distribution charges including the maximum charge for services, the principles for setting such charges and the methodology for setting such charges;
- set out the methodology by which a distributor may augment its distribution system in relation to an offer to provide connection services; and
- provide retailers with information to allow them to separately identify network charges in their statement to customers.

The Regulator-General has indicated in its Electricity Industry Guideline No 1 and its Regulatory Statement that it bases its approval of PNV's or a distribution business'
statement of charges on its objectives under the ORG Act and the EI Act (which are listed above and include the promotion of efficiency and competitive markets) and on principles developed under the Act to determine whether cross subsidies between regulated and non-regulated charges and between franchise customers and non-franchise customers are anti-competitive or otherwise not in the interests of customers. Clause 17.2 of the Regulator-General's Electricity Industry Regulatory Statement states that "while cross subsidisation is not bad per se, cross subsidisation... will be examined to determine whether such cross-subsidisation is anti competitive or otherwise not in the interests of customers."

The licences require that offers to connect by PNV and the distribution businesses must be consistent with the EI Act and the Tariff Order, applicable guidelines published by the Regulator-General and a statement of approved charges (ie a statement of charges for network services prepared by PNV or a distribution business and approved by the Regulator-General). The licences provide that any term or condition of an offer by PNV or a distribution business which is not already regulated in these ways must be fair and reasonable in the opinion of the Regulator-General.

It is submitted that the regulatory requirements concerning connection are intended to encourage:

- cost efficiency and equity on the part of Network Service Providers in providing services to users;
- transparency and accountability in meeting regulatory standards and enabling users to make informed choices;
- non-discriminatory policies and practices in relation to connection, with emphasis on the control of unnecessary cross-subsidies; and
- regulatory instruments which seek to balance the need for commercial flexibility with the objectives of competition and efficiency.

The safeguards seek to minimise unnecessary barriers to connection to the transmission and distribution networks and have the intent of being non-discriminatory by obliging Network Service Providers to use all reasonable endeavours to accommodate the requirements of persons seeking access. The terms and conditions also allow non-discriminatory access by ensuring that the cost of connection is transparent and applies equitably to all potential users of the network.

These arrangements provide a safeguard against excessive connection charges, and against the gold-plating of connection equipment by Network Service Providers as a means of raising charges.

## Criterion 1: the legitimate business interests and investments of the Network Service Provider

Victoria's access arrangements provide for negotiation between the access seeker and the Network Service Provider on terms and conditions relating to any aspect of the service which can be varied without adversely affecting the quality of supply to network users and the safety of the network as a whole.

## Criterion 2: the public interest, including the public interest in having competition in markets (whether or not in Australia)

Victoria's access arrangements impose minimum and uniform levels and standards of network performance and customer service on each Network Service Provider with regard to connection arrangements.

The specification of technical standards for equipment connected to the distribution and transmission networks in applicable Victorian industry codes overseen by the Regulator-General is designed to ensure that, from a participant's perspective, a clear and unambiguous framework is established within which they can negotiate with Network Service Providers the terms and conditions on which they can obtain a connection facility and at the same time ensure the integrity of the network to provide a quality of service required by other users.

It is important to note that the conditions for connection by a Generator to a distribution or transmission network have been specified in a manner to remove any bias against alternative generation technology provided that the alternative is safe for public use.

Despite their different impacts on suppliers and customers, these technical standards operate in the public interest because without them the power system would not operate safely to convey electricity to customers at an acceptable technical quality of supply and reliability of service. The ability to choose the retailer from which they obtain their supplies of electricity has given contestable customers a considerable degree of leverage in negotiating the terms and conditions on which they purchase electricity.

Criterion 3: the interests of persons who may require access to the service
Distribution businesses and PNV are required under their licences to make a fair and reasonable offer to connect to any person eligible to seek connection within specified periods of time;

Each licensee is required under the Regulator-General's Guideline No. 1 to prepare and publish in plain English a statement of the policies, practices and procedures it proposes to apply in relation to applications to connect;

There is nothing in any of the Victorian regulatory instruments that precludes a licensee and connection applicant from negotiating with each other in respect of the terms and conditions for the provision of connection and any other matters relevant to the provision of the connection.

The interests of the party seeking access are also protected because according to the Regulator-General's Guideline No. 1:

- a licensee's statement of its policies, practices and procedures must be sufficiently comprehensive to enable an applicant to understand the information the licensee might reasonably require to formulate an offer;
- a licensee must make standard plain English forms available for routine applications;
- a licensee must identify and give the reason for any differences between an offer for connection and its published policies, practices and procedures or its Approved Statement of Changes;
- an offer must state the terms and conditions upon which it will offer connection services and supply and, in particular:
- identify costs a customer may incur and the payment terms and conditions;
- the technical parameters of the offer;
- the terms upon which the licensee is prepared to accept liability for failure to supply to a specified standard or standards;
- the basis upon which charges may be made for maintenance or disconnection; and
where an offer is different from that sought by an applicant the offer must include a statement that the applicant may ask the Regulator-General to review the offer to decide whether the offer complies with the Tariff Order, the Guidelines, the licensee's Approved Statement of Changes and is otherwise fair and reasonable.
- Disputes relating to access to distribution and transmission networks will be investigated on request by the Regulator-General, who is empowered to make determinations binding on the distribution businesses and PNV.


## Matter 1: economic efficiency including efficient resources allocation

Matter 2: market transparency and appropriateness of the proposed access pricing
and terms and conditions;
Matter 3: equity considerations including non discrimination between like access seekers.

Licensees and parties seeking to establish connection may negotiate connection agreements that meet the needs of the connection applicant without materially adversely affecting the levels of service and quality or reliability of supply received by other network users. The approach of the Regulator-General is light-handed and parties are encouraged to resolve disputes commercially rather than depend on regulation. Therefore, regulatory intervention should only be required as a last resort in the event of an access dispute or where a party believes they have been subjected to discrimination.

The terms and conditions of a connection agreement are left to negotiation between licensees and connection applicants, subject to licensees being required to offer connection on fair and reasonable terms. The participants have full control over the planning decisions with knowledge of the price associated with provision of additional network service. They are able to make appropriate trade-offs between costs and the performance and reliability of the Network Service Provider.

New entrants can seek access to a transmission or distribution network and will be able to obtain access at defined (fair and reasonable) prices which accurately reflect the cost of
providing the necessary assets to allow connection at the specified capacity and level of performance.

In terms of efficiency and equity:

- PNV's main connection charges to generators, distribution businesses and customers are regulated by revenue and price caps under the Tariff Order which are directed to preventing misuse of market power and providing incentives to pursue gains in efficiency and productivity;
- other connection charges levied by PNV are subject to regulatory oversight by the Regulator-General based on "fair and reasonable" criteria having regard by the Regulator-General to general economic efficiency objectives;
- terms and conditions for connection to distribution networks are left to negotiation between licensees and connection applicants (subject to a requirement that they be fair and reasonable and that they comply with a statement of approved charges, approved by the Regulator-General, which is a requirement of the distribution licence) to allow for an open access regime of commercially negotiated terms in accordance with the Regulator-General's guidelines and oversight; and
- the Regulator-General has oversight of connection procedures, including connection which involves augmentation.

In terms of transparency and accountability:

- the Regulator-General has a clearly defined role as both regulator and arbiter of disputes in context of providing appropriate incentives for parties to use market processes for negotiation of access and resolution of disputes;
- PNV and the distribution businesses both are required under their licences to publish statements of connection charges and related charges for Regulator-General approval;
- PNV and the distribution businesses are required under Guideline No. 1 to publish connection conditions such as requirements for financial guarantees associated with connection, disconnection procedures and identification of connection charges with use of system charges, also subject to Regulator-General approval;
- PNV and DBs both have to provide separate accounts to the Regulator-General for the different functions within their businesses - especially in regard to the ring-fencing of distribution and retail functions - and comply with any accounting related guidelines issued by the Regulator-General.

The regulation of connection prices and conditions by the Regulator-General pursuant to the provisions of each licensee's licence requiring such prices and conditions to be fair and reasonable has several features which are intended to promote non-discriminatory practices in connection offers and agreements:

- distribution businesses are required to offer prices on the same basis for connection to similar users and customers, irrespective of their retailing arrangements;
- the Regulator-General's obligation to ensure a fair sharing of benefits to customers in its price reviews has been interpreted by the Regulator-General, in its regulatory statement, as a duty to ensure that the price cap rules minimise incentives to create discriminatory cross-subsidies;
- the Regulator-General is presently assessing connection charges;
- the Regulator-General will examine disputes over connection on the basis of its objectives (which include the promotion of competitive markets and efficiency, prevention of misuse of monopoly power and facilitation of entry into relevant markets) and its judgment as to what is "fair and reasonable".

Matter 4: the extent and significance of any barriers to new entry in related markets including the promotion of competition in upstream and downstream markets

Retail, distribution and transmission licences are non-exclusive - persons other than the five original distribution businesses are able to apply and obtain licences.

The success of this policy in the retail market is evidenced by the fact that, to date, seven new persons have applied for and been issued with retail licences. Victoria now has 12 licensed retailers actively competing to supply and sell electricity to contestable customers.

Similarly, persons who wanted to construct a new distribution or transmission network, whether in a greenfields site or otherwise, would be able to apply for distribution or transmission licences to enable them to do so.

## Matter 5: any operational and technical constraints imposed on market participants

The industry codes prescribe extensive minimum technical requirements on a party seeking connection to a transmission and distribution network and operational requirements on the party after connection has been established in order to ensure the achievement of minimum standards of quality and safety of supply. A distribution businesses is required under its distribution licence to include in every offer for a connection a condition that the customer comply with the relevant provisions of the Distribution Code. These provisions include:

- not allowing electricity supplied to the customer to be used other than at the customer's premises and not to supply the electricity to another person unless they have an exemption granted by the government which enables them to do so;
- keeping the power factor of its electrical installation within a defined range;
- ensuring the harmonic distortion level in the supply voltage is less than the applicable limit;
- ensuring that the aggregate current, reactive power and active power in each phase of supply do not deviate from the average by more than $1 \%$;
- ensuring that variations in current do not cause voltage disturbance above certain levels; and
- ensuring that inductive interference caused by its electrical installation and connection appliances is less than certain limits which are considered not to significantly affect the performance of the electrical system or the security and quality of supply.

The System Code imposes connection related obligations on the distribution businesses and other persons supplied electricity directly from a transmission network in respect of:

- power factor requirements;
- aggregate power factor;
- load balance;
- disturbing loads;
- voltage notching,
- current harmonics; and
- data provision.

These technical and operational requirements are consistent with good electricity industry practice and applicable Australian standards. They are also essential to the ability of the distribution businesses and VPX to meet the minimum network performance requirements and system security responsibilities and obligations necessary to ensure the power system operates safely and delivers satisfactory quality of supply. The Regulator-General will ensure the distribution businesses comply with these rules.

The Regulator-General has established a performance reporting regime pursuant to government policy, under which comparative reports are submitted to ensure the level of services is maintained. The fact that electricity cannot be stored and must be transported through fixed infrastructure means that any one action affecting the power system affects all users of the power system. This means that it is necessary for the benefit of all users of the power system and the public as a whole to impose minimum technical standards on each individual licensee. A power system that meets quality of supply and technical safety standards is in the public interest.

## Matter 6: the adequacy of information disclosure requirements on the provider to meet the needs of potential third parties

The Regulator-General's Guideline No. 1 provides for extensive information disclosure requirements to assist the distribution businesses to meet the needs of potential third parties. The Regulator-General's Regulatory Statement indicates that the requirements imposed on the distribution businesses under the provisions of Guideline No 1 are indicative of the requirements the Regulator-General would apply to PNV. These provisions include:

- plain English statements of connection policies, practices and procedure;
- standard forms for routine applications;
- identification of and reasons for any differences between an offer for connection and published standards;
information requirements in relation to:
- possible costs and payment terms and conditions;
- technical parameters;
- liability for failure to supply; and
- maintenance and disconnection; and
- notification of a customer's right to request the Regulator-General to review an offer to ensure it complies with the relevant regulatory requirements and is otherwise fair and reasonable.

These information disclosure provisions have been designed to ensure that:

- the party seeking connection is fully aware of the information that is required to enable connection to be established; and
- a Network Service Provider can provide access to a transmission or distribution network without materially or adversely affecting levels and quality and reliability of service received by other network users.

The Regulator-General has indicated in its Guideline No. 1 that it will determine whether a term of a particular offer is fair and reasonable on the merits of each offer examined, and that the matters to which it may have regard in making its decision include:

- the objects of the Regulator-General under the ORG Act and the EI Act;
- the relative bargaining strength of the parties;
- whether the term would be likely to have been negotiated by parties dealing at arms length;
- the terms offered by other licensees and retailers in similar circumstances;
- whether the term goes beyond what is required to protect the legitimate interests of the licensee;
- the period for which connection services and supply (delivery services) is sought;
- the incremental impact of the applicant's load on the licensee's local capacity, including the nature of augmentation work needed to guarantee the level of service requested by the customer;
- the likelihood of an applicant ceasing to take supply (delivery) from the licensee's network;
- whether the term is consistent with the terms offered by a licensee to its retail arm in similar circumstances;
- whether the term offered to a franchise customer is different from a term offered to a non-franchise or contestable customer; and
- in respect of an offer to a new generator, whether the term gives proper recognition to any enhancement of the distribution system by virtue of the generator's location within the system.


## Performance Standards

In addition to the disclosure requirement outlined above, each licensee is required by its licence to provide to the Regulator-General, in the manner and form decided by the Regulator-General, such information as the Regulator-General may from time to time require.

The Regulator-General has required each distribution business to establish an auditable reporting regime and to report monthly against relevant performance indicators developed by the Regulator-General with respect to:

- quality of supply;
- reliability of supply;
- credit and security policy policies; and
- disconnection policies, practices and procedures.

Customer Service Indicator Reports comparing the performance of the distribution businesses against these indicators are being published by the Regulator-General on a regular basis. A yearly, independent review of each distribution business' recording and reporting systems ensures the information is reported accurately.

Exception Reports are also published where a monthly report by a distribution business reveals something out of the ordinary.

These reports enable customers and businesses to accurately and regularly compare the standard of service being offered by each distribution business.

## The role of the Regulator-General

The ORG Act provides that one of the objectives of the Regulator-General is to ensure that users and consumers benefit from competition and efficiency.

To meet this objective, the Regulator-General has undertaken extensive public education campaigns in order to ensure that franchise customers who become contestable customers are fully informed of their rights and the opportunities available to them.

This included a series of seminars designed to assist customers make an informed choice of electricity supplier, publication of booklets and a video relating to choice of electricity retailer and publication of Fact Sheets dealing with commonly asked questions.
(ii) Assessment of the network planning and augmentation provisions of Victoria's access arrangements against the criteria

## Overview

While PNV is the owner and responsible for maintenance of the transmission network, VPX is responsible for network planning, pricing and new investment decisions, including the co-ordination of extensions or modifications to the transmission network to accommodate load growth or new generators or to make the network more efficient.

This separation of the ownership and planning of the transmission network is a world first solution to the conflict of interest inherent in augmentation planning being carried out by a body whose ability to increase charges is linked to its ability to improve its asset base.

Every effort has been made to minimise the extent of the distribution businesses' and PNV's effective monopolies. The transmission and distribution licences are non-exclusive, allowing other persons to apply for and be granted such licences. All transmission and most distribution network augmentations are required to be offered for tender which encourages competition in the related markets of construction and maintenance of electricity networks.

As part of its role in providing information to facilitate decisions for investment and the use of resources in the electricity industry VPX publishes an annual planning review in which it details 10 year forecasts of demand.

In order to ensure that VPX has the necessary degree of industry expertise, yet remains independent of particular industry participants, types of industry participant and of government, the EI Act provides that its Board of Directors consists of:
(a) a chairperson;
(b) a director nominated by the relevant Victorian Minister after consultation with PNV;
(c) 2 directors nominated by the relevant Victorian Minister after consultation with the holders of generation licences;
(d) 2 directors nominated by the relevant Victorian Minister after consultation with distribution companies and the holders of licences to sell electricity otherwise than through the wholesale electricity market; and
(e) not less than 3 and not more than 6 other directors.

Criterion 1: the legitimate business interests and investments of the Network Service Provider

Criterion 2: the public interest, including the public interest in having competition in markets (whether or not in Australia)

Criterion 3: the interests of persons who may want access to the service
Matter 1: economic efficiency including efficient resource allocation

# Matter 6: adequacy of information disclosure requirements on the provider to meet the needs of potential third parties 

These criteria and matters are considered jointly.

## Augmentation of the EHV Transmission Network

PNV, as owner of the EHV transmission network, is responsible for identifying and promoting cost effective options for network asset investments and for providing VPX with information on the available options. However, it is the role of VPX under section 41C of the EI Act, as a non-operational, non-profit organisation, to plan and direct the augmentation of the electricity transmission system.

This arrangement ensures that:

- the minimum cost options for grid improvements are identified; and
- PNV's commercial interest in increasing its transmission charges does not bias augmentation decisions in favour of transmission assets over improvements that do not improve its asset base.

For some network assets, ownership other than by PNV is practical, in which case competitive tendering processes are adopted by VPX. Tenders are called by VPX under the oversight of the Regulator-General. PNV may compete for the augmentation work with other tenderers.

The separation of VPX and PNV, the requirement that tenders for augmentation work be called and Regulator-General oversight promotes the augmentation process and avoids the potential for over capitalisation in the system.

These augmentation arrangements are economically efficient and involve cost reflective pricing criteria and investment guidelines.

## Augmentations of sub-transmission and distribution networks

It is expected that most activity in network augmentation will continue in the future at the sub-transmission and distribution level. The majority of investment in new generation is likely to relate to smaller scale plants connected at the sub-transmission or distribution level and a large proportion of augmentation requirements should derive from the increased needs of existing customers consistent with price/ access signals under the Code.

The Regulator-General is responsible for regulating augmentation at the sub-transmission level and distribution level and has published Electricity Industry Guideline No. 2 "Distribution Systems Augmentation" in which it details its approach to relevant licence provisions and its policy towards augmentation regulation.

It is the distribution licences and the Regulator-General's Guideline No. 2 that will generally govem the obligations and rights of the distribution businesses and other interested parties regarding augmentation.

Under the distribution licences and Guideline No. 2, a distribution business is required to call tenders for augmentation work relating to an offer to provide connection services that would cost more than $\$ 5,000$, unless:

- the distribution business and the connection applicant agree in writing that the distribution business need not call tenders and the agreement is either in a standard form approved by the Regulator-General or specifically approved by the Regulator-General; or
- the distribution business satisfies the Regulator-General that, on cost-benefit grounds, it is uneconomical or inefficient to call tenders.

The exemption in relation to calling tenders for augmentation work relating to an offer to provide connection services costing less than $\$ 5,000$ is subject to the safeguards that:

- the customer may call tenders against the distribution business' initial estimate;
- the customer's right to call tenders must be explained in the distribution business' standard connection services agreement of the distribution business; and
- the Regulator-General will review the tendering and outservicing policies, practices and procedures of each distribution business.

A distribution business is not required to call tenders for its own augmentation work.
The system of competitive tenders assures the work is carried out on a least cost basis, consistent with relevant standards and the distribution businesses are prevented from taking advantage of their monopoly power by inflating the cost of augmentation and passing it on to customers.

## (iii) Assessment of the transmission revenue regulation and transmission pricing

 provisions of Victoria's access arrangements against the criteria
## Overview

Until 1 January 2006, revenues from transmission services are regulated under the Tariff Order. For transmission charges levied by VPX, for connection and use of the system, the following applies:

- assets are valued on the basis of optimised depreciated replacement cost with adjustment to achieve tariff objectives;
- calculation of rates of return are based on a weighted average cost of capital;
- costs are allocated in two segments: use of the network system and recovery of other costs such as connection, metering and equipment;
- a CPI - X regime applies to PNV's revenue cap, where the X value is set at $1.79 \%$; and
- PNV connection charges to users and its charges to VPX for use of the grid are subject to revenue and price caps.

This pricing regime continues in tandem with deregulation of the customer market until 1 January 2001 when the ACCC will assume responsibility for regulation of transmission prices.

The benefits of this approach are that:

- the customer has flexibility in determining the installation which will best meet their specific requirements and can readily determine the economic implications of the available choices;
- PNV carries the risk associated with the construction of the transmission network and the procurement of plant and therefore, PNV has the incentive to minimise those costs;
- it greatly reduces the impact of disaggregation and privatisation on the distribution businesses; and
- it ensures the impact of deregulation and transition to the NEM is gradual rather than overwhelmingly immediate.

In addition, further protection is obtained from the responsibility VPX has for decisions about new investments in the transmission network.

## Criterion 1: the legitimate business interests and investments of the Network Service Provider

Asset values have been locked in for PNV since 1994 and then depreciated in preparation for price reviews. This protects the value of PNV's assets.

The CPI - X regime provides a reasonable rate of retum for PNV and incentive for increasing those rates of return because it is not possible for the $X$ value to be increased except legislatively.

Criterion 2: the public interest, including the public interest in having competition in markets (whether or not in Australia)

## Meaning of the term "public interest"

The term "public interest" is not defined in the Act. Presumably, it relates to "public benefit" type factors. The Industry Commission's paper entitled Implementing the National Competition Policy: Access and Price Regulation (published in November 1995) suggested that the key consideration to be taken into account when assessing the public interest should be economic efficiency. The "public interest" factors relevant to this particular appear to be:

- promotion of competition;
- fostering business efficiency;
- promotion of cost savings in industry and the consequent containment or reduction of prices at all levels in the supply chain and the pass-through of cost savings to end-use customers; and
- provision of better information to consumers and business.


## Promotion of Competition

There are significant benefits to be derived from increasing the level of competition for the right to execute and own transmission augmentation projects and for the performance of on-going asset maintenance. The August 1993 report by the Independent (Hilmer) Committee of Inquiry into National Competition Policy stated that:
"The 'first best' solution [to monopoly pricing problems] is to address the underlying cause of monopoly pricing by increasing the contestability of the market. This might be achieved by removing or reducing regulatory barriers to entry; [or] restructuring public monopolies". ${ }^{8}$
"The Committee recommends that concerns over monopoly pricing be addressed primarily through appropriate regulatory and structural reform to enhance competition..."
"From a competition policy perspective, structural reforms will be particularly relevant where traditional monopoly markets are being opened to competition, and it is desired to ensure that effective competition can be established with minimal need for ongoing regulatory supervision."10

The Competition Principles Agreement executed by COAG on 11 April 1995 specifies a competitive neutrality policy and principles for the structural reform of public monopolies which principles are consistent with the Hilmer recommendations cited above. Clause 4(1) of the Competition Principles Agreement leaves the determination of matters relating to structural reform of public monopolies very much at the discretion of the owners of those monopolies by stating "Each party is free to determine its own agenda for the reform of public monopolies."

## Fostering Business Efficiency, Promotion of Cost Savings and Consequent Containment or Reduction of Prices

The CPI-X regime allows PNV to keep efficiency improvements beyond the $X$ value.

## Level of risk borne by Network Service Providers and the associated returns to Network Service Providers

Efficient resource allocation is facilitated where:

- the risks of a particular activity are bome by the party best able to manage that risk; and
- the rate of return expected (and achievable) by the risk-taking party is commensurate with the risk borne by that party.

[^29]A key principle of the regulatory approach is that the required rate of return of the enterprise should reflect the risk bome by its owners.

Criterion 3: the interests of persons who may require access to the service
Charges for connection to and use of the monopoly transmission network are, and will continue to be, regulated.

Terms and conditions relating to pricing of services not regulated under the Tariff Order must be fair and reasonable, as judged by the Regulator-General.

Matter 1: economic efficiency, including efficient resource allocation

## Neutrality between existing and new technologies

The use of the relevant asset valuation methodology ensures that the impacts of new technologies (in the network sector and in substitute sectors such as distributed generation) are taken into account in the valuation of assets for revenue purposes. It is understood that the impacts of new technology will be subject to customer impact statements under the provisions of the anticipated revised Distribution Code, and also subject to benchmarking by the Regulator-General over time.

Matter 2: market transparency and appropriateness of the proposed access pricing and terms and conditions

The regulatory arrangements for PNV are set out in the applicable licences and codes and the Regulator-General has oversight of the terms and conditions on which PNV operates. This highlights the transparency of the regulatory arrangements.

## Transparency of revenue capping process

The terms on which the revenue capping process is undertaken are set out in the Tariff Order. There is a high degree of transparency in this regard.

## Appropriateness of asset valuation approach in determining revenue requirements

Victoria's arrangements, including the revenue requirement determination, have been in place since 1994. This pre-dates the proposed amendments to the Act relating to the acceptance by the ACCC of an access code, and the establishment of the ACCC.

## Consistency of proposed asset valuation approach with "normal commercial practice"

A key principle of Victoria's access arrangements is that network owners should have a reasonable prospect of earning a normal commercial return on assets, but only given efficient investment in, and operation of, the network business. It is suggested that this fundamental objective is the basis of all "normal commercial practice". It is asserted that achievement of this basic objective is in the public interest in that it provides appropriate signals to public and private sector investors to continue to make capital available for the maintenance and expansion of existing network facilities to meet the demands of users.

## Matter 3: equity considerations, including non-discrimination between like access

 seekersThe prime "equity consideration" in respect of the proposed revenue regulatory arrangements is the extent to which those arrangements provide an equitable starting point, in terms of the revaluation of existing assets, for revenue determination purposes.

The results of empirical studies conducted within Victoria were provided to the ACCC in a document dated 5 July 1996, entitled: Submission to Australian Competition and Consumer Commission on the subject of transmission revenue regulation (Part B of Chapter 6 of the Code). These studies found that the optimised depreciated current cost of assets is highly unlikely to exceed the amount of the sunk investment which is yet to be recovered from customers through future charges.

It is possible that in some cases, the application of current cost asset values in network revenue determination may lead to increases in transmission use of system charges ("TUOS") delivered by VPX on behalf of PNV, that are politically unacceptable to owner govemments. This is likely to be the case where network tariffs have in the past been set at levels substantially below full cost. To address this, Victoria has implemented appropriate transitional arrangements, including re-valuing assets for revenue determination purposes, to levels below their deprival value, and directing the entities they own not to seek or apply a higher revenue amount.

Matter 6: adequacy of information disclosure requirements on the provider to meet the needs of potential third parties

PNV is required under the provisions of its transmission licence to provide information to VPX and the Regulator-General, respectively, on request.

## Criterion 4: any other matters that the ACCC thinks are relevant

The Issues Papers published by the ACCC in March and June 1996 have been examined to identify any other matters likely to be considered relevant by the ACCC in the context of the Victorian access arrangements.

## Appropriateness of revenue capping

In its March 1996 Issues Paper, the ACCC posed the following question:
> "Is revenue capping the most efficient method of economic regulation to ensure efficient operation and pricing of network services and to ensure effective access for [NEM] participants?"

In response, it is considered that the natural monopoly characteristics dictate the need for explicit revenue capping. This is necessary to protect the interests of "captive" grid users who have no alternative but to purchase transmission network service from the regional incumbent. There has been some discussion in recent US and UK literature of 'sliding scale approaches', 'sharing mechanisms' and other forms of incentive-based regulation, but all of these discussions are based around revenue capping rather than rate of return regulation.
(iv) Assessment of the distribution revenue regulation and distribution pricing provisions of Victoria's access arrangements against the criteria

## Overview

Until 1 January 2001, revenues from and prices for distribution and tariffs for franchise customers are regulated under the Tariff Order and, in certain circumstances, by guidelines published by the Regulator-General. For distribution charges levied by the distribution businesses for use of the system, the following applies:

- assets are valued on the basis of optimised depreciated replacement cost with adjustment to achieve tariff objectives;
- calculation of rates of return are based on a weighted average cost of capital;
- costs are allocated in two segments: use of the network system and recovery of fixed costs such as connection, metering and equipment;
- revenues and use of system prices for distribution are subject to CPI-X price caps with regulatory oversight by the Regulator-General;
- different CPI-X price caps apply to different customers in order to progressively reduce cross-subsidies, as part of a gradual movement towards cost-reflective pricing;
- charges for distribution business connection and services provided by a distribution business such as metering may be published and are subject to a "fair and reasonable" test administered by the Regulator-General;
- $\quad$ end prices to franchise customers (known as Maximum Uniform Tariffs or MUTs which combine energy and network charges) are also subject to a pre-determined CPI-X regime; and
- non-franchise customers will pay for energy at prices determined through the market but their maximum network charges will be regulated under the CPI-X regime noted above.

This pricing regime continues in tandem with deregulation of the customer market until 1 January 2001 when responsibility for regulation of transmission prices and distribution prices will be reviewed by the Regulator-General pursuant to clause 5.10 of the Tariff Order.

## Customer Class and Geographic Cross-Subsidies

Historically Victorian electricity tariffs have been uniform across the State within each customer class and across regions. This involved cross-subsidies of two main types:

- customer class - for the most part smaller business customers subsidising other customers; and
- geographic - densely populated areas subsidising sparsely populated areas.


## Geographic cross-subsidies

To manage the gradual adjustment of existing rural cross subsidies, the pricing arrangements for network charges alone will also reflect:

- revaluations of the assets of different DBs to achieve lower rural asset costs and higher urban asset costs than would otherwise have been the case; and
- the use of a transfer of amounts (called equalisation adjustments) through the VPX use of system fees from the urban distribution businesses to the rural distribution businesses.

These actions ensure that existing subsidies are phased out in a measured and gradual manner, minimising the impact on rural customers. The equalisation adjustments will become less significant over time as they will not be adjusted for CPI over five price review periods. The year 2020 is the final year in which the equalisation arrangements exist.

Connection charges for customers, including other distributors/retailers and embedded generators will be based on negotiation to maximise commercial outcomes, with Regulator-General supervision.

Under its licence, a distribution business is able to levy the following charges:

- network tariffs (i) which include recovery of distribution use of system costs ("DUOS"), use of transmission system fees and PNV's connection charges. Network tariffs are intended to cover the costs of providing, operating and maintaining the distribution network, except to the extent the relevant costs are recoverable through connection charges or other excluded services, and the charges levied by PNV and VPX for connection to and use of the transmission system. Network tariffs are paid by retailers supplying electricity through a distribution business' distribution network, or by large customers who purchase their electricity directly from the Pool or are reflected in the distribution business' charges to its franchise customers;
- connection charges (ii) for connecting customers to the network, taking into account that portion of the costs of connection which are recovered through network tariffs;
- charges for services not within (i) and (ii) which are required to be fair and reasonable; and
- charges for other non-regulated services provided in the course of operating the distribution business' business.

Distribution charges which are one element of the network tariffs are controlled for the period to 31 December 2000 through a CPI-X regime, using a weighted average charge formula. This price control formula is set out in the Tariff Order.

Network tariffs are set to recover projected distribution operating and maintenance costs (including current cost accounting ("CCA") depreciation on the opening asset values) and
anticipated transmission charges, to earn an assumed real rate of return on the opening distribution asset values measured on a CCA basis, and to earn a return and recover CCA depreciation costs on projected distribution capital expenditure. These tariffs are set out in the Tariff Order.

The initial structure of network tariffs comprises fixed annual charges (except in the case of unmetered supplies) together with variable charges (in $\varnothing / \mathrm{kW}$ per annum) for demand metered tariffs. Tariffs for those customers metered by two rate meters include peak and off peak usage charges (in $\phi / \mathrm{kW}$ per annum) for demand metered tariffs. . The prices vary between tariffs and between distribution businesses. The Tariff Order also limits the annual rate of change in the average price of each of its distribution categories (which under the Tariff Order, means the various categories of network charges) to CPI $+2 \%$ per annum.

Up to 31 December 2000, distribution businesses have the ability to vary network tariffs subject to the approval of the Regulator-General. The approval process takes account of the requirements of the Tariff Order including the distribution charge price control, the restrictions on annual variations of $\mathrm{CPI}+2 \%$ in any one year until 2000 in the average price for each of its distribution categories and the restrictions designed to ensure that the distribution businesses do not charge more for transmission and connection services than they are charged by PNV and VPX by way of connection and use of system fees.

## Distribution Price Control

Allowed DUOS revenue, net of the expense associated with transmission and equalisation charges, is regulated through a weighted average revenue yield formula. The ultimate regulatory control is the maximum average charge ("MAC") expressed in $\$ / \mathrm{kWh}$ (i.e. the revenue yield). Over or under recovery relative to the MAC is carried forward to the following year's price control through a " K " factor. As distribution revenue is regulated in terms of the MAC per unit, the " $K$ " factor for distribution adjusts revenue for differences resulting from the average charge, based on actual revenue, not equalling the MAC in the preceding year. Under this method of regulatory control, volume growth in excess of that adopted in setting the $\mathbf{X}$ factor will result in higher distribution revenue.

The price controls exclude amongst others, the following items, which are required to be fair and reasonable as judged by the Regulator-General:

- charges for rechargeable works not part of the standard distribution service to all customers;
- charges for transportation of energy for customers connected to the grid or subtransmission networks at 66 kV or higher, and some specifically nominated Public Transport Corporation sites;
- connection charges, including any customer contributions to capital works;
- charges for transportation of energy to an adjoining distribution network;
- non-standard network charges, including:

> reserve or duplicate supplies;

- supplies with special increased reliability requirements; and
- stand-by supply for parallel generators;
- charges for provision of non-standard metering; and
- charges for provision of reactive power.

In addition to the MAC price control, the Tariff Order contains a control on the maximum network tariff revenue recovered by the distribution businesses. This price control seeks to ensure that the distribution businesses do not over recover transmission use of system charges by VPX and connection charges by PNV. The distribution charge element of the network tariff is only limited by the MAC price controls.

## Non-Regulated Revenue

The distribution businesses have the potential to expand into a number of areas of "non regulated" activity. These include carrying out construction works for other distribution businesses or other utilities, entering the gas retailing business, providing billing services for other utilities, providing engineering expertise to other organisations, and using distribution infrastructure for other purposes (such as communication networks and cable TV).

## Criterion 1: the legitimate business interests and investments of the Network Service Provider

The regulatory regime seeks to achieve the following objectives:

- the provision of incentives to Network Service Providers to seek to maximise efficiency of their operations and maintenance activities and capital investment;
- the provision to the network users of a reasonable share of the financial benefits flowing from the achievement of efficiency improvements by the Network Service Provider; and
- the provision to Network Service Providers of an income stream which has a reasonable probability of delivering them a normal rate of return on their investment, after providing for efficient levels of operating and maintenance costs.

