WHO SHOULD PAY FOR ANCILLARY SERVICES?

A Project Commissioned by the NEMMCO Ancillary Services Reference Group

FINAL REPORT

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GLOSSARY OF TERMS

AC Loadflow Model: A mathematical model of an electrical network that includes an explicit representation of voltage, angles and real and reactive power, and potentially other facilities such as explicit models of contingency constraints. Such a model could be embedded in a nodal energy market model.

AGC regulation: A sub-task of AGC explicitly concerned with the management of frequency and time errors.

Ancillary Service (AS): A set of technical services necessary or desirable to support the secure trading of electricity over the network.

Area Control Error (ACE): An estimate of the MW generation deficiency in a given control area. In the NEM, a control area is usually the whole of an interconnected system.

Automatic Generation Control (AGC): A centralised process whereby generators are controlled to meet generation targets set by the energy market and by the requirements to manage frequency and other deviations.

Contingency control: In the context of an electricity system, the management of possible event whose timing is unpredictable but which can potentially disturb the system, thereby requiring explicitly measures to be taken beforehand to protect system security.

Continuous control: In the context of an electricity system, the management of a particular technical variable such as voltage or frequency on an ongoing basis.

Cost Reflective Network Pricing (CRNP): The methodology used in the NEM to allocate location-specific costs of the transmission network to loads.

Dispatch Price: An energy price (regionally-based) calculated by the SPD process just prior to the start of the 5-minute dispatch period to which it applies.

Distribution Network Service Providers (DNSPs): Code participants who provide the network that connects end users to a point of connection to the transmission network.

Enablement: A process by which a facility is made ready to provide an ancillary service should a contingency occur. In some cases enablement is used to provide a continuous service when there is no current means to measure continuous performance.

Energy Deviations: The difference between actual energy production or consumption and that which had been scheduled through the energy market SPD process.

Energy Deviations Market: An arrangement whereby energy deviations are paid and charged to parties in the energy market according to an accounting process based on a real time pricing formula. This formula is designed to reward behaviour that tends to correct frequency deviations, and charge for behaviour that causes them.

Energy Market/Dispatch Basepoint: A continuous profile of power production (measured in MW but with an energy profile equivalent) determined by the scheduling prcing and dispatch process (see later definition). Note that this has been adjusted in the AGC implementation to correct for plant performance lags. The term *Five-minute Basepoint* is used to distinguish the profile that would follow from the five-minute energy market dispatch process by ramping between energy market *Dispatch Setpoints*.

Energy Market/Dispatch Setpoint: A power level, determined through the energy market SPD process, which is level of generation (or load) targeted for a unit or load at the end of the following 5 minute dispatch period.

Filtered System Error (FSE): A system-wide variable derived from the System Error by a calculation that smooths out very short-term (of the order of seconds) fluctuations.

Frequency Control Ancillary Services (FCAS): A group of technical services that are provided to manage frequency and time errors in the system to within standards set by the NECA Reliability Panel.

Half-hour Energy Market Price: In the context of the NEM, this is a regionally-based price calculated as the arithmetic average of the 5-minute dispatch prices determined by the SPD process within the half hour.

Light on the Hill: A term used in this report to describe the future time and ultimate vision of how the AS markets should operate.

National Electricity Market (NEM): The electricity market that operates in Australia under the National Electricity Code.

National Electricity Code (Code): The formal rules for the operation of the NEM.

National Electricity Code Administrator (NECA): The organisation set up under the National Electricity Law to administer the Code

National Electricity Market Management Code (NEMMCO): The organisation set up under the National Electricity Law to run the NEM and to operate the electricity system.

NECA Reliability Panel: A Panel set up under NECA to make determinations relating to reliability standards in the NEM.

Network Control Ancillary Services (NCAS): A group of technical services that are provided to support and enhance the secure power transfer capability of the network.

Network Service Providers (NSPs): Code participants who provide network transfer capability to the NEM.

One-way Market: A term used in this report to describe a market arrangement where a single buyer (usually NEMMCO) procures services through some competitive process. A key characteristic of a one-way market is that the requirement for the service is determined by the buyer, and not by any direct beneficiaries of the service, so that some means must be found to pay for the services procured.

Real Time Pricing (RTP): The pricing mechanism proposed for the *energy deviations market*, whereby prices are calculated at very short time intervals (of the order of seconds) depending on the physical state of the system at the time.

Spot Market: A market that operates in the timeframe of the energy market established by the NEM: i.e. prices are determined each 5 minutes and settled on the half-hour. This is to be distinguished from a real time market (using *Real Time Pricing*), which is a characteristic of the energy deviations market proposed in the Evaluation Report.

Scheduling, Pricing and Dispatch (SPD): The process by which facilities operating in the energy market are scheduled for operation, their output or consumption priced and the instructions issued (by NEMMCO) for actual operation. In the NEM this operates on a 5-minute time-step at present.

System Control and Data Acquisition (SCADA): A geographically dispersed system for gathering data throughout the electricity system, processing it centrally and transmitting signals to control electricity facilities. In the NEM this operates in tiers run by NSPs and, at the peak, NEMMCO.

System Error: A term used in this report to represent a value calculated by the AGC that includes frequency error, time error and various other adjustments, but prior to being "filtered" (see *Filtered System Error*).

System Restart Ancillary Service (SRAS): The AS that provides facilities to allow the system to be re-started in the event of a widespread system failure.

Transition: A term used in this report to describe the period of AS market evolution prior to the achievement of the light on the hill, which is the long-term vision of how AS markets should operate.

Transmission Network Service Providers (TNSPs): Code participants who provide high voltage network transfer capability to the NEM. These are currently regionally-based.

Two-way Market: A term used in this report to highlight a market arrangement whereby the beneficiaries of particular AS trade directly with potential AS providers through some mechanism managed by NEMMCO. NEMMCO does not directly determine how much is traded, but manages the system to maintain system security depending on the outcome of that trading.

EXECUTIVE SUMMARY

Background

The Ancillary Services Reference Group (ASRG) which advises NEMMCO commissioned Intelligent Energy Systems (IES) to prepare a report on the development of an ancillary services market to support the National Electricity Market (NEM). This was to be based on a framework for the study developed by the ASRG and reviewed by the consultant. The complete study was split into two stages that were, in brief:

- an evaluation of and recommendations on the mechanism that should apply to the procurement pricing and dispatch of each defined ancillary service; and
- a framework and recommendations for which Code participants should be charged for each ancillary service and appropriate charging mechanisms.

At the time of writing a draft of the first stage report is available on NEMMCO's website[1]. This will be referred to as the draft Evaluation Report. The ASRG's document describing the framework within which the review is to be conducted will be referred to as the Framework Report, also available on NEMMCO's website. The current report covers the second stage of the project - the issue of "who pays" and the appropriate charging mechanisms. Reflecting current usage it will be called the Who Pays Report.

The following overview requires a familiarity with the terms and proposals developed in the first stage Evaluation Report. However, some approaches have evolved in the period since the draft was prepared.

In both parts of the study the ASRG required the consultant to describe a long-term view of desired outcomes, which it termed the light on the hill. This term will be used to describe the long-term in this report. The ASRG also required that a transition path from the present to the light on the hill be developed, both for market arrangements and for charging mechanisms. The report describes the transition, but many details need to be finalised during the implementation phase.

For the purpose of analysis IES has chosen to group the ancillary services defined in the ASRG's Framework Report:

- Ancillary Services concerned with balancing power supply and demand over short time intervals throughout the system; the ***Frequency Control Ancillary Services (FCAS);***
- Ancillary Services concerned with maintaining and extending the operational efficiency and capability of the network within secure operating limits; the ***Network Control Ancillary Services (NCAS);***

[1] www.nemmco.com.au

- The Ancillary Service concerned with recovery from a partial or total power system failure; the ***System Restart Ancillary Service (SRAS);***

It is also useful to divide the first two into those required for continuous operation and those that are required to deal with contingencies. It should be noted, however, that these services would begin to overlap if steps are taken to utilise networks more intensively. In this report, it has been found convenient to analyse the options within closely-related sub-groups of the above. For example, continuous and contingency-base voltage control are treated together because of their close relationship.

Overview of Charging Approach

Current practice

Under the current arrangements for ancillary services (AS) in the NEM, resources are procured in several ways.

- Some are provided by NEMMCO though a tender process and long-term contracts written with successful providers. NEMMCO then uses long-term contract prices and quantities to dispatch the resources at spot time, with the key objective of maintaining a secure system. Some of this dispatch is organised through the energy market clearing software known as the Scheduling, Pricing and Dispatch module (SPD). For various reasons others are dispatched manually.

- Some are mandated under the Code and provided though connection agreements between energy market participants and their network service providers (NSPs), For example, generators are required to provide a basic reactive power capability. No payments are made to providers for these services and there has been controversy as to how these mandatory requirements are to be interpreted.

- Some are provided by NSPs who recover their fixed costs through regulated network charges.

- Some can potentially be provided by resources owned either by competitive or by regulated entities. Difficult boundary issues arise between the regulated and competitive sectors in these cases.

NEMMCO's contracts with AS providers have remuneration arrangements based essentially on long term offer prices, with some provision for compensation if the position of providers in the energy spot market is affected. Irrespective of the method of payment, AS costs incurred by NEMMCO are recovered by charging *Customers who are loads in proportion to the energy they consume* (gross trading interval energy). By and large, retailers pay these costs in the first instance.

Payments under proposed light on the hill arrangements

The two-way market arrangements proposed for the light on the hill in the Evaluation Report resolve "who pays and how much" for AS where such markets are feasible, as the costs of AS provision would be internalised within the prices of products traded between market participants. Standards and tradeable products must be defined. These markets would implement the policy prescriptions along lines that arise from the work of the American economist Coase.

For some ancillary services and for some cost elements, such two-way markets may not be practicable in any foreseeable timeframe. This is almost certainly the case for system restart facilities, which will remain an externality to the energy and ancillary service markets. It is also possible that some forms of NCAS will not be prime candidates for provision by markets in the foreseeable future, although this outcome should not be pre-judged. In these cases the payment principle described below for the transition should continue to apply.

The proposition that some AS should be provided as a mandatory requirement has been rejected. All AS should be provided on a commercial basis, even though competition may not be practicable. This proposition should not be contentious for FCAS. In the case of some forms of NCAS there are market power considerations that must be managed, but these may not be as pervasive as is sometimes argued. However, the mandating of certain technical requirements for facilities connecting to the network should be maintained.

Payments during the transition to the light on the hill

Recommended transitional arrangements for the procurement and dispatch of ancillary services generally involve improving the competitiveness of one-way procurement and dispatch arrangements. In addition, the Evaluation Report recommends clarification and re-definition of frequency and network security standards and implementation, with a view to making them more transparent. During this transition period NEMMCO will continue to procure many of these services – they will *remain external to the energy market* and must be paid for in some other way. The principle to be applied where practicable in this case is that of “causer pays”, an application of the well known “polluter pays” principle first expounded by the English economist Pigou. The causer pays principle should also be applied to cost elements in the light on the hill arrangements that cannot practically be included in two-way market arrangements.

It must be recognised that the light on the hill conditions are likely to be reached at different times for different ancillary services. Further, the transition in terms of who pays for particular ancillary services will involve a number of discrete steps:

- Subject only to Code changes and the development of alternative payment procedures, a re-assignment of costs to different participants before *any* change in the procurement or operational arrangements. We propose such an early re-assignment for most NCAS costs.

- A re-assignment of costs upon the implementation of transitional procurement and market arrangements. This could be done through the proposed FCAS enablement markets, although it may be simpler in this and other cases to proceed directly to market arrangements proposed for the light on the hill, where the question of payment would be resolved in any case, as noted below.

- A further re-assignment of costs will occur upon the implementation of two-way market arrangements where they are practicable. For example, this would occur when the proposed energy deviations market is implemented.

The following summarises the light on the hill and transition payment arrangements that are set out in tabular form, and in more detail, in the conclusions section of this report.

FCAS: Management of Small Frequency Deviations

Proposed market arrangements

For the light on the hill an energy deviations market is proposed. Energy market participants will trade deviations from energy market outcomes, here called energy deviations, essentially by responding to a pricing rule that would reward behaviour that tends to stabilise frequency, and charge for behaviour that tends to destabilise it. To support this market it is proposed to make a settlement adjustment that would correct a current anomaly whereby units are dispatched on the basis of 5-minute energy market dispatch prices, but are paid on the basis of half-hour average prices. This issue is being addressed in another NEMMCO forum. It is not strictly necessary to resolve it to implement the proposed AS arrangements, although it would be desirable.

The proposed energy deviations market would also be supported by an enhancement to the current procedure whereby providers are paid for the *enablement of capability* to manage small frequency deviations under the control of NEMMCO's Automatic Generation Control (AGC) system. This latter arrangement, which we call a *spot market for small deviation FCAS enablement*, is an extension of the current approach and is also recommended as a priority for implementation over for the transition period. Any potential provider will be able to offer her capability into the spot market for small deviation FCAS enablement, which operates in conjunction with the energy spot market. All successful providers will receive a common clearing price if accepted.

Light on the hill payment arrangements

5-minute settlement adjustment

1. We note that the NEMMCO Pricing and Settlement reference Group is considering this matter. However, we note also that an adjustment based on the calculation of 5-minute performance factors would be consistent with our proposed approach to allocating the cost of small deviation FCAS enablement and phasing in the energy deviations market.

Energy deviations market

2. The energy deviations market will provide for most small deviation FCAS and there will be no additional cash injections required after settlement. There may be a small residue as for the energy market depending on the details of the implementation. The effect of this market is that those who cause frequency deviations and those who act to correct them will pay and receive accordingly.

Spot market for small deviation FCAS enablement

3. Providers will be paid for providing this capability through NEMMCO's settlement process and these costs must be recovered. Options for this are considered for the transition.

Payments by non-dispatchable loads and other plant

4. For retail loads supplied through a given connection point or points between the transmission and distribution network, and where deviation performance can be measured, costs or payments should be assigned in proportion to energy consumed:
    - on a trading interval basis for the energy deviations market; and
    - on a settlement period basis for the one way spot market for enablement; and
    - excepting loads that can demonstrate energy deviation performance, whose payments will be netted out from the remainder of the load supplied through the connection point or points.

Transition payment arrangements

Market for small deviation FCAS enablement

1. Prior to development of the systems for spot trading as proposed for the light on the hill, weekly re-submits of small deviation FCAS offer prices for enablement should be supported, and a common clearing price obtained from the SPD engine paid. The spot market facility (requiring some additional IT development) should be implemented as a priority for the transition.

2. The preferred approach to payment could be to phase in the energy deviations market directly to move directly to continuous measurement for the purpose of allocating small deviation FCAS costs and to phase in the energy deviations market from there. Other phasing options should also be evaluated. For this reason we commend early development of a demonstration software module and associated testing and evaluation of phasing options.

Transition to the energy deviations market

3. See above.

Impact of payment arrangements

At present, all small deviation FCAS is charged to retailers or direct energy users in the first instance, in proportion to their gross trading interval consumption. Under the proposed light on the hill and transition payment arrangements, the costs and benefits would be shared between energy market buyers and sellers according to their measured contribution to causing and correcting frequency deviations. These arrangements would be phased in, so that the sharing and total cost of the service can be expected to evolve during the transition.

Preliminary studies indicate that a proportion of these costs would be re-assigned to generators under the proposed payment arrangements, and especially to those generators who fail to follow energy market dispatch outcomes, including any energy variations to dispatch required if they are *enabled* to perform small deviation FCAS. There would be no mandatory provision or long term contracting by NEMMCO for this service.

FCAS: Management of large frequency deviations

Proposed market arrangements

The market arrangements proposed to manage small frequency deviations should help manage a significant part of the large frequency deviations arising from contingencies such as generator, load and certain network outages. As such events are infrequent, additional facilities are required. We propose spot markets for large deviation FCAS enablement, run along similar lines to the markets for small deviation FCAS enablement, which is also an extension of current practice. This would be implemented in a one-way form for the transition i.e. NEMMCO sets the requirement and pays for its provision). For the light on the hill this facility would be retained and extended for two-way trading i.e. when this is done the requirement for the service will be set by the energy dispatch patterns determined through the energy market SPD process.

Light on the hill payment arrangement

Two-way market for large deviation FCAS enablement

1. The energy SPD process would be used to clear the offers made into this market. As proposed in this report, the requirement would be set as a variable rather than a fixed, externally determined amount. The SPD logic would then determine the optimal quantity of large deviation FCAS to be enabled, the corresponding energy market dispatch and a common clearing price for the FCAS as well as for the various regions in the energy market. The effect is that the potential causers of the largest frequency deviations at any time will pay for these enablement costs.

Large deviation FCAS use costs

2. No explicit use costs for large deviation FCAS will be paid. Providers that incur such costs will be paid in the market for large deviation FCAS enablement and in the energy deviations market if used. To this end registered potential providers should be subject to SCADA-level metering or a satisfactory alternative to measure performance and to provide a basis for payment.

Other Costs

3. To the extent that enablement and use costs cannot reasonably be assigned according to the above logic, they should be allocated to all market participants according to gross trading interval energy.

Transition payment arrangements

One-way spot market in large deviation FCAS enablement

1. During the transition, the requirement for large deviation FCAS enablement will continue to be externally determined by NEMMCO rather than through the SPD model. This will result in a net payment by NEMMCO to providers whose cost must then be recovered.

2. In view of the potential difficulty of identifying and assigning costs to potential causers of large contingencies by alternative means, it is proposed that the default cost allocation arrangements in the Code for this service be retained in the interim, and that the implementation of the light on the hill in this service be a high priority.

Likely impact of payment arrangements

Under current arrangements, retailers and direct consumers pay for all large deviation FCAS costs. This is an inappropriate cost allocation given that the requirement for this service is predominantly driven by the supply-side of the market, and the large suppliers or transporters in particular. Under the proposed payment arrangements the costs would generally be assigned to the largest generators, loads and network elements that might cause a contingent event, with any "use" covered through the energy deviations market. There would be profitable opportunities for fast-acting plant on both-sides of the energy market to operate under the large deviation FCAS arrangements. There would be no mandatory provision or long term contracting by NEMMCO for this service.

NCAS: Voltage Control-continuous and contingency

Proposed market arrangements

As recommended in the Evaluation Report, the light on the hill arrangements have the quantity of reactive necessary to support energy transfers across the network (in the face of possible contingencies) provided through competitive two-way spot markets, coordinated with the energy spot market and dispatched by NEMMCO. Under such market arrangements there would be no requirement to separately assign reactive/NCAS enablement costs, as such payments would come through spot market settlements. Such arrangements would support long-term contracting either by NEMMCO, NSPs, entrepreneurial NCAS providers or parties in the business of selling network hedges, perhaps to support an entrepreneurial link.

For the transition, the Evaluation Report recommended a review, reformulation and publication of the generic constraints that expresses the relationship between the capability of the network and NCAS services (predominantly the contingency group of NCAS services). This was intended to prepare the way for progressive implementation of the proposed light on the hill arrangements, beginning with the most prospective applications. Also recommended for the transition is a broadening of the potential sources of reactive supply and a continuation of the current dispatch process by NEMMCO.

In recognition of the close relationship between voltage continuous and voltage contingency, this report recommends that a single set of arrangements be established for voltage control *during the transitional period. The rationale for this is that during the transitional period, the value of reactive (either procurement or reserve) derives from the common generic constraint equations formulated in the SPD. Consequently, any separation of the voltage continuous and voltage contingency services would be arbitrary during this period. For the eventual light on the hill arrangements, there would be scope for the separate pricing of reactive enablement and provision.*

Light on the hill payment arrangements

The intent behind implementing a workable AC loadflow model for the SPD engine for the light on the hill is to support two-way trade in both reactive power and "real" power in the normal energy market, while explicitly recognising the requirement to manage voltages throughout the network.

1. Where reactive enablement and provision is suitable for two-way trading as recommended in the Evaluation Report, no further payment arrangements are required.

2. For the purpose of settling reactive consumption and provision at the boundaries between distribution and transmission networks, the reactive requirements of the Code (expressed as a power factor) should set as a base contract level for trading in reactive power.

3. Where such a market is not established and these ancillary services costs would continue to be incurred by NEMMCO in the first instance, costs should continue to be allocated as for the transition, described below. This allocation would emulate the market outcome.

Transition payment arrangements

During the transition period voltage control/NCAS quantities would be determined and procured or provided by NSPs in respect of support for transfer capability for individual Generators or groups of Customers, or by NEMMCO or any other party willing to so provide in the case of services supporting inter-regional transfer capability. Economic efficiency would be improved through more transparent pricing arrangements and cost allocation principles that recognised the causers and beneficiaries of reactive/NCAS services.

1. The provision of reactive power or reactive power capability by generators should cease to be regarded as a mandatory service.

2. NSPs and generators should negotiate a base level of reactive capability and provision that would be sufficient to support the generator's own use of the network. The capability should be provided as part of the generator's connection agreement, as it would have been if commercially negotiated. The method of calculation should be determined by NEMMCO in consultation with the generators and the NSPs, and published.

3. In broad terms, the remaining capability should be provided as a commercial service either under the proposed arrangements described below, or by negotiation, and in both cases subject to limits on market power. *Providers should continue to be dispatched according to NEMMCO instructions except where noted below.*

4. Reactive provision should be priced and traded jointly with reactive capability through the SPD generic constraints[2] formulated by NEMMCO, for which relatively early implementation should be possible. (i.e. there would be no distinction made between the two services).

5. The rule for charging for reactive (provision and enablement) and the other NCAS is that the party should pay who ultimately receives the residue stream impacted by the particular ancillary service (or the corresponding premiums after the cash flow stream is assigned to a hedge contract or auctioned). This maintains an accountability link between the cost of any additional ancillary service provision and the energy spot market benefits from providing the corresponding increased secure network capability. Prior to the light on the hill this cost allocation would be:

   - To the TNSP or other party that receives, or would receive, the settlement residue associated with each generic constraint or potential constraint managed by the SPD;
   - If a recipient is a TNSP the amount would flow through to customers through a modification to network charges.
   - Services supporting a regional network may not accrue settlement residues directly but the costs should in any case be assigned to the TNSP in the first instance, as the beneficiaries are the customers of that TNSP.

