Emissions reduction options

A REPORT PREPARED FOR THE AUSTRALIAN ENERGY MARKET COMMISSION (AEMC)

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Executive summary

The Australian Energy Market Commission (AEMC or Commission) engaged Frontier Economics to advise on the theory and design of alternative options for reducing emissions in the electricity sector (consistent with a national emissions reduction target of 28 per cent reduction on 2005 levels by 2030) and to model the impacts of these alternatives.

The mechanisms considered include:

- An **Emissions Intensity Target (EIT)**: a declining emissions intensity target is introduced for the electricity sector, where generators with an emissions intensity above the target are liable to buy certificates and those with an emissions intensity below the target sell certificates.
  - This involves a **market for tradeable certificates**;
  - It is **technology neutral**: allowing for least cost abatement, which does not limit emissions abatement to a particular technology type; and
  - It is **revenue neutral**: does not involve tax transfers to Government.
- An **Expanded Large-scale Renewable Energy Target (LRET)**: extension of the existing LRET from 33,000 GWh to 86,000 GWh (in the base case scenario) to meet the emissions reduction target.
- **Regulatory closure (REG):** policy is implemented to force the closure of a number of high emissions (coal) power stations required to meet the emissions reduction target. We do not consider how closure is achieved, or whether compensation to generators closing is involved.

These are compared against a **Business as Usual (BAU)** scenario which includes the existing LRET but no other policy measures to reduce electricity sector emission.

The following impacts are considered and compared for each:

- Change in **resource costs**, including fuel, operating and maintenance cost, and new capital costs. Existing capital costs are sunk (not included) but are the same across the BAU and all scenarios.
- **wholesale price effects** (including the effect of the LRET levy on retail prices), as a measure of how costs are distributed between consumers and generators;
- **cost of abatement;** (change in resource costs relative to change in emissions) and
- **new investment, output mix** and **retirements:** to assess how the emissions reductions are achieved and the extent of structural adjustment required.

Table 1: Summary of Base Case results

Case	Consumer impact [1] (NPV, Real2016$m, 2020-2030): change on BAU	Cost of abatement (Discounted), $/tCO2 reduced	Resource cost (NPV, Real2016$m, 2020-2030): change on BAU	New investment (MW) to 2030			Retire-ments (MW) to 2030	Average Output mix (2020-2030 average, %)		
				Gas	Renew	Total		Coal	Gas	Renew
BAU	0	0	0	1,341	4,809	6,150	406	75%	5%	20%
EIT	($4,945m)	$30.4/t	$5,546m	7,590	5,441	13,031	6,852	60%	19%	21%
REG	$10,843m	$34.2/t	$5,838m	7,212	5,266	12,478	6,406	62%	17%	21%
LRET	$1,062m	$75.7/t	$11,248m	0	26,166	26,166	2,559	65%	2%	33%

Source: Frontier Economics

Table 1 provides a high level summary of results for the Base Case, including:

- **Resource costs:** The EIT has lowest resource cost and hence cost per tonne of abatement as it is market based and technology neutral. Extended LRET has considerably higher resource cost/cost per tonne as emissions abatement under this mechanism is limited to investment in new, higher cost renewable technologies, which is a more expensive form of abatement than the alternative of investing in new lower emissions gas[1]. In this case REG is marginally higher than EIT, because the assumed (administrative) retirement decisions are largely based on the outcomes from the EIT modelling (which are optimised). This result is less likely to be as robust to changes in costs/demand in the same manner that a market based option would adjust.
- **Consumer costs:** The EIT has the lowest consumer costs, lower than even the BAU consumer costs despite the higher resource costs. Fundamentally this is due to the different drivers of prices and costs Although the EIT penalises (raises the costs of) higher emissions generation, these penalties flow as subsidies that lower the cost of new low emission gas generation. On balance this results in a higher **cost** generation mix but because **prices** are more frequently set by the new entrant gas (and the net effect is more entrant gas capacity than coal retirements) this results in lower overall prices. If resource costs increase and consumer costs fall then this means that existing thermal generators bear the burden of the increased resource cost. Extended LRET

[1] The EIT is a "no regrets" option: as it is technology neutral it should always favour the lowest cost abatement option. Even in a scenario of higher gas prices/lower renewable costs such that renewable investment was a lower cost option than gas, the cost of the EIT should always be less than, or at worst equal to, the cost of an extended LRET.

has a similar impact: although the cost of reducing emissions is relatively high, the impact on consumers is far less due to some expected 'merit order' effect.[2] Again, the lower consumer impact suggests that existing thermal generators bear a larger share of the resource cost increases. REG has a much higher impact on consumers than the resource cost increase: withdrawal of capacity/supply leads to higher short-term prices than under BAU. Despite the relatively low resource costs of this option, in this case generators benefit at the expense of consumers.

- **New investment/retirements:** under the **BAU** almost all of the new investment is new renewables to meet the existing LRET. EIT and REG result in a small increase in renewables investment (400-600MW higher than the BAU) but a much stronger switch from existing coal to new gas plant over the decade: around 6000MW of existing coal (including Hazelwood, Liddell and Yallourn) is replaced with new gas in both cases. In the REG case this is by assumption and largely informed by the EIT modelling results. The extended LRET results in no new gas, and crowds out fewer existing coal plant. As there is no penalty on high emissions/brown coal plant, Hazelwood is not retired in this scenario and because new wind and solar has lower capacity factors than thermal plant, this requires a much larger increase in new capacity: 26,000MW.
- **Output mix (2020-30 average, grid connected not rooftop solar PV):** the BAU suggests a mix of coal (75%), gas (5%) and renewables to meet the existing LRET (20%). EIT and REG both project a similar level of renewables (also driven by the existing LRET) with mostly switching from coal to gas (around 13-15% on average over the decade). The Extended LRET results in a decline in both coal (mostly black coal) and gas output as it is displaced by new renewables. The extended LRET sees almost no change in brown coal output over the decade. This is because the LRET shifts the merit order outward by adding additional renewable capacity but does not change the relative costs of existing plant according to emission intensity: low cost/high emissions brown coal will continue to be cheaper than higher cost/lower emissions black coal (hence gas and black coal will tend to be crowded out first).
  - This output mix implies 2030 gas use for power generation (across the NEM and SWIS) rising to 138PJ/year in the BAU, 527PJ in EIT and 421PJ in REG; it falls to 15PJ in the extended LRET.
  - For context, 2P gas reserves are estimated at around 49,500 PJ for the east coast and 89,000 PJ for the west coast.

