ACIL ALLEN CONSULTING

REPORT TO
NSW DEPARTMENT OF PLANNING, INDUSTRY AND ENVIRONMENT
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ENERGY SECURITY SAFEGUARD SCENARIO PROJECTIONS

MODELLING REPORT

FINAL REPORT

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EXECUTIVE SUMMARY

ACIL Allen Consulting (ACIL Allen) has been engaged by the New South Wales (NSW) Department of Planning, Industry and Environment (the Department) to provide National Electricity Market (NEM) projections to assess the impact of the NSW Government's Energy Security Safeguard on NSW electricity prices and retail bills.

ACIL Allen has undertaken market projections of the following four scenarios:

1. **Business as usual** (BAU): NSW maintains current energy policy schemes. Victoria and Queensland pursue their 2030 renewable energy targets via reverse capacity auctions. The Large-scale Renewable Energy Target (LRET) is retained in its current form. No new schemes are introduced beyond existing state and federal schemes.
2. **Expanded energy savings scheme** (Expanded ESS): As for the BAU plus NSW extends its existing energy savings scheme beyond 2025 with a target of 13% by 2030
3. **Peak demand scheme**: As for the BAU plus NSW introduces a new scheme from 1 January 2022 which supports deployment of demand response technologies
4. **Combined demand scheme**: As for the BAU plus the combined impact of the expanded ESS and the peak demand scheme described above.

ACIL Allen has undertaken projections of retail prices and bills for NSW consumers under the BAU as well as the combined demand scheme.

The market projections are based on ACIL Allen's June 2019 Reference case[1] assumptions and cover the calendar years 2020 to 2030. Wholesale projections are presented on a calendar year basis unless noted otherwise. Retail projections are presented on a financial year basis. Prices are presented in 2019 real dollars unless stated otherwise.

The modelling component of the analysis has been undertaken using ACIL Allen's proprietary model *PowerMark*. All assumptions used in the modelling are taken from publicly available or in-house information and databases maintained by ACIL Allen, except for input assumptions of the three schemes which were provided by the Department as noted in the report.

This report provides an overview of the key assumptions and projection results for each of the four scenarios, as well as the projected retail prices and bills under the BAU and the combined demand scheme.

Key findings

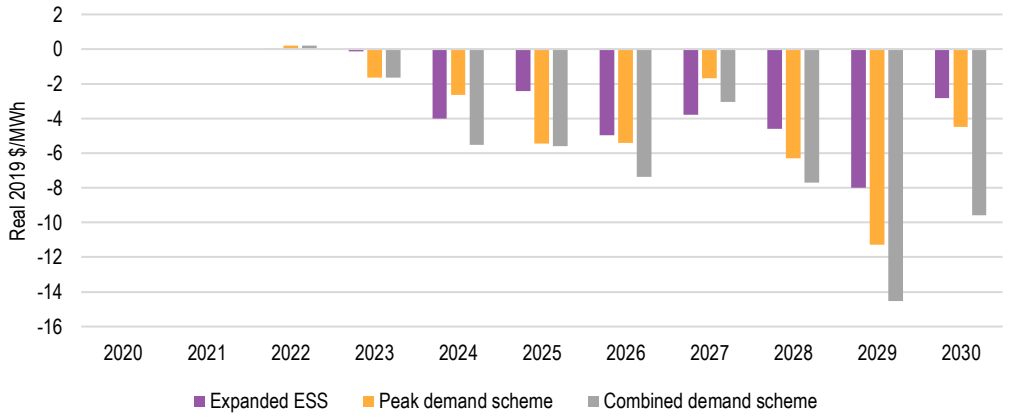
As an important input into the retail cost stack for consumers, the changes projected for the wholesale cost of electricity is a key driver for the impacts of the policy. For residential customers, it is the load-

[1] The latest Reference case projections available at the time ACIL Allen commenced the market modelling presented in this report. For the sake of continuity, the same set of input assumptions were used for scenarios modelled later in the engagement.

weighted wholesale price which is the key indicator for future changes in the wholesale cost component of retail bills.[2]

The combined demand scheme scenario is projected to have the largest downward impact on the NSW load-weighted price over the modelling horizon, as seen in Figure ES 1, with the greatest price impacts projected at the end of the decade as the scheme's target energy savings increase.

FIGURE ES 1 PROJECTED IMPACT ON NSW LOAD-WEIGHTED PRICE RELATIVE TO THE BAU BY SCENARIO



Note: Calendar year data

SOURCE: ACIL ALLEN CONSULTING

Table ES 1 presents the differences in retail bills between the combined demand scheme and the BAU scenario. The key findings are:

- The largest cost decrease occurs in the wholesale cost of energy modelled in the scenario with this delivering total projected savings of $304 in real terms over the period to 2030
- Further related savings occur in retail cost and margins (some of these costs are expressed as a percentage of wholesale cost)
- Offsetting these savings are direct costs relating to the new schemes in place which total around $181 over the period to 2030. These include:
  - Increased costs of the expanded ESS totalling $106/household to 2030 (note that the expanded ESS costs would also extend beyond 2030)
  - Costs incurred from the Peak demand scheme totalling $75/household to 2030.

It should be noted that the costs of the peak demand scheme have been shared equally across all NSW electricity consumption in calculating these residential cost impacts. Should some larger customers be exempt from liability, then the cost impacts to residential customers would be higher than those shown.

The retail projections do not consider avoided network losses or avoided network expenditure due to the energy savings and peak demand reductions under the combined demand scheme although if these did occur this would represent an incremental saving to NSW electricity consumers.

[2] A load-weighted price is more reflective of the net system load profile which retailers are charged by AEMO compared with time-weighted wholesale prices.

TABLE ES 1 PROJECTED CHANGE IN NSW RESIDENTIAL RETAIL BILL: COMBINED DEMAND SCHEME CHANGE FROM BAU (REAL 2019 $)

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Regulated networks	$0	$0	$1	$1	$1	$2	$3	$6	$5	-$2	$1
Wholesale	$0	$0	$2	-$7	-$25	-$30	-$41	-$19	-$31	-$97	-$56
LRET - LGC cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SRES - STC cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy savings scheme	$1	$2	$3	$4	$4	$5	$11	$18	$18	$19	$20
Peak demand scheme	$0	$0	$1	$3	$4	$6	$8	$10	$12	$15	$17
Retail cost and margin	$0	$0	$0	-$1	-$2	-$3	-$4	-$2	-$3	-$10	-$6
Residential retail bill	**$1**	**$3**	**$7**	**$0**	**-$18**	**-$21**	**-$23**	**$13**	**$2**	**-$75**	**-$24**

Note: Based on a representative NSW residential customer with annual consumption of 6 MWh per annum on a market offer. Values rounded to nearest whole dollar value.

SOURCE: ACIL ALLEN ANALYSIS

1 BUSINESS AS USUAL

The Business as usual (BAU) scenario assumes all existing state and federal energy policies affecting the NEM. It draws from ACIL Allen's internal Reference case assumptions as at June 2019.

This chapter outlines the input assumptions and summarises the market projections under the BAU.

1.1 Input assumptions

The principal underlying assumptions of the BAU scenario are summarised in Table 1.1. It includes assumptions for macro-economic variables, greenhouse gas emission policies, electricity demand, supply side assumptions around existing and new entrant electricity generators, fuel prices, interconnectors and the representation of bidding behaviour in the *PowerMark* model.

All assumptions used in the modelling are taken from publicly available or in-house information and databases maintained by ACIL Allen, except for input assumptions of the three schemes which were provided by the Department (these are noted within the report). In addition, the Department requested that ACIL Allen assume a fixed closure date of Vales Point power station in 2028 at the end of its technical life.