6. In the event of a contingency, any NCAS use costs should be assigned to the party who caused the contingency, or assigned to the same beneficiaries as for other NCAS costs if a causer cannot be identified.

NCAS: Stability and Network Loading Control

Proposed market arrangements

As for voltage control, the stability and network loading ancillary services that support energy transfers across the network (in the face of possible contingencies) should ideally be provided through competitive two-way spot markets, coordinated with the energy spot market and dispatched by NEMMCO. As previously mentioned for the voltage control services:

- There would be no requirement to separately assign enablement costs, as such payments would come through spot market settlements.

[2] Continuous reactive power that supports network flows between regions, or to major load centres within regions, can be subject to effective competition from alternative sources. In such cases voltage-continuous NCAS should be the subject of a generic constraint applied to the SPD process, dispatched in this manner and generally follow the same approach as for contingency-based NCAS (see later). Suitable network locations for this treatment should be determined by NEMMCO during its ongoing review of the application of generic constraints in the SPD, as proposed in the Evaluation Report.

- Such arrangements would support long-term contracting either by NEMMCO, NSPs, entrepreneurial NCAS providers or parties in the business of selling network hedges, perhaps to support an entrepreneurial link.

The limited number of suppliers and the technical nature of these services suggest that they may not be immediately suitable for competitive trading. Negotiated or regulated procurement may be the most suitable.

Together with the voltage control ancillary services, the transition period would consist of the review, reformulation and publication of the generic constraints that drive the valuation of these ancillary services under the current SPD formulation.

Light on the hill payment arrangements

The payment proposals follow the summary outlined for voltage control. Particular issues for stability and network loading control are as follows:

1. The installation of generator stability equipment (eg. stabilisers) should remain a power system security issue, and remain mandatory if required.
2. In the event of a contingency, any NCAS use costs should be assigned to the party who caused the contingency, or, if such a causer cannot be identified, to the beneficiaries who pay for the costs of NCAS enablement.

Transition payment arrangements

1. Stability and network loading ancillary services would be procured and provided either through NEMMCO or NSPs, albeit subject to more transparent pricing arrangements.
2. In the same manner as for voltage control ancillary service, the rule for charging for enablement is that the party should pay who ultimately receives, or would receive, any settlement residue stream supported by the particular NCAS service (or the corresponding premiums after the cash flow stream is assigned to a hedge contract or auctioned).

Likely impact of payment arrangements

As for voltage control ancillary services, the net effect of the proposed changes would be first, to re-align these ancillary service costs more directly to the causers and beneficiaries of these services and, second, to make more transparent the scope for competitive provision. Specifically, changes along these lines will be required to support the ancillary service needs of entrepreneurial links.

NCAS: Spot Market Trading Benefits

Proposed market arrangements

Spot market trading benefits will accrue by implementing the light on the hill trading arrangements for NCAS and, more broadly and after due consideration of the options, from progressively relaxing a range of constraints currently imposed on spot market outcomes in the SPD dispatch process.

The ultimate vision is based on a more accurate network model that would replace the current transportation model in the SPD with a full AC loadflow model. This would improve the benefits of trade and also improve prospects for pricing and managing the continuous voltage control service. Such an approach would be consistent with NECA's flagging of this option in the draft report on its transmission and distribution network pricing review.

Light on the hill payment arrangements

1. No additional costs would be incurred that would need to be explicitly covered, other than development costs that would be recovered either through pool fees and a focussed research and development program that could attract R&D funding from governments.

Transition payment arrangements

1. Implementation costs funded through pool fees.

Likely impact of payment arrangements

Implementation of spot market trading benefits should deliver an unambiguous improvement in economic efficiency (development costs and other overheads aside) although some re-allocation of financial outcomes in the energy market could occur in the short term. Such a re-allocation occurs with every change in market conditions.

SRAS: System restart ancillary service

Proposed procurement arrangements

While there is no prospect of establishing two-way market arrangements for this service, some marginal improvements have been proposed. In essence, these reduce to providing a basic service obtained through a process of competitive acquisition, much as for recent practice except that the term of the contract should be longer than one year. In addition, supplementary re-start resources could be registered for use as required (accepting that such resources could also be used for other ancillary services). These resources may be procured by a DNSP to provide local relief or possibly by NEMMCO at the request of a regionally-based coalition that has indicated a willingness to pay. The intent is to ameliorate, where possible and desirable, the immediate costs to end users of any total or partial system shutdown, in addition to providing a basic restart service. The Reliability Panel would oversee the development of a system re-start strategy.

Light on the hill payment arrangements

Basic restart service

1. For each set of electrically inter-connected NEM regions, all ongoing basic re-start SRAS costs to support that inter-connected set of regions should be allocated to market participants in proportion to gross trading interval energy produced or consumed within those inter-connected regions.

2. Use costs should be allocated in a similar way, expect where review after an event reveals a clear and culpable causer, in which case use costs should be assigned to them.

Supplementary restart facilities

3. Availability and use costs would be assigned by DNSPs to their customers or by NEMMCO to the coalition of interests that has agreed to pay for a particular regionally-facility.

Transition payment arrangements

1. The payment methodology for the light on the hill should be implemented as soon as possible.

Likely impact of payment arrangements

The cost of the basic restart service arrangements will be shared by all market participants, except for that component of costs which, after a specific incident, would be allocated to the assessed causer. The costs of any supplementary service would be paid by the customers who benefit directly from the additional local or regional facility.

Code Changes

Both the new market arrangements and the new arrangements for payments will require Code Changes. It is important that these define the objectives of the new arrangements and the expected milestones but maintain some flexibility in the details of how they are achieved. The areas where changes are likely to be required are summarised in Section 9 of this report.

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1 Introduction

1.1 The Brief

The Ancillary Services Reference Group (ASRG) which advises NEMMCO commissioned Intelligent Energy Systems (IES) to prepare a report on the development of an ancillary services (AS) market to support the National Electricity Market (NEM). This was to be based on a framework for the study developed by the ASRG and reviewed by the consultant. The complete study was to be split into two stages that were, in brief:

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In both parts of the study the ASRG required the consultant to describe a long-term view of desired outcomes, which it termed the light on the hill. This term will be used to describe the long-term in this report. The ASRG also required that a transition path from the present to the light on the hill be developed, both for market arrangements and for charging mechanisms.

1.2 Structure of this Report

For the purpose of analysis in the Evaluation Report, IES chose to group the Ancillary Services defined in the ASRG's Framework Report in the following way:

- Ancillary Services concerned with balancing power supply and demand over short time intervals throughout the system; the ***Frequency Control Ancillary Services (FCAS)****;*
- Ancillary Services concerned with maintaining and extending the operational efficiency and capability of the network within secure operating limits; the ***Network Control Ancillary Services (NCAS);***

[3] www.nemmco.com.au

- The Ancillary Service concerned with recovery from a partial or total power system failure; the ***System Restart Ancillary Service (SRAS);***

The purpose of this grouping was to highlight the common features of each service when considering the possibilities for market arrangements. It is also useful to divide the first two into those required for continuous operation and those that are required to deal with contingencies. It should be noted, however, that the continuous services generally support the contingency services, and the boundaries between the broad groups could begin to overlap if steps are taken to utilise networks more intensively. This matter is discussed in more detail in the following section.

For this report, each service has been considered separately where a significance difference in approach is indicated. For example, the continuous and contingency voltage control services are treated together because of their close relationship. Similarly, stability and network loading control have been grouped together to avoid undue repetition. While these NCAS are driven by different technical issues, and while the timing and practicality of implementing market arrangements will also differ between them, their common role in supporting secure network transfer capability, as considered at some length in the Evaluation Report, should be borne in mind.

Section 2 following considers the principles for allocating the cost of ancillary services from an economic perspective. These principles are then applied to each of the services or service groupings in the sections that follow. Each of these sections first reviews the proposals for that service or service grouping from the Evaluation Report. A discussion of the potential causers, providers and beneficiaries of the service then follows. Options for payment are then considered and the final proposals for the service or service grouping are then summarised, together with the likely impact on various Code participants.

Section 9 contains an outline of the Code changes that would be required to implement the recommendations of this review.

The Conclusions include tables that show the present situation, transition arrangements and the light on the hill. They show the key market proposals from the Evaluation Report as well as payment proposals from the current report. As noted earlier, some market proposals have evolved since the draft Evaluation Report was published, and some gaps that were deferred to this stage of the project have been filled in.

The Appendices contain studies and example that support the discussion and proposals contained in the body of the report.

2 Principles for Allocation of Ancillary Service Costs

2.1 The Origins of the Notion of 'Ancillary Services'

Briefly, according to the Code, '(a) Ancillary Services are services that are essential to the management of power system security, facilitate orderly trading in electricity and ensure that electricity supples are of acceptable quality ...' (Clause 3.11.1). Proposals for the development of markets in AS raise complex issues related to the move from the former public service arrangement to the new market arrangements. It will be useful to restate here some relevant points.

As outlined in the evaluation study, under the previous centralised regime the integrated utility defined and provided a set of operations, commonly called 'ancillary services'[4], necessary for the production, distribution and use of electricity. The evaluation study has categorised these into three classes: frequency control ancillary services (FCAS), network control ancillary services (NCAS), and system restart ancillary services (SRAS)[5]. The purpose of these services was to allow the former central public utility, by deploying system control functions, to keep the system operating stably within prescribed standards of security and reliability and to provide, qualitatively, a basic service of electricity. Quality here refers to the production of electrical energy with characteristics, notably of frequency, voltage, waveform and others, which make it useable.

The relevant security, reliability and quality criteria were self-prescribed by the public utility according to what it regarded as best available practice based on the state-of-the-art in technical knowledge. The operating assumption was that the relevant security, reliability and basic quality criteria formed a discrete bundle, capable of feasibly precise definition, necessary for maintaining the physical and functional integrity of the system. In fact, notions of what was technically and practically appropriate varied. The criteria for these services differed somewhat from State to State, although the differences were generally minor. Some of these differences persist in the NEM arrangements.

Because of the physical and mechanical characteristics of the production, distribution and use of electricity, in an operating network there are constant imbalances or interactions between generation (supply or production) and loads (demand or consumption) which result in actual or potential system changes. These affect the operational characteristics of the power system, in particular, the frequency, voltage and waveform, and may also affect the secure capability of the network. They may be random and generally rather large, as, for example, in the case of

[4] The services designated as ancillary vary from system to system around the world, as outlined in the evaluation study. In Australia the decision was made to bundle as many as possible of the operations required for electrical energy production into the energy market and under the NEM only those dealt with in the Evaluation Report were classified as ancillary.

[5] In general, these categories can be regarded as distinct but there are some interdependencies between them, notably between FCAS and NCAS, which, under some circumstances, need to be taken into account and are discussed further later in this section.

large generator and network outages. At the other extreme they may be more or less continuous and generally rather small, as, for example, in the case of the adjustments which have to be made as loads switch on or off or generators ramp up or down. Ancillary services were the technical operational responses necessary to constrain these effects of various kinds, which could be more or less continuous, or more or less random (contingent), within the set criteria previously described. The various types of AS required for these functions were produced by specific technical resource capabilities as discussed in the Evaluation Report, and taken up later in this report.

2.2 Ancillary Services and the Economics and Regulation of the NEM

Under the design of the NEM the wide range of *system control* functions of the previous integrated utilities was replaced by a partitioning of those functions into two groups of *regulatory control* functions:

- those allotted to the *market manager/regulator*, NEMMCO, which are required essentially to ensure the provision and maintenance of arrangements for the sale and purchase of the commodity, electrical energy, in the spot market in accordance with the relevant provisions of the Code; and
- those allotted to the *system administrator/regulator*, NECA, which are required essentially to administer the Code provisions, other than those relating to market management, and to coordinate Code change processes.

Both NEMMCO and NECA are companies formed by guarantee under the corporations law and owned by the participating jurisdictions. Thus, the former, largely self-regulating government business enterprise that provided electricity as a *service* to users in the community through a publicly owned network, for which service users paid tariffs set by governments, was transformed into a commercial system. Regulated by public entities, this commercial system would support the sale by producers of a *commodity*, electrical energy, and its purchase by consumers, either through public or private distributors and retailers, or directly. These transactions are made at prices achieved by the matching of offers and bids in the auctions provided through the energy spot market.

Under the previous dispensation there was no functional or legal separation between the provision and the maintenance of a secure and reliable power system, but with the new dispensation the institutional arrangements are very different. The primary exchange of electrical energy in the spot market is functionally and legally separated from the ongoing maintenance and regulation of a stably operating *market system* based on a *secure and reliable power system*. Both of these are oversighted and coordinated by NEMMCO through the powers and responsibilities allotted to it by the Code.

In effecting this decentralised re-configuring of the previously centralised production and distribution system, it was necessary to find a place for the balancing, risk management and restart functions. While the market designers realised that future development and redefinition of these functions would be necessary, as an interim measure the criteria for ancillary services were expressed technically, and allotted to and taken over by NEMMCO pretty much as they had stood. But they were now specified as requirements under the Code, necessary for the provision of a secure power system and of a commodity of standard, acceptable quality. Since the market could not exist without these standards, because the physical system underlying it would be unstable, the provision of the services necessary to achieve them produces benefits to all Participants, but not necessarily uniformly.

2.3 Approaches to Allocating the Costs of Externalities

As noted in the Evaluation Report, two broad approaches have been developed in economics for meeting the costs of the recognised externalities of transactions. The first is attributed to Pigou who, in 1932, proposed that economic efficiency would be promoted if they were charged as taxes to those responsible for producing them. Known popularly as ‘polluter pays’, and in the present application referred to as ‘causer pays’, this is now a widely adopted basis for policy. This principle is adopted, in general, in this study for the allocation of costs of AS during the transition period and the development of one-way competitive markets and related arrangements.

Numerous difficulties were found in attempts around the world to set appropriate levels of these taxes for externalities, mainly because of difficulties in defining, measuring and allotting them. The theorem published by Coase in 1960 was largely a response to these difficulties and formed part of the general policy framework favouring markets which is known as ‘public choice’. The theorem can be stated in several ways. Basically, it seeks to reduce the involvement of central public regulators by allowing wider scope for negotiation, based on property rights, among those producing and those affected by the externalities. One formulation useful here is: ‘when the parties affected by externalities can negotiate costlessly with one another, an efficient outcome results no matter how the law assigns responsibility for damages’.

There are numerous theoretical and practical restrictions on the applicability of this policy prescription. These relate to the availability of information, the practical definition of property rights and difficulties of measurement, but it has enjoyed wide application in policy approaches for dealing with externalities over the last fifteen years or so. The principle is adopted in this study where evaluation of the practical issues specific to each case suggests that two-way competitive markets within the stipulated security and reliability standards are feasible. In the remaining cases, including the transition to the light on the hill, costs incurred by NEMMCO for the purchase of AS would be assigned according to the ‘causer pays’ principle where possible.

2.4 Present Arrangements for the Charging of Ancillary Services

As we have seen in the evaluation study, under the present arrangements, NEMMCO, as the central, monopsonistic buyer, procures the defined services through a range of mechanisms. Competitive tendering has been used where there are competing providers. Negotiated contracts are used where competition is insufficiently effective because the potential provider(s) of the service have undue market power. Some services rely on technical requirements currently mandated by the Code. NSPs provide the equipment for some services that support network operation. NEMMCO can, if necessary, obtain some AS by direction. The last is rarely resorted to, but is a source of aggravation to some energy market participants. In short, the current arrangements for procuring AS are complex.

Generally the AS sources previously procured are dispatched at spot time by NEMMCO. It is useful to note two distinctions here. Some resources, namely those used to deal with contingencies, are dispatched to be on immediate standby duty; this process is called *enablement* and typically a payment is then required to the provider for that service. If a contingency occurs and a resource is actually used to deal with a contingency, or of the service is of a continuous nature, additional *use* costs are also incurred, which may also attract a payment, but not always.

Thus, in general, using contract arrangements with Participants that provide for the necessary services to be available, and enabled and used as necessary, NEMMCO procures and deploys the services to meet the stipulated security and quality criteria.

The payments required for the purchase of those services is then subsequently distributed by way of fees to those Market Participants who are *purchasers of electrical energy* (loads), according to their 'trading interval gross energy' (Clause 3, Definitions, Schedule 9G, Code Chapter 9)[6].

Thus, in terms of regulatory economics, the current model is that of a central public regulator acquiring resources necessary to maintain set system standards of security and reliability to ensure market stability, *without inquiring into the responsibility or accountability for whatever it was that produced the need for the service*. The regulator then recoups the expenditures incurred to obtain those services by levying taxes on the purchasers of the primary traded good according to their consumption of that good. It might be noted in passing that this does not follow Pigou's approach and is a somewhat unusual method of defraying the costs of regulation for maintaining the integrity of an operating system. Such costs are more generally allotted, as we have seen, to those who produce them so that they bear the costs of their actions and thus have incentives to modify their behaviour.

It was no doubt because of this that the ACCC said, *inter alia*, in its Determination that

…'it therefore appears to be inherently inequitable that only buyers are expected to pay for the provision of such services... the Commission considers that the best signals will be sent to the market if the fee recovery model allocates costs to those who caused the need for ancillary services or, if that is not feasible, then charges for those services should be based on the benefit received, perhaps determined by reference to energy transactions in the market.'

[6] It is to be noted that Clause 6.2 of Schedule 9G provides that the costs of ancillary services are payable by Market Participants. The ambit of this is narrowed by the definition of 'trading interval gross energy' in Clause 3 of that Schedule as relating to Market Participants financially responsible for loads, ie, Customers.

2.5 Recommended Payment Proposals

2.5.1 Light on the hill phase

For the light on the hill, the introduction of two-way competitive markets would allow, to a considerable degree, the application of Coase's theorem and for participants 'to negotiate costlessly' with each other, or at acceptably low cost, to meet the security and quality requirements imposed by the regulator. . It should be noted that the light on the hill is likely to be achieved much more quickly for some services than others. In overview, then:

- Where two-way markets in AS can be established, the costs of AS provision would be internalised into the market trading arrangements and the requirement for the service would be determined by competitive supply and demand rather than centrally. No external funding would be required.

- In other cases there may be no prospect of establishing two-way markets. In these cases the costs should be allocated according to those who caused the need or who are assessed as the beneficiaries of the service.

- Where security and reliability standards would be breached or threatened despite the above arrangements, some additional AS costs could be incurred by NEMMCO. These would be allocated according to those who caused the need for them or who are the beneficiaries of their provision, or, for any remainder where such causers or beneficiaries cannot be determined, according to metered energy on both sides of the energy market, as system security is a matter of importance to all market participants.

2.5.2 Transition phase

During the transition phase, the costs of some forms of AS can be reduced by developing more efficient ways by which they can be purchased by NEMMCO. Specifically, and for FCAS in particular:

- Competitive spot markets and other transitional arrangements for promoting more competition in AS *supply* could be implemented relatively quickly in some cases. To the extent that is practicable given that such arrangements are transitional, costs should be allocated according to those who caused the need or who are assessed as the beneficiaries of the service. These competitive *supply* arrangements are referred to as one-way markets in this report, to distinguish them when necessary from arrangements where multiple buyers determine the amount supplied.

- Even where no immediate change in market arrangements is practicable in the short-term, it should still be possible to allocate most AS costs those who caused the need or who are assessed as the beneficiaries of the service.

- Where neither of these this is practicable, remaining costs could be allocated to participants according to metered energy, defined as the trading interval gross energy supplied *or* consumed by them individually.

This broad approach implements the philosophy outlined by the ACCC in its determination.

2.6 Related Points

These rules are adopted as the broad bases for dealing with the costs of AS in this report. In implementation it will be necessary to take into account specific considerations such as difficulties in discrimination of accountability and measurement and to make pragmatic judgments as appropriate, and these specifics are dealt with in later sections of this report. However, there are several specific points related to these general rules that need comment.

2.6.1 Mandatory provision and market power

Under the present arrangements it is incumbent upon some Participants to render some part of AS capability and actual AS provision *gratis* as an obligation of connection under Chapter 5 of the Code. Negotiated requirements may also be included as part of generator connection agreements, or on the basis of some other obligation. For example, there is a connection obligation for a significant component of the reactive power capability provided by generators to meet voltage control requirements. Though there might be practical considerations that will have to be taken into account, on the face of it this arrangement is inequitable and may result in some Participants providing ‘hidden subsidies’ to others.

For example, parties other than generators often object to paying extra for generator facilities (specifically, governor control and reactive capability) that they perceive to be an inherent part of the facilities needed by generators to produce and deliver their energy. However, if such capability is not paid for, in the long run it may not be available when needed due to a delayed investment in new plant or an unwillingness to maintain existing plant. The effectiveness of current NEM arrangements in encouraging capacity at the peak or “top end’ of the energy market has been a matter of policy concern for some time and is currently being reviewed by NECA. Failure to pay a fair price for ancillary services required at peak times will tend to exacerbate that problem.

The general economic rule in such cases is that relevant services should be recompensed according to their opportunity cost and, if possible, this should be done by incorporating these services directly into the market arrangements**.**

A related question is how to manage the provision of AS in some circumstances where the provider has market power. This especially applies to reactive power for voltage control and where a particular generator has a degree of spatial monopoly, at least in the short term. Such situations are common but not universal. As argued above, imposing a requirement for mandatory provision as a means of managing market power is not an appropriate paradigm for commercial relationships, as it stifles commercial operation when competitive provision might otherwise be practical.

Where it is not possible to assess the competitive price of the relevant AS by reference to the prices of AS purchased in competitive markets elsewhere, the local value could be computed from the opportunity cost of alternative ways of providing the capability. For example, the cost of capacitor banks could provide such a benchmark where the demand for the service is clearly growing and new increments of supply are required. Even if there were no entry of such plant after a period of, say, 5 years, the service could still be regarded as competitive if the regulator can be satisfied that potential new entry is an effective brake on generator market power in the provision of this service. This matter could be reviewed periodically.

It should also be noted that some requirement for AS may be needed to meet an AS burden imposed by the provider itself as it operates in the energy market. Clearly, it is commercially reasonable that such a component be part of a connection agreement and self-provided by the participant concerned. This situation arises in the case of reactive power provided for voltage control to support market access to the regional reference node.