2 Subsidies to new entrant renewables can have a **short-term** depressing effect on pool prices. This is limited by the cost of existing thermal as a price floor: further renewables entry will only encourage retirements of existing coal beyond a certain point.

- Our forecast BAU gas use in 2017 is 194PJ (NEM + SWIS) compared with actual 2014 gas use for east coast power generation of 220PJ[3]. AEMO forecasts total gas use on the east coast to rise from around 700PJ (2014) to around 2000PJ (2017) to supply LNG exports[4]. The LNG projects at Gladstone each have annual gas requirements around the 400-500PJ range.

These results are robust to sensitivities testing higher gas prices, higher forecast demand and for a greater emissions reduction target (50PC): Table 2.

Low demand is excluded from this summary as BAU emissions are sufficient to meet a 28PC target without further policies. Low solar has only marginal impacts on results and is not summarised here.

Table 2: Resource cost, revenue, CO2, cost per tonne by key scenario (2020-30)

	Base Case	High demand	High Gas	50PC	Base Case	High demand	High Gas	50PC
	Resource cost (Real 2016$b NPV)				Change v BAU			
BAU	$55.4	$63.5	$57.0	$55.4				
EIT	$60.9	$71.5	$64.2	$70.0	$5.5	$8.0	$7.2	$14.6
LRET	$66.6	$85.6	$66.9	$89.3	$11.2	$22.1	$9.9	$33.9
REG	$61.2	$71.9	$67.2	$71.1	$5.8	$8.4	$10.2	$15.7
	Revenue /consumer cost (Real 2016$b NPV)				Change v BAU			
BAU	$82.8	$102.4	$104.1	$82.8				
EIT	$77.9	$87.4	$90.0	$79.4	($4.9)	($15.0)	($14.0)	($3.4)
LRET	$83.9	$112.1	$89.2	$110.9	$1.1	$9.7	($14.9)	$28.1
REG	$93.6	$106.0	$128.2	$97.5	$10.8	$3.7	$24.1	$14.7
	Cumulative 2020-30 emissions MTC02: (28PCTarget 1751Mt / 50PC target 1508Mt)				Change v BAU			
BAU	2054	2173	2048	2054				
EIT	1737	1722	1794	1343	(318)	(451)	(254)	(711)
LRET	1787	1738	1801	1353	(268)	(435)	(247)	(701)

3 http://forecasting.aemo.com.au/Gas/AnnualConsumption/GPG

4 http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities

	Base Case	High demand	High Gas	50PC	Base Case	High demand	High Gas	50PC
REG	1755	1753	1814	1345	(299)	(420)	(235)	(710)
	Cost per tonne abated $/tCO2 (**undiscounted** emissions)				Cost per tonne abated $/tCO2 (**discounted** emissions)			
EIT	$17.5	$17.7	$28.4	$20.5	$30.4	$29.8	$51.4	$34.7
LRET	$42.0	$50.8	$40.0	$48.3	$75.7	$93.6	$72.0	$85.3
REG	$19.5	$20.0	$43.6	$22.1	$34.2	$35.5	$73.9	$37.9

- **Resource costs**: The EIT consistently has the lowest **resource costs** and **cost of abatement** for each scenario, as all abatement options are available under this approach.
  - REG generally has the second higher resource cost (other than in the High Gas approach), though this assumes perfect foresight based on the outcomes of the EIT results, hence this cost estimate is likely understated and would not be as flexible to changes in market conditions.
  - The LRET approach generally has the highest resource cost/cost of abatement as this is technology constrained (other than in the High Gas case where this is relatively cheaper than the REG option).
- **Consumer costs:** The EIT consistently reduces consumer costs compared with BAU: imposing penalties on high emissions plant to fund subsidies for low emissions plant (new entrants) flattens the merit order and has a mild 'merit order effect' (surplus supply reduces wholesale prices). Although this encourages early retirements of high emissions plant, it also encourages new entrants at lower cost for lower net impact on prices. As such, existing thermal plant bears more than 100 per cent of the resource costs of reducing emissions under this approach.
  - The REG approach results in the highest cost for consumers under Base Case/High Gas scenarios. The withdrawal of capacity alone results in higher price effects, which is favourable for existing generators at the expense on consumers (consumer impacts are larger than the resource costs of the scheme). Under the High Demand/50PC case the consumer impacts are still positive but less than the resource costs, suggesting that generators begin to bear some of the costs of emissions reductions.
  - Under LRET the consumer costs are generally lower than the overall resource costs, as subsidies to new entrants tends to lower wholesale prices and shift overall costs onto existing generators. However, this must be balanced against the higher overall cost of the scheme, hence in most

scenarios consumers still face higher overall costs. This is particularly evident as the target is scaled up as the cost of the LRET increases materially but any further merit order effects is limited: scaling up the LRET results in more retirements of existing thermal which sets an effective floor on wholesale prices (while LRET levy costs continue to rise due to higher quantities and certificate prices). In the 50PC case consumers bear most of the cost of the scheme.

- The 50PC target results in lower cumulative emissions from 2020-30 than the target. This is because we model to 2040 and the most efficient/lowest cost option is to outperform the target from 2020-30 to bank surplus credits for use from 2030-40. We assume that LRET and REG policies adopt a similar approach to ensure that results from 2020-30 are comparable.

