Benefits and Costs of Multiple Trading Arrangements and Embedded Networks

AEMO

Report

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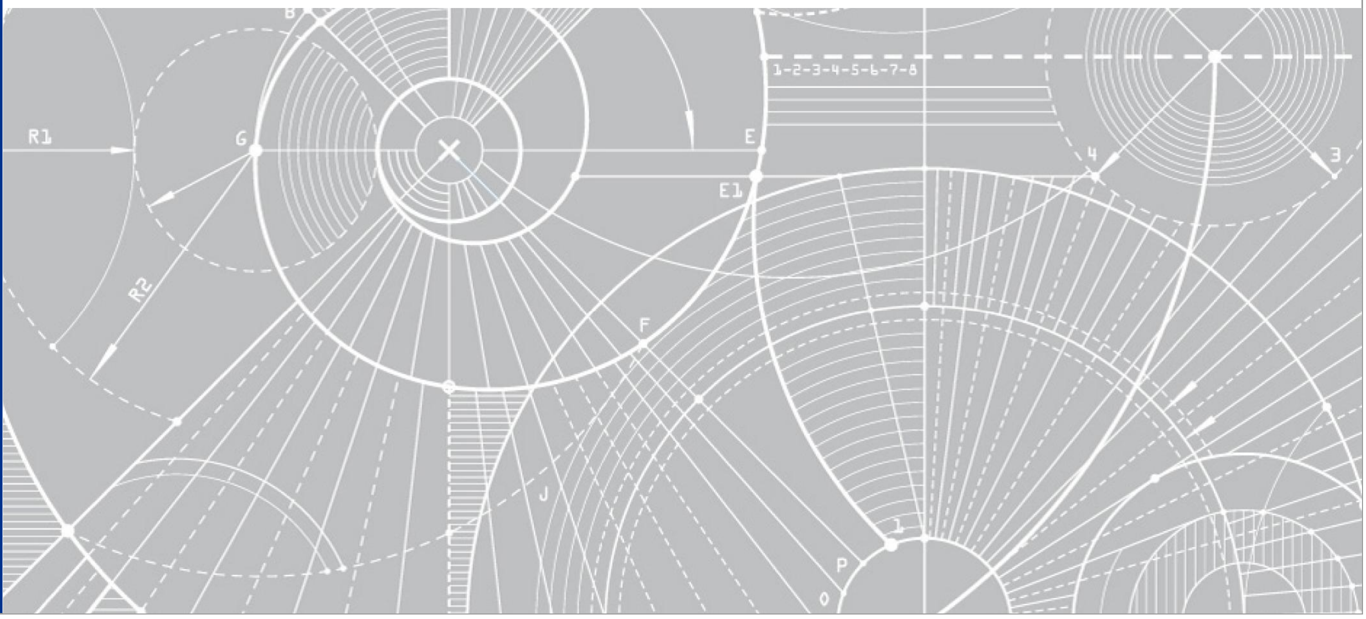

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Executive summary

The final report of the AEMC *Power of Choice* review set out a reform package for the National Electricity Market (NEM). This package provides households, businesses and industry with more opportunities to make informed choices about the way they use and purchase electricity. The overall objective is to ensure that the customer's demand for energy services is met by the lowest cost combination of demand and supply side options.

As part of this reform package, the Australian Energy Market Operator (AEMO) has been tasked by the Standing Council on Energy and Resources (SCER), in consultation with industry, to develop a rule change proposal for consideration by the Australian Energy Market Commission (AEMC) for changes to the national electricity rules (NER). The changes are to allow multiple trading relationships (MTRs) at a single connection point and to formalise metering and other arrangements associated with embedded networks (ENs) to remove any potential barriers to embedded customers accessing offers from competing market participants.

AEMO has engaged Jacobs SKM to undertake a high-level benefits cost study of the proposed changes.

Background

The current arrangements for customer engagement with a retailer are based on the set of relationships at the physical connection point to the network, which include a one-to-one relationship between the connection point, customer, and the retailer. The intent of moving to a MTR is to enable customers to engage with multiple retailers or energy service providers (through eligible retailers) at their site and to find the best solution for buying and selling electricity for different components of the customer's load and on-site generation[1].

The key enabler for MTRs is to separate the settlements point from the connection point so that there may be multiple settlements points per connection point. Each settlements point will have its own set of operational and trading relationships. Participation in multiple trading arrangements is voluntary, and may require more sophisticated metering than is currently provided in the roll out of smart meters in Victoria and other regions to allow for separate settlements of portions of the customer's load.

One of the key benefits of the implementation of MTR is to better facilitate demand side responses over and above the level of demand side response that currently occurs. The proposed changes would enable customers to better segregate and manage portions of their load potentially facilitating uptake of new technologies or sophisticated appliances that may be remotely or automatically controlled, New, bespoke services may be offered to customers focusing on a portion of domestic customer loads, such as heating or air conditioning services. The changes would also enable customers with roof-top PV systems or other embedded generation to sell their surplus electricity through an independent retailer if a better price is offered. Moreover, supply aggregators may emerge to "collect" surplus electricity from some households and sell to other customers within the same distribution area. New electrical loads or embedded supply points, such as from electric vehicles, may also be facilitated in the longer terms.

An EN is a private network usually connected to a distribution system (or another EN) via a parent connection point. An EN is operated by an Embedded Network Operator (ENO). Examples include airports, shopping centres or apartment blocks. Where allowed by jurisdictional policy[2], customers are not required to obtain their energy from the ENO/reseller and can obtain electricity from another NEM retailer. However, there are some barriers to the embedded customers from engaging with other NEM retailers, with such barriers including a lack of clarity on obligations of different parties with respect to metering arrangements, a lack of visibility of contestable customers within ENs, differing metering standards from the NEM, and a lack of uniformity in distribution use of system pass through arrangements[3].

[1] AEMO (2013), *Multiple Trading Relationships and Embedded Networks – High Level Design*, December
[2] Not allowed in Queensland, ACT and Tasmania
[3] AEMC (2012), *Power of Choice Review: Giving Consumers Options in the Way They Use Electricity*, 30 November

At present, EN operators have an AER exemption from registering as a network operator in the NEM, and this will continue for the foreseeable future. However, the proposed changes may recognise an ENO as a new type of network operator under the NER. They may also be required in the future to follow shadow pricing guidelines set by the AER in setting DUOS charges to be charged to each customer within their networks.

All settlements points within an EN, including at ENO customers, will be recorded in AEMO's Market Settlement and Transfer Solutions (MSATS) systems and will be discoverable by other retailers.

The design options for changes to the allocation of National Metering Identifiers (NMIs) in ENs that have been considered in this study are:

- The local retailer would set up NMIs to enable NMI discovery in Market Settlement and Transfer Solutions (MSATS) for all child settlements points within each EN including both NEM customers and ENO customers for existing ENs and as an ongoing role for future ENs
- The local retailer would only set up NMIs (and hence NMI discovery) for settlement points as and when they become NEM Customers.

The main purpose of these changes is to provide regulatory certainty in relation to ENs, by recognising these networks in the NER, and formalising the required obligations and arrangements in the NEM regulatory framework. Clarifying and codifying the rules and procedures around ENs would allow other jurisdictions to allow customers within ENs to seek competitive prices. This would increase competition and improve regulatory certainty between jurisdictions.

Additionally, the proposed changes would allow retailers to get better load information on some customers which would enable them to craft more bespoke tariffs to embedded customers.

Benefit cost analysis

Both of MTR and EN proposed rule changes could lead to changes in the way customers purchase their electricity and enhance the competitive dynamics as a result. The benefit-cost framework is designed to capture the resulting impacts on:

- Productive efficiency. This refers to the way in which the proposed changes allow for more efficient use of the current stock of capital and generation. For example, will the potential for demand side participation improve the productivity of use of network elements?
- Allocative efficiency. This refers to the more efficiency allocation of resources. For example, do the proposed changes in rules lead to more efficient allocation of distributed or centrally supplied generation?
- Dynamic efficiency. This refers to the way in which the proposed changes affect the timing and pattern of future investments in electricity supply.

A benefit-cost framework based on a quantitative model of the NEM has been developed for this analysis. The benefits and costs measured include the following:

- Change in prices to wholesale market participants due to altered dispatch or bidding behaviour and by changing the timing and pattern of entry of new distributed supply options
- Lower or higher system costs due to more efficient provision of market services
- Enhancement of competition in the retail sector
- Development of a more service oriented retail sector
- Increase in the uptake of embedded generation options plus more active participation in demand side management and flexible supply/demand options such as electric vehicles. The increase in uptake of embedded generation would only occur when there is potential for large amount of exports to the grid especially at peak demand periods.

Costs were sourced from a survey undertaken by AEMO of retailers and distribution network providers. Both implementation costs and ongoing costs were considered and included:

- Registration and setup: In the case of MTRs - the creation and maintenance of multiple trading settlement points within a connection point and associated relationships between settlements points. In the case of ENs - the creation and maintenance of EN parent and child sites and relationships.

- Metering: Establishing and maintaining metering at the site and market system, including activities such as disconnections and reconnections. The cost of process and system changes to facilitate service provision/data delivery or processing of the data.

- Operations: Other operational costs.

- Billing: Changes to enable subtractive arrangements within ENs and handle discrepancies between network and retail bills.

- Reporting: Changes to reports required for regulatory purposes.

Costs were provided by market participants for four scenarios: MTR, EN option1, EN option2 and implementation of both MTR and EN. The mean, median and maximum total costs under each scenario are summarised in Exec Table- 1.

Exec Table- 1 Overall costs provided in survey, per market participant ($)

		MTR	EN option1	EN option2 Cost	MTREN
Implementation					
Retailer	mean	13,051,000	7,832,400	3,095,800	8,215,820
	median	15,573,000	7,228,000	1,410,000	6,915,300
	max	50,100,000	17,082,000	10,246,000	19,698,000
DNSP	mean	10,464,833	1,759,833	1,701,000	1,697,067
	median	9,891,500	353,000	227,000	25,000
	max	18,191,000	9,046,000	9,046,000	9,581,400
Ongoing costs					
Retailer	mean	7,765,400	3,555,400	2,784,400	3,384,320
	median	5,719,000	1,810,000	1,010,000	1,582,600
	max	20,100,000	11,046,000	9,846,000	9,741,800
DNSP	mean	2,738,500	980,000	946,667	245,167
	median	2,010,000	250,500	175,500	0
	max	7,537,000	4,726,000	4,726,000	1,279,100

Note: Not all respondents provided data for the MTREN scenario. For the benefit-cost analysis for that scenario, costs for these respondents were derived from their cost estimates for MTR and EN scenarios deflated by the same economies in costs recorded by those participants who did provide comparable data for all scenarios.

The range of estimates in implementation costs was wide, with higher costs associated with established or Tier 1 retailers. This is likely to be due to the highly integrated systems for these organisations resulting in changes to one part of the system needing to be reflected in changes to other parts of the systems. Ongoing costs for market participants for billing, metering and reporting were mainly due to the perception by respondents that there would be higher propensity for errors to be made which would require additional costs for rechecking and resolution. Because of the uncertainty in estimates of costs and the tendency for much of the costs to be borne upfront, sensitivity analysis was conducted testing the impact of higher or lower implementation costs.

An uptake model was fundamental to the benefit cost analysis, with uptake rates being highly uncertain given the lack of any relevant precedent. Uptake was modelled for the following components:

- DSP services by independent service providers for customers who want to manage their loads to minimise network and wholesale costs, or where customers just buy a service and the service provider will manage the loads to minimise costs.

- MTR by residences with roof-top PV systems, who wish to separate out the retailer that sells them electricity from the retailer they sell surplus electricity to on the basis that they wish to shop around for the best deal to sell surplus electricity. MTR would encourage additional (to retailers already offering these services) independent aggregators to enter the market to purchase surplus electricity from rooftop systems.

- Customers who purchase an electric vehicle and wish to use independent service providers to purchase electricity needed to charge batteries. MTR would provide enhanced ability to manage charging times to periods of low electricity prices. The modelling of uptake considers the (additional) number of customers that are likely to uptake electric vehicles as a result of the MTR arrangements or the lower cost of electricity supply arrangements to all owners of electric vehicles.

- Customers within ENs who wish to attain retail energy from participants other than the host EN.

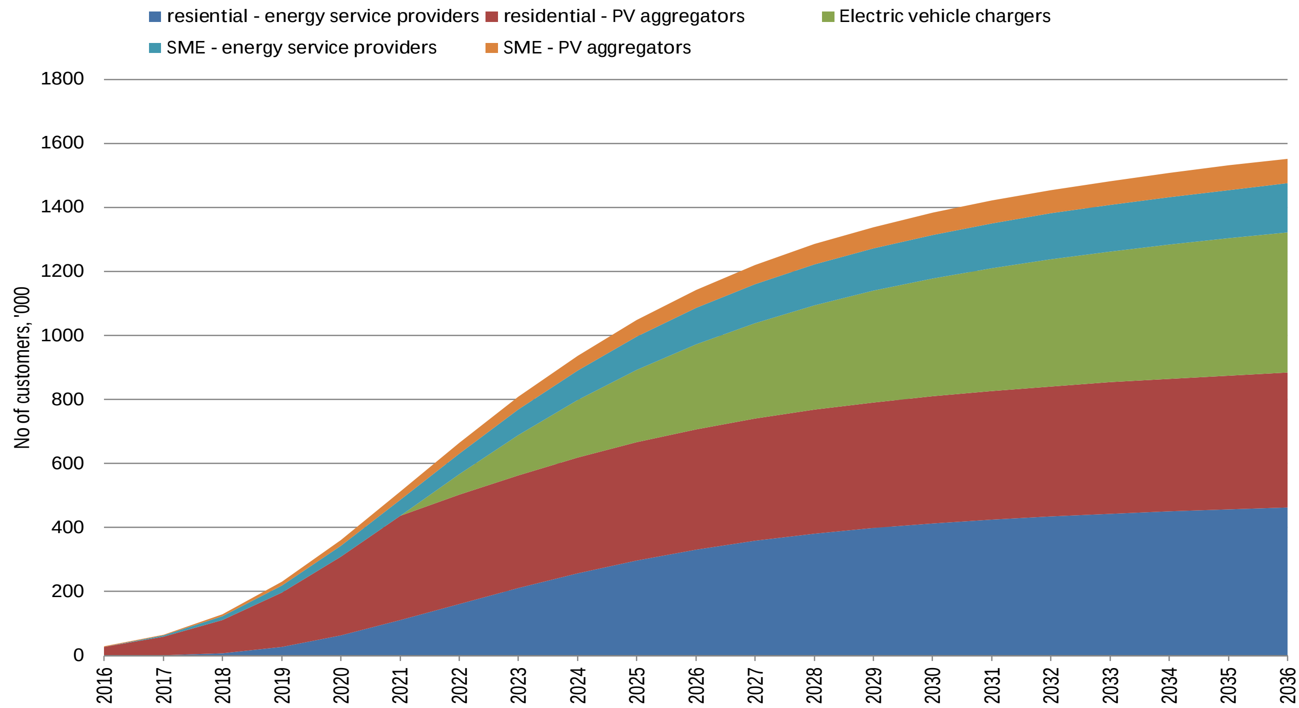
In modelling uptake, it was assumed that customers would adopt MTR or take advantage of the EN provisions only if the benefits to them are greater than the additional metering costs to customers.

Uptake was modelled using a sigmoid curve. The sigmoid curve represents adoption with a slow gradual start followed by a period with rapid uptake levelling out over time to a saturation level of adoption. Sigmoid adoption curves are typically used to model uptake of new products, technologies or services for which there is little historical data to indicate adoption. Given the uncertain nature of new technology uptake, sensitivity analysis was also conducted varying the rate of uptake.

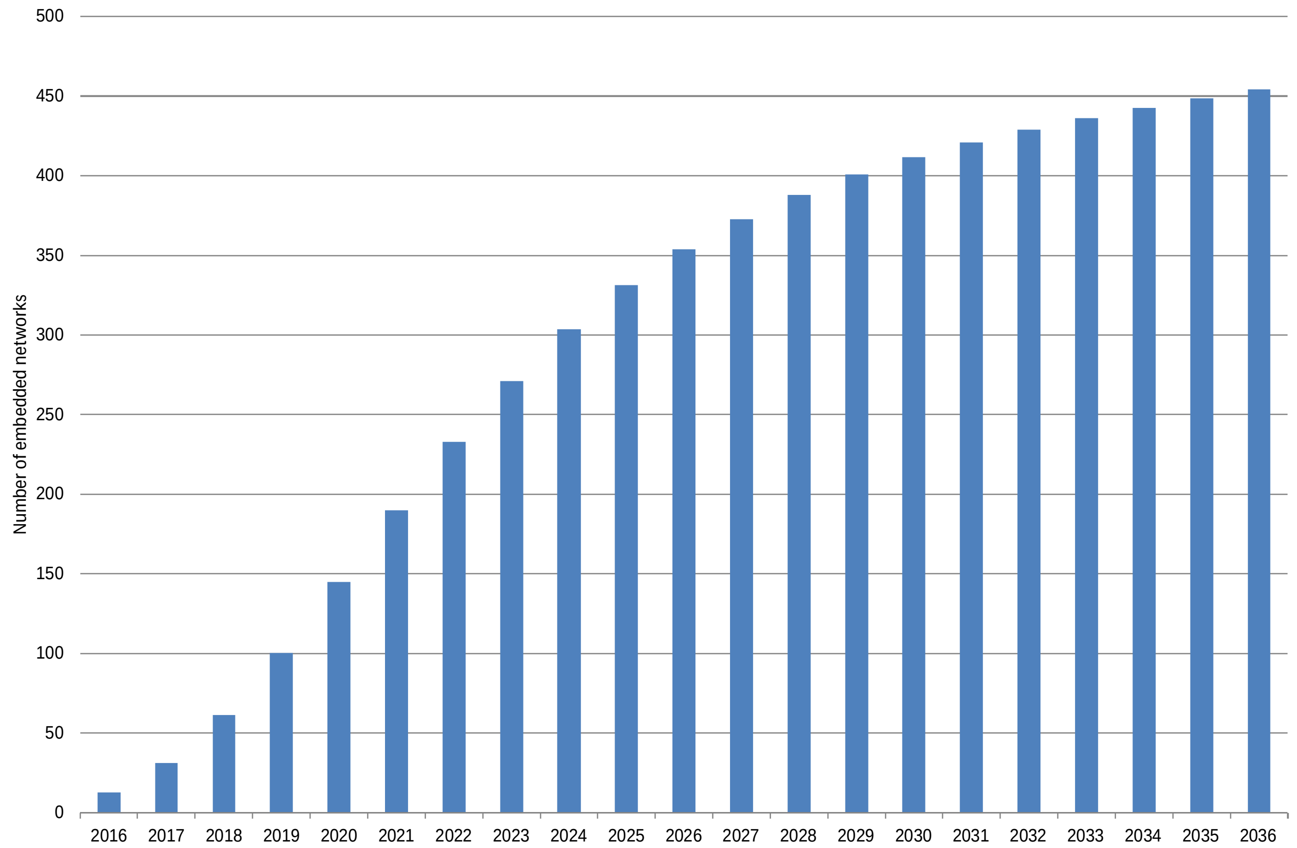
Exec Figure- 1 shows the uptake rates assumed to be facilitated by MTRs, by customer category. Uptake is relatively slow in the initial period with only 6% of total residential and SME customers adopting MTR by 2020 and mainly from residential customers who wish to use MTR to maximise the value of export sales from rooftop PV systems. By 2030, it is projected that around 1,384,000 customers have adopted MTR, or 17% of total customers.

Uptake rates for ENs are shown in Exec Figure- 2. A high portion of known embedded networks (estimated to be around 500) eventually adopt the option to have separate NMIs to allow their customers to access other competing service providers. Uptake is higher in this option because of the lower transactions costs involved in accessing alternative providers.

Exec Figure- 1 Uptake rates by customer category - MTRs



Exec Figure- 2 Projected uptake of NEM participation by embedded networks



Net benefits

The analysis indicates quantifiable net economic benefits are negative for MTR or MTREN proposed rule change under most plausible futures around electricity demand, uptake rates and system costs. This is largely a function of the assumed slow rate of adoption of MTR and the high cost of implementation of this measure. Allowing embedded customers to source alternative market participants may lead to some net benefits, mainly through enhanced competition.

The calculated net present value (using a discount rate of 7% real) of benefits and costs are summarised in Exec Table- 2.

