ENA response to Australian Energy Market Commission

Draft report—Request for advice on cost recovery for mandated smart metering infrastructure

EPR0018

23 July 2010

energy networks association

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Contents

Glossary

AEMC	Australian Energy Market Commission (also referred to as 'the Commission')
ACCC	Australian Competition and Consumer Commission
AER	Australian Energy Regulator
ENA	Energy Networks Association
NPV	net present value

1. Overview

The Energy Networks Association (ENA) welcomes the further opportunity to respond to the Australian Energy Market Commission's (the Commission's) *Draft Report—Request for Advice on Cost Recovery for Mandated Smart Metering Infrastructure* (Draft Report).

Electricity distribution networks face significant potential costs from future Ministerial determinations which may impose a range of complex and challenging mandatory obligations in relation to smart meter rollouts, trials and pilots. Ensuring appropriate cost recovery for these obligations is critical to achievement of the national electricity objective and the maintenance of a stable, financially sustainable, energy distribution sector and continued incentives to invest.

Energy network businesses strongly support the Commission's clear recommendations that alignment of distribution determinations and mandated rollout obligations represents the 'first best' policy outcome which collectively minimises potential risks, costs and inefficiencies for consumers and network business alike. Network businesses strongly encourage the Commission to consider all additional mechanisms available through its review to promote this outcome.

Recognising that alignment may not occur in all cases the Commission has developed a set of proposals designed to provide for cost recovery in a range of other circumstances. In some significant areas of it review of the *National Electricity Rules*, the Commission has also identified potential generic changes to economic regulatory rules that it considers warranted.

The raising of potential changes to the generic regulatory framework beyond those required to accommodate mandated smart meter obligations is a cause of significant concern for network businesses. The sector is strongly of the view that the Commission's review has the best opportunity to produce practical outcomes if it is focused more tightly on the scope of issues identified by the Ministerial Council on Energy, rather than considering the merits of major changes in regulatory policy affecting the operation of the broader *ex ante* incentive-based framework currently operating in the *National Electricity Rules*.

A further substantial concern is that some of the proposed generic and smart meter infrastructure-related rule amendments have significant conceptual problems that either require addressing or which mean the amendments are inappropriate in any form. Many of these conceptual problems relate to an over-reliance in the proposed amendments on highly discretionary *ex post* cost recovery and adjustment mechanisms which have a recognised ability to lead to heighten regulatory risk, reduced and distorted investment incentives, and higher overall costs to consumers. These characteristics have led both Australian and international regulatory frameworks to increasingly give a greater emphasis to establishment of sound incentives for businesses to pursue efficient outcomes. Many of the proposals in the Draft Report, however, would represent a reversion back towards discredited models of regulatory design and decision-making particularly unsuited to incentivising the commercially efficient management of risky innovative investments in the network sector.

Network businesses consider that the investments required to meet other mandated smart meter obligations can generally be accommodated with some of the more minor proposed changes to Chapter 6 identified by the Commission, and that there are strong benefits to current and future consumers through a revision of some of the Commission's proposals to include a stronger reliance on incentive-based approaches. In this regard, network businesses do not consider that the investment, operational or asset life characteristics of smart meter infrastructure are different in kind to the range of assets which are currently successfully commercially deployed by networks on a continuous basis. For this reason, the essential design principles underpinning existing regulatory approaches and rule frameworks continue to be appropriate.

Network businesses consider the defining and critical features of Ministerially-determined deployments are that they are mandatory, externally determined, and that government policy is effectively being carried out through the placing of obligations on commercial businesses. These features place special obligations on the Commission to give priority to considerations of long-term regulatory certainty where debt and equity providers are being asked to fund mandatory rollouts according to timing and other specifications made by Ministerial order. This special obligation is best discharged through a reliance on stable, existing incentive-based approaches rather than proposed moves to increase the scope of regulatory discretion and move towards a low-powered *ex post* regulatory model.

Recommended approach

Based on its assessment of the Draft Report and work to date through the review, ENA recommends that the Commission should:

1. reconsider proposed rule amendments which are beyond the scope of the review and which represent regulatory policy decisions outside of simple 'enabling' changes to the regulatory framework
2. better recognise in the design of rule amendments that smart metering infrastructure investment is not distinctly or sufficiently 'different in kind' to current and future technology investments as to warrant a movement away from the currently sound set of ex ante incentive-based regulatory approaches
3. seek to build on the 'fit-for-purpose' model of the National Electricity Rules, by creating incentives and mechanisms that provide scope for the commercial choices of distribution businesses to reveal robust information on overall levels of efficient costs
4. ensure proposed rule amendments have a clear operation by reviewing and addressing a range of terms which have no certain, defined or accepted regulatory meaning
5. avoid wherever possible the creation of a 'dual track' regulatory processes or depreciation approaches
6. rely on existing industry-wide information collection powers and established sharing processes until a need for any additional targeted measures is clearly demonstrable
7. minimise issues of regulatory uncertainty and reduce possible distortions to future pricing and competition by removing scope to defer the depreciation of high technology, short-lived assets offering services which may be ultimately be contestable.

