Cost-benefit analysis of a possible Demand Response Mechanism

prepared for:
Department of Industry

Melbourne +613 9016 2550 Sydney +612 8091 3650 Adelaide +618 8331 1358 Brisbane +617 3263 7612

DISCLAIMER

This report has been prepared for the Department of Industry (DoI) as an input to the Energy Council's consideration of whether to proceed with the development of a Rule Change proposal based on the merits of implementing the Demand Response Mechanism (DRM) now (or possibly later), and whether it should be in its originally proposed form, or whether certain changes to the DRM should be considered that might improve its cost-efficiency.

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Report prepared by	Lance Hoch (lhoch@oakleygreenwood.com.au) Don Anderson (danderson@oakleygreenwood.com.au) Rohan Harris (rharris@oakleygreenwood.com.au) Ed Smith (esmith@oakleygreenwood.com.au) Greg Thorpe (gthorpe@oakleygeenwood.com.au) David Waterson (sdwaterson@energisedprojects.com)
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1. Executive summary

1.1. Background and purpose

1.1.1. Project background

In January 2013, the Standing Council on Energy and Resources (SCER) directed the Australian Energy Market Operator (AEMO) to develop a rule change proposal on a Demand Response Mechanism (DRM) for submission to the Australian Energy Market Commission (AEMC) by 15 December 2013. This proposal originated as a recommendation from the AEMC's *Power of Choice* review.

The DRM was intended to facilitate large energy users to participate in the wholesale market as though they were non-scheduled generators, and receive reimbursement for reducing energy demand in response to high price events. It was designed to increase demand side participation by large energy consumers. The range of potential benefits from such a scheme was assumed to include:

- greater opportunities for large energy users to reduce their net energy costs and seek more competitive offers for their demand response;
- reduced wholesale market costs for all users through greater market competition, potentially also resulting in deferred investment in peak generation;
- deferred network investment through both reduced system-wide peak demand and flow on impacts for network support services of a stronger demand response market; and
- potential to reduce volatility in demand and support new suppliers in ancillary services markets.

As part of its development of the rule change proposal requested by SCER, AEMO convened a set of working groups to develop a design under which the DRM would be implemented and administered. In parallel with this the Energy Retailers Association of Australia undertook a survey of its members to estimate the likely cost of implementing the DRM as described in the detailed design document.

In December 2013 AEMO wrote to SCER seeking further advice on whether to submit the proposed rule change. Ministers agreed that officials should undertake further work on the DRM, including a cost benefit study. This was in the context of changes in market circumstances since the completion of the *Power of Choice* review.

When the AEMC analysed a possible DRM, peak and average electricity demand were assumed to increase at a steady growth rate. Additional energy infrastructure, such as generation and network assets, would hence be required to meet this growth. In such circumstances, the DRM could potentially assist in providing a cheaper option to meet system reliability requirements, resulting in economic benefits by deferring investment in this energy infrastructure. Since that time, energy demand has shown a trend of flattening and declining. As such, there is a lower projected need for capital investments in additional energy infrastructure, which may in turn reduce the potential benefits of the DRM.

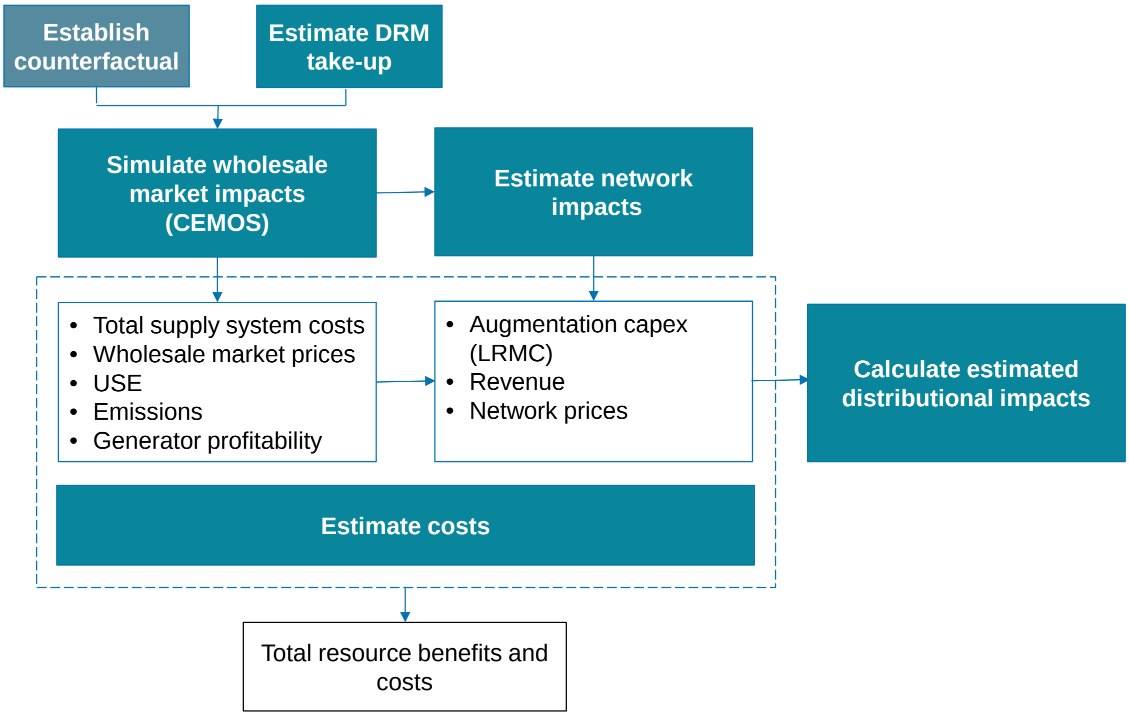
1.1.2. Project objectives

Oakley Greenwood was commissioned to assist officials undertake a cost benefit analysis, to re-evaluate whether or not there are net economic benefits associated with introducing a DRM under current circumstances. Results of the assessment and associated information/reasoning are expected to support decisions by the COAG Energy Council on whether it should proceed with the development of a Rule Change proposal based on the merits of implementing the DRM now (or possibly later), whether it should be in its originally proposed form, or whether certain changes to the DRM should be considered that might improve its cost-efficiency.

1.1.3. Overview of approach taken

Figure 1: Overview of the approach taken to the cost-benefit analysis below provides an overview of the approach used in undertaking the quantitative cos-benefit analysis.

Figure 1: Overview of the approach taken to the cost-benefit analysis



Establishment of the counterfactual was undertaken to define the conditions that would be considered to be in place and against which the impacts of the DRM would be assessed. Three counterfactual scenarios were developed, as follows:

- The current forecast, as defined in AEMO's 2014 National Electricity Forecast Report;
- The current forecast, as defined in AEMO's 2014 National Electricity Forecast Report, but with the assumption that a robust form of cost-reflective network pricing (CRNP)[1] is universally adopted by all network businesses within the NEM by the beginning of FY2016; and

1 AusNet Services' Critical Peak Demand tariff which has been in place since 2011 served as the model for this tariff and the impacts that could be expected to result.

- An illustrative capex requirement scenario, in which it was assumed that
  - the significant over-supply of generation has been absorbed and installed capacity levels are more like longer term averages, and
  - average annual growth rates in both peak demand and overall electricity consumption are similar to those experienced in the period 1998 -2008.

  It is important to note that:
  - the 'Illustrative capex requirement' scenario was developed solely to assess the impacts of the DRM under conditions under which it would be expected to offer significant benefits, and
  - while the conditions assumed in this scenario are plausible (in that they have existed in the recent past), they are not conditions that are expected to exist in the near- to mid-term.

Further information regarding the methodology and analysis undertaken in each of the other steps shown in Figure 1 are presented in the following section.

1.2. Results of quantitative cost-benefit analysis

1.2.1. Take-up

Approach

The primary information sources for the estimation of the amount of demand response likely to result from implementation of the DRM were:

- A February 2014 ClimateWorks study entitled *Industrial demand side response potential*, from which the demand response potential of the industrial sector was estimated;
- ABARE information on the energy consumption of twelve different ANZSIC Divisions within the commercial sector from which the likely peak demand and demand response potential of these customers was estimated;
- Information from the ClimateWorks study and other sources (including state government data) was used to assess the amount of standby generation available in the various NEM jurisdictions; and
- Information from
  - AEMO on the amount of DR currently available in the NEM and the specific proportions of that DR that have been observed since 2000 to come forward at several specific spot price levels, and
  - DR take-up in other jurisdictions was used to estimate the amount of DR likely to be available as a result of the DRM.

Adjustments were then made to (a) subtract the amount of DR already being provided in the NEM (as this amount would not be the result of the DRM), and (b) in the case of the CRNP counterfactual, to account for the fact that the change in network pricing (which was assumed to occur prior to implementation of the DRM[2]) would result in an amount of DR that would reduce the amount of the remaining DR potential that would be available to the DRM.

Results

The methodology described above provided an estimate of the total DR potential available in the NEM. That had to be converted to the specific amount of DR that could be expected to be available in each year over the analysis period and the amount that could be expected to materialise at specific spot prices.

Table 1 below shows the proportions of the total DR exercised annually in the NEM since 2000 that have come forward at five specific levels of spot price, as identified by AEMO. Those percentages were adjusted, as also shown in Table 1, to reflect the incremental impact of the DRM in terms of the rate of DR provision it would drive in the market.

Table 1: Assumed percentage of total DR potential realised at different spot market prices

Trigger spot price ($/MWh)	Cumulative % of total DR potential that will respond	
	AEMO	Assumed for DRM
$300	19%	25%
$500	22%	30%
$1,000	23%	40%
$7,500	59%	80%
MPC	100%	100%

Source: AEMO 2014 NEFR, information from other jurisdictions and OGW professional judgement

The reasoning that informed the higher proportions used to reflect the impact of the DRM was as follows:

- The AEMO data reflects DR that has been provided without the specific features assumed to become available through implementation of the DRM and as such reflects a mix of DR based on spot exposure and participation in retailer programs in which
  - the percentage of the spot price arbitrage that has generally been made available to DR providers has been around 50%, and

2 As noted above, CRNP was assumed to be implemented in 2016. The DRM was assumed to be implemented in 2017. These assumptions reflect the fact that (a) the rule change concerning cost-reflective network pricing has already been endorsed by the AEMC in a draft determination, and cost reflective pricing for the class of customers that would be eligible for the DRM does not require any additional equipment or software to be put in place by the network businesses, and (b) the DRM rule change has not begun to be considered as yet and would require further definition and at least some (and possibly extensive) changes in AEMO and retailer IT systems prior to being ready for implementation.

- dispatch calls have not always been made at the price levels at which DR providers have said they would be willing to reduce their load.

- Most customers are not interested in spot exposure, so the majority of growth will come from customers who are likely to prefer participation through the DRM (which can offer the end-use customer a means whereby they can provide DR when it is convenient without having to take direct exposure to pool price for any part of their load on a full time basis.
- The DRM rule change would create a new category of market participant called a Demand Response Aggregator (DRA). Because the exercise of demand response will constitute the primary focus of the third-party DRAs that will be empowered by the DRM, they can be expected to offer higher levels of arbitrage to DR providers, and to call for their dispatch more regularly, which will serve to increase the percentage of the total DR potential that will become available at each of the AEMO price points.

Annual take-up of the total potential was assumed to occur over a ten-year period, with the no-cost and low-cost portions of the resource taken up in the first two years and 25% of the medium and higher cost portions being taken up in subsequent four year periods. Table 3 and Table 4 below show the take-up of the DR under the AEMO forecast and AEMO forecast plus CRNP scenarios. The AEMO forecast take-up was also used in the 'Illustrative capex requirement' scenario.

Table 2: Annual DR impacts (MW) in the AEMO forecast scenario

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
NSW	312	312	375	439	503	566	628	689	751	812
VIC	231	231	278	325	373	420	465	511	556	602
QLD	238	238	286	335	383	432	479	526	573	620
SA	72	72	87	102	116	131	145	160	174	188
TAS	71	71	85	100	114	129	143	157	171	185
NEM	923	923	1112	1300	1489	1678	1860	2042	2225	2407

Source: OGW analysis

Table 3: Annual DR impacts (MW) in the AEMO plus CRNP forecast and Illustrative capex requirements scenarios

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
NSW	217	217	257	297	337	377	415	454	492	531
VIC	156	156	184	212	289	369	422	511	556	602
QLD	238	238	286	335	383	432	479	526	573	620
SA	72	72	87	102	116	131	145	160	174	188
TAS	71	71	85	100	114	129	143	157	171	185
NEM	753	753	899	1045	1240	1438	1604	1807	1966	2125

Source: OGW analysis

1.2.2. Wholesale market impacts

Approach

The impact of the DRM on the NEM's wholesale electricity market was analysed through the use of the CEMOS market simulation model. The basic inputs to the modelling were taken from AEMO's 2014 NEFR and ESOO. These included:

- Forecast annual sent-out electricity requirements, peak demand and load duration curves (LDCs);
- Current and committed generation plant and transmission interconnections; and
- Costs and operating characteristics of candidate conventional and renewable plant.

Consistent with current Commonwealth government policy, the modelling did not include a price on carbon. In a similar vein and in order to make the modelling assumptions similar to those used in the *RET Review*, conventional coal generation technologies were included as options in the event that additional generation capacity was found to be needed to meet demand growth.

As has been the case in most market simulation modelling undertaken in the past several years, various adjustments needed to be made due to the significant over-supply of generation capacity in the market. The basic problem is that the combination of the over-supply of generation capacity, the forecast softness of demand growth and the existence of the RET result in unsustainably low wholesale market prices. Generators have already responded to this by removing or reducing the operation of capacity in order to better balance supply with demand and thereby raise prices to levels that provide minimally adequate returns.

In our analysis, we ensured that wholesale electricity prices were plausible (i.e., would provide at least minimally sustainable profitability levels for all operating generators over the analysis period) by balancing the amount of coal, gas and renewable generation in the market. This required withdrawal of both coal and gas capacity and a reduced (and floating) level of renewable generation. Withdrawal of coal and gas capacity was informed by assessment of the profitability levels of specific plants. In addition, in practice, the approach taken meant that the full LRET quota was not met in the modelling.

It was also assumed that providers of DR under the DRM will offer quantities of DR in a rational manner – that is, they will not knowingly over-dispatch DR in a way that crashes price.

The DR to be made available under the DRM itself was modelled as a series of plants having the following characteristics:

- Specific trigger prices at which it will enter the market and flexibility in operations such that they can respond when those prices occur;
- A minimum run time of 30 minutes
- A maximum run time of 8 hours per event (though in fact no high price events of that duration occurred in the modelling)
- A maximum of 80 hours of dispatch per year (though this threshold was also not met in the modelling)[3].

3 Note that no more than 9 hours were found with prices at or above trigger points in most years, in either the AEMO forecast or AEMO forecast plus CRNP scenarios, though in some years they occurred for up to 15 hours.

Results

Table 4 below presents the results of the analysis of the impact of the DRM on the wholesale market in each of the three scenarios analysed.

As can be seen, impacts in terms of reductions in total generation sector costs is minimal in both the AEMO forecast and AEMO forecast plus CRNP scenarios. It is also the case that all of the generation sector cost reductions in both of those scenarios are due only to reductions in fuel (and other variable operating and maintenance) costs, rather than reductions in capacity requirements or capacity costs.

Table 4: DRM impacts on the wholesale market

Impact item (2017 thru 2035, NPV @ 7.5%)	AEMO 2014 forecast	AEMO 2014 forecast + CRNP	Illustrative capex requirements	Price volatility
Change in generation sector capacity & FOM costs (NPV)	NIL	NIL	\$63 million (10 yrs) \$1.1 billion (19 yrs)	NIL
Change in generation sector fuel and VOM costs (NPV)	\$2.6 million	NIL +	minor	\$1.9 million
Change in total generation sector costs (NPV)	\$2.6 million	NIL +	\$63 million (10 yrs) \$1.1 billion (19 yrs)	\$1.9 million
Reduction in installed capacity as at 2035	0 MW	0 MW	1,968 MW (10th yr) 1,980 MW (19th yr)	0 MW
Reduction in generation	136 GWh	57 GWh	296 GWh (10th yr) 437 GWh (19th yr)	57 GWh
Average annual change in NEM wholesale price (\$/MWh)	\$0.73	\$0.26	\$0.79 (10 yrs) \$1.56 (19 yrs)	\$0.42
GHG emission reductions	259,000 tonnes	182,000 tonnes	467,000 (10 yrs) 1.5 million (19 yrs)	777,000 tonnes
Average annual reduction in unserved energy	0.02 GWh	0.01 GWh	0.4 GWh	0.02 GWh

Source: OGW analysis

This is not surprising given the initial over-supply in generation capacity, the quite flat forecast for growth in total and peak demand, and the fact that the capacity withdrawals that were undertaken in the modelling to maintain a reasonable wholesale market spot price were assumed to be mothballings rather than abandonments. This follows the developments in the market: the withdrawals that have been seen to date have not entailed permanent shutdown of plant. Temporary withdrawal is likely to be preferable to permanent shutdown for several reasons: (a) it allows plant to return if and when supply/demand/price conditions warrant it, (b) it is relatively inexpensive in the short to medium term, and (c) it avoids the significant expense associated with site remediation which accompanies permanent shutdown.

Impacts in the illustrative capex requirements case are material, which is also not surprising. The high growth rate provides the opportunity for the DR made available by the DRM to defer plant, thereby materially reducing the capital and other fixed operation and maintenance costs incurred in the generation sector. However, this scenario is optimistic in that it does not account for policies such as CRNP that are likely to be implemented and that would reduce the incremental impact of the DRM.

As can be seen, a scenario was also run testing the impact of increased wholesale market price volatility on the benefits possible from the DRM. Benefits in that case are also small, primarily because while the volatility results in DR being called more often (and increasing fuel cost savings), the over-supply of generation capacity still results in their being no possibility of deferring capacity additions.

Some stakeholders noted that there is likely to be some cost in either maintaining the plant while it is withdrawn or in refurbishing it when it is re-entered into operation. These stakeholders suggested that the analysis as currently constituted did not account for those costs and that by not doing so it did not account for the savings that the DRM could provide by deferring the re-entry of withdrawn capacity.

That is true, but accurate modelling of these costs is very difficult. Doing so would require:

- nominating the re-entry costs of the specific plants that have been withdrawn, and
- re-running the 'without DRM' and 'with DRM' cases in each scenario to see whether and to what extent the additional DR in the 'with DRM' case delays re-entry and its associated costs as compared to the base case

The primary difficulty with this approach is that the re-entry costs of the specific plants that have been withdrawn will be entirely plant-specific (as compared to the generic capital costs of candidate plant included in the AEMO dataset) and are also likely to vary with the amount of time the plant is out of service. We simply have no way of knowing those costs, and as a result, the outcome would be a direct product of the inputs – all of which would be assumptions.

In addition, the results of such an analysis would of necessity fall between the results of the AEMO forecast scenarios and the illustrative capex requirements scenario. The degree to which the results could be expected to approach the higher end of that range would depend entirely on how high the re-entry costs are assumed to be. But even at relatively high re-entry costs the low growth in the present forecast would tend to push the results closer to the lower end of the range between the AEMO forecast scenarios and the illustrative capex requirements scenario.

As a result, refurbishment costs for mothballed plant re-entering the market have not been included in the analysis, and this should be recognised as an area of conservatism in the modelling[4].

4 Another area in which some stakeholders felt the analysis was overly conservative concerned the omission of DR's capability to deal with outlier price spikes – those not related to supply demand conditions. An analysis of these events will be included in the full version of the final report.

1.2.3. Network impacts

Approach

The results of the wholesale market modelling in terms of the amount of DR brought forward by the DRM at the state level served as the primary input to the network analysis, in which those impacts were adjusted to account for the following factors:

- The fact that networks do not necessarily experience peak demand at the same time as the wholesale market
- The fact that a CRNP tariff targeted at larger customers could be expected to focus on those hours during which those customers put their highest demands on those parts (i.e., voltage levels) of the network to which they are connected.

More specifically, the analysis included the following steps:

- The impact of DR was assumed to exhibit some 'spread' around the time of peak demand in each NEM region – a normal distribution was assumed to spread from 1.5 hours before to 1.5 hours after the time that AEMO forecast peak demand to occur in each region in each year of the analysis period[5];
- The DR estimates were further adjusted to reflect:
  - the timing of peak demand at the different voltage levels within each network,
  - the proportion of the load of DRM eligible customers that is served at each voltage level,
  - the proportion of the DR that will impact each specific network business in each State (based on the proportion of state-wide electricity consumption of non-residential customers within each network);
- The amount of DR determined at each voltage level within each network was multiplied by the voltage-specific LRMC for each network business – the LRMC figures used were based on published information wherever possible, unpublished information that we are aware of, or (where nothing was available) the LRMCs of another similar network business[6];
- Adjustment was also made to reflect the proportion of the load in each network that peaks in the same season as the wholesale market.