Exec Table- 2 Net present value of benefits and costs, $M

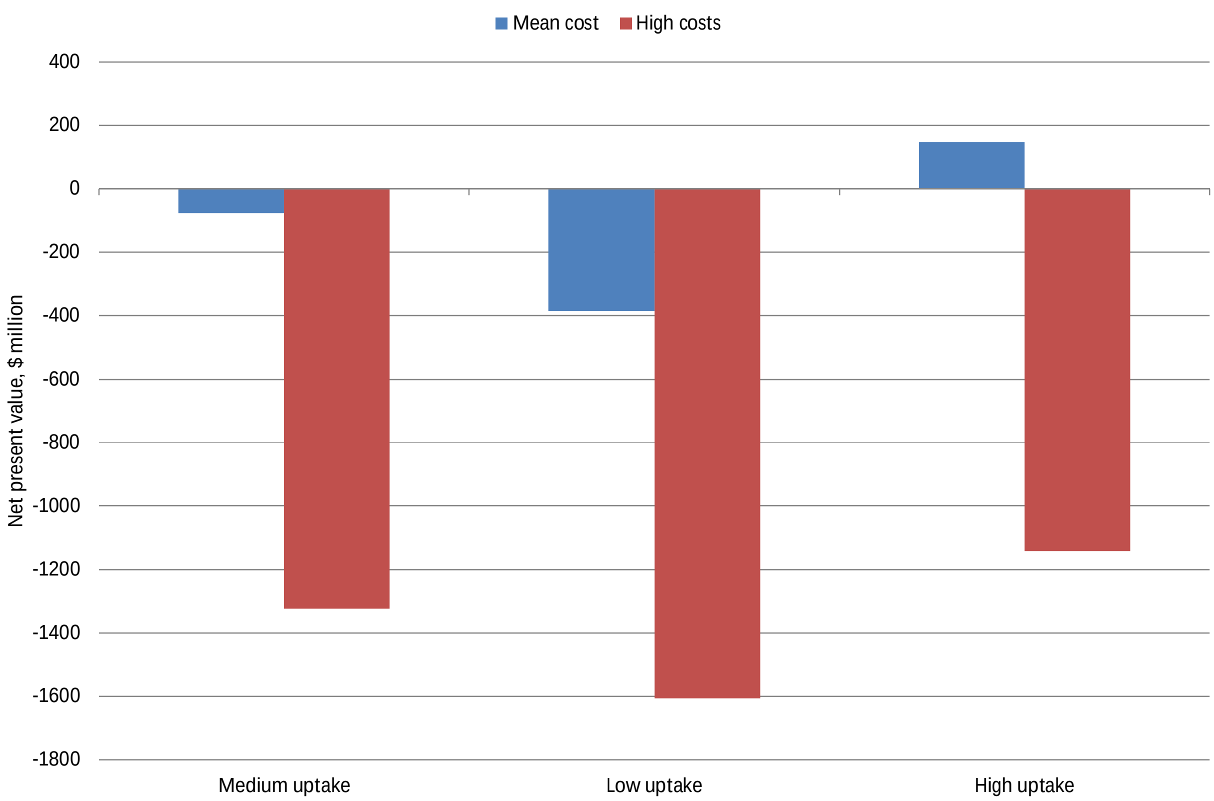
Item	To 2025				To 2035			
	MTR	EN1	EN2	MTREN	MTR	EN1	EN2	MTREN
Benefits	574	103	103	585	951	165	165	973
Costs	823	126	107	824	1027	162	146	1027
Net benefit	-249	-22	-3	-239	-76	2	19	-54

Source: Jacobs SKM analysis

It is important to note that the net impacts tend to be small. Costs tend to be borne upfront but benefits are incurred around 5 years after the introduction of the changes. Consequently, net benefits generally do not occur until after 2025.

Sensitivity analysis on uptake rate and implementation costs indicated that the net present value of benefits were highly sensitive to these assumptions, as shown in Exec Figure- 3, although the net benefits for MTR were only positive in the case where higher uptake rates were assumed.

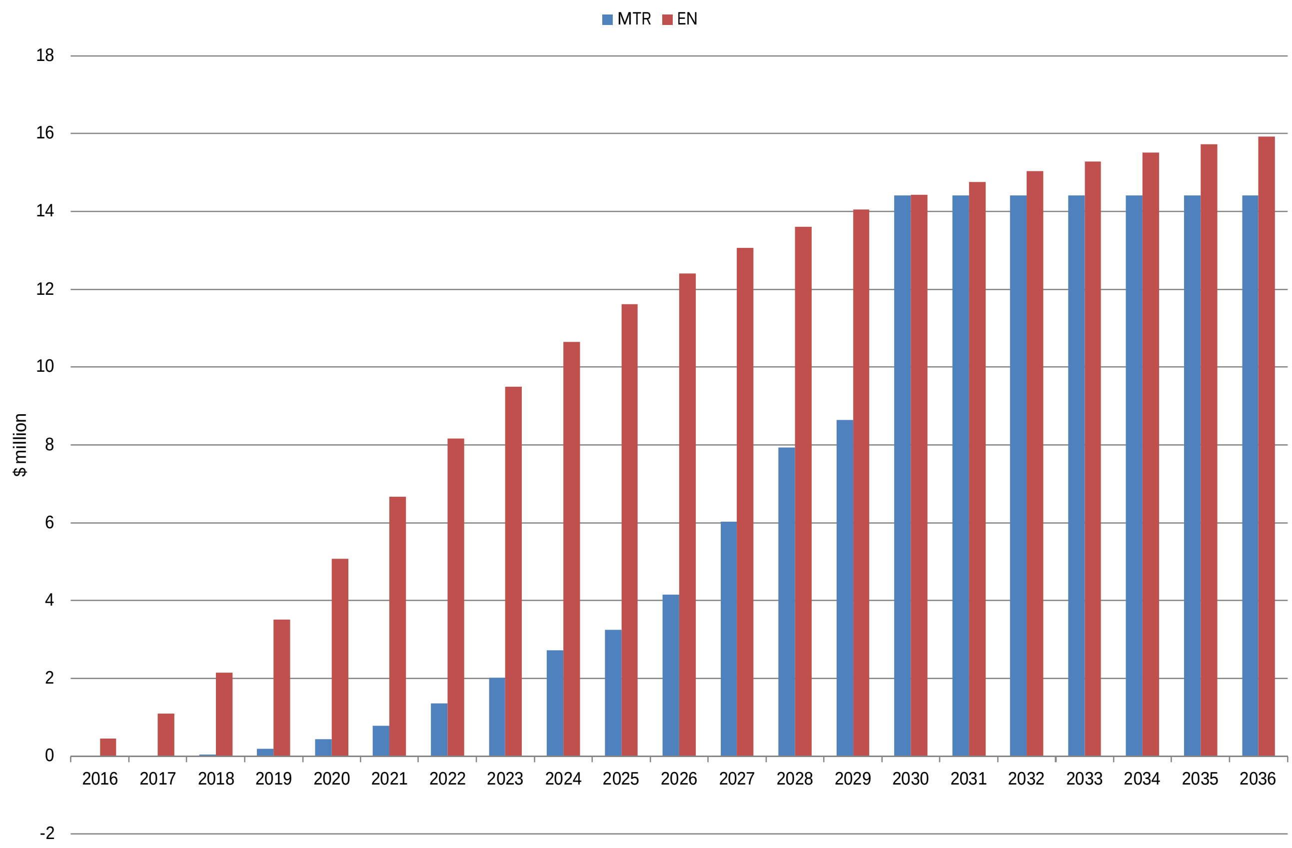
Exec Figure- 3 Net present value of MTR as a function of implementation costs and uptake rates, Sm



The MTR results were also highly sensitive to assumptions on demand growth as a major source of benefits is deferred network infrastructure expenditure. Network benefits for scenarios modelled were based on AEMO's medium rates for peak demand growth, which showed modest pickup in growth rates from 2015 onwards and reasonable growth rates for Queensland. Sensitivity analysis was performed with flat load growth until 2020 assuming medium uptake. Under this sensitivity, the net present values of benefits reduced by approximately 66%. This indicates the considerable importance of deferred infrastructure expenditure particularly from the uptake of MTR. The implication is that if current low growth rates in peak demand continue then there may be minimal market benefits to uptake of MTR.

On the other hand, the market benefits for both EN options considered are slightly positive by 2035 and are less sensitive to assumptions around demand, or new technology uptake. This is because the majority of these benefits are associated with improvements in competition in the retail sector. To the extent that competition leads to lower prices, there will be a demand response and this will lead to resource allocation benefits. The estimated value of the benefits of improved resource allocation is shown in Exec Figure- 4. Competition benefits are estimated to be greater for EN than for MTR.

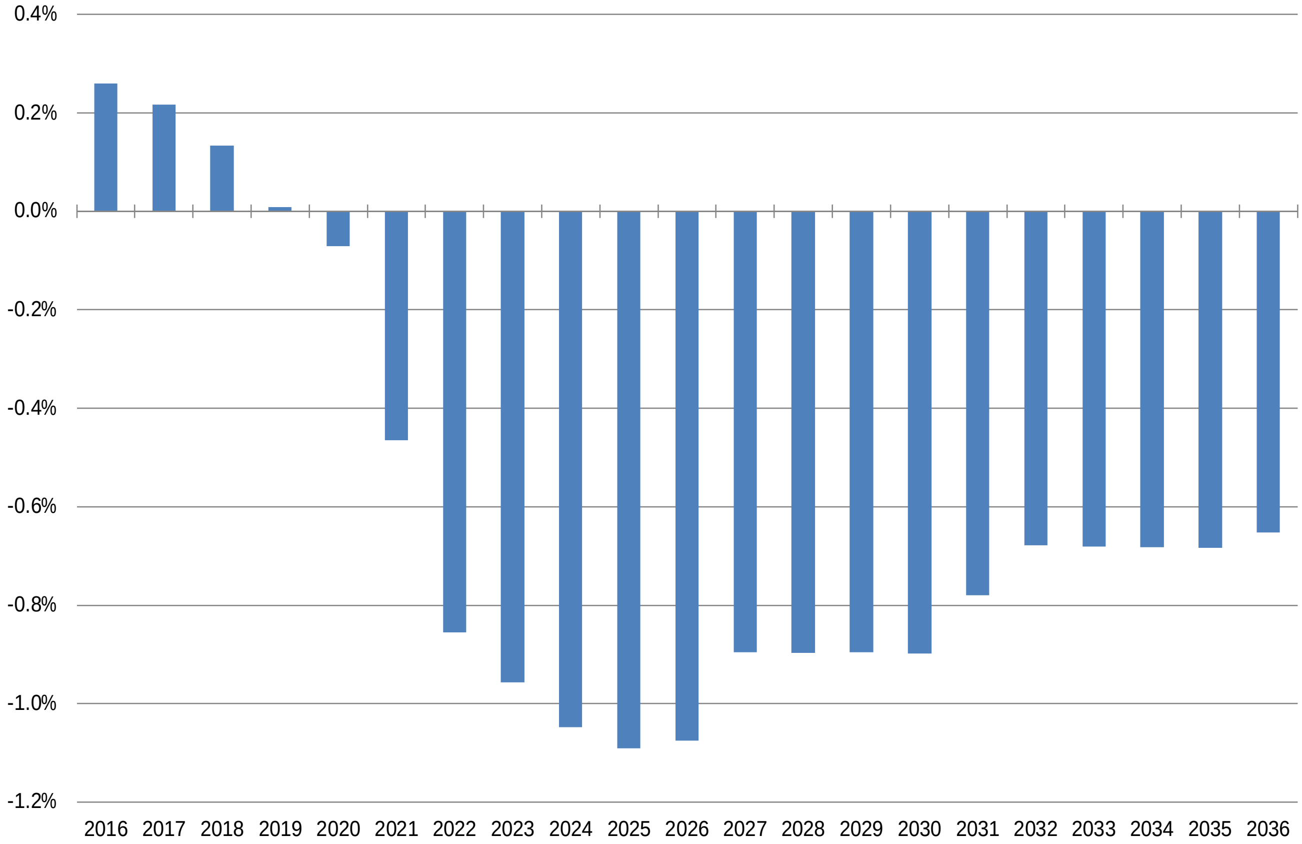
Exec Figure- 4 Competition benefits



Price impacts

The analysis indicates a small decrease in retail prices as competition reduces retail margins and wholesale prices, as shown in Exec Figure- 5. The price reduction more than outweighs the increase in retail costs from implementation and higher ongoing costs. This represents a transfer of the value of electricity to customers rather than an economic benefit.

Exec Figure- 5 Changes to retail price due to MTR



Other considerations

Although the quantitative economic analysis would suggest that it is not beneficial to proceed with changes to allow MTRs, there needs to be consideration of some other issues that were not considered as part of the benefit cost analysis. These include:

- MTREN changes may help to overcome barriers to development of energy service industry for mass market customers, and could facilitate the development of an innovative services market.
- Cost estimates provided by retailers and network service providers are likely to be conservative due to lack of detail/understanding of the changes involved. With sufficient notice, and clarity of design, the costs of implementing the required changes in the system may be lower than currently estimated. Moreover, it may be possible to explore alternative cost options whilst uptake is minimal and defer implementation of the full system changes until a later date.
- Delaying implementation is likely to increase the net economic benefits through deferral of network augmentation.
- There are likely to be synergies between this program and other DSP reform programmes currently being considered. The system changes incurred for MTREN are likely to also be required for some of the other programmes which, if considered in combination, would mean that the costs could be shared over a broader range of potential benefits.

It is important to note that this is a high level study of benefits and costs based on preliminary designs for regulatory changes to allow multiple trading relationships (MTRs) and embedded customer participation. It should be considered as a screening study given the high level of uncertainty over uptake rates, potential benefits and the cost to market participants. As a result, conservative assumptions have been adopted, with sensitivity analysis on the key assumptions.

Important note about your report

The sole purpose of this report and the associated services performed by Jacobs SKM is to identify and discuss the issues surrounding the modelling of benefit and costs of proposed alterations to market rules to allow multiple trading arrangements and embedded networks in accordance with the scope of services set out in the contract between Jacobs SKM and AEMO. That scope of services, as described in this report, was developed with AEMO.

In preparing this report, Jacobs SKM has relied upon, and presumed accurate, any information (or confirmation of the absence thereof) provided by AEMO and/or from other sources. Except as otherwise stated in the report, Jacobs SKM has not attempted to verify the accuracy or completeness of any such information. If the information is subsequently determined to be false, inaccurate or incomplete then it is possible that our observations and conclusions as expressed in this report may change.

Jacobs SKM derived the data in this report from information sourced from AEMO (if any) and/or available in the public domain at the time or times outlined in this report. The passage of time, manifestation of latent conditions or impacts of future events may require further examination of the project and subsequent data analysis, and re-evaluation of the data, findings, observations and conclusions expressed in this report.
Jacobs SKM has prepared this report in accordance with the usual care and thoroughness of the consulting profession, for the sole purpose described above and by reference to applicable standards, guidelines, procedures and practices at the date of issue of this report. For the reasons outlined above, however, no other warranty or guarantee, whether expressed or implied, is made as to the data, observations and findings expressed in this report, to the extent permitted by law.

This report should be read in full and no excerpts are to be taken as representative of the findings. No responsibility is accepted by Jacobs SKM for use of any part of this report in any other context.

This report has been prepared on behalf of, and for the exclusive use of AEMO and is subject to, and issued in accordance with, the provisions of the contract between Jacobs SKM and AEMO.
Jacobs SKM accepts no liability or responsibility whatsoever for, or in respect of, any use of, or reliance upon, this report by any third party.

1. Introduction

The Australian Energy Market Operator (AEMO) has been tasked by the Standing Council on Energy and Resources (SCER), in consultation with industry, to develop a rule change proposal for consideration by the Australian Energy Market Commission (AEMC) for changes to the national electricity rules (NER). The changes are to allow multiple trading arrangements at a single connection point and to formalise metering and other arrangements associated with embedded networks (ENs) to remove any potential barriers to embedded customers accessing offers from competing market participants.

Both changes offer scope for increasing the level of competition, at the wholesale as well as the retail level, and enhance the range of services offered by market participants. However, adoption of both measures may lead to high upfront costs to AEMO, market participants and metering providers even though adoption of the opportunities provided by the changes may not occur for some time.

Jacobs SKM[4] has been commissioned by AEMO to undertake a benefits cost study of the proposed changes. This report outlines the method and the assumptions applied in the analysis, and discusses the results. The study considered economic benefits and costs as well as impacts on prices to consumers.

It is important to note that this is a high level study of benefits and costs based on preliminary designs for regulatory changes to allow multiple trading relationships (MTRs) and embedded customer participation. It should be considered as a screening study given the high level of uncertainty over uptake rates, potential benefits and the cost to market participants. As a result, conservative assumptions have been adopted, with sensitivity analysis on the key assumptions. The findings of this study point to the factors that need to be understood better to ensure success for the changes.

[4] Jacobs® and Sinclair Knight Merz (SKM) have combined to form one of the world's largest and most diverse providers of technical, professional and construction services across multiple markets and geographies.

2. Impacts of Proposed Changes

2.1 Background

The final report of the AEMC *Power of Choice* review set out a reform package for the National Electricity Market. This package provides households, businesses and industry with more opportunities to make informed choices about the way they use and purchase electricity. The overall objective is to ensure that the customer's demand for energy services is met by the lowest cost combination of demand and supply side options.

The final recommendations are a package of reforms designed to increase the responsiveness of the demand side to evolving market, technological developments and changing consumer interests.

These reforms act to facilitate efficient Demand Side Participation (DSP) in two ways:

- Enabling consumers to see and be rewarded for taking up demand side options (demand side changes); and
- Enabling the market to support consumer choice through better incentives to capture the value of demand side participation options and through decreasing transaction costs and information barriers (supply side changes).

The execution of these reforms has been split into a number of different projects each resulting in a Rule change proposal. These Rule change projects have been run by either AEMC or AEMO. All of these Rule changes and/or reviews are part of the broader Power of Choice Reform.

The Rule changes and reviews relevant to metering are:

- Multiple Trading Relationships and Embedded Networks (MTREN) - Rule, Procedure and System changes to:

  - Support multiple retailers operating at a single connection point.

  - Encompass current NSW, SA, Victorian and AEMO protocols for operating ENs to ensure other States can facilitate full retail contestability.

  The SCER has tasked AEMO to run this project.

- Competition in Metering - Establishment of enhanced full competition in metering service provision (including metering coordinator, ownership, access rights, and use of consumers metering data). This project is being run by AEMC.
- Open Access Review - Establishment of a framework for open access, interoperability and common communication standards to support competition in DSP energy management services enabled by smart meters. This project is being run by AEMC.
- Consumer Access to Data - Allow entitled parties to access energy data in meters irrespective of what process the meter was installed (commercial or mandated). This project is being run by AEMC.

- Demand Response Mechanism (DRM) - Establish a new demand response mechanism that allows consumers, or third parties acting on consumers' behalf, to directly participate in the wholesale market and to receive the spot price for the change in demand. The SCER tasked AEMO with running this project. SCER has instructed AEMO not to submit the Rule change proposal pending a further review of DRM including a further cost benefit review.

2.2 Proposed changes

SCER has tasked AEMO with investigating changes to the NER to allow MTRs at a single connection point and to formalise arrangements for customers connected to an EN to contract with a retailer of choice. AEMO, in conjunction with stakeholders, have designed some high level changes to the current rules to allow for multiple trading arrangements. The focus of the changes is on domestic and small to medium sized enterprises (SMEs).

The current arrangements for customer engagement with a retailer are based on the set of relationships at the physical connection point to the network, which include a one-to-one relationship between the connection point, customer, and the retailer. The intent of moving to a MTR is to enable customers to engage with multiple retailers or energy service providers (through eligible retailers) at their site and to find the best solution for buying and selling electricity for different components of the customer's load and on-site generation[5].

The key enabler for MTRs is to separate the settlements point from the connection point so that there may be multiple settlements points per connection point. Each settlements point will have its own set of operational and trading relationships. Participation in multiple trading arrangements is voluntary, and may require more sophisticated metering than is currently provided in the roll out of smart meters in Victoria and other regions to allow for separate settlements of portions of the customer's load.

An EN is a private network usually connected to a distribution system (or another EN) via a parent connection point. An EN is operated by an Embedded Network Operator (ENO). Examples include airports, shopping centres or apartment blocks. Where allowed by jurisdictional policy[6], customers are not required to obtain their energy from the ENO/reseller and can obtain electricity from another NEM retailer. However, there are some barriers to the embedded customers from engaging with other NEM retailers, with such barriers including a lack of clarity on obligations of different parties with respect to metering arrangements, a lack of visibility of contestable customers within ENs, differing metering standards from the NEM, and a lack of uniformity in distribution use of system pass through arrangements[7].

At present, EN operators have an AER exemption from registering as a network operator in the NEM, and this will continue for the foreseeable future. However, the proposed changes may recognise an ENO as a new type of network operator under the National Electricity Rules. They may also be required in the future to follow shadow pricing guidelines set by the AER in setting DUOS charges to be charged to each customer within their networks.

All settlements points within an EN, including at ENO customers, will be recorded in AEMO's Market Settlement and Transfer Solutions (MSATS) systems and will be discoverable by other retailers.

The design options for changes to the allocation of National Metering Identifiers (NMIs) in ENs that have been considered in this study are:

- The local retailer would set up NMIs to enable NMI discovery in MSATS for all child settlements points within each EN including both NEM customers and ENO customers for existing ENs and as an ongoing role for future ENs

- The local retailer would only set up NMIs (and hence NMI discovery) for settlement points as and when they become NEM Customers.