2.6.2 The security framework for AS

The Code sets out criteria for the secure operation of the system by NEMMCO that have guided the recommendations of this review. In the Evaluation Report we have recommended that the security standards be reviewed through the Reliability Panel against economic criteria. At some stage this could lead to some modification of the criteria set out in the Code and implemented in the various security standards set through NEMMCO and NECA. It is therefore pertinent to briefly review the nature of the security criteria and how any changes in them might affect implementation of the recommendations of this review.

In essence, the Code requires that NEMMCO generally operate the system to withstand a single contingency (random event that physically disturbs the electricity system) without non-commercial load shedding or risk of system instability. If such a contingency occurs, NEMMCO is generally required to restore secure operation as rapidly as possible, and certainly within half an hour. Secure system operation is ultimately a short-term operational matter, and in most cases can be restored with some load shedding if there are no other options. Thus there is a close operational relationship between system security and system reliability.

The “single contingency” security provision implements a common form of risk management for complex systems. If system components are highly reliable (but not fully reliable), the likelihood of more than one contingency occurring at any given time is considered to be much smaller than the likelihood of most single contingencies by themselves. Over all components in the system, a contingency of some sort is not an unusual event, and the costs of guarding against it are generally considered justified. On the other hand, a double contingency is much less likely and more costly to guard against. Thus the single contingency forms a simple and natural boundary for the management of risks in the system, but can only be a rough heuristic. One practical advantage is that the likelihood and duration of contingent events, together with the likely severity of their consequences, do not need to be known with any precision. This advantage carries some weight when the reliability of single components (but not the system as a whole) is so high that estimates of reliability and costs are difficult to obtain. The approach does not preclude the reclassification of multiple events as a single contingency in particular circumstances, for example when the risk of common-mode failure is higher than normal.

One consequence of this approach for ancillary services is that the provision of FCAS to guard against single contingencies allows FCAS to be managed on a system-wide basis. This can be done because a single contingency affecting frequency can be managed from anywhere in the transmission network provided the consequential transmission power flows do not exceed any allowance made for dealing with a single network contingency. This is generally the case at present. However, the implementation of market-based arrangements should not assume that this will continue, although the same principles would still apply. For example, FCAS might need to be provided regionally to some extent, so that the SPD formulation that deals with this should ultimately cater for the trade-off between regional sources where constraints are involved.

A closer examination of the single contingency criterion suggests that it cannot be applied everywhere. For example, the closer to the point of delivery (within the distribution system), the more costly it is likely to be to provide redundancy to meet the criterion. At the other extreme, there may be some critical loads or load zones where a case can be made for more stringent criteria to be applied (e.g. the ability to withstand two contingencies)[7].

To summarise, further consideration of the NEM security criteria as recommended by this review could lead to more complex interactions between the various ancillary service groups identified for analysis in this review. We do not expect charging principles to change, but implementation would need to recognise the interactions.

[7] It should be noted that the desirability of meeting such a criterion does not necessarily imply that it should be done by augmenting the network.

3 FCAS: Management of Small Frequency Deviations

3.1 Overview of Proposed Market Arrangements

3.1.1 Light on the hill

For the light on the hill a two-way energy deviations market is proposed. Energy market participants will buy and sell energy deviations relative to energy market outcomes. The pricing rule for energy deviations would reward behaviour that tends to stabilise frequency, and charge for behaviour that tends to destabilise it.

To support this market, this report proposes a settlement adjustment that would correct a current anomaly whereby units are dispatched on the basis of 5-minute energy market dispatch prices, but are paid on the basis of half-hour average prices. This matter is being considered within another NEMMCO forum. The manner and timing of its resolution need not affect implementation of the other recommendations in this report.

3.1.2 Transition

The proposed energy deviations market would be supported by an enhancement to the current procedure whereby providers are paid for the *enablement of capability*.to manage small frequency deviations under the control of NEMMCO's Automatic Generation Control (AGC) system. This latter arrangement, which we call a *spot market for small deviation FCAS enablement,* is an extension of the current approach and is recommended as a priority for implementation over for the transition period. Any potential provider will be able to offer her capability into a spot market for this service, which will operate in conjunction with the energy spot market. All successful providers will receive a common clearing price if accepted. However, the cost of paying the providers to this *supply* market will need to be recovered in some way.

A phasing in of energy deviations market is also proposed. In addition, there are several transition steps that could be followed when implementing the enablement market that would accelerate the introduction of further competition.

3.2 Causers, Providers and Beneficiaries

Small frequency deviations are the results of an accumulation of relatively small random effects leading to power (and therefore frequency) deviations in one direction or another, as well as potentially more systematic deviations. The main ***causers*** are summarised below.

3.2.1 Causers

Load forecast errors

Short-term load forecasting is normally performed by NEMMCO, for the day ahead, for the hour ahead and five minutes ahead in the 5-minute SPD process. These forecasts always have an inherent inaccuracy, due to the probabilistic nature of system load. Load changes from the forecast can be due to incorrect weather forecasts, changes in large industrial loads from their forecast values and the other factors listed below. However, it may be that forecasting is simply not performed as well as it could be.

Through the development of the NEM consideration has been given to the possibility that retailers could provide their own forecasts (and be accountable for them) through a forward market mechanism integrated with the NEM. This concept was rejected by the ACCC in its determination on the Code, so there is no mechanism for such forecasts to be provided to the system operator. In any case, NEMMCO would still do its own short-term forecasts to meets it system security obligations. Many argue that these forecasts will be superior to any that retailers or other end users could provide (individually, and then aggregated), especially in the SPD 5-minute timeframe of interest here.

If this position is accepted, NEMMCO must be accountable for errors in the 5-minute load forecasts used for the SPD process. Its forecasts can and do affect energy market outcomes and the use of small deviation FCAS. Perfect forecasts cannot be expected, and even if they were accurate over 5 minutes on average, they would not obviate the need to manage some load deviations within the 5-minutes. A reasonable requirement is that NEMMCO's forecasts:

- be *unbiased* in a statistical sense i.e the mean error of actual load and forecast load should approach zero over many samples; and
- achieve a *minimum variance*, i.e. that the statistical measure of variance, or variability from the mean, be as small as possible.

NEMMCO would be accountable for any failures on that score and should report on and explain forecasting performance and what is being done to improve it. If this approach is followed, there is no option but for NEMMCO to charge for the use of the FCAS as if the loads themselves had provided the forecasts that were used. An alternative approach would be to encourage loads to provide 5-minute forecasts. The advantage for a load would be that it could attempt to minimise its liability to pay for load forecast errors through the payment it makes for this service, depending on the payment regime to be implemented. This in turn depends on how the service is to be paid for, to be examined in the next sub-section.

General load variation

There are many cyclic industrial loads, some quite large such as the controllable hot water loads operated by some distributors, which can cause measurable and identifiable frequency excursions. In any case, under current AS arrangements, loads will take no account of the costs they might be incurring in FCAS, even if they are fully responsive to energy spot prices.

As noted above, NEMMCO currently forecasts load each 5 minutes on behalf of the loads but cannot capture in its forecasts the fundamental randomness of most loads, nor significant load variations that occur within the 5 minutes. To the extent that such load variations, or lack of them, can be separately measured from general loads, it may be possible to be more precise in the allocation of costs and rewards to them. They key issue here is one of measurement and, ultimately, materiality.

Deviations (non-conformance) of dispatchable plant

The energy market produces precise dispatch targets that participating dispatchable units are supposed to achieve at the end of each 5-minutes by steadily ramping (if required) toward that value. This is normally done through NEMMCO's AGC. There are many reasons why dispatchable plant may not achieve the desired target level or may deviate within the 5 minutes[8]. Indeed, the Code does provide a tolerance band for such deviations. Further, deviations of this sort (and load deviations as well) are just as capable of reducing as well as increasing the requirement for FCAS.

3.2.2 Current and potential providers

Some important current and potential providers of the service are:

- Plant dedicated to frequency regulation under the control of NEMMCO's AGC.
- Other generating plant not under AGC regulation.
- Controllable DC links that join separate systems; these would be a provider for one system, but should be charged as a non-conforming dispatchable load or generator in the other.
- The natural response of loads to frequency variations.
- Possible direct load modulation on the demand-side

Note that the last two are or could be non-dispatchable and could be significant in their impact.

3.2.3 Measurement of cause and provision

It is evident from the discussion above that the identification and quantification of both the causers and the providers of small deviation FCAS cannot be assessed without detailed quantitative study. Specifically, causers and providers, or even the performance of currently contracted providers, cannot be assessed without measurement. To the extent that this can be done to an acceptable degree of robustness and accuracy, it would provide the basis for allocating the costs of the service provided through a one-way arrangement, as is proposed for the transition. In the absence of such measurements cost allocation would be arbitrary. There can be causers and providers on both sides of the energy market, both currently and with even more variation in future. Such measurement is essential to support the energy deviations market proposed for the light on the hill.

As part of the current brief, NEMMCO supplied some sample 10-second SCADA and AGC data to IES to test the possibility of measuring cause and provision of this service. The results of this preliminary work are summarised in Appendix A. An important conclusion is that measurement and assessment of cause and provision of small deviation FCAS through

[8] The inherent response lags in large thermal plant are one reason. NEMMCO's AGC attempts to account for this to some extent.

SCADA and AGC data is feasible and in fact relatively straightforward, albeit subject to the current limitations of SCADA measurement. The possibilities raised by this are discussed later in the section.

3.2.4 Beneficiaries

The beneficiaries of small deviation FCAS are generally market participants as a whole, who enjoy the stable operation of the system that FCAS provides. However, the Framework Report explicitly notes that a key driver for small deviation FCAS is to ease the burden of providing large deviation FCAS. Thus it could then be argued that the beneficiaries of this service are the potential causers of large contingencies, who might otherwise be burdened with higher enablement and use charges for large deviation FCAS. This argument provides the basis for one option that will be considered later in the section.

3.3 Broad Options for Allocating the Cost of Small Deviation FCAS

3.3.1 Overview

While the light on the hill and transition market proposals for this service define the payment mechanism to a large extent, it is useful to review some broader payment options and issues before proceeding to payment options that are consistent with the AS market proposals.

3.3.2 Potential causers of large contingencies pay

As noted in the Framework Report, the main driver for the requirement for this service is help manage large frequency deviations. Thus it could be argued that the potential causers of large deviations should pay for this as well as for the large deviation service. Counter-arguments are:

- Small deviations are only small because they are controlled. So it is still important for both efficiency and equity that the causers for small deviation pay for that correction.
- At the time of a contingency, both the existing (small) frequency deviation and the larger ones contribute to the extent of the frequency excursion.

Efficiency ought to be the prime consideration in reaching a conclusion on this issue. For this to be achieved it is important that the causers of small frequency deviations incur the costs of correcting their actions whatever the ultimate driver of the requirement is assessed to be. If the causers of large deviations pay, it would be in their interest to seek this outcome, but they then have the practical problem of achieving it. Given the short term and highly dynamic nature of this activity, NEMMCO is in by far the best position to manage it. It should do this by working to achieve a set of frequency standards that have a defendable economic basis, as we have proposed in the Evaluation Report.

3.3.3 Self provision

This was considered as a general option in the Evaluation Report, and is a feature of regulatory arrangements in the US. As noted in the Evaluation Report, self-provision of AS outside some market arrangement does not remove the need to set a quantitative requirement for the AS centrally. As we argue that the market arrangements proposed would produce a more efficient outcome, we do not pursue this approach here.

3.3.4 Mandatory provision

This service is not subject to any form of mandatory provision at present. The case against mandatory provision as a paradigm has been argued in Section 2. In this case there is strong evidence from NEMMCO that the level of competition should be adequate.

3.3.5 Who should act on behalf of non-dispatchable loads?

While customers who are loads currently pay for this service in proportion to trading interval gross energy, for both the light on the hill and the transition the aim is to allocate costs in way that encourages responses that will improve efficiency. This raises an issue of metering practicality. Most end users cannot be metered at the half hourly level, much less over intervals of a few seconds as would be required if costs are to be allocated strictly according to the “causer pays” principle. On the other hand, SCADA-level metering is generally available at the connection points between distributors and transmission networks. The issue of metering and control is critical if anything more than a simple cost allocation based on energy consumed over long periods is to be used. There are two possibilities.

Distributors (DNSPs)

Distributors could be charged or rewarded according to energy deviations measured at their connection points to the transmission network. This would be consistent with the proposed approaches to measuring performance for dispatchable plant, as discussed in Appendix A. Arguments for and against are:

- Metering is relatively easily managed, as noted above.
- As energy deviations and associated large deviation and other fast-acting AS responses are short-term responses requiring communication and control, distributors could be regarded as well suited to manage the service on behalf of their customers. A particular advantage is the likely greater interest in investing in equipment long-term, relative to retailers.
- On the other hand, distributors do not see themselves as being in the energy business, and are not set up to handle trading activities.

Retailers

If retailers are to be charged or paid by whatever mechanism applies, a metering problem arises because many retailers can be operating within a distribution network. Setting aside possible approaches to this issue for the moment, the arguments for and against retailers playing this role are:

- There are metering problems as noted.

- The management of energy deviations can be considered to be a natural extension of the retail energy and load management activities of retailers at present.

Some options for dealing with the metering issue are:

- Assign the charge levied or payment made in relation to this (and other) services at the connection point with the TNSP to all embedded loads, pro-rated on a trading interval gross energy basis.
- Follow the deemed profile approach being considered for the deregulation of small loads in the energy market. In essence, a sample of each class is measured and the performance of that sample is deemed to apply across the whole class.
- Follow either of these approaches but net out any sites (presumably the larger ones) that can provide the evidence of small deviation FCAS performance.

Assessment

Given the close relationship between the proposals for FCAS and the energy market, we consider retailers to be the most appropriate Code Participants to deal with this and other FCAS services involving non-dispatchable loads. Assigning costs to retailers will require a pragmatic approach to cost allocation to deal with the metering issues. The following closely follows the approach used in the energy market, which we commend for consideration during the implementation phase.

- The default cost allocation (however calculated) should be based on performance measurements at the DNSP/TNSP metering point.
- If deeming profiles are used for further retail deregulation, a similar philosophy could be carried though for allocating the costs of this service.
- Where suitable metering or some other evidence of performance is available, these loads should be treated individually and their impact netted out from the residual loads.

It should be noted that the management of this service (including the financial consequences) could be delegated from a retailer to a DNSP or some other third party under a commercial arrangement.

3.4 Payment Options for the Light on the Hill

3.4.1 Settlement adjustment to correct 5-minute dispatch/ half-hour settlement anomaly

This anomaly was considered in the Evaluation Report in relation to this service and it recommended an adjustment to settlements to deal with it. NEMMCO’s Pricing and Dispatch Reference Group is currently considering various options for dealing with this issue. The following should be regarded as options for consideration by that Group. It would be highly desirable, but not strictly necessary, to resolve this anomaly as soon as possible, prior to implementing the proposed small deviation FCAS market arrangements.

We suggest the adjustment could be done in two ways. Further, the change could be made optional during the transition, whatever approach is taken.

5 minute metering

Existing half-hour metering could be adjusted to record at 5-minute rests and settlement carried out on that basis. This would formally recognise that the NEM is actually a 5-minute spot market, even though contracts are traded on a half-hour basis. Advantages and disadvantages are:

- Full metering accuracy would be maintained.
- Settlement and communication loads would increase by a factor of six.
- The approach would not provide any facility for making shorter-term measurements as is proposed for this service.

Use of SCADA metering

Appendix B considers an approach that would correct this anomaly, with an example. It could be implemented in the first instance with SCADA metering, not to record total energy consumption as such, but to record a *5-minute performance factor* that could be used to make a (normally small) adjustment to energy market settlements. While SCADA metering is not ideal, it should be workable if used in this way. We suggest that this approach could be be taken during the transition, pending consideration of metering strategies co-ordinated with the proposed energy deviations market for the light on the hill.

Who pays? – mandatory participation

In this case settlements should balance in the same general way as the energy market. Whether the net effect is a small surplus or deficit, that surplus or deficit should be lumped with the energy market residue and distributed or paid for in the same way.

Who pays? – optional participation

Participation in the adjustment could be optional during the transition, managed as follows.

- Provide the settlement facility and make it optionally available.
- Those who would immediately benefit (i.e. those disadvantaged at present) would be likely to sign up voluntarily.
- Costs would be passed to other energy market participants on a trading interval gross energy basis, to both generators and loads.
- This process would proceed until it would be made a mandatory part of settlement for the light on the hill, although some flexibility should be possible here.

Assessment

During the transition, calculating the adjustment using 5-minute performance factor measurements using SCADA data would be the most readily implemented solution. It would be consistent with proposals for paying for small deviation FCAS, and the workings of the proposed energy deviations market.

Participation should be optional during the transition to reduce concerns about metering. However, the incentive to participate should grow over time.

3.4.2 Energy deviations market

Appendix A contains a preliminary analysis of how frequency deviations could be assessed and priced, and what the outcome of such an approach might be. The study is based on a 10-hour sample of 10-second SCADA data provided by NEMMCO. While further study and analysis during the implementation phase will be required, the preliminary study suggests that the approach is workable. Two matters need to be considered; how settlements are likely to balance and metering issues.

Likely balance of settlements

There are strong parallels between the energy deviations market and the energy spot market as currently implemented. Suppose loads are assessed simply as the sum of the metered energy of generators. Noting that the energy deviations market will trade deviations in energy relative to the spot market:

- Energy market dispatch target generation and loads under the convention above must sum to zero (enforced by SPD dispatch model).
- Actual generation and loads under the convention above must sum to zero (enforced by laws of physics as well as the convention for defining loads).
- It follows that energy deviations must sum to zero and that the net financial outcome for the settlement agent from trading must be zero.

In this simple case there are no residual payments required.

In a real implementation loads would be measured at terminal stations connecting distribution networks to the transmission network. There would then be two sources of a potential settlement residue or shortfall:

- metering error; and
- network losses.

While the parallels with the energy market are close, it is not clear what the sign of the residue will be. It is likely to be small compared to the turnover of the energy deviations market and small also compared to the settlement residue in the energy market. Metering error will also have an effect as discussed below. Given the close relationship to the energy market, one approach would be to treat this residue in the same way as the energy market residue is treated. A much simpler approach would be to make a small percentage adjustment to all charges to ensure the fiscal balance.

Metering issues

The energy deviations market will require measurements at short time intervals probably (4 to 10 seconds) so current commercial metering cannot be used. Long run metering options are:

- Existing commercial meters converted to shorter recording intervals
- SCADA metering
- Specialised local metering

It would be possible in principle to convert existing metering to, say, 5-minute recording intervals but the sheer volume of data would preclude anything more. SCADA level should be adequate for an early implementation as discussed for the transition, although initially limiting the scope of participation. Ultimately, however, dedicated metering with a high level local processing and diagnostics could be developed. Such a development may be additional specialised functions built into existing meters. There are requirements for auditability that must be met.

Irrespective of the form of metering used for the light on the hill or during the transition, it would be inappropriate to alter the energy market metering and settlement process for this purpose. In Appendix A, we consider an approach whereby an *energy deviations performance factor* can be determined. This factor can then be applied to energy market metered vales to calculate the energy deviations market settlements. Auditability will require the development of redundancy checks and other procedures. However, early implementation should be possible if initial participation in the energy deviations market is voluntary.

W*ho should act on behalf of non-dispatchable loads?*

As recommended in the general discussion, retailers rather than distributors should be the counter-parties to dispatchable plant in relation to this service.

3.4.3 Spot market in small deviation FCAS enablement

It is proposed that this facility be implemented during the transition and will remain in operation for the light on the hill. In essence, small deviation FCAS enablement will be purchased through a spot *supply* (one-way) market, the costs of which must be allocated according to some rule. Options for this are considered for the transition later in the section. The preferred approach implemented for the transition should carry through to the light on the hill.

3.5 Payment Options for the Transition

3.5.1 Current SPD facility for small deviation FCAS enablement (AGC regulation)

Early implementation of a spot market in small deviation FCAS enablement is proposed for the transition and considered in the next sub-section. This is an extension of the current approach. An approach that could be implemented even more quickly would be to:

- use the current SPD facilities for co-dispatch of FCAS services, although some re-definition of product categories could be considered as long ads they require no software changes to the SPD;
- support periodic (say weekly) submission of offer prices for the enablement of this and related FCAS services; and
- pay the common clearing price currently available from the SPD process.

This could be done relatively rapidly as no SPD changes would be required and other IT changes should be relatively small.

There seems to be no compelling reason why this transitional step should be tied to any changes in cost allocation. However, it would be preferable in terms of participant acceptance if this could be done. The preliminary analysis of frequency deviations and possible cost allocation approach described in Appendix A suggests that development time should be no obstacle to achieving a simultaneous introduction. This is considered in the next sub-section.

3.5.2 Spot market for small deviation FCAS enablement

This facility is a priority for implementation for the transition. The intermediate step just described would be a large step towards it. This market would remain for the light on the hill, complementing the energy deviations market that would be the main mechanism for dealing with small deviation FCAS. However, while the energy deviations market is two-way and requires no external funding, the spot market in small deviation FCAS enablement is a *supply* market to NEMMCO that must be funded. Options are set out below.

Assign costs to energy market participants in proportion to trading interval gross energy

This is the current approach with market participants being restricted to loads. As loads are by no means the only causers of small frequency deviations, the current approach is neither efficient nor equitable.

Based on the preliminary quantitative study reported in Appendix A, an approach that recognises that causers lie on both sides of the energy market could be to share the cost more broadly: for example, according to trading interval gross energy bought or sold by *all* energy market participants. However, this is also crude, as it does not recognise the individual diversity of cause, and that some parties can cause frequency deviations on some occasions and correct them on.

A more finely tuned application of the “causer pays” principle, and one more likely to result in efficiency improvements, is to measure the cause and correction of these deviations and to charge and pay accordingly. This possibility is considered in the next sub-section.

Assign costs to market participants in proportion to measured cause and provision

Application of the causer pays principle works best if the costs are allocated as directly as possible. If this is not done, causers will see little or no benefit in modifying their behaviour. In the case of small deviation FCAS we have noted that causers and providers are likely to lie on either side of the energy market. In particular, there will be some effective providers who are currently excluded from being paid for their responses.