This approach significantly improves on the type of static analysis commonly undertaken of the impact of demand-side activities on network peak demand in that it adjusts for potential differences in the timing of network peak demand across networks (including the fact that much of the CRNP will affect higher voltage levels) and in terms of seasonality.

However, it should be noted that because it is a top-down approach, it cannot accurately account for the current headroom and growth rates characterising each network (and each local asset area within each network area).

5 It should be noted that where the wholesale market modelling indicated that the timing of peak demand would change due to either (or both) the CRNP or the DRM, the new peak demand time was used.

6 In the CRNP scenario the LRMC figures were discounted by 5% from year 3 onwards to reflect the fact that CRNP is likely to lower network business' demand forecasts, delaying the need for capex, and therefore reducing their LRMC of supply, at least marginally.

Results

Table 5 presents the results of the network impact analysis.

Table 5: Network benefits of the DRM

Network benefits (2017 thru 2035, NPV @ 7.5%)	AEMO forecast	AEMO forecast + CRNP
Distribution system benefits	$147.3 million	$101.4 million
Transmission system benefits	$31.1million	$16.4 million
Total network benefits	$178.4million	$117.8 million

Source: OGW analysis

As can be seen, network benefits are very high relative to wholesale market benefits in both the AEMO forecast and AEMO forecast plus CRNP scenarios[7].

Some stakeholders noted that the results of this analysis and those in the initial *Power of Choice* modelling both indicated that the majority of the benefits accrued to networks. They questioned whether it made sense to use a wholesale market mechanism to drive network benefits. This question has merit.

However, the difference in the magnitude of the benefits accruing to the wholesale market and the network sector in the analyses is likely to be at least in part a product of the differences in the two types of analyses undertaken. The wholesale market analysis, as a product of market simulation modelling, calculates the actual forecast change in the amount of generation capacity and fuel that will be needed, given a starting point, a forecast of growth in overall electricity demand and peak demand, and the available plants type (including DR), their operating characteristics and costs. By contrast, the network analysis, as a static analysis, uses only the assumed impacts and their value (in terms of LRMC). It does not have starting headroom and growth rates and the costs of various augmentation options at either the network or spatial levels[8].

Undertaking a similar analysis for networks would require that data at the zone substation level for each of the 13 distribution and 5 transmission business in the NEM over the 20 years of the analysis period. This was far beyond the timeframe and resources available for this project.

As a result, while the network benefits are difficult to quantify on the same basis as those of the wholesale market, there is very little doubt that the DRM would have flow-on benefits to the network sector. More generally, it should be recognised that once enabled, DR providers (and the aggregators whose business model is to maximise revenue available to DR) will seek to deploy DR to their maximum advantage, subject to their production requirements.

7 Network benefits in the illustrative capex requirements scenario were not calculated for this report, but are less critical to the outcome of that scenario.

8 A bottom-up analysis across 20 years and all of the networks in the NEM was far beyond the timeframe and resources available for this project.

1.2.4. Costs

Approach

Estimation of the costs likely to be entailed in implementation and administration of the DRM proved to be exceedingly difficult.

AEMO estimated the costs it would incur in implementing and administering the DRM at somewhere in the order of $8 million over ten years (NPV). However, to the extent that the DRM will require retailers to make changes to those parts of their IT systems that interact with the market, the costs are very much a product of the current IT system and landscape within each retail business.

In parallel with the detail design process convened by AEMO, the Energy Retailers Association of Australia (eraa) undertook a survey of its members to estimate the likely cost of implementing the DRM. The survey asked respondents to estimate the level of cost they felt they would be likely to incur in five different areas related to implementation of the DRM. The costs were categorised as low medium and high, and each category had an associated dollar range.

Results from the nine retailers that responded indicated that their costs would be in the order of $112 million over ten years. The method for calculating these aggregate costs was conservative in that the dollar figure associated with the lower end of the range for each category of costs was used. It should also be noted that the $112 million figure was based on the responses of only the nine retailers that responded. If the DRM were to be implemented such that all retailers were required to participate, these costs would be expected to be higher.

It was not possible to fully deconstruct the drivers of the costs reported from the eraa survey. In an attempt to get a better understanding of the drivers of these costs and how they might be reduced we approached three parties involved in IT system development/alteration for the electricity industry to see if we could obtain an independent estimate of the costs likely to be incurred by retailers in implementing and administering the DRM.

Results

A summary of their views includes the following key points:

- At this point in the design and specification of the DRM, IT build estimates would be expected to be in the order of +/- 50% accuracy at best;
- Better estimates would require that a draft Rule be available and an industry ‘build pack’ be developed;
- Even then, it would still require a considerable time and effort to develop a cost estimate that would be within +/-20% accuracy;
- And costs could vary considerably depending on
  - the system landscape of the individual retailer, and
  - the fact that most/all retailers have other systems in addition to their core system that need to act in concert and therefore would also need to be modified; and
- Market-facing systems in particular (MSATS, etc.) would be a major driver of development and testing costs.

As a result, none of the three was prepared to provide an alternative cost estimate, and all felt that, based on the level of detail currently available, the estimates provided by the retailers and distributors that responded to the ERAA survey appear reasonable.

Section 1.3.2 provides a discussion of ways in which the design and implementation of the DRM could be altered to reduce costs.

1.2.5. Distributional impacts

Approach

The analysis of the distributional impacts of the DRM was undertaken at the distribution business level and used the following approach:

- All customers were assumed to benefit from the wholesale price reductions available at the applicable regional node.
- Variations were undertaken in the allocation of benefits to different customer classes, but the distribution business was assumed to retain 30% of the benefit in all cases (consistent with the AER's capital expenditure incentive guideline).
- Variations were also undertaken in the allocation of DRM costs to different customer classes.
- The impact of the reduction in throughput due to the exercise of demand response under the DRM on network tariffs was not calculated; nor was the impact of that reduced consumption included in the analysis of DR providers' benefits. This was not felt to be a material omission given the relatively small amount of consumption reduction involved.
- Consistent with the *Standard Practice Manual for the Economic Analysis of Demand Side Management Programs and Projects*[9], DR providers' costs were not included in this analysis[10].

Results

Three different variations of the distributional impacts analysis in the AEMO forecast plus CRNP were undertaken. The three variations differed in how the costs of the DRM (assumed to be $120 million in NPV terms[11]) and its benefits were allocated between customer classes.

Although the allocation of DRM costs and benefits between customer classes was varied, all three runs showed positive results for the distributional impacts of the DRM case (with CRNP in the counterfactual) for customers eligible to participate in the DRM, commercial customers and residential customers in all DNSP service areas in the NEM. All results are in NPV terms over a 20 year period for the average customer within each of those groups. This would tend to indicate that the DRM, as assessed here, is unlikely to result in increased costs for any customer class, and to be of assistance in helping those who participate save money on their bills.

9 California Public Utilities Commission, *California Standard Practice Manual for the Economic Analysis of Demand Side Management Programs and Projects*, October 2001, available at http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF.

10 In response to comments from some stakeholders, a calculation of the distributional impacts of the DRM including an estimate of DR providers' costs will be included in the full version of the final report.

11 It should be recalled that that the $120 million is probably a low estimate (as it does not include any software refresh costs over the 20-year period), and is based on the costs likely to be incurred by only nine retailers.

Table 6 below shows the results for the AEMO plus CRNP scenario and under the assumptions that (a) all DRM costs are allocated across the residential and commercial customer classes in proportion to their consumption volume; and (b) all customers equally share in 70% of the network benefits (with the other 30% being retained by the network business.

Table 6: Distributional impacts of the DRM

NPV of Benefits (costs) Per Residential Customer	Citipower	Ausgrid	SP AusNet	Endeavour	Energex	Ergon	Essential	Jemena	Powercor	SAPN	United
Reduced wholesale prices	$7.10	$17.95	$7.74	$20.00	$12.39	$15.25	$19.37	$6.67	$7.82	$8.58	$6.99
Allocation of costs	-$8.65	-$10.81	-$9.43	-$12.05	-$11.23	-$13.83	-$11.67	-$8.12	-$9.52	-$9.66	-$8.51
Revenue generated by DR providers	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Network Benefits	$21.23	$4.29	$5.57	$4.69	$5.08	$9.01	$9.23	$12.35	$9.26	$8.21	$7.98
TOTAL	$19.68	$11.42	$3.89	$12.63	$6.23	$10.43	$16.93	$10.89	$7.56	$7.13	$6.46

NPV of Benefits (costs) Per Commercial Customer	Citipower	Ausgrid	SP AusNet	Endeavour	Energex	Ergon	Essential	Jemena	Powercor	SAPN	United
Reduced wholesale prices	$56.53	$57.50	$36.85	$85.40	$39.88	$15.93	$66.15	$33.30	$31.99	$29.49	$35.92
Allocation of costs	-$68.85	-$34.64	-$44.88	-$51.45	-$36.17	-$14.45	-$39.85	-$40.55	-$38.96	-$33.17	-$43.74
Revenue generated by DR providers	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Network Benefits	$21.23	$4.29	$5.57	$4.69	$5.08	$9.01	$9.23	$12.35	$9.26	$8.21	$7.98
TOTAL	$8.91	$27.14	-$2.46	$38.63	$8.79	$10.49	$35.52	$5.09	$2.29	$4.52	$0.16

NPV of Benefits (costs) Per DR Customer	Citipower	Ausgrid	SP AusNet	Endeavour	Energex	Ergon	Essential	Jemena	Powercor	SAPN	United
Reduced wholesale prices	$2,401.36	$1,157.31	$1,814.13	$5,668.11	$2,177.97	$1,951.13	$4,290.92	$1,786.71	$2,911.40	$1,994.81	$1,226.74
Allocation of costs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Revenue generated by DR providers	$638.94	$4.66	$638.94	$4.66	$945.44	$945.44	$4.66	$638.94	$638.94	$708.80	$638.94
Network Benefits	$4,016.96	$232.22	$1,623.16	$730.01	$612.00	$850.45	$1,675.77	$2,049.15	$2,543.30	$1,648.65	$1,261.32
TOTAL	$7,057.26	$1,394.18	$4,076.23	$6,402.78	$3,735.41	$3,747.02	$5,971.35	$4,474.80	$6,093.64	$4,352.27	$3,127.01

Source: OGW analysis

The results show that while the distributional impacts are not particularly material, the DRM does provide benefits to all customer classes across the three scenarios tested (though this does not necessarily mean that all customer classes would have net benefits under all possible combinations of cost and benefit allocation) case. DR providers achieve benefits in the thousands over the period, while the net benefits to residential and commercial customers is generally only in the tens of dollars. The primary benefit to DR providers is the wholesale market payments at spot price when they provide DR. For the other customer classes, the benefits are the sharing of the network cost reductions due to lower peak demand and the impact of the reduction in the price of electricity at the wholesale level.

It should be noted, however, that the definition of the customer classes used was constrained by the nature of the information available from distribution companies regarding their sales. We have used the following:

- those customers on demand tariffs have been taken as constituting the customers eligible for the DRM; this will:
  - undercount that population as it is unlikely to include many customers between 100 and 160 MWhpa, and
  - under-estimate the income benefits to those who participate in the DRM because it spreads the DR spot price income across all such customers;
- those non-residential customers that are not on demand tariffs have been defined as commercial; this is likely to undercount those customers; and
- residential customers have been classified as residential.

It should also be noted that the pool revenue income earned by the DR providers enabled by the DRM represents a gross wealth transfer from generators to DR providers. The net wealth transfer, assuming the generators are not subject to take-or-pay fuel contracts, would be equivalent to the gross wealth transfer less the cost not spent on fuel for the amount of generation displaced by DR.

1.3. Qualitative factors

1.3.1. Non-quantifiable benefits

The most significant non-quantifiable benefit of the DRM is its potentially considerable impact on competition. At present, a customer seeking to exercise DR has only three basic ways to do so:

- Take full or partial exposure to pool price
- Participate in a DR program offered by the customer's serving retailer.

Full spot exposure can be undertaken by the customer on their own and essentially precludes any involvement by a retailer. This is not a viable choice for most customers due to the significant costs it imposes on the customer in needing to monitor pool price in order to manage consumption and costs. Most end-use customers are simply not capable technically of doing this and the cost of electricity as a percentage of total business cost does not justify the amount of resource that would be required for the level of reduction in business cost to be gained. The limited applicability of this approach even to large, sophisticated and technically capable customers is evidenced by the very small number of customers that have ever taken up this option. It also sacrifices the benefits the customer derives from the services a retailer provides.

Full or partial spot exposure can also be undertaken through a retailer. However, while this potentially limits the amount of load exposed to the spot price, it does not reduce the price risk inherent in pool price exposure. This will then require either that the customer monitors pool price (with the costs and risks discussed above) or that the retailer provides that service.

It should also be noted that spot price exposure offers the ability to reduce costs – but at the risk of incurring higher costs. Retailer DR programs and the DRM both change that risk profile. Through either type of program the customer can gain revenue if they reduce consumption when prices are high, without incurring the risk of higher costs in the event they cannot reduce consumption at those times[12].

However, the difficulty with retailer DR programs according to large customers is that the retailers often do not call for DR when pool price is at a level at which the customer is prepared to reduce load, and that the retailers retain what the customers feel is a disproportionate share of the pool price arbitrage.

More generally, except by taking pool price exposure directly with the market, the customer can only provide DR through the serving retailer. Essentially, the retailer can exercise monopsony power. And given the fact that the base price of energy in their retail contract is likely to be more important that the opportunity to provide demand response, it is quite likely that the customer's DR potential will be a secondary concern in the vast majority of cases.

12 Unless perhaps if they are participating in a demand response event and increase their consumption – but this would probably be unlikely, given notification of the event and their agreement to reduce load during it.

In this regard, the DRM would open that DR potential to competitive offers without any impact on the choice of retailer for basic electricity supply. Such competition would appear to increase customer choice and reduce retailer market power. It would provide a more competitive marketplace for DR as a commodity.

1.3.2. Options for reducing costs

A significant issue with the DRM is its cost under the current design. There would seem to be options for reducing these costs, however.

The most attractive one would be to not make the program mandatory for retailers but rather to rely on competitive forces within the retail market. Such an approach would require that AEMO undertakes the IT modifications required for it to implement and administer the DRM, but then simply allow retailers to enter into DRM services on a voluntary basis – essentially, if they could make an internal business case for it on the basis of its ability to increase their customer base, top-line or bottom-line revenues, or simply help to position or differentiate them in the market.

There is certainly at least some reason to expect that such a business would come forward, given that there are several retailers in the market that actively present themselves as being interested in offering demand response opportunities to their customers, as well as several non-retail businesses offering specialist services in demand response or related areas.

Such an approach would avoid imposing large IT costs on all retailers and would much better match cost incurrence with DRM uptake. If participation in the DRM remained small, it would be expected that DRM expenses would also be small. In any case, these costs would only be incurred where the retail business felt it was justified by the benefits they would receive. Perhaps as importantly, such an approach would encourage retailers to undertake only those costs necessary to provide the DRM service, and to do so as efficiently as possible.

In the event that no retailer opted to offer the DRM, other approaches could be considered including not pursuing the matter, or creating a DRM retailer of last resort and auctioning off the role.

Such an approach would also allow synergies to be captured between the IT system changes needed for the DRM and those required for other initiatives currently under consideration, in particular Multiple Trading Relationships and Embedded Networks.

An alternative approach for matching costs and benefits would be to defer implementation of the DRM until such time as a sustained period of growth in peak demand could be seen to be developing. This would avoid the significant costs of the current design of the DRM being incurred at a time in which its benefits (as suggested by the market simulation modelling undertaken in this project) are likely to be very small.

On balance the former approach would seem to be preferable as it (a) relies on market forces, (b) would provide a softer start to the DRM thereby allowing learnings to be integrated prior to any problems incurring major costs or dislocations in the market, and (c) allows the benefits of the DRM – including its competition benefits as well as the potential benefits it offers to individual customers – to commence earlier.

1.3.3. Ancillary services

The DRM has also been seen as having the potential to support new suppliers in ancillary services. This has not been tested quantitatively, but to the extent that the DRM raises awareness of the potential and provides another source of revenue for DR, it could be expected to do so.

It is also understood that the costs of opening ancillary services to third-party aggregators are unlikely to be very high given there does not appear to be a requirement to change retailers' billing and customer information systems. Based on that, and the fact that (a) opening the provision of ancillary services to third-party aggregators would introduce competition to another commodity currently controlled by the serving retailer, and (b) providing this option would also have the potential to reduce the additional costs (at least for AEMO) of implementing the DRM, there do not seem to be strong reasons not to implement this initiative.

1.4. Conclusions

Of necessity the various analyses undertaken in this study have had to rely on a number of assumptions, which are discussed throughout the report. Some will result in over-estimation of the impacts of the DRM and others will result in under-estimation. On balance, we do not feel that the impacts of the assumptions that have been made materially affect the outcome of the analysis in either direction.

More generally, the analysis suggests that the DRM would be likely to achieve several of the objectives that were put forward for it, as discussed in Table 7 below.

Table 7: Likely impacts of the DRM on the objectives put forward for it

Objective	Likely result of the DRM
Greater opportunities for large energy users to reduce their net energy costs and seek more competitive offers for their demand response	The DRM would certainly increase the options for large energy users to use their DR capabilities to reduce their energy costs
Reduced wholesale market costs for all users through greater market competition, potentially also resulting in deferred investment in peak generation	The results of the modelling indicated that the DRM can be expected to exert downward pressure on wholesale market prices, and has the potential to defer investment in peaking generation under conditions where such capacity additions might otherwise be required by growth in peak demand
Deferred network investment through both reduced system-wide peak demand and flow on impacts for network support services of a stronger demand response market	The DRM has the potential to provide flow-on benefits to networks through reduce peak demand at a system and spatial level, but the degree to which it will provide this depends to a large extent on the number and nature of pricing and DR activities undertaken by the networks themselves
Potential to reduce volatility in demand and support new suppliers in ancillary services markets	The results of the modelling indicated that the DRM could assist in reducing demand volatility, and it is very likely that the DRM would support new suppliers in the ancillary services market

The results of the modelling suggest that the DRM would exert downward pressure on wholesale electricity prices and have a flow-on impact to networks. It would certainly assist large energy users in reducing their energy costs and have flow-on benefits on network peak demand.

It is also consistent with competition principles and would open the potential for new and innovative services.

The cost of the DRM as it is currently designed and assumed to be implemented is very high, however, and the current forecast significantly limits its ability to defer capital expenditure on new generation infrastructure for the simple reason that very little additional capacity is expected to be needed over the next 10 to 15 years[13].

There are ways to reduce the costs of the DRM, particularly by allowing its use in the market to evolve due to competitive market forces, and to seek to achieve synergies with other initiatives that are currently being considered for implementation, most notably Multiple Trading Relationships and Embedded Networks.

Where those costs can be managed the DRM has the potential to allow DR to serve as a competitor to peaking generation. Where it can do so successfully – that is by offering a reliable source of generation at specific price points that allow it to compete in the contract market – it will offer an alternative to peaking generation that has the potential to provide material benefits to the market and all consumers in addition to the end-use customers that provide it.

13 Other than the return of capacity that has recently been withdrawn or that may be withdrawn in response to the current stagnant demand growth.

2. Project background and purpose

2.1. Background

In January 2013, the Standing Council on Energy and Resources (SCER) directed the Australian Energy Market Operator (AEMO) to develop a rule change proposal on a Demand Response Mechanism (DRM) for submission to the Australian Energy Market Commission (AEMC) by 15 December 2013. This proposal originated as a recommendation from the AEMC's *Power of Choice* review.

The DRM was intended to facilitate large energy users to participate in the wholesale market as though they were non-scheduled generators, and receive reimbursement for reducing energy demand in response to high price events. It was designed to increase demand side participation by large energy consumers. The range of potential benefits from such a scheme was assumed to include:

- greater opportunities for large energy users to reduce their net energy costs and seek more competitive offers for their demand response;
- reduced wholesale market costs for all users through greater market competition, potentially also resulting in deferred investment in peak generation;
- deferred network investment through both reduced system-wide peak demand and flow on impacts for network support services of a stronger demand response market; and
- potential to reduce volatility in demand and support new suppliers in ancillary services markets.

As part of its development of the rule change proposal requested by SCER, AEMO convened a set of working groups to develop a design under which the DRM would be implemented and administered. In parallel with this the Energy Retailers Association of Australia undertook a survey of its members to estimate the likely cost of implementing the DRM as described in the detailed design document.

When the AEMC analysed a possible DRM, peak and average electricity demand were assumed to increase at a steady growth rate. Additional energy infrastructure, such as generation and network assets, would hence be required to meet this growth. In such circumstances, the DRM could potentially assist in providing a cheaper option to meet system reliability requirements, resulting in economic benefits by deferring investment in this energy infrastructure. Since that time, energy demand has shown a trend of flattening and declining. As such, there is a lower projected need for capital investments in additional energy infrastructure, which may in turn reduce the potential benefits of the DRM.

