Electricity Network Economic Regulatory Framework Review Approach Paper submission

6 February 2017

Energy Networks Australia

Contents

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Introduction

Energy Networks Australia welcomes the opportunity to make a submission to the Australian Energy Market Commission (AEMC) in response to the *Electricity Network Economic Regulatory Framework Review Approach Paper* (the Approach Paper) published by the AEMC on 1 December 2016.

Energy Networks Australia is the national industry association representing the businesses operating Australia's electricity transmission and distribution and gas distribution networks. Member businesses provide energy delivery services to virtually every household and business in Australia.

Energy Networks Australia welcomes the opportunity to provide submissions to the Approach Paper and to contribute more broadly to the *Electricity Network Economic Regulatory Framework Review* (the Review).

Energy Networks Australia's submission in response to the Approach Paper reflect the following key messages:

» Networks support the role allocated by COAG Energy Council to the AEMC to monitor developments in the energy market, including the increased uptake of decentralised energy, and to provide advice as to whether the economic regulatory framework for electricity transmission and distribution networks is sufficiently robust and flexible to continue to achieve the national electricity objective (NEO) in light of these developments.

» Networks consider that the AEMC Review can be constructively informed by the detailed analysis and findings included in the *Electricity Network Transformation Roadmap* developed over two years with wide stakeholder engagement;

» Integrated, cohesive and investment-friendly energy policy, carbon policy and regulatory frameworks will be critical to enabling agile, efficient, customer-focussed responses by current and future industry participants; and

» Greater coordination of regulatory review and rule change processes is necessary to avoid unintended consequences to market and consumer outcomes.

Energy Networks recognise the importance of a robust, stable and predictable regulatory framework to supporting the capacity of network service providers to excel in delivering innovative, continuously improving customer services while continuing to access low cost financing which ensures lower costs to network customers. Energy Networks Australia supports the AEMC adopting a holistic approach to evaluating the regulatory framework. In particular, the Commission should consider the risks to customer outcomes of confusion in the regulatory framework should it be subject to multiple overlapping review and rule change processes pursuing piecemeal change, without an assessment of the overall impact on the regime, its stability and outcomes for customers.

Energy Networks Australia recognises that there are a number of important reviews underway, including the *Independent Review into the reliability and stability of the National Electricity Market* chaired by Australia's Chief Scientist, Dr Alan Finkel AO. It is likely that further changes to the regulatory framework may result from these reviews. Energy Networks Australia hopes that this AEMC Review will incorporate the findings of other review and rule change processes underway.

Energy Networks supports the need to consider prudent regulatory reform, while noting the evolution of the regulatory framework should be well-planned, coherent and nationally integrated.

Consequently, the AEMC's Review provides an opportunity to ensure that the Economic Regulatory Framework remains fit-for-purpose in the context of a rapidly changing market environment.

Energy Networks Australia notes that the conduct of the Commission's review results from policy advice received by the COAG Energy Council regarding the adequacy of the regulatory framework to continue to deliver the National Electricity Objective (NEO) based on four scenarios developed by the CSIRO in their *Future Grid Forum report*[1].

CSIRO developed four scenarios in its *Future Grid Forum report,* which Energy Networks Australia and CSIRO have further developed through the *Network Transformation Roadmap Key Concepts Report*. The Roadmap looks at five areas of transformation of the energy sector and identifies a suite of integrated measures focussed on better customer outcomes, including enhanced consumer choice, reduced emissions, reduced electricity network costs and increased levels of reliability and security.

The 5 key areas of transformation examined were:

» Customer oriented electricity;
» Carbon abatement;
» Incentives and Network Regulation;
» Power System Security; and
» Intelligent Networks and Markets.

Consistent with the Commission's Power of Choice reforms – and the COAG Energy Council work program – the Roadmap highlights opportunities to enable customer participation in markets, where customers or their agents may determine 25% to 50% of system expenditure.

Integrated actions to enable transformation could have material benefits for customers, including:

» Achieving deep decarbonisation in accordance with the aspiration of COP 21, including meeting and exceeding emissions reductions in the electricity sector of 26 to 28% below 2005 levels by 2030 and achieving zero net emissions in the electricity sector by 2050.
» Retention of the security and reliability essential to the lifestyle and employment in a period of unprecedented change in technology and customer electricity use.
» Enabling customer choices and providing fair incentives, with a majority of customers in 2050 utilising distributed energy resources and 'paid' $2.5 billion per annum by networks in exchange for grid support services.
» Cumulative total system savings (across the supply chain) of $101 billion by 2050 through fully realising complementary benefits of centralised and distributed resources.
» Reduced network investment due to the ability to 'orchestrate' distributed resources, saving approximately $16 billion by 2050.
» Lower bills for valued services and fairer outcomes for customers by 2050, including:
  – network charges could be approximately 30% lower compared to 2016;
  – average households are expected to save around $414 in their annual electricity costs;
  – a medium family who cannot take up distributed energy resources is better off by over $600 per annum through lower network costs and the removal of cross subsidies.

However, the Roadmap program highlights that this transition will not happen without deliberate and prompt action by industry and government institutions in key areas. For instance, key factors

[1] CSIRO (2013) *Change and choice: The Future Grid Forum's analysis of Australia's potential electricity pathways to 2050*.

are likely to include:

» Stable and enduring, outcome focussed carbon policy;

» Establishing a modernised electricity grid enabled by open standards, extended monitoring, advanced network planning, forecasting and hosting capacity analysis; and the mapping and locational value of distributed energy resources.

» Achieving fair and efficient cost reflective network charges and enabling network optimisation markets – new incentive frameworks which enable the full value of distributed resources to be realised; and

» Flexibility in the regulatory framework to encourage alternatives for new and existing grid connection, such as economic use of stand-alone systems and microgrids.

Given the scale of actions required and the need for carefully coordinated management of regulatory change, Australia's successful energy transformation is likely to benefit from centralised monitoring by the Commission, potentially through the current Review.

As an example, the significant transition to cost-reflective network tariffs by 2020 is identified in the Roadmap as a key prerequisite to other market enabling measures and incentives important to customer outcomes. It itself has dependencies on the timely and efficient adoption of advanced metering in contestable markets, and together they provide a 'critical path' for the resilience of energy market frameworks to rapid changes in technology adoption and customer choice. It would be appropriate to monitor the progress of both tariff reform and metering deployment.

Energy Networks Australia recommends that the AEMC consider the findings of the Roadmap during this current Review, in light of the linkages between the *Electricity Network Economic Regulatory Framework Review* Terms of Reference and the previous CSIRO *Future Grid Forum analysis*. Detailed underlying Roadmap expert reports are accessible here. Energy Networks Australia suggests that the AEMC may consider whether some or all of the milestones developed as part of the Roadmap may be appropriate for the AEMC to track and report on through this Review process.

Energy Networks Australia

A review of the current state of the market

Energy Networks Australia supports the collection of indicator data to inform the AEMC's Annual Review. Energy Networks Australia's members are pleased to assist the AEMC in this area. We note that:

- » reliable and complete information on some of these indicators may not yet be readily accessible to the AEMC, or other participants such as electricity network businesses; and
- » there is no central registry currently operating to collect such information. Distribution businesses are likely to have varying reporting arrangements and it would be necessary to recognise the current information format may not be uniform across jurisdictions.

The Clean Energy Regulator (CER) regularly publishes updated small-scale renewable energy installation data on:

- » small generation units (SGU) (small-scale solar panel, wind and hydro systems) and kilowatt (kW) capacity by installed postcode, and
- » solar water heaters (SWH) and air source heat pumps by installed postcode.

Energy Networks Australia notes that the register is organised by postcode and does not readily allow mapping back to distribution network service provider (DNSP) zone substation. Hence, without additional information, clear addressing matches or NMI level information as a key, the utility of currently collected CER data for electricity network planning purposes has some limitations.

Noting these limitations, Energy Networks Australia and its members would be pleased to provide input and contribute case studies, building on the work already undertaken by other agencies and as part of the Roadmap.

Additional Reporting Requirements

The Roadmap has identified a series of "no regrets" actions aimed directly at navigating the expected energy transformation. The precise scale and timing of Australia's energy transformation is inherently uncertain. However, the Roadmap analysis confirms that the agility with which networks are able to connect, integrate and incentivise new lower carbon energy choices will directly influence the cost, fairness, security and reliability of outcomes to customers.

It will be important to manage the prudent and timely evolution of the regulatory framework. In key areas, the regulatory framework may already permit the flexibility required for innovation in customer outcomes. However, some regulatory and policy barriers will need to be addressed or avoided to achieve the best outcomes for customers during the transformation.

Example – pricing and incentive frameworks

Energy Networks Australia considers that introducing additional monitoring and reporting on the uptake of cost reflective tariffs and the uptake of smart meters would be one way to assist in early identification of barriers to market transformation. The Approach Paper notes:

> *"In November 2014, the AEMC made a new rule to require network businesses to set prices that reflect the efficient cost of providing network services to individual consumers. This will allow consumers to compare the value they place on using the network against the costs caused by their use of it. Consumers who choose to respond to network prices by reducing their consumption in higher cost periods will be rewarded, through lower network charges. Over time all consumers will benefit through lower network costs and*

> *lower average network charges."*

However, Energy Networks Australia notes that while many DNSPs have developed and made available some form of cost-reflective tariff, the level of take-up by customers has been very low.

In fact, the evidence in the Roadmap report suggests that a reliance on current status quo "opt in" approaches will see the majority of customers remaining on unfair and inefficient network tariffs out to 2050. Such an outcome would have substantial effects on network costs and on the future cross subsidies occurring between customers who own distributed energy resources and those who do not.

The early transition of the majority of customers to cost-reflective tariffs is a necessary precondition to developing market-based solutions for network optimisation and full use of innovative market opportunities such as 'peer-to-peer' trading.

Consequently, Energy Networks Australia recommends that the AEMC include reporting on:

- the number of customers who have transitioned from legacy tariffs to cost reflective tariffs; and
- the current and estimated penetration of smart meters (critical for the implementation of the cost reflective tariffs).

Links to other reforms

Energy Networks Australia notes that increased centralised oversight and coordination of the numerous Review and/or Rule Change processes underway may provide significant potential benefits to market participants and to consumers. This will reduce fragmentation and duplication. The example of the proposed battery storage register is highlighted below.

> Energy Networks Australia notes that the Energy Market Transformation Project Team (EMTPT) under the Council of Australian Governments' (COAG) Energy Council has initiated a work program to understand the regulatory and policy implications of increasing deployments of distributed battery storage systems, including safety, installation and connection practices, operation and maintenance, and disposal[2].
>
> In general, stakeholders support the concept of establishing a battery storage register, but there were some concerns that requiring battery systems to be registered would add costs and complexity to an emerging industry.
>
> Stakeholders' views included that:
>
> - the register should be a national database, supported by a clear policy objective and governance framework;
> - the cost of setting up and maintaining the register should be justified
> - privacy and consumer information must be protected;
> - the regulatory framework that governs the proposed register should be flexible and adaptable to future technologies; and
> - COAG should ensure the implementation of appropriate regulatory changes to ensure all necessary data is collected.
>
> Energy Networks Australia notes that the COAG Energy Council has agreed in-principle to develop a national battery storage register, subject to a cost-benefit analysis that

[2] Commonwealth of Australia Approach to Market *Consultancy Services to Produce a Cost-Benefit Analysis of a National Battery Storage Register to collect and share information about small-scale battery storage* - Consultancy Services Reference No: 2000001105 p. 2-3.

compares a register with other options.

The Commonwealth, as represented by Department of the Environment and Energy, is currently seeking tenders for the provision of Consultancy Services to Produce a Cost-Benefit Analysis of a National Battery Storage Register to collect and share information about small-scale battery storage (Reference No: 2000001105). Tenders close on 6 February 2017. Consultancy services are due for completion on or before 30 June 2017.

The Australian Government's approach to market (ATM) stipulates that design of the cost benefit analysis should include consideration of collection and appropriate sharing of information about distributed battery storage systems and should be flexible and scalable so that information on other distributed energy resources (DER) such as solar PV could be included if beneficial in the future.

Energy Networks Australia's members would be pleased to assist the AEMC including in contributing case studies where valuable.

Robustness of the economic regulatory framework

Energy Networks Australia notes that the AEMC will review whether the economic regulatory framework is sufficiently flexible and robust to promote the NEO through the following assessment criteria:

Criteria	Assessment approach
Incentives	Does the framework provide the correct incentives for participants to: » make efficient planning, investment and pricing decisions; » sufficiently adapt business models; and » utilise non-network solutions?
Flexibility	Does the AER have appropriate and sufficient tools and flexibility over how to use them, for a changing environment?

The Roadmap identified key drivers of change to the current regulatory and policy framework in Australia. These included:

- the emergence of new technologies and new business models, providing capacity for greater competition and service tailoring;
- the potential for the development of off grid solutions and competition in a range of traditional network services to lead to an unplanned and disruptive break down of the funding of the commons of a shared network service capable of integrating efficient levels of centralised generation and distributed energy resources that meet customer needs; and
- the potential for the regulatory framework to stifle unintentionally the delivery of customer-valued services by a variety of competing business models, operating on a level playing field to deliver value.

Some of the key findings from *Chapter 8: Regulatory and Policy Frameworks* include:

- that there is the opportunity to move to more of a consumer centric, and less of a regulator driven framework;
- that there is also the opportunity to move to lighter handed regulatory models, especially for services which are increasingly subject to competitive disciplines;
- that there is an increasing role for emerging competition tests - the threshold for where more intensive and costly economic regulatory approaches are necessary will need closer consideration and design as competition for network services strengthens; and
- that a range of services may become completely contestable, changing the monopoly regulation presumption. The regulatory framework will need to have flexibility to incorporate new service types while continuing to support long-lived investments.

Cambridge Economic Policy Associates (CEPA) undertook detailed work on *Future Regulatory Options for Electricity Networks* as part of the Roadmap. Their report and an accompanying Policy Summary is available on the Energy Networks Australia website and is attached (<u>Appendix A</u>).

The AEMC inquires whether the Australian Energy Regulator (AER) has appropriate and sufficient tools and flexibility over how to use them, for a changing environment. Energy Networks Australia recommends evaluation of the AER's current tools and actions against a set of expectations, milestones and actions identified as necessary for energy market transformation to occur. It is important that the AEMC provide clear guidance to the AER, and to other market participants, to ensure the implementation of recommendations from Reviews and rule changes. The Roadmap recommends some further evolution of regulatory arrangements, commencing as early as 2019. Energy Networks Australia suggests that it may be appropriate for the AEMC and AER to consider these milestones as part of this reporting framework.

Energy Networks Australia considers that the AEMC's Review should (in addition to assessing incentives and flexibility) also consider the importance of the role of a stable, predictable regulatory framework in helping to minimise the financing costs borne by customers for long-lived network infrastructure investments and to ensure that networks continue to provide reliable and secure network services.

Energy Networks Australia agrees with the AEMC that recently made rule changes may have significant bearing on the regulatory framework's flexibility and robustness and that not all of these rule changes will have been in place for long enough to assess fully their effect for the 2017 report.

Energy Networks Australia agrees that the AEMC's assessment should also consider existing relevant schemes and guidelines such as:

- the efficiency benefit sharing scheme (EBSS);
- the capital efficiency sharing scheme (CESS);
- the regulatory investment test for transmission and distribution (RIT-T and RIT-D); and
- the distribution ring-fencing guidelines.

AEMC key priority areas for future reforms

Energy Networks Australia notes that each year in its Review the AEMC will identify key risk factors and emerging themes for potential challenges that may be faced by the regulatory framework in the near to medium term. The COAG Energy Council may focus on identified priority areas for future reforms.

For the 2017 report, the three preliminary priorities are:

» continued implementation of network pricing reform;

» the ability of networks to utilise increasingly diverse grid supply and network support options; and

» different network operating models (for example, the distribution market model).

AEMC Priority 1: Continued implementation of network pricing reform.

The Roadmap *Key Concepts Report* noted that an efficient adoption and integration of distributed energy resources (DER) through appropriate pricing and incentives should deliver significant savings in network augmentation costs, while at the same time delivering significant additional value to customers via their ability to participate in other markets.

The alternative, however, is failure to transition to a fairer system of prices and incentives, which will expose customers to the risk of over investment in the system, leading to higher average electricity bills and unfair cross subsidies paid for by some customers.

Key findings from Chapter 7: Incentives and Network Regulation include:

» Finding 1: Fairer system of prices can only be achieved in a reasonable timeframe with changes to tariff assignment policy;

» Finding 2: Smart meters are essential to ensuring a fair system of prices; and

» Finding 3: Over $16bn in network savings are possible by 2050 through improving existing tariffs, introducing new tariffs and establishing frameworks for networks to buy grid services from customers with distributed energy resources.

Energeia research undertaken to inform the Roadmap shows that "with the increase of new technologies in the energy system, early opportunities for buying and selling grid services are best served through agreements between customers and service providers. This will allow for dynamic and locational network orchestration of distributed energy resources where they can provide a lower cost solution to a traditional distribution service expenditure, to either augment or replace the existing grid.

An additional layer of direct, targeted incentive signals to integrate new technologies at a locational level, to complement more efficient broad-based tariff structures. Under its preferred scenario, Energeia predicts a third of customers will participate in some type of additional incentive, either directly or through an intermediary[3]".

Energy Networks Australia recommends that the AEMC, as part of its annual monitoring and reporting to COAG on technology trends and changes in market conditions, report on:

» the pace of market led smart meter deployment to ensure that it is on track to deliver the required number of meter installations to transition to an opt-out tariff assignment framework as soon as possible, and ideally from 2021; and

[3] Energeia (2016) Unlocking Value for Customers: Enabling New Services, Better Incentives, Fairer Rewards p. 3.

- the transition of customers from legacy to cost reflective tariffs to determine whether further regulatory and policy change is required to achieve a faster transition.

This finding links to the AEMC's second priority:

AEMC Priority 2: The ability of networks to utilise increasingly diverse grid supply and network support options.

The Roadmap notes that over the next 35 years, it will be possible to connect up to 27,000 rural customers with a lower cost solution through a standalone power system[4]. It will be possible to save almost $700 million by supplying these connections, usually farms, with a standalone power system[5]. It is also likely that transitioning existing grid connected remote customers to alternative supply via micro-grids or standalone power systems will result in a lower cost overall (in certain circumstances). This can also result in other benefits such as reduced bushfire risk. Current regulations can make the transition from conventional grid supply arrangements very difficult to enact.

With these potential circumstances in mind, on 9 September 2016 Western Power lodged a Rule Change proposal with the AEMC titled: *Removing Barriers to Efficient Network Investment*.

Western Power is concerned that a lack of clarity in the National Electricity Rules (NER) may unintentionally create a barrier to the use of certain types of technology that will deliver not only the most cost-effective services, but also potentially more reliable and safe services.

Western Power seeks to ensure that the definition of distribution service facilitates the achievement of efficient costs as intended under the NER economic regulatory framework by:

- removing any technology bias which could exist in the current definitions, thereby enabling DNSPs to have choice in the type of assets employed;
- promoting consistency between the planning obligations on DNSPs under Chapter 5 of the NER and the economic regulation frameworks under Chapter 6 of the NER; and
- aligning the flexibility currently provided to the AER regarding its approach to expenditure approvals and its approach to service classification.

Energy Networks Australia supports the AEMC's initiation and consideration of Western Power's rule change request and considers that clarification of regulatory arrangements allowing networks to connect customers at least cost will become increasingly important as the cost of alternatives to grid augmentation / replacement improve over time.

AEMC Priority 3: Different network operating models (for example, the distribution market model).

The Roadmap identifies that, irrespective of the network operating model chosen, there are a substantial number of identified initiatives which will be required to ensure that distribution networks can operate safely, reliably, securely and efficiently, as the mix of generation becomes more decentralised over time. Energy Networks Australia recommends that the AEMC consider identifying and reporting against key grid modernisation milestones as part of this Review.

As noted above, key elements of a modernised electricity grid are likely to include:

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[4] Energy Networks Australia and CSIRO (2016) *Electricity Network Transformation Roadmap: Key Concepts Report* p. 41.
[5] Ibid, p.42.

- open standards including communication protocols for distributed energy resources;
- extended distribution system monitoring,
- advanced network planning, forecasting and hosting capacity analysis; and
- the mapping and locational value of distributed energy resources.

Energy Networks Australia has also made a separate submission to the AEMC's *Distribution Market Model Approach Paper*. Please see our previously lodged submission on this matter.

If further information is sought on this matter, please contact Ms Kate Healey, Director Regulation, on 02 6272 1516 or by email on khealey@energynetworks.com.au.

Prepared by:
Cambridge Economic Policy Associates Pty Ltd

FUTURE REGULATORY OPTIONS FOR ELECTRICITY NETWORKS

Policy Summary August 2016

ELECTRICITY NETWORK TRANSFORMATION ROADMAP

ena energy networks association

CSIRO

A partnership between ENA and CSIRO

Prepared by:

Cambridge Economic Policy Associates Pty Ltd

IMPORTANT NOTICE

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FUTURE REGULATORY OPTIONS FOR ELECTRICITY NETWORKS

Executive Summary

Technological change - including the rapid integration of distributed energy resources - is transforming the electricity industry, the way that electricity networks are used, and potentially the economics of these networks.

This change creates the opportunity for the regulatory framework to evolve from a regulator-driven approach to more customer-led or lighter touch 'information disclosure' approaches. Cambridge Economic Policy Associates has reviewed possible future approaches and proposes a range of measures that could better incentivise electricity networks in the short-term and provide a pathway to transition to a lighter touch framework in the longer term.

Electricity markets, consumer technologies, network business models and energy resources are changing. The ENA and CSIRO are exploring the implications of these changes through the *Electricity Network Transformation Roadmap* (*the Roadmap*) in order to develop pathways for navigating critical change in Australia's electricity networks during 2017-2027.

ENA and CSIRO asked CEPA to review developments in other jurisdictions, and to consider and provide recommendations on regulatory options and pathways for Australian electricity networks based on a range of future energy market scenarios.

This work benefitted from discussions with industry and stakeholders through workshops and direct engagement, as well as guidance, input and review by internationally-recognised regulatory and energy market experts, Professors David Newbery and Stephen Littlechild.

Lessons from international experience

Many jurisdictions are considering how their regulatory frameworks should evolve to accommodate the transformation occurring in the electricity sector. We reviewed four regimes – Australia, California, New York and Great Britain's – where detailed consideration is being given to these issues. There are also a number of alternative regimes and innovative approaches being used in other sectors which we investigated. Some key lessons we have drawn from the review of the regimes are set out in the box below.

1. The electricity regulatory framework visions of other jurisdictions reflect the existing structure – vertically separated networks in Great Britain and Australia, and vertically integrated in California and New York, but separate or potentially separate system operators (at transmission level and/or at the distribution level) – therefore approaches and mechanisms need to be considered in the Australian context of the clear separation of networks from electricity generation and retailing.
2. Most regulators are taking a cautious but flexible approach to allowing networks to offer services that may become contestable – they are allowing distributed energy resources (DER) (particularly storage) to be directly owned by the regulated firm in a limited way – and encouraging networks to source these services from third parties.
3. There has been a push to ensure networks have balanced incentives for alternative solutions to poles-and-wires, which would require achieving returns through 'opex' . Incentivisation could occur through project-based measures (eg. New York and proposed for California) or total expenditure (eg. Great Britain).
4. The regimes are getting more complex as the industry transforms. While there is some significant 'refocusing' of regulatory frameworks, some of the added complexity appears to be the result of layering new arrangements on top of the existing frameworks. This should be avoided where possible.

The transformation has the potential to lead to a new regulatory framework

Under the current Australian incentive-based regulatory 'building blocks' process, there is a **regulatory-driven settlement** – i.e., the regulator makes the majority of decisions around services and prices on behalf of consumers. As customer access to information and new technologies increases, including in some cases expanding cost-effective and sufficiently reliable off-grid options, the opportunity exists to move towards **customer-led settlements**.

Under these types of approaches customers or their agents engage and negotiate directly with energy network businesses. Even lighter touch frameworks may become feasible over time, such as **information disclosure** oversight models that place a greater emphasis on lower cost monitoring approaches.

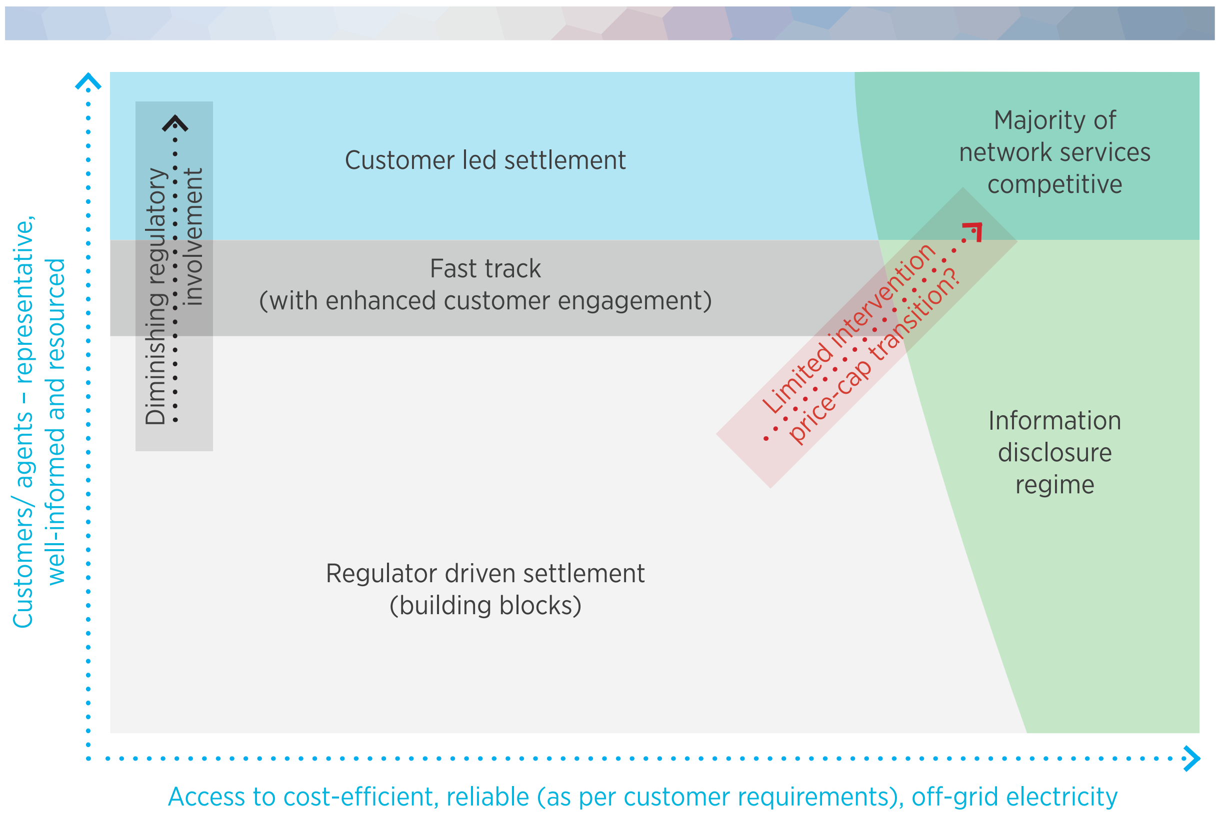
This change, driven by increased customer choice and engagement and potential access to non-grid alternatives, is illustrated in Figure 1.

With robust **consumer protection** mechanisms in place, these customer-led settlement options offer potential improvement over the current framework. This is because the services that customers most value are directly taken into account, and the framework is likely to be more flexible for the evolution of services and to be nimbler, allowing it to change over time to meet emerging customer needs.

The evolution of service obligations and consumer protections will be a critical part of the pathways to and eventual scenario reached in 2027. In our view the transformation requires networks to have greater flexibility in their service obligations, such as:

- offering flexible connection choices (e.g. limited capacity, options to disconnect at peak times);
- potentially having a different role as provider of last resort (as cost effective off-grid supply becomes more widely available); and
- ensuring that those going 'off-grid' are offered information/ education and, potentially, a way to reconnect.

Figure 1: Framework evolution driven by customers and off-grid options



Reaching the right risk allocation for the future

Under all regulatory frameworks there are aspects of risk allocation which need to be managed. How risks are allocated between customers and energy networks are a critical part of a future regulatory framework.

The significant changes to energy markets means it is timely for the community to consider risk allocation models of the future that will allocate risks between those best able to manage them and deliver efficient future investment decisions while minimising financing costs.

Critically, while different allocations of risk are possible, all involve trade-offs and costs have to be borne somewhere in the system. The appropriate risk allocation will also flow from community expectations of what the 'grid' is, and what it is expected to deliver as a shared national asset.

Options for risk allocation include:

- varying the incentive rates on efficiency sharing schemes;
- introducing more output incentive arrangements (to align with customers' values);
- changing the balance of risks borne by current and future users, for example, by changes to asset depreciation profiles;
- introducing longer-term connection contracts (for covering sunk costs); or
- changing the profile and allocation of risk for new investments.

Scope for change by 2027

Reaching the frameworks towards the top-right of Figure 1 requires substantial change in the sector which may not be reached by 2027. Therefore, an evolved form of incentive-based regulation may still be needed in 2027, but with a greater range of incentives, and embedded tests to provide a smooth process for more services to become competitive (or move to an information disclosure regime) and greater customer involvement in any price/revenue control process.

At present, there is provision for the classification of network-related services to change when they become contestable. However, the regulatory framework in Australia needs a clear and logical system and test to determine and manage this issue. Networks could provide these contestable services subject to specific conditions including a cost-benefit test demonstrating if this is in the interest of consumers. A cost-benefit test could either be included in the regulatory framework, or networks could themselves make proposals on business structures and mechanisms.

We note that the Australian regulatory framework is already evolving to include some of the above mechanisms.

Measures that may help transition to lighter (regulator) touch frameworks, include:

- increasing the incentive on networks to treat alternative (and innovative) solutions equally – we suggest that the total expenditure (totex) is a promising way of achieving this;
- increasing the opportunities for networks to propose outputs/ incentives which align with the services that customers value;
- allowing different network structures to reflect their changing functions and ability to offer services customers value; and
- increasing the role of customers in the regulator driven settlement process and offering ways to reduce regulatory burden where not necessary – i.e., the regulator can 'fast track' business plans that demonstrate a clear regard to the long-term interests of consumers.

Our review of international experience provides examples of successful implementation of some of these ideas.

Transitional arrangements

As competition for core network services develops, one possible transitional approach is to move towards a price-cap regime where the regulatory involvement in setting ongoing prices is more limited and focuses on only using external measures such as productivity measures (including so-called total factor productivity index approaches) to adjust future prices.

The pathway for regulation should accommodate the uncertainty to 2027

Next steps for regulatory development should reflect the range of possible regulatory models that may be appropriate. However, there are a range of steps illustrated in Figure 2 that can be taken that would accommodate all these models, meet best practice regulatory design principles, and at the same time enhance the regulatory process better to meet the needs of customers.

Figure 2: Pathways for regulation

STEPS → **OPTIONS**

1. Test totex incentive approaches – rather than project/ expenditure type incentivisation schemes.
2. Develop competition tests for introduction into the regulatory framework, which assess network operators' scope for competing and allow for competition to develop.
3. Development of guidelines / principles for network proposals for outputs/ incentives, which ensure that the regulator assesses them for positive consumer benefits.
4. Develop a code-of-conduct for industry actors to provide information and education regarding services to customers.
5. Reduce the rules-based approach, by focusing on outputs and incentives, to allow discretion for the regulator and companies to increase innovation.
6. Consider how the regulatory process can place more 'weight' on network operators' engagement with customers to agree outputs and risk allocation.
7. Investigate the establishment of a process where network operators can adopt alternative business structures – including the trade-off between more service offerings and 'policing' of its arrangements – and the need for differentiated rules.
8. Develop guidance on how to deal with underutilisation of assets (stranding), if it arises.
9. Introduction of more granular cost reflective pricing on demand and generation connections.
10. Move to align all DNSPs price controls and separately align all TNSPs.

Focus on outputs and incentives

Enhanced customer engagement

Majority of network services competitive.

Information disclosure

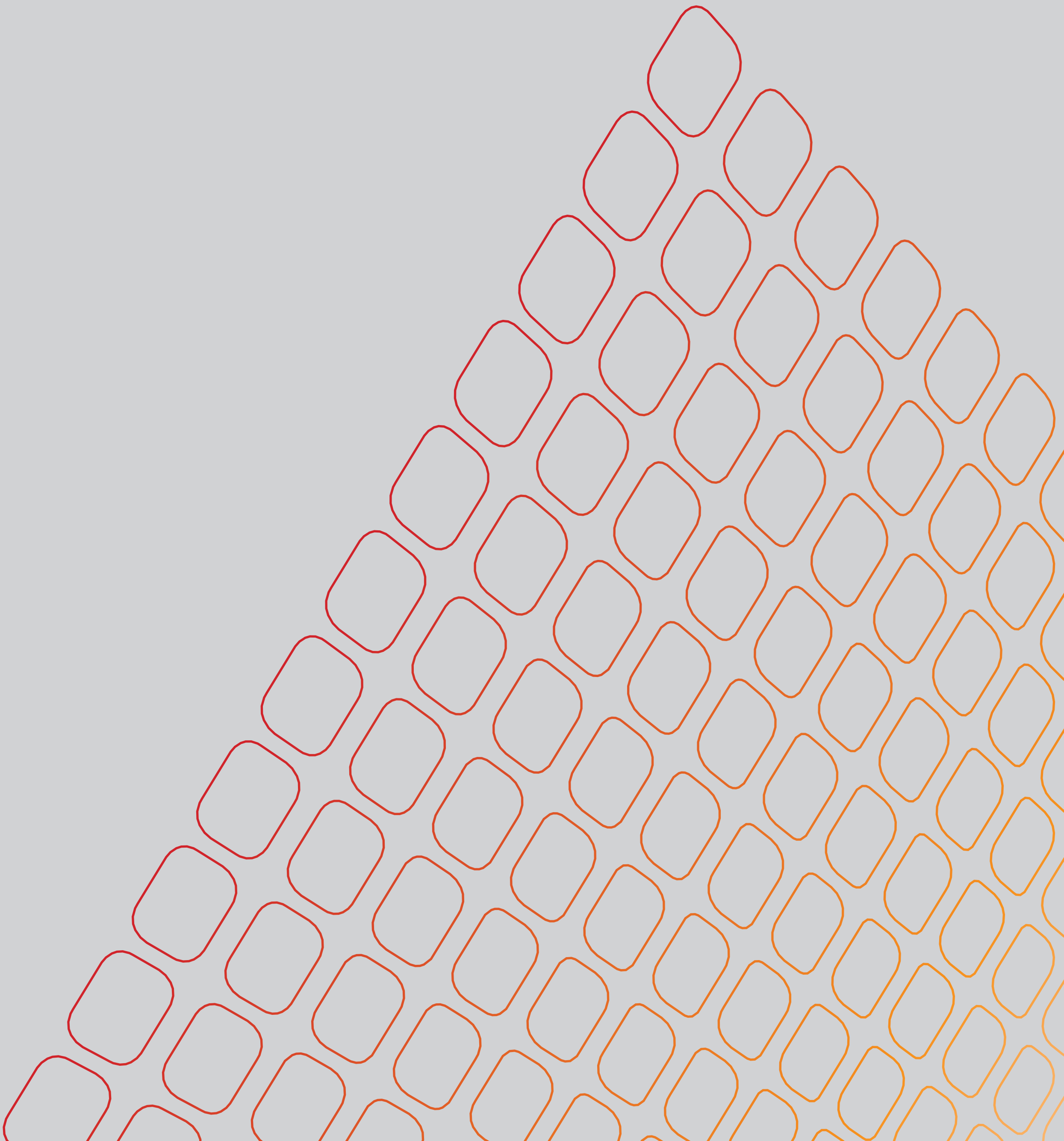
1. Clear guidelines on the information networks are required to disclose.
2. Vertical competition may still be restricted.