2. Background

ENA is the peak national body for Australia's energy networks which provide the vital link between gas and electricity producers and consumers. ENA represents gas distribution and electricity network businesses on economic, technical and safety regulation and national energy policy issues.

Energy network businesses deliver electricity and gas to over 13.5 million customers, employ more than 40,000 people and contribute approximately 1.25 percent to Australia's gross domestic product. Energy is delivered across Australia through approximately 48 000 km of transmission lines, 800 000 kilometres of electricity distribution lines and 81 000 kilometres of gas distribution pipelines. Energy network businesses are valued at over $65 billion and annually undertake an average investment of approximately $12 billion in network operations, reinforcement, expansions and greenfield extensions.

3. High-level response to Draft Report approach

This section provides a high-level response to the overall approach proposed by the Commission in the Draft Report.

3.1 Scope of issues under review

Through the Draft Report a number of changes are suggested to the existing Chapter 6 framework which extend beyond the scope of issues identified for advice by the Ministerial Council on Energy directly relating to mandated smart meter rollouts and pilots. These proposals are generally identified as options for consideration in the treatment of smart meter rollout and trial issues, with the Commission then identifying that a broad policy change to the operation of existing Chapter 6 rules might be warranted.

Examples of this include a proposal to alter the future depreciation arrangements of a wide range of short-lived non-smart meter related assets, a proposal to insert regulatory guidance on cost pass through assessments, and provide for inter-period shifting of the recovery of a variety of costs (such as deferred recovery of pass through costs).

3.2 Conceptual problems with proposed rule amendments

A number of the major rule proposals in the Draft Report have conceptual problems that may affect their capacity to facilitate the efficient rollout and trialling of smart metering infrastructure and the operation of the existing Chapter 6 framework.

Examples of this are the insertion of potentially vague terms in the Rules, a significant increase in unconstrained Australian Energy Regulator (AER) discretion in some areas giving rise to regulatory uncertainty, and inconsistencies between the creation of new risks to the timing and adequacy of regulated revenues of distributors under proposed new cost recovery and depreciation arrangements and the financing requirements and the cost of capital faced by businesses.

3.3 Relying on existing Chapter 6 and incentive-based approaches

A major underpinning assumption of the Draft Report is that the existing incentive-based frameworks are inadequate to facilitate the efficient deployment and recovery of costs associated with smart metering infrastructure.

Energy networks, however, consider that with some of the relatively minor 'enabling' amendments to Chapter 6 outlined in the Draft Report incentive-based approaches can serve to deliver positive long-term consumer outcomes compared to alternative approaches featuring heavy reliance on *ex post* regulatory discretion. This is because the existing frameworks already provide strong incentives for efficient delivery of innovative short-lived investments across a range of business operations, including those required to meet and outperform mandatory reliability and safety obligations.

3.4 Requirement for certainty given 'Ministerially directed' nature of investments

A further factor that needs to be given greater weight in the design of rule amendments is the critical need for regulatory certainty around cost recovery processes due to the mandatory nature of Ministerially-determined rollout and pilot decisions.

Through Part 8A of the *National Electricity Law* jurisdictional Ministers have the capacity to effectively require the deployment of significant network resources to deliver smart metering infrastructure to particular customers, geographic areas and classes of customers according to Ministerially-determined timelines. The high degree of Ministerial discretion and uncertainty surrounding the development and nature of the specific obligations requires Rule amendments which fully recognise the fiduciary responsibilities of distribution business Boards and management who are required to make funding decisions to support these obligations.

The AEMC's proposed rule amendments also need to better recognise the requirements of debt and equity investors for certainty around the manner in which cost recovery of proposed sunk capital investment will occur over the life of the asset. A key part of this recognition is ensuring a stable, predictable cost recovery process which relies on consistent incentives to deliver efficient outcomes and does not introduce risks for ex post cost or asset stranding without full consideration of their implications for businesses' risk profiles and the cost of capital.[1]

1 It is acknowledged that the MCE Terms of Reference in discussing incentives to manage technology risks determines that WACC should not be re-examined. This ought not, however, be interpreted to prevent the Commission's recommendations being cognisant of the practical financing implications of any proposed Rule amendments .

4. Cost recovery under the distribution determination process

This section provides a more detailed response to the Commission's proposed approach on cost recovery under the distribution determination approach set out in the Draft Report.

4.1 Alignment of rollouts and pilots to determination schedules

The Draft Report emphasises the benefits of mandated pilots and rollout timetables being aligned with and considered as part of the normal distribution determination process. Network businesses consider this is a sound 'first best' policy approach and endorses the Commission's findings in this area.

Alignment of this kind enables the holistic consideration of smart metering infrastructure as an integral part of a networks longer-term capital and operating programs. By addressing otherwise problematic issues such as the interaction of mandated obligations on already approved expenditure programs, demand forecasts, and pricing, alignment of this kind offers the best opportunity to secure a coherent and robust regulatory package which promotes the long-term interests of consumers.

4.2 Revenue adjustment mechanism for rollout timing variance

In principle, a revenue adjustment mechanism to account for differences in the timing of a rollout which are either within or outside of a distributors control is sound. A number of network businesses have operated under conceptually similar schemes which automatically adjust the target revenue of the business based on out-turn demand volumes or other cost drivers.