Achievement of the third objective is clearly in the business interests of the Network Service Provider: However, taking into account the longevity of the assets and the high sunk costs involved, achievement of the third objective is also regarded as being in the public interest as it provides a signal to capital markets that there is a reasonable prospect of earning normal returns on future new investment in the network.

As discussed above, the primary price control device is the MAC and the value of $X$. The MAC is built up on the weighted average of regulated charges in six tariff categories. The six distribution categories were developed in conjunction with the distribution businesses and reflect the different cost drivers. A distribution business must use its reasonable endeavours to ensure that the weighted average of its distribution charges (in $\phi / \mathrm{kWh}$ ) for all customers falling within the above distribution categories in each financial year does
not exceed the MAC in any year. The X factor for each distribution business has been established as a fixed annual rate to apply until December 2000 in the Tariff Order.

The X factors for the first regulatory period are based on load growth forecasts for each distribution business and limited productivity improvements. To the extent that actual productivity improvements exceed the assumed levels, the distribution businesses should earn a rate of return on the distribution element of their businesses in excess of the levels implicit in the setting of the distribution revenue at least through to the first distribution charges review in 2000. These ensure that the legitimate business interests of the Network Service Provider are protected.

Criterion 2: the public interest, including the public interest in having competition in markets (whether or not in Australia)

Criterion 3: the interests of persons who may require access to the service
The Victorian access arrangements ensure that the network prices for distribution services are consistent and easily understood, as the methodology for their calculation is a matter of public record.

The incentive based regulatory regime will ensure that the prices charged by the Network Service Provider are commensurate with what would be achieved in a competitive market.

While some categories of a distribution business' activities are labelled as non-regulated activities, these are regulated to varying degrees. The Regulator-General oversees activities involving the use of the distribution infrastructure of other communication networks and in particular will take an interest in the cost allocations and pricing associated with such activities. To the extent that other services are provided into competitive market environments, such as construction services, little oversight by the Regulator-General is expected.

## Matter 1: economic efficiency including efficient resource allocation

The Victorian access regime promotes the first best outcome of structural reform and fosters competitive market outcomes. Where structural reform is not possible the Victorian access regime establishes an incentive based regulatory regime which is directed at producing pricing outcomes that are commensurate with market based prices. The objectives of the regulatory environment promote:

- a reasonable balance between the conflicting interests of network owners and network users;
- a minimisation of undue regulatory risk thereby enabling Network Service Providers to raise capital at the minimum possible cost;
- the lowest possible network prices without depriving Network Service Providers of reasonable opportunities to eam a fair rate of return;
- correct price signals to users which will lead to appropriate customer and business investment decisions

Matter 2: market transparency and appropriateness of the proposed access pricing and terms and conditions

The CPI-X regime and the equalisation adjustments which are being implemented to gradually phase out cross-subsidies are fully disclosed in the Tariff Order. This allows complete transparency of the pricing regime.

## Matter 3: equity considerations, including non-discrimination between like access seekers

Fair and reasonable access will be fostered in the following ways.

- clear pricing objectives to promote equity and price stability;
- an incentive based regulatory regime that is predicated on a equitable sharing of the prospective gains from efficiency improvements in business operation;
- flexibility for the devolvement of cost reflective pricing;
- non discriminatory access to the network.

In addition, the maximum network tariff that may be levied by a distribution business will be the same for all retailers and large customers using the relevant distribution network within a given customer distribution category.

## Matter 6: adequacy of information disclosure requirements on the provider to meet the needs of potential third parties

The information disclosure requirements on the regulated entities will ensure the provision of appropriate and timely information to both consumers and business. The Regulator-General will have considerable discretion in determining the information to obtained from Network Service Providers, depending on what it considers may be necessary to enable it to achieve its objectives under the ORG Act and the EI Act.
(v) Dispute Resolution Procedures

## Connection related disputes

The holders of distribution, retail and transmission licences have established the Electricity Industry Ombudsman (Victoria). The Ombudsman is empowered to make a binding determination in a dispute where the amount of money in dispute does not exceed $\$ 10,000$ and, with the consent of all parties, to make either a binding determination or a non-binding recommendation in a dispute where the amount of money in dispute is between $\$ 10,000$ and $\$ 50,000$.

If a dispute does not fall within the jurisdiction of the Ombudsman, the Regulator-General has power under the transmission and distribution licences to decide any question as to the fairness and reasonableness of an offer to connect. The Regulator-General has indicated in its Guideline No 1 that it will consider the fairness and reasonableness of an offer to connect on its merits, having consideration to matters such as:

- the objects of the Regulator-General under the ORG Act and the EI Act;
- the relative bargaining strength of the parties;
- whether the term would be likely to have been negotiated by parties dealing at arms length;
- the terms offered by other licensees in similar circumstances;
- whether the term goes beyond what is required to protect the legitimate interests of the licensee;
- the period for which connection services and supply (delivery services) is sought;
- the incremental impact of the applicant's load on the licensee's local capacity, including the nature of augmentation work needed to guarantee the level of service requested by the customer;
- the likelihood of an applicant ceasing to take supply (delivery) from the licensee's network;
- whether the term is consistent with the terms offered by a licensee to its retail arm in similar circumstances;
- whether the term offered to a franchise customer is different from a term offered to a contestable customer; and
- in respect of an offer to a new generator, whether the term gives proper recognition to any enhancement of the transmission or distribution system by virtue of the generator's location within the system.


## Industry Code related disputes

The Regulator-General has power under section 163(6)(b) of the EI Act to resolve disputes relating to industry codes and rules and documents referred to in those codes and rules. That power has been delegated to the Dispute Resolution Panel (established under the VicPool Rules) in respect of disputes relating to the VicPool Rules, the System Code and the Wholesale Metering Code.

## Disputes relating to determinations of the Regulator-General

A determination of the Regulator-General can be appealed to an Appeal Panel established under the ORG Act on the grounds that:

- there has been bias; or
- the facts on which a determination was based have been misinterpreted.

A determination may also be challenged in the Supreme Court on the grounds that the Regulator-General did not have power to make the determination or that the procedural requirements in relation to the making of the determination have not been complied with.

## (vi) Enforcement Procedures

## Enforcement by the Regulator-General

If a licensee is contravening, or is likely to contravene, a licence condition and the Regulator-General believes the contravention is not of a trivial nature, the Regulator-General has power under section 35 of the ORG Act to issue an enforcement order requiring the licensee to comply with the condition. There is a $\$ 100,000$ penalty for failing to comply with an enforcement order, and a further $\$ 10,000$ penalty for each day the contravention continues.

As every licence contains a condition requiring the licensee to comply with all applicable laws and the provisions of applicable industry codes and rules, any breach of law or of industry codes or rules also amounts to a breach of licence. This means that the Regulator-General can issue an enforcement order in respect of any non-trivial breach of law or of industry codes or rules.

If a licensee does not comply with an enforcement order the Regulator-General may, after at least 20 business days' notice, revoke the licensee's licence.

## Enforcement of the Ombudsman's decisions

The decisions of the Electricity Industry Ombudsman are binding on the holders of distribution, retail and transmission licences under the terms of the articles of association of the Electricity Industry Ombudsman (Victoria) Limited and the Electricity Industry Ombudsman (Victoria) Constitution.
(vii) Transitional Arrangements

## Introduction

Victoria is moving towards full implementation of the National Electricity Code by 2001.
As mentioned above, Network Service Providers, upon registration by NEMMCO, will submit to the ACCC an access undertaking in the form set out in Schedule 5.8 of the National Electricity Code. This undertaking presently provides that the Network Service Provider will maintain and make available its networks for access in accordance with:

- applicable regulatory instruments, including but not limited to, the Act;
- the requirements of the National Electricity Code; and
- good electricity industry practice and applicable Australian Standards.


## Objectives of the Transitional Arrangements

However, some provisions of the National Electricity Code will not become operational in Victoria before 2001. Chapter 9 of the National Electricity Code sets out the transitional arrangements applicable to Victoria. The objective of these arrangements are as follows:

- to ensure that certain arrangements for reform of the Victorian electricity supply industry implemented under the Electricity Industry Act 1993 (Vic) continue after the National Electricity Code commencement date;
- to enable the State and its agencies to perform its obligations under contracts particularly those relation to the Loy Yang B Power Station, and the Portland and Point Henry Smelters;
- to provide certain specific derogations from technical standards set out in the National Electricity Code for Code Participants in Victoria; and
- where required by the National Electricity Code, to nominate the regulatory arrangements applicable in Victoria.


## Basis for the Transitional Arrangements

As mentioned, unlike other Australian States, Victoria has already privatised the distribution businesses and is in the process of privatising the generators created from the disaggregation of Generation Victoria. It has therefore already made significant inroads into the promotion of competition and efficiency in its electricity industry.

Those private investors in industry assets have invested significant funds ( $\$ 8.31$ billion for the five distribution businesses) on the basis of the current Victorian access regime and have organised their operations and financial arrangements to comply with the legislative scheme currently goveming Victoria's electricity industry. In fact, these commercial investors, in making their bid, sought certainty in the regulatory regime that would apply to their acquisitions, to the extent that the State Govemment's power to influence the role of the Regulator-General was reduced by amendments to the Office of the Regulator-General Act 1994.

It is reasonable that these bodies be given sufficient opportunity to adjust their activities to comply with the changes to be made by the National Electricity Code and much of this can be achieved in the period between the time that the National Electricity Code becomes operational and 2001. To unilaterally impose a new regime upon these private investors, the fine details of which were unknown and could not be foreshadowed to them prior to their investment, would create future uncertainty and a higher awareness of potential risk for Victoria's future privatisation. Any delay to the process or a reduction in the value of these assets is not in the public interest of Victoria, or in the interests of promotion of competition.

Although the transitional arrangements temporarily create a series of different access arrangements, it is submitted that this is outweighed by the benefits an efficient and managed transition process will have on both the Victorian and National electricity regimes.

### 8.5.4 Queensland

Transmission arrangements for Queensland in the areas of connection requirements, transmission revenue, network planning and augmentation, transmission pricing and distribution pricing will be determined subsequent to the Queensland Electricity Industry Structure Task Force report.

The benefits of the transition arrangements relate to the reduction in transactions costs associated with unstructured and arbitrary changes from jurisdictional arrangements to those envisaged in the industry access code of the Code.

For this reason it is submitted that the jurisdiction transition arrangements on access (many of which are included in Chapter 9 of the Code) are similarly developed to deliver a transparent and smooth transition to the fully competitive NEM.

On balance, it is considered that there is considerable public benefit from the transparency and measured phase-in of the NEM arrangements on access.

It is contended that it makes little sense to distort these arrangements because it is only through the introduction of the fully competitive NEM that the broader benefits of reform of the electricity supply industry can be delivered.

### 8.5.5 Assessment of proposed South Australian access arrangements

## (a) Introduction

This paragraph focuses on those parts of the proposed South Australian access arrangements which are specific to South Australia and describes how these arrangements satisfy the criteria used by the ACCC to assess access codes.

An outline of the present South Australian electricity industry arrangements relating to access to network services and the changes in those arrangements that will occur as South Australia prepares for the commencement of the NEM, are set out in Schedule 9 to this Submission. Upon the commencement of the NEM in South Australia access to these network services will be govemed by the provisions of the Code (including the South Australian derogations set out in Chapter 9 of the Code) and the South Australian applicable regulatory instruments.

At this stage, the South Australian applicable regulatory instruments simply comprise the proposed Electricity Act which is currently being debated by the South Australian Parliament. As outlined in Schedule 9, this legislation is designed to complement (and not duplicate) the regulatory arrangements contained in the Code. Regulations, standard licence conditions and guidelines are currently being developed to complement and augment the provisions of the Electricity Act. In particular, it is intended that the Electricity Act will deal with arrangements for access to those network services not covered by the provisions of the Code.

## (b) Satisfaction of criteria in section 44ZZAA(3)

The arguments set out in pargraph 8.4 are equally applicable to the question of whether the South Australian access arrangements (during the transition period ending on 31 December 2000) satisfy the section 44ZZAA criteria; South Australia is essentially adopting the provisions of the Code relating to access to the network services (other than the provisions of Chapter 6 of the Code) upon the commencement of the NEM in South Australia.

The South Australian Government, like other jurisdictions, has included derogations in Chapter 9 of the Code allowing it to apply its own detailed pricing principles and regulation procedures for network services during its transitional period.

Unlike New South Wales and Victoria, South Australia has not yet reached the stage in its electricity reform process, where it is able to publish these detailed pricing principles and regulation procedures. Work is currently proceeding on the development of this information and it is envisaged that indicative prices and regulation procedures will be available during the first half of 1997.

It is intended that the detailed pricing principles and procedures will broadly follow the principles set out in Chapter 6 of the Code. In particular, the general principles for asset valuation and establishing an appropriate weighted average cost of capital defined in Chapter 6 of the Code, will be applied during the transition period (after taking into account the criteria and methodologies for the determination of the maximum aggregate annual revenue requirement currently being developed by the South Australian Government). In this way, participants in the South Australian electricity industry will have sufficient time to prepare and adjust for a nationally regulated system of network service pricing and the impact on those participants (especially customers) of the transition to the National Electricity Market will be minimised.

These transitional arrangements also allow for reasonable recognition of South Australia's pre-existing policies relating to transmission asset values, revenue paths and prices. Support for these transitional arrangements is also implicit from the terms of Chapter 6 of the Code which are proposed to be reviewed within the next 2 years in preparation for the end of the transition period and the assumption of control for transmission pricing by the ACCC.

It is submitted that these considerations satisfy the criteria set out in the proposed section 44ZZAA.

## NATIONAL ELECTRICITY CODE

## SCHEDULES TO THE SUBMISSION TO THE AUSTRALIAN COMPETITION AND CONSUMER COMMISSION RELATING TO THE NATIONAL ELECTRICITY CODE

## These are Schedules $\mathbf{1 - 1 7}$ (both inclusive) referred to in and forming part of the Submission being the Submission referred to:

(1) in each of the applications for authorisation in respect of the National Electricity Code; namely:
(a) Form A: Exclusionary Provisions dated 13 November 1996
(b) Form B: Agreements Affecting Competition dated 13 November 1996
(c) Form E: Exclusionary Dealing dated 13 November 1996; and
(2) in the draft application for acceptance of the industry access code as an access code for the purpose of the Act.

Dated this 13th day of November 1996

Signed on behalf of NECA

(Signature)
Mr John McMurtrie
Chairman, National Electricity Code
Administrator Limited

Signed on behalf of NEMMCO


Mr Olaf O'Duill
Chairman, National Electricity
Market Management Company
Limited

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## SCHEDULE 1

## APPLICANTS

A Applicants - authorisation of anti-competitive arrangements and conduct

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## SCHEDULE 2

## AUSTRALIAN ENERGY REFORMS SINCE 1990

May 20 Reference by P J Keating, the then Treasurer, to the Industry Commission for an inquiry into the generation, transmission and distribution of electricity and the transmission and distribution of gas (excluding tax, resource rent and royalty issues).

May 17 Industry Commission "Report on Energy Generation and Distribution" recommends a major restructuring of the electricity and gas industries by disaggregating existing utilities into generation, transmission and distribution elements (in the case of the ESI) and transmission and distribution elements (in the case of NGI), corporatising each entity and placing them in a competitive market place, with minimal political interference in operational aspects.

July Release by the Department of Primary Industries and Energy of a discussion paper entitled "A National Strategy for the Natural Gas Industry". Discusses the need for a national gas strategy and identifies a number of options for Government action:


July Agreement at special Premier's Conference to form a National Grid Management Council ("NGMC") made up of representatives of the States of Queensland, New South Wales and Victoria, Tasmania and South Australia, the Australian Capital Territory, the Commonwealth and an independent chairman. The role of the NGMC was to encourage open access to the eastern and southern Australian electricity transmission grid and free trade in bulk electricity, to co-ordinate planning and to encourage competitive sourcing of new generation.

Announcement by Minister for Resources of major reforms to encourage 28

- free and fair interstate trade in gas;
- the removal of export controls on gas volumes;
- reform of the Pipeline Authority (owner of the Moomba-Sydney pipeline); and
- adoption of a "light-handed" regulatory approach to the NGI through the Trade Practices Commissions.

December NGMC issues draft National Grid Protocol covering the planning, operation, development, monitoring and extension of the south eastern electricity grid for public discussion and submission.

January Comments and submissions received by the NGMC on the draft National Grid Protocol.

February "One Nation Statement" by Prime Minister P J Keating. Proposal included the formation of a National Grid Corporation for the ESI.

May Heads of Government Meeting agrees to form Council of Australian Governments ("COAG") as a permanent body for consultation between the Prime Minister, Premiers of the States and Chief Ministers of the Territories to:

- increase co-operation among Govemments in the national interest; and
- increase co-operation among Governments on reforms to achieve an integrated, efficient national economy and single national markets. Specifically noted was the development of an interstate transmission network across the eastern States.

July $\quad$ Release by the Australian Gas Association of a public report on the findings of its study into Australia's natural gas supply and demand to the year 2030 entitled "Gas Supply and Demand Study Third Report Public". Major recommendations include:

- that the State and Territory Governments relinquish or at least limit their reserve powers in respect of gas production and transmission;
- that there should be open access for gas carriage;
- that all Governments commit to honouring existing long-term contracts in the production, transmission and distribution sectors; and
- that the principal gas markets in southern and eastern Australia should be inter-connected via further development of a pipeline grid.

July Pacific Power commences internal trials of the ELEX pool. (This is essentially a spot market based approach similar to arrangements adopted in England and Wales.)

September Release by the Energy Board of Review, Western Australia, of its discussion paper "The Energy Challenge for the 21st Century: A Public Discussion Document" dealing with the reform of the Western Australian combined electricity and gas utility (SECWA).

October Reference by P J Keating, Prime Minister, to an independent committee for an inquiry into the implementation of a national competition policy for Australia. The aim of the review was to develop a policy to promote and maintain competitive forces within Australia as a single integrated market.

December NGMC publishes its "National Grid Protocol: First Issue" and "Network Service Pricing: An Information Paper". (The NGMC protocol has been conditionally supported by State Governments.)

December Perth COAG meeting: The Prime Minister and the Premiers of the eastern States reaffirm their commitment to the principle of separate electricity generation and transmission element in the electricity sector and agreed to give early consideration to the NGMC's December 1992 report. The Heads of Government noted the work done by the NGMC on transmission pricing, pooling and customer-generation links. The Council noted the current impediments to interstate gas trading and asked Council (ANZMEC) to report to the Council in 1993 on the current barriers, action to remove them, a basis for third party access to transmission pipelines and free and fair trade in gas.

1993 January NGMC publishes "National Electricity Market and Common Trading Arrangements: An Information Paper".

March NGMC published a paper on "The Structure of an Interstate Transmission Network for Eastern and Southern Australia".

April Energy Board of Review, Western Australia publishes its report "The Energy Challenge for the 21st Century". This report recommends:

- as a first step, the electricity and gas businesses of SECWA should be separated;
- there should not be vertical integration in the electricity industry generation should be separated from transmission and distribution;
- there should be a competitive generation sector;
- the gas transmission function should be separated from the purchase, sales and distribution functions;
- the Dampier to Bunbury gas pipeline should be accessible to both producers and purchasers on reasonable and published terms;
- a structure of light handed regulation should be introduced; and - privatisation can follow later.

May Queensland Government announces intention to further restructure the Queensland ESI (corporatisation announced originally in 1991) from 1 January 1995 involving:

- separation of generation from transmission and distribution;
- development of a competitive electricity market; and
- the transmission system providing services on a nondiscriminatory basis to all participants.

| June | Gas Council of New South Wales publishes its report to the New South Wales Minister for Energy "Joint Study on the Long -Term Supply of Natural Gas for New South Wales". This report recommends: <br> the NSW Government continue to work towards the goal of free and fair interstate trade in natural gas and the consideration of any nationally uniform competition policy; <br> the Minister initiate a study to determine the criteria by which gas pipelines should be identified as appropriate for third party access; <br> the development of a nationally uniform approach to monopoly pricing in, and third party access to, gas transport infrastructure; <br> the establishment of an efficient regime of gas pipeline regulation in eastern and central Australia; <br> ensuring that despite the effect of AGL's contractual arrangements on third party access, moves to establish third party access to the extent not inconsistent with AGL's rights be taken; and <br> the preferable ownership of the Moomba to Sydney pipeline be by a person who has no other interest in gas supply, or, if as a result of its pre-emption rights, AGL assumes ownership of the pipeline, AGL be required to separate its transmission activities from its other gas supply activities. |
| :---: | :---: |
| June | New South Wales Government Pricing Tribunal commences inquiry into pricing policies of Government agencies supplying electricity and related services. (The purpose of the inquiry is to examine the pricing of electricity transmission and supply, in order to protect consumers from abuses of monopoly power and to encourage ESI efficiency. The final report is expected shortly). |
| June | Melbourne COAG meeting discussed electricity industry reform and proposals on free and fair trade in natural gas. In respect of the ESI, agreed to the establishment of multiple network corporations based on State grids in Victoria, New South Wales and Queensland by July 1995, recognising this will require resolution of a number of major issues including the following: <br> market trading, grid pricing and regulatory arrangements; the budget impact on the States; <br> the resolution of tax compensation issues; and <br> the resolution of reform arrangements for the Snowy Mountains Scheme. |


| July | NGMC publishes a paper on "Regulatory Framework Issues for a <br>  <br> National Electricity Market" and a paper on "Transition to a National <br> Electricity Market". |
| :--- | :--- |
| July | The Australian Gas Association, Australian Petroleum Exploration |
|  | Association Limited and Australian Pipeline Industry Association jointly |
| release an industry "Code of Practice for Access to Interstate Natural Gas |  |
| Transmission Pipelines in Australia". The Code sets out a framework to |  |
| facilitate effective commercial negotiation for access to interstate natural |  |
| gas transmission pipelines. It advocates a commercial renegotiation |  |
| process and is not legally binding. |  |

August Australian Bureau of Agricultural and Research Economics publishes its research report 93.12 "The Economics of Interconnection: Electricity Grids and Gas Pipelines in Australia". This report recommends:

- the potential benefits are significantly greater from interstate gas pipeline developments than from electricity interconnections; and
- the benefits of making the gas and electricity interconnections identified in the study would have a discounted present value of $\$ 1,800$ million over 35 years, but this economic benefit might be foregone if institutional arrangements, of whatever form, inhibit co-operative investment in infrastructure at the appropriate times.

August The Independent Committee of Enquiry ("the Hilmer Committee") publishes its report "National Competition Policy". This report recommends:

- the Trade Practices Act should be extended to cover State and Territory businesses to the same extent that it covers Commonwealth businesses;
- Government regulation (including legislated monopolies) and Government ownership impose the greatest impediment to competition in many key sectors of the economy;
- a national competition council should be established jointly between the Commonwealth, State and Territory Governments and would administer the national competition policy;
- all Australian Governments should adopt a set of principles ensuring:
- the separation of regulatory and commercial functions of public monopolies;
- the separation of natural monopolies and potentially competitive activities;
- the separation of potentially competitive business units into a number of smaller, independent business units;
- a new legal regime be created for access rights to "essential facilities" on fair and reasonable terms; and
- there should be greater transparency and consistency in monopoly pricing and such monopoly pricing should be subject to overview by the National Competition Council.

September New South Wales Government Pricing Tribunal publishes its report "Paying for Electricity - An Issue Paper".

October The Victorian Government's Office of State Owned Enterprises, Department of Treasury, publishes its report "The Electricity Supply Industry in Victoria: A Competitive Future - Electricity". This report confirmed the Government's intention to:

- separate the industry into a number of generators, retailers, regional distributors and an independent transmission grid;
- create a wholesale electricity market for generators, retailers and large customers;
- provide for all electricity to be traded through a power pool, using both spot sales and capacity contracts; and
- defer privatisation until after the new ESI structure has been settled.

October NGMC publishes its paper on "Regulatory Arrangements for a National Electricity Market". This report recommends:

November
NGMC commences Paper Trial for the National Market.
1994 February Victorian Government's Office of State Owned Enterprises (Department of Treasury) publishes its report "Reforming Victoria's Electricity Industry, 2: A Competitive Future - Electricity". This report confirmed the Government's intention to:

- create an internationally efficient industry providing the lowest possible costs to customers;
- empower customers by offering choice and service;
- reduce public debt;
- implement a further state of reforms involving:
- the creation of an independent company to manage and control the wholesale electricity market and to ensure system security;
- the creation of a transmission grid company to own and operate (as a natural, State-owned monopoly) the high voltage transmission grid;
- individual generators within Generation Victoria trading in the market as independent producers;
- the creation of live regionally based distribution companies; and
- the establishment of an independent regulator to monitor the market and the operation of the system.

New South Wales committed to form a separate incorporated transmission subsidiary to Pacific Power as the first step in separation of transmission. It had also agreed to review the structure of the generation sector by 1 July 1995.

Hobart COAG meeting agrees to a more extensive microeconomic reform agenda and to establish a working group on microeconomic reform. COAG received reports on natural gas reform and electricity reform. COAG agreed to proposals from the NGMC for a regulatory framework for the electricity industry which reflected the decision of COAG on the Hilmer Report recommendations.

March Western Australian Parliament passes Goldfields Gas Pipeline Agreement Act to authorise development of a gas pipeline from Dampier (near the North West Shelf natural gas project) through the Pilbara region to the goldfields surrounding Kalgoorlie. The Act required:

- the pipeline owners to provide third parties with nondiscriminatory access to uncontracted or unused capacity of the pipeline;
- the pipeline owners to transport gas for third parties in accordance with tariff principles approved by the Government; and
- the owner of the Dampier to Bunbury pipeline (currently SECWA) to provide the owners of the goldfields pipeline with the necessary access on the same non-discriminatory basis.

March Gladstone Power Station sold to a consortium headed by Comalco.

| April | Electricity Supply Industry Reform Unit (Office of State - Owned |
| :--- | :--- |
| Enterprises, Department of Treasury) publishes its report "The Proposed |  |
| Framework for a Wholesale Electricity Market for Victoria" (Third Draft) |  |
| for wide consultation. This report outlines the proposed framework for |  |
| the wholesale electricity market in the context of the restructure of the |  |
| Victorian ESI. |  |

May Pacific Power's network business unit established as a separate legal entity.

June Commonwealth Parliament passes Moomba-Sydney Pipeline System Sale Act 1994 which provides for the sale of $51 \%$ of the Moomba-Sydney pipeline to AGL and $49 \%$ to a consortium headed by Novacorp International and Petroliam Berhard Nasional (Petronas).

July Energy Implementation Committee, Western Australia, published its "Progress Report: Gas Transmission Access and Pricing Issues for the Dampier to Bunbury National Gas Pipeline". This report details the progress made in implementing the recommendation of the Energy Board of Review for restructuring the State's electricity and gas industries, including the development of an access regime for the State's electricity and gas transmission and distribution facilities and the replacement of SECWA by an electricity corporation and a gas corporation.

July The Office of the Regulator-General (ORG) was established. With regard to electricity, the key tasks of the ORG are to oversee franchise customer tariffs, service standards, pool rules and operating procedures, transmission and distribution access and pricing, and market conduct.

July Snowy Mountains Hydro-Electric Authority is commercialised.
August Darwin COAG meeting confirms substantial progress in relation to ESI restructure.

September NGMC publishes its paper "Principles for a Fully Competitive Market".
September Victorian Government's Office of State - Owned Enterprises (Department of Treasury) publishes its report "The Gas Industry in Victoria - A Competitive Future" which confirms the Government's intention to:

- desegregate the Gas and Fuel Corporation of Victoria into separate transmission and distribution entities;
- develop a framework for light-handed regulation of the gas industry to be administered ultimately by the Office of the Regulator General;
- provide access to the transmission system on a non-discriminatory basis;
- provide direct access to large customers for gas producers, distributors and marketers;
- consider further restructuring of the distribution sector to create competition; and
- work toward overcoming the existing constraints to reform by renegotiating existing long-term contacts with suppliers, addressing the State and Commonwealth resource rent taxation system and participating in national reforms to establish an access regime for interstate transmission facilities.

September Western Australian Government introduces final legislation (The Gas Corporation Bill and the Electricity Corporation Bill) to split the State Energy Commission of Western Australia into two corporatised entities dealing with gas and electricity (and including detailed rules for providing access to and pricing for gas and electricity transmission and distribution networks).

September Government tariff policy announced:

- residential customer tariffs frozen until June 1996, followed by a $2 \%$ real price fall in July 1996, and a $1 \%$ real price fall each year thereafter to the year 2000;
- small business tariffs to be reduced by $20 \%$ over three years;
- large industrial (tariff H) customers offered a safety net; and
- vesting contracts to be phased out as the retail sector is opened to competition.

October National Electricity split into two businesses:

- Victorian Power Exchange (VPX) established to develop and administer the wholesale electricity market (VicPool). System control and planning functions are the responsibility of VPX; and
- Power Net Victoria established as a separate statutory corporation responsible for high voltage transmission functions.

October - Five regulated regionally based distribution businesses were established, comprising the 18 business units of the former Electricity Services Victoria and the 11 Municipal Electricity Undertakings. Each comprises a competitive retail arm. The retail and distribution functions are ring-fenced within each business.

January Generation Victoria disaggregated into five corporatised regionally based companies.

| January | The vertically integrated Queensland Electricity Commission was divided into two corporations - Queensland Generation (trading as AUSTA Electric) and Queensland Transmission and Supply Corporation (QTSC). |
| :---: | :---: |
| January | QTSC is a holding company for eight subsidiary corporations - seven regional distribution corporations and the Queensland Electricity Transmission Corporation, trading as Powerlink Queensland. |
|  | QTSC has responsibility for planning, co-ordinating and supplying electricity. |
| February | NSW- high voltage transmission and system control activities placed within the responsibility of the Electricity Transmission Authority trading as Transgrid. Transgrid to develop and operate the NSW electricity market. |
| May | NSW Government endorses restructuring of generation and distribution sectors of electricity industry; introduction of interim wholesale market and development of retail competition policy for retail competition. |
| June | Announcement that the number of distribution companies be reduced from 26 to 6 , through mergers: 4 rural and 2 metropolitan distributors. Each distributor will have a "wires" and retail supply business. |
| July | Privatisation of the five distribution companies commences. |
| July | Customers with load in excess of 1 MW are removed from the franchise market. |
| July | Cross-ownership controls apply, such that parties will be allowed to own or control $100 \%$ of one licensed Victorian electricity company, 20 per cent of another, and $5 \%$ thereafter. |
| July | Electricity Trust (ETSA) corporatised and a new Board appointed. Separate business units were established through vertical ring-fencing arrangements - ETSA Generation, ETSA Transmission, ETSA Power (distribution and retail), and ETSA Power (trading in fuels, new sources of energy and energy services). |
| July | Agreement reached for the construction of a co-generation plant at the Penrice Soda ash plant, supplying 180 MW to the State grid. Built and operated by joint venture partners Canadian Utilities and Boral Energy (CUBE), it is scheduled to commence operation in 1998. |
| July | Commitment to corporatise the scheme has been agreed by the three Governments involved (set to occur in 1996). They will retain equity in the new corporation in return for giving up present entitlements for electricity at cost. |
| November | Announcement that Pacific Power will be split into two competing generation companies. |

December Bills passed to:

- formally split Pacific Power into two State-owned generation companies - First State Power and Macquarie Generation;
- establish six energy services (distribution) corporations: Energy South, FarWest Energy, MetNorth Energy, MetSouth Energy, MidState Energy and NorthPower Energy;
- establish an interim State wholesale market from the first quarter of 1996, and allow for the transition to full wholesale and retail competition; and
- allow for generation corporations to participate in the wholesale market, the distributor corporations to compete in the wholesale and retail markets, and other forms of energy and services.

ACT Electricity and Water Authority is corporatised.
March New generation and energy service corporations commenced operation. TransGrid commences interim State wholesale market.

March Sale of Yallourn Energy to a consortium headed by PowerGen International.

## SCHEDULE 3

## CURRENT STATE ARRANGEMENTS

## 1 Victoria

### 1.1 Reforms

Victoria commenced its reforms in October 1993 with the separation of the generation, transmission and distribution sectors of its electricity supply industry.

The generation sector was divided into 5 competing generators which were subsidiaries to the generation holding company Generation Victoria. Two of those generation companies, Yallourn Energy Pty Ltd and Hazelwood Power Corporation Limited, have since been sold to the private sector.

The wholesale market, which operates on a spot price basis, is administered by another statutory corporation, Victorian Power Exchange ("VPX"). Victoria introduced this competitive wholesale electricity market in October 1994.

Transmission functions are the responsibility of PowerNet Victoria which is a statutory corporation.

The distribution sector was divided into five regionally based distribution businesses, all of which have been sold to the private sector.

In the restructured industry, the wires and the retail functions of distribution are separated for regulatory and competition purposes. As such, the five initial distribution businesses are also the five initial retailers, although each distribution business is required to "ringfence" its two functions, accounting separately for its wires business and retailing business. Whereas the wires business is regarded as a local monopoly, and therefore will remain subject to regulation by the Office of the Regulator General, the retail function will be progressively opened to competition by 31 December 2000. Until full competition is achieved, the Office of the Regulator General will also play a part in the regulation of the retail function.

A timetable for the contestability of customers has been developed with all customers to be contestable (ie., entitled to purchase electricity from any retailer rather than from the retailer within whose distribution area the customer lives) by December 2000.

This timetable is summarised below:

## RETAIL COMPETITION IN VICTORIA

| Dates | Prescribed limits (based on the Electricity Industry (Non- <br> franchise Customers) Regulations 1995) |
| :--- | :--- |
| 1 July 1995 to 30 June 1996 | Load of 1 MW |
| 1 July 1996 to 30 June 1997 | Load of 1 MW or annual consumption of 750 MWh |
| 1 July 1998 to 31 December <br> 2000 | Load of 1 MW or annual consumption of 160 MWh |
| 1 January 2001 | All customers |

In the interim, electricity prices will be regulated by a Tariff Order and the Office of the Regulator General to ensure that the distribution businesses cannot exploit their monopoly positions with respect to franchise customers within their areas.

Regulation of the industry is carried out primarily by the Office of the Regulator General which has powers under the Electricity Industry Act 1993 ("the EI Act") and the Office of the Regulator-General Act 1994. The Office of the Regulator General's regulatory powers include the issuing of generation, transmission, distribution, retail and marketoperation licences and the regulation of certain prices.