TABLE 1.1 KEY ASSUMPTIONS USED FOR THE BAU

Item	Summary of assumption
Macro-economic variables	– Exchange rate of AUD to USD converging to 0.75 AUD/USD – Inflation of 2.5% p.a.
Federal greenhouse gas emission policies	– Between 26 and 28 percent reduction in GHG emissions below 2005 levels by 2030 – No emissions scheme required in the NEM over the period 2021 to 2030, assuming an economy-wide pro-rata share of abatement across all sectors[3] – Retention of the LRET in its current form
State Based Schemes	– Inclusion of committed plant under the first stage of the VRET auction – Incremental renewable capacity such that VRET targets are met (25% of renewable generation by 2020 and 40% renewable generation by 2025) – Inclusion of Queensland's "Renewables 400" reverse auction from 2021. – Deployment of an additional 600W by 2025 of CleanCo renewable capacity in Queensland included ("Renewables 400" assumed to be included as a part of the CleanCo portfolio, bringing the aggregate capacity for the portfolio to 1,000MW) – Incremental renewable capacity such that QRET 2030 target of 50% renewable generation is met

[3] Based on the Department of Energy and the Environment's 2018 emission projections.

Item	Summary of assumption
Electricity demand	– ACIL Allen has used the official projection of regional summer and winter peak demand and annual energy published in the Electricity Statement of Opportunities (ESOO) by AEMO in August 2018[4]. The demand projection is based on the neutral growth outlook and the 50 per cent probability of exceedance (POE50) level peak summer and winter peak demands. – Adjustments have been made to incorporate ACIL Allen's own projections of the uptake of rooftop solar and behind-the-meter battery storage in both the residential commercial sectors, and electric vehicles. These projections are internally consistent with other assumptions (such as exchange rates, capital costs, network tariffs etc.) adopted in ACIL Allen's internal Reference case.
Supply side	– Named new entrant projects are included in the modelling where there is a high degree of certainty that these will go ahead (i.e. project has reached final investment decision) – 600 MW of additional "corporate PPA" capacity assumed to enter in 2020-2021 across Queensland, New South Wales and Victoria – Beyond the above, new entrant capacity is introduced in the model only on a commercial basis – Committed or likely committed generator retirements included where the retirement has been announced by the participant (i.e. Liddell) – Retirements of other existing generators where the generator is projected to be unprofitable over an extended period of time – Snowy 2.0 included, assumed to be commissioned in 2026
Gas as a fuel for electricity generation	– Gas market is modelled in ACIL Allen's GasMark Australia model – Gas prices for power generation are projected to rise from $9-$10/GJ to $10-$12/GJ by 2030 in real 2019 terms. By 2035 gas prices reach LNG netback, equating to $11-$13/GJ in real 2019 terms.

Coal as a fuel for electricity generation	– The marginal price of coal for electricity generation is assessed in consideration of the specific circumstances for each generator considering:
	  – Short term supply issues in New South Wales
	  – Suitability of coal for export and the assumed international thermal coal price
	  – Location of power station in relation to the mine and export terminals
	  – Mining costs
	  – Existing contractual arrangements
	– International thermal coal prices are assumed to converge to real 2019 US$61.50/t in the long term

Representation of bidding behaviour	– Contracted capacity:
	  – Minimum generation levels are offered at negative of zero price
	  – Remaining contracted capacity offered at short run marginal cost
	– Remaining capacity:
	  – Maximisation of dispatch for price takers
	  – Maximisation of net uncontracted revenue for price makers

New entrant capital costs (AUD$/kw, real 2019)	– Wind
	  – $2,050/kW in 2019
	  – $1,700/kW in 2030
	– Solar (Single Axis Tracking)
	  – $1,450/kW in 2019
	  – $1,080/kW in 2030
	– Storage (with four hours)
	  – $1,875/kW in 2019
	  – $980/kW in 2030

[4] AEMO's 2019 ESOO forecast was published after ACIL Allen commenced the market modelling presented in this report. For the sake of continuity, the 2018 ESOO demand was retained as the input assumption for all modelled scenarios.

Item	Summary of assumption
Weighted average cost of capital (WACC)	– The required returns for new entrant power generation projects are derived using a discounted cash flow model with a discount factor set at the investment's assumed WACC. We use a standard post tax real officer WACC formulation. – Our estimate of the current post tax real WACC for power generation projects is 4.2 percent based on the lower current interest rates. However, we assume that interest rates normalise by the early 2030s and similarly the WACC recovers to our long-term view of 6.13 percent.
Interconnectors	– Existing interconnection included – ISP[a] Groups One, Two and Three projects included – QNI stages one and two – EnergyConnect – VIC to NSW upgrade – SnowyLink

[a] AEMO's 2018 Integrated System Plan

SOURCE: ACIL ALLEN CONSULTING

1.1.1 PowerMark

ACIL Allen's in-house model *PowerMark* has been developed over the past 20 years in parallel with the development of the NEM. The model is used extensively by ACIL Allen in simulations and sensitivity analyses conducted on behalf of industry clients.

PowerMark effectively replicates the AEMO NEM dispatch engine. This is achieved through the use of a large-scale linear program (LP) based solution. In accordance with the NEM's market design, the price at any one period is the cost of the next increment of generation in each region (the shadow or dual price within the LP). The LP seeks to minimise the aggregate cost of generation for the market as a whole, whilst meeting regional demand and other network constraints.

Portfolio optimisation

A distinctive feature of *PowerMark* is the inclusion of a portfolio optimisation module. This component allows selected portfolios to seek to maximise net revenue positions (taking into consideration contracts for differences) for each period. These modified generator offers are then resubmitted to the settlement engine to determine prices and dispatch levels. Each period is iterated until a convergence point (based on Nash-Cournot / Supply Function equilibrium theory) is found.

The benefits of the optimisation module are twofold:

— portfolios structure their generation offers in an economically rational way. From past experience, this optimisation process generates strategies which align with the behavioural reality in the marketplace

— second-round effects from fundamental changes to the market — such as a policy change, addition or closure of generators, transmission augmentation or creation of additional regions, can automatically be incorporated without imposing explicit constraints or directions for incumbents.

PowerMark can be configured to run at varying time intervals, however running at higher resolution increases run time exponentially due to the sophisticated portfolio optimisation module. The model is typically run at an hourly resolution, as has been done for the projections summarised in this report.

New entrant supply

PowerMark introduces new investment in generation capacity based on price signals, rather than using some form of centralised planning criteria. This approach attempts to mimic the investment decisions made by project proponents. The modelling assumes perfect foresight and introduces the most profitable new entrant providing once it is introduced it meets its required investment return over the long term.

It should be noted that this approach to new entry – and the fact that the modelling is carried out on P50 demand conditions – may result in reserve levels which are below what AEMO might consider to be required to ensure reliability criteria are met. Where this is the case, it is implicitly assumed that

AEMO utilises its Reserve Trader Role to contract for additional supply and that this supply is offered to the market at the market price cap and therefore only operates when unserved energy is likely to occur. This additional supply therefore does not affect market price outcomes projected.

Plant closures

ACIL Allen assesses the net revenue on a per kW/year basis for each generation unit installed in the NEM (capital return per installed kW after accounting for variable costs and fixed maintenance costs). Where net revenues become negative on a sustained basis, the relevant plant is retired. While this is in effect an exercise in perfect foresight which would not be available to plant owners, we consider that on balance, it is a reasonable approach to modelling likely outcomes.

The O&M cost profiles for major coal-fired power station is not smooth as it is corresponds with major maintenance cycles. However, the modelling assumes a smoothed fixed O&M profile for each station in the NEM as ACIL Allen does not have detailed maintenance schedule information. Therefore, the closure of individual units, as suggested by the modelling, may in practice, be brought forward or delayed slightly by the actual timing of major maintenance outages. In addition, ACIL Allen does not have detailed information on abnormal capital expenditure items – such as those required for life extensions beyond typical economic lives. However, to address this issue for life extension, capital expenditures are assumed in the modelling to equate to an increase in fixed O&M by 100 percent at the time of life extension.