Customer driven settlement.

1. Customers and their agents engage directly with the networks
2. Regulator acts as arbitrator and provides objectives/ guidelines for agreement.

Incentive based regulation for a narrower scope of services

1. Regulator still determines bulk of building blocks.
2. Proportionality increased – fast track
3. Competition across a wider range of services.



ELECTRICITY NETWORK TRANSFORMATION ROADMAP

ena energy networks association

CSIRO

FUTURE REGULATORY OPTIONS FOR ELECTRICITY NETWORKS

ENERGY NETWORKS ASSOCIATION (ENA) AND COMMONWEALTH SCIENTIFIC AND INDUSTRIAL RESEARCH ORGANISATION (CSIRO)

3 AUGUST 2016

FINAL REPORT

Prepared by:

Cambridge Economic Policy Associates Pty Ltd

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IMPORTANT NOTICE

EXECUTIVE SUMMARY

Electricity markets, consumer technologies, network business models and energy resources are changing. The ENA and CSIRO are exploring the implications of these changes through the *Electricity Network Transformation Roadmap (the Roadmap)*[1] in order to develop pathways for navigating critical change in Australia's electricity networks during 2017-2027.

ENA and CSIRO identified that "a regulatory regime that is outpaced by technology and market developments cannot protect consumers or deliver a balanced scorecard of societal outcomes."[2] Given the potentially significant transformation of the energy sector, ENA and CSIRO consider that a clear conversation on the purpose and expectation of a regulatory framework is required. ENA and CSIRO asked CEPA to review developments in other jurisdictions, and to consider and provide recommendations on regulatory options and pathways for Australian electricity networks based on a range of future energy market scenarios. As the future is unknown, ENA and CSIRO has asked us to consider regulatory options that are in line with a set of design principles, reproduced in the text box below.[3]

Text box 1: ENA and CSIRO regulatory framework design principles

A. Focused on the long-term interests of customers.
B. Flexible and enabling for emerging technology, technology diffusion, new competition and marketplaces.
C. Able to align network incentives with long-term consumer value.
D. Proportional and bounded
E. Non-discriminatory.
F. Consistent, coherent, and knowable to all participants.
G. Independent and accountable.

Regulatory frameworks comprise many different elements. We have focused on those set out in the boxes below. We note that separate ENA-CSIRO work streams are investigating other framework components including different business models and tariff structures. Given the broad nature of regulatory frameworks we have chosen, with carefully consideration of the terms of reference, to specifically focus on the following aspects:

[1] http://www.ena.asn.au/sites/default/files/roadmap_interim_report_final.pdf
[2] ENA & CSIRO (2015), page 101.
[3] ENA & CSIRO (2015), page 111.

Scope of services

- Regulatory implications from different network operator structures.
- The development of competition across services.

Process

- Who does what?
- How does it get done?
- Service obligations and consumer protections

Remuneration

- Alignment of businesses' incentives with customers' values
- Risk allocation between businesses and customers

Before we set out our analysis on the three areas set out in the boxes above, we provide a summary of key points from a review of regulatory frameworks in a number of different jurisdictions.

The views presented in this paper are those of CEPA alone, however this paper has benefitted from discussions with industry and stakeholders in workshops, as well as input and review by internationally-recognised regulatory and energy market experts, Professors David Newbery and Stephen Littlechild.

Case studies

Many jurisdictions are considering how their regulatory frameworks should evolve to accommodate the transformation occurring in the electricity sector. We have reviewed four regimes where detailed consideration is being given to these issues:

- **Australia**, the current regulatory approach in Australia is evolving to meet the challenges of relatively high levels of distributed energy resources (DER) and changing consumers values. A key part of this evolution is the Australian Energy Market Commission's (AEMC's) 'Power of choice' reforms which aim to give consumers more options in the way they use electricity.
- **California**, where the regulator overseeing investor owned utilities, the California Public Utilities Commission (CPUC) has already taken a number of steps to respond to relatively high levels of DER and it is in the process of continued rule making initiatives.
- **New York**, where the "Reforming the Energy Vision" (NY REV) initiative is an ambitious attempt to reform the way the industry operates in order to integrate DER and incentivise the Utilities to create markets for new services. The Order establishing this change was only announced in May 2016.
- **UK's "RIIO"** ("Revenue = Incentives + Innovation + Outputs") approach developed by Ofgem, the regulator for electricity and gas markets in Great Britain, as an evolution of the previous process used for energy network regulation. The aim of the regulatory changes was to ensure that network companies could deliver the networks required for a low carbon economy with secure energy supplies. Ofgem

completed its review, and established RIIO, in 2011. Since then there has been an evolution of its processes.

We also investigated alternative regimes and innovative approaches being used in other sectors. Some key lessons we have drawn from our review are set out in the box below.

Text box 2: Lessons from the case studies

1. Visions for electricity regulatory frameworks reflect existing structures – vertically separated networks in GB and Australia, and vertically integrated in California and New York, but separate or potentially separate system operators (at transmission level and/ or at the distribution level). Approaches and mechanisms for scope of services, incentives and risk allocation need to be considered in the Australian context of the clear separation of networks from electricity generation and retailing.
2. Regulators are providing, or moving to provide, a 'return' on alternative solutions (predominately operating expenditure [opex]) to poles-and-wires, in order to neutralise networks' incentives across these options. There is a range of project based incentivisation (NY REV and proposed for California) and total expenditure (Ofgem).
3. Most regulators are taking a risk-averse, but flexible approach to allowing networks to offer services that may become contestable. They are allowing DER, particularly storage, to be owned in a limited way, but are encouraging networks to source these services from third parties.
4. The regulators are trying to increase and improve the information provided to consumers, third parties and networks. This includes investigating the provision of information on granular level locational demand, generation and pricing signals.
5. Approaches to risk allocation are similar: the RAB is either legally protected or there are high levels of assurance around recovery of past costs; networks purchasing services from third parties rather than owning the assets themselves is seen as a way of transferring risk. Although Ofgem's approach to third party competition for 'core' network services has been to transfer the risk to customers by providing guaranteed revenue (as long as performance is appropriate).
6. Consumer involvement in the regulatory process is being enhanced (not just in electricity, but all infrastructure regulation). The benefits from customer engagement include more input into the outputs required/ desired, and buy-in from consumers of the regulatory process. In some instances, consumers have taken a role in the decisions making process.[4]
7. The regimes are becoming more complex as the industry transforms. While there is some significant 'refocusing' of regulatory frameworks, some of the added complexity appears to be the result of layering new arrangements on top of the existing frameworks.

One clear lesson from the case studies is that the **structure of charges** is critical in ensuring that customers (and consumers) can make appropriate choices in regards to DER, their electricity use and generation placement. The availability of timely and locational specific pricing is a key part of the network transformation, however consideration of the

[4] We note that Ofgem's review of its price control process concluded that consumers were not willing or able to take a decision making role.

appropriate approach to structure of charges is outside the scope of this report. ENA & KMPG (2016) set out their view of the reforms required by 2025, and this includes the option of introducing localised pricing.

Scope of regulated services of electricity network businesses

The approach to establishing which activities in the Australian electricity industry should be regulated has been strongly influenced by the review of competition by Hilmer et al (1993). This led to division of the industry into contestable segments (at that time primarily generation and supply) and non-contestable segments (primarily the network activities). This is a division which reflects that adopted in many countries worldwide which have sought to introduce competition into the electricity market.

With the change in technology underway three important issues arise that may affect the regulatory options around the scope of regulated services:

- As technology and understanding of energy networks has evolved – for example, the introduction and development of advanced and smart meters, and the changes occurring in storage – some activities previously considered non-contestable may now be contestable (for both transmission and distribution).
- There is potential for network activities across transmission and/ or distribution as a whole to be contestable, or contestable for some customers, as it may be economic for them to have all electricity their electricity supply needs met from off-grid services. There has been much discussion worldwide about the potential for the reduction in costs of new technology, in particular distributed solar PV generation combined with a battery, to make it economic for customers to go off-grid, with forecasts of the date at which might happen in some cases to be in the next decade (RMI 2016, UBS 2014). It is beyond the scope of this report to assess these reports.[5]
- The technological change may lead to changes in the organisation of some non-contestable activities undertaken by networks such as system operation and provision of data. This could include the establishment of system operator(s) and/or market operator(s) at the distribution level. These could be separate or combined with the network asset owner. This may change the range of services that are contestable/ price regulated.

Regulation of services has to balance allowing the natural monopolies efficiently to employ their economies of scale and scope where this ultimately benefits consumers, with policing

[5] The economics of such decisions will depend on a number of factors including: whether the structure of network charges is cost reflective; and the path of electricity prices on the grid, where changes in some of the costs will be correlated with the changes in cost of the new technology, and whether customers with solar and battery wish to retain access to the network in order to sell generation and/or other services.

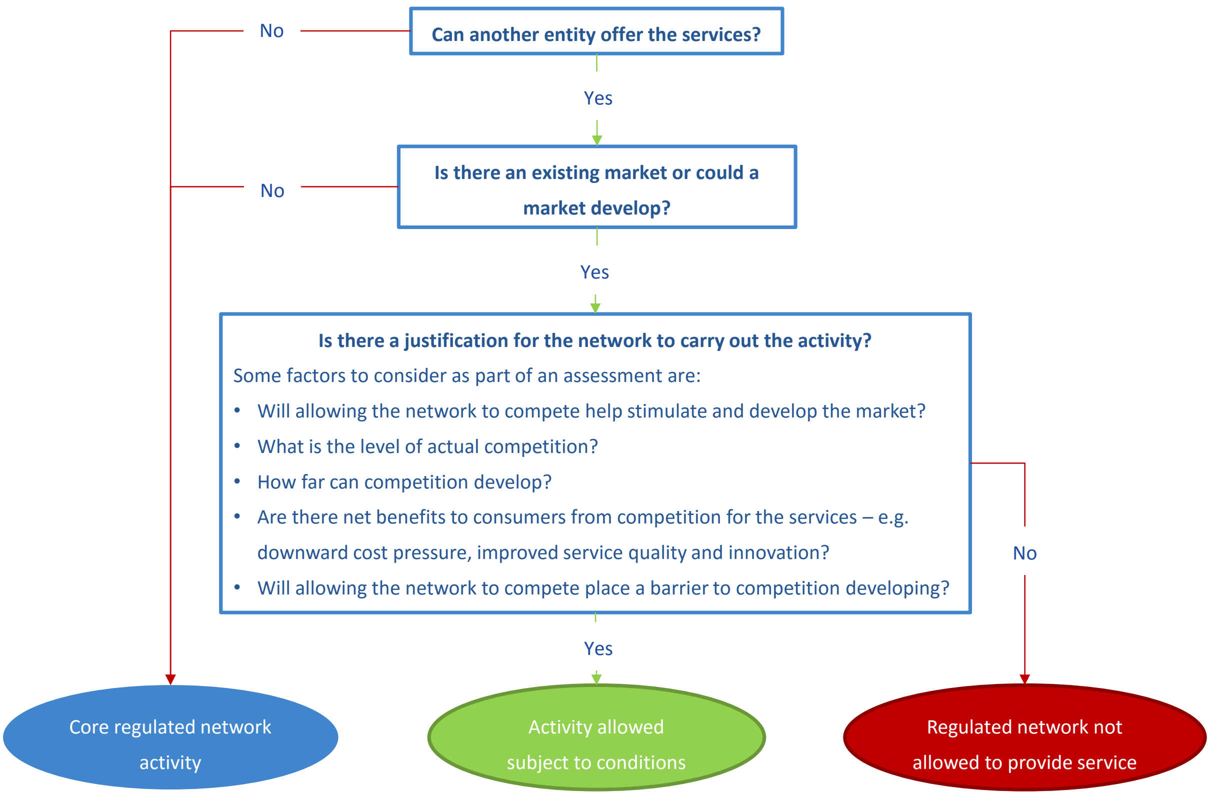
them to ensure that consumers are protected from the business exercising monopoly power (including asymmetry of information) and that the businesses' costs are efficiently incurred.[6]

We note that networks are sometimes encouraged to earn revenue from outside the energy sector, by using existing assets, for example networks can earn revenue from selling space on towers to mobile phone operators. This revenue can be shared in such a way that the networks' electricity customers benefit from offering other services while using regulated assets.

Changing the scope of regulated services

There is provision under the current regulatory framework for the classification of services to change to allow them to be considered contestable and thus removed from the scope of regulation. However, given the speed of transformation in the sector, we consider that the regulatory framework could benefit from a clear and logical process to determine this. On the basis of lessons learned from other jurisdictions and our own analysis, we have developed a set of tests for this, illustrated in Figure 1 below.

Figure 1: Determining regulated activities



Source: Council of European Energy Regulators, CEPA analysis

The last step in Figure 1, the key test is whether having networks perform the activities is in the long-term interests of customers.

[6] See Synergies (2016), for a detailed discussion of the application of the Hilmer principles to the changing energy markets.

Strawman options of ways (not mutually exclusive) to increase the nimbleness of the regulatory framework to allow transition between regulated, new and contestable services are set out in the box below.

Text box 3: Options – Increasing nimbleness of the regulatory framework to services

- Integrate a competition (regulated services) test within the regulatory framework.[7] Individual networks could apply for services to be classified as unregulated. These services would be subject to price-monitoring. The AER/ AEMC would consider applications first, with a 'back-stop' process if the network disagreed with the ruling. Service obligations across networks and competitors should, insofar as possible, be the same. A code of conduct for the services, which apply to all players, can be used to help ensure customer protections and a level playing field.
- Allow networks to make proposals for their own business structures and mechanisms to provide transparency and to demonstrate that it does not create a barrier to competition developing (if that is a positive outcome). This may require a shift to specific rules (or licences) for each network operator, which sets out common, but also individual obligations.

A test to determine whether transmission and distribution services as a whole are contestable (with or without a lighter touch regime)[8] could follow a similar process to that laid out above. Key elements of the test would likely be: (i) the proportion of the market with access to off-grid services; and (ii) the price differential between the two.[9]

Text box 4: Principles for the competition test

It is important to ensure that:

- Competition tests and processes restricting that the way that networks are involved in these markets are appropriate. Consistent with Hilmer, it is appropriate for restrictions on networks' involvement in these activities to be assessed on whether it harms consumers, rather than a default prohibition. This assessment will need to reflect the structure of the business.
- Competition tests are applied in a way that facilitates appropriate investment in services/ technologies in a timely manner.
- Competition tests should be proportionate to the size of the market they are serving.
- Restrictions on activities should take account of the value they can provide to consumers and investors.

[7] We note that the UK Civil Aviation Authority (CAA) has a test embedded in law as to when it is required to regulate (provide an 'economic licence' to) airports. This test is based on market power.

[8] The ability for competition of off-grid electricity services (with comparable reliability) to offer a 'soft' price-cap may assist in a move to an information disclosure/ pricing monitoring regime.

[9] The method for separating, or comparing combined, energy and network prices would need to be developed as well as an approach for reflecting differential locational and time of day pricing.

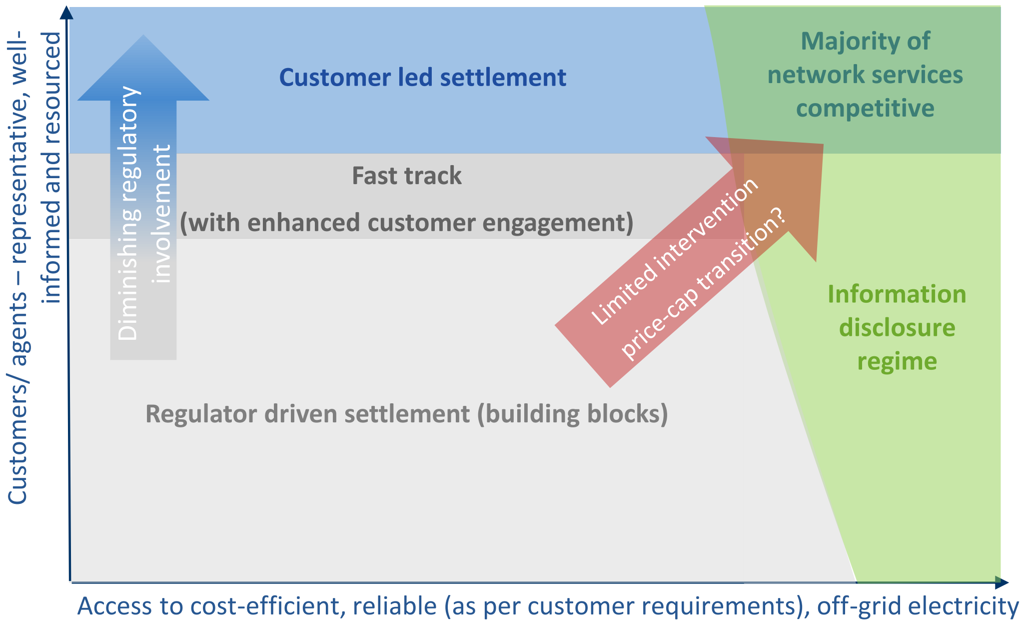
Regulatory process

Developments on three main dimensions will affect the feasible and appropriate future regulatory frameworks:

- decisions around business model (discussed above);
- whether off-grid services become a cost-effective (and appropriately reliable) way of accessing the grid (i.e., a substitute to remaining connected to the network is available); and
- whether consumers and/ or their representatives are willing and well enough informed credibly to negotiate with networks, and the regulator is willing to reduce its own role in this process.

How far along these dimensions the world is in 2027 will have a direct bearing on the type of regulatory process options that can be considered. Government policy will also have an important role in determining this evolution. In Figure 2 below we show the interaction between the latter two points above and some different options for process regimes.

Figure 2: Process driven by customers and off-grid option



Source: CEPA

To further illustrate the above, two examples along the horizontal and vertical axis are:

- If a significant proportion of customers have access to a reasonably priced off-grid substitute, with reasonably supply security, then it may be possible to move to an information type disclosure regime.
- If customers/ consumers (and/ or their representatives) are sufficiently engaged in determining their electricity service, have sufficient information, resources and education, and the range of consumers are well represented then the regulator may

be able to reduce its involvement by asking the customers/ consumers directly to negotiate with the networks for their services.

Our high level descriptions of the regulatory processes labelled in Figure 2 are set out in the text box below.

Text box 5: Options - Regulatory framework process

- **Regulator driven settlement.** The process may be largely unchanged from the current framework with the regulator/ rule maker still making the majority of decisions around services and prices, however enhancements such as new incentive arrangements, streamlined rule making and appeals process (discuss below) would be in place.
- **Fast track.** A process still relying on building blocks to determine revenues, however the ability for the regulator to 'fast track' a network operators proposals where it considers that the overall package is acceptable. While similar to Ofgem's fast track process we consider enhancements over this are required, this includes more robust consultation to avoid 'errors' and a greater role for network operator's customer engagement in the decision making process.[10]
- **Price-cap (with limited intervention).** A CPI-X price-cap approach with the X-factor limited to being set using reference to total factor productivity (and potentially input prices) only. We see this as a transitional measure as we get closer to an information disclosure regime. Because of the limited flexibility in this type of approach to dealing with changing service levels of core network services, difficulties carving out other services for contestability, we do not see this type of regime as a long-term solution.
- **Customer led settlement.** The customers/ agents negotiate directly with network operators to agree services and prices.[11] This implicitly covers risk allocation, service obligations and consumer protections.[12] Only in the event that the parties disagreed would the regulator be involved, and resort to choosing either the customers proposal or the network operator's proposal, or making a determination based on a building blocks approach. It is likely that the regulator would need to provide some guidance on the agreement that needs to be reached and the range of inputs and outputs that need to be considered. The scope of services would still be driven via some form of testing.
- **Information disclosure.** The network operators are required to disclose a range of information that allows the regulator, customers and competitors to monitor its performance and prices.
- **Majority of network services competitive.** The network operator will be unregulated insofar as its offered services are concerned. The structure of the sector may still be regulated (e.g., vertical separation), and price monitoring may be in place, but otherwise the services will be subject to standard competition laws.

It is difficult to provide a comparative assessment across the options as they depend on different states of the world. However, our belief is that the options that open up as we move along either axis are improvements when we assess them against the ENA & CSIRO

[10] For example, if the network operator outputs (and financial incentives) can be clearly linked to customer engagement, and unless the regulator can show an error in the engagement process then these outputs should be accepted.

[11] This approach may be more readily achievable for transmission networks as there are fewer direct customers who may be better informed – i.e., generators, retailers, third party users.

[12] Some consumer protections would still be provided via licences or competition law, particularly around safety but also vulnerable customers.

proposed design principles. An important consideration for greater consumer involvement in decision making, is their ability to take account of the long-term interests of consumers (future use of the network) given the nature of the investments decisions which will underlie the pricing and service levels.

While some of the above options are only opened up through movements along the axis, we do consider that there are options for specific elements of the broader regulatory framework to provide pathways and/ or enhancement the regulatory framework

Service obligations and consumer protection

The evolution of service obligations and consumer protections will be a critical part of the pathways to and eventual scenario reached in 2027. For the scope of this report we have focused on service obligations and consumer protections are: connections, reliability, those going off-grid (and reconnecting), and vulnerable customers. In our view, the transformation in the sector means that customers should be able to request different level of services and accompanying prices (to the extent practicable), network operators need flexibility in offering a range of service levels, and customers will still need to be protected. As we have already noted, considering the structure of tariffs is beyond the scope of this report, but this directly affects what protections might be required.

Drawing on our analysis of the regimes, and COAG's consultation on new products and services,[13] in the box below we set out options in terms of connection obligations and protections, including reconnecting customers who chose to go off-grid.

Text box 6: Options – Service obligations and consumer protections – connections and off-grid

- **Flexible connections.** The customer could request, and the networks could offer, flexible connections. For example, the customer may agree to being disconnected (or having generation feed-in limited) for a lower price/ or different benefits.
- **The network could be obliged to maintain spare capacity on the network for a set period of time for the customer to 'test out' an alternative 'off-grid' option**. After this time if the customer needed to reconnect and no capacity were available then it would face cost reflective connection charges.
- **The network could be able to use the spare capacity as soon as the customer exited the network**, and it would not be required to provide any preferential rights for reconnection. It may be able to offer (at a price) the customer an 'option' to reconnect while the customer tried out the alternative service.
- **The retention of the obligation to offer a reasonable quote to connect, however no obligation on networks if quote rejected.**

Trade-offs between flexibility in service obligations and consumer protections can be mitigated through the use of code of conducts and/ or dispute resolution. Non-network services providers should face similar obligations.

[13] COAG (2015b).

Options that we think networks can adopt to assist vulnerable customers include those set out in the box below.[14]

Text box 7: Options – Vulnerable customers

- **Information sharing and education.** To prevent vulnerable customers being taken advantage off, clear information, which provides certainty, should be provided on the costs/ risks associated with the different options they are faced with.
- **Social tariff.** Cross-subsidy from other customers. This could be network operator driven through discussion with its broad customer based around the willingness of customer to fund a social tariff.
- **Government funding.** Specific government funding for vulnerable customers. This could also mean, with appropriate privacy protections and permissions, keeping the networks keeping track of vulnerable customers to ensure that they are supported.

The above options are not mutually exclusive. Information sharing and education is not costless, and there may privacy concerns need to be alleviated, however this option is likely to provide net benefits to vulnerable customers. Social tariffs and government funding are similar approaches, but the funding is sourced differently.

Remuneration – incentives and risk allocation

We envisage that the incentive base regulation (IBR) building blocks approach to setting services levels and remuneration will continue to be used as customers' and/ or their agent's ability and willingness to directly negotiate with network operators (and the regulatory entities are satisfied with rolling back their involvement) and/ or effective competition for network services develops. Under the IBR customers could play a greater role in the setting outputs and incentive properties. Rather than the regulator prescribing what outputs/ incentives should be in place, a framework of principles should be drawn up that output/ incentives proposals should meet. This would include ensuring that the mechanisms have a clear purpose and linked to consumers' values.[15] **Incentivisation of incorporation of new technology, services and innovation**

We consider that one area where incentive arrangements can be very beneficial is to neutralise incentives on the networks across expenditure solutions and/ or innovative solutions. We set out some options for achieving this in the text box below.

Text box 9: Options – Incentivisation of non-traditional solutions

- **Project specific allowed returns.** Companies could propose specific projects, which are
- **Allowed margin on opex solutions/ services.** Companies can earn a margin on solutions/

[14] These options draw from HoustonKemp (2015).

[15] With separately regulated entities such as a network asset owner, system operator, market operator, it is likely to be harder to provide effective incentive regulation, compared an integrated entity, as some entities will be 'asset light' which makes it more difficult to link the actions of the entity with the value that customers place on the actions.

typically opex driven, that defer or avoid less cost-effective long-term capital expenditure (capex) solutions.

- **Total expenditure (totex).** Under a building blocks approach both opex and capex are treated the same, and combined for output assessment purposes, with a pre-determined capitalisation rate. This approach helps to equalise incentives, as there is no differential treatment between opex and capex and outperformance is treated the same regardless of expenditure type. If this is coupled with strong incentives, then it can help encourage innovative solutions as well as existing alternative non-traditional capex ones.

services which defer or avoid capex and/or value-added services they deliver (for example, data access, market facilitation or operations). Depending on the structure of the industry this may be difficult to apply, as there would need to be clear cost reporting guidelines.

- **Innovation funds or competitions.** Specific funds (use-it-or-lose-it) or competitions that encourage networks to apply to for research and development projects which they can demonstrate have the potential to improve services/ bring about cost efficiencies. The funds/ competition can be partially funded by network operators and consumers. This option has been applied in GB and Australia.

We consider that Ofgem's totex approach provides significantly better incentive properties than individual project incentive schemes. The benefits are not simply limited to the incorporation of new technologies, as it reduces the need to police cost allocation and capitalisation policies. This approach is not without its own problems[16] and requires clear outputs driving the allowance, such as measures of system health and performance, and customers' services and quality of the service. This approach will also have a significant impact on the current electricity rules and the approach to benchmarking.

Risk allocation

A balance between allocating risks to those able to manage them and minimising the financing cost of investment is required. Aside from the risk allocation of future expenditure – where options include varying incentive rates and uncertainty mechanisms – consideration around the balance of risk transfer around the existing sunk 'common' network is required. In Australia the regulatory regime provides commitments to a return on and recovery of the RAB, and similar commitments are in place in other jurisdictions. There is a strong view that this approach has led to a stable investment platform and in turn a low cost of capital. The costs of these sunk investments need to be covered somewhere in system. The current risk allocation is that existing users of the grid cover these sunk costs. Alternative approaches to sunk costs, either realigning costs with utilisation or if full cost recovery via the current approach is threatened, are set out below.[17]

Text box 10: Options – Risk allocation

- **Flexible depreciation profile.** For example, using accelerated or front-loaded depreciation profiles to better approximate

- **Longer-term agreements with customers**. I.e., long-term take-or-pay agreements to ensure that costs can be recovered from

[16] As Ofgem has discovered in its attempts to close out DPCR5, where some networks significantly underspent against their capex allowance and thus triggered a reopener.

[17] A range of these options have been previously discussed in ENA (2014) and ENA (2015).

the usage of the assets. (This would also affect future investment.)

- **Pricing changes**. This could be done as a price reduction for those customers who have a realistic option of leaving the grid. This requires that costs can be recovered for other customers. Alternative specific charges could be applied for those who 'exit' the grid to reflect the expenditure required to provide the customer with capacity.
- **Increasing third-party ownership of assets**, with networks, system operators or customers purchasing services from the third parties.

those customers who impose costs on the system.

- **Asset value write-down.** Under this approach there is a question of who would bear the cost of an asset write-down. If the regulated companies are exposed to this risk then they would require an increase in their allowed cost of capital commensurate with the increased risk they would bear.

Changing the depreciation profile to reflect utilisation is an approach which has already been adopted by Ofgem in its reformed approach to depreciation (see CEPA et al (2010)), and is within the current scope of the NER. It also combines well with a totex approach.

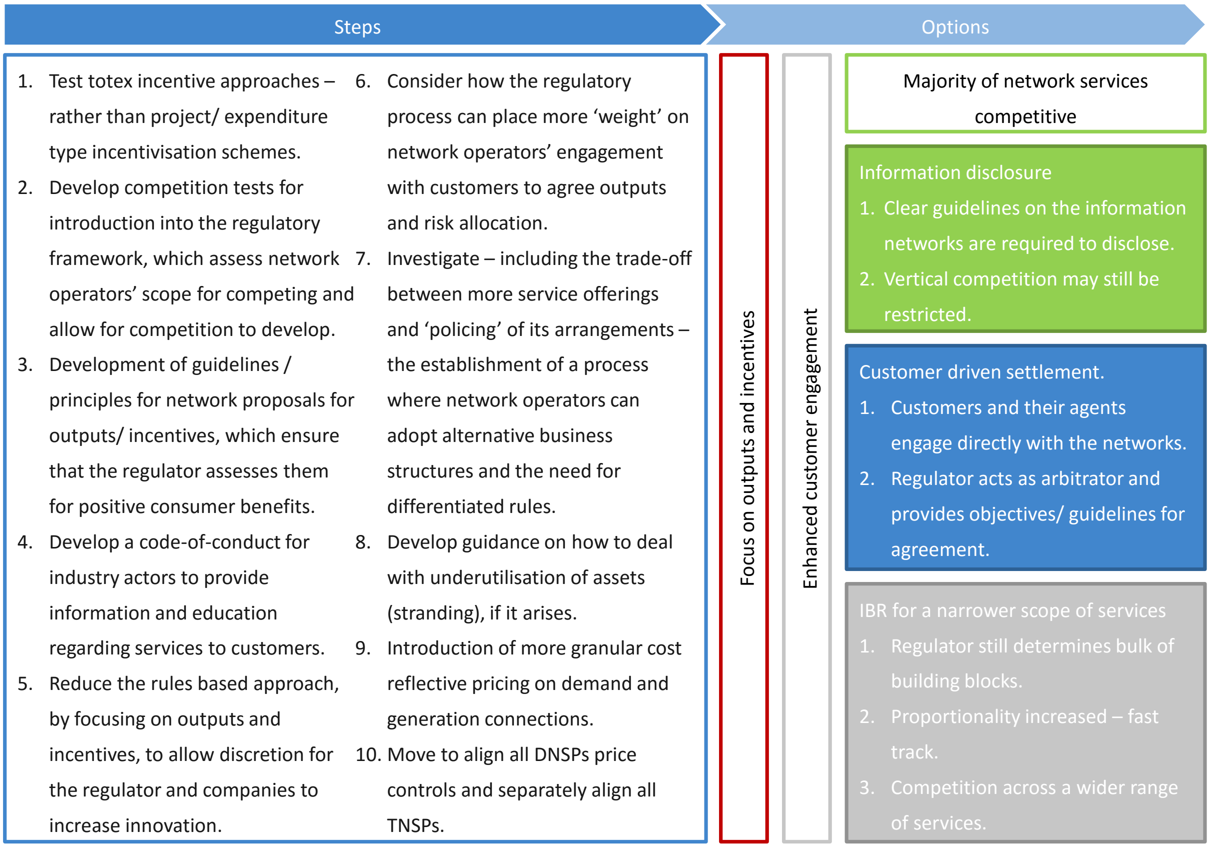
Pathways

In the sections above, we have identified different regulatory frameworks that may be appropriate for electricity networks in 2027. The choice of which type of model will be available and most appropriate is contingent on three main factors:

- The extent to which agents and representatives of all types of customer participate effectively in the regulatory process.
- Whether the cost of off-grid electricity supply is low enough and sufficiently reliable for enough customers for electricity network services to be considered competitive.
- The structure of the market for network services, and in particular which activities DNSPs perform.

This means that the pathway to 2027 needs to comprise a set of steps that would achieve the objectives of facilitating technical change, but at the same time allow evolution towards any of the above options depending on the circumstances. We have set out our view of key steps in the figure below.

Figure 3: Pathways



Source: CEPA

Specific examples of what might need to be done as part of the steps laid out in Figure 3 are set out in Table 1 below.

Table 1: Supporting activities for pathway steps

Steps	Supporting activities
Totex	• Assess the rules which would need to change: depreciation, RAB roll-forward, opex, capex, capitalisation rules. • Introduce rules that allow for testing of totex without requiring initial wholesale changing of the framework (a 'sand-box approach'). • Test totex use for a set of business as part of a single price control cycle.
Competition tests	• Establish flexible criteria for testing scope of regulated services. • Allow networks to propose which services they can offer without price regulation.
Guidelines for outputs and incentives	• Identify the scope for allowing new/ changed outputs and incentives under the rules. • Set a commitment that if networks demonstrate that outputs and incentives deliver net consumer benefits then it should be included in the price control.
Code of conduct	• Carry out consultation across stakeholders as to what clear and relevant information is required for different consumers – location based, need

Steps	Supporting activities
	based. • Determine obligations on what services can be offered to different consumers. • Establish an 'explicit' consent mechanism that consumers must give that demonstrates understanding of the services provided.
Decrease in the rules	• Establish a process to trial a simplification of rules or ability of networks/ or introduce lighter touch regulatory process AER to request more discretion.
Place more weight on consumers' input	• Explore the potential to add a dedicated 'fast track' regulatory process into the Law and Rules as an alternative to the full existing determination process. • Start with small decisions and, if successful, increase consumers' role. Regulator provides commitment that decisions will be taken account of. • Could form part of the fast track process, with consumers being required to sign-off a range of outputs.
Forward guidance on risk allocation	• This would require the development of a policy paper to identify potential approaches and indicators of the need for any further action.
Granular cost reflective pricing	• Accelerate the current pricing reform processes being undertaken.
Alignment of price controls	• AEMC to undertake a CBA of aligning, including transitional costs and resourcing requirements. • Identification of any rule change requirements. • Test the alignment process across one set of networks.