Victoria remains committed to electricity reforms within the State, particularly with a view to participation in the NEM. Privatisation of all Victorian generators is likely to occur over the next few years.

Victoria is also committed to microeconomic reform of its Government business enterprises generally, with reforms occurring in the gas, water and ports sectors.

### 1.2 The wholesale market

In Victoria, a competitive market has operated from 3 July 1994, consisting of five distribution companies, a grid company, a wholesale market company, five generation companies, retailers and traders. The diagram below shows the structure of the Victorian Electricity Supply Industry, including the major generators, the transmission network operator and distributors and retailers in Victoria.

## Vietorian Atcent Reyime



Victoria's wholesale market (ie., sale of electricity by generators to retailers or large customers) consists of a spot market which operates through a pool into which all licensed generators are required to sell all electricity generated by their units (except electricity confirmed directly at the licensed power station in the course of generating activities).

The pool is operated and administered by VPX a body corporate established under the EI Act. The functions of VPX, which include managing pool settlements under the VicPool Rules and assembling and distributing a variety of information to industry participants and other persons, are set out in its wholesale market-operation licence which was issued to it by The Office of the Regulator General under Part 12 of the EI Act.

The operation of the Victorian wholesale electricity market is governed mostly by the VicPool Rules with system security being governed by the System Code and metering being governed by the Wholesale Metering Code. Compliance with these Codes (among others) is a requirement under each market participant's licence.

The price of electricity supplied through the pool is determined in accordance with the VicPool Rules. It varies on a half hourly basis, depending on system demand, bid prices and availability of generation and transmission.

Electricity is bought from the pool by retailers or contestable customers. Risk created by the fluctuating spot prices may be managed by way of bilateral vesting and hedging contracts between generators and retailers/arge customers.

New South Wales

### 2.1 Reforms

On 10 May 1996 the New South Wales electricity supply industry commenced competitive trading in the wholesale market for electricity in New South Wales. This wholesale electricity market was the culmination of structural and market reforms that commenced in 1991.

In July 1991 Pacific Power, the authority responsible for electricity generation and transmission in New South Wales, was internally restructured into commercially oriented business units. Pacific Power introduced an internal electricity exchange market. Although this market evolved over several years, it essentially involved a wholesale spot generation market in which the entire output of electricity from Pacific Power was purchased at spot prices by divisions within Pacific Power and on-sold to distributors and to direct customers under tariff arrangements. This market had the desired effect of focusing on the cost structure within Pacific Power and obtaining considerable experience in market behaviour. Competitive pressures on the generating business units, together with the creation of business unit profit centres and internal charging, resulted in increased availability, reduced start-up times, reduced fuel oil usage and other improvements.

As a step towards the setting up of the proposed NEM in south and east Australia, the States agreed to separation of transmission from the generation functions in their vertically integrated power authorities. In New South Wales, Pacific Grid was formed as a whollyowned transmission network subsidiary of Pacific Power. On 1 February 1995 full separation occurred with the establishment of the Electricity Transmission Authority of New South Wales. This statutory authority now trades under the name of TransGrid.

In May 1995, following the April 1995 COAG meeting, the New South Wales Government issued an electricity reform statement which detailed its position on the restructuring of the industry in New South Wales. These reforms included the setting up of a State wholesale electricity market, pending the implementation of the proposed national market arrangements.

On 30 June 1995 an amendment to the Electricity Transmission Authority Act made TransGrid accountable for the development and implementation of the State wholesale electricity market in New South Wales. This market was required to be operational by the first quarter in 1996 and was to remain in place until replaced by the NEM.

At the same time the New South Wales Government announced a number of structural reforms to the electricity distribution and generation sectors of the New South Wales electricity supply industry. The New South Wales Government announced the amalgamation of the 25 distribution authorities in New South Wales into 6 larger stateowned corporations, each of which has financially separate retail and distribution network functions. Subsequently, it was announced that 2 generation State-owned corporations would be split from Pacific Power, previously the only New South Wales generator.

On 1 March 1996 the 6 New South Wales distributors were created, namely:

- Australian Inland Energy;
- Advance Energy;
- Energy Australia;
- Great Southern Energy;
- Integral Energy Australia; and
- NorthPower.

Also on 1 March 1996 the 2 new generators were established, such that 3 generators are now the principal generators of electricity in New South Wales, namely:

- Pacific Power;
- Macquarie Generation; and
- Delta Electricity.

With the establishment of the 6 New South Wales distributors and the 2 new generators, the first stage of the New South Wales wholesale electricity market commenced on 1 March 1996 with generators bidding in a limited fashion to produce a schedule of available electricity with trading taking place at an administered price. TransGrid directed the operation of this market under its powers contained in the Electricity Transmission Authority Act.

On 10 May 1996, after receiving an interim authorisation from ACCC in relation to the New South Wales wholesale electricity market, together with a declaration from the Australian Securities Commission for New South Wales participants to operate an exempt futures market, the Electricity Supply Act was proclaimed to commence. This Act enabled the commencement of the second stage of the New South Wales wholesale electricity market where the "pool" price for electricity was set by supply and demand in the wholesale market and participants could enter into financial contracts to manage their risks associated with movements in the pool price.

It is proposed that the Snowy Mountains Hydro-Electric Authority will be corporatised. Until it is corporatised, a "ring-fenced" unit within Pacific Power will trade the New South Wales entitlement of the power output of the Authority. Once the Authority is corporatised it is expected that the corporatised entity will trade its entire capacity as an independent generator into the NEM.

### 2.2 The wholesale market

New South Wales has a compulsory wholesale electricity market described above currently consists of three separate government-owned generators, a transmission/pool authority (TransGrid) and six retailers/distributors, which have been set up as an interim market until the commencement of the NEM.

The diagram below shows the structure of the New South Wales electricity supply industry including the participant generators, the transmission network operation, distributors and retailers in New South Wales


Schedule 3

The trading of electricity in New South Wales under its State wholesale electricity market involves a spot market which operates through the pool, in conjunction with bilateral vesting contracts between generators and retailers and bilateral hedging contracts.

All persons who operate an electricity generating unit within New South Wales beyond 30MW capacity are required to sell all electricity generated by those units through the pool operated by the Market and System Operator ("MSO"), which is a ring-fenced entity within TransGrid. Retailers and wholesale customers purchase electricity from the pool.

The MSO carries out an economic, regulatory and a technical role:

- Regulation - in this capacity, the MSO advises the Minister for Energy on the grant of, and conditions for, authorisations under the Electricity Supply Act to wholesale traders and network operators.
- Market management - in this capacity, the MSO accepts bids from market participants, calculates the pool price for each 30 minute trading interval, calculates the amount payable by participants, collects payments from parties owing sums to others under the pool arrangements and makes payments to parties entitled to sums from the pool.
- System operation - in this capacity, the MSO prepares dispatch schedules, issues dispatch instructions, ensures the security and reliability of the State electricity supply system and the transmission of electricity to, from and along the transmission systems.

The operation of the New South Wales Wholesale Electricity Market is governed by the New South Wales Wholesale Electricity Market Code by which all market participants are bound. The connection of retail end use customers to distribution systems and the sale of electricity by retailers to end use customers are regulated by the Electricity Supply Act 1995. All market participants must be authorised by the New South Wales Minister for Energy.

## 3 Queensland

### 3.1 Current structure of the Queensland Electricity Supply Industry

On 1 January 1995, the Queensland Electricity Supply Industry (QESI) was restructured and corporatised pursuant to the Government Owned Corporations Act 1993. This created two new Government owned entities, the Queensland Generation Corporation (which trades as AUSTA Electric) and the Queensland Transmission and Supply Corporation (QTSC). QTSC also has eight subsidiary corporations. Regulatory functions of the former Queensland Electricity Commission (QEC) were transferred to the Department of Mines and Energy. The structure of the QESI is described below.

Structure of QESI


## Generation

AUSTA Electric owns, operates and maintains the generating facilities of the former QEC. A number of Independent Power Producers also operate and maintain or are refurbishing existing generating units.

Electricity generation by AUSTA Electric is currently undertaken with:

- four black coal-fired power stations ( 4408 MW );
- three hydro-electric stations ( 632 MW ); and
- five gas turbine power stations ( 170 MW ).

These stations provide approximately $75 \%$ of Queensland's current generating capacity, the remainder is provided by private generators.

As a result of a recent invitation to bid, 774 MW of new generating plant will be commissioned in 1999/2000 by three private sector developers.

QTSC is also currently seeking to purchase electricity at competitive rates from small scale generation projects of less than 40MW export capacity, using renewable or other energy sources. Under these arrangements QTSC intends to purchase up to 120 MW from small generation projects under negotiated contracts executed prior to October 1996.

Preliminary estimates which take into account these developments and the likely benefits to be derived from interconnection with New South Wales, see the need for new capacity arising in 2003 or early 2004. Whether the new capacity will be sourced through a further bidding process or simply left to market forces is yet to be determined.

## Transmission, Distribution and Retailing

QTSC currently has responsibility for:

- buying electricity from AUSTA Electric and Independent Power Producers;
- transmission and distribution - through its subsidiary companies;
- selling electricity to the seven subsidiary retail/distribution companies and some direct customers; and
- provision of customer advisory services.

QTSC also holds the statutory obligation to supply in the Queensland electricity market and is responsible for forecasting changes in electricity demand and coordinating plans to expand Queensland's electricity system. Implicitly, therefore, QTSC is responsible for the oversight of system planning for the QESI.

Powerlink Queensland (a subsidiary of QTSC) is responsible for:

- maintaining and operating the high voltage transmission network;
- determination of network augmentation requirements;
- system control, including scheduling of generators to meet demand and coordination of generation and transmission maintenance programs;
- settlements in the interim electricity market (prior to joining the NEM); and
- pricing of and access to transmission infrastructure.

The system control and settlement functions are currently undertaken by independent, ring-fenced business units within Powerlink Queensland.

System control is responsible for the commitment and dispatch of generation, the management of system security and transmission system operations. It also coordinates the preparation of maintenance schedules for generation and transmission.

The seven Retail/Distribution Boards (subsidiaries of QTSC) are:

- $\quad$ South East Queensland Electricity Board (SEQEB);
- South West Queensland Electricity Corporation (SouthWest Power);
- Wide Bay-Burnett Electricity Corporation
- Capricomia Electricity Corporation (CAPELEC);
- Mackay Electricity Corporation (MEB);
- Northern Queensland Electricity Board (NORQEB); and
- Far North Queensland Electricity Board (FNQEB).

These corporations are responsible for forecasting demand growth in their own supply areas and developing their distribution systems in support of customer demand. In addition, NORQEB has a ring-fenced electrical appliance retailing operation.

### 3.2 Regulatory controls

The Electricity Act 1994 is the key legislation governing the sector's institutional arrangements and relationships. It establishes the basis for the purchase and sale of electricity and regulates entry into the industry. Investment in the electricity sector is not restricted to State Government entities, as the Electricity Act 1994 legislates for participation in the QESI by any person, subject to authorisation.

Regulatory oversight is the responsibility of the Director-General of the Department of Mines and Energy. The Director-General is also responsible for providing authorisation for the entry of market participants and monitoring their compliance with the Electricity Act 1994.

In order to maintain its independence as a transmission authority, Powerlink Queensland is prohibited under the Electricity Act 1994 from entering into contracts to buy or sell electricity.

A Queensland Grid Code has been developed to govern the operations of and access to the Queensland network. This Code is based on the principles expected to be adopted by the NGMC for the National Electricity Code.

Under the Electricity Act 1994, transmission and distribution network owners are required to provide access to their networks on a non-discriminatory basis. The distributors are moving towards accounting separation of the retail and network functions of their businesses in order to improve the commercial costing of their activities.

### 3.3 The wholesale market

QTSC purchases electricity from AUSTA Electric by agreement, based on the electricity trading provisions of the Electricity Regulation 1994. Within the framework of the Regulation, the terms of the agreement are determined as a commercial matter between the two corporations.

Within the QTSC Group, wholesale sales by QTSC to the subsidiary Electricity Corporations are made under contract. Prices are based on the costs of electricity obtained from AUSTA Electric and under QTSC's contracts with Independent Power Producers. QTSC's sales to direct customers are made on a contract basis.

Prices charged by the Electricity Corporations to franchise retail customers are developed on a QTSC Group basis, having regard to the Queensland Government's uniform retail tariff policy. The Government provides an explicit Community Service Obligation payment to the Group to fund the delivery of uniform tariffs to remote consumers.

The QTSC Group's pricing policy is established in its Statement of Corporate Intent agreed with Shareholding Ministers. It is also, like that of any other supplier, subject to the reserve power of the Minister for Mines and Energy to fix prices of electricity where it is considered necessary in the public interest.

The Electricity Act 1994 provides that no-one may trade in electricity unless authorised under that Act. That Act contains provisions in relation to the authorisation of a person as a supply entity or an authorised supplier, or by means of a special approval. These provisions are not limited to the existing participants or to public sector entities. Once authorised, a person may retail to contestable customers throughout the State and to franchise customers within a defined supply area. No customers have been prescribed as contestable customs as yet.

On 12 April 1996 the Premier of Queensland stated that Queensland will establish a fully competitive electricity market in accordance with its COAG commitments, including the establishment of a NEM with the interconnected jurisdictions (New South Wales, Victoria, South Australia and Australian Capital Territory) as the initial parties. Queensland will join upon interconnection or earlier by Government decision.

In July 1996 the Queensland Government appointed an independent Electricity Industry Structure Task Force to:
recommend a set of structural, institutional and regulatory arrangements for the electricity supply industry that will best suit the energy needs of Queensland, while having regard to the Government's regional and economic developments and the need to maintain system security.

The Task Force consisting of Professor Don Anderson (Chair), Dr Paul Moy and Mr Peter Garlick has recently presented its report to the Government for consideration.

The Government has recognised that a number of major policy decisions and announcements will be required subsequent to its consideration of the Task Force's report including the timing and nature of progression to a competitive electricity market in Queensland and that a substantial work program will then need to be undertaken over 1996/97 and 1997/98.

To undertake the work program the Queensland Government in August 1996 established a Queensland Electricity Reform Unit (QERU). The QERU will progressively develop the policies and implementation processes for:

- interim competitive electricity market arrangements in Queensland;
- Queensland's full participation in the NEM including the physical interconnection of the Queensland and New South Wales electricity grids;
- any necessary structural reform of the government owned electricity corporations; and
- legislative and regulatory reforms required to complement deregulation of the industry and structural reform.


## 4 South Australia

### 4.1 Reforms

At present, ETSA Corporation (and its separate subsidiaries responsible for generation, transmission and distribution and retail) dominates the electricity supply industry in South Australia.

Under the Electricity Corporations Act 1994, ETSA Corporation was established on 1 July 1995 as a public coiporation under the Public Corporations Act 1993 with electricity functions including system control, generation, transmission, distribution and supply of electricity in South Australia. These functions were inherited from the former Electricity Trust of South Australia - which was also responsible for the regulation of technical and safety aspects.

ETSA Generation Corporation, ETSA Transmission Corporation, ETSA Power Corporation and ETSA Energy Corporation were established in 1995 by regulations under the Public Corporations Act as subsidiary corporations of ETSA Corporation. These subsidiaries have their own administration and separate audited financial accounts and in general terms have the following functions:

- ETSA Generator Corporation - Leigh Creek Coal Field Operations; Northern Power Station (500MW base load generation); Torrens Island Power Station (1280MW mid range generation); Mintaro, Snuggery and Dry Creek, Playford B (440MW peaking/standby plant);
- ETSA Transmission Corporation - Transmission, System Planning and System Control operations
- ETSA Power Corporation - Distribution and Retailing (separately ring fenced) operations; and
- ETSA Energy Corporation - Gas Trading.

Various assets and liabilities at ETSA Corporation have now been allocated to the appropriate subsidiaries.

The Electricity Corporations Act was amended in July 1996 to allow for the establishment of a separate generation corporation in South Australia, to be known as SA Generation Corporation. From 1 January 1997 there will be two government-owned, but separately and independently controlled, electricity corporations: ETSA Corporation (responsible for system control, transmission, distribution and supply of electricity) and SA Generation Corporation (responsible for generation). The establishment of SA Generation Corporation will effectively separate the competitive generation function from the monopoly transmission and distribution functions.

SA Generation Corporation will comprise:

- the mining operations at Leigh Creek; and
- the Northem, Playford and Torrens Island Power Stations;

ETSA Corporation will retain control of and responsibility for:

- ETSA Transmission Corporation (including a ring-fenced system control function);
- ETSA Power Corporation (including ring-fenced distribution and retail functions); and
- ETSA Energy Corporation (including gas trading functions).

While SA Generation Corporation will dominate the generation of electricity in South Australia in the near term (providing about $60 \%$ of the State's electricity requirements), other electricity sources include:

- imported electricity through an interconnection with Victoria providing up to $35 \%$ of the State's electricity requirements. These imports are primarily provided through a contract lasting until April 1997 under the Interconnection Operating Agreement;
- privately owned CUBE Penrice Cogeneration to be commissioned in 1998 and expected to supply in excess of $10 \%$ of the State's electricity to ETSA Power;
- privately owned small generators contributing approximately $2 \%$ of the State's electricity; and
- remote areas "off-grid" generators.

The diagram below shows the current structure of the South Australian electricity supply industry:

Structure of SA ESI


[^30]
### 4.2 Regulatory Controls

From 1 July 1995, the Department of Mines and Energy has been responsible for administering most of the technical and safety regulation for the South Australian electricity supply industry. Licensing of electrical contractors is the responsibility of the Office of Consumer and Business Affairs (which is under the control of the Attorney General's Department).

South Australia has prepared new legislation (known as the Electricity Act) establishing the future regulatory framework for the electricity supply industry in South Australia. This legislation is designed to complement (and not duplicate) the regulatory arrangements contained in the Code and the National Electricity (South Australia) Act 1996. (e.g. licence conditions must be determined with regard to the Code and the need to avoid duplication of and any inconsistencies with, the provisions of the Code).

The Electricity Act is currently being debated by the South Australian Parliament. The objects of this act are:

- to promote efficiency and competition in the electricity supply industry;
- to promote the establishment and maintenance of a safe and efficient system of electricity generation, transmission, distribution and supply;
- to establish and enforce proper standards of safety, reliability and quality in the electricity supply industry;
- to establish and enforce proper safety and technical standards for electrical installations; and
- to protect the interests of consumers of electricity.

Amongst other matters, this Bill locates the technical and safety regulatory arrangements with a Technical Regulator (probably an officer under the South Australian Minister for Mines and Energy) and introduces a new licensing regime requiring public and private electricity entities (generators, network providers, retailers and possibly other operators) to be licensed before they can operate in the South Australia electricity supply industry. In particular, the Technical Regulator will have the following functions:

- the administration of the licensing system for electricity entities established by this Act;
- the monitoring and regulation of safety and technical standards in the electricity supply industry;
- the monitoring and regulation of safety and technical standards with respect to electrical installations; and
- the monitoring of plans or action to increase or reduce electricity generation, transmission or distribution facilities or capacities and the likely effect on customers;
- the establishment and monitoring of standards in respect of services provided by electricity entities to customers; and
- any other functions assigned to the Technical Regulator under this Act.

The Electricity Act is expected to be passed by the South Australian Parliament before the end of 1996 and commence operation on 1 January 1997. It is also expected that regulations under the Electricity Act will be prepared in the near future. Licence conditions, rules and guidelines are also likely to be prepared during 1997. The Technical Regulator will determine the conditions to be imposed upon electricity entities under their licences. These conditions are likely to include a requirement to comply with specified standards, codes or other safety or technical requirements.

ETSA Corporation currently recommends end use electricity tariffs which are approved by the South Australian Cabinet. These tariffs currently comprise energy, network and retail margins bundled into one all inclusive price which applies uniformily across the state for particular categories of customers. Further legislation is expected to be presented to the South Australian Parliament in or about April 1997 to establish a South Australian Pricing Regulator. The Pricing Regulator will be independent from ETSA Corporation and will be responsible for setting the network prices in South Australia and ETSA Power Corporation's retail franchise prices. The exact principles to be applied by the Pricing Regulator in fixing these prices (particularly network prices during the NEM transition period) are currently being developed and should be available later this year or early next year.

### 4.3 The Wholesale Market

Unlike New South Wales and Victoria, South Australia has not implemented, and at this stage will probably not implement a wholesale competitive electricity market in South Australia prior to the commencement of the NEM (i.e. NEM3). Currently, all electricity generated in ETSA Generation Corporation is sold under contract to ETSA Power Corporation. Under this arrangement ETSA Power Corporation effectively controls $99 \%$ of South Australia's electricity supply.

As noted above, since 1990 interstate trade in electricity has occurred between Victoria and South Australia, with ETSA (and subsequently ETSA Corporation) importing 12-24\% of South Australia's electricity requirements from Victoria. The existing interconnection capacity should allow for up to $35 \%$ importation.

Currently, ETSA Power Corporation is the only organisation which "retails" electricity in South Australia (other than certain building owners in respect of the supply of electricity to their tenants and one regional council). When the NEM commences operation in South Australia, ETSA Power Corporation's retail franchise will be progressively opened up to competition in accordance with a "contestability timetable". The SA Government will announce the SA contestability timetable early next year. In transition to the fully competitive market, vesting contracts will be established between the new SA Generation Corporation and ETSA Power Corporation for a proportion of the franchise load.

## 5 Australian Capital Territory

### 5.1 Current position

ACTEW Corporation Ltd, a distributor and retailer of electricity, is the only provider of electricity in the ACT.

There is currently no generation capacity in the ACT that is relevant to the NEM.

There is no legislation which regulates operation of generation or which regulates transmission lines. Nor is there any legislation setting up any access regime to networks and there is no legislation dealing with access disputes at this stage.

Regulation of electricity in the ACT is based on legislation administered by the Minister for Urban Services and the Minister for the Environment, Land and Planning. It includes the following:

- Electricity Act 1971
- Energy and Water Act 1988
- Essential Services (Continuity of Supply) Act 1992; and
- Building and Services Act 1924.

Technical regulation is carried out by Building, Electricity and Plumbing Control located in the Department of Urban Services.

Regulation of pricing determined by ACTEW Corporation is carried out by the Energy and Water Charges Commission established under the Energy and Water (Regulation of Charges) Regulations 1996. These Regulations were made under powers set out in the Energy and Water Act.

ACTEW Corporation has powers to determine charges under the Energy and Water Act. In making such determinations, the Corporation must take account of the determinations of the Energy and Water Charges Commission.

No explicit monopoly status is given to ACTEW Corporation under the legislation.
ACTEW Corporation currently sources about $28 \%$ of its electricity from the Snowy Mountains Hydro-electric scheme. The remainder is currently sourced from within New South Wales. Since March 1996, under arrangements agreed by the Minister for Urban Services and the New South Wales Treasurer, ACTEW Corporation has been participating in the New South Wales Wholesale Electricity Market.

### 5.2 Adjustments required for the National Electricity Market

A review of the ACT legislation is now underway to:

- identify necessary consequential amendments required for the operation of the National Electricity Law in the ACT;
- provide an appropriate framework for regulating those aspects of electricity for which the Territory will still have jurisdiction and which are not currently covered by ACT legislation. These would include pricing issues (replacing the current Energy and Water (Regulation of Charges) Regulations), consumer protection, technical standards, liability and safety;
- deal with access and market structure issues (eg. recognising the existence of multiple retailers in the ACT); and
- streamline regulation of electrical work including a system of manuals.

The revised legislation will be needed to support introduction of staged deregulation of the retail market in the ACT over the next few years. The Government will be announcing a policy position on the appropriate timetable for the ACT within the next few months.

## 6 Interstate arrangements

### 6.1 Interconnection Operating Agreement trade

New South Wales and Victoria were interconnected in 1959 and South Australia joined that interconnection in 1989.

Interstate trade between New South Wales, Victoria and South Australia is currently governed by the Interconnection Operating Agreement ("IOA") which expires in 2010.

The IOA provides for three types of exchange:

- opportunity interchange: this provides opportunities for reducing the cost of power generation by swapping cheaper sources of power generation for more expensive sources, with the cost savings split between parties;
- emergency assistance: this covers capacity support if any party has insufficient capacity to meet demand; and
- contract energy transfers: these contracts are priced as agreed between the parties.

As continuation of the IOA is inconsistent with the NEM, it is proposed that the IOA will be terminated prior to the commencement of the NEM

New South Wales, Victoria and South Australia are renegotiating the future of IOA with a view to replacing it with interjurisdictional arrangements more consistent with the National Electricity Market.

### 6.2 Snowy scheme

The Snowy Mountains Hydro-Electric Authority ("SMHEA") is a Commonwealth trading enterprise operated under agreement between the Commonwealth, New South Wales and Victorian Governments. The Governments intend to corporatise the SMHEA to be a market generator in the NEM

## NGMC WORKING GROUP/COMMITTEE STRUCTURE

The working group and committee structure supporting the NGMC has altered significantly since the initial NGMC framework was first agreed. The changes have largely reflected the evolution of the NGMC, the changed nature of the activities it has been undertaking, the need to bring more resources to bear to develop the NEM and most recently, the need to undertake some of the implementation activities owing to the delays in the establishment of NEMMCO and NECA.

There have probably been three distinct phases to the NGMC committee structure: "Initial", "Development" and "Implementation". The role of the main committees in each is briefly described below.

In each phase there has tended to be a core of working groups and committees drawn from representatives of the various NGMC jurisdictions. However, when specific one-off tasks have been required it has been useful for a subgroup to be established to perform or oversee that particular function. The following list does not identify every single subgroup.

Throughout the process, the NGMC has made extensive use of consultants in all areas of its activities.

## Initial Phase

## Competitive Sourcing Review

- Coordinate and review the effectiveness of competitive sourcing procedures. Recommend to the NGMC the timing and scope of competitive sourcing to be undertaken - not activated.


## Environmental Approval Processes

- Coordinate with governments the development of environmental approval processes which recognise the national scope of environmental matters in relation to energy supply and demand - not activated.

Report and Protocol Review

- Monitor and report to the NGMC on national and international comparisons of performance of grid and the effectiveness of the Protocol, and to review, recommend amendments to, and provide guidance on the implementation of the Protocol.

Transmission Structure Group (ad hoc group)

- At the direction of Heads of Government, report on the nature and operating guidelines of an interstate transmission network across the eastern States. Report submitted to Heads of Government in December 1992.

Working Group (ad hoc group)

- Address regulatory issues which will underpin the arrangements for the new electricity market.


## Consultative Working Group

- To involve a broader range of industry stakeholders. To address the impact of matters related to the development and implementation of an interstate transmission grid and a competitive national electricity market.


## National Grid Operating Committee

- The main technical committee supporting the NGMC. Develop broad technical guidelines for planning, design and reliable and economic operation of the Grid. Work through a structure of specialist sub-committees.


## Planning Sub-committee

- Coordinate overall system planning, including preparation of forecasts, advice on new capacity, extensions or interconnections.


## National Grid Design Sub-committee

- Coordinate design and planning studies for the interconnected transmission system.

Operating Sub-committee

- Establish and maintain operating requirements for the interconnected system so as to ensure the most efficient use of system resources and that technical requirements are met for reliability.
- System control arrangements.

Transmission Pricing Working Group (ad hoc group)

- Develop a framework for transition to a national electricity market.
- Transmission asset valuation methodology.


## Development Phase

In mid 1994 the NGMC overhauled its committee structure due to the volume and complexity of the work needed to achieve the timely implementation of the NEM. In particular:

- a high level policy Market Steering Committee (MSC) was established to report to the NGMC;
- the MSC was supported by a number of working groups;
- a full-time General Manager of Projects was appointed to coordinate the activities of the various committees and the resources;
- a broad "experts" Reference Group was established to review position papers and provide input to the NGMC processes as appropriate. One of the objectives of the new project arrangements was to involve representatives from a broader cross - section of electricity interest groups more directly in NGMC activities;
- responsibility for progressing the technical work previously carried out under the direction of the NGMC's National Grid Operating Committee was transferred to the new working groups.


## Market Steering Committee

- High level policy committee responsible for considering and developing the form of the market and resolving major issues in relation to the market arrangements. The primary function of the MSC is to oversee design of the NEM, drafting of Code and development of systems specifications for tender to support the NEM. Membership includes generators, distributors, BCA, consumers and finance and policy representatives.


## Market Trading Working Group

- Consider and develop recommendations on the form of the national market, including its initial shape, transition arrangements and ultimate form.


## Transmission Pricing Working Group

- Examining and making recommendations on:
- grid connection and access arrangements
- grid investment process
- grid fee charging arrangements
- asset valuation methodologies
- network pricing calculations


## Code of Conduct Working Group

- Five subgroups responsible for development of Codes of Conduct for:
- grid connection and access
- market and access regulation
- market rules
- network pricing
- systems operations

Systems Development Working Group

- Responsible for overseeing the development of the various systems, testing and implementation:
- pool operations
- systems operations
- settlements
- communications
- metering
- database


## Systems Control/Pool Administration Working Group

- Group of state systems operators responsible for providing technical advice on development and implementation of trading systems.

Reference Group

- A broadly based reference group with over 300 people/organisations represented to interact with the various working groups, providing comments or alternative positions on papers as they are being developed by the working groups.

Demand Management Working Group

- Ad hoc group to review public submissions on NGMC's DM report and develop report for NGMC. Membership included utility, distributor, Greenpeace, New South Wales Government Pricing Tribunal and energy conservation industry.


## Implementation

In August 1995 the NGMC agreed to a new project structure which would enable it to move from the development to implementation phase required for the start of the market.

This action was in part also required due to delays in the establishment of NEMMCO and NECA and the need for the NGMC to assume some of those responsibilities. A summary of the functions of the additional committees is outlined below.

Market Implementation Steering Committee

- To oversee or establish the processes necessary to implement the NEM. Has responsibility for developing for NGMC approval/endorsement
- legislation to underpin the NEM
- review and approval of Code versions
- review of due diligence of Code provisions
- determination of policy issues for Code
- governance arrangements for NEMMCO and NECA
- the initial market functionability
- NEMMCO and NECA establishment details
- $\quad$ systems development joint venture
- change management for the National Electricity Code prior to the takeover by NECA


## Legislation Working Group

- Develop detailed legislative and regulatory arrangements.


## NEMMCO Establishment Group

- Consider establishment tasks such as company structure, governance arrangements, Board appointment process, funding and financial structures and development of company documents.


## NECA Establishment Group

- Consider establishment tasks such as company structure, governance arrangements, Board appointment process, funding and financial structures and development of company documents.

System Control and Market Administration Group

- Reconstituted System Control and Pool Administration WG. To provide expert technical support on systems specifications for dispatch and control interfaces, development of service agreements between NEMMCO and the systems operators, training of new system operators.


## Systems Establishment Working Group

- The former Systems Development Working Group. To be utilised in the NEM systems delivery process to provide IT technical advice.


## Dispatch Function Working Party

- Provide expert advice on the procedures for dispatch function and coordinate their production and implementation in each system control centre.


## Systems Development Joint Venture

- Responsible for managing the:
- specification of the NEM systems to comply with the business rules in the Code of Conduct

NEM systems development budget
preparation of tenders and tender evaluation
negotiation of contracts and delivery timetables
development of the systems including software, user procedures, user training, systems and user acceptance training
transfer of the completed systems to NEMMCO or State based organisations

## SCHEDULE 5

## REPORTS AND PUBLICATIONS OF NGMC

| Publication Date | Title of Report/Publication | Public | Provided to Heads of Government |
| :---: | :---: | :---: | :---: |
| Dec 1992 | First Issue National Grid Protocol | X | X |
| Dec 1992 | Network Service Pricing - Information Paper | X |  |
| Jan 1993 | National Electricity Market and Common Trading Arrangements - Information Paper | X |  |
| March 1993 | The Structure of an Interstate Transmission Network for Eastern and Southerm Australia | X | X |
| May 1993 | Statement of Opportunities 1993-2005 <br> (To provide basic market information, including power transfer capabilities of existing and committed interstate and regional connections, to potential Grid Participants who wish to make an assessment of the future need for electricity generating capacity or demand management.) | X |  |
|  | Upgrading NSW/Victoria/SA Grid Interconnections |  | X |
| July 1993 | Regulatory Framework Issues for a National Electricity Market | X |  |
| July 1993 | Transition to a National Electricity Market | X | X |
| Oct 1993 | National Electricity Market - Paper Trial Information Kit | X |  |
| Oct 1993 | Regulatory Arrangements for a National Electricity Market | X | X |
| Feb 1994 | Issues for Government |  | X |

Feb 1994
Issues for Government
X
(i.e. identification of a number of key issues which the NGMC believed needed addressing as a matter of priority prior to the commencement of a competitive electricity market from 1 July 1995. The issues related to network pricing, financial implications of the competitive market, regulation,

| Publication <br> Date | Title of Report/Publication | Public |
| :---: | :---: | :---: | | Provided to |
| :---: |
| Heads of |
| Government |

May 19941994 Review of Statement of Opportunities X
May 1994 Electricity Usage Projections 1994-2006 X
(outlining in more detail the underlying economic scenarios used to derive the electricity projections)

| June 1994 | Demand Management Opportunities in the <br> Competitive Electricity Market - Vol 1 Discussion <br> Paper and Vol 2 Appendices |
| :--- | :--- |

Aug 1994 Towards a Competitive National Electricity Market X
(Remit from February 1994 COAG meeting at which NGMC was asked to report on its progress towards uniform pool arrangements and any necessary refinements to market trading arrangements in light of a review of the market trial.)