Measurement of cause and provision should be done by comparing actual energy (power)[9] deviations, relative to the energy market outcome, of individual devices over intervals of much less than 5 minutes (say 4 or 10 seconds) with some benchmark measure of the current energy (power) deviation of the whole system. Power deviation is closely related to frequency deviation[10]. In broad terms:

- If the system is in a current power surplus and a particular measured device or load is also in a power surplus (relative to the outcome of the energy market), then the device can be assessed to be a causer at that instant. Similarly, if the system is in a current power deficit and a particular measured device or load is also in a power deficit, then the device can be assessed to be a causer at that instant also.

- Conversely, if the system is in a current power surplus and a particular measured device or load is in a power deficit (relative to the outcome of the energy market), then the device can be assessed to be a provider at that instant. Similarly, if the system is in a current power deficit and a particular measured device or load is in a power surplus, then the device can be assessed to be a provider at that instant also.

Quantification of these relationships between cause and effect over time is the statistical measures of *covariance* and *correlation*. The application of this measure was discussed at some length in Section 3.5 of the Evaluation Report. It is worthwhile re-quoting the US researchers Hirst and Kirby[11] on this point:

"Generation can be treated in the same way as load in terms of time-varying fluctuations. Generation fluctuations that are positively correlated with load fluctuations are providing regulation and should be compensated for that service. Generation fluctuations that are negatively correlated with load fluctuations increase the load following burden on the control area and should be charged accordingly. Thus while it may make sense to pay generators for making their units available to the system operator (a reservation charge), it may be more important to pay (or charge) generators for real time performance."

Appendix A contains a study that applies that philosophy to a set of sample real time (10 second) data spanning about 10 hours. The study considered the pricing logic that could be

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[9] The instantaneous *rate* of production or consumption of electrical energy is *power* and is measured in MW. Over a small time interval, the energy produced or consumed is simply the power multiplied by the (small) time interval. The dynamic behaviour of a system is best described in terms of power, but the commodity that would be exchanged in any market arrangements would be the corresponding energy.

[10] Specifically, power deviation is closely related to the acceleration of the system and to any sensitivity that the load had with frequency deviation relative to the frequency standard of (50 Herz in Australia). Any system acceleration results in a change in frequency deviation over time.

[11] Hirst and Kirby ORNL/Con-433 "Ancillary Service Details: Regulation, Load Following and Generator Response ", p27.

applied for an energy deviations market, and also the logic that could be applied to allocating the costs of small deviation FCAS enablement. The latter is the task considered here. The study took the following approach:

- Energy deviations (over 10 seconds) of participants were taken to be:

  Actual energy – Energy market base energy – Share of regulation energy if enabled

- The deviation of the system (i.e. a measure of the frequency and time error deviation) was taken to be the *filtered system error*. This measure is available directly from NEMMCO's AGC which is used directly to drive the generating units that regulate the system i.e. drive those that have been selected for small deviation FCAS enablement.

- The value of cause or correction as measured above is proportional to the system deviation, or the *filtered system error*.

When this analysis is followed through, it is possible to draw up a table showing the relative performance of participants in causing and correcting deviations. As presented, the table shows the distribution of dollar payments to participants for each dollar paid out to providers of small deviation FCAS enablement, through NEMMCO's settlement process. The Appendix also argues that this procedure is best performed on a settlement period rather than trading interval basis.

While there are many details to address, implementation of this calculation procedure on an on-line basis should be relatively straightforward. No modification of existing SPD or AGC logic is involved. We therefore commend it for consideration. However, as noted in Appendix A there are several ways to phase in such cost allocation arrangements consistent with the energy deviations market proposed for the light on the hill. We suggest that the appropriate strategy be reviewed after a review of the outcome of a trial using a demonstration pricing and settlement software module for measuring and settling energy deviations.

Determining the amount of small deviation FCAS enablement required

If costs are charged in the manner proposed above, there is a reasonable expectation that generating units enabled for FCAS will be used less than before. We therefore propose that the NEMMCO review the usage of the enabled units 6 months after implementation or earlier and more regularly if practical. The aim of each review would be to adjust the amount that NEMMCO requires to while maintaining the same level of confidence that small deviations can be controlled. The requirement could be related to time of day, type of day and season, or to some other variable such as reserve margins. Ideally, the adjustment would be automatic and adaptive to system conditions, but this could be a longer-term development.

Assigning costs to non-dispatchable loads

Some the usage of small deviation FCAS results from inaccuracies in NEMMCO's short term forecasts and the issue arises as to how the costs of this part of the service should be met. The study reported in Appendix A suggests such measurements can certainly be performed, although this was not done.

While it might seem reasonable that the costs of forecast errors should accrue to NEMMCO, that entity does not in fact possess resources of its own since it is funded by Market Participants. Consequently, if NEMMCO is to continue in this role, such costs should be treated like other costs incurred by NEMMCO; they should be levied on participants in some way, then publicly reported and justified.

The only reasonable approach here is to pass on the costs *on as if the forecasts had been provided by the loads themselves*. If this were done, it would be reasonable, in principle at least, to allow loads to provide NEMMCO with forecasts if they chose to do so, and to pay for the service on the basis of measured deviations from that forecast. This would only make sense if actual performance could be measured in the appropriate time-scale (5 minutes, but at the level of individual retailer loads). This is not generally possible for the transition since metering is not currently available at the level of individual retailers. Thus we propose that NEMMCO remain responsible for dispatch interval load forecasting during the transition.

For retail loads supplied through a given connection point or points between the transmission and distribution network, and where deviation performance can be measured, costs or payments should generally be assigned in proportion to energy consumed on a trading interval basis for the energy deviations market; and on a settlement period basis for the one way spot market for enablement. An exception would be where loads can demonstrate energy deviation performance, whose payments will be netted out from the remainder of the load supplied through the connection point or points.

3.5.3 Phasing in the cost allocation arrangements and energy deviations market

While the proposed energy deviations market will deliver balanced or near-balanced settlements[12], during a transition it may be possible and desirable to have voluntary participation or at least to phase the energy deviations market in. This approach has been proposed for correcting the 5-minute/half hour settlement anomaly in the energy market.

The preliminary study presented Appendix A shows that the recommended approach to allocating small deviation FCAS costs would essentially determine an *ex-post reference price* for energy deviations measured over the previous settlement period. Actual costs incurred by NEMMCO would be charged on that basis. The energy deviations market would be similar except that *the reference price would be set ex ante* and probably with more discrimination in time and location if linked to the energy market price, for example. The ex ante price could be phased in gradually, with the ex post likely to fall to the same degree from competitive pressure.

Appendix A considered a number of phasing options for the cost allocation arrangements for small deviation FCAS enablement, and the closely related energy deviations market. The choice depends amongst other things on the confidence one has in the practicality of real time measurement of deviations. The preliminary study reported in Appendix A gives some cause

[12] Some possible implementations might actually result in settlement residues in a similar way to the energy spot market.

for optimism on this score, but a fuller consideration and more extended testing is required. For this reason we commend early development and trial of the cost allocation, pricing and settlement logic that could be applied.

All small deviation FCAS costs are currently paid by loads. In the absence of a specific cost allocation mechanism, recent Code changes would, from July 2000, default this to payment by all energy market participants on the basis of gross trading interval energy. Given this Code change that applies from July 2000, the choices from that time are:

- Accept the new default payment arrangements and phase in the energy deviations market from there. This could be seen as just as arbitrary and probably more so (on the basis of the preliminary study reported in Appendix A) than is the current allocation to loads, and would be difficult to justify on that ground.
- Allocate small deviation FCAS enablement costs according to some logic based on the measurement of cause and provision, as proposed in this report for this service, phasing in the energy deviations market from there. Two options here are:
  - ❑ maintain payment of enablement by loads initially, to be phased out as the energy deviations market is phased in. This would be based on an assessment along the lines of that reported in Appendix A (which should be confirmed with a large sample), that loads drive the majority of most of the net requirement for this service, even though generators at times do cause deviations that require correction.
  - ❑ Allocate costs to each participant based on a sample measurement period. Although apparently fairer and more discriminating, allocating costs at this level of discrimination on the basis of any sample is potentially fraught with controversy.
- Finally, the energy deviations measurement and settlement logic based on continuous measurement could be implemented on or prior to that date.

In our view the last approach is much to be preferred if it can be achieved in the timeframe. We see no technical reason why it could not be achieved. Such an approach could hardly be called voluntary, however, and does raise the issue of the acceptability of SCADA measurements for cost allocation purposes in such a situation. There are other issues that should be accounted for in any assessment of transition strategy as discussed in Appendix A.

If such a timetable cannot be met, the choices are some initial allocation of enablement costs that will inevitably have some arbitrary elements and associated controversy. On the basis of the studies thus far performed, continuing to allocate costs to loads during the phase-in of approaches based on continuous measurement would be closest to the likely longer-term outcome and less disruptive in the short term. If this is unacceptable even for the transition then some sharing across all market participants would be the starting point for the transition to the energy deviations market.

Our preliminary assessment is that, subject to satisfactory testing and closer examination of the issues, it could be simpler, quicker, smoother and less (potentially) disruptive to move directly to continuous measurement for the purpose of allocating small deviation FCAS costs.

3.5.4 Some Issues Relating to the Allocation of Small Deviation FCAS Enablement Costs

Before the energy deviations market is fully established, allocating the costs of small deviation FCAS enablement on the basis of measured cause and provision would act as a proxy for that market[13]. As the energy deviations market is phased in, there is a question as to whether the payment logic for the enablement should stay the same. To take an extreme case, if system deviations were greatly reduced in normal circumstances, it may be that NEMMCO, initially at least, might be reluctant (and justifiably reluctant, at least initially) to reduce enablement requirements until there has been more experience with unusual situations.

In such a situation, enablement costs would begin to assume the role of pure insurance for the system as whole. Because no causer of significance can be identified (hypothetically), a case could then be made for allocating these costs equitably across the whole energy market. On the other hand, if deviations of any scale continue such a case would be much weaker, and a simple pro-rating the costs based on measured cause and provision (in the same proportions as the energy deviations market settlements) would be justified. The best outcome, if it could be achieved, would be for the requirement to be reduced as experience indicates that it is not required, so that the insurance element in the service is minimised, as recommended in Section 3.5.2.

3.6 Summary of Payment Proposals

3.6.1 Light on the hill payment arrangements

5-minute settlement adjustment

1. We note that the NEMMCO Pricing and Settlement reference Group is considering this matter. However, we note also that an adjustment based on the calculation of 5-minute performance factors would be consistent with our proposed approach to allocating the cost of small deviation FCAS enablement and phasing in the energy deviations market.

Energy deviations market

2. The energy deviations market will provide for most small deviation FCAS and there will be no additional cash injections required after settlement. There may be a small residue as for the energy market depending on the details of the implementation. The effect of this market is that those who cause frequency deviations and those who act to correct them will pay and receive accordingly.

[13] As noted in Appendix A, it would be a very close proxy. If implemented as proposed, the cost allocation logic would result in a cost and payment allocation based on an ex post calculation of the reference price, while the energy deviations market would set that price ex ante.

Spot market for small deviation FCAS enablement

3. Providers will be paid for providing this capability through NEMMCO's settlement process and these costs must be recovered. In principle, they could be allocated to energy market participants based on real time measurements of small deviation FCAS cause and provision by those participants. This would follow essentially the same measurement and calculation procedure as that proposed for the energy deviations market.

Payments by non-dispatchable loads and other plant

4. For retail loads supplied through a given connection point or points between the transmission and distribution network, and where deviation performance can be measured, costs or payments should be assigned generally be assigned in proportion to energy consumed:

   - on a trading interval basis for the energy deviations market; and
   - on a settlement period basis for the one way spot market for enablement; and
   - excepting loads that can demonstrate energy deviation performance, whose payments will be netted out from the remainder of the load supplied through the connection point or points.

3.6.2 Transition payment arrangements

Spot market for small deviation FCAS enablement

1. Prior to development of the systems for spot trading as proposed for the light on the hill, weekly re-submits of small deviation FCAS offer prices for enablement should be supported, and a common clearing price obtained from the SPD engine paid. The spot market facility (requiring some additional IT development) should be implemented as a priority for the transition.

2. The preferred approach to payment could be to phase in the energy deviations market directly to move directly to continuous measurement for the purpose of allocating small deviation FCAS costs and to phase in the energy deviations market from there. Other phasing options should also be evaluated. For this reason we commend early development of a demonstration software module and associated testing and evaluation of phasing options.

Transition to the energy deviations market

3. See above.

3.6.3 Impact of payment arrangements

At present, all small deviation FCAS is charged to retailers or direct energy users in the first instance, in proportion to their gross trading interval consumption. Under the proposed light on the hill and transition payment arrangements, the costs and benefits would be shared between energy market buyers and sellers according to their measured contribution to causing and correcting frequency deviations. These arrangements would be phased in, so that the sharing and total cost of the service can be expected to evolve during the transition.

Preliminary studies indicate that a proportion of these costs would be re-assigned to generators under the proposed payment arrangements, and especially to those generators who fail to follow energy market dispatch outcomes, including any energy variations to dispatch required if they are *enabled* to perform small deviation FCAS.

There would be no mandatory provision or long term contracting by NEMMCO for this service.

4 FCAS: Management of Large Frequency Deviations

4.1 Overview of Proposed Market Arrangements

The market arrangements proposed to manage small frequency deviations should help manage a significant part of the large frequency deviations arising from contingencies such as generator, load and certain network outages. As such events are infrequent, additional facilities are required. We propose spot markets for large deviation FCAS enablement, run along similar lines to the market for small deviation FCAS enablement, which is also an extension of current practice. These would be implemented in a one-way form as a priority for the transition (i.e. central procurement would remain), and would be extended for two-way trading for the light on the hill by matching the requirement for the service with the supply within the SPD logic.

4.2 Causers, Providers and Beneficiaries

In the case of single contingencies the quantity of service *enabled* is currently driven by the largest credible single contingency (irrespective of its probability) while use is driven by the actual contingency. Examples of such large contingencies that ***cause*** the requirement are:

4.2.1 Causers

Generation unit trips

The possibility of large unit trips are one cause of the requirement for the current 6 second raise (governors) and 60 second raise (rapid generator unit loading) ancillary services. Some additional capability up to 5 minutes may also be necessary to meet such contingencies, beyond that required to deal with small frequency deviations.

Transmission line/ interconnector trips

Frequency deviations (in both directions) are also caused by transmission line trips, particularly interregional inter-connectors. This can be caused either directly (in the case where the system separates) or indirectly, due to the need to make rapid adjustments (such as load or generator trips) to avoid network element overloading or system instability.

Trip or connection of large industrial loads

These can cause deviations in either direction but will generally smaller than those possible from large generator trips. Load trips are one of the large contingencies on the high frequency side.

4.2.2 Current and potential providers

- generator governors
- generating units with a raid load and unloading capability
- load shedding and load modulation.

The following can also provide some of this service:

- the inertia of a large system (increased by the connection of Queensland with the SE Australian system);
- the natural system frequency response (including enhanced response as noted above); and
- any response provided by the small frequency deviation service.

It should be noted that the response required to deal with a contingency must be sustained for the duration of the contingency or until the beginning of the next 5 minute dispatch period boundary, when any remaining requirement will be met by the energy market.

4.2.3 Measurement of cause and provision

Unlike small deviation FCAS, it is generally possible to identify readily:

- the potential causers of contingencies that drive the requirement for large deviation FCAS; and
- the actual causer when a contingency occurs.

In the first case, an assessment of the nature of an energy market participant's equipment is required. In the latter case, an examination of dispatch records will usually produce an unambiguous result. This ability to anticipate potential causers and identify actual causers has a major bearing on how the cost of the service can be charged. Note that the number of potential causers in terms of items of equipment that might drive the requirement for large deviation FCAS would be of the order of dozens or even less.

4.2.4 Beneficiaries

The beneficiaries of the service are essentially all market participants. We note here that there may be differences between participants in their desire for QoS and to the extent that their QoS is affected by frequency. However, as discussed earlier, QoS is secondary to system security for FCAS, so that the focus should be on the causers and providers of the service.

4.3 Broad Options for Allocating the Cost of Large Deviation FCAS

4.3.1 Overview

Application of the "causer pays" principle in this case narrows down the payees to the potential (for *enablement* costs) and actual (for *use* costs) causers of the contingencies that drive the need for the service. *Mandatory provision* under the Code is also an option. While the light on the hill and transition market proposals for this service define the payment mechanism to a large extent, it is useful to review some broader payment options and issues before proceeding to the more specific payment options that are consistent with the AS market proposals.

4.3.2 Payment on basis of energy production or consumption

Customers who are loads currently pay. This is clearly an inappropriate cost allocation, as the majority of potential causers of frequency deviations lie on the supply side of the energy market. Payment could be made more equitable if costs were shared between the supply and the demand-side or even solely by the supply-side. However, the requirement is not driven by the volume of energy production or transmission, but by loadings in the context of others. As it is possible to allocate cause and potential cause reasonably precisely as discussed in this section, and as this seems likely to have a beneficial economic effect in reducing the requirement for large deviation FCAS, we reject the option of charging on the basis of energy production or consumption.

4.3.3 Self provision

Under this approach, the "owners" of the potential contingencies assessed to be causing the need for FCAS enablement would each be assigned an obligation to bring to the system operator for dispatch a certain proportion of the assessed need for the service. Given the central dispatch of energy in the NEM (not always the case in the US), secure operation in the NEM also requires central dispatch of ancillary services. The participants would then make their own arrangements for providing the service, procuring the capability to be dispatched by NEMMCO, or NEMMCO could do it on their behalf if requested.

This approach foregoes the opportunity to test the willingness of causers to pay. Further, the main objective of self-provision (control of costs by those who pay) could be achieved by hedging between providers and causers under a centralised ancillary service dispatch regime.

4.3.4 Mandatory provision

The Code provides for generators to maintain a governor capability and that this has been used as an argument for free provision of that service, albeit strongly disputed by generators.

We make no comment as to whether there is an over-riding technical or safety requirement that dictates such a provision. That is a different question as to whether governor enablement and/or use ought to be exempt from payment under the ancillary services umbrella. There is no case for persisting with a hidden subsidy, as argued in Section 2. Governor capability should be fully paid for under the FCAS arrangements proposed in this study. Given the scope for high competition across all regions in the provision of governor and similar capability, there should be no problem arising from market power.

4.3.5 Build large deviation FCAS requirement into the dispatch process

The requirement to enable a quantum of the service is driven by the assessed size of the likely contingency. This approach would allocate the enablement cost to *the potential causer or causers of the largest contingency.* For the under-frequency case these could be 660MW units, 500 MW units if 660MW units are all backed off sufficiently, or a network contingency of the same size. Network contingencies that could drive an FCAS requirement are a failure of Basslink or the Queensland/NSW inter-connector (assuming they are built). For example, a failure of Basslink would cause frequency to rise in Tasmania and fall on the mainland, or vice versa, depending on the direction of power flow over the link at the time.

While the *size* of a potential contingency is clearly a dominant factor in determining how much of the service is required, the *probability* of the occurrence might be considered relevant to determining how and to whom the cost of the service is to be charged. There are formulae of varying degrees of complexity that would implement such an approach. One problem here is that the contingencies are unusual events so that the basis on which the probabilities of contingencies are assessed will always be contentious.

We resolve the matter by asking what would drive a change in the amount of large deviation management FCAS enablement required. Under the current NEM security criterion, the answer is that it is simply the *size* of the potential contingency that counts in that respect. Therefore, it is the size of the potential contingency, irrespective of its probability, that should govern who pays for enablement. This conclusion rests on the assumption that this is the method by which the assessment would be carried out, and that this method is reasonable in all the circumstances. We find no compelling basis for querying the method in principle at this point, although it may change in future.

The next question is how the largest contingencies are to be assessed at any time, noting that they can be affected by spot market outcomes. It is not desirable to make an ex ante assessment (based on pre-dispatch outcomes, for example) and charge costs to a single potential contingency on that ground. The charged party might well argue that they would have, or could have, changed the size of their potential contingency had they known they would be charged with all FCAS enablement costs for that period. Further consideration of this apparent dilemma suggests that it would be desirable to implement the following logic:

- Propose a level of FCAS that could be enabled and note the cost[14].
- Require participants to operate their plant within this limit in spot market operations (by imposing constraints in the SPD process, for example)
- Discover in some way the willingness of potential contingency causers to pay for changing the level of FCAS enabled.
- Adjust the level of FCAS to maximise the benefits i.e., so that the willingness to pay for a marginal change in FCAS enablement equals the marginal cost of providing the FCAS enablement.

The following approach to solving this problem within the SPD logic is consistent with the Framework requirement that dispatch be co-optimised with the energy spot market where practicable.

- Define “FCAS enablement requirement (MW)” as variables rather than fixed quantities[15].

[14] This is in fact a profile of capability from close to zero to about 5 minutes and possibly beyond.

- Enforce the relationship:
  Total FCAS enablement provided >= FCAS enablement requirement[16]

Note that this facility is already available in the SPD although the requirement is currently fixed externally.

Noting that the requirement is now a variable:

- Enforce the following relationship *for each identifiable contingency* that might be a member of the "set of largest contingencies":

  MW of contingency – Response from other sources <= FCAS enablement requirement

Note that the MW of the contingency will normally depend on the MW of output of a generator, consumption by a load, or a combination of dispatch quantities determined in off-line network contingency studies or throughput through a single device at spot time. It should not be difficult to identify these potential contingencies amongst the various elements defined in the SPD model. The task of implementing these relationships in a multi-region network model should not be under-estimated[17], but should be easier on a system-wide basis, as would be the requirement for the foreseeable future.

If these relationships are applied in the SPD the following will result[18]:

- An optimal *level of FCAS enablement* (MW of each FCAS enablement product) is selected, based on energy spot market and FCAS enablement offers as well as identified potential contingencies.
- The common clearing price for each FCAS enablement product satisfies all providers according to their offers i.e. they should be willing participants in this transaction.
- A number of generation or load units or transmission links are likely to be constrained by the limited FCAS enablement provided. Each of them will have a shadow price attached to each FCAS product requirement constraint that, if paid, would balance the benefits of energy spot market output against their contribution to FCAS enablement costs.
- If payments are made on the basis of the shadow prices of the FCAS enablement constraints, payments to providers will balance the payments by the causers, in proportion to their willingness to pay for FCAS enablement to increase their throughput.