1.2 Results summary

BOX 1.1 MEDIAN ANNUAL WHOLESALE ELECTRICITY PRICE PROJECTION

The electricity price projections presented in this report have been normalised for weather and plant outage effects and represents broadly the median or central case rather than the mean of the distribution of possible annual pool price projections. The annual electricity price distribution exhibits positive skewness (long right-hand side tail). Lower annual pool price projections are associated with cooler summers/warmer winters/lower outage rates and higher annual pool price projections are associated with hotter summers/colder winters/higher outage rates. The lower annual price projections are less volatile and cluster close to the median projection as they are limited by the underlying marginal costs of the various plants operating in the market. The higher annual price projections are more volatile and spread over a longer tail above the median projection. This is because higher prices driven by higher demand and/or more plant outages are a result of less effective competition and are only limited by the market price cap. Hence the average or mean of the annual price projections is usually above the median annual price projection. Throughout this chapter reference will be made to average prices – these are averages of the hourly projected prices from the median or central reference case.

When generators and retailers contract they are more likely to price the contracts at prices in excess of the median price, typically at or above the mean. The extent that contracts are priced above the mean depends on the relative risk appetites of participants. Stand-alone retailers tend to be thinly capitalised and have lower risk appetites than generators. Therefore, when participants contract their output forward, it is reasonable to add a premium to the median prices in this report to reflect the premium that contracts would be sold for in the market. If requested by clients, ACIL Allen undertakes a stochastic analysis to estimate the distribution of annual prices due to weather and power station availability variations.

SOURCE: ACIL ALLEN

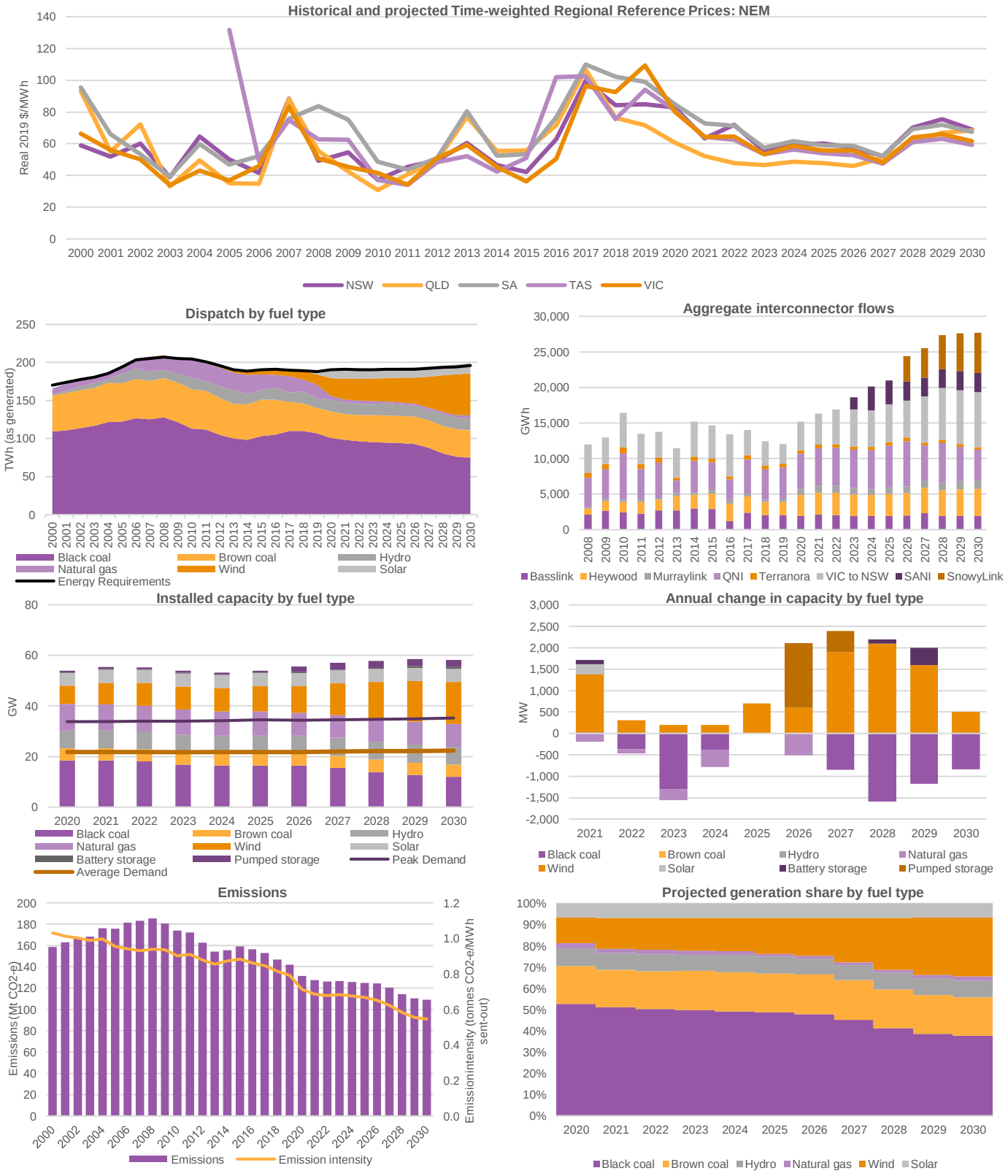
The projections for the NEM and the NSW region under the Business as usual scenario are summarised in Figure 1.1 and Figure 1.2.

In NSW and across the NEM, average annual wholesale electricity prices are projected to decline in the period to 2023 to levels of around $60/MWh. This decline is driven by a combination of several thousand MW of additional renewable capacity committed to enter the market in this period, and the assumed commissioning of interconnector upgrades between Queensland and NSW, Victorian and NSW and a new link between South Australia and NSW.

Average wholesale prices are projected to continue to decline in the medium term to lows of around $50/MWh by 2027, driven primarily by the increase in generation supply in Victoria and Queensland resulting from their respective renewable energy targets. In addition, the entry of the Snowy 2.0 pumped hydro system in 2026 is projected to have additional downward impact on the NSW wholesale price.

In 2028, Vales Point coal power station exits the market, per the input assumption provided by the Department. This closure along with the projected closure of Gladstone power station in 2029 are the key drivers behind the projected rise in wholesale prices across the NEM at the end of the decade, to levels of $60-$70/MWh. The power stations are projected to be replaced by a combination of wind and battery storage capacity. Other thermal closures in the NEM include Torrens Island A and Liddell in 2022 and 2023 respectively (per AGL's announcement in August 2019); Torrens Island B in 2023 (projected to become uneconomic once the EnergyConnect interconnector between NSW and SA comes online), and Newport in 2025 (projected to become uneconomic as VRET capacity ramps up).