Aug 1994 Options for Reducing the Initial 10MW Customer
Threshold
$\begin{array}{lll}\text { Aug } 1994 & \begin{array}{l}\text { Options for Network Pricing, including Discussion } \\ \text { Paper on Distribution Pricing }\end{array} & \mathrm{X}\end{array}$
Aug 1994 Asset Valuation Methodologies X
$\begin{array}{llll}\text { Oct } 1994 & \begin{array}{l}\text { Proposed Electricity Market Design papers } \\ \text { Disk RG001 }\end{array} & \text { X }\end{array}$

- Proposed National Market Design
- Market Overview
- Demand Side Participation
- Commitment and Dispatch of Generation and Dispatchable Loads
- Bidding Process
- Designing the Market to Maximise Economic Efficiency
- Long - Term Trading
- Short - Term Trading
- Managing Risks
- Short - Term System Security
- Network Issues for Energy Trading
- Ancillary Services and Reserves
Publication Title of Report/Publication ..... Date
Public Provided to Heads of Government
- Metering and Settlements
- Long - Term Reliability- Network Energy Losses
- Price Pool Calculation
- The Threshold for Participation and VestingContracts
- Issues Raised after September 1994 Presentations
Dec 1994 Framework for Administration of the code of Conduct for the NEM
(This report was the result of considerable input anddebate from a wide cross - section of customers,electricity supply industries and governments.)
Dec 1994 National Electricity Market Paper Trial Evaluations ..... X
Vols 1 \& 2
Vols 1 \& 2
Dec 1994 Empowering the Market - National Electricity ..... X Reform for Australia
Feb 1995 Demand Management and Energy Efficiency in the ..... X ..... X Competitive Electricity Market
(A report based on feedback to a July 1994 discussion paper.)
March 1996 National Electricity Code (Version 1.0) ..... X
Consultation papers:CCWG007 National Electricity Code OverviewCCWG008 General Overview of MarketCCWG009 Summary of Comments System SecurityChapter (response to Reference Groupcomments 1995)CCWG010 Summary of Comments NetworkConnection Chapter (response toReference Group comments 1995)CCWG011 Response to the NSW GovernmentPricing Tribunal Research PaperNo. 5 "Review of TransmissionPricing for Electricity"

Publication Date

## Public Provided to

 Heads of Government| CCWG012 | Summary of Comments Market Rules <br> Chapter |
| :---: | :--- |
| CCWG013 | Mechanisms for Dealing with Excess <br> Generation in the NEM |
| CCWG014 | Chapter 9 Report on Transitional <br> Provisions |
| CCWG015 | Chapters 1, 2, and 8 - Major Changes to <br> the Code |
| NPSC010b | Response to Reference Group <br> Submissions on Network Pricing |
| M017V01 | Summary of Resolutions for Reference <br> Group Issues Metering Code |
| M015V042 | Transitional Arrangements for Metering <br> Code at Market Start - Up (Draft of <br> Chapter 9 for comment) |
| SCMA001 | Governance Arrangements for Global <br> Power System Planning <br> (background policy paper to Chapter 5 <br> of the Code) |
| CCWG016 | National Electricity Code Outline and <br> Rationale |
| CCWG017 | Complexity of Market Operations - A <br> Response to Participants' concerns |

## SCHEDULE 6

## MAJOR CHANGES TO THE NATIONAL ELECTRICITY CODE

## 1 Code Complexity

The Code has been restructured particularly in:

- Chapter 1 - focus on market and code objectives and functions of NEMMCO and NECA
- Chapter 2 - covers each category of Code Participant and registration requirements
- Where possible, details on Code Participants have been moved from other chapters to Chapter 2
- A preamble has been added to each chapter (excluding Chapters 1-2) to define how the chapter applies to each category of Code Participant
- Both Chapters 5 and 6 now include an explanatory box to explain the access regime.
- Where possible mechanical details have been deleted from the Code - responsibility of NEMMCO and NECA to publish with due notice.

In recognition of the Code complexity concern, the NECA Chairman has stated that NECA are prepared to develop indexes, handbooks and user manuals (as suggested by the ACCC), and other guidance material to ensure that the Code is accessible and more user friendly. It is expected that these materials will be completed by April, 1997.

In addition, a Market Liaison Panel has been established to provide a forum for discussing the details of the Code and to develop suitable materials to assist persons operating in the NEM. The Market Liaison Panel is chaired by the NECA Chairman and consists of key stakeholders including generators, large and small customers, network service providers, retailers, and NEMMCO.

## 2 Protected provisions and reviewable decisions

The Code now identifies several clauses as protected provisions. This means that these clauses cannot be changed without the unanimous approval of participating jurisdictions.

The Code also identifies several clauses as reviewable decisions when NEMMCO and NECA takes a decision that affects the rights of an individual Code Participant. In this case these decisions may be reviewed by the National Electricity Tribunal if the party wants the decision reviewed.

### 2.1 Chapter 1 Introduction and Code Supervision

Chapter 1 has been amended to include:

- a statement of market objectives;
- descriptions of NECA and NEMMCO;
- provisions on interpretations, notices, and retention of records which were previously in Chapter 2; and
- provisions to establish a NECA Civil Penalties Fund and NEMMCO Code funds as required under the National Electricity Law.


### 2.2 Chapter 2 Code Participants and Registration

To simplify the Code, Chapter 2 has been re-written to describe the various categories of Code Participants and the registration procedures. In the new version of the Code, the term Code User has been replaced with Code Participant. The other Code Chapters 3 through to 8 have been amended to include a preamble to describe how the provisions of each Chapter apply to particular categories of Code Participants.

Network Service Provider are now required to register with NEMMCO and to give an undertaking to the ACCC to provide access to its network in accordance with the Code. NECA can exempt a Network Service Provider from registration. Guidelines are yet to be developed for these exemptions, but they are likely to include local "systems" such as city buildings and caravan parks. NECA in consultation with jurisdictional regulators will develop guidelines exemptions for NSPs from the Code.

The category of Retailer has been dropped from the Code. It is now included in Market Customer.

The market participation rules for generators have been modified to address many of the issues raised in submissions to the NGMC on the Code. The major change has been to separately distinguish whether a generator is participating in central dispatch (for system security reasons) from participation in the spot market. Under the Code, Generators are now required to register with NEMMCO as Scheduled or Non-Scheduled Generator and as Market or Non-Market Generator.

Chapter 2 also describes how participant fees will be determined to cover the costs of NEMMCO, NECA and the National Electricity Tribunal. The key principles for determining participants fees are simplicity, user pays (noted by the ACCC as desirable), non-discriminatory application and where practicable avoid cross subsidies.

### 2.3 Chapter 3 Market rules

The major changes to the market rules are described below by topic.

## - Liability of NEMMCO

This clause has been reworded to ensure that NEMMCO is liable for acts of negligence or bad faith.

## - Prudential requirements

Clause 3.3 include provisions for the prudential requirements to be met by Market Participants based on the recommendations of the independent Prudential Panel established by the NGMC. In relation to the STFM and inter-regional hedge contracts, the Code provides for NEMMCO to be able to reassess exposures in the spot market on the basis of STFM and inter-regional hedge contracts just as in any other contract reassignment.

## Projected Assessment of System Adequacy (PASA)

Previously there was a short, medium, and long term PASA. This has been simplified to only a short term (rolling 7 days) and medium term PASA (2 years ahead). The medium term PASA will be reviewed and issued each week by NEMMCO instead of every three months. The short term PASA is issued each day by NEMMCO and each time there is a material change in circumstances.

## - Central Dispatch Process and Spot Market

The central dispatch process has been modified to introduce the concept of a self dispatch level whereby a Scheduled Generator one day ahead of each trading day will notify NEMMCO of its MW capacity profile for an intended self dispatch level and an (optional) incremental MW amount for each price band being offered by the Scheduled Generator. A dispatch offer which specifies a self dispatch level of more than zero must specify at least one price band for off-loading below the intending self dispatch level such that the unit may be decommitted if required during an excess generation period. (Note: Scheduled Generators are also required to notify NEMMCO of their unit commitment and decommitment intentions two days ahead of each trading day.)

## - Excess generation periods

In the Code public consultations three options for dealing with excess generation were discussed. Option 3 was adopted, as favoured by most respondents. As part of a standard offer, a Scheduled Generator is required to submit at least one off loading price with a MW quantity consistent with reducing the generating unit's dispatch level to zero. If an excess generation
period is occurs, the dispatch price to customers shall be clamped at zero $\$ / \mathrm{MWh}$, whilst generators are exposed to negative prices. During excess generation periods, Scheduled Generators pay NEMMCO their dispatched MW multiplied by the negative pool price. This market mechanism will provides a very strong incentive to avoid excess generation situations from occurring.

## Value of Lost Load (VoLL)

The maximum spot price (VoLL) is set at $\$ 5,000$ per MWh upon commencement of the NEM, with a review to be conducted by NECA after one year. Previously, VoLL started at $\$ 2,000$ and increased to $\$ 10,000$ by year 4 after market commencement. Any change to VoLL is to be handled through the Code change process but the change is not to take effect less than two years after the notice of change has been published.

## - $\quad$ Short term forward market (STFM)

The level of detail regarding the STFM has been removed from the Code. Now, NEMMCO will determine the initial form of the short term forward market prior to the market commencement in consultation with Code Participants and any other persons NEMMCO thinks appropriate. NEMMCO's facilitation role in STFM to cease after three years with NECA to consult widely on the need for any continuing role by NEMMCO.

## - Inter-regional hedging

NEMMCO will determine the form of the inter-regional hedge contracts and inter-regional exchange in consultation with Code Participants and any other persons NEMMCO considers appropriate. NEMMCO's facilitation role in the inter-regional exchange will cease after three years with NECA to consult widely on the need for any continuing role by NEMMCO.

## Ancillary services

The treatment of ancillary services has been simplified. Previously the Code required NEMMCO to determine a spot price for ancillary services managed in central dispatch like regulating capability and contingency reserve. Ancillary services are essential for power system security and integral with central dispatch arrangements. Code Participants will be required to provide a some level of ancillary services under their connection agreements and NEMMCO is to purchase the balance of ancillary services requirements through commercial processes. NEMMCO is to investigate and report within two years on possible development of improved market based arrangements.

## NEMMCO's reserve trading activity and intervention

The Code provides for a five year sunset period on NEMMCO's reserve trading activity with the Reliability Panel to review the need for any continuing role by NEMMCO. NEMMCO is also provided with an additional power of direction to maintain reserve levels ("reliable operating state") to reduce the risk of involuntary load shedding. When plant under a NEMMCO reserve contract is dispatched or a direction is issued, NEMMCO is obligated to determine spot prices at a value which NEMMCO considers would have applied if the reserve plant had not been dispatched or the direction had not been issued. NEMMCO is also obligated to compensate any Scheduled generator or Market Customers during these interventions based on determination made by an independent expert appointed by NEMMCO. NEMMCO is to intervene in a manner that minimises total costs to customers according to guidelines developed by the Reliability Panel.

- Force Majeure and market suspension
- NEMMCO may impose an administered price cap in one or more regions due to market suspension or because a material force majeure event has occurred.
- NECA is to develop and publish a schedule to define force majeure and material force majeure events which, if not rectified within 24 hours, would cause NEMMCO to invoke an administered price cap in the affected region(s). It is also the responsibility of NECA to establish a schedule of price caps for each region.
- When an administered price cap is imposed in one region, it in effect caps prices at the regional reference nodes in all interconnected regions. Central dispatch is still run as far as possible according to the Code rules.
- If this approach leads to generators being dispatched at a price below its bid or offer price then those generators may claim compensation. Such claims are to be processed by NECA's Dispute Resolution Panel based on the Panel's assessment of a fair and reasonable amount of compensation. The compensation payments are to be funded through a levy on Market Customers in the affected region(s).


## - Payment default procedure

A payment default procedure for Market Participants has been added to the Code based on the recommendations of the of the independent Prudential Panel established by the NGMC. Under these procedures, unless a participating jurisdiction provides a nominated third party to assume the obligations of the suspended Market Participant, NEMMCO will request

NECA to seek an order from the National Electricity Tribunal to physically disconnect all market loads the suspended party is responsible for.

### 2.4 Chapter $4 \quad$ Power system security

Chapter 4 has been amended to provide a better definition of NEMMCO's accountabilities for power system security and reliability.

The technical schedules for power system security have been deleted and will now be determined by the Reliability Panel to be formed by NECA. The Reliability Panel functions include monitoring, reviewing and reporting on the performance of the market in terms of power system security and reliability. The Reliability Panel will on the advice of NEMMCO and after public consultations determine the power system security and reliability standards for the market which are required under Chapter 4 of the Code

The new power system security and reliability definitions included in Chapter 4 are:

- satisfactory operating state - these are the technical operating limits which must not be exceeded by the power system without a risk to public safety or the risk that the power system breaks down and goes to a black system (Note: this term was formerly "normal operating state" in Version 1.0 of the Code)
- secure operating state - the power system has sufficient contingency reserves in accordance with the standard set by the Reliability Panel to sustain one single credible contingency event and still maintain a satisfactory operating state; (Note: if more than one credible event occurs, some customer load may be shed involuntarily if necessary to ensure the power system stays within a satisfactory operating state)
- power system security - is defined as making sure to the extent practicable that the power system is operated such that it is and will remain in its secure operating state; (Note: Following a credible contingency event or a significant change in power system conditions, it is possible that the power system may no longer be in a condition which could be considered secure on the occurrence of a further contingency event. In that case, NEMMCO should take all reasonable actions to adjust, wherever possible, the operating conditions with a view to returning the power system to its secure operating state as soon as practical.)
- reliable operating state - the power system has sufficient short term capacity reserves in accordance with the standard set by the Reliability Panel to sustain more than one single credible contingency event and reduce the risk of involuntary load shedding to maintain a secure operating state.

Under the Code, NEMMCO is now required to:

- contract for and dispatch ancillary services, including contingency reserves, to ensure power system security;
- monitor and inform the market in the Projected Assessment of System Adequacy process ("PASA") of the extent to which the market is not meeting the reserve standards specified by the Reliability Panel in the power system security and reliability standards;
- intervene to contract for reserves when it becomes clear that the market is not responding to a projected lack of reserves through the PASA process;
- intervene to direct plant to maintain a reliable operating state and reduce the risk of involuntary load shedding if sufficient reserves cannot be commercially contracted; and
- intervene, as a last resort, to maintain public safety and the security of the power system in order to prevent a collapse to a black system.

NEMMCO's powers to intervene in the market to contract for reserves or to direct plant to maintain a reliable operating state and reduce the risk of involuntary load shedding will have a sunset period of 5 years from market commencement which may be reviewed by the Reliability Panel in public consultations.

Chapter 4 now requires the System Operator for each participating jurisdiction to advise NEMMCO of the requirements of the participating jurisdiction regarding sensitive loads (eg hospitals) and priority of load shedding. If involuntary load shedding is required NEMMCO will implement based on the priority provided by each System Operator. In the event the situation is so extreme, that NEMMCO for reasons of public safety or for power system security, needs to interrupt supply to any sensitive loads, NEMMCO may only effect that interruption or give a direction requiring that interruption once the System Operator for the relevant jurisdiction has given NEMMCO its approval (which must not be unreasonably withheld).

Despite these powers, under the National Electricity Law NEMMCO nor any Code Participant is not liable in damages to any person for any partial or total failure to supply electricity unless the failure is due to anything done or omitted to be done by the Code Participant in bad faith or to the negligence of the Code Participant.

Chapter 4 has also been amended to:

- include a new provision that details the obligation of Market Customers whose expected peak demand at a connection point is in excess of 10 MW must provide automatic interruptible load of a minimum of $60 \%$ of their expected peak demand. (Note: this obligation will be arranged with the Network Service Provider in a connection agreement.)
- include a new provision to define NEMMCO's responsibility to coordinate power system stability in accordance with Section 5.1.8 of Schedule 5.1.


### 2.5 Chapter 5 Network Connection

The major changes in Chapter 5 are set out below in terms of the major issues they address.

## - Generator Access Arrangements

A new clause 5.5, Access Arrangements for Generators, has been added to replace the Firm Access clause 3.14 in version 1.0 of the Code. Under the new clause, Generators and Network Service Providers will negotiate the use of system charges and any associated compensation arrangements between the parties in relation to those occasions where a generator are constrained off due to network constraint.

## - Negotiation of network connection services

The cost of the provision of network connection services is to be achieved by negotiation rather than regulation in the following ways:

- clause 5.3 .4 of the Code provides that a party seeking connection may submit applications to connect to more than one Network Service Provider in respect of facilities to be provided that are contestable;
- the Code neither encourages or discourages by-pass, it simply permits it.
- the Code does not preclude a party owning the connection facilities and arranging a maintenance service agreement with the Network Service Provider
- A new clause 5.6.6 defines the access arrangements for parties seeking to establish a new interconnector to connect transmission networks across regions.


## - Network planning processes and competition

The network planning provisions of Chapter 5 have been changed to obligate NEMMCO and Network Service Providers to subject network augmentation proposals to a cost benefits test where the augmentation option is to be assessed against options for the implementation of demand side or generation investments proposed by parties in a public consultation process and the prime criterion is the minimisation of customer costs, having regard for the costs of network losses and constraints (as manifested in the market) and the cost of investing to reduce those losses and constraints.

If a proposal is recommended to proceed which is likely to increase the use of system charges of a Code Participant by more than $2 \%$ at the date of the next price review, it may be disputed by that Code Participant and if agreement cannot be reached in negotiations with the Network Service Provider, then the matter is to be resolved by using the dispute resolution procedures involving the NECA or the appropriate regulator.

## Levels and standards of network service

Chapter 5 has been revised to impose a clearer obligation on the Network Service Provider and the party seeking access to agree on reasonable expectations regarding the level and standard of service of power transfer capability that the network should provide in developing a connection agreement.

Schedule 5.1 - Network performance standards, which defines the planning, design and operating criteria that must be applied by Network Service Providers to the transmission networks and distribution networks which they own or control, now defines the criteria and obligations as falling into two categories, namely:

- those required to achieve adequate levels of network power transfer capability or quality of supply for the common good of all, or a significant number of Code Participants; and
- those required to achieve a specific level of network service at an individual connection point.

In developing a connection agreement with a party, the Network Service Provider is now obligated to:

- fully describe the quantity and quality of network services which it agrees to provide to a person under a connection agreement in terms that apply to the connection point as well as to the transmission or distribution system as a whole;
- ensure that the quantity and quality of those network services are not less than could be provided to the relevant person if the national grid were planned, designed and operated in accordance with the criteria set out in this Schedule 5.1 and recognising that levels of service will vary depending on location of the connection point in the network; and
- to the extent that this Schedule 5.1 does not contain criteria which are relevant to the description of a particular network service, the Network Service Provider must describe the network service in terms which are fair and reasonable.
- Technical bias in conditions for connection

The conditions for connection for generators (Schedule 5.2) has been revised to remove any perceived bias for or against alternative generator technologies. Any further comments during the ACCC review process will be welcome.

### 2.6 Chapter 6 Network Pricing for Transmission and Distribution Systems

Chapter 6 has undergone major revisions in response to the ACCC Issues paper (March 1996) and submissions on the Code. The major revisions are:

- Part B (transmission pricing regulation) and Part D (distribution pricing regulation) have been completely redrafted in the form of regulatory principles. This reduces the level of prescription in the Code and provides more flexibility to regulators to strike the appropriate balance between:
- the legitimate business interests and investments of the network service provider;
- the interests of persons seeking access to a transmission or distribution network; and
- the public interest, including the public interest in having competition in related markets.
- Part C (transmission prices) and Part D (distribution prices) are the starting point for two major public reviews to be conducted by NECA prior to 1 July, 1999. The outcomes of those reviews will be resubmitted to the ACCC for approval.
- Transmission pricing and access will be regulated at the jurisdictional level until 1 July, 1999 in New South Wales when the ACCC will assume responsibility in line with the original COAG guideline. The other jurisdictions will transfer responsibility for transmission pricing and access to the ACCC on 1 January, 2001.
- Distribution pricing and access will be regulated by Jurisdictional Regulators applying Chapters 5 and 6 of the Code along with the transitional derogations in Chapter 9. Most transitional derogations will cease on 1 January, 2001.
- The transitional derogations in Chapter 9 for both transmission and distribution access provide for the following principles:
- The Network Service Provider is obliged to connect a party and give them access to its network if they have entered into a fair and reasonable connection agreement.
- The process of applying, assessing, and negotiating a connection agreement is designed to ensure that the Network Service Provider uses its best endeavours to give users access to its network, while maintaining the safety and security the network.
- The preferred approach to network access and connection agreements is to allow negotiation between the parties.
- The prices for transmission use of system and distribution use of system determined by the Regulator are maximum reference prices. Scope is provided to negotiate lower prices or differentiated service levels.


### 2.7 Chapter 7 Metering

The major changes in Chapter 7 are set out below in terms of the major issues they address.

## - Rights of access to data

Clause 7.7 has been amended to provide that any customer who is registered with NEMMCO and who purchases electricity at the associated connection point is entitled to have either direct or remote access to metering data from a metering installation, the metering database or metering register.

## - New technologies and processes

Chapter 7 has been largely drafted to deal with metering requirements of generators and large end user customers based on current metering technologies. As customer thresholds drop it has been recognised that the metering provisions may need to change to deal with smaller end user customers seeking market access. A new clause has been added to Chapter 7 to deal with evolving technologies and processes and development of the market. The new clause 7.13 provides that:
(1) Evolving technologies or processes that:
i) meet or improve the performance and functional requirements of this Chapter, or
ii) facilitate the development of the market,
may be used if agreed between the Market Participant, the Local Network Service Provider and NEMMCO, and the agreement of the Local Network Service Provider and NEMMCO must not be unreasonably withheld.
(2) By not later than 30 June 1997 and at least annually thereafter, NEMMCO must publish a report on the application of evolving technologies and processes.
(3) By not later than 30 June 1997 and at least annually thereafter, NEMMCO must submit a written report to NECA on the extent to which this Chapter may need to be amended in order to accommodate the evolving technologies and processes or the development of the market.

### 2.8 Chapter 8 Administration Functions

The major changes to Chapter 8 are:

- In version 1.0 the enforcement of the Code was managed by a Disciplinary Panel and Disciplinary Tribunal and Appeals Panel. These bodies have been replaced by the National Electricity Tribunal which will be established under the National Electricity Law. Clause 8.5 now defines how the Code will be enforced by NECA and the National Electricity Tribunal.
- A new clause 8.6.6 has been added to require NEMMCO to develop a policy on information disclosure in a manner which promotes the orderly operations of the markets it facilitates.
- The role of the Reliability Panel has been modified to include the determination of the power system security and reliability standards and guidelines for NEMMCO to follow in issuing directions or contracting for reserves to maintain a reliable operating state.


## SCHEDULE 7

## VICTORIAN ACCESS REGIME

## 1. ACCESS PRINCIPLES

The electricity supply industry in Victoria has undergone significant reform in the past three years. Key principles of the reform process included disaggregation of the formerly vertically integrated State owned utility (SECV) and the introduction of competition into the generation and retail sectors, particularly through ensuring access to the transmission and distribution networks.

The Victorian access regime was the subject of a review by the Trade Practices Commission in 1995. Part 3 below provides an overview of the Trade Practices Commission's findings.

## 2. DESCRIPTION OF THE CURRENT VICTORIAN ACCESS REGIME

### 2.1 Regulatory framework

Two pieces of legislation regulate the access principles established for the electricity industry in Victoria: the Electricity Industry Act 1993 ("the EI Act") and the Office of the Regulator-General Act 1994 ("Regulator General Act").

The EI Act establishes the regulatory regime for the Victorian electricity industry. Among other things, the EI Act deals with the role of the Office of the Regulator-General ("RegulatorGeneral"), licensing, price regulation and the introduction of retail competition.

The Regulator-General Act establishes the Office of the Regulator-General. The RegulatorGeneral is responsible for regulatory oversight of a number of utility type industry sectors subject to reform in Victoria, including the electricity industry. The ORG Act includes powers which enable the Regulator-General to regulate pricing, market conduct, and to issue guidelines, licences and codes.

### 2.2 Entry into the market

### 2.2.1 Licences

Participation in the Victorian electricity industry is governed by the licensing provisions of the EI Act. Under section 159 , generation, transmission, distribution, supply, sale and market operation activities are prohibited (subject to certain authorised exemptions) unless the participant obtains a licence.

Licences are issued by the Regulator-General. In determining licence applications, the RegulatorGeneral must consider a number of matters including:

- the objectives of the EI Act itself (for example, the promotion of competition in the industry, maintenance of system efficiency, safety and financial viability and the interests of consumers); and
- in some cases, the financial viability and technical capabilities of the applicant.

There are significant penalties under the Act for breaching section 159. Fines can be imposed up to $\$ 100,000$ initially and $\$ 10,000$ for each subsequent day that the contravention of licensing requirements persists.

### 2.2.2 Licence conditions

Under section 163 of the EI Act, the licence may be subject to conditions. Among other things, the licence conditions may:

- require the licensee to observe specified industry codes and rules;
- specify methods or principles to be applied by the licensee in determining prices or charges; and
- specify methods or principles to be applied in the conduct of activities authorised by the licence.

The Regulator-General has power to impose considerable fines for contravention of licence conditions ( $\$ 100,000+\$ 10,000$ for each day that contravention continues) and to appoint an administrator should a contravention continue.

### 2.2.3 Codes

Codes of practice include the VicPool Rules (which set out the way in which VicPool operates), the System Code (dealing with system security for the transmission network) as well as codes dealing with metering, distribution, and supply and sale of electricity to retail customers. Guidelines are also published by the Regulator-General to supplement the codes. The guidelines cover such things as offers to connect a customer, and augmentation.

### 2.4 Terms and conditions of access

The detailed regulation of network and market access is achieved through the licensing regime and through the various industry codes, rules and guidelines.

### 2.4.1 Wholesale electricity market

Victorian Power Exchange ("VPX") operates and administers the Victorian wholesale electricity market known as VicPool. VicPool customers buy electricity at spot market prices, which are set using a competitive bidding process in which both generators and buyers may participate.

To trade in VicPool, a person must hold a licence issued by the Regulator-General, and must apply to VPX under the VicPool Rules for admission as a VicPool participant.

### 2.4.2 Retail market

A retail licence issued by the Regulator-General is required to sell electricity to customers in Victoria. The retail market is being opened to competition in accordance with a timetable established under the EI Act. The disaggregation process has resulted in each DB having a monopoly over franchise customers which are located in its geographic domain. The reforms provide for a gradual phasing in of customer contestability so that by the year 2000, all electricity customers in Victoria will be able to purchase electricity from the retailer of their choice (although they will still be charged by their local distributor for access to, and use of, the local distribution
network). Until that time, all customers who remain subject to a DB's monopoly (i.e. franchise customers) will be protected from exploitation of market power by way of regulation by the Regulator-General, and the Tariff Order.

### 2.4.3 Transmission networks

In the reformed Victorian electricity supply industry, two bodies are responsible for the transmission of electricity. Power Net Victoria ("PowerNet") owns the high voltage transmission network and provides connection to the network to those using the system. VPX operates and controls the transmission network, and provides use of system services to network users in Victoria. It is VPX, rather than PowerNet, that makes decisions relating to planning and augmentation of the transmission network.

Access to the transmission network is regulated by the Regulator-General under the licences issued to PowerNet and VPX. For example, under its licence, PowerNet must:

- offer to provide connection services if requested by a licensee or a person that wishes to take supply from the transmission system; and
- augment the transmission network only in accordance with its network agreement with VPX and the guidelines issued by the Regulator-General.


### 2.4.4 Distribution networks

At present, the five DBs operate the wires management aspects of electricity distribution. The DBs are required to ring - fence their retail business from their wires business.

Access to the distribution networks is regulated by the Regulator-General under the distribution licences, and the various codes, rules and guidelines. The distribution licences oblige DBs to:

- make offers to connect customers or generators upon request;
- provide offers of connection services to other DBs; and
- call for tenders before undertaking network augmentation.


### 2.4.5 Dispute resolution

Under the terms of the transmission and distribution licences, the Regulator-General has power to decide any question as to the faimess or reasonableness of an offer to connect on the basis of the Regulator-General's opinion of its fairness and reasonableness. The Regulator-General acts as a kind of arbitrator in relation to access disputes, offering opinions where parties cannot reach a commercially negotiated outcome and, if necessary, issuing binding determinations of what it considers fair and reasonable. Appeals can be made from such decisions.

The Regulator-General has power under the El Act to resolve disputes relating to industry codes and rules. That power has been delegated to the Dispute Resolution Panel (established under the VicPool Rules) in respect of disputes relating to the VicPool Rules, the System Code and the Wholesale Metering Code.

The licences require retailers, distributors and PowerNet to establish dispute resolution procedures for customers and others. In Victoria, a number of licence holders are complying with this requirement through participation in the Electricity Industry Ombudsman Scheme.

### 2.5 Network pricing

The Tariff Order made under section 158A of the EI Act is the principal instrument for the regulation of network pricing in Victoria.

### 2.5.1 Transmission pricing

Transmission prices are customer specific and reflect two aspects of transmission: use of network costs and connection costs.

Until the year 2000, transmission network pricing will be regulated under the Tariff Order. In particular, the Tariff Order provides:

- transmission revenues will be subject to CPI-X revenue caps with compliance to be overseen by the Regulator-General;
- PowerNet connection charges to users will be subject to approval by the RegulatorGeneral; and
- VPX use of system charges will be subject to price caps.

By the year 2000, the Regulator-General is to have reviewed the network tariff components and the revenue and pricing controls, and thereafter, the Regulator-General is to review them every five years.

### 2.5.2 Distribution pricing

The Tariff Order regulates network prices charged by DBs to their customers and overall price increases for franchise customers. In particular, the Tariff Order provides:

- that DBs must offer the same network prices to retailers and customers as they charge to their own retail businesses, such charges to be regulated by a CPI-X regime;
- revenues and use of system prices will be subject to CPI-X price caps with compliance to be overseen by the Regulator-General;
- charges for DB connection and services such as metering may be published and are subject to a "fair and reasonable" test administered by the Regulator-General; and
- end prices to franchise customers are subject to a predetermined CPI-X regime.

By the year 2000, the Regulator-General is to have reviewed the network tariff components and the revenue and pricing controls, and thereafter, the Regulator-General is to review them every five years.

The Tariff Order also provides for the maintenance of geographic cross-subsidies, which will phase down by 2025.

## 3. TRADE PRACTICES COMMISSION REVIEW

In May 1995, the Trade Practices Commission reviewed the Victorian access regime, both in light of its operation and effects in Victoria and in relation to its interstate and national market implications to determine whether the regime was "effective" for the purposes of the Competition Principles Agreement (and thus exempt from Part IIIA of the TPA).

In relation to the operation and effect of the access regime and related reforms in Victoria, the Trade Practices Commission found conformity with the criteria in the Competition Principles Agreement and found that the regime could be assessed as "effective" for the purposes of that Agreement. In particular, the Trade Practices Commission found that the following aspects of the regime conformed with Principle 6 of the Competition Principles Agreement (which is the Principle relating to access):

- the regulatory controls seek to strike a balance between the interest of network companies, access rights and commercial opportunities of third parties and the general aim of fostering competition. In particular:
* the emphasis on cost reflectivity in the accounting principles adopted is enhanced by the appropriate choice of an asset valuation method and rate of return target approach;
* certain cross - subsidies between customer groups will remain, but the cross subsidy from large to small customers is being phased out by the year 2000, and there will be a continual run down in the significance of the locational cross - subsidies between rural and urban customers over the long term;
* CPI-X type price caps on PowerNet and the DBs (and a revenue cap on PowerNet) with ex post adjustments to correct for forecasting errors (which, although introducing a cost-plus element, is an approach superior to rate-of-return controls); and
* the mandatory application of public tenders to augmentation investments by the network owners with the additional cost-reflective feature that VPX rather than PowerNet itself will be managing the assessment and tendering process for transmission grid augmentations;
- rights to negotiate access to Victoria's electricity network are to be established in the following manner.
* a licence condition for network owners is that on request they must make an offer of connection; codes and guidelines further define this obligation;
* network owners are required to notify the Regulator-General of non-regulated prices; customers will be free to choose their energy retailer and by implication, at least some of their network services; and
* the emphasis is on negotiation, but the ultimate prospect, in the event that negotiations break down, is that the Regulator-General can make a binding determination of the terms and conditions it considers fair and reasonable; and
these aspects are bolstered by the proposed structural measures to ring-fence the natural monopoly part from other parts of the electricity market. This is likely to promote cost reflectivity by deterring hidden cross - subsidies.

The Trade Practices Commission also considered those aspects of the regime which it considered at odds with the preference for cost reflectivity shown in the Competition Principles Agreement. In particular, the Trade Practices Commission noted that the proposed method for handling the rural-urban cross-subsidies was not cost reflective. However, the Trade Practices Commission noted that Principle 2(4)(b) provided for the continuance of community service obligations where the instructions are explicit and the community service obligation is transparent.

From the Victorian aspect, the Trade Practices Commission also found that the Regulator-General's role is consistent with the Competition Principles Agreement as it focuses on different dispute resolution techniques and there is an emphasis on commercial negotiation.

In relation to the interstate and national implications of the Victorian access scheme, the Trade Practices Commission found that some aspects raised difficulties in terms of Principle 6(2) and Principle 6(4)(p) and thus the regime was not effective and was inconsistent with the Competition Principles Agreement in this regard. In particular, the Trade Practices Commission identified four areas of potential duplication and conflict arising between the Victorian arrangements and the proposed national electricity market, such as the overlap in functions of the Regulator-General and NECA or ACCC, or the overlap in regulation by Victorian licences or the National Electricity Code. The Trade Practices Commission concluded that if Victoria would give an assurance that it would modify those areas of concern by commencement of the NEM, the Trade Practices Commission would be prepared to recommend that Victoria's access regime be assessed as "effective" in terms of the Competition Principles Agreement, subject to the fulfilment of the undertaking at the appropriate time.

## 4. TRANSITION TO THE NATIONAL MARKET

This section outlines the main changes which will occur in the move from the current Victorian access regime to that which will exist in the national market.

### 4.1 Entry into the market

When the national market commences, the Code, rather than licences and the VicPool Rules, will govern participation in the wholesale electricity market. The VicPool Rules and Wholesale Metering Code will be replaced by the Code. The other Codes will continue to apply, at least to some extent.

Licences will still be required for transmission, distribution and sale, and will be granted and enforced by the Regulator-General. Existing licences may need amendment.

### 4.2 Access to networks

Connection to transmission and distribution systems will continue to be regulated by the RegulatorGeneral until 2000. After that time:
(a) the National Electricity Code will apply to access to transmission networks; and
(b) the Regulator-General will continue to regulate access to distribution networks for as long as the Regulator-General is also responsible under the Code for regulation of distribution network pricing.

### 4.3 Network pricing

The Tariff Order will continue to apply to all pricing up until the end of 2000, with the RegulatorGeneral continuing its regulatory oversight of network pricing. After 31 December 2000:
(a) distribution network pricing will continue to be regulated by the Regulator-General exercising the powers of a Jurisdictional Regulator under the Code, using the explicit price capping option. The Regulator-General will also apply the principles in the Tariff Order that are expressed to continue beyond 2000 and are still relevant (clause 5.10); and
(b) transmission network service pricing will be regulated by the ACCC under the Code. The equalisation factors in the Tariff Order will still apply.