In December 2013 AEMO wrote to SCER seeking further advice on whether to submit the proposed rule change. Ministers agreed that officials should undertake further work on the DRM, including a cost benefit study. As such, the then SCER requested that officials undertake an analysis, including a cost benefit analysis, to re-evaluate whether or not there are net economic benefits associated with introducing a DRM under current circumstances.

Appendix A contains a copy of the Terms of Reference for this study.

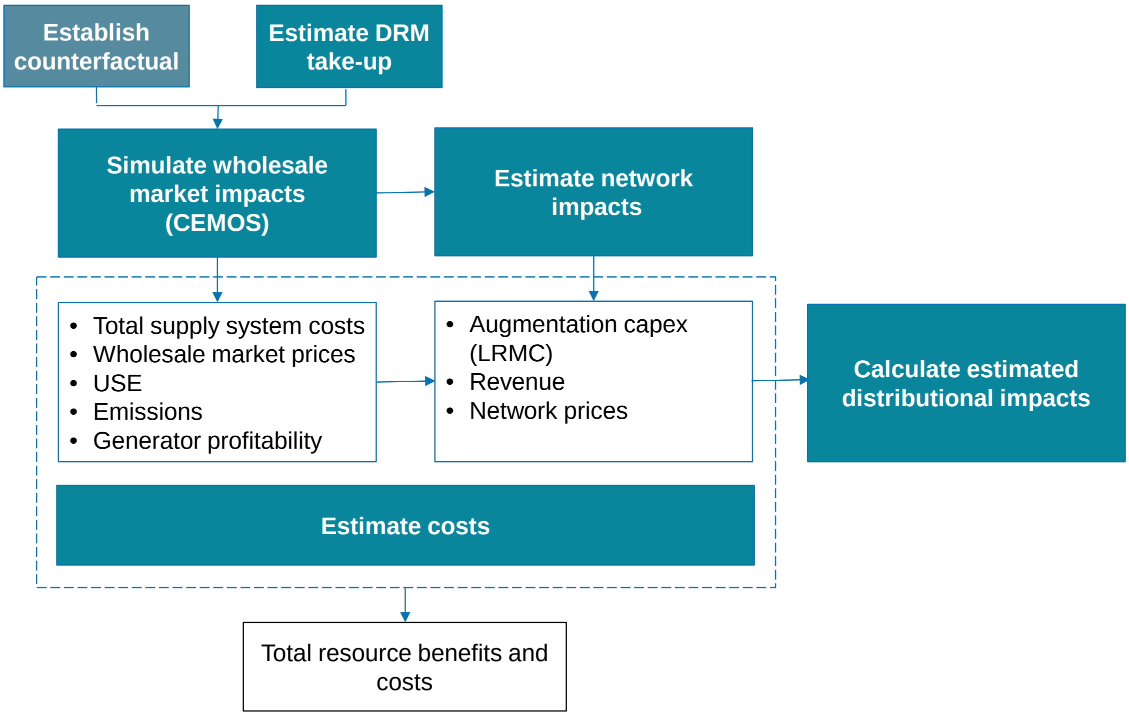
2.2. Objectives of the study

Oakley Greenwood was commissioned to assist officials undertake the cost benefit analysis to re-evaluate whether or not there are net economic benefits associated with introducing a DRM under current circumstances. Results of the assessment and associated information/reasoning are expected to support decisions by the COAG Energy Council on whether it should proceed with the development of a Rule Change proposal based on the merits of implementing the DRM now (or possibly later), whether it should be in its originally proposed form, or whether certain changes to the DRM should be considered that might improve its cost-efficiency.

2.3. Overview of approach

Figure 2 below provides an overview of the approach used in undertaking the quantitative cos-benefit analysis.

Figure 2: Overview of the approach taken to the cost-benefit analysis



Further information regarding the methodology and analysis undertaken in each of the other steps shown in Figure 2 are presented in the following sections of this report.

2.3.1. Specific activities to be undertaken

The following summarises the specific activities that were undertaken in each part of the approach illustrated in Figure 2 above.

- Development of the counterfactual (i.e., the 'without DRM') – The first step in the approach considered what could be expected to occur in the absence of the DRM being implemented. More detail on the key issues addressed in developing the counterfactual and the approach adopted for defining and quantifying the counterfactual is provided in Section 3.

- Estimation of the incremental provision of DR under the DRM – Once the counterfactual was defined, the incremental impact of the DRM was assessed. This included the development of a take-up model that incorporated information on the technical potential for DR of different types within the eligible customer base, and the minimum spot price at which these customers (or segments within this customer group) can be expected to provide DR.

  More detail on the key issues concerning the development of projected take-up of DR under the DRM is discussed in Section 4.

- Assessment of the impacts of the incremental DR on wholesale market outcomes – This was undertaken using the CEMOS market simulation model over the period from 2015 through 2034. CEMOS is a linear optimisation model set up to examine the NEM in either of two modes: least cost analysis or market behaviour analysis. In the former, the model uses only predicted costs for the capital and operation of different types of generation plant to determine the operation of and additional investment in plant for the market. The model then makes decisions regarding the dispatch of plant and the need to introduce additional plant purely on the basis of minimising cost. The decision to introduce additional plant is made on the basis of a reserve margin provided as an input to the model. As a result, when run in the least-cost mode, the model cannot determine the market price of electricity. In the market behaviour mode, by contrast, the model forecasts likely generator bidding behaviour in the NEM and makes investment decisions based on the expected profitability of future price outcomes. As a result, market price outcomes are available as outputs. The cost of investment and operation across the generation sector is available in both modes, along with information on all other relevant operating parameters of the generation system.

  This study used the market behaviour configuration which includes a Cournot-Nash profit maximising algorithm to determine generator bidding behaviour. The Cournot-Nash algorithm takes account of generation portfolios and determines the price that should be set for each generator such that the price-volume trade-off is optimised. The optimisation is such that at the equilibrium: (a) any generator that offers a higher price will lose more revenue due to reduced dispatch volume than it gains from a higher market price, and (b) any generator that offers a lower price in order to increase its dispatched volume will wind up with lower total revenue due to the lower market price.

  In the market modelling DR was characterised as a plant (or series of plants) based on the financial and operating characteristics of different types of DR. The primary financial parameter considered was minimum dispatch spot price. Operating parameters included minimum notice period, minimum and maximum run period in any particular dispatch event, and maximum hours of dispatch per year or season.

  Section 5 discusses the key issues involved in assessing the wholesale market impacts of the DRM, the approach we used to address them within the study, and the results obtained.

- Assessment of the impacts of the incremental DR on network costs – Once the impacts of the dispatch of incremental DR under the DRM were determined in the wholesale market modelling, its impacts on network costs were estimated by reference to the coincidence between the timing of trigger prices in the wholesale market and the timing of peak demand in the various network service areas.

  The key issues involved in assessing the impact of the DRM on network costs, the approach used and results obtained are presented in Section 6.

- Estimation of the costs likely to be incurred in implementing and administering the DRM – Information was sought regarding the costs that would be expected to be incurred by AEMO and electricity retailers due to the DRM. This included consideration of the costs required to develop and implement the processes and systems needed to implement the DRM, plus the costs of running the systems and procedures in order to administer the operation of the DRM over the study timeframe.

  Section 7 discusses the information that was available to assess the costs of the DRM under different assumptions regarding its design and implementation.

- Assessment of the distributional impacts of the incremental DR attributable to the DRM – The DRM may change wholesale prices and network costs and therefore network charges. To the extent that it does, the DRM will affect the bills of other (and potentially all) electricity consumers in addition to those of the customers that participate in the DRM itself. The costs associated with the implementation of the DRM may also affect the bills of customers other than those that participate in the DRM, depending on how those costs are recovered.

  The issues involved in assessing the distributional impacts of the DRM, the approach adopted for doing so and the results of the analysis are discussed in Section 8.

- Consideration of other potential but essentially qualitative benefits of the DRM are discussed in Section 9.

- Section 10 considers the somewhat separate issue of whether and the extent to which third-party aggregation of demand response in the provision of ancillary services should be considered as a possible extension to the 2010 Rule change that allowed Retailers to aggregate the demand response of their customers for that purpose.

- Section 11 provides the conclusions of the study.

3. Counterfactual

3.1. Objectives and key issues

In order to assess the impact of the DRM over the study timeframe, consideration needs to be given to the counterfactual - that is, the conditions that would pertain in the market in the absence of the DRM and the amount of DR that would be expected to occur under those conditions.

This included consideration of:

- the amount of DR already being made available in the NEM, plus likely growth in that amount absent any of the considerations discussed below;
- the likely impacts of policies and mechanisms that have only recently been put in place, such as the RIT-D, and the requirement that distribution businesses (DNSPs) develop demand management strategies, the impacts of which have not yet become apparent or incorporated into forecasts;
- the likely impacts of policies and mechanisms that are currently under consideration, but whose implementation and therefore impacts are uncertain, an example of which is the potential for regulatory reform requiring that DNSPs implement more cost-reflective pricing structures; and
- other potential developments, such as increased involvement on the part of retailers in enlisting their customers in DR programs and actively dispatching that capability.

Each of these is considered in further detail in the following section.

3.2. Elements considered in developing the counterfactual

The following sections provide additional detail regarding each of the elements that was considered in defining the counterfactual and determining the amount of DR that could be expected to occur in the absence of the DRM.

3.2.1. The amount of DR being provided into the wholesale market at present

This level of DR has come into existence without the features of the DRM, and therefore should be considered to be part of the counterfactual unless there is some reason to believe that either:

- this DR (or some portion of it) would be removed from the market in the absence of the DRM; or
- the DRM would increase the amount of DR being provided by those end-use customers currently providing DR, which could occur if the DRM increased the benefits received by those customers or reduced the transaction costs incurred by customers wishing to provide DR into the market.

3.2.2. The impact of policies and programs that have recently been implemented or that are actively being considered

Recently implemented policies and programs

Examples of such policies include (but are not limited to):

- Implementation of the RIT-D, under which electricity distribution businesses are required to actively engage with customers and third parties to seek out non-network alternatives (including demand response) to network augmentation when making network investment planning decisions in which the estimated cost of the most expensive credible option exceeds $5 million.
- The requirement that electricity businesses develop, publish and follow through on a demand management engagement strategy.

These measures have only recently come into effect, and as a result, what their impacts are likely to be as they become integrated into business as usual is not yet clear. However, there is reason to believe that they could affect the wholesale market in several ways: (a) demand response activated to defer network augmentation may impact peak demand and/or high spot market prices directly (to the extent that the times of peak network demand coincide with times of high wholesale market price), or (b) simply activate demand response capabilities that can also be used at times of high wholesale market price.

Policies and programs under active consideration but not yet implemented

Examples in this regard include (but are not limited to):

- The Distribution Network Pricing Arrangements rule change, the objective of which is to improve the arrangements within the National Electricity Rules around how distribution businesses set and structure cost reflective network prices.
- The Rule Change proposal that AEMO has been tasked with developing by the Standing Council on Energy and Resources (now called the Energy Council), which would allow multiple trading relationships (MTRs) at a single connection point, and thereby potentially allow end-use consumers greater flexibility in entering into arrangements that would maximise the benefits they could derive from their ability to seek the best competitive offer for different parts of their energy load.
- The Demand Management and Embedded Generation Connection Incentive Scheme (DMEGCIS), which is already in place but according to the AEMC's *Power of Choice* review has not had much impact to date and therefore which should be amended[14]. A Rule Change to improve network incentives to develop and pursue DSP as an efficient alternative to capital investment has been submitted to the AEMC. This includes permitting the network businesses to retain a share of the non-network related market benefits arising from the DSP option.

Consideration of the merits and feasibility of including recently implemented policies and programs and those under active consideration in the counterfactual

In considering the importance to the counterfactual of the various policies that have recently been implemented or are currently being considered for implementation the following considerations were material:

- RIT-D and associated requirements for NSP involvement in demand-side activities – These requirements have already been implemented and are being progressively taken up by NEM DNSPs. We are not aware of any forecast of the amount of DR likely to result from the RIT-D, but make the following observations:

14 AEMC, *Power of Choice review - giving consumers options in the way they use electricity, final report*, 30 November 2012, p 206.

  - The demand forecasts that have been produced by AEMO and a number of DNSPs over the last several years indicate that growth in overall electricity consumption and peak demand are both slowing, indicating that the need for network augmentation will almost certainly be less than had been forecast at the time the RIT-D was proposed.
  - If cost-reflective network pricing is implemented (see the discussion of Distribution Network Pricing Arrangements below) it will reduce the impact of the RIT-D. This is because the cost-reflective price would be based on the long-run marginal cost (LRMC) of network services, which is comprised almost exclusively of the cost of additional capacity required to meet incremental load. This in turn will reduce the impact attributable to the RIT-D, because, in this case, the incremental value of DR would be reduced to the difference between the LRMC of capacity in the local area as compared to RIT-D value[15].
  - It is also the case that (a) local network areas do not necessarily experience their peak demand at the same time that high spot prices occur in the jurisdictional pool price, and (b) as currently implemented, RIT-D payments tend to apply for only limited duration (generally one to two years), due to their SRMC basis. Once the augmentation has been required the SRMC reduces to virtually zero and DR is not needed until the next augmentation nears. While the DRM would provide a means for this DR to then be used in the wholesale market, it would be difficult to identify the DRM as the factor that brought this DR into being.

  As a result of the considerations above, we did not think it was critical to assess the impact of the RIT-D as part of the counterfactual.

- Small Generator Aggregator Framework – This change in the Rules, enacted in November 2012, creates a new Market Participant that is able to receive spot price on behalf of a portfolio of generators that are exempt from the requirement to register with AEMO due to their small size, and therefore can operate as non-scheduled generation. The change was undertaken to reduce the costs faced by these generators. To date eight organisations have registered themselves with AEMO as SGAs, but total capacity represented by these participants remains very small. Given that (a) to our knowledge, the NEFR does not explicitly forecast increased generation due to the SGA, and (b) it would be extremely difficult to definitively allocate attribution of increased participation of small generators in the market to either the SGA or the DRM, we did not explicitly account for the SGA in the counterfactual. We also note that the level of incentive provided by the SGA and the DRM to the owners of small generating plant differ substantially. However, the DRM adds considerably to the potential scope of the aggregator business model, and therefore is likely to provide more impetus for these resources to be pursued.

15 The magnitude of this difference will be greater where the RIT-D is based on the SRMC of the local area as compared to its LRMC. Current practice is to use SRMC in RIT-D applications, but the Distribution Network Pricing Arrangements appear to have put greater emphasis on LRMC-based pricing. This mix of the use of LRMC and SRMC approaches to signalling the cost of augmentation may be a matter that attracts additional consideration as the pricing reforms are put into practice.
It is also the case that different parts of the network will experience peak demand at different times of day (for example, areas that are dominated by commercial establishments will likely experience peak demand in the mid to latter part of the afternoon, whereas areas dominated by residential loads will experience peak demand in the late afternoon to early evening. Similarly, parts of a network that on average peaks in the summer may have local peak demand in the winter -- such as the snowfields in Victoria. In such cases, the RIT-D can provide a means for addressing these differences where the cost-reflective price signal is postage stamped.

- Distribution Network Pricing Arrangements – This Rule change proposal was initiated in November 2013, and was put into place in a final determination that was published in November 2014. The Final Determination sets out significant changes to the rules on how distribution network businesses are to develop and structure their prices, the objective being that network prices better reflect the costs of providing network services to individual consumers. Specifically, under the Rule change, each network tariff must be based on the long-run marginal cost of providing the service. This will mean that there will likely be more attention to price signals concerning coincident peak demand. The modelling was done assuming the final Rule would be very similar to the draft determination, published in August 2014.

  One such pricing signal already exists in the NEM – AusNet Services' Critical Peak Demand Tariff. The CPD tariff was introduced in 2011 to replace the company's Any Time Demand (ATMD) tariff. The objectives of the CPD tariff are to:

  - decrease demand on the network at times when demand could exceed design capability,
  - reduce investment requirements,
  - increase supply reliability, and
  - provide an opportunity for customers to reduce their electricity costs.

  The critical features of the CPD tariff are as follows:

  - it is mandatory for all customers (~ 2000) with annual consumption greater than 160 MWh
  - it measures the customer's average demand between 2:00 and 6:00 PM (AEST) on five CPD days identified by AusNet Services during the months of December through March (inclusive) each year (note that the specific days will change from year to year)
  - that average sets the critical peak demand component of the customer's tariff for the following 12 months (April through March) – the CPD component of the tariff comprises, on average, between 15% to 20% of the annual bill of these customers
  - AusNet Services provides up to 7 days advance notice of a 'potential' CPD day, based on Bureau of Meteorology forecasts of extreme or consecutive days of hot weather, but in any case will never provide less than 24 hours' notice of a CPD day.

  Results in the 2012-13 summer were as follows:

  - just over 9% of customers reduced their demand on the 5 nominated days by 40% or more;
  - just over 25% reduced their demand by 10% or more;
  - the average total demand reduction over the 5 days was between 50MW and 60MW, representing approximately 7.3% of total group peak demand and approximately 5% of total network peak demand;
  - 67% of customers experienced no increase in their CPD as compared to their ATMD;
  - the average increase in CPD for the remaining customers was 6.7%, and for half of these customers the increase was less than 5%

  It is also important to note that:

  - the implementation and administrative costs of the CPD tariff to AusNet Services have been low,

- the metrology required to support this type of pricing is already in place for virtually all customers with annual consumption above 160 MWh.

  In short, the CPD provides a very good model of how DNSPs could easily and quickly comply with the intent of the Distribution Network Pricing Arrangements Rule Change. Given that this type of pricing is highly relevant to a very large percentage of the load that would be eligible to participate in the DRM (though a smaller proportion of the total number of customers), we used the results of the AusNet Services CPD tariff as the basis from which to extrapolate the NEM-wide impact of cost-reflective network pricing from 2016 within the counterfactual. It should be noted that this is likely to overstate the amount of DR produced by cost-reflective network pricing, at least in the early years of the analysis, as it assumes that all networks in the NEM would put in place such pricing from 2016[16] and achieve similar results as those achieved by AusNet Services in the first year of the tariff going into operation.

- Connecting Embedded Generators – This Rule change proposal was initiated in May 2014 and a Draft Determination was published in August 2014. The Draft Determination provides eligible embedded generator proponents a choice of framework to use when negotiating connection to a distribution network. The choice enables the embedded generator proponent to use the process that best suits his needs and is expected to result in more efficient and timely investment decisions and connections.

  This Rule change, if enacted, is expected to improve the investment environment for and reduce the time required to arrange a connection for embedded generators of 5 MW or less. Our view is that the magnitude of the expected reduction in delays will not be material for the cost-benefit assessment of the DRM (particularly as it will affect the 'with' and 'without DRM' cases equally). And while we agree that the improved investment environment is likely to increase the total amount of embedded generation that is connected, this increment is essentially impossible to quantify with any degree of accuracy. As a result, we ignored this Rule change in quantifying the counterfactual.

- Bidding in Good Faith – This Rule change proposal was initiated in April 2014; no position has been taken on it as yet by the AEMC. As part of its consideration of this Rule change proposal the AEMC is currently assessing, among other things, the impact of late re-bidding on DR. While it is likely that late re-bidding may present challenges to DR, there is no reason at this point to assume that the presence of late re-bidding degrades the potential returns from DR to the point where DR would no longer be able to be seen as cost-effective. On the other hand, if that were found to be the case, it might be taken as a reason to consider more seriously options for limiting its use. In addition, we note that the occurrence of late re-bidding is extremely difficult to model in long-term simulations of the wholesale market. As a result, we left consideration of late re-bidding out of the construction of the counterfactual.

- Competition in metering and related services – This Rule change proposal was initiated in April 2014 and would make the provision of meters and metering services competitive functions within the NEM, with responsibility for their provision placed with the serving Retailer. Metering and metering services are already competitive functions for medium and large non-residential customers; the Rule change would extend this approach to small non-residential and all residential customers, replacing the DNSP as the provider of these services to these consumers.

[16] Under the final Rule, network prices determined under the new pricing principles will begin in 2017, not 2016.

We note that the impact of improved metering and metering services to these customers does not affect consumers who are targeted to be eligible for the DRM and can be expected to equally affect the counterfactual and with DRM cases of the cost-benefit analysis. As a result, we did not take account of this Rule change proposal in constructing and quantifying the counterfactual.

- Multiple Trading Relationships (MTR) – This possible Rule change would provide end-use consumers the flexibility to enter into arrangements with more than one retailer (or other electricity supply entity) through a single connection point. This would provide arrangements that are similar in some respects to the DRM but would not provide the essential ingredient of allowing the end-use consumer to receive payment at spot price for demand reductions.