Glossary

Term	Definition
AER	Australian Energy Regulator.
AEMC	Australian Energy Markets Commission.
AEMO	Australian Energy Markets Operator.
BAU	Business as usual.
CAA	Civil Aviation Authority.
CAISO	California Independent System Operator.
CCP	Consumer Challenge Panel.
CPUC	California Public Utilities Commission.
DER	Distributed Energy Resources. Includes distributed generation, storage, electric vehicles and demand response. Our definition means that DER can occur on the transmission networks as well as the distribution networks.
DNO/ DNSPs	Distribution network operator/ Distribution network system provider.
DSO	Distribution system operator. Could be DNSP + SO, or separate entity.
EIM	Earnings impact mechanism.
ESCOs	An Energy Service Company is a commercial structure created to deliver a decentralised energy service to end-users, developers or the local community.
FERC	Federal Energy Regulatory Commission, the national energy regulatory in the USA.
IBR	Incentive based regulation.
ISO	Independent System Operator.
Off-grid	Without a connection at any voltage level to the national grid. This covers premises that have never had a connection (i.e., new builds) and those premises/ customers that have previously had a connection to the grid (ad have no disconnected).
Ofgem	The Great Britain 'Office of Gas and Electricity Markets'.
Ofwat	England and Wales water regulator.
NAO	Network asset operator.
NECF	National Energy Customer Framework. The National Energy Retail Law (NERL) and Rules (NERR) form the National Energy Customer Framework.
NEM	National Electricity Market. The NEM operates in Queensland, New South Wales, the Australian Capital Territory, Victoria, Tasmania and South Australia.
NEO	National Electricity Objective.
MO	Market operator.
NY REV	New York 'Reforming the Energy Vision'. The NY Public Services

Term	Definition
	Commission's electricity networks regulatory framework (adopted in May 2016).
ENTR	Electricity network transformation roadmap. ENA and CSIRO's road map as set out in the December 2015 report.
RAB	Regulatory asset base. The value networks earn a return of and on.
RIIO	Revenue = Incentive + Innovation + Outputs. Ofgem's price control framework.
SO	System operator.
Total expenditure (totex)	Operating expenditure (opex) and capital expenditure (capex) combined.
TPP	Transaction Platform Provider.
WICS	Water Industry Commission for Scotland.

1. INTRODUCTION

Electricity markets, consumer technologies, network business models and energy resources are changing. The ENA and CSIRO are considering whether there are alternative ways of regulating electricity networks to allow Australia better to meet these changes. CEPA has been engaged by the ENA and CSIRO to consider and provide recommendations on future regulatory options and pathways for Australian electricity networks. This project is one of a number of work streams that ENA and CSIRO are running as part of their Electricity Network Transformation Roadmap Stage 2 Work Package.

The ENA and CSIRO aim for this part of the Work Package to explore at a high level the appropriate role and nature of broad economic regulatory frameworks that would both:

- promote the **long-term interests of consumers** as a fundamental precondition; and
- protect the **legitimate commercial interests of network businesses** through the anticipated technological, competitive and commercial transformations ahead.

The ENA and CSIRO *Electricity Network Transformation Roadmap Interim Report* (ENA & CSIRO 2015)[18] noted that "a regulatory regime that is outpaced by technology and market developments cannot protect consumers or deliver a balanced scorecard of societal outcomes."[19] We have been asked to consider the regulatory framework for 2027 rather than today.

The views presented in this paper are those of CEPA alone, however this paper benefitted from discussions with industry and stakeholders in workshops, as well as input and review by internationally-recognised regulatory and energy market experts, Professors David Newbery and Stephen Littlechild.

1.1. Context of this report

Current regulatory framework

In the Interim Report, ENA and CSIRO set out that the current regulatory regime for electricity networks is a product of successive governments' public policy objectives that include: [20]

- Having a safe and reliable universal service.
- Protecting consumers from monopoly power.
- Minimising the cost of delivering energy to consumers.
- Promoting innovation and competition.

[18] http://www.ena.asn.au/sites/default/files/roadmap_interim_report_final.pdf
[19] ENA & CSIRO (2015), page 101.
[20] ENA & CSIRO (2015), pages 103-105.

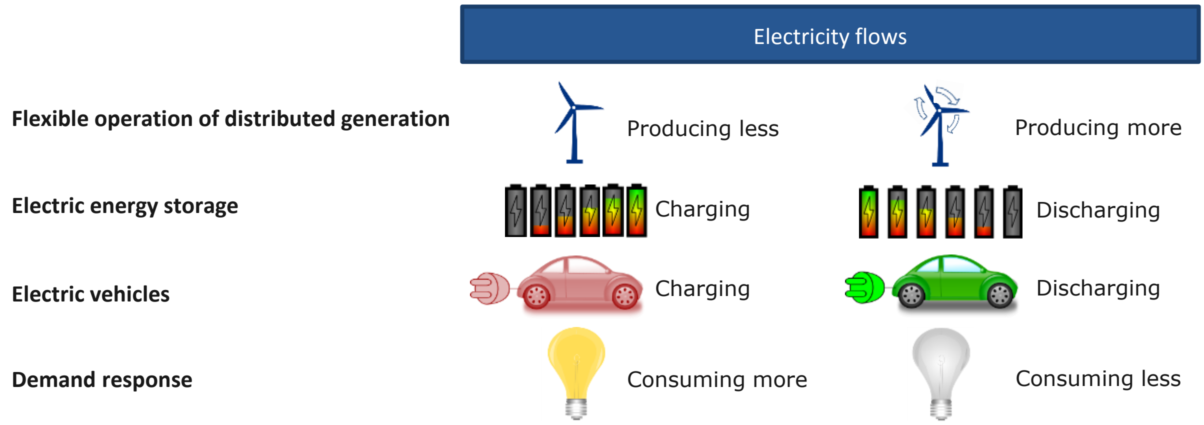
What is changing?

The disruption from new technologies (e.g., bi-directional flow requirements, off-grid options) and increasing detail and availability of data on electricity usage means that a future regulatory framework needs to be considered with regard to the changing nature of the services offered (and required to be offered) by the networks. In particular, it is considered that DER may allow networks cost effectively to defer or avoid more traditional 'poles and wires' capital expenditure (capex) and provide a greater range of ancillary services at different voltage levels of the grid. In addition, innovation means that the prospect of customers adopting cost-competitive 'off-grid' solutions (rather than for environmental sustainability or energy independence) is more probable, particularly in those areas that are high cost to serve.

The key difference between grid and off-grid services will be the reliability of supply, at least in the short to medium term, and the access to services and markets provided by the grid connection. All four future scenarios set out in ENA & CSIRO (2015) indicate that the grid will still have a role, with forecast operating expenditure (opex) and capital expenditure (capex) on the grid (distribution and transmission) between \$280bn and \$340bn by 2050.[21]

The changes mean that a much more active role on the part of networks or system operators will almost certainly be required in future to balance the system and source ancillary services. Figure 1.1 highlights the operational requirements and bi-directional flows that are likely to be placed on networks in the future.

Figure 1.1: Bi-directional flows created by distributed energy resources (DER)



Source: THINK (2013), CEPA

Some DER might be within the networks' control via contracts with DER providers, customers, retailers, or its own ownership, however some will be outside its control e.g. DER aggregators acting in the wholesale market, consumers managing their own supplies. Of course some DER can work in combination on networks, i.e., storage of electricity generated from wind/ PV.

[21] ENA & CSIRO (2015), page 9.

Outside the networks, there are new products and services being offered by retailers and new energy services companies (ESCOs) – such as real-time management of customers' electricity flows. These products and services are driven by the new technologies and increasing amounts of accurate and real-time data available to consumers and suppliers.

To sum up, the changes occurring in the electricity sector, which need to be considered in a regulatory framework for 2027, are:

- Increasing bi-directional flows on the network, requiring more active system operation.
- Increasing probability of cost-effective off-grid electricity supply.
- Opportunities for networks to defer or avoid more costly 'traditional' capex by using DER services.
- Increasing amounts of accurate and timely data for participants in the electricity sector to access.
- New consumer valued services and products being developed/ offered.
- DER may allow networks to lower their costs and offer benefits to customers who remain on the grid (e.g., a large market for them to sell power/ services into). However, competition from off-grid electricity supply could mean that networks will struggle to fully recover their costs. If the networks were to charge higher costs to remaining customers then that might also encourage them to disconnect.[22]

Risks from slow moving regulation

In the Interim Roadmap, ENA and CSIRO posited that that consumers would face the following risks if regulation were to be outpaced by technological change:

- "Regulatory barriers to parties participating in rapidly emerging new energy service markets may constrain competition, the pace and scale of technology deployment, service innovation and cost efficient service delivery.
- If a regulatory regime fails to provide network service providers with a reasonable expectation of recovering their efficient costs, then inefficient underinvestment may occur. As a result, the community may lose service quality and reliability that it values.
- A regulatory regime that promotes inefficient bypass of the network may result in significant inequities if some communities or individuals have the financial capacity to disconnect, and subsequently a smaller number of network users have to bear common network costs.

[22] This has led to fears of the so called utility 'death spiral'.

- If a regulatory regime fails to balance (a) providing consistent and appropriate levels of consumer protection, with (b) providing for customers to make their own choices around price-service options, then it will undermine competition, innovation and service delivery options for consumers.
- When promoting the efficient commercial use of customer data to deliver value to those customers, a regulatory regime must provide the right customer protections. If it does not, then the outcomes may be higher costs, unrealised consumer gains, and a loss of synergies along the energy delivery chain."[23]

In light of the risks and technological changes, in ENA and CSIROs laid out specific priority issues that need to be examined:

- the nature of the universal service obligation, and how this obligation is met on a sustainable community-wide basis in the face of new technologies, network configurations, and grid substitutes;
- how to ensure economic regulation of monopoly power is responsive to the erosion or disappearance of such power, and serves to promote efficient market participation and service delivery in new markets for the benefit of consumers;
- how to protect consumer interests while minimising the cost to finance significant network infrastructure investments in the grid, given the grid's continuing role in delivering essential services, and its emerging role as an active platform for market participation and exchange;
- how to best ensure innovation and efficient integration of new technology throughout the electricity delivery chain; and
- how adequately to protect consumers through the energy market transformation.[24]

As noted in the above points, the increasingly active role of networks in balancing the system, regulating voltage, and dealing with load switching will likely require market facilitation (or platforms) to ensure that information on required services and offerings, and price signals lead to the efficient deployment of products and services.

1.2. ENA & CSIRO regulatory framework design principles

The National Electricity Objective (NEO) is to "promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to— (a) price, quality, safety, reliability and security of supply of electricity; and (b) the reliability, safety and security of the national electricity system"[25].

[23] ENA & CSIRO (2015), page 106.
[24] ENA & CSIRO (2015), page 112.
[25] National Electricity Law, section 7.

This is reflected in the ENA's and CSIRO's aim for this Work Package which is to explore regulatory frameworks that both promote the long-term interests of consumers and protect the legitimate commercial interests of network businesses. The Electricity Network Transformation Roadmap Interim Report (ENA & CSIRO 2015) proposed a set of principles with which to assess future regulatory frameworks. These elaborated on the broad NEO aims and incorporated elements of Better Practice Regulation principles:

A. **Focused on the long term interests of customers** – Regulatory decisions on remaining regulated services should account for the perspectives and priorities of both current and future customers. They should focus on providing a stable framework for investments that deliver the connectivity and access to bi-directional electricity services that customers value.

B. **Flexible and enabling for emerging technology, technology diffusion, new competition and marketplaces** – Efficient competition should be allowed to emerge, with flexible and dedicated processes to recalibrate or remove regulation where appropriate. Rules should be nimble and facilitative, enabling prompt market action.

C. **Able to align network incentives with long term customer value** – The regulatory framework should provide clear revenue and profit opportunities for delivering services that create value for customers and market actors.

D. **Proportional and bounded** – In an environment of increasing contestability and competition, regulatory intervention needs to be well justified and proportional to the risks of a clearly identified problem. Further, its application should account for the costs and benefits of intervention. Robust independent processes are needed for regularly evaluating the boundaries of competition, considering the full range of costs and benefits.

E. **Non-discriminatory** – Network service providers should be free to deliver valued, efficient energy service solutions to each customer. The framework should not be reactive or 'permission' based. It should provide a competitively neutral platform that does not pre-define a single 'ideal' network business model.

F. **Consistent, coherent and knowable for all participants** – Regulatory rules should continue to be consistent across Australia, and they should be predictable, simple, precise and knowable in advance, to facilitate least cost market participation and efficient investment. Regulatory decisions that share risks across networks, debt and equity providers, and customers need to be conscious, consistent with the risk compensation provided in the framework, and predictably implemented. Similarly, cost recovery should align with those customers that initiate the system cost.

G. **Independent and accountable** – Regulatory rules should be applied and enforced independently, commonly, transparently and accountably, including the rights to reasons and appeal for consumers and businesses whose interests are materially affected. These general principles have been converted into specific criteria against which future options are assessed. This allows a better focus on the areas of difference between the options considered and the emerging problems that changes to the regulatory frameworks are intended to solve.

1.3. Our approach

Regulatory frameworks for natural monopolies are complex and comprise a range of different components. In comparing and assessing regulatory frameworks for this work, we have found it helpful to consider these different components in three broad categories:

- **Scope and organisation of regulated services** – who does what, and the activities in the industry that are regulated. The allocation of activities by company is in part a business decision by those companies, but regulators also impose restrictions on which activities can be performed by the same company. For electricity, this includes defining which services are contestable and for which competition will be allowed to develop, and where it is efficient to restrict competition.
- **Regulatory process** – how it is decided what is done. This set of components is the approach regulators have to making decisions (e.g. the extent to which customers are involved), and the way that outputs and services are determined.
- **Remuneration** – There are a range of methods for determining overall allowed revenues for regulated companies including cost of service and building blocks. The choice of approach will provide a set of **incentives** and **risk allocation** on the regulated company. The structure of the price/revenue control will determine the allocation of risk between regulated companies and consumers. An additional consideration is the **structure of charges** (by geographical location, time of day, customer type etc.) which is becoming increasingly important as distribution market participants become more active.

These components interact, and so to assess whether a framework meets its objectives, it is necessary to consider the overall impact of different elements working together, nevertheless this is a useful way to categorise the core components of a regulatory framework. This is not a complete list, and we note that other components are included for consideration by ENA and CSIRO ENTR. For instance, while we cover the implications of different business models for a regulatory framework, there is a separate ENTR work stream considering different business models and it is outside the scope of this report to provide a recommendation. Likewise, structure of charges is being dealt with through a separate ENTR work stream.

Our approach to meeting our main objective and the other regulatory framework principles set out in ENA & CSIRO (2015):

- Review the range of regulatory frameworks – focusing on the scope of services, process and revenue setting elements – for electricity networks and other sectors which exhibit innovative or alternative forms of regulation.
- Carry out in-depth reviews of the Australian electricity networks regulatory framework, New York 'Reforming the Energy Vision' (NY REV), the California Public Utilities Commission (CPUC) and Ofgem's Revenue = Incentives + Innovation + Outputs (RIIO) frameworks.
- Consider the above material in the context of the Australian electricity sector and where it might be in 2027.
- Consider whether there are other options either original or previously proposed by regulators/ academics/ consultants, but not implemented anywhere.
- Develop a range of options and consider these against the principles.

1.4. Structure of this report

The rest of this report is structures as follows:

- Section 2 provides a summary of approaches to electricity regulation in other jurisdictions.
- Section 3 sets out our discussion around the scope of services and our development of the options.
- Section 4 sets out our discussion around the regulatory process and our development of the options.
- Section 5 sets out our discussion around the remuneration and our development of the options.
- Section 6 provides our view on the pathways to the regulatory options and our overall conclusions.

Additional information is provided in the Annexes.

2. CASE STUDIES

The transformation of the electricity sector, and in particular a large increase in DER, is not restricted to Australia. Accordingly, many jurisdictions are considering how their regulatory frameworks should evolve to accommodate this. We have reviewed four regimes that have been, and still are, actively dealing with aspects of the transformation:

- **Australia**, the current regulatory approach in Australia is evolving to meet the challenges of relatively high levels of distributed energy resources (DER) and changing customer values. A key part of this evolution is the Australian Energy Market Commission's (AEMC's) 'Power of choice' reforms – which are designed to give consumers more options in the way they use electricity.
- **California**, where the regulator overseeing investor owned utilities, the California Public Utilities Commission (CPUC) has already taken a number of steps to respond to relatively high levels of DER and it is in the process of continued rule making initiatives.
- **New York**, where the "Reforming the Energy Vision" (NY REV) initiative is an ambitious attempt to reform the way the industry operates in order to integrate DER and incentivise the Utilities to create markets for new services. The Order establishing this change was only announced in May 2016.
- **UK's "RIIO"** ("Revenue = Incentives + Innovation + Outputs") approach developed by Ofgem, the regulator for electricity and gas market in Great Britain, as an evolution of the previous process used for energy network regulation. The regulatory changes were designed to ensure that network companies could deliver the networks required for a low carbon economy with secure energy supplies. Ofgem completed its review, and established RIIO, in 2011. Since then there has been substantial evolution of processes.

We provide a detailed summary of relevant aspects of the regimes in ANNEX A. Below we draw out conclusions from them that are relevant for our work here. Specifically, we have focused on the following aspects:

- **Incentivisation of DER**. How do the regulatory frameworks encourage networks to seek cost effective alternatives to poles-and-wires?
- **Better aligning network and customer incentives**. How does the regulatory framework take customers' preferences into account when determining the outputs networks are obliged to deliver?
- **Risk allocation**. How are risks allocated between networks and customers?
- **Competition for network services**. How is competition allowed for?
- **Innovation**. How is innovation encouraged?

We note that all the regimes follow a broadly similar approach for the regulation of their core network activities. Each has a 'base' framework, which follows a rate of return or building blocks approach. Additional elements are then added to this underlying framework to accommodate and/or incentivise DER or other changes to the industry.

2.1. Australian framework

Since the early 1990s, Australia's electricity sector has undergone substantial reform, moving from vertically-integrated state-owned utilities to the current separation of contestable and regulated activities within the National Electricity Market (NEM). While in recent years a number of reviews and reforms of network regulation have taken place in response to concerns around increasing network charges, debate continues as to the appropriate regulatory framework.

The Better Regulation reforms resulted in a number of changes impacting network regulation, including: increased stakeholder involvement in regulatory reviews (e.g., establishment of Consumer Challenge Panel, publication of consumer engagement best practice guidelines); stronger AER powers to assess and amend revenue proposals (e.g., use of benchmarking); a common approach to setting the cost of capital; and efficient investment incentives (e.g., sharing efficiency gains, ability to exclude imprudent or inefficient capex from the RAB).[26]

The Power of Choice review aimed to enhance consumers' ability to actively manage their electricity consumption through better information, services and price signals. The review led to a number of rule changes, including the requirement for cost-reflective distribution tariffs to be developed, opening metering services to competition, allowing consumers to more easily access their consumption data and incentivisation of demand management. Implementation of these (and other) changes is underway.[27]

Competition for network services

While the initial unbundling of the Australian electricity sector into contestable and regulated activities concentrated on the separation of generation, retail and networks, more recently consideration has been given to the role of competitive markets in providing DER and other innovative services. Amendments to the regulatory framework have occurred in some areas - for example, the AEMC's Power of Choice review resulted in a rule change that will open metering services to competition from 2017.[28] However, regulation governing the participation of both incumbent network service providers (NSPs) and new third-party entrants in providing DER and other services is still evolving.

[26] AER (2014)
[27] AEMC (2012)
[28] AEMC (2015b)

In terms of third-party providers, the AEMC's Power of Choice review expressed the view that arrangements should facilitate efficient new entry to DM markets, while still ensuring adequate protection for consumers.[29] Details on how this applies in practice have been reviewed as new products and services emerge - for example, in November 2014 the AER consulted on whether Alternative Energy Sellers (AES) who provide storage services should remain exempt from electricity retail law provisions[30].

In terms of regulated NSPs, the boundaries of their activities are established under the NER. For DNSP's, the AER's pre-price control service classification process determines which services will be subject to regulation and what form the regulatory control will take. For TNSPs, the NER set out criteria determining which services will be prescribed (subject to revenue determination by the AER), negotiated or non-regulated. Both transmission and distribution network providers are also subject to ring-fencing provisions, stating conditions under which they may provide contestable services. Ring-fencing guidelines for electricity distribution are currently under review by the AER, following the recent rule change opening metering services to competition[31].

Consumer engagement

The Australian regulatory framework provides for consumer input into the AER's decision making through the Consumer Challenge Panel (CCP) as well as through public forums and submissions during price control reviews. The CCP was established in 2013 as part of the Better Regulation reforms. The CCP's core role includes advising the AER on: whether networks companies' revenue proposals are in the long-term interest of consumers; the effectiveness of the networks' customer engagement activities; and how customer engagement is reflected in the proposals.

Under the NER, the AER's assessment of network companies' revenue proposals must consider whether forecast expenditure addresses the concerns of electricity consumers. To this end, revenue proposals must include details on how NSPs have engaged with consumers and how concerns identified through the engagement process have been addressed[32]. In 2013 the AER issued a set of best-practice guidelines to inform the NSPs' customer engagement approach, but does not otherwise prescribe how this should take place[33]. While the AER considers whether regulatory proposals have regard for customer engagement, there are currently no financial or other process incentives in place, as have been implemented in other jurisdictions.

[29] AEMC (2012), page 43.
[30] AER (2014b)
[31] AER (2016)
[32] NER, 6A.10.1 (g) (2) and 6.8.2 (c1) (2)
[33] AER (2013)

Incentivisation of DER

The main mechanisms to encourage DER uptake are through network planning requirements and demand management incentive scheme (DMIS).

Under the Distribution Network Planning and Expansion Framework (DNPEF), DNSPs are required to undertake investment tests (RIT-D) for large individual projects, including cost-benefit analysis that considers other credible options such as non-network solutions (similar arrangements apply for transmission). DNSPs are also required to develop demand side engagement strategies (detailing their approach to non-network options and providers) and Distribution Annual Planning Reports (DAPR), which may assist third parties to identify DM opportunities[34]. Reviews of these initiatives suggest that there has been a shift in focus towards consideration of DM, but there are questions around consistency in standards and approach[35].

A Demand Management and Embedded Generation Connection Incentive Scheme (DMEGCIS) has been in use, however the AEMC's Power of Choice review found that the scheme had not been effective. As a result, a 2015 rule change provided for two new mechanisms: a DMIS, intended to reward implementation of efficient non-network options to manage demand; and a DM innovation allowance (DMIA), providing R&D funding for pilot projects. These incentives will come into effect for the next round of revenue determinations, however the AER will have discretion over their application, depending on its view of existing incentives. Details of the schemes will be published by AER towards the end of 2016.[36]

Risk allocation

The NEL and NER appear to provide strong protection for the RAB, through the roll-forward mechanism and acceptance of the legislative principle that network companies should have a reasonable opportunity to earn a return on their investments (notwithstanding the AER's ability to exclude inefficient or imprudent capex from the RAB). This reflects a conscious and public choice made by ACCC and past policy makers and regulators (in the context of privatisations and establishment of the original energy rules) to not provide an opportunity for ex post fact regulatory stranding or optimisation of the regulatory asset base.

While the current risk allocation for existing assets is clear, reductions in peak demand and the growing cost-competitiveness of off-grid options have raised questions around whether the approach could change in future. In particular, there are concerns that the current regulatory approach – which implicitly presumes that cost-recovery of long-term network assets will be substantially met by future consumers – could become unsustainable. The

[34] AEMC (2015a)
[35] MHC (2015)
[36] AEMC (2015a)

emerging debate considers how market developments might alter the balance of risk between networks and consumers, as well as between different groups of consumers. For example, this includes the interests of customers with access to non-grid options compared to those who lack such alternatives, as well as the interests of current versus future consumers[37]. A range of potential policy and regulatory responses have been raised, as discussed further in section 5.3.

The allocation of other risks (demand, cost, regulatory) in the current regulatory regime is outlined briefly in ANNEX A.

Innovation

The main regulatory mechanism to encourage innovation by distribution network businesses is the DMIA. While the effectiveness of this incentive has been questioned, the measure has been the subject of a recent rule change, with details on the revised scheme to be provided by the AER towards the end of 2016. Innovation may also be funded as a "public good", for example through the Australian Renewable Energy Agency (ARENA) programmes.

Broader cape and opex efficiency incentives included in the current revenue setting framework are designed to encourage efficient service provision – including investment in innovative solutions, where these offer cost-effective alternatives to traditional poles-and-wires options. However, questions have been raised as to whether current incentive rates, combined with the removal of benefits from efficiency gains after 5 years, are sufficient to balance incentives between traditional and innovative solutions, considering the relatively higher risks associated with the latter[38].

We note other aspects of the network revenue setting process that may not be conducive to incentivising innovation, in particular: perceived reluctance of the regulator to accept initiatives proposed by network businesses; initial costs of introducing innovative solutions (or costs from trialling solutions) may not be appropriately taken account of in high-level benchmarking; and a lack of incentives for large-scale innovation until reflected in superior efficiencies. We also observe that Australia's regulatory approach was developed during a period of lower technological change, and that debate continues as to whether the current model adequately responds to an environment of rapid technological development[39].

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[37] Further discussion can be found in ENA (2014) and ENA (2015). AusNet Services also raised utilisation risk during consultation on their recent Victorian transmission review (see AusNet Services (2015)).

[38] For example, COAG has observed that as demand management technology is at a "relatively early stage of evolution", there are consequently "greater risks and uncertainties" around its implementation compared to more traditional investments (COAG, 2013, page 3).

[39] See for example, the discussion in Synergies (2015).

2.2. California

California's electricity industry is ranked second (after Texas) among US states by electricity consumption and fifth by generation (after Florida, Illinois, Pennsylvania and Texas)[40]. It is the US state with the highest penetration of DER.

California experienced an energy crisis in 2000-01, with volatile electricity prices and blackouts. This followed deregulation in the 1990s, combined with a regulatory framework that prevented utility companies serving final customers from hedging their purchase costs and from passing on high wholesale prices. This placed severe financial pressure on the companies, and forced one (PG&E) into bankruptcy. In response to this, the state government developed an Energy Action Plan to ensure sufficient generation capacity and network infrastructure to meet demand.

The regulatory framework has therefore clearly encouraged the development of DER and has been successful in this. The approach to achieve this has been top-down: legislation has provided targets for DER, and the regulator has put in place rules to achieve the targets, which have in turn been implemented by the utilities and other industry organisations.

Competition for network services

CAISO's current planning framework allows non-incumbent transmission developers to compete to build transmission facilities that are eligible for competitive procurement. Over 2013-15, the majority of project proposals submitted to CAISO's planning process were from non-incumbents.[41]

CAISO also facilitates market entry of storage and other aggregated DERs. New companies, for example storage providers or other prospective providers of DER, can enter the market either by becoming certified as a Scheduling Coordinator or entering into a commercial arrangement with an existing one. In June 2016, FERC approved a CAISO proposal to allow aggregations of small DER resources to participate in energy and ancillary services markets (previously access was allowed for individual participants with a minimum capacity of 0.5MW).[42]

There is currently very limited provision of data to third parties to allow them to identify network services opportunities.

Consumer engagement

California's rate-making process is similar to others operating across the USA. Utilities apply to the regulator (the CPUC) to request rate rises in a "General Rate Case", which are

[40] See EIA (2016)
[41] FERC (2016a)
[42] FERC (2016b)

scheduled to take place every three years in California. Within this framework, there is a formal process for customers or their representatives (some of whom access public funding) to intervene in the proceedings. Further details on the rate-making process can be found in ANNEX A.

Incentivisation of DER

The combination of all elements of the regulatory framework in California has to date facilitated the strong take up of DER and in particular Solar PV. Action to be taken by the utilities is clearly indicated by the government and related organisations. The regulatory framework is well understood by all parties. Stakeholder consultation appears to lead to a professional approach to changing of rules in response to new circumstances by the CAISO.

However, there are a number of concerns.

It appears that there is a perception that the current industry structure will not support the neutral deployment of DER, which has led to some[43] to call for the establishment of independent system operators at the distribution level.

The response to market developments may be slow. Market participants in distribution may have insufficient incentives to innovate, receiving no extra revenue for this.

There is an interaction between state and federal regulation. A recent court cases have (Hughes v Talen marketing, decided in the Supreme Court), indicated that there is an open issue about the definition of wholesale markets which will need to be resolved.

The approach to the development of DER means that it is projected that there will be an increasing need to curtail generation at times of low electricity demand. Projections by CAISO indicate that this may be as much as 12GW. Action to manage this by market pricing approaches, deployment of energy storage and other related actions will be needed (see Denholm et al (2015)).

Risk allocation

The approach to utility regulation gives strong protection against asset stranding. There is explicit legal protection which has been established by case law, for example the 1944 Hope Gas Ruling. In California, stranded costs as a result of the anticipated impact of competition in the 1990s were compensated through a specific mechanism.

However, this protection may not be absolute. Commentators (e.g. see Hempling (2015)[44], and Tong & Wellinghoff (2015)) indicate that the right to recovery of stranded costs is by no means absolute, and that regulators in the US have a range of options to deploy depending

[43] For example, ex-FERC chair Jon Wellinghoff (see AEEI 2015).

[44] At the same time, Hempling (2014) has also commented on the need to "protect the commons" (page 11), referring to the grid infrastructure that will continue to be required even with the uptake of DER.

on the circumstances. Investors have legitimate expectations to recovery of stranded costs, but these in practice will be balanced with those of other stakeholders.

Innovation

Innovation under the CPUC framework is currently driven by the regulator. As detailed further in ANNEX A, CPUC has identified and implemented specific targets and measures Through a top-down process, to incentivise the desired change (for example, energy storage targets placed on utilities). This approach may pose challenges associated with information asymmetry, and the difficulty for the regulator in identifying which innovations are likely to be appropriate for particular locations.

2.3. NY REV

The REV is an ambitious and aspirational program which seeks a major restructuring of how utilities operate, are incentivised and earn revenues. It places a strong reliance on the emergence of effective markets for customer and third-party DER involvement through the obligations and incentives placed on the utilities developing as platform service operators (PSO). The utilities are to be market facilitators for product and services offerings.

Competition for network services

The NY REV framework aims to encourage competition for the provision of network services through creation of a Distribution Services Platform (DSP) and provision of system data to allow new opportunities to be identified. Existing utilities, third-parties and customers would have opportunities to provide network services and own assets.

Concerning the ownership of DER assets by utilities, the NY Public Service Commission (PSC) acknowledged potential market power concerns, while also considering the need to balance this against other policy objectives, such as the promotion of DER, system efficiency, and reliability and resilience of the grid. As such, the PSC proposes to assess utility participation on its merits, taking into account whether: it will facilitate growth and operation of markets; there is an existing third-party market; there are benefits from economies of scale or utility expertise; and if foreclosure of third-party providers would be likely to result[45].

While the detailed architecture and implementation pathway for this long-term vision is not yet determined, interim incentives also exist to encourage competition in the near term. For example, as noted in the discussion of DER incentivisation below, utilities will be able to increase their revenue allowance through EIMs encouraging provision of network services by third parties.

[45] NY PSC (2016a)

Consumer engagement

NY REV is primarily focussed on facilitating greater levels of consumer participation in the market, as distinct from engagement in the rate-making process. Measures to increase consumer participation are detailed in the Incentivisation of DER section below.

Nonetheless, the NY regulatory model currently retains cost-of-service ratemaking for core network services, although it is envisaged that over time these will form a smaller part of network revenues. Similar to the Californian process described above, customers or their representatives may intervene in rate case proceedings. Parties involved in the rate case may also negotiate a settlement with the utility and submit this for review. In the New York context, concerns have however been raised around the effectiveness of representation for smaller customers, considering the complexity of the rate case process[46].

Incentivisation of DER

Under the NY REV model, DER investment is envisaged to be undertaken primarily by third-party service providers, although as noted in the Competition section above, utilities can own DER assets under a range of circumstances.

While in the long term incentivisation focusses on the development of markets for DER, interim measures include incentives for utilities to consider third-party DER instead of traditional network solutions and undertake demonstration projects.

Incentives currently in place include:

- Under Track One of the REV, the NY Public Service Commission (PSC) has directed the six large investor-owned utilities (IOU) to prepare initial demonstration projects to inform the future implementation of DER. An example of the type of project to be pursued under this directive is the Brooklyn Queens Demand Management (BQDM) program. The PSC authorised a return on the totex of the project, which proposes non-traditional alternatives to address an overloaded sub-transmission feeder[47].
- The New York State Energy Research and Development Authority (NYSERDA) also runs customer energy efficiency and demand management programs.

Incentives that are planned, but still being developed, include:

- Performance-based earning impact mechanisms (EIMs) covering a number of factors, including: rewards for avoiding traditional investment through the use of DER; incentives for peak and load factor reduction; incentives for innovative customer engagement (including the development of interfaces to link customers

[46] For example, the Moreland Commission's 2013 report identified weaknesses in customer representation, and recommended the establishment of an independent consumer advocacy board (as is found in a number of other US states). See Moreland Commission (2013), pages 46-47.
[47] NY PSC (2014)

and DER providers, expansion of access to consumer data and promotion of demand response and time-of-use programs); and incentives for the timely progression of interconnections (assisting small distributed generation projects). Only positive incentives apply to the new EIMs at this stage[48].

- Utilities are required to file Distributed System Implementation Plans (DSIPs), which will contain system information for use by third parties in identifying and planning their participation in the market. The DSIPs will include actual and forecast system loads, assessment of opportunities for DER solutions and plans to deploy DER. Initial DSIP filings are due for submission on 30 June 2016[49].

Risk allocation

As in the Californian context, the current regulatory approach provides utilities with strong protections against asset stranding. Precedent exists for the inclusion of stranded asset costs in the rate base. However, while legal protection for the rate base has been established in case law (1944 Hope Gas Ruling), commentators suggest that the right to recover cost of stranded assets is not absolute (Hempling 2015; Tong & Wellinghoff 2015). There is currently no explicit mechanism allowing for the recovery of investments in stranded assets, in the event that networks become uncompetitive.

Innovation

At present, innovation in network services is primarily incentivised through NYSERDA funding for pilot projects. In future, the NY REV framework aims to encourage innovation in both business models and DER technology. For example, utilities will be encouraged to move away from the current revenue model by developing 'market-based earnings' (MBEs) in their new capacity as DSPPs. By providing a platform, it is expected that utilities will earn revenue from new value-added services, driven by market requirements (for example, connecting customers to DER providers, data analysis, platform fees)[50]. Innovation by third party service providers will also be incentivised by the availability of data to identify new opportunities, and access to the DSP. At this stage however, specific mechanisms to drive this change are still being developed, and it is unclear to what extent or at what rate innovative DER and network services will emerge.

