

Ms Jill McCarthy
Manager, MCE Secretariat,
Department of Industry, Tourism and Resources,
GPO Box 9839
Canberra ACT 2601



30 May 2007

Dear Ms McCarthy,

Submission on Draft National Electricity Distribution Revenue and Pricing Rules

Email: MCEMarketReform@industry.gov.au

The Australian Business Council for Sustainable Energy (BCSE) appreciates the opportunity to comment on the draft National Electricity Distribution Revenue and Pricing Rules and the Review of network incentives for Distributed Generation and Demand Side Response.

The BCSE is an independent member-based industry association representing the broader sustainable energy industry in Australia. The BCSE has about 300 organisations as members covering renewable, gas and distributed energy generation equipment suppliers and installers, energy retailers, networks and generators and energy efficiency product service providers. The common feature of our membership is their interest in meeting Australia's energy needs with lower greenhouse emissions.

The extensive barriers in the national electricity market to the efficient development of clean energy options have long been acknowledged. More recently, our Federal, State and Territory Governments have recognised that redressing these barriers are not just a matter of competitive neutrality and economic efficiency, but also a primary element in the urgent task of reducing Australia growing greenhouse gas emissions.

Ongoing analysis of the barriers to demand management and distributed generation will continue to be required as the electricity market and the clean energy sector evolve. However, it is crucial that those barriers that are already well identified and understood in the electricity market be remedied now. Key measures that can and should be undertaken within the current round of reforms include:

1. Explicitly and unambiguously, require environmental sustainability and its associated economic impacts to be considered by the AER and AEMC;
2. Explicitly and unambiguously, require demand management to be undertaken wherever it is cost effective, prior to network augmentation;
3. Ensure that economic regulation financially rewards rather than penalises distribution network service providers (DNSPs) for supporting cost effective demand management;
4. "Decouple" DNSP revenue and profit from sales volume and avoid price cap regulation of DNSPs;
5. Ensure prudence of capital and operating expenditure reviews fully and fairly consider demand management options;
6. Ensure Distributed Generators receive the full benefit of pass through of avoided transmission use of system (TUOS) charges and DNSPs are not disadvantaged in this process;

7. Apply transitional incentives to build DNSP expertise and familiarity with demand management.

These issues are discussed in our attached submission. We do not believe that these measures alone would be sufficient to overcome fully the longstanding barriers to clean energy in the National Electricity Market. They would however, represent important first steps in tilting the balance back towards a more competitive, sustainable and efficient electricity sector.

Yours sincerely

Original signed by

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Executive Director

Australian Business Council for Sustainable Energy

Submission on the

National Electricity Distribution Revenue and
Pricing Rules

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1. Introduction

1.1 ...A little more action.

The extensive barriers in the national electricity market to the efficient development of clean energy options have long been acknowledged. More recently, our Federal, State and Territory Governments have recognised that redressing these barriers are not just a matter of competitive neutrality and economic efficiency, but also a primary element in the urgent task of reducing Australia growing greenhouse gas emissions.

As noted in the overview to this Review, the Council of Australian Governments (COAG) appeared to make clear its wishes to remedy this situation, when it stated it had agreed,

“to improve the price signals for energy investors and customers by...

c) implementing a comprehensive and enhanced MCE work program, from 2006, to establish effective demand side response mechanisms in the electricity market, including network owner incentives, effectively valuing demand-side responses, regulation and pricing of distributed and embedded generation, and end user education.”¹

BCSE welcomes this commitment, but is conscious that despite numerous studies and reports since the establishment of the National Grid Management Council on 1991, progress on developing demand management and distributed generation has been slow at best.

Ongoing analysis of the barriers to demand management and distributed generation will continue to be required as the electricity market and the clean energy sector evolve. However, it is crucial that those barriers that are already well identified and understood in the electricity market be remedied now. Key measures that can and should be undertaken within the current round of reforms include:

1. Explicitly and unambiguously, require environmental sustainability and its associated economic impacts to be considered by the Australian Energy Regulator (AER) and the Australian Energy Market Commission (AEMC);
2. Explicitly and unambiguously, require demand management to be undertaken wherever it is cost effective, prior to network augmentation;
3. Ensure that economic regulation financially rewards rather than penalises distribution network service providers (DNSPs) for supporting cost effective demand management;
4. “Decouple” DNSP revenue and profit from sales volume and avoid price cap regulation of DNSPs;
5. Ensure prudence of capital and operating expenditure reviews fully and fairly consider demand management options;
6. Ensure Distributed Generators receive the full benefit of pass through of avoided transmission use of system (TUOS) charges and DNSPs are not disadvantaged in this process;
7. Apply transitional incentives to build DNSP expertise and familiarity with demand management.

These issues are discussed below. These measures alone will not overcome the longstanding barriers to clean energy in the National Electricity Market. They would however, represent important first steps in tilting the balance back towards a more competitive, sustainable and efficient electricity sector.