2.3 Potential impacts

2.3.1 Multiple Trading Relationships

MTRs may improve customer choice, and improve efficiency of demand and supply by potentially:

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[5] AEMO (2013), *Multiple Trading Relationships and Embedded Networks – High Level Design*, December
[6] Not allowed in Queensland, ACT and Tasmania
[7] AEMC (2012), *Power of Choice Review: Giving Consumers Options in the Way They Use Electricity*, 30 November

- Enabling customers to better (than they can now) separate out portions of their load (more or less controllable) and to improve their management of these portions. This will become more important with the uptake of more sophisticated appliances with the ability of remote or automatic operation of use.
- Facilitating development of new (or expansion of existing) competing service providers or more retailers who could provide bespoke services to portions of domestic customer loads. For example, energy service companies could focus on providing heating and air conditioning energy services.
- Enabling customers with roof-top PV systems or other embedded generation to sell their surplus electricity through an independent retailer depending on which retailer provides the best offer. This may lead to the development of an aggregator service allowing eligible aggregators or competing retailers to "collect" surplus electricity from a number of households and sell to other customers within the distribution area.
- Facilitating the development of new electrical loads or embedded supply points such as from electric vehicles in the longer term. For example, charging of electric vehicles may be supplied by an independent specialist retailer that could manage the profile of recharging to periods when wholesale prices are low, thereby reducing costs and avoiding network peak periods.

2.3.2 Embedded networks

The main purpose of these changes is to provide regulatory certainty in relation to ENs, by recognising these networks in the NER, and formalising the required obligations and arrangements in the NEM regulatory framework. The benefit of the proposed change is regulatory certainty, and clearly defined roles and obligations (ENs are not currently recognised in the NER). Another benefit is that the formalisation of ENs could lead to a consumer uptake, as competition in ENs is currently not allowed in some jurisdictions. These arrangements will allow participants to have a consistent approach across the NEM, and so consumers can benefit from having participants as more willing providers. Clarifying and codifying the rules and procedures around ENs would allow other jurisdictions to allow customers within ENs to seek competitive prices. This would increase competition and improve regulatory certainty between jurisdictions.

The main advantage of the proposed changes would be to make upstream (network and any wholesale) cost pass-through more transparent to individual customers within a network making it more difficult for EN retailers to offer non-linear pricing to embedded customers (that is, offering price schedules whereby some customers with more buying power get more favourable tariffs than other customers). Under current arrangements, the ENO or Retailer is almost like a local monopoly, and is able to use their ability to pass on DUOS costs in a non-transparent way so that they can cross subsidise across customers according to the customer's ability to access competing retailers.

Another impact is to allow retailers to get better load information on some customers which would enable them to craft more bespoke tariffs to embedded customers.

2.4 Issues for assessing benefits and costs

2.4.1 Benefits

Key issues with assessing the benefits include:

- A potential benefit is that customers avoid the cost of a second connection point. This cost is currently a potential barrier to innovation, and any reduction in this through the MTR may increase the penetration of innovative customer operations. However, in some cases, the costs associated with applying MTR may offset some or all of the savings. For example, where the customer is adding new load (as will be the case in many situations – such as electric vehicles), cost of upgrading the supply to the customers' premises may be similar to the creation of a second connection point. Equally, any MTR arrangement that would require separation of load would need to include electrical work to separate those electrical components and potentially the installation of a new meter cabinet. These costs need to be considered in modelling of uptake of MTR.

- In this study, it has been assumed that a key benefit of the implementation of MTR is to better facilitate demand side responses over and above the level of demand side response that currently occurs. It is possible that other approaches could achieve the same outcome.

- Determining the costs of implementation. In particular, how much of the implementations costs have to be borne upfront (once the changes are promulgated) ahead of any uptake by customers. In this study, we explore this issue by using sensitivity analysis over plausible ranges over the timing of implementation costs.

3. Approach

A quantitative approach has been developed to evaluate the indicative market implications of the high level design. The quantitative approach is designed to estimate overall market benefits and costs, as well as to assess the implementation and distributional impacts (such as potential changes to customer tariffs).

3.1 Overall framework

Both of the proposed rule changes could lead to changes in the way customers purchase their electricity and enhance the competitive dynamics as a result. The benefit-cost framework is designed to capture the resulting impacts described above on:

- Productive efficiency. This refers to the way in which the proposed changes allow for more efficient use of the current stock of capital and generation. For example, will the potential for demand side participation improve the productivity of use of network elements?
- Allocative efficiency. This refers to the more efficiency allocation of resources. For example, do the proposed changes in rules lead to more efficient allocation of distributed or centrally supplied generation?
- Dynamic efficiency. This refers to the way in which the proposed changes affect the timing and pattern of future investments in electricity supply.

The benefits realised from the proposed changes were quantified and compared to the costs of the proposed changes. This includes the costs of implementation as well as the incremental operating costs to network service providers and AEMO. For implementation cost, a critical issue is the timing of these costs and how these costs can be deferred (or staged) to better match uptake of the new arrangements.

Given that uptake of these options is voluntary, customer uptake would only occur when the benefits to the individual customer (through reduced electricity tariffs and bills) exceed the cost of implementing changes to their metering. Currently, customers can achieve the same outcomes through installing a second connection point, the cost of which can be high. Some customers may find this economical and would already have or consider having this second connection point to capture any benefits to them associated with better facilitation of demand response. For these customers, there is no difference between the base case (status quo) or project case (implementing the proposed changes). Where the cost of the proposed change is lower than the base case cost of a second connection, and the cost is less than the benefits to the consumer, demand side participation may increase. Uptake of these options is voluntary. For the customer, uptake would only occur when the benefits to the individual customer (through reduced electricity tariffs and bills) exceed the cost to the customer of implementing changes to their metering. Currently, customers can achieve the same outcomes through installing a second connection point, the cost of which can be high. The highest costs under current arrangements relate to connection augmentations and this cost would still be borne as a result of an increase in a customer’s capacity (connection of an EV load for example). So MTR may provide no additional benefit in these cases. Some customers may find this economical and would already have or consider having this second connection points to capture any benefits to them associated with better facilitation of demand response. The MTR argument comes down to whether MTR can be delivered at less cost than a network connecting a second connection point where the capacity is not changing. The costs to perform this activity from the network would not be excessive and we see this happen today when a customer separates a portion of their premises into a granny flat, or second occupancy for letting as examples.

In this study, these customers are part of the no change or base case. The benefit of the proposed changes is translated to a higher level of participation of customers in demand side response because the cost of doing so is now lower. The benefit of lower costs of participation (e.g. avoided second connection point or second meter costs) is reflected through higher levels of participation in demand side response.

Costs included in the analysis covered:

- Registration and setup: In the case of MTRs - the creation and maintenance of multiple trading settlement points within a connection point and associated relationships between settlements points. In the case of ENs - the creation and maintenance of EN parent and child sites and relationships.

- Metering: Establishing and maintaining metering at the site and market system, including activities such as disconnections and reconnections. The cost of process and system changes to facilitate service provision/data delivery or processing of the data. Metering costs borne by the customer were assumed to form part of the decision by the customer to participate in the new arrangements. Thus, since participation in the rule changes is voluntary, to the extent that these costs are not outweighed by the returns to the customers (in the form of reduced electricity supply costs or increased revenue from sale of surplus embedded generation), they would not take advantage of the new rules.

- Operations: Other operational costs.

- Billing: Changes to enable subtractive arrangements within ENs and handle discrepancies between network and retail bills.

- Reporting: Changes to reports required for regulatory purposes.

3.2 Method for quantitative study

Productive, allocative and dynamic efficiency gains arising from the proposed rule changes come from two sources. First, under MTRs, residential and SME customers will be better able to manage their loads so that there will be shifts in consumption from high price periods to low price periods. This will improve the productivity of use of network elements possibly deferring any future investments to meet peak demand (at the regional and system level), and will lead to better utilisation of generating plant, with less call on the need for peaking plant with high operating cost. Second, the changes affecting ENOs may ultimately lead to more competitive outcomes by allowing retailers to compete better to supply portions of the embedded loads (say overnight loads, at sites with cogeneration), leading to a more efficient allocation of resources devoted to generation of electricity and possibly leading to improvements of network productivity.

A benefit-cost framework based on a quantitative model of the NEM was developed. The benefits and costs measured include the following:

- Change in prices to wholesale market participants due to altered dispatch or bidding behaviour and by changing the timing and pattern of entry of new distributed supply options
- Lower or higher system costs due to more efficient provision of market services
- Enhancement of competition in the retail sector
- Development of a more service oriented retail sector
- Increase in the uptake of embedded generation options plus more active participation in demand side management and flexible supply/demand options such as electric vehicles. The increase in uptake of embedded generation would only occur when there is potential for large amount of exports to the grid especially at peak demand periods.

The process involved the following steps:

- Uptake model: This determines the number of customers willing to adopt these options. Uptake is based on data on the number of sites (embedded generators, residential, SME loads) that could already be able to take advantage of these options. The uptake model then predicts the extent of uptake using a sigmoid adoption curve typically used to model uptake. Uptake commences when the prospects of future costs from current supply arrangements to customers exceed the costs to customers of electrical wiring and metering configuration changes under the proposed changes. The shape and parameters of the sigmoid curve has been adapted from empirical uptake studies of simular types of reforms to market or from trial data such as the Magnetic Island Solar Cities study, the Futura Consulting study on DSP potential, data on uptake of energy efficiency programs under the NSW Energy Savings Scheme and evidence provided by network service providers for trials such as by Ergon. Uptake of MTR to take advantage of DSP services is separately treated from uptake of MTR to take advantage of trading arrangements to sell surplus self-generation or trade/purchase electricity for the charging of electric vehicles. As uptake is uncertain, sensitivity analysis on the rate of uptake has also been conducted.

- Once uptake was predicted, the likely manifestations of the uptake were determined in terms of reduced peak demand, reduced electricity use, and the impact on uptake of distributed generation or trigeneration options (where these options become lower cost than grid supplied generation options). This produced a time stream of peak demand reduction and electricity consumptions by region, as well as a net demand to be supplied from the grid.
- There is also the prospect for new loads to be added (e.g. electric vehicles) and the management of these new loads to minimise costs. This benefit was captured by estimating the increase in electricity demand and estimating the resource benefit of supplying this additional demand.
- The time stream of peak demand reductions and net energy demand changes were input into Jacobs SKM's Strategist model of the NEM. The model has been used to estimate productive and allocative efficiency benefits in the wholesale market by determining changes to bidding behaviour and entry of new plant as a result of any impact of the proposed changes on the level and uptake of distributed (embedded) generation plus demand management options, including electric vehicles.
- Jacobs SKM's distributed network model was used to determine network benefits arising from reductions in peak demand. The model determines deferred expenditure on distribution network infrastructure on a regional basis.

3.3 Scenarios modelled

Four design scenarios were modelled:

- MTR scenario: changes are enacted to allow for customers to adopt MTRs.
- EN1 scenario: changes enacted to enable embedded customers to seek alternative retailers of choice. In this scenario, the local retailer would set up NMIs for all embedded customer settlement points within each EN.
- EN2 scenario: changes enacted to enable embedded customers to seek alternative retailers. In this scenario, the local retailer would only set up NMIs when embedded customers become NEM customers.
- MTREN scenario: changes to allow both MTRs and EN customers to participate in the NEM are enacted.

The benefits and costs arising from these scenarios were estimated against outcomes under a no change (base) scenario.

Costs and benefits were calculated for the period from 2015/16 to 2034/35. Implementation costs were assumed to be incurred during 2014/15.

3.4 Assumptions

3.4.1 Uptake Model

Uptake was modelled for the following components:

- DSP services by independent service providers for customers who want to manage their loads to minimise network and wholesale costs, or where customers just buy a service and the service provider will manage the loads to minimise costs.
- MTR by residences with roof-top PV systems, who wish to separate out the retailer that sells them electricity from the retailer they sell surplus electricity to on the basis that they wish to shop around for the best deal to

sell surplus electricity. MTR would encourage additional (to retailers already offering these services) independent aggregators to enter the market to purchase surplus electricity from rooftop systems.

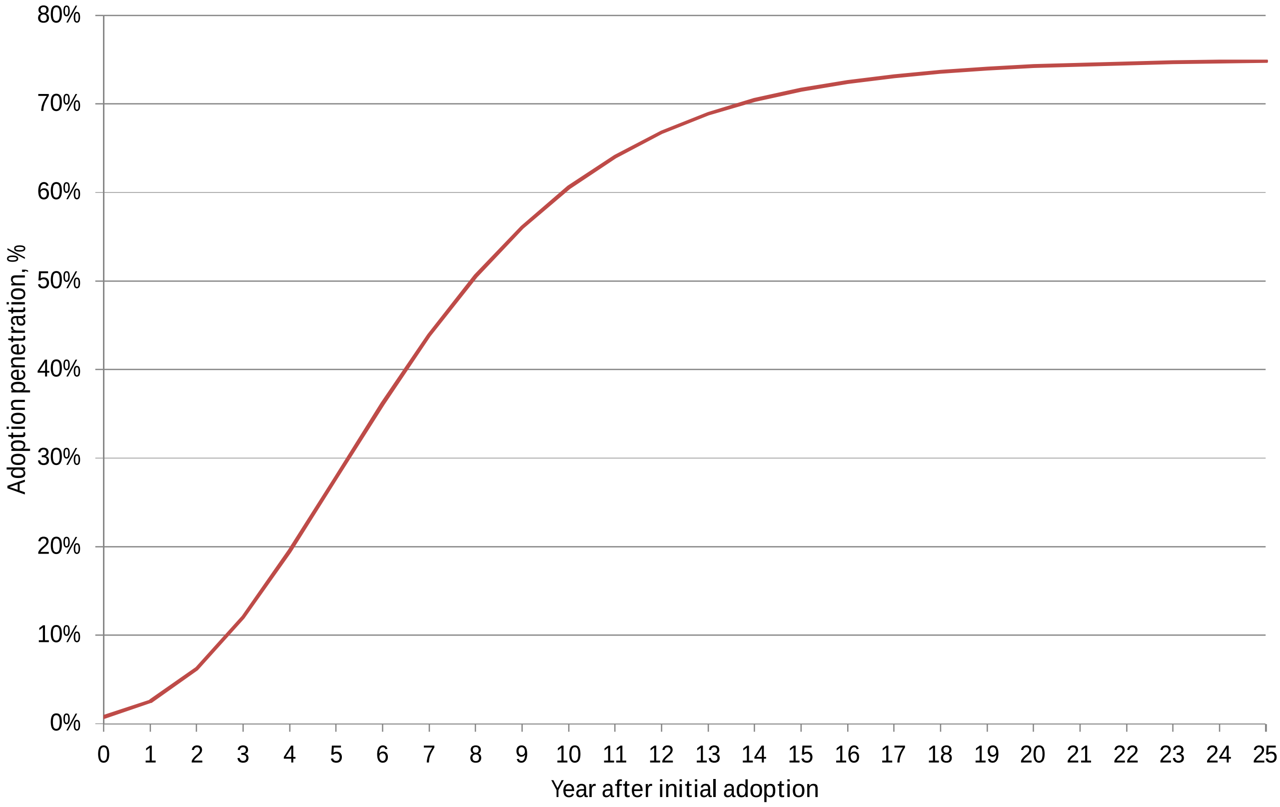
- Customers who purchase an electric vehicle and wish to use independent service providers to purchase electricity needed to charge batteries. MTR would provide enhanced ability to manage charging times to periods of low electricity prices. The modelling of uptake considers the (additional) number of customers that are likely to uptake electric vehicles as a result of the MTR arrangements or the lower cost of electricity supply arrangements to all owners of electric vehicles.

- Customers within ENs who wish to attain retail energy from participants other than the host EN.

In modelling uptake, it was assumed that customers would adopt MTR or take advantage of the EN provisions only if the benefits to them are greater than the additional metering costs to customers.

Uptake was modelled using a sigmoid curve. The sigmoid curve represents adoption with a slow gradual start followed by a period with rapid uptake levelling out over time to a saturation level of adoption[8]. Sigmoid adoption curves are typically used to model uptake of new products, technologies or services for which there is little historical data to indicate adoption. A representative curve is shown in Figure 1.

Figure 1: Representative sigmoid adoption curve



Under this approach, uptake is modelled using the following formula:

$U_t = a_t * Exp^{(b*exp(ct))}$

[8] A sigmoid curve approach was adopted because of the heterogeneity of customer characteristics makes it difficult to determine customer uptake on individual customer benefits. The sigmoid curve accommodates this in that the slow initial uptake is reflective of small payback periods or high return hurdles due to the level of uncertainty over the purported benefits to the customer. As consumers gain confidence of the benefits to them, they then often relax the hurdle rates.

Where: *Ut* = uptake in year *t*

Exp = exponential operator

a = system parameter associated with maximum penetration rate

b = parameter determining when the inflexion point (the period when rapid uptake has begun

c = rate of acceleration in uptake

The parameter *a*, *b*, and *c* are determined by using information on known update patterns for similar services and/or subjective judgements of industry experts. Because there is limited experience with similar services in the NEM, the parameters were estimated in this study based on anecdotal evidence on the potential rate of uptake. The values of the parameters are shown in Table 1. A maximum potential uptake rate of 30%.

Uptake rates are highly uncertain given the lack of any relevant precedent. Due to the lack of hard data on adoption and the resulting uncertainty in uptake rates, sensitivities of potential benefits to uptake rates were performed (low, medium and high uptake rates). But given the importance of uptake to the benefit-cost analysis, there should be further work to determine the potential uptake particularly the rate of uptake in the early period after implementation. There may also be some value in undertaking some suasive programs (advertising and marketing) to promote the potential benefits, which could help accelerate uptake.

Table 1: Estimated parameter values for modelling uptake

Parameter	DSP services			PV exports			Electric Vehicles		
	Low	Medium	High	Low	Medium	High	Low	Medium	High
Years to inflexion	3	5	7	10	13	15	3	5	7
Initial adoption	0.0%	0.0%	0.0%	2.5%	2.5%	2.5%	1%	2%	3%
Acceleration rate	0.00001	0.0001	0.01	0.00001	0.005	0.02	0.00001	0.0001	0.01
Parameter *a*	0.10	0.15	0.20	0.20	0.25	0.30	0.05	0.08	0.10
Parameter *b*	-6.00	-5.99	-5.98	-3.5	-2.86	-2.25	-5.97	-5.9	-5.79
Parameter *c*	-0.30	-0.30	-0.37	-0.30	-0.36	-0.60	-0.30	-0.30	-0.37

Source: Jacobs SKM

3.4.2 Estimating economic benefits

Uptake of MTR has a number of potential economic benefits. For customers or niche retailers who adopt or promote MTR to enable DSP to minimise their electricity purchase costs, their actions may lead to the following system benefits:

- Smoothing out of load shape to avoid peak demand periods which has economic benefits through more productive use of generation assets and the deferment or curtailment of the need to install peaking plant. The benefits are reflected through reduced capital costs in generation, reduced fixed costs of operating redundant peaking plant and through reduced fuel use from operating plant more efficiently. In the case of electric vehicle battery charging, MTR may facilitate the management of charging times to off-peak or low price periods.
- Lower transmission losses due to reduced call on transmission assets during peak periods.

- Enhancing competition. Uptake of MTR may encourage the entry of competing service providers that would compete with retailers to supply parts of domestic and SME loads. The enhanced competition is likely to reduce costs to customers. It would also facilitate competition from exempt sellers who already operate in the market. Alternative service providers would have to be eligible as the FRMP (financially responsible market participants).

- Enhancing returns to owners of small scale embedded generators allowing more optimal allocation of energy from these systems so that more energy is exported during wholesale peak periods, bringing additional generation system benefits.

- Smoothing out load shapes to reduce the use of distribution networks during local network peaks.

Allowing embedded loads to access alternative retailers would also lead to enhanced competition, which could lead to lower prices to electricity consumers. Again the economic benefit of this enhanced competition is reflected through a small increase in demand as a result of the lower prices.

Increased competition is also likely to drive down retail margins, delivering a wealth transfer from retailers and some customers[9]. While this may not be a true economic benefit, it is likely to result in reduced prices to consumers and therefore lead to a greater achievement of the NEO.

Network benefits were estimated using three approaches:

- For interregional interconnectors, the savings in upgrade costs were deemed part of the electricity market modelling. The market models were designed to choose between generation and transmission upgrades to meet load growth and reliability criteria. Data on upgrade costs for interconnectors were obtained from the transmission planning statements published by the Transmission Network Service Providers (TNSP) in each jurisdiction.

- Deferrals to intraregional transmission upgrades were based on reductions in system peak demand. Data on upgrade costs were sourced from documents published as part of the Regulatory Reset proposals/approvals for the TNSPs.

- Deferral of distribution network infrastructure. A network deferral model was used to determine the benefits of local peak demand reduction on each distribution network zone.

The approach used for this project recognised that a significant portion of network costs are not based on throughput energy but on obligations to supply capacity. The method estimated the capital costs savings that may result from a reduction in the rate of peak demand growth.

The impact on network tariffs was estimated, considering the reduced energy throughput (leading to lower network revenue recovery) and reduced peak network demand (leading to a capacity deferral benefit). Our approach determined network prices by re-applying the variable and avoidable portion of reduced network charges to recalculate energy savings.

3.4.3 Estimating network benefits

The benefit of uptake of DSP as a result of MTR was assumed to be reflected in the level of load shifted to off-peak periods. It was assumed that customers with MTR were able to divert a portion of their load away from system peak periods, with the load shifted assumed to be equivalent to a refrigeration unit or air-conditioning unit. Not all customers who adopt MTR will perfectly or always shift load away from system peak periods. System peak and local network peak may not be perfectly aligned. To account for these issues only a portion of the load shift potential was assumed to be used.