2.4. Ofgem RIIO

After a two-year review, with input from numerous consultancies and academics, Ofgem launched its new price control framework in 2010. It termed this framework 'Revenue = Incentive + Innovation + Outputs' or RIIO. A key premise of the new regime was to

[48] NY DPS (2015a)
[49] NY DPS (2015b)
[50] NY DPS (2015a)

incentivise the delivery of outputs (or services) rather than inputs. This is mainly done through a total expenditure (totex) approach and specific targeted incentive arrangements for outputs. Another aspect of the RIIO controls was increasing the length of the price controls to eight years (they previously lasted for five years). Ofgem believed the longer period would provide the networks with greater confidence in setting longer term objectives.

Competition for network services

In the UK context, third-party competition for network services is enabled through a range of measures:

- **Metering** is subject to competition.
- **Competition in connections**: Independent network companies may compete with incumbent Distribution Network Operators (DNOs) in the provision of some connection activities. During the DCPR5 price control, Ofgem implemented a 'competition test' process through which DNOs could apply to have price regulation lifted if effective levels of competition in connections could be demonstrated.
- **Offshore transmission:** Under the offshore transmission owners (OFTO) regime, third-party providers may own and operate offshore transmission assets. Projects are awarded competitively, and the OFTOs are guaranteed a return over 25 years (refer to ANNEX A for further details).
- **Onshore transmission:** Ofgem is currently considering an enlarged role for third parties in onshore transmission ownership, through competitively appointed transmission owners (CATOs). While the regime is still in development, eligible assets will likely need to be 'new' and with clearly delineated ownership boundaries (refer to ANNEX A for further details).

In terms of future developments, the Council of European Energy Regulators sees the need for a more flexible way forward for DSOs, with a view that they should have a neutral market facilitator role. Ofgem is also consulting on the potential future role for DSOs.

Provision and access to metering data is through a centralised, regulated, provider – the Data Communications Company (DCC). The DCC was formed to help facilitate the roll-out of smart meters and to facilitate the development of competition for electricity services to end customers.

Consumer engagement

Ofgem has increased the requirement for enhanced consumer engagement, but as Littlechild and Mountain (2015) sets out, Ofgem remained the sole decision maker and customer engagement only played a limited role. Littlechild goes on to note, that in both RIIO-T1 and RIIO-ED1 (where fast-tracking occurred) demonstrating effective consumer engagement did not appear to play a large part in Ofgem's decisions to fast-track the companies.[51]

However, we understand from informal discussion with network operators that the fast-tracking did create 'competition' between the networks to outperform each other in the business plan stage. While there is no limit on the number of firms that can be fast-tracked the comparative cost assessment meant that fast tracking multiple companies would be difficult.

Networks play an important, but limited role in consumer protection. They have set obligations to meet across connections and ongoing services (with guaranteed service payments if they do not). They play a role in providing information to vulnerable customers and keeping a database of these customers.

Incentivisation of DER

For all the changes that came out of the RPI-X@20 review process, RIIO is still fundamentally based on a building blocks approach to regulation. The outputs – consumer satisfaction, reliability and availability, safety, conditions for connection, environmental impact and social obligations – rely on the use of totex to estimate the input requirements. The use of totex equalises incentives across opex and capex for the networks to choose the most efficient and appropriate solution for customers.

While totex and fixed capitalisation in principle equalise the incentive between a 'poles and wires' and opex solution, in practice, it does not equalise entirely due to:

- benchmarking and differences in actual 'depreciation'; and
- different risk and rewards to the company from using non-BAU (capex) solutions.

In a high DER future, Ofgem's approach to totex benchmarking cost drivers – 88% weight on modern equivalent asset valuation (MEAV) and 12% of customer numbers – may need to change. This is because MEAV may not be representative of the DER costs.

Although the totex approach helps equalise incentives across capex and opex, there is no explicit requirement for DNOs to consider non-wires solutions. Ofgem required the DNOs to undertake cost-benefit analysis (CBA) as part of their business plans for RIIO-ED1, however its findings during the fast-track process indicated that the DNOs' CBA processes were not robust. In addition, quality of service incentives may encourage capex solutions over opex as it provides more 'real' capacity, rather than relying on contracted DER (which is not necessarily guaranteed). We also note that non-wires solutions may expose the networks to greater contracting risk and remove some of the control networks have over the system.

[51] Littlechild and Mountain (2015), pages 26-28.

It is also important to note that the current engineering standards requirements for electricity networks in the UK (referred to as P2/6), do not allow for the recognition of non-network solutions in improving reliability of supply.[52] While distributed generation can be taken into account, electrical storage or demand side response cannot be.

Risk allocation

Ofgem deals with risk allocation through the Totex Incentive Mechanism (TIM - sharing of over/underspending) and an assessment of financial metrics. It looks to balance the financial costs of placing additional risks on the networks against who is best placed to manage them. The TIM works by allocating a proportion of any over/underspend of totex to customers and networks. For example, if the sharing rate is 50% and the company overspends totex by $50 then it will bear $25 of the total overspend and customers the other $25.

Ofgem's use of uncertainty mechanisms around outputs allows it to transfer risk away from or to companies. The premise of these mechanisms is to encourage the companies to better manage the risk they face, as they bear some of the cost/ reward (in a similar way to the TIM) due to changes in outputs, prices and/ or volumes.

Ofgem has made no provisions for the risk of existing assets being stranded during the first RIIO price controls. Ofgem relied on CEPA et al (2010) which assessed that electricity assets built today or soon to be built would be viable until at least 2050.

Innovation

Innovation incentives are seen as a vital component of the RIIO framework, to encourage the use of new service delivery solutions and collaboration between network operators and third parties. To this end, Ofgem has introduced a Network Innovation Competition (NIC), Network Innovation Allowance (NIA) and Innovation Roll-out Mechanism (IRM). The NIC provides an annual fund which networks can compete for by submitting proposals for 'innovative' projects. The NIA allowance is 'use it or lose it' and is a percentage of base revenue. For further details, refer to ANNEX A.

2.5. Lessons

There are a number of key takeaways that are relevant for this report, which are discussed below. As a broad observation, we note that all the regimes are evolving and – particularly in the case of NY REV, where the Rate-Making Order was only set in May 2016 – there is limited experience of how successful the elements of the frameworks have been.

[52] NERA (2015), page 44.

Existing industry structure

It is important to recognise that the regulatory frameworks assessed have some very different underlying aspects. In particular, New York and California have vertically integrated utilities, with functions and scope of services that are significantly different from the vertically separated network operators in Australia and GB. As such, an evaluation of the approaches and mechanisms in other jurisdictions needs to take into account the Australian industry context, with clear separation of networks from electricity generation and retailing.

The different structures result in a different range of services that are regulated and they are also likely to impact on the services that may eventually become contestable. For example, having separate system operators may lead to greater transparency around the procurement of services, hence increasing market participation (this follows along the lines of the NY REV approach).

DER incentivisation

Regulators face challenges in balancing incentives between DER and more traditional poles-and-wires investments. In the case studies, they have taken a range of approaches to address this by providing a form of 'return' on alternative solutions:

- Ofgem has gone the furthest in equalising the incentives across opex and capex via its totex approach with pre-determined capitalisation. However, the risk and rewards of using alternative solutions may not be fully equalised through this mechanism. For instance, if a DER offset cannot be 100% guaranteed, the network may face contracting risk and will need to put in place contingency plans.
- NY REV has taken an alternative approach by implementing project-based incentives (such as for the BDQM project), while performance-based mechanisms are also planned.
- Regulatory benchmarking also introduces challenges in the appropriate use of cost drivers and incorporating the trade-off between opex and capex. For example, Ofgem's heavy reliance on modern equivalent asset valuation as an explanatory variable for totex, or the AER's use of peak demand for opex, may not provide appropriate cost signals for DER use. Similarly, the different 'life' of services from capex and opex against economic depreciation profiles may result in networks choosing (or at least proposing) non-optimal long-term solutions.

Contestable services

We observe that regulators are taking a risk-averse but flexible approach towards the provision of contestable (or potentially contestable) services by networks, with ownership of DER assets allowed in a limited way. Competition is being encouraged at the edges of network services (recent examples include metering, connections and defined projects) and networks are being incentivised to source services from third-party providers. Key points from the case studies include:

- The proposed structure of the utilities/ networks will impact their allowed role in providing services and products. The NY REV view is that utilities (which are vertically integrated) will be market facilitators of DER products and services, and will provide the data platform for this. At the same time, the REV framework allows for utilities to own DER assets in specific circumstances, balancing potential competition concerns against other policy objectives.
- In the UK, Ofgem looks to encourage competition where there is a positive benefit for consumers. For example, Ofgem is seeking to remove price regulation from a number of connection categories where networks can satisfy competition and legal tests. Separately, there is already a standalone entity which will manage the flow of data to electricity sector participants. It is not yet clear how this will limit, or allow, the provision of contestable services by networks.
- In Australia, the AER is conducting a review of ring fencing guidelines to determine the scope for network ownership and services offerings. Competition in connections and metering is developing.

An important consideration is the interaction between the regulator's decisions around prices/revenues and competition. For instance, if off-grid electricity supply becomes more cost-effective, then regulatory decisions on depreciation (among other factors) could affect network prices and either harm or help competition.

Information

The case studies highlight the importance of better information to consumers, third parties and networks in determining the future development of the market. Developments include:

- In Australia, the Power of Choice review aimed to improve customers' ability to manage their energy use, and included rule changes to improve price signals through cost-reflective network tariffs and allow consumers to more easily access their consumption data.
- The NY REV model considers that access to customer data (with appropriate privacy provisions) and the Distributed System Implementation Plans (DSIPs) filed by utilities will increase the visibility of market opportunities.
- Separate to the RIIO process, the UK has established the Data Communications Company (DCC) as a centralised, regulated provider of metering data. The DCC was formed to help facilitate the roll-out of smart meters and to facilitate the development of competition for electricity services to end customers.

Risk allocation

All of the case studies consider the risk allocation between consumers and networks, and each regime appears to be based on the recognition that consumers can benefit from a lower cost of capital provided by regulatory certainty. Approaches to risk allocation are broadly similar, with the RAB receiving legal protection or strong assurance that prudently-incurred past costs may be recovered. However, we note the following points:

- The impact of high energy charges on the economics of grids is well understood, with charging structures being reconsidered in many places including Australia. The extent to which asset stranding is a real risk depends on how this develops and whether aggregate costs increase above the level that customers are willing to pay.
- There are significant investments planned for the grids in the next 25 years. This suggests that assets will not be redundant in the foreseeable future.
- The jurisdictions examined do not have a clear pre-packaged view on the appropriate treatment of stranded costs and how they should be recovered, potentially reflecting a current perception that the level of uncertainty around any future stranding means this issue has not yet been confronted.
- The purchase of services from third parties, as an alternative to asset ownership by networks, has been seen as a means of transferring risk to competitive market participants. However, this may also depend on the service and reliability obligations retained by networks, and the extent to which cost-recovery for the procurement of third-party services is assured. We also note that Ofgem's approach to third-party provision of certain core network services has transferred risk to customers through providing guaranteed revenue (albeit contingent on acceptable levels of performance).

Ofgem perhaps goes the furthest in terms of discussing risk allocation between consumers and networks, and the use of the totex incentive mechanisms (TIM) to share out-/under-performance. We note that the sharing arrangements set by Ofgem for the networks are significantly stronger than those in place currently in Australia. In GB, networks share the full cost of under/over spends on capex, they do not simply bear (gain) the financing costs as in Australia.

Consumer engagement

Customer engagement is seen by all regulators as a key feature of future regulatory regimes. Benefits of engagement may include customer input into the services required or desired, and increased 'buy-in' from consumers in the regulatory process. However, there are different views on how and to what extent customers could be engaged.

- Rather than increasing consumer participation in rate-making, NY REV is relying on the development of markets (and price signals) to provide utilities with signals as to the required services. There is also an incentive on networks for innovative customer engagement, although what this means in practice is not yet clear.

- Ofgem encourages the networks to engage with customers as part of its fast track assessment, and it also has a customer challenge group (CCG). However, Ofgem still makes the final decisions and the majority of the revenue allowances are not linked to individual network's engagement. We note that Ofgem's review of its price control process concluded that consumers were not willing or able to take a decision making role.
- US regulation involves customer representatives as a formal part of the regulatory process in California and New York, with a specific role for intervention in rate-making proceedings.
- In Australia, the networks engage with consumers as part of, and in most cases prior to, the regulatory process. The AER also has a CCG which acts as a critical friend to the AER, advising both on how companies have consulted with customers, and how specific aspects of their decisions can reflect the interests of consumers.

Complexity

The cases studies suggest that the complexity of regimes is increasing as the industry transforms. While there is some significant 'refocusing' of regulatory frameworks, some of the added complexity appears to be the result of layering new arrangements on top of the existing frameworks. For example, while the NY REV model envisages a shift in the long-term to a market-led approach, in the foreseeable future incentives to encourage this will augment, rather than replace, the existing cost-of-service model. Complexity may pose additional challenges, for example in the realisation of increased consumer engagement.

3. SCOPE OF SERVICES

The approach to determining the structure and regulation of the electricity industry in Australia has been heavily influenced by the thorough review of competition policy of Hilmer et al (1993) commissioned by the Keating government. This ground-breaking report set a framework that has underpinned competition policy in Australia ever since, with a presumption that competition leads to more favourable outcomes for consumers and the economy. However, the report notes that "Competition policy is not about the pursuit of competition per se. Rather, it seeks to facilitate effective competition to promote efficiency and economic growth while accommodating situations where competition does not achieve efficiency or conflicts with other social objectives"[53].

The approach can be seen in the recommendation of the separation of the natural monopoly components of relevant industries from those components which are potentially competitive. For electricity, this led to the current structure of the industry into:

- business areas subject to competition, the most significant of which are generation (production of electricity) and supply (the sale of electricity to final customers); and
- regulated networks, which contain the natural monopoly components, comprising transmission and distribution networks.

The reason for this is that application of competition law alone was seen to provide insufficient protection, and that structural remedies were necessary to promote the public interest.

It is important to note that the Hilmer report does not require separation, but rather the structural choice should be subject to cost-benefit analysis. Without separation, "more intrusive regulatory controls to guard against cross-subsidisation and, where a vertical relationship is involved, the potential misuse of control over access to the natural monopoly element" [54]. Furthermore, for potentially competitive activities, "the case for such separation will be stronger where there are substantial barriers to new market entry" [55], indicating a somewhat nuanced approach to these issues.

This suggests that an application of Hilmer et al (1993) in the situation faced in the 2020s and beyond may be very different from the considerations of wholly publicly owned monopolies in the 1990s. This is the argument of Synergies (2016), which suggests that more vertical integration in energy markets may be appropriate in the changing technological environment.

The structure of the electricity industry and in particular areas related to network operations are evolving in two ways. First, the structure needs to evolve to accommodate a

[53] Hilmer et al (1993) page xvi.
[54] Hilmer et al (1993) page 219.
[55] Hilmer et al (1993) page 223.

significant increase in DER. Second, there are changes to the activities within the industry that are contestable or potentially contestable. These may move out of core DNSP functions.[56]

3.1. Evolution of functions – to accommodate new technology

What is changing?

Network operators' operations and functions will need to change with new technology and increasing customer/ third party use of the bi-directional nature of the network. This means that the regulatory framework needs to reflect the following:

- There will be a large number of nodes on the distribution network which have DER that may either be consuming or producing electricity. As a result of this, electricity will sometimes flow to the node, and sometimes away from it.
- Electricity flows will need to be monitored in real time (or at least close to real time), and information passed to the customer and/or its supplier and/or any other agents acting for the customer.
- Customers (or their agents) will need to be able to participate in a real time power market to sell their electricity. Even if they operate under a contract, differences between injections and/or withdrawals from the network will need to be paid for. This implies that there will need to be a form of market operator on the distribution network.
- Agents may take an enhanced role for customers compared to that of suppliers at present. Agents may for example take control of the timing of the use of appliances to optimise the use of behind the meter storage.
- Data access. Agents will need access to data for their customers so that they can manage their demands. System operators also need real time data access to be able to call on DER at appropriate times.

An important feature of DER is that it may be used for each of the following:

- **In the energy market.** If the time of use of DER can be controlled, then it can be used to arbitrage on the wholesale energy market. Customers can profit by appropriate use and sale of electricity to benefit from fluctuations in prices. This is particularly the case for storage, as well as demand side management (DSM).
- **To support networks.** DER can provide voltage support and other ancillary services. In operating timescales, DER may be used to ensure stability and reliability of the

[56] We discuss some the changes in ANNEX B.

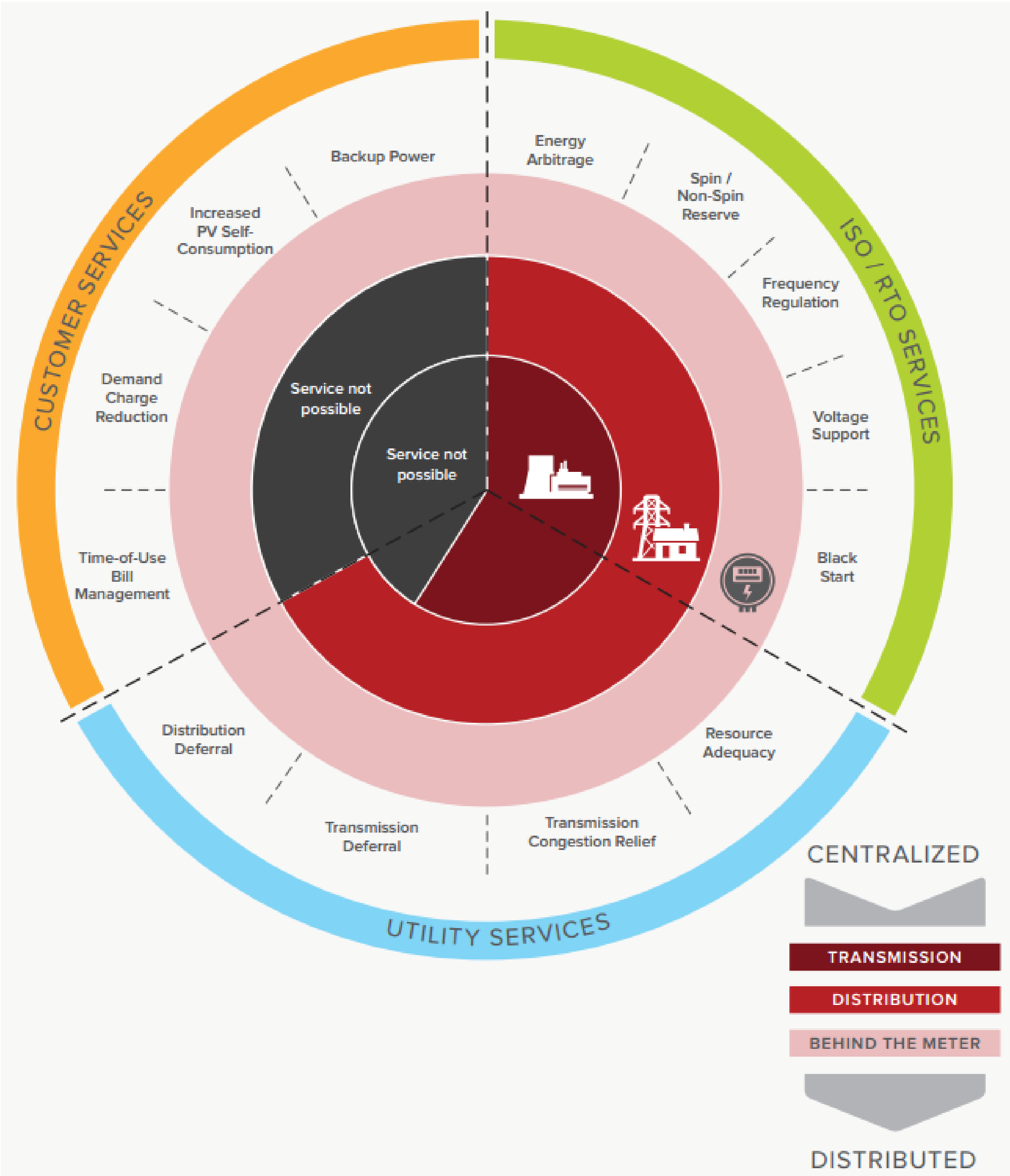
network. In planning timescales, DER may be used as a substitute for network augmentation.

The value of the DER on the network is that it may provide support in both areas. If any asset is excluded from any particular specified use, then there is potentially an inefficient use of that asset.

It is beneficial for the deployment of DER if it can be ensured that resources primarily installed for energy market operations can be deployed by the network operator when needed. Likewise, it is beneficial if DER deployed for network reasons can also be used in the energy market. For example, storage is seen as a 'value stacking' system as it can provide multiple services via the grid. The Rocky Mountain Institute (2015) have identified 13 different services that storage could offer across three stakeholder groups. The authors proposed that "the further downstream energy storage is located on the electricity system, the more services it can offer to the system at large."[57]

[57] Rocky Mountain Institute (2015), page 18.

Figure 3.1: Battery services



Source: Rocky Mountain Institute

Organising distribution activities - the ENTR distribution system operator (DSO) taxonomy

There are a number of different ways in which the functions identified above can be organised, and in particular the combination of different activities performed by the network companies. The ENTR team has prepared a working paper (ENA-CSIRO 2016) which sets out five options for the organisation of the DSO. From an activities viewpoint, the options discussed in that paper can be considered as follows:

- Model 1, DSO Lite, is similar to a DNSP combined with the SO.

- Model 2, DSO Comprehensive includes market operation functions as well as the system operator (SO) role.
- Model 3, DSO Total, includes market facilitation in addition to market operation and SO.
- Model 4 is a variant of Model 3, which reflects particular characteristics of the NY REV model.
- Model 5 (Transaction Platform Provider) is one example of how a separated DNSP and DSO might work. It is combined with a specific approach to pricing. The DNSP does not undertake system operations but rather provides price signals, and the TPP passes on those price signals and organises the market.

Which of these structures is chosen will affect how technology is incorporated into the electricity system and how competition develops, whether this is that competition can develop without intervention or whether strict regulatory rules/ guidelines (e.g., ring fencing, etc) are required.

Table 3.1 we set out a high level assessment of the regulatory implications from the different structures. We have done this on the basis of the broader options around separation without specifying the exact role of the network asset owner (NAO), SO and market operator (MO).

Table 3.1: Regulatory implications of different structural options

Structure	Implications
NAO separate from SO/MO	• Separate regulatory control for the NAO, SO, and, potentially, a MO. • Likely to increase the transparency of the operations and engagement, for competition development. • Governance arrangements would need to increase. • Incentive arrangements would need to be established for the SO (and possibly MO), which are asset light. • NAO may be able to compete for a greater range of services, without specific arrangements, on the basis of the SO procuring required services for the networks operation.
NAO+SO	• Single regulatory control (although separate arrangements for MO). • Greater policing (relative to separation) of service competition may be required, due to the combined structure. • SO (and MO) have 'skin in the game' so easier to incentivise.

3.2. Identifying services with the scope for competition

As experience of separation of networks has developed, it has been found that some activities previously considered to be core network activities – e.g., metering and connections – are contestable or potentially contestable. This means that arrangements can be made for these activities to be undertaken by a separate organisation rather than the core network operator. It is possible that a range of activities considered to be core to networks may in future become contestable.

The most recent activities that were in the past a core part of network operation is the ownership and management of metering equipment. This activity was the subject of a rule made by the AEMC in 2015, which provides for the opening up of competition for all metering by end 2017.

The scope of services that a network operator is able to offer is tied to the structure. While there are ways, such as ring fencing and rules, to abstract away from the structure, the overall structure must be considered when determining regulated and unregulated services. There are two specific types of competition that need to be considered with regards to regulation:

- Competition for supplying electricity access ('core network services').
- Competition in other services.

Contestability of the network as a whole?

There has been much discussion worldwide about the potential for the reduction in costs of new technology, in particular distributed solar PV generation combined with a battery, to make it economic for customers to go off-grid, with forecasts of the date at which might happen in some cases to be in the next decade (RMI 2016, UBS 2014).

It is beyond the scope of this report to analyse these claims in detail. Whether grid plus storage is viable as a replacement for a grid connection will depend on a number of factors including: the load profile of the customer; the tolerance of interruptions to supply from faults in the system; and of course most importantly the cost of the solar panels and the batteries, and the available tariffs. While there are already customers with off-grid or micro-grid connections, with continued falls in the cost of solar installations and batteries, it is plausible that more customers in a greater range of locations have the cost-effective (and reliable) option to go off-grid. It should, of course, be noted that customers may wish to retain access to the grid not to buy electricity but rather to sell it (or ancillary services), and the grid connection therefore provides an option to buy and sell electricity when the economics of this are favourable.

If off-grid options do develop as viable substitutes to a grid connection for a significant proportion of consumers then the network operator's natural monopoly may be eroded.[58] If a part – but not all - of network utilities' core operations become contestable, this poses questions as to the appropriateness of regulation. This is illustrated in Figure 3.2, which shows stylised supply curves for grid activities and the network component of off-grid

[58] Corneli et al (2015) put forward this possibility as well (see pages 21 to 22).

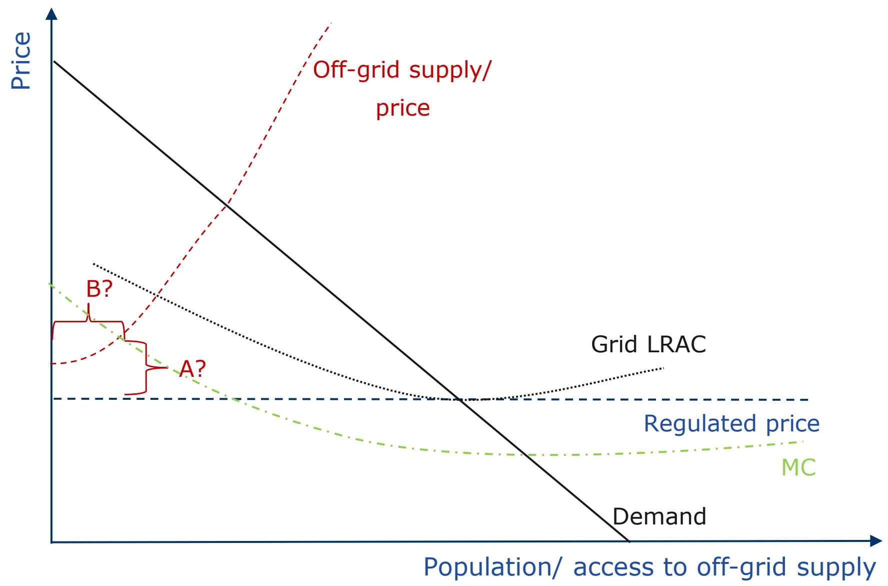
supplies. In the chart, off-grid is a viable option for customers in the far left of the diagram. In determining at which point the provision of network services may be considered contestable, two key questions arise (from the areas in Figure 3.2):

A. How close do the prices between off-grid and grid access (adjusting for quality) need to be before the market for 'full' supply can be considered 'competitive'?

B. What proportion of the market needs to have access to off-grid solutions at this price? Or put another way, what proportion of consumers are 'captive' on the network?

If prices become close and a significant proportion of consumers have access to these options, then the threat of customers going 'off-grid' could be sufficient to create a 'soft price' cap.[59] We note that there is a strong consensus that off-grid options will become cheaper over time and therefore the red line will move downwards, off course on-grid access may also decrease in price .

Figure 3.2: Cost of grid supply and off-grid supply % of population



Source: CEPA

The question for the regulatory framework is:

- Should a test be in-built for competition of core networks services (see Text box 3.2 for an example of an explicit regulatory test carried out by UK CAA)? For example, if 20% of consumers have access to cost-effective (within or below 15% of average network price), reliable, off-grid supply should a full market power assessment be carried out?

[59] See Corneli et al (2015), page 6.

- Should the network be able to refer itself to the competition body to assess the scope for competition?

Text box 3.1: UK CAA – Regulation test[60]

The UK Civil Aviation Authority (CAA) has a test embedded in law[61] as to when it is required to regulate (provide an 'economic licence') airports. This test is based on market power and has three parts: a) That the airport operator has, or is likely to acquire, substantial market power in a market, either alone or taken with other such persons as the CAA considers appropriate. b) That competition law does not provide sufficient protection against the risk that the airport operator may engage in conduct that results in an abuse of the substantial market power. c) That, for users of air transport services, the benefits of regulating the airport operator by means of a licence are likely to outweigh the adverse effects. The CAA began its investigation of market power for three airports – Gatwick, Heathrow and Stansted – in 2011. In 2014 it published its findings. It found that Gatwick and Heathrow passed the tests – and therefore required economic regulation – while Stansted did not for services to passenger airlines. The CAA is consulting further guidance on is market power test.

Defining the values for A (availability of alternative access) and B (price of the alternative) is not straightforward as:

- The price of the alternative is likely to be a bundled energy and network service, rather than a network-only offer. Analysis will be needed to determine the network-only price (or alternatively the energy-network bundle that is consistent with the base network price.
- A proper comparison between alternatives by a customer should be based on an appropriate structure of charges.

We do not envisage that core network services would become unregulated at this point, rather it seems more plausible that regulation be wound back into an 'Information Disclosure' type regime (this is discussed further in Section 4).

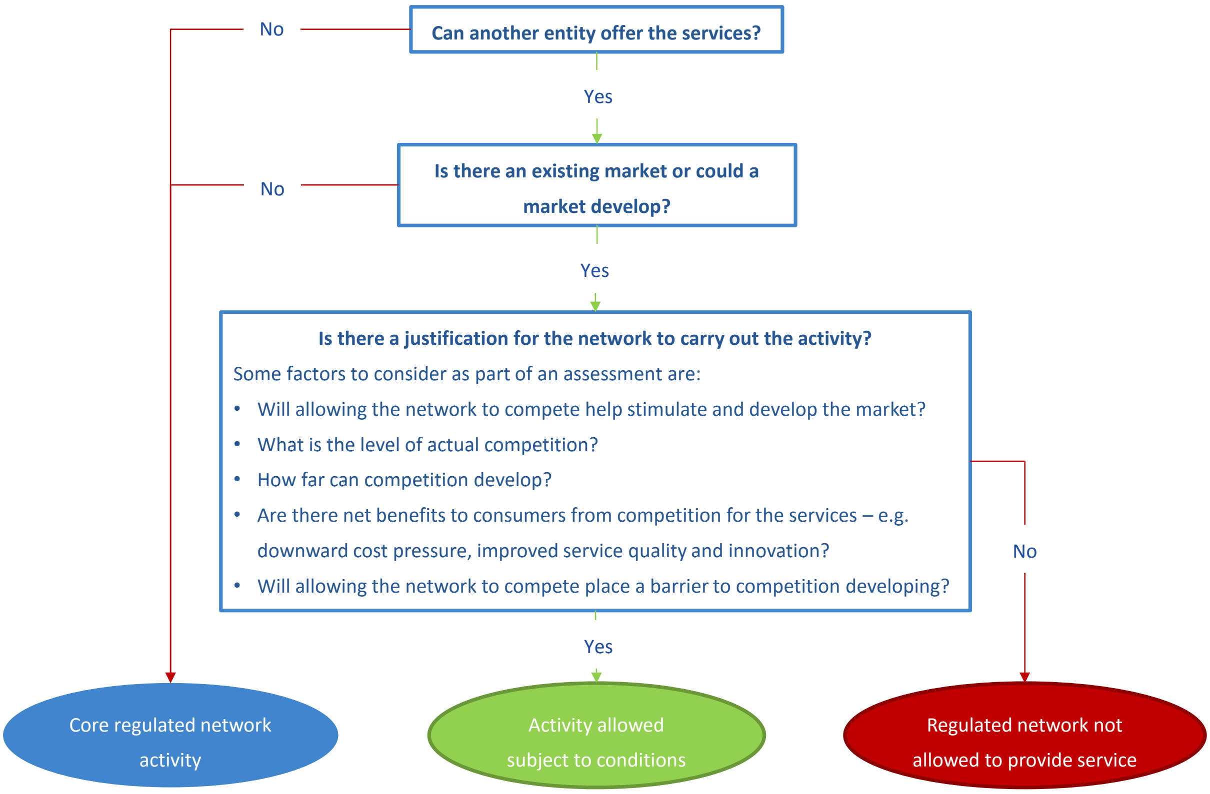
Competition in services

While all business structures can allow for competition to develop, the extent of regulatory intervention may well vary based on the business model operated by the network. For example, if the network is responsible for market facilitation (and data provision) of DER services (or an affiliate) then the rules will need to be put in place to prevent any market abuse (or the perception of market abuse). The rules could vary from market monitoring by the regulator to ring-fencing. The key principle that must be applied is that the network operators act as neutral market facilitators.

[60] CAA (2015).
[61] Civil Aviation Act (2012).

More generally, the ability of the network to compete for services can be considered in the way set out in the flow chart below. If the network is the market facilitator, then it would be unlikely that it would be allowed to compete in a well-developed competitive market (except with specific exemptions).

Figure 3.3: Determining regulated activities



Source: CEER, CEPA analysis

An example of competition testing comes from Ofgem. Ofgem introduced competition testing for specific segments of the connections market. Networks apply to Ofgem providing evidence that a market had developed. After testing this Ofgem could decide whether the networks could offer connections in the segment without price regulation.[62]

Strawman options of possible ways to increase the nimbleness of the regulatory framework to allow transition between regulated, new and contestable services are set out in the box below.

Text box 3.2: Options – Increasing nimbleness of the regulatory framework to services

- Integrate a competition test within the regulatory framework.[63] Individual networks could apply for services to be classified as unregulated. These services would be subject
- Allow networks to make proposals for their own business structures and mechanisms to provide transparency and to demonstrate that it does not create a barrier to

[62] To help develop markets for some segments, Ofgem allowed a regulated margin to be earned by networks.
[63] We note that the UK Civil Aviation Authority (CAA) has a test embedded in law[63] as to when it is required to regulate (provide an 'economic licence') airports. This test is based on market power

to price-monitoring. The AER/ AEMC would consider applications first, with a 'back-stop' process if the network disagreed with the ruling. Service obligations across networks and competitors should, insofar as possible, be the same. A code of conduct for the services, which apply to all players, can be used to help ensure customer protections and a level playing field.

competition developing (if that is a positive outcome). This may require a shift to specific rules (or licences) for each network operator, which sets out common, but also individual obligations.

A test to determine whether transmission and distribution services as a whole are contestable would likely follow a similar process to that laid out above. The test should be included in the framework, and the ability for competition of off-grid electricity services (with comparable reliability) to offer a 'soft' price-cap may assist in a move to an information disclosure/ pricing monitoring regime. The key elements of the test would be: (i) the proportion of the market with access to off-grid services; and (ii) the price differential between the two.[64] We are not aware of evidence of these factors being calculated in other jurisdictions, and careful consideration would need to go into determining them. However we suggest that only a significant minority (10-20%) would need access and the price need to have reached parity before it can be used as a cross-check to a network price.