1 Introduction

1.1 Background and scope

The Australian Energy Market Commission (AEMC or Commission) engaged Frontier Economics to advise on the theory and design of alternative options for reducing emissions in the electricity sector and to model the impacts of these alternatives.

The AEMC asked Frontier Economics to develop scenarios setting out alternative mechanisms for achieving an electricity sector target consistent with a 28 per cent reduction nationally on 2005 level CO2 emissions by 2030, including: least cost abatement, staged generator exit and accelerated deployment of renewable energy. The mechanisms considered include:

- An **Emissions Intensity Target (EIT)**: a declining emissions intensity target is introduced for the electricity sector, where generators with an emissions intensity above the target are liable to buy certificates and those with an emissions intensity below the target sell certificates.
  - This involves a **market for tradeable certificates**;
  - It is **technology neutral**: allowing for least cost abatement, which does not limit emissions abatement to a particular technology type; and
  - It is **revenue neutral**: does not involve tax transfers to Government.
- An **Expanded Large-scale Renewable Energy Target (LRET)**: extension of the existing LRET from 33,000 GWh to 86,000 GWh (in the base case scenario) to meet the emissions reduction target.
- **Regulatory closure (REG):** policy is implemented to force the closure of a number of high emissions (coal) power stations required to meet the emissions reduction target. We do not consider how closure is achieved, or whether compensation to generators closing is involved.

These were tested for a Base Case scenario (default assumptions) and for sensitivities around High/Low demand, High gas prices, a 50 per cent emissions reduction target and lower utility solar PV costs.

1.2 Report structure

The remainder of this report is set out as follows:

- Section 2 includes a detailed discussion of the economic theory underlying emissions reduction mechanisms and how an EIT could work for the electricity sector. This includes: how EIT (targets) are set; how this drives emission reductions; differences between cost and price effects; options for international linkage (and implications); issues around uncertainty (actual demand varying from forecast); options for legacy hydro (that existed prior to the existing LRET) and emissions intensive trade exposed industries (EITEI); and discussion of how the EIT could interact with the existing LRET.

- Section 3 describes the modelling methodology.
- Section 4 summarises scenarios and assumptions.
- Section 5 presents and analyses results for the Base Case scenarios.
- Sections 6, 7 and 8 present results for alternative cases for High Demand, High Gas, Low Demand.
- Section 9 presents results for a 50 per cent emissions reduction target by 2030.
- Section 10 considers EIT and LRET results for lower solar PV costs (compared with the Base Case).
- Section 11 discusses results for an EIT scenario where 'legacy hydro' and emissions intensive trade exposed industries (EITEI) each receive an equivalent share of EIT credits.
- Section 12 presents the estimated effects of the recently announced pre-2020 closure of Hazelwood.
- Individual state results are reported in Appendix A.

2 Theoretical underpinnings and scheme design

This section discusses key issues of scheme design and resulting market impacts. This draws on our detailed experience advising on and modelling these types of schemes for the electricity sector. Frontier Economics has previously provided similar advice to the AEMC on carbon pricing and RET impacts on the generation and retail sectors[5] and has written extensively on the design, operation and effects of an emissions intensity target (EIT)[6].

2.1 Explanation of an emissions intensity target (EIT)

Figure 1 shows a stylised example of how a standard emissions trading scheme (ETS) compares with an EIT for the electricity sector.

The issue is that lower cost plant (coal) is more emissions intensive than higher cost plant (gas) per unit of output.

A standard ETS charges for all emissions produced: gas is charged less than coal which (for a sufficient price) drives a switch in relative output from coal to gas. Since all emission are penalised, this raises revenue (transferred to Government) and results in wholesale price increases.

An EIT sets a target emissions intensity for the sector: emissions above the target are penalised (coal) and emissions below the target (gas, renewables) are rewarded **for each unit of output**[7]. Gas/renewables can sell credits to coal (liable parties).

For a similar certificate price this should encourage the same degree of fuel switching but (a) without a transfer of revenue to government (revenue neutral)

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5 Weblinks: Impacts of climate change policies on generation investment and operation (2008) http://www.aemc.gov.au/getattachment/1a21ab8c-49d5-462b-9cba-089be0efc9c3/Impacts-of-climate-change-policies-on-generation-i.aspx ;

Impacts of climate change policies on electricity retailers (2009) http://www.aemc.gov.au/Media/docs/Frontier%20Economics%20Report%20-%20%20Impact%20of%20Climate%20Change%20Policies%20on%20Electricity%20Retailers-e004f70d-67f4-413c-8736-4f4f0896c303-0.pdf

6 Weblinks: The economic impact of the CPRS (2009) http://www.frontier-economics.com.au/publications/economic-impact-cprs/ ; Options for the design of emissions trading schemes in Australia (2008); Options for pricing emissions in Australia (2010) http://www.frontier-economics.com.au/documents/2010/11/options-pricing-emissions-australia-senate-submission.pdf

7 The EIT must be intensity or output-based to result in lower wholesale prices than an ETS. Other forms of allocations based on historical output or some other absolute basis are equivalent to grandfathering of permits. Even if grandfathered permits are allocated freely, if they are not output-based (as under an EIT) then there is an opportunity cost of generating electricity/using these permits, and this will be passed through as higher electricity prices.

and (b) without causing the same degree of wholesale price increases (which are largely driven by the tax transfer effect). For an EIT of 0tCO2/MWh, the EIT becomes equivalent to a standard ETS.

