EVALUATION OF OPTIONS FOR AN ANCILLARY SERVICES MARKET FOR THE AUSTRALIAN ELECTRICITY INDUSTRY

A Project Commissioned by the NEMMCO Ancillary Services Reference Group

APPENDICES

August 1999

Intelligent Energy Systems Pty Limited

SYDNEY: Tel: +61 2 9436 2555, Fax: +61 2 9436 1218, Level 1, 10-12 Clarke Street (PO Box 931) Crows Nest NSW 2065

MELBOURNE: Tel: +61 3 9821 5331, Fax: +61 3 9821 5334, Level 1, 3 Bowen Crescent Melbourne VIC 3004

EMAIL: ies@intelligentsys.com.au WEB: http://www.intelligentsys.com.au

APPENDICES

1 Overview of Current Ancillary Service Arrangements

This appendix outlines the current approach to the provision of ancillary services in the National Electricity Market. The contents are taken from the NEMMCO operating procedure document SO_OP3708 entitled "Operating Procedure: Ancillary Services".

To avoid confusion in this appendix, clarification of the currently used terms is provided.

The current procedures refer to the technical options that provide the service as ancillary services, and the functional classification of these technical options as categories of Ancillary Service or System Operator Requirements. This is unlike the Framework document that refers to ancillary services in terms of the functional classification.

The current market approach to ancillary services aims to ensure that sufficient ancillary services are enabled to meet security needs, and that the Service Providers are selected on the basis of least cost.

The system requirement for Ancillary services is divided into 5 categories or classifications:

- Frequency control
- Voltage control
- Network Loading Control
- Stability Control
- System Restart

The general approach to satisfying the requirements for each of these categories follows a two step process. Firstly the actual requirement is identified and secondly sufficient applicable ancillary services are enabled to ensure that the requirements are meet. The ancillary services used to satisfy the requirements of each category are illustrated in the Table 1. Of particular note is that frequency control is utilises four ancillary services (ie. technical options) while the other ancillary services use at most two.

The approach to each category of Ancillary Service follows.

Table 1.1 Ancillary Services and Categories

	------------	------------	Category	------------	-----------
Ancillary Service	**Frequency Control**	**Voltage Control**	**Stability Control**	**Network Loading Control**	**System Restart**
Auto. Gen Control (AGC)	Used			Used	
Governor Control	Used				
Load Shedding	Used			Used	
Rapid Gen. Unit Loading	Used				
Reactive Power		Used			
Rapid Gen. Unit Unloading			Used		
System Restart					Used

1.1 Frequency Control

Frequency control ancillary services are required to maintain appropriate levels of contingency reserve and regulating reserve:

- Contingency reserve is required to ensure that frequency remains within defined standards following credible contingency events. The requirement for contingency reserve is a function of the largest generator unit or load block on the system.
- Regulating reserve is required to maintain frequency within the normal band of operation for normal variations in demand and generation.

The frequency control standards, that require frequency recovery within specified time periods, result in the definition and use of seven categories of frequency control. These seven categories of frequency control are used to satisfy contingency reserve requirements, while two of these categories serve for regulation reserve requirement. These categories of frequency control, together with a description of the category, ancillary service used to meet the category, and method of dispatch are shown in the Tables 1.2 and 1.3 below.

Note that the use of the Scheduling, Pricing and Dispatch (SPD) algorithm implies that the category of frequency control is co-optimised with dispatch in the energy market. Manual dispatch implies no co-optimisation with dispatch in the energy market.

Table 1.2 Frequency Categories Used to Meet Contingency Requirements

Frequency Control Category	**Description**	**Dispatch Method**	**Ancillary Services Used**
6 second raise (high band)	Generation that can increase within 6 seconds	SPD	Governor, Load shedding
6 second raise (low band)	Applicable to multiple contingencies	Manual	Governor, Load shedding
6 second lower	Generation that can be reduced within 6 seconds	SPD	Governor
60 second raise	Generation that can increase within 60 seconds	SPD	Governor, Load shedding
60 second lower	Generation that can be reduced within 60 seconds	SPD	Governor, Load shedding
5 minute raise	Capacity to increase generation - to restore frequency to within normal band within 5 minutes	Manual	AGC, Rapid Gen Unit loading
5 minute lower	Capacity to decrease generation - to restore frequency to within normal band within 5 minutes	Manual	AGC

Table 1.3 Frequency Categories Used to Meet Regulation Requirements

Frequency Control Category	Description	Dispatch Method	Ancillary Services Used
5 minute raise – Regulating	Capacity to increase generation to load follow and maintain frequency.	SPD	AGC
5 minute lower - Regulating	Capacity to decrease generation to load follow and maintain frequency	SPD	AGC

The process of using these ancillary services for frequency control is outlined as follows.

1. The quantities of frequency control categories are initially determined in pre-dispatch by identifying the following:
   - largest generating unit;
   - two largest generating units;
   - largest single load block; and
   - two largest load blocks.
2. From this the necessary quantities of the frequency control for each category are determined. This is done on the following basis:
   - 6 second raise/lower requires the replacement of the largest generator unit less aux. load or largest load block, assuming a 2% contribution from load relief/increase;
   - 60 second raise/lower requires the replacement of the largest generator unit less aux. load or largest load block assuming a 2% contribution from load relief/increase. This assumes no 6 second respond after 60 seconds;
   - 5 minute raise/lower requires the replacement of the largest generator unit less aux. load or largest load block assuming no contribution from load relief/increase. This assumes no 60 second respond after 5 minutes.
3. If the pre-dispatch identifies insufficient frequency control ancillary services (FCAS), then the regions with insufficient FCAS are identified, and the responsible control centres would determine the most appropriate course of provision as outlined in set procedures.
4. At the time of actual dispatch, regular monitoring and management of the SPD enabling and usage of the various ancillary services is performed. Issues that may need specific actions include:
   - non performance of a service provider;
   - potential shortages of ancillary services;
   - following a contingency event, any load shed as an ancillary service should be restored as soon as possible; and
   - commitment decisions in circumstances of steadily rising demand in a region operating against an import limit.

1.2 Voltage Control

As previously described there is currently one ancillary service for voltage control (ie. reactive power). This service provides reactive above that provided by Transmission Network Service Providers (TNSP's) and generators under their mandatory code obligations.

The general approach to voltage control is to assess (via power system analysis) the requirements for reactive, and to utilise voltage control assets in an assessed cost order:

1. Firstly, use is made of transmission elements and generators online to the full extent possible, within mandatory code requirements or ancillary service contract quantities, without constraining real power output. Generators without ancillary service contracts are only used for reactive to the mandatory code requirement.
2. If further reactive were required, use would be made of synchronous compensators in specific areas - in a defined merit order based on enabling prices. This synchronous compensator merit order is provided to system operators based on synchronous compensator contract details.
3. Further reactive requirements may require the constraining of generator units on or off to provide the additional service.

1.3 Network Loading Control

This service is needed when transmission elements are operating at 5 minute operating limits, implying the need to reduce post contingency flows to within ratings within 5 minutes in the event of a contingency occurring.

This is a specialised service that is manually dispatched when required, providing that there is sufficient lead-time for the Ancillary Service provider to enable the service. As such the use of this ancillary service will be limited to those network elements for which feasible network load control service exists.

1.4 Stability Control

Currently, this is a specialised service to support high transfers on the SYTS-MLTS and MLTS-HYTS 500kV lines. This control scheme monitors the status of critical circuits associated with the supply to South Australia and Portland smelters, as well as frequency.

If the scheme detects loss of these circuits in conjunction with a sudden high frequency, it will rapidly offload generation in Victoria (and automatically offload the Moorabool Terminal Station 500/220 kV transformer).

This scheme is dispatched manually based on a system security requirement of flows on the MLTS to HYTS lines exceeding 680MW.

1.5 System Restart

Contracted service providers receive availability payments for the provision of this service, who are expected to maintain system restart capability. There is no ongoing dispatch for this service.

2 Voltage Control Ancillary Services

Voltage control is an integral component of power system management from both a quality of supply and security perspective. Voltage control ancillary services relate to those services that provide and regulate reactive power.

The Framework distinguishes the roles of managing transmission voltage levels during normal power system conditions to that of ensuring voltage level recovery following a credible contingency. To this end the framework segmented voltage control ancillary services into two categories – continuous and contingency.

The Framework indicated the need for continuous voltage control as changes in reactive demand due to changes in demand and generation, and on the network side changes in configuration and transport distances between load and generation. For contingency voltage control, the framework specified generation/demand change, and on the network side contingencies and pre-contingency flows.

The Framework listed the "drivers" for these needs in terms of QoS, equipment rating and network capability for the continuous case, and power transfer limits across critical links and size of critical contingency for the contingency case. This demonstrated the close link between these services.