¹ The COAG Background Paper: [COAG National Competition Policy Review](http://www.coag.gov.au/meetings/100206/national_competition_policy_report.pdf), Feb 2006, p. 12
http://www.coag.gov.au/meetings/100206/national_competition_policy_report.pdf

(Given that the process of reform required establish a competitively neutral market for DSR and DG is likely to require years of sustained effort, BCSE strongly believes that complementary measures outside of the NEM will be required for the foreseeable future. For this reason, BCSE has advocated measures such as mandatory energy efficiency targets and substantial funding support independent of the utilities to develop demand management and distributed generation in the near term. It was in recognition of this principle that such “public benefit funds” have been created in some two dozen states of the USA as well as in NSW in the form of the Energy Savings Fund. It is recognised however, that the establishment of such mechanisms is outside the scope of this Review.)

Our key concern with the draft National Electricity Distribution Revenue and Pricing Rules is that they continue the strong bias in favour of centralised supply systems and against clean energy options that has characterised the national electricity market (NEM) since its establishment. This chronic bias against energy efficiency, demand management and distributed generation clearly contravenes the competitive neutrality and economic efficiency principles of the NEM.

This failure to ensure competitive neutrality and economic efficiency would be true even if the science of climate change is ignored. However, in 2007 in the wake of the Stern Report², the IPCC Working Group III Report³ and the 2006 IEA Energy Technology Perspectives Report⁴, it would be irresponsible for energy and economic policy and regulators to ignore the expected economic impacts of unabated climate change.

Every Government in Australia, Federal, State and Territory has stated its desire to encourage investment in energy efficiency, demand management and renewable and low greenhouse gas emission technology. The National Electricity Distribution Revenue and Pricing Rules will strongly influence billions of dollars worth of energy sector investment decisions over the next decade. These investments will be with us for decades. Each time that investment in clean energy is overlooked in favour of traditional centralised high-carbon electricity supply represents not just a lost opportunity, but a liability that will have to be compensated for in the decades to come.

A truly “level playing field” would require full recognition of the **economic** costs of increasing greenhouse gas emissions. However, the NEM now appears to be committed to ignoring these economic costs. Yet the NEM fails to even provide a “level playing field” that ignores these economic costs.

1.2 Defining “Demand Management”

As a rapidly evolving field globally, there is some confusion in how terms like “demand side management”, “distributed generation”, “demand response” and so on are used. This Review has adopted an unusual approach in applying the term “Demand Side Response” to refer to a broad range of demand management activities including load management, energy efficiency, and interruptible load.

For the purposes of this submission, the more conventional term “demand management” is applied as for all of the above activities and distributed generation (unless otherwise indicated).

² Stern Review on the Economics of Climate Change http://www.hm-treasury.gov.uk/independent_reviews/stern_review_economics_climate_change/sternreview_index.cfm

³ Intergovernmental Panel on Climate Change Working Group III, Fourth Assessment Report Climate Change 2007: Mitigation of Climate Change, http://arch.rivm.nl/env/int/ipcc/pages_media/ar4.html

⁴ International Energy Agency (IEA), Energy Technology Perspectives Report -- *Scenarios & Strategies to 2050*, www.iea.org/w/bookshop/add.aspx?id=255

1.3 Limitations to the Review and this Submission

The preface to the review states that the draft Laws were written before the NERA Review was completed and therefore the draft Rules laws do not incorporate NERA's recommendations to remove barriers to DSR and DG. Conversely, the NERA review does not include specific proposed amendments to the draft Laws to give effect to their recommendations. This limits the capacity to respond concretely to both the Draft Rules and the NERA Review.

This submission seeks to respond to this limitation by both suggesting specific proposed amendments to the draft Laws (Section 2) and commenting on NERA's recommendation (Section 3). However, it is inevitable that this approach will lead to an incomplete response to the relevant issues and additional issues will come to light when the Draft Rules are amended to address the issues raised by both the NERA Review and stakeholder submissions such as this. We hope that we will have further opportunities to contribute to the drafting process at that time.

Given these constraints, it is recommended that the AER establish a specific consultation process for considering demand management in the context of the forthcoming NSW and ACT distribution determinations. It is also recommended that MCE/SCO initiate a consultation process to review demand management measures and issues in the wake of NSW and ACT determination.

1.4 Relationship between the Rules and the National Electricity Law

The National Electricity Rules must be consistent with National Electricity Law. It is therefore impossible to consider the appropriateness of the Rules without reflecting on the appropriateness of the Law.

The legislated objective of the National Electricity Market “*is to promote efficient investment in, and efficient use of, electricity services for the long-term interests of consumers of electricity with respect to price, quality, reliability, and security of supply of electricity and the reliability, safety and security of the national electricity system.*” This objective was drafted before it became universally accepted that our energy sector faces massive changes to respond to the challenge of climate change. Building institutions based on the high carbon emission model of the past is no longer environmentally sustainable, economically prudent, or politically viable.