Text box 3.3: Principles for the competition test

It is important to ensure that:

- Competition tests and processes restricting that the way that networks are involved in these markets are appropriate. Consistent with Hilmer, it is appropriate for restrictions on networks' involvement in these activities to be assessed on whether it harms consumers, rather than a default prohibition. This assessment will need to reflect the structure of the business.
- Competition tests are applied in a way that facilitates appropriate investment in services/ technologies in a timely manner.
- Competition tests should be proportionate to the size of the market they are serving.
- Restrictions on activities should take account of the value they can provide to consumers and investors.

[64] The method for separating, or comparing combined, energy and network prices would need to be developed as well as an approach for reflecting differential locational and time of day pricing.

4. REGULATORY PROCESS

Regulatory process is about how it is decided what is done.

4.1. Level of customer engagement

Under "traditional" regulation, the regulatory body makes decisions that it believes are in the best interests of consumers without direct reference to them. The regulator makes judgments that it believes are in the best interest of consumers, but there is no requirement for consultation. It is the informed judgment of the regulatory authority that is intended to ensure that decisions match the needs of customers.

There has been a recent push for much greater involvement of customers in the regulatory process. The involvement of customers is seen as a way of better ensuring that the balance between services and prices are in line with customers' values. In addition, greater customer involvement also increases customer 'buy-in' and legitimacy of regulators' decisions. There are a range of options for regulators to involve customers in their process. For example, panels of customers may be consulted on regulatory initiatives, review and comment on proposals, with regulators having discretion on the extent to which views are taken into account. There may, however, be a more formal and substantive role for customers or their representatives.

We note that customer engagement is changing in Australia. Examples include:

- The AER is revisiting its Consumer Challenge Panel.[65]
- ENA has published a handbook on customer engagement.[66]
- SA Power Networks created a dedicated 'Talking Power' customer engagement channel.[67]

Regulatory settlement

Regulatory settlements involve a more direct role for customers in driving the revenue setting process. Negotiated approaches are held to provide benefits in terms of understanding customer priorities, gaining acceptance for decisions, innovations in price-setting and a more open, less adversarial process. In the UK, for example, in recent processes to determine price controls for water, there was a formal role for customers in setting outputs for businesses. Although, the regulator is still responsible for agreeing the companies' business plans and final prices/ revenues.

[65] Nous Group (2016).
[66] ENA (2016).
[67] http://talkingpower.com.au/

The Water Industry Commission for Scotland (WICS), took an approach which involved direct engagement by consumer representatives in the price control decisions. WICS established a nine-member Customer Forum to represent the views of customer to Scottish Water (SW) and WICS, and to argue for their interests. Approximately halfway through the process, WICS asked the Consumer Forum to seek to agree a business plan as the basis for the price control. Overall, WICS believes that the use of the Customer Forum led to proposals which better reflect customer priorities. Key features of the WICS revenue-setting approach are outlined in the text box below.

Text box 4.1: Regulatory settlement – WICS[68]

- The Forum included customer representatives, water suppliers, chambers of commerce and an independent chair.
- The Forum and SW were asked to seek agreement on a business plan, intended to form the basis of the final price determination.
- WICS issued substantial guidance to frame the negotiation, specifying ranges that it would likely agree to (for example, on opex, capex, inflation, growth assumptions).
- Rather than using a building blocks model, WICS used SW's business plan and made assumptions about efficient costs, government lending, interest rates on debt, etc, to establish the range of key inputs.
- Financial "tramlines" were put in place around three financial metrics: adjusted cash interest cover; gearing; and FFO: net debt.
- Adjustments may occur during the price control period in response to SW's performance against these metrics.
- The tramlines aimed to ensure that SW's financial performance remains consistent with the price determination and financially sustainable.

Customer led settlement

Under what we term a customer led settlement (which we consider is a negotiate-arbitrate type regime), customers (or their representatives) directly agree a range of outputs and revenues with their service provider. Unlike a regulatory settlement approach, this results in a commercial contract rather than a regulatory price determination. The role of the regulator within such a regime may involve ongoing price monitoring and acting as arbitrator in the event of dispute or failure to reach agreement. [69] The regulator may also retain the ability to further scrutinise agreements if there is evidence of abuse of market power.

[68] See WICS (2014) and Littlechild and Mountain (2015).

[69] The framework may include a provision that if the two sides are sufficiently close then the arbitrator will choose one side or the other.

This type of approach, at least to the extent of customer making decisions on the prices and services, is not widely seen in the electricity sector, but is used (or available for use) in Australian and New Zealand regulation in other sectors.

Text box 4.2: Negotiate-arbitrate – Australian airport regulation[70]

- Airports and airlines negotiate directly to reach agreement on terms. The Board of Airline Representatives of Australia (BARA) is authorised by the ACCC to negotiate on behalf of airlines.
- Annual price, cost, profitability and service quality monitoring by the Australian Competition and Consumer Commission (ACCC).
- Airports potentially subject to the general third-party access provisions of the Competition and Consumer Act 2010, under which the ACCC may be asked to arbitrate if a commercial agreement cannot be negotiated.
- Revenue/ price setting
- Price controls removed in 2002, replaced with commercial negotiations between airports and airlines.
- The Government has published 'Aeronautical Pricing Principles' to frame negotiations. For example, these have included that prices should reflect a reasonable sharing of risks and returns, and that asset revaluations should not generally provide a basis for price increases.

Note, negotiate-arbitrate regimes are different to the negotiated settlement approach used in the US and discussed in Littlechild and Mountain (2015).

Who represents 'customers'?

There are benefits from customer engagement in aligning customer and regulated businesses incentives, i.e., determining outputs that customers genuinely value and ensuring business plans deliver these outputs. While the largest customers will have sufficient interest in the quality and price of their electricity supply to be willing to engage with their connection provider, most other customers are unlikely to have the time or resources to do so. However, given the diverse range of customers even carefully directed customer engagement can be limited, as demonstrated by the range of value of lost load (VOLL) estimates in Great Britain.

Text box 4.3: Great Britain estimates VOLL[71]

GB estimates of VOLL from a number of different studies:

- VOLL estimates for domestic customers range from around £700/MWh to £59,000/MWh;
- the values for SME customers fell between £9700/MWh and £225,000/MWh; and
- for larger commercial and industrial they ranged from £423/MWh to £12,336/MWh

Source: NERA 2015

We see three main considerations for the greater involvement of customers:

[70] See Littlechild (2011); Productivity Commission (2012).
[71] See NERA (2015). The ranges are based on estimates provided in four different reports.

- The definition of the customer representative. Customers may not have the time or resources to negotiate on their own behalf and therefore a form of representative may be needed. In the case of electricity, one can envisage that suppliers might take on this role, but the interests of customers and their supplier are not necessarily aligned. An alternative is for customer organisations to take their place. These organisations can be effective at highlighting the needs of certain classes of customer/ special interests, but again may not be representative of all customers (and resourcing issues still exist).[72] Although customers may be more readily identifiable and informed for the transmission networks.
- The role of consumers in the engagement process and the outcomes needs to be clearly defined, and there needs to be a strong commitment to these outcomes in order for stakeholders to be sufficiently invested in the process.
- The default arrangements in the event of failure of the parties to agree. For parties to agree, they need to be convinced that the deal on offer is better than a deal that would be imposed by an arbitrator. Any agreement struck is therefore likely to be strongly influenced by the approach that that an arbitrator would take.

In relation to the first point, there are other companies emerging that are seeking to develop a more active relationship with their customers, facilitating energy market activity with bi-directional electricity flows. They may provide metering support, or even negotiate access to a consumer's premises. It is possible that these new energy market agents may be able to provide a more balanced representation of their customers than suppliers currently appear to do.

Information disclosure (without formal price regulation)

An information disclosure regime is based around the regulator setting out specific information – such as pricing, volumes and financial information – that companies must publish publically for their customers to consider. The regulator may specify how these values should be calculated. The regulator may also provide guidance on the expected ranges of financial values to provide more information to the customers.

Information disclosure typically is only used where the regulated company's market power may be weaker (e.g., a viable alternative to the using the natural monopoly exists) or the regulated company's incentives are not necessarily purely profit seeking (e.g., government owned entities). If customers believe companies are abusing market power, are inefficient

[72] See Littlechild and Mountain (2015), pages 58-61, and ECA (2016) which notes that UK CAA constructive engagement process identified distinct differences in opinion across airlines and that the CAA considered more end-user research was required. As the range of airlines is much more limited than electricity consumers, it highlights the difficulty in getting agreement across consumers, even before the negotiation with networks begin.

or not delivering the required services they can ask the regulator or competition authority to step-in.

An information disclosure regime (without formal price regulation) was used by the New Zealand Commerce Commission for electricity distribution before it adopted a thresholds based price-cap regime (with information disclosure requirements) in 2004. Formal price regulation was introduced to limit the ability of networks to extract excessive profits, to incentivise efficiency and share gains with consumers. The Commerce Commission does operate a modern information disclosure regime for airports, and this provides an example of the processes an information disclosure regime might require (see Text box 4.4 below).

Text box 4.4: Information disclosure (Airports) – New Zealand Commerce Commission[73]

- Two airports (Christchurch and Auckland) are currently subject to a 'light touch' information disclosure regime under the Commerce Act 1986. Prices are not regulated, but airports are required to consult with their customers on major investments that may impact prices. (Wellington Airport is also subject to an information disclosure regime, but its prices are set through NZCC's Input Methodologies.)
- Public disclosure of financial and quality performance information is required annually, and price-setting information is disclosed following a price change.
- The CC sets input methodologies relating to the calculation of asset values, cost of capital and cost allocation in the annual information disclosure.
- The CC also reviews information disclosures and reports to the Ministers of Commerce and Transport on the effectiveness of the regime.
- For example, in their initial observations on Christchurch Airport's prices applying over 2012-2017, the CC concluded that information disclosure had not been effective in constraining excess profits, nor in providing sufficiently transparent information.
- Christchurch Airport revised its information disclosure, for example moving to an implied depreciation method, rather than a standard straight-line method. This alleviated the CC's main transparency concerns, but did not alter its conclusions regarding excessive profits.

Options

The regulatory framework process – what happens, who does what and what are obligations and protections – and its application is directly influenced by:

- decisions around business model (discussed in the previous section);
- the development of off-grid services as a cost-effective (and appropriately reliable) way of accessing the grid (i.e., a substitute to remaining connected to the network is available); and

[73] See ACCC/AER (2013), NZC (2015)

- consumer advocates/ groups being willing and well enough informed, and the regulator is willing to reduce its role and give consumers a greater role, to provide a credible bargaining position.

How far along these dimensions the world is in 2027 will have a direct bearing on what type of process is in place. Depending on the extent of the above occurring by 2027, or before, we see a number of options for the electricity networks. Note, we set out some framework specific obligations and consumer protections in the options below, however we discuss a broader range of options in the subsequent sub-section.

A **customer led settlement** approach. Rather than a regulator deciding the outputs that electricity networks should achieve, and determining their revenues, these decisions would be negotiated between customers or their representatives. Only in the event that the parties disagreed would the regulator be involved, and resort to making a determination based on a building blocks approach. For this approach to be successful, customers or their agents need to be well-informed and motivated to participate in the process, and the regulator needs to be prepared to accept their agreements. In addition, the regulator would need to provide clear guidance on the agreement that needs to be reached and the range of inputs and outputs that need to be considered. The approach would ensure that the networks were providing services that customers value, including facilitating DER if they would like it to.

Some key features of this type of approach could be:

- Customers and customer representatives / agents agree a range of outputs and the level of revenues with the network operators. The outputs could include, for example, levels of reliability, or achievement of specific investment goals.
- A regulatory body provides guidelines for the agreement (customers/ users need to be clear on what they are bargaining for e.g., signing up to investment in long-life assets [future consumers], or less reliable supply).
- The regulator may retain the ability to determine certain aspects of the settlement which are too difficult for the consumers to agree, e.g., the cost of capital.
- If an agreement is not reached then the regulator steps in and uses a building blocks approach to estimate the required revenue.
- Information disclosure and service quality monitoring used.
- Any service obligations would be adjusted to reflect express customer desires (with consumer protections in place).

At the distribution network level it may take longer for customers or their agents to be adequately resourced, or willing to negotiate for prices and service quality, however a customer led settlement may be more viable for the transmission network given the more smaller range of customers.

Table 4.1: Advantages and disadvantages of 'Customer led settlement'

Advantages	Disadvantages
• Customers/ users responsible for negotiating the services at a level they desire. • Investment decisions driven by the settlement. • Incorporation of new technology enabled through the settlement. • Consumer engagement should be proportionate. • Risks allocated based on the agreement. • Customer buy-in for service delivery costs. • Enables regulator to take "light handed" independent arbitrator role (unless they need to 'step-in').	• Need to have well-informed customer representatives for the whole customer base – vulnerable customers may not have a strong voice. • Likely to be limited or no representation of interests of future consumers, despite this party bearing the consequences of decisions • Innovation could be limited based on customer appetite for R&D. • Regulatory tests for contestable services still required. Assessment will follow similar process as for the other options. • Potential difficulties agreeing full range of services.

A **Fast-track** approach. Network utilities would propose business plans, outputs, and revenues, and engage with customers to ensure that they were appropriate. If acceptable to the regulator with a high-level review, they would be accepted and implemented with a much lighter regulatory process. If the proposals are not accepted, a normal building blocks approach would be implemented. This process parallels that of Ofgem's, with the fast track determination made within six months of receiving the business plans, however we consider that a number of enhancements could be made compared to Ofgem's process:

- The regulator should demonstrate how it takes a network operator's customer engagement into account – on the basis that network operators undertake customer engagement.
- The regulator could set specific elements of the business plan that required customer representatives (see discussion in the preceding option) to sign-off.[74]
- Sufficient time should be built into the fast track process to allow for a robust review of any comparative (benchmarking) models. With recognition for their high-level use in the fast-track process.

The companies benefit from being fast-tracked through a reduced cost of negotiation. It is possible to provide additional financial incentives to be fast-tracked. The financial reward should be carefully consider so as not to over reward fast-tracked companies.

[74] This would be in a similar way to the 'Constructive Engagement' approach adopted by the UK Civil Aviation Authority. In the constructive engagement approach airlines agree the passenger forecasts, services levels and capex plans with the airports, while the CAA determines all the other inputs such as the cost of capital and opex. Littlechild and Mountain (2015), page 13.

Table 4.2: Advantages and disadvantages of 'Fast track approach'

Advantages	Disadvantages
• Regulator determined services, but strong customer input provided for identifying services and quality levels. • Incentive on companies to deliver high quality plan. • Provides a stable environment for investment, and typically encourages a low cost of capital through high assurance of recovery of efficient costs. • No impediment for networks allowing bi-directional flows. However, the revenue allowances needs to take this into account. • Incentives for incorporation of new technologies can be included, however mechanism based rather than market driven. • Networks incentivised to 'beat' the competition via comparative assessment of costs. • Building blocks allow the contestable activities to be included/ excluded as determined. • Building blocks flexible to allow for different business models. • Building blocks regimes well known to participants. • Risks can be explicitly shared between parties, with a balance between those best placed to manage them and minimising the financing cost of the risk.	• Regulator still required to determine the services and quality level customers value. • While outputs can be targeted and incentives equalised it is still a cost of service driven regime. • Regulatory testing for contestable services. • Assessment of innovation funding required. • Potential lag between the identification of contestable services and an adjustment to allow for them in the regime. • Cost drivers/ outputs need to be identified/ measured for the totex assessment. • Can be burdensome on all parties. • Complexities with the application of some blocks and disagreement between parties.

An **information disclosure** approach (without price regulation). In the event that off-grid becomes a sufficiently reliable cost-effective solution, a "lighter touch" regulatory option may be appropriate. A pre-requisite for this approach would be that the market-based price of an alternative to grid-supplied energy is sufficiently low for a sufficient number of customers. In this case, it is possible that there is a limit to what a network would be able to charge all customers. Corneli et al (2015) state "[t]he mere ability of significant numbers of customers to disconnect would likely create a "soft" market-based cap on how much utilities can charge their customers for being connected to the grid."[75] Under this approach:

[75] Corneli et al (2015), page 6.

- A regulatory organisation would have the power to make a determination that sufficient customers had an effective alternative to grid-supplied electricity. Work would be needed to assess the appropriate market prices of grid supplied and non-grid supplied energy to compare; how low the cost of the alternative needs to be for how many customers to assess whether such a determination is appropriate.
- The network utility would have a degree of freedom to charge what it liked to customers who had effective choice. As a result, prices for networks may begin to reflect willingness to pay and the value they deliver to the grid, rather than be purely cost-reflective. That is, if a customer is likely to switch to an off-grid solution it would have a lower network charge so that it remains connected and makes some financial contribution to the network.[76]
- Consumers would have the ability to appeal to a government authority in the event that they are dissatisfied with the price / service offering of the utility.

Options to ensure consumer protections for consumers who do not have options (e.g., low-income or apartment dwellers) include:

- Have a regulated price, which could reflect the equivalent per annum price as that seen in the market for off-grid services, or still be calculated on the basis of building blocks.
- Continue to regulate some of the services that could be contestable for these customers.

Table 4.3: Advantages and disadvantages of '"Information Disclosure'

Advantages	Disadvantages
• Competition driven value of services. • Commercial decisions for investments. • Flexible and enabling of new technology. • Competition driven innovation • Market based price discovery	• Requires reasonable levels of effective competition for electricity access. • Will likely require a range of new rules to able the regime to develop. • Not clear if stable investment environment provided. • Depends on business model for transparency. • New consumer protection rules likely to be required.

[76] This type of regulation is analogous to many features of the US rail regulation under which: most companies (those which are liable to switch) are charged low prices whereas stickier customers (e.g. hauling coal and chemicals) with limited opportunity to switch are charged more. A class of customers which are charged higher prices have some protection, and more effective rights of appeal to the regulator. The consequence of all this is that it can be argued that the customers are charged "Ramsey" prices for their network charges. (See US Senate (1983).

Advantages	Disadvantages
	• Asset stranding and risk sharing rules not defined

We have discussed information disclosure with regards to core networks services. However, information disclosure regimes can be applied to specific services in markets that the networks could compete in, without fully deregulating them.

4.2. Consumer protection and service obligations

We reiterate that we are focusing on **consumer protection and service obligations in regards to electricity networks, not for all energy services**. We note that in the current market the majority of customer protection arrangements focus on the retailer or energy service company (ESCO). We do not expect this to change by 2027. We have also observed that consumer protection elements are typically driven by policy decisions and are placed on top of a core regulatory framework, rather than directly influencing the core structure, process or revenue setting approach.

Where the networks' revenues/ prices are regulated, consumer protection and obligations in relation to electricity networks can be categorised as follows:

- **New connections.** The requirement to provide new customers with an offer to connect to the national grid.
- **Reliability and security of supply.** To provide a reliable and secure supply (the provisions of which are specified in Schedules 5.1a, 5.1, 5.2, 5.3 and 5.3a of the NER and some state legislation).
- **Off-grid customers.** Insofar as networks are concerned, the consumer protections and obligations are around customers disconnecting from the grid, and customers who were previously on the grid, disconnected, and now wish to reconnect. This might also include obligations on the networks that, for cost-effective and reliability reasons, propose that certain customers are placed on an off-grid supply.
- **Public safety.** Networks must ensure that electricity is delivered in a safe way.
- **Vulnerable customers.** Networks assist vulnerable customers through the requirement that they deliver a safe, reliable and cost efficient electricity connection.
- **Prices.** Consumers are protected from the companies incurring inefficient costs via the regulator's revenue/ price setting process.

We would not expect any changes to obligations on networks, and other electricity access providers, **to provide safe networks**. However, reliability and access obligations may change. For instance:

- Will network operators be required to provide connection offers (and electricity access suppliers of last resort)?
- Will electricity access for vulnerable customers be cross-subsidised or explicitly subsidised?
- Can different reliability levels be offered to customers based on the price they pay, and access type?

Trade-offs between flexibility in service obligations and consumer protections can be mitigated through the use of code of conducts and/ or dispute resolution. Non-network services providers should face similar obligations.

If the regulatory framework does evolve to a point of information disclosure then we would expect the service obligations and customer protections to better reflect this environment. We would see these reducing to focus on **safety**, **vulnerable customers,** and **arrangements for those leaving the grid**. General customer protection laws would cover the other aspects of the services provided by the networks.

New connections

The current NER requires that networks provide a connection offer to those requiring a new connection. The offer will set out the cost of the works, and any terms and conditions. Under cost reflectivity principles, the cost offered should reflect the cost imposed by the new connection on the system. We consider that options around the service obligations in relation to new connections include those in the text box below.

Text box 4.5: Options – Service obligations and consumer protections – connections

- **Cost reflective connection pricing for demand and generation.** New connectors should be provided quotes that reflect the demand and reinforcement costs and benefit (if any) for generation. Although we note, that there are difficulty pricing at this granular level and pricing methodologies may introduce distortion.
- **Flexible connections.** The customer could request, and the networks could offer, flexible connections. For example, the customer may agree to being disconnected (or having generation feed-in limited) for a lower price/ or different benefits.
- **The retention of the obligation to offer a reasonable quote to connect, however no obligation on networks if quote rejected.**

These options are not mutually exclusive and we note that some of these are being used under the current regulatory framework.

Reliable and security of supply

In terms of reliability and security of supply, networks in Australia are incentivised through the Service Target Performance Incentive Scheme (STPIS) to improve reliability and customer service over time. There is also varying jurisdictional legislation throughout the NEM that requires guaranteed service level (GSL) payments if networks do not deliver to targets.

A key question (highlighted above) is whether customers should be able to request, and networks should be allowed to offer, a greater range of connection reliability i.e., more flexible connections. For instance, could a customer request a connection with lower levels of reliability for a lower price? In terms of customer protection and obligations, there would need to be clear guidelines on the networks, such that the customer understood what they were signing up to and potentially had some form of 'veto' to ensure supply was not interrupted at critical times.

A separate issue is where a customer (or groups of customers), who remains on-grid, enters into relationships with alternative energy suppliers whose actions can result in the customer being disconnected and/or damage to the customer's or the network provider's equipment.[77]

Options around service obligations and consumer protections for supply include those in the text box below.

Text box 5.6: Options – Service obligations and consumer protections – Reliability an security of supply

- Consumers allowed to 'select' their desired level of electricity supply (off-grid or on), and accompanying price.
    - Consumers need to be supplied information ensuring they understand consequences.
    - Networks could offer 'back-up' for customers on a feeder, circuit, who do not want lower quality of supply, and it is more cost effective to defer or avoid shared reinforcement costs.
- Networks able to offer flexible connections with varying levels of supply (and option to disconnect if required).
    - Consumers need to be supplied clear and relevant information to ensure they understand consequences.

Off-grid customers

Off-grid services are potentially an economically viable option for a range of customers and this is forecast to increase.

In advice to the COAG Energy Council (COAG 2015b) the Energy Working Group (EWG) highlighted that there are different types of risks involved with going off-grid, compared to on-grid customers. For on-grid customers:

- retailers manage risk in the cost of generation (although there are now retailers whose business model passes on this risk); and
- networks manage the risks involved in providing regulated levels of quality and reliability.

[77] Networks NSW (2015), pages 2-3.

The EWG noted that "*Most stakeholders considered that there should be some level of consumer protection for customers thinking about going off-grid, ranging from requirements to provide information to help customers make this choice, to requiring explicit informed consent in the same way as the NECF [National Energy Customer Framework], to extending similar consumer protections to off-grid customers as on-grid customers.*"[78]

A key factor of off-grid supply is whether it can offer the same quality of services as an on-grid connection. It is entirely plausible that customers who go off-grid may wish to return to the grid either if the quality of service is not what they expected or better prices/ opportunities were offered on the grid. This was a much debated point, and it was pointed out in COAG's consultation that the option to reconnect to the grid may not be at lowest cost, as networks may not be able to simply keep capacity available.

A related question, is whether, if the network offers the 'off-grid' supply, it needs to provide the same level of service quality as an 'on-grid' supply, or whether its obligations are the same as other off-grid suppliers. There are already customers in remote locations (e.g., regional Queensland) whose electricity supply is not via a connection to the grid.[79] These customers are not considered to be part of the NEM and are covered under jurisdictional consumer protections. This question extends to those consumers that are connected, but which the networks determine it would be more cost effectives (and with similar reliability levels) for them to put those consumers on off-grid supplies.

The EWG noted that many of the NECF protections do not extend to off-grid customers. Therefore, obligations may be required, particularly if the networks are able to place consumers on off-grid supplies. We note that standard consumer laws do apply.

In the case of customers disconnecting from the grid, **some options to provide protection** are set out in the box below.

Text box 5.7: Options – Service obligations and consumer protections – Off-grid customers

- **The network could be obliged to maintain spare capacity on the network for a set period of time for the customer to 'test out' an alternative 'off-grid' option**. After this time if the customer needed to reconnect and no capacity were available then it would face cost reflective connection charges.
- **The network could be able to use the spare capacity as soon as the customer exited the network**, and it would not be required to provide any preferential rights for reconnection. It may be able to offer (at a price) the customer an 'option' to reconnect while the customer tried out the alternative service.

[78] COAG (2015b), page 15.
[79] COAG (2014), page 9.

Vulnerable customers

Energy affordability, and the ability of customers to understand the services they receive and the cost of these services is a significant concern Australia. Options which have been proposed and or are in use in Australia include those in the box below.[80]

Text box 7: Options – Vulnerable customers

- **Information sharing and education.** To prevent vulnerable customers being taken advantage of, clear and relevant information should be provided on the costs/ risks associated with the different options they are faced with. This could also mean, with appropriate privacy protections and permissions, keeping track of vulnerable customers to ensure that they are supported.
- **Social tariff.** Cross-subsidy from other customers. This could be network operator driven through discussion with its broad customer based around the willingness of customer to fund a social tariff.
- **Government funding.** Specific government funding for vulnerable customers. The networks could assist the government in identifying those most at need.

4.3. Other process considerations

In this section we set out some other points we have considered as part of the wider options we have developed. Given the interaction with other parts of a regulatory framework, and subsequent analysis required, we are not in a position to give a firm view on possible options. However, we have raised them below in order to provide our preliminary thinking on possible options.

Rules

Australia has a unique system of developing regulatory rules in the electricity system. A rule-making body (AEMC) sets industry and regulatory rules, following an extensive consultation process. A different organisation, the AER, then implements those rules.

The **advantages** of retaining separate organisations for these functions include:

- It provides stability, transparency and significant investor confidence in the rule-making process.
- It lower regulatory risk by avoiding the potential for 'regulatory opportunism' i.e. changing the rules to reach a desired outcome
- It makes it more likely that rule change assessments do not take account of any failure to implement the previous system properly, but rather are based on a more directed assessment of the rule change.
- It provides a neutral forum for debate about the system.

However, there are **disadvantages** as well, such as:

[80] See for instance, HoustonKemp (2015), page ii.

- It makes it more likely that a rules-based approach to any problem will be adopted. Not every decision can be codified. It is often the case in regulation that the regulator needs to exercise discretion, using its judgement on what the facts of the case are. An institution with a job to make rules is likely to do so, rather than seek an alternative.
- It is unlikely that the institutional framework can be nimble. The rule making process takes 6 months for a standard rule change, excluding prior consultation and preparation time.[81] If a decision is taken to make a substantial change to the regulatory framework, it is unlikely that the regulator can implement this at the next price control review. This makes change very hard.
- It provides incentives for a regulatory body to attribute failures to the rules.

The rule setting/ implementation process is an important part of the regulatory framework. As a pathway to alternative regulatory frameworks, consideration needs to be given to how the rule maker and rule implementer should be arranged and what is appropriate under different approaches – e.g., customer led settlement, information disclosure. A formalised rules-based approach may be inconsistent with an industry where negotiation is more prevalent.

Conduct simultaneous price control reviews for DNSPs and TNSPs

Price control reviews of DNSPs and TNSPs are currently conducted in different years in different states. Transmission determinations are planned for Victoria in 2017, New South Wales, South Australia and Western Australia in 2018, and Tasmania in 2019. For distribution, determinations are planned for Victoria in 2016, Tasmania in 2017, Western Australia in 2018, and New South Wales, ACT, and Northern Territory in 2019.

There may be net benefits from aligning all DNSP price controls and, separately, all TNSP price controls. Some advantages of this approach are:

- Running all price controls simultaneously allows more effective benchmarking and comparisons of different networks. This is likely to promote the use of lighter handed benchmarking tools.
- It is easier to make policy changes on a procedurally fair and equitable basis for all networks. There will be periods when there is no price control work for a particular subsector, a sensible time to make a considered review of regulatory policy.

[81] Except for rule changes where there has been prior consultation (4 months) or where changes are not considered controversial (6 weeks). MHC (2015) (p38) provides several examples of extended rule making processes.

- It makes a level playing field between different network operators, incentivising business improvements. The regulator can implement changes at the same time which means that all networks will be treated equally.
- Provides for focused application of AER resources to a small number of processes, enabling deep analysis of sectoral drivers and conditions

However, there are some **disadvantages** of this are:

- Staggering the price controls may allow for the AER better to manage its resources. With price control determinations in different years for different states, the use of AER's resources would be phased.
- Staggering the price controls allows for continuous improvement of network business planning – as network operators can learn from the business plan layout and the regulator's decisions for other network operators.

We suggest that simultaneity can be handled. Even though price control work for companies in one sub-sector is at the same time, there are other subsectors. Regulators in some other countries have successfully handled a larger number of separate price controls. Setting the price control review timetable to match the set of tools they intend to deploy will help determine the length of time required for the price control review. In the longer term if fast track, customer led or information disclosure approaches are used the burden of simultaneous price change reviews will be reduced.

Appeal mechanisms

The appeals mechanisms, and bodies who hear those appeals, are an important part of the framework. They provide a check against regulatory discretion and incorrect decisions. The exact specification of an appeals mechanism and body depend on a number of elements of the framework including: the overall process approach (i.e., building blocks, information disclosure, etc); and the rule making/ implantation process. We consider that an appeals process will still be an important part of the regulatory framework in 2027, however given factors and the significant analysis (both economic and legal) that needs to be undertaken, options for the appeals process are outside the scope of this report.

5. REMUNERATION

There are many different approaches to setting the remuneration for regulated natural monopolies. These approaches have different attributes and to varying extents depend on the structure of the industry. The choice of remuneration approach is also intrinsically linked to the regulatory process. For example, if there is significant and robust consumer engagement then prices could be agreed based on consumers' values, without an intrusive regulatory assessment.

The current Australian regime relies on incentive based regulation (IBR) framework for setting the networks remuneration. IBR allows for flexible regimes that have an overarching price-cap or revenue-cap to incentivise the regulated company to reduce expenditure in order to earn a higher return. IBR typically extends across multiple years.

The primary difference between using a price path or revenue profile is that under the former the company will bear the volume risk/ reward relative to the forecast demand and therefore has an incentive to increase volume sales.

A key aspect of effective IBR is that it encourages regulated companies to reveal their true efficient costs as they keep (or bear) the difference between allowances and their actual spending. The regulator can then use the revealed cost information to set future allowances. The strength of the incentive to reveal costs depend on how much of the savings (costs) companies can retain and how long they can retain (bear) them for.

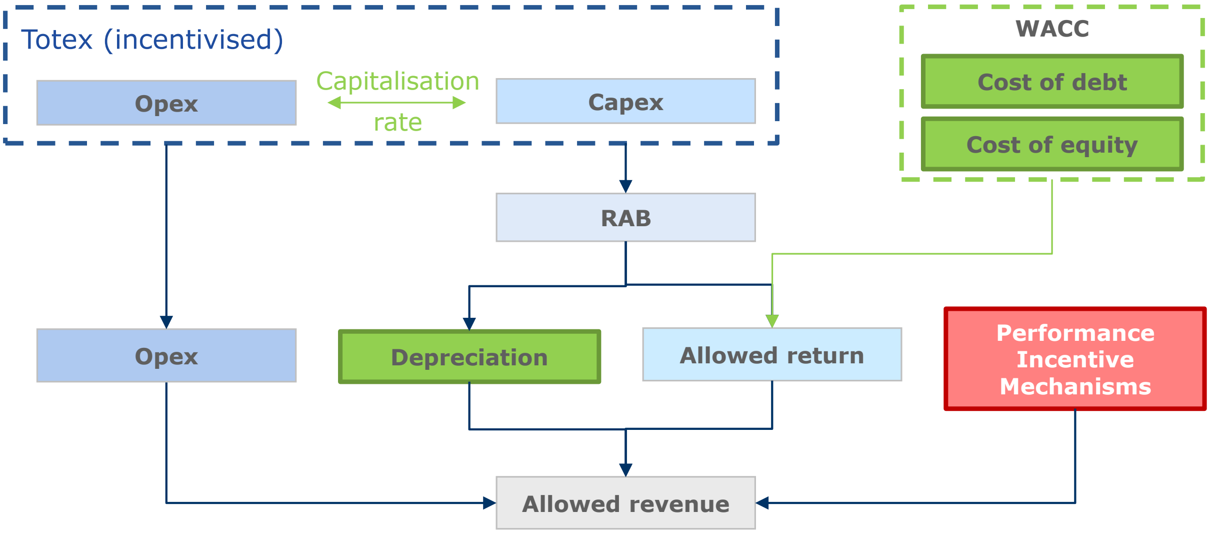
The discussion here is focused on the level of revenue / prices, rather than the structure of charges. The design of the structure of charges is crucial to achieving appropriate outcomes for customers and companies. As highlighted in ENA & KMPG (2016), an appropriate structure should ensure that: customers are able to understand and respond to price signals; customers face prices that are perceived as fairer; there are incentives to facilitate efficient investment in network and distributed energy; and the impact on vulnerable customers can be managed. A full discussion of the structure of charges is outside the scope of this report, and is being considered as part of a separate ENTR work stream.

5.1. The mechanics of estimating revenue/ prices under IBR

IBR is derived from Littlechild (1983). In this seminal paper, Littlechild set out an approach to setting future prices using RPI, the retail price index, which was at the time the main measure of general inflation in the UK, and an adjustment of an 'X-factor'. This is now known commonly as RPI-X or CPI-X regulation. This approach meant that prices would reduce by at least X percent in real terms. RPI-X was invented for the telecoms industry and Littlechild thought that the regime might only need to be in place for a short while as competition developed. Littlechild envisaged the Monopolies and Mergers Commission (MMC) would review the need for the price control at the end of the first one.[82]

The process for determining the X-factor for electricity companies in the early years was less transparent. It was not until after MMC heard the Scottish Hydro-Electric appeal in 1995 that the RPI-X approach developed into what we now commonly refer to as a building blocks approach.[83] Under this approach each element of a regulated company's required costs – i.e., opex, capex, depreciation, RAB and the WACC – over the coming regulatory period are assessed, with an allowance set on the basis of these findings. In addition to the basic cost building blocks, the regulator may also impose incentive mechanisms. These were likely to cover quality of services, either via penalties to prevent services deteriorating and/or rewards to improve service quality. The building blocks approach is illustrated in Figure 5.1.