  Given this, and because a Rule change proposal regarding the MTR has not been submitted as yet, we do not see it as a material concern with regard to the potential impacts of the DRM. However, if implemented, it would require a number of IT system changes very similar to those likely to be required to support the DRM. Therefore, if contemplated for implementation at around the same time as the DRM, it should be considered as part of the counterfactual in terms of the costs of implementing and administering the DRM.

3.2.3. Increased engagement in DR by electricity retailers

It is certainly possible that electricity retailers will become more actively involved in DR even if the DRM is not implemented. Some developments in this regard have taken place with one gentailer and one pure-play Retailer using demand management as a prominent service offering and a key element in their acquisition strategies. Such involvement may be easier and more attractive given the improved availability and performance of, and cost reductions in, DR, controls and communications technologies.

It is also possible that the real or potential competition fostered by the DRM may encourage more active participation by Retailers in DR as a means for retaining market share.

3.3. Counterfactual cases adopted for use in the CBA

Based on the considerations above, three counterfactual scenarios were developed, as follows:

- The current AEMO forecast, as defined in its *2014 National Electricity Forecast Report*;
- The current forecast, as defined in AEMO's *2014 National Electricity Forecast Report*, but with the assumption that a robust form of cost-reflective network pricing (CRNP)[17] is universally adopted by all network businesses within the NEM by the beginning of FY2016; and
- An illustrative capex requirement scenario, in which it will be assumed that
  - the significant over-supply of generation has been absorbed and installed capacity levels are more like longer term averages, and
  - average annual growth rates in both peak demand and overall electricity consumption are similar to those experienced in the period 1998 -2008.

  It is important to note that:

17 AusNet Services' Critical Peak Demand tariff which has been in place since 2011 served as the model for this tariff and the impacts that could be expected to result.

- the ‘Illustrative capex requirement’ scenario was developed solely to assess the impacts of the DRM under conditions under which it would be expected to offer significant benefits, and
- while the conditions assumed in this scenario are plausible (in that they have existed in the recent past), they are not conditions that are expected to exist in the near- to mid-term.

4. DR potential and DRM take-up

4.1. Objectives and key issues

The level of incremental DR likely to be made available by the introduction of the DRM was a critical aspect of the study.

The specific key issues that needed to be addressed in seeking to model the take-up and impacts of the DRM are as follows:

- understanding the technical potential for DR and the criteria affecting its actual take-up and therefore its economic and market potential within the eligible customer segments (i.e., non-residential customers with annual electricity consumption of 100 MWh or more), which also required:
    - identifying the number of eligible firms (load) able to provide DR at the time of peak demand;
    - including and taking account of the associated investment and opportunity costs of DR provision; and
    - establishing the price responsiveness of DR;
- understanding the counterfactual, which will affect the additional take-up of the DRM as compared to the gross take-up of DR within the market;
- accurately reflecting the nature of the mechanism and how it will function in the NEM, including understanding how the commercial business model of Demand Response Aggregators (DRAs) is likely to affect take-up; and
- reasonably accounting for the load and price duration curves that are likely to pertain in the market.

4.2. Data sources and methodology

To date most investigations of demand-side potential in the NEM (or Australia more broadly) have included demand management and energy efficiency and to some extent fuel switching. Only one study – ClimateWorks' study entitled *Industrial demand side response potential*, which was completed in February 2014 for the Department of Industry – has specifically sought to define the technical and economic potential of DR itself.

The primary information sources for the estimation of the amount of demand response likely to result from implementation of the DRM were:

- The February 2014 ClimateWorks study, from which the demand response potential of the industrial sector was estimated;
- ABARE and ABS information on the energy consumption of twelve different ANZSIC Divisions within the commercial sector from which the likely peak demand and demand response potential of these customers was estimated;
- Information from the ClimateWorks study and other sources (including state government data) was used to assess the amount of standby generation available in the various NEM jurisdictions.

The ClimateWorks information was used to provide base data sets, and the ABARE and ABS data was used to allocate the amount of DR identified by ANZSIC to the NEM jurisdictions (from the Australia-wide base used in the ClimateWorks study). ClimateWorks, ABARE, ABS data and the professional experience of members of the OGW project team were used to extrapolate the DR potential of smaller industrial firms and commercial firms.

Information from

- AEMO on the amount of DR currently available in the NEM and information on DR take-up in other jurisdictions was used to estimate the amount of DR likely to be available as a result of the DRM. Adjustments were then made to:
  - subtract the amount of DR already being provided in the NEM (as this amount would not be the result of the DRM), and
  - in the case of the CRNP counterfactual, to account for the fact that the change in network pricing (which was assumed to occur prior to implementation of the DRM[18]) would bring forward an amount of DR that would have the effect of reducing the amount of remaining DR potential that could be available to the DRM
- AEMO on the price responsiveness of the DR already present in the market was used to estimate the level of price responsiveness of the DR expected to be generated by the DRM.

The following sections of the report discuss the use of the data in estimating the likely take-up of the DRM.

4.2.1. Use of the ClimateWorks data

The ClimateWorks data was used as core information on which the DR take-up was estimated. In using this data it is recognised that:

- While the data provides solid insights into the potential practices of industry, the data sets are limited, and
- The interviews were undertaken for a different reason than assessing the potential of the DRM to increase the deployment of DR in the NEM, and therefore some key aspects in relation to the extent of predicted opportunity cost issues and the impact of notification periods are not as fully covered as we would have liked – therefore some estimates and assumptions from information obtained during discussions with stakeholders as well as the responses to the consultation paper have been used to help with the estimation process.

To address this, the ClimateWorks data was adjusted as follows:

- For industrial facilities – the level of DR expected in the NEM was identified by undertaking the following activities:

18 As noted above, CRNP was assumed to be implemented in 2016. The DRM was assumed to be implemented in 2017. These assumptions reflect the fact that (a) the rule change concerning cost-reflective network pricing has already been endorsed by the AEMC in a draft determination, and cost reflective pricing for the class of customers that would be eligible for the DRM does not require any additional equipment or software to be put in place by the network businesses, and (b) the DRM rule change has not begun to be considered as yet and would require further definition and at least some (and possibly extensive) changes in AEMO and retailer IT systems prior to being ready for implementation.

  - ABARE Table F[19] was used to obtain a percentage of energy use in the NEM vs all Australia.
  - The above allocation was applied to all industrial sectors except Alumina and Aluminium Smelting, Water and Wastewater and Mining, but includes Quarrying.
  - Alumina was assumed to have 50% activity in the NEM.
  - Aluminium Smelting was reduced to 67% of the ClimateWorks data to account for impending closures.
  - Mining operations assumed that 60% occurs in the NEM (which recognises that WA is a very significant mining State).
  - Water supply was reduced to 88% of ClimateWorks values, which is representative of population.
- Industrial facilities were looked at in greater detail as there was concern regarding the ratio of larger sites to smaller facilities in each sub-sector and whether a direct extrapolation was appropriate. ABS data was used to evaluate the ratios of large, medium and small facilities based on numbers of employees and turnover.
  - Where the ratio of large to the rest was >15% then a direct extrapolation was accepted.
  - If the ratio was between 10-15% then the ClimateWorks data was further adjusted down by 10%.
  - If the ratio was <10% then the reduction was increased to 20%.
  - These percentages were purposely kept on the lower side as while the ClimateWorks data had already made an adjustment to account for the variation in size of facility and its potential to secure equivalent DR, these adjustments were made to ensure that the expected DR Take-up would reside more on the conservative side.
  - These adjustments were applied on a sector basis to each of the individual DR types within that sector.
  - It was recognised that certain DR types would be applicable in other sectors, although have not been recorded as such within the ClimateWorks data sets. This is because the interviewees had not specifically identified these activities. While it is recognised that some of the DR types would be applicable in other sectors, no attempt was made to adjust the reported numbers further to account for this and as a result, this initial level of DR Take-up should represent a conservative estimate.

4.2.2. Identification of DR in the Commercial sector

No published data on DR potential in the Commercial Sectors was available for inclusion, so an estimate needed to be generated starting from first principles. For the purposes of this evaluation, the Commercial sector is taken to include ANZSIC divisions F, G, H, J, K, L, M, N, O, P, Q, R and S.

- ABARE Table F data was used to obtain an estimate of the energy consumption in the commercial sectors nationally, in the NEM and in NSW/VIC specifically.

19 Available at http://industry.gov.au/search/results.aspx?k=Table F

- Specific ABS data on numbers of facilities, turnover and number of employees was used to allocate numbers of facilities into large, medium and small groupings and the respective energy consumptions identified through the ABARE analysis were allocated on a proportional basis.
- Reviews of DR take-up in the commercial sector, along with industry knowledge of energy allocation by end users, were used to identify key groups of activities with DR potential.
- Using average operating hours, an average demand per sector was obtained and it was assumed that actual demand would build through the day with the higher ranges of contribution occurring during the critical system peak periods. To allow for this, 150% of the average demand was taken as actual contribution to critical system peak.
- Typical end-user lists were reviewed to identify the type and potential magnitude of their contribution to the peak.
- Based on industry knowledge of areas where DR could be possible, along with identified researched data, the potential for DR and an estimate of the probability of participation were identified to obtain the estimated level of DR take-up. (A range of documents, including "*Building Our Savings: Reduced Infrastructure Costs From Improving Building Energy Efficiency", Institute for Sustainable Futures & Energetics* and *"Demand Response in Commercial Buildings" Institute for Building Efficiency*, along with results obtained from analysis of a variety of client reports, were referenced to establish these estimates.
- The aggregated DR potential for the large facilities was used for the Base Case, while the Medium and Large facility information was used for the High Case.

4.2.3. Estimate DR potential for standby generation

Limited data was available relating to the quantity of standby generation installed across the NEM States, however, some documents were useful in establishing a baseline estimate. The steps included:

- For Commercial:
  - Use of various surveys and studies to obtain an indication of levels of standby available (e.g. DEUS Survey in NSW).
  - The reported available standby generation and surveyed number of small generators that were identified in available reports were used to establish an initial estimate, which was then extrapolated to cover commercial entities across all the NEM States and was based on both sector splits and population.
  - A conservative estimate of 40% participation rate was used for the Base case and elevated to 60% for the High case.
- For Industrial:
  - The ClimateWorks project had identified a limited range of standby generation available across industry and this was used as a starting point.
  - The available standby generation was then allocated to the States based on the industrial loads.
  - The assumed participation rates were similar to those identified in the Commercial assessment.

4.2.4. Estimate of existing DR currently being exercised and estimate potential DR available through DRM

It is recognised that some DR is currently being exercised either through pricing signals or through direct engagement of customers by retailers. This step sought to establish and extract this impact from the estimated totals in order to identify the DR take-up potential available through the DRM.

- AEMO data was utilised to obtain the projects Demand Side Potential (DSP) and the maximum level was used which equated to Summer with price at market price cap (MPC)
- This maximum was then subtracted from the total aggregated Process DR estimated using the methodology identified in the sections above.
- The estimated level of (participating) standby for both commercial and industrial was added to the total.
- The resulting figure represents the total DR available through DRM (assumed to be at MPC), although it should be noted that this is a conservative estimate and the actual level of DR that could eventuate as a result of the DRM is expected to be significantly higher once the mechanism is in place.

4.2.5. Split process DR by State

The aggregated DR was split back to the State level for use in the model using the following process:

- ABARE Table F data for each sector and each State was accessed to establish allocations according to the sector splits used in this evaluation.
- The DR was proportionally split by State according to the energy use and sector data identified above.

4.2.6. Allocation of DR by group and ramp up

To establish an estimate of the speed of take up the following process was adopted:

- Break out Process DR into three groups (easy, medium and hard) based on the following criteria:
  - ‘Easy’ represents DR that is easy to implement and will not require much in the way of process change, risk of product spoilage or cost.
  - ‘Medium’ represents DR that could have an impact on production and costs.
  - ‘Hard’ represents DR that is more complex and require significant costs for controls or additional equipment.
  - Allocation is based on research data and industry knowledge.
- Standby generation was kept as a separate line item and was assumed to be available on commencement of the DRM, along with the easy DR.
- Medium DR assumed to kick in from Year 3 and introduced progressively as follows:
  - For the base case – assume 1/4 of Medium DR is available each year for 4 years.
  - For High case – assume 1/3 of Medium DR is available each year for 3 years.
- Hard DR assumed to kick in from Year 7 (for Base) or Year 6 (for High) and introduced progressively as follows:

  - For the base case – assume 1/4 of High DR is available each year for 4 years.
  - For High case – assume 1/3 of High DR is available each year for 3 years.
- The ramp up is then split by State using the same proportional allocation process as identified in the above sections.

4.2.7. DR availability as peak shifts

- Analysis of counterfactual time of peak data and process data was used to identify a practical breakpoint (identified to be 6pm):
  - Single shift industrial operations are unlikely to provide DR after 6PM as many of their operations will be winding down by 4pm
  - 2 and 3 shift operations in industrial and mining will contribute to DR even as peak shifts to hours after 6PM
  - Commercial buildings were split based on likely usage patterns, e.g. accounting firms will contribute to peak and therefore can participate in DRM before 6pm, but unlikely to do so after 6pm, while more continuous operations, e.g. data centres or hospitals will be able to participate both before and after 6pm
- Analysis and allocation of DR by sector was then reanalysed to account for a potential drop in DR as peak times shift later in the day.
  - This included a review of the sub-sectors that would be impacted as a result of the shift and their contribution to the DR total was reduced accordingly.
  - Following this the State splits were then reallocated according to the total available DR and the impact of the timing of peak and the remaining sectors were re-split based on the ABARE energy consumption data.
  - Standby generation was addressed separately to account for those sectors that may be impacted by a change in peak times and was then reallocated across the States.

4.2.8. Estimating DR price-responsiveness under the DRM

The methodology described above provided an estimate of the total DR potential available in the NEM. That had to be converted to the specific amount of DR that could be expected to be available in each year over the analysis period and the amount that could be expected to materialise at specific spot prices.

Table 8 below shows the proportions of the total DR exercised annually in the NEM since 2000 that have come forward at five specific levels of spot price, as identified by AEMO. Those percentages were adjusted, as also shown in Table 8, to reflect the incremental impact of the DRM in terms of the rate of DR provision it would drive in the market.

Table 8: Assumed percentage of total DR potential realised at different spot market prices

Trigger spot price ($/MWh)	Cumulative % of total DR potential that will respond	
	AEMO	Assumed for DRM
$300	19%	25%
$500	22%	30%
$1,000	23%	40%
$7,500	59%	80%
MPC	100%	100%

Source: AEMO *2014 NEFR,* information from other jurisdictions and OGW professional judgement

The reasoning that informed the higher proportions used to reflect the impact of the DRM was as follows:

- The AEMO data reflects DR that has been provided without the specific features assumed to become available through implementation of the DRM and as such reflects a mix of DR based on spot exposure and participation in retailer programs in which
  - the percentage of the spot price arbitrage that has generally been made available to DR providers has been around 50%, and
  - dispatch calls have not always been made at the price levels at which DR providers have said they would be willing to reduce their load.
- Most customers are not interested in spot exposure, so the majority of growth will come from customers who are likely to prefer participation through the DRM (which can offer the end-use customer a means whereby they can provide DR when it is convenient without having to take direct exposure to pool price for any part of their load on a full time basis.
- The DRM rule change would create a new category of market participant called a Demand Response Aggregator (DRA). Because the exercise of demand response will constitute the primary focus of the third-party DRAs that will be empowered by the DRM, they can be expected to offer higher levels of arbitrage to DR providers, and to call for their dispatch more regularly, which will serve to increase the percentage of the total DR potential that will become available at each of the AEMO price points.

4.3. Results

4.3.1. Take-up by NEM jurisdiction over the analysis period

Annual take-up of the total potential was assumed to occur over a ten-year period, with the no-cost and low-cost portions of the resource taken up in the first two years and 25% of the medium and higher cost portions being taken up in subsequent four year periods. Table 9 and Table 10 below show the take-up of the DR under the AEMO forecast and AEMO forecast plus CRNP scenarios. The AEMO forecast take-up was also used in the 'Illustrative capex requirement' scenario. Note that the difference in the amount of DR under the two scenarios is not a product of different price responsiveness, but rather the fact that the cost-reflective network pricing that is in place in the AEMO forecast plus CRNP scenario results in a quantum of DR being taken up prior to the availability of the DRM, and thereby reducing the potential for incremental DR due to the DRM.

Note that MW capacity was assumed to remain constant in all DRM cases after full ramp-up was achieved in year 10.

Table 9: Annual DR impacts (MW) in the AEMO forecast scenario

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
NSW	312	312	375	439	503	566	628	689	751	812
VIC	231	231	278	325	373	420	465	511	556	602
QLD	238	238	286	335	383	432	479	526	573	620
SA	72	72	87	102	116	131	145	160	174	188
TAS	71	71	85	100	114	129	143	157	171	185
NEM	923	923	1112	1300	1489	1678	1860	2042	2225	2407

Source: OGW analysis

Table 10: Annual DR impacts (MW) in the AEMO plus CRNP forecast and Illustrative capex requirements scenarios

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
NSW	217	217	257	297	337	377	415	454	492	531
VIC	156	156	184	212	289	369	422	511	556	602
QLD	238	238	286	335	383	432	479	526	573	620
SA	72	72	87	102	116	131	145	160	174	188
TAS	71	71	85	100	114	129	143	157	171	185
NEM	753	753	899	1045	1240	1438	1604	1807	1966	2125

Source: OGW analysis

4.3.2. Constructing DRM 'plants'

Once the DRM potential was established, it was organised into a series of plants that could be dispatched in the wholesale market simulation modelling (described in Section 5 below). These DRM 'plants' were constructed by state with reference to the MW capacity available at each trigger price in each year of the time frame.

Other assumptions about the plants were as follows, based on experience provided by DRAs:

- minimum spot price at which DR is assume to enter the market, based on the strike price of the underlying cap contracts, was taken as $300/MWh;
- the minimum run time of 30 minutes, the maximum number of hours per event to be 8 hours (with some drop in capacity starting at 4 hours, though we note that no examples were found in which a high-price event of 8 hours was found); and
- the maximum number of hours of DR provision to be capped at 80, though we note that high prices characterised no more than the first 5 load blocks (a total of 9 hours) in most years, and no more than the first 6 blocks (15 hours) in any year in the analysis.

5. Wholesale market impacts

5.1. Objectives and key issues

The DRM is a wholesale market mechanism with the potential to impact on dispatch and Spot Price and potential consequential impacts on wholesale market contracting and investment activity. Further consequential impacts are likely in networks due to reduced flows but also potentially increased flexibility. This section discusses the analysis of direct and indirect wholesale generation market impacts.

Like any market mechanism for DR, the effect of the DRM is expected to be limited to only a few hours per year when prices would otherwise be very high. The DRM will therefore reduce demand at high price times, reducing fuel use and other operating costs.

The presence of DRM may also reduce investment in peaking generation resulting in a reduction in capital spending and possibly rebalancing the economic mix of generation plant – but at the possible expense of a loss in production and/or amenity on the part of the DR provider. In the short term the DRM may displace and strand existing investment. Reduction in fuel cost will occur whenever DRM is exercised. However, changes in investment costs will only occur to the extent industry changes investment activity. If all DRM is opportunistic and response is not reliable or backed by some form of commercial guarantee, the DRM may have negligible impact on capital cost, as there will be no change in the cost of peaking generation required to meet aggregate demand when DR does not respond. In such a case, market price may be more volatile in that it will be lower when the DRM does respond and will need to be higher when it does not[20]. On the other hand even if each individual DR provider responded entirely opportunistically, over a large enough number of DR providers there would be a reliable response meaning that capital requirements would be less[21].

In order to assess the impact of the DRM on operation of the wholesale sector it is necessary to compare wholesale market outcomes with and without the DRM and to recognise both the timing and level of take up and carefully consider if both fuel and capital costs will be affected equally. There are a number of parallel rule and policy changes at various stages of debate that may affect the operation of the DRM. The key amongst those is the CRNP discussed in Section 3. We considered the likely impact of CRNP would be material as it may bring forward DR reducing the level available to respond to the DRM. Accordingly we ran two sets of cases to examine the wholesale market impacts, with and without CRNP.

The next section describes the methodology and data that were employed to undertake the quantitative analysis, and is followed by a description of the results of this analysis. Additional factors considered through quantitative analysis are then discussed.

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20 If we assume that generators have certain fixed annual costs, they will also have a target wholesale selling price based on their expected utilisation. Where sales volume declines (in this case due to the dispatch of DR) the target price will need to increase to compensate.

21 This reflects the portfolio effect. While the opportunistic behaviour of one or two DR providers within a region – especially if they were to be relatively large – could result in increased volatility, the behaviour of a large number of providers – even if they were relatively large and behaved opportunistically – would be likely to be less so, as it would be expected that a relatively stable percentage of them would be expected to respond in any particular event (as long as there were not one or two DR providers that were very large compared to all the others). In fact, this percentage of nameplate portfolio effect has been observed in a number of DR programs.