Thus, the actual reduction in weekly and annual peak demand was calculated using the following relationship:

[9] To the extent that shifting loads leads to reduced wholesale prices, then it might benefit a broad range of customers not just those customers who take up MTR

$$PRS_t = U_t * MLD_t * CSt$$

and

$$PRLN_t = U_t * MLD_t * CN_t$$

Where: PRS_t = System peak reduction in MW in year t

$PRLN_t$ = Local network peak reduction in MW in year t

U_t = uptake of MTR (customer numbers) in year t

MLD_t = maximum peak load deferred by customer in year t

CS_t = contribution of maximum deferral to reducing system peak

CN_t = contribution of maximum deferral to reducing local network peak peak

System peak reduction was used to calculate the benefits from deferral of investments in the wholesale market and transmission networks. Local network peak reduction was used to calculate deferral of investments in distribution networks.

The assumptions used to calculate peak reduction benefits are outlined in Table 2. The model is set up to undertake three cases to test the sensitivity of the results to peak reduction. The central case assumed that households could shift around 1 KW of load away from peak price periods (approximately the load of one major appliance) and 4.0 kW for SMEs. The contribution to reducing peaks assumed that DSP shifted loads away from peak periods in the wholesale market.

Table 2: Assumptions used to calculate peak reductions

	Central	High	Low
Maximum load deferred (kW)			
Residential	1.0	1.5	0.5
SMEs	4.0	8.0	2.0
Contribution to system peak (firm %)			
Residential	80%	90%	70%
SMEs	80%	90%	70%
Contribution to local network peak			
Residential	15%	20%	10%
SMEs	80%	90%	70%

Source: Jacobs SKM

Transmission network benefits were derived as follows:

- Take peak demand forecasts by State published in the NEFR 2013.
- The contribution to peak reduction is equal to the portion of calculated peak reduction, which is equal to maximum load deferred in any year times the contribution to system peak.
- Multiply the amount of network capacity deferred by the average cost of transmission capital expenditure. This number was assumed to be $514/kW.

Distribution network benefits were estimated by distribution zone using the following procedure:

- Derive the average network spend on capital for load growth to get a $/kW estimate for deferred expenditure. The estimates for each distribution zone are provided in Table 3.

- Derive local region peak reduction. The local peak reduction due to uptake was equal to a discount of the system peak reductions, where the discounts for each customer class are listed in Table 2.
- The value of peak reductions were discounted by 30% due to potential non-alignment of peak shifts to local peak demand and then discounted another 30% to cover the perception that DSM cannot be relied upon when reducing network peak demand (so that some network elements will still need to be built in order to ensure supply reliability). This could be considered a conservative assumption.

Table 3: Estimates of average capital expenditure for net upgrades due to demand growth

Distribution zone	DNSP peak demand benefit, $/kW, adjusted to $2013
Endeavour Energy	2,611.12
Ausgrid	2,541.73
Essential Energy	3,451.51
ActewAGL	457.74
Powercor	806.98
Jemena	992.02
SP Ausnet	1,169.35
United Energy	953.47
Citipower	1,662.79
Energex	514.00
Ergon Energy	5,246.40
SA Power Networks	1,824.52
Aurora Energy	629.65

Further detail about the modelling of electricity networks is provided in Appendix B.

3.4.4 Savings in electricity generation costs

Savings in electricity generation costs, including operating and deferred capital costs, were estimated using Jacobs SKM's proprietary energy market models, adapted for each scenario. The models take into consideration of the impacts on generator dispatch and temporal impacts on capital investments in generation. The models simulate generation and market price behaviour to provide projections of fuel use, generation, emissions, wholesale electricity prices, and consequently retail electricity prices.

The core market model determines dispatch of generating plant and the pattern and timing of new investments in generation to meet load reliably and to minimise the cost of generation. The eventual impact of uptake of MTR changes the pattern of demand, which has an impact on the generation sector through:

- Changing dispatch by having greater levels of dispatch in non-peak periods and less dispatch in peak periods.
- By smoothing out demand, deferring the need for new peaking plant.

A more detailed explanation of the wholesale electricity market models is found in Section A.

3.4.5 Competition benefits

Competition leads to reduced prices to customers and this engenders an increase in demand for electricity. Competition benefits were estimated through the value of additional generation required to meet this increase in demand. The price reduction through increased competition was multiplied by own price elasticity of demand for electricity assumed to be -0.3 to derive the additional use of electricity in GWh. This was then multiplied by the LRMC of generation to derive a value of the impact of improved competition.

3.5 Estimating Costs

Three sets of costs were estimated in this study:

- Implementation costs, assumed to be incurred upfront (that is, from the beginning of the changes). These costs cover the adjustments to IT, metering and billing systems required to accommodate the potential for MTR or ENs. Costs of training staff to operate the adjusted systems are also included in implementation costs.

- Ongoing costs, which are incurred annually and which reflect the costs of accommodating customers with MTR. These costs were assumed to be a function of uptake of MTR or the EN changes.

- Metering costs for customers and market participants.

Costs were sourced from a survey undertaken by AEMO of retailers, and distribution network providers. AEMO separately provided data on its cost estimates. Participants were asked to provide data on registration and set-up, metering, operations, billing and reporting costs as a result of the proposed changes. Responses on cost items were categorised by:

- Small : up to $100,000
- Medium: between $100,000 to $500,000
- Large: between $500,00 to $2,000,000
- Very large: greater than $2 million.

Mean, medium and maximum estimates of the costs provided for each scenario are shown in Table 4 to Table 7. The costs shown were for individual participants. Total costs of retailers were calculated assuming there were 10 major retailers that would incur costs[10]. Total cost of network service providers were calculated assuming there were 11 distribution network service providers. In the case of MTR, it was assumed that the three larger retailers incurred maximum implementation cost whilst other retailers incurred the mean implementation cost. This was because it was assumed that the larger retailers had more extensive and integrated systems that would all need to be altered.

Ongoing costs were disaggregated into fixed and variable costs. It was assumed that 50% of the ongoing cost listed in the following tables was fixed and 50% varied according to uptake.

Not all respondents provided data for the MTREN scenario. For the benefit-cost analysis for that scenario, costs for these respondents were derived from their cost estimates for the MTR and EN scenarios deflated by the same economies in costs recorded by those participants who did provide comparable data for all scenarios.

AEMO costs are shown in Table 8.

[10] There are other retailers competing in the market but these mainly serve a small range of customers particularly commercial and industrial customers and were assumed not to incur MTREN costs

Table 4: Cost assumptions per market participant – MTR scenario, $

		Overall	Registration	Metering Cost	Operations	Billing	Reporting
Implementation							
Retailer	mean	13,051,000	2,320,600	2,722,600	2,722,600	3,326,200	1,959,000
	median	15,573,000	2,511,000	4,020,000	4,020,000	4,020,000	1,002,000
	max	50,100,000	4,020,000	4,020,000	4,020,000	4,020,000	4,020,000
DNSP	mean	10,464,833	2,360,833	1,842,667	2,444,333	2,042,667	1,774,333
	median	9,891,500	2,511,000	2,111,000	2,511,000	1,756,500	1,002,000
	max	18,191,000	4,020,000	2,111,000	4,020,000	4,020,000	4,020,000
Ongoing costs							
Retailer	mean	7,765,400	1,466,800	1,355,400	2,180,800	1,657,200	1,105,200
	median	5,719,000	602,000	1,002,000	2,511,000	1,002,000	602,000
	max	20,100,000	4,020,000	4,020,000	4,020,000	4,020,000	4,020,000
DNSP	mean	2,738,500	836,667	653,500	636,667	451,833	159,833
	median	2,010,000	602,000	202,000	402,000	602,000	202,000
	max	7,537,000	2,111,000	2,511,000	2,111,000	602,000	202,000

Note: Metering cost include costs of customer metering. Ongoing costs are assumed to be at maximum implementation

Table 5: Cost assumptions per market participant– EN1 scenario, $

		Overall	Registration	Metering Cost	Operations	Billing	Reporting
Implementation							
Retailer	mean	7,832,400	2,029,000	2,420,800	1,445,600	1,435,400	501,600
	median	7,228,000	2,511,000	2,511,000	1,002,000	1,002,000	202,000
	max	17,082,000	4,020,000	4,020,000	4,020,000	4,020,000	1,002,000
DNSP	mean	1,759,833	469,667	351,833	377,000	385,500	175,833
	median	353,000	202,000	0	0	0	151,000
	max	9,046,000	2,111,000	2,111,000	2,111,000	2,111,000	602,000
Ongoing costs							
Retailer	mean	3,555,400	793,400	1,115,400	723,400	511,800	411,400
	median	1,810,000	602,000	202,000	202,000	602,000	202,000
	max	11,046,000	2,511,000	4,020,000	2,511,000	1,002,000	1,002,000
DNSP	mean	980,000	117,500	360,167	385,333	50,333	66,667
	median	250,500	125,500	0	25,000	0	100,000
	max	4,726,000	202,000	2,111,000	2,111,000	202,000	100,000

Note: Metering cost include costs of customer metering. Ongoing costs are assumed to be at maximum implementation

Table 6: Cost assumptions per market participant – EN2 scenario, $

		Overall	Registration	Metering Cost	Operations	Billing	Reporting
Implementation							
Retailer	mean	3,095,800	633,400	733,600	1,035,400	511,800	181,600
	median	1,410,000	202,000	202,000	202,000	602,000	202,000
	max	10,246,000	2,511,000	2,511,000	4,020,000	1,002,000	202,000
DNSP	mean	1,701,000	436,000	351,833	377,000	385,500	150,667
	median	227,000	151,500	0	0	0	75,500
	max	9,046,000	2,111,000	2,111,000	2,111,000	2,111,000	602,000
Ongoing costs							
Retailer	mean	2,784,400	703,200	945,200	713,200	261,600	161,200
	median	1,010,000	202,000	202,000	202,000	202,000	202,000
	max	9,846,000	2,511,000	4,020,000	2,511,000	602,000	202,000
DNSP	mean	946,667	100,833	360,167	385,333	50,333	50,000
	median	175,500	100,500	0	25,000	0	50,000
	max	4,726,000	202,000	2,111,000	2,111,000	202,000	100,000

Note: Metering cost include costs of customer metering. Ongoing costs are assumed to be at maximum implementation

Table 7: Cost assumptions per market participant – MTREN scenario, $

		Overall	Registration	Metering Cost	Operations	Billing	Reporting
Implementation							
Retailer	mean	8,215,820	1,395,980	1,737,960	1,717,960	2,261,200	1,102,720
	median	6,915,300	951,900	901,800	901,800	3,618,000	541,800
	max	19,698,000	3,618,000	4,020,000	4,020,000	4,020,000	4,020,000
DNSP	mean	1,697,067	410,150	333,317	619,667	166,967	166,967
	median	25,000	25,000	0	0	0	0
	max	9,581,400	2,259,900	1,899,900	3,618,000	901,800	901,800
Ongoing costs							
Retailer	mean	3,384,320	610,540	519,120	1,225,980	762,740	265,940
	median	1,582,600	151,000	541,800	202,000	551,900	135,900
	max	9,741,800	2,259,900	1,002,000	3,618,000	2,259,900	602,000
DNSP	mean	245,167	107,133	30,300	47,133	30,300	30,300
	median	0	0	0	0	0	0
	max	1,279,100	541,800	181,800	191,900	181,800	181,800

Note: Metering costs include costs of customer metering. Ongoing costs are assumed to be at maximum implementation

Table 8: AEMO costs, $

Cost item	MTR/MTREN	EN1	EN2
Market arrangements (design and implementation)	2,101,000	1,597,000	1,345,000
Systems	1,441,000	1,095,000	922,000
Preparedness (training)	993,000	993,000	993,000
Project wide costs (admin)	1,581,000	1,581,000	1,581,000
Total	6,116,000	5,266,000	4,841,000

An appraisal of costs was undertaken by Jacobs SKM. The appraisal found that:

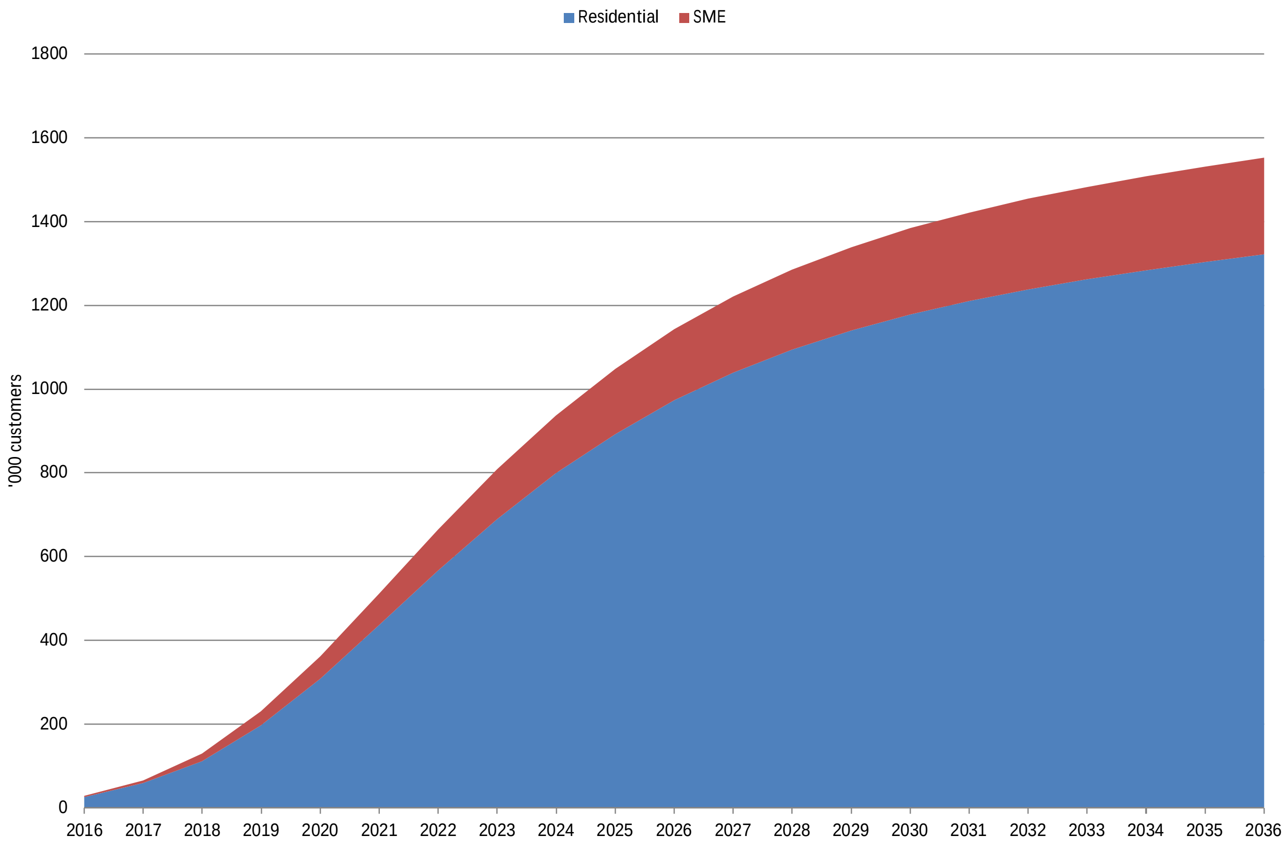
- Implementation costs tended to be higher for the established or Tier 1 retailers. Using information provided by respondents and confirmed with follow up consultations, this was likely due to the highly integrated systems for those organisations meaning that changes to one part of the systems had to be reflected in changes to other parts of the systems. Testing of systems and training are also likely to be higher as a result. A Tier 1 retailer also has obligations for the provision of metering data as a Local Retailer. For this reason in the central cases we tended to use a high implementation costs (equal to the maximum cost listed) for the Tier 1 retailers and the average of the estimates of implementation costs for other retailers.
- Implementation costs for retailers tended to be greater for larger organisations and the larger the geographic scope of the organisation.
- The estimates of implementation costs for retailers tended to contain a large number of responses in the large category but one outlier response in the low category. This response was excluded as it was deemed that they underestimated the tasks involved.
- Estimates of total costs of implementation for network service providers were derived by summing implementation costs for individual components rather that the total estimates provided by the respondents. The range of estimates in implementation costs was not as great for network service providers and was generally lower than for retailers. The estimates were deemed to be reasonable and the mean estimate was used in the calculation of these costs.
- Estimates of ongoing costs based on total costs provided by respondents were very high and equivalent to implementation costs but applied every year. This did not correspond to the expected relationship of ongoing costs to implementation costs and appeared to be the result of an entry that was not filled in correctly for one respondent. Therefore, the sum of ongoing costs for individual components was used. This provided a mean estimate of ongoing costs for retailers of $8 million per annum per retailer for the MTR case.
- Ongoing costs for market participants for billing, metering and reporting were mainly due to the perception by respondents that there would be higher propensity for errors to be made which would require additional costs for rechecking and resolution.
- Because of the uncertainty in the estimates of costs, sensitivity analysis to lower and higher costs was performed. The higher costs were based on the maximum estimates provided and the lower costs on median estimate provided (which tended to be lower than the average estimate).

4. Benefits and costs

4.1 Uptake rates

Projected uptake rates of MTR are shown in Figure 2. Uptake is relatively slow in the initial period with only 6% of total residential and SME customers adopting MTR by 2020, and mainly from residential customers who wish to use MTR to maximise the value of export sales from rooftop PV systems. By 2030, it is projected that around 1,384,000 customers have adopted MTR, or 17% of total customers.

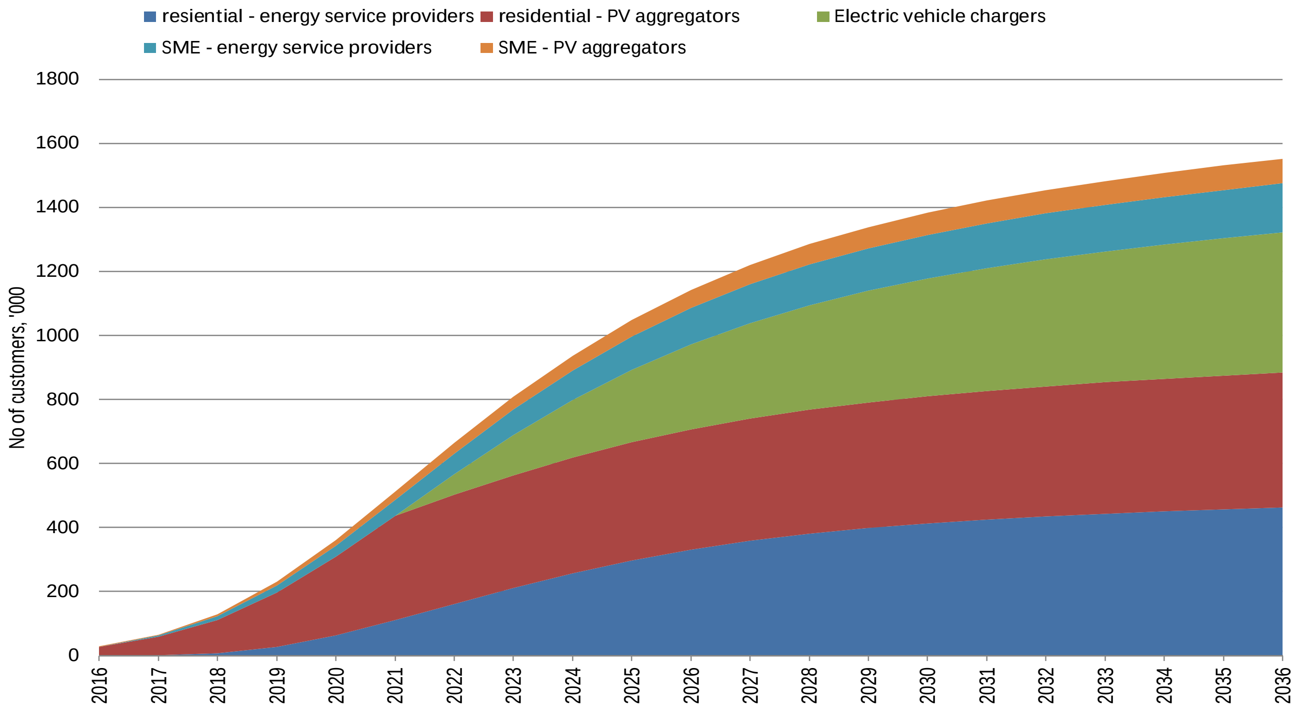
Figure 2: Projected uptake rates, MTR, '000 customers



The uptake rates by category of customer are shown in Figure 3. The largest uptake occurred in the residential sector to allow competing service providers (including incumbent retailers) to service residential customers and to allow eligible market aggregators to optimise sales of PV exports from the residential sector. Early adopters of MTR tend to be households with PV systems who use MTR to sell surplus electricity to entities other than the host retailer. Uptake rates rise sharply in the period after 2020. This reflects the assumption that it would take some time for other energy service providers and customers to understand and develop alternative services.