Figure 5.1: Building blocks approach



Source: CEPA

As mentioned at the start of this sub-section, price-caps and revenue-caps are alternative approaches with different risk sharing arrangements. In addition to the volume risk/ reward, a revenue-cap typically allows more flexibility during a price control for a company to change its services offering (insofar as its revenue allowance allows) to reflect the needs of customers.

Both revenue-cap and price-cap approaches can include mechanisms for uncertainties (risk), such as volume drivers, indexation, pass-throughs, etc. Besides the building blocks approach, other techniques that have been used to set allowances during revenue/ price controls include index based approaches.

[82] Littlechild (1983), page 36.
[83] MMC (1995).

Index based (e.g., TFP - total factor productivity)

Rather than using building blocks to determine forward estimates of required revenue an alternative approach, which is seen as a simpler, is to use a TFP index and extrapolate out the starting prices by CPI-TFP, i.e., base the X-factor solely on a TFP estimate. This approach accepts some 'starting' prices and then prices would need to decrease at least in real terms. In some instances, a forecast of input price inflation can be used as well to adjust for the differences between CPI and the input prices the regulated companies could face. We note that index based techniques can be used within a building blocks approach to set real-price effects (input price changes above/ below CPI) and 'frontier-shift' challenges.[84]

There a number of points to consider with this approach:

- How are initial prices set? Are the starting prices taken as given, does a building blocks approach need to be used on historical costs, or can a financial model be used to estimate the prices?
- What TFP index should be used? How can it be forecast?
- Are consumers protected from companies earning excessive profits? Are companies commercially viable, and is investment supported?
- Should there be an adjustment for input price changes? If so, how should these be calculated?
- Are adjustments needed for the changing outputs?

The answers to these questions are part of the reason why building blocks is the current preferred approach to use with IBR.

A variant of a TFP approach was used by the NZ Commerce Commission in setting distribution network price controls for 2004-09 (described in Text box 5.1 below).

[84] See CEPA (2012b), pages 16-20 for more detail.

Text box 5.1: Price-cap with TFP set X-factor – NZ[85]

The NZ Commerce Commission for its 2004 price control used a TFP approach based on existing starting prices revealed through an information disclosure regime.

- CPI-X was not used to set initial prices, but rather to establish a maximum threshold for price increases.
- If a network breached the threshold, the CC could then impose a full price control (a building-block type approach) or a negotiated settlement.
- While separate quality thresholds were set, these were not explicitly linked to the TFP assessment. As such, increases in cost associated with quality improvements would have appeared as a reduction in productivity (this was identified as a significant issue).
- The X-factor was made up of two components:
    - an industry-wide TFP measure; and
    - an adjustment reflecting whether a network was considered to have high, medium or low productivity/profitability relative to its peers.
- The principle of the comparative component was that low productivity firms should be able to make more rapid improvements.

A key benefit of using a more top-down approach to determining the 'X-factor' rather than building blocks is that network operators are still set the target of lowering their prices in real terms (and incentivised to do better) and the approach to doing this is less intensive for the regulator and network companies. Trade-offs include: that it is may be restrictive on network operators in terms of changing their regulated services offerings (how are prices for different regulated services set), it is more difficult to incentivise service changes, and it may result in financeability concerns (either profits are too low or too high).

5.2. Incentivisation of incorporation of new technology, services and innovation

New technology and innovative solutions, commonly involving opex, may be more cost-efficient than traditional capex solutions. If the building blocks assessment remains focused on opex and capex separately, then networks may be less inclined to implement opex solutions as they will only be able to 'earn' a return by outperforming the opex allowance. The key properties of IBR mean that revealed costs are used by regulators to help set allowances in future. Therefore, over time the scope for networks to outperform their allowances should diminish as they approach the performance frontier. If the regulated companies are profit driven (although this is less clear for government owned utilities)[86] then it is unlikely they will select solutions which do not generate (or potentially reduce) profit unless incentives are put in place to drive this.

[85] Brattle Group (2008); Meyrick and Associates (2003).
[86] For further discussion on this see CEPA (2016a), page 6, and Dimasi (2015).

In the text box below are some mechanisms which can be used to change the incentives on networks that help to make their decision making neutral between methods of delivering services to consumers.

Text box 5.2: Options – Incentivisation of non-traditional solutions

- **Project specific allowed returns.** Companies could propose specific projects, which are typically opex driven, that defer or avoid less cost-effective long-term capex solutions**.**
- **Total expenditure (totex).** Under a building blocks approach both opex and capex are treated the same, and combined for output assessment purposes, with a pre-determined capitalisation rate. This approach helps to equalise incentives, as there is no differential treatment between opex and capex and outperformance is treated the same regardless of expenditure type. If this is coupled with a strong incentive strength then it can help encourage innovative solutions as well as existing alternative non-traditional capex ones.
- **Allowed margin on opex solutions/ services.** Companies can earn a margin on solutions/ services which defer or avoid capex and/or value-added services they deliver (for example, data access, market facilitation or operations). Depending on the structure of the industry this may be difficult to apply, as there would need to be clear cost reporting guidelines.
- **Innovation funds or competitions.** Specific funds (use-it-or-lose-it) or competitions that encourage networks to apply to for research and development projects which they can demonstrate have the potential to improve services/ bring about cost efficiencies. The funds/ competition can be partially funded by network operators and consumers. This option has been applied in GB and Australia.

In the box below we outline some principles that could be used in establishing guidelines for outputs and incentive mechanisms. Incentives should not simply be established as a way for companies to earn more from outperformance; they need a clear link to customers' values and the incentive strength needs be calibrated to this value.

Text box 5.3: Guiding principles for incentive mechanisms

- Focus for establishing incentives.
- The process of how the outputs/ incentives are agreed.
- Incentive strength (financial or non-financial.
- Degree of symmetry – stick, carrot or both?
- Balancing incentives (and trade-off with other outputs/ incentives).
- No double counting of incentives (which includes across expenditure incentives.
- The treatment of risk (for example, the network operator is willing to accept a lower 'base' return for a greater share of outperformance).

We consider that Ofgem's totex approach provides a more robust approach to neutralising incentives across different solutions than individual project incentive schemes or estimating an opex margin. This is because the approach does not require an assessment of each solution/ project, rather the network is empowered to choice the appropriate solution. The benefits are not simply limited to the incorporation of new technologies, as it reduces the need to police cost allocation and capitalisation policies. However, this approach is not without its own problems[87] and requires clear outputs driving the allowance, such as measures of system health and performance, and customers' services and quality of the service. This approach will also have a significant impact on the current electricity rules and the approach to benchmarking in Australia.

Benchmarking will need to evolve with changing technology to ensure that inputs and outputs are reflective of customer and business choices. For example, outputs/ cost drivers based on an overall estimate of fixed assets (a key driver used by Ofgem) or peak demand/ installed capacity (as used in Australia) may not reflect the costs and services the networks face.

We discussed some of the regulatory implications of different business structures – integrated NAO and SO, or separate NAO and SO – in Section 3.1. One implication is around the incentivisation of the different business models. This is discussed in the text box below.

Text box 5.4: Incentivisation of different business models

Implication of different business structures on incentivisation options:

- With integrated network activities, a broad set of incentives can be placed on the network operator linked to the value that customers place on the actions that it takes. As the entity has more 'skin in the game' due to its RAB, the entity has the ability to absorb risks and therefore effective incentives can be placed on their decisions.
- With separately regulated activities, it is likely to be hard to provide such effective incentive regulation for a separate system operator than it would for a company which has network and system activities integrated. 'Asset light' entities do not have the ability to absorb risk. This constrains the effective use of incentives on their decisions (as they pass through most costs).

If different business structures are adopted by different states / networks, this implies that different regulatory rules and approaches to incentives will need to be accepted.

5.3. Risk allocation

Risk allocation is an integral part of any regulatory framework, in the same way as it is in a standard commercial contract, and because of the current scrutiny around this in Australia we consider it appropriate to discuss this in more detail here.

All regulatory regimes require some form of risk allocation, which may vary across different types of risk. Risks can be fully allocated to the regulated company, consumers, to third parties or shared to varying extent across the parties. Risks should be allocated to those best placed to manage them or allocated in such a way as to minimise the overall cost of pricing in these risks. In regards to the latter point, it may be that the network is best placed to manage the risks, however the increased cost of capital the network would require to bear the risk would be significant and therefore the risk is best borne by consumers. This is

[87] As Ofgem has discovered in its attempts to close out DPCR5, where some networks significantly underspent against their capex allowance and thus triggered a reopener.

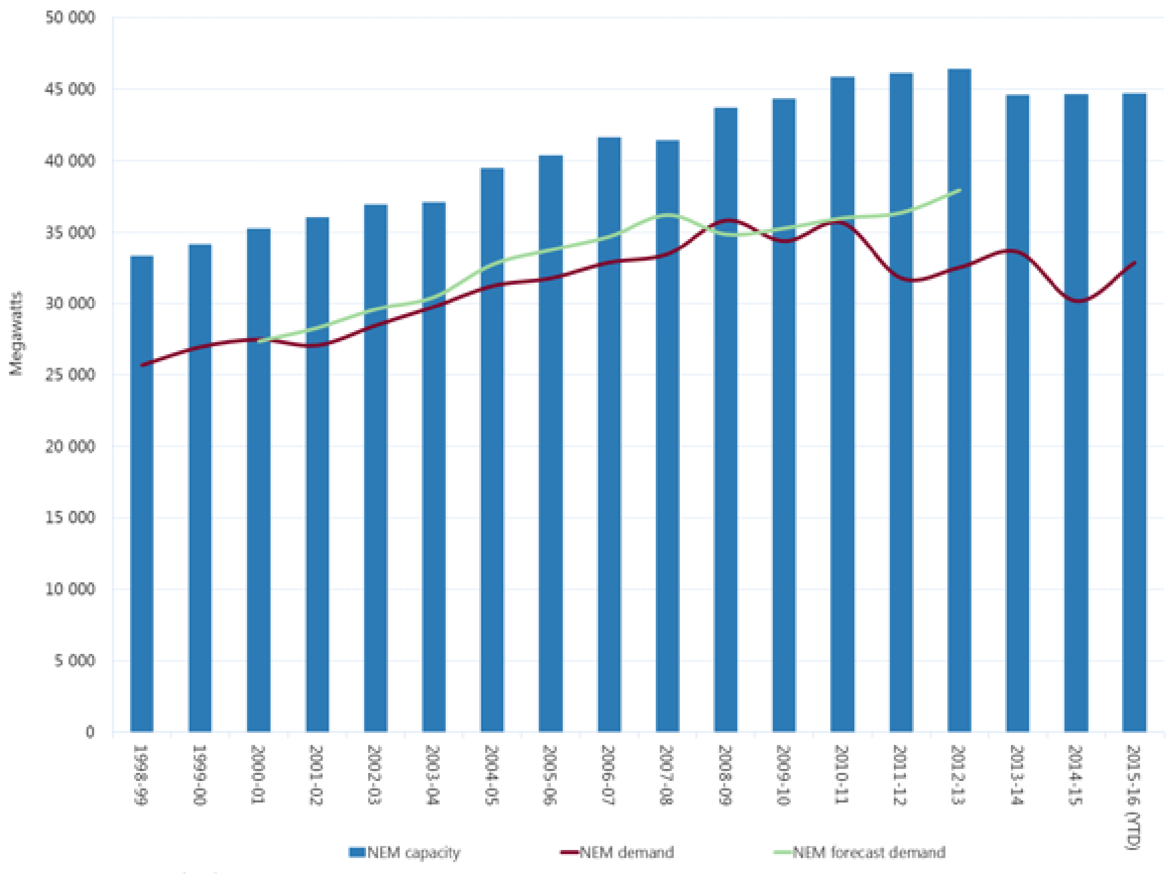
particularly the case where there is a low probability of the risk occurring, but the financial consequences are high.

There are numerous risks that are allocated under a regulatory framework. These include the following:

- **Demand risk.** The demand for services/ products is higher or lower than anticipated.
- **Cost risk.** The expenditure required to provide services/ products is higher or lower than forecast.
- **Stranding risk.** Assets are under-utilised (and forecast to continue to be so) or become obsolete.
- **Regulatory risk.** The regulator makes an incorrect decision or changes the direction of its decisions.

The stranding risk has come under specific focus in Australia with a decrease in peak and electricity demand in recent years since 2008/09 (see Figure 5.2), and the increasing possibility of economically viable low-carbon off-grid electricity supply.

Figure 5.2: Generation capacity and peak demand



Source: AER, AEMO (May 2016)

COAG has explicitly recognised this risk and published initial policy advice in June 2015 (COAG 2015a). In its report, COAG stress tested the regulatory framework around stranding using four scenarios. Under two of these scenarios – 'New consumer choices drive an evolution' and 'Centralised to localised' – there was a medium to high risk of under-utilisation/ asset stranding, increasing the unit price of electricity network services.

We accept that the risk of under-utilised assets and the full stranding of assets, in terms of their usage, are considerable. However, we do note that all four CSIRO scenarios outlined in the ENTR, including 'leaving the grid', estimate that large investments in grid assets will still be required. The forecasts range from $283bn to $336bn (for both distribution and transmission) of opex and capex by 2050.[88]

Under the current regulatory framework, the NER states that the RAB will be rolled forward and the networks will be able to earn a reasonable return of and on this asset base. The NER allow for the AER, at the end of a price-control, to roll-forward the RAB using actual or forecast capex and depreciation. While it has the option to use either, in its most recent decisions it has rolled forward the RAB using actual capex and forecast depreciation. This approach means that for historical assets the stranding and under-utilisation risk is fully transferred to customers. The AER does have some ability under the NER to make *ex post* adjustments to remove inefficient or imprudent capex at the end of each price control.[89]

There is a general view (see for instance Stern 2013), which we agree with, that the RAB roll-forward type approach has led to low required returns on capital.

Approaches to risk allocation and stranding

Approaches to dealing with risk allocation for existing and new assets (i.e., asset stranding or under-utilisation) are, for the most part, entwined, however specific approaches can be taken for future capex. We note that some of the options set out below are available, and potentially, already in use the Australian framework. Until (or if) a point of lighter tough regulation occurs, we still believe these options will be an important part of the regulatory framework's tool-kit.

Approaches for dealing with risk allocation of existing assets include those in the box below.

[88] ENA & CSIRO (2015), page 10.
[89] NER v 80, S6.2.2A and S6A.2.2A.

Text box 5.5: Options – Risk allocation

- **Flexible depreciation profile.**[90] For example, using accelerated or front-loaded depreciation profiles to better approximate the usage of the assets.[91] Ofgem has already adopted an accelerated depreciation approach for gas distribution networks (see Text box 5.6) and ENA (2015) discusses the use of accelerated depreciation to reflect the potential decreasing use of the grid going forward.[92]
- **Asset value write-down.** Under this approach there is a question of who would bear the cost of an asset write-down (see Text box 5.7 for an example of compensation for devaluing regulated assets). If the regulated companies are exposed to this risk then they would require an increase in their allowed cost of capital commensurate with the risk they bear.[93] Rather than pure write-down, the underutilised assets could be 'sold' to governments to bear the risk that the utilisation does not increase; companies could pay the governments a 'fee' to use the assets.[94]
- **Longer-term agreements with customers**. I.e., long-term take-or-pay agreements to ensure that costs can be recovered from those customers who impose costs on the system. Ofgem accepted UK Power Networks' (UKPN) 'strategic' investment proposal for London as it considered UKPN had appropriately demonstrated, through usage commitments, that consumers would be protected from bearing the risk of the stranded assets.[95]
- **Pricing changes**. This could be done as a price reduction for those customers who have a realistic option of leaving the grid.[96] This requires that costs can be recovered for other customers. Alternative specific charges could be applied for those who 'exit' the grid to reflect the expenditure required to provide the customer with capacity.[97]

One of the more interesting issues relates to potential asset stranding under the information disclosure regime, which may apply in the event that there is effective competition for network services. A reduced value of assets would evolve in response to the competitive dynamics. However, it may still be possible for networks to recover these

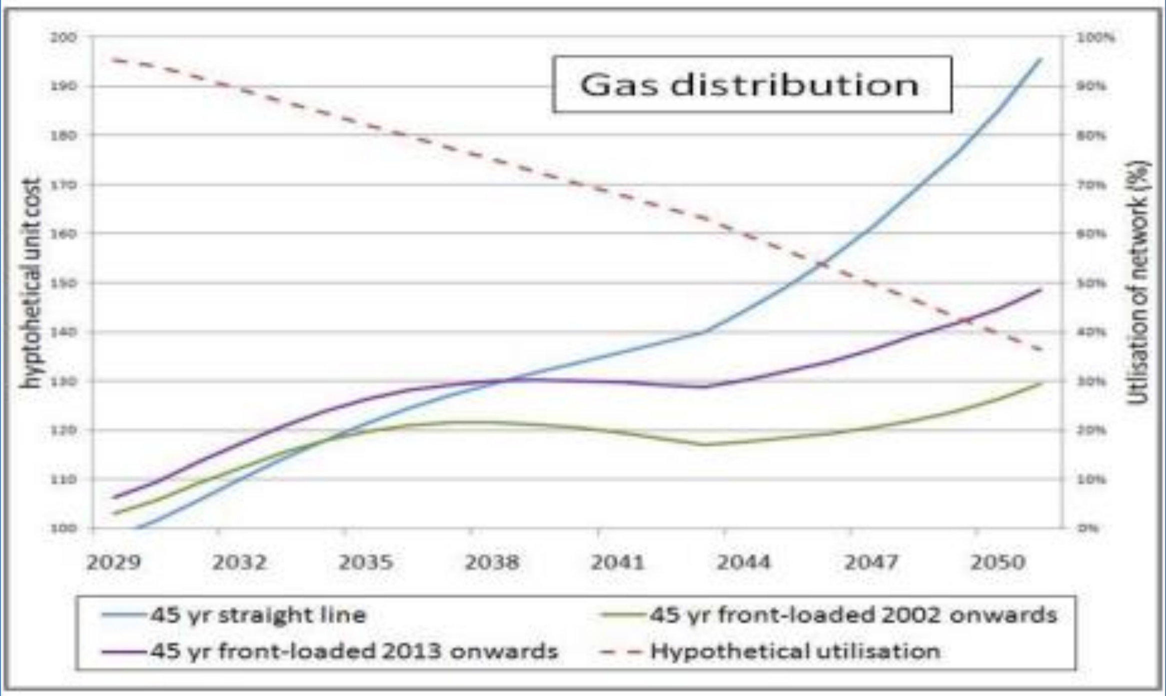
[90] NER v 80, 6.5.5 and 6A.6.3.
[91] For example, if current users are expected to use the network more than future users then they should pay relatively.
[92] ENA (2015), cites the benefits of flexible depreciation of: better reflects 'user pays' principles, longer-term price stability consistent with economic efficiency and consumer preferences, replicate the outcomes observed in competitive markets, position networks to best serve customers in the emerging market, and avoid higher costs by de-risking future cash flows.
[93] See Vogelsang (2014) and ENA (2014). ENA (2014) estimated that the higher cost of capital would led to higher overall prices than if the assets were not written off.
[94] This could work in a similar way to the bad debt transfers from banks seen after the global financial crises. If the networks earn above a certain cap, or network utilisation increases then the networks could pay the government a fee for these assets.
[95] Ofgem (2015a), footnote 9.
[96] We note that under the NER, networks are already able to offer 'prudent discounts' to transmission customers.
[97] These options were discussed in ENA (2015).

charges from other customers. If they cannot then these costs may well have to be borne by the system as an asset write-down.

Text box 5.6: Example of adjusting depreciation profiles

This type of approach has also been used in the UK where Ofgem front-loaded gas networks depreciation due to a view of increased stranding (or under-utilisation) risk. Ofgem applied a recommendation in CEPA et al (2010) that a 45 year sum-of-digits depreciation profile to all of the gas networks' assets would be appropriate based on an estimate of the economic life for these assets. Ofgem illustrated the potential impact of depreciation profiles on unit costs, this is provided below.

Figure 5.3: Illustration of potential per unit charges for the gas distribution network



Source: Ofgem[98]

Text box 5.7: NSW taxi industry[99]

In December 2015 the NSW Government legalised ride-sharing (e.g., Uber). This legislative change had an immediate and significant impact on the value of taxi licence plate holders. In order to compensate the licence plate holders for the loss in value the NSW Government announced a $250m compensation package (around $20,000 per plate). The NSW Government announced that it would fund $100m of the package, with the other $150m being raised through a temporary $1 levy on all rides (on both licenced taxis and ride-sharing services).

For additional forwarding looking risk allocation, if the framework has not developed to the point of information disclosures, approaches include those in the box below.

Text box 5.8: Options – Forward looking risk allocation

- **Increasing the incentive strength on capital**.
- **Allowing for a greater range of output**

[98] Ofgem (2011), page 13.
[99] NSW (2015).

Rather than networks receiving (bearing) the financing benefit (cost) of avoided capex they should receive (bear) a much higher proportion of any under/ overspent against the allowances.

- **Uncertainty mechanisms.** Mechanisms such as indexation, volume drivers, and cost pass-through which allow the allocation of uncertainty (risk) between the companies and customers. This also includes the specific transfer of risk for example companies are able to finance projects a low rates if volume risk is transferred away from them (see Text box 5.9).

incentives which align with customers' valued services. The incentives could adopt a range of mechanisms to transfer risk based on services delivery e.g., networks trade-off between a lower 'base' return on capital and a high-powered incentive to deliver the outputs, or the incentive is symmetrical and targeted to deliver the base return on capital if there is no under- or out-performance.

- **Incentives across opex and capex should be equalised.**[100] The incentive rate on capex should be the same as that on opex.

Text box 5.9: Offshore Transmission Operators regime[101]

In the Offshore Transmission Operators (OFTO) regime run by Ofgem. The operators are guaranteed payment across the life of their contract; they only face an availability risk (i.e., they have an incentivised target level of availability for the transmission asset). In their review of the first tender round of the OFTO regime, CEPA and BDO considered that the cost of capital was significantly lower than it would otherwise have been as a result of the guaranteed payments.

Third party investment

While not a risk allocation mechanism *per se*, customers and other third parties investing in DER or other assets can reduce the investment requirements of the networks. This transfers the investment risk away from the networks and therefore of all customers bearing the full investment costs (if the resource is underutilised). Of course if the third party investment (e.g. storage) is used solely for offsetting network augmentation then the return on this investment, and hence charges, will reflect the risk allocated to the investor.

Advantages and disadvantages of the different options

In the table below we set out some of the advantages and disadvantages of the risk allocation options discussed above.

Table 5.1: Assessment of risk allocation options

	Advantages	Disadvantages
Flexible depreciation profile	• Depreciation profile can be changed to reflect economic (customers') use of the assets – i.e., intergenerational equity better reflects asset usage.	• Depreciation profile needs to be determined. • Some customers may bear higher costs depending on the profile.

[100] CEPA's (2016) review of efficiency benefit sharing schemes for IPART indicates that the current approaches in electricity in Australia do not equalise opex and capex incentives.
[101] CEPA and BDO (2014).

	Advantages	Disadvantages
	• It can help to stabilise prices. • Maintain financial capital maintenance.	• May have an impact of competition developing if accelerated profile used.
Pricing – Flexible pricing/ exiting the grid prices	Flexible pricing (customers charged differently to retain them on the grid) • Customers retained on the network. Exit prices • Customers are charged for the costs they created for the system.	Flexible pricing • Perception that the pricing is 'unfair'. Exit prices • Difficulty in implementing these *ex post.* • An accurate estimate of the costs created by the customers would need to be determined. • May be seen to impede competition.
Longer-term agreements with customers – long-term take-or-pay contracts.	• Customers are charged for the costs they created for the system. • Incentive on customers to remain connected.	• Difficult to impose these terms on existing customers. • Difficult to impose terms on domestic or smaller commercial customers.
Asset value write down	• Prices reduced to reflect utilisation of assets. • Could enable networks to retain customers on the network.	• Unclear how to assess magnitude of required write down given high likelihood that individual assets will continue to be used. • Unclear that utilisation of assets reflects private value associated with connectivity (i.e. % utilisation may be the wrong measure). • An entity has to bear the cost of the write-down. • Depending on who bears the cost: ○ it may significantly increase costs to current and future consumers in future due to higher financing costs or required adjustments to maintain financeability; and ○ potential to raise regulatory risk profiles across –infrastructure. • How should utilisation increases of a written down asset be dealt with?
Incentive rates on future capex/opex	• Calibrated to reflect an appropriate transfer of risk around forecast expenditure.	• Difficult to get the incentive strengths right. • Stronger rates increase the incentive

	Advantages	Disadvantages
		on networks to over-forecast.
Uncertainty mechanisms	• Specific mechanisms can be used to allocate risk between parties. • Different services/ costs can have their own mechanism.	• They add complexity to the regime. • There may be inefficient transfer of risk for items which networks have partial control over.
Third party investment	• Risk of underutilisation transferred to third parties. • Use of services determined by the market.	• Purchased services will reflect the risk associated with underutilisation. • May be more cost effective for networks to own the assets.

6. PATHWAYS AND CONCLUSIONS

Technological change, including the rapid integration of DER and increases in detail and availability of data on usage, is transforming the electricity industry, the way that energy networks are used, and potentially the economics of networks.

Lessons from case studies

Many jurisdictions are considering how their regulatory frameworks should evolve to accommodate the transformation occurring in the electricity sector. We reviewed four regimes – Australia, California, New York and Great Britain's – where detailed consideration is being given to these issues. There are also a number of alternative regimes and innovative approaches being used in other sectors which we investigated. Some key lessons we have drawn from the review of the regimes are set out in the box below.

Text box 6.1: Lessons from the case studies

1. Visions for electricity regulatory frameworks reflect existing structures – vertically separated networks in GB and Australia, and vertically integrated in California and New York, but separate or potentially separate system operators (at transmission level and/ or at the distribution level). Approaches and mechanisms for scope of services, incentives and risk allocation need to be considered in the Australian context of the clear separation of networks from electricity generation and retailing.
2. Regulators are providing, or moving to provide, a 'return' on alternative solutions (predominately operating expenditure [opex]) to poles-and-wires, in order to neutralise networks' incentives across these options. There is a range of project based incentivisation (NY REV and proposed for California) and total expenditure (Ofgem).
3. Most regulators are taking a risk-averse, but flexible approach to allowing networks to offer services that may become contestable. They are allowing DER, particularly storage, to be owned in a limited way, but are encouraging networks to source these services from third parties.
4. The regulators are trying to increase and
5. Approaches to risk allocation are similar: the RAB is either legally protected or there are high levels of assurance around recovery of past costs; networks purchasing services from third parties rather than owning the assets themselves is seen as a way of transferring risk. Although Ofgem's approach to third party competition for 'core' network services has been to transfer the risk to customers by providing guaranteed revenue (as long as performance is appropriate).
6. Consumer involvement in the regulatory process is being enhanced (not just in electricity, but all infrastructure regulation). The benefits from customer engagement include more input into the outputs required/ desired, and buy-in from consumers of the regulatory process. In some instances, consumers have taken a role in the decisions making process.[102]
7. The regimes are becoming more complex as the industry transforms. While there is some significant 'refocusing' of regulatory frameworks, some of the added complexity appears to be the result of layering new arrangements on top of the existing frameworks.

[102] We note that Ofgem's review of its price control process concluded that consumers were not willing or able to take a decision making role

improve the information provided to consumers, third parties and networks. This includes investigating the provision of information on granular level locational demand, generation and pricing signals.

One clear lesson from the case studies is that the **structure of charges** is critical in ensuring that customers (and consumers) can make appropriate choices in regards to DER, their electricity use and generation placement. The availability of timely and locational specific pricing is a key part of the network transformation, however consideration of the appropriate approach to structure of charges is outside the scope of this report. ENA & KMPG (2016) sets out their view of the reforms required by 2025, and this includes the option of localised pricing options.

The transformation has the potential to lead to a new regulatory framework

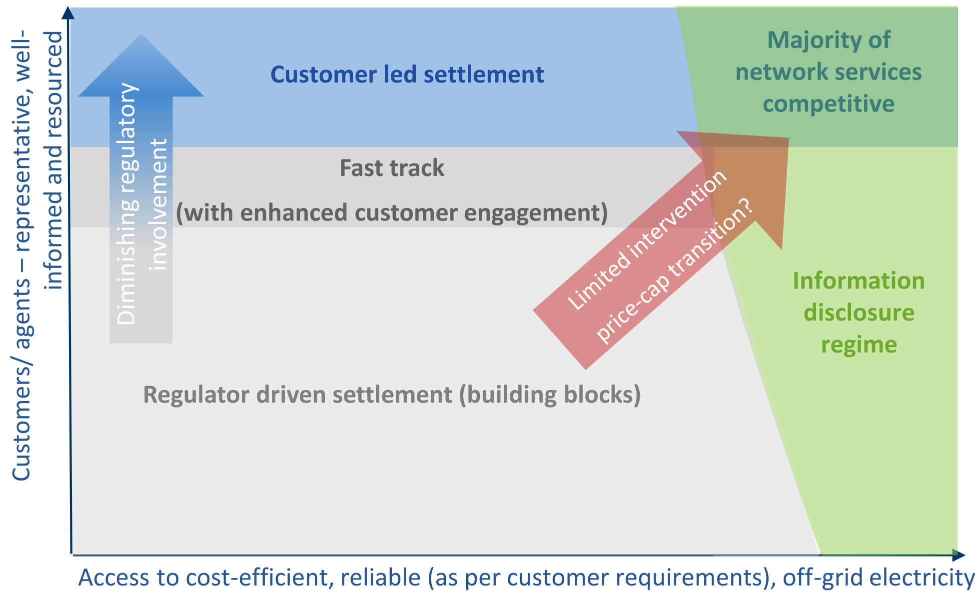
The transformation provides potential for the regulatory framework to evolve from a regulator-driven approach to more customer-led or lighter touch information disclosure approaches. This is not an overnight process and we have been asked to consider possible regulatory framework options for 2027.

Under the current Australian incentive-based regulatory 'building blocks' process, there is a **regulatory-driven settlement** – i.e., the regulator makes the majority of decisions around services and prices on behalf of consumers. As customer access to information and new technologies increases, including in some cases expanding cost-effective and sufficiently reliable off-grid options, the opportunity exists to move towards **customer-led settlements.**

Under these types of approaches customers or their agents engage and negotiate directly with energy network businesses. Even lighter touch frameworks may become feasible over time, such as **information disclosure** oversight models that place a greater emphasis on lower cost monitoring approaches.

This change, driven by increased customer choice and engagement and potential access to non-grid alternatives, is illustrated in Figure 6.1.

Figure 6.1: Framework evolution driven by customers and off-grid option



Source: CEPA

With robust **consumer protection** mechanisms in place these framework options offer potential improvement over the current framework. This is because the services that customer most value are directly taken into account, and the framework is likely to be more flexible for the evolution of services and to be nimbler, allowing it to change over time to meet emerging customer needs.

Text box 6.2: Service obligations and customer protections

The evolution of **service obligations and consumer protections** will be a critical part of the pathways to and eventual scenario reached in 2027. In our view the transformation requires networks to have greater flexibility in their service obligations, such as:

- offering flexible connection (e.g. limited capacity, option to disconnect at peak times);
- potentially having a different role as provider of last resort (as cost effective off-grid becomes more widely available); and
- ensuring that those going 'off-grid' are offered information/ education and, potentially, a way to reconnect

Reaching the right risk allocation for the future

Under all regulatory frameworks there are aspects of risk allocation which need to be managed. How risks are allocated between customers and energy networks are a critical part of a future regulatory framework.

The significant changes to energy markets mean it is timely for the community to consider risk allocation models of the future that will allocate risks between those best able to manage them and deliver efficient future investment decisions while minimising financing costs.

Critically, while different allocations of risk are possible, all involve trade-offs and costs have to be borne somewhere in the system. The appropriate risk allocation will also flow from community expectations of what the 'grid' is, and what it is expected to deliver as a shared national asset.

Text box 6.3: Risk allocation options

Options for risk allocation include:

- varying the incentive rates on the networks;
- introducing more output incentive arrangements (to align with customers' values);
- changing the balance of risks borne by current and future users, for example, by changes to asset depreciation profiles;
- introducing longer-term connection contracts or grid exit payments (for covering sunk costs); or
- changing the profile and allocation of risk for new investments.

Sufficient change may not have occurred by 2027

Reaching the frameworks towards the top-right of Figure 1 requires substantial change in the sector which is unlikely to be reached by 2027. Therefore, an evolved form of incentive-based regulation may still be needed in 2027, but with a greater range of incentives, and embedded tests to provide a smooth process for more services to become competitive (or move to an information disclosure regime) and greater customer involvement in any price/revenue control process.

At present, there is provision for the classification of network-related services to change when they become contestable. However, the regulatory framework in Australia needs a clear and logical system and test to determine and manage this issue. Networks could provide these contestable services subject to specific conditions including a cost-benefit test demonstrating if this is in the interest of consumers. A cost-benefit test could either be included in the regulatory framework, or networks could themselves make proposals on business structures and mechanisms.

We note that the Australian regulatory framework is already evolving to include some of the above mechanisms.