5.2. Data sources and methodology

5.2.1. Methodology

The impact of the DRM on the NEM's wholesale electricity market was analysed through the use of the CEMOS market simulation model. CEMOS is a linear optimisation model of the NEM and includes a game theoretic analysis of generator bidding behaviour. It allows analysis of investment (and dis-investment), dispatch, fuel use, emissions, market price, generator revenues/ profitability and generator capital and operating costs. The model is configured to examine each NEM region and flows on interconnectors.

Market outcomes with and without the DRM and with and without CRNP were run and compared.

At this point it is useful to note that the design of the suite of cases modelled was adjusted during the course of the project in light of primary results showing little wholesale market impact of the DRM. The reasons for this are discussed in section 5.3. Once this initial result was observed and confirmed we focussed on considering the conditions under which the DRM might provide material wholesale market benefit in order to test the plausibility of those conditions.

The rapidly growing level of solar PV 'behind the meter' is contributing to flattening (and in some cases falling) demand growth, and is also changing the profile of demand within each day. DR availability, particularly its incremental availability after the potential impact of CRNP is accounted for, differs by time of day. AEMO's *2014 NEFR* includes load profiles for each region over each year of the forecast. These load profiles include the expected impact of increasing rooftop PV penetration on total sent-out energy requirements, the shape of the load profile and the resulting timing of regional peak demand. We further modified these load profiles for each year in each region by the potential impact of CRNP to create a new base case for the CRNP counterfactual, and then for the incremental effect of the DRM in the 'with DRM' case.

Consistent with current Commonwealth government policy, the modelling did not include a price on carbon. In a similar vein and in order to make the modelling assumptions similar to those used in the *RET Review*, conventional coal generation technologies were included as options in the event that additional generation capacity was found to be needed to meet demand growth.

As has been the case in most market simulation modelling undertaken in the past several years, account was taken of the impact of the existing significant over-supply of generation capacity in the market. The basic problem is that the combination of the over-supply of generation capacity, the forecast softness of demand growth and the existence of the RET result in unsustainably low wholesale market prices. Generators have already responded to this by removing or reducing the operation of capacity in order to better balance supply with demand and thereby raise prices to levels that provide minimally adequate returns.

In our primary analysis, we ensured that wholesale electricity prices were plausible (i.e., would provide at least minimally sustainable profitability levels for all operating generators over the analysis period) by balancing the amount of coal, gas and renewable generation in the market. This required withdrawal of both coal and gas capacity and a reduced (and floating) level of renewable generation.[22] Withdrawal of coal and gas capacity was informed by assessment of the operational profitability levels of specific plants. In addition, in practice, the approach taken meant that the full LRET quota (i.e. 41,000GWh for LRET) was not met in the modelling.

The result of the primary analysis showed little wholesale market impact as no new generation investment is expected for around 10 years. The important implication for the DRM was that because no new generation capacity was forecast to be needed over the analysis period[23], there was simply no opportunity for the DRM to reduce generation capex – at least over the course of the 20 years analysed (2016 – 2035). To examine the impact of a situation where capital savings could take place we created an illustrative case that did require new capital where:

- the significant over-supply of generation has been absorbed and installed capacity levels are more like longer term averages, and
- average annual growth rates in both peak demand and overall electricity consumption are similar to those experienced in the period 1998 -2008.

It is important to note that:

- the 'Illustrative capex requirement' scenario was developed solely to assess the impacts of the DRM under conditions under which it would be expected to offer significant benefits, and
- while the conditions assumed in this scenario are plausible (in that they have existed in the recent past), they are not conditions that are expected to exist in the near- to mid-term future.

Another important factor contributing to the low impact of the DRM in the primary analysis is that the capacity that was withdrawn from service in order to provide minimally sustainable profitability levels for all operating generators was assumed to be mothballed rather than scrapped, and was also assumed to be able to return to operation without new capital spending. This point is discussed in greater detail in Section 5.3.

2222 The choice of which generators to withdraw is not critical to the analysis of DRM as the objective was to ensure that remaining generators were broadly covering operating costs with a small margin. In practice consideration of debt, fuel costs (e.g. contract or cost implications of ceasing to take fuel) and holding costs would be likely to impact the choice.

23 Although no new generation capacity is required over the analysis period, there is a significant amount of generation capacity withdrawn or put on a reduced operating schedule (as opposed to being permanently shut down) in the early years of the analysis period in an effort to shore up pool price. This withdrawn capacity is then available to meet the relatively modest level of growth that occurs in the latter portion of the analysis period. The modelling of this effect and its impacts on results is discussed in Section 5.3.4.

DRM inputs

The modelling also assumes that providers of DR under the DRM will offer quantities of DR in a flexible and rational manner and will also have perfect foresight in exercising DR[24]. If it is assumed that most of the incremental DR that will occur under the DRM will be managed by DRAs, it would seem likely (rational) that they would seek to bid in such a way as to maximise revenue to their client base (as this will also presumably maximise their own revenue)[25]. The assumptions about flexibility implies that in aggregate, across the available base of DR, DRAs will be able to and will dispatch only enough DR to limit its impact on the Spot Price, and certainly to avoid it changing the Spot Price to a level below the trigger price nominated by their clients (plus an allowance for their own costs and expected return). Put more simply, DRAs (or individual DR providers) will not over-dispatch DR in a way that crashes price. Rational dispatch assumes that in making dispatch decisions about dispatch of DR with minimum notice periods and minimum exercise times, the DRAs will have perfect foresight. Clearly, in practice dispatch may not be as flexible as this and DRAs will not have perfect foresight and the benefit from the DRM will be less – this is an optimistic aspect of the analysis[26].

Within the modelling, the DR to be made available under the DRM itself was modelled as a series of fully flexible virtual generation plants having the following characteristics:

- Specific trigger prices at which it will enter the market and flexibility in operations such that they can respond when those prices occur. In the model DR generation is dispatched only if the resultant Spot Price is equal to or greater than the bid prices which were determined as the trigger prices for DR. Essentially, five different DR plants were constructed in each state corresponding to the five trigger prices that had been established for DR. The capacity of each plant was determined by the take-up analysis which established the potential for DR at each price point within each NEM region (see Sections 4.2.8 and 4.3.1 for details);
- A minimum run time of 30 minutes;
- A maximum run time of 8 hours per event (though in fact no high price events of that duration occurred in the modelling); and
- A maximum of 80 hours of dispatch per year (though this threshold was also not met in the modelling)[27].

The basic inputs to the modelling were taken from AEMO’s 2014 NEFR and ESOO. These included:

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24 It should be noted that the game theoretic algorithms in the market simulation model make the same assumption about traditional electricity generators. As noted below, the DR to be provided under the DRM was treated as a generation source within the market simulation modelling, and was therefore treated similarly. If it is assumed that most of the incremental DR that will occur under the DRM will be managed by DRAs, it would seem likely that they would seek to (and over time be able to) bid in such a way as to maximise revenue to their client base (as this will also presumably maximise their own revenue).

25 It would be logical to assume that individual DR providers under the DRM would also want to maximise their revenue from DR provision. However, such customers would have to incur the expense of careful pool price monitoring, which is why it is highly likely that DRAs will manage most of the incremental DR that would come forward under the DRM.

26 In actual practice, DR dispatch will be less flexible than this and DRAs and individual DR providers will not have perfect foresight. As a result, we might not get as much DR as is assumed in the modelling, and the DR that is dispatched may in fact at times reduce Spot Price below the trigger price.

27 Note that no more than 9 hours were found with prices at or above trigger points in most years, in either the AEMO forecast or AEMO forecast plus CRNP scenarios, though in some years they occurred for up to 15 hours.

- Forecast annual sent-out electricity requirements, peak demand and load duration curves (LDCs); See AEMO *2014 National Electricity Forecasting Report (2014 NEFR)*
- Current and committed generation plant and transmission interconnections drawn from AEMO's *2014 Electricity Statement of Opportunities*; and
- Costs and operating characteristics of candidate conventional and renewable plant[28].

Table 9 and Table 10 in Section 4.3.1 above identify the total amount of DR expected to be available in each NEM region in each year of the analysis period. The proportions of the available DR that is estimated to be provided in the market at specific Spot Prices is shown in Table 8 in that same section. These two sources were combined to determine the capacity and trigger price of the DR plants constructed in each NEM region for use in the wholesale market modelling.

As described in Section 4 above, the availability of DRM varies by region, time of day and daily demand profile. The modelling considered two types of demand profile, one for the high demands represented by the AEMO 10POE forecast and the other for all other demands in the 50POE. The results for the two cases were combined in the ratio of 30:70[29]. The 10 POE and 50 POE cases therefore had different (in some cases) levels of DR available for dispatch.

Price volatility may change in the future due to changes in daily demand profile and greater levels of intermittent generation plant. Changes due to daily profile were inherently accounted for, as the profile was amended each year based on AEMO's demand profile data (as noted above). Changes in volatility were not modelled directly but assessed by changing the ratio of 10 POE to 50 POE cases. As discussed below, there was little impact in either the 10 POE or 50 POE cases (although slightly more in the 10 POE case, as would be expected) and hence we concluded changes in volatility would not be material to the benefit of the DRM under present forecast conditions.

5.3. Results

5.3.1. Results of primary scenarios

Table 11 on the following page presents the results of the analysis of the impact of the DRM on the wholesale market in each of the three scenarios analysed.

As foreshadowed above, wholesale market impacts measured in terms of reductions in total generation sector costs is minimal in both the AEMO forecast and AEMO forecast plus CRNP scenarios. It is also the case that all of the generation sector cost reductions in both of those scenarios are due only to reductions in fuel (and other variable operating and maintenance) costs, rather than reductions in capacity requirements or capacity costs.

28 See http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions

29 Our use of this ratio was discussed in Section 5.3.3 of the *Consultation Paper*. This is the ratio that has been identified by AEMO and has been used in most studies of the market as creating a realistic picture of the time-weighted Spot Price that can be expected to result over the course of a number of years.

Table 11: DRM impacts on the wholesale market

Impact item (2017 thru 2035, NPV @ 7.5%)	AEMO 2014 forecast	AEMO 2014 forecast + CRNP	Illustrative capex requirements	Price volatility
Change in generation sector capacity & FOM costs (NPV)	NIL	NIL	$63 million (10 yrs) $1.1 billion (19 yrs)	NIL
Change in generation sector fuel and VOM costs (NPV)	$2.6 million	NIL +	Minor	$1.9 million
Change in total generation sector costs (NPV)	$2.6 million	NIL +	$63 million (10 yrs) $1.1 billion (19 yrs)	$1.9 million
Reduction in installed capacity as at 2035	0 MW	0 MW	1,968 MW (10th yr) 1,980 MW (19th yr)	0 MW
Reduction in generation	136 GWh	57 GWh	296 GWh (10th yr) 437 GWh (19th yr)	57 GWh
Average annual change in NEM wholesale price ($/MWh)	$0.73	$0.26	$0.79 (10 yrs) $1.56 (19 yrs)	$0.42
GHG emission reductions	259,000 tonnes	182,000 tonnes	467,000 (10 yrs) 1.5 million (19 yrs)	777,000 tonnes
Average annual reduction in unserved energy	0.02 GWh	0.01 GWh	0.4 GWh	0.02 GWh

Source: OGW analysis

These results are not surprising given:

- the initial over-supply in generation capacity,
- the quite flat forecast for growth in total and peak demand, and
- the fact that the capacity withdrawals that were undertaken in the modelling to maintain a reasonable wholesale market spot price were assumed to result in (a) the mothballing of plant (rather than its full closure and permanent shutdown), and therefore (b) its ability to return to service when (and if) suitable market conditions returned[30].

Impacts in the illustrative capex requirements case are material, which is also not surprising. The high growth rate underlying this scenario (and the fact that it started from a position of relative balance in supply and demand rather than one of generation over supply) provide the opportunity for the DR made available by the DRM to defer new capital spending, thereby materially reducing the capital and other fixed operation and maintenance costs that would be incurred by the generation sector in the forecast scenario in the absence of the DRM. However, this scenario is optimistic in that it does not account for policies such as CRNP that are likely to be implemented and that would reduce the incremental impact of the DRM.

30 This strategy for responding to depressed price conditions due to oversupply in the generation sector is what has actually been taking place. The withdrawals that have been seen to date have not entailed permanent shutdown of plant. This is because, at least initially, temporary withdrawal is likely to be preferable to permanent shutdown for several reasons: (a) it allows plant to return if and when supply/demand/price conditions warrant it, (b) it is relatively inexpensive in the short to medium term, and (c) it avoids potentially significant expense associated with the site remediation requirements that accompany a decision to permanently shut down a generating plant.

5.3.2. Volatility

We tested the impact of increased wholesale market price volatility on the benefits possible from the DRM. Benefits in that case are also small, primarily because although the increased volatility in price results in DR being called more often (thereby resulting in greater fuel cost savings and slightly lower average wholesale prices), the over-supply of generation capacity[31] still results in their being no possibility of deferring capacity additions.

5.3.3. Price outliers

Stakeholders noted that extreme prices can occur at times other than peak and that customers directly exposed to the Spot Price (Pool Pass-Through tariff) can achieve very significant savings by responding and that our analysis had not accounted for this type of situation.

Market models, including CEMOS, typically show 'well behaved' price-quantity relationships even when random outages and game-theoretic analysis of behaviour are accounted for. In practice there is a range of situations and events -- such as reductions in inter-connector network capacity from the modelled form and level, and statistically low probability combinations of generator outages at times that allow opportunistic generator bidding activity – that result in high prices that do not align with high demand. These miss-aligned prices can be described as outliers. Historically the occurrence of outliers has varied markedly in different years and in different regions of the NEM.

Individual customers capable of responding to these events can obviously benefit by avoiding high prices. Customers on Pool Pass-Through tariffs can capture 100 per cent of the benefit – or be subject to 100% of its effect if they cannot reduce load during such periods. The key question in evaluating the impact of the DRM during outlier price events is whether the DRM would bring forward additional DR and thus lower price for tariff customers in general.

To assess the potential impacts of the DRM on outlier events, we undertook the following analysis:

- Outlier half hours were identified on an annual basis in each NEM region over the period 2014 through 2013
- An outlier half hour was defined as any half hour in which Spot Price was $300/MWh **and** demand was less than 95% of the annual peak half-hour demand in that region in that year (this was done to ensure that the event did not reflect a high price that would be expected as a product of high demand)
- Individual outlier half hours that were contiguous in time were combined to form outlier events of varying duration
- The price within each outlier event was used in conjunction with information regarding the amount of DR available in each year in each region (Table 10) and the proportion of available DR assumed to be provided into the market under the DRM at specific Spot Prices (Table 8) to estimate the amount of DR that would respond to each outlier event
- The impact of the DR determined to be available to respond to outlier events in each region in each year was assessed in two ways:

31 Volatility was not tested in the illustrative capex requirements case, as the benefits were significant without considering the impacts of increased volatility.

- Under the assumption that the DR dispatched does not change average market price and all savings flow to those customers providing the DR - In this analysis, the response in the first half hour of each outlier event was discounted to zero to reflect the fact that (a) true outlier events are almost always unforeseen and (b) very little DR is able to respond in less than 30 minutes (and even where DR can respond in less than 30 minutes it will only attain a proportion of the potential benefit available in that first half hour), and
- Under the assumption that the DR dispatched reduces Spot Price in the outlier event to the DR trigger price of the marginal tranche of DR dispatched, but no further[32], which has the effect of reducing wholesale Spot Price and thereby creating a benefit for other customers sharing the benefit through lowering the average wholesale price experienced in the year, including the impact of those reductions on average Spot Price for the year.

The results of the outlier analysis are shown in Table 12 below.

Table 12: Number of outlier events (1 half hour and more than 1 half hour) by NEM region and year, 2004 through 2014

	NSW		QLD		SA		TAS		VIC		NEM	
Event duration (hh)	1	> 1	1	> 1	1	> 1	1	> 1	1	> 1	1	➢
2004	8	32	8	14	4	9	0	0	10	5	90	60
2005	5	15	2	2	3	8	7	11	10	5	68	41
2006	4	3	5	2	9	8	4	4	18	11	68	28
2007	31	45	30	25	17	10	8	5	41	25	237	110
2008	2	6	5	7	6	11	0	0	9	2	48	26
2009	10	14	1	7	8	22	14	11	12	2	101	56
2010	6	8	1	1	7	6	3	5	19	6	62	26
2011	4	2	9	4	2	3	2	3	4	1	34	13
2012	2	0	23	0	5	5	0	0	2	4	41	9
2013	0	2	48	17	10	13	1	2	12	2	107	36
2014[33]	0	0	4	1	6	12	2	0	3	2	30	15
Average	12	7	7	12	13	6	7	10	4	4	81	38

Source: OGW analysis

32 That is, if the Spot Price in an outlier event was $475, it was assumed that the 25% proportion of available DR in a NEM region that would be dispatched (the proportion willing to be dispatched when Spot Price is between $300 and $499 per MWh) would be sufficient to reduce Spot Price in that NEM region to that trigger price. Similarly, if the Spot Price in an outlier event was $1,350, it was assumed that the 40% proportion of the available DR in the region that would be dispatched (the proportion willing to be dispatched when Spot Price is between $1,000 and $4,999 per MWh) would be sufficient to reduce Spot Price in that NEM region to the trigger price of the marginal DR group (that is, the marginal 10% of DR that becomes available when Spot Price rises above $1,000). In this analysis it was not possible to remove the first half hour of the outlier event.

33 Through 30 November 2014.

As can be seen, the number of outliers varies materially from year to year. The 2007 year experienced the largest total number of outlier events, and at least a typical relationship between the number of single half-hour outlier events and all outlier events. As such, it was used in the remainder of the outlier analysis to demonstrate the largest effect that the DRM could have with regard to such events.

Table 13 calculates the revenue that would flow to DR providers under the following assumptions:

- the total amount of DR potential identified in Table 3 had been available in 2007,
- all of that DR was able to respond to every outlier in 2007 that lasted 1 hour or more (i.e., it would all be available at 30 minutes' notice, but none would be available at less than 30 minute's notice)
- the available DR would respond to the prices during the outlier events in the proportions shown in the last column of Table 8, and
- the DR dispatched would not change Spot Price and as a result all of the Spot Price revenue generated by the DR under the DRM would flow to the DR providers.

As such, Table 13 shows what is probably the highest possible estimate[34] of the total benefits that would be available to DR providers in outlier events.

Table 13: DR provider revenue assuming Spot Price for all DR impacts in outlier events in 2007 flow to DR providers under the DRM

	300	500	1000	5000	7500	Total
NSW	$ 1,632,219	$ 125,820	$ 1,154,166	$ -	$ 7,162,979	$ 10,075,185
QLD	$ 876,067	$ 69,307	$ 3,852,910	$ 1,453,725	$ 4,875,990	$ 11,127,999
SA	$ 135,812	$ -	$ 62,659	$ -	$ -	$ 198,472
TAS	$ 48,845	$ -	$ 157,595	$ -	$ -	$ 206,440
VIC	$ 472,446	$ 54,337	$ 4,527,479	$ -	$ 6,020,000	$ 11,074,262
NEM Total	$ 3,165,389	$ 249,464	$ 9,754,810	$ 1,453,725	$18,058,969	$ 32,682,358

Source: OGW analysis

34 It is a high case estimate because it used the year in which the most outlier events occurred over the last decade, which was also a year characterised by relatively high Spot Prices. While the analysis assumes that no DR is available in less than 30 minutes, it also assumes that all DR is available in 30 minutes, that it all responds to every event, and that it never reduces Spot Price in an outlier event. Clearly, not all of these conditions would pertain (in fact it is more likely that none of them would).

Table 14 makes an alternative (and largely opposite) set of assumptions regarding the impact of the DR provided in response to 2007 outlier price events. It assumes that the same amount of DR is dispatched[35], but it assumes that the DR always reduces Spot Price to the minimum acceptable dispatch price of the last tranche of DR dispatched in response to the price that pertained in each outlier event. That is, if the average price in a particular outlier event was $6,550, it was assumed that 80% of the total DR available in the state would respond, and that it would reduce Spot Price in the outlier event to $5,000, which is the trigger price of the incremental 40% of DR potential assumed to become available when price exceeds $5,000/MWh (see Table 8).