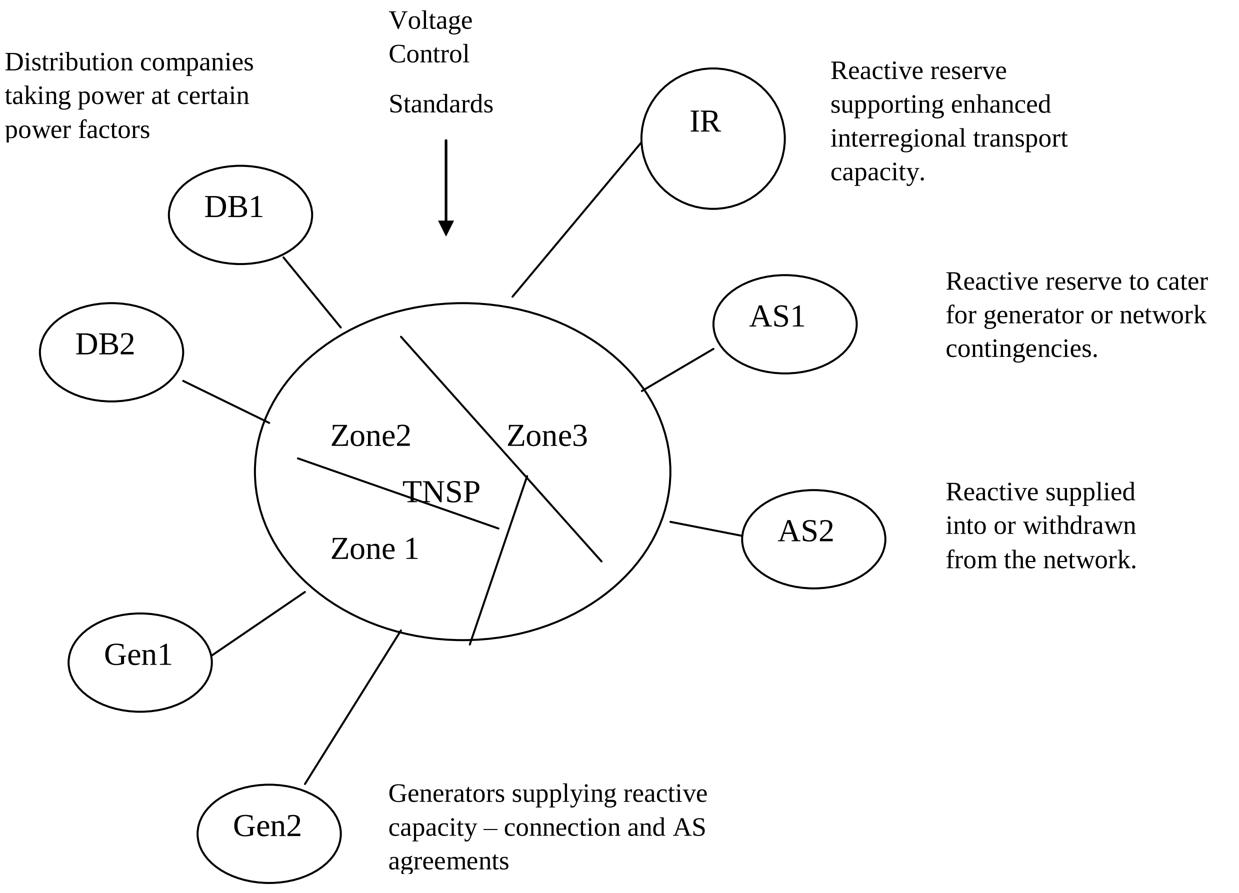
An overview perspective on these voltage control ancillary services is shown diagrammatically in Figure 2.1 overleaf, which shows the relationship between voltage control (ancillary service) users and providers in a single region.

Particular points of relevance to arrangements developed are the following:

- AS1, AS2 etc. refer to the voltage control ancillary services, while Gen and DB refer to the generator and distribution businesses respectively.
- Reactive within each zone may not sum to zero, and there is likely to be reactive flows from "low priced reactive zones" to "high priced reactive " zones.
- Voltages are controlled by the injection and withdrawal of reactive power, and the use of transmission elements and switching to control reactive power flows.
- The difference between reactive generation and reactive reserve is a small production cost indicating that the reactive supply curve is almost vertical.
- The demand for reactive power does not have the "predictable" characteristics of energy, as reactive demand is much more a function of line flows and dispatch patterns.
- Because the transmission network itself can produce and absorb reactive, procurement / payments for reactive would need to be based on the input to and output from the transmission network. Any contribution from within the network, such a line charging reactive, should not be part of any ancillary service and should not attract any payment.
- Reactive value may be location specific and dependent on the demand and generation dispatch profile. Consequently this ancillary service should be defined at each node in the network. Spatial monopoly issues will also need to be considered in the development of market arrangements.

- There may be potential competition between DBs, generators and the TNSPs for the provision of reactive services. A major benefit from competition could arise from improved dynamic efficiency through competition between providers and appropriate signals to users, in particular power factor correction by DBs reducing the need for grid and generator reactive capability.

Figure 2.1 Voltage Control Ancillary Services



2.1 Description of Voltage Control Ancillary Services

2.1.1 Voltage Control - Continuous

The ancillary service "voltage control – continuous", is the service that provides for the continuously balancing of the supply and demand of reactive power in a manner that maintains system voltage profile within acceptable limits and conforms to the prevailing system conditions[1].

As customer demands vary with location together with reactive transport losses, the requirement for reactive generation and absorption varies with power system conditions on a

[1] In addition to maintaining voltages within prescribed limits, transmission system voltage profiles are also established to cater for contingency events.

location basis. In particular, reactive requirements vary with real and reactive demand at each node in the network and with the disposition of generation (ie. dispatch).

An example of conditions that greatly influences reactive requirements on the power system is that of high interregional power transfers under conditions of high system (real and reactive) demands.

Thus the demand for reactive power cannot be determined independently of the disposition of generation and consequential network transport requirements. To this degree, reactive requirement is a dynamic function with energy dispatch. The joint nature of real and reactive power means that there are potential efficiency gains through the co-optimisation of real and reactive power in the dispatch process.

Nevertheless, the very weak link between real and reactive power (except under extreme conditions where generating units may be required to generate substantial quantities of reactive), makes questionable the value of dynamic co-optimisation although that such an option could be a longer term goal.

It is interesting to note that in many respects, voltage control - continuous has similar characteristics to small deviation frequency control. The security implications of these ancillary services relate to establishing pre-contingency voltage/frequency levels to assist in constraining post contingency voltage/frequency levels to acceptable “secure” levels. Quality of Service is associated with regulating voltage/frequency within prescribed limits.

2.1.2 Voltage Control - Contingency

As well as maintaining acceptable voltage levels pre-contingency, system security requires that there is sufficient spare or reserve reactive (generation and absorption) to maintain voltage levels should a credible contingency event occur. Credible contingencies occur from the loss of either a large generator unit, large demand change or the loss of a critical network element. As such generators, demands and networks are all potential causers of voltage control – contingency ancillary services.

Like voltage control continuous, the requirement for reactive reserve varies with system conditions and is location specific. Consequently, the requirement for reactive power reserves cannot be determined independently of the disposition of generation and potential network transport requirements. As with voltage control – continuous, reactive reserve requirement is a dynamic function with energy dispatch, and the joint nature of real and reactive power means that there are potential efficiency gains through the co-optimisation of real and reactive power in the dispatch process. These efficiency gains include trading benefits through including the impact reactive capability/reserve has on network link power flow limits. For example, under high demand conditions, the amount and location of reactive reserve can define the transport capability across interconnectors. There are potential trading benefits from maximising interconnector capability through appropriate reactive scheduling.

The current approach by NEMMCO is to schedule sufficient reactive capability to ensure the reliability of the power system and to ensure that network link constraints are not binding (up to their maximum transport capacity).

Like voltage control – continuous, voltage control - contingency has many characteristics similar to large-scale frequency deviations. These ancillary services provide reserve to cater for credible contingency events, and constitute additional resources to that required by the small scale/continuous corresponding ancillary service.

2.1.3 Relationship between Voltage Continuous and Contingency

The ancillary services voltage control - continuos and voltage control - contingency are joint products and constitute the total reactive requirements in terms of:

- locational requirements;
- static and dynamic reactive requirements; and
- total reactive capability.

Consequently, reactive deficits in one of these services can impact the capability of the other voltage control ancillary service. For example, under conditions of very high real and reactive demands, substantial quantities of reactive sources would be required to satisfy reactive demand and maintain system voltage levels within limits (ie. voltage control - continuous). This may require substantial amounts of reactive from dynamic sources, depleting the ability to provide the reactive reserves required by the voltage control - contingency ancillary service.