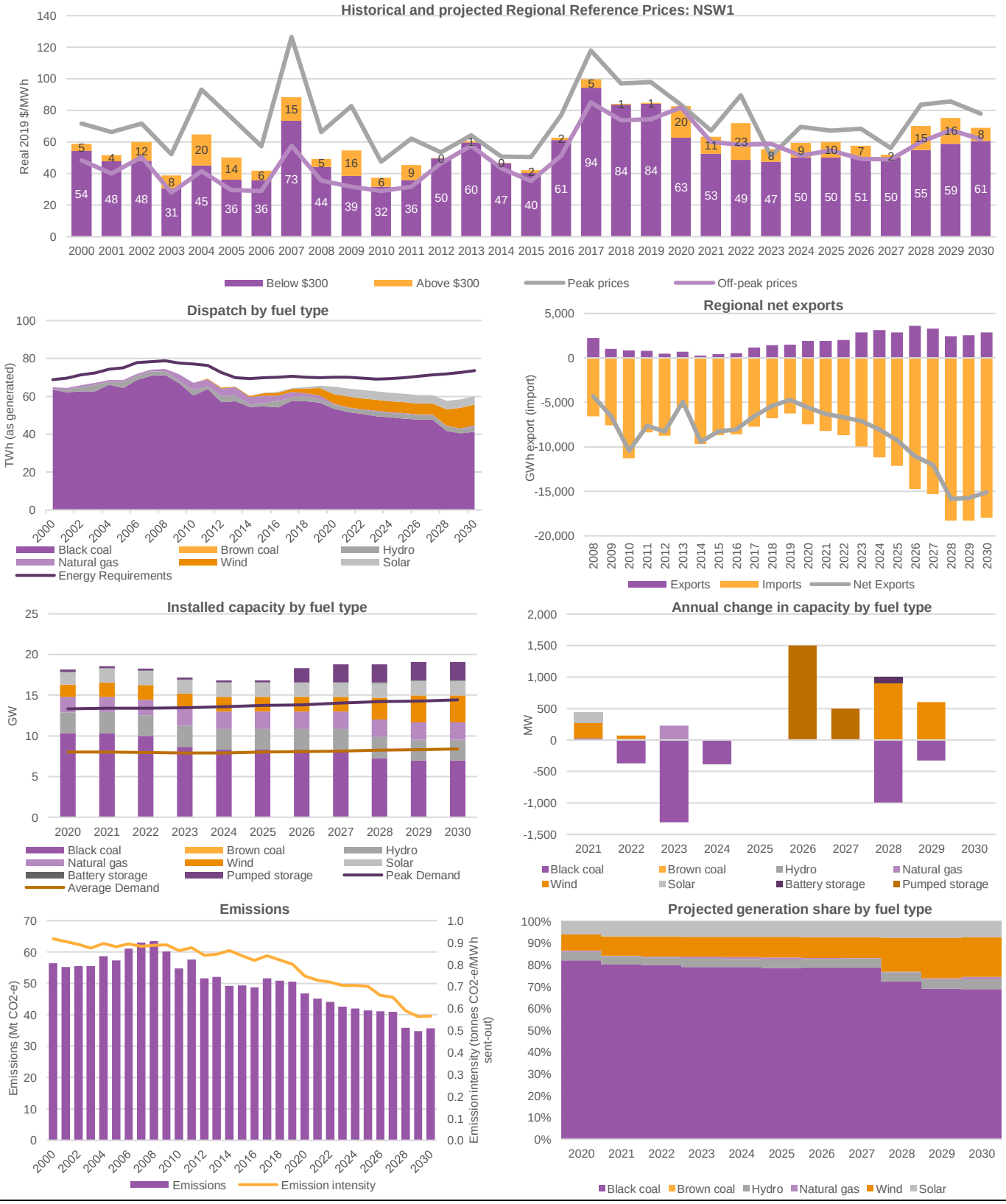
FIGURE 1.1 SUMMARY OF NEM OUTCOMES UNDER THE BAU



Note: Calendar year data. Actuals from AEMO to December 2019. EnergyConnect is denoted as "SANI".

SOURCE: ACIL ALLEN POWERMARK MODELLING

FIGURE 1.2 SUMMARY OF NSW OUTCOMES UNDER THE BAU



Note: Calendar year data. Actuals from AEMO to December 2019.

SOURCE: ACIL ALLEN POWERMARK MODELLING

2 SCENARIOS

This chapter provides a summary of the input assumptions of the three scenarios and projected impacts on the NSW region under each scenario relative to the BAU. The summary of key impacts includes annual impact on NSW average and peak demand, wholesale price, dispatch by fuel type, capacity by fuel type, net interregional flows and emissions.

2.1 Expanded energy savings scheme

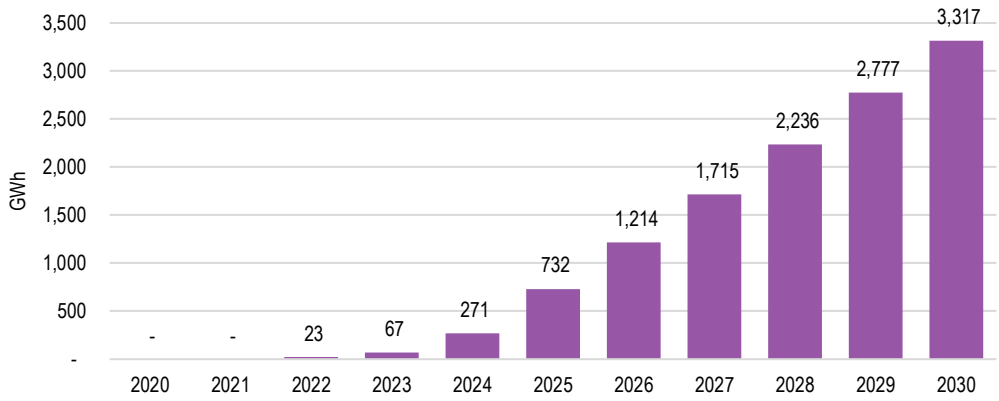
In this scenario the existing energy savings scheme is extended beyond 2025, with a more ambitious energy savings target of 13% by 2030.

2.1.1 Input assumptions

The Department provided ACIL Allen with a projection of incremental energy savings expected to be achieved (relative to the Business as usual scenario) if the energy savings scheme is extended and the target lifted to 13% by 2030. This series is shown in Figure 2.1. Incremental energy savings are forecast from 2022 onwards, rising to about 3,300 GWh by 2030.

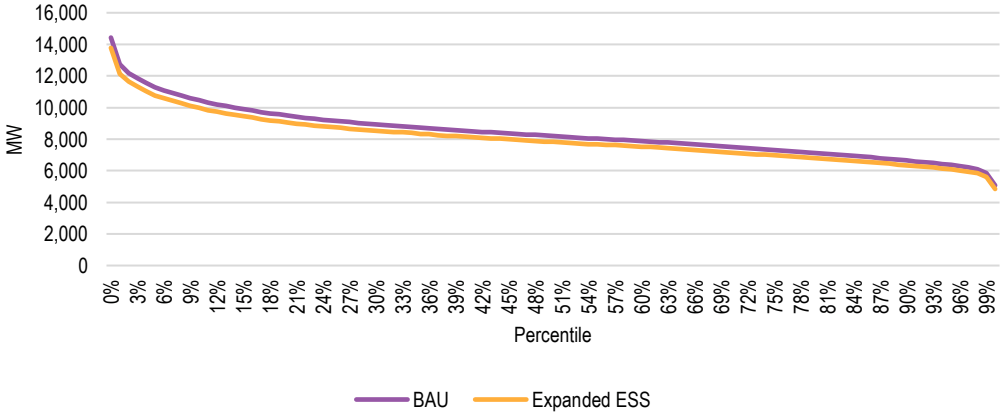
ACIL Allen applied the annual energy savings to the Business as usual demand trace on a proportional basis i.e. in a given interval for a given year, the demand was reduced proportionately to its ratio to the annual energy requirement. In other words, the demand was reduced more in high demand periods than in low demand periods in MW terms. A comparison of load duration curves in the year 2030 is provided in Figure 2.2.

FIGURE 2.1 DEPARTMENT'S FORECAST OF INCREMENTAL ANNUAL ENERGY SAVINGS UNDER THE EXPANDED ESS - BY CALENDAR YEAR



SOURCE: THE NSW DEPARTMENT OF PLANNING, INDUSTRY AND ENVIRONMENT

FIGURE 2.2 CHANGE IN LOAD DURATION CURVE UNDER THE EXPANDED ESS IN CALENDAR YEAR 2030



SOURCE: ACIL ALLEN CONSULTING

2.1.2 Results summary

Under the expanded ESS, annual average NSW demand and peak NSW demand are projected to be up to 380 MW and 650 MW lower by 2030, respectively, relative to the BAU. As a result, there is an average downward impact on NSW load-weighted price of $3.40/MWh (real 2019) in the period 2022 to 2030.

In the period 2022 to 2027, the lower demand displaces a combination of black coal, hydro and natural gas dispatch. By 2028, wholesale prices in the BAU reach a level sufficient to incentivise new entrant wind and battery storage capacity (replacing Vales Point power station closing in that same year). However up to 900 MW of this wind capacity and 100 MW of battery storage is displaced by 2030 under the expanded ESS scenario as a result of the lower demand.

Overall the region's imports are projected to be lower than under the BAU. The impact on regional emissions is small, on average representing a less than one percent decrease in annual emissions.

FIGURE 2.3 SUMMARY OF CHANGES IN NSW OUTCOMES UNDER THE EXPANDED ESS RELATIVE TO THE BAU

Note: Calendar year data.

SOURCE: ACIL ALLEN POWERMARK MODELLING

2.2 Peak demand scheme

In this scenario, a new peak demand scheme is introduced to support technologies that can shift demand away from peak periods.