Table 14: Impact of DR on 2007 Spot Price assuming that all DR available from the DRM reduced outlier Spot Price to the marginal DR trigger price

	$/MWh		Change	
	Without DRM	With DRM	$/MWh	% Change
NSW	$ 67.07	$ 63.82	- $ 3.25	- 4.9%
QLD	$ 66.84	$ 61.86	- $ 4.98	- 7.5%
SA	$ 57.50	$ 56.53	- $ 0.97	- 1.7%
TAS	$ 56.85	$ 55.76	- $ 1.10	- 1.9%
VIC	$ 63.40	$ 59.58	- $ 3.82	- 6.0%

Source: OGW analysis

As in the case of Table 13, Table 14 presents what is almost certainly the highest possible estimate of the potential impacts of DR on Spot Price in outlier events. Like Table 13 it uses 2007, which was the year with the largest number of outlier events, as the base, and it also assumes that:

- all of the available DR can and does respond immediately to outlier event Spot Prices, and
- the exercise of this DR never reduces DR below the trigger price of the last tranche of DR that responded to the outlier event Spot Price (which is an important assumption because if the dispatch of DR reduces Spot Price below the trigger price of some of the DR that participated, it would have to be assumed that that tranche of DR would be less likely to participate in subsequent events).

In sum, the analysis undertaken of outlier events suggests that while the DRM could be expected to have an effect in such events, it is unlikely to represent a source of sufficient net economic benefit under present and forecast market conditions to change the conclusions reached in the previous portions of this section of the report.

35 However, it was not possible to remove the first half hour of the outlier events in the analysis undertaken in Table 14.

5.3.4. Unaccounted for capital cost savings

Some stakeholders noted that there is likely to be some cost in either maintaining withdrawn plant during the course of time it is removed from operation, or in refurbishing it when it is re-entered into operation. Where re-entry costs are material and the DRM defers the timing of re-entry, the DRM would offer capital cost savings. However, quantifying these savings is extremely difficult as it would require an understanding of plant-specific costs for an action that may or may not occur a number of years in the future[36].

We simply have no way of knowing those costs, and as a result, the outcome would be a direct product of the inputs – all of which would be assumptions.

In addition, the results of such an analysis would of necessity fall between the results of the AEMO forecast scenarios and the illustrative capex requirements scenario shown in Table 11 above. The degree to which the results could be expected to approach the higher end of that range would depend entirely on how high the re-entry costs are assumed to be. In this regard, it should be noted that where those refurbishment costs approach or exceed those of new capacity, new capacity will be preferred.

But regardless of the cost of the refurbishment, the low growth in the present forecast would tend to delay this plant resuming operation (or new plant entering the market) until the latter part of the analysis period, which will reduce its impact on the overall present value of this unaccounted for capital cost saving in any case.

As a result, refurbishment costs for mothballed plant re-entering the market have not been included in the analysis, and this should be recognised as an area of conservatism in the modelling potentially underestimating the DRM benefit.

A more likely situation that would lead to capital savings and results closer to the illustrative capex saving case would arise if there were formal announcements of closure or a return to policy initiatives that would result in closure. If the timing and magnitude of closure, or more generally any factors that prevent re-entry (such as permanent shutdown) were known, the analysis could be more definitive about wholesale market capex savings.

36 By contrast, AEMO in its planning studies (and most other studies undertaken by other parties) use a set of data about the operating and costs characteristics of the range of generation plant options currently and anticipated to be available for commercial use. As noted earlier, the dataset of generation options used by AEMO was also used in this study.

6. Network impacts

6.1. Objectives and key issues

The overarching objective of this component of the analysis was to estimate whether or not any benefits will accrue to network businesses from the introduction of a DRM, and if so, the quantum of those benefits.

Our starting assumption was that a by-product of reducing electricity demand in response to a wholesale market price signal (which is what the DRM is) is that there *may* be consequential benefits to network businesses that provide grid-related services to the customers contributing to that demand response (and that would be passed on to customers of that network business). This would occur if the reductions in demand stemming from that demand response also reduce peak demands[37] on the distribution system the DR participant is connected to, and therefore, reduce that distribution business' (as well as the local transmission network's) future augmentation costs.

To assume otherwise – namely, that the benefits of the DRM only relate to energy cost savings attributable to spot market participation by DRM participants – would be to implicitly assume that:

- the timing of any response to the DRM does not, at any time, overlap with the timing of when the distribution system that that DR participant is connected to peaks, and thus it has no impact on a network business' future augmentation costs, or
- even if the timing of any response to the DRM did overlap, network businesses could not rely upon that DR unless it was 'firm' (e.g., guaranteed, via a direct contractual relationship with the DR provider), and therefore, the non-firm nature of the DRM means that there would be no reduction in future network augmentation costs, or
- all respondents to the DRM were located in areas where there is significant spare capacity in the distribution and transmission network, meaning that their DR does not in any way impact upon a network business' future capacity augmentations requirements, as no expenditure is forecast to be required under the base case.

To address the first issue, our methodology includes an estimate of the probability that the timing of peak periods in each regional wholesale market will overlap with the network peaks of distribution businesses in that region. This is discussed in more detail in the next section.

37 Or energy at risk, depending on which approach to network planning a distribution business adopts.

In relation to the second issue, it is our view that because the DR that is incentivised by the DRM will come from hundreds if not ultimately thousands of individual customers, it should be considered as a "portfolio" of DR providers. By having access to this "portfolio of DR", network businesses reduce their exposure to individual DR providers, simply because they have access to a diversified portfolio of DR providers (i.e., combinations of DR that are not perfectly positively correlated). Where such diversification occurs, it is likely to be reasonable (and efficient) for a network business to not in fact "contract" with each and every one of those individual providers to guarantee their individual supply, but rather, to either (a) simply rely on the diversified nature of its broader DR portfolio to mitigate the risk that individual DR providers may or may not produce at any single point in time, or (b) contract with DRAs that represent multiple individual DR providers. It can be expected that DRAs would actively seek such contracts as an additional source of revenue for their clients and themselves. Entering into such contracts would also be consistent with the requirements of the RIT-D, and would reduce the prospecting and administrative costs that would be incurred by the network business in doing so.

In relation to the third issue, we are not, as we stated in the *Consultation Paper*, in a position to identify the exact feeder/ zone substation that a particular DR provider will be connected to, and the extent to which that feeder/zone substation may or may not be congested. However, we do not believe that this automatically requires us to assume that there will not be any network benefits stemming from the introduction of the DRM, as to do so implicitly assumes that any proposed modelling approach could only lead to an *underestimate* of the value of network benefits of the DR that would be elicited as a result of the DRM. To our mind, this is not correct, particularly as our methodology applies an average LRMC (by each voltage level and for each distribution business) to the value of DR activated by the DRM (again, by each voltage level and for each distribution business). What this means is that there should be an *equal probability* that the DR that *actually* occurs as a result of the DRM is in areas that are:

- less congested than the "average" (and thus deliver less benefits than what is modelled using the average LRMC), versus
- more congested than the "average" (and thus deliver more benefits than what is modelled using the average LRMC).

This occurs because the LRMC itself (for any particular voltage level within any particular distribution network) reflects both congested and non-congested areas (i.e., it is an average, reflecting demand growth in areas that require little in the way of future augmentation capital expenditure, as well as demand growth in areas that may require significant augmentation related capital expenditure)[38].

In summary, like any CBA analysis, the actual results will inevitably differ to modelled results. The key concern, from an analytical perspective, is to ensure that the modelling approach does not skew the analysis in favour of one outcome over another.

6.2. Data sources and methodology

The primary features of our approach to the calculation of network benefits included:

38 In actual fact, the net effect will depend on the proportion of areas with immediate and distant augmentation needs, and the size of those augmentations. Therefore, while the actual benefits of DR will differ in each local area from the average, the analysis based on the average will be taken as representing the expected, central case.

- Adjusting the amount of DR activated by the DRM at the state level (from the wholesale market modelling) to account for the fact that networks do not necessarily experience peak demands at the same time/season as the regional wholesale market;
- Allocating that DR to:
  - one of three different voltage levels (e.g., sub transmission, high voltage and low voltage), and
  - the different distribution networks within each NEM jurisdiction.
- Multiplying the resultant DR figures for each distribution and transmission network, by an estimate of the annualised benefit that will accrue from the activation of that DR over the evaluation period, given the voltage level at which customers providing the DR are assumed to be connected.

The following sections explore each of these steps in further detail.

6.2.1. Networks do not necessarily experience peak demand at the same time as the wholesale market

To reflect the wholesale market modelling results in the modelling of network benefits, we assumed that the DR activated by the DRM was ‘spread’ over only a fairly small amount of time in and around the peak demand period in each NEM region. This ‘spread’ was based on the following assumptions:

- 100% of that year’s DR assumed to occur at time of system peak in that region,
- 75% half hour before and after this time,
- 50% one hour before and after this time,
- 25% one and a half hours before and after this time, and
- 0% outside of that +/- 1.5 hours on either side of peak demand in the jurisdiction

Further to the above, to account for the fact that different parts of a distribution network do not necessarily experience peak demands over the same time period as the wholesale market, the DR estimates were further adjusted to reflect their estimated coincidence with the timing of peak demand at the different voltage levels within each network. These timing assumptions were based on various information sources, including information provided by businesses in response to the *Consultation Paper* (and correspondence following the *Consultation Paper*), and OGW knowledge and experience regarding when different parts of distribution networks are likely to peak. These estimates of the timing of peak demand at different voltage levels were as follows[39]:

- Sub transmission – 3 to 6 PM AEST
- High voltage – 3 to 5:30 PM AEST
- Low voltage – 4:30pm to 7:30 PM AEST.

39 We acknowledge that there will almost always be examples of feeders within each of these voltage levels that peak outside these time periods. However, the time-periods were defined so as to capture the times when the vast majority of feeders within those voltage levels are likely to peak.

Collectively, the two steps above allowed us to estimate the average amount of DR that is activated in response to the DRM that is likely to coincide with when different voltage levels within the distribution network peak. An example demonstrating this calculation is outlined in the Box below.

Box: 1 Example of how steps 1 and 2 interact

If the wholesale system is expected to peak at 6PM (AEST) in NSW, the proportion of DR activated by the DRM that will reduce peak demands on LV networks in NSW (which, as outlined above, are assumed to peak between 4.30pm and 7.30pm) would be ~57%, based on the *average* of:

- 100% * DR (the 6PM 'peak' figure)
- 75% * DR (for 5:30PM) + 75% * DR (for 6:30PM)
- 50% * DR (for 5PM) + 50% * DR (for 7PM)
- 25% * DR (for 4:30PM) and 25% * DR (for 7.30PM)

This methodology implicitly reflects the fact that not all parts of that part of the LV network in NSW will peak exactly when 100% of the DR estimate is likely to be available (6PM, when the wholesale system peaks). Rather, some parts of the LV network will, for example, peak at 4.30PM, and therefore, only 25% of the maximum DR will be available then; some parts of the LV network will peak at 7pm, and therefore, only 50% of the maximum DR is assumed to be available.

6.2.2. DR providers are spread across different distribution networks, and are not all connected at the same voltage level

Following on from the two steps above, we made three further adjustments to the amount of DR available to network businesses in each State, to reflect the:

- Proportion of DR that is estimated to impact each specific network business in each State – This proportion was based on the contribution of each network business' non-residential electricity consumption to their respective State's overall non-residential electricity consumption[40].
- Estimated proportion of each network business' distribution system that is likely to peak in the same *season* as the wholesale market – This was based on various sources, including high level information provided by a number of distribution businesses in response to the *Consultation Paper* (e.g., Ausgrid), a review of distribution businesses' annual network planning reports to assess the number of zone substations that were winter peaking versus summer peaking (e.g., Ergon, Energex), or our own estimates, where no other information was readily available. These percentages are outlined in Table 15 on the following page[41].

40 This information was in turn based on information provided by network businesses to the Australian Energy Regulator as part of their recent Regulatory Information Notices (RINs). This can be found at: http://www.aer.gov.au/taxonomy/term/1495

41 It should be noted that the impact of the DRM was not assessed with regard to Tasmania or the ACT. See Appendix B for further information.

Table 15: Alignment factors to account for the proportion of local areas within the network that peak in the same season as the generation market in that NEM region

Distribution Business	Alignment
Ausgrid	70%
Endeavour	70%
Essential	80%
SP AusNet	95%
Powercor	95%
Citipower	100%
United Energy	95%
Jemena	95%
SA Power Networks	95%
Ergon	97%
Energex	93%

- DR potential of customers connected at each voltage level – An assessment of DR potential at each voltage level was required, as the benefits that accrue from DR are inextricably linked to the voltage level at which the end customer providing DR is connected[42]. The estimated dispersion of DR potential across each voltage level was based on the proportion of consumption[43] of customers at each voltage level that are eligible to participate in the DRM (i.e., customers whose consumption exceeded 100MWh). This information was provided by SA Power Networks and Ausgrid, which, in turn, were used as the basis for the other NEM jurisdictions[44]. The figures used were:
  - Sub transmission: 25% (All states)
  - High voltage: 10% (NSW) / 13% (VIC/QLD) / 17% (SA)
  - Low voltage: 65% (NSW) / 62% (VIC/QLD) / 58% (SA).

42 The DR provided by a customer who is connected to the LV network may impact not only the need to augment the LV network, but also the HV network and the sub-transmission network, whereas the DR provided by a customer who is connected to the sub transmission network *cannot* impact upon the future augmentation requirements of the HV or LV network.

43 The proportion of consumption was used, as it was considered to be the best available proxy for the amount of DR potential that will be connected at different voltage levels. We note that the proportion of demand would have been an alternative proxy, however, this information was not readily available; and the proportion of customers would have been unlikely to reflect the DR potential connected at different voltage levels, as it does not take into account the overall size and scale of the operations of those connected customers.

44 In QLD and VIC, where limited information was available, we used the average of NSW and SA.

6.2.3. Multiplying the adjusted DR figures by an estimate of the annualised benefit that will accrue from the activation of that DR over the evaluation period

The final step of the process was to multiply the amount of DR determined at each voltage level within each network (from the above steps) by the voltage-specific LRMC for each network business.

Unfortunately, not all distribution businesses have published LRMC figures. Therefore, we were unable to base each business' LRMC estimate on their own published figures. For those businesses that have published LRMC estimates as part of their Annual Pricing Proposals, we have used these estimates (e.g., Ausgrid, Endeavour, SA Power Networks, Jemena, Ergon). For other businesses, we have used one of a number of alternate methodologies, including:

- cost reflective network prices, as a proxy for their LRMC (e.g., SP AusNet),
- unpublished information that we are aware of, or
- the LRMCs of another similar network business (e.g., Citipower, Powercor, Essential and Ergon).

For the businesses that fall into the two latter categories, we have used information on the capital expenditure plans (in dollars) and the demand forecasts (in MW) approved by the AER as part of their most recent regulatory determinations to estimate an annualised LRMC of supply. This annualised figure was then cross-checked against the unpublished figures or the businesses that we considered as likely comparator businesses (in the case of Citipower, etc.). This cross check was to ensure that that comparator business' LRMC was a reasonable approximation of that businesses LRMC[45].

The following table highlights the specific figures used for each business.

Table 16: LRMC ($/kVA) estimates used in the modelling

Distribution Business	Sub transmission	High voltage	Low voltage	LRMC source
Ausgrid	$39.0	$170.4	$156.1	Published by DNSP
Endeavour	$26.7	$39.8	$159.5	Published by DNSP
Essential	$26.7	$39.8	$159.5	Other DNSP ('Endeavour')
SP AusNet	$5.0	$60.0	$80.0	CRNP
Powercor	$15.0	$40.0	$85.0	Other DNSP ('United Energy')
Citipower	$39.0	$170.4	$156.1	Other DNSP ('Ausgrid')

45 For example, using the AER's 2011 Final Decision for the Victorian Distribution Businesses, we calculated that the cost per MW to augment Citipower's network was $1,600/KW, which, on an annualised basis over a 25 year evaluation period (assuming 0.5KW of demand in year 1, and 1kW in year 2 onwards), equates to an annualised LRMC of $139.55/kW using a 7.5% WACC, and $168.94/KW using a 10% WACC. Based on this information, as well as the similarities in network composition, we chose to utilise Ausgrid's LRMC as a proxy for Citipower. Utilising the same methodology for Powercor, we calculated an LRMC of $79.44/KW based on a 10% WACC, and $65.71/KW based on a 7.5% WACC. Based on this information, we utilised United Energy's LRMC as a proxy for Powercor. We undertook the same methodology for United Energy, and its LRMC (at a 10% WACC) was $82.26/KW.

Distribution Business	Sub transmission	High voltage	Low voltage	LRMC source
United Energy	$15.0	$40.0	$85.0	Unpublished
Jemena	$92.1	$92.2	$93.3	Published by DNSP
SA Power Networks	$46.0	$104.0	$152.0	Published by DNSP
Ergon	$27.1	$40.5	$162.0	Published by DNSP[46]
Energex	$27.1	$40.5	$162.0	Other DNSP ('Ergon')

Source: OGW analysis

We based our estimate of the LRMC of each transmission business on a selection of the businesses' published tariffs. The figures adopted from this method ranged from $18/kVA (in Victoria) to $21/kVA (in SA).

Finally, we made a slight (5%) downward adjustment to the above LRMC figures from year 3 onwards in the 'with CRNP' case, to reflect the fact that CRNP – as well as responses to the DRM itself – are likely to lower network businesses' demand forecasts, delaying the need for capex, and thereby reducing their LRMC of supply.

6.3. Results

Table 17 presents the results of the network impact analysis.

Table 17: Network benefits of the DRM

Network benefits (2017 thru 2035, NPV @ 7.5%)	AEMO forecast	AEMO forecast + CRNP
Distribution system benefits	$147.3 million	$101.4 million
Transmission system benefits	$31.1million	$16.4 million
Total network benefits	$178.4million	$117.8 million

Source: OGW analysis

As can be seen, network benefits are very high relative to wholesale market benefits in both the AEMO forecast and AEMO forecast plus CRNP scenarios[47].

More generally, it should be recognised that once enabled, DR providers (and the aggregators whose business model is to maximise revenue available to DR) will seek to deploy DR to their maximum advantage, subject to their production requirements.

46 Based on "Benchmark Cost of Supply" published by Ergon as part of their most recent Annual Pricing Proposal, with the split into voltage levels based on the same ratio as Endeavour Energy.

47 Network benefits in the illustrative capex requirements scenario were not calculated for this report, but are less critical to the outcome of that scenario.

7. Costs

7.1. Objectives and key issues

7.1.1. Objectives

The purpose of this section is to determine the quantum and drivers of cost associated with the implementation and administration of the DRM. Those costs include:

- The costs that would be incurred by AEMO in establishing and administering the scheme, the main new capability required being the ability to determine the baselines to be used in calculating the DR provided by each DRM participant in each event along with significant changes required in AEMO retail and settlement functions and
- The cost that would be incurred by retailers in adjusting existing or developing new computer systems and processes and/or manual business processes as required in order to:
  - bill customers participating in the DRM, which includes both their energy consumption and network charges (which under the DRM would need to be calculated on different consumption streams),
  - reconcile the wholesale market settlement associated with their consumption and DR provision, and
  - settle their contract positions (which will need to be calculated on a different consumption stream as compared to that used in billing the customer).

A retailer may incur other or additional costs for system or process changes (or other things) that are required in order for them to function as a DRM aggregator (as compared to merely being able to accommodate its customers participating in the DRM, either on their own or through another party). However, our view is that the decision to act in that capacity should be seen as a commercial decision on the part of the retailer, and therefore should not be considered as either an implementation or administrative cost of the DRM itself. Similarly, any such costs incurred by a non-industry firm that decides to set themselves up as a DRA under the DRM would also be seen as a commercial decision and not taken as an implementation or administrative cost of the DRM[48].

For the sake of clarity, therefore, the costs associated with the base level changes required by all retailers (or at least all retailers that serve customers who are eligible to participate in the DRM) - as opposed to any costs that would be incurred in the event the retailer chose to function as a DRA, will be referred to in this section as costs associated with the **DRM Base Service.**

7.1.2. Key issues

The costs associated with implementation and administration of the DRM will be highly dependent upon both (a) the details of the DRM design and its associated requirements, and (b) the systems and business processes that AEMO and each retailer needs to modify or develop and maintain in accordance with the design and requirements of the scheme.

48 It should also be noted that a Retailer or a new entrant seeking to act as a DRA would presumably expect to recoup any costs incurred in setting up and acting as a DRA through that business activity or some other associated business activity.

A high-level design for the DRM was developed by a set of working groups coordinated by AEMO. AEMO assessed the costs it would likely incur for the systems and processes it would be responsible for in accordance with the high-level design. In parallel but separately, the ERAA undertook an assessment of the costs that would likely be incurred by retailers responding to the high-level design.

In combination, these assessments indicated that the high-level design could involve significant costs.

A number of issues (discussed below) were encountered in reviewing the cost information that was available from these processes for use in this cost-benefit assessment.

The need for relevant cost information

Given that it is not compulsory for retailers to be DRAs, the costs to be considered as being incurred due to the development, implementation and ongoing administration of the DRM will be restricted to:

- AEMO costs, and
- only those retailer costs that are required in order for the retailer (in its capacity as a retailer, and not in the capacity of a DRA) to interact with the AEMO-developed procedures for the DRM. This is referred to in this section as the DRM Base Service.