### 4.4 Other market arrangements

Certain arrangements put in place in Victoria to assist the reform process will continue for a limited time in the national market, in particular those relating to long - term supply contracts with the Loy Yang B Power Station, and the Portland and Point Henry smelters.

VPX and PowerNet will continue to have separate roles in relation to the transmission network, particularly with respect to planning and augmentation. VPX will continue to operate the transmission network as agent for NEMMCO.

## NEW SOUTH WALES ACCESS ARRANGEMENTS

## 1. ACCESS PRINCIPLES

### 1.1 Contestability

As stated by the Minister for Energy in the New South Wales Parliament, a key objective of the New South Wales reforms has been to foster competition and competitive processes wherever practicable. Thus, policy has focused on separating monopoly from competitive activities, promoting competition where possible, and continuing to regulate monopoly activities. Where feasible, contestability will be introduced in the provision of network and related services. For example:

- network augmentation
- metering
- data communication
- network related services


### 1.2 Regulation of monopoly services

To a large extent, transmission and distribution services are natural monopolies. In return for the right to own and operate monopoly wires businesses, these businesses are subject to regulation to ensure they do not take advantage of their market power to extract excess profits. In New South Wales the Independent Pricing and Regulatory Tribunal ("IPART") is responsible for regulating maximum prices for monopoly businesses (see Section 2.2.2 below).

### 1.3 Separation of businesses

Separation of businesses is important to ensure that monopoly businesses do not cross- subsidise the parts of their business which operate in competitive markets. The New South Wales transmission business has been established as a separate entity in New South Wales, the New South Wales Electricity Transmission Authority, trading as TransGrid. TransGrid is also the Market and System Operator of the New South Wales wholesale electricity market (until these functions pass to NEMMCO); TransGrid is required to keep these functions separate from its other functions and activities ${ }^{\text {i }}$. Distribution businesses are required to separate their monopoly

[^31]activities from their competitive activities (such as retail supply) ${ }^{2}$. Accounting separation guidelines will be released in the near future.

### 1.4 Right to negotiate

While IPART regulates the maximum prices which can be charged for network services provided in New South Wales (which are services currently provided by government-owned corporations), there is flexibility for network users to negotiate prices and service standards (see Section 2.2.2 below).

### 1.5 Dispute resolution

IPART also currently has primary responsibility for the resolution of access disputes between wholesale market participants. IPART will have a corresponding role under the National Electricity Market arrangements although in the case of disputes as to access to the transmission network, from 1 July 1999 these will be dealt with in accordance with the dispute resolution procedures in Section 8.2 of the National Code ${ }^{3}$. Additionally, distribution and retail supply licensees are required to establish independent dispute resolution mechanisms for retail customers, covering matters such as capital contributions for connection services (see Section 2.3 below).

## 2. DESCRIPTION OF THE CURRENT NEW SOUTH WALES ACCESS ARRANGEMENTS

The Electricity Supply Act 1995 ("ESA") is the principal statute governing the electricity supply industry in New South Wales. It establishes the framework for wholesale and retail competition, and provides for:

- the licensing of retail suppliers and distributors, and the contractual arrangements by which they may provide connection and supply to customers;
- the authorisation of wholesale electricity market participants, and supervision of wholesale market operations and network access arrangements; and
- measures to ensure the ongoing soundness of the industry structure and compliance with legislative requirements.

The existing electricity businesses in New South Wales were deemed to have authorisations and licences to undertake their current activities (wholesale traders, network service operators, distributors or retailers) ${ }^{4}$.

[^32]
### 2.1 Entry to the market

Electricity trading (across the wires network - "network access") occurs through the wholesale and retail markets. Participation in these markets currently requires authorisation, in the case of the wholesale market, or a licence, in the case of the retail market.

### 2.1.1 Wholesale market

The Minister for Energy is responsible for granting network operator's authorisations which permit a business to operate transmission or distribution systems, to convey electricity for and on behalf of, and between, wholesale traders ${ }^{5}$. Network service operators must only convey electricity for wholesale traders if they are authorised.

The Minister is also responsible for granting wholesale trader's authorisations, which are required in order to operate in the wholesale market ${ }^{6}$. The Minister grants authorisations on the recommendation of the Market and System Operator (TransGrid). Wholesale traders can only enter wholesale arrangements with other authorised wholesale traders, or with the MSO.

Upon commencement of the National Market the requirement to hold or obtain authorisations for network services or wholesale trading will be removed. In its place will be the registration provisions under the National Code which will be administered by NEMMCO.

### 2.1.2 Retail market

In order to operate a distribution network to allow electricity to be conveyed across the network for and on behalf of retailers and to final customers (unless exempted), a business must hold an electricity distributors' licence ${ }^{7}$. Licences are granted by the Minister for Energy. In granting a distribution licence, the following factors are taken into account:

- the Minister must give due consideration to matters arising from any submissions received in relation to applications for a distribution licence; and
- the Minister must consult with the Minister administering the Protection of the Environment Administration Act 1991 before granting a distribution licence.

An application for a distribution licence may be refused on the following grounds:

- failure to meet prudential or technical criteria which are adopted by the Minister to determine whether a person is able to operate a viable business as a distributor; and

[^33]such grounds as the Minister considers relevant, having regard to the need to promote a competitive retail market for electricity, prevent misuse of market power and to ensure the security and reliability of the State electricity supply system ${ }^{8}$.

A person who supplies electricity to retail customers (unless exempted) must hold a retail suppliers' licence, granted by the Minister for Energy, to ensure that retail supply arrangements are enforceable. A retail supplier's licence authorises its holder to supply electricity to retail customers ${ }^{9}$. An application may be refused on the same grounds as apply to an electricity distributors' licence ${ }^{10}$.

In considering licence applications, the Minister is required to consider all applications according to the same criteria. Further, all licensees will be required to meet the conditions which apply to the type of licence they hold (distribution or retail).

The Minister for Energy recently endorsed proposals for the introduction of retail competition in electricity. These proposals allow retailers to compete to supply electricity to final customers. The proposals are outlined in the paper entitled "The New South Wales Electricity Supply Industry: Information Paper on the Transition to Full Retail Competition". An extract of the paper, which forms Attachment 1, outlines the timetable for introducing retail competition in New South Wales. Large customers have been able to choose their supplier from 1 October 1996, with other customers being entitled to choose their supplier (ie: become non-franchise customers) over a period of years as the market develops and metering and settlement systems are developed. All customers in New South Wales will be able to choose their supplier by July 1999. Following the date on which they become eligible to become non-franchise customers, they will be given a period in which they will be free to either become non-franchise or remain a franchise customer.

### 2.2 Terms and conditions of access

Commercial negotiation is a key principle of the New South Wales regulatory framework. However, in recognition of the monopoly status of the wires businesses, and potential differences in market power between network service providers and their customers, more specific regulation of revenue is in place.

### 2.2.1 Connection and use of system

### 2.2.1.1 Wholesale Market

Network service operators are required to operate their transmission or distribution systems in accordance with the wholesale market rules developed and published by the Market and

[^34]System Operator and any directions given by the MSO ${ }^{11}$. These rules are defined in the State Electricity Market Code, which has received interim authorisation from the ACCC. The Chapters most relevant to access provisions are:

- Chapter 5 - Network rules (described below)
- Chapter 6 - Network pricing (see Section 2.2 .2 below)
- Chapter 7 - Metering (see Section 2.2.3 below)
- Chapter 8 - Administration functions (which defines the dispute resolution procedures; see Section 2.3 below).

Chapter 5 of the State Code outlines the rights and obligations of network operators and those seeking access or connection. Its primary intention is that access and connection arrangements will be set out in a connection agreement between these parties. However, in order to regulate the network operators' market power, it sets out the minimum requirements for connection or access to the network. The Code does not regulate connection by end use customers who are not wholesale market participants and who (accordingly) are entitled to customer connection services under a customer connection contract (see Section 2.2.1.2 below).

Salient provisions include:

- the network operator has an obligation (when requested to do so) to connect a network participant and give them access to its network if they have entered into a connection agreement; and
- the process for applying, assessing and negotiating a connection agreement, which is designed to ensure that the network operator uses its best endeavours to give network users access to the network, while maintaining the safety and security of the network.

In the case of existing connections at the commencement of the State wholesale market, the State Code requires the network operator to use all reasonable endeavours to negotiate a connection agreement within 120 business days of the commencement date (ie: by November 1996) ${ }^{12}$. There are similar obligations imposed on network operators in respect of new connections.

### 2.2.1.2 Retail Market

Part 3 of the ESA outlines retail supply and connection arrangements for end-use customers who are not wholesale market participants. It obliges electricity distributors to provide connection to the distribution network or to ensure that such services are so provided (and to provide other customer connection services) to persons within that distribution area who are not wholesale market participants entitled to connection services under the State Electricity

[^35]Market Code ${ }^{13}$. Connection must be made under a customer connection contract. These contracts can take two forms:

- Standard form customer contract. The Act outlines the matters which must be addressed in these contracts, and provides that their form and content may be prescribed by regulation. Such regulation has been made (the Electricity Supply (General) Amendment (Customer Contracts) Regulation 1996) and prescribes mandatory provisions for the protection of customers against abuse of monopoly power. Matters which must be covered include the charges for connection, standard of service, disconnection and reconnection and a mandatory dispute resolution procedure (see 2.3.2 below). Standard form contracts, complying with the Regulation, are currently being developed by the 6 distribution companies in New South Wales.
- Negotiated customer contract. By mutual agreement, distributors and end-use customers can negotiate different customer connection services, terms and conditions from those established in the standard form contract.


### 2.2.1.3 Requirements as to Retail Customer Connection Services

Division 4 of Part 3 of the ESA details a number of requirements relating to customer connection services provided in the retail market. The Division includes rules relating to:

- the circumstances in which an electricity distributor may require a new customer to contribute towards the costs incurred, or to be incurred, by the electricity distributor in extending the distribution system or in increasing in its capacity;
- the circumstances in which an electricity distributor may require a customer to install service equipment necessary for the safe and efficient supply of electricity to the customer;
- requirements as to electricity meters including standards of installation; and
- the right of a customer to choose between the electricity distributor and any other accredited person for the provision of electrical and other goods and services required in relation to customer connection services ${ }^{14}$.


### 2.2.2 Network pricing principles

Chapter 6 of the New South Wales State Code describes the current regulation of network pricing in New South Wales. It notes that network prices in New South Wales are regulated by the Independent Pricing and Regulatory Tribunal (IPART). IPART is constituted under the Independent Pricing and Regulatory Tribunal Act 1992. A summary of IPART's

[^36]functions and powers are attached in Attachment 2. Important aspects of IPART's pricing regulatory framework include the following:

- The Tribunal is independent of Ministerial control or direction in making determinations or recommendations ${ }^{15}$.
- In making its determinations, IPART is required to take a range of matters into account as described in Attachment 2. These require the balancing of the interests of monopoly service providers, their customers, and the wider community. IPART must also take account of the need to promote competition.
- IPART has stated that its preferred approach is to allow negotiation between the parties involved. In recognition of the natural monopoly position of the network business, however, IPART sets an overall revenue cap and maximum reference prices for transmission and distribution. Scope is provided to negotiate lower prices or differentiated service levels. The guidelines for negotiation of prices are currently being developed.
- The ESA requires licensees in their customer connection contracts (and customer supply contracts) to follow any IPART determination. ${ }^{16}$ The Minister has sanctions available if licensees fail to do this in breach of the ESA or their licence. ${ }^{17}$

In March $1996^{18}$ IPART completed a review of maximum prices to be charged for transmission and distribution services in New South Wales. IPART's determination of maximum prices and revenue caps will apply until 30 June 1999.

### 2.2.2.1 Transmission pricing

The main features of the March determination are:

- TransGrid is subject to a cap on its overall revenue from monopoly transmission services. The cap is adjusted annually by a (CPI-X) factor.
- TransGrid is also able to derive revenue from non-regulated activities such as capital contributions, recoverable works and other miscellaneous charges. IPART have indicated they may investigate these charges if concerns arise. Connection charges are currently included as monopoly services, but are intended to be excluded once there is a contestable market for connection services.
- Transmission prices established within TransGrid's revenue caps are maximum prices, with scope for negotiation.

[^37]Transmission prices to distributors are calculated as an average of the cost reflective network price (CRNP) to the bulk supply points for each distributor.

- The structure of transmission prices to distributors will comprise $50 \%$ fixed, $25 \%$ demand and $25 \%$ energy charges.
- Transmission prices to generators relate only to connection charges.

In making its determination, IPART noted that it was, as far as possible, consistent with the proposals for the national electricity market at that time.

### 2.2.2.2 Distribution Pricing

The main features of the determination are:

- The distributors are subject to a revenue cap for network services, which is adjusted annually by a CPI-X factor.
- Revenue caps do not include income from capital contributions, public lighting revenues, miscellaneous charges, green pricing initiatives and approved renewable energy schemes.
- Pricing for inter-distributor transfers are negotiated by the relevant distributors, with recourse to IPART if arbitration is required.
- Where underground residential development connection works are contestable, capital contributions are not regulated. Where the works are not contestable, capital contributions cannot exceed those calculated under the existing methodology. IPART is currently undertaking a separate review of capital contributions.
- IPART is developing guidelines for bypass and negotiation of network charges below maximum schedule tariffs.


### 2.2.3 Metering

Metering arrangements for the New South Wales market are contained in Chapter 7 of the New South Wales State Code. This Chapter closely reflects the metering requirements of the National Code. It has been primarily designed to apply to wholesale market participants, who must have a half-hourly meter able to communicate in real-time with the Market and System Operator.

The Retail Competition Policy paper released by the Taskforce in June 1996 outlined the proposals for metering arrangements for retail customers. A key guiding principle for metering proposals is that metering requirements be defined according to the function which the meters and communication linkages will perform, without locking in particular hardware to perform these functions.

Non-franchise customers with sites using 4 GWh or more per annum will be required to install half-hourly meters (many customers this size already have half-hourly metering). Metering rules for smaller customers will be announced according to a timetable outlined in the Taskforce Report.

These rules will take into account the cost of metering and communication options, and may include options such as load-profiling.

The metering requirements of the New South Wales State Code are currently being reviewed. This results from concern that the rules focus too heavily on specific metering and communication hardware, rather than specifying the functions to be achieved, and allowing appropriate hardware solutions to develop in the marketplace. It is expected that this review will result in a proposal for a code change to the State Code.

### 2.2.4 Notification of access arrangements

The IPART Act requires network operators to notify the Tribunal at least 30 days before entering into a proposed connection agreement under the New South Wales State Code. The network operator must also provide the Tribunal with a copy of the proposed agreement, if requested.. This allows IPART to review individual access terms under those agreements and (at its discretion) to give advice on a proposed agreement to the network operator or the Minister. ${ }^{19}$ The Tribunal must register connection agreements, and this register must be publicly available.

### 2.3 Resolution of access disputes

### 2.3.1 Wholesale Market Disputes

Division 8A of the New South Wales State Code sets out the procedures for dispute resolution. In the case of access disputes between wholesale market participants, the matter in dispute must be referred to IPART and Part 4A of the IPART Act will apply.

If an access disputes arises, any party to the dispute may refer the dispute to arbitration. The Commercial Arbitration Act 1984 applies to arbitration of access disputes (subject to the IPART Act). Under the Act, IPART may act as the arbitrator, or may appoint an arbitrator from a panel approved by the Minister.

Where the dispute is over third-party access being denied, the arbitrator must give public notice of the dispute and must invite public submissions. In reaching a determination the arbitrator must take the following into account:

- the matters set out in clause $6(4)(\mathrm{i})$, (j) and (l) of the Competition Principles Agreement;
- any guidelines on access regimes released by IPART;
- any public submissions; and

[^38]any other matters that the arbitrator considers relevant.

The determination may deal with any matter relating to third-party access, including:

- requiring the network operator to give the third-party access;
- requiring the third party to accept and pay for access;
- specifying the terms and conditions of third-party access;
- requiring the network operator to extend the infrastructure facility; and
- specifying the extent to which the determination overrides an earlier access determination.

The determination does not have to require the network operator to provide third-party access.

The disputing parties are required by the IPART Act to give effect to the determination ${ }^{20}$.

### 2.3.2 Retail Market Disputes

In the New South Wales retail market, any person who owns or occupies premises within an electricity distributors' distribution district is entitled to connection to that network and the supply of electricity along the network. Connection is provided under standard form customer connection agreements or negotiated agreements (see 2.2.1.2 above). If an agreement cannot be negotiated then the default position is that the standard form of agreement applies, subject to the "checks and balances" contained in the Electricity Supply (General) Amendment (Customer Contracts) Regulation 1996). Among other things (as indicated in 2.2.1.2 above) the Regulation is designed to limit abuse of market power.

Any dispute arising under the standard form agreement must be resolved by a dispute resolution procedure provided for in the Regulation. This includes alternative dispute resolution procedures (which must be established by distributors) and arbitration by independently appointed arbitrators.

The Electricity Supply Association has been developing an Industry Ombudsman scheme which the incumbent distributors have agreed to join. It is expected that many of the disputes handled by the Ombudsman will be regarding capital contributions. By agreeing to join the scheme, industry members agree to be bound by the Ombudsman's decisions. However,

[^39]under the Regulation, customers are free to pursue other alternative dispute resolution procedures or arbitration.

Where a dispute arises in respect of a decision by an electricity distributor as to a charge payable under a standard form customer connection contract, the customer may appeal against that decision under the provisions of the ESA ${ }^{21}$.

### 2.4 Enforcement

IPART has no direct enforcement powers in relation to its decisions as to pricing or determinations of wholesale market access disputes. However, breach of pricing determinations may amount to a breach of the New South Wales State Code, which would be a breach of the network operator's authorisation, for which sanctions can be imposed by the Minister (including revocation of the authorisation). Also, IPART determinations as to wholesale market access disputes under Part 8A of the New South Wales State Code may, with leave of the Supreme Court, be enforced in the same manner and to the same effect as a judgment of the Court.

At the retail market level, as noted above, standard form contracts for connection and supply of electricity must comply with relevant IPART pricing determinations.

## 3. TRANSITION TO THE NATIONAL MARKET

This section outlines the main changes which will occur in the move from the current New South Wales access arrangements, to that which will exist once the national market is operational.

### 3.1 Entry to the market

### 3.1.1 Wholesale market

Upon commencement of the National Market the New South Wales Minister for Energy will cease to have responsibility for granting authorisations to wholesale electricity market participants in relation to wholesale trading and network services ${ }^{22}$.

In place of authorisations granted by the New South Wales Minister for Energy, participants in the national wholesale and electricity market will be required to register with NEMMCO. The registration provisions are contained in Chapter 2 of the National Code. Amongst other things wholesale market participants will be obliged to comply with applicable prudential requirements and technical standards.

[^40]
### 3.1.2 Retail market

The New South Wales Minister for Energy will continue to have responsibility for granting distribution and retail licences, according to the same criteria. The Minister will also continue to regulate adherence to licence conditions, and exercise sanctions where those conditions are breached.

In the longer term, New South Wales sees benefit in further harmonisation of the retail markets in each State, including the move towards consistent licensing and other provisions of a regulatory nature.

### 3.2 Terms and conditions of access

### 3.2.1 Connection and use of system

When the National Code is introduced, the connection to the network of certain New South Wales customers will be governed by Chapter 5 of the National Code, whilst others will remain regulated by the New South Wales access arrangements described in section 2 above.

Those New South Wales customers that will be governed by Chapter 5 of the National Code will be customers who register as such with NEMMCO, namely:

- holders of retail suppliers licences in New South Wales ${ }^{23}$;
- those customers in New South Wales who are allowed by the New South Wales Minister for Energy to choose their supplier of electricity (ie non-franchise customers) who either buy their electricity through the spot market or who do not purchase their electricity through the spot market but who nevertheless elect to be registered as a customer under the National Code.

All other customers in New South Wales will remain regulated by the New South Wales retail market access arrangements in terms of connection to the network and supply of electricity in the manner described in section 2.2 above. Those customers will be:

- all customers who are not entitled to choose their supplier of electricity (ie franchise customers);
- any non-franchise customers who either do not buy their electricity through the spot market or who elect not to be registered as customers in the national market.


### 3.2.2 Network pricing principles

Responsibility for transmission pricing will be transferred to the ACCC from 1 July 1999. The principles under which the ACCC will regulate prices are outlined in Chapter 6 of the National Code, and will be further articulated in the regulatory statement to be developed by the ACCC. These principles coincide, in the main, with the principles by which IPART currently regulates transmission pricing. Significant differences include:

[^41]- IPART has to consider environmental matters;
- IPART has to consider the social impact of its determinations, which are not explicitly referred to in Chapter 6 (though Chapter 6 does refer to the adaptive capacities of stakeholders, and also to the pricing policies of governments);
- in valuing new investment, Chapter 6 requires the ACCC to have regard to the decision of COAG which preferred a deprival value approach, whereas IPART currently has more flexibility in determining asset values for regulatory purposes;

New South Wales has until 1 January 2001 derogated from the National Code in regard to distribution pricing. The reasons for this derogation are detailed in Chapter 7 of the Submission. New South Wales anticipates that the review of Parts D and E of Chapter of the Code, which is to be conducted by NECA, may provide a basis for New South Wales to further limit the period for which derogation is necessary.

### 3.2.3. Metering

The metering requirements in the New South Wales State Code closely reflect those contained in the National Code. However, as noted in section 2.2 .3 above, New South Wales is currently reviewing this part of the State Code, to allow more flexible market-based metering solutions. The review group will be established by New South Wales and will include representatives from other jurisdictions. It is anticipated that the recommendations of this group would be used to consider changes to the National Code, as well as the State Code. Therefore it is expected that New South Wales metering requirements will be consistent with those in place in the national market.

## $3.3 \quad$ Resolution of disputes

Until 1 July 1999 any disputes as to access to transmission network services between persons registered with NEMMCO will be dealt with by IPART (see section 2.3.1 above). Following 1 July 1999 disputes regarding access to transmission network services will be determined in accordance with the dispute resolution procedures set out in section 8.2 of Chapter 8 of the National Code. ${ }^{24}$

In relation to access disputes regarding distribution network services, New South Wales has derogated from the National Code such that for distribution access disputes between persons registered with NEMMCO arising on or before 31 December 2000, Part 4A of the IPART Act will apply, and thereafter the provisions of Chapter 8 of the National Code will apply with IPART acting as the dispute adviser and dispute resolution panel. ${ }^{25}$

This position has been taken in view of the fact that distribution pricing will remain regulated by IPART indefinitely (see sections 3.2.2 and 2.2.2 above). Again, however, New South

[^42]Wales is confident that once Parts D and E of Chapter 6 of the National Code are reviewed, there will be a basis for New South Wales to limit the period for which distribution access disputes are dealt with by IPART.

### 3.4 Enforcement

Network service providers that are registered by NEMMCO ${ }^{26}$ are obliged to comply with the access rules set out in the National Code, particularly those contained in Chapters 5, 6, 7 and 8. If a registered network service provider fails to comply with relevant requirements set out in the National Code, NECA may institute proceedings against the network service provider, and, amongst other things the network service provider can be ordered to take certain actions so as to comply with relevant Code requirements ${ }^{27}$.

It is also relevant to note that customers seeking to gain access to the network and related services can enforce their rights under the National Code by becoming registered as "intending customers". As intending customers they are entitled to all of the relevant rights of code participants, including the right to have any dispute dealt with in accordance with the dispute resolution procedures set out in section 8.2 of Chapter 8 of the National Code.

As to customers who are not bound by the National Code they will be entitled to obtain access and to enforce their rights in accordance with the New South Wales retail market access arrangements described in sections 2.2-2.4 above.

[^43]
## ATTACHMENT 1: TIMETABLE FOR THE INTRODUCTION OF RETALL COMPETITION IN NEW SOUTH WALES

| Site <br> threshold | Approximat <br> e annual <br> power bill | Date of <br> eligibility | Date for <br> Mandated <br> Eligibility* | Number <br> of eligible <br> sites | Examples |
| :---: | :---: | :---: | :---: | :---: | :--- |
| $>40 \mathrm{GWh}$ pa | $>\$ 2,000,000$ | 1 October | 1 October 1997 | 47 | Large metropolitan hospital <br> heavy <br> manufacturing plant |
| $>4 \mathrm{GWh}$ pa | $>\$ 250,000$ | 1 April 1997 | 1 October 1997 | 660 | Multi-storey office block <br> Food processing plant |
| $>750 \mathrm{MWh} \mathrm{pa}$ | $>\$ 75,000$ | 1 July 1997 | 1 July 1998 | 3,500 | Supermarket <br> Engineering workshop |
| $>160 \mathrm{MWh}$ pa | $>\$ 16,000$ | 1 July 1998 | 1 July 1999 | 10,800 | Fast food restaurant <br> Bakery |
| $<160 \mathrm{MWh}$ pa | $<\$ 16,000$ | 1 July 1999 | 1 July 2000 | $2,700,000$ | All other New South Wales <br> based customers |

* If the customer has not previously elected to become non-franchise, on the specified date the customer will automatically become non-franchise.


## ATTACHMENT 2: FUNCTIONS AND POWERS OF IPART

## Price determination

The Act requires IPART to consider a range of matters in making a price determination, including:

- the cost of providing the services;
- the protection of consumers from abuses of monopoly services in terms of prices, pricing policies and standard of services;
- the appropriate rate of return, including appropriate payment of dividends;
- the effect of general price inflation;
- the need for greater efficiency;
- the need to maintain ecologically sustainable development;
- the impact on pricing policies of borrowing, capital and dividend requirements, in particular, the impact of any need to renew or increase relevant assets;
- the need to promote competition in the supply of services concerned;
- considerations of demand management and least cost planning;
- the social impact of determinations; and
- standards of quality, reliability and safety of services.


## Arbitration of disputes

Where a dispute arises in relation to a "public infrastructure access regime" and that regime provides for the application of a Part 4A of the Independent Pricing and Regulatory Tribunal Act 1992 ("IPART Act"), as the New South Wales wholesale market access regime does in division 8A of the New South Wales State Code, the following rights and obligations arise:

- any party to the dispute may refer the dispute to arbitration, in which case the Commercial Arbitration Act 1984 applies to any such arbitration subject to the provisions of Part 4A of the IPART Act;
- a dispute is taken to exist in relation to such an access regime of a person (the third party) who wants access to a service, or wants a change to some aspect of the person's existing service under the access regime, is unable to agree with the service provider on one or more aspects of access;
- the arbitration provisions for access disputes under Part 4A only apply in relation to services that are owned, controlled or operated by a government agency;

IPART may act as arbitrator or may appoint someone to act as an arbitrator to hear and determine disputes;

- the parties to an arbitration are required to give effect to the arbitration determination.
- New South Wales will be reviewing the IPART Act to determine whether any changes are necessary in order for IPART to fulfil the pricing and access dispute roles that will apply as part of the National Market access arrangements.


## SA ELECTRICITY INDUSTRY AND ACCESS REGIME

## 1 ACCESS PRINCIPLES

This section 1 outlines the present South Australian electricity industry arrangements relating to access to the services provided by the South Australian transmission and distribution network and the changes that will occur as South Australia prepares for the commencement of the National Electricity Market. An outline of the present South Australian electricity supply industry arrangements (other than those specifically relating to access to the South Australian network) is set out in Schedule 3.

### 1.1 Contestability

The South Australian Government is committed to promoting competition where possible and ensuring that there is appropriate regulation of monopoly activity.

### 1.2 Current arrangements

Transmission and distribution services are, to a large extent, natural monopolies in South Australia. ETSA Transmission Corporation and ETSA Power Corporation currently own all transmission networks and most distribution networks in South Australia (ie some remote off grid distribution networks are owned by other entities). Therefore a customer or generator wishing to connect to that network must enter into negotiations with ETSA Power Corporation and/or ETSA Transmission Corporation (whichever organisation is the owner and operator of the relevant portion of the network).

The terms of any arrangement to connect to the network negotiated with ETSA Power Corporation and/or ETSA Transmission Corporation would address the arrangements relating to connection to, and the cost of using, the relevant networks. Consideration would also need to be given to determining the arrangement for inputting electricity into the network and taking it out at the relevant connection point together with suitable provisions for dealing with losses, mismatches between instantaneous entry and exit quantities and ensuring that system security, quality of supply and minimum technical and safety standards are maintained.

The price for connection to the network (including any necessary network augmentation) would be fixed with a reference to, amongst other matters, the relevant capital costs, projected revenue and any capital contribution from the customer or generator.

## 2 Current reforms

This section 2 outlines changes to the South Australian electricity supply industry arrangements which will take place in the period leading up to the commencement of the National Electricity Market in South Australia.

### 2.1 Regulatory framework

South Australia has prepared new legislation (known as the Electricity Act) to establish the regulatory framework for the electricity supply industry in South Australia. As noted in Schedule 3, this legislation is designed to complement (and not duplicate) the regulatory arrangements contained in the Code and the National Electricity (South Australia) Act 1996. The Electricity Act is currently being debated by the South Australian Parliament and is expected to commence operation on 1 January 1997.

### 2.2 Licences

Under the Electricity Act, a person will be prohibited from carrying on various categories of operations in the South Australian electricity supply industry unless that person is licensed to carry on those operations. Currently, the following operations will require a licence:

- generation of electricity;
- operation of a transmission or distribution network; or
- retailing of electricity.

Provision has been made for future regulations to prescribe other operations requiring a licence. The Technical Regulator appointed under the provisions of the Electricity Act will be responsible for processing and issuing licences and determining the conditions to be imposed upon electricity entities under their licences.

At this stage, no regulations or draft licence conditions have been prepared. However, these conditions are likely to include a requirement to comply with specified standards, codes or other safety or technical requirements. In particular, the Electricity Act envisages that the Technical Regulator may make a licence, authorising an electricity entity to operate a transmission or distribution network, subject to conditions requiring:

- the electricity entity to allow other electricity entities, as far as technically feasible, access to the network, on fair commercial terms, for the transmission or distribution of electricity;
- the electricity entity to allow, as far as technically feasible, access to the network, on fair commercial terms, to all electricity entities and customers of a class specified in the condition who want to obtain electricity from the network;
- the electricity entity to provide network services on fair commercial terms;
- a specified process to be followed to resolve disputes between an electricity entity and another electricity entity or a customer as to the provisions of such access or services or the terms on which such access or services should be provided; and
- the electricity entity to inform persons seeking or in receipt of network services of the term on which the services are provided (including the charges for the services) and of any changes in those terms.

The provision for an exclusive right to sell and supply electricity to non-contestable customers within a specified area has been included to permit one or more franchise areas to be prescribed
for the purposes of the transitional pathway to full contestability. Other than this, the Electricity Act does not seek to erect barriers to entry beyond the Code requirements.

At this stage, it is not intended to introduce an interim access regime in South Australia pending the commencement of the National Electricity Market. Considerations are continuing as to the additional South Australian access requirements needed to deal with those portions of the network and those aspects of the services provided by the network which are not covered by the provisions of the Code. A final decision concerning these matters is likely to be made during the first half of 1997.

### 2.3 Dispute handling

The Electricity Act gives the Technical Regulator the power to mediate any disputes concerning the activities of electricity entities. The Technical Regulator is not required to mediate a dispute but if it does decide to become involved in the mediation of a dispute, it is required to make a reasonable attempt to negotiate a settlement. The provisions relating to the resolution of disputes in the Electricity Act are specifically expressed not to be an exclusive method of dispute resolution.

It is envisaged that more detailed provisions relating to the resolution of access disputes will be included in any future South Australian access regime covering access to network services not covered by the Code. In this regard, it is currently proposed that it will be a condition of the grant of licences to particular entities that they demonstrate they have adequate internal dispute handling mechanisms.

### 2.4 Pricing and contestability

South Australia is committed to opening up the market for the supply of electricity to customers with a maximum demand at a single location of 5 MW or greater, upon commencement of the National Electricity Market in South Australia. These customers will be free to choose their supplier of electricity, or buy their electricity directly through the wholesale electricity market. Eligible customers will also be free to ask their retailer of choice, to negotiate on that customers behalf, its terms and conditions of access to the South Australian network.

The South Australian Government is committed to reducing the eligibility limit down to an agreed technical and economic limit by 1 July 2001. It is expected that the South Australian Government will announce its timetable for reduction of the eligibility limits early in 1997.

## 3 Transition to the National Electricity Market

This section outlines the main changes which will occur once South Australia joins the National Electricity Market and moves towards a fully competitive market.

### 3.1 Entry to the market

Participants in the National Electricity Market will be required to register with NEMMCO. The registration provisions are contained in Chapter 2 of the National Electricity Code. Amongst other things, wholesale market participants will be obliged to comply with applicable prudential requirements and technical standards. South Australian customers will progressively become eligible to participate directly in the wholesale market or to choose a retailer other than ETSA Power Corporation in accordance with the timetable noted above.

The Technical Regulator to be established in South Australia will continue to have responsibility for granting licences and regulating adherence to licence conditions, (including in relation to distribution and retailing of electricity), and exercise sanctions where those conditions are breached.

### 3.2 Terms and conditions of access

### 3.2.1 Connection and use of system

When the Code comes into force in South Australia, connection to the network will be governed by Chapter 5 of the Code.

Those South Australian customers covered by Chapter 5 of the National Code will be customers who register as such with NEMMCO, namely:

- holders of retail licences in South Australia; and
- those customers in South Australia who are allowed by the regulations under the Electricity Act to choose their supplier of electricity (ie: non-franchise customers) and who either buy their electricity through the spot market or who do not purchase their electricity through the spot market but who nevertheless elect to be registered as a customer under the National Code. ${ }^{1}$

All other customers in South Australia will remain under the regulated arrangements described in section 2 above in terms of connection to the South Australian network and the use of the network. Those customers who will remain regulated by such arrangements will be:

- all customers who are not eligible to choose their supplier of electricity (ie: franchise customers); and
- any non-franchise customers who either do not buy their electricity through the spot market or who elect not to be registered as customers in the National Electricity Market.


### 3.2.2 Network pricing principles

Responsibility for transmission pricing will be transferred to the ACCC after 31 December 2000. Distribution pricing will remain a responsibility for the SA jurisdictional regulator up to and beyond 31 December 2000 as contemplated by Chapter 6 of the Code. The principles under which the ACCC will regulate prices are outlined in Chapter 6 of the Code, and may be further articulated in the regulatory statement to be developed by the ACCC. Prior to 31 December 2000 the South Australian jurisdictional regulator will be responsible for fixing transmission network charges in accordance with principles which will broadly reflect the

[^44]principles under the Code. Further details concerning the transitional pricing arrangements for transmission and distribution pricing are set out in the commentary on South Australia's derogations in Chapter 7 of the submission.
3.3 Access disputes

When the National Electricity Code comes into force in South Australia, the dispute resolution procedures in Chapter 8 will apply to access disputes between Code Participants and NECA will manage the process. Access disputes between non-Code Participants relating to matters not addressed in the Code will be dealt with in accordance with the procedures established under the Electricity Act from time to time.