Figure 1: Theoretical example of an ETS versus EIT

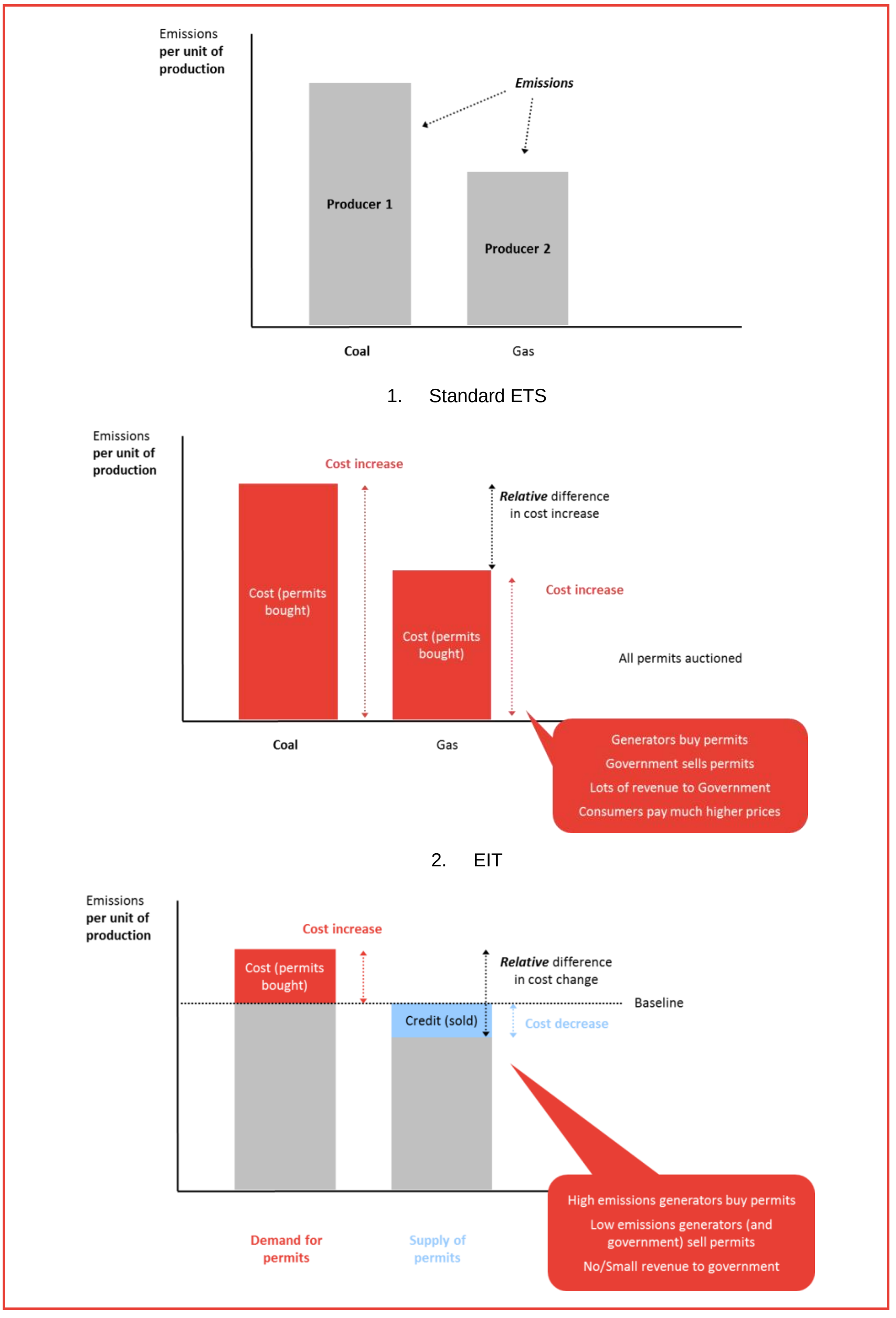

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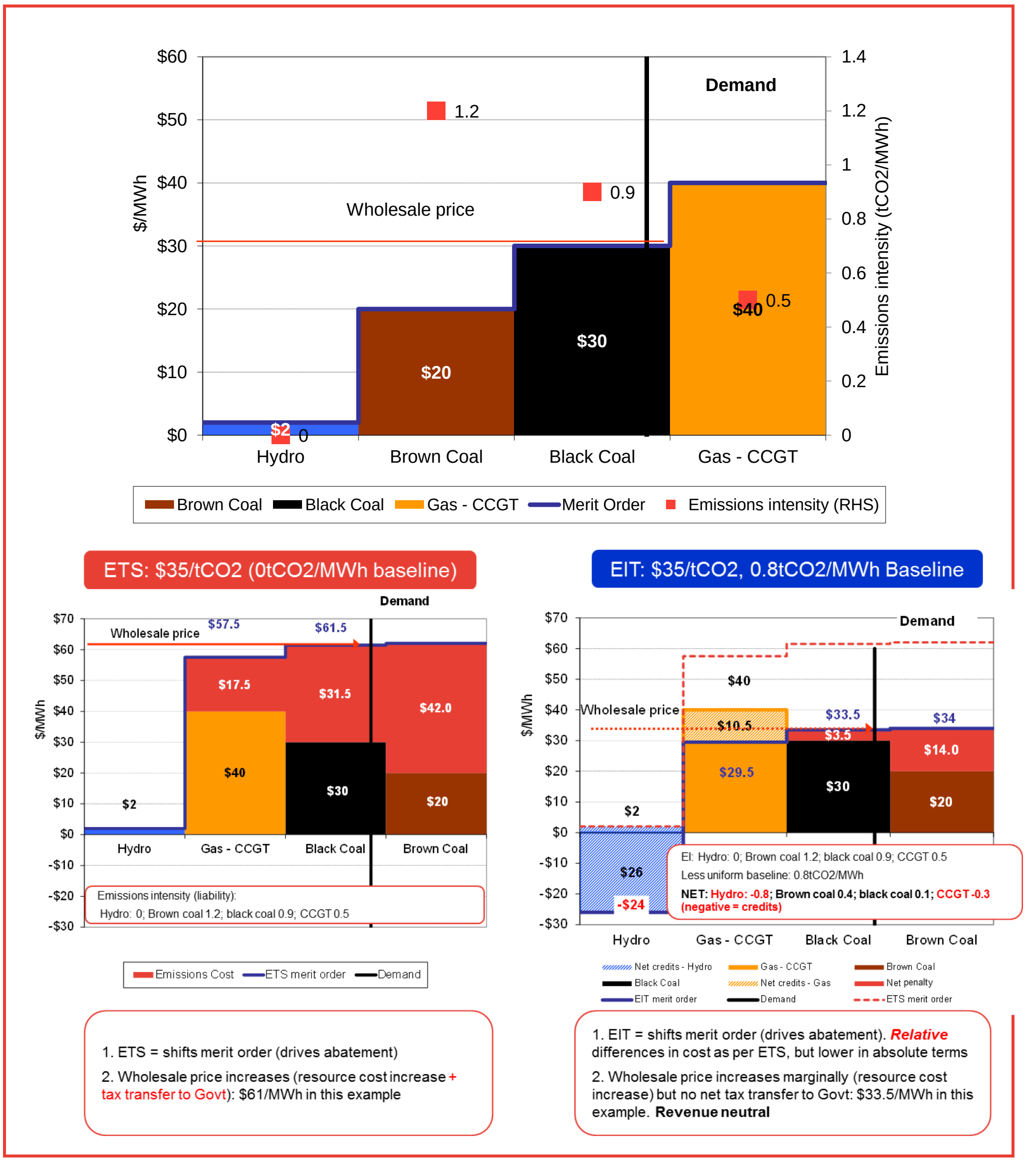
Figure 2 shows a more detailed worked example. Without any policy, brown/black coal are cheaper than gas but higher emissions intensity.