The workable implementation of the scheme would require three important conditions to be met:

» **Certainty**—including the up-front specification of 'triggers' points and 'deadbands'

» **Symmetry**—the operation of the scheme would need to be symmetrical and therefore have the capacity to positively accommodate any outperformance of mandated timelines, or any under-delivery based on factors beyond the distributor's control.

» **Consistency with access pricing principles**—to be consistent with the *National Electricity Law* pricing and revenue principles the mechanism must provide a reasonable opportunity to recover efficient costs, i.e. be net present value neutral in an *ex ante* sense

To ensure the clear operation of this rule amendment it is recommended that the principle that the overall operation of the mechanism must be 'NPV neutral' should be included in any rules in this area, for example through a reference that the design and expected operation of the mechanism must satisfy the revenue and pricing principles of the *National Electricity Law* and the principles in Clause 6.5.9 of the *Rules*.

4.3 Regulatory 'menu' approach to address expenditure uncertainty

The Commission proposes providing the AER with a 'menu' of cost sharing or depreciation arrangements to apply at its discretion to respond to expenditure uncertainty arising from smart meter infrastructure deployments. Energy network businesses have a number of concerns with this proposed arrangement.

Cost uncertainty as the prevailing state under economic regulation

Existing incentive regulation enshrined in Chapter 6 is specifically designed to address uncertainty facing regulators over the efficient level of forward expenditure for electricity distribution businesses. Significant weight is placed in the Draft Report on what is argued to be a 'unique' level of uncertainty over the efficient level of expenditure for the installation and operation of smart meter infrastructure. There is significant uncertainty over the costs and benefits of a range of smart meter infrastructure investment for distribution businesses (indeed, uncertainty over the costs and benefits and distributors' capacity to capture claimed benefits is a primary driver of a policy of mandated rollouts). These uncertainties should be carefully assessed as part of Ministerial cost-benefit studies underpinning mandatory rollouts.

A high degree of uncertainty about the overall costs and benefits of smart meter investments does not, however, necessarily imply a unique level of uncertainty in the profile of expenditure required to meet well-specified requirements of mandated obligations. Distribution networks routinely make significant investments in short-lived technology based investments where there is potentially substantial uncertainty over the level of efficient costs that should be incurred. As an illustrative example, Table 1 below outlines the types of information technology-related investments planned and outlined by network businesses in the most recent round of distribution determination processes:

Table 1—Proposed investments in IT by electricity distributors—current network determinations

Businesses	Types of investments in information technology
Country Energy	» Asset management systems » Customer management and market systems » Network quality monitoring system » Purchase of new IT infrastructure » Hardware and software upgrades
EnergyAustralia	» Data center to manage data security » Integrated asset management system » Support systems for mobile staff and workers in field
Integral Energy	» Outage management system » Field force automation » Geographic information system » Program management system
Energex	» Maintenance of software and hardware technologies » Customer service relationship management systems
ETSA Utilities	» Mobility and associated IT governance system » Enterprise data management system (integration, standardization and support of business database and information) » Asset management system » Enterprise project management system » Business workflow system (to provide outage-related data to customers)

Whilst typically network investment is dominated in absolute value terms by investments in relatively mature or known technologies, this is increasingly changing as, for example, digitisation of network management systems, remote mobile communications technologies, and enterprise-level information technology platforms become a critical part of managing distribution network operation.

Distinguishing the regulatory treatment of smart metering infrastructure investments programs from these 'business as usual' and normal network-wide business improvement projects is arbitrary and unnecessary. Under the existing incentive-based regulatory framework it is recognised that network businesses are best placed to manage the substantial commercial uncertainties for highly business-specific technology investments, for example through contractual arrangements, within a framework which rewards efficient management of costs and delivery of outputs. There is thus no strong case to seek to introduce a distinction between these two types of investments if the scope of the Ministerially-directed investment is sufficiently clear as the network business prepares its expenditure forecasts for a distribution determination process.

Applying a 'fit-for-purpose' menu-based approach

An aspect of the design of the proposed rule amendment which deserves further consideration is the placing of an absolute discretion over the 'regulatory menu' of options in the hands of the AER. This appears to be a response to the commonly identified issue of information asymmetry which lies at the basis of why incentive-based approaches were developed. Yet in regulatory policy terms, responding to concerns around information asymmetry as to 'efficient costs' (which as noted arise across all network investments) by vesting greater regulatory discretion in the AER is not consistent with best practice or recent developments in incentive regulation.

Regulatory practice in the UK, for example, has instead placed before *regulated businesses* a menu of potential cost recovery and sharing options, and provided scope for the business, not the regulator, to select a model. A variant of this approach also occurs in New Zealand where regulated firms may select between a 'default' or a 'customised' price path. The choices made by the firms against these menus in fact yield concrete information for the regulator which can be used in future decision-making.[2] By contrast, a choice by the AER to impose one or other option in the AEMC's proposed menu would reveal only the regulators' views on the likely cost variances and uncertainties, as well as its organisational risk appetite.

Reliance on a menu of options for the distribution business to select between would also be consistent with the 'fit-for-purpose' features of the current *National Electricity Rules*, which place emphasis on the proposed capital and operating expenditure allowances the distribution business considers to be required to meet a realistic view of expected demand and the cost of regulatory obligations.