It is intended[2] that the identification of which of these ancillary services is being provided will be determined from the assessed cause of the requirement. Reactive actually being supplied to satisfy varying reactive demands including losses would be classified as continuous, while reactive resources associated with security to network contingencies would be classified as contingency. It should also be noted that alternatively, voltage levels could be held at a higher level as a partial substitute for reactive reserve.

The joint nature of these two ancillary services makes the distinction in many way arbitrary, as there is a use and pricing connection between these service based on the opportunity cost of the other. In addition, as separate pricing of each of these ancillary services would lead to arbitrage opportunities, the arrangements established will need to account for the joint nature of the continuous and contingency voltage control services.

2.2 Procurement Pricing and Dispatch - Potential Arrangements

The consideration and development of procurement pricing and dispatch arrangements needs to recognise the economic nature of the product, main areas where potential efficient gains can be made, current institutional arrangements, and provide for a transition path to more competitive arrangements if appropriate.

2.2.1 Current Arrangements

The responsibility for voltage control is currently shared between the TNSP's and NEMMCO. With reference to the NEM Code, the TNSP's have a responsibility to maintain satisfactory voltage profiles (Chapter 5), while NEMMCO have the responsibility for overall system security also requiring the maintenance of acceptable voltage levels (Chapter 4). Nevertheless as an interim measure, NEEMCO have established agency agreements with the TNSP's for

[2] ASRG Ancillary Services Framework.

voltage control services[3]. (The TNSP's control regional voltage levels from their respective control centers).

In additional to these agency agreements, NEMMCO have currently entered into ancillary service agreements for additional reactive[4] (for system security purposes). This reactive is in addition to the reactive resources provided by mandatory generator connection agreements and by TNSP's reactive plant. The need for these additional voltage control services was the result of the current voltage control standards, and the balance of available voltage control resources and the assessed potential reactive demands of distribution companies at their point of connection.

The ancillary service contracts provide for additional generator reactive capacity at specific locations than is provided for by generator connection agreements. The form of the contracts has an availability payment and an enabling payment. There is no usage payment recognising the very low marginal cost of reactive production.

The main driver for the additional reactive capacity contracted by NEMMCO was the maintenance of network capacity at times of high reactive demand, considered necessary to maintain network capability. As such, these reactive ancillary service contracts services compete with other options such as location generation and demand side response that are integrally related to the top end functioning of the market. In this sense the competitive provision of voltage control services needs to be seen in the wider context of market efficiency (esp. top end).

In addition to NEMMCO involvement, market efficiency and the potential for competition is currently "clouded" by the apparent code inconsistencies and different incentives that apply to the TNSP's, DB's and generators in respect to these services. In particular:

- the incentives and responsibilities of TNSP's, that have voltage control services "bundled" in with the regulated assets (in accordance with TNSP planning criteria); and
- the incentives for DB's to control reactive withdrawals (although the Code does provide power factor standards that can form the basis for TNSP's and DB's to co-operate in the provision of reactive sources such as capacitor banks).

From an operational perspective, reactive resources - both static and dynamic – are used in a manner designed to maximise the value of trade and maintain a secure network. Voltage control services / reactive flows are not currently optimised by NEMMCO, although the TNSP's may optimise the use of reactive plant via some form of optimised power flow approach. In the short to medium term this approach is most probably sufficient, as the expected benefits that would likely be achieved from dynamic reactive scheduling[5] are moderate. [6]However, dynamic reactive scheduling could remain a longer term goal.

---

[3] The apparent Code inconsistency with regard to voltage control responsibilities is a matter that has been noted by NEMMCO.

[4] NEMMCO direct the use of synchronous condensers due to the high enablement costs.

[5] This would include optimised reactive dispatch or co-optimised real and reactive dispatch.

[6] The main impact reactive has on the energy spot market relates to supporting network capacity and this is more a function of available reactive capability than dispatch.

2.2.2 Potential for Competitive Provision

As indicated above, the efficient procurement of voltage control services cannot be considered in isolation from other market options, but should be procured in an environment that has voltage control resources completing with other potential alternatives. These other means of provision were recognised in the framework classification matrices that listed technical options for provision such as demand shed in addition to reactive resources. It becomes a mood point whether ancillary services contracts, established by NEMMCO to maintain network capacity, are fulfilling an ancillary service role or are in affect some form of market intervention at the top end. To address this issue would require some form of two way that tested the "willingness to pay" for voltage control services.

Regarding the supply of voltage control services, the form of arrangements suitable for procurement will depend on the nature of the service/commodity, how closely the elements of competition are matched and the benefits to be gained (over the associated costs).

Unlike frequency, voltage levels can vary across the transmission system, and the ability of reactive resources to maintain voltage levels is location specific. Nevertheless within voltage control "zones", all customers and generators experience approximately the same voltage levels, and voltage levels have a public good characteristic[7]. This public goods nature of voltage indicates that voltage control standards need to be determined in some centralized way. This is the case and voltage levels are controlled within standards established by the Reliability Panel (RP).

However, within the standards established, there is the potential for voltage control services, in particular reactive, to traded as normal goods – with buyers (users) and sellers (suppliers). The arrangements established would depend on the potential for competition and the benefits to be gained (over the associated costs).

As alluded to earlier, the total contestablility of all voltage control services could require regulatory and Code amendments relating to the inclusion of such plant in the regulated asset base of TNSP's and the mandatory provision of reactive by generators. The need for mandatory generator reactive requirements arises from the view that reactive is an integral to the product being sold and to the secure (via. ensuring network capacity) operation of the power system. However, these are not necessary reasons for mandatory provision such as safety, legislative or monopoly reasons.

In the longer term, the provision of reactive is potentially competitive, conforming to the requirements of competition (as outlined in the Framework). In the medium to short term, issues of spatial monopoly, entry and information become in question. Information issues relate to the predictability of reactive needs in the shorter term including amounts that might be assessed as required for system security, and the likely pricing of reactive provided. Currently, entry is restricted to reactive providers under some form a long term contract.

The locational nature of reactive supply may always imply spatial monopoly issues in the short to medium term indicating the need to secure or regulate this provision in some manner. This could be by way of contracted provision or regulated supply offers under some form of market arrangement. Competition under such arrangements would be improved by the

[7] Public goods are characterised by non-rejectable, non-diminishability and non-excludability.

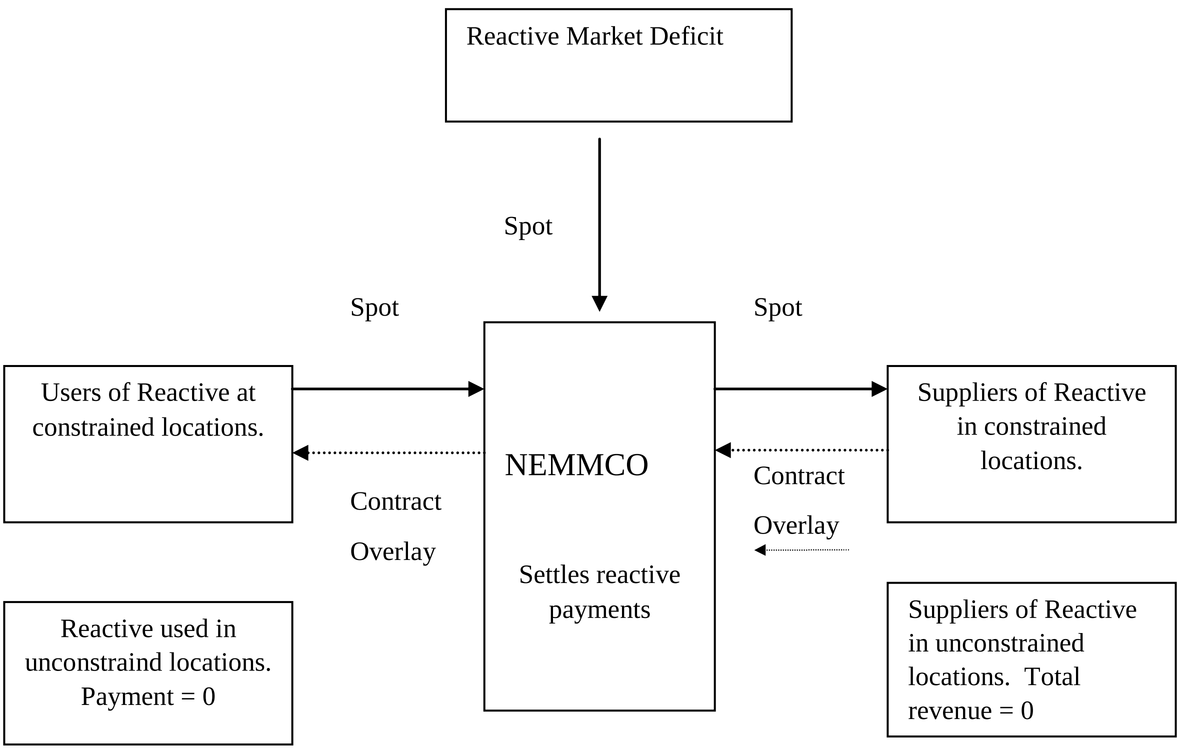
inclusion of all reactive services and a transparent signal as to the value of reactive that could form the basis of market response, contracting and pricing

2.2.3 Competitive Provision – Spot Market Arrangements

The basis for reactive procurement arrangements based on the value of reactive as signaled through the dispatch and pricing process is shown in Figure 2.2. The particular advantages of this arrangement are as follows:

- it is based on the value of the service;
- it does not require the development of "reactive zones", as the reactive-constraint relationships would have this implicitly included;
- the joint production nature of voltage continuos and voltage contingency provides for a common price for the two voltage control ancillary services;
- it does not require reactive bidding by generators and other providers, but only the commitment of plant availability; and
- information needs are reduced with simplified bidding and greater certainty of value.