Ambiguous law is bad law. While at first glance, the above objective appears clear, it is in practice very ambiguous in relation to clean energy development. In pursuing this objective, the AEMC and the AER are required to make judgements on the following questions. *(BSCCE's view of what reflects the long-term interests of consumers is included in parentheses.)*

1. Does “efficient investment in ... electricity services” mean that network businesses should invest in alternatives to network infrastructure, such as distributed generation, demand management and energy efficiency (“DM”), wherever this would lead to lower average energy bills for consumers? *(Yes.)*
2. Does “efficient investment in ... electricity services” mean that network businesses should offer incentives to individual consumers to adopt DM, wherever this would lead to lower energy bills for consumers (or improved quality, reliability, and security of supply)? *(Yes.)*
3. Where a conflict arises between lower average prices and lower average bills (such as in relation to encouraging end use energy efficiency), which should the AER support? *(Lower average bills)*
4. Does “efficient use of, electricity services” also mean that the “efficient use of electricity” by means of DM? *(Yes.)*
5. Does “the long term interests of consumers” include consideration of the expected long term costs of the economic impacts of climate change and policy responses in response to climate change? *(Yes.)*

6. Does “the long term interests of consumers” include consideration of the likely trends in the regulated and market costs associated with greenhouse gas emissions? *(Yes.)*
7. Does “the long term interests of consumers” include consideration of current and expected future trends in the relative costs of different supply options, including renewable energy technologies and DM? *(Yes.)*
8. Does “the long term interests of consumers” include investigation and consideration of consumers stated preferences as to their long term interests, particularly regarding supply options, DM and social equity? *(Yes.)*

These are high level policy principles, not fine details of regulatory interpretation. Stakeholders (and the AER) may legitimately expect such policy principles to be defined by Government policy. They should not be left to the discretion of the AER.

Indeed, the State, Territory and Federal Governments have already made a number of statements that outline Government’s intent on these policy issues. For example, in its February 2006 communiqué, COAG stated:

“COAG also agreed to ensure the electricity transmission system supports a national electricity market, providing energy users with the most efficient, secure *and sustainable* supply of electricity from all available fuels and generation sources, and include where appropriate an increased share of renewable energy.”

-COAG Communiqué 10 Feb 2006

“COAG has agreed that:

- all jurisdictions are committed to working collaboratively as well as individually to reduce Australia’s emissions of greenhouse gases, ...making Australia a leader in the global effort to stabilise greenhouse gas levels in the atmosphere; ...
- action on climate change requires a comprehensive policy framework which includes action to *promote changed patterns of investment*, technology innovation and take up, adaptation, *demand management and improved energy efficiency*....”

“Energy Efficiency

Energy efficiency has a significant role to play in reducing greenhouse gas emissions, and in *reducing requirements for future investments in energy supply and infrastructure*. Energy users currently spend \$50 billion annually on energy. It is widely considered that many businesses and households can save 10-30 per cent of their energy costs without reducing productivity or comfort levels.

Energy efficiency has consistently proved to be the most cost-effective of Australia’s responses to greenhouse gases. ...

Jurisdictions note and support the proposal in the Review of National Competition Policy for COAG to task the MCE to develop a work program from 2006 *to establish effective demand-side response mechanisms in the electricity market*.”

-COAG Communiqué 10 Feb 2006 Attachment C
Plan for Collaborative Action on Climate Change

http://www.coag.gov.au/meetings/100206/attachment_c_climate_change.pdf

If the above Government policy statements are as deliberate and consistent as they appear, then there seems no reason why they should not be reflected in the National Electricity Law by removing the above ambiguities.

2. Additions to Draft National Electricity Rules

The following comments relate to the specific content of the Draft National Electricity Distribution Revenue and Pricing Rules. The following comments have been made on the basis of what seems a reasonable, interpretation of “*the long-term interests of consumers of electricity*”, consistent with the COAG policy statements above.

6.1.0 Definitions

Insert:

demand management means assisting customer to reduce their demand for electricity by means of financial payments or incentives, network support payments, information and education initiatives, tariff design or other measures to encouraging end use energy efficiency, peak load reduction, demand side response or distributed generation (of less than 30 MW generating capacity).

6.2.5 Control Mechanism

Following paragraph (4), insert

- (5) the need to support the long term environmental sustainability of electricity supply;
- (6) the need to encourage cost effective *demand management*;
- (7) any other factor the AER considers relevant

6.5.5 Efficiency benefits sharing scheme

Replace paragraph (b) with the following

- (b) (1) An efficiency benefit sharing scheme may (but is not required to) extend to efficiency gains and losses related to capital expenditure;
- (2) An efficiency benefit sharing scheme must extend to efficiency gains and losses related to capital expenditure where this is necessary to give effect to paragraph (c).

In paragraph (c) add

- (4) the need to ensure that *Distribution Network Service Providers* have effective incentives to support *demand management* wherever doing so is likely to be at least as cost effective as network capital expenditure, or wherever doing so is likely to lead to a lower overall cost to consumers than undertaking network capital expenditure

6.5.6 Forecast operating expenditure

Insert in (a)

- (5) support *demand management* wherever cost effective.

Insert in (e)

- (10) the appropriateness of the proposed level of expenditure on *demand management*.

6.5.7 Forecast capital expenditure

Insert in (a)

(5) support *demand management* wherever cost effective.

Insert in (e)

(10) the appropriateness of the proposed level of expenditure on *demand management*.

6.6.2 Service target performance incentive scheme

Insert in paragraph (b) (3)

(v) the extent to which *demand management* may assist in meeting service targets.

6.18.3 Pricing proposals

Insert in paragraph (b)

(8) support cost effective *demand management*.

6.21.1 Prudential requirements for distribution network services

Insert after paragraph (b)

(1) Where negotiation is not successful and agreement is not achieved, either party to the negotiation may seek dispute resolution by the AER under clause 6.23.1.