## QUEENSLAND ACCESS REGIME

As noted in Schedule 3 of this Application, access to Queensland's electricity grid is governed by the Queensland Grid Code which is based on the principles expected to be adopted in the National Electricity Code.

The Queensland Electricity Transmission Corporation (Powerlink Queensland) manages and administers the Queensland Electricity Market and separately operates the transmission wires business.

The Electricity Act 1994 provides that transmission and distribution network owners must provide access to their networks on non-discriminatory terms. The process for gaining access to the transmission networks is specified in the Queensland Grid Code, which drew heavily on drafts of Chapter 5 of the National Electricity Code.

Under the Electricity Act, a person may not connect generation to the system, or operate a transmission grid, without the appropriate authority under that Act. Any person, public or private, may apply for such an authority. Criteria for consideration of such applications are set out in that Act but are mainly limited to the suitability and ability of the person to carry out the function. They explicitly exclude any consideration of the existing share of the electricity market or the number of authorities in force. In the case of transmission authorities, the regulator may consider the existing capacity of transmission grids in deciding whether to issue an authority.

Under the Electricity Act, network service prices are to be set by providers on a commercial basis but the Minister for Mines and Energy has power to intervene to fix prices where he or she considers it necessary in the public interest. The determination of transmission service prices is covered by provisions of the Queensland Grid Code.

## ACT ACCESS REGIME

As noted in Schedule 3 to this Application, there is no legislation setting up access regimes or dealing with access disputes at this stage. There is no generation capacity in the ACT and there is only one distributor/retailer in the ACT (i.e. ACTEW Corporation Ltd) although ACTEW Corporation Ltd is not granted monopoly status under any legislation.

Regulation of that distributor/retailer is achieved under various pieces of ACT legislation.

SCHEDULE 12

## NATIONAL ELECTRICITY CODE -POTENTIALLY ANTI-COMPETITIVE PROVISIONS

## Glossary

Means an anti-competitive contract, arrangement or understanding, being one that has the purpose, or would have or be likely to have the effect, of substantially lessening competition within the meaning of section 45 of the Trade Practices Act.

Means price fixing within the meaning of section 45A of the Trade Practices Act, being a contract, arrangement or understanding which has the purpose, or would have or be likely to have the effect, of fixing, controlling or maintaining the price for goods or services supplied or acquired by the parties to the contract, arrangement or understanding where those parties are competitors.

Means exclusive dealing within the meaning of section 47 of the Trade Practices Act, being conduct such as:

- acquiring goods or services on the condition that the supplier will not supply goods or services to particular persons or classes of persons;
- supplying goods or services on the condition that the acquirer will not acquire goods or services from particular persons or classes of persons; or
- supplying goods or services on the condition that the person supplied will acquire goods or services of a particular kind or description directly or indirectly from another person (third line forcing).

Means an "exclusionary provision" within the meaning of sections 4D and 45 of the Trade Practices Act, being a contract, arrangement or understanding or a proposed contract, arrangement or understanding between 2 or more competitors which has the purpose of preventing, restricting or limiting the supply of goods or services to, or the acquisition of goods or services from particular persons or classes of persons by all or some of the parties to the contract, arrangement or understanding or proposed contract, arrangement or understanding.

[^45]
## Code <br> Comments/description

Category
Reference

## Chapter 2

2.2.1

It is compulsory to register generators (subject to NEMMCO exemption) who can then participate in the wholesale market but only with other market participants.
2.2.2 Scheduled generators are required to operate certain generating units (scheculed generating units) in accordance with the spot market rules. Accordingly all electricity generated by such units must be sold into the spot market and thus bought only by market participants.
2.2.3 Some non-scheduled generators may be required to comply with certain code provisions specified by NEMMCO (eg: they may be required to sell some of their electricity only on the spot market).
2.2.4(c) \& (d) Market generators must sell (and purchase) all electricity through the spot market and accept (or make) payments at the spot price.

Non-market generators are not entitled in most cases to participate in or receive payments through the spot market.

Only registered Market Participants can directly purchase electricity from the market at a connection point, and, in addition, that connection point is classified as one of that person's market connection points.
2.3.2(c), 2.3.3(c) \& 2.3.5(c)
2.3.4(c)
2.3.4(e)

First tier and second tier customers may not participate in the spot market for any first tier load or second tier load respectively and intending customers may not so participate in relation to intending loads.

It is compulsory for market customers to buy all electricity through the spot market and pay the spot price.

Market participants can only have a market load (and

AC, ED \& EP

AC, ED \& EP PF

AC, ED \& EP
AC, ED \& EP

AC, ED \& EP

AC, ED \& EP

AC, ED \& EP PF

AC, ED \& EP

AC, ED \& EP thus participate in the spot market) if they provide certain data and meet certain technical requirements.
2.4

## Chapter 3

3.2. 3.6.3
3.6.5
3.7
3.8 \& 3.9
3.11
2.5.1(c), 2.5.2 Market participants may only participate in the markets and trading activities conducted by NEMMCO if they satisfy the relevant prudential requirements and other applicable obligations under the code.
2.10.1 The applications for registration in any category of code participant must be in the form prescribed by NEMMCO.
2.12 Code participants are required to pay various fees to NEMMCO and NECA

NEMMCO may trade in the inter-regional hedge exchange which it conducts.
3.3 Market participants are required to satisfy certain prudential requirements.
3.6.1, 3.6.2 \& These provisions require the calculation of inter-

All electricity supplied and used by Market Participants must be transacted through the spot market and the spot market price (or the excess generation rate) is to be paid/received in respect of such generation and usage.
Traders in the financial markets must be registered with NEMMCO otherwise they cannot trade in any form of financial instrument through the market. is to be distributed differently as between regulated and non-regulated Network Service Providers.

The publication of projected assessment of system adequacy (PASA) for release to market participants and to others on request.

Inter-regional hedges are originated and sold at a reserve price which minimises the difference between the sale price and payments to be made under the contract. Any

AC, ED \& EP

AC, ED \& EP

AC

AC, ED \& EP

AC \& PF

AC
AC \& EP
shortfall in revenue from the price paid for the contract is to be met from settlement surpluses.

| 3.11 .3 | NEMMCO may undertake secondary trading in the inter-regional hedge contracts including on any interregional hedge exchange which it conducts. | AC |
| :---: | :---: | :---: |
| 3.11.1(e) and (g) | NEMMCO may enter into contracts with Network Service Providers and ancillary service providers relating to interconnector capacity. Network Service Providers must negotiate such agreements in good faith. | AC |
| 3.11.3 | NEMMCO may undertake secondary trading in interregional hedge contracts, including on any inter-regional hedge exchange which it conducts. |  |
| 3.12 | Separate rules are specified for non-regulated interconnectors. | AC |
| 3.13.1 | Network service providers may be required to obtain ancillary services from code participants under connection agreements, in order to be able to obtain services from NEMMCO. | $\begin{aligned} & \text { AC, ED \& } \\ & \text { EP } \end{aligned}$ |
| 3.14 | NEMMCO must engage in reserve trading in certain circumstances. | AC |
| 3.15.4(p) and (q) | Each day, NEMMCO must publish details of final dispatch offers and dispatch bids, actual availabilities and dispatched levels of generating units and scheduled load. | AC |
| 3.16 | Force majeure and market suspension events are defined in which the market price is capped. NEMMCO has the power to suspend the market during force majeure events and set an administered price cap on prices during market suspension. | AC, PF |

## Chapter 4

| Chapter 4 | Chapter 4 contains provisions requiring NEMMCO to be <br> responsible for system security and frequency control. <br> Under Chapter 3, NEMMCO may recover the costs of <br> maintaining those standards from participants. | AC |
| :--- | :--- | :--- |
| Chapter 4 | Chapter 4 contains various technical standards regarding <br> power system operations. | AC |

Chapter 4 NEMMCO may direct certain participants to perform various actions. It is possible that participants will not be compensated for the costs of complying with NEMMCO directions.

4.3.4 Network service providers must assist NEMMCO in its
power system security responsibilities, which may result
in increased network costs.

$$
\begin{aligned}
& \text { 4.8.9 } \begin{array}{l}
\text { A region must provide interruptible load to a specified } \\
\text { level before a lower level of security for that region's } \\
\text { part of the power system may be accepted. }
\end{array} .
\end{aligned}
$$

## Chapter 5

Chapter 5

Chapter 5 contains various technical standards regarding connection to the network.
5.2.3 Network service providers are required to give access undertakings regardless of whether they supply monopoly services.
5.3.7 Connection Applicant can only connect to a Network Service Provider's network if it agrees to be bound by the relevant provisions of the Code.
5.5 Firm access compensation is only required under the Code to be available to and payable by generators, and not by other parties who use network services such as customers, other network service providers and interconnectors.
5.6.5(m) \& (o) NEMMCO can direct a Network Service Provider to arrange augmentation of their networks, and the cost of the relevant assets are to be included in the determination of the revenue cap in accordance with Part B of Chapter 6.
5.6.2(f) It appears that generation and demand side alternatives to network augmentation cannot be included in a network service provider's regulated revenue in the same way as network augmentation can.

## Chapter 6

Parts B, C, D \& These parts contain provisions for fixing and allocating E maximum charges for network services, including the formulation of guidelines for calculating such charges.

Parts B, C, D \& These parts contain provisions addressing connections E between generators and customers on the one hand and networks on the other and between transmission networks and distributions networks. However, similar provisions are not provided for connection of interconnectors to networks, transmission networks to other transmission networks and distribution networks to other distribution networks.

Parts B, C, D \& The revenue regulating regime set out in these parts E focuses on the case where the assets used to provide a particular network service are owned by the network service provider. There is no recognition that the network service provider can outsource the provision of certain services which it then on-supplies.

Part F
6.3.2

The pricing arrangements for non-regulated interconnectors are not set out in the Code. Before a non-regulated interconnector can begin operations, code rules will need to be developed and significant code changes made. By contrast, the pricing rules for existing interconnectors are fully specified.

This clause provides for the co-ordinated allocation of revenue requirements between more than one transmission network owner in a particular region.
6.6 Prudential requirements may be imposed by the transmission network service provider.
6.15 Prudential requirements may be imposed by the distribution network service provider.

## Chapter 7

7.1.4

Market participants must establish metering installations consistent with the standards set out in Chapter 7 at each of their market connection points before they will be permitted to participate in the market in respect of that connection point.
7.2.5(a) This clause makes it compulsory for responsible persons to ensure that revenue metering installations and check metering installations are provided and installed in accordance with, and to the standard set out in, Schedule 7.2.

Metering installations must contain certain components and satisfy various requirements.

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AC, ED \& EP
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AC, ED \& EP

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AC, ED \& EP
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7.3.1(d)
7.3.5

Schedule 7.4
Metering providers of certain categories must have various types of equipment and software.
8.7.2(d)

Metering installations cannot be used for purposes additional to the provision of metering data to NEMMCO where that use causes an infringement of the requirements of the Code.

Responsible persons are required to install communication links between each metering installation and the public telecommunication network.

The installation and maintenance of metering installations can only be carried out by metering providers, who must be registered with NECA in that capacity.

Metering data from connection points must comply with certain levels of accuracy and time limits.

Responsible persons must ensure that equipment in metering installations comply with certain inspection and testing requirements.

Metering providers must undergo a qualification process and be registered only for the type of work they are qualified to provide.
various types of equipment and software.

## Chapter 8

NECA is given the discretion to establish additional or more onerous reporting requirements and monitoring standards which do not apply to all code participants.

AC, ED \& EP

AC, ED \& EP

AC, ED \& EP

AC, ED \& EP

AC, ED \& EP

AC, ED \& EP

ED \& AC

AC, ED \& EP

## SCHEDULE 13

## TRANSGRID - MARKET DEVELOPMENT INFORMATION SYSTEMS GROUP

## ANALYSIS OF POOL PRICING

Phil Hayes<br>27 May 1996

## INTRODUCTION

This report investigates volatility in State Electricity Market pool prices which have been observed over recent times and explains the reasons for these large fluctuations.

## ANALYSIS

A single day (17th May 1996) was chosen for this analysis. The concerned phenomena can be seen when comparing pool price and Gross Demand Dispatch (GDD) in Figure 1 below:


As can be seen, there are certain periods where quite unusual results occur. In half-hour number 15 , the pool price drops significantly while the system demand is steadily rising. In half-hours 36 to 48 the price see-saws considerably, almost doubling from some half-hours to the next while the load is steadily running off. This analysis will concentrate on the period 18:00 to 24:00 on 17th May, as analysis for a full day would be quite onerous.

The first step is to examine the band stack. As each dispatchable entity can vary any one of three bands on a per half-hour basis, this can produce significant differences in the band stack from one half-hour to the next. For the purposes of brevity, this report will only examine the band stack for the Economic Dispatch run at 19:30, targeting 20:00 as an indicative result, which had a
significant price drop compared to the adjoining half - hours. The band stack (which also indicates the price sensitivity to demand) is shown in Figure 2 below:


As can be seen, there is a significant plateau around $\$ 15.00$, where the demand can vary between approximately 6000 MW and 7500 MW without any significant pool price fluctuations. It should be noted that the GDD at this particular time ( 7625 MW ) is almost directly on a knee-point in the band stack where the price begins to rise significantly with small positive changes in demand.
Figure 3 expands the band stack around the operating point at the 19:30 Economic Dispatch run:


Figure 3 concurs with the above conclusion, where in some instances an increase of just over 100 MW can triple the pool price. It is not unreasonable, therefore, for significant changes to occur in the pool price as demand varies. The pool price is a function of a bidding behaviour where there is a disproportionate spread of band capacity around $\$ 15.00$, a discontinuity in the band stack at approximately 7700 MW where the price doubles to $\$ 30.00$, and a pool price which is very sensitive to changes in demand thereafter. The graph indicates quite clearly that price is not a linear function of demand, so it is inappropriate to draw conclusions based upon demand trending as to where the pool price might move.

This in part explains why small changes in demand can result in volatile pool price outcomes, but does not satisfactorily explain the see-sawing in pool prices. Between 18:00 and 21:30, where there is an almost linear decrease in GDD, the pool price varies from $\$ 50.00$, to $\$ 15.00$, to $\$ 45.00$, to $\$ 15.00$ and so on in adjoining half-hours. To explain these variations, one needs to examine the capacity profiling across the period in question. In order to preserve participant confidentiality and improve readability, bands have been collated into $\$ 5.00$ increment groupings. Figure 4 below shows the how capacity in the band stack varies across the period 18:00 to 24:00 on 17th May 1996:


This graph indicates that band capacities are by no means static. In fact, they are quite dynamic, which means that it is possible that price can vary considerably as capacity becomes available in or withdrawn from cheaper bands. It is entirely reasonable that even given a flat demand across a whole day (constant GDD), price would vary considerably. This tends to indicate that not only is price very sensitive to demand at a certain knee-points and beyond in the band stack, but that these knee-points are also quite volatile and vary from one half-hour to the next. Figure 5 below expands the band summary around GDD for the period:


It becomes immediately apparent that although GDD is running off, so too is capacity being withdrawn from the lower priced bands. Note particularly that as the GDD is running off, capacity is being withdrawn at a different rate, sometimes forcing GDD to land in a more expensive band grouping. Each grouping that is crossed results in a $\$ 5.00$ change in pool prices. Thin areas indicate large discontinuities within the band stack. (Note that the $\$ 20.00-\$ 25.00$ to $\$ 35.00-$ $\$ 40.00$ groupings do not even exist until 19:30.) For the particular period in question, the kneepoint appears to follow the run-off in demand, thus explaining the see-sawing effect, depending on which side of the knee-point GDD is satisfied in each half-hour. This is consistent with the band stack/demand-price sensitivity analysis for the ED run targeting 20:00 in Figures 2 and 3.

## Conclusions

The above analysis has shown that the volatility of pool price observed in the State Electricity Market is primarily a function of participant bidding behaviour, resulting in dynamic band stacks that have very large regions where price does not vary with demand; followed by a knee-point in demand where price becomes extremely sensitive to changes in demand. The see-sawing effects in pool price that have been observed are due to the GDD following these knee-points as capacity is either withdrawn from generating plant or re-distributed from cheaper generation bands into higher priced generation bands.

## SCHEDULE 14

# ELECTRICITY MARKET TRANSPARENCY 

(A Report by St Clements Services for Victorian Power Exchange)

## 1

Introduction
This report has been produced by St Clements Services for Victorian Power Exchange. It provides both quantitative and qualitative analysis of how transparency increases market efficiency, primarily based on St Clements Services' experience of the England and Wales Electricity Market.

The report outlines the benefits of transparency, concluding that transparent markets operate more efficiently. The experience of the England and Wales Electricity Market suggests that transparency should be implemented during the initial development of an electricity market.

Within the England and Wales Electricity Market support for increased transparency has primarily come from retailers and the regulator. The regulator was concerned about National Power and PowerGen's large market share and their control over setting SMP. The retailers were not driven by a requirement for greater efficiency, but by a wish to improve on their status as ill-informed purchasers, thereby allowing more rational purchasing decisions. However, transparency has also delivered quantifiable benefits to retailers.

## 2 Market efficiency

The ideal of market efficiency leading to perfect competition, theoretically the most efficient of all market structures, is underpinned by many assumptions. Two of these assumptions are perfect knowledge and free flow of all information allowing agents within a market place to make fully rational decisions and no party within the market place being able to influence the market in any way. In real life this ideal is not attainable with different agents having access to different quantities of information.

The imbalance between the stocks of knowledge and access to information gives some agents an advantage over others. An increase in the stock of knowledge causes a more efficient allocation of resources even if it accrues to one agent more than another. The reason for this is by gaining more information the agent will be able to make a more informed decision, therefore signalling to all other agents the commercial benefit of the extra information.

A more transparent market would therefore lead to a more efficient allocation of resources. Therefore all agents are able to make more informed decisions thus reducing the implicit risk of this decision, which will inevitably lead to a more efficient outcome.

## 3 Benefits of market transparency

This section of the report details the benefits of transparency based on examples from the electricity industry of England and Wales.

### 3.1 Reduces market abuse

One defines market abuse or "gaming" as actions by market participants that maximise their profits by either exploiting a weakness in the rules or by certain anti-competitive behaviour. Since the creation of the England and Wales Electricity Market a number of instances of "gaming" have occurred. Some of these have been addressed by either one or a mixture of:

- regulatory intervention; and
- the market participants directly implementing changes to the trading arrangements.

In most cases the actual market abuse was detected by market players who were able to identify the abuser from the data available in the market.

An illustration of the beneficial effects of transparency in reducing market abuse is given by the case of under-generation in the England and Wales Electricity Market. Under the Market rules, the Units which under-generate receive a lost profit payment because the rules assume the Units are being constrained-off (i.e. not running at scheduled output when in merit - for which a payment is made) and at the same time other Units are paid to provide the shortfall in electricity required. The costs are bundled with many other (mainly transport related) costs into "uplift", which is paid by retailers. In effect the retailers are paying twice for this component of electricity which is clearly inefficient.

Following retailer concerns regarding the costs of under-generation there was an improvement, i.e. a reduction in the amount of under-generation. The retailers' concerns were based on the reporting of Generating Unit Instruction Following Error as a percentage of all generation which showed that on average Generating Units under-generate. The chart below plots monthly mean Generating Unit Instruction Following Error between from April 1993 and August 1996 and clearly demonstrates the improvements realised.

This improvement was supported by National Grid Company who, with retailer support, introduced a system that monitors Generating Units performance against instruction and uses commercial "embarrassment" via reporting of poor behaviour to deliver improvements. Additionally minor modifications were made to the market rules to remove certain inconsistencies. The main factor behind commercial "embarrassment" is that the reporting of poor behaviour increases the risk of further regulatory intervention.

Initially the reporting of Generating Unit Instruction Following Error only provided the mean errors across the entire system. This was enhanced by providing the mean errors for various grouping of generators, delivering further improvements as retailers voiced their concerns more rigorously. Although some under-generation will occur due to technical problems (with the individual Units concerned) some results from market abuse.

Based on the data available, we have quantified the saving retailers received though the reduction of Generating Unit Instruction Following Error. The analysis assumes that, without transparency, the level of under-generation during 1993/94 would have remained constant ( $-0.96 \%$ ) with retailers continuing to pay for shortfalls at this level. These cost savings are presented in the following table and clearly show the significant benefits of around $£ 51 \mathrm{~m}$ retailers have achieved. On balance, we feel that the calculation (explained in Appendix A) under-estimates both the actual cost of shortfalls and the savings achieved and therefore can be viewed as a lower bound estimate.

Percentage Unit Shortfall - April 1993 to August 1996


Shortfall Cost Estimates

| Financial Year | Without <br> Improvement <br> Shortfall Cost | Annual <br> Shortfall Cost | Delivered <br> Saving | Delivered <br> Saving |
| :--- | :---: | :---: | :---: | :---: |
| $1993 / 94$ | $£ 45.348 \mathrm{~m}$ | $£ 45.348 \mathrm{~m}$ | $£ 0.000 \mathrm{~m}$ | $0.00 \%$ |
| $1994 / 95$ | $£ 49.909 \mathrm{~m}$ | $£ 30.468 \mathrm{~m}$ | $£ 19.441 \mathrm{~m}$ | $38.95 \%$ |
| $1995 / 96$ | $£ 48.529 \mathrm{~m}$ | $£ 23.149 \mathrm{~m}$ | $£ 25.380 \mathrm{~m}$ | $52.30 \%$ |
| $1996 / 97$ (Apr to Aug) | $£ 17.5690$ | $£ 11.408 \mathrm{~m}$ | $£ 6.161 \mathrm{~m}$ | $35.07 \%$ |
| Totals (excl. 1993/94) | $£ 116.008 \mathrm{~m}$ | $£ 65.025 \mathrm{~m}$ | $£ 50.983 \mathrm{~m}$ | $43.95 \%$ |

Following continued retailer pressure for transparency, the regulator suggested that the market players close this loop-hole in the market rules and it is planned that these costs will be transferred to generators from 1 April 1997 onwards. It is likely that without the transparency of this problem, no cost savings would have been achieved. The retailers would have continued to pay twice for this component of electricity via uplift with the market continuing to operate inefficiently in this area.

### 3.2 Improves market comprehension

The England and Wales Electricity Market is extremely involved. On the day prior to trading around 300 Units make a daily price offer and minute by minute availability declarations. The
calculation of prices is very complex which makes comprehension of these calculations difficult for the well-informed players and almost impossible for some smaller players.

Since the inception of the England and Wales Electricity Market certain Generating Unit information was released. The information primarily relates to the price and availability of individual Units. Even with this information, retailers raised a number of concerns regarding the difficulty in comprehending Pool price calculation and the issue of transparency was debated at length.

The retailers' primary reason for requiring increased transparency of the market was their requirement to comprehend pool prices. During 1993, it was finally agreed to review "all data and information having a direct bearing on Pool Payments and Pool Prices". The process for deciding whether data should remain confidential was based on the assumption that all data should be released unless the "owner" (i.e. the party to whom the data relates) could present a valid case supporting confidentiality.

Finally, it was agreed to release a significant amount of Pool data to both market players and the general public. The comprehensive implementation of this agreement (reached during 1994) has not yet been delivered due to technical constraints which are discussed in section 4.

However, as an interim measure certain data has been released, notably the post-event identification of the marginal Unit (i.e. the Unit setting SMP). This proposal was agreed and implemented from 1 November 1995 onwards following the concerns by retailers over the delays in implementation.

During the debate on the release of this marginal Unit information, retailers stated the main driver was understanding price setting to enable forecasting. Quantification of the benefits from releasing information of this type, in terms of the impact on prices, is unachievable because there is a multitude of other interrelated factors, the effects of which cannot easily be separated.

In order to gauge the success of this initiative, we sought views on the benefits of releasing the marginal Unit data from around $20 \%$ of the market players in the England and Wales Electricity Market. Every player consulted indicated the marginal Unit information was of benefit in the understanding of pool prices for the reasons outlined below':

- Allows more comprehensive price analysis.
- Highlights areas for more detailed research.
- To some degree reduced the risks although this benefits not quantifiable in $£$ terms.
- Allows more rational behaviour by market players.
- Reveals the ability to set price of key market players.
- Gives an insight into how SMP is affected by GOAL (the scheduling software) by comparing SMP with the Units' incremental prices.
- In the longer term, allows new entrants to make more informed hence rational decisions and reduces barriers to entry.
- Useful for new generator entrants in their comprehension of the market.

[^46]- Aids the understanding of anomalous or unusual prices.
- Useful for both generators and retailers in understanding the operation of a complex competitive market.


### 3.3 Delivers self regulation

It is preferable for markets to be designed such that they do not require a large degree of regulatory control. This will reduce the uncertainty of regulatory intervention, thereby encouraging new entrants. These new entrants may otherwise be deterred by the perceived risks of regulation.

However, new entrants may be deterred by the risk that existing players collude. The risk of collusion in any market is real whether the market is transparent or opaque and is increased in an oligopoly. However, in a transparent market such collusion can be detected by both existing and new entrants who are able to highlight areas of collusion. Once highlighted, such behaviour can be addressed by the relevant authority.

## 4 Implementation experience

During the creation of the England and Wales Electricity Market, the issue of transparency was discussed at length, with all parties concerned that data release would reduce their competitive advantage. However it was agreed that the availability and price data for every Unit would be released along with a number of summary statistic to allow simple price validation and forecasting.

Initially, the software (known as the "Settlement System") used to calculate prices and payments was designed with a number of security measures to ensure these confidentiality agreements were respected.

During the next few years the Settlement System was, on an ad-hoc basis, amended by a number of software projects to deliver amendments to the trading rules. The system currently produces around 130 data files each containing a number of different data items.

Once the agreement to make most data available was reached, it was thought that implementation would be relatively straightforward. However, three major problems existed:

- the operator (and developer) of the Settlement System was unsure which data were in which reports;
- a number of new data files were needed, to release data only included in files with data remaining confidential; and
- the Settlement System design prevented the transmission of files currently classified as confidential to other players.

The first of these problems took a considerable amount of time to address but is now resolved. The second problem will shortly be addressed, as during October 1996 a few new reports will be made available. The third problem will be overcome by a new report transmission system which
is due to be implemented during February 1997. In total, this development funded by the market players will cost around $£ 1 \mathrm{~m}$.

Based on these experiences it seems prudent to implement systems able to provide transparency during the initial development stage rather than follow the evolutionary route take by the England and Wales Electricity Market.

## 5 Conclusion

Based on the quantitative and qualitative analysis on the England and Wales Electricity market, we conclude that transparency allows market players to improve market efficiency by:

- reducing market abuse;
- enhancing market comprehension; and
- delivering self regulation.

Such transparency should be implemented during the initial development of an electricity market to avoid extra trading costs.

## Costing of Under-Generation

This appendix explains how the estimate of cost savings for under-generation was produced. Exact calculation of this value is not possible given the limited data available; however the results are reasonable when compared against a Pool study which estimated that the overall cost of undergeneration during $1995 / 96$ was between $£ 30 \mathrm{~m}-50 \mathrm{~m}$. On balance, we feel that the calculation under-estimates both the actual cost of shortfalls and the savings achieved and therefore should be viewed as a lower bound estimate.

### 6.1 Materiality calculation

In broad terms this costing is based on both the payment for the replacement Unit and the "constrained-off" payment made to the short-falling Unit. If a Generating Unit under-generates, their shortfall has to be met by an alternative Generating Unit. For a Unit to pick up the additional load, it would need to have been part-loaded, or not generating. Generating Units that undergenerate will lose the payment for their shorffall at their metered price. The replacement Unit is paid for its generation at its metered price. The cost of the shortfall is therefore paid through the metered payment component of Uplift at the difference between the two metered prices e.g.:

## SHORT-FALLING UNIT

| Metered Price: | £20/MWh |
| :--- | :--- |
| Instructed Generation: | 500 MW |
| Actual Generation: | 490 MW |
| Shortfall: | 10 MW |

## REPLACEMENT UNIT

| Metered Price: | $£ 25 / \mathrm{MWh}$ |
| :--- | :--- |
| Instructed Generation: | 10 MW |
| Actual Generation: | 10 MW |

## COST OF SHORTFALL

$(25-20) £ / \mathrm{MWh} \times 10 \mathrm{MW}=£ 50$ per hour.
Any shortfall would be picked up on the marginal Unit running, the metered price of which can be approximated to using the sum of SMP and Uplift. The metered prices of the under-generating in merit Units can be approximated by their Bid Price.

The increased price for the generation called to make up the shortfall can then be approximated to as the average difference between SMP + Uplift and the bid prices below SMP. This average needs weighting to reflect how much generation each Unit would have been despatched for. As these Generating Units are in-merit, a suitable weighting is their availability.

The cost estimate was obtained as the product of the actual shortfall and the availability weighted average difference between (SMP + Uplift), and the bid prices of those Units with a lower Bid

Price. The actual shortfall is estimated using the mean shortfalls as reported to the Operations Group - a committee of the England and Wales Electricity Market and included the chart in section 3.1.

The saving to retailers have been estimated by costing the shortfalls on the basis that there was no reduction compared with 1993/94-the saving is then the difference between the real estimate and that assuming no improvement. The estimate of shortfall with no improvement used in the model is $-0.96 \%$ which is the cost weighted average shortfall during $1993 / 94$. A summary analysis is included in Section 3.1 and a more detailed breakdown provided in Appendix B.

The method of reporting shortfalls to the Operations Group has changed over recent years. Early reporting only recorded errors at demand peaks, when SMP is high and there is a large amount of generation in use, whilst subsequent reporting averaged errors over the entire day. We rationalised the information available to achieve a consistent data set.

### 6.2 Potential errors

The estimate is subject to a number of errors, which can not be resolved due to lack of data. Overall we feel that these errors do not undermine the results. These possible errors are separately discussed below.

## (a) Saving Calculation

During 1993/94 (the base year) retailers began to raise concerns over the costs of undergeneration thereby to some degree driving down the shortfall. Therefore the use of $0.96 \%$ as the level of shortfall with no improvement is an underestimate which will lead to significant under-estimates of the cost savings.
(b) Estimating Individual Units Instructed Generation

The estimate assumes a Unit's actual output, on the basis that all Units have a bid price less than SMP (i.e. in merit) are instructed to their full availability. There are a number of problems with this as follows:

- The Pool variable "Bid Price" (BPij) is a nominal price per MWh for each Unit, assuming that Unit generates at full load. As such, generators with a high last incremental may be very expensive at full load, but scheduled to generate at a lower load. This would not be detected, given an underestimate of the costs.
- The influence of constraints means that some such Units will be constrained off, with more expensive Units running. This would tend overestimate the costs.
- Generator dynamics can effectively constrain a Unit off (e.g. through very slow rates for changing load, or long notices to sync) which can not be accounted for.
- The use of Re-Declared Availability (XDij) to estimate each in-merit Unit's actual running probably overstates their running, as some Units will only have been part-loaded in the schedule (e.g. because of dynamic parameters and/or high incremental prices). This would give rise to an overestimate of the costs.
(c) Identifying Which Units are Short-falling

We assume all Units that are generating are short-falling at the average level for the relevant month. This is unlikely to be the case, with the actual amount of shortfall varying both by Unit and by time. Given the cost of a shortfall (difference between Bid Price and \{SMP + Uplift\}) the lack of this information can have a large effect on the estimate. The most expensive shortfall would be by cheap Units at a time when SMP + Uplift is high. However the errors are reported as an average over the entire day, which will lead to a substantial underestimate of the costs of generator shortfall.

The Metered Price of the shortfalling Unit has been approximated using the Pool variable "Bid Price". As previously discussed, where a Unit has a high incremental this will overstate its actual price; this will lead the model to underestimate the costs of shortfalls.

## (d) Estimating Costs of Replacement Units

We estimate the cost of the replacement generator at SMP + Uplift which gives two conflicting effects. Primarily we underestimate the costs of shortfall, as in many cases the Unit that is operationally at the margin will have been constrained on, and be costing more than SMP + Uplift. Occasionally we overestimate the costs of shortfall, as in some cases the Unit that is operationally at the margin will be in-merit and costing SMP. On balance the former effect overwhelms the latter to give an overall underestimate.
(e) Interaction with the Unconstrained Schedule

Where a Unit is scheduled in the Unconstrained Schedule and is then despatched to a level at or below that to which it was scheduled, any under-generation will be treated as if that Unit had been constrained off, i.e. the generator would be paid PPP - bid for the amount of shortfall.

With the model discussed in this paper, all the identified costs would be these constrained off type payments. As such, the estimate of the cost of constrained off payments due to generator shortfall is subject to the errors as discussed in Section 6.2.