Figure 2.2 Spot Price Reactive Arrangements



In a similar manner to the energy market, settlements based on participant withdrawals and injections do not sum to zero. In the case of the reactive arrangements described, there would be a settlement deficit that would need to be funded. There are logical means of provision based on the benefits provided by the service. However, the issue of payment frameworks is outside the considerations of this report.

Particular characteristics of this arrangement are as follows:

- There exists the flexibility to establish "vesting" contracts that might be established to secure current financial positions and responsibilities (associated with DB reactive withdrawals and generation connection agreements). These would have no associated premium payments and correspondingly would present no risk to NEMMCO.
- Ancillary service contracts that NEMMCO might counter party to secure sufficient reactive would most likely have premium payments. There would be a risk to NEMMCO in over valuing the benefits associated with contracted ancillary services.
- Ancillary services would be dispatched to maximise the value of trade, and would occur as part of the competitive operation of the market.
- The reactive price signal will reflect the value of additional reactive, and as such will have the characteristic similar to that displayed by the "top end" of the energy market.

Of note is that the above arrangements have been based on the one-way market arrangements with NEMMCO as the monopsonic purchaser (and monopoly seller). Under these arrangements competition can be introduced by the unwinding of vesting and other contracts (in the same manner as the energy market). However, the arrangements also provide for the development of two-way markets that remove NEMMCO as the buyer and seller and provide for reactive services to compete on a level playing field with other services. It should be noted that spatial monopoly issues that characterise reactive provision can be managed by the appropriate use of contracts, as can any requirements that NEMMCO may have in relation to system security.

Further refinement may be possible through the use of co-optimised dispatch of reactive in the scheduling process. However, as indicated earlier, the benefits of co-dispatch do not appear convincing and would need to be established prior to developments in this direction. As part of this process, consideration could be given to developing an AC nodal pricing model to run in parallel with the existing systems. This could also form part of a strategy for ultimate conversion of the existing NEM systems.

The above arrangements do not specifically separate voltage continuous and contingency services that cannot be explicitly done without some form of reactive dispatch. The most significant difference from a suppliers viewpoint may be the costs (although small) of actually providing reactive. This can be incorporated in any contracting arrangements.

Section 2.3, which follows, provides a detailed explanation of the arrangements outlined, including the form of contract overlays and settlement deficit funding.

2.3 Description Of Reactive Spot Market Arrangements

This section presents a description of a potential spot market arrangements for reactive based on the value output from the SPD formulation, including the use of a contract overlay to "vest" current positions.

Figure 2.3 illustrates the price setting and settlement arrangements. Of note are the following:

- Constraint relationships within SPD establish the marginal value of reactive in each dispatch period;

  Network constraints are of the form[8] λ [Link Flow - K + $\sum a_j R_j$ - $\sum a_k R_k$]

  where:

  - K is a constant associated with the network,
  - $\sum a_j R_j$ is the summation of critical reactive sources recognising the contribution to the limit,
  - $\sum a_k R_k$ is the summation of critical reactive users recognising the contribution to the limit,
  - λ is the marginal value of reactive when the constraint is binding.

- Dispatch optimisation is based on dynamic scheduling/recognition of reactive resources to optimise the value of trade. Note: this service may be considered integral to the voltage control arrangements or part of the enhanced spot market ancillary service.
- The a_k can be regarded as "influencing coefficients" that describes how much reactive capability at a given node affects the constraint. Nearby nodes will have relatively high coefficients while more remote nodes lower values (and ultimately zero).
- The value of reactive is zero in a particular location if the reactive constraints associated with reactive at that location are not binding.
- Payment is made on reactive service provided – that being actual reactive metered or reserve recorded. An explanation of the terms is as follows:

  - The term $\lambda \sum a_j R_j$ represents the total payment by buyers of reactive.
  - The term $\lambda \sum a_k R_k$ represents the total payment to the sellers of reactive.
  - The term λ K represents the payment to the network for its contribution.
  - The term (λ Flow limit) represents the total settlement surplus of payments over revenues.
  - λa_j can be thought of as the reactive price at location j.

- The price determined by a constraint applies only to that constraint. The total value of reactive at a node will be the summation of all prices over all contingencies.

These terms represent the values of reactive and send the appropriate signals to the market. With the value of reactive and market signals established, a contract overlay can be instituted to make Market Participants equivalent to their current positions, and to provide NEMMCO assurance that appropriate ancillary services will be available when required. These contracts would take the form of option and swap contracts.

For reactive providers under ancillary service contracts, an option contract would provide the equivalent effect as the current contracts that consist of availability and enablement components. The structure and equivalence is displayed in Table 2.1 below.

[8] Although the exact form in SPD may be different and may not include all these terms.

Table 2.1 Ancillary Service Contract

Option Contract	Physical Contract (current form)	Interpretation
Premium	Availability	Payment for being there for a defined period.
Strike price	Enablement	Payment for commitment
Quantity	Quantity	MVARS

Of note are the following:

- The premium would be based on the expected reactive revenue over the period and any risk premium. Note: The expected revenue is given by the sum of the difference between the locational reactive price and strike price over the period:

  ie. $\sum (a_j\lambda$ - strike price $)$[9];
- The strike price would most likely be zero or a small number. A small amount may be required to account for the costs of producing reactive. This would be the main distinguishing feature separating reactive continuous and reactive reserve.
- The use of option contracts would provide the same incentives as in the energy market for contracted providers.

In the same vein, "protection" or vesting of previous positions can be accommodated by the use of swap contracts that would effectively swap out the impact of reactive pricing. This could apply to reactive generation under mandatory connection agreements, and reactive withdrawals by distribution businesses from the transmission network. The structure and equivalence of these contracts for generators and DBs is displayed in Tables 2.2 and 2.3 below.

[9] The expected revenue needs to be qualified in relation to revenues that would occur without the service (ie. before) and with the service (ie. after). Because contracting may be required to capture the benefits, the premium would most likely be higher than that associated with actual price outcomes. Note also that an omnibus contract would capture all relevant contingencies.

Table 2.2 Generators Contracts

Swap Contract	Interpretation
Payment Direction	Generators pay difference between reactive price and strike price.
Premium	Mandatory requirement – no premium
Strike price	Set = 0. Generators repay total revenue from mandatory reactive provision.
Quantity	Reactive generation contracted – may be a function of available capacity.

Table 2.3 Distribution Business Contracts

Swap Contract	Interpretation
Payment Direction	DB's are paid difference between reactive price and strike price.
Premium	Mandatory requirement – no premium
Strike price	Set = 0. DB's are paid the total revenue associated with reactive purchase.
Quantity	Quantity of reactive demand deemed to be vested. Could potentially vary with real power demand.