S6.1.2 Information and matters relating to operating expenditure

Insert after paragraph (8)

(9) a forecast of expenditure on *demand management* and expected associated savings in operating and capital expenditure.

S6.2.2 Information and matters relating to operating expenditure

Insert after paragraph (6)

(7) the need to provide incentives to the provider to undertake efficient *demand management* expenditure.

3. BCSE Comments on NERA Recommendations

As noted in section 1, it is recognized that the current draft of the Rules do not incorporate proposed DM provisions. This creates a problem in that stakeholders are not able to respond to specific proposed mechanisms. Given the limited time before legislation will be considered and passed, the opportunity for a normal consultation process seems limited.

Given these circumstances, it is recommended that the AER establish a specific consultation process for considering demand management in the context of the forthcoming NSW and ACT distribution determinations. It is also recommended that MCE/SCO initiate a consultation process to review demand management measures and issues in the wake of NSW and ACT determination.

Summary of potential DSR and DG incentive barriers – Revenue and Pricing Rules

Stage of regulatory process/ rules	Recommendation	BCSE Comments
Form of Regulation	The Rules should require that, once the appropriate form of regulation is determined for domestic distribution use of system charges, DNSPs should be required to allow such customers to install and use PV on the basis of the same usage and capacity tariff elements applying to equivalent sized load.	<p>Partially supported. Suggest replacing “<i>the basis of the same...</i>” with “<i>a basis no less favourable to the customer than the same...</i>”.</p> <p>Need to clarify that this excludes possible additional benefits that may accrue to the customer/PV system owner for energy export associated with RECs, feed in tariffs, etc.</p> <p>While this approach to “Net metering” falls well short of the sort of “feed in tariff” applied in many countries, announced in South Australia and supported by the BCSE, it provides a baseline safety net for customers installing PV.</p>
Control setting method	Provision in the Rules for the inclusion of payments made by DNSPs for ‘network support’ expenditure in the derivation of the building block revenue requirement should be retained. The method for recognising network support payments in the derivation of the building	<p>Supported in principle, but needs to be clarified in practice and applied fairly and effectively. Networks should be able to recover any such ‘network support’ expenditure on equivalent terms to network expenditure.</p> <p>The method for calculating the value of network support payments needs to be developed urgently and endorsed by the AER.</p>

	<p>block revenue requirement should provide unbiased incentives for the efficient substitution of network support for network augmentation.</p>	<p>The NSW Demand Management Code of Practice for Electricity Distributors and the South Australian Industry Guideline 12: Demand Management for Electricity Distribution Networks provide a precedent for the minimum level of disclosure and for the basis for evaluating network support payments. It is recognised that this may be better dealt with in Chapter 5 of the rules rather than Chapter 6.</p>
	<p>The revenue rule approach to WACC determination should avoid creating systematic upward bias in the WACC. Equally it should not create systematic downward bias, either for the purpose of balancing DSR and DG incentives or any other reason. The range of regulatory measures available to address the potential imbalance of incentives as between capital and operating cost expenditure should include:</p> <ul style="list-style-type: none"> ▪ allowing (but not requiring) the AER to include a capital expenditure efficiency incentive mechanism in the building blocks control setting method for individual DNSPs; and ▪ requiring the AER to consult on the potential DSR and DG incentive implications of any proposed operating or capital expenditure efficiency incentive mechanism. 	<p>Supported.</p> <p>However, determining an unbiased WACC has long been an objective of economic regulation of DNSPs.</p> <p>The overall regulatory structure needs to recognise and accept that DNSPs are likely to perceive greater risk in adopting new (more sustainable) practices in relation to DSR and DG, than in the conventional past practices on which the current WACC's have been derived. Allowing DNSPs to earn a higher return on investment in DSR and DG could, in principle, help to offset this bias. However, as DNSP expenditure on DSR and DR is often regarded as operating rather than capital expenditure, in practice such a reform may have little effect.</p>
	<p>The distribution revenue rule should include operating and capital expenditure assessment criteria that require the AER to be satisfied that the forecast expenditure reasonably reflects efficient non-network alternatives available to a DNSP.</p>	<p>Supported.</p> <p>Such “expenditure assessment criteria” need to be sufficiently specific to ensure that the consideration of “efficient non-network alternatives” is more thorough than the cursory review that has often been applied in the past.</p> <p>Disclosure and publication of relevant network data must also be required to allow a thorough assessment to be undertaken. The NSW Demand Management Code of Practice for Electricity Distributors and the South Australian Industry Guideline 12: Demand Management for Electricity</p>