Importantly, any costs beyond those required to allow the retailer to interact with the AEMO procedures (and particularly any costs associated with enabling the Retailer to function as a DRA) should not be included, as they are discretionary for the Retailer and would be offset by the price the retailer chooses to charge for the service (as noted in 7.1.1 Objectives above).

It is not possible to determine from the information currently available whether the retailers that responded to the ERAA cost survey restricted their cost considerations solely to the second dot point above.

Can procedures be simplified to reduce retailer costs?

The specific procedures that are required due to the detail of the DRM design will be a major driver of the cost of implementation and administration. We understand through discussions with AEMO that the procedures are still to be approved, and that detailed analysis of the retailers' costs has still to be undertaken to identify opportunities to amend the detailed design of the DRM and the associated procedures in order to reduce retailer costs, including determining if there is potential for AEMO to undertake additional functions centrally.

What is the scale and timing of the anticipated uptake?

The scale and timing of the anticipated take-up of the DRM (in terms of both the number of customers participating and the amount of load in flux) will have a significant impact on the solutions employed by those retailers seeking to act as DRAs and those retailers who plan to provide the DRM Base Service.

Given that the DRM will be restricted (at least in the first instance, given the existing DRM design) to customers consuming more than 100MWh per annum, the total number of customers with potential to participate in the DRM is in the order of 60,000. The take-up rate, along with the degree of integration and automation of retailer systems, will be a major determinant of whether a manual system for billing and reconciliation might be sufficient or whether a fully automated process integrated with the retailer's billing and other systems is required. In this regard it is worth noting that a cumulative take-up of the DRM by 20% of the eligible customers over the first two years of the program would result in a total of 12,200 DRM customers after 2 years.

In this regard it is worth noting that manual systems were used for billing large customers that took contestable terms in the first several tranches of the electricity market being opened to retail competition. As more customers became eligible to take market contracts and more did so, the need for and cost-effectiveness of fully automated billing systems became incontrovertible.

The magnitude of costs to be incurred by retailers due to the DRM could be further managed by allowing a reasonable "grace" period for retailers to put the required capabilities and functionalities in place, thereby allowing these changes to be scheduled for implementation at the time of the next regular upgrade of their systems.

Similarly and as an extension to the point above, we note that the DRM as originally conceptualised would require all retailers that serve a material proportion of DRM-eligible customers to participate in the DRM and to be ready to do so at the date identified as the commencement of the scheme. However, being able to commence with a subset of retailers would have an impact on overall industry costs, as some retailers with high systems implementation costs could defer the implementation of systems to a time where costs can be minimised.

There may also be opportunities to coordinate the implementation of DRM with other *Power of Choice* initiatives such as Multiple Trading Relationships, given the potential overlap of these initiatives in terms of retailer system implementation costs. Such coordination could lead to lower overall costs.

Is the implementation of the DRM Base Service optional?

Costs associated with implementation are also heavily influenced by the number of retailers that are required to provide the DRM Base Service and therefore incur costs to modify their IT systems. It may be that a number of retailers do not serve any consumers that are eligible to participate in the DRM, and as such do not need to establish the DRM Base Service functionality in their systems.

Further, given the potential for consumers to change retailers, it may be that consumers who wish to utilise the DRM service, but whose current retailer does not provide the DRM Base Service could choose to change to a retailer that does provide the DRM Base Service, making it a commercial decision for the retailer as to whether they even offer the DRM Base Service[49].

7.2. Data sources and methodology

7.2.1. Methodology

The ideal cost inputs to the cost-benefit scenarios would be costing data that is considered robust and defensible, and that provides an understanding of the drivers of those costs.

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49 In theory this could raise the possibility of the DRM being available in the Rules, but not available in fact, in the event that no Retailer chose to offer the DRM Base Service. The business model of several retailers as well as competition theory suggests this outcome is unlikely. In addition, if it were to occur, there might be the potential for a measure such as Retailer of Last Resort to be implemented, whereby the provision of the DRM Base Service could be tendered out or auctioned off.

The information that is available based on the ERAA provided information is at a very high level, and is not sufficiently detailed to allow an understanding of what exactly contributes to the total cost nor how DRM costs would change in the event of changes in the design and requirements of the DRM itself. This lack of detail significantly limited the degree of analysis that could be undertaken on implementation and administration costs. Having access to more granular information on the costs retailers believe they will incur in providing the Base DRM Service would be of significant assistance.

To gain additional information, industry was asked to provide their responses to a number of questions raised via a consultation.

In addition to the consultation, additional clarity around cost and cost drivers was determined by:

- engaging with several service providers to get independent estimates of costs; and
- endeavouring to review the cost impacts of mechanisms similar to the DRM or that place system and business process requirements on a market party that are similar to those imposed by the DRM,

Originally, we had also planned to undertake sensitivity analysis of the cost-benefit outcomes to different cost input assumptions regarding various options for reducing DRM implementation and administration costs such as;

  - variations to scope;
  - variations to implementation timing, including phasing of systems based on take up of the service;
  - coordination of implementation with other *Power of Choice* initiatives (e.g. MTR); and/or
  - optionality around the implementation of the DRM Base Service noting that the number of retailers required to implement and support the DRM Base Service is a large driver of cost.

  However, this proved impossible given:

  - the relative lack of specificity regarding how the DRM would be implemented and the resulting requirements it would place on Retailers' IT systems, and
  - the lack of information regarding the specific cost drivers assumed by the Retailers in the costs they had estimated in developing the system required to implement the DRM, and the costs they would incur in administering it on an on-going basis.

  In addition, the economic benefits identified as likely to result from the DRM under the AEMO forecast and AEMO forecast plus CRNP scenarios were so low that almost any level of implementation and administration costs would make a mandatory scheme uneconomic.

7.2.2. Data Sources

Input provided by AEMO on AEMO costs

AEMO estimated the costs it would incur in implementing and administering the DRM based on information contained in the Detailed Design Document prepared through the AEMO working groups.

Input provided by ERAA on Retailer Costs

In parallel with the detail design process convened by AEMO, the Energy Retailers Association of Australia (ERAA) undertook a survey of its members to estimate the likely cost of implementing the DRM. The survey asked respondents to estimate the level of cost they felt would be likely to be incurred in five different areas related to implementation of the DRM.

The five areas in which costs were likely to be incurred were:

- Registration
- Metering and data management
- Settlements and prudentials
- Reporting, and
- Retail customer billing

The survey asked the individual retailers to estimate the costs likely to be incurred in each of those areas over a notional ten-year period of DRM implementation using the ranges shown in the table below.

Table 18: Ranges used in the ERAA survey of Retailer costs of the DRM

Order of magnitude of cost	Range	Cost value used in cost calculation
Small	Up to $100k	$20k
Medium	Greater than $100k, up to $500k	$100k
Large	Greater than $500k, up to $2m	$500k
Very large	Greater than $2m, up to $5m	$2m
Very, very large	Greater than $5m	$5m

Source: Seed Advisory, *The case for a Demand Response Mechanism in the NEM: an assessment*, 16 December 2013, for the Energy Retailers Association of Australia, the Private Generators Group and the National Generators Forum, pp 50-51.

7.3. Results

Estimation of the costs likely to be entailed in implementation and administration of the DRM proved to be exceedingly difficult.

7.3.1. AEMO cost estimate

AEMO estimated the costs it would incur in implementing and administering the DRM at somewhere in the order of $8 to $14 million over ten years (NPV).

7.3.2. Costs provided by Retailers through the ERAA survey

The results of the ERAA survey were provided in a report by Seed Advisory[50]. The Seed Report states that the ten-year cost to retailers of implementing and administering the DRM is in the order of $112M. However, the Seed report does not provide:

- the responses of individual retailers to the ERAA cost survey, or
- the breakdown within each cost category between up-front and on-going, or fixed and variable costs.

Seed has indicated that the estimate of retailer costs was based on the responses received from the nine retailers that responded and that their costs were not extrapolated to estimate the total costs likely to be incurred by all affected retailers.

The estimate of costs provided by the retailers was based on:

- the procedures prepared by the AEMO-facilitated Working Group, and
- a firm date of March 2015 for the implementation to be complete, and the DRM to be available to all eligible customers (i.e. all customers with annual consumption greater than 100MWh).

As a result of these bases and the nature of the information available regarding the responses to the ERAA survey, it is not possible to assess the impact on implementation and administration costs due to a range of possible changes in the design and implementation of the DRM, including if the:

- procedures were altered to reduce effort in areas that result in high retailer costs;
- implementation date was delayed to a date post March 2015;
- implementation was staged such that the DRM was progressively opened to customers, commencing initially with the largest energy usage customers; and
- implementation was coordinated with the implementation of other *Power of Choice* initiatives, particularly the arrangements being considered to allow greater deployment of embedded networks and/or multiple trading relationships.

We also understand that there may have been a high degree of variability in the cost estimates across the responding retailers. A high level of variability in such estimates would seem to be beyond what would be expected due to the differing system and processing capabilities across a group of retailers, and also leads to questions regarding (a) how the brief was interpreted by the various retailers that responded, and (b) whether, as a result, their responses were undertaken under sufficiently consistent interpretations to allow direct use of the aggregated results.

There are two main factors that, in combination, could account for the high degree of variability in the costs estimates supplied by the responding retailers, as follows:

- the significant differences in IT system landscape across the various retailers, and
- significant scope for varied interpretation of the Design Brief.

As a consequence it was not possible to fully deconstruct the drivers of the costs reported from the ERAA survey.

50 Seed Advisory, *The case for a Demand Response Mechanism in the NEM: an assessment*, 16 December 2013, for the Energy Retailers Association of Australia, the Private Generators Group and the National Generators Forum.

7.3.3. Outcomes of consultation with independent experts in retailer and market IT systems

In an attempt to get a better understanding of the drivers of retailer costs and how they might be reduced, two parties involved in IT system development/alteration for the electricity industry were approached to see if an independent estimate of the costs likely to be incurred by retailers in implementing and administering the DRM could be obtained. The key points they provided in their responses were as follows:

- At this point in the design and specification of the DRM, IT build estimates would be expected to be in the order of +/- 50% accuracy at best;
- Better estimates would require that a draft Rule be available and an industry 'build pack' be developed;
- Even then, it would still require a considerable time and effort to develop a cost estimate that would be within +/-20% accuracy;
- Costs could vary considerably depending on (a) the system landscape of the individual retailer, and (b) the fact that most/all retailers have other systems in addition to their core system that need to act in concert and therefore would also need to be modified; and
- Market-facing systems in particular (MSATS, etc.) would be a major driver of development and testing costs.

As a result, neither of the independent experts we consulted was prepared to provide an alternative cost estimate, and all felt that, based on the level of detail currently available, the estimates provided by the retailers and distributors that responded to the ERAA survey appear reasonable.

This lack of information made it impossible to undertake a quantitative sensitivity analysis of cost-benefit results to changes in the features of the DRM scheme that drive costs. As noted previously, however, the extremely low quantum of benefits in the AEMO forecast and AEMO plus CRNP scenarios essentially obviated the need for any sensitivity analysis. Only the illustrative capex requirements scenario produced benefits at a material enough level to warrant sensitivity analysis (though it also needs to be noted that the conditions underlying that benefit case are not expected to materialise in the foreseeable future).

Despite this, we have identified several ways in which the costs of the DRM could be substantially decreased. These are discussed qualitatively in Section 9.2. We have not attempted to quantify the costs of these approaches, as they do not constitute the DRM as it was referred to AEMO for consideration by the AEMC.

8. Distributional impacts

8.1. Objectives and key issues

As has been described in earlier sections of this report, the implementation of the DRM will lead to certain benefits and costs being incurred by various electricity industry stakeholders – from individual customers providing DR, to generators[51], retailers and network businesses.

We believe that it is unlikely that the costs and benefits stemming from implementing the DRM will 'fall' entirely on those customers who are participating in the scheme. For example, whilst only large customers may be eligible to participate in the scheme, retailers may choose, for commercial reasons, to recover the costs of implementing the scheme from a broader suite of customers than just those customers that are eligible to participate in the DRM (e.g., they may recover some of their implementation costs from residential customers). Notwithstanding this, it is noted that even if the costs of implementing the scheme were recovered from the customer classes that are eligible to participate in the scheme, it is unlikely that every single eligible customer within that customer class would in fact participate in the scheme, for any of a number of different reasons. Therefore, in this situation, an eligible customer who does not participate in the scheme may still face higher electricity charges as a result of the decision their retailer makes regarding how to recover the costs of implementing the scheme[52].

All-in-all, the implementation of the DRM may lead to a redistribution of costs and benefits, thus leading to varying bill impacts across different customers (or as a proxy, different customer classes), and possibly even across different geographic regions.

Therefore, as an adjunct to the cost/benefit analysis, part of the terms of reference required us to estimate the potential distributional impacts associated with the implementation of the DRM.

8.2. Data sources and methodology

The analysis of the distributional impacts of the DRM was undertaken at the distribution business level and used the following approach:

- All customers were assumed to benefit from the wholesale price reductions available at the applicable regional node. The NPV benefit per customer (for each customer class) was simply the difference in wholesale price in each year (from the wholesale modelling) multiplied by the average usage of that customer class in 2013[53]
- The direct benefits accruing to the DR providers (or more accurately, customers eligible to participate in the DRM) were included. These benefits reflected the (NPV) of revenue that they would receive from selling DR into the market under the DRM.

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51 While generators will not incur costs as a direct result of the DRM, their spot market revenue is likely to change. These changes will be reported as a direct output of the wholesale market as described in Section 5 above and are therefore not discussed further in this section.

52 For completeness, it should be noted that the cost recovery charges levied on eligible and non-eligible non-participants may be offset by the indirect benefits those customers may receive due to the impact of the DRM on either or both wholesale electricity prices and/or network augmentation expenditures.

53 Information on the number of customers, usage, and the resultant average usage was derived from information provided by network businesses to the Australian Energy Regulator as part of their recent Regulatory Information Notices (RINs). This can be found at: http://www.aer.gov.au/taxonomy/term/1495

- Variations were undertaken in the allocation of benefits to different customer classes, but the distribution business was assumed to retain 30% of the benefit in all cases (broadly consistent with the AER's capital expenditure incentive guideline).
- Variations were also undertaken in the allocation of DRM costs to different customer classes.
- The impact of the reduction in throughput due to the exercise of demand response under the DRM on network tariffs was not calculated; nor was the impact of that reduced consumption included in the analysis of DR providers' benefits. This was not felt to be a material exclusion given the very small amount of energy consumption reduction involved.
- Costs incurred by DRM participants were treated in two ways:
  - Consistent with the *Standard Practice Manual for the Economic Analysis of Demand Side Management Programs and Projects*[54], DR providers' costs were not included in this analysis, and
  - In a more traditional manner, in which an allowance was made for the estimated costs that DR providers could incur in reducing their consumption (or running standby generators) at time of high wholesale price[55].

8.3. Results

Three different variations of the distributional impacts analysis in the AEMO forecast plus CRNP were undertaken. The three variations differed in how the costs of the DRM (assumed to be $120 million in NPV terms[56]) and its benefits were allocated between customer classes.

Although the allocation of both DRM costs and benefits between customer classes was varied, all three runs showed positive results for the distributional impacts of the DRM case (in the 'with CRNP' counterfactual case) for customers eligible to participate in the DRM, as well as all other non-residential (i.e., non-residential customers that are not eligible to participate in the DRM) and residential customers in all DNSP service areas in the NEM. All results were expressed in NPV terms over a 20-year period for the average customer within each of those customer groups. This would tend to indicate that the DRM, as assessed here, is unlikely to result in increased costs for any customer class, and to be of assistance in helping those who participate save money on their bills.

Table 19 below shows the results for the AEMO plus CRNP scenario under the assumptions that (a) all DRM costs are allocated across the residential and commercial customer classes in proportion to their consumption volume[57]; and (b) all customers equally share in 70% of the network benefits (with the other 30% being retained by the network business).

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54 California Public Utilities Commission, *California Standard Practice Manual for the Economic Analysis of Demand Side Management Programs and Projects*, October 2001, available at http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF.

55 This was undertaken in response to comments received to the Consultation Paper and at the stakeholders' workshop.

56 It should be recalled that that the $120 million is probably a low estimate (as it does not include any software refresh costs over the 20-year period), and is based on the costs likely to be incurred by only nine retailers.

57 Retailers felt that this was a realistic assumption given that (a) the customer class that is eligible for the DRM is more price sensitive than other customer classes, and (b) the large base of consumption of the non-DRM-eligible customer classes in total would result in the upward pressure on bill of any individual customer within these classes being relatively small.

Table 19: Distributional impacts of the DRM (assuming DR providers incur no implementation or opportunity costs)

NPV of Benefits (costs) Per Residential Customer	Citipower	Ausgrid	SP AusNet	Endeavour	Energex	Ergon	Essential	Jemena	Powercor	SAPN	United
Reduced wholesale prices	$7.10	$17.95	$7.74	$20.00	$12.39	$15.25	$19.37	$6.67	$7.82	$8.58	$6.99
Allocation of costs	-$8.65	-$10.81	-$9.43	-$12.05	-$11.23	-$13.83	-$11.67	-$8.12	-$9.52	-$9.66	-$8.51
Revenue generated by DR providers	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Network Benefits	$21.23	$4.29	$5.57	$4.69	$5.08	$9.01	$9.23	$12.35	$9.26	$8.21	$7.98
TOTAL	$19.68	$11.42	$3.89	$12.63	$6.23	$10.43	$16.93	$10.89	$7.56	$7.13	$6.46

NPV of Benefits (costs) Per Commercial Customer	Citipower	Ausgrid	SP AusNet	Endeavour	Energex	Ergon	Essential	Jemena	Powercor	SAPN	United
Reduced wholesale prices	$56.53	$57.50	$36.85	$85.40	$39.88	$15.93	$66.15	$33.30	$31.99	$29.49	$35.92
Allocation of costs	-$68.85	-$34.64	-$44.88	-$51.45	-$36.17	-$14.45	-$39.85	-$40.55	-$38.96	-$33.17	-$43.74
Revenue generated by DR providers	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Network Benefits	$21.23	$4.29	$5.57	$4.69	$5.08	$9.01	$9.23	$12.35	$9.26	$8.21	$7.98
TOTAL	$8.91	$27.14	-$2.46	$38.63	$8.79	$10.49	$35.52	$5.09	$2.29	$4.52	$0.16

NPV of Benefits (costs) Per DR Customer	Citipower	Ausgrid	SP AusNet	Endeavour	Energex	Ergon	Essential	Jemena	Powercor	SAPN	United
Reduced wholesale prices	$2,401.36	$1,157.31	$1,814.13	$5,668.11	$2,177.97	$1,951.13	$4,290.92	$1,786.71	$2,911.40	$1,994.81	$1,226.74
Allocation of costs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Revenue generated by DR providers	$638.94	$4.66	$638.94	$4.66	$945.44	$945.44	$4.66	$638.94	$638.94	$708.80	$638.94
Network Benefits	$4,016.96	$232.22	$1,623.16	$730.01	$612.00	$850.45	$1,675.77	$2,049.15	$2,543.30	$1,648.65	$1,261.32
TOTAL	$7,057.26	$1,394.18	$4,076.23	$6,402.78	$3,735.41	$3,747.02	$5,971.35	$4,474.80	$6,093.64	$4,352.27	$3,127.01

Source: OGW analysis

The results show that while the distributional impacts are not particularly material, the DRM does provide benefits to all customer classes across the three scenarios tested (though this does not necessarily mean that all customer classes would have net benefits under all possible combinations of cost and benefit allocation) case. DR providers achieve benefits in the thousands over the period, while the net benefits to residential and commercial customers is generally only in the tens of dollars. The primary benefit to DR providers is the wholesale market payments at spot price when they provide DR. However, offsetting this would be the costs to DR providers of providing DR services. For the purposes of this analysis, we have approximated the costs to the DR provider as being half of the value of the DR produced, with the value of DR produced being the pool price multiplied by the volume of DR dispatched at that pool price. This is outlined in the table below.

Table 20: Costs per eligible DR customer

Costs Per DR Customer	Citipower	Ausgrid	SP AusNet	Endeavour	Energex	Ergon	Essential	Jemena	Powercor	SAPN	United
Revenue generated by DR eligible provider	-$319.47	-$2.33	-$319.47	-$2.33	-$472.72	-$472.72	-$2.33	-$319.47	-$319.47	-$354.40	-$319.47

Source: OGW analysis

Using these results, produces the revised outcome for DR providers as shown in Table 21 below.