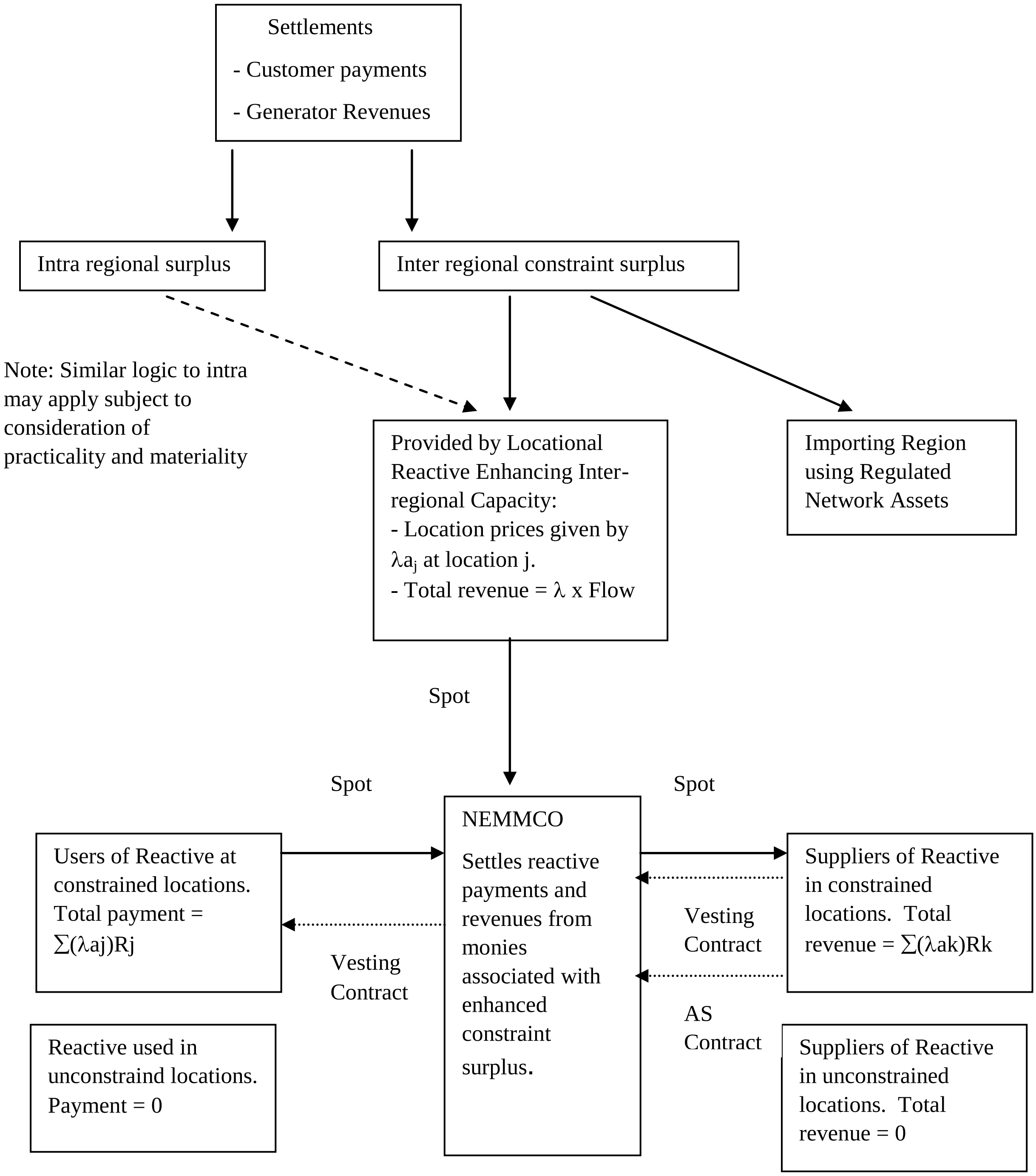
With pricing based on the value of reactive as determined through the dispatch process, the settlement and payment flows, together with a contract overlay, are displayed in Figure 2.3. Of particular note are the following:

- "Vesting" contracts that might be established to secure current financial positions and responsibilities (associated with DB reactive withdrawals and generation connection agreements) would have no associated premium payments. There is correspondingly no risk to NEMMCO associated with these contracts.
- Ancillary service contracts that NEMMCO counter party would most likely have premium payments. There would be a risk to NEMMCO in over valuing the benefits associated with contracted ancillary services.
- The (locational) reactive price signals the value of reactive in the market.
- Ancillary services would be dispatched to maximise the value of trade, and would occur as part of the competitive operation of the market.
- The interregional surplus allocation to the importing region would not contain that contribution associated with enhanced capacity provided by the ancillary service.

- The reactive price signal will reflect the value of additional reactive, and as such will have the characteristic similar to that displayed by the "top end" of the energy market.
- The allocation of constraint surplus to NEMMCO for contract settlement is a "who pays" issue. There are alternative models such as a levy on the market.

Figure 2.3 Spot Price Reactive Arrangements

(Arrows indicate money flows)



3 Code Obligations for Network Control Ancillary Services

The National Electricity Market (NEM) Code outlines the obligations and responsibilities of NEMMCO, network service providers and generators with regard to the services classified as ancillary services. An understanding of the current obligations and potential Code issues is integral to the development of alternative arrangements intended to introduce increased competition for these services.

Of particular interest in this appendix are the Code responsibilities and obligations associated with the procurement and use of voltage control / reactive services. These responsibilities and obligations relate to the providers and users of reactive services, which are NEMMCO, Transmission Network Service Providers (TNSP), Distribution Network Service Providers (DNSP)[10] and generators. The other network ancillary services of stability and network loading control have not been subject to the same level of interpretation and debate as have reactive services.

With regards to the Code, particular issues relevant to the development competitive arrangements for the provision of Network Control Ancillary Services (NCAS) are as follows:

- the responsibilities of NEMMCO in relation to power system security, voltage control, intra and inter-regional network planning;
- the responsibilities and obligations of TNSP's in relation to maintaining satisfactory voltage profiles and reducing network constraints within a region; and
- the responsibilities of DNSP's in relation to reactive withdrawn from transmission networks.

3.1 Code and Interpretation of Responsibilities

3.1.1 NEMMCO

Chapters 3 and 4 of the Code provide NEMMCO with responsibilities regarding ancillary services provision and for voltage control[11]. This includes the determination of the quantity of ancillary services needed.

NEMMCO has the responsibility to establish an inter-regional Planning Committee to assist in the preparation of the statement of opportunities, to undertake an annual planning review of the power system and to assess applications for new inter-connectors between regions. Among other things, the annual planning review is to identify future network constraints on

10 Retailers have not been included as the control of reactive is considered a Distribution Business issue.

11 3.11.3 (a) of the Code states "NEMMCO must use reasonable endeavours to enter into ancillary services agreements to provide sufficient ancillary services to meet the requirements of Chapter 4 taking into account those which are available for provision or provided under connection agreements."

Section 4.5.2 of the Code states "NEMMCO must use its reasonable endeavours to ensure that sufficient reactive power reserve is available at all times to maintain or restore the power system to a satisfactory operating state after the most critical contingency event as determined by previous analysis or by periodic contingency analysis by NEMMCO".

Section 4.5.1 states "NEMMCO must use its reasonable endeavours to maintain voltage conditions throughout the power system so that the power system remains in a satisfactory operating state.".

power transfers within and between regions, and identify and assess options for the reduction or removal of future network constraints (including the construction of new transmission lines between regions). This responsibility also includes approving regulated inter-connectors based on a net benefit to Customers.

3.1.2 Transmission Network Service Providers

The responsibilities and obligations of TNSP's are outlined in Chapter 5 and Schedule 5 of the Code. This chapter and section outline the responsibilities for voltage control[12], together with identifying and costing options for the removal of intra-regional network constraints.

In principle, the main responsibilities of TNSP's are to develop the technical envelope of the transmission network, and undertake economic analysis for intra-regional network augmentations. There appears no incentives or responsibilities for TNSP's to be concerned with enhancing the capability of regional inter-connectors.

With respect to intra-regional network constraints, the Section 5.6.2 of the Code says that each TNSP and DNSP must analyse the expected future operation of their networks and conduct an annual planning review. Where necessity for augmentation is identified joint planning by the relevant NSP's should be undertaken in order to determine plans for consideration by relevant parties. Where analysis indicates that relevant technical limits of the network will be exceeded, the NSP must notify any affected Code Participants and advise of the expected time required to allow appropriate corrective action. Within this time the NSP must consult the relevant parties on the possible options to address the projected limitations. NSP's must carry out economic cost effectiveness analysis of possible options that maximises the net benefit to Customers while meeting technical requirements of schedule 5.1 of the Code. Following consultations, the NSP must prepare a report to be made available to relevant parties that includes recommended action to be taken. This may be disputed by Code Participants if the impact on system charges applicable to that Code Participants is more than 2%, in which case the affected Code Participant must negotiate in good faith with a view to reaching an agreement on the action to be taken.

The above description indicates that the Code provides for distribution business and TNSP's to cooperate in the development of options for reactive supply. Schedule 5.3.5 places power factor limits that DNSP's should remain within during periods of high loading. However, there appear no clear commercial incentives on NSP's to arrive at the most economic option.

Further and what has been subject to different interpretations is the obligation of TNSP's to reduce intra-regional constraints through a process that does not consider the economics of removal, but only the costs – via economic cost effectiveness analysis - of options to remove the constraint(s)[13]. Noting that cost effective analysis is not defined in the Code, the question

[12] S5.1.4 of schedule 5.1 states "A Transmission Network Service Provider must plan and design extensions of its network and equipment for control of voltage such that … As the voltage limits that apply in different parts of the power system are dictated by considerations of economics or voltage stability or the design of existing equipment, the Network Service Provider must advise NEMMCO where a different range of voltage magnitude applies.