Definition of regulatory discretion and rule amendments

For economic regulation to be transparent, effective and predictable regulatory rules need to be clearly defined and capable of relatively certain operation. A number of the key terms in the Commission's proposed amendment do not meet this test.

Examples of this in the proposed rule drafting include:

» incentives must not be 'stronger' than incentive otherwise applied, without clarity as to how or over what timeframe the strength of incentives should be measured;

» the AER must judge if these is a 'substantive degree of uncertainty' regarding the 'actual' level of 'efficient cost', in circumstances where the design and operation of the *ex ante* incentive framework is predicated on such uncertainty; and

» the AER must assess where an 'incentive to underspend' is 'too strong' or whether an 'inappropriate balance of expenditure risk' exists between the DNSP and customers, with no guidance to inform this judgement.[3]

It is unclear how these critical requirements will be assessed by the AER, and each of the qualitative concepts described have in common that they have no close analogs in the existing *National Electricity Rules* which would enable reasonable conjectures to be made over their interpretation. The lack of definition or guidance as to the matters to be taken into account when making these subjective assessments implies a shift to a more highly discretionary regulatory regime, with consequently increased levels of regulatory uncertainty.

4.4 Use of forecast depreciation on short lived or smart metering infrastructure

The Commission proposes to give scope for the AER to roll forward the regulatory asset base on the basis of forecast depreciation in either smart metering infrastructure or all short-lived assets rather than actual depreciation. This is designed to provide weakened incentives to address a claimed systematic potential underspending against regulatory benchmarks in these areas.

2 See for example Joskow, P. *Incentive Regulation and its application to electricity networks*, Review of network economics, December 2008.

3 See AEMC *Draft Report—Request for Advice on Cost Recovery for Mandated Smart Meter Infrastructure*, 18 June 2010, p.144-146

Discretion to applying forecast depreciation to all short-lived assets

If the forecast depreciation approach were to be available for all short-lived assets this would, as the Commission's options report identifies, represent a sharp change in access pricing policy.[4] Such a significant shift in the regulatory treatment of new and existing assets would be outside of the scope of the current MCE directed review, and would raise a broader set of regulatory policy considerations which would require more comprehensive evaluation.

Such a move would also significantly 'de-power' the incentive framework for all short-lived assets embodied in the existing rules. The likely impacts of providing for weaker incentives for efficiencies on the full range of short-lived assets that form part of the distribution businesses assets has not been investigated or modelled by the Commission. In theory such a de-powering would create poor incentives for efficiency in relation to capitalised short-lived assets, potentially leading to higher overall costs for consumers even if it was assumed to have the desired impact of addressing potential underspending on smart metering infrastructure. It also has the potential to lead to inefficient substitution decisions between operating and capital expenditure. In the absence of a full assessment of this trade-off issue, and analysis of how application of forecast depreciation would interact with other elements of the Chapter 6 regime, it is unsound to move to applying the proposal generically.

Discretion to applying forecast depreciation to smart metering infrastructure

An alternative raised by the Draft Report is providing for the forecast depreciation approach only for smart metering-related investments. This would essentially provide scope for a 'dual' system of forecast and actual depreciation to operate in parallel through a regulatory period, with most assets being rolled forward using actual depreciation but smart metering assets being isolated and treated differently.

Based on the information provided above there is not a clear distinction between, innovative high technology investments with short asset lives and uncertain costs which already form a part of distributors 'business as usual' regulatory expenditure proposals and potential investments in smart metering infrastructure. This has the potential to lead to practical problems in designing a 'bespoke' depreciation regime for a subset of distribution assets, as the Commission's paper identifies.[5] Most significantly this could cause the drawing of arbitrary and ultimately efficiency-destroying boundaries between interrelated and functionally identical technology investments made by distribution businesses.

These problems are exacerbated by a continuing lack of certainty over the scope of the term 'smart metering infrastructure' and in particular how this term excludes new investments and upgrade programs as businesses make increasing use of 'smart' information communications technology throughout their networks.

4.5 Option of a 'sliding scale' cost sharing mechanism

The other mechanism the Commission proposes to address expenditure uncertainty is a 'sliding scale' cost recovery mechanism. This option also has the disadvantage of requiring the complex and potentially arbitrary separation of smart metering investments from a likely portfolio or other planned or complementary ICT investments in a regulatory proposal. If this issue is able to be sufficiently addressed such a sliding scale mechanism may be an appropriate way to share the risks and costs of mandated rollouts and trials.

Assessing the practical operation of the mechanism, however, is not possible on the information provided by the Commission, and this lack of definition of the parameters of the mechanism should be addressed by the Commission through draft rules in preference to design being left wholly within AER discretion. In the design of provisions which served as a guide for Chapter 6, the Commission has previously emphasised the need for regulatory discretion to be accompanied with guidance on its exercise, and this is a consistent feature of the National Electricity Rules approach to other decisions involving the exercise of discretion.6

4 AEMC *Assessment of Options: Cost Recovery Mechanisms for Mandated Smart Meter Rollout Expenditure*, 18 June 2010, p.26

5 AEMC (June 2010), p.26

6 AEMC *Final Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No.18*, 16 November 2006, p.34-35 and see also *National Gas Rules*, Clauses 40, 79 and 87.