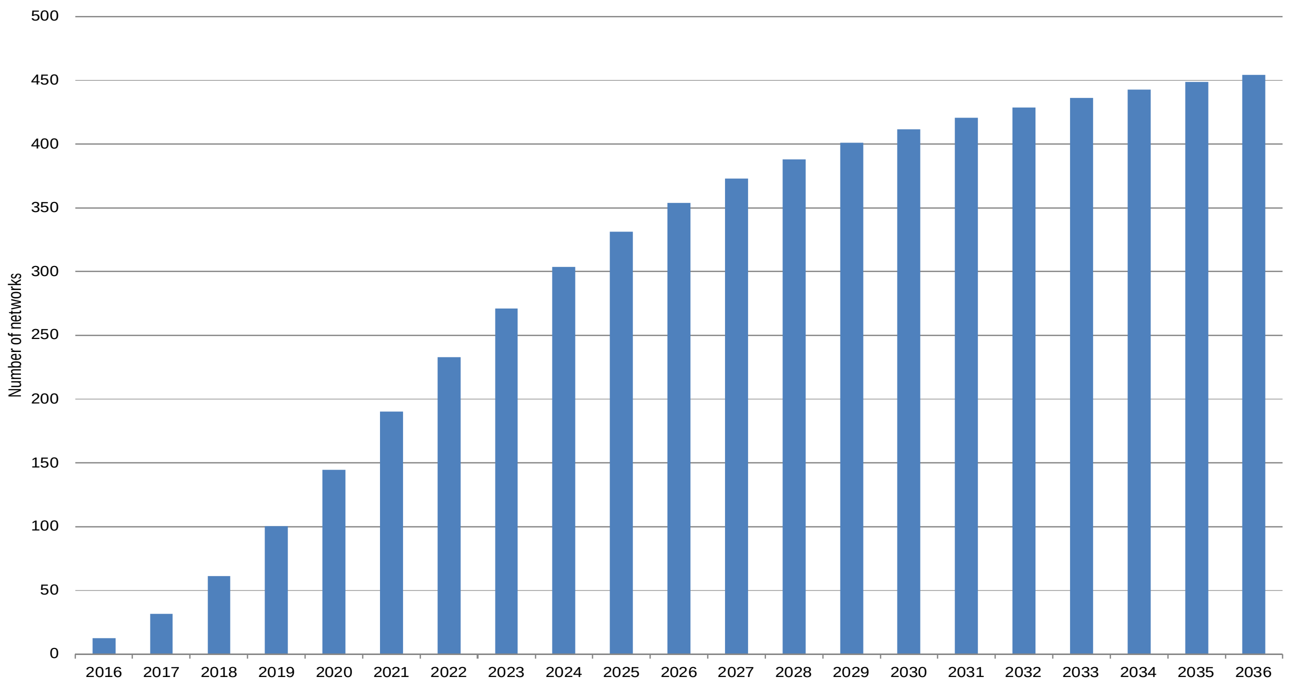
Uptake of MTR for charging of electric vehicle batteries accelerates after 2020. By 2030, it is projected that around 360,000 customers would use MTR to supply electricity to recharge batteries. Although there is a large degree of uncertainty around adoption of electric vehicles, it is worth noting the level of uptake in this category represents less than 0.5 per cent of total vehicle fleet.

Figure 3: Uptake rates by customer category, MTR



Uptake rates for ENs are shown in Figure 4. A high portion of known embedded networks (estimated to be around 500) eventually adopt the option to have separate NMIs to allow their customers to access other competing service providers. Uptake is higher in this option because of the lower transactions costs involved in accessing alternative providers.

Figure 4: Projected uptake of NEM participation by embedded networks



4.2 Estimate of benefits of MTR

The benefits of uptake are reflected through deferred network investments, lower generation costs and enhanced competition benefits.

4.2.1 Network benefits

Network benefits are derived mainly through the use of MTR to promote and encourage DSP. By shifting demand (i.e. load shifting), peak demand can be reduced.

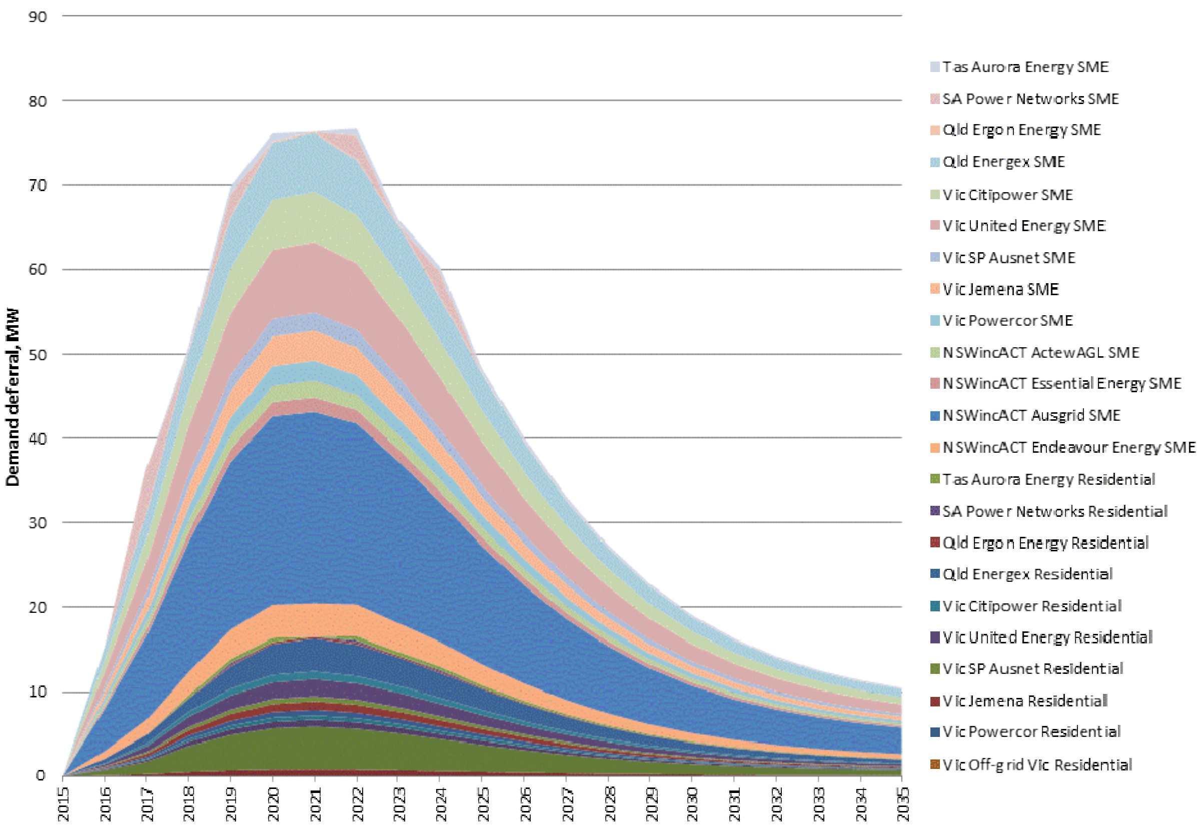
Based on the uptake of MTR, the level of peak demand reduction to the transmission grid or wholesale market is shown in Table 9. The reductions are mainly due to competing service providers shifting load out of peak demand periods to manage energy costs. The largest peak reductions occurred in New South Wales, followed by Victoria. By 2025, the peak reduction ranges from around 500 MW in NSW to 28 MW in Tasmania. By 2030, the peak reduction ranges from 35 MW to 622 MW.

Table 9: Peak demand reductions by State, MW

	2016	2020	2025	2030
Queensland	6	78	199	252
New South Wales/ACT	17	210	496	622
Victoria	12	156	367	459
Tasmania	1	12	28	35
South Australia	6	46	103	128

Distribution network reductions due to MTR are shown in Figure 5. Distribution network reductions occur mainly around 2018 to 2023, which is the period of rapid uptake of MTR options to facilitate demand side response.

Figure 5: Reductions in local peak demand by distribution zones



Estimates of the value of network deferral benefits by distribution zone are shown in Table 10. The bulk of the benefits tend to occur in the urban areas due to the customer numbers present in urban areas. The bulk of the benefits are concentrated in the period from 2021 to 2025.

Table 10: Value of distribution network deferral benefits, $M

Zone	NPV	2016 -2020	2021 -2025	2026 - 2035
Endeavour Energy	34	13	28	19
Ausgrid	191	74	156	109
Essential Energy	24	9	19	14
ActewAGL	3	1	2	2
Powercor	7	3	5	4
Jemena	12	5	10	7
SP Ausnet	9	3	7	5
United Energy	27	10	22	15
Citipower	31	12	26	18
Energex	15	5	12	9
Ergon Energy	5	2	4	3
SA Power Networks	9	8	5	0
Aurora Energy	2	1	1	1

Source: Jacobs SKM. Note: the net present value is calculated using a 7% real discount rate applied to values of deferred expenditure over the period 2015/2016 to 2034/2035

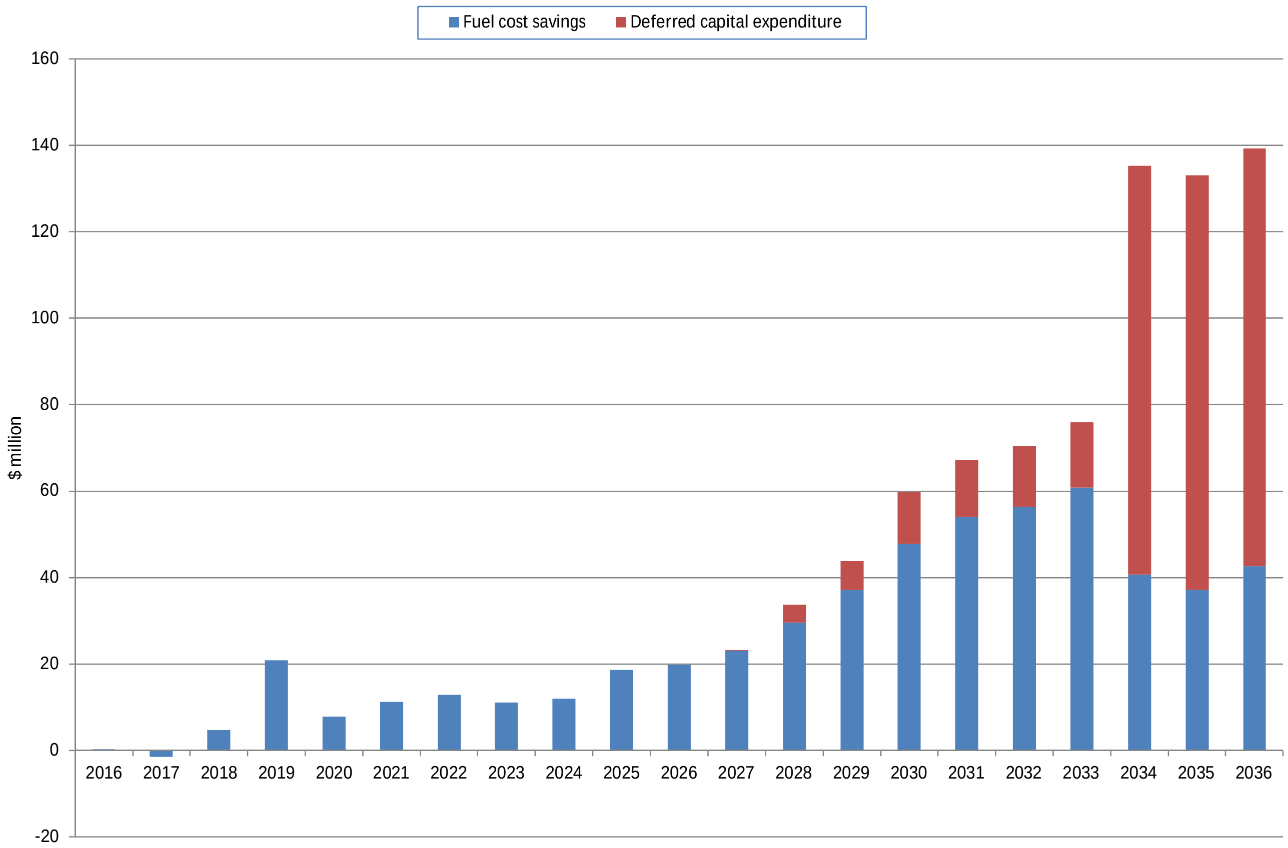
4.2.2 Generation benefits

Generation benefits come from two sources and occur mainly for MTR uptake. The benefits come from:

- Load shifting facilitated by MTR reducing generation in periods when high cost gas-fired generation is occurring to periods when relatively lower cost coal-fired generation would be predominantly dispatched. Thus, the benefits come from fuel cost savings. This is the major source of generation savings in the period to 2025.
- Deferring the need for new investment in generation. This benefit is estimated to be relatively low due to current overhang in capacity in the market, meaning that no new thermal generation is required until after 2025.

Annual benefits from fuel savings and deferred generation benefits are shown in the following chart.

Figure 6: Generation benefits



4.2.3 Competition benefits

The changes to allow MTR and to formalise EN arrangements are designed to foster competition and to reduce electricity supply costs. To the extent that competition leads to lower prices, there will be a demand response and this will lead to resource allocation benefits.

The estimated value of the benefits of improved resource allocation is shown in Figure 7. Competition benefits are estimated to be small in the period to 2025, growing to $14 million per annum.

It should be noted that competition benefits reflect the potential for the proposed changes to enhance competition in the retail sector. There is also the possibility that MTREN could help facilitate the development of an innovative services market. This benefit was not considered in this analysis because of the uncertainties over what these services could be. But the benefit to consumers could potentially be large.

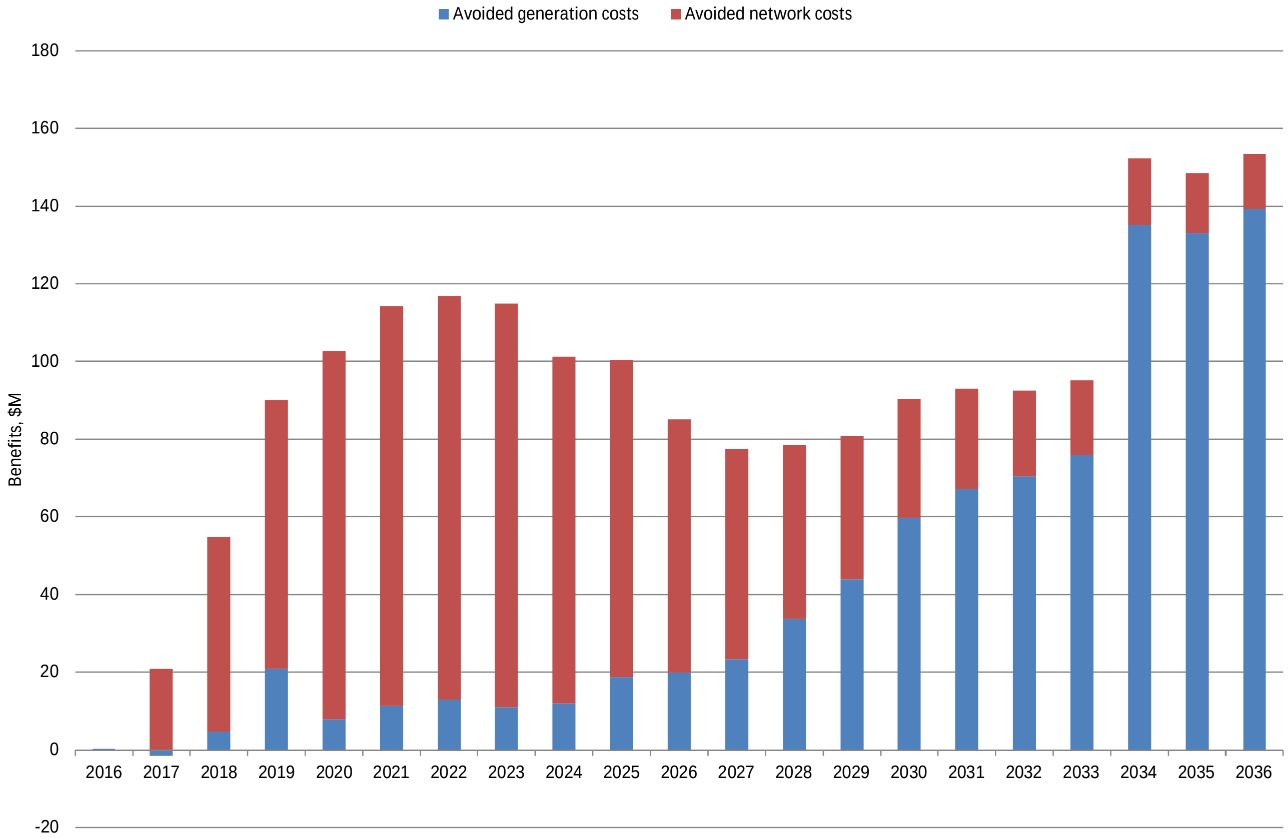
Figure 7: Competition benefits

4.2.4 Overall benefits

The annual stream of benefits under MTR is shown in Figure 8. Avoided generation benefits are minimal in the period to 2030 due to overhang is supply, meaning that even in the no change scenario there is minimal investment in plant to 2030 so that deferment of capital spend is not possible. Network benefits are substantial but these benefits dissipate as network upgrades are only deferred not eliminated.

While overall demand is not growing significantly, there are areas of local growth within the network where there is an opportunity to defer augmentation. The model considers deferment at a distribution zone level, where the growth rate in demand may differ from that for the system as a whole, to identify potential savings.

Figure 8: Annual stream of benefits from adoption of MTR



To put this into context, total network spend deferred or avoided amounts to approximately 11% of annual expenditure on network upgrades.

4.3 Net benefit analysis

The calculated net present value (using a discount rate of 7% real) of benefits and costs are summarised in Table 11. The analysis indicates two key findings:

- Implementation of MTRs tends to have a net cost. This is largely a function of the assumed slow rate of adoption of MTR and the high cost of implementation of this measure.

- Implementation of the changes to embedded customer arrangements tends to have a small net benefit. Implementation costs associated with this option tend not to be high. The annual benefits are small due to the low number of customers involved and the low elasticity of demand which results in only a small increase in demand through reduced prices brought about by enhanced competition.

Table 11: Net present value of benefits and costs, $M

Item	To 2025				To 2035			
	MTR	EN1	EN2	MTREN	MTR	EN1	EN2	MTREN
Benefits	574	103	103	585	951	165	165	973
Costs	823	126	107	824	1027	162	146	1027
Net benefit	-249	-22	-3	-239	-76	2	19	-54

Source: Jacobs SKM analysis

Implementation of both measures still yields a small net cost despite the increase in costs of implementation and operation from combining both changes being less than the increase in benefits.

It is important to note that the net impacts tend to be small. Costs tend to be borne upfront but benefits are incurred around 5 years after the introduction of the changes. Consequently, net benefits generally do not occur until after 2025.

4.4 Sensitivity analysis

Sensitivity analyses were performed on key variables such as discount rates, uptake rates and cost of implementation. The results of this sensitivity analysis for implementation of MTR are shown in Table 12.

As the EN benefits are largely attributable to competition benefits, the EN net market benefits are most sensitive to assumptions around the cost of implementation and discount rates. The competition benefits assessed tend not to be dependent on demand growth assumptions. Nor is the uptake rate for EN dependent on new technologies or appliances.

4.4.1 Discount rates

The analysis indicates that the implications of the results are not sensitive to discount rates. But the net benefit of MTR is highly sensitive to uptake rates.

4.4.2 Uptake rates

The net benefits appear to be sensitive to uptake rates, particularly on the rate of uptake in the period to 2020. Even so, the net present value is negative even for high uptake rates. In this case, high uptake rates mean that 11% of total customers have adopted MTR by 2020 and around 23% by 2030. With this level of uptake benefits were significantly higher particularly the avoided generation costs. But they were still not high enough to engender a positive net benefit.