[13] Section 5.6.2 (f) states "Network Service Providers must carry out economic cost effectiveness analysis of possible options to identify the option that maximises the net benefit to Customers over a period of at least 15 years, while meeting technical requirements of schedule 5.1 of the Code."

is whether TNSP's should consider the "do nothing" option in the economic cost effectiveness analysis of projected intra-regional constraints. The Code does not seem to impose an obligation to maintain regional status, but only specifies that TNSP's are to identify constraints and what needs to be done to eliminate these constraints. This interpretation has intra and inter-regional network planning decisions made on a similar basis.

3.1.3 Distribution Network Service Providers

As previously mentioned, schedule 5.3.5 of the Code indicates the obligations on DNSP's to maintain reasonable power factors.

3.1.4 Generators

The obligations of generators are set out in Section 5.2.5 and Schedule 5.2 of the Code.

The obligation on generators for reactive (schedule 5.2.5.1) has also been subject to interpretation, in regard to capability to supply and actual supply.

The issue here whether generators need to supply reactive to enable their trading product of MW to be transported, or whether it is a TNSP responsibility to provide transport capacity for MWs injected into to grid. The former interpretation would have reactive capability and use as part of a connection agreement, while the later would have reactive sold by generators. Of note is that for a number of NSW generators, reactive capability greater than the Code requirement of 0.9 power factor is needed to obtain full generation capability.

In any case, the current arrangements have mandatory provision of reactive from generators under their respective connection agreements.

3.2 Summary and Recommendations Relating to Voltage Control

As has been noted, there are a number of current issues with the Code that are subject to review. In particular the Code appears to signal joint responsibilities in some areas and has also been subject to different interpretations in other areas. Of note is that the Code:

- signals both TNSP's and NEMMCO to have responsibilities in regard to voltage control service;
- provides NEMMCO with the overall responsibility for coordination of intra and inter-regional network planning;
- provides for TNSP's and DNSP's to cooperate in the development of optimal planning, and while does place a requirement on DNSP's to maintain reasonable power factors, may not provide clear commercial incentives to these parties;
- has been subject to interpretation as to the responsibilities of TNSP's in regards to maintaining inter-regional capability;
- is silent on the requirement of either NEMMCO or TNSP's to maintain inter-regional transfer limits at defined levels.

Noting the observations regarding the Code and the move towards competitive arrangements in NCAS, the following Code issues should be considered:

- Because (as described in the main body of the report) the market can ascribe a value to link transfer capacity at the margin, augmentation of intra-regional network capacities should be by way of economic analysis (that includes the “do nothing” option).
- Responsibilities for voltage control services and for maintaining or enhancing inter-regional capacity should be clarified.
- In relation to potential changes to the arrangements associated with the procurement of reactive:
  - review the commercial incentives regarding reactive planning for TNSP’s and DNSP’s; and
  - review of the mandatory reactive requirements of generators in relation to the reactive provision.

4 Enhanced Spot Trading Examples

This appendix presents an example of the way enhanced spot trading would function, to illustrate the sorts of outcomes that would result to dispatch, pricing and financial positions of participants.

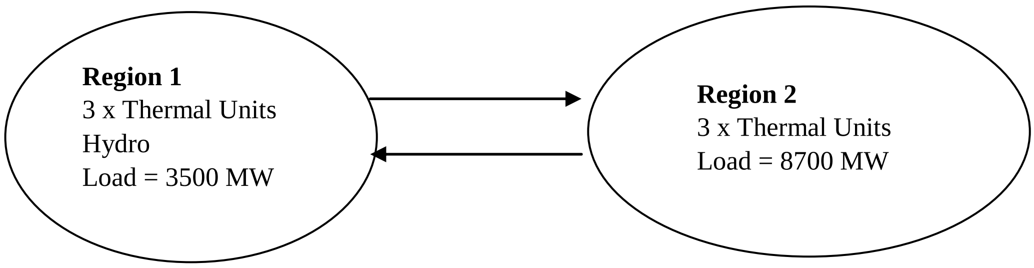
The example consists of three cases in which an assumed hydro power station, by way of its generation, can influence the capacity of imports from an interconnector.

The example assumes the following:

- There are two regions (Region 1 and Region 2) that each have three thermal generators. Region 1 also has the generator known as "Hydro".
- The demands in the respective regions are 3500 MW in region 1 and 8700 MW in region 2.
- The regions are connected by an interconnector that has a normal limit of 1000 MW for power transfers from Region 2 to Region 1. This limit can be increased with Hydro operation - to a maximum limit of 1500 MW. The relationship of transfer limit to Hydro operation is as follows:

  Region 2 to Region 1 Limit = 1000 MW + 2.5 x Hydro Gen

The figure below presents the situation described.



Limit = 1000 MW + 2.5 x Hydro Gen

For simplicity, the example is based on a one hour time interval.

Case 1: Hydro Not Required in Current Situation

Region 1 Generator 2 bids in 2000 MW of generation. Hydro is the most expensive generator bidding and is not required under current dispatch rules.

Current Dispatch Rules

Limit treated as 1000 MW

Hydro not dispatched.

Bids

Item	Region 1	Region 2
Generator 1 Bid	1000 MW @ $10/MWh	5000 MW @ $5/MWh
Generator 2 Bid	2000 MW @ $50/MWh	5000 MW @ $10/MWh
Generator 3 Bid	1000 MW @ $200/MWh	2000 MW @ $15/MWh
Hydro Bid	200 MW @ $70/MWh	NA

Dispatch

Item	Region 1	Region 2
Generator 1	1000	5000
Generator 2	1500	4700
Generator 3	0	0
Hydro	0	NA

Regional Summary

Item	Region 1	Region 2
Total Generation	2500	9700
Import	1000	-1000
Load	3500	8700
Pool Price	$50/MWh	$10/MWh

Notes:

IR Constraint Surplus
Income: 1000MW x $40/MWh = $40,000
Expenses TNSP's 1000MW x $40/MWh = $40,000
Hydro is not dispatched as it is more expensive than Generator 2 in Region 1.

Enhanced Dispatch Model

Hydro impact on interconnector limit recognised in dispatch.
All Hydro dispatched

Bids

Item	Region 1	Region 2
Generator 1 Bid	1000 MW @ $10/MWh	5000 MW @ $5/MWh
Generator 2 Bid	2000 MW @ $50/MWh	5000 MW @ $10/MWh
Generator 3 Bid	1000 MW @ $200/MWh	2000 MW @ $15/MWh
Hydro Bid	200 MW @ $70/MWh	-

Dispatch

Item	Region 1	Region 2
Generator 1	1000	5000
Generator 2	800	5000
Generator 3	0	200
Hydro	200	NA

Regional Summary

Item	Region 1	Region 2
Total Generation	2000	10200
Import	1500	-1500
Load	3500	8700
Pool Price	$50/MWh	$15/MWh

Notes:

IR Surplus

Income 1500MW x $35/MWh= $52,500
Expenses TNSP's 1000MW x $35/MWh = $35,000
To Hydro 500 MW x $35/MWh = $17,500

It is cheaper to use the high priced Hydro together with lower priced Region 2 generation than Generator 2 in Region 1.

Total Hydro income

Spot	200 MW @ $50/MWh = $10,000
IR Allocation	500 MW @ $35/MWh = $17,500
Total	= $27,500
Average Hydro price for generation $27,500/200	= $137.5/MWh

Hydro is not the marginal plant and receives an average price for generation dispatched greater than its bid price.

Increased value of trade due to Hydro operation:

Region 1: Generator 2 savings	700 MW @ $50/MWh = + $35000
Hydro cost	200 MW @ $70/MWh = - $14000
Region 2: Generator 2 cost	300 MW @ $10/MWh = - $ 3000
Generator 3 cost	200 MW @ $15/MWh = - $ 3000
Total	**$15000**

Changed Financial Positions $

	Region 1	**Region2**
Generator 1	0	25,000
Generator 2	0	25,000
Generator 3	0	0
Hydro	13,500	NA
Customer	0	-43,500
NSP	-5,000	-

Totals 8,500 6.500 **$15,000**

Case 2 Hydro Required in Current Situation

Generator 2 in Region 1 MW bid reduced (from 2000 MW) to 1000 MW.
Hydro required under current dispatch rules.