2.2.1 Input assumptions

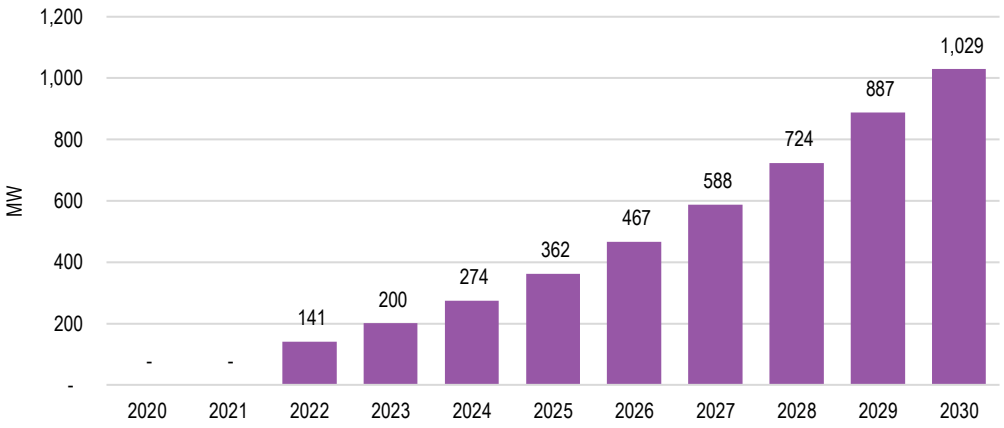
The Department provided ACIL Allen with a forecast of annual peak demand reduction expected to occur as a result of the introduction of the scheme, as shown in Figure 2.4. The scheme commences 1 January 2022 and is projected to result in up to 1,029 MW reduction in annual NSW peak demand by 2030.

ACIL Allen has assumed that the upper 25th percentile of demand periods in each year (of the BAU scenario) is impacted by the scheme. The reduction is applied on a proportional basis e.g. in 2030, 0% of the 1,029 MW reduction is applied to the 75th percentile, with the reduction increasing linearly to 100% at the 100th percentile (as illustrated in Figure 2.5). This produces a load duration curve in 2030

as shown in Figure 2.6. The demand reduction primarily impacts the evening peak period (6-9pm) and to a smaller extent the morning peak (7-9am).

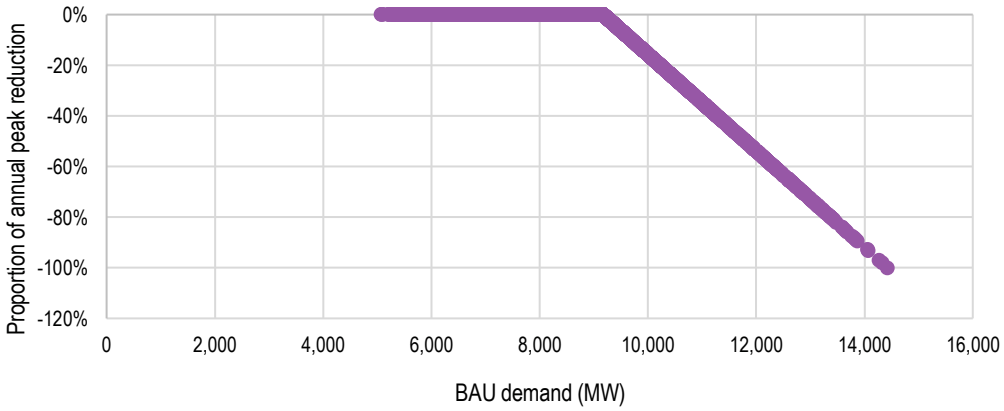
The curtailed energy in peak demand periods is assumed to represent energy savings for the purpose of the market modelling. The total curtailed energy represents less than 0.8% of annual consumption in any year. If this demand was displaced to another time of day, the impact on NSW wholesale prices would depend on when the demand is displaced to – if at times of low demand such as the middle of the day, the impact would be negligible.