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[15] There will be one for each enablement product. Each will reflect in some way a profile of requirement for FCAS enablement.

[16] The inequality will normally be forced to an equality if FCAS enablement is offered in at a positive price. However, there is no reason to rule out negative offers in this case, however unlikely. Nothing is lost by using the inequality in this way.

[17] We understand that the existing SPD module already has a capability broadly along these lines.

[18] Mathematical proof is possible and should be provided???.

Appendix C contains a simple example and discussion on how this arrangement would work. An apparently odd result is the appearance of a “sudden death” syndrome as a large contingency causer attempts to increase its output beyond a level where it was previously sharing the cost of large deviation FCAS with others. The causer would then appear to incur a step increase in large deviation FCAS costs. As argued in the Appendix, this outcome is an illusion. Under the logic proposed, the participant would, in a perfect market at least, already have been incurring most of these costs before breaking out to the new and higher dispatch level.

The key outcome is that large deviation FCAS enablement would be paid for in a manner consistent with the application of the “causer pays” principle. It is the recommended approach for the light on the hill.

4.4 Payment Options for the light on the hill

4.4.1 Energy deviations market

The energy deviations market has been proposed in this report primarily to provide the small deviation FCAS service. However, it would also reward providers of responses to large frequency excursions and penalise those who caused the problem, at least within a 5-minute dispatch interval and partly over the next.[19]. As the system grows (with the interconnection Queensland and perhaps Tasmania), the ability of the small deviation service to cope with larger deviations will increase. Nevertheless, as large contingencies are not everyday events, it is reasonable to presume that some additional physical capability will need to be provided through a dedicated large deviation FCAS service.

As noted earlier, the energy deviations market as well as the transition arrangements for small deviation FCAS should charge causers of frequency deviations and reward providers with reasonable precision, in proportion to the size of the deviation. It could remove the need to make explicit use payments for large deviation FCAS. This possibility will be discussed.

4.4.2 Two-way spot market in FCAS enablement

This option was outlined in Section 4.3.5. It should be noted that he two-way market proposed here, with the matching of supply and demand embedded in the SPD process, differs from that proposed for small deviation FCAS enablement. The reason is that the potential causers of large frequency deviations can be determined in advance and they are relatively few in number.

[19] There are issues here concerning the boundary between ancillary services and the energy spot market. Under the proposed energy deviation market arrangements the energy dispatch used as the reference would ramp between each 5 minute dispatch interval (see Appendix A). Thus the effect of the contingency on a causer or provider would last around 5 minutes, even if the event occurred on a 5-minute boundary. This and related boundary issues should be reviewed at a broader level, as they have arisen and are not fully resolved in other contexts, including the current arrangements promulgated by NEMMCO for dealing with dispatch outcomes when the current dispatch is temporarily violating a network constraint.

With such an arrangement, payments by potential causers to the providers of large deviation FCAS capability (enablement) should balance through NEMMCO's settlement process. This balancing is guaranteed by the SPD logic. Where the potential contingency is a network event, the costs should be borne by the NSP and passed though to the appropriate NSP customers. However, this matter requires more detailed consideration during the implementation phase as it may depend on the fine detail of the implementation.

As noted earlier, any use costs should be rewarded through the energy deviations market. If this is not sufficient to cover costs, providers could build a premium into their offers into the enablement market. These opportunities are likely to be sufficient to bring the required quantities of the service forward, but the matter should be kept under review.

4.5 Payment Options for the Transition

4.5.1 Current SPD facility for large deviation FCAS dispatch

A relatively early move to flexible offers and a common clearing price for large deviation FCAS enablement should be possible and desirable using existing SPD facilities[20]. Offer prices could be made weekly, which would avoid the immediate need for IT facilities for dealing with spot trading at both NEMMCO's and the participants' ends.

As this would remain a one-way market where costs would be incurred by NEMMCO, there is a question as to whether transition arrangements for paying for the service should be implemented. As argued earlier, the current approach is clearly deficient. However, it is not possible to design a formula for charging potential causers of large contingencies without taking the dispatch into account, as proposed for the light on the hill. Rather than attempt rough justice, we strongly commend a move to the light on the hill as rapidly as possible.

4.5.2 One way spot market in FCAS enablement

This development was proposed for the transition in the Evaluation Report, prior to implementing a two-way market through the SPD process such as that now proposed for the light on the hill. Given the intermediate step now proposed (not involving major IT), the spot market development would best be timed with the two-way facility in the SPD. The issue of payment for the service would be resolved at that time.

4.6 Summary of Payment Proposals

4.6.1 Light on the hill payment arrangement

Two-way market for large deviation FCAS enablement

1. The energy SPD process would clear the offers made into this market. As proposed in this report, the requirement would be variable rather than a fixed, externally determined amount. The SPD logic would determine the optimal quantity of large deviation FCAS to be enabled, the corresponding energy market dispatch and a common clearing price for

[20] Contingent upon those facilities being commissioned satisfactorily, as they are not all used at present.

the FCAS. The effect is that potential causers of the largest frequency deviations at any time will pay for these enablement costs.

Large deviation FCAS use costs

3. No explicit use costs for large deviation FCAS will be paid. Providers that incur such costs will be paid in the market for large deviation FCAS enablement and in the energy deviations market if used. To this end registered potential providers should be subject to SCADA-level metering or a satisfactory alternative to measure performance and to provide a basis for payment.

Other Costs

4. To the extent that enablement and use costs cannot reasonably be assigned according to the above logic, they should be allocated to all market participants according to gross trading interval energy produced or consumed.

4.6.2 Transition payment arrangements

One-way spot market in large deviation FCAS enablement

1. During the transition, the requirement for large deviation FCAS enablement will continue to be externally determined by NEMMCO rather than through the SPD model. This will result in a net payment by NEMMCO to providers whose cost must then be recovered. In view of the potential difficulty of identifying and assigning costs to potential causers of large contingencies by alternative means, it is proposed that the default cost allocation arrangements in the Code for this service be retained in the interim, and that the implementation of the light on the hill in this service be a high priority.

4.6.3 Likely impact of payment arrangements

Under current arrangements, retailers and direct consumers pay for all large deviation FCAS costs. This is an inappropriate cost allocation given that the requirement for this service is predominantly driven by the supply-side of the market, and the large suppliers or transporters in particular. Under the proposed payment arrangements the costs would generally be assigned to the largest generators, loads and network elements that might cause a contingent event, with any “use” covered through the energy deviations market. There would be profitable opportunities for fast-acting plant on both-sides of the energy market to operate under the large deviation FCAS arrangements. There would be no mandatory provision or long term contracting by NEMMCO for this service.

5 NCAS: Voltage Control – Continuous and Contingency

5.1 Introduction

5.1.1 Background

The Framework Report separated voltage control services into continuous and contingency services. This was done in recognition of the distinguishing characteristics of each service considered important to procurement, dispatch and pricing. The Evaluation Report maintained this separation in the development of procurement arrangements.

Continuous voltage control is required to maintain and stabilise voltages in the network within acceptable limits[21] both before and after a contingency, as well as having a role in the minimisation of power system losses. Voltage control contingency is concerned with maintaining reactive reserve to cater for power system contingency events such as the unexpected breakdown of a large generator or trip of a heavily-loaded transmission line. The term "reserve" includes the requirement that continuous control must be maintained after the event. Continuous and contingency control are therefore jointly provided.

In respect of one important provider, namely large synchronous generators, the continuous service is always enabled in order to satisfy mandatory Code requirements associated with excitation control systems that ensure power system stability is maintained. The fact that all such generators respond to contingencies by changing their reactive power generation in accordance with their location on the system means that constraints will need to be placed on both the pre-contingent continuous reactive power flow from the generator and network power flows in order to satisfy constraints on operation required by the contingency service.

Both services are characterised by the provision of reactive power, and payments would be made on this basis. As previously noted however, reactive power provision is not currently accounted for in the SPD process. This, as well as concerns about market power, present particular challenges when considering possible arrangements for the provision of reactive and payment for it.

As outlined in the Evaluation Report, reactive power contingency capability impacts transmission constraints, and to the extent that these are able be valued in SPD, can be priced through this process. Reactive reserve has two components that impact costs, reactive enablement (i.e. the placement of a reactive source in reserve mode ready for use), and the actual provision of reactive (i.e. use of the reactive plant). Use of reactive reserve would normally follow a contingency event.

Since reactive power enablement and reactive power provision are essentially joint products, usually with very similar production costs, the proposed trading in reactive capability provides a price for reactive provision at these times and locations. Due to the very close

[21] Acceptable limits are determined by equipment tolerances and voltage-sensitive customers, as noted in the Framework

relationship between voltage continuous and voltage contingency services, and a recognition that they need to be developed jointly, these services are considered together in this section.

5.1.2 Presentation

The structure of this section on voltage control ancillary services, and generally followed by the sections on the other network ancillary services, is as follows.

Section 5.2 begins with a review the procurement arrangements presented in the Evaluation Report. The close relationship between cost allocation and procurement arrangements, especially as the market moves to light on the hill arrangements, makes it important that these not be considered in isolation.

Section 5.3 then examines the causers and beneficiaries of the voltage control services in line with the principles presented in the Evaluation Report. Under the one-way market arrangements for certain services proposed for the transition period, these principles will determine the allocation of costs of reactive power procured by NEMMCO. Of note is that the two-way markets proposed for the light on the hill are intended to result in market-determined procurement quantities and cost allocation for these services. We also consider a possible interim arrangement for procuring local reactive for voltage control should it be desired to move quickly to support entrepreneurial network augmentation. This is followed in Sections 5.4 and 5.5 by a discussion on potential options for cost allocation, and the proposed arrangements during the light on the hill and transition periods.

It should be noted that the discussion on payment options is also relevant to all the contingency based network ancillary services. Consequently, through the discussion on voltage control, reference is often made to the general NCAS services, the details of which are not repeated in the sections on stability and network loading ancillary services.

A proposed staged approach to the introduction of all the network ancillary services is summarised in the Conclusions to the report.

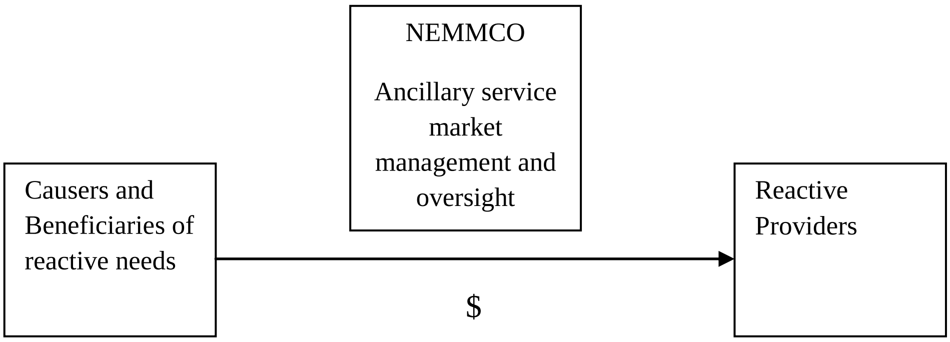
5.2 Market Arrangements

5.2.1 Light on the Hill

As recommended in the Evaluation Report, the light on the hill arrangements have the quantity of reactive/NCAS capability necessary to support energy transfers across the network (in the face of possible contingencies) provided through competitive two-way spot markets, coordinated with the energy spot market and dispatched by NEMMCO. For as long as the NEM model comprises linked regions, this trading is likely to be concentrated on NCAS that supports inter-regional power transfer capability, because intra-regional capability is not readily priced. The general two-way arrangement is presented in Figure 5.1 below.

Under such two-way market arrangements there would be no requirement to separately assign reactive/NCAS enablement costs, as such payments would come through spot market settlements. Such arrangements would support long-term contracting either by NEMMCO, NSPs, entrepreneurial NCAS providers or parties in the business of selling network hedges, perhaps to support an entrepreneurial link. In practice, some forms of NCAS, such as those supporting intra-regional energy trading, may not be immediately suitable for competitive trading, although negotiated or regulated procurement would still be supported through such a framework.

Figure 5.1 Light on the Hill Arrangements (Two-way Markets)



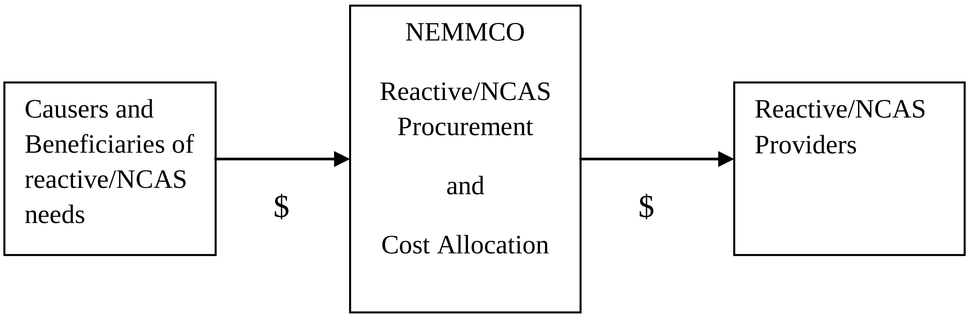
For the light on the hill, an enhanced version of the SPD market model that could price and dispatch continuous reactive to meet voltage requirements was recommended. Such an approach, if it could be implemented, could provide the facilities to promote two-way markets in both the voltage continuous and all the contingency services, at least in situations where market power could be managed. However, it was noted that this would be a challenging technical development and, even then, the workability of a broadly applicable market-oriented arrangement is still not clear at present. Incremental steps should be taken in the first instance, based on existing SPD technology.

5.2.2 Transition

The transition arrangements are highly influenced by the existing capabilities of SPD. As previously noted, SPD does not contain a network model that would provide for pricing continuous reactive or for (without difficulty) recognising the impact of reactive/NCAS enablement or provision on intra-regional constraints. Until SPD is enhanced to include such a model, it is necessary to operate within its current capabilities.

For the transition, the Evaluation Report recommended a review, reformulation and publication of the generic constraints that expresses the relationship between the capability of the network and NCAS services (predominantly the contingency group of NCAS services), beginning with the most prospective applications. This was intended to prepare the way for progressive implementation of the proposed light on the hill arrangements.

Figure 5.1 Transitional Arrangements (One-way Markets)



For the transition, the Evaluation Report also recommended a broadening of the potential sources of reactive power that are subject to competitive supply and a continuation of the current dispatch process by NEMMCO. Currently, a substantial part of the reactive requirement is provided at no charge by as mandated under the Code. Possible changes to this and related arrangements were deferred to this report. Consequently, this report presents a refinement of the broad arrangements presented in the Evaluation Report in relation to the treatment of generator reactive and in the combined treatment of continuous and contingency reactive power in the transition steps.

In recognition of the close relationship between voltage continuous and voltage contingency, this report recommends that a single set of arrangements be established for voltage control during the transitional period. The rationale for this is that during the transitional period, the value of both classes of reactive derives from the common generic constraint equations formulated in the SPD. Consequently, any separation of the voltage continuous and voltage contingency services would be arbitrary during this period. For the eventual light on the hill arrangements, there would be scope for the separate pricing of reactive enablement and provision.

We note that the pricing of reactive for voltage control in an enhanced SPD model based on an AC loadflow network model is a significant technical challenge. Even with a higher priority given to its development, and a greater priority given to implementation than at present, such an outcome could be five to ten years away. In the event of a development in NEM regulation required future network development, both intra as well as inter-regional, to be entrepreneurial, it might be necessary to re-consider arrangements that would support the entrepreneurial provision of voltage control services within a region. This regulatory development could occur prior to an SPD-based facility being available that could price and dispatch such a service.

One arrangement that could operate outside the SPD process would require NEMMCO to nominate its expected reactive requirements in each trading period on some zonal basis (i.e. several zones within a region). Offers would then be made by providers to meet these requirements. A common clearing price in each zone would be paid from a simple clearing process running in parallel with, but separate from, the energy and associated spot-based ancillary service markets. Such an approach raises issues of:

- how zones are to be defined;
- how reactive capability at any point is to be assigned to one zone or another;
- how market power is to be managed, and
- whether the effort required is worth the rewards.

For these reasons, consideration of such an arrangement should rank behind the other proposals for NCAS market development. However, if a decision is taken that all new network increments should be entrepreneurial, and if such a decision precedes the development of a supporting SPD capability, the matter should be re-considered at that time.

5.3 Causers, Providers and Beneficiaries

5.3.1 Causers

The Evaluation Report argued that NEMMCO must and will operate the network within secure operating limits, and will do so primarily by imposing constraints on the dispatch that reflect the amount of reactive/NCAS available. This line of argument would indicate that the causers of the requirement for NCAS are the parties that wish to trade, or promote trade, over the affected network elements[22]. They can also be regarded as the beneficiaries of that provision.

As noted in the Framework Report, the determinants of the requirement for reactive/NCAS services can be expressed as follows:

- MW or MVAR contingencies both on the supply and the demand side since voltages in the system must be managed through continuous and contingency control to ensure stable operation after the contingency;
- changes in network configuration and switching;
- changes in power system MW and MVAR demands;
- changes in generation dispatch patterns.

5.3.2 Providers

An extensive range of providers and potential providers is listed in the Framework Report, highlighting the potential for, and importance of, competitive provision in the service where practical. It is perhaps most useful to focus on the Code participants who can be reactive providers, namely generators, TNSPs, DNSPs, end users and entrepreneurial providers.

The wires of the TNSPs and DNSPs are also consumers and sometimes producers of reactive power that can effect the supply of continuous capability. In a similar way to small deviation FCAS, it is important to note that there are parties that detract from network capability by

[22] This is not an assertion that those parties can be individually identified from spot market transactions, as the spot market operates as a pool.

consuming reactive/NCAS (e.g. reactive power consumers) and that there is a case on efficiency grounds for charging them for reactive/NCAS just as providers are paid.

Further, there are locations in the network where there is potential for competitive supply from any of these sources. Those locations are in the vicinity of major load centres, and where contingency voltage control services can support power transfers over interregional links.

5.3.3 Beneficiaries

Secure operation of the system benefits the market as a whole. However, as secure operation can be maintained by limiting network transfers, the beneficiaries can be identified more closely as those parties with a commercial interest in maintaining secure network power transfer capability, particularly on inter-regional links. As noted in the discussion on NCAS in the Evaluation Report, secure network transfer capability can be valued with reference to trade in the energy spot market. SPD provides a means to do this, noting the limitations of the SPD representation.

End use customers and Network Service Providers have varying needs for supply quality and different tolerances / preferences in regards to voltage levels. However, the SPD does not contain any means to assess the relationship between reactive provision and system voltage levels. Consequently and as previously mentioned, it would be very difficult to implement any arrangements that attempted to price continuous reactive provision without significantly enhancing SPD.

Network losses can be optimised by managing voltages through the provision of reactive power. In the context of the energy market rules as currently defined, such benefits would appear first as potentially lower pool prices, and may also accrue as additional regional settlement residues, as interregional loss factor calculations do not optimise voltages to reduce losses. Lower costs would therefore potentially apply to customers through the energy settlements and additional revenues would be passed on to customers through reduced network charges. However, as the benefits to be gained by optimising losses in SPD would be small, such arrangements are not considered worthwhile prior to the development of light on the hill arrangements. Consequently, such arrangements are not considered further in this report.

5.4 Payment Options for the Light on the Hill

The intent of the light on the hill arrangements is to establish two-way markets to provide continuous and contingency voltage control to meet market-driven demand for network capability within defined technical and security limits. In general, the proposal is based on a recognition that NCAS, and contingency-based NCAS in particular, is largely concerned with maintaining the secure transfer capability of the network. This has a direct benefit to participants in the market. The relationship between secure network limits and the provision of NCAS is currently implemented by constraining network flows when the system is dispatched by NEMMCO. The extent of the constraint is determined by the amount of each particular form of NCAS that is made available to be used if there is a contingency.

At present, the amount NCAS provided that determines the limits set by each constraint is determined *externally* to the energy market, by NEMMCO and the NSPs through off-line calculations. The proposal for the light on the hill is to *internalise* the provision of NCAS services so that they are traded as part of the market system. This can be done by allowing such services to be offered in accordance with bids and offers where that is practical, or otherwise simply priced and settled. The existing SPD process can support this approach with modest extension.

The approach is considered in some detail in the Evaluation Report and some examples of application are given in Appendix D to this report. The key point is that payment for these services would be *internalised* into the trading system, so that no additional arrangements would be required to pay for them.

5.5 Payment Options – Transition Period

Unlike the light on the hill where the allocation of costs is inherent in the arrangements, during the transitional period reactive/NCAS quantities are determined and procured by NEMMCO through one-way market arrangements. The issues associated with payment options during the transition period are as follows:

- economic efficiency;
- identification of the causers and beneficiaries of reactive/NCAS services;
- the treatment of generator reactive required to support a generator's own output;
- the ability of the market arrangements to value reactive/NCAS capability (and use) in order to determine an appropriate cost/price;
- the distinction between reactive/NCAS enablement costs and reactive/NCAS use costs;
- associated overhead costs and the practicality of implementation; and
- transparency of procurement and dispatch.

5.5.1 Mandatory Provision of Reactive by Generators

As a mandatory requirement of the Code Generators must currently negotiate with their TNSP for their provision of a basic nominal reactive power capability for both continuous and contingency voltage support. In the event that this is not able to be provided physically the Code provides for the negotiation of a commercial arrangement that is recorded in their connection agreement. However all Generators that cannot meet the physical requirement have been derogated under chapter 10, and so this negotiation framework is currently not implementable. NEMMCO has determined that the basic requirement is to be interpreted as a specific reactive capability over all real power ranges while operating at the nameplate rating of the generator, or below. Currently this basic capability is provided free of charge if the unit is on line.

The intent of specifying a base reactive power capability in the Code was to form a distinction, albeit arbitrary, between what part of the reactive provision should be considered as a connection asset, with the remainder being considered a shared network asset and paid for accordingly. An analogous framework applies at the connection points between NSPs.

As previously argued in Section 2, mandatory provision of any ancillary service is generally an unsatisfactory solution. We make the distinction here that the service, if provided, must be provided to a satisfactory and agreed standard. Thus the question is whether or not the provision of continuous reactive at the required standard should be mandatory[23].