An unresolved issue in applying a specific cost sharing mechanism to a subset of a distributor's expenditure is that this has the potential to interact with existing efficiency sharing and other incentive mechanisms applying more broadly. Further the specification of a 'sliding scale' cost sharing approach necessarily involves weakening incentives for commercial decision-making in the event of a significant cost overrun, meaning risk passing to consumers from businesses which have the better capacity to manage the cost risks involved through contractual and other means.

4.6 New reporting requirements on costs and benefit of rollouts and trials

Energy network businesses consider that the creation of new specific information-gathering requirements in relation to smart meter infrastructure rollouts or trials is an unnecessary and disproportionate proposal that will not assist in practical efficient outcomes.

Some of the difficulties with the proposal are:

» *ex ante* incentive based regulation was developed to incentivise businesses to reveal efficient costs and achieve efficiencies over time, due to a recognition that simply gathering 'more' information to address information asymmetries in the regulatory process was a costly dead-end

» deriving and isolating the costs and benefits of a single component of a broad expenditure program is not a realistic objective for even a detailed information-gathering process

» the derivation of 'robust cost and benefits' information will be problematic given smart metering infrastructure will likely form part of larger integrated high technology 'smart network' investments

» the Ministerial determination to require a smart meter rollout will itself be underpinned by a policy based assessment of costs and benefits

» the highly prescribed and jurisdictionally-tailored nature of projects is likely to make the information of limited use in benchmarking 'efficient costs', noting that benchmarking has been identified by the AER as of limited value even when comparing costs of stable sets of existing 'known technology' assets, and

» the proposed use of mandatory requirements proceeds without reference to whether existing regular information sharing processes already in place under the National Smart Metering Program provide a sufficient lower cost alternative.

The use of existing information-gathering powers is also a relevant consideration prior to any proposal to significant widen these powers. Under the current *National Electricity Law* (NEL) the AER is granted regulatory information powers to support its functions, including the requirement to require the collection, maintenance and reporting of information where this is 'reasonably necessary' for the conduct of its duties. This may be carried out on an industry-wide basis if required by the AER through the issuance of a Regulatory Information Order under Section 28.

This mechanism under Section 28 was specifically inserted into the NEL to meet a claimed requirement of regulatory bodies for more clearly prescribed industry-wide information gathering powers. Since their inclusion in the energy laws, these powers have remained unused whilst the AER has progressed to finalise over a dozen major regulatory determinations providing for total allowed revenues of approximately $60 billion. The development of specific new industry-wide information gathering provisions where the approximate cost of a national smart meter deployment has been estimated by MCE at between $2.8-4.6 billion would appear a disproportionate regulatory tool in the circumstances.

A reliance on existing information powers also appears to be the preferred approach of the Commission's legal advice provided by Allens Arthur Robinson. This advice recommends that a 'better approach' is to rely on the regulatory information order process to obtain industry-wide information that is required.[7] This preferable option, which does not require the specification of further powers and which is appropriate constrained by the balancing protection of all other information collection powers in the NEL, is not considered in the Draft Report.

7 Allens Arthur Robinson *Advice in response to MCE Request for Advice on Cost Recovery for Mandated Smart Metering Infrastructure*, April 2010, p.42

If the Commission does consider it appropriate to proceed with dedicated information collection powers they should be limited in a number of ways to ensure consistency with the policy intent of the information-gathering framework established under Section 28. At minimum, would that require that any such powers be:

1. **time-limited**—include a sun-set clause providing for their automatic expiry five years following the commencement of the first Ministerially mandated rollout or trial
2. **purpose-focused**—be constrained to collecting such information as is 'reasonably necessary' for the carrying out of the AER's functions
3. **least cost**—recognise the cost of compliance by not incurring costs in excess of the benefits reasonably anticipated to flow from the collection of the information
4. **procedurally balanced**—by featuring equivalent procedural protections as policy makers have required for existing powers under Sections 28F-28K.

5. Mid-period cost recovery for mandated rollouts

This section provides more detailed views on the Commission's proposals in relation to mid-period cost recovery.

The Commission proposes an option of deferring a regulatory determination on cost recovery for smart meter infrastructure for consideration in the next distribution determination. This proposal has a number of problems at both conceptual and practical levels which have not been adequately considered in the Draft Report.

5.1 Ex-post regulatory reviews of cost

The Commission's proposal would represent a significant step backwards from the principle of a reliance on prospective incentive-based regulation. Movement to the current *ex ante* approach in place across electricity and gas networks has been driven by a wide and growing consensus amongst regulatory commentators, regulatory bodies and governments that *ex post* cost assessments have a number of fundamental incentive problems and adverse consequences which ultimately harm the long–term interests of consumers.