Table 12: NPVs of implementation of MTR for a range of assumptions on costs and benefits, $M

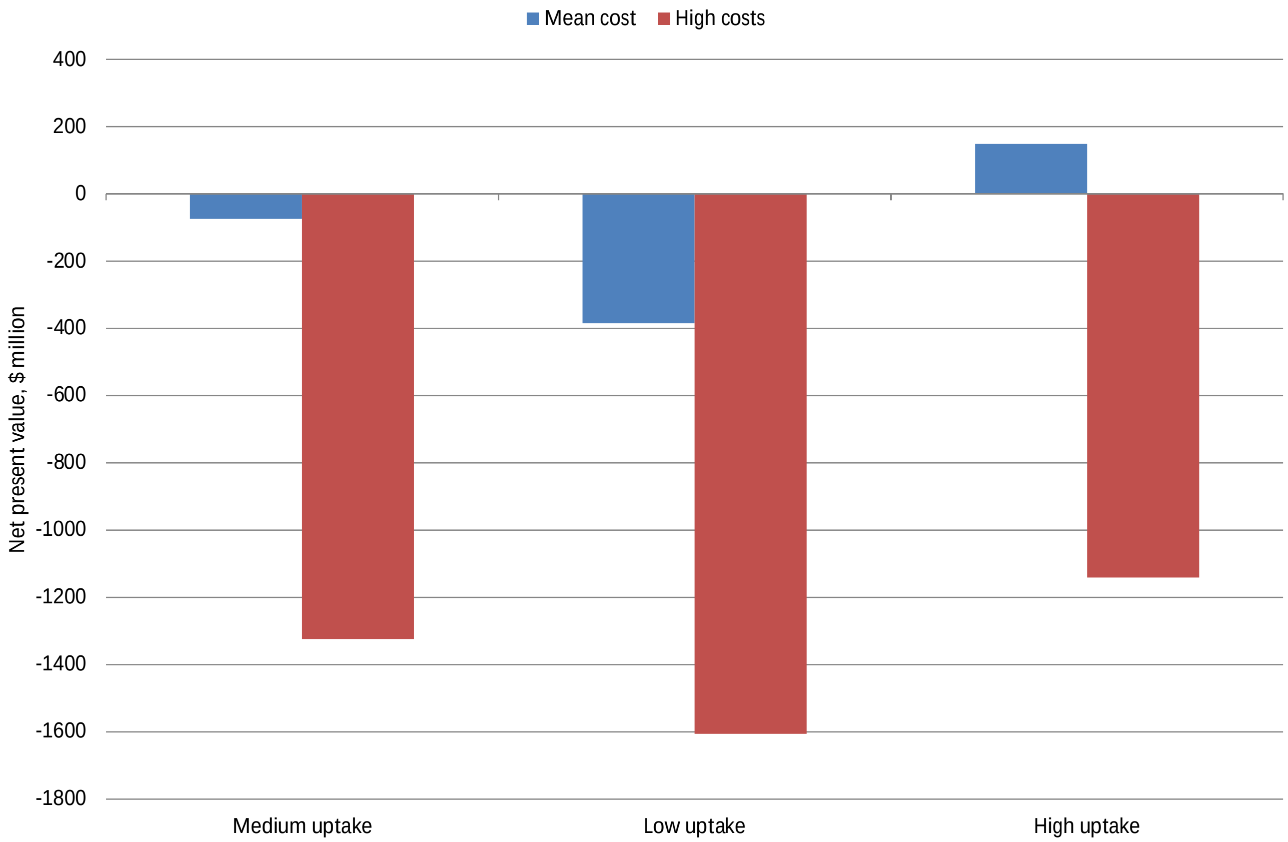
Sensitivity	7% Discount rate		10% Discount rate		4% Discount rate	
	To 2026	To 2035	To 2026	To 2035	To 2026	To 2035
Medium uptake						
Benefits	574	951	478	717	696	1,303
Costs	823	1,027	728	870	867	1,213
Net benefit	-249	-76	-250	-152	-171	90
Low uptake						
Benefits	379	624	315	472	461	851
Costs	816	1,010	722	857	857	1,187
Net benefit	-437	-386	-407	-385	-396	-336
High uptake						
Benefits	835	1,201	706	938	997	1,587
Costs	839	1,053	742	891	887	1,252
Net benefit	-4	148	-36	47	110	335

Source: Jacobs SKM analysis

4.4.3 Implementation costs

Higher implementation and ongoing costs obviously resulted in lower net benefits (see Figure 9). There is considerable variation in the implementation cost estimates and the high rates were some four times higher than the median estimate.

Figure 9: Net present value of MTR as a function of implementation costs and uptake rates, Sm



4.4.4 Low demand peak demand growth

A major source of benefits is deferred network infrastructure expenditure. Network benefits for scenarios modelled were based on AEMO's medium rates for peak demand growth, which showed modest pickup in growth rates from 2015 onwards and reasonable growth rates for Queensland. A sensitivity was performed with flat load growth until 2020. This was performed for the medium uptake case.

The results of the analysis are shown in Table 13. The net present values of benefits are about one third the level for low peak demand growth. This indicates the considerable importance of deferred infrastructure expenditure particularly from the uptake of MTR. The implication is that if current low growth rates in peak demand continue then there may be minimal market benefits to uptake of MTR.

Table 13: Sensitivity of net benefits of MTR to peak demand growth rates, $m, 2013 dollars

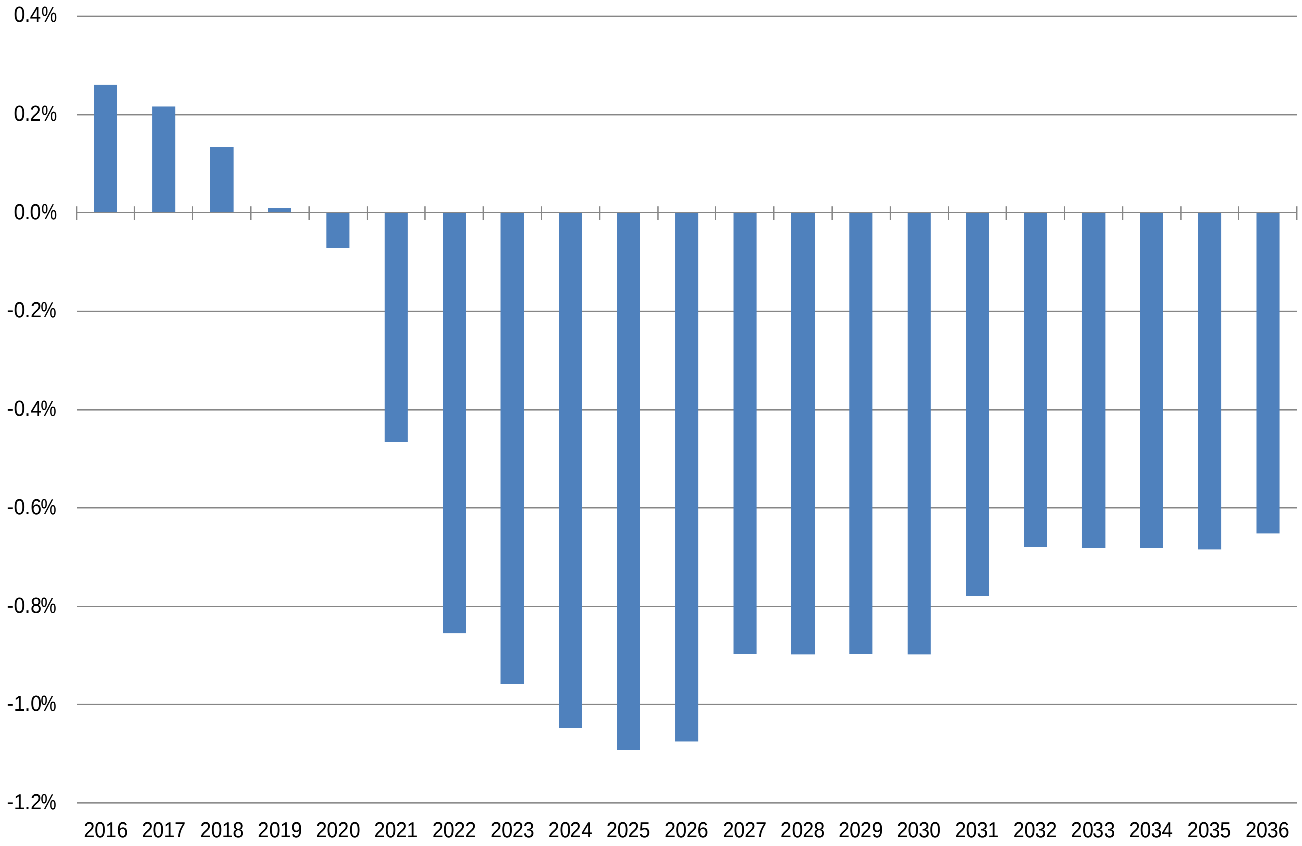
	Median growth		Low growth	
	To 2026	To 2035	To 2026	To 2035
Benefits	574	951	219	415
Costs	823	1,027	823	1,027
Net benefit	-249	-76	-604	-612

5. Distributional impacts

5.1 Price impacts

Price impacts are shown in the following chart. The analysis indicates a small decrease in retail prices as competition reduces retail margins and wholesale prices. The price reduction more than outweighs the increase in retail costs from implementation and higher ongoing costs.

Figure 10: Changes to retail price due to MTR



6. Discussion of results

The analysis indicates quantifiable net economic benefits are negative for MTR or MTREN proposed rule change under most plausible futures around electricity demand, uptake rates and system costs. Allowing embedded customers to source alternative market participants may lead to some net benefits, mainly through enhanced competition.

Table 14: Summary of results

	MTR			EN			MTREN		
	2015	2020	2030	2015	2020	2030	2015	2020	2030
Uptake rates,									
Residential, '000 customers									
DSP	0	110	426	0	0	0	0	110	426
Distributed generators	26	326	401	0	0	0	26	326	401
Other	0	0	383	0	0	0	0	0	383
SME, '000 customers	2	75	212	0	0	0	2	75	212
EN networks, number	0	0	0	13	190	421	13	190	421
% of total customers	0%	6%	17%	0%	0%	0%	0%	6%	17%
Costs, $M									
Implementation	438	0	0	20	0	0	439	0	0
Ongoing	52	55	61	12	12	12	52	55	61
Total	491	56	61	32	12	12	491	55	61
Benefits, %M									
Reduced generation costs	0	11	67	0	0	0	0	11	67
Deferred network benefits	0	103	26	0	13	3	0	103	26
Competition benefits	0	1	14	0	7	15	0	2	18
Total	0	115	107	0	19	18	0	117	111
NPV of net benefits, $M	-76			19			-54		
Price impacts, $/MWh									
Wholesale price change	0	-1	-2	0	0	0	0	-1	-2
Retail price change	1	-1	-2	0	0	0	0	-1	-2
% of total price	0.3 %	-0.5%	-0.8%	0.0%	0.0%	0.0%	0.0%	-0.3%	-0.8%

Source: Jacobs SKM analysis

6.1 Implications

Although the quantitative economic analysis would suggest that it is not beneficial to proceed with changes to allow MTRs, there needs to be consideration of some other issues that were not considered as part of the benefit cost analysis.

First, the intent of the changes is to allow additional competition by allowing competing service providers and eligible aggregators to enter the market. At the moment, customers are able to achieve the same outcome as under the MTREN changes by putting another connection on their premises. The cost of doing this is currently high, estimated from $1,000 to $8,000 per workplace or residence[11], and the potential benefits from doing this are likely to be insufficient to recover this cost. The high cost of connection therefore acts as a barrier to the

[11] Better Place (2011), *Submission to the Power of Choice – Stage 3 DSP Review*.

development of an energy services or aggregation function. The proposed MTREN changes would help to overcome these barriers and lead to the development of energy services industry for mass market customers.

Second, the low or negative net benefit estimated is a function of the high upfront costs. Upfront costs for implementing changes in systems are estimated to amount to around $450 million to $1,000 million. With slow uptake, it would take some time for these costs to be recovered through the additional benefits. Consideration should be given to whether these costs can be minimised. For example, by sharing the costs across other changes being proposed (so that system costs can be shared jointly for the proposed changes) as there will be considerable overlap in the system upgrades required for the changes proposed to be implemented.

One possibility is that cost estimates were an overestimate particularly for ongoing costs. The cost estimates were obtained from a survey of retailers and network service providers. It is possible that conservative estimates were provided because there was little detail or understanding of what would be involved with the changes. In practise, once the changes are implemented, it is likely that retailers and market participants would focus on meeting the obligations at least cost, and this could result in reduced costs. To facilitate cost minimisation, it is recommended that sufficient time be given to market participants to design and implement the required changes in the system.

Another possibility is to explore whether alternatives may be possible whilst uptake is minimal. The full system changes can be deferred to a time when uptake is reasonably prevalent or when a proponent for MTR can be identified.

There is a broader issue of whether high system costs should be allowed to block reforms such as this. As upgrades will always involve high costs especially for market participants with highly integrated systems, it is probable that any changes that involve upgrades of systems are not likely to proceed. This lock-in to current arrangements would entrench current levels of competition. Part of the reason is that the time period for analysis has been constrained to 2030 and a high discount rate has been used to discount future benefits. But part is also due to the high fixed costs involved in changing systems, and the conservative assumptions behind the estimated competition benefits arising from the changes (due to the uncertainty of these benefits).

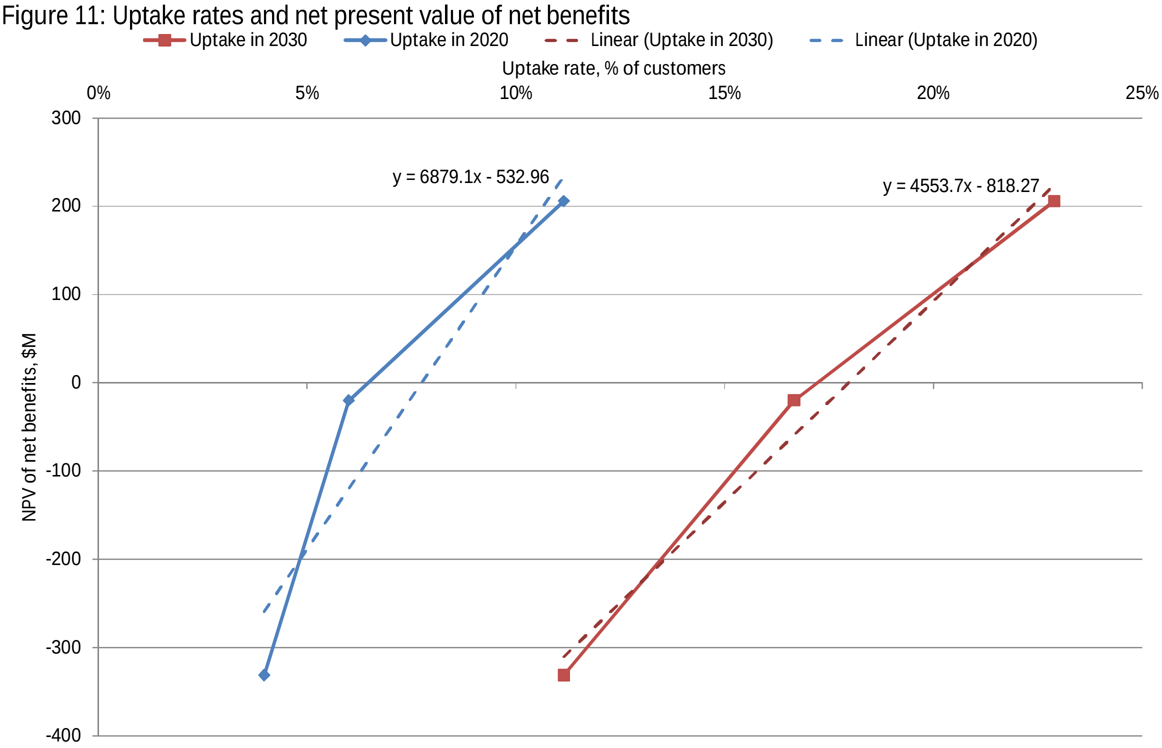
Third, delaying the implementation is likely to increase the net economic benefits. Low demand growth means there is little need for augmentation of networks and for constructing new power stations in the near future.

Fourth, the proposed changes are likely to lead to competition benefits. These benefits are reflected to lower prices to consumers through reduced retail margins as a result of additional competition from competing service providers in the MTR case and alternative retailers in the EN case.

Fifth, significant transfers are possible as a result of the suggested changes. Due to the inelastic nature of electricity demand (especially in the short term), there is likely to be minimal economic benefits from increasing the level of competitiveness. But there would be a significant transfer of the value of electricity to customers (through lower prices). The equity implications of the lower prices may require consideration.

The analysis found that the net benefit arising from changes to allow MTR is highly sensitive to uptake rates. The relationship between net present value of net benefits and uptake rates is shown in Figure 11. Based on a linear interpolation, the relationship indicates that uptake rates need to be around 7% in 2020 and 18% in 2030 in order for net benefits to be positive, assuming median electricity demand growth rates and other central assumptions.

Figure 11: Uptake rates and net present value of net benefits



6.2 Limitations and uncertainties

The results of the study need to be interpreted with care as the results are dependent on a number of key assumptions used.

There is a high level of uncertainty around what uptake rates would be as there are very few examples of analogues that could be used to base uptake rates. From a review of other programs, uptake tends to be more rapid for programs or changes that incentivise third parties (such as competing service providers) to engage with customers to highlight the direct benefits. These proposed rule changes have elements of incentivising third parties but the novelty of the proposed arrangements may take time to lead to the development of third party service providers. This led to the use of conservative assumptions on uptake and reduced the benefits of the changes accordingly. Higher uptake rates would possibly lead to net benefits under a wider range of economic assumptions. Higher uptake rates are possible particularly if competing service providers are encouraged into the market by the proposed changes. At the same time the results are contingent on an electric vehicle charging market being established after 2020. There is considerable uncertainty over the development of and uptake of electric vehicles.

The maximum level of uptake was also assumed to be modest (no more than 30%) again as a strategy of using conservative assumptions. Since the benefits mainly occur over the medium to longer terms, maximum uptake rates may have a significant impact on net benefits.

The analysis also did not include the benefits to customers of improved energy services and the costs to customers of adopting MTRs. The assumption in the analysis is that uptake is voluntary and would only occur should individual customer benefits be higher than costs of adopting MTR.

The costs were based on a broad high level design and there may be opportunities to trim these costs as the high level design is tightened up.

Finally, all of the costs of implementation are assumed to be borne upfront. It may be possible to better phase implementation costs to uptake rate. This possibility should be explored further.

Appendix A. Assumptions used to measure wholesale market benefits

Jacobs SKM's market models are designed to create predictions of wholesale electricity price and generation driven by the supply and demand balance, with long-term prices capped near the cost of the cheapest new market entrant (based on the premise that prices above this level provide economic signals for new generation to enter the market). Price drivers include fuel costs, unit efficiencies and capital costs of new plant.

The primary tool used for modelling the wholesale electricity market benefits is Strategist model. Strategist simulates the most economically efficient unit dispatch in each market while accounting for physical constraints that apply to the running of each generating unit, the interconnection system and fuel sources. Strategist incorporates chronological hourly loads (including demand side programs such as interruptible loads and energy efficiency programs) and market reflective dispatch of electricity from thermal, renewable, hydro and pumped storage resources.

Strategist also accounts for inter-regional trading, and scheduled and forced outage characteristics of thermal plant (using a probabilistic mechanism).

Timing of new generation is determined by a generation expansion plan that defines the additional generation capacity that is needed to meet future load or plant retirements. As such by comparing a reference case to a test case, we can quantify any deferred generation benefits. The expansion plan has a sustainable wholesale market price path, applying market power where it is evident, a consistent set of renewable and thermal new entry plant and must meet reserve constraints in each region.

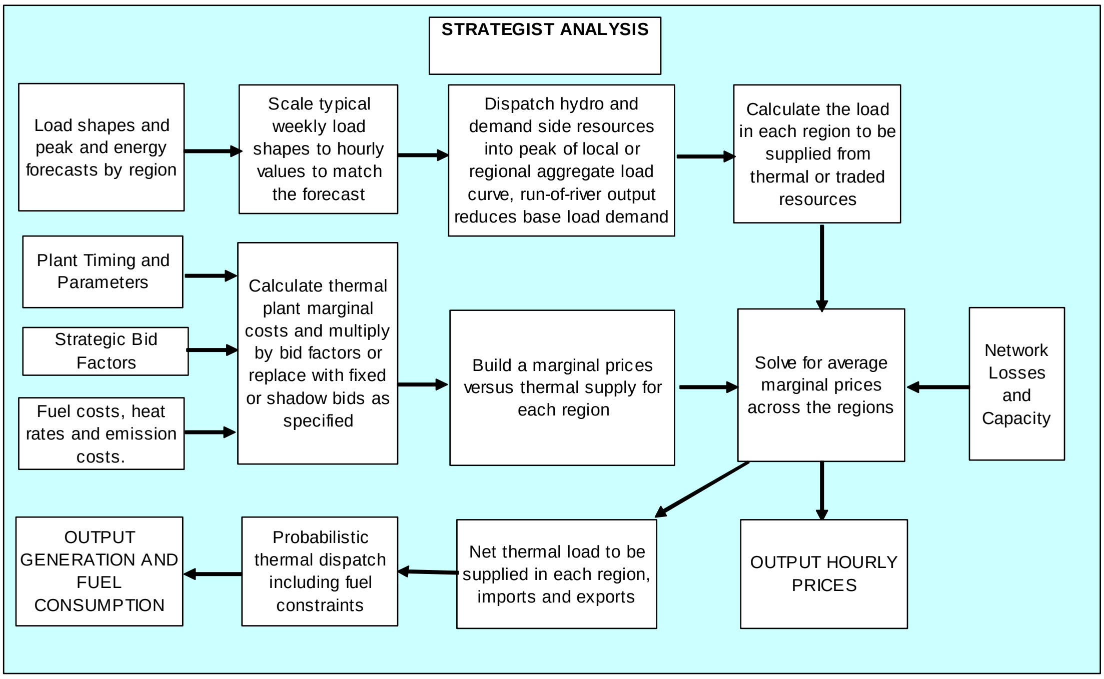
General assumptions are provided below:

- Capacity is installed to meet the target reserve margin for the NEM in each region.
- Utilises medium demand growth projections with annual demand shapes consistent with the relative growth in summer and winter peak demand.
- Generators behave rationally, with uneconomic capacity withdrawn from the market and bidding strategies limited by the cost of new entry.
- The expanded RET scheme with ultimate target of 41,000 GWh of large-scale renewable generation by 2020.