		Distribution Networks provide useful precedents for the minimum level of disclosure.
Regulatory test	No recommendations – to be addressed as part of network extensions/expansions review.	We look forward to participating in consultation process in relation to the forthcoming review of Chapter 5.
Service incentives	<p>Where the perceived ‘firmness’ of DSR and DG present a potential barrier to their efficient uptake by DNSPs, the Rules should not prevent DNSPs from entering into service contracts with DSR and DG service providers that transfer the relevant service incentive scheme payments and penalties to such providers.</p> <p>The potential DSR and DG incentive impacts of service incentive schemes should be considered by the AER when specifying the operational detail, service targets and applicable penalties and rewards for such schemes. This may be achieved by including this as a principle under the initial distribution rule (equivalent to clause 6A.7.4 of the transmission rule).</p>	<p>Supported in principle but any transfer of risks, incentives and penalties needs to be undertaken equitably and not used as a pretext to block DSR and DG.</p> <p>It should be recognised that DNSPs in Australia generally have limited experience in supporting DSR and DG. Imposing new risk elements on networks to manage may simply drive the networks to rely more heavily on network technologies with which they have greatest familiarity, to the exclusion of DSR and DG.</p> <p>In relation to the perceived lack of firmness of DSR and DG, it should be noted that networks themselves only achieve their required level of “firmness” through redundancy and overcapacity. It is unrealistic to expect individual DSR and DG elements to provide the same level of firmness as a integrated system of network elements. DSR and DG elements need to be aggregated and integrated both with each other and with the network to achieve optimal firmness and efficiency.</p> <p>Any transfer of risks, incentives and penalties needs to be undertaken equitably and not used as a yet another pretext to block DSR and DG. In particular, the use of penalties against consumers providing DSR and DG should be avoided. It is worth remembering that consumers have been suffering the effects of “lack of firmness” in network services for decades without compensation and without the networks being subject to penalties.</p> <p>In particular, the use of penalties against consumers providing DSR and DG should be avoided. After all, consumers have been contending with the effects of “lack of firmness” in network services for decades without compensation and without the DNSPs being subject to penalties.</p>

<p>Form of price control</p>	<p>Price caps should be preferred over revenue controls for the purpose of facilitating the utilisation of DSR and DG, particularly once advanced meters and the easing of side constraints improve the opportunity for more efficient forms of pricing.</p>	<p>We strongly reject this recommendation.</p> <p>This recommendation contradicts fundamental and widely-recognised principles of the incentives created by price regulation. In the context of distribution networks with high fixed and low variable costs, it should be clear that, applying price cap regulation that links total revenue directly to sales volume will inevitably create disincentives to DSR and DG measures that reduce those sales. This is true whether the sales volumes are measured in simple “anytime” kWh with accumulation meters or with variable time-of-use tariffs.</p> <p>So long as the marginal revenue (i.e. price under a price cap) is higher than the marginal cost, then networks will be discouraged from undertaking any DSR or DG that reduces sales. This is why electricity regulators around the world have created mechanisms to “decouple” electricity sales volume from network revenue (and profits). For example California has had such mechanisms in place at least as far back as the early 1980’s.</p> <p>This is not to diminish the importance of more efficient time of use tariffs. Such tariffs are crucial in providing incentives to customers to shift load and reduce demand at peak times. However, such tariffs will do little to encourage networks to invest in DSR or DG measures that reduce overall energy consumption. In recognition of this, the NSW Independent Pricing and Regulatory Tribunal adopted the D-factor. The fact that this mechanism – which NERA regards as “over-rewarding” demand management- has to date only enjoyed modest success in encouraging demand management is testimony to the strong barriers to DM that exist within price cap regulation.</p> <p>In suggesting that price caps provide stronger incentives for customers to undertake DSR and DG, NERA appears to confuse the incentives faced by consumers with those of the networks. While efficient time of use pricing will provide incentives for consumers to reduce peak demand, they will do little if anything to redress the perverse incentives to DSR and DG that are created for networks as a consequence of price cap regulation.</p> <p>Price cap regulation sets the financial interests of the networks in conflict with the broader interests of its consumers and the community. However, price</p>
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		<p>cap regulation can be just as bad for the financial interests of DNSPs as they are for consumers and the environment. Price cap regulation locks DNSP profitability into old fashioned business model based on increased consumption, just as Governments are realising that energy efficiency is the likely to be the cheapest, largest and quickest option for reducing greenhouse gas emissions. This creates a major unnecessary financial risk for the networks if consumption volume growth is significantly curtailed as a result of government policy to encourage energy efficiency (the proposed banning of incandescent bulbs is a simple example).</p> <p>In referring to “a DNSP’s output (whether measured in capacity or energy usage terms)” NERA assumes that the role key of the DNSP is to either build capacity or carry kWh rather than to ensure a safe, secure and reliable network for through an optimal mix of network and DM resources.</p> <p>It also suggests that price caps which leads to marginal revenue far exceeding marginal cost better reflects the “the relationship between a DNP’s marginal costs and its marginal revenue that would otherwise prevail in an effectively competitive market. In fact, the reverse is true. Competitive markets lead to marginal revenue being driven down to equal marginal cost. For a DNSP with high (long run) capital costs and low (short run) operating costs, the effects of a revenue cap is much closer that of a competitive market.</p>
	<p>That the Rules should permit the AER to establish an incentive mechanism that compensates DNSPs operating under the price cap form of control for the revenue lost as a consequence of undertaking efficient DSR initiatives.</p>	<p>Supported, but only where more direct forms of compensation, such as revenue caps are not possible.</p> <p>If a price cap methodology is applied to DNSPs (as has been flagged in the proposed transitional arrangements for the forthcoming NSW and ACT 2009 distribution determinations) , then it must include incentives for DSR and DG to counter the massive incentives and cultural bias for DNSPs to sell more electricity.</p> <p>It is encouraging that the reports notes, “However, in light of the disincentives for the DNSPs to promote DSR ...under the price cap form of control, we see</p>