Reasons for the growing reliance on ex ante approaches

These considerations underpinned the Commission's own conclusions on the appropriate form of electricity transmission revenue regulation, and these conclusions also influenced later policy design by policy makers of energy distribution rules. For example in its 2006 Final Rule Determination for its *Review of Transmission and Revenue Pricing Rules* the Commission removed scope for *ex post* review of capital expenditure, observing:

> In general the criticism of the proposed ex post prudency review was that it undermined the incentives of the ex ante cap and contributed to the investment uncertainty that the remainder of the package sought to overcome. Submissions also raised the legitimate concern that ex post prudency reviews are, by their very nature, an intrusive form of regulation. An ex post review effectively requires the regulator to put itself in the position of a TNSP at the time that they were undertaking a particular project to determine if the project was undertaken efficiently. Previously, this process has been the subject of controversy when it has been applied to network businesses. For these reasons, the Commission has removed the arrangements for ex post reviews and instead focused more on improving ex ante incentives.[8]

The Commission's proposals do not overcome these well-established flaws in ex post regulation, nor do the particular characteristics of smart meter infrastructure investment reduce the potential risks and costs of employing a backward-looking 'cost of service' approach. Indeed, the nature of such investments as innovative investments deeply integrated in network operation, with significant cost uncertainties, is likely to interact with and exacerbate these risks and costs in a number of ways.

The commonly identified impacts of applying ex post regulation with scope for cost stranding are:

» increased regulatory uncertainty, reducing investment incentives or increasing the cost of capital[9]

» increased potential for dispute by involving the regulator in making subjective assessments against a highly artificial information standard (i.e. what was reasonable to know at the time, which inevitably encompasses information which becomes more prominent in hindsight than it was in prospect)[10]

» significant regulatory intrusion into, and 'second-guessing' of the commercial and operation decision-making of the business, and

» a biasing of the composition of investment and decisions by the firm towards conservative 'low variance' projects involving lower upfront sunk costs over those that fully capture potential economies of scale over a full project life, with this effect pronounced in investments in areas with fast technological progress.[11]

8 AEMC (November 2006), p.98

9 Vogelsang, I. *Incentive Regulation, Investments and Technological Change*, CESifo Working Paper N0.2964, February 2010, p.27

10 Volgelsang (February 2010), p.27

11 Egert, B. *Infrastructure Investment in Network Industries: The Role of Incentive Regulation and Regulatory Independence*, CESifo Working Paper No.2642, May 2009, p.7

The Commission's Draft Report has sought to address some, but not all, of these impacts through a number of features of the rule amendments. However, a number of substantial flaws remain in the proposals as presented.

Significant remaining issues in Commission's proposal

The proposal to adopt a 'no hindsight' test will not fully address the scope for the AER's *ex post* decisions to significantly rely on information that was not available or salient at the time of the investment decision. Inevitably, *ex post* regulatory judgements can rely on information not prominent at the point of investment, be informed by subsequent experience and information, and involve uncertain and subjective assessments as to the nature of project planning and risk assessments that a regulator not responsible for carrying out large commercial projects against fixed timelines has little information about. In reality, decisions made in this environment will be informed by *ex post* experience, and the complex, artificial and unworkable nature of a 'no hindsight' rule is a key reason why such *ex post* cost assessment rules are increasingly rarely applied across Australian and international regulatory regimes.

A second flaw in the deferring of a cost recovery decision until the next determination is that it would require the AER to assess expenditure which has already occurred against capital and operating expenditure criteria which were designed to inform *ex ante* decisions on future regulatory allowances. This conflicts with the 'no hindsight' principle, and it is not obvious that such criteria provide as useful a basis for backward looking assessments of costs as they do for their originally intended purpose. Indeed, this is likely to be one reason why capital and operating criteria are not referenced in the existing cost pass through provisions of the *National Electricity Rules*.

The Commission seeks to reduce the regulatory uncertainty which it concedes is created by the *ex post* approach through requiring the AER to produce a guideline outlining its approach to *ex post* reviews. In the absence of regulatory guidelines having the power to bind the exercise of regulatory discretion, however, general guidelines on regulatory approaches are likely to have an extremely limited impact in reducing regulatory uncertainty. This consideration, for example, was a significant driver of the codification by the Commission itself of many elements of the ACCC previous non-binding *Statement of Regulatory Principles for the Regulation of Transmission Revenues* into the current Chapter 6A rules. Experience with that ACCC guideline, including multiple revisions reversing regulatory approaches on issues of fundamental regulatory practice, indicates that provision of generic guidance is of limited value where incentives for what is termed 'regulatory opportunism' or time-inconsistent behaviour are present.[12]

A third difficulty with the Commissions' proposed rule amendment is that while a mandated rollout would have the potential to materially impact the cash flow volatility and financing costs of the network, the amendment (even including the temporary adjustment mechanism discussed below) would not adequately recognise these costs, effectively guaranteeing some form of cost stranding would result from a rollout decision. The Commission's proposal is that the AER would provide the distributor with the 'time cost of money for incurred costs' based on the weighted average cost of capital of the *previous* regulatory period. A cost of capital from a previous determination, however, will not reflect:

» the likely prevailing conditions in the market for funds which a distributor may be required to access to fund the additional operating and capital costs of the rollout, in circumstances where the risk-free rate, liquidity and debt and market risk premiums may have materially varied from previous regulatory assumptions

» the risk characteristics of a network business required to carry out a complex integrated technology deployment against a Ministerially determined timeline, or

» the additional unanticipated regulatory risks of the exposure of substantial business revenues to ex post prudency reviews.