Current Dispatch Rules

Bids

Item	Region 1	Region 2
Generator 1 Bid	1000 MW @ $10/MWh	5000 MW @ $5/MWh
Generator 2 Bid	1000 MW @ $20/MWh	5000 MW @ $10/MWh
Generator 3 Bid	1000 MW @ $200/MWh	2000 MW @ $15/MWh
Hydro Bid	200 MW @ $70/MWh	-

Dispatch

Item	Region 1	Region 2
Generator 1	1000	5000
Generator 2	1000	4700
Generator 3	300	0
Hydro	200	NA

Regional Summary

Item	Region 1	Region 2
Total Generation	2500	9700
Import	1000	-1000
Load	3500	8700
Pool Price	$200/MWh	$10/MWh

Notes:

IR Constraint Surplus
Income: 1000MW x $190/MWh = $190,000
Expenses TNSP's 1000MW x $190/MWh = $190,000

All Hydro is required.

Enhanced Dispatch Model

Hydro dispatch in turn increases the import limit to Region1 allowing greater imports of lower priced Region 2 generation. When 143MW of Hydro has been dispatched, the import limit has increased to the extent that no more Hydro is required.

Note that the marginal generation source in Region 1 is a combination of Hydro and the additional generation that can be used from Region 2 by virtue of the consequential increase in import limit. Consequently, Region 1 Pool Price can be understood as follows:

One additional MW of demand in Region 1 would be supplied by Hydro generation and imports in the ration of 1 to 2.5 respectively (using Hydro has a consequential impact to the import limit to Region 1).

Region 1 SMP = ($70/MWh + 2.5 x $15/MWh)/3.5 = $31/MWh

Bids

Item	Region 1	Region 2
Generator 1 Bid	1000 MW @ $10/MWh	5000 MW @ $5/MWh
Generator 2 Bid	1000 MW @ $20/MWh	5000 MW @ $10/MWh
Generator 3 Bid	1000 MW @ $200/MWh	2000 MW @ $15/MWh
Hydro Bid	200 MW @ $70/MWh	-

Dispatch

Item	Region 1	Region 2
Generator 1	1000	5000
Generator 2	1000	5000
Generator 3	0	57
Hydro	143	NA

Regional Summary

Item	Region 1	Region 2
Total Generation	2143	10057
Import	1357	-1357
Load	3500	8700
Pool Price	$31/MWh	$15/MWh

Notes:

IR Constraint Surplus

Income: 1357MW x $16/MWh = $21,712

Expenses TNSP's 1000MW x $16/MWh = $16,000

To Hydro 357MW x $16/MWh = $ 5,712

Total Hydro Income

Spot 143MW x $31/MWh = $4,433

IR Allocation = $5,712

Total = $10,145

Average Hydro price for generation $10145/143MW = $70/MWh

Hydro is the marginal plant and receives its bid price.

Changed value of trade due to changed Hydro operation:

Region 1 Generator 3 savings 300 MW @$200/MWh =+$60000

Hydro cost 57 MW @ $70/MWh = +$ 3990

Region 2 Generator 2 cost 300 MW @ $10/MWh = - $3000

Generator 3 cost 57 MW @ $15/MWh = - $ 835

Total **$60,155**

Changed Financial Positions $

	Region 1	**Region2**
Generator 1	-169,000	+25,000
Generator 2	-169,000	+25,000
Generator 3	0	0
Hydro	-26,000	NA
Customer	+591,500	-43,500
NSP	-174,000	

Totals 53,500 6,500 **$60,000**

Note small difference due to rounding of pool price in Region 1

Case 3 Hydro Required in Current Situation

Generator 2 in Region 1 further reduces it's Bid MW from 1000 MW to 500 MW.

Current Dispatch Rules

Bids

Item	Region 1	Region 2
Generator 1 Bid	1000 MW @ $10/MWh	5000 MW @ $5/MWh
Generator 2 Bid	500 MW @ $20/MWh	5000 MW @ $10/MWh
Generator 3 Bid	1000 MW @ $200/MWh	2000 MW @ $15/MWh
Hydro Bid	200 MW @ $70/MWh	-

Dispatch

Item	Region 1	Region 2
Generator 1	1000	5000
Generator 2	500	4700
Generator 3	800	0
Hydro	200	NA

Regional Summary

Item	Region 1	Region 2
Total Generation	200	9700
Import	1000	-1000
Load	3500	8700
Pool Price	$200/MWh	$10/MWh

Notes:

IR Constraint Surplus

Income:		1000MW x $190/MWh = $190,000
Expenses	TNSP's	1000MW x $190/MWh = $190,000

Enhanced Dispatch Model

Hydro dispatch in turn increases the import limit to Region1 allowing greater imports of lower priced Region 2 generation. However, all Hydro is now needed as well as 300 MW of Generator 3 in Region 1. Generator 3 is the marginal generator in Region 1.

Bids

Item	**Region 1**	**Region 2**
Generator 1 Bid	1000 MW @ $10/MWh	5000 MW @ $5/MWh
Generator 2 Bid	500 MW @ $20/MWh	5000 MW @ $10/MWh
Generator 3 Bid	1000 MW @ $200/MWh	2000 MW @ $15/MWh
Hydro Bid	200 MW @ $70/MWh	-

Dispatch

Item	**Region 1**	**Region 2**
Generator 1	1000	5000
Generator 2	500	5000
Generator 3	300	200
Hydro	200	NA

Regional Summary

Item	**Region 1**	**Region 2**
Total Generation	200	10200
Import	1500	-1500
Load	3500	8700
Pool Price	$200/MWh	$15/MWh

Notes:

IR Constraint Surplus

Income:		1500MW x $185/MWh = $277,500
Expenses	TNSP's	1000MW x $185/MWh = $185,000
To Hydro		500MW x $185/MWh = $ 92,500

Total Hydro Income

Spot	200MW x $200/MWh = $ 40,000
IR Allocation	= $ 92,500
Total	$132,500

Average Hydro price for generation $132,500/200MW = $662/MWh

Changed value of trade due to changed Hydro operation:

Region 1	Generator 3 savings	500MW @$200/MWh =+$100,000	
Hydro cost		0 MW @ $70/MWh = +$	0
Region 2	Generator 2 cost	300 MW @ $10/MWh = -$	3,000
Generator 3 cost		200 MW @ $15/MWh = - $	3,000
Total			**$94,000**

Changed Financial Positions $

	Region 1	**Region2**
Generator 1	0	25000
Generator 2	0	25000
Generator 3	0	0
Hydro	92,500	NA
Customer	0	-43500
NSP	-5000	-

Totals	87,500	6,500	**$94,000**

5 Reform in the US Relating to Ancillary Services

5.1 FERC Electricity Reforms

5.1.1 Background

In recent years the US Federal Energy Regulatory Commission (FERC) has promoted the concept of open access transmission as the latest stage in reform of the US electricity industry. The US industry traditionally relied on investor owned utilities providing exclusive supply in franchise areas under state based formal regulatory regimes.

Over time, these arrangements resulted in large differences in average retail prices between states, with low price states charging in the order of 5 to 6 c/kWh (US$), and the high price states (California and the NY/New England region) between 10 and 12 c/kWh.

The objective of open access transmission is to facilitate an increased level of interstate trade, so that low cost power can more readily flow to the high cost regions. Earlier reforms under the Public Utility Regulatory Policies Act (PURPA) of 1986 enabled the development of new generation entry in the form of Independent Power Producers (IPP's). However, under PURPA existing utilities were obliged to purchase the energy from IPP's under regulated tariffs, for on sale to utility customers. Open transmission access is seen as a means of removing barriers to new entry, and improving the ability of IPP's to secure direct access to contestable customers.

On 29 March 1995, the FERC issued a Notice of Proposed Rule (NOPR), which outlined the FERC's approach to transmission open access. This was followed by a period of public consultations and hearings on the NOPR.

On 24 April 1996, the FERC handed down their Final Rule No.888 - "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities".

The Rule basically requires transmission-owning entities to offer an open access transmission tariff on a non-discriminatory basis, with such tariffs to be filed with the FERC for approval. The Rule seeks to unbundle the costs of transmission service, including the provision of ancillary services, from other utility costs. Rule 888 is a large document of some 800 pages.

Handed down at the same time as Rule 888 was an associated Rule 889 - "Open Access Same-Time Information System and Standards of Conduct (OASIS Final Rule)". This Rule requires the installation of OASIS computer systems, so that there can be full real time public access to current transmission tariffs and electricity system data and conditions. (Presumably this is to overcome problems of information asymmetry).

There have been three subsequent amendment to Rule 888 (Amendment A, B, and C). Amended Rule 888A, handed down on 4 March 1997, reaffirmed the basic determinations of Rule 888, and made a number of clarifications. This was in response to a number of submissions from utilities challenging various aspects of Rule 888.

Amendment B (25 November 1997) examined the public reporting burden estimated in Rule 888, and reaffirmed the requirements of the Rule. Amendment C (20 January 1998) denied a re-hearing request from Otter Tail Power Company concerning the services a pool may offer and provided clarification of the Rule on this point.