		<p>merit in arrangements that allow a DNSP to recover the within-period revenue foregone as a consequence of implementing DSR projects. Such an arrangement could operate along the lines of the relevant component of the NSW D-factor scheme...”</p> <p>NERA suggests that the D-factor allowing recovery of both DM program costs and retaining avoided network capital expenditure is effectively double counting and over-rewards DM. There would be practical merit to this theoretical argument were it not for the range of other disincentives and barriers to DM that are still weighted against DM in the wider context of the D-Factor’s operation, price cap form of control and the medium term operating and capital expenditure review process.</p> <p>While the D-factor is recognised as a genuine attempt to compensate for the perverse incentives of price cap regulation, it has had only limited success in stimulating DSR and DG activity. This is probably in part because DSR and DG are not regarded as core business and in the current environment; DNSPs are stretched in managing their committed capital works programs. The D-factor’s two year lag between investment and cost recovery and the uncertainty about its medium term continuity creates further disincentives to DNSPs directing resources towards DSR and DG.</p> <p>A useful enhancement to the D-factor approach may be to “prime the pump” by stipulating an expenditure allocation specifically for DNSPs DM. (This approach is similar to that adopted by ESCOSA’s \$20 DM fund.) If this expenditure is not undertaken then it would be returned to customers through a “negative pass through”. In order to encourage investment in DM by DNSPs uncertain about cost recovery, this expenditure could be subject to a priori assessment by the AER as representing genuine efforts to develop effective DM, rather than made “at risk” subject to ex post assessment of its effectiveness. An appropriate level could be in the order of 1% of the projected network capital expenditure for the first two years of a pricing determination. It is emphasised that such a mechanism should only be applied as a short term mechanism to initiate “learn by doing” DM investment. In general, it is important that incentives are provided to maximise the effectiveness and minimise the cost of DM rather than spend a</p>
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		<p>given amount on DM. The effectiveness of such a mechanism should be reviewed at the end of the regulatory period.</p> <p>When and only when an efficient level of investment in DSR and DG has been attained should the continued provision of such compensation support mechanisms be reviewed.</p>
Pricing Principles	The initial distribution rules should not prevent DNSPs from offering prudent discounts.	<p>“Prudent discounts” need to be approach with some caution. Apart from potential adverse social equity impacts, discounts can both be anti-competitive and adversely impact on the efficient development of DSR and DG. An example is the aggressive (and arguably predatory) discounting of off peak electricity tariffs for residential water heating in NSW in the early 1980’s in response the growing popularity of natural gas water heating. A healthy solar water heating industry in the state was virtually wiped out as a consequence.</p> <p>In general, rather than leading to efficient pricing, “Ramsey pricing” is likely to be economically <i>inefficient</i> in discouraging end use efficiency and DM.</p>
	The requirement for the periodic review of side constraints should be retained in the initial Rules.	Voluntary relaxation of side constraints should be permitted subject to the customer informed consent.
	<p>Where tariff reassignment restrictions are to be included in the Rules, these should be limited to principles that ensure tariff assignment and reassignment is based upon:</p> <ul style="list-style-type: none"> ▪ customers’ usage and connection characteristics, ie, the drivers of network costs; and ▪ providing equal treatment to customers with similar usage and connection characteristics. 	Voluntary reassignment should be permitted with the customer’s informed consent.
	DNSPs should be required to reassign customers to a time of use tariff following installation of advanced metering	This recommendation seems reasonable. However, the initial emphasis should be on voluntary adoption of TOU tariffs. The potential benefits of using effective time of use tariffs should allow plenty of scope for

	<p>infrastructure at a customer's connection point.</p> <p>Reassignment should be accompanied by a requirement for customer education regarding ways in which they can manage their demand to affect their bill. Further work is required to identify whether this is a role best served by retailers or DNSPs.</p>	<p>incentivising customers to transition.</p> <p>It is also crucial that time of use tariffs are appropriately designed. Capacity charges must be carefully designed to reflect customers real contribution to peak demand, to avoid removing incentives to reducing consumption at all times and to ensure that customers are fully aware of the cost of peak demand and when peak demand occurs.</p>
	<p>The initial Rules should not include requirements for geographic tariff averaging, and instead leave such decisions to the discretion of DNSPs, subject to compliance with generic principles for efficient pricing. Any jurisdictional variation agreed under the AEMA should be handled through the derogation process.</p>	<p>Removal of geographic tariff averaging is supported in principle where this accurately reflects long run marginal costs and encourages demand management. Any adverse equity implications should be addressed by measures to assist affected customers through compensation payments and or assistance in enhancing end use energy efficiency. However, the practical, administrative and political barriers to achieving this are acknowledged.</p> <p>It is likely to be much easier and effective to offer locally targeted incentives and network support payment for demand management to reflect the marginal costs associated with network constraints.</p> <p>In either case, full public disclosure of cost drivers should be supported as required in the NSW DM Code of Practice for Electricity Distributors.</p>
	<p>DNSPs should be required to submit to the AER for approval and publish protocols for the assessment and review of capacity demand and determination of capacity charges including:</p> <ul style="list-style-type: none"> ▪ the period over which capacity demand will be reassessed before capacity charges are reset (say, every 12 months). 	<p>See above. Greater transparency as required by the NSW DM Code of Practice is essential to ensure that capacity charges are addressing the real peaks</p>
Pricing Principles	<p>The initial Rules should not permit DNSPs to levy on DGs either positive DUOS charges for energy exported to the grid or deep connection costs.</p>	<p>Prohibition of DNSPs levying on DGs either positive DUOS charges for energy exported to the grid or deep connection costs is supported. Voluntary payments should be permitted provided this is not used as a barrier to DG. DGs should not be required to pay deep connection costs until such time as beneficiary pays principles are implemented for all generators for</p>