For a generator, the voltage support currently required at any location can be considered in two parts:

- that required to support the generator's own operations; and
- that required to support the network for use by others.

The boundaries between these two may not always be precise, but TNSPs have confirmed that this is a current planning paradigm. Each case will be considered in turn.

Treatment of own requirements

In some cases and to some level of reactive provision, it is only the desire of a generator to be on line and generating at a particular level and location that drives a requirement for reactive power. In such a case, the TNSP in its connection negotiations might reasonably assign the cost of reactive provision at that location at that level to the generator concerned. The two parties would then very quickly conclude whether or not provision by the generator itself would be the cheapest option. If so, the reactive power would be provided by the generator when it is required to support its own operation, and this understanding would be written into the connection agreement. Any saving in the cost of connection from that self-provision would be taken into account in the connection charges levied by the TNSP. The agreed provision may be related to output, for example by being defined in terms of a power factor.

There is an alternative model for this case that ought to be equivalent, but which may in fact be more transparent. This would simply enforce a relationship in the dispatch process that limited local network capability according to the reactive power supplied or absorbed by the generator concerned. Thus it would be a decision for the generator itself to determine what to do. No concerns about market power should arise in this case.

In summary, particular options for the treatment of reactive required to support a generator's own operations are:

- Base capability in connection agreement

[23] The issues discussed here are essentially identical to those for the voltage-continuous service and the same conclusions can be drawn.

The effect would be similar to the current position, but operating under a different paradigm. An agreed quantum would be provided gratis, in support of one's own operations. The requirement for a generator's own use may be more or less than is currently mandated.

- Application in the SPD process of a limit on local flow due to reactive

  This would remove any distinction between own use and use by others. Market power should not be an issue, but the likely return does not suggest the highest priority for implementation.

Adjustment of the base reactive capability in the connection agreements would be the simplest approach. This could be reviewed after investigation and progress on other fronts.

Treatment of other's requirements

If generator reactive power capability is required to be enabled to support voltages in the network, and hence secure network transfer capability irrespective of the presence of a particular generator, in principle the dispatch can be constrained through so-called generic constraints in the SPD process to reflect the continuous/contingency reactive available.

Apart from implementation issues, the question is one of market power, as it is with other contingency-based NCAS. Market power will be least where there are clear and practical alternatives. The fact that competition may not be present in the short run in these should not be a constraint, as that could be managed through a vesting procedure. Lead times for reactive equipment are relatively short.

Where market power is an issue, the price of reactive provision would need to be regulated. An alternative approach would be to maintain the essence of the current arrangements in such cases (but without a connotation of mandatory provision) and to phase in the payment of a regulated price for provision under contract.

5.5.2 Consolidate Costs with TNSPs Who Provide a Packaged Service

At present some NCAS is essentially organised by TNSPs through their own asset purchases and through reactive capability specified in connection agreements. The later is currently the case for the mandatory component of reactive capability provided by generators. The non-mandatory component of generator reactive is currently procured by NEMMCO (if required) with costs allocated to loads across the whole market. Such a cost allocation does not accord with where the benefits are gained, as previously noted.

The rationale for market based arrangements in NCAS is improved efficiency. However, if the value of NCAS cannot be assessed or the causers identified, the benefits from implementing market arrangements in such services would be dubious. This is particularly the case for reactive provision (ie. continuous voltage control) that currently cannot be valued in SPD model or the causers and beneficiaries clearly identified. Maintaining such reactive assets in the regulated asset bases of TNSPs may be the most appropriate solution until such time as such reactive can be valued in the market.

Nevertheless, one approach could be simply to have all reactive provision made a matter for negotiation between the TNSPs and potential providers, including generators, DNSPs, independent providers as well as its own resources that would then become part of the regulated network rate base. The problem with this approach is that it might fail to make the process of procurement and dispatch transparent and fully contestable, which runs counter to the objectives of this project. While the allocation of costs in this case would be better focussed than at present, it does not account for the development of contestable procurement and dispatch processes.

5.5.3 Emulate Two-way Markets

The effective allocation of reactive/NCAS costs as proposed for the light on the hill can be emulated during the transition, whether or not the light on the hill trading arrangements are in place, and whether or not spot trading turns out to be possible or desirable in particular cases. Changing the cost allocation now should minimise any financial impacts that might otherwise occur as market arrangements are implemented.

Two-way markets in reactive/NCAS would have the following financial effect. A part of what is now the settlement residue would be paid to providers of NCAS enablement, as part of NEMMCO's settlement process and in accordance with the principles set out the ASRG's Ancillary Services Framework. In effect, the cost of the reactive/NCAS would be passed to the *ultimate recipient of the settlement residue* in the first instance, or the party who would be entitled to that residue (if there is a residue). This could be:

- an entrepreneurial NCAS provider;
- an intermediary interested in selling interregional hedges and maintaining the associated network capability; or
- NEMMCO, who would then pass it on to NSPs according to principles determined by NECA. From there the residue would be passed on to NSP customers though modified use charges.

The first two cases would be the outcome for entrepreneurial provision, the last under the current regulated arrangement. Where the residue would be auctioned, the cost of the reactive/NCAS would be set against the amount received from that auction [24].

If the allocation of the settlement residue is correct, then the parties who will pay for the reactive/NCAS will be the parties who directly benefit from the network capability. This

[24] The question is often asked regarding the situation where the provision of an ancillary service were to result in a reduction or elimination of a network constraint, and the corresponding reduction or elimination of the associated settlement surplus. In such cases the same rules would apply. Specifically, the outcome may result in a net additional charge to TNSP customers for the residue/AS package. Customers might question at this point whether or not too much is being spent on ancillary services. If the expenditure can be justified, such cases may require benefits to be captured through appropriate prior contracting. It should also be noted that intra-regional constraints do not at present generate settlement residues because all prices within a regional are related to the regional price through a loss factor only and do not consider the impact of intra-regional constraints.

outcome is clear for entrepreneurial ancillary service provision. In the case of regulated networks, it would depend on how well the CRNP network pricing mechanism allocates costs.

Of note is that allocating costs to emulate two-way NCAS market outcomes should achieve the same or similar cost allocation as the packaged approach, while maintaining transparency and the potential for credible contestability. This is the preferred approach if achievable.

Some examples of this cost allocation process are set out in Appendix D. In broad terms, the effect is to package the ancillary services with the associated network assets that, together, provide a firm network transfer capability.

5.5.4 Payment by Exporting Generators and/or Importing Customers

A criticism of the previous approach is that the allocation of settlement residues of inter-regional links is arbitrary, and might not provide a sound basis for allocating the costs of the NCAS that supports the associated inter-regional trade.

An alternative approach would allocate the costs directly to assessed beneficiaries. For example One such formula would be to allocate the NCAS costs 50% to the exporting generators of a region and 50% to the importing customers at the other end of the link. The argument for such an approach is that these are the parties that would benefit from any price movements from the increased inter-regional transfer capability associated with NCAS provision.

Changing price outcomes is not the only or even the main justification for providing NCAS. If trade can be increased from a low priced region to a higher priced one, the additional volume of trade delivers a net economic benefit even if prices in all regions remain unchanged. Consider the following trivial example:

- Inter-regional price difference is $5/MWh average
- 1 MW of additional NCAS is available at $2/MWh average

Now consider the following cases:

- If the NCAS is charged entirely to the recipient of the residue, that recipient will see a net benefit of $5-$2 =$3/MWh average and will support the NCAS expenditure. There should be no interests opposing the expenditure on the basis of it being a net cost to them. All available economic benefit will be achieved and captured by the residue recipient (in this case).
- If the NCAS is charged to 50% to exporting generators and 50% to importing customers, only the latter of whom receives the residue, the economic benefit of $3/MWh is still available to be captured. In this case the residue recipient will see an NCAS cost of only $1/MWh and a resulting $5-$2/2=$4/MWh net benefit and will support the expenditure. On the other hand the exporting generator will only see the NCAS cost of $2/2=$1/MWh allocated to him and will oppose the expenditure. The economic benefit may be lost as a

result of this conflict. Even if it is not, the exporting generator has incurred a cost for no benefits received.

Now suppose the NCAS available to support the additional trade costs \$6/MWh on average:

- If the NCAS is charged entirely to the recipient of the residue, that recipient will see a net benefit of \$5-\$6= \$1/MWh average *loss* and will oppose the NCAS expenditure. There should be no interests supporting the expenditure. The net economic loss from providing the NCAS will avoided.
- Now suppose the NCAS is charged to 50% to exporting generators and 50% to importing customers. In this case the residue recipient will see an NCAS cost of only \$6/2=\$3/MWh and a resulting \$5-\$3=\$2/MWh net benefit and will support the expenditure. On the other hand the exporting generator will see the NCAS cost of \$6/2=\$3/MWh allocated to him and will naturally oppose the expenditure as it is of no benefit to him. The outcome should be no additional NCAS provision, but there are interests that would oppose it.

This example is by no means unrealistic as some forms of NCAS can be supplied in small increments (e.g reactive power capability). Even if prices at either end of the link do move, similar conflicts could arise.

Given that receiving regions currently receive the inter-regional settlement residue through the TNSPs, some of the distortions evident in the example above would be avoided if the costs were charge directly to customers who are loads within that region. This has the disadvantage that any change in the allocation of the inter-regional residue either between regions or within regions will again separate the residue for the cost of the supporting services, leaving to dysfunctional incentives as illustrated in the example above.

We take the view that it would be better to refine the logic for network pricing and the allocation of settlement residue than to separate the residue from the cost of NCAS that affects its size.

5.5.5 Payment According to Trading Interval Gross Energy Across the Whole NEM

This could be done by restricting the payment burden to loads by allocating costs across loads in the whole market, which is the status quo. However, such allocation does not recognise the location-special nature of reactive services (and some other NCAS). Costs could also be allocated to include market producers across the whole market but there is no basis for such an approach.

5.5.6 Customer Reactive Demands – Allocate to Retailers or Distributors?

Where NCAS is provided or consumed from a diversity of sources within a distribution area, the question arises as to which party is to pay or receive the NCAS costs that may be assigned to them under the arrangements proposed. This issue arises in relation to both continuous and contingency aspects of voltage control, both of which are affected by reactive power consumption within the distribution network. Customer plant is a source of such consumption, but DNSP wires also have an affect and, in either case, the consumption can be corrected within the customer premises, by the DNSP with dedicated reactive equipment, or ultimately, by the TNSP to which the DNSP is connected.

The Code currently assigns a power factor base level to DNSPs at peak times (effectively defining the ratio of reactive to real power consumption at those times) as a financial rather than a physical obligation, although there are currently no market based penalties or rewards backing up the performance of those obligations. It is intended as a negotiating baseline between TNSPs and DNSPs, which has the effect of defining the connection responsibility and hence what portion of the reactive power is billed to the shared network.

If reactive power is priced at the point of interconnection with the transmission network as proposed in the Evaluation Report, the DNSP would remain the most appropriate party to accept and manage that charge. The power factor obligation in the Code would provide a contract benchmark. Reactive consumption above this level would attract a charge and supply a payment.

It should be noted that these arrangements would not differ fundamentally from those that apply at present. The key difference is that reactive would be priced and attract payment under either spot or contract arrangements, or both. If they chose to do so, a TNSP and a connected DNSP could write a contract between them that reproduced the current negotiated position. However, transparent pricing or continuous reactive would open up opportunities for others, which is of course the intent of the changes proposed.

5.5.7 Use Costs

Following the "causer pays" principle, any use costs associated with a contingency should be allocated to the assessed causer of that contingency. In the case of NSPs that cost would be passed on to the NSP's customers, and particularly those who pay for the asset that caused the contingency.

Where the causer of a contingency cannot be identified, the cost should be passed on to the previously identified beneficiaries of the service.

5.6 Summary of Payment Proposals

5.6.1 Light on the Hill Payment Arrangements

The intent behind implementing a workable AC loadflow model for the SPD engine for the light on the hill is to support two-way trade in both reactive power and "real" power in the normal energy market, while explicitly recognising the requirement to manage voltages throughout the network.

1. Where reactive enablement and provision is suitable for two-way trading as recommended in the Evaluation Report, no further payment arrangements are required.

2. For the purpose of settling reactive consumption and provision at the boundaries between distribution and transmission networks, the reactive requirements of the Code (expressed as a power factor) should set as a base contract level for trading in reactive power.

3. Where such a market is not established and these ancillary services costs would continue to be incurred by NEMMCO in the first instance, costs should continue to be allocated as for the transition, described below. This allocation would emulate the market outcome.

5.6.2 Transition Payment Arrangements

During the transition period voltage control/NCAS quantities would be determined and procured or provided by NSPs in respect of support for transfer capability for individual Generators or groups of Customers, or by NEMMCO or any other party willing to so provide in the case of services supporting inter-regional transfer capability. Economic efficiency would be improved through more transparent pricing arrangements and cost allocation principles that recognised the causers and beneficiaries of reactive/NCAS services.

6. The provision of reactive power or reactive power capability by generators should cease to be regarded as a mandatory service.

7. NSPs and generators should negotiate a base level of reactive capability and provision that would be sufficient to support the generator's own use of the network. The capability should be provided as part of the generator's connection agreement, as it would have been if commercially negotiated. The method of calculation should be determined by NEMMCO in consultation with the generators and the NSPs, and published.

8. In broad terms, the remaining capability should be provided as a commercial service either under the proposed arrangements described below, or by negotiation, and in both cases subject to limits on market power. *Providers should continue to be dispatched according to NEMMCO instructions except where noted below.*

9. Reactive provision should be priced and traded jointly with reactive capability through the SPD generic constraints[25] formulated by NEMMCO, for which relatively early implementation should be possible. (i.e. there would be no distinction made between the two services).

10. The rule for charging for reactive (provision and enablement) and the other NCAS is that the party should pay who ultimately receives the residue stream impacted by the particular ancillary service (or the corresponding premiums after the cash flow stream is assigned to a hedge contract or auctioned). This maintains an accountability link between the cost of any additional ancillary service provision and the energy spot market benefits from providing the corresponding increased secure network capability. Prior to the light on the hill this cost allocation would be:

[25] Continuous reactive power that supports network flows between regions, or to major load centres within regions, can be subject to effective competition from alternative sources. In such cases voltage-continuous NCAS should be the subject of a generic constraint applied to the SPD process, dispatched in this manner and generally follow the same approach as for contingency-based NCAS (see later). Suitable network locations for this treatment should be determined by NEMMCO during its ongoing review of the application of generic constraints in the SPD, as proposed in the Evaluation Report.

- To the TNSP or other party that receives, or would receive, the settlement residue associated with each generic constraint or potential constraint managed by the SPD;
- If a recipient is a TNSP the amount would flow through to customers through a modification to network charges.
- Services supporting a regional network may not accrue settlement residues directly but the costs should in any case be assigned to the TNSP in the first instance, as the beneficiaries are the customers of that TNSP.

6. In the event of a contingency, any NCAS use costs should be assigned to the party who caused the contingency, or assigned to the same beneficiaries as for other NCAS costs if a causer cannot be identified.

5.6.3 Likely impact of payment arrangements

The net effect of the proposed changes would be first, to re-align these ancillary service costs more directly to the causers and beneficiaries of these services and, second, to make more transparent the scope for competitive provision. Specifically, changes along these lines will be required to support the ancillary service needs of entrepreneurial links.

6 NCAS: Stability and Network Loading Control

6.1 Overview of Market Proposals

As indicated in the previous section, the discussion of reactive ancillary service applies equally to the stability and network loading ancillary services. Apart from the technical differences in these services, the main consideration in the establishment of market arrangements are issues of competition, in particular the number of suppliers and market information.

As for voltage control, the stability and network loading ancillary services that support energy transfers across the network (in the face of possible contingencies) should ideally be provided through competitive two-way spot markets, coordinated with the energy spot market and dispatched by NEMMCO. As previously mentioned for the voltage control services:

- There would be no requirement to separately assign enablement costs, as such payments would come through spot market settlements.
- Such arrangements would support long-term contracting either by NEMMCO, NSPs, entrepreneurial NCAS providers or parties in the business of selling network hedges, perhaps to support an entrepreneurial link.

The limited number of suppliers and the technical nature of these services suggest that they may not be immediately suitable for competitive trading. Negotiated or regulated procurement may be the most suitable.

Together with the voltage control ancillary services, the transition period would consist of the review, reformulation and publication of the generic constraints that drive the valuation of these ancillary services under the current SPD formulation.

6.2 Causers, Providers and Beneficiaries

6.2.1 Causers and Beneficiaries

As for the voltage control ancillary service, the causers of the requirement for stability and network loading ancillary services are the parties that wish to trade, or promote trade, over the affected network elements. They can also be regarded as the beneficiaries of that provision.

6.2.2 Providers

Providers of stability and network loading ancillary services are outlined in the Evaluation Report and Framework Report. As indicated, possible providers are:

- For stability – generators, demand control, protection schemes, series capacitors, braking resistors etc, and
- For thermal control – generators, demand, network outage management and others.

6.3 Payment Options

The payment options are the same as for the voltage contingency service. These are discussed briefly below in the context of stability and thermal loading control.

6.3.1 Mandatory Provision

There is no mandatory provision of any of the services in this category.

Currently there are mandatory technical requirements for generators to connect to the network associated with stability. These requirements are for generators to have installed automatic excitation regulators with specified performance and specialised control facilities (stabilisers) to enhance power system stability. As with all ancillary services, this equipment is not required to ensure power system security, but to maintain security within defined network transfer limits.

The relatively small costs associated with the installation of equipment such as stabilisers suggests that the issue of mandatory installation (required for stability) remain a security issue, and not be included in ancillary service markets, at least for the transition period.

6.3.2 Cost Allocation to Emulate Two-way Markets

As indicated with voltage control ancillary services, if the allocation of the residue is correct, then the parties who will pay for the ancillary services will be the parties who directly benefit from the network capability. This should produce the most efficient outcomes and is the preferred approach if achievable, even though the logic for allocation of the residue could be improved.

6.3.3 Allocate over the Whole Market or Allocate to Retailers or Distributors

Cost allocation that ignores the causer/beneficiary principles fails the objectives of the project are not recommended. The allocation to retailers or distributors raises the same issues as for voltage control.

6.3.4 Consolidate Costs with TNSPs who Provide a Packaged Service

At present stability and network loading ancillary services are organised by TNSPs and NEMMCO.

The rationale for market based arrangements in NCAS procurement and cost allocation is improved efficiency, taking account of the overheads involved. As for voltage control ancillary services, one approach could be to have stability as well as reactive provision made a matter for negotiation between the TNSPs and potential providers. However, as previously indicated, this approach might fail to make the process of procurement and dispatch transparent and fully contestable, as well as imposing transactions costs that might outweigh any potential benefits.

6.3.5 Use Costs

As with reactive ancillary services and following the "causer pays" principle, any use costs associated with a contingency should be allocated to the assessed causer of that contingency or, if such a causer cannot be identified, to the beneficiaries who pay for the costs of NCAS enablement.

6.4 Summary of Payment Proposals

The payment proposals follow the summary outlined for voltage control. Particular issues for stability and network loading control are as follows:

- During the transition, stability and network loading ancillary services would be procured and provided through NEMMCO, albeit subject to more transparent pricing arrangements.
- The installation of generator stability equipment (eg. stabilisers) should remain a power system security issue, and remain mandatory.
- In the same manner as for voltage control ancillary service, the rule for charging for enablement is that the party should pay who ultimately receives, or would receive, any settlement residue stream supported by the particular NCAS service (or the corresponding premiums after the cash flow stream is assigned to a hedge contract or auctioned).

In the event of a contingency, any NCAS use costs should be assigned to the party who caused the contingency, or, if such a causer cannot be identified, to the beneficiaries who pay for the costs of NCAS enablement.

As for voltage control ancillary services, the net effect of the proposed changes would be first, to re-align these ancillary service costs more directly to the causers and beneficiaries of these services and, second, to make more transparent the scope for competitive provision. Specifically, changes along these lines will be required to support the ancillary service needs of entrepreneurial links.

7 NCAS: Spot Market Trading Benefits

7.1 Overview of Spot Market Trading Benefit Proposals

7.1.1 Light on the Hill

The vision for the light on the hill is based on replacing the current transportation model in the SPD with a full contingency-constrained optimal AC loadflow model. This would improve the benefits of trade and also improve prospects for pricing and managing the continuous voltage control service. This is a significant development that would extend the state-of-the-art, and will take some time to come to fruition.

7.1.2 Transition

Spot market trading benefits will accrue by implementing arrangements that progressively introduces flexibility into the treatment of the constraints currently imposed on spot market outcomes in the SPD dispatch process. This would require recognition of the costs associated with reducing the imposed constraint or constraints (through the enablement or provision of a particular service) to the increasing benefits of trade achieved.

7.2 Causers, Providers and Beneficiaries

This service defined by the ASRG is not often considered in terms of an ancillary service. We interpret it as shifting the technological and economic boundaries that constrain market operations in the NEM at any given time. Following this line:

- *Causers and beneficiaries* are those that perceive the benefit from improving the operation of the market. In the long run the market as a whole would benefit. Taking this further, efficiency improvements in the industry benefit the whole community in the long run.
- *Providers* would be market participants, their advisers and the research community.

While the ancillary service sector of the NEM is relatively modest in size, along with Transmission and Distribution (T&D) networks, the market “top end” and other issues currently attracting NECA and NEMMCO’s attention, they can cause a disproportionate degree of potential risk to the market through being not fully and adequately resolved.

7.3 Payment Options

7.3.1 Light on the Hill

The light on the hill in both FCAS and NCAS, as well as the effective operation of the market in broader terms, must involve evolutionary improvements and, in some cases, quantum changes in technology and approach, backed up by a significant research and development effort carried out well in advance.

While it would be appropriate for the incremental changes to be funded by the industry generally as noted for the transition, a case can be made that any longer term research effort should attract support at a higher level, perhaps through federal research programs. The alternative would be to rely on internal industry funding or the efforts of entrepreneurs.

Our recommendation is that the industry develops arrangements to ensure that the further beneficial evolution of the market is promoted through a focused long-term research and development program.

7.3.2 Transition

The transitional arrangements require implementation rather than research and are appropriately funded through pool fees, as were the original market systems.