Text box 6.4: Transitional options

Measures that may help transition to lighter (regulator) touch frameworks, include:

- increasing the incentive on networks to treat alternative (and innovative) solutions equally – we suggest that the total expenditure (totex) is a promising way of achieving this;
- increasing the opportunities for networks to propose outputs/ incentives which align with customers' values;
- allowing different network structures to reflect their changing functions and ability to offer

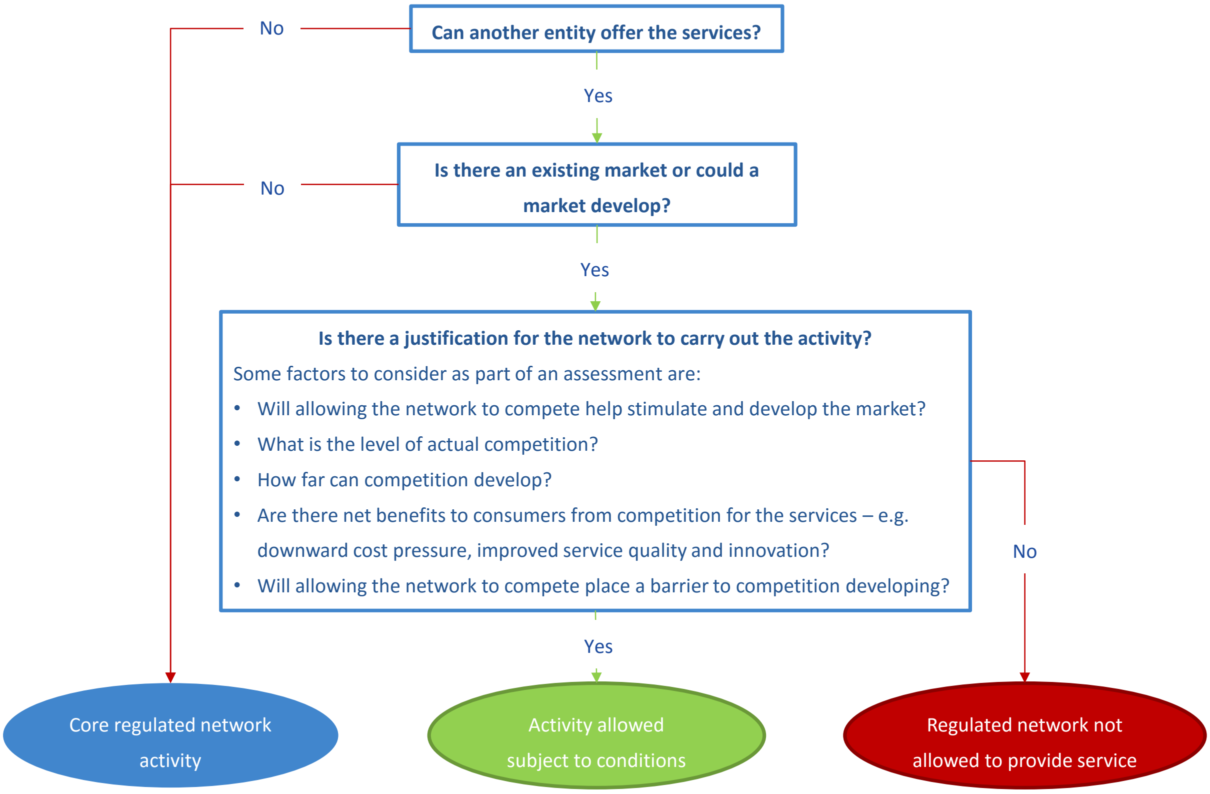
services customers value; and

- increasing the role of customers in the regulator driven settlement process and offering ways to reduce regulatory scrutiny – i.e., the regulator can 'fast track' business plans, with or without a financial reward, that demonstrate a clear regard to the long-term interests of consumers.

Our review of international experience provides examples of successful implementation of some of these ideas.

At present, there is provision for the classification of network-related services to change when they become contestable, but the regulatory framework in Australia needs a clear and logical test to determine this (we have developed a set of tests for this, illustrated in Figure 6.2 below). Networks could provide these services subject to conditions including a cost-benefit test demonstrating if this is in the interest of consumers. A cost-benefit test could either be included in the regulatory framework, or networks could themselves make proposals on business structures and mechanisms.

Figure 6.2: Determining regulated activities



Source: CEPA analysis

The last step in Figure 1, the key test is whether having networks perform the activities is in the long-term interests of customers.

Strawman options of possible ways to increase the nimbleness of the regulatory framework to allow transition between regulated, new and contestable services are set out in the box below.

Text box 6.5: Options – Increasing nimbleness of the regulatory framework to services

- Integrate a competition test within the regulatory framework. Individual networks could apply for services to be classified as unregulated. These services would be subject to price-monitoring. The AER/ AEMC would consider applications first, with a 'back-stop' process if the network disagreed with the ruling. Aside from an information disclosure regime, networks should only be subject to the same obligations as their competitors. A code of conduct for the services, which apply to all players, can be used help ensure customer protections and a level playing field.
- Allow networks to make proposals for their own business structures and mechanisms to provide transparency and to demonstrate that it does not create a barrier to competition developing (if that is a positive outcome). This may require a shift to specific rules (or licences) for each network operator, which sets out common, but also individual obligations.
- Services that are contestable should be subjected to less regulatory oversight.

A test to determine whether transmission and distribution services as a whole are contestable would likely follow a similar process to that laid out above. The test should be included in the framework, and the ability for competition of off-grid electricity services (with comparable reliability) to offer a 'soft' price-cap may assist in a more to an information disclosure/ pricing monitoring regime. The key elements of the test would be: (i) the proportion of the market with access to off-grid services; and (ii) the price differential between the two.[103] We are not aware of evidence of these factors being calculated in other jurisdictions, and careful consideration would need to go into determining them, however we suggest that only a significant minority (10-20%) would need access and the price need have reached parity before it can be used as a cross-check to a network prices.

Text box 6.6: Principles for the competition test

It is important to ensure that:

- Competition tests and processes restricting that the way that networks are involved in these markets are appropriate. Consistent with Hilmer, it is appropriate for restrictions on networks' involvement in these activities to be assessed on whether it harms consumers, rather than a default prohibition. This assessment will reflect the structure of the business.
- Competition tests are applied in a nimble way so that they facilitate appropriate investment in technologies.
- Competition tests should be proportionate to the size of the market they are serving.
- Restrictions on activities are such that the maximum commercial value both in energy and network markets will be exploited.

[103] The method for separating, or comparing combined, energy and network prices would need to be developed as well as an approach for reflecting differential locational and time of day pricing.

Transitional arrangements

As competition for core network services develops, one possible transitional approach is to move towards a price-cap regime where the regulatory involvement in setting ongoing prices is more limited and focuses on only using external measures such as productivity measures (including so-called total factor productivity index approaches) to adjust future prices.

The appropriate pathway for regulation should accommodate the uncertainty to 2027

Next steps for regulatory development should reflect the range of possible regulatory models that may be appropriate. However, there are a range of steps illustrated in Figure 6.3 that can be taken that would accommodate all these models, meet best practice regulatory design principles, and at the same time enhance the regulatory process better to meet the needs of customers.

Figure 6.3: Pathways

Steps

1. Test totex incentive approaches – rather than project/ expenditure type incentivisation schemes.
2. Develop competition tests for introduction into the regulatory framework, which assess network operators' scope for competing and allow for competition to develop.
3. Development of guidelines / principles for network proposals for outputs/ incentives, which ensure that the regulator assesses them for positive consumer benefits.
4. Develop a code-of-conduct for industry actors to provide information and education regarding services to customers.
5. Reduce the rules based approach, by focusing on outputs and incentives, to allow discretion for the regulator and companies to increase innovation.
6. Consider how the regulatory process can place more 'weight' on network operators' engagement with customers to agree outputs and risk allocation.
7. Investigate – including the trade-off between more service offerings and 'policing' of its arrangements – the establishment of a process where network operators can adopt alternative business structures and the need for differentiated rules.
8. Develop guidance on how to deal with underutilisation of assets (stranding), if it arises.
9. Introduction of more granular cost reflective pricing on demand and generation connections.
10. Move to align all DNSPs price controls and separately align all TNSPs.

Focus on outputs and incentives

Enhanced customer engagement

Options

Majority of network services competitive

Information disclosure
1. Clear guidelines on the information networks are required to disclose.
2. Vertical competition may still be restricted.

Customer driven settlement.
1. Customers and their agents engage directly with the networks.
2. Regulator acts as arbitrator and provides objectives/ guidelines for agreement.

IBR for a narrower scope of services
1. Regulator still determines bulk of building blocks.
2. Proportionality increased – fast track.
3. Competition across a wider range of services.

Source: CEPA

Specific examples of what might need to be done as part of the steps laid out in Figure 3 are set out in Table 6.1 below.

Table 6.1: Supporting activities for pathway steps

Steps	Supporting activities
Totex	• Assess the rules which would need to change: depreciation, RAB roll-forward, opex, capex, capitalisation rules. • Introduce rules that allow for testing of totex without requiring initial wholesale changing of the framework (a 'sand-box approach'). • Test totex use for a set of business as part of a single price control cycle.
Competition tests	• Establish flexible criteria for testing scope of regulated services. • Allow networks to propose which services they can offer without price regulation.
Guidelines for outputs and incentives	• Identify the scope for allowing new/ changed outputs and incentives under the rules. • Set a commitment that if networks demonstrate that outputs and incentives deliver net consumer benefits then it should be included in the price control.
Code of conduct	• Carry out consultation across stakeholders as to what clear and relevant information is required for different consumers – location based, need based. • Determine obligations on what services can be offered to different consumers. • Establish an 'explicit' consent mechanism that consumers must give that demonstrates understanding of the services provided.
Decrease in the rules	• Establish a process to trial a simplification of rules or ability of networks/ or introduce lighter touch regulatory process AER to request more discretion.
Place more weight on consumers' input	• Explore the potential to add a dedicated 'fast track' regulatory process into the Law and Rules as an alternative to the full existing determination process. • Start with small decisions and, if successful, increase consumers' role. Regulator provides commitment that decisions will be taken account of. • Could form part of the fast track process, with consumers being required to sign-off a range of outputs.
Forward guidance on risk allocation	• This would require the development of a policy paper to identify potential approaches and indicators of the need for any further action.
Granular cost reflective pricing	• Accelerate the current pricing reform processes being undertaken.
Alignment of price controls	• AEMC to undertake a CBA of aligning, including transitional costs and resourcing requirements. • Identification of any rule change requirements. • Test the alignment process across one set of networks.

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ANNEX A CASE STUDIES

A.1. Australian framework

A.1.1. Structure

Decision maker/implementer

Responsibility for electricity network regulation is divided between the AEMC (rule maker) and the AER (rule implementer):

- The AEMC's primary responsibility is to make and amend the NER. Rule change proposals may not be instigated by the AEMC (except in very limited circumstances), but rather initiate with other regulatory bodies, market participants or other interested parties.
- The AER undertakes economic regulation of electricity networks operating in the NEM, determining the allowable revenue they may recover for the provision of regulated services. Other regulatory functions include network tariff compliance reviews (including compliance with cost-reflectivity principles, when this comes into effect) and the development of ring-fencing arrangements where networks provide both contestable and regulated services.
- AER determinations may be referred to the Australian Competition Tribunal for a merits review. A judicial review process is also available.

Market participants

The NEM comprises five transmission networks, as well as three interconnectors linking the different NEM regions. All are regulated with the exception of Basslink (the Victorian-Tasmanian interconnector). The networks are maintained and operated by Transmission Network Service Providers (TNSPs), who – with the exception of Victoria - also undertake network planning and development. Victoria is unique in separating transmission asset ownership from planning and investment decision-making, which is undertaken by AEMO. [104]

There are 13 major distribution networks within the NEM, maintained and operated by Distribution Network Service Providers (DNSPs). The networks have a monopoly position in their region, and are thus subject to economic regulation by the AER. Ownership of distribution network assets overlaps with retail services in the ACT and Queensland, which currently requires ring-fencing for operational separation. [105]

[104] AER (2015b)
[105] AER (2015b)

In addition to the NEL and NER provisions, TNSPs and DNSPs are subject to other national and state regulation including: network reliability standards (shaping network development and investment); licence conditions (which set out a range of obligations, including consumer protection measures); and other environmental and planning regulation.

System operations

AEMO has the core roles of Power System Operator and Market Operator, with responsibility for management of the NEM and oversight of system reliability and security. As the National Transmission Planner, AEMO also guides transmission network investments through preparation of the 20-year National Transmission Network Development Plan (identifying constraints and potential network and non-network solutions) and the Electricity Statement of Opportunities (a 10-year forecast of the supply-demand balance within the NEM).[106] As noted above, in Victoria AEMO also undertakes transmission planning.

A.1.2. Process

Network businesses are required to periodically submit revenue proposals to the AER for review. Reviews typically take place every five years, although the regulatory periods for network businesses in different regions are not synchronised. The revenue setting process commences 32 months before the end of the current price control, with the AER required to deliver a final determination at least two months before the new regulatory period commences.

The NER require service providers to outline how they have engaged with electricity consumers and reflected their concerns in the regulatory proposal.[107] In 2013 the AER issued a set of best-practice guidelines on customer engagement, but does not otherwise prescribe how this should take place. The AER also incorporates consumer views into its own decision-making, primarily through the Consumer Challenge Panel (CCP), as well as through public forums and submissions during the price control review.

A.1.3. Revenue setting

The AER applies a standard building-block approach to setting allowable revenue, overlaid with additional incentive adjustments:

- The building block model assesses each network's efficient costs to provide the regulated services, including estimation of capital expenditure (and the regulated asset base), operating and maintenance costs, depreciation, taxation, and a return on capital (updated annually to reflect changes in the cost of debt). This sets a cap

[106] AEMO (2014)
[107] AER (2013)

on the maximum revenue that a network can recover during the regulatory period.[108]

- In addition to the building-block assessment of total efficient investment, network businesses must also undertake cost-benefit analysis of large individual projects, taking into account other credible options (including non-network solutions).[109]
- Under the operating cost efficiency benefit sharing scheme (EBSS) and capital expenditure sharing scheme (CESS), outperformance (or underperformance) is partially shared with customers, incentivising networks to make efficiency gains. The CESS combines with ex-post assessments that allow the AER to exclude inefficient or imprudent capital expenditure from the regulated asset base.[110]
- A service target performance incentive scheme (STPIS) operates for both transmission and distribution networks, and is intended to balance the EBSS so that expenditure is not reduced at the expense of network performance.[111]
- In 2015 the AEMC finalised a rule change providing for a demand management incentive scheme (DMIS) - rewarding implementation of efficient non-network options to manage demand – and a demand management innovation allowance (DMIA) - providing R&D funding for pilot projects.[112]

A.1.4. Power of Choice Reforms

The Power of Choice review concluded by the AEMC in 2012 set out recommendations to facilitate demand side participation (DSP) in the NEM. In particular, the reforms aim to improve customers' ability to manage their consumption through better information, services and price signals. The review led to a number of proposed rule changes, including the development of cost-reflective distribution tariffs, opening metering services to competition, allowing consumers to more easily access their consumption data and incentivisation of demand management services. Changes relating to metering services and network tariffs are summarised below:

- In 2015 the AEMC concluded a rule change opening metering and related services to competition, intended to facilitate the deployment of smart meters. Under the new rule, from 1 December 2017 any registered party will be able to provide metering services to retailers. The implementation of arrangements to support this rule

[108] For distribution, the AER may apply either a revenue or price cap. At present, total revenue caps are used in most states, while an average revenue cap applies in the ACT (linking revenue to sales volumes). AER (2015b).
[109] AER (2015b)
[110] AER (2015b)
[111] AER (2015b)
[112] AEMC (2015a)

change are currently underway, including development of revised distribution ring-fencing guidelines by the AER[113].

- Commencing no later than 2017, distribution network tariffs will be required to comply with four cost-reflective pricing principles, with the aim of providing price signals to consumers that incentivise efficient consumption. The principles state that tariffs must: reflect the long run marginal cost of providing the service; minimise distortions to price signals; apply price structures that consumers are able to understand; and comply with any jurisdictional pricing obligations. The AER is currently consulting on DNSP proposals to incorporate these principles into their pricing structures[114].

A.1.5. Risk Allocation

The regulatory framework implies an allocation of risk between regulated businesses, customers and third parties. Risk allocation in the current regulatory regime is outlined briefly below.

- **Demand Risk:** The AER currently applies a revenue cap approach to setting allowable network revenue. This reduces the exposure of network businesses to demand fluctuations, relative to a price-cap approach.
- **Stranding Risk:** In the current regulatory framework, this risk has been largely allocated to customers through the roll-forward of historical capital expenditure into the RAB (notwithstanding AER adjustments to remove inefficient investments).
- **Cost Risk:** Risks associated with unforeseen changes in CAPEX or OPEX are currently allocated through incentive mechanisms (EBSS, CESS) which provide for a sharing of costs/benefits between the regulated business and its customers. Annual adjustments are also made to share the impact of fluctuations in the cost of debt, although shifts in the cost of equity are borne by the network business. The AER may also consider adjustments to revenue determinations for contingent projects that are subject to considerable timing or cost uncertainty.
- **Regulatory Risk:** Under the NEL, any interested party (network businesses, customer groups or others) may apply to the Australian Competition Tribunal for a review of AER decisions. The Tribunal is required to determine whether an alternative decision would have been materially preferable in meeting the long term interest of consumers.

[113] AEMC (2015b)
[114] AEMC (2014)

A.2. California

Context

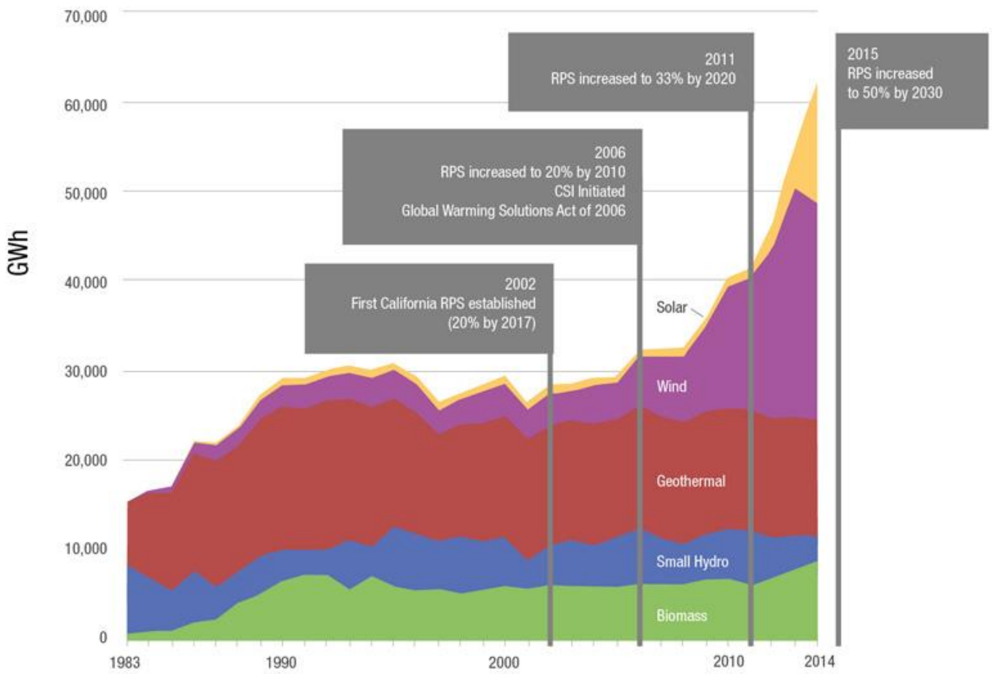
California's electricity industry is ranked second (after Texas) among US states by electricity consumption and fifth by generation (after Florida, Illinois, Pennsylvania and Texas)[115]. More importantly for this report is that it is the US state with the highest penetration of DER. In data collated for the New York System operator (DNV GL 2014) California was reported to have over 2GW of installed DER – more than three times the level for the second ranked state, New Jersey (671MW).

California experienced an energy crisis in 2000-01, with volatile electricity prices and blackouts. This followed deregulation in the 1990s, combined with a regulatory framework that prevented utility companies serving final customers from hedging their purchase costs and from passing on high wholesale prices. This placed severe financial pressure on the companies, and forced one (PG&E) into bankruptcy. In response to this, the state government developed an Energy Action Plan to ensure sufficient generation capacity and network infrastructure to meet demand.

An important feature of California's energy policy has been to decarbonise electricity supply. In 2006, the State passed legislation to reduce GHG emissions to 1990 levels by 2020 (AB 32). Renewable energy has been incentivised directly since the 1970s with obligations placed on utilities to purchase renewables at cost. In 2002, California introduced a Renewable Policy Standard with a target of 20% of retail sales being met by renewables by 2017, later increased to 20% by 2010 and 33% by 2020. In 2015 this target was further extended which among other provisions set a target of 50% contribution of renewables to electricity generation by 2030 (Senate Bill 350). It is this legislation that has driven the strong growth in electricity production from renewables and solar energy, with a focus on wind from 2006 to 2013, and a subsequent material increase in solar energy.

[115] See EIA (2016).

Figure A.1: California Renewable Energy generation from 1983-2014 by resource type (in and out of state).



Source: California Energy Commission (2015).

The regulatory framework has therefore clearly encouraged the development of DER and has been successful in this. The approach to achieve this has been top-down: legislation has provided targets, and the regulator has put in place rules to achieve the targets, which have in turn been implemented by the utilities and other industry organisations. Further rules and initiatives are under discussion to implement the more recent legislated targets of Senate Bill 350.

More radical reform is being considered by the industry (see AEEI (2015)), but the initiatives here are at the very preliminary discussion stage.

A.2.1. Structure

Industry structure

- California's electricity industry comprises:
- Six investor owned utilities, of which three are dominant (Pacific Gas and Electric (PG&E), Southern California Edison, owned by Edison International, and San Diego Gas & Electric, owned by Sempra Energy);
- 46 public-owned utilities;
- A range of other electricity service providers, rural electricity cooperatives, and community choice aggregators; and

- Independent generators.

While there are a large number of load-serving entities, the five largest utilities (the three dominant investor owned utilities, together with Los Angeles Department of Water and Power, and the Sacramento Municipal Utility District) serve over 80% of consumption.

In contrast to Australia, therefore, the industry exhibits a higher degree of integration between generation, networks, and retail.

System and market operations

The largest utilities own transmission assets in addition to distribution. System operation is coordinated by the California Independent System Operator (CAISO). The CAISO has a very wide set of responsibilities which includes:

- Operation of a spot electricity market to ensure balancing of supply and demand (based on differences from scheduled transactions).
- Coordinating the despatch of any required ancillary services.
- As system operator, identifies any adjustments to despatch schedules to maintain system integrity.
- System planning, for connection of new generation assets as well as required expansion of the network to accommodate changing patterns of electricity flows.
- Settlement of transactions using the market functions of the ISO.

CAISO is run as a non-profit public benefit corporation. It is intended through its structure to be independent of the wholesale market.

Structure of regulatory organisations

There is a common structure to regulation across the USA. Regulation of transmission and wholesale electricity prices is the responsibility of the Federal Energy Regulatory Commission (FERC). Final customer prices are regulated by the state regulator when customers are served by investor-owned utilities. In the case of California, this is the California Public Utilities Commission. Public utilities are regulated by the relevant local authority.

In addition, California has an Energy Commission which is a policy and planning agency established by state law. In addition to long-term planning, it has responsibilities to facilitate investment in renewable energy and innovation.

Prospective changes

No formal change is envisaged in the structure of the California electricity system or its regulation to accommodate DER in the short term. There are, however, proposals being discussed to integrate CAISO with other neighbouring systems.

As noted in Section 3 of this report, changes are needed to the framework of electricity markets to ensure that DER can be used both for energy and capacity. In California, this is being handled by ongoing processes at the California ISO. A process to implement revised rules is ongoing (see CAISO (2015) and CAISO (2016)). Special rules are being devised to ensure an appropriate treatment of storage and other forms of DER within the rules of the CAISO. Aggregations of demand response, for example, will be managed by their "Scheduling Coordinator", the organisation that represents them and provides an interface with the CAISO.

New entrants to the energy market, for example storage providers or other prospective providers of DER can enter the market, either becoming certified as a Scheduling Coordinator or entering into a commercial arrangement with an existing one.

Accommodating additional DER, therefore, is not leading to any short term structural changes, but rather a clarification of the roles and responsibilities of existing institutions. The market structure may change, with new services offered by aggregators and other new service providers. This will not, however, lead to any direct change to the functions of the utilities responsible for networks and serving load.

Longer term, though, there is a prospect of structural change e.g. through the initiatives of the AEEI. This sponsored a program to investigate future directions for regulation to accommodate additional DER. Stakeholders involved included representatives of the CAISO, leading utilities in California, generators, equipment suppliers and other services providers. This group identified that new activities are needed to ensure DER/DSM are integrated, including data capture / communication, advanced control systems etc. It identifies a range of structures to accommodate this such as:

- Distribution Service Platform, a fully integrated distribution organisation which will be incentivised neutrally to determine appropriate DER/DSM procurement.
- Independent Distribution System Operator. System operators separated from asset ownership to ensure neutrality, with the DSO procuring appropriate services from third parties.

It envisages that a new regulatory framework might be needed to accommodate this such as:

- Potential use of TOTEX (capex plus opex) to make utilities neutral between generation and DSM.
- Allow rate of return on third party assets procured, or other enhancements to existing regulation.

A.2.2. Process

Overall process

California has a rate-making process that is similar to that which operates across the USA, with a few particular differences for the state. Utilities apply to the regulator (the CPUC) to request rate rises in a "General Rate Case". In California these are scheduled to take place every three years. It is a legal process, involving submissions by companies, and a formal process for intervention by public interest advocates, with public funding. There is a formal process for the filing of cases and submission of evidence. There is the potential for other parties to participate but they need to be granted standing by the regulator, demonstrating that there is a need for their representation. Hearings are in front of an Administrative Law Judge, which makes recommendation, followed by a final decision by the Commission. Formal process for filing and submission of evidence. Decisions are appealable in court.

The cost of capital as well as determinations on other incentive mechanisms are dealt with in other proceedings.

In addition to general rate cases, the CPUC determines and administers the implementation of other rules. Three examples are relevant here and are discussed below:

- The demand side response rulemaking (R13-09-011)
- Energy storage target.
- DER resource planning rulemaking.

Demand side response rulemaking

A rulemaking process was initiated in 2014 by the CPUC with the aim of facilitating DER. After much engagement with stakeholders, a proposed rule has been published (CPUC (2016)). The aim would be to reward utilities for the introduction of DER in a neutral way, i.e. without distortion between investing in their own networks and investing in DER solutions provided by third parties. Returns equivalent to 3.5% or above on a measure of capital invested in the scheme, would be awarded to utilities when the overall cost is lower than that of alternatives. The proposed approach would involve:

- Utilities to propose schemes, either on their own initiative or in response to suggestions by third parties.
- Opportunities would be assessed through an internal process by the utility.
- Regulator would be notified of the process, and there would be a request by the utility to undertake a procurement for the services, with associated costs.
- Public workshops would be held to communicate the process.
- Following this process, a formal procurement procedure would be implemented, with a proposed incentive scheme in line with the Commission's guidance.

- A decision on this in progress, with stakeholders invited to comment on the scheme.

Energy Storage rule-making

Energy market developments indicated to policy makers in California that it should encourage energy storage. Accordingly in 2010 legislation was enacted requiring the CPUC to determine appropriate targets for storage, implement a process for procurement, and provide an obligation on utilities to report on progress. Public utilities have separately also had storage obligations placed on them.

The CPUC subsequently imposed a target on each of the utilities. A total installed storage capacity target of 1325MW was imposed, allocated between the three major utilities in the state (580MW to PG&E, 580MW to Southern California Edison, and 165 MW to San Diego Gas & Electric). Procurement of the storage was to be completed by 2020, with installation by 2024. The utilities have subsequently run procurement procedures, with decisions to install a mixture of lithium-ion, zinc-air, and flywheel projects.

DER resource planning rulemaking

In 2014, legislation was passed (AB 327) which lifted many of the restrictions on the CPUC which were implemented at the time of the California energy crisis. This also guaranteed that new solar installations installed by 2017 would benefit from net metering, and also gave CPUC authority to simplify the rate structures. These measures have been implemented by the CPUC in rulemaking processes.

In addition, the law requires that investor-owned utilities file Distributed Resource Plans. These must: take account of scenario planning; identify the optimal location for DER deployment; and indicate forecasts of capital investment needed to support DER deployment. It was also suggested that they should include plans for automation of the distribution network, new communication systems, and identify any other related spending.

The plans were filed by each of the utilities in July 2015.

A.2.3. Revenue setting

Revenue setting in California for the regulated utilities is a standard (for the US) cost of service approach. Required revenues are established for the first year for which a General Rate Case (GRC) applies, and increases ("attrition rate adjustments") are provided for increases related to higher capital spending and inflation.

The utilities are load-serving, and therefore procure electricity from third parties. The procurement approach is part of plans requiring regulatory approval, and this then gives a right to recover associated costs.

This is the general approach. The state legislature sets targets, which are implemented by the CPUC. If a utility meets these obligations, it will be able to recover the associated costs.

No change is envisaged for this underlying revenue-determination framework.

A.3. REV - New York's "Reforming the Energy Vision"

The NY REV is an ambitious policy to restructure the value chain and incentive structure for electricity. While the impact of Superstorm Sandy in 2012 focussed attention on the importance of a reliable and resilient electricity supply, a wide range of drivers provided the impetus for reform, including: limitations of the existing cost-of-service revenue setting approach; aging electricity infrastructure; continued growth in peak demand; interstate energy imports; policies to reduce carbon emissions; and developments in DER technology[116].

As with Ofgem's RIIO framework, the REV attempts to decouple the traditional relationship between network revenues, capital investments and asset ownership. While the REV retains cost-to-serve components for core network services, the proposal adds enhanced output-based performance incentives. However, its key aim is to create competition by incentivising networks to earn revenue from "Distributed Platform Services" (DPS), by supporting third-party solutions as a Distributed System Operator (DSO). REV envisages that an increasing proportion of networks' future revenues will come from facilitating markets for non-traditional network assets and services. Significantly, the REV aims to incentivise the emergence of third-party service providers and support the development of new business models. In light of the dynamic nature of market developments, the framework is intended to be an evolving regime, with support for experimentation built into the process and the incentives. The REV will begin to take effect in 2016, with utilities filing their initial Distribution Service Implementation Plans (DSIPs).[117]

A.3.1. Structure

New York utilities have a greater degree of vertical integration compared to Australia and the UK. The industry is composed of a mixture of publicly and privately owned utilities, generation companies, transmission-only companies and energy service companies (ESCOs)[118], while generation is predominantly gas, nuclear and hydro. Retail competition exists, however the level of market competition, innovation and customer switching is low.

The PSC, New York's Public Service Commission, regulates and oversees the (distribution) electric, gas, water, and telecommunication sectors and decides on price control policy, objectives, incentives and implementation. The PSC is tasked with managing the implementation of the REV with assistance from NYSERDA, the New York State Energy Research and Development Authority. NYSERDA promotes energy efficiency, new technologies, customer savings, renewable energy, and reduced reliance on fossil fuels and

[116] NY DPS (2014)
[117] NY DPS (2015a)
[118] NYSEPB (2015)

is mainly funded by a System Benefit Charge (SBC) on rates. NYSERDA activities and funds are being redirected, away from customer incentives and technology trials to REV objectives including promoting third-party platform services, DER and renewable energy.

NYISO, The New York Independent System Operator, administers the wholesale market and operates New York's bulk power system. Governance of the reliability of the transmission system is shared by the PSC and the Federal Energy Regulatory Council (FERC). While FERC has oversight over NYISO's system planning processes, the PSC holds the authority to direct the construction of infrastructure in the public interest.[119]

The REV framework uses the existing industry structure as its base, but proposes radical changes to support and incentivise third-party involvement through development of a Distributed System Platform (DSP). This seeks to mimic other sectors (for example, telecommunications) where *"the traditional provider's role has evolved to a platform service that enables a multi-sided market in which buyers and sellers interact. The platform collects a fee for this critical market-making service, while the bulk of the capital risk is undertaken by third parties"*[120]. Accordingly, the REV envisages a new role for distribution networks as Platform System Operators (PSO) and market-makers, as opposed to asset owners and managers. Under the current REV framework, this role has been allocated to the utilities.

A.3.2. Process

The REV is attempting a substantial departure from previous price controls, as it is designed to be transitional and experimental and to develop rather than proscribe market models with an end to *"reorient the electric industry and the ratemaking paradigm toward a consumer-centered approach that harnesses technology and markets"*[121]. The REV aims to drive competition to minimise, or end, price controls as far as possible. While this aims for light-handed regulation in future, it requires substantial intervention and direction to drive this change.

The process is designed to retain universal access requirements – safe, reliable, affordable – with the addition of new elements:

1. Customer-centric – with short-term incentives for longer-term market outcomes.
2. Animating markets – putting private capital to work through third-party involvement.
3. System wide efficiency – emphasising bills, not rates or tariffs.
4. Flexible /Fuel Diversity – nuclear, hydro, gas, PV and renewables.

[119] NYSEPB (2015)
[120] NY PSC (2016a), page 4.
[121] NY PSC (2016b), page 2.

5. Low-Carbon – statutory obligations to achieve 50% renewable by 2030 (Clean Power Plan).

Customer engagement

Traditional cost-of-service ratemaking customer engagement practices will continue under the REV. To these are added direct incentives through Earnings Adjustment Measures (EAMs), including performance measures relating to market and customer engagement. What differentiates the REV approach is a new emphasis not on the direct engagement of utilities with customers, but on the facilitation of third-parties to drive a customer-centric approach:

"to serve consumer requirements, utilities must be prepared to design and operate systems that are adaptable and supportive of third-party investments that increase both the system and economic efficiency of the fully integrated grid."[122]

The process rests on the assumption that transparency, information provision and incentives will lead to customer engagement through markets and third-party service providers.

"With improved access to system and customer information, through the DSIP and data access processes established in REV, visibility of market and profit opportunities will be greater for all parties. As a result, historical concerns on our ability to monitor utility costs are mitigated by the information transparency and ease of consumer access that characterize more competitive markets and multi-sided platform businesses"[123].

Information provision in the Distributed System Implementation Plans (DSIPs) is key to overcoming traditional information asymmetry problems and enabling delivery of platform services. There has also been a shift in NYSERDA's approach to incentives, moving from government-supported subsidies for customers towards market incentives through third-parties. As with other REV proposals, it is still unclear if this is a practical system wide solution, expects that selected successes can be generally adopted; or assumes away the problem.

Supporting the DSIP is the utilities' Benefit Cost Analysis (BCA) framework applied to:

- Investment in Distributed System Platform (DSP).
- Procurement of DER though competitive selection.
- Procurement of DER through tariffs.
- Energy efficiency programs.

[122] NY PSC (2016a), page 5.
[123] NY PSC (2016a), page 8.

Utilities will each produce a handbook on BCA methods and its application to DER, which is to use a Societal Cost Test (SCT) as its primary measure and includes a cost of carbon and qualitative consideration of non-monetised societal benefits. A Utility Cost Test (UCT) and Rate Impact Measure (RIM) are to form part of the analysis. The DSIPs and BCA handbooks can be seen as driving long-term capital efficiency, which is supported by utilities' EAM and PSR revenues.

While NY PSC and other stakeholders share concerns about inappropriately incentivising capex, an underlying cost-to -serve ratemaking approach continues to be applied. A totex approach has been adopted in the limited context of new expenditures in the BQDM project (see below). While a totex approach is capable of wider application in principle, this is seen as an experiment, rather than heralding a shift in the overall revenue setting approach.

Text box A.1: Brooklyn Queens Demand Management project (BQDM)[124]

A "ground-breaking" non-wires-alternative, yet includes transitional incentives and falls short of the DSP third-party vision.

Involves 52 MW of non-traditional utility-side and customer-side solutions and traditional utility infrastructure investment, including 6 MW of capacitor bank installations and 11 MW of load transfers.

Consolidated Edison defers $1.2B Capex for two substations and with DG, DM and EE which receive a return on totex and performance incentives.