FIGURE 2.4 DEPARTMENT'S FORECAST OF ANNUAL PEAK DEMAND REDUCTION UNDER THE PEAK DEMAND SCHEME - BY CALENDAR YEAR



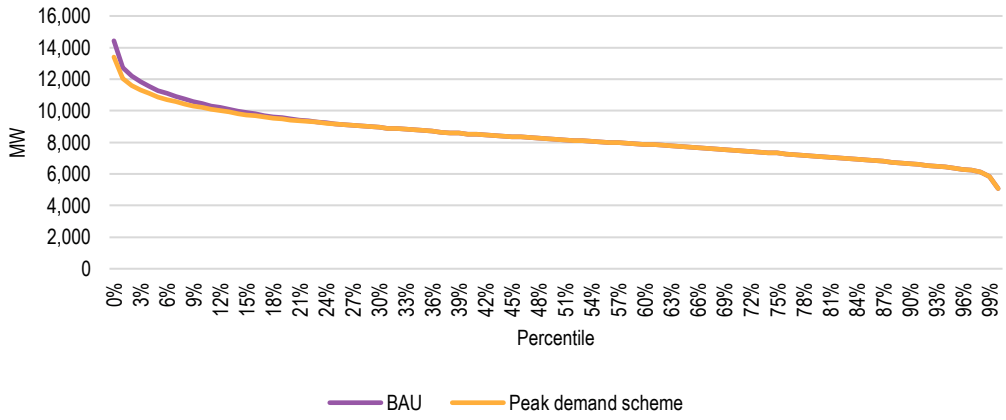
SOURCE: THE NSW DEPARTMENT OF PLANNING, INDUSTRY AND ENVIRONMENT

FIGURE 2.5 PROPORTION OF ANNUAL PEAK REDUCTION APPLIED TO BAU DEMAND TRACE IN CALENDAR YEAR 2030



SOURCE: THE NSW DEPARTMENT OF PLANNING, INDUSTRY AND ENVIRONMENT

FIGURE 2.6 CHANGE IN LOAD DURATION CURVE UNDER THE PEAK DEMAND SCHEME IN CALENDAR YEAR 2030



SOURCE: ACIL ALLEN CONSULTING

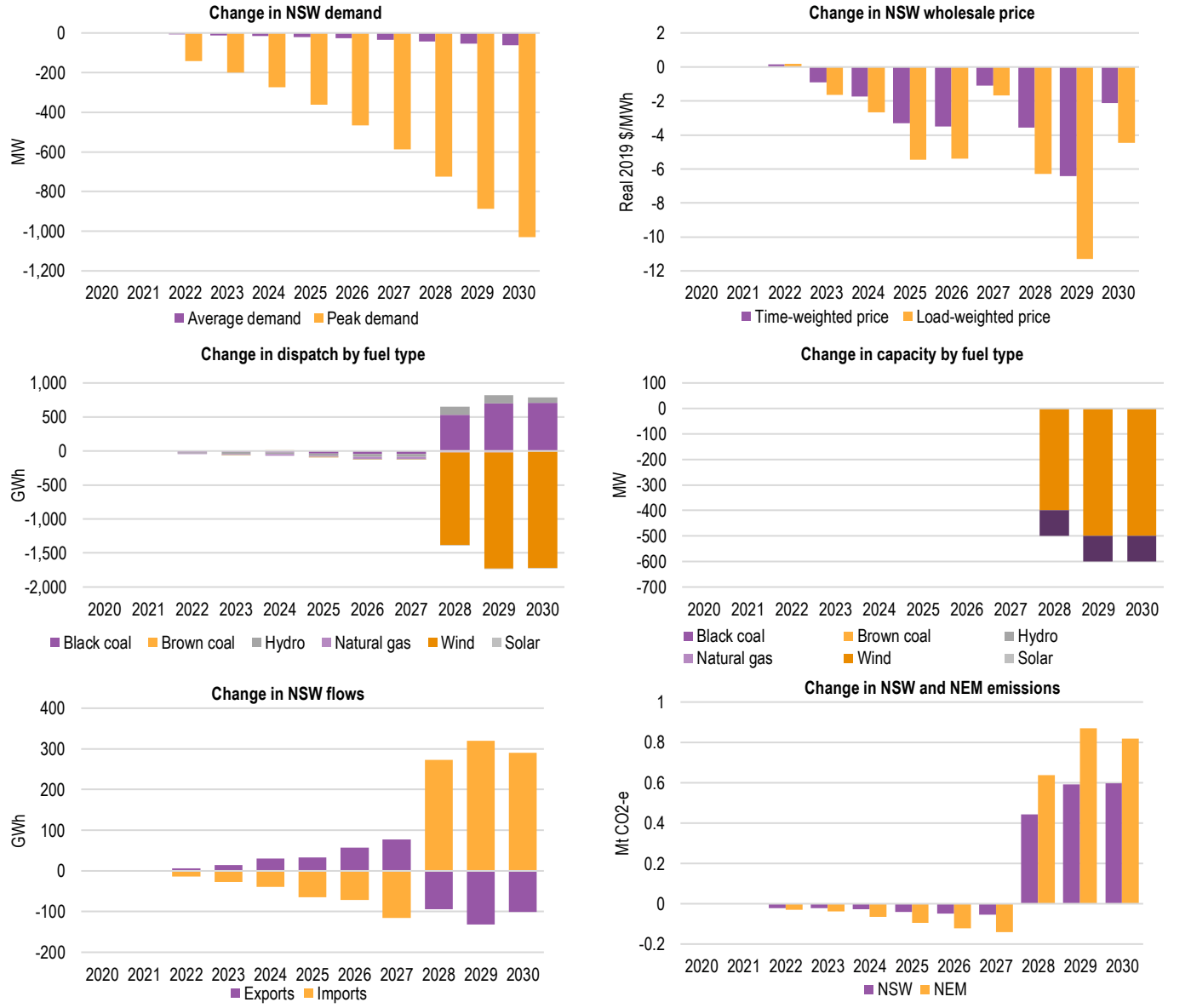
2.2.2 Results summary

Under the peak demand scheme, annual average NSW demand and peak NSW demand are projected to be up to 61 MW and 1,029 MW lower by 2030, respectively, relative to the BAU. The reduction in demand drives the lower load-weighted price outcome in NSW, which is on average $4.30/MWh (real 2019) lower in the period 2022 to 2030. In most years, the reduction in wholesale price is greater under the peak demand scheme than under the expanded ESS, consistent with the relative impacts on annual peak demand (noting that high electricity demand is an important driver of high pool prices).

In the period 2022 to 2027 the lower demand displaces a combination of black coal, hydro and natural gas generation – although to a smaller extent than under the expanded ESS, since a considerably smaller amount of energy is displaced. In 2028-2030, some wind and battery storage capacity is displaced (up to 500 MW and 100 MW by 2030, respectively) driven by the fall in wholesale price. The wind generation is replaced by coal and hydro dispatch, resulting in a small increase in regional emissions at the end of the decade (up to 0.6 Mt CO_2-e).

The region's energy imports are projected to be lower than under the BAU in the period to 2027. From 2028, its imports are greater due to the displacement of new wind and battery storage capacity.

FIGURE 2.7 SUMMARY OF CHANGES IN NSW OUTCOMES UNDER THE PEAK DEMAND SCHEME RELATIVE TO THE BAU



Note: Calendar year data.

SOURCE: ACIL ALLEN POWERMARK MODELLING

2.3 Combined demand scheme

In this scenario, the combined impact of the expanded energy savings scheme and the peak demand scheme on the wholesale energy market is assessed.

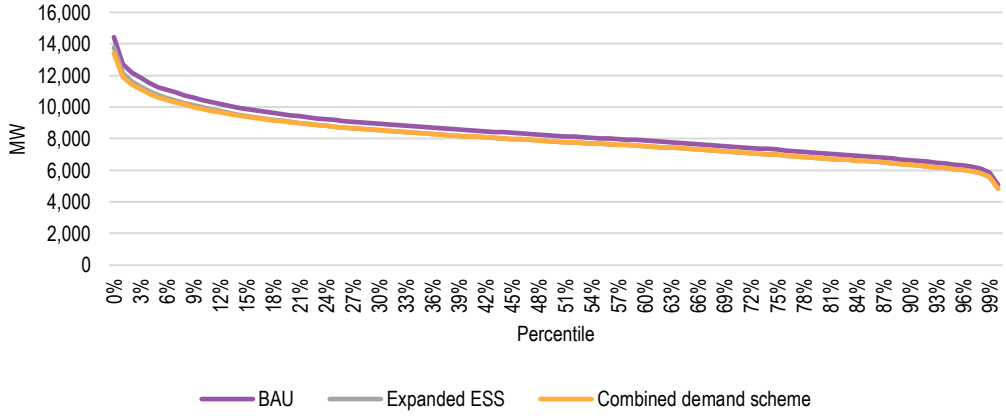
2.3.1 Input assumptions

The combined impact of the two schemes on the NSW demand has been modelled using the same methodology as that applied for assessing each individual scheme's impact.

The same forecasts of energy and peak demand impacts provided by the Department (see Figure 2.1 and Figure 2.4) are used in this scenario. The resulting load duration curve for calendar year 2030 is presented in Figure 2.8, showing the combined impact of energy savings across the year and the demand reduction in the upper 25th percentile of demand periods. The load duration curve is identical

to the load duration curve under the expanded ESS, except for the upper 25th percentile of demand periods which are further reduced by the peak demand scheme component.[5]

FIGURE 2.8 CHANGE IN LOAD DURATION CURVE UNDER THE COMBINED DEMAND SCHEME IN CALENDAR YEAR 2030



SOURCE: ACIL ALLEN CONSULTING

2.3.2 Results summary

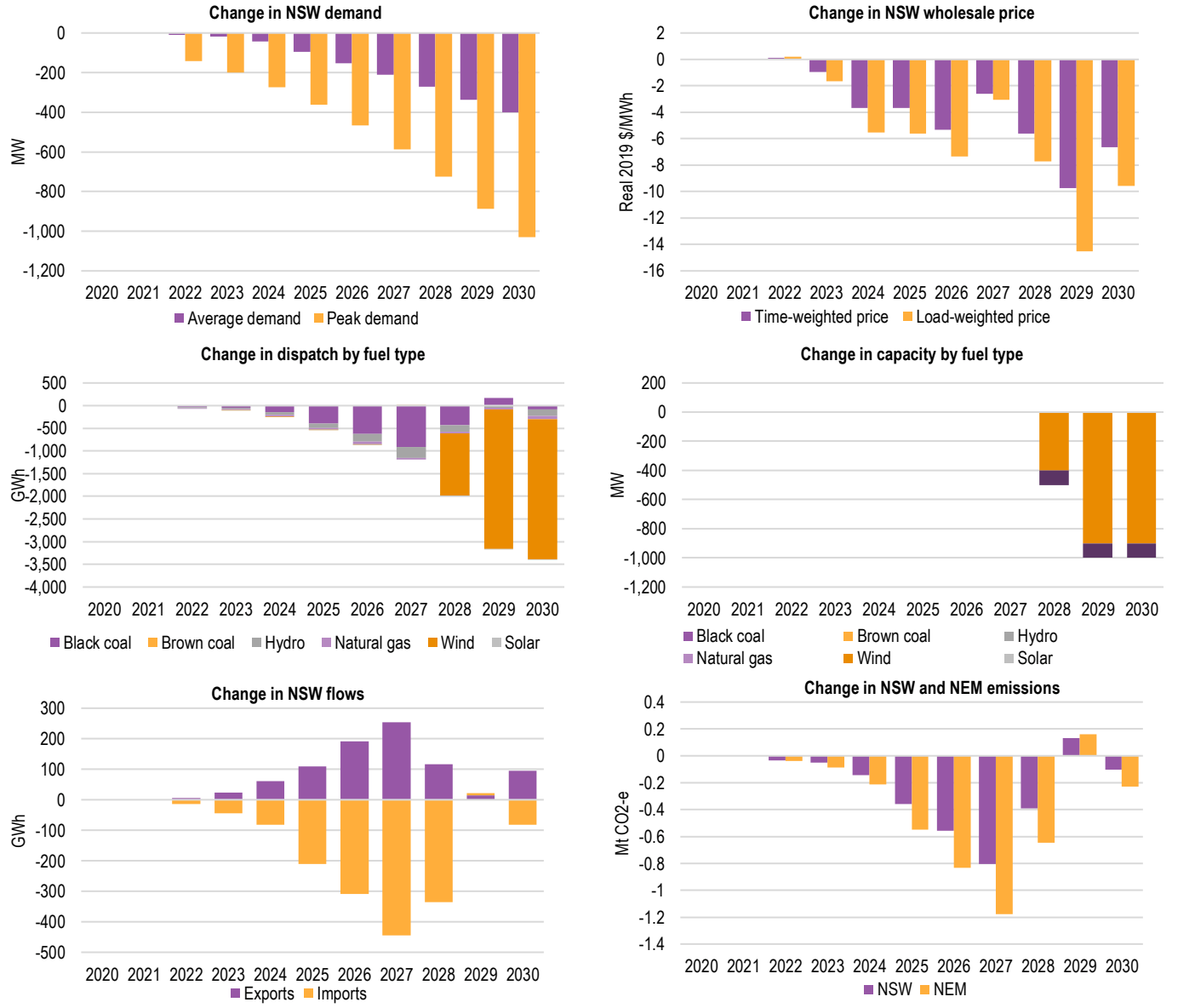
Under the combined demand scheme, annual average NSW demand and peak NSW demand are projected to be up to 401 MW and 1,029 MW lower by 2030, respectively, relative to the BAU. The reduction in demand drives the lower load-weighted price outcome in NSW, which is on average $6.10/MWh (real 2019) lower in the period 2022 to 2030.