7.4 Summary of Payment Options

7.4.1 Light on the Hill Payment Arrangements

1. No additional costs would be incurred that would need to be explicitly covered, other than development costs that would be recovered either through pool fees and a focussed research and development program that could attract R&D funding from governments.

7.4.2 Transition Payment Arrangements

1. Implementation costs funded through pool fees.

7.4.3 Likely Impact of Payment Arrangements

Implementation of spot market trading benefits should deliver an unambiguous improvement in economic efficiency (development costs and other overheads aside) although some re-allocation of financial outcomes in the energy market could occur in the short term. Such a re-allocation occurs with every change in market conditions.

8 SRAS: System Restart

8.1 Overview of SRAS Market Proposals

8.1.1 Light on the hill

For the light on the hill we propose a review oversighted by the NECA Reliability Panel of a long-term strategy for the provision of system re-start services, taking into account:

- the need to maintain a basic set of resources to ensure the system can be re-started within a reasonable time, recognising that such resources might be more cheaply procured with longer term contracts, and may in part be available through arrangements that the current NECA capacity payments review might recommend;
- the desirability of acquiring supplementary resources on a competitive basis to meet immediate needs, including rapid relief for the worst impacts of localised or widespread system black conditions; and
- the various options, especially those embedded within the distribution network, that could be developed over the next three years (say) and called upon at short notice to support local customers, but not contribute to system restart.

We also propose a broad strategy to develop embedded load management and generation resources that can support a wide range of frequency-related, distribution and transmission ancillary service requirements, as well as system restart.

8.1.2 Transition

For the transition we propose little change to recent practice, except to note that a longer-term contractual arrangement might be more cost-effective. However, bearing in mind proposals for the light on the hill, the immediate contract term from July 1999 should be for a further year only.

8.2 Causers, Providers and Beneficiaries

As there is no practical prospect of any two-way market arrangement for providing system restart capabilities, it would be desirable to charge for this service on a “causer pays” basis or failing that, on the basis of who benefits from the service.

Causers

It is not possible to predict with any certainty what chain of events might cause a system black. Clearly, such the possibility of events would be analysed in advance to the extent possible and steps taken to guard against them. The NEM’s system security requirements as embodied in the Code and in good operational practice deliver a remarkably reliable system, considering its huge scale and complexity.

It is unlikely that any single producer or consumer could be attributed as the sole causer of a system black, but they could trigger such an event. A local failure, system operator error or some act of God such as a major bushfire could trigger cascading trips and failures in the network. These are matters for which NEMMCO, TNSPs and DNSPs are accountable. For example, an act of God such as a major bushfire that disrupts major transmission lines many not be under the direct control of a TNSP, but the design, siting and maintenance that could affect the consequences of such a natural event to the system are controllable, at least to some extent. Even accepting that major failures can always occur despite good practice, it still makes sense to assign accountability where the problem area lies. The party concerned could then, in principle at least, manage those risks that are manageable and absorb or insure against the remainder.

Given that system blacks are rare events and the causes are likely to be diffuse and complex, such considerations do not provide clear guidance as to who should pay for the ongoing costs of maintaining a basic restart capability. Assigning cause might be feasible in some, but not all, cases after a specific event, but is likely to be contentious even then. Nevertheless, an attempt to trace the cause would be a necessary exercise following such an event, and it could in some cases provide a basis for assigning any use costs associated with recovering from a particular system failure.

Beneficiaries

Identifying the beneficiaries of system re-start facilities could be another criterion for identifying who should pay for them. We would not expect such beneficiaries to volunteer that status, and this has proved to be the case during the discussions prior to the drafting of this report. None of the generators, networks or retailers we spoke to expressed any direct interest in seeing the system re-started for their benefit. We doubt that there are many other industries where the wholesalers, transporters and retailers could afford to stand so aloof from a complete failure of the market system that supports their businesses and their customers.

When an electricity system fails on a large scale, the consequences can be severe. One member of the ASRG described the consequences in these terms:

"The driver for the recovery of the power system is the cost to individual critical loads such as smelters first… and then to major load centres generally to avoid the societal cost of the chaos the normally follows such system failure (looting, traffic chaos, loss of essential services, contamination, loss of communication systems, disease outbreaks after a day or so, and so on). In fact, the justification for restart resources was (in the previous utility-based world) based on a cost benefit basis to the load taking account of how long it would take to restart and rebuild the system…"

This passage vividly describes how it is not just individual loads concerned about lost production that suffer from such an event, but the whole social fabric, of which all the individuals and institutions in society are a part. Clearly, a rapid recovery from the failure focussing on the most critical loads from a social and then an economic perspective will be a primary goal. But it should also be noted that generators do not all have their own re-start facilities and that some equipment can be subject to damage if no power is available for an extended period. Indeed, system operators point out that the main focus of their re-start strategy is to get generators re-started, both to avoid such damage as well as to support the gradual re-connection of loads that the re-started generation can support.

In our view, none of this is a particularly useful basis for determining how the cost of the service should be allocated. In very broad terms it is the market as a whole, and society in general, that benefits from the ongoing operation of a facility for the trading of electrical energy of adequate quality and reliability. Thus the matter of insuring against and recovering from system failure must be a considered a matter of public policy.

Providers

It is possible to conceptualise a trade-off between the cost of an increment of restart capability (which has a geographical basis as well as other dimensions, incurring the reliability of the facility) and the marginal benefits of that increment. One could envisage some form of regionally based common clearing price for the facility, established by a yearly bidding process. Such a line of thinking is not likely to be useful in practice for this service, so that competitive tendering is the most appropriate approach, implementing a re-start strategy determined through some communal process as recommended in the Evaluation Report.

The question of who pays might be resolved with reference to operational and management issues. Following the recommendations in the Evaluation Report, we have suggested two categories of restart facility:

- Basic restart facilities, intended to ensure that the system can be restarted, but with minimal concern about timing
- Supplementary restart facilities, focussed on ameliorating the cost of a system or more local blackout, and which will have a strong regional basis and local basis.

In fact these categories represent two polar extremes. In the limit, just one restart facility in the whole system could get the system going again. In practice, a basic service could be defined as one which would see the system re-started after a complete system black (provided there is no major equipment damage) within a set time period with a set level of reliability. This may involve some regional spread of facilities, but not necessarily to a high level of reliability within each region, as a facility in one region can support another[26]. Such an approach would provide the necessary assurance that the system can be re-started, but not necessarily as fast as some market participants would like, and be prepared to pay for.

Focussing on the other extreme, supplementary facilities will tend to be local or regional, and accessed and managed and initially paid for in the event of an incident by the DNSPs. NEMMCO could also manage a supplementary service if requested to do so by a regionally-based coalition of interests who express a willingness to pay for it.

[26] The current approach is to maintain two facilities within each region, which would certainly extend beyond the concept of a basic service.

8.3 Payment Options for the Light on the Hill

8.3.1 Basic restart facilities

Consumers v. Producers

System re-start facilities are to be used when the whole or large parts of the physical and market system have failed. We have argued that the market as whole benefits from them. Consumers or producers (more likely the latter) may play some role in a system black event in a particular case, but there is no basis on this ground for assigning ongoing basic system restart costs to one or the other as a group.

Regions v NEM as a whole

As basic re-start facilities could be spread across several regions, one option is that they be paid for on a regional basis. This might check any regionally-based pressure to hold a disproportionate share of the basic facilities in one region or another. However, the process recommended for the development of that strategy under the aegis of the Reliability Panel should avoid this outcome in any case. Further, the supplementary service is intended to provide the additional support that might be desired regionally.

If we accept that the beneficiaries of the basic service are spread throughout an inter-connected set of regions, there is a question as to whether currently *separate* regions should pay for their own basic re-start facilities. A distinction in this case may be justified if there is no prospect of a facility in one region being of potential benefit to regions that are not connected to it.

Energy Market Participants v. TNSPs

If all energy market participants in a region are considered to be the beneficiaries of a re-start service, the cost could be charged either directly to energy market participants or to the relevant TNSPs, and then passed on to TNSP customers through network charges. At the moment loads are the only TNSP customers who pay general network costs. NECA in its recent transmission and distribution and pricing review has proposed that new generators only should make a contribution to network costs in future. For the foreseeable future, allocating basic restart costs in this way would be inequitable, given our assessment of the broad scope of the beneficiaries of this service. We therefore prefer an approach that would charge all market participants for the basic service directly, on the basis of gross traded energy. Such an approach would not preclude some locational discrimination where regions are electrically separate.

Payment for Use

The suggestions above relate to the costs of ensuring that plant is available for use for system re-start. In the event of an incident additional use costs will be incurred. In principle these should be charged out to the assessed causers of the incident. This might be difficult in practice as argued earlier. Given also the rarity of such events, any use costs associated with basic restart should be charged on the same basis as that for fixed costs.

Assessment of payment options for the basic re-start service

There are fundamental difficulties with attempting to apply the "causer pays" principle to the basic system restart service. This arises because of the likely complex nature of such causes when viewed after the fact, a complexity and uncertainty multiplied many times when viewed before the fact.

It is more appropriate to recognise that such facilities are provided irrespective of likely cause as a matter of public policy, and for the benefit of the market as a whole. There is therefore no general basis for charging for a basic service regionally. However, it is reasonable to recognise that basic restart facilities located in electrically disconnected sets of regions serve those regions alone and might therefore be charged separately.

The principles laid out in Section 2.5 provide the basis for charging for an ancillary service that benefits the markets as whole, and for which no clear causer can be allocated. Such costs should be charged to all market participants in proportion to gross traded energy. We propose this both for the ongoing costs of providing basic restart facilities and also for use charges, except where review after an event reveals a clear and culpable causer, in which case use costs should be assigned to them. Where regions remain electrically separate we propose that the above rule be applied to the costs incurred in each electrically separate region.

8.3.2 Supplementary re-start facilities

Unlike the basic restart service, supplementary re-start facilities are specifically intended to ameliorate the costs of a system black condition to customers and are essentially regional local in nature. When such an event occurs, they would be managed by DNSPs if local or by NEMMCO if it has been approached by a coalition of interests who have expressed a willingness to pay for a service in specific locations. It is appropriate that all the costs of such a service be passed on to DNSP customers if local facilities are used, or be charged to the parties who specific requested additional facilities.

8.4 Payment Options for the Transition

There are no significant transitional issues in moving to the light on the hill payment arrangements.

8.5 Summary of Payment Proposals

8.5.1 Light on the hill payment arrangements

Basic restart service

1. For each set of electrically inter-connected NEM regions, all ongoing basic re-start SRAS costs to support that inter-connected set of regions should be allocated to market participants in proportion to gross trading interval energy produced or consumed within those inter-connected regions.

2. Use costs should be allocated in a similar way, expect where review after an event reveals a clear and culpable causer, in which case use costs should be assigned to them.

Supplementary restart facilities

3. Availability and use costs would be assigned by DNSPs to their customers or by NEMMCO to the coalition of interests that has agreed to pay for a specific regional facility.

8.5.2 Transition payment arrangements

1. The payment methodology for the light on the hill should be implemented as soon as possible.

8.5.3 Likely impact of payment arrangements

The cost of the basic restart service arrangements will be shared by all market participants, except for that component of costs which, after a specific incident, would be allocated to the assessed causer. The costs of any supplementary service would be paid by the customers who benefit directly from the additional local or regional facility.

9 Code Issues

9.1 Overview

The arrangements proposed in the previous sections would require Code and regulatory changes as part of the implementation process. This section presents broad areas that such Code changes would need to address. It is not the purpose of this report to indicate the Code changes required in detail.

There is a question as to how much should be included in the Code and how much left to regulations or policies developed according to broader codified principles. In this context, it must be recognised that the strategy proposed for the development of markets in ancillary services in this and the previous Evaluation Report cannot spell out the final arrangements in detail. Some latitude is required, as long as this does not jeopardise the achievement of the objectives. A preferred approach would be to:

- set out the objectives of the ancillary service arrangements
- set out the guiding principles to be followed;
- set out the broad milestones to be achieved (as proposed in the tables contained in the Conclusions to this report) and their timetables; and
- make specific changes in related Code areas necessary to support the proposed ancillary services arrangements

9.2 Overall

1. Provide for arrangements that would support on ongoing long-term market review and R&D programs in ancillary service market development, and development of the NEM generally.
2. For the ancillary services part of the NEM, the following should be included:
   - The ancillary services principles set out in the Framework Report.
   - Ancillary service definitions at a broad level (FCAS, NCAS and SRAS proposed).
   - The types of arrangements that will and will not be supported:
     - ❑ Mandatory technical requirements for connection will continue;
     - ❑ No mandatory provision of ancillary services.
     - ❑ Market arrangements that internalise ancillary service provision with the operation of the energy market and maximise contestability are to be preferred where practicable.
     - ❑ The next preference is for arrangements that maximise contestability and competition in the provision of services preferably through spot markets but

otherwise through competitive tender, in which case costs should be charged as far as practicable on a causer pays basis.

- If none other basis can apply, procurement can be by negotiation.

- The broad basis for charging which is:
  - Left to the market arrangements if two-way markets are possible
  - Otherwise on a causer pays basis if practicable and if causers can be identified and their performance measured.
  - Otherwise, allocated to both sides of the energy market on a gross trading interval energy basis.

9.3 FCAS

The Code change areas for the frequency control ancillary services are as follows:

1. Provide that NEMMCO implement periodic reviews for consideration by the NECA Reliability Panel and market participants generally on:
   - frequency standards
   - criteria for the determination of assessing the requirement for FCAS, where this is not accounted for in market processes.
   - load forecasting accuracy and procedures used in the SPD process.
2. Describe the major facilities as set out in the tables in the conclusions to this report, and when they are to be achieved.
3. Provide for the use of SCADA data for measuring performance and, where applicable and participation can be made voluntary, settling some ancillary service accounts.

9.4 NCAS

The Code change areas for the network control ancillary services are as follows:

1. The removal of the mandatory provision of generator reactive and the requirement for generators and TNSPs to negotiate in regards to:
   - reactive provision required to support a generators own requirements, and
   - to support additional network capability.
2. Provide criteria for defining reactive (and any other assets) that should be included in competitive ancillary service arrangements. This would initially be for those future ancillary service assets, reactive or otherwise, that provide for enhanced inter-regional capability.

3. Provide that future reactive assets providing NCAS in the latter category be excluded from the regulated asset bases of the TNSPs.
4. Provide that NEMMCO allocate the costs of NCAS it incurs to the causers and beneficiaries of the provided ancillary service. This would entail the development of rules that would provide for:
    - the allocation of ancillary service enablement costs to the beneficiaries, and
    - the allocation of the ancillary service use costs resulting from a known contingency event to the causer of the contingency, or if such a causer cannot be identified, to the beneficiaries identified above.
5. Provide criteria that would signal and define the ancillary services suitable for two-way trade.
6. Provide that a defined portion of the settlements residue (or auction component) due to a particular ancillary service, as defined by the relevant SPD generic constraint, be allocated to the provider of that ancillary service;
7. Foreshadow the introduction of an enhanced version of SPD, initially providing for the co-optimisation of the generic constraints, and later for the introduction of a more complete network model such as a contingency-constrained optimal AC loadflow. This should reference areas considered in other reviews that are relevant, such as nodal pricing and congestion contracts.

9.5 SRAS

The Code change areas for the system restart ancillary service are as follows.

1. Provide that NEMMCO in association with NSPs, representatives of other Code participants and in consultation with the jurisdictions, develop and periodically review a system restart strategy for consideration and approval by the NECA Reliability Panel after public consultation.
2. Provide that the ongoing costs of the basic re-start service that supports an inter-connected set of regions be allocated to market participants in proportion to gross traded energy within those inter-connected regions.
3. Provide that a coalition of interests may request NEMMCO to organise supplementary regionally-based services provide that those services are paid for by the coalition.

10 Conclusions

This review has followed three basic principles for cost allocation:

- For the light on the hill, two-way ancillary service markets should be established where practicable, coordinated with the energy spot market. Such markets will internalise ancillary service activities that were previously external to the market and will resolve the issue of who pays for them.
- During the transition, and where two-way markets in an ancillary service cannot be established, the principle of "causer pays" should be applied where practicable.
- Where no market is possible or where clear causers and beneficiaries cannot be established, the service must be considered to be a benefit to the market as a whole. In these cases the costs will be allocated according to gross trading interval energy produced or consumed.

Application of these principles to the three broad categories of ancillary services defined in this report for the purpose of discussion gives the outcomes summarised below.

Also included is a staged approach to implementing the proposed service grouping, including payment arrangements. There is no attempt to nominate absolute timing; nor do we suggest that the steps should be carried out sequentially, as some packaging of steps to minimise the number of changes seen by both participants and NEMMCO would be desirable. The focus is on staging rather than all of the details of each step.

10.1 FCAS

10.1.1 Overview of payment proposals

FCAS is about half the cost of ancillary services and offers the greatest prospects to allocate costs effectively and to establish more competitive markets in the immediate future.

For the management of small frequency deviations we have proposed propose direct measurement of cause and provision and cost allocation on that basis. The preferred approach (subject to further investigation in the implementation phase) would be to implement continuous measurement of cause and provision and the payment of enablement costs on that basis, followed by a phasing in of the energy deviations market. These approaches have been considered in Appendix A to this report. We expect that this approach will lead to wider and more competitive participation in small deviation FCAS provision. Costs will be allocated to both sides of the energy market, not just to loads.

For the management of large frequency deviations, application of the causer pays principle implies that the potential and actual causers of the need for the service should pay for this service. This is a significant switch from the current position, where loads pay all of these costs.

10.1.2 Staged implementation

The proposed staging follows the consideration of FCAS in the Evaluation Report, the discussion in this section and also the consideration of small deviation FCAS phasing in Appendix A.

1. To prepare for the phasing in of the *energy deviations market* and/or cost allocation arrangements outlined in Step 6, implement a prototype energy deviations pricing and settlement module to demonstrate the feasibility and likely outcomes of the energy deviations market and small deviation FCAS cost allocation logic.

2. Following analysis of results from this prototype, review the pricing and settlement logic for, as well as the transition strategy to, the energy deviations market, including possible cost allocations options for small deviation FCAS enablement. This should include consideration of:

   - whether energy deviations prices should be weighted by the regional energy prices as well as system deviations;
   - the method of distributing the possible small settlement surpluses or deficits as occurs in the energy market;
   - the various options for the transition, including those outlined in Appendix A; and
   - any other relevant matter.

3. For both *small deviation and large deviation FCAS enablement*, implement a staged approach, beginning with the *first stage* that would require no SPD changes:

   - FCAS product definition to be compatible with current SPD logic, but reviewed to improve them where possible;
   - weekly bidding;
   - settlement based on common clearing price for each service and each dispatch interval (requiring some IT development).

4. During this transition phase, charge FCAS enablement costs as follows:

   - for small deviation FCAS, to causers and providers in proportion to performance measured on a continuous basis. This approach should be reviewed following studies using the energy deviations demonstration module.
   - for large deviation FCAS, to market participants who are loads or such other default arrangement that may currently apply, noting that, for the light on the hill, the two-way market in this service that would allocate costs to causers should be expedited.
   - To phase in the energy deviations market and to improve the cost allocation of small deviation FCAS, progressively ramp up the reference price (energy deviations price scaling factor) for the energy deviations market until a balance is struck which places

minimal financial reliance on enablement and which achieves the desired frequency performance standards

5. NEMMCO should:

    - periodically review the frequency standards necessary to maintain system security, for consideration and approval by the NECA Reliability Panel;

    - review FCAS enablement requirements according to logical time or condition divisions every six months as a minimum, or more frequently as opportunity permits, with a view to reducing enablement requirements while maintaining system security; and

    - measure, assess and improve its load forecasting accuracy to produce unbiased load forecasts with minimum variance.

6. The spot market (daily and shorter bidding) in small and large deviation FCAS enablement (an enhancement of the facility already in place), together with enhanced FCAS product definitions as appropriate, should be established as soon as practicable.

    - In the case of large deviation FCAS, this should include a facility in the SPD to support two-way trade in the service.

7. Implement the proposed 5-minute settlement adjustment, noting that this step does not impact directly on any others and could be omitted.

10.2 NCAS

10.2.1 Overview of payment proposals

Customers who are loads (mostly retailers) across the whole energy market currently pay for contingency-based NCAS costs incurred by NEMMCO, in proportion to gross trading interval energy consumed. Fixed costs incurred by NSPs are passed on though network charges.

The key recommendation for cost allocation is to assign NCAS costs to the parties who are, or could be, the recipients of any network financial residue, or proceeds from the sale of those residues, associated with the network constraint that the NCAS is intended to affect. At present these are ultimately the customers in particular regions through their network charges.

The net effect of the proposed changes would be first, to re-align these NCAS costs more directly to the causers and beneficiaries of these services and, second, to make more transparent the scope for competitive provision. Specifically, changes along these lines will be required to support the ancillary service needs of entrepreneurial links.

The charging approach proposed for NCAS should support the development of markets in NCAS where and whenever these are practical, and also support entrepreneurial links that require NCAS support. For this reason we recommend that they be implemented as soon as practicable.

10.2.2 Staged implementation

Transition period

1. NEMMCO should publish the generic constraints and shadow prices associated with the impact of all network ancillary services. This would involve the development of a process to review the SPD generic constraints and the economic basis for these constraints, with an initial focus on the most significant constraints in the network. The finding of this review would be published in a report such as the statement of opportunities.

2. The provision of reactive power by generators should cease to be regarded as a mandatory service. However, NSPs and their customers (generators, DNSPs etc., may negotiate a base level of reactive capability via a connection agreement or any other arrangement and NEMMCO will be advised of this capability. The provision of additional reactive should be regarded as a commercial service, either by negotiation with TNSPs, NEMMCO or an entrepreneurial link provider and/or through any spot trading arrangements in the service that are established.

3. As only minimal changes would be required in SPD, a phased introduction of the enhanced spot trading ancillary service should be considered for early implementation. This would involve the co-optimisation in SPD of defined services that impact network constraints, as expressed through the generic constraint relationships.