Appendix B
Monthly Breakdown of Under-Generation Analysis

| Month and Year | Monthly Mean Shortfall | Without Improvement Shortfall Cost | Actual Shortfall Cost | Delivered Saving |
| :---: | :---: | :---: | :---: | :---: |
| April 1993 | 1.10\% | £4.105m | £4.696m | - $£ 0.591 \mathrm{~m}$ |
| May 1993 | 1.24\% | £3.676m | $£ 4.762 \mathrm{~m}$ | -f1.086m |
| June 1993 | 1.21\% | $£ 4.027 \mathrm{~m}$ | $£ 5.102 \mathrm{~m}$ | -£1.075m |
| July 1993 | 1.11\% | £4.005m | £4.620m | - $£ 0.615 \mathrm{~m}$ |
| August 1993 | 1.08\% | £3.755m | $£ 4.216 \mathrm{~m}$ | - $£ 0.461 \mathrm{~m}$ |
| September 1993 | 1.29\% | £3.645m | £4.896m | - $£ 1.251 \mathrm{~m}$ |
| October 1993 | 1.05\% | £4.052m | $£ 4.427 \mathrm{~m}$ | - $£ 0.376 \mathrm{~m}$ |
| November 1993 | 0.71\% | £4.032m | $£ 2.967 \mathrm{~m}$ | £1.064m |
| December 1993 | 0.56\% | £4.235m | £2.485m | £1.750m |
| January 1994 | 0.71\% | £4.195m | £3.087m | £1.107m |
| February 1994 | 0.77\% | £3.366m | $£ 2.693 \mathrm{~m}$ | £0.673m |
| March 1994 | 0.59\% | £2.257m | £1.397m | £0.861m |
| April 1994 | 0.26\% | £4.288m | £1.144m | £3.145m |
| May 1994 | 0.87\% | £3.464m | £3.137m | £0.327m |
| June 1994 | 1.16\% | £3.543m | £4.279m | -£0.735m |
| July 1994 | 0.90\% | £3.352m | £3.142m | £0.210m |
| August 1994 | 0.69\% | £3.031m | £2.167m | £0.864m |
| September 1994 | 0.97\% | £2.785m | £2.832m | - $£ 0.047 \mathrm{~m}$ |
| October 1994 | 0.50\% | $£ 4.787 \mathrm{~m}$ | $£ 2.510 \mathrm{~m}$ | £2.277m |
| November 1994 | 0.41\% | £6.191m | £2.656m | £3.535m |
| December 1994 | 0.30\% | $£ 6.571 \mathrm{~m}$ | £2.088m | £4.483m |
| January 1995 | 0.53\% | £8.029m | £4.439m | £3.591m |
| February 1995 | 0.44\% | £1.816m | £ 0.833 m | £0.983m |
| March 1995 | 0.58\% | £2.051m | $£ 1.241 \mathrm{~m}$ | £0.810m |
| April 1995 | 0.40\% | £3.292m | £1.373m | £1.918m |
| May 1995 | 0.37\% | £3.440m | £1.328m | £2.113m |
| June 1995 | 0.48\% | £3.237m | £1.621m | £1.616m |
| July 1995 | 0.62\% | £2.544m | £1.645m | £0.899m |
| August 1995 | 0.52\% | £2.990m | £1.622m | £1.368m |
| September 1995 | 0.43\% | £2.918m | $£ 1.309 \mathrm{~m}$ | $£ 1.609 \mathrm{~m}$ |
| October 1995 | 0.41\% | £3.073m | £1.314m | £1.759m |
| November 1995 | 0.36\% | £6.163m | £2.314m | £3.849m |
| December 1995 | 0.47\% | £6.801m | £3.334m | £3.467m |
| January 1996 | 0.50\% | £6.227m | £3.248m | £2.980m |
| February 1996 | 0.49\% | £4.672m | £2.388m | £2.284m |
| March 1996 | 0.50\% | £3.172m | £1.655m | £1.158m |
| April 1996 | 0.62\% | £4.280m | £2.768m | £1.512m |
| May 1996 | 0.64\% | £3.312m | £2.211m | £1.101m |
| June 1996 | 0.63\% | £3.583m | £2.355m | £1.229m |
| July 1996 | 0.64\% | £3.303m | £2.205m | £1.098m |
| August 1996 | 0.58\% | £3.090m | £1.870m | $£ 1.221 \mathrm{~m}$ |

# THE IMPORTANCE OF INFORMATION DISCLOSURE - THE NASDAQ CASE 

## 1 Purpose

The purpose of including this material in the submission is to demonstrate the practical importance of widespread disclosure of information about market operations and bidding in the process of keeping markets competitive. Wide disclosure of information to market participants serves not only to increase the opportunities that they have for informed and competitive involvement in the market concerned, but also the opportunity to observe the behaviour of other participants and conformity to the requirements of arms length competition.

## 2 NASDAQ

NASDAQ is one of the three major stockmarkets in the US, and is best known for its listings of speculative, technology and computer stocks. In the 1990s it has claimed success beyond these areas, and has been successful in attracting overseas companies from all economic sectors. Although the New York Stock Exchange has the largest companies listed, NASDAQ has nearly double the number of companies, with nearly $35 \%$ higher share turnover by volume ${ }^{1}$.

## 3 Background

Both the American Securities and Exchange Commission (SEC) and Justice Department concluded investigations of the NASDAQ market saying that brokerage firms had illegally conspired to keep profits high at the expense of customers.

The NASDAQ market grew out of the over-the-counter market 25 years ago, being initially dominated by smaller companies that did not qualify for listing on major stock exchanges. In 1982, NASDAQ began to look more like a major stockmarket by reporting actual trades, rather than only showing bid and asking prices, for its major companies. Ten years later it extended the practice to all of its stocks ${ }^{2}$.

Stock exchanges are auction markets, bringing together buy and sell orders from the public. By contrast, NASDAQ is a dealer market, in which dealers participate in every trade. In NASDAQ there are effectively two markets as far as public investors are concerned, one for buying and one for selling. The public paid the higher asking price when it bought, and received the lower bid price when it sold. Most investors would have found it impossible to "get inside the spread"".

[^47]There has been little incentive for dealers to reduce their spreads. Dealers in NASDAQ received orders from customers' brokers, and often paid a small rebate as a commission to brokers. A dealer would not necessarily acquire any more business by reducing the spread for a customer's broker. It was assumed that spreads did not narrow because the dealer market had insufficient incentives to reduce them.

## Discovery

In May, 1994 two academics - William Christie of Vanderbilt University, and Paul Schultz of Ohio State University - undertook a study which suggested that market makers (dealers) on NASDAQ were colluding to maintain artificially high spreads on the shares that they traded. Though not looking for fraud, the academics' study of price movements unearthed glaring price anomalies. The academics were using publicly available information about the market ${ }^{4}$.

As a result of this study, investigations were instituted by the Department of Justice and the SEC. The SEC estimated that investors in NASDAQ stocks had lost millions of dollars in recent years as a result of price fixings.
"SEC Chairman Mr Arthur Levitt Jr. said the commission had found a pattern of conduct in which brokers co-ordinated what they charged customers. 'Investors paid too much, and received too little, when they bought and sold stock on NASDAQ', he said. Mr Levitt said the anti-competitive practices, far from being a secret, were routinely taught to new traders and became part of expected behaviour. 'Where was the NASD [the National Association of Securities Dealers, the self-regulatory organisation that oversees the NASDAQ market], the cop on the NASDAQ beat?' he asked. 'The NASDAQ was not blind to these practices in the marketplace. It simply looked the other way'." ${ }^{\prime}$

## 5 Conclusions

The particular practices involved in the NASDAQ case involved behaviour that clearly infringed US competition law and the specific laws governing securities transactions. The importance of the case for present purposes is not that such behaviour occurred, or that self-regulation can fail because this can occur in any market under appropriate conditions - but that the public regulators, the SEC and the Department of Justice, were alerted to the behaviour through a study by academics.

Nobody in the market - participant or customer - alerted the government regulators. The academic research was able to make up for this lack of action elsewhere because of the amount of information about individual transactions that was in the public domain. Nowhere in the literature available to NECA or NEMMCO is there a reference suggesting that widespread information disclosure assisted in the prohibited forms of behaviour in the first place - although that may have been the case. The transgressing traders were much more blatant. Their behaviour was allegedly anti-competitive and illegal. It was not simply gaming. What is certain, however, is that the amount of information in the public domain, information available to all who were interested, helped to uncover the behaviour in the first place. Once the official government regulators were alerted, other and more damaging evidence of anti-competitive conduct came to light.

[^48]NECA and NEMMCO offer the NASDAQ case as evidence of the benefit of substantial disclosure of bidding and transaction information in detecting patterns of conduct that are inimical to competition, and of adding the resources of vigilant third parties in this regard to those of the regulator.

## METERING STANDARDS

## ACCURACY LEVELS FOR METERING INSTALLATIONS NATIONAL ELECTRICITY CODE

Please find attached two position papers which were prepared by members of the Metering SubGroup in early 1995 to address the question of accuracy of meters as set out in Schedule 7.2. These papers were discussed at the Metering Sub-Group meetings and the levels of accuracy as recorded in the Metering Chapter of the Code were approved by NGMC. A third paper (also attached) provides a discussion on the cost benefit of adopting the levels of accuracy as recommended by the Metering Sub-Group.

## Peter Egger

Convenor
Metering Sub-Group
30th September 1996.

POSITION PAPER
NATIONAL ELECTRICITY MARKET
CODE OF CONDUCT

21 February 1995

## METERING ACCURACY

The following information is provided for discussion by the Code of Conduct Working Group's Metering Sub-Group, at our 22 February meeting and should be read in conjunction with similar information prepared by South Australia and Queensland

Information on the Victorian position on metering accuracy requirements is provided below, together with a summary of U.K. requirements, followed by a summary of New Zealand requirements

VicPool Wholesale Metering Code accuracy requirements are based on :

- the NG Protocol requirement of $0.5 \%$, which should at least apply at EHV voltages;
- the cost of metering compared with the value of the energy being metered, leading to relaxed requirements at lower power/voltage levels; and
- comparison with UK practice

The decision to use voltage levels rather than real or apparent power was essentially to make it more definitive and avoid the situation where metering has to be upgraded just because the power level has risen above the threshold (possibly only slightly).

The UK levels are summarised as follows

| LEVEL | TRANSFORMERS |  | OVERALL |  |
| :--- | :--- | :--- | :--- | :--- |
|  | VT | CT | ENERGY | REACTIVE |
| above 100MVA | 0.2 | 0.2 | 0.5 | 4.0 (approx 800 GWh pa) |
| up to 100MVA | 0.5 | 0.2 | 1.0 | 4.0 |
| up to 10 MVA | 1.0 | 0.5 | 1.5 | 4.0 (approx 800 GWh pa) |
|  |  |  |  |  |

Note that the reactive metering was not intended for billing

The Victorian levels for new installations are summarised as follows:

| LEVEL | TRANSFORMERS |  | OVERALL |  |
| :--- | :--- | :--- | :--- | :--- |
|  | VT | CT | ENERGY | REACTIVE |
| 220 kV and <br> above | 0.2 | 0.2 | 0.5 | 1.0 |
| 66 kV | 0.5 | 0.5 | 1.0 | 2.0 |
| 22 kV | 1.0 | 1.0 | 2.0 | 4.0 |

When you consider that a 22 kV distribution circuit will have a rating of 8 to 12 MVA and a 66 kV subtransmission circuit will have a rating of 80 to 100 MVA , there is a high degree of consistency between UK and Victorian levels. Our old 22 kV subtransmission could carry up to 30 MVA, but only a couple of feeders would normally be above 10 MVA and this voltage would not be used for new stations. The differences are that the UK requirements for CTs are tighter (higher cost for little real benefit), UK use an accuracy of $1.5 \%$ where we use $2.0 \%$, and UK accuracy for reactive is relaxed at higher power levels because it is not used for billing

The Victorian levels could also be viewed as corresponding to transmission, subtransmission and distribution, but different voltage levels are used for different purposes depending on the size of the power system. Voltage correlates better with power levels than with network function.

Other states will need to see where 33 kV and $110 / 132 \mathrm{kV}$ levels fit in. In the UK, these would be in the "up to 100 MVA" and "above 100 MVA" categories respectively, whereas in Victoria they would be in the two lower categories. This is an area where there is no impact on Victoria.

New Zealand levels are summarised in the paper I circulated at the 8 February meeting by B J McGlinchy on Requirements For Metering In A Competitive Market as:

| ACTIVE (kV Arh) METERING | MAX. PERMITTED <br> \% ERROR |
| :--- | :--- |
| Installation with measurements greater than 10 GWh per annum | 0.5 |
| Installation with measurements greater than 0.5 GWh per annum but <br> less than 10 GWh per annum | 1.0 |
| Installation with measurements less than 0.5 GWh per annum | 2.0 |
| REACTIVE (kV Arh) METERING |  |
| Installation with measurements greater than 10 GWh per annum | 2.0 |
| Installation with measurements less than 10 GWh per annum | 3.0 |

(Submitted by M Robson, Manager Metering, VPX)

BULK SUPPLY METERING PRACTICES POSITION PAPER, 16th February, 1995

## South Australia

- Greater than 1.2 GWh pa but less than 12 GWh pa class 1.0 with no check metering.
- Greater than 12 GWh pa class 0.5 with revenue and check meters. Check meters of same accuracy as revenue meters.


## Pacific Power

$\left.\begin{array}{llll} & \text { GWhs } & \begin{array}{l}\text { \% accuracy } \\ \text { meter }\end{array} & \text { overall }\end{array}\right\}$

- Check metering is approximately twice the accuracy level of revenue meter and is generally installed at all locations.


## Victoria

| Connection at: | Class |
| :--- | :--- |
| $>66 \mathrm{kV}$ | class 0.5 |
| $>22 \mathrm{kV}$ but $<66 \mathrm{kV}$ | class 1.0 |
| $<22 \mathrm{kV}$ | class 2.0 |

## SEQEB

- For larger customers 100 GWhs pa class 0.5 CT and VT and class 1.0 meter calibrated to $<0.2 \%$. Overall system well within class 1.0
- Generally don't use check metering.


## Sydney Electricity

- $\quad>5 \mathrm{GWh}$ pa meters better than or equal to class 0.5 , overall accuracy $<1.0 \%$.
- Generally don't use check metering.


## New Zealand

$$
\begin{array}{ll}
>10 \mathrm{GWh} \text { pa } & 0.5 \% \text { max. allowable error } \\
>0.5 \mathrm{but}<10 \mathrm{GWh} \text { pa } & 1.0 \% \text { max. allowable error. } \\
<0.5 \mathrm{GWh} \text { pa } & 2.0 \% \text { max. allowable error. }
\end{array}
$$

Summary of requirements - National Electricity Market

| Consumption <br> (GWh pa) <br> per meter point | Approximate Load <br> (MW) at 60\% <br> Load Factor | Overall Accuracy | Check Metering - <br> see note (a) |
| :---: | :---: | :---: | :---: |
|  | 2 | $<2.0$ | optional |
| $<10$ | $2-20$ | 1.0 | optional |
| $10-100$ | $20-100$ | 1.0 | mandatory |
| $100-500$ | $100-300$ | 0.5 | mandatory |
| $500-1,500$ | $>300$ | $<0.5$ <br>  <br> equipment) | mandatory |
| $>1,500$ |  |  |  |

Note (a): The actual method for providing check metering is as agreed by the affected participants at the point of connection.

These requirements would apply only to new 'greenfield' installation.
Existing installations that at the time of construction complied with the appropriate Standards and Codes of Practice shall be deemed as satisfying the requirements of the Code.

This table was the basis of the final Tables included in the Metering Chapter of the Code. The volumes were simplified to three levels, viz: > 1,000 ; between 1,000 and 100 ; and $<100 \mathrm{GWh}$ pa. The overall accuracy level for $<100 \mathrm{GWh}$ pa loads was set at $1.5 \%$.
(This paper was submitted by G Rice, ETSA)

Peter Egger, Convenor, Metering Sub-Group

## ACCURACY LEVELS OF METERING EQUIPMENT COST BENEFIT ANALYSIS

(Submitted to Market Steering Committee on 8/4/95 and subsequently endorsed.)

## Summary:

The report recommends that:
i. the accuracy of metering installations be based on a range of maximum allowable errors varying from $\pm 0.5 \%$ for high loads to $\pm 1.5 \%$ for low loads.
ii. the transitional details be determined after a review of Reference Group responses.

## Introduction

The Metering Sub-Group was requested by the Market Steering Committee (14/3/95) to prepare a cost benefit analysis of the implications of imposing a level of accuracy equivalent to a maximum allowable error of $\pm 0.5 \%$ for revenue and check metering installations for all market participants. The report was to recommend whether transitional measures would be required for metering accuracy.

## Background

The level of accuracy applied to revenue and check metering installations at existing locations varies from state to state and across the range of volumes measured by the meter. Considering all locations, the maximum allowable error for both revenue and check metering installations is $\pm 0.5 \%$ and the minimum level is $\pm 2.0$.

Because of this variation, and because the size of the error varies with load, one view is to grade the level of error to the level of energy flowing through the meter, giving a range of errors between $\pm 0.5 \%$ and $\pm 1.5 \%$. An alternate view is to nominate one level of error ( $\pm 0.5 \%$ ) across the range of loads experienced by meter. The report compares the cost of these two views.

The determination of the error of a metering installation is complicated by several factors:

- The overall error consists of errors associated with four items of equipment: the current transformer; the voltage transformer, the associated wiring up to the meter panel; and the meter.
- Both CTs and VTs are given design or performance error ratings, called `Class’ ratings. A Class 0.2 CT would exhibit a range of errors according to the burden placed on the CT, the range not exceeding $\pm 0.2 \%$
- Thus the actual error of both the CT and VT will be dependant on the actual burden placed on the equipment. A VT will vary from a positive error at low burden to a negative error at high burden. A CT will exhibit a reverse pattern, with negative error at low burden and positive error at high burden.
- If the burden placed on the VT is around mid range, then the actual error of the VT will be close to $0 \%$. A similar situation would be experienced with the CT. Hence both devices could have actual measurement errors of close to zero. Because of
this, the Class rating of the equipment can not be used as the level of error of the measurement. It only has significance as a design or performance standard.
- The overall accuracy level is obtained as the vector sum of the errors of each of these four components, or alternatively as the scalar sum of the 'real-axis' errors.
- Since overall errors in accuracy can be positive or negative, it is unlikely that errors for each metering component will all be in the same direction. Statistically, the errors will trend toward a combined error of zero, rather than combine to the worst case scalar sum.
- For example, a CT with a Class error of $0.2 \%$, a VT with a Class error of $0.2 \%$, wiring with an error of $+0.05 \%$, and a $0.2 \%$ Class meter might have an actual overall error of $+0.25 \%$ (say). Or it could equally have an overall error of $-0.1 \%$. Both these values would meet the $\pm 0.5 \%$ overall requirement.
- For market participants who require several metering installations, and hence many components, there is a greater probability of a combined error of zero. Hence, a diminishing level of benefit will be gained from the use of more accurate metering components for such participants.
- The error of a CT normally applies to the lowest ratio available. If a higher ratio is used then a higher level of accuracy is usually achievable.
- The accuracy level will vary as the load through the CT varies. The value of $0.2 \%$ infers an average value across the range of loads experienced by the CT.
- The error also varies with power factor. It is usual to test at unity p.f, 0.87 lag and lead, 0.5 lag and lead.
- A revenue metering installation with $\pm 0.5 \%$ overall error may have a check metering installation with either $\pm 0.5 \%$ error, or some other level of error (e.g. $\pm 1.0 \%$ ).

The report considers two situations, greenfield installations and existing installations. Greenfield installations apply when a market participant establishes new metering points, requiring the purchase of new equipment. Existing installations apply to all organisations where equipment has been installed and is in service.

## Metering Accuracy - Practical considerations

The accuracy classes of electrical energy revenue metering equipment are arranged to correlate with the accuracies achievable for the various feasible methods of measurement. The term feasible is intended to encompass both the electrical engineering principles employed in the measurement and the economic justification for employing metering of a particular price range. Obviously, an organisation will not want to spend more money on metering than it can hope to recoup via the energy charges for that installation. It equally does not want to risk lost revenue or disputation with the customer by installing metering of coarse accuracy. The logical selection of metering accuracies is demonstrated by internationally accepted practices which have evolved over the past 80 years.

Direct connected meters possess the coarsest accuracy rating due to the difficulty in providing a measurement current circuit capable of handling up to 125 ampere per phase without producing appreciable heating effects and without having noticeable variation in performance due to magnetic interaction effects between the phase elements. The range of accuracy classes provided by direct connected meters is $\pm 1 \%$ to $\pm 2 \%$ and the price is modest.

Current transformers are employed to minimise, in an accurate and controlled fashion, the magnitude of the current which must be coupled to a meter for measurement purposes. This reduction in current virtually eliminates the heating effect, allows closer tolerance in meter construction and reduces the interaction effects. The range of accuracy classes provided by current transformer coupled meters is $\pm 0.2 \%$ to $\pm 2.0 \%$ with a concomitant spread in price ranging from expensive to modest.

Voltage and current transformers are employed for high voltage measurements to provide a safe, isolated environment with an accurately scaled version of the high voltage system available for connection to the meter. The benefits provided are similar to the considerations for current transformer coupled meters and the range of prices and accuracy classes provided are also similar at $\pm 0.2 \%$ to $\pm 2.0 \%$

Following from the considerations above, the most obvious reasons for employing different measurement methods, and hence different accuracy classes, are the step changes in circuit topography which are necessary for the practical transmission and distribution of electricity.

If we consider the energy levels which may be supported by the various circuit configurations employed in transmission and distribution of energy within Australia the breakpoints as listed in the Attachment 1 are established.

The expression "Practical accuracy" is intended to express the actual values of accuracy afforded by the relevant metering system. These values are typical of the accuracy's observed in field samples. Although the sample sizes for the highest accuracy classes are quite small the calibration validation process is undertaken regularly (electromechanical) and the meter error characteristic is adjusted to compensate for known errors of the measurement transformers.

The term accuracy is prone to ambiguous interpretation. The assertion that a class 1.0 meter generally exhibits errors close to $1.0 \%$ is erroneous. The class index relates to the largest error that the meter is allowed to display under conditions of extreme external influence. The typical class 1.0 meter displays errors of less than half the class index ( $< \pm 0.5 \%$ ) when operating under conditions that are within the designed "normal" ratings.

If we consider the components of the metering systems which contribute to inaccuracy it must be recognised that the meter is by far the most complex item and also the most uncertain. Measurement transformers are inherently stable (as evidenced by the recommended long periods between re-calibrations, 5 years for CTs and 10 years for VTs) and hence are the most reliable part of the system. The ratings of measurement transformers employed for Distribution System Customer metering in Australia have been rationalised for the past thirty years, via ESAA Committee recommendations, at accuracy class 0.5 . Only a few early installations still exist with class 1.0 measurement transformers.

The above statements may be placed into context by considering the relevant influence that each component has in the measurement system.

If we represent the probable distribution of errors that each component in the measurement system has and assess the accuracy benefit that can be obtained by reducing the class index of each component, the following conclusion may be reached:
"the component offering the greatest scope for increasing metering system accuracy is the meter".
It is noted that the Australian Standards call for $\pm 1.5 \%$ for electro-mechanical meters, and Class 1 (approx. 1.0\%) for electronic meters.

The suggestion that metering system accuracies should be tightened to $\pm 0.5 \%$ for all energy levels, regardless of the revenue earned at the metering point is neither economically viable nor technically feasible. The costs of measurement transformers with a class 0.2 index are virtually the same as for class 0.5 due to the increased accuracy being achieved by derating the compliance burden rating of the transformers. This approach may be unacceptable for some installations if wiring or device burdens cannot be similarly reduced. For single feeder supplies, the costs involved in lost production by the customer due to the necessity to isolate the customer from supply to allow replacement of measurement transformers and/or site test and re-rating of existing transformers could be extremely large. Validation of measurement transformer performance could conceivably be undertaken as a long term project if timed to coincide with planned customer outages.

The systematic assessment of commercially feasible metering elements that constitute the measurement aspect of metering systems, when overlaid onto the broad generic types of metering systems in use demonstrate unequivocally that improvement in meter performance offers the most cost effective and practical approach to improving metering system accuracy.

## Revenue Implications of Metering Errors

A positive overall error for a customer means that the metering installation is indicating a higher value of energy than actually occurring in the power conductor. This would imply that the market participant would be charged more for both energy and network services.

A positive overall error for a generator implies that the generator would be paid more for energy but charged more for network services.

Market participants who have more than one metering point, with each metering installation being set as close to zero as was possible, are likely to have a total error even closer to zero due to the statistical variations of each individual metering installation.

## Greenfield Installations

Manufacturers have indicated that there would be a $0 \%$ to $20 \%$ increment in plant costs in specifying an overall class error of $\pm 0.5 \%$, and that installation costs would not alter appreciably. Table 1 details the estimated incremental costs for installing new $\pm 0.5 \%$ versus $\pm 1.0 \%$ to $\pm 1.5 \%$ metering installations as detailed in Attachment 2.

| ORGANISATION | COST OF COMPLIANCE |  |  |  |  |  |
| :---: | :---: | :---: | :---: | :---: | :---: | :---: |
| $\begin{gathered} \hline \text { INCREMENTAL TO } \pm 0.5 \% \\ \text { ERROR ONLY } \\ \text { PER METERING POINT } \end{gathered}$ | $\begin{gathered} 500 \mathrm{kV} \\ \& \\ 330 \mathrm{kV} \end{gathered}$ | $\begin{gathered} 275 \mathrm{kV} \\ \& \\ 220 \mathrm{kV} \end{gathered}$ | $\begin{gathered} 132 \mathrm{kV} \\ \& \\ 110 \mathrm{kV} \end{gathered}$ | 66 kV | $\begin{gathered} 33 \mathrm{kV} \\ \& \\ 22 \mathrm{kV} \end{gathered}$ | 11 kV |
| NATIONAL AVERAGE \$ (1) | \$0 | \$0 | $\begin{aligned} & \$ 17,00 \\ & 0 \end{aligned}$ | \$10,000 | \$ 7,000 | \$6,500 |
| NATIONAL AVERAGE \% (2) | 0\% | 0\% | 11\% | 9\% | 9\% | 35\% |

TABLE 1
ESTIMATED INCREMENTAL COST TO $\pm 0.5 \%$ FOR GREENFIELD INSTALLATIONS
Notes: (1) At $500 / 330 \mathrm{kV}$ and $275 / 220 \mathrm{kV}$ all revenue metering points are designed to the $\pm 0.5 \%$ level. Hence the incremental cost is zero.
(2) The National Average $\%$ is based on the cost of providing the overall metering installation.

From Table 1 it can be observed that the effect on the market participant in improving the overall class error to $\pm 0.5 \%$ at voltage levels down to 22 kV would be in the order of an additional $10 \%$. At 11 kV this cost increases to an additional $35 \%$, which is considered substantial.

No benefits could be identified for improving the level of class accuracy of the individual components such that the overall maximum allowable error is $\pm 0.5 \%$ for all metering installations.

## Existing Installations

The cost of compliance with $\pm 0.5 \%$ overall error for organisations with existing sites has been estimated as shown in Table 2, along with the cost of compliance for the range $\pm 0.5 \%$ to $\pm 1.5 \%$. The costs are shown from the existing position. In general, the values shown assume a high reliance on applying calibration factors to compensate for existing CT and VT errors. If such compensation was not acceptable, then substantially higher costs would be shown in Table 2 as detailed in Attachment 3.

| ORGANISATION | COST OF COMPLIANCE |  |
| :--- | :---: | :---: |
| METERING | $0.5 \%$ ACCURACY | $0.5 \%$ to $1.5 \%$ ACCURACY |
| INSTALLATIONS FOR | REVENUE + CHECK | REVENUE + CHECK |
| LOADS $>10 \mathrm{MW}$ | $>10 \mathrm{MW}$ | $>10 \mathrm{MW}$ |
| NATIONAL TOTAL | $\$ 125 \mathrm{~m}$ | $\$ 20 \mathrm{~m}$ |

TABLE 2
ESTIMATED COST OF UPGRADING REVENUE METERING INSTALLATIONS >10MW

From Table 2, it can be seen for metering installations $>10 \mathrm{MW}$ that the cost of upgrading to $\pm 0.5 \%$ error for all energy levels would vary from state to state, and would impose an additional expenditure of approximately $\$ 125$ million nationally. Note that in the Victorian wholesale electricity market it is proposed to use compensation to achieve a metering installation accuracy of better than $\pm 0.5 \%$ where existing measurement transformers are of a lower accuracy class.

On the other hand, the cost of upgrading existing metering installations $>10 \mathrm{MW}$ to $\mathrm{a} \pm 0.5 \%$ to $\pm 1.5 \%$ accuracy range would impose a $\$ 20 \mathrm{~m}$ expenditure nationally, and this amount could be considered justified to ensure that new market participants were not discriminated against.

No benefits could be identified for improving the level of class accuracy of the individual components such that the overall maximum allowable error is $\pm 0.5 \%$ for all metering installations.

## Conclusion

On a national basis, the cost benefit analysis would have to assume that all metering installations on average approached the zero percentage error point, irrespective of the Class of CT and VT installed. Thus the cost of upgrading the class of equipment for existing metering installations could not be offset against the improved level of accuracy expected to be gained. For a similar reason, the cost of specifying a higher level accuracy metering installation for all greenfield sites could not be justified since this would severely affect the smaller customers. In their case, the incremental cost of the changed specification becomes more significant, with little to no opportunity to offset the cost against expenditure foregone.

It is to be noted that historical practice in Australia has arrived at an economic range of accuracy levels for metering installations, varying from $\pm 0.5 \%$ to $\pm 2.0 \%$. Although this range has been based on a combination of economic considerations and legislative requirements, it has also been based on burdens associated with electro-mechanical meters. With electronic meters, it is considered that a range of $\pm 0.5 \%$ to $\pm 1.5 \%$ is more relevant and economically feasible.

The error considered should only be the uncertainty of the measurement, not the know error which should be corrected. If it is known that a particular metering installation is reading $1 \%$ high, then payment should be based on $99 \%$ of the reading, adjusted either in the meter or in the database. The net effect of the uncertainties of the measurement should be determined on a statistical basis, not just added.

## Recommendations

Based on this initial cost benefit analysis, it is recommended that the level of accuracy of metering installations be based on maximum allowable errors ranging from $\pm 0.5 \%$ for higher loads ( $>1000$ GWh per annum) to $\pm 1.5 \%$ for lower loads ( $<100 \mathrm{GWh}$ per annum).

It is also recommended that the matters pertaining to Transitional details for existing sites be held over until responses from the Reference Group have been reviewed.
(Editor's Note: The transitional details for existing sites are in the Chapter 9 derogations.)

ATTACHMENT 1 - PRACTICAL ERRORS OF METERING INSTALLATIONS

| Circuit Configuration | Low Voltage <br> Distribution <br> 1 phase | Low Voltage <br> Distribution <br> 3 phase | Low Voltage <br> Distribution |
| :--- | :--- | :--- | :--- |
| Meter Configuration | Direct Connect | Direct Connect | Current <br> Transformer <br> Coupled |
| Voltage Levels | 240 V | $240 / 415 \mathrm{~V}$ | $240 / 415 \mathrm{~V}$ |
| Maximum <br> Power Levels | 15 kVA | 90 kVA | 2 MVA |
| Equivalent <br> Energy Levels | $5 \mathrm{MWh} / \mathrm{yr}$. | $250 \mathrm{MWh} / \mathrm{yr}$. | $10 \mathrm{GWh} / \mathrm{yr}$. |
| Best Feasible <br> Meter Class | $\pm 2 \%$ | $\pm 1 \%$ | $\pm 0.5 \%$ or $\pm 1.0 \%$ |
| Feasible CT Class | NA | NA | $\pm 0.5 \%$ |
| Feasible VT Class | NA | NA | NA |
| Calculated <br> Overall System <br> Accuracy <br> Note 1 | $\pm 2.0 \%$ | $\pm 1.0 \%$ | $+0.7 \%$ or $\pm 1.0 \%$ |
| Practical Overall <br> Accuracy | $\pm 1.0 \%$ | $\pm 0.5 \%$ | $\pm 0.5 \%$ or $\pm 0.6 \%$ |

Note1: Calculated using R.S.S. summation of contributing components and assuming the meter error characteristic is not compensated for the errors of measurement transformers.

| Circuit <br> Configuration | High Voltage <br> Distribution | High Voltage <br> Distribution | High Voltage <br> Distribution | EHV <br> Transmission |
| :--- | :--- | :--- | :--- | :--- |
| Meter <br> Configuration | Current and <br> Voltage <br> Transformer <br> Coupled | Current and <br> Voltage <br> Transformer <br> Coupled | Current and Voltage <br> Transformer Coupled | Current and <br> Voltage <br> Transformer <br> Coupled |
| Voltage Levels | 11 kV | 11 kV or 22 kV | 66 kV | 110 to 500 kV |
| Maximum <br> Power Levels | 10 MVA | 15 or 27 MVA | 20 to 200 MVA | 200 to 600 MVA |
| Equivalent <br> Energy Levels | 10 to 50 <br> GWh/yr. | 50 to $100 \mathrm{GWh} / \mathrm{yr}$. | 100 to $1000 \mathrm{GWh} / \mathrm{yr}$. | $>1000 \mathrm{GWh} / \mathrm{yr}$. |
| Best Feasible <br> Meter Class | $\pm 0.5 \%$ | $\pm 0.2 \%$ | $\pm 0.2 \%$ | $\pm 0.2$ |
| Feasible CT Class | $\pm 0.5 \%$ | $\pm 0.5 \%$ | $\pm 0.2 \%$ | $\pm 0.2$ |
| Feasible VT Class | $\pm .05 \%$ | $\pm 0.5 \%$ | $\pm 0.2 \%$ | $\pm 0.2$ |
| Calculated <br> Overall System <br> Accuracy <br> Note 2 | $\pm 1.0 \%$ | $\pm 0.7 \%$ | $\pm 0.35 \%$ | $+0.35 \%$ |
| Practical Overall <br> Accuracy | $\pm 0.5 \%$ | $\pm 0.4 \%$ | $\pm 0.3 \%$ |  |

Note 2: In fact the actual accuracies achievable for metering systems employing current AND voltage transformers, operating within a power factor range of 0.8 lead to 0.8 lag, will be significantly better than the basic calculation indicates. This is due to the inherent characteristic of uncompensated current transformers that produce current ratio errors with a slight negative bias while the inherent error of a lightly loaded voltage transformers is generally slightly positive. The net effect is a significant reduction in the combined ratio error of the measurement transformers.