In the period 2022 to 2027 the lower demand displaces a combination of black coal, hydro and natural gas generation. In 2028-2030, some wind and battery storage capacity is displaced relative to the BAU (up to 900 MW and 100 MW by 2030, respectively) driven by the fall in wholesale price.

The region's energy imports are projected to be lower than under the BAU, driven by the lower local energy requirement (this impact is partially offset in 2028-2030 due to the displacement of new entrant capacity in this period).

[5] ACIL Allen has assumed that there is some overlap between the two schemes such that the impact on annual peak demand does not exceed that of the impact under the peak demand scheme (e.g. 1,029 MW reduction in 2030).

FIGURE 2.9 SUMMARY OF CHANGES IN NSW OUTCOMES UNDER THE COMBINED DEMAND SCHEME RELATIVE TO THE BAU



Note: Calendar year data.

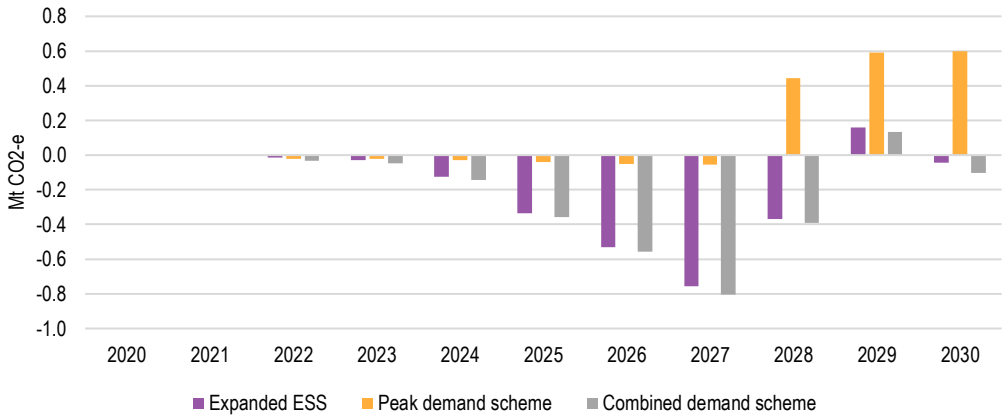
SOURCE: ACIL ALLEN POWERMARK MODELLING

2.4 Emissions

The projected impact of each demand-side scheme on NSW emissions is small, as shown in Figure 2.10. In the period to 2027, emissions are projected to fall relative to the BAU under all three scenarios, with the combined demand scheme having the greatest downward impact in 2027 at less than 2% of the region's emissions in the BAU. Of the three schemes, the peak demand scheme is projected to have the smallest impact on emissions, given its small impact on NSW annual energy requirement (less than 0.8% in any year).

Post-2027, the downward impact of the lower demand on emissions is either partially or more than offset by the projected delay in new entrant renewable capacity.

FIGURE 2.10 PROJECTED IMPACT ON NSW EMISSIONS RELATIVE TO THE BAU BY SCENARIO



Note: Calendar year data

SOURCE: ACIL ALLEN CONSULTING

3 RETAIL IMPACTS

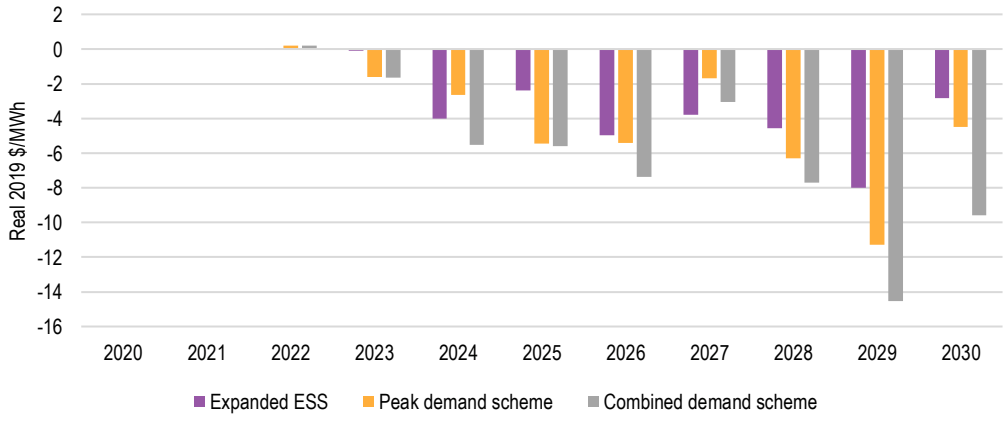
This section examines the modelled impact from the combined demand scenario upon projected retail prices and retail bills for a representative residential consumer in NSW.

3.1 Load weighted price impact

As an important input into the retail cost stack for consumers, the changes projected for the wholesale cost of electricity is a key driver for the impacts of the policy. For residential customers, it is the load-weighted wholesale price (rather than time-weighted wholesale price shown in previous sections) which is a closer reflection of future changes in the wholesale cost component of retail bills.

The combined demand scheme scenario is projected to have the largest downward impact on the NSW load-weighted price over the modelling horizon, as seen in Figure 3.1, with the greatest price impacts projected at the end of the decade as the scheme's target energy savings increase.

FIGURE 3.1 PROJECTED IMPACT ON NSW LOAD-WEIGHTED PRICE RELATIVE TO THE BAU BY SCENARIO



Note: Calendar year data

SOURCE: ACIL ALLEN CONSULTING

3.2 Retail prices in the BAU

ACIL Allen has projected retail prices for a representative NSW residential customer[6] using its retail model. The approach used is not too dissimilar to that used by the AEMC in its annual retail price trends report.[7]

Table 3.1 presents the projected residential retail prices for NSW under the BAU scenario. The projections are presented on a financial year basis as network and retail prices are typically reset on the 1st July each year. These prices reflect expectations of a relatively flat network cost component, and wholesale costs which align with modelled outcomes under the scenario. Retail prices are projected to fall by around 20% over the next four years driven primarily from the projected reductions in wholesale electricity costs.