12 Egert (May 2009), p.8 and see also Cambini, C. and Rondi, L. *Incentive Regulation and Investment: Evidence from European Energy Utilities*, Journal of Regulatory Economics, November 2009, p.5

In these circumstances, reliance on a previous cost of capital estimate is likely to be no more than an approximation of the actual cost of funds. Further consideration of alternatives approaches that do not potentially strand efficient financing costs is required. Such approach might include updating cost of capital assumptions applied to smart metering infrastructure investment to better reflect prevailing market conditions.

A further difficulty with the proposed rule amendment is in the intractably uncertain nature of defining 'network operational benefits'. While the Commission has sought to require that such gains must be solely and directly occurring to the distributor as a result of the rollout, even these tests involve substantial areas of uncertainty and unguided regulatory discretion. This is an inevitable consequence of relying on the judgement of a regulatory body to assess benefits, rather than a strong reliance incentives to reveal realised efficiencies.

A minor improvement that can be made in this 'second-best' approach is to ensure the rule amendment captures the concept that benefits must be *actually accrued* prior to their being taken into account in offsetting past costs and relevant to metering services as opposed to any other network function, e.g. a reduced charge to connect/disconnect customers remotely compared to the current field work costs.

A superior approach, however, which would encourage the Commission's primary goal of aligning distribution determinations and mandated rollouts, would be for the rule to require that if a mandated rollout is due to commence less than 2.5 years prior to the next determination, <u>no</u> network operational benefits should be assumed in the subsequent *ex post* review. This step would incentivise policy makers to closely consider the costs of misaligned regulatory and rollout processes, reduce the costs and negative incentive effects of the *ex post* review, and more accurately reflect the likely limited benefits accruing over a 2.5 year period.

5.2 Proposed mid-period rollout 'temporary adjustment' mechanism

The Commission proposes a possible 'temporary adjustment' mechanism to seek to address the cash flow impacts of mandated rollout obligations being applied to electricity distributors whose regulated revenues have already been set in prior reviews.

A significant uncertainty in the proposed mechanism is the definition of what would constitute 'material cash flow difficulties'. Such uncertainty has the potential to compromise the intended goal of risk minimisation that underpins the temporary adjustment mechanism. Continuing instability and lack of certainty around the AER's definition of 'materiality' in respect of specific cost pass-through events demonstrates that an identification of a specific threshold is likely to be required to resolve this particular uncertainty and align the operation of the provision to some degree with concepts of materiality elsewhere in *National Electricity Rules*. One option would be to set the threshold at one per cent of annual regulated revenues, the prescribed threshold for electricity transmission pass through events. This temporary adjustment mechanism must also take into account any financing costs associated with the additional rollout obligations.

To be an efficient workable mechanism consistent with the access and pricing principles contained in the *National Electricity Law*, the adjustment must be based on the distributors own estimated forecast of costs and benefits. Together with scope for a subsequent 'truing up' of these estimates[13] this approach ensures that the business has a prospective reasonable opportunity of recovery of efficient costs, as determined by an independent and accountable regulatory process. This critical condition is not fulfilled if the costs and benefits from a separate Ministerial cost benefit process, which is not subject to the same procedural and substantive disciplines and protections, are inserted into an economic regulatory pricing process.

13 It is assumed this is the purpose of the clause in C.2 (f) of the Commission's draft rule amendment (See AEMC Draft Report, June 2010, p. 148)

6. Mid-period cost recovery for mandated pilots and trials

This section provides more detailed comments on the Commission's rule amendment proposals in relation to mid-period cost recovery for mandated pilots and trials.

The proposed cost recovery arrangements for mandated pilots and trials outlined by the Commission broadly appear to be appropriate. Due to the likely difference in scale between mandated rollouts and pilots and trials, a primary consideration for cost recovery arrangements for these activities is that they allow a least cost, simple and timely process for allowing recovery of incurred costs.

6.1 Proposals on classification, timelines and eliminating the pass through 'dead-zone'

The proposal to require the AER to indicate its classification of pilots and trials is a practical positive change that addresses a potential area of uncertainty affecting both consumers and network decision-making, and is supported. Similarly, a capacity to extend the existing cost pass through assessment timeline to allow fuller evaluation of costs incurred in pilots and trials is likely to be justified.

The proposal to remove the effective 'dead-zone' for general cost pass through applications within the last 13 months of the regulatory period is supported on the basis that it appears to directly address a current drafting deficiency of the *National Electricity Rules* which the AER considers prohibits the consideration of pass through events during this period. In fact, depending on the timetable of the mandated rollout decision, and businesses' processes to undertake business planning, tendering activities and evaluation the effective 'dead-zone' can extend beyond a 13 month period.

It is noted that in this case a change which affects the generic operation of Chapter 6 (and, in addition, Chapter 6A) is being supported where in general industry has supported the scope of the review being confined to core enabling changes necessary for, and applicable only to, the rollout of smart metering infrastructure. In this case, however, the deficiency correctly identified by the Commission is a material problem with the potential to unintentionally result in a failure of the regulatory rules to provide distribution businesses with forward revenues that match expected costs. Further, there is no evidence that this 'dead-zone' is the result of deliberate policy design. It appears, rather, to be a technical oversight in the drafting of the relevant rules. By contrast, in other areas where the Commission has proposed to alter the generic rule after consideration of its particular interaction with smart metering rollouts the network sector considers the existing rules are the outcome of a deliberate policy design process which included extensive consultation and negotiation between policy makers and industry stakeholders.