Table 21: Distributional impacts of the DRM (with an estimate of DR provider implementation and/or opportunity costs)

NPV of Benefits (costs) Per DR Customer	Citipower	Ausgrid	SP AusNet	Endeavour	Energex	Ergon	Essential	Jemena	Powercor	SAPN	United
Reduced wholesale prices	$2,401.36	$1,157.31	$1,814.13	$5,668.11	$2,177.97	$1,951.13	$4,290.92	$1,786.71	$2,911.40	$1,994.81	$1,226.74
Allocation of costs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Revenue generated by DR providers net of costs incurredin doing so	$319.47	$2.33	$319.47	$2.33	$472.72	$472.72	$2.33	$319.47	$319.47	$354.40	$319.47
Network Benefits	$4,016.96	$232.22	$1,623.16	$730.01	$612.00	$850.45	$1,675.77	$2,049.15	$2,543.30	$1,648.65	$1,261.32
TOTAL	$6,737.79	$1,391.86	$3,756.76	$6,400.45	$3,262.69	$3,274.30	$5,969.02	$4,155.33	$5,774.17	$3,997.86	$2,807.54

Source: OGW analysis

For the other customer classes, the benefits are the sharing of the network cost reductions due to lower peak demand and the impact of the reduction in the price of electricity at the wholesale level.

It should be noted, however, that the definition of the customer classes used was constrained by the nature of the information available from distribution companies regarding their sales. We have used the following:

- those customers on demand tariffs have been taken as constituting the customers eligible for the DRM; this will:
  - undercount that population as it is unlikely to include many customers between 100 and 160 MWhpa, and
  - under-estimate the income benefits to those who participate in the DRM because it spreads the DR spot price income across all such customers;
- those non-residential customers that are not on demand tariffs have been defined as commercial; this is likely to undercount those customers; and
- residential customers have been classified as residential.

It should also be noted that the pool revenue income earned by the DR providers enabled by the DRM represents a gross wealth transfer from generators to DR providers. The net wealth transfer, assuming the generators are not subject to take-or-pay fuel contracts, would be equivalent to the gross wealth transfer less the cost not spent on fuel for the amount of generation displaced by DR.

9. Qualitative considerations

9.1. Non-quantifiable benefits

The most significant non-quantifiable benefit of the DRM is its potentially considerable impact on competition. At present, a customer seeking to exercise DR has only three basic ways to do so:

- Take full or partial exposure to pool price
- Participate in a DR program offered by the customer's serving retailer.

Full spot exposure can be undertaken by the customer on his own and essentially precludes any involvement by a retailer. This is not a viable choice for most customers due to the significant costs it imposes on the customer, which include a prudential requirement for purchasing electricity directly from the wholesale market, and the need to monitor pool price in order to manage consumption and costs. Most end-use customers are simply neither willing to post the prudential nor capable technically of doing the required monitoring, and the cost of electricity as a percentage of total business cost does not justify the amount of resource that would be required for the level of reduction in business cost to be gained. The limited applicability of this approach even to large, sophisticated and technically capable customers is evidenced by the very small number of customers that have ever taken up this option. It also sacrifices the benefits the customer derives from the services a retailer provides.

Full or partial spot exposure can also be undertaken through a retailer. However, while this removes the prudential requirement and potentially limits the amount of load exposed to the spot price, it does not reduce the price risk inherent in pool price exposure. This will then require either that the customer monitors pool price (with the costs and risks discussed above) or that the retailer provides that service.

It should also be noted that spot price exposure offers the ability to reduce costs – but at the risk of incurring higher costs. Retailer DR programs and the DRM both change that risk profile. Through either type of program the customer can gain revenue if they reduce consumption when prices are high, without incurring the risk of higher costs in the event they cannot reduce consumption at those times[58].

However, the difficulty with retailer DR programs according to large customers is that the retailers often do not call for DR when pool price is at a level at which the customer is prepared to reduce load, and that the retailers retain what the customers feel is a disproportionate share of the pool price arbitrage.

More generally, except by taking pool price exposure directly with the market, the customer can only provide DR through the serving retailer. Essentially, the retailer can exercise monopsony power. And given the fact that the base price of energy in their retail contract is likely to be more important that the opportunity to provide demand response, it is quite likely that the customer's DR potential will be a secondary concern in the vast majority of cases.

In this regard, the DRM would open that DR potential to competitive offers without any impact on the choice of retailer for basic electricity supply. Such competition would appear to increase customer choice and reduce retailer market power. It would provide a more competitive marketplace for DR as a commodity.

58 Unless perhaps if they are participating in a demand response event and increase their consumption – but this would probably be unlikely, given notification of the event and their agreement to reduce load during it.

9.2. Options for reducing costs

A significant issue with the DRM is its cost under the current design. There would seem to be options for reducing these costs, however.

The most attractive one would be to not make the program mandatory for retailers but rather to rely on competitive forces within the retail market. Such an approach would require that AEMO undertakes the IT modifications required for it to implement and administer the DRM, but then simply allow retailers to enter into DRM services on a voluntary basis – essentially, if they could make an internal business case for it on the basis of its ability to increase their customer base, top-line or bottom-line revenues, or simply help to position or differentiate them in the market.

There is certainly at least some reason to expect that such a business would come forward, given that there are several retailers in the market that actively present themselves as being interested in offering demand response opportunities to their customers as a core offering, as well as several non-retail businesses offering specialist services in demand response or related areas.

Such an approach would avoid imposing large IT costs on all retailers and would much better match cost incurrence with DRM uptake. If participation in the DRM remained small, it would be expected that DRM expenses would also be small. In any case, these costs would only be incurred where the retail business felt they were justified by the benefits they would receive. Perhaps as importantly, such an approach would encourage retailers to undertake only those costs necessary to provide the DRM service, and to do so as efficiently as possible.

In the event that no retailer opted to offer the DRM, other approaches could be considered including not pursuing the matter, or creating a DRM retailer of last resort and auctioning off the role.

Such an approach would also allow synergies to be captured between the IT system changes needed for the DRM and those required for other initiatives currently under consideration, in particular Multiple Trading Relationships and Embedded Networks.

An alternative approach for matching costs and benefits would be to defer implementation of the DRM until such time as a sustained period of growth in peak demand could be seen to be developing. This would avoid the significant costs of the current design of the DRM being incurred at a time in which its benefits (as suggested by the market simulation modelling undertaken in this project) are likely to be very small.

On balance the former approach would seem to be preferable as it would (a) rely on market forces rather than intervention, (b) provide a softer start to the DRM thereby allowing learnings to be integrated prior to large scale implementation and the major costs or market dislocations that could result if problems are only identified at that point, and (c) allow the benefits of the DRM – including its competition benefits as well as the potential benefits it offers to individual customers – to commence earlier. Such an approach would also allow the planning and implementation horizon of the scheme to be extended without significantly impacting on the likely benefits, while also delaying some or even a significant proportion of the implementation costs.

10. The DRM and ancillary services

The DRM has also been seen as having the potential to support new suppliers in ancillary services. This has not been tested quantitatively, but to the extent that the DRM raises awareness of the potential and provides another source of revenue for DR, it could be expected to do so.

On the other hand, the DRM itself is unlikely to be required in order to introduce third-party aggregation in the ancillary services market. The DRM, at its core, provides two new features in the wholesale electricity market:

- It allows a party other than the serving retailer to interact with an end customer regarding the customer's use of electricity at the wholesale market level[59]; that is, it establishes a new class of wholesale market participant and
- It provides for the DR provider (or aggregator) to receive the spot market payment for verified consumption reductions.

Aggregation of DR by the serving Retailer for use in the ancillary services market is already in place. In this regard, third-party aggregation of DR use in the ancillary services market requires only that a third party be recognised as an ancillary services market participant.

Further, third-party aggregation in the ancillary services market does not require spot market payment, and there is already a delivery methodology and payment process for raise services (which is the ancillary service most likely to be provide by DR). It is also understood that the costs of opening ancillary services to third-party aggregators are unlikely to be very high given there does not appear to be a requirement to change retailers' billing or other internal or market facing IT systems.

Based on these considerations, and the fact that (a) opening the provision of ancillary services to third-party aggregators would introduce competition to another commodity currently controlled by the serving retailer, and (b) providing this option would also have the potential to reduce the additional costs (at least for AEMO) of implementing the DRM, there do not seem to be any material reasons to link consideration of this initiative to whether the DRM is established or not, or any material reasons not to proceed with further consideration of this initiative in its own right.

59 In this regard the DRM can be seen as a specific application of the functionality envisaged by the Multiple Trading Relationships initiative.

11. Conclusions

Of necessity the various analyses undertaken in this study have had to rely on a number of assumptions, which are discussed throughout the report. Some will result in over-estimation of the impacts of the DRM and others will result in under-estimation. On balance, we do not feel that the impacts of the assumptions that have been made materially affect the outcome of the analysis in either direction.

More generally, the analysis suggests that the DRM would be likely to achieve several of the objectives that were put forward for it, as discussed in Table 22 below.

Table 22: Likely impacts of the DRM on the objectives put forward for it

Objective	Likely result of the DRM
Greater opportunities for large energy users to reduce their net energy costs and seek more competitive offers for their demand response	The DRM would certainly increase the options for large energy users to use their DR capabilities to reduce their energy costs
Reduced wholesale market costs for all users through greater market competition, potentially also resulting in deferred investment in peak generation	The results of the modelling indicated that the DRM can be expected to exert downward pressure on wholesale market prices, and has the potential to defer investment in peaking generation under conditions where such capacity additions might otherwise be required by growth in peak demand
Deferred network investment through both reduced system-wide peak demand and flow on impacts for network support services of a stronger demand response market	The DRM has the potential to provide flow-on benefits to networks through reduce peak demand at a system and spatial level, but the degree to which it will provide this depends to a large extent on the number and nature of pricing and DR activities undertaken by the networks themselves
Potential to reduce volatility in demand and support new suppliers in ancillary services markets	The results of the modelling indicated that the DRM could assist in reducing demand volatility, and it is very likely that the DRM would support new suppliers in the ancillary services market

The results of the modelling suggest that the DRM would exert downward pressure on wholesale electricity prices and have a flow-on impact to networks. It would certainly assist large energy users in reducing their energy costs and have flow-on benefits on network peak demand.

It is also consistent with competition principles and would open the potential for new and innovative services.

The cost of the DRM as it is currently designed and assumed to be implemented is very high, however, and the current forecast significantly limits its ability to defer capital expenditure on new generation infrastructure for the simple reason that very little additional capacity is expected to be needed over the next 10 to 15 years[60].

60 Other than the return of capacity that has recently been withdrawn or that may be withdrawn in response to the current stagnant demand growth.

There are ways to reduce the costs of the DRM, particularly by allowing its use in the market to evolve due to competitive market forces, and to seek to achieve synergies with other initiatives that are currently being considered for implementation, most notably Multiple Trading Relationships and Embedded Networks.

Where those costs can be managed the DRM has the potential to allow DR to serve as a competitor to peaking generation. Where it can do so successfully – that is by offering a reliable source of generation at specific price points that allow it to compete in the contract market – it will offer an alternative to peaking generation that has the potential to provide material benefits to the market and all consumers in addition to the end-use customers that provide it

Appendix A – Terms of Reference

Extract from Standing Council on Energy and Resources Meeting Communiqué (13 December 2013)

> *Ministers considered the DRM and the work by AEMO in developing the proposed rule change. Ministers also noted the change in market circumstances since the completion of the Power of Choice review. While continuing to recognise the value of demand side reform, ministers agreed to request AEMO to defer lodgement of the rule change proposal and* ***requested officials to undertake further work on DRM, including a cost benefit study****, and report back to ministers at their first meeting in 2014 {emphasis added}.*

Services required: Economic analysis and energy market modelling of the potential costs and benefits of introducing a Demand Response Mechanism policy.

The services required are:

1. **Review of existing DRM work**

The review is to identify:

- the robustness of conclusions, and representations of cost and benefits, in the existing reports;
- whether material gaps remain and further analysis is justified to effectively inform SCER ministers on major costs and benefits in considering the DRM rule change proposal.

2. **Establishing market assumptions**

The DRM modelling needs to incorporate whole-of-government agreed economic and energy market assumptions. This includes, but is not limited to, demand trends, economic growth forecasts and generation technology costs. Consideration will need to be given to how other energy market reforms (including those arising from the Power of Choice review) may affect the DRM's operation, costs and benefits. Particular attention should be given to the attribution of costs and benefits to the DRM where some proportion may be non-additional.

3. **Establishing a hypothetical DRM**

There are three elements to modelling the DRM's impacts.

Uptake

The analysis will require some estimation of the extent and characteristics of end users' participation in the DRM. Participation can be calculated either 'top down' or 'bottom up'.

Variable Costs

The variable costs arising from DRM participation, generally connected to the frequency of high price events, need to be considered. These include the marginal cost incurred by the Australian Energy Market Operator (AEMO) for each additional participant and each DRM event. Retailers may incur similar variable costs. These should be incorporated into the overall CBA.

Fixed Costs

It is expected that AEMO and retailers will need to update their information technology (IT) systems to accommodate the DRM. This is a fixed cost, and will need to be estimated in order to complete the CBA.

Costs provided to AEMO in the development of its detailed design could provide a basis for establishing a broad benchmark of these costs.

Recommendations may be offered as to how these costs might be managed to ensure the policy operates as efficiently as possible.

Consideration should also be given to whether capital investments by end users to facilitate their participation in the DRM are included. This fixed cost would vary given rate of participation.

Sensitivity testing may be required of both implementation cost estimates and of aspects of the proposed DRM design options which may impact on costs, for example the design option which could utilise either a single National Meter Identifier (NMI) or a dual NMI approach.

A consultation paper and final approach paper is required.

Consultation on the approach and assumption paper will take place before the modelling phase.

4. **Wholesale market modelling**

The DRM is expected to have interrelated impacts on the wholesale market, networks, and the hedging market.

Modelling of the wholesale market will therefore be required to consider how future volatility and high price events will impact on levels of participation, the quantum of demand response and benefits generated. It should also be recognised that a successful DRM will temper high price events over time, which could flow through to lower retail prices but may also reduce the incentive to participate in the scheme.

The CBA is expected to identify, disaggregate and quantify the economic benefits and costs, and wealth transfers, arising from the policy under the different scenarios modelled. This should include consideration of impacts on different stakeholder groups, specifically including benefits for DRM participants, large energy users, and wider consumer price impacts.

5. **Modelling requirements**

The proposed modelling approach needs to be capable of forecasting up to the medium term (between 15 and 25 years). The final CBA will need to quantitatively include wholesale market and network benefits.

6. **Sensitivities and scenarios**

The CBA will require modelling a number of cases and sensitivities to inform a robust understanding of the net costs and benefits of a potential DRM.

The analysis is to consider aspects of the design that could significantly impact on the costs, including whether a modified design could be implemented more cost effectively. The cost analysis could be conducted post-processing of the modelling results.

All scenarios will be agreed with the Department.

7. Qualitative analysis

The overall CBA will also involve qualitative analysis, which will require evidence-supported assessment and/or reasoned consideration of the following issues:

- Key economic issues which would impact on overall CBA
- Key implementation issues which would impact on overall CBA
- Benefits or costs which may be difficult to quantify but should be considered, such as impacts on competition and broader consumer benefits
- Timeframe or scenario considerations: if the DRM is not currently net beneficial, identifying some indicators which indicate when the DRM may become beneficial
- Potential alternatives to DRM in achieving greater demand side participation originally intended to be achieved by the DRM

8. Deliverables

Deliverables for the project:

- Consultation ‘Approach’ Paper (outlining CBA approach and assumptions)
- Finalised Approach Paper and summary of submissions
- Final Report

The scenarios to be modelled as agreed with the Department of Industry.

Appendix B – Note on Tasmania and ACT

B.1 Tasmania

B.1.1 Generation impacts

Generation in Tasmania is almost exclusively hydro based except in drought years. As such generation in Tasmania is energy constrained (i.e., it is limited by the availability of water or the need for water in other uses) rather than capacity constrained (as is the case in the rest of the NEM). It is not a case of whether there is enough capacity available: the turbines can produce more than sufficient energy per unit time than is needed. Rather, the constraint is having enough water over the days, months and years to run through the turbines.

The hydro system also has a very low incremental cost of production. The economic value of its generation is related to the alternative source of generation (i.e., what would need to be used if water were not available).

In order to ensure the market (through AEMO) dispatches it within the constraints of available water, Hydro Tasmania must bid a price that reflects the prevailing economic value of the water. If it bids too low, AEMO will dispatch hydro to the point where it would exhaust the available water (in the extreme, dams would empty). If it bids too high, AEMO will dispatch too little and storages may rise (in the extreme to the point of spilling).

The water available at any time will vary over a day, week and throughout the year and over a series of years depending on inflows, outflows for downstream use and the size of storages above and below the multiple power stations in each group of generators that enable water to be held back for times when the alternative (capacity limited) generation is high cost, thus maximising the economic value of the water. Because the water available at any time can vary, so must the price that is bid to the market. For example, when it rains, small intermediate storages may fill unless water is released (through associated power stations) requiring lower prices for those stations but at the same time allowing larger storages to fill by raising the price for generation from stations associated with them. At other times when water is to be released from the larger stations the relativity of price will be reversed.

Only a full hydrological model of inflows, storages and outflows together with a model of the market can assess the value and thus the appropriate price for a hydro scheme with significant storage with any accuracy.

In the absence of hydrological modelling, market models to determine bid prices on which hydro will be dispatched and possibly determine price in Tasmania must employ approximations or alternatively set energy production targets that ensure target levels of energy are produced but do not accurately determine regional price. Depending on the purpose of the each particular analysis, models can be set up using these approximations on a case by case basis and produce reasonable forecasts of the ***average*** Tasmania wholesale price.

However, to assess the impact of the DRM, it is necessary to produce robust estimates of the occurrence and level of the limited number of high (in fact the highest) prices that will occur during the year. This is a far more difficult task and is dependent in Tasmania on modeller input to a far higher degree than in the other NEM regions. The following explains why this is the case and considers situations where Basslink is constrained and where it is not.

High prices in Tasmania can occur when Basslink is not constrained and the Tasmanian and Victorian prices are both high (at which time they will only differ by the loss factor in each state) or when Basslink is constrained and price is being set by the Tasmania price which will be set by Hydro Tasmania.

For price to be high enough to trigger a DRM response when Basslink is constrained requires either:

- An unusual condition of low generation capacity due to outages in Tasmania and high import into Tasmania leading to high priced generation being called on in Tasmania (these are rare events, and are not related to seasonal factors); or
- Victorian prices at very high levels (which is more frequent in summer) and Hydro Tasmania bidding slightly lower but nevertheless high enough to ensure that it continues to export thereby maintaining the constraint on the link;

For price to be high enough to trigger a DRM response when Basslink is not constrained requires either:

- An unusual situation of coincident shortfalls of generation in both regions (a quite rare coincidence of events); or
- High price in Victoria (which is more frequent in summer) but Basslink flow below capacity because of the price offered by Hydro Tasmania being high enough that flow into Victoria is not maximised

Unusual shortfalls due to outages in Tasmania, while rare, can occur at any time of year. High prices in Victoria are more likely in summer but can occasionally occur throughout the year. The key point, however, is that because of the energy limited nature of the Tasmanian generation fleet (and therefore surplus of generating capacity) sufficiently high price to trigger a DRM response is dependent on the bidding of Hydro Tasmania.

Because of Hydro Tasmania's dominant position in the Tasmania market and its contracted rights to instruct Basslink (as an MNSP) on the amount of capacity and the price Basslink will offer, Hydro Tasmania is subject to regulatory constraints on its bidding behaviour. The nature of these constraints has varied over the years.

Accordingly, modelling of prices at the level that will trigger the DRM is very dependent on regulatory constraints – which as noted have varied over the years. Models do not readily accommodate such constraints especially where they would allow high prices.

In summary robust modelling of the Tasmania market price requires assessment of water value or the use of broad approximations but is least viable in the case of those high price events that are really the only points we are interested in, as it is only at those times that the DRM can be expected to operate. This is the case because it is these times when bidding behaviour restrictions will be in place on Hydro Tasmania.

As a result, **our view is that it is not practicable to use any standard modelling techniques to assess the impact of the DRM on wholesale prices in Tasmania.**

B.1.2 Distributional impacts

Distributional impacts are comprised of two primary components: reductions in wholesale market price and changes in network costs and prices.

As explained above, it is not possible to assess the impact of the DRM on:

- wholesale market prices in Tasmania, and therefore on
- the amount of DR the DRM is likely to result in Tasmania.

Without the magnitude of the DR caused by the DRM it is impossible to assess the impact of the DRM on network costs (or revenue). It is worth noting however, that high price events in Tasmania are primarily driven by Hydro Tasmania's bidding behaviour. There is likely to be a slightly greater likelihood of prices being higher in Tasmania when the Victorian price is high. This is likely to be in the summer, all other things being equal. To the extent that the DRM results in summertime deployment of DR in Tasmania, the impact on Tasmanian network capacity requirements will be minimal as the Tasmanian networks experience their peak demand in the winter.

B.2 ACT

A separate analysis of the impact on the ACT was not undertaken as it is defined as part of the NSW NEM region.