4. As voltage control is the most significant NCAS, early attention should then be given to this service. For the transition period a single voltage ancillary service should be established, combining continuous and contingency services, possibly termed “reactive support ancillary service”. This reactive support ancillary service would be priced through the identification of reactive provision and enablement relationships to network capability contained in the SPD generic constraints (particularly interregional), with costs allocated according to causers / beneficiaries (see below). The stability and thermal control ancillary services should also be included in such arrangements.

5. A first step in this process would involve a moderate change to the current payment arrangements. The costs of reactive requirements determined by NEMMCO and procured by NEMMCO would be levied to those parties responsible for the need (as opposed to current arrangements where such costs are allocated to all market participants that are loads). Guiding rules under this initial development would be:

   - the beneficiaries of the increased interregional capability made available by the supporting ancillary service should pay for that ancillary service as noted in the recommendations; and

   - Ancillary service use costs allocated to the causer of the contingency or, if a causer cannot be identified, to the beneficiaries identified above.

   This would involve regulatory / Code changes relating to payment rules only. Of note is that NEMMCO would incur the risk associated with the procurement in the first instance, although this risk would be passed on.

The incorporation of competitive stability and thermal loading control ancillary services could also be incorporated in the changed payment arrangements at this stage, as no additional issues should arise.

6. A possible next step (or incorporated into the first proposed step) would be aimed at improving reactive procurement transparency and as a precursor to the establishment of two-way markets. This would involve de-regulating future reactive provision for the purposes of supporting interregional transfer capability. Reactive procured for such purposes by TNSPs or NEMMCO would be paid from settlement residue streams (or by capturing the potential value of such streams through appropriate contacting had the reactive procurement not occurred). This step would involve regulatory and Code changes associated with the de-regulated payment of such assets. Regulated reactive assets or reactive assets under contract to NEMMCO would not be entitled to payments (settlement residues) from the spot market for there contribution to interregional capability.

   During the transition period or until such time as a suitable network model is introduced that can value full network capability / voltage profiles, future TNSP reactive assets required for local voltage regulation would remain in the TNSPs regulated asset base. This would be so even if such reactive has the potential to influence interregional transfer capacity at times of high reactive demands. No de-regulation of existing TNSP reactive assets is proposed and regulated reactive assets would continue to be paid for under the transmission and distribution pricing rules established.

7. The final step in the transition period would involve the establishment of two-way spot markets in the reactive support ancillary service, and the stability and thermal loading control services that support inter-regional transfer. This would commence with the co-optimisation in SPD of the most significant limiting interregional constraints.

During the transition period, reactive taken from the transmission network by distribution companies would be priced at times when reactive is limiting interregional flows (as included in SPD constraint equations), and paid to or by the corresponding distribution companies. This would be based on reactive values determined through SPD recognising the locational "influence factors". A reference level would be established for reactive taken or provided to the transmission network based on that currently in the Code. Initial risks could be managed via appropriate vesting contracts.

8. As bidding of reactive sources is difficult without the means to schedule reactive and to properly value reactive from different locations, possible bidding arrangements should be left and considered as part of a possible move to light on the hill arrangements.

Light on the hill

1. To value and trade reactive/NCAS through its contribution to inter/intra-regional network capability and voltage profiles, commence an investigation into a contingency-constrained optimal AC nodal dispatch and pricing model as a next step in SPD development. This would also from part of the Spot Market Trading Benefits service.

2. As a step towards this the development of a stand-alone online network contingency analysis capability could be undertaken to support a more conventional AC SPD model. However this may require that many of the generic constraints remain.

3. The ultimate light on the hill arrangements would have the complete AC nodal market with reactive priced and traded via two-way markets, including the possibility of reviewed NCAS products. Such arrangements would require:

   - the development of "transmission congestion contracts";
   - the development of locational voltage preference curves (or the equivalent); and
   - consideration of network market power issues within regions.

4. All future reactive assets would be priced and traded outside of the regulated asset bases of TNSPs. The possible introduction of ancillary service bidding would need to be considered at this stage.

5. Finally, the implementation of light on the hill arrangements would require the development of appropriate transmission pricing rules and a supporting regulation philosophy.

10.3 SRAS

10.3.1 Overview of payment proposals

The change proposed for the system re-start service is allocate the ongoing costs of a basic system restart service implemented within a set of inter-connected regions to all market participants in those regions. The rationale for this approach is no clear-cut causers can be identified in advance and that that the basic service, as distinct from the supplementary service, is a benefit to the market as whole and should be paid for accordingly.

To the extent that additional facilities beyond a basic restart capability are desired to ameliorate local costs in the event of an incident requiring system re-start, they should be paid for at the level that they are implemented. This allocates the cost to the beneficiaries of that service, either within regions or within particular distribution areas.

10.3.2 Staged implementation

1. NEMMCO should manage the development of the proposed system re-start strategy for consideration by the Reliability Panel.

2. When the system restart strategy is settled, NEMMCO should arrange for the procurement of the necessary basic restart resources through a process of competitive tender.

3. The cost of the procurement and any use of the basic restart facilities procured as a result of this process should then be charged to market participants within each set of interconnected regions as proposed.

4. The cost of any supplementary facilities should be borne at the level at which they are procured and passed on to the relevant NSP customers, or to the coalition that may have requested NEMMCO to provide such facilities.

10.4 Summary Tables of Recommendations

The Tables that follow summarise in a concise form the proposals for ancillary service market development and cost allocation made in this report, taking into account the broad strategy for implementing ancillary service markets that has been proposed in the Evaluation Report and the staged implementation outlined above.

10.5 Market Power

One of the more contentious issues for this review is the extent to which market power might exist in the provision of various services, how that power might be managed and whether its apparent existence might affect the development of market arrangements in ancillary services.

In the case of the frequency-related services, it is currently the case that the network security criteria essentially allow provision to be sources almost anywhere in the inter-connected system. While this continues, supply of FCAS will be sufficiently competitive. At a later stage it may be that network limits will become tighter, in which case FCAS might need to be sourced regionally to some extent. Issues of possible market power in FCAS provision may need to be re-visited in this case, although it seems unlikely to be a problem in most regions as long as if competitive arrangements in FCAS have progressed well in the interim.

The issue is more complex in the case of NCAS, which are to do with supporting network transfer capability and which have a more localised characteristic. The general approach here is to assess each situation on its merits. For example, there seem to be no compelling arguments to suggest that, in general, undue market power can be influenced in the case of inter-regional transfers. This is the basis on which the NEM is moving to support entrepreneurial inter-connectors, a matter addressed in the current NECA review.

There may be short-term market power that would be resolved by commercial contracting and competitive entry (or the threat of it) in the longer term. When introducing new market arrangements it is therefore reasonable to consider “vesting contracts” to protect financial positions until commercial negotiation can have an effect. However, a difficulty can arise if contracting is poorly supported. This is a particular concern in relation to the inter-regional hedge market that seems to be slow in developing because of various controversies surrounding the treatment of settlement residues from the energy market.

These issues highlight the relationship between how NCAS arrangements might evolve and broader developments in network regulation that will arise from NECA’s review.

1. FCAS: Management of small frequency deviations				
Timing		**Facility**	**Who Pays?**	**How Much?**
Present	**1**	Energy market dispatch based on 5 minute prices, with settlement based on half-hour averages	• Fast-response dispatchable plant effectively subsidises other energy market participants at times when fast response is required	• Negligible during most periods of market operation, but potentially the same order as market settlements at times when system conditions are changing rapidly.
	2	Facility to enable and dispatch units for AGC regulation in order of long-term contract offer prices for *enablement*, managed through the dispatch process.	• NEMMCO is sole buyer • Costs are then passed to *Customers who are loads* according to gross trading interval energy consumed	• NEMMCO assesses requirement for *enabled* MW to meet frequency standards • NEMMCO pays cost of *enabled* MW at long-term contract price, and also for *use*. • NEMMCO pays an assessed *compensation* cost for backing units out of the energy market
Transition	**1**	Current AGC regulation enablement facility with: ❑ Weekly offers ❑ Common clearing price	• NEMMCO is sole buyer • Costs then passed to *energy market participants* according to the strategy proposed for the transition to the energy deviations market (see below).	• Enablement costs are paid at a common clearing price obtained from the SPD process. There are no use or compensation costs in this facility.

	2	❑ *Transition* to the energy deviations market. This strategy is subject to review after testing of energy deviations prototype.	• Allocate costs and payments of enablement in proportion to continuously measured cause and provision. • Phased in energy deviations market will allocated costs in a similar way	• Assessed proportion of enablement costs incurred over the period. • Gradually ramp up energy deviations RTP reference price from initial low value.
1. FCAS: Management of small frequency deviations (continued…)				
Light on the Hill)	**1**	Settlement adjustment to correct anomaly between 5-minute pricing and dispatch and energy market settlement	• Adjustment will compensate currently disadvantaged energy market participants and will be paid by those currently advantaged.	• Can be assessed from historical records. Adjustment will be significant only in periods where there are short-term price spikes.
	2	Spot market for small deviation FCAS *enablement*, coordinated with the energy spot market. This is an enhancement of the current AGC enablement facility.	• NEMMCO is sole buyer • Costs incurred in the one way enablement market charged according to continuously measured cause and provision. • This allocation should be reviewed on the basis of experience.	• NEMMCO assesses requirement to meet frequency standards, periodically adjusting it to maintain a target level of confidence with a minimal FCAS enablement requirement • Enablement costs are paid at a common clearing price obtained from the SPD process. There are no use or compensation costs in this facility.

	3	Energy deviations market; the end point of the proposed transition process.	• Market outcome, with effect that *energy market participants pay and receive* in proportion to deviations from energy market outcomes, valued at the RTP	• The RTP for energy deviations is set by an algorithm designed and tuned to achieve frequency standards. • RTP algorithm should be tuned so that the dollar turnover in the spot market for small deviation FCAS enablement is small

2. FCAS: Management of large frequency deviations

Timing		Facility	Who Pays?	How Much?
Present	**1**	Facility to enable and dispatch units/loads ready for rapid response, according to long-term contract offer prices for enablement	• NEMMCO procures for *enablement* and *use* as required • Costs are then passed to *Customers who are loads* according to gross trading interval energy consumed	• NEMMCO assesses requirement for *enabled* MW to meet frequency standards following a contingency • NEMMCO pays cost of ❑ *enabled* MW at long term contract prices ❑ assessed *compensation* (opportunity) cost for backing units out of the energy market ❑ *use* cost for the actual use of an enabled facility after a contingency
Transition	**1**	Facilities for the management of small frequency deviations	• As for the *transition* for the management of small frequency deviations.	• As for the *transition* for the management of small frequency deviations, noting that this may not be sufficient to fully pay for the management of large deviations.
	2	Activate existing SPD procedures for enablement of large deviation FCAS with: ❑ Weekly offers ❑ Common clearing price	• NEMMCO remains the effective buyer • Retain current or agreed interim general payment arrangements until the light on the hill is implemented, which should be expedited.	• NEMMCO assesses requirement to meet frequency standards. • NEMMCO pays cost of *enabled* MW at common clearing price set in the dispatch process price that rolls in any *compensation* for being backed out of the energy market • No *use* costs payable unless the outage time of a used provider exceeds half an hour.

2. FCAS: Management of large frequency deviations (continued….)				
Timing		**Facility**	**Who Pays?**	**How Much?**
Light on the Hill	**1**	Facilities for the management of small frequency deviations	• As for the light on the hill for the management of small frequency deviations.	• As for the light on the hill for the management of small frequency deviations. Note that the deviations market will contribute to the payment and charging of *use* costs, but this may not be sufficient to fully manage large deviations.
	2	*Two-way* spot markets for large deviation FCAS *enablemen*t, extended from the one-way facility by linking large deviation FCAS requirement to energy market dispatch outcomes	• The market clearing logic implemented in the SPD has the effect of allocating large deviation FCAS enablement costs to the potential causers of the largest contingencies • Any abnormal use costs arising from the inability of NEMMCO to re-establish secure operations within half an hour will be allocated to all energy market participants according to gross trading interval energy	• Units/loads *enabled* for FCAS receive a common clearing price set in the dispatch process that rolls in any compensation for being backed out of the energy market. • Causers driving the requirement will share costs in proportion to their willingness to pay. This is an outcome of the FCAS market clearing process. • No *use* costs are payable except in the exceptional circumstances noted.

3. NCAS: Continuous and contingency				
Timing		**Facility**	**Who Pays?**	**How Much?**
Present	**1**	Mandatory provision of reactive capability by generators up to a level set by the Code.	• Generators	• Generally part of generation equipment but extra facilities as well as operation and maintenance costs may be incurred.
	2	Additional provision or absorption of reactive power by generators (above mandatory requirement).	• NEMMCO in the first instance, and the passed on to *Customers who are loads* in proportion to gross trading interval energy.	• Cost of *enablement* per long term contracts; • Cost of *compensation* if generation backed out of the energy market based on NEMMCO assessment of opportunity cost.
	3	Reactive absorption or production through points of interconnection between transmission and distribution networks.	• Code provisions provide for TNSPs and DNSPs to negotiate on best solution to provide or absorb reactive power, relative to a power factor standard. Cost of agreed solution is passed to respective NSP customers through network charges.	• As above, as shared between TNSP and DNSP.
	4	Reactive enablement and provision to ensure the network is secure from defined contingency events.	• Fixed costs relating to facilities provided by TNSPs and then passed to customers through network charges. • Additional costs paid by NEMMCO and then passed to *Customers who are loads* in proportion to gross trading interval energy	• Costs incurred by TNSP for fixed facilities at allowed regulated rate. • *Availability, enablement and use* costs incurred by NEMMCO paid as specified in long-term contracts. • *Compensation* costs paid by NEMMCO at a cost estimated through “what if” procedure.

3. NCAS: Continuous and contingency (continued)				
Timing		**Facility**	**Who Pays?**	**How Much?**
Transition	**1**	Review, refine and report on generic constraint definitions and costs of cause and provision.	• No immediate costs other than those incurred by NEMMCO, which should be included in pool fees.	• At cost
	2	Provision of reactive by generators, assessed as sufficient to meet the reactive requirement for their own operation, as would be the outcome of commercial negotiation.	• Generators	▪ As for the *present*, but for a different level of reactive capability.
	3	Provision of reactive by generators, required to support the use of the network by others, by negotiation with TNSPs, NEMMCO or entrepreneurial link providers.	• TNSPs, NEMMCO or entrepreneurial link providers.	▪ Negotiated.
	4	Re-allocation of reactive costs to those parties who cause the requirement	• Guiding rules under this initial development should be: ❑ The beneficiaries of the increased interregional capability made available by the supporting NCAS should pay for that ancillary service; and ❑ NCAS use costs allocated to the causer of the contingency, or, if the causer cannot be identified, to the beneficiaries identified above.	▪ As for the *present.*

3. NCAS: Continuous and contingency (continued)				
Timing		**Facility**	**Who Pays?**	**How Much?**
	5	Exclude future TNSP reactive facilities that maintain/enhance network transfer capability (and that can be valued in SPD) from the regulated rate base. Future reactive for local voltage control to remain in the regulated asset base unless a decision is made that future network expansion should be entrepreneurial, in which case this should be reviewed).	▪ TNSP investment in NCAS will be justified in the context of NCAS arrangements in competition with other potential NCAS providers, rather than through the regulated network process. To the extent that TNSPs are successful costs, will be charged as for the transition.	▪ As determined in each NCAS market, tender or negotiation process.
	6	Reactive pricing through SPD generic constraints linking inter-regional network transfer or network transfer to major loads to reactive provision.	▪ The recipients of the actual or potential settlement residue associated with the flow and thence to their customers if they are regulated networks.	• Value of the corresponding settlement residue stream. • Negotiated contract price capped at cost of competitive facility.
	7	Reactive absorption or production through points of interconnection between transmission and distribution networks.	• Reactive is priced in the SPD when reactive limits inter-regional flows. Establish a reference level for reactive taken or provided to the transmission network based on that currently in the Code	• Valued at the impact reactive taken has to the benefits of trade.
	8	Initial establishment of 2-way spot market in reactive support services.	• As for the initial transitional steps.	• As for the initial transitional steps.

3. NCAS: Continuous and contingency (continued)				
Timing		**Facility**	**Who Pays?**	**How Much?**
Light on the Hill	**1**	*Spot markets in NCAS enablement* (one sub-market for each significant active generic constraint in the SPD) based on spot trading coordinated with the energy market through the SPD process	• The two-way arrangements based on SPD generic constraints provide balanced settlements for NCAS *enablement* between the providers and causers (spot market beneficiaries of the network capability), so that: ❑ where the procurer is NEMMCO or a TNSP, then the payment logic for the *transition* applies, ❑ where the procurer is an entrepreneurial NCAS provider or intermediary, then no further payment arrangements are required. • Distribution NSPs (as distinct from retailers) should be the party to any reactive-related transactions at the distribution/transmission boundary.	• As determined by each NCAS market. • In the case of Distribution NSPs charging or paying for reactive power or reactive power capability, the benchmark consumption level should be at the power factor nominated in the Code as the benchmark for their points of connection with the transmission network. • As determined by spot market in NCAS or negotiated arrangement, as appropriate.
	2	Subject to development and testing, dispatch and pricing of reactive using SPD based on AC loadflow model, with two-way trading operating where market power is considered manageable.	• As determined by market outcomes.	• As determined by market outcomes.

4. NCAS: Stability and Network Loading Control				
Timing		**Facility**	**Who Pays?**	**How Much?**
Present	**1**	Stability and network loading control services are contingency-based ancillary services managed by NEMMCO that provide for enhanced network capability.	• Mandatory components paid for by provider (generator, TNSP) in the first instance. • Fixed costs relating to facilities provided by TNSPs then passed to customers through network charges. • Additional fixed and variable costs paid for by NEMMCO and then passed to *Customers who are loads* in proportion to gross trading interval energy	• Costs incurred by TNSP for fixed facilities at allowed regulated rate. • *Availability, enablement and use* costs incurred by NEMMCO paid as specified in long-term contracts. • *Compensation* costs paid by NEMMCO at a cost estimated through an SPD "what if" procedure.
Transition	**1**	As per voltage control. Review and refine and report on generic constraint definitions and costs of cause and provision.	• No immediate costs other than those incurred by NEMMCO, which should be included in pool fees.	• At cost.
	2	Re-allocation of costs according to the rules specified for voltage control.	• Mandatory technical requirements and TNSP fixed costs for NCAS facilities to be paid for as at *present*. • Any additional availability, use and compensation costs to be paid by NEMMCO in the first instance. • Noting that such NEMMCO NCAS costs should be a charge against network capability, they should then be passed on:	• As for the *present*

4. NCAS: Stability and Network Loading Control (continued…)				
Timing		**Facility**	**Who Pays?**	**How Much?**
Transition (continued)		(continued)	❑ to the TNSP that receives the settlement residue associated with each generic constraint or potential constraint, be it inter or intra-regional; ❑ and thence on to TNSP customers through a modification to network charges.	
Light on the Hill (timing for each NCAS will differ)	**1**	Future TNSP facilities for providing NCAS to be outside the regulated rate base.	• TNSP investment in NCAS will be justified in the context of NCAS arrangements in competition with other potential AS providers, rather than through the regulated network process. To the extent that TNSPs are successful costs will be charged as for the transition.	• As determined in each NCAS market, tender or negotiation process.
	2	*Spot markets in NCAS enablement* (one sub-market for each significant active generic constraint in the SPD) based on spot trading coordinated with the energy market through the SPD process	• The two-way arrangements based on SPD generic constraints provide balanced settlements for NCAS *enablement* between the providers and causers (spot market beneficiaries of the network capability), so that: ❑ where the procurer is NEMMCO or a TNSP, then the payment logic for the *transition* applies, ❑ Where the procurer is an entrepreneurial NCAS provider or intermediary, then no further payment arrangements are required.	• As determined by each NCAS market.
	3	*Use* of NCAS	• The assessed causer of the contingency or, where the causer cannot be identified, to the beneficiary identified above.	• As negotiated with the NCAS provider

5. NCAS: Spot market trading benefits				
Timing		**Facility**	**Who Pays?**	**How Much?**
Present	**1**	Current market design limits spot market trading benefits by limiting the products traded to real energy	• The cost of inefficiency on this ground would be distributed between market participants but would be a cost to end-users in the long run.	• Not known, likely to be small in relation to energy market turnover but potentially significant in absolute terms
	2	Current SPD model limits spot market trading benefits through limitations in its embedded network model	• As above	• As above
Transition	**1**	Progressive implementation to *light on hill*	• As for *light on hill*	• As for *light on hill*
Light on the Hill	**1**	Integrate ancillary service trading into spot market logic, as proposed for the *light on the hill* for other services	• Beneficiaries as determined by integrated energy and AS spot market logic • There may be some re-distribution of costs and benefits in the short term in the same way as normal market shifts have such effects	• Not known, likely to be small in relation to energy market turnover but potentially significant in absolute terms
	2	Develop, evaluate and implement SPD model based on AC loadflow analysis	• As above	• As above

6. SRAS: System restart				
Timing		**Facility**	**Who Pays?**	**How Much?**
Present	**1**	Procurement and management of system restart facilities by NEMMCO. This to continue through the transition.	• All costs are passed to *Customers who are loads* according to gross trading interval energy consumed	• *Availability* and *use* payments based on long-term contract prices of accepted tenders
Transition	**1**	NEMMCO to co-ordinate the development of a system re-start strategy, to be overseen and approved by the NECA Reliability Panel.	• Charged through pool fees	• At cost
Light on the Hill	**1**	Procurement and management of *basic system restart facilities* on a regional basis by NEMMCO.	• For each set of electrically inter-connected NEM regions, all *ongoing* basic-restart costs should be allocated to market participants within that set of inter-connected NEM regions in proportion to gross trading energy produced or consumed within those inter-connected regions. • *Use* costs should be allocated in a similar way, expect where review after an event reveals a clear and culpable causer, in which case use costs should be assigned to them.	• *Availability* and *use* payments based on long-term contract prices of accepted tenders
	2	Procurement and management of *supplementary facilities* as required to ameliorate the impact on customers of a system black condition	• Costs paid in the first instance by the party that organised the facility (e.g. DNSPs) or requested NEMMCO to organise the facility (e.g. a regional coalition), and then on to their customers.	• *Availability* and *use* payments as incurred and agreed.

11 Appendices

Appendices A though D are bound in a separate volume.