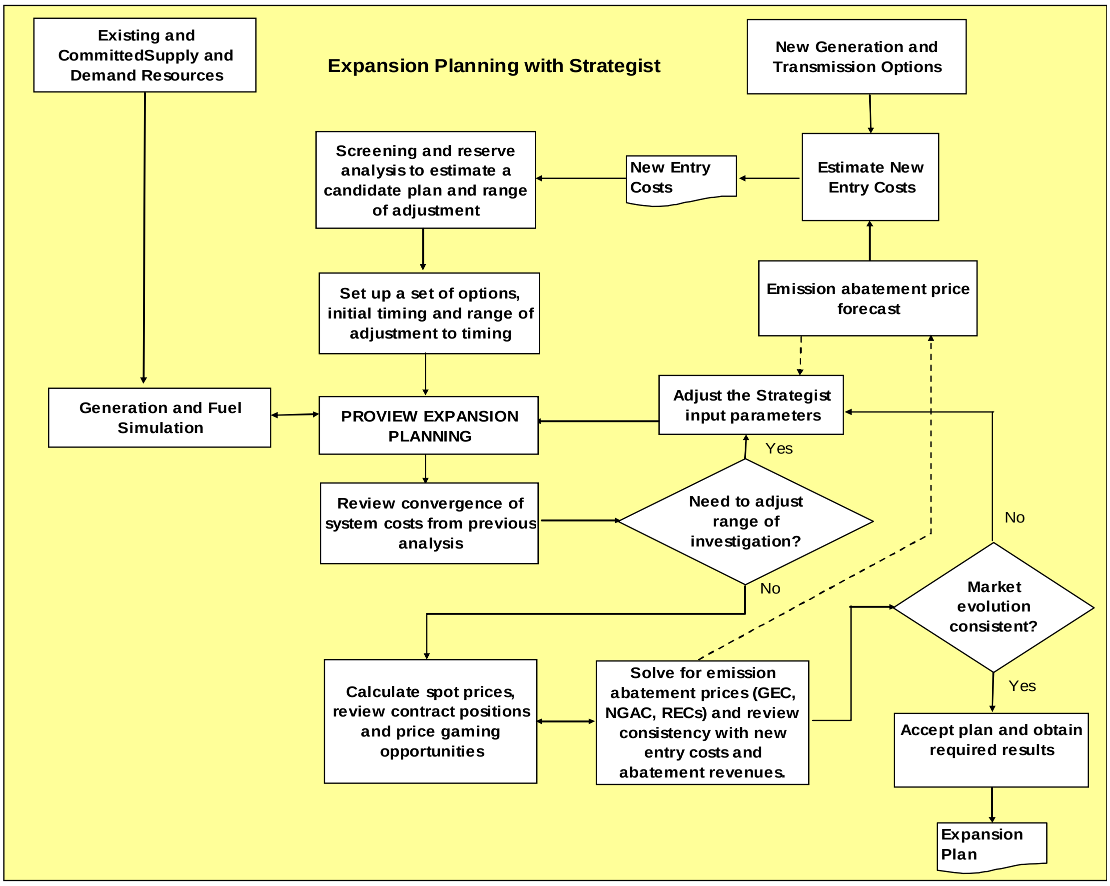
A.1 Methodology

Average hourly pool prices are determined within Strategist based on thermal plant bids derived from marginal costs or entered directly. The internal Strategist methodology is represented in Figure 12 and the modelling procedures for determining the timing of new generation and transmission resources are presented in Figure 13.

Figure 12: Strategist Analysis Flowchart



■ Figure 13: Strategist Modelling Procedures



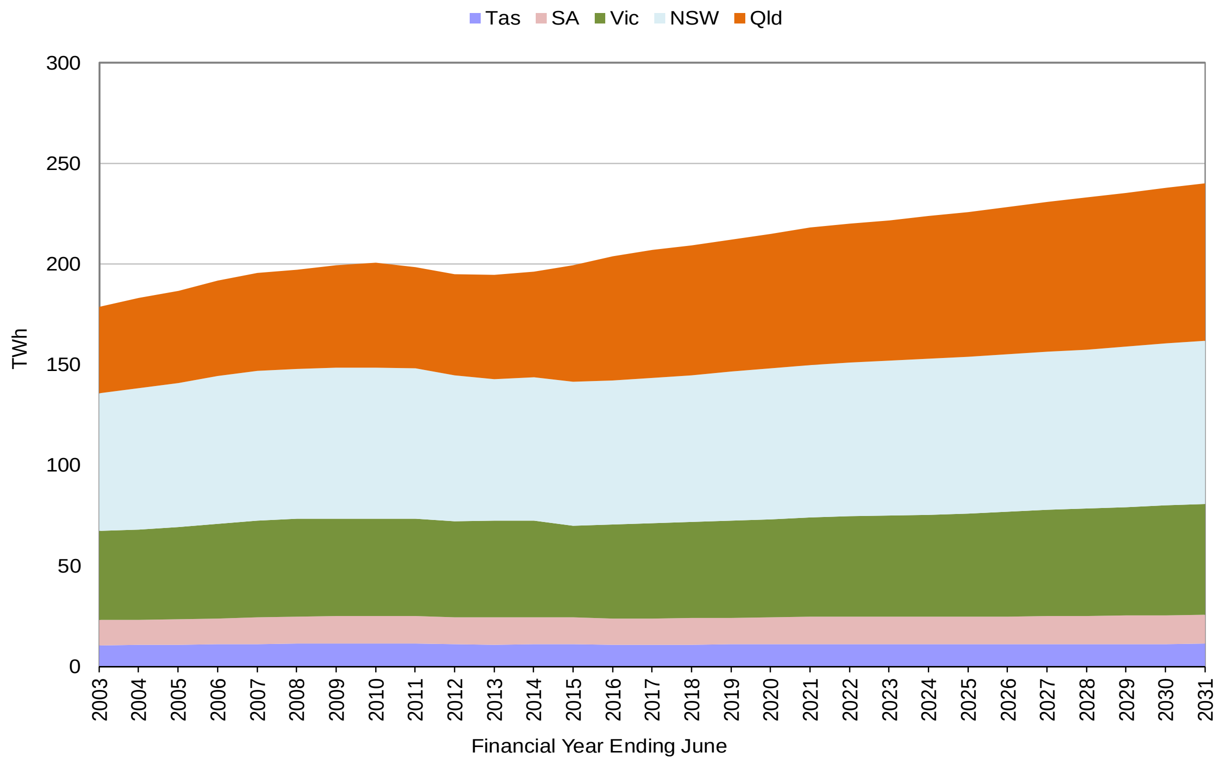
Strategist generates average hourly marginal prices for each hour of a typical week for each month of the year at each of the regional reference nodes, having regard to thermal plant failure states and their probabilities. The prices are solved across the regions of the NEM having regard to inter-regional loss functions and capacity constraints. Transmission failures are not represented although capacity reductions are included based on historical chronological patterns. Constraints can be varied hourly if required and such a method is used to represent variations in the capacity of the Heywood interconnection, between Victoria and South Australia, which have been observed in the past when it was heavily loaded. Such variations in interconnection capacity occur during the threat of thunderstorms in proximity to the interconnecting transmission line to enhance system security, and during transmission line outages.

A.2 Assumptions

A.2.1 Demand

The demand forecast adopted is AEMO's latest medium forecast of electricity demand[12] modified by the shutdown of the Pt Henry Aluminium Smelter load in August 2014. The forecast for each region is shown in the figure below. The forecasts indicate relatively flat load growth in the period to 2018 in most regions with the exception of Queensland. Over the long term, the average growth rate is 1.1% per annum compared with an average historical growth rate to end of 2012/13 of 1.5% per annum. The lower growth rate reflect the impact of consumers' reaction to higher retail electricity prices, slower world economic growth rates and the impact of restructuring of the manufacturing sector. The load supplied by embedded generation (e.g. roof-top solar PV systems) is included.

- Figure 14 Medium demand growth forecast sent out



We have used the 2010/11 load shape as it reflects demand response to normal weather conditions and captures the observed demand coincidence between States. Jacobs SKM adjusts the AEMO forecasts to

12 AEMO (2013), National Electricity Forecasting Report for the National Electricity Market, June, Melbourne

add back in the "buy-back" component of the renewable embedded generation including small scale embedded generation from roof-top solar PV systems. The Strategist model is then used in conjunction with a renewable energy model to explicitly project the renewable energy. Some embedded generation, such as small scale cogeneration is not included in the Strategist model, and the native load forecasts are adjusted accordingly.

The use of the 50% POE peak demand is intended to represent typical peak demand conditions and thereby provide an approximate basis for median price levels and generation dispatch.

The peak is applied as an hourly load in Strategist rather than half-hourly as it occurs in the market. Because the Strategist model applies this load for one hour in a typical week it is applied for 4.3 hours per year and therefore it represents a slightly higher peak demand than the pure half-hour 50% POE. This compensates to some degree for not explicitly representing the variation up to 10% POE.

A.2.2 Short run marginal costs of generation

The marginal costs of thermal generators consist of the variable costs of fuel supply, including fuel transport, plus the variable component of operations and maintenance costs. The indicative variable costs for various types of existing thermal plants are shown in Table 15. We also include the net present value of changes in future capital expenditure that would be driven by fuel consumption for open cut mines that are owned by the generator. This applies to coal in Victoria and South Australia.

Table 15: Indicative average variable costs for existing thermal plant (June 2013 dollars)

Technology	Variable Cost /MWh	Technology	Variable Cost /MWh
Brown Coal – Victoria	3 - 10	Brown Coal – SA	24 - 31
Gas – Victoria	46- 64	Black Coal – NSW	20 - 23
Gas – SA	37 - 111	Black Coal - Qld	9- 31
Oil – SA	250 - 315	Gas - Queensland	25 - 56
Gas Peak – SA	100- 164	Oil – Queensland	241- 287

Thermal power plants are modelled with planned and forced outages with overall availability consistent with indications of current performance. Coal plants have available capacity factors between 86% and 95% and gas fired plants have available capacity factors between 87% and 95%.

A.2.3 Capital costs

Cost and financing assumptions used to estimate investment costs are shown in the following table. The pre-tax real equity return was 17% and the CPI applied to the nominal interest rate of 9% was 2.5%. The capital costs are generally assumed to deescalate 1% per annum until they reach the long term trend. New technologies have higher initial costs and greater rates of real cost decline up to -1.56% per annum for IGCC. The debt/equity proportion is assumed to be 60%/40%. This gives a real pre-tax WACC of 10.60 % pa.

Table 16: New entry cost and financial assumptions for 2014/15, December 2013 dollars

	Type of Plant	Capital Cost, $/kW	Available Capacity Factor	Fuel Cost , $/GJ*	Weighted Cost of Capital, %	LRMC $/MWh (d)
SA	CCGT (a)	1,268	90%	6.32	10.60%	75.46
Vic	CCGT (a)	1,150	90%	5.52	10.60%	64.31
NSW	CCGT (c)	1,150	90%	6.06	10.60%	67.01
NSW	Black Coal (b)	2,624	91%	1.76	13.60%	73.47
Qld	CCGT (c)	1,150	90%	7.77	10.60%	73.02
Qld	Black Coal (Tarong) (b)	2,624	91%	1.31	13.60%	67.88
Qld	Black Coal (Central) (b)	2,624	91%	1.45	13.60%	68.97

Note: fuel cost shown as indicative only. Gas prices vary according to the city gate prices. (a) extension to existing site; (b) not regarded as a viable option due to carbon emission risk; (c) at a green field site; (d) excluding abatement costs or revenues

These capacity factors do not necessarily reflect the levels of duty that we would expect from the units. The unit's true LRMC measured in /MWh is higher than this level. For example, we would expect to find a new CCGT operating in Victoria with a capacity factor of around 60% to 70% rather than the 90% as indicated in the table. Ideally, in determining the timing of new entry of such a plant we would compare the new entry cost of a CCGT operating at this level against the time-weighted prices forecast in the top 60% to 70% of hours.

Inter-regional loss equations are modelled in Strategist by directly entering the Loss Factor equations published by AEMO except that Strategist does not allow for loss factors to vary with loads. Therefore we allow a typical area load level to set an appropriate average value for the adjusted constant term in the loss equation. The losses currently applied are those published in the AEMO 1 April 2012 Report “List of Regional Boundaries and Marginal Loss Factors for the 2012/13 Financial Year”.

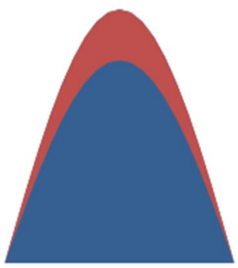
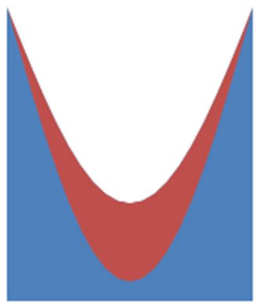
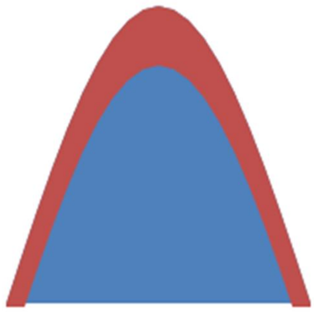
Intra-regional losses are applied as detailed in the AEMO generator regional loss factors

The long-term trend of marginal loss factors is extrapolated for three more years and then held at that extrapolated value thereafter.

A.3 Modelling energy demand reductions

The electricity market modelling also deducts energy savings from an underlying demand forecast, using one of three load shaving methods in Strategist. Two of the methods – peak and off-peak shaving – require a peak input and an energy input. Under peak shaving, load above median demand is shaved in proportion to the load shape so the shaved load is consistent with the peak and energy values input by the user. Off-peak shaving works in a similar way, where load below median demand is shaved in proportion to the load shape so the shaved load is consistent with the peak and energy values input by the user. Flat shaving requires either a peak input or an energy input, and will reduce the load by a fixed quantity evenly over the profile, adjusting it so that the load never becomes negative. These methods are illustrated in Figure 15.

- Figure 15 Load adjustment examples

Peak shave	***Off-peak shave***	***Flat shave***
Used for residential area heating and cooling, electronics, commercial lighting and space conditioning	*Used for residential water heating*	*Used for residential and commercial refrigeration, industrial applications*
		

For the electricity market modelling component of this work, the software deducts the peak savings from the total as appropriate.

Appendix B. **Modelling network benefits**

The financial impact on distribution and transmission network service providers will largely depend on the following factors:

- The impact on reducing overall load. Uncertainty in energy demand from customers will make establishing appropriate energy throughput tariffs more difficult, reducing the confidence DNSPs will have in their forward revenue forecasts.
- The impact on load shape, such that reductions in peak demand will defer investment in capital expenditure.
- The ability of networks to adequately predict "out-of-forecast" changes in energy and peak demand, which can materially impact projected assessments of necessary capital investment and subsequent revenue requirement, and or reliability.
- Timing of network revenue and tariff determinations. Tariffs are fixed for five-year intervals as determined by the Regulatory Proposal reset periods. Without "re-openers" there is no scope to modify the tariff components for changing loads and load profiles.[13]
- Structural tariff considerations, such as recent trends to increase capacity charges for networks rather than energy consumption charges, to minimise risk related to energy uncertainty, thereby reducing revenue recovery.
- The financial value of the 'Regulated Asset Base' (RAB) for each of the DNSPs is already established. Reduced energy consumption as a result of the ESI will not change the amount of money to be recovered from consumers; it will increase the cost per kilowatt hour consumed to return the same level of regulated revenue. Alternatively, if the reduced energy consumption has a greater proportional impact on network capacity needs than on total volume then an ESI might reduce network tariffs into the future. This temporary change in prices could affect the adoption of energy-efficient activities, changing the cost of reaching ESI targets. The modelling approach has therefore been designed to allow for dynamic market interactions of this nature.
- It is neither trivial nor straightforward to develop a framework that will help definitively describe the physical and financial impacts on network providers, incorporating feedback elements between consumers and the network charges imposed on them. Jacobs SKM has developed an approach which considers each of the factors described above and the associated feedback.

This appendix describes the transmission and distribution network assumptions applied in this study in order to estimate the peak demand impacts on electricity networks.

B.1 Deferred transmission benefits

Jacobs SKM assumed a uniform transmission deferral benefit of A$514 /kW based on in-house advice. An alternative source of the value of deferred transmission and distribution expenditure is provided by ISF and Energetics[14]. Their estimates are based on five-year proposed system augmentation capital expenditure estimates for a large range of transmission network service providers. The report also qualifies that the NSW estimate is based on "growth-related" rather than augmentation expenditure, and therefore may be somewhat less conservative than estimates from the other states. If averaged over system peak demand in

[13] Regulation allows DNSPs to submit annual pricing proposals. Subject to the applicable side constraints, the DNSP can change the levels of charges within various tariff components of any tariff (eg reduce energy charge and increase the daily supply charge). Jacobs SKM does not attempt to model this re-balancing in any way.

[14] http://www.climatechange.gov.au/what-you-need-to-know/~/media/publications/buildings/building_our_savings-pdf.pdf

each state, these estimates average to approximately A$700/kW. The value used in this study is therefore slightly lower, and somewhat more conservative than the assumption applied in the Energetics/ISF study.

B.2 Deferred distribution benefits

The modelling approach considered energy savings at the regional Distribution Network Service Provider (DNSP) level rather than the state level to better correlate energy savings with the characteristics and costs relevant to each DNSP. These detailed calculations are then aggregated before estimating final costs and benefits at a national level. Table 17 outlines the areas for which separate energy savings, costs and benefits are to be estimated. It also outlines the distribution network service areas and the off-grid areas pertinent to each state.

Table 17 : Distribution network service areas

State	Distribution Network Service Areas
Victoria	Powercor, Jemena, SPAusnet, United Energy, Citipower
New South Wales	Endeavour, Ausgrid, Essential, ActewAGL
Queensland	Energex, Ergon
South Australia	SA Power Networks
Tasmania	Aurora

Characteristics of DNSP areas vary significantly depending on climate, population density and area covered. A pictorial view of the various distribution areas is provided in Figure 16. The map show clearly that Ergon Energy and Essential Energy's service areas are large compared to other DNSPs. Similar challenges of geographical spread are faced by SA Power Networks, Powercor and SP AusNet in South Australia and Victoria. Distributors serving the largest numbers of customers include Energex and AusGrid, implying much greater economies of scale in these distribution areas.

To appropriately consider costs and benefits at the regional DNSP level, the modelling requires the development of a relationship between energy reductions and infrastructure expenditure. That is for each DNSP's service area a metric that links the probable financial and economic benefit (or disadvantage) to the change in load shape and/or the reduction in peak demand.

The evaluation of network benefit considers each of the following in each DNSP service area:

- Demand reductions in MW, based on the MTR scenarios. Demand reductions are split to DNSP regions and converted to 'demand deferrals', which incorporate the change in year to year demand, limited by projected change in DNSP demand projections. In addition, a coincidence factor of 0.8 was applied to allow for peak demand for different markets occurring at different times of the day.
- Load reductions in GWh, assumed to be nil
- Expectations of multiple trading in each network area

Table 18 presents assumed uptake of MTRs in each network area. Jacobs SKM assumed that there would be little uptake of MTRs in regional areas and has therefore allocated low proportional uptake to DNSPs that include a large regional component.

Figure 16: Pictorial view of distribution networks

Source: NEM: State of the Energy Market 2011, AER, WEM/NT: *http://www.tia.asn.au/static/files/pdfs/Australian_Energy_Overview_v8-Davidson_Paper.pdf*

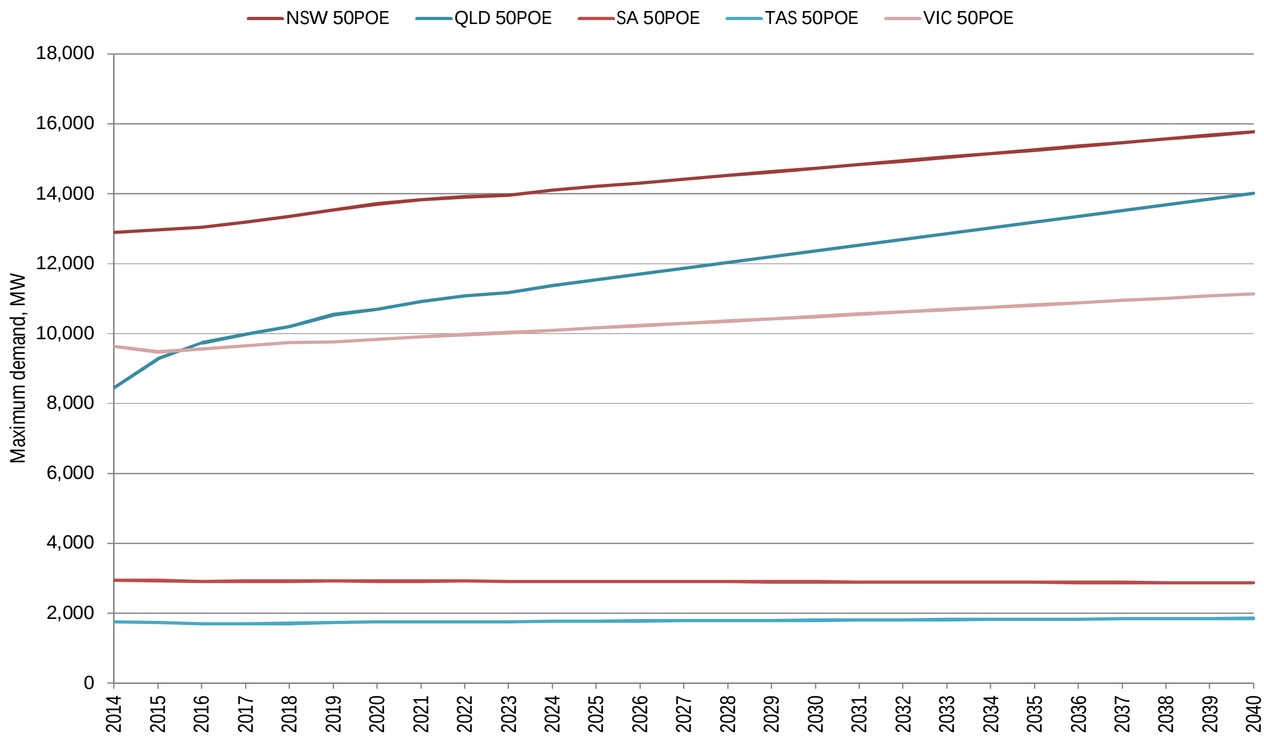
MTR induced reductions in peak demand was spread over each DNSP according to the values in the table above in combination with estimates of customer numbers in each area. Similarly AEMO state based demand forecasts were spread into each DNSP using the same factors. It is important to understand expectations of demand growth in each DNSP as lack of growth in demand will limit network benefits.