TABLE 3.1 PROJECTED NSW RESIDENTIAL RETAIL PRICES: BAU SCENARIO (REAL 2019 C/KWH)

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Regulated networks	13.24	13.46	13.52	13.29	12.70	13.26	13.15	13.11	13.39	13.73	13.86
Wholesale	11.63	10.43	9.74	6.92	7.94	8.08	7.67	7.01	9.03	10.71	10.47
LRET - LGC cost	0.66	0.46	0.30	0.21	0.10	0.02	0.02	0.02	0.02	0.01	0.01
SRES - STC cost	0.84	0.59	0.50	0.40	0.31	0.25	0.20	0.15	0.11	0.08	0.05
Energy Savings Scheme	0.18	0.18	0.18	0.18	0.18	0.18	0.09	0.00	0.00	0.00	0.00
Retail cost and margin	3.19	3.07	3.00	2.71	2.82	2.83	2.79	2.72	2.93	3.09	3.07
Residential retail price	**29.73**	**28.19**	**27.24**	**23.71**	**24.04**	**24.63**	**23.92**	**23.01**	**25.47**	**27.63**	**27.46**

Note: Based on a representative NSW residential customer on a market offer.

SOURCE: ACIL ALLEN ANALYSIS

Residential electricity bills are calculated by multiplying the consumption of the representative consumer in each jurisdiction by the price they pay for electricity.[8] The representative consumer's consumption in NSW has been assumed at 6 MWh per annum, per advice from the Department. Table 3.2 presents the corresponding projected residential bill values for the BAU scenario.

TABLE 3.2 PROJECTED NSW RESIDENTIAL RETAIL BILL: BAU SCENARIO (REAL 2019 $)

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Regulated networks	$794	$808	$811	$797	$762	$796	$789	$787	$804	$824	$831
Wholesale	$698	$626	$584	$415	$476	$485	$460	$421	$542	$643	$628
LRET - LGC cost	$40	$28	$18	$12	$6	$1	$1	$1	$1	$1	$1
SRES - STC cost	$50	$36	$30	$24	$19	$15	$12	$9	$7	$5	$3
Energy Savings Scheme	$11	$11	$11	$11	$11	$11	$5	$0	$0	$0	$0
Retail cost and margin	$191	$184	$180	$163	$169	$170	$167	$163	$176	$186	$184
Residential retail bill	**$1,784**	**$1,692**	**$1,634**	**$1,423**	**$1,443**	**$1,478**	**$1,435**	**$1,381**	**$1,528**	**$1,658**	**$1,647**

Note: Based on a representative NSW residential customer with annual consumption of 6 MWh per annum on a market offer. Values rounded to nearest whole dollar value.

SOURCE: ACIL ALLEN ANALYSIS

Costs under the NSW Energy Savings Scheme are around 0.18 cents/kWh (or approximately $11/annum for the representative NSW residential customer). It has been assumed that Energy Savings Certificate (ESC) prices under the BAU commence at $21.10/certificate in 2020 and escalate at CPI. This is approximately the traded price for certificates prior to the announcement of the NSW

[6] The representative residential customer has an assumed cost and consumption profile blended for the three NSW distribution networks and varying levels of annual residential consumption.

[7] See: https://www.aemc.gov.au/market-reviews-advice/residential-electricity-price-trends-2019

[8] It is important to recognise that the billing outcomes do not constitute specific billing forecasts, and that the results may not reflect the actual consumption levels and prices that consumers pay. Actual price movements will be influenced by how retailers compete, the dynamics of the wholesale spot and contract markets, the outcome of network regulatory decisions, and changes in policy and legislation.

Electricity Strategy in late 2019. The target is assumed to remain at 8.5% of liable acquisitions through to the scheme end in 2025.

3.3 Retail prices under the combined demand scheme

Table 3.3 presents the projected retail price outcomes under the combined demand scheme through to 2029-30. Corresponding retail bills are shown in Table 3.4.

TABLE 3.3 PROJECTED NSW RESIDENTIAL RETAIL PRICES: COMBINED DEMAND SCHEME (REAL 2019 C/KWH)

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Regulated networks	13.24	13.47	13.54	13.30	12.71	13.29	13.19	13.22	13.49	13.70	13.87
Wholesale	11.63	10.43	9.77	6.81	7.52	7.58	6.99	6.70	8.51	9.10	9.53
LRET - LGC cost	0.66	0.46	0.30	0.21	0.10	0.02	0.02	0.02	0.02	0.01	0.01
SRES - STC cost	0.84	0.59	0.50	0.40	0.31	0.25	0.20	0.15	0.11	0.08	0.05
Energy savings scheme	0.20	0.22	0.23	0.24	0.25	0.27	0.28	0.29	0.30	0.32	0.33
Peak demand scheme	0.00	0.00	0.02	0.05	0.07	0.10	0.13	0.16	0.20	0.24	0.29
Retail cost and margin	3.19	3.07	3.00	2.70	2.78	2.78	2.72	2.69	2.87	2.93	2.98
Residential retail price	**29.76**	**28.24**	**27.35**	**23.71**	**23.74**	**24.28**	**23.53**	**23.22**	**25.50**	**26.38**	**27.06**

Note: Based on a representative NSW residential customer on a market offer.

SOURCE: ACIL ALLEN ANALYSIS

TABLE 3.4 PROJECTED NSW RESIDENTIAL RETAIL BILL: COMBINED DEMAND SCHEME (REAL 2019 $)

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Regulated networks	$794	$808	$812	$798	$762	$797	$792	$793	$809	$822	$832
Wholesale	$698	$626	$586	$408	$451	$455	$420	$402	$511	$546	$572
LRET - LGC cost	$40	$28	$18	$12	$6	$1	$1	$1	$1	$1	$1
SRES - STC cost	$50	$36	$30	$24	$19	$15	$12	$9	$7	$5	$3
Energy savings scheme	$12	$13	$14	$14	$15	$16	$17	$18	$18	$19	$20
Peak demand scheme	$0	$0	$1	$3	$4	$6	$8	$10	$12	$15	$17
Retail cost and margin	$191	$184	$180	$162	$167	$167	$163	$162	$172	$176	$179
Residential retail bill	**$1,785**	**$1,694**	**$1,641**	**$1,423**	**$1,424**	**$1,457**	**$1,412**	**$1,393**	**$1,530**	**$1,583**	**$1,624**

Note: Based on a representative NSW residential customer with annual consumption of 6 MWh per annum on a market offer. Values rounded to nearest whole dollar value.

SOURCE: ACIL ALLEN ANALYSIS

Table 3.5 presents the differences in retail bills between the combined demand scheme and the BAU scenario. The key findings are:

- The largest cost decrease occurs in the wholesale cost of energy modelled in the scenario with this delivering total projected savings of $304 in real terms over the period to 2030
- Further related savings occur in retail cost and margins (some of these costs are expressed as a percentage of wholesale cost)
- Offsetting these savings are direct costs relating to the new schemes in place which total around $181 over the period to 2030. These include:
  - Increased costs of the expanded ESS totalling $106/household to 2030 (note that the expanded ESS costs would also extend beyond 2030)
  - Costs incurred from the Peak demand scheme totalling $75/household to 2030.

It should be noted that the costs of the peak demand scheme have been shared equally across all NSW electricity consumption in calculating these residential cost impacts. Should some larger customers be exempt from liability then the cost impacts to residential customers would be higher than those shown.

The retail projections do not take into account avoided network losses or avoided network expenditure due to the energy savings and peak demand reductions under the combined demand scheme.

TABLE 3.5 PROJECTED CHANGE IN NSW RESIDENTIAL RETAIL BILL: COMBINED DEMAND SCHEME CHANGE FROM BAU (REAL 2019 $)

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Regulated networks	$0	$0	$1	$1	$1	$2	$3	$6	$5	-$2	$1
Wholesale	$0	$0	$2	-$7	-$25	-$30	-$41	-$19	-$31	-$97	-$56
LRET - LGC cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SRES - STC cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy savings scheme	$1	$2	$3	$4	$4	$5	$11	$18	$18	$19	$20
Peak demand scheme	$0	$0	$1	$3	$4	$6	$8	$10	$12	$15	$17
Retail cost and margin	$0	$0	$0	-$1	-$2	-$3	-$4	-$2	-$3	-$10	-$6
Residential retail bill	**$1**	**$3**	**$7**	**$0**	**-$18**	**-$21**	**-$23**	**$13**	**$2**	**-$75**	**-$24**

Note: Based on a representative NSW residential customer with annual consumption of 6 MWh per annum on a market offer. Values rounded to nearest whole dollar value.

SOURCE: ACIL ALLEN ANALYSIS

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