Under an ETS ($35/tCO2), this (a) changes the relative costs of plant to a lower emissions fuel mix (gas displaced coal) and (b) raises wholesale prices, mostly due to the tax transfer effect (revenue transferred to government as permit sellers).

Under an EIT, hydro and gas create credits, which are sold to coal plant. For an equivalent EIT certificate price this results in the same fuel switching but without the same wholesale price increase.

Figure 2: Worked example of an ETS versus EIT



2.2 Sector EIT

Uniform

To maximise efficiency the intensity target should ideally be uniform for the sector, not varying by facility or technology type. Otherwise, a higher intensity target for brown coal (over black coal/gas, for example) would create distortions and a less efficient abatement outcome. A uniform EIT is also administratively simpler than facility based EITs, subject to potential complications around legacy hydro (discussed below).

With regard to different targets for different grids (WEM and NEM), if permits are fungible between the two markets/grids (which we assume would be the case given Australian emissions should have the same value) then the carbon price should equalise across the grids in the same manner as LGCs. With a common/uniform intensity target it is likely that the WEM (with lower average intensity) will create more credits and sell these to the NEM (with higher average intensity). This would reflect the WEM's greater relative contribution to meeting the overall target.

With fungible permits, the carbon price will be a function of the overall (average) target across the WEM and NEM irrespective of whether the target is the same or different for each.

The effect of a different intensity baseline for each grid (with fungible permits) would only have an impact on the resulting electricity prices for each market: a lower baseline target in the WEM would likely result in higher pool prices than if a common/uniform target was adopted for the WEM/NEM. Conversely, if the NEM were assigned a higher intensity target than the uniform NEM/WEM average then this would lead to lower pool prices than would otherwise be the case.

In general we would not recommend any other differences in target by region within the NEM where energy is tradeable (for example, a lower target in SA or Tas), as this could lead to distortions and inefficiencies. The possible exceptions are discussed below where different rates could be considered for legacy hydro that has lowest generation costs that will not change their overall output as a result of eligibility for credits.

Output based

The theory and example for an EIT above are based on credits/penalties that are **output based (<u>tCO2/MWh</u>)**. There is an important distinction between an output based allocation (intensity target) and a scheme designed with an **Absolute Baseline** for each generator (not tied to output); this will have different price effects.

For example, if each generator is allocated an Absolute Baseline of X% of historical emissions (expressed in Mt as opposed to tCO2/MWh) then this is no longer an intensity target and has different market effects. An Absolute Baseline designed this way is actually a grandfathered allocation of free permits. The critical difference is that because permit allocations (the Mt baseline) are not conditional on output in this design, there is an opportunity cost associated with using permits which should result in higher electricity prices.

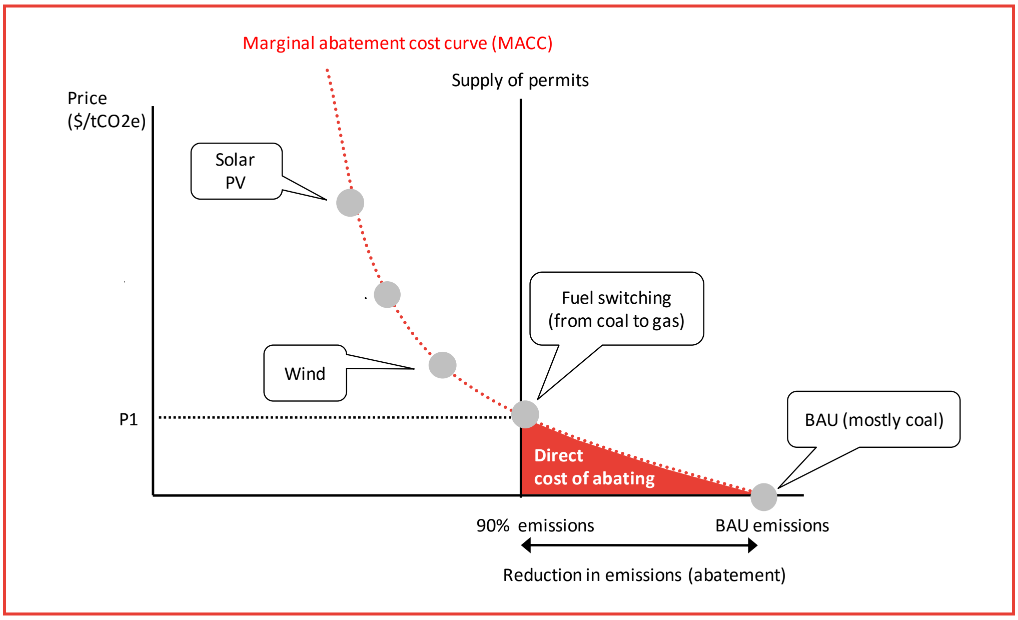
For example, consider a coal generator that was allocated an Absolute Baseline of 10Mt: if it reduces emissions to zero (by not producing) it still receives this allocation and can sell these permits. Conversely, producing (and emitting) means that permits are used but not sold. This is an opportunity cost of producing electricity which changes their marginal cost of production. Even though the permits were allocated freely, they still have a market value and the full cost of permits should be passed-through to higher electricity prices in the same way as an ETS (and in contrast to an EIT). This pass-through to higher electricity prices also occurs to the same extent when permits are auctioned, in which case the implicit (opportunity) cost of holding a permit becomes an explicit cost.