Based on 2013 50% POE demand projections from AEMO, regional demand growth is assumed to follow the trends depicted in Figure 17. Demand growth was assumed to follow growth rates between 2019 and 2023, the latter five year period reported by AEMO.

Table 18: Assumed spread of MTR peak demand reductions

		Residential	SME
QLD	Energex	100%	100%
QLD	Ergon Energy	10%	10%
NSW/ACT	AusGrid	100%	100%
NSW/ACT	Endeavour Energy	30%	30%
NSW/ACT	Essential Energy	30%	30%
NSW/ACT	ActewAGL	100%	100%
VIC	Powercor	30%	30%
VIC	SP AusNet	30%	30%
VIC	United Energy	100%	100%
VIC	CitiPower	100%	100%
VIC	Jemena	100%	100%
SA	SA Power Networks	100%	100%
TAS	Aurora Energy	100%	100%

Figure 17: Demand growth in the NEM



Source: AEMO 2013 demand projections, 50PoE

Deferred demand was calculated for each scenario by distribution zone and customer group (i.e. residential/SME) using the formulation below:

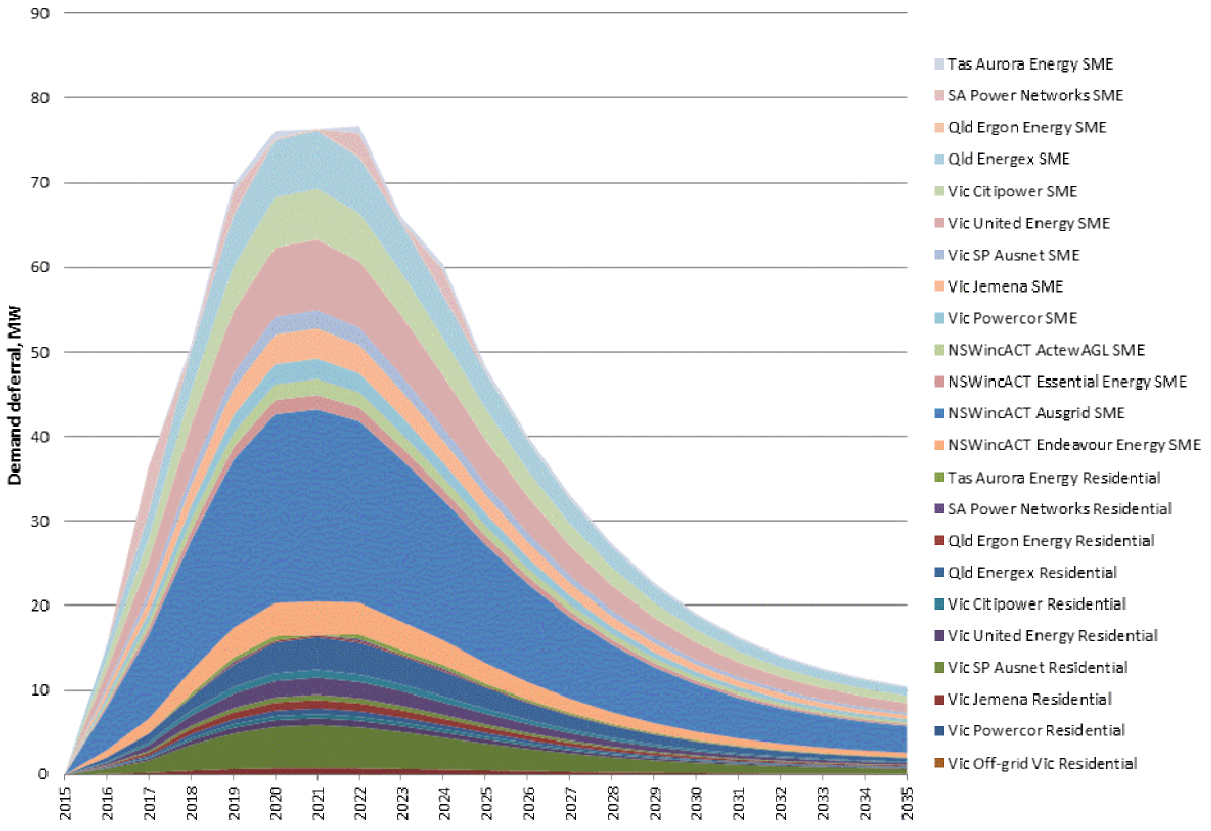
$$\textit{Deferred demand in year } t = \max(0, \min(D_t - D_{t-1}, M_t - M_{t-1}))$$

Where D_t refers to demand reduction in year t and M_t refers to regional maximum demand in year t.

This approach has the advantage that it limits estimates of deferred demand where there is little to no growth in demand (e.g. SA and Tasmania).

The derived demand deferrals are displayed in Figure 18. Notably the largest deferral is applicable to the Ausgrid DNSP, with significant deferrals also available in Energex, Citipower, United Energy and Endeavour energy.

Figure 18: Estimated demand deferrals for MTR by distribution area



Source: Jacobs SKM analysis

B.3 Estimates of network value of peak demand

A simple overview of our approach to estimating the value of network augmentation deferral is as follows:

- Establish state-based average network augmentation costs (on a $/kW basis) to establish factors for each DNSP as a general ‘sense-check’ of more detailed outcomes,
- Build from public data and professional expertise a set of augmentation cost values for each DNSP, and

- Where information is not available for a certain DNSP, identify similar DNSPs and make appropriate comparative assumptions in estimating values.

Resolving this high level state-based data down further for individual distributor's service areas is more difficult. Every five years each DNSP must submit, to the AER, a regulatory proposal that describes their services, expenditure and operation for the next five regulatory years. Once reviewed, potentially adjusted, and approved by the AER, this provides a guide to future capital projects and expenditure.

Table 19 presents average network costs associated with delayed peak demand for each DNSP. This data is based on work by Ernst and Young for the AEMC's *Power of Choice* Review on the potential benefits of increased demand side participation in the NEM. Ernst and Young extracted the growth-related capital expenditure for all of the DNSPs operating in the NEM and reported, amongst other things, the capital expenditure related to demand growth.

Table 19: Network cost associated with delayed peak demand for each DNSP for current regulatory period[15]

Network	Capital spend (A$m)	Demand growth spend (A$m)	Asset replacement spend (A$m)	Customer connection spend (A$m)	Network reliability spend (A$m)	Change in demand[16] (MW)	Demand growth A$/kW	Non-growth related $/kW
Energex	6,258	2,510	1,120		1,770	802	3,130	4,670
Ergon Energy	6,468	2,141		1,903	1,295	393	5,450	6,170
AusGrid	7,438	2,710			3,232	657	4,120	7,200
Endeavour Energy	2,885	1,160			1,278	360	3,220	4,790
Essential Energy	4,270	1,535	874		974	356	4,310	7,680
ActewAGL	293	81	104	99		188	430	600
Powercor	1,656	323	497	529	43	367	880	2,190
SP AusNet	1,581	465		418	509	345	1,350	2,540
United Energy	839	248	289	121	72	232	1,070	2,140
CitiPower	979	332		268	275	167	1,990	2,270
Jemena	600	126		125	164	113	1,120	3,040
SA Power Networks	1,848	692			420	318	2,180	3,160
Aurora Energy	693	74			180	114	650	3,650

For the purposes of this study we have developed a top-down model to determine the value of kW reductions in each distribution network zone. We have not, however, built a bottom-up model which predicts which and when augmentation projects might be deferred. As a result, the approach we have taken is to ascribe a value for each reduction in kW capacity *at the time the reduction in capacity occurs*.

Therefore the approach has been modified to limit deferral benefits by reasonable expectations of regional demand growth. These expectations were based on AEMO 2013 demand projections.

The temporal nature of distribution network benefits in this study does not reflect a time-specific economic benefit arising from a particular augmentation deferral, but rather the value of a reduction in capacity which will – at some point in the future – result in an augmentation deferral benefit.

This modelling exercise has calculated final network economic benefits with a 30% discount factor. This factor is intended to account for uncertainty of demand reduction benefits.

The estimates of peak demand benefit used for each distribution zone are displayed in Table 20.

[15] Source: Ernst & Young (2012). For the period to end of 2015.
[16] It is not clear from the Ernst and Young report or AER reports if this figure is exclusive or inclusive of new customer connections.

Table 20: Peak demand benefits by distribution area, $/kW, $2013

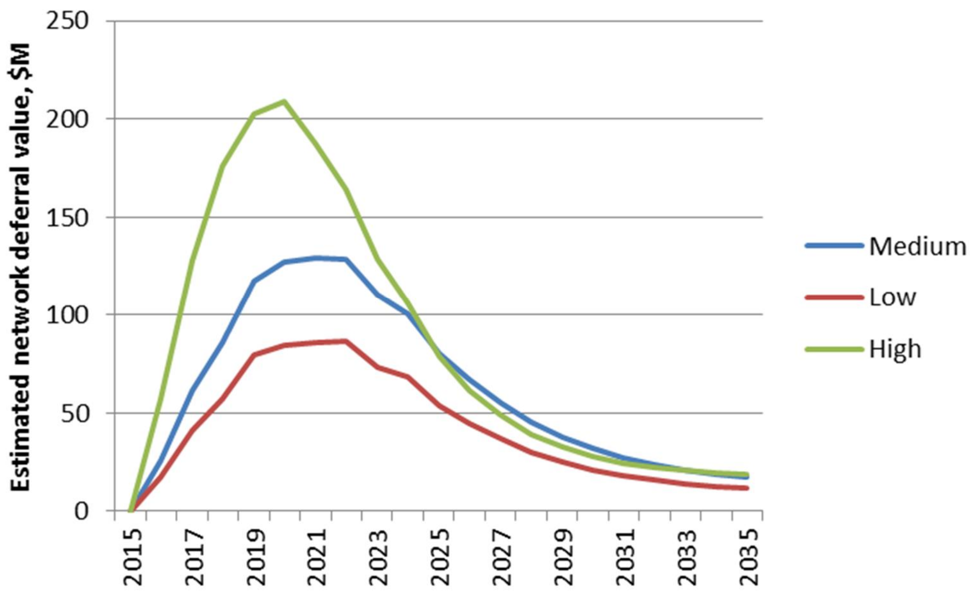
NSP	Peak demand benefit, $/kW
Endeavour Energy	1,462
Ausgrid	1,851
Essential Energy	1,933
ActewAGL	256
Powercor	452
Jemena	556
SP Ausnet	655
United Energy	534
Citipower	932
Energex	288
Ergon Energy	2,938
SA Power Networks	1,022
Aurora Energy	353

B.4 Estimated peak demand benefits

Estimated peak demand benefits for each of the scenarios are obtained by multiplying the estimates of network deferral value in Table 20 by the estimates of deferred peak demand in each year.

The results are shown below in Figure 18. The overall value ranges from $492 million in the low scenario to $1,059 million in the high scenario (discounted at 7% between 2015 and 2035). Medium benefits are evaluated at $737 million.

Figure 19: Estimated peak demand benefit



Source: Jacobs SKM analysis

Appendix C. **Determining network charges**

The adoption of demand side participation in each region will vary according to the mix of customers, loads and potential for energy efficiency, and the energy prices being paid. This section describes further the approach employed to vary baseline energy values by distribution service area and the approach for estimating retail energy prices in each region.

Retail energy cost savings are the primary benefit attributable to a high-efficiency activity for any consumer of that activity. Retail energy cost savings are estimated in this study using a build-up of avoided network, wholesale and other market costs. The AEMC have summarised how these components impact the typical residential bill, and how they were expected to increase between 2009/10 and 2012/13, as summarised in Table 21. While the make-up and growth in costs will vary significantly by jurisdiction, transmission and distribution charges are a non-trivial component of costs in all locations, making up around half the typical residential bill combined in 2009, and projected to grow around 35% combined by 2013. Growth in network charges has been most pronounced in areas where growth has required significant grid capacity augmentation to maintain regulated service levels.

Distribution network charges are the only component of retail costs that varies within state boundaries because the expenditure required to service customers in each different DNSPs service area changes. Network costs are, therefore, the focus of this section and are considered a key differentiator in investment in energy efficiency.

Network charges are a composite of distribution and transmission charges, and are subject to regulation. Recently, network charges have increased substantially and are projected to continue to increase. This increase has been most evident in NSW and Queensland, where considerable growth in the use of air conditioning has significantly increased grid capacity requirements to maintain required service levels.

Table 21: Composition of retail tariffs

Component of retail tariff	Estimated proportion of residential retail cost	Estimated change to cost between 2010 and 2013
Wholesale electricity costs	30-35%	19%
Transmission network charges	8%	8%
Distribution network charges	40-45%	41%
Retail costs, including margins	8-16%	14%
Renewable Energy Target (RET) costs	2-4%	11%
Feed-in tariff scheme costs	0.12-2.4%	3%
Other costs relating to government programs	1-7%	3%

Source: http://www.aemc.gov.au/Media/docs/CoAG%20Retail%20Pricing%20Final%20Report%20-%20Publication%20Version%2010%20June%202011-5fa4f4b8-8098-420c-a014-fa70808bb2e4-1.PDF

Network tariffs were collected for each distribution service area, and representative tariffs were determined for each of the residential, SMEs, low voltage (LV) and high voltage (HV) customers. Representative tariffs were chosen as they serve the customers that would be the target market for the program. In this study, LV customers were considered a proxy for commercial customers, while HV customers were considered a proxy for industrial customers.

All network tariffs were converted to a representative standing or supply charge, a demand charge and a variable energy-use charge. Supply charges were not considered in the calculation of energy savings because they do not contribute to the avoidable energy costs that would count as energy savings benefits in a cost-benefit calculation.

A representative network tariff applicable for each distribution area is supplied in Table 22[17].

C.1 Residential and SME tariffs

In most cases, residential and SME tariffs consisted of a supply charge and an inclining block tariff rate, and did not include a demand charge. If an inclining block tariff was in place, only the price of the first block was taken, as some customers would not have large enough loads to meet higher blocks. This increases the potential to understate adoption because the price of the first block is always the lowest in an inclining block tariff. This potential to understate adoption provides a more conservative bias to the analysis, since energy savings are marginal and would normally reduce energy from higher blocks rather than lower blocks.

C.2 Calculating network tariff impacts

Jacobs SKM undertook two forms of adjustment:

- Estimate energy impact – ie the impact on total revenue under reduced energy use compared to business as usual. It would be expected that fixed revenue requirements and reduced energy use through energy efficiency could lead to higher network tariffs unless the utilisation of the network also improves.
- Estimate peak impact; i.e. the impact of deferred network upgrades resulting from reduced network peak load, if any. To account for the regulatory environment governing electricity networks, tariff adjustments (as a result of an energy efficiency scheme) will take place only in the years following the existing tariff review period, since networks are unable to accurately forecast and assess changes to their projected revenues prior to the next tariff review. We note that some DNSPs can rebalance tariffs annually to try to respond to what they forecast in terms of customer numbers, peak demand and consumption by tariff. We have not attempted to model this behaviour. While this may reduce the efficacy of our assumptions, any attempt to presume this behaviour would have introduced greater potential for misestimating. Capital expenditure by the DNSP's requires some level of Regulatory Investment Test examination if only to identify the most appropriate lowest capital cost option. However, neither annual rebalancing, nor Regulatory Investment Test behaviour, has been incorporated into this study. We believe this simplification is justifiable and reinforces a reasonable approach to benefits in our analysis.

Two assumptions were made in regard to adjusting network tariffs:

- Increases to network charges (as a result of lower throughput) were applied only to the standing charge. In this work, this effect is non-existent.
- Reductions to network charges (as a result of augmentation deferral) were applied only to the energy component of the network tariff, as this mimics the existing trend for networks to be risk averse in increasing fixed charges and reducing throughput charges.

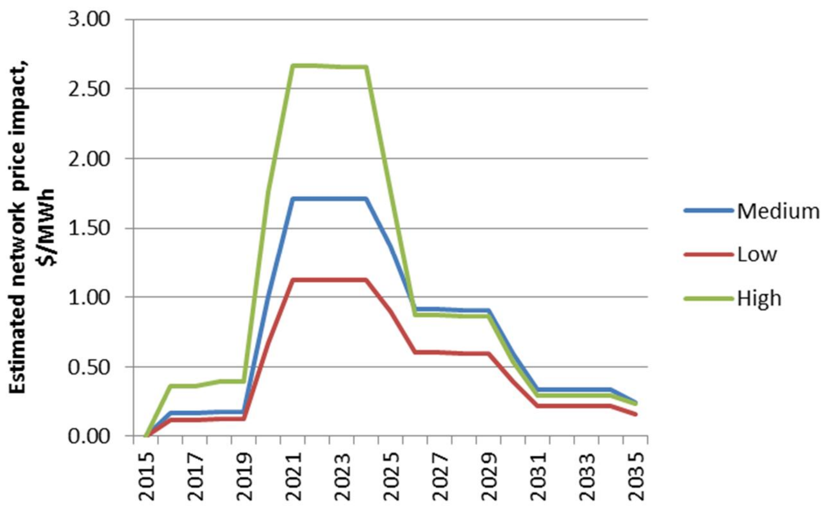
Network charges were projected to future years using the regulatory 'x-factors[18]' applicable to each DNSP. These tariff increases are only available for the regulatory period (5 years), and beyond this time a flat price was assumed to be applicable. A flat tariff beyond the regulatory period was assumed because it was not reasonable to assume that current rates of growth will continue into the future in case this assumption overstated network tariff benefits in the modelling. These assumptions may not provide an accurate means of forecasting network charges; however the approach is defensible from the point of view that our results compare the difference in network prices given a specific change in load and demand. For this study it was most important that a consistent approach was taken between all modelled scenarios (including the reference cases), as the final results are derived by comparing outcomes between these scenarios.

[17] This is by no means all of the tariffs that are used by the Network service providers but it is a realistic and representative sample of typical arrangements.

[18] These 'x-factors' are effectively allowable real tariff increases that have been agreed to with the regulator. There is no guarantee that the tariff increase will be applied, or even that it will be applied to each market, since a higher rate can be applied to one market in compensation for a lower rate in an alternative market.

The impact of MTRs on network prices by scenario is illustrated in Figure 20.

Figure 20: Impact of MTRs on network prices



Source: Jacobs SKM analysis

Table 22: Representative network charges[19] by distribution area[20]

State	Network	Market segment	Representative tariff	Standing charge[21] (c/day)	Demand rate (c/kW/day)[22]	Energy rate (c/kWh
Qld	Energex	Residential	Domestic	36.30	-	9.706
		SME	SAC demand small Demand	324.50	49.357	2.245
Qld	Ergon Energy	Residential	SAC – volume small	150.2		21.13
		SME	SAC – volume large	458.9		21.13
NSW	AusGrid	Residential	Residential IBT	31.057	-	11.69
		SME	Small business IBT	100.90	-	9.959
NSW	Endeavour Energy	Residential	Domestic	34.10		11.471
		SME	General supply non-TOU	47.30		9.869
		LV	LV demand TOU	1659.90	64.302	2.817
		HV	HV demand TOU	2746.70	46.464	2.229
NSW	Essential Energy	Residential	Residential LV continuous	76.16		16.240
		SME	Business LV general supply	76.16		21.185
ACT	ActewAGL	Residential	Residential basic network	16.775		6.941
		SME	Commercial LV general network	33.781		10.604
Vic	Powercor	Residential	Residential interval	14.360		8.720
		SME	Non-residential interval	14.361		8.327
Vic	SP AusNet	Residential	Small residential single rate	2.755		10.192
		SME	Small business single rate	2.755		15.340
Vic	United Energy	Residential	Low voltage small 1 rate	5.915		5.845
		SME	Low voltage medium 1 rate	11.306		7.758
Vic	CitiPower	Residential	Residential single rate	6.789		5.764
		SME	Non-residential single rate	15.335		6.828
Vic	Jemena	Residential	Residential general Purpose	6.621		8.154
		SME	Small business general Purpose	17.208		9.445
SA	Power Networks	Residential	Low voltage residential	33.79		10.97
		SME	Low voltage business 2 rate	33.79		16.96
		SME	General supply			30
Tas	Aurora Energy	Residential	Residential light and power	89.145		25.132
		SME	General	96.303		34.277

Source: Jacobs SKM Analysis of DNSP Tariffs for 2011/1

[19] Includes transmission use of system charges and GST
[20] SAC=Standard Asset Customers
[21] Requires conversion to a c/kWh rate and requires an estimate of customer numbers to energy ratio
[22] Where kVA has been quoted in the tariff this has been converted to kW using a conversion factor of 1.25 kVA = 1 kW