It uses a totex-style approach to amortising all BQDM program costs over a 10-year period, with an ROR adder increasing the returns to capital.

Represents an early experiment in developing new business models, rather than a preferred approach

Utilities will take the PSO role with responsibility for managing integrated system planning, grid operations and market operations, structure and products. The DSP is seen as a fair, open and transparent market, where DER providers are customers and partners, and obligations and incentives exist to support DER. As part of its role the PSO will provide data at a granularity and timeliness appropriate for the market, but will not be able to own DER except in limited cases.

A.3.3. Revenues

While innovative in many respects, the REV remains an augmented cost-to-serve regime. Returns on the existing RAB will form the bulk of revenues, however this is meant to change over time. The four ways of achieving earnings in the REV framework are:

- traditional cost-of-service earnings;
- earnings tied to achievement of alternatives that reduce utility capital spending and provide definitive consumer benefit (Earnings Adjustment Mechanisms or EAMs);

[124] NY PSC (2014)

- earnings from market-facing platform activities (Platform Service Revenues or PSRs); and,
- transitional outcome-based performance measures.

The NY PSC considers that *"there is no fixed line, however, between "REV" activities and "conventional" activities,"*[125] however market-facing platform activities and transitional incentives are new features of the regulatory regime and incentives are geared to promote these new elements. How this translates into actions will become clearer when utilities file their individual DSIPs on June 30, 2016. A second filing on how the NY state utilities will work together to specify shared tools, processes and protocols to manage DER is due September 1, 2016. The overall effectiveness of the REV will only be determined in the medium- to longer-term, when market building elements are removed and market incentives operate independently.

The Earnings Adjustment Mechanisms (EAM) support new incentives for:

- peak reduction;
- customer engagement;
- affordability;
- interconnection (e.g., connection of DER); and,
- energy efficiency

It is intended that these EAM incentives are transitional measures, leading to a process where platform service revenues (PSRs) increase and eventually markets set prices and revenues, effectively reducing the role for regulation. Implicitly revenues for traditional network services in areas covered by PSRs will be set with reference to PSR market prices. Utilities DSIPs are to identify opportunities to defer or avoid traditional investment by calling on DER alternatives.

Negative revenue adjustments for failure to meet basic standards remains part of the estimation of traditional cost-of-service earnings, as do "clawback" provisions for inefficient investments. Tariff restructuring is to be driven by DER and DM facilitation, but on an opt-in basis to include enhanced time-of-use and demand charges.

A.4. Ofgem – Revenue = Incentives + Innovation + Outputs

In 2008 Ofgem began the process of reviewing whether its approach to price controls was appropriate. It referred to this review as RPI-X@20, reflecting the approximately 20 years since RPI-X regulation had been used for energy regulation. This was undertaken under the view that the price control framework had become burdensome (both in the time to complete a review and the resources required on all sides) and that it may not be

[125] NY PSC (2016a), page 8.

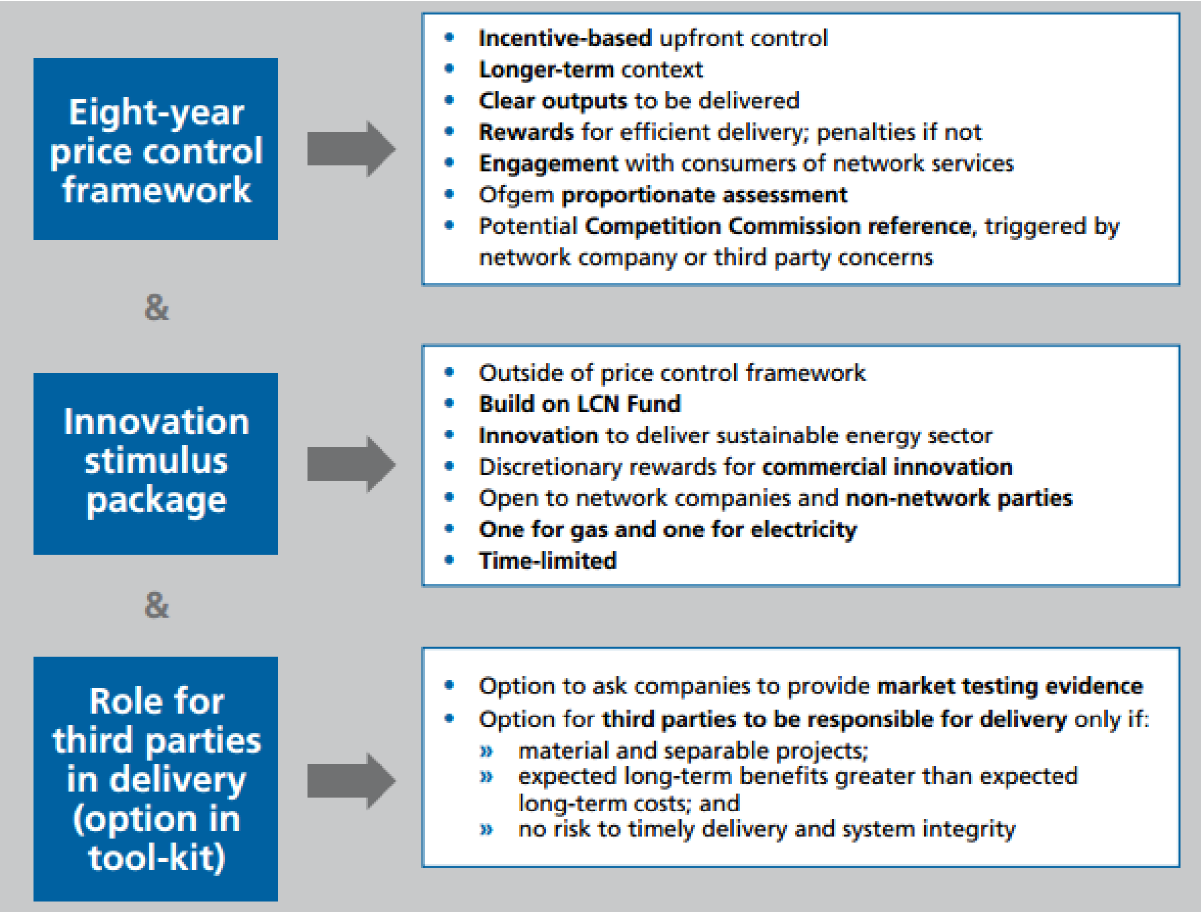
appropriate given the changing role of the energy networks (i.e., it did not provide well for innovation). One of the key considerations was the need to deliver a low carbon economy (2020 targets).

After a two-year review, with input from numerous consultancies and academics, Ofgem launched its new price control framework in 2010. It termed this framework 'Revenue = Incentive + Innovation + Outputs' or RIIO. A key premise of the new regime was to incentivise the delivery of outputs (or services) rather than inputs. This is mainly done through a total expenditure (totex) approach (we discuss this further below).

It has now used this framework for three price controls – one each for transmission, gas distribution and electricity distribution. In its 2010 decisions document Ofgem noted the following challenges facing the electricity sector: offshore networks, electric vehicles, electric heating, smart grids, electricity storage, new nuclear, renewables, local generation, energy efficiency, district heating, fuel poor, climate change adaptation and energy service companies.

The components of RIIO, which Ofgem see as driving smart and more sustainable networks, are shown in Figure A.2 below. One aspect of the RIIO controls was increasing the length of the price controls to eight years (they previously lasted for five years). Ofgem believed the longer period would provide the networks with greater confidence in setting longer term objectives.

Figure A.2: RIIO – Component of sustainable network regulation



Source: Ofgem[126]

For the purposes of this case study we focus more on the electricity distribution price control (RIIO-ED1), but cover issues specific to electricity transmission as well. It is important to note that RIIO itself focuses on the price control process and other aspects of the regulatory framework (such as structure of charging) are considered outside of the RIIO process.

A.4.1. Structure

Decision maker/ implementer

Ofgem is the sole energy regulator in GB. While policy is driven by the government it has the responsibilities of being both the rule maker and the rule implementer (i.e., equivalent to the AER and AEMC being rolled into one). The Competition and Market Authority (CMA) is the appeal body for merit reviews and there is a judicial review process available as well. Ofgem, the regulated companies, suppliers and consumers can refer the price control to the CMA. Under new arrangements, the referrer can choose which elements to refer (previously all had to be referred).

[126] Ofgem (2010a), page 11.

There are three electricity transmission networks, and National Grid (the largest network operator) also undertakes the transmission system operator (TSO) role. As the TSO it is responsible for balancing the supply of electricity with demand at the national level, for example by ensuring power stations are on standby in case of a sudden increase in demand and ensuring that the network operates safely, securely and efficiently.[127]

There are 14 distribution network operator (DNO) licences, but only six group owners. At this stage the DNOs are responsible for operating their networks, but they do not have a role in managing supply and demand on their systems.

System operations

The current arrangements are under consideration by the Department for Energy and Climate Change (DECC) and Ofgem. Ofgem is currently consulting on 'making the electricity system more flexible and delivering the benefits for consumers'.[128] Ofgem's initial position is that DNOs will take a more active role in network management, move to being distribution system operators (DSOs) and engage effectively with the TSO.[129] A recent report by the UK National Infrastructure Commission (NIC 2016) set out similar recommendations. However, they also proposed that the TSO become independent and that Ofgem should consider encouraging the TSO to develop new markets to provide ancillary services.[130] There are no proposals at this stage for separate distribution system operators.

Barriers Ofgem identified to the development of a DSO role are:

- Hesitance to adopt new practices as business as usual (BAU).
- A lack of clarity around key arrangements:
    - How DNOs engage with consumers to procure flexibility.
    - The relationship/interaction/overlap between the DSO and SO.[131]

A key point being considered by Ofgem around flexibility (including storage), both in transmission and distribution, is whether the current charging arrangements are appropriate for efficient choices to be made. In particular, whether the fixed (sunk) charge element is incentivising efficient behaviour (e.g., DER may be used to avoid network charges).

At the time of writing Ofgem has not yet published an updated position paper.

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[127] NIC (2016), page 13.
[128] Ofgem (2015b).
[129] Ofgem (2015b), page 5.
[130] NIC (2016), pages 13 and 14.
[131] Ofgem (2015b), page 25.

Third party competition

The RIIO framework included the provision that third parties could be involved in the delivery and ownership of large and separate projects. The involvement of third parties was restricted to projects:

- that are significant in scale and/or cost;
- that involve assets required for expansion of the network that are not meshed with existing assets, or can be defined in such a way that they are not meshed with existing assets;
- where giving third parties a greater role in delivery will not pose significant risks to timely delivery, including constraints on the delivery of emission reduction or renewable targets;
- where giving third parties a greater role in delivery will not pose significant risks to the safety, security, integrity and quality of energy services;
- where Ofgem can demonstrate that the expected potential long-term net benefits (in terms of delivering the objectives of the RIIO model) are significant; and
- where Ofgem are confident that giving third parties ownership of relevant assets will not compromise the legitimate expectations of existing licensees when making investments without knowledge of the possibility of assets potentially being transferred to a third party at a later date.

The offshore transmission owners (OFTO) regime is a regime where third-party providers have taken on the role of owning and operating offshore transmission assets. Projects are competitively appointed offshore electricity network operators who have the responsibility for operating newly constructed electricity transmission network assets, which connect offshore electricity generation (wind farms) to the shore. The OFTOs are guaranteed a return over 25 years. The OFTO is not reliant on the offshore generator paying, as its allowed revenues are underwritten by the onshore consumers. Therefore the risk of stranding or under-utilisation has been allocated to consumers.[132] A review of the OFTO tendering by CEPA and BDO (CEPA 2014 and CEPA 2016b) found that regime delivered overall financing savings, compared to a merchant counterfactual, by reducing demand and stranding risk faced by the OFTO.

Ofgem is now looking at increasing the role of third parties for onshore transmission ownership with competitively appointed transmission owners (CATO). The regime is still in development, but it is designed to target 'Strategic Wider Works (SWW) projects' during RIIO-T1 (expected expenditure over £100m). Assets needs to be 'new' and with clearly delineated ownership boundaries. The system operator identifies need, options, and

[132] Stranding was estimated as a low probability event, but with a high impact on the OFTO.

preferred solution. Ofgem will run the tendering process. Ofgem's intention is to fix a revenue allowance (initial view is for 25 years) before they appoint and to have limited re-openers, but it is open to considering options if it is not efficient to fix costs.

Central data hub

Separate to RIIO, the UK government announced a mandatory roll-out of smart meters for all connections. In order to help facilitate this roll-out the UK government, via the Department of Energy and Climate Change (DECC), established a single entity responsible for the collection and provision of data from the smart meters – the Data Communications Company (DCC). All actors in the energy sector are required to use the DCC to access consumer data.

The DCC is regulated by Ofgem. It is an asset light company, it procures services from other providers, and therefore it is allowed a margin rather than a return on capital. Ofgem currently carries out *ex post* regulatory assessments of DCC's performance, which includes a review of its internal costs, an assessment of whether the external (pass-though) costs are efficiently incurred and whether adjustments to the margin are required for failing to meet performance criteria.

Consumer protection

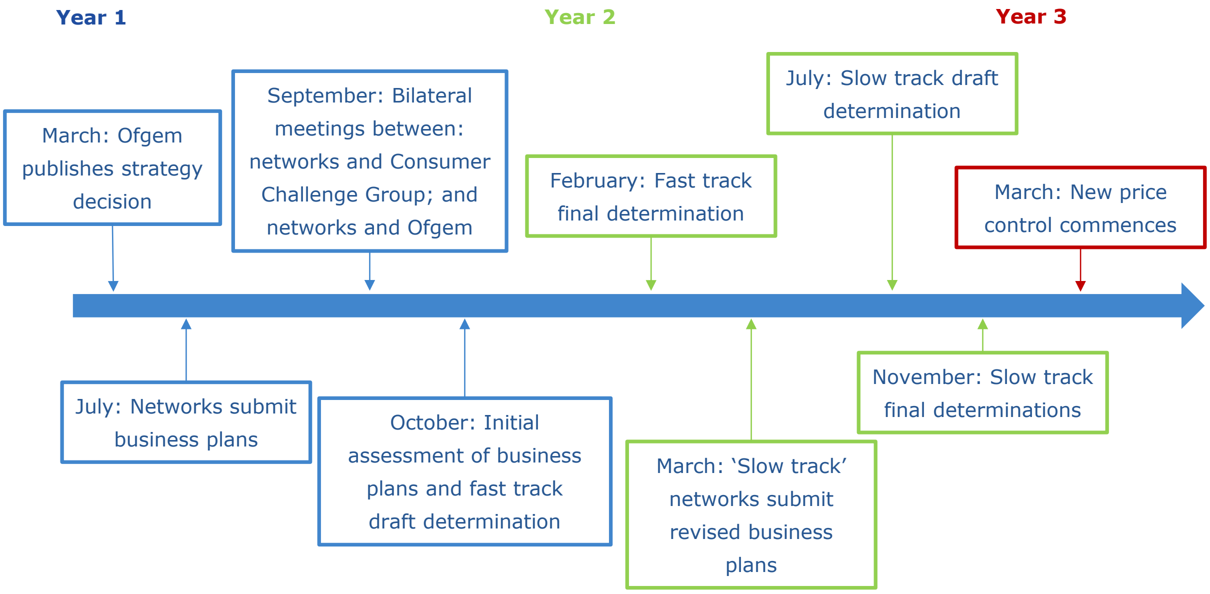
The majority of consumer protections are placed on the suppliers. The networks have supply obligations and are required to offer connections. The connection offers are subject to strict guidelines on who has to pay for what, typically customers on the distribution network only have to pay for connection upgrades at their connection voltage level. If reinforcement is required above this level, then this expenditure is placed into the RAB and charged through the distribution use of system charges (DUoS). Ofgem is currently in the process of consulting on new connection guidelines in order to make the connection process more efficient and quicker. Part of this is to establish guidelines on flexible connections when a connection is occurring on a network which is constrained.

Ofgem does expect the networks to play an active role in helping protect vulnerable customers. Most of the network programs focus on providing information to customers and keeping a database of vulnerable customers.

A.4.2. Process

The price control review process that Ofgem follows is not too dissimilar to its previous RPI-X building blocks approach. However, there is a notable change from Ofgem's previous approaches – the introduction of 'fast tracking' in RIIO. Figure A.3 below provides an illustration of the RIIO timeline and interaction between the regulator and the regulated networks.

Figure A.3: RIIO-ED1 timeline



Source: Ofgem, CEPA analysis

As can be seen from the diagram above, the whole RIIO process is intended to take less than two years, with fast tracking completed within the first year. There is an approximately six-month gap between the submission of business plans and the final determination.

Fast tracking

Fast-tracking is part of a more general principle of 'proportionate treatment' under RIIO, whereby if a network is considered to produce a high quality business plan, Ofgem proposed to subject their business plans to a lower level of scrutiny and focus attention on the areas that deserve further analysis. In some cases, where a network produces a very high quality business plan, Ofgem would consider whether it was appropriate to conclude that network's price control process early (this is known as "fast-tracking"). This process allowed Ofgem to complete an "initial sweep" of the networks' business plans and identify those companies that might be subject to less scrutiny during the RIIO-ED1 review process, and those that might need to be subject to more intensive scrutiny.

Ofgem's initial sweep focused on identifying whether networks' business plans demonstrate evidence of delivering primary outputs consistent with the views of stakeholders and, more generally, delivering long-term value for money for sustainable network services. Ofgem stated that this would be based on combined evidence from three sources:

- review of the quality of the business plans;
- performance during the previous regulatory control; and
- benchmarking of business plans.

If a company were fast-tracked, Ofgem would accept its business plan and it would not be submitted to further scrutiny. If a company were not fast-tracked, then Ofgem would proceed with an in-depth analysis of the company's business plan, in line with a full building blocks assessment.

Ofgem fast-tracked two of the three transmission companies during RIIO-T1, but only fast-tracked one of the six electricity distribution groups. In the latter case, concerns arose around the assessment of costs and the possibility that it had led to customers in the fast-tracked regions bearing significantly higher costs than if the business plan had been slow-tracked.[133]

Enhanced stakeholder engagement

Ofgem encouraged the networks to actively engage with stakeholders and indicated that a well-justified business plan (i.e., one that would be fast tracked) would have to clearly demonstrate this engagement, including the link to outputs. Ofgem did not specify how companies should engage with stakeholders, rather it wanted the engagement to be company-led. However, Ofgem had a Consumer Challenge Group (CCG), which was made up of a small number of consumer experts. The CCG had the role of a 'critical friend' to help inform Ofgem's decision-making process.

RIIO also includes an incentive (Broad Measure of Customer Service (BMCS)) which provides a financial reward/ penalty based on an assessment of companies' ongoing stakeholder engagement.

Ofgem had considered a greater role for consumers, but during RPI-X@20 Ofgem rejected "the model advocated by some of constructive engagement – or the more radical alternative of allowing customers and the company to propose a deal and the regulator only stepping in if they can't. This is born of one concern and one practical reality. The concern is how you ensure that all customers are represented effectively… The practical concern is that we asked the various consumer representatives covering both domestic and industrial whether they would want this sort of process and they told us no."[134]

A.4.3. Revenue setting

Building blocks

Ofgem's RIIO still relies heavily on a building blocks platform for estimating each networks revenue-cap. Where it differs significantly from other building blocks regimes is that it focuses on estimating efficient total expenditure (totex), rather than estimating operating expenditure (opex) and capital expenditure (capex) separately. For RIIO-ED1 this approach involved Ofgem modelling one disaggregated totex benchmark model (e.g. combining

[133] The Energy and Climate Change questioned whether the decision to fast track Western Power Distribution (WPD) led to customers being overcharged by £860m. See Utility Weekly (2015).
[134] Ofgem, cited in Littlechild and Mountain (2015), page 23.

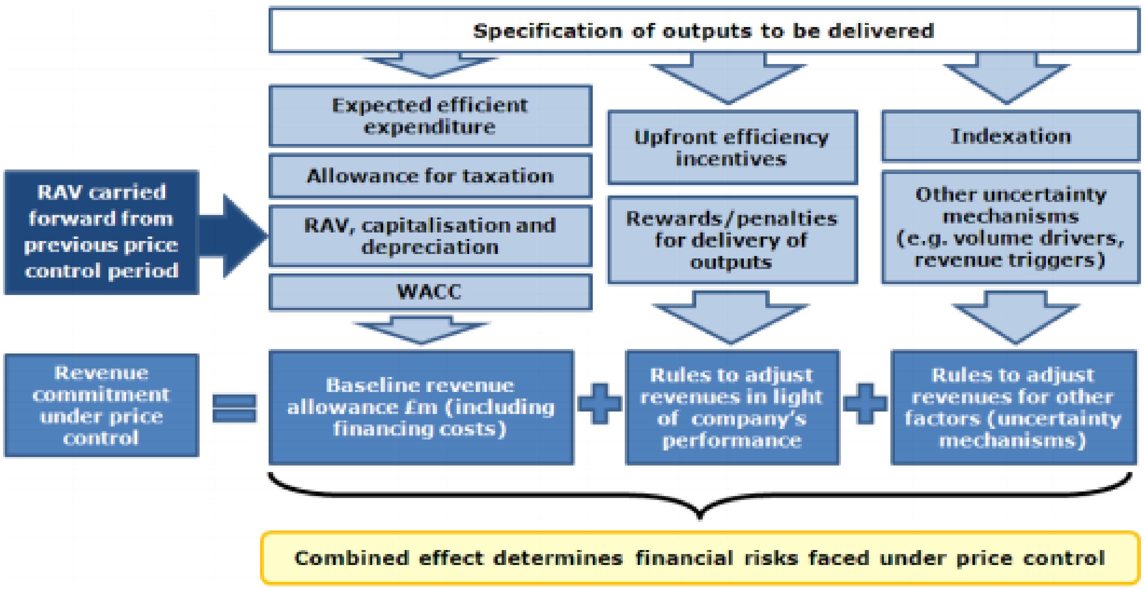
numerous activity level models) and two top-down benchmarking models (e.g., modelling totex against specific cost drivers).

The totex benchmarking is combined with a pre-determined capitalisation ratio for each network operator. This means that the network could use an opex solution rather than a capex one and would receive the same returns as the opex would be 'capitalised' into the RAB. This approach was designed to equalise incentives across opex and capex (i.e., prevent a capex bias). It is worth noting at this point that Ofgem applies a uniform depreciation rate across the RAB. The RAB is depreciated on a straight-line basis over 45 years. In other words, there are no specific asset depreciation lives.

The RAB is indexed to inflation to provide companies protection against general inflation. Ofgem separately make allowances for 'real price effects' (RPEs) which are the differences between changes in input prices and general inflation. It is important to note that the regulator asset value (which is the same as a RAB) is not guaranteed under law.

The building blocks specification used by Ofgem is illustrated in Figure A.4.

Figure A.4: RIIO building blocks



Source: Ofgem[135]

It is important to note that the regulated asset value (which is the same as a RAB) is not guaranteed under law.

A key element of Ofgem's approach to revenue setting is its use of financeability analysis. This involves assessing whether a company is able to fund its investment programme and meet basic financial ratio tests, based on the way credit rating agencies assess whether a company is investment grade, given the expected cash-flows generated by the regulatory

[135] Ofgem (2012), page 19.

price determination. Ofgem have made adjustments to cash flows in the RIIO based on its financeability assessment.

Mid-period review

With a longer price control period (eight years) Ofgem also introduced a mid-period review. This review is intended to assess the businesses' performance in delivering outputs against their targets.

The reviews are will included assessing whether the output targets have changed (e.g. different connection targets for EVs, etc) and if so Ofgem will be able to make adjustments to the allowed revenue to compensate customers or consumers.

Uncertainty mechanisms

Ofgem has included a number of 'uncertainty mechanisms' in its RIIO price controls to date. These mechanisms (which included the indexation of revenues to RPI) provide ways to allocate the risk between the networks and consumers. For the most part the business will be best placed to manage costs and service delivery, however there are outputs and costs outside of its control. If it were to manage these uncertainties then it would likely require a higher return (or more generous allowances to compensate for the risk).

There are numerous mechanisms which can be used to allocate these uncertainty risks. As set out in Ofgem (2010b) these include:

- Volume drivers. For example, revenues are adjusted based volumes (e.g., connections).
- Revenue trigger. Revenue can be provided or removed based on certain events or outputs occurring.
- Indexation. Revenue can be linked to specific indices.
- Pass-through or logging-up. Costs outside of the companies' control can be passed directly through to consumers. In the case of logging-up, Ofgem may review to ensure the expenditure was efficient.
- Ex post review. For use with new services where benchmark costs are not available.

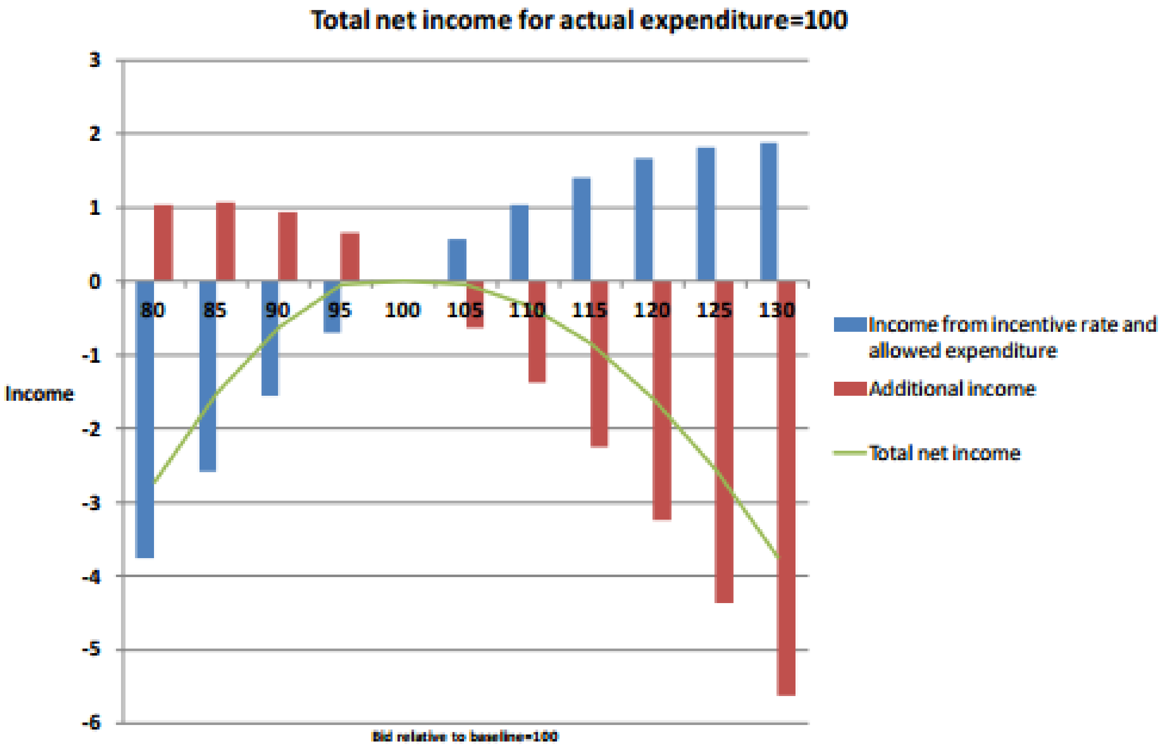
Incentives

The RIIO framework involves a number of incentive mechanisms. Some of these are embedded directly in the revenue setting framework, for example the information quality incentive (IQI) mechanism, while others are placed on top of the building blocks regime, for example time-to-connect incentives. We will not go through all the incentives here, rather we focus on those most specific to incentivising electricity networks for the future.

IQI

The IQI is an incentive based on an incentive-compatible menu.[136] The IQI incentivises the companies to make a truthful bid. The idea behind the IQI is that it reduces the asymmetry of information faced by the regulator. The IQI has three features – an ex ante additional income/ penalty, the sharing rates on the differences between forecast and actual income (totex incentive mechanism [TIM]) and it provides the final expenditure allowances. The interaction between the elements is illustrated in Figure A.5, which looks at the net income that a company that expects its actual expenditure to be 100 would get for different forecasts or bids, for an indicative incentive-compatible menu. It can be seen that the company maximises its net income by 'bidding' 100.

Figure A.5: How net income changes with forecast expenditure



Source: CEPA

The way Ofgem sets out the menu requires that the final totex allowances are based 75 percent on Ofgem's view of efficient totex and 25 percent on the company's view of totex. This also recognised the asymmetry of information.

While the IQI is relatively simple in concept, its construct and workings are more complex. CEPA (2012a) provides more details on the mathematical specification of regulatory menus.[137]

[136] This is based off work done by the Nobel prize-winning economist Jean Tirole (see Laffont and Tirole (2003)).

[137] See CEPA (2012a), Annex 2.

Totex incentive mechanism (TIM)

The TIM is an integral part of the IQI. However, it is worth discussing this element separately given its importance in incentivising the companies and, therefore, allocating risk.

Because the sharing rates are applied to totex, the incentive on over/underspending on opex and/or capex can be quite strong. For instance, if the sharing rate is set at 50% then this means that the company must fund 50% of any totex overspend or share 50% of any underspend with consumers. Therefore, the company does not simply bear the financing cost of any overspend on capex, it instead bears 50% of the expenditure (i.e., only 50% of the capex enters the RAB).

Innovation

Innovation incentives are seen as a vital component of the regulatory framework in order to encourage the use of new solutions to delivering services and to encourage collaboration between the network operators and third parties. Ofgem introduced a Network Innovation Competition (NIC), Network Innovation Allowance (NIA) and Innovation Roll-out Mechanism (IRM). The NIC provides an annual fund which networks can compete for by submitting proposals for 'innovative' projects. The NIA allowance is 'use it or lose it' and is a percentage of base revenue.

NIC and NIA are part-funded with DNOs and partners providing at least 10% of funding. Findings from innovation fund/ allowance projects must generate learning for all companies to share.

Ofgem made significant cuts to the DNOs' allowances (£322m) for its view on 'smart-grid benefits', based on the networks' results from the innovation funds and allowances in DPCR5.[138]

[138] Although we note that Northern Powergrid, on appeal to the CMA, was able to overturn Ofgem's smart grid adjustment to its allowances.

ANNEX B FRAMEWORK TO ACCOMMODATE DER

At present, there is a real-time market for electricity at transmission level which requires a certain architecture to be in place for it to function. There are a range of functions relating to the operation of the energy market, so that producers and consumers of electricity (and their agents) are able to trade at market prices, and make decisions on production and consumption in response to those prices.

In addition to wholesale market prices, production and consumption decisions must also take account of the physical limits of the electricity system. The system will not always be able to accommodate all the generation that would be economic in an unconstrained system, and at those times generation needs to be curtailed. Likewise, there are times when generation needs to be increased locally (or demand reduced) for system needs. Coordinating this process in the most efficient way is the tasks of the system operator. In liberalised markets like Australia and the UK, the role of system operation on a transmission system is very well defined with clear rules as to how the interaction between system operations and the energy market should work.

The increase in DER, and the need to accommodate the entry of new agents, means that over time the key elements of this architecture need to be developed and created at distribution level so that the energy wholesale market mechanisms can work optimally, alongside appropriate interaction with the network operator:

- It is likely that energy trading platforms (or organised markets of another form) will emerge that would allow DER providers /users to interact with the wholesale electricity market. Mechanisms will be needed to ensure appropriate measurement of trades and pricing of differences between trades and physical production / consumption. This is a market operation function.
- The system operator will need information on planned and actual production and consumption, and to make decisions and given instructions on system operation including instructing increase / decreases in production / consumption. This is a system operation function.

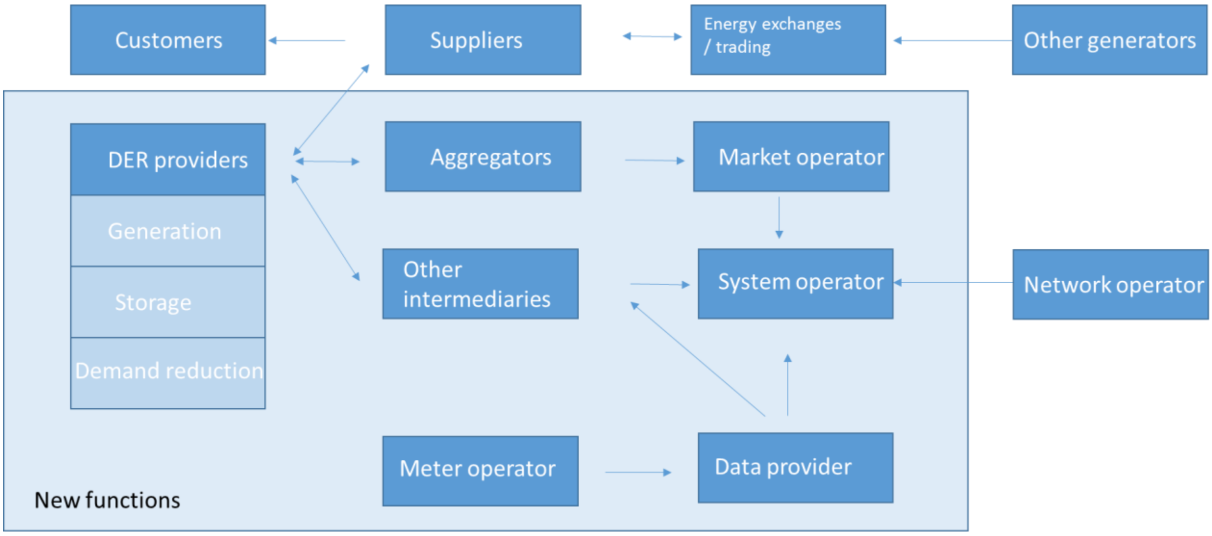
It should be noted that the market operation functions set out here need not be organised in the same way as AEMO's organised power market. Decentralised trading mechanisms may emerge, based on the needs of users of the system, but in that case there will still be a need to organise the pricing and settlement of non-contracted trades.

The system operation (SO) activities will include more active control of the network. There will be a need to manage the despatch of DER: additional generation may be needed locally to maintain stability of the system; or the SO may need to curtail DER if networks cannot accommodate the resulting electricity flows. The SO will also need to plan future investment in the system to accommodate anticipated DER deployment.

The elements of the industry structure are illustrated in Figure B.1, with new components needed to accommodate the large increase in DER on the distribution network within a shaded box.

The illustration shows the main functions that will need to be performed. However, this does not mean that these functions need to be contained within different organisations. Many of these activities are currently performed by the same organisation, and it is both a regulatory decision and a decision for companies themselves as to whether this should continue. There are a range of alternative institutional arrangements to organise these functions: system operation functions could be organised across network boundaries (both of different distribution companies, and transmission and distribution companies), and similar arrangements could be made for the market operation functions.

Figure B.1: Activities required for increase in DER on distribution networks



Source: CEPA