2.3 Resource cost versus price effects

In understanding and explaining the price and cost effects of an intensity target, it is essential to understand the economics of abatement, in particular the differences between taxes and transfers and the impacts on electricity prices.

For example, Figure 3 shows a stylised example of an abatement cost curve for the electricity sector. The vertical axis is the cost of abatement, the horizontal axis is emissions (where business as usual intersects at a price of \$0/tCO2): a reduction in emissions requires movement up the marginal abatement cost curve (MACC). In this diagram, the area under the curve reflects the **resource** cost of reducing emissions, for example, switching from coal generation to higher cost gas.

Figure 3: A stylised diagram of an abatement cost curve



The large increase in price effects under a standard carbon tax/ETS (not an emissions intensity scheme) is evident in Figure 4. The electricity price increase reflects a combination of (a) resource cost of reducing the emissions intensity of supply (red) and (b) the tax revenue generated (blue), as firms are charged for **all** emissions. Initially for small reductions in emissions the tax revenue is large and the resource cost is small. Hence the large majority of the electricity price increases observed during the carbon tax (FYe2013-14) was more due to tax revenue, not the resource costs of reducing emissions. This tax revenue is a transfer that can theoretically be used to offset the effects of electricity price rises, but how well it does this depends heavily on assumptions around how the revenue is used. The revenues could be used to address equity issues (compensation to low income households) ***or*** efficiency issues (reducing inefficient taxes, such as company/payroll taxes), but not both. But over time as the emissions target falls, the resource cost of reducing emissions to achieve harder abatement targets should rise and become a larger cause of price increases (see part 2 of the diagram).

Under an EIT, the rise in electricity prices should be much less as it will only reflect the resource costs (red), not the tax transfer effects. So although there is no revenue generated to compensate consumers for price increase, there is also less need to compensate consumers as the scheme design results in much lower price rises than a standard cap and trade. Although the resource cost of reducing emissions will contribute to rising electricity prices over time, the effect of the tax transfer (under a standard ETS) will be avoided. An alternate representation of this difference is shown in Figure 5: under an intensity target, only the higher cost of generating from lower emissions sources will contribute to higher prices (a shift from P1 to P3, not P2).

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Figure 4: A stylised diagram of the resource cost versus tax transfer (auction revenue) for different targets