	<p>Voluntary payments from DGs to DNSPs should be permitted where a DG agrees to pay for upstream augmentations in order to increase energy transfer capability, in the same way that a transmission connected generator can pay for upstream augmentations of the transmission system.</p>	<p>transmission upgrades.</p> <p>It is also worth reiterating that price cap regulation creates a short term bias for DNSPs to maximise throughput and sales volume. The lack of adequate consideration of DG (and DSR) at the prudence review and at the roll in of capital expenditure creates a long term bias in favour of network capacity investment. So long as these fundamental biases are not redressed, competitive neutrality will not be achieved in relation to all of the issues in Chapter 8 of the NERA Review.</p>
<p>Pricing of negotiated DG connection charges</p>	<p>The initial Rules should retain a requirement for DNSPs to submit their proposed negotiating framework for DG connection charges to the regulator for approval and subsequent publication. The Rules should require the AER to be satisfied that this framework:</p> <ul style="list-style-type: none"> ▪ provides for a robust procedure for the negotiation of connection agreements, including information exchange; ▪ requires DGs only to fund shallow connection costs, where shallow is defined as the nearest point of the existing shared distribution network; and ▪ provides for DG proponents to be made aware of the options for the funding of deep connection costs or the connection constraint consequences of these not being funded (either by the DG or customers), including measures to ensure the provision of sufficient information to apply the regulatory test so as to determine the extent of any appropriate user-funded network augmentation. 	<p>Supported, however it must be acknowledged, that DNSPs have considerable bargaining power in negotiating with DG proponents. Whilst a DG project may be able to provide a benefit to the DNSP in an area of network constraint, the local DNSP has a monopoly control on that particular area of network constraint. The DNSP may also see the DG proposal as in competition with the DNSP's own proposals for investing in its network. In short, the DNSP can operate without the support the DG project, while the reverse is generally not true. This places the DNSP in a position of considerable negotiating strength and potential conflict of interest, and needs to be acknowledged in the development of negotiation procedures.</p> <p>DGs should not be required to pay deep connection costs until such time as beneficiary pays principles are implemented for all generators for transmission upgrades. Requiring DG to pay for deep connection is a distortion of the market place against new entrants while existing centralised generators benefit from transmission and distribution augmentation and do not have to contribute to its cost.</p>

<p>Avoided TUOS payments</p>	<p>The Rules should remove the requirement for DNSPs to make avoided TUOS payments to DGs. The Rules should continue to provide for both TNSPs and DNSPs to make network support payments to DGs, EGs or DSR providers, where the planning and regulatory test obligations under the Rules establish that such non-network solutions represent the most efficient means of alleviating a network constraint.</p>	<p>This recommendation is strongly rejected.</p> <p>Requirements for DNSPs to pay avoided TUOS pass through to DG should only be removed when an equivalent mechanism to deliver avoided TOUS benefit to DGs is instituted and operating effectively.</p> <p>It is quite clear that DG, by definition, avoids the need for transmission capacity. It equally clearly follows that in the interests of economic efficiency and competitive neutrality, DG projects should have access to these avoided transmission costs, in order to facilitate DG projects that otherwise may not be established. This is why TUOS pass through arrangements were established. We accept the presentation of the current problems surrounding the payment of avoided TUOS charges to DG proponents. It is not sustainable to require DNSPs to pass through avoided TUOS charges to DG proponents if the DNSP's themselves do not in fact avoid these charges. However, the solution to problems in a valuable mechanism is not to abandon the mechanism but to fix the problems. The simplest way to do this is to ensure that DNSPs do receive the avoided TUOS charges. One possible mechanism to achieve this is for TNSPs to rebate avoided TUOS charges directly to DNSPs that are making TUOS pass through payments to DG providers. In practice, this could be effected through an explicit reduction TUOS charges paid by the DNSP. These avoided TUOS payments would of course need to be explicitly excluded from subsequently recovery by the TNSP through the operation of the "unders and overs" account under the TNSP revenue cap.</p> <p>It is recognised that as NERA suggest, in principle, the TUOS pass through rule could be replaced with a requirement for DNSPs and TNSPs to consider non-network alternatives and to pay network support payments to DG and DSR proponents. In practice however, there is little prospect of such an alternative arrangement being effectively applied in the near future. For such an approach to succeed, it would be essential, that the full range of benefits arising from DG and DSR projects are able to be captured by their proponents, including improved supply reliability through generation diversity, improved power quality and reduced transmission losses, reduced greenhouse gas emissions, avoided distribution and transmissions network</p>
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Summary of potential DSR and DG incentive barriers – non-revenue and non-pricing Rules