## ATTACHMENT 2

NEW INSTALLATIONS

| Voltage Level (kV) | VT cost per phase | CT cont per phase | Total 3 <br> phase cost | Labour \& minc. material | Meter Costs meluding installation | $\begin{aligned} & \text { OVERALL } \\ & \text { COST } \\ & 0.5 \% \text { to } \\ & 1.0 \% \text { to } \\ & 1.5 \% \end{aligned}$ | OVERAL L COST FOR $0.5 \%$ ONLY | INCREMENTAL COST FOR 0.5\% ONLY |
| :---: | :---: | :---: | :---: | :---: | :---: | :---: | :---: | :---: |
| 275 | \$21,000 | \$30,000 | \$153,000 | \$62,000 | \$13,000 | \$228,000 | \$228,000 | \$0 |
| 132 | \$14,000 | \$16,000 | \$90,000 | \$51,000 | \$13,000 | \$140,500 | \$154,000 | \$13,500 |
| 66 | \$8,500 | \$11,000 | \$58,500 | \$41,000 | \$13,000 | \$103,700 | \$112,500 | \$8,800 |
| 33 | \$8,000 (3ph) | \$7,000 | \$29,000 | \$38,000 | \$13,000 | \$76,200 | \$ 80,600 | \$ 4,400 |

TABLE 2A - SA COSTS OF NEW 0.2 CLASS CTs AND VTs

| Voltage Level <br> (kV) | VT cost per <br> phase | CT cost per <br> phase | Total 3 <br> phase cost | Meters \& misc. <br> material | TOTAL <br> INCREMENTAL <br> COST TO 0.5\% |
| :--- | :--- | :--- | :--- | :--- | :--- |
| 66 | $\$ 3,000(3 \mathrm{ph})$ | $\$ 3,000(3 \mathrm{ph})$ | $\$ 6,000$ | $\$ 2,000$ | $\$ 88,000$ |
| 33 | $\$ 3,500(3 \mathrm{ph})$ | $\$ 4,000(3 \mathrm{ph})$ | $\$ 7,500$ | $\$ 2,000$ | $\$ 9,500$ |
| 11 | $\$ 1,500(3 \mathrm{ph})$ | $\$ 2,500(3 \mathrm{ph})$ | $\$ 4,000$ | $\$ 2,000$ | $\$ 6,000$ |

TABLE 2B - NSW COSTS OF NEW 0.2 CLASS CTs AND VTs (Distributor 1)

| Voltage Level <br> $\mathbf{( k V )}$ | VT cost per <br> phase | CT cost <br> per phase | Total 3 <br> phase cost | Other <br> Costs | TOTAL COST <br> CT/VT TO <br> $\mathbf{0 . 5 \%}$ |
| :--- | :--- | :--- | :--- | :--- | :--- |
| 132 | $\$ 12,500$ | $\$ 13,500$ | $\$ 78,000$ | $\$$ | $\$ 78,000$ |
| 66 | $\$ 8,500$ | $\$ 9,000$ | $\$ 52,500$ | $\$$ | $\$ 52,500$ |
| 33 | $\$ 8,550(3 \mathrm{ph})$ | $\$ 6,500$ | $\$ 28,050$ | $\$$ | $\$ 28,050$ |
| 11 | $\$ 5,500(3 \mathrm{ph})$ | $\$ 4,500$ | $\$ 19,000$ | $\$$ | $\$ 19,000$ |

TABLE 2C - NSW COSTS OF NEW 0.2 CLASS CTs AND VTs (Distributor 2)

| Voltage Level <br> (kV) | VT cost per <br> phase | CT cost <br> per phase | Total 3 <br> phase cost | Other <br> Costs | TOTAL <br> COST CT/VT <br> TO 1.0\% | INCREMENTAL <br> COST BETWEEN <br> 0.5\% \& 1.0\% |
| :--- | :--- | :--- | :--- | :--- | :--- | :--- |
| 132 | $\$ 12,000$ | $\$ 12,500$ | $\$ 73,500$ | $\$$ | $\$ 73,500$ | $\$ 5,500$ |
| 66 | $\$ 7,500$ | $\$ 9,000$ | $\$ 49,500$ | $\$$ | $\$ 49,500$ | $\$ 3,000$ |
| 33 | $\$ 8,000(3 \mathrm{ph})$ | $\$ 6,000$ | $\$ 26,000$ | $\$$ | $\$ 26,000$ | $\$ 2,050$ |
| 11 | $\$ 5,000(3 \mathrm{ph})$ | $\$ 4,000$ | $\$ 17,000$ | $\$$ | $\$ 17,000$ | $\$ 2,000$ |

TABLE 2D - NSW COSTS OF NEW 0.5 CLASS CTs AND VTs (Distributor 2)

| ORGANISATION | COST OF COMPLIANCE |  |  |  |  |  |
| :---: | :---: | :---: | :---: | :---: | :---: | :---: |
| INCREMENTAL TO 0.5\% ACCURACY ONLY PER METERING POINT | $\begin{gathered} \hline 500 \mathrm{kV} \\ \& \\ 330 \mathrm{kV} \end{gathered}$ | $\begin{gathered} 275 \mathrm{kV} \\ \& \\ 220 \mathrm{kV} \end{gathered}$ | $\begin{gathered} 132 \mathrm{kV} \\ \& \\ 110 \mathrm{kV} \end{gathered}$ | 66 kV | $\begin{gathered} 33 \mathrm{kV} \\ \& \\ 22 \mathrm{kV} \end{gathered}$ | 11kV |
| ETSA | na | \$0 | \$13,500 | \$8,800 | \$4,400 | na |
| Powerlink QLD |  |  |  |  |  | na |
| QLD Boards | na | na | \$30,000 | \$20,000 | \$14,000 | \$11,000 |
| PowerNet Victoria | \$0 | \$0 | na | \$ 6,000 | \$ 5,000 | na |
| VIC Distribution | na | na | na | \$ 6,000 | \$ 5,000 | \$ 4,000 |
| NSW Electricity Transmission Authority | \$0 | na | \$0 | \$0 | na | na |
| NSW Distribution (1) | na | na |  | \$8,000 | \$9,500 | \$6,000 |
| NSW Distribution (2) | NA | NA | \$5,500 | \$3,000 | \$2,050 | \$2,000 |
| NSW Distribution (average) | NA | NA | \$5,500 | \$5,500 | \$5,500 | \$4,000 |
| NATIONAL AVERAGE $\$$ | S0 | S0 | \$17,000 | \$10,000 | \$ 7,000 | \$6,500 |
| NATIONAL AVERAGE \% | 0\% | 0\% | 11\% | 9\% | 9\% | 35\% |

TABLE 2E - INCREMENTAL COST OF GREENFIELD METERING INSTALLATIONS

## ATTACHMENT 3 - EXISTING INSTALLATIONS

## ORGANISATION COST OF COMPLIANCE

| METERING <br> NSSTALLATIONS <br> FOR LOADS $>10$ <br> MW | O.5\% <br> ONLY <br>  <br> CHECK <br> $>10 \mathrm{MW}$ | $0.5 \%$ TO <br> 1.5\% <br> REVENUCY <br> CHECK <br> $>10 \mathrm{MW}$ | NUMBER OF <br> METERING <br> PINTS <br>  <br> CHECK <br> $>1000 \mathrm{GWh}$ | NUMBER OF <br> METERING <br> POINTS <br>  <br> CHECK <br> $>1000 \&>100$ <br> GWh | NUMBER OF <br> METERNNG <br> POINTS <br>  <br> CHECK <br> <100 GWh |
| :--- | :--- | :--- | :--- | :--- | :--- |
| ETSA | $\$ 19 \mathrm{~m}$ | $\$ 9.5 \mathrm{~m}$ | 10 | 205 | 0 |
| SA customers | $\$ 3.0 \mathrm{~m}$ | $\$ 0.75 \mathrm{~m}$ | 0 | 2 | 37 |
| AUSTA | $\$ 6.0 \mathrm{~m}$ | $\$ 4.0 \mathrm{~m}$ | $25 \times 2$ | 0 | 0 |
| Powerlink QLD | $\$ 45.0 \mathrm{~m}$ | $\$ 0$ | 0 | 300 | 0 |
| QLD Boards | $\$ 10.0 \mathrm{~m}$ | $\$ 0$ | 0 | 50 | 300 |
| NSW Generation | $\$ 6.1 \mathrm{~m}$ | $\$ 6.1 \mathrm{~m}$ | $26 \times 2$ | 0 | 0 |
| NSW Buik Supply | $\$ 7.9 \mathrm{~m}$ | $\$ 0$ | 0 | 70 | 0 |
| NSW Distribution | $\$ 16.2 \mathrm{~m}$ | $\$ 0$ | 0 | 0 | 200 |
| Victoria | $\$ 10$ | $\$ 0$ | 460 | na | na |
| NATIONAL TOTAL | $\$ 125 \mathrm{~m}$ | $\$ 20 \mathrm{~m}$ | 100 (say) | $600(\mathrm{say)}$ | 600 (say) |

TABLE 3A
COST OF UPGRADING METERING INSTALLATIONS $>10 \mathrm{MW}$

| METERNG <br> NSTALLATIONS <br> FOR MARKET <br> FULLY OPENED UP | $0.5 \%$ ACCURACY <br> ONLY <br> MARKET FULLY <br> OPENED UP |
| :--- | :--- |
| ETSA | $\$ 0$ |
| SA customers | $\$ 38(1)$ |
| AUSTA | $\$ 0$ |
| Powerlink QLD | $\$ 0$ |
| QLD Boards | $\$ 90 \mathrm{~m} \mathrm{(2)}$ |
| NSW Generation | $\$ 0$ |
| NSW Bulk Supply | $\$ 0$ |
| NSW Distribution | $\$ 300 \mathrm{~m} \mathrm{(3)}$ |
| Victoria | na |
| NATIONAL TOTAL | $\$ 430 \mathrm{~m} \mathrm{(4)}$ |

TABLE 3B

## COST OF UPGRADING METERING INSTALLATIONS WHEN MARKET OPENED UP

Note: (1) down to 1 MW customers.
(2) down to 100 kVA customers.
(3) down to domestic customers.
(4) In opening the market up beyond 10 MW customers, all loads would be less than 100 GWh per annum. Therefore no check metering installations would be required. The costs indicated in Table 3B refer to the upgrading of revenue metering installations only.

| VOLTAGE | AREA | METERING installation cosTs | NUMBER OF CUSTOMERS $>10 \mathrm{MW}$ | NUMBER OF METERING POINTS per customer (Ave) | $\begin{aligned} & \text { TOTAL COST } \\ & >10 \mathrm{MW} \end{aligned}$ | TOTAL $\cos$ T FOR ALL CUSTOMERS |
| :---: | :---: | :---: | :---: | :---: | :---: | :---: |
| 330 | Generation | \$230,000 | 1 | 22 (thermal) | \$5.1m | NA |
| 132 | Generation | \$155,000 | 1 | 4 (GTs) | \$0.6m | NA |
| other | Generation | \$115,000 | 1 | 4 | \$0.4m | NA |
| 132 | bulk supply | \$155,000 | 10 | 3 | \$4.7m (3) |  |
| 33 | bulk supply | \$80,000 | 20 | 2 | \$3.2m |  |
| 66 | Distributor 1 | \$50,300 | 1 | 2 | \$0.10m |  |
| 33 | Distributor 1 | \$26,400 | 7 | 2 | \$0.4m |  |
| 11 | Distributor 1 | \$16,700 | 3 | 2 | \$0.10m |  |
| 11/415 | Distributor 1 |  |  |  |  | \$4.0m (2) |
| all | Distributor 2 |  |  |  | \$4.0m (say) |  |
| all | Distributor 3 |  |  |  | \$1.6m | \$140m (1) |
| all | Distributor 4 |  |  |  | \$2.0m (say) |  |
| all | remainder |  |  |  | \$8.0m (say) |  |
| $\begin{aligned} & \hline \text { TOTAL } \\ & \text { S } \\ & \hline \end{aligned}$ | $\begin{aligned} & \hline \text { NSW } \\ & >10 \mathrm{MW} \end{aligned}$ |  |  |  | \$30.2m(say) | $\begin{aligned} & \mathbf{\$ 3 0 0 m} \\ & \text { (say) } \\ & \hline \end{aligned}$ |

TABLE 3C
DETALLED COST COMPONENTS FOR $0.5 \%$ LEVEL ACCURACY $>10 \mathrm{MW}$ (NSW)

NOTES:
(1) Covers the cost of upgrading all franchised customers when the market fully opens up.
(2) Covers the cost of upgrading all customers above 200 kVA .
(3) Assumes an average of 3 metering points across all 132 kV bulk supply market participants.
(4) Assumes an average of 2 metering points across all non- 132 kV bulk supply market participants.

## References:

Australian Standard 1243 \}- for Voltage and Current transformers used for Australian Standard 1675 \} measurement and protection.

## RATIONALE FOR USE OF DEPRIVAL VALUE ASSET VALUATION AS A BASIS FOR SETTING NETWORK COMPANY REVENUE REQUIREMENTS

## 1. Background

In economic theory, a perfect market is characterised by low barriers to entry and exit, and many buyers and sellers. Although very few perfect markets exist in reality, many markets are highly competitive. The level of prices in these markets is the outcome of competitive forces; no one firm has the ability to influence the level of the market price.

Under competitive conditions, the asset values' of incumbent suppliers will reflect the long run marginal cost of efficient new entrants to that market: the threat of entry imposes a discipline on incumbents to maintain prices at levels sufficiently low enough to ensure that new suppliers are not unduly encouraged to enter the market by the prospect of earning abnormally high profits. Figure 1 below illustrates the relationship between market prices and asset values in competitive markets.


In any market (competitive or otherwise) the value of a business or an asset is ultimately set by the total present value of the cash flows it can generate.

[^49]2. Asset valuation as a basis for setting the revenue requirements of a natural monopoly

The network elements of the electricity industry are often defined as natural monopolies; it is generally uneconomic to replicate these networks, so the incumbent network owners face little threat of direct competition from new entrants. Given an absence of competitive pressures to contain output prices, businesses which have natural monopoly characteristics could theoretically enjoy a level of market power enabling them to set prices by decree.

In monopoly markets therefore, there is a circular problem if discounted cash flow-based asset valuations are used to set prices, since prices will influence the level of expected cash flow, which in turn determines asset value (refer to Figure 2 below).


The lack of real competition in the transmission sector (due to its "natural monopoly" characteristics) means that there is no readily observable market-driven benchmark for setting revenue requirements and transmission prices. In the absence of effective competition, asset valuation must form the basis for setting the capital-related portion of annual revenue requirements.

Given the nexus between the value of a network company's assets and the company's annual revenue requirement, valuation should focus on:

- the minimum efficient replacement cost of the assets, rather than their potential for generating cash flow; and
- their value to the buyer or consumer, rather than their cost alone.

3. Asset valuation at "Deprival Value" as a means of mimicking competitive pressure on natural monopolies

In monopoly markets asset valuation can be used to mimic the outcomes of perfectly competitive markets. To achieve this, the valuation approach should reflect the following fundamental competitive market conditions:

- Freedom of entry: Freedom of entry implies that the initial valuation should not exceed minimum efficient replacement cost. This ensures that uneconomic new entrants, such as self-generation, and by-passing or replication of the grid are not encouraged by distorted price signals.
- Supply/demand balance: Economic theory suggests that when a market is in equilibrium, marginal price equals marginal value. Where the value placed on an asset by a consumer is less than the asset's replacement costs, the valuation should be set at the consumer's value. Where the consumer places a value on the asset in excess of its replacement cost, the value of the asset should be set at replacement cost. This ensures that the consumer surplus is not eroded through monopoly pricing.
- Freedom of exit: In the event that the asset is of no value to the consumer, the net realisable value provides a lower bound to the valuation of the asset.

Deprival Value determines the "value to the network business" of each asset by estimating the minimum loss that the business would incur if it was deprived of the asset. For example, if an asset can and should be replaced, then the loss is the current cost of replacing it with an asset which provides the most efficient means of meeting present and reasonable expected future requirements. If the greatest amount that can be recovered from that asset, either through its continued use or through its disposal, is less than the replacement cost, then this lower value (the asset's economic value) represents the loss to the business.

Thus Deprival Value is the lower of the optimised replacement cost of an asset and its economic value to the business. Under the Deprival Value method, assets are valued at replacement cost and then adjusted for any over-capacity and lower consumer value. This is entirely consistent with outcomes in a competitive market, in which:

- capital markets determine asset values on the basis of their expected future cash flow; and
- prices which influence an entity's expected future cash flow are effectively capped at a level reflecting the entry cost of efficient new producers.

Application of Deprival Value in the determination of network owner revenue requirements results in the network company's revenue requirement being set at levels which ensure that:

- the consumer surplus is not appropriated by the network owner through monopoly pricing;
- transmission charges to consumers are set to reflect the opportunity value of the assets that are used in the provision of transmission service; and
- existing consumers do not have to pay for past poor investment decisions which may have been made by network owners.

4. Application of Deprival Value where the asset owner does not make the decision to invest in the asset

The purpose of initial Deprival Value re-valuation of assets is to establish an asset value for revenue determination purposes which excludes the effects of any sub-optimum investment decisions made in the past. ${ }^{2}$ This in turn ensures that network prices are established at efficient and equitable levels.

A potential weakness of the proposed approach to determining the network owner's revenue requirement is the direct relationship between the value of assets and the magnitude of the revenue requirement: on the face of it, the network owner appears to have an incentive to over-invest in network assets, since the addition of new assets to the asset base results in an increase in the network owner's own revenues and profits (in absolute terms). The application of Deprival Value revaluations on an on-going basis is intended to address this weakness: any sub-optimum investment made by the asset owner will be exposed periodically, and be excluded from the asset valuation applied to determine the asset owner's revenue requirement.

Application of Deprival Value revaluation on an on-going basis is therefore:

- an artificial means of imposing the discipline of perfectly competitive markets on monopolists; and
- a means of ensuring that market risk associated with a decision to invest in network assets is borne by the investment decision-maker.

In Victoria, the functions of network investment decision-making and asset ownership have been separated as follows:

- VPX has responsibility for maintaining security of the power system. Responsibility and accountability for making decisions to expand the capacity of the transmission network is vested in VPX.
- PowerNet owns and maintains the transmission assets, but it has no mandate to increase the size (and value for revenue determination purposes) of its asset base unless such an increase is pursuant to an agreement with VPX.

Part of the rationale for the separation of the asset ownership and investment decisionmaking functions is to remove any incentives and means for a transmission asset owner to drive up its own revenues and profits by over-investing in the network.

[^50]Where the asset owner invests in new assets at the direction or request of some other party, it is neither efficient nor appropriate for the (passive) asset owner to be exposed to the risk of fluctuations in revenues arising from on-going Deprival Value revaluations. In such cases, the asset owner and the user of the service would typically enter into a long term take-or-pay contract under which the market (ie. asset utilisation) risk of the asset is borne by the party which has requested or directed the creation of the asset. Under such a contract, the present value of contract payments to be received by the asset owner fixes the value of the asset.

If assets covered by such contracts were to be optimised and re-valued on an on-going basis for revenue determination purposes, the revenue earning capability of the assets could vary from that agreed between the two parties to the contract. Such an outcome would distort the allocation of risk agreed between the two parties, and would not be acceptable to either party.

For these reasons, clauses 6.2.3(d)(4)(i) and (ii) provide for assets to be valued for revenue determination purposes by the ACCC in a manner consistent with the provisions of any relevant take-or-pay contract, or network augmentation determination made by NEMMCO pursuant to clause 5.6.5. In effect, these clauses provide for the recognition by the ACCC of the allocation of "stranded asset risk" inherent in any relevant take-or-pay contract or NEMMCO augmentation determination. These provisions are aimed at ensuring that the network owner or service provider does not bear "stranded asset risk" where some other party or parties have agreed to bear that risk.

## NATIONAL ELECTRICITY CODE

> ATTACHMENTS TO THE SUBMISSION TO THE AUSTRALIAN COMPETITION AND CONSUMER COMMISSION RELATING TO THE NATIONAL ELECTRICITY CODE

## ATTACHMENT 1

## The proposed Code (Version 2.0)

A copy of the proposed Code (Version 2.0) was lodged with the Australian Competition and Consumer Commission on 9 October 1996 together with a draft submission in support of:

1. proposed applications for authorisation under Division 1 of Part VII of the Act in relation to the Code; and
2. a proposed draft application for acceptance of the industry access code (as defined in Chapter 8 of the Submission) as an "access code" for the purposes of the Act (as proposed to be amended).

Accordingly, a further copy of the proposed Code (Version 2.0) is not contained in this Attachment 1.

However, the proposed Code (Version 2.0) is proposed to be amended by Addendum 1 which is contained in this Attachment 1.

## ADDENDUM 1

## AMENDMENTS TO NATIONAL ELECTRICITY CODE

This is an addendum to the National Electricity Code ("the Code").
It sets out amendments to the Code which are to be read as part of the Code.
The Code will not be reprinted at this time but to correct any errors, it is likely that a revised code will be issued after further examination of the Code Version 2.0 by the ACCC.

When the Code becomes effective in each of the participating jurisdictions, the amendments set out below will be included in the Code.

The amendments are:
1 Definition of "applicable regulatory instruments" - new definition to be added to Chapter 10

Applicable regulatory instruments means all laws, regulations, orders, licences and codes (other than this Code) which apply to Code Participants from time to time including those applicable in each participating jurisdiction as listed below, to the extent that they regulate or contain terms and conditions relating to access to a network, connection to a network, the provision of network services, network service pricing or augmentation of a network.
(1) New South Wales:
(a) the Electricity Supply Act 1995 ("ES Act");
(b) all regulations made and licences ("Licences") issued under the ES Act;
(c) the Independent Pricing and Regulatory Tribunal Act 1992 ("IPART Act");
(d) all regulations and pricing determinations made under the IPART Act;
(e) all regulatory instruments applicable under the Licences; and
(f) the Commercial Arbitration Act 1984;
(2) Victoria:
(a) the Electricity Industry Act 1993 ("EI Act");
(b) all regulations made and licences ("Licences") issued under the EI Act;
(c) the Office of the Regulator-General Act 1994 ("ORG Act");
(d) all regulations and determinations made under the ORG Act;
(e) all regulatory instruments applicable under the Licences; and
(f) the Tariff Order made under section 158A of the EI Act;
(3) South Australia:
(a) the Electricity Bill 1996 which, when passed, will be the Electricity Act;
(b) all regulations made and licences ("Licences") issued under the Electricity Act; and
(c) all regulatory instruments applicable under the Licences;
(4) Australian Capital Territory:
(a) the Energy and Water Act 1988 ("E\&W Act");
(b) all regulations made under the E\&W Act including the Energy and Water (Regulation of Charges) Regulations 1996 ("the Charges Regulations");
(c) a pricing direction made under the Charges Regulations; and
(d) a direction made under the E\&W Act following declaration of an emergency in relation to the supply of electricity.
(5) Queensland:
(a) the Electricity Act 1994
(b) the Electricity Regulation 1994
(c) the Queensland Grid Code;
(d) Authorities and Special Approvals granted under the Electricity Act 1994; and
(e) Gladstone Power Station Agreement Act 1993 and associated agreements.

2 Amendment to Clause 5 of Schedule 5.8 - Substitution of "applicable regulatory instruments" for "relevant laws"

## 5. Terms and conditions of connection and access

The Network Service Provider undertakes to maintain and make available its network services for access:
(a) by Code Participants in accordance with the requirements of the Code; and
(b) by all persons in accordance with:
(i) applicable regulatory instruments; and
(ii) good electricity industry practice and applicable Australian Standards.

4 Amendment of definition of "good electricity industry practice" - Chapter 10 - in the manner marked

The exercise of that degree of skill, diligence, prudence and foresight that reasonably would be expected from a significant proportion of operators of facilities forming part of the power system for the generation, transmission or supply of electricity under conditions comparable to those applicable to the relevant facility consistent with applicable regulatory instruments, taws, regulations, lienees reliability, safety and environmental protection. The determination of comparable conditions is to take into account factors such as the relative size, duty, age and technological status of the relevant facility and the applicable regulatory instruments, taws, regulations, licences andeodes.

Amendment of clause $\mathbf{1 . 1 2}$ in the manner marked

### 1.12 ACCESS CODE

(a) This Code sets out details of the terms and conditions on which Network Service Providers undertake to provide access to network services.
(b) The provisions of this Code that set out rules for access to network services, comprise an access code.
(c) The provisions of the access code and any access undertaking given by a Network Service Provider in the form of Schedule 5.8 of the Code, both expire on 31 December 2010.
(d) Nothing in this clause 1.12 is to be read or construed so as to affect, limit, modify or terminate the operation of any applicable regulatory instruments, other than this Code.
(e) This clause 1.12 is a protected provision.

## ATTACHMENTS 2-6(BOTH INCLUSIVE)

The documents identified in paragraph 1.8 of the Submission as Attachments 2-6 (both inclusive) were lodged with the Australian Competition and Consumer Commission on 9 October 1996 together with a draft submission in support of:

1. proposed applications for authorisation under Division 1 of Part VII of the Act in relation to the Code; and
2. a proposed draft application for acceptance of the industry access code (as defined in Chapter 8 of the Submission) as an "access code" for the purposes of the Act (as proposed to be amended).

Accordingly, a further copy of each of the documents identified in paragraph 1.8 of the Submission as Attachments 2-6 (both inclusive) is not provided with the Submission.


[^0]:    ${ }^{10}$ (1978) 31 FLR 193 at 216
    ${ }^{11}$ Queensland Wire Industries Pty Ltd v Broken Hill Pty Ltd (1989) 167 CLR 177 at 197 per Deane J.

[^1]:    ${ }^{12}$ QCMA at page 184; Re Rural Traders Cooperative (WA) Ltd (1979) 37 FLR at 261-262; Re Queensland Independent Wholesalers Limited (1995) at ATPR 40,914 at 40,927-40,928

[^2]:    ${ }^{13}$ (1994) ATPR 42,644 at 42,677

[^3]:    ${ }^{14}$ Outboard Marine Australia Pty Ltdv Hecar Investments No. 6 Pty Ltd (1982) 66 FLR 120 at 128-129 (per Fitzgerald J)

[^4]:    ${ }^{15}$ The Electricity Users Group has an expanded role and is now called the Energy Users Group

[^5]:    ${ }^{16}$ ECC Consultants, Brief (a) Bidding and Dispatch Proposals, A report to the NGMC, December 1995, page 27

[^6]:    ${ }^{17}$ Issues Paper on NEM - page 15

[^7]:    ${ }^{18}$ Industry Commission, The Electricity Industry in South Australia, 15 March 1996, p 135

[^8]:    19 "Free riding" refers to the situation where participants can enjoy the benefits of the shared system, but avoid paying the cost. In the NEM some functions and services are provided to the benefit of the market as a whole, for example ancillary services. To avoid participants gaining the benefits of these services without paying, some mechanism must be put in place to ensure that all those deriving such benefits contribute towards the full cost of the service.

[^9]:    ${ }^{20}$ ECC Consultants, Brief (a) Bidding and Dispatch Proposals, December 1995, pp8-9, report prepared for the NGMC.

[^10]:    ${ }^{21}$ In other markets such registration requirements are unnecessary because there are time lags between ordering, production, transportation and retail distribution and also because commodities generally are storable over this extended sale time

[^11]:    ${ }^{22}$ Putman, Hayes and Bartiett, The Proposed Framework for a Wholesale Market for Victoria, Report to the Victorian Government, June 1994 - Appendix 1 page 10

[^12]:    ${ }^{23}$ Putman, Hayes and Bartlett, The Proposed Framework for a Wholesale Electricity Market for Victoria, June 1994. (Appendix 1, page 36)

[^13]:    ${ }^{24}$ Putnam, Hayes and Bartlett, The Proposed Framework for a Wholesale Market for Victoria, Report to the Victorian Government, June 1994 - Appendix 1 page 3

[^14]:    ${ }^{25}$ The algorithm dispatches inter-regional flows so that there are no residual opportunities for arbitrating between regional spot markets conducted at regional reference nodes
    ${ }^{26}$ See paragraph 6.3.4 above

[^15]:    ${ }^{27}$ Participants wishing to execute identical transactions in opposite directions can hedge each other's interregional price risks, but this mechanism cannot facilitate net inter-regional trade. Other parties may choose to offer IRHs. However, they would be incurring risk by so doing and hence would probably require a significant extra risk premium
    ${ }^{28}$ That is, directly competing arbitrage between regional spot markets conducted at the reference nodes

[^16]:    ${ }^{29}$ Expressing this another way, they would be natural arbitragers between regional forward markets

[^17]:    ${ }^{30}$ Network users paying service charges on interconnection assets

[^18]:    ${ }^{31}$ The anti-competitive aspects of the PASA requirements and the public benefits of the PASA requirements are discussed at paragraph 6.3.5 of this Application

[^19]:    ${ }^{32}$ ECC Consultants, Brief (a) Bidding and Dispatch Proposals, December 1995, page 57 (brief prepared for the NGMC)
    ${ }^{33}$ Case for the Release of Bid Information and Quantities being a paper attached to letter from Dr Brian Spalding to Ms V. Brown, ACCC, dated 27 June 1996, at p.3. That paper forms Schedule 13 of this Submission

[^20]:    ${ }^{34}$ St Clements Services Report, Electricity Market Transparency, as reproduced at page 2 of Schedule 14 to this Submission

[^21]:    ${ }^{35}$ OFFER, Pool Price Statement, July 1993, at p. 62

[^22]:    ${ }^{36}$ William M. Mercer and Clayton Utz, Market Suspension Criteria and Pricing, December 1995, (page 2)

[^23]:    - ensure that meters and metering installations currently in place comply with the Code; and
    - register as Metering Providers; and
    - provide all information required of them to NEMMCO.

[^24]:    ${ }^{1}$ Assets are "stranded" when they are no longer required, but their cost has not yet been fully recovered. (For example, assets may be "stranded" due to charges in technology, a decrease in demand, or augmentation in other parts of the network which make the "stranded" assets redundant.)

[^25]:    ${ }_{3}^{2}$ Independent (Hilmer) Committee of Inquiry into National Competition Policy, August 1993 (page 272)
    ${ }^{3}$ Independent (Hilmer) Committee of Inquiry into National Competition Policy, August 1993 (page 289)
    ${ }^{4}$ Independent (Hilmer) Committee of Inquiry into National Competition Policy, August 1993 (page 226)

[^26]:    ${ }^{5}$ Industry Commission paper Implementing the National Competition Policy: Access and Price Regime, November 1995 (page 72)

[^27]:    ${ }^{6}$ The three staged approach is:

    1. Develop revenue requirement;
    2. Allocate revenue requirement; and
    3. Determine transmission prices
[^28]:    ${ }^{7}$ Section 33, Electricity Supply Act 1995

[^29]:    ${ }^{8}$ Independent (Hilmer) Committee of Inquiry into National Competition Policy, August 1993 (page 272)
    ${ }^{9}$ Independent (Hilmer) Committee of Inquiry into National Competition Policy, August 1993 (page 289)
    ${ }^{10}$ Independent (Hilmer) Committee of Inquiry into National Competition Policy, August 1993 (page 226)

[^30]:    - Note: CUBE Penrice Co-generation to be commissioned 1998

[^31]:    ${ }^{1}$ Section 77(5) of the Electricity Supply Act 1995 ("ESA").

[^32]:    ${ }^{2}$ This is one of the licence conditions imposed on electricity distributors under clause 6(2)(e) of schedule 2 of the ESA.
    ${ }^{3}$ See National Code Chapter 9 derogations of New South Wales at clause 9.15 of the National Code and Section 3.3 below.
    ${ }^{4}$ See clause 16 of Schedule 6 of the ESA.

[^33]:    ${ }^{5}$ Section 7 and schedule 1 of the ESA.
    ${ }^{6}$ Section 10 and schedule 1 of the ESA.
    ${ }^{7}$ Section 14 and schedule 2 of the ESA and clause 9 of the Electricity Supply (General) Regulations 1996.

[^34]:    ${ }^{8}$ Clauses 4(2) of schedules 1 and 2 of the ESA
    ${ }^{9}$ Sections 33 and 98 and schedule 2 of the ESA and clause 11 of the Electricity Supply (General) Regulations 1996.
    ${ }^{10}$ See clause 4 of schedule 2 of the ESA.

[^35]:    ${ }^{11}$ Section 9 of the ESA.
    ${ }^{12}$ See Division 5C of the New South Wales State Code.

[^36]:    ${ }^{13}$ See sections $15(1)($ a) and 78(3)(a) of the ESA
    ${ }^{14}$ Section 31 of the ESA.

[^37]:    ${ }^{15}$ Section 7 of the IPART Act.
    ${ }^{16}$ See sections $18,19,38,39$ and 20(3)(b) and 40(3)(b) of the ESA.
    ${ }^{17}$ See schedule 2 clauses 8 and 9 of the ESA.
    ${ }^{18}$ Electricity Prices, Determinations No 1.2, 2.1 and 2.2 IPART, March 1996.

[^38]:    ${ }^{19}$ Section 12B, IPART Act.

[^39]:    ${ }^{20}$ See section 24D of the IPART Act and sections 28 and 33 of the Commercial Arbitration Act. Sections 28 and 33 effectively provide that the parties to "arbitration agreements" must comply with any arbitral awards or determinations under those agreements. Arbitration agreements are agreements in writing that refer present or future disputes to arbitration. In that regard, clause 1.15 of the New South Wales State Code provides that the Code has the effect of a contract, and clause 8.1(c)(6) of the New South Wales State Code provides for referral of access disputes to IPART for arbitration under Part 4A of the IPART Act.

[^40]:    ${ }^{21}$ See section 96 of the ESA
    ${ }^{22}$ The relevant provisions of the ESA will be repealed in so far as the relate to authorisation of network operations and wholesale trading in the wholesale market.

[^41]:    ${ }^{23}$ See New South Wales derogation in section 9.12.1 of Chapter 9 of the National Code.

[^42]:    ${ }^{24}$ See NSW derogation in section 9.15.1(b) of the National Code.
    ${ }^{25}$ See New South Wales derogation in section 9.15.2(a) of the National Code.

[^43]:    ${ }^{26}$ See section 2.7 of the National Code.
    ${ }^{27}$ Section 44 of the National Electricity Law.

[^44]:    1 See SA Derogation in section 9.26 .2 of Chapter 9 of the National Code. The regulations to the Electricity Act (which is only a draft Bill as at the date of this submission) have yet to be prepared or promulgated.

[^45]:    To the extent that competitors on one side of the market all agree between themselves to supply to or to acquire only from certain persons, the provisions may be exclusionary provisions. To the extent that parties on opposite sides of the market agree that one (or both) of them will not supply to or acquire from other persons, the provisions may be exclusive dealing provisions.

[^46]:    ${ }^{1}$ However these views were given in confidence and therefore not attributed to any player.

[^47]:    ${ }^{1}$ Australian Financial Review, 7 August, 1996, p. 30.
    ${ }^{2}$ Australian Financial Review, 21 August, 1996, p. 10 (Byline: Mark Jeanes).
    ${ }^{3}$ Ibid.

[^48]:    4 "The mysterious case of the cheap cheddar", The Economist, 25 May, 1996, p.91.
    ${ }^{5}$ Sydney Morning Herald, 12 August, 1996, p. 32 - sourced from the New York Times.
    ${ }^{6}$ Ibid.

[^49]:    ${ }^{1}$ Throughout this appendix "asset value" means the present value of the net cash flow which an asset is expected to produce over its life. This definition of "asset value" is based on economic rather than accounting concepts.

[^50]:    ${ }^{2}$ In effect, at the time of the initial Deprival Value re-valuation, the network asset owner bears all financial risk associated with the re-valuation.