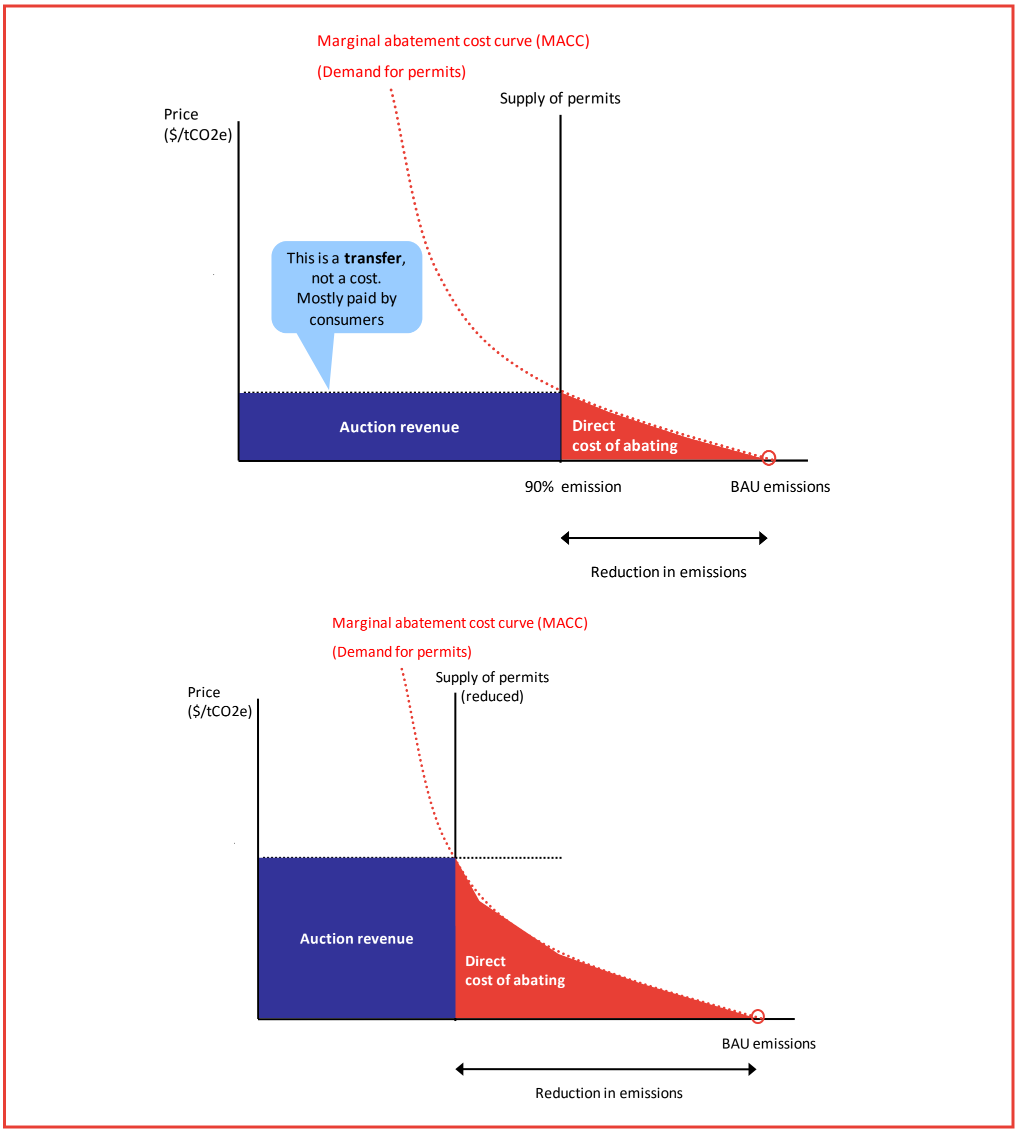
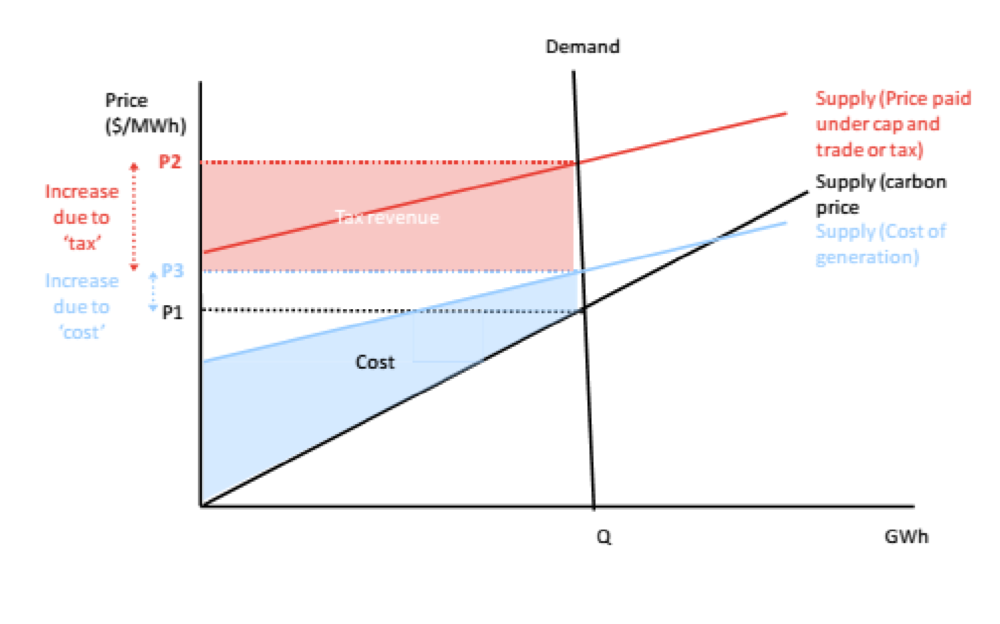


Figure 5: A stylised diagram of the resource cost versus tax transfer (auction revenue)

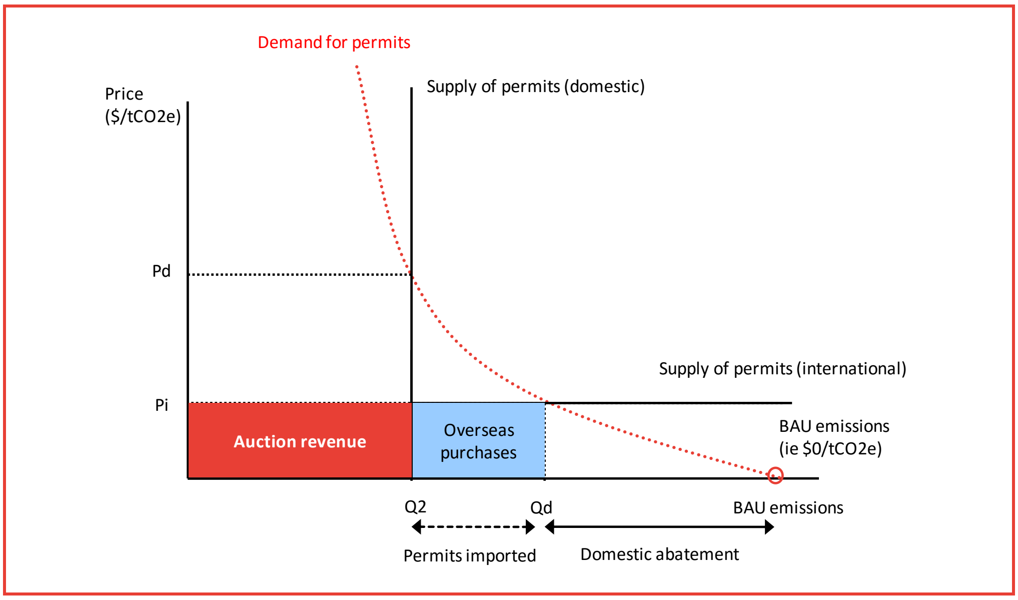


2.4 International linkage

If international linkage of schemes is recognised then it is likely that the Australian electricity sector will be a price taker in the global carbon market with the price determined by international action. This means that there would be little certainty over domestic electricity sector emissions – the market would operate more like a carbon tax (set at the international price) and any shortfall between domestic emissions/target will be met through permit imports. This is illustrated in Figure 6: any change in the domestic target (supply of permits) from Q2 will change the level of permit imports but will not change the carbon price from Pi.