6.2 Introduction of a prescribed 'efficient cost' standard into pass through assessments

One aspect of the Commission's proposal which is not within the scope of the review, or warranted on the basis of experience to date, is the explicit incorporation of an 'efficient cost' standard into the cost pass through provisions of Chapter 6. This proposal has significant policy implications for the operation of the general rules, by altering the existing provisions, and thereby introducing the possibility that a future regulator or review body will interpret this change as indicating that the Commission seeks to alter the future substantive interpretation of the provision.

The Commission's proposals for altering the guidance on cost pass through assessments appear to be based on assumptions about possible adverse outcomes from a lack of more prescriptive regulatory guidance. In the first instance, network businesses consider proposals should be based on overcoming observed, rather than hypothesised, problems with the operation of regulatory rules. In this case, there is no evidence that the AER would or has applied an inappropriate cost standard in the assessment of cost-pass through events. Further, the AER has a broad discretion under Clause 6.6.1 (J) (8) to accommodate the considerations which are suggested to be relevant by the Commission.

The importation into cost pass through assessments of the *ex ante* criterion used to determine the reasonableness of proposed capital and operating expenditures also risks creating, rather the resolving, uncertainty as these provisions would be being applied for a different purpose (backward looking cost assessment) than their original design.

As noted previously, it may in fact be a deliberate outcome of policy design that the 'efficient cost' standard (which is recognised to be a dynamic rather than static concept) is not referenced in the existing cost pass through clause. One reason for this may be a recognition that circumstances where a cost pass through event has occurred are not analogous to those facing a distribution business outlining its planned medium and long-term operating and capital expenditures prior to a distribution review.

In the case of pass throughs, a business is directly responding to an external event whose probability and expected costs were not able to be anticipated at the time of the review. Where this pass through event is a mandatory obligation to undertake pilots and trials of potentially varying scopes according to fixed timelines, the distribution business will necessarily not be in the same position to plan and shape its expenditure program with the same flexibility as it otherwise possesses in its normal commercial network operations. This reinforces the point that applying the same criteria used to assess *ex ante* regulatory proposals is likely to lead to greater uncertainty and prospect for disputation for little overall practical benefit.

7. Tariff issues and smart meter infrastructure investments.

This section provides selected comments on the Commission's rule amendment proposals affecting tariff issues arising from mandated smart meter infrastructure investments.

Many of the proposals relating to tariff and smart meter infrastructure appear to be sound adaptations and additions to the regulatory framework to accommodate the specific issues arising from Ministerial mandated rollouts, pilots and trials. For example, the proposed smart meter pricing principles initially appear to be broadly appropriate and to provide positive guidance to consumers and network businesses.

7.1 Guidance on use of x-factor to smooth tariff impacts

The proposal to include specific guidance in the *National Electricity Rules* encouraging the use of the x-factor to smooth rollout costs within the regulatory period is appropriate. The drafting of this particular amendment, however, must ensure that the critical existing regulatory principle that the target revenue must equalise expected costs over the regulatory period is maintained as a threshold requirement in setting the x-factor. This is necessary to ensure the continued satisfaction of the 'NPV=0' principle which serves at the minimum threshold for regulatory determinations to comply with the revenue and pricing principles.

7.2 Scope for AER to 'back-end' recovery of smart meter infrastructure costs

The Draft Report includes a proposal to allow the AER to modify distributors' proposed depreciation schedule to effectively defer or 'back-end' depreciation associated with new smart metering infrastructure, to assist in smoothing potential cost impacts.

As a principle, concerns relating to the costs of the project compared to its tangible benefits should be transparently considered and consulted upon in the Ministerial review process leading up to the imposition of a mandatory rollout. If there is a significant community view that the immediate costs of implementation are not likely to be matched by readily definable medium-term benefits this represents a broader policy question which is more suitable for resolution through the public policy and political process than through *ad hoc* amendments to the economic regulatory framework.

Network businesses have a range of significant concerns around a proposal to allow the AER to back-end the depreciation of smart meter infrastructure and consider the approach should be avoided. The principal concerns of network businesses are that the approach:

» overturns the 'fit-for-purpose' operation of the *National Electricity Rules* which provides for the distributor to nominate depreciation that comply with the relevant Rule obligations, effectively reversing the operation of the existing clauses

» potentially only defers and complicates issues of cost recovery and competition in the light of potential future contestability of smart meter services

» is inconsistent with other elements of the Commission's Draft Report that places weight on the short asset lives of smart meter infrastructure

» would involve arbitrary and uncertain regulatory decision-making in relation to asset classification (i.e. how would assets serving more than one function be defined and split without perverse incentives and distortions arising?), and

» would increase regulatory and financing risks due to the inability of a regulatory body to credibly commit to cost recovery or depreciation arrangements over multiple regulatory periods, without contemplating offsetting adjustments to cost of capital assumptions.

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