Amendments B and C therefore deal with relatively minor matters. Amendment A however is a restatement and clarification of Rule 888, and is a similarly large document of some 920 pages.

5.1.2 Ancillary Service Provisions of FERC Rule 888

Both Rule 888 and Rule 888-A have a Chapter D that deals with ancillary services. Rule 888 requires that the following **six ancillary services** must be included in an open access transmission tariff (the approximate Australian NEM equivalents as defined in the Ancillary Service Framework or elsewhere in the Code are shown in brackets):

(1) Scheduling, System Control and Dispatch Service
(paid for through pool fees in the NEM);

(2) Reactive Supply and Voltage Control from Generation Sources Service;
(part of the continuous and contingency voltage control services)

(3) Regulation and Frequency Response Service;
(small and large frequency deviation management services)

(4) Energy Imbalance Service;
(not applicable in the NEM centralised pool design)

(5) Operating Reserve - Spinning Reserve Service; and
(energy market top end and large deviation frequency management service)

(6) Operating Reserve - Supplemental Reserve Service.
(energy market top end)

The Rule requires that the Transmission Provider **must provide**, and the Transmission Customer **must purchase** from the Transmission Provider, the first **two** services, subject to conditions set out in the Rule.

The Transmission Provider **must offer** the remaining **four** services to the Transmission Customer serving load in the Transmission Provider's control area. The Transmission Customer that is serving load in the Transmission Provider's control area **must acquire** these four services from the Transmission Provider, or a third party, or self provide.

In the Australian context, a Transmission Provider would be a transmission NSP such as TransGrid, and a Transmission Customer would be a Distributor/Retailer such as EnergyAustralia or Integral Energy. Note that the Transmission Provider must provide reactive supply from its own assets, or by agreement with generators within its area, and that the Transmission Customers must purchase this reactive supply at the tariff price.

In general, the required quantities of ancillary services are centrally determined in accordance with “Good Utility Practice”, and follow guidelines laid down by the National Electricity Reliability Council (NERC), and its regional subsidiaries.

5.2 Californian Electricity Market Reforms

5.2.1 Background

The Californian electricity system is large by Australian standards, with a summer peak load in the order of 42,000MW. Three large vertically integrated investor-owned utilities have traditionally dominated electricity supply in the state. These are:

- Pacific Gas & Electric (PG&E - the largest investor owned utility in the USA);
- Southern California Edison (SCE); and
- San Diego Gas & Electric (SDGE).

These utilities supply to their own customers, and also supply in bulk to various publicly owned Municipal Utility Departments, which provide distribution and retail services to their own customers. The high voltage transmission network is also connected to the neighbouring states of Oregon, Nevada, and Arizona.

Electricity prices in California are the highest in the USA, and this has resulted in the Californian Government mandating substantial reform of the industry through Assembly Bill 1890, which was enacted in September 1996. This Bill promotes competition in electricity supply through the creation of Power Exchange to facilitate day to day electricity trading, and an Independent System Operator, with responsibility for system control and security.

5.2.2 Structural Reform

Since the passage of AB1890, the Californian ISO, and the Californian Power Exchange (PX) have been created, with the wholesale market commencing operation in March 1998. The three utilities have separate, and largely independent, operating divisions for generation, for transmission and for retailing and distribution, with some, but not all, of the generation facilities being sold to other companies. The generation division is required to sell all of its production through the PX just as the retail division is required to buy all of its purchases through the PX. Having made the sales/purchases, these three utilities are free to act as their own Scheduling Coordinators (SC) for the lodging of detailed schedules with the ISO. Use of the PX by other utilities is not compulsory, and other utilities are free to purchase through other Scheduling Coordinators (SC's). It is estimated that approximately 80% of California's energy is traded through the PX.

The SC's must lodge all power production schedules with the ISO, which then examines the schedules to ensure reliable operation of the network. If the lodged schedules result in congestion, or operation of the system outside safe and reliable limits, then the dispatch schedules are adjusted in accordance with incremental and decremental bids and offers until the congestion is relieved and/or reliable limits are achieved. The trading period is one hour, and prices are set on an ex-post basis.

5.2.3 The ISO Tariff

Details of the operation of the ISO are included in the ISO Tariff, which was submitted and approved by the FERC in early 1998. Section 2.5 of the Tariff deals with ancillary services. The Tariff is in a continual state of revision, and the sections shown in the Appendices were current as at November 1998. The ancillary service provisions are discussed below.

5.2.4 Ancillary Services

The ancillary services covered by the ISO Tariff are:

(i) Regulation (frequency);

(ii) Spinning Reserve;

(iii) Non-Spinning Reserve (fast start plant);

(iv) Replacement Reserve (capable of starting in 2 hours);

(v) Voltage Support; and

(vi) Black Start capability.

Bids for Non-Spinning Reserve and Replacement Reserve may be submitted by the Demand-side as well as by owners of Generation.

The ISO is responsible for ensuring that there are sufficient ancillary services available to maintain the reliability of the ISO Controlled Grid consistent with Western System Coordinating Council (WSCC) and NERC criteria. The ISO sets the required standard for each Ancillary Service necessary to maintain the reliable operation of the ISO Controlled Grid. Ancillary service standards are based on WSCC Minimum Operating Reliability Criteria (MORC) and ISO Controlled Grid reliability requirements. The ISO Grid Operations Committee, in conjunction with the relevant reliability council (WSCC), develops these ancillary service standards to determine reasonableness, cost effectiveness, and adherence to national and WSCC standards.

The ISO standards are then used as a basis for determining, on an hourly basis, the required quantity and type of each Ancillary Service. The ISO then allocates the required quantities to the Scheduling Coordinators.

The ISO's ancillary service requirements may be self provided by Scheduling Coordinators. Those ancillary services which the ISO requires to be available, but which are not being self provided, are competitively procured by the ISO from Scheduling Coordinators in the Day-Ahead Market, Hour-Ahead Market and in real time or by longer term contracts.

The ISO manages both ISO procured and self-provided ancillary services as part of the real time dispatch, and calculates payments and charges the cost for ancillary services to Scheduling Coordinators. While the price for ancillary services might be determined on a market basis from offers, the FERC has imposed cost based price caps on certain services. There is concern for the possible exploitation of local market power. However this is causing some problems, with the price cap ($US250/MWh) being below the operating costs of some types of reserve plant.

For Frequency Control and System Reliability, the ISO procures on a daily and hourly basis, Regulation, Spinning, Non-Spinning and Replacement Reserves. There is also provision for the ISO to procure Replacement Reserve on a longer-term basis if necessary to meet reliability criteria, subject to ISO Board approval.

For Black Start Generation, the ISO contracts annually (or for such other period as the ISO may determine is economically advantageous).

For Voltage Support, the ISO contracts annually, and on a daily or hourly basis as required to maintain system reliability. The ISO determines on an hourly basis for each day the quantity and location of Voltage Support required to maintain voltage levels and reactive margins within WSCC and NERC criteria using a power flow study based on the quantity and location of scheduled Demand. The ISO issues daily voltage schedules, which are required to be maintained for ISO Controlled Grid reliability.

There is an obligation for generators to maintain the ISO specified voltage schedule at the transmission interconnection points to the extent possible, while operating within the power factor range specified in their interconnection agreements, or for contracted Must Take or Must Run Generation, in accordance with those obligations.

For Generating Units not operating under one of these agreements, the minimum power factor range is within a band of 0.90 lag (producing VARs) and 0.95 lead (absorbing VARs) power factors. Participating Generators with Generating Units existing at the ISO Operations Date that were unable to meet this operating power factor requirement could apply to the ISO for an exemption. Prior to granting such an exemption, the ISO required the Participating Transmission Owner (TO) or Utility Distribution Company (UDC), to whose system the relevant Generating Units were interconnected, to notify it of the existing contractual requirements for voltage support established prior to the ISO Operations Date.

The ISO is entitled to instruct Participating Generators to operate their Generating Units at specified points within their power factor ranges. Generators receive no compensation for operating within these specified ranges.

If the ISO requires additional Voltage Support, it procures this either through Reliability Must-Run Contracts or, if no other more economic sources are available, by instructing a Generating Unit to move its MVar output outside its mandatory range. Only if the Generating Unit must reduce its MW output, in order to comply with such an instruction, is it compensated.

All Loads directly connected to the ISO Controlled Grid are required to maintain reactive flow at grid interface points within a specified power factor band of 0.97 lag to 0.99 lead. Loads are not compensated for the service of maintaining the power factor at required levels within the bandwidth.

The ISO is authorised to levy penalties against Participating Generators, UDCs or Loads, whose Voltage Support does not comply with ISO's requirements.