Stage of regulatory process / rules	Recommendation	BCSE Comments
Negotiate Arbitrate Form of Regulation	Any changes to the principles for dispute resolution arising from the current review of Chapter 6 should ensure that consequent changes (or relevant transition measures) are made for the Chapter 5 dispute framework.	<p>The NSW Demand Management Code of Practice for Electricity Distributors and the South Australian Industry Guideline 12: Demand Management for Electricity Distribution Networks should provide the precedent for the minimum level of disclosure and for the basis for evaluating network support payments.</p> <p>It is recognised that this may be better dealt with in Chapter 5 of the rules rather than Chapter 6</p>
Service reliability standards	It is important that jurisdictional standard setters be cognisant of the DSR and DG incentive implications of network planning or service reliability standards. Consideration should be given to the use of probabilistic planning standards and their relative costs and benefits as compared with deterministic standards.	<p>The use of probabilistic planning standards should not be perceived as a key priority in removing barriers to DSR and DG.</p> <p>It is acknowledged that that prescriptive and deterministic standard have been used as a rationale to argue against DSR and DG because of perceived lack of firmness. However, it is less clear that prescriptive probabilistic standards would lead to a significant increase in the network support for DSR and DM. While we support t</p> <p>Networks themselves only achieve their required level of “firmness” through redundancy and overcapacity. It is unrealistic to expect individual DSR and DG elements to provide the same level of firmness as a integrated system of network elements. DSR and DG elements need to be aggregated and integrated both with each other and with the network to achieve optimal firmness and efficiency. Any transfer of risks, incentives and penalties needs to be undertaken equitably and not used as a yet another pretext to block DSR and DG. In particular, the use of penalties against consumers providing DSR and DG should be avoided. It is worth remembering that consumers have been suffering the effects of “lack of firmness” in network services for decades without compensation and without the networks being subject to penalties.</p>

Metering	Potential benefits in terms of improved pricing and incentives for DG and DSR should be taken into account in evaluation of large scale AMI roll-out.	See comments above re price caps. As noted above, under a price cap form of control and in the absence of effective long term incentives for DSR and DG, there is no guarantee that the roll out of AMI will encourage efficient network tariff signals.
	DNSPs should be encouraged or required to ensure that customers subject to large scale PV roll-out receive priority in the roll-out of AMI, thereby facilitating the development of network tariff structures that provide efficient signals for the installation of PV.	It is also essential that customers with small DG who are migrated onto AMI should not be disadvantaged by being subject to meter replacement charges that are not intended to be incurred by consumers later in the “roll-out”. Moreover, as noted above, under a price cap form of control and in the absence of effective long term incentives for DSR and DG, there is no guarantee that the roll out of AMI will encourage efficient network tariff signals.
Losses	Further analysis be undertaken on whether the current treatment of losses is consistent with promoting efficient distributed generation projects.	While further analysis on the treatment of losses may be useful this should not delay concrete action to remove barriers to DG and DSR. As losses are strongly related to demand levels, supporting DSR and DG by removing the range of existing barriers should also reduce the extent of losses.
Constraints on energy export	That further work be undertaken to investigate whether the non-price connection terms and conditions provided in Chapter 5 of the Rules create any impediments to the efficient utilisation of distributed generation capacity.	We look forward to participating in consultation process in relation to the forthcoming review of Chapter 5.
Access to load control infrastructure	Where a direct load control facility is available at a customer’s connection point, consideration should be given to ways to ensure the controller of this infrastructure provides access (on reasonable or regulated terms) to that customer’s retailer, DNSP, TNSP or other DSR intermediary engaged by the customer for the purposes of load control.	A customer’s load and the control of this load should ultimately always remain the domain of the customer. Control of this load should only be transferred to another party with the full informed consent of the customer. As long as any agreements with the customer appropriately reflect this principle, this recommendation should be supported in allowing other parties to make DSR offers to interrupt or otherwise manage the load with customer consent. This would help streamline direct load control arrangements and reduce costs for the other parties.

<p>Connection Information</p>	<p>A review of the information requirements in chapter 5 of the Rules is necessary to ensure that:</p> <ul style="list-style-type: none"> ▪ DNSPs provide DG proponents with the information necessary to apply the regulatory test to a DG connection proposal; ▪ DNSPs provide information on the emergence of network constraints as well as areas of substantial under-utilised existing transfer capability in order to allow prospective DGs to identify and site in the best location by reference to: <ul style="list-style-type: none"> – alleviating network constraints (and potentially earning network support payments); or – maximising energy transfer capability without incurring additional deep connection costs; ▪ DG proponents reveal their intended energy export levels such that DNSPs can accurately assess deep connection costs and formulate any connection constraint conditions that are required to protect network performance where: <ul style="list-style-type: none"> – the DG proposal does not satisfy the regulatory test; and – the DG proponent chooses not to fund the deep connection costs. 	<p>We look forward to participating in the consultation process regarding Chapter 5 of the NER. Adequate provision of information by DNSPs is essential. The present information asymmetries are heavily in favour of the DNSPs, and greater transparency could only be beneficial to DSR and DG proponents. This is particularly the case with regards to areas of network constraints, where (with the exception of the NSW Demand Management Code of Practice for Electricity Distributors and the South Australian Industry Guideline 12: Demand Management for Electricity Distribution Networks) very little information exists to aid DSR and DG proponents in planning suitable locations to establish projects.</p>
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