Under an EIT, this could result in an actual sector emissions intensity exceeding the EIT with the difference met through permit imports. The

Figure 6: A stylised diagram of the domestic target, permit imports and domestic abatement



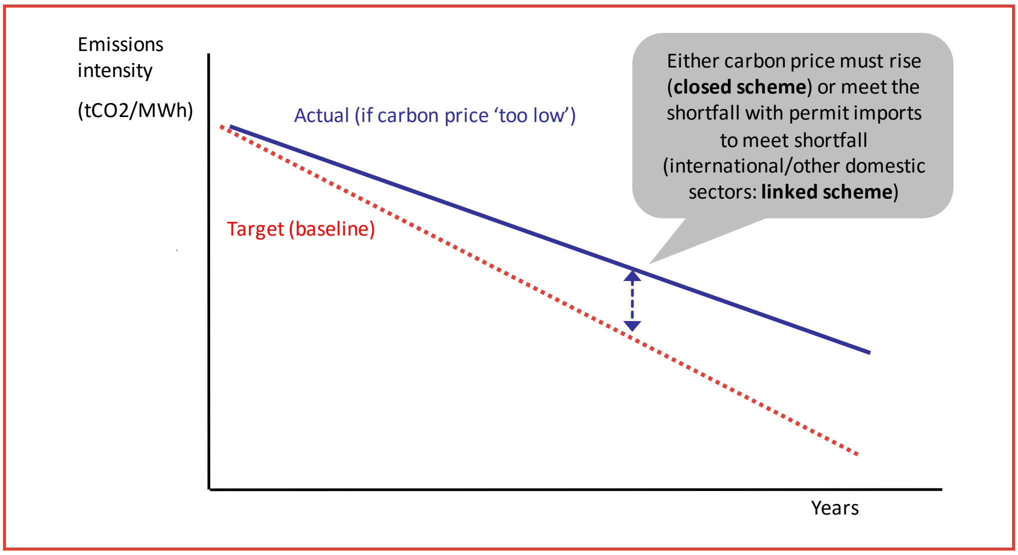
2.5 Potential for variance between actual and forecast demand

An intensity target can operate either as a domestic only ("closed sector") scheme or could involve trade with other sectors/internationally ("open"). If the scheme is "closed" then the carbon price should adjust so that actual intensity matches the target (subject to possible banking/borrowing between years and treatment of legacy hydro, discussed below).

If the scheme involves linkage with international markets ("open") then the electricity sector will likely be a price taker and the actual intensity of the sector may be higher/lower than the target, depending on the prevailing carbon price. This is illustrated in Figure 7. In the diagram, actual intensity is higher than the target, which means that more generators would face a penalty than generate a credit. If the sector were "closed", this would lead to more liabilities than credits, which should raise the carbon price until the actual emissions intensity falls to meet the target intensity. If the sector were "open" to linkage then the difference between actual and the target intensity could be met through permit imports and domestic electricity emission could remain higher than the target (for the given carbon price).

Note that total sector emissions (Mt) will be a function of the intensity and total demand, so even if the actual sector intensity equalled the target, if demand were higher (lower) than forecast then total sector emissions could be higher (lower) than the target.

Figure 7: A stylised diagram: potential variance between target and actual intensity



Given that electricity sector **modelling** is inherently deterministic with perfect foresight on future assumptions, it will not always illustrate the effects of uncertainty and differences in scheme designs. This uncertainty ideally needs to be understood in theory and tested via modelling sensitivities.

The different characteristics of different mechanisms are summarised in Table 3.

Theoretically, a carbon tax provides certainty over carbon price but uncertainty over emissions; an emissions trading scheme has certainty over emissions and uncertainty over carbon price. An EIT can have characteristics of either, depending on whether the EIT is regularly updated/adjusted for variations in demand (from forecast) or whether international permit imports are allowed. For example, this could involve some form of **EIT updating** if demand varies from forecasts. This could involve either a revision to future intensity targets (e.g. a reduction in the intensity target to offset demand higher than forecast) or the use of offsets (such as international permits).

Table 3: Uncertainty and impacts of different schemes

Area of uncertainty	Cap and trade (electricity sector only)	Emissions Intensity target (EIT: electricity sector only)	Carbon tax
Supply side: cost of generation, fuel switching differs from forecasts	Permit **prices** vary	Permit **prices** vary With international trade (open scheme), characteristics closer to tax	Sector **emissions** vary
Demand side: demand higher/lower than forecasts	Permit **prices** vary	With Updating EI, characteristics closer to cap and trade ETS Sector **emissions** vary	Sector **emissions** vary
Combined	Uncertainty in permit prices, certainty in sector emissions	Moderate uncertainty in both permit prices and sector emissions	Uncertainty in sector emissions, certainty in price
Commentary	If permits allowed from other sectors / internationally (and the sector is a price taker) then price will be more certain, sector emissions may vary: similar to a carbon tax. There is also uncertainty in practice around potential changes to targets	Depends on specific design: **Updating EI:** If a **firm** sector emissions target is required (in Mt, without offsets) then the intensity target will need to vary over time to adjust for any variance in demand (between actual and forecast). This alternative approach would reduce uncertainty in sector emissions but would increase uncertainty in permit prices. (Shift toward Cap and Trade characteristics) **Open scheme**: If **international permits** (offsets) are allowed then the sector will likely be a price taker (importing international permits). **Domestic** emissions intensity in the sector may be higher than the baseline, where the gap is met through permit imports This alternative approach would reduce uncertainty in permit prices emissions but increase uncertainty in domestic sector emissions. (Shift toward carbon tax characteristics)	There is still policy uncertainty in practice around potential changes to carbon prices

2.6 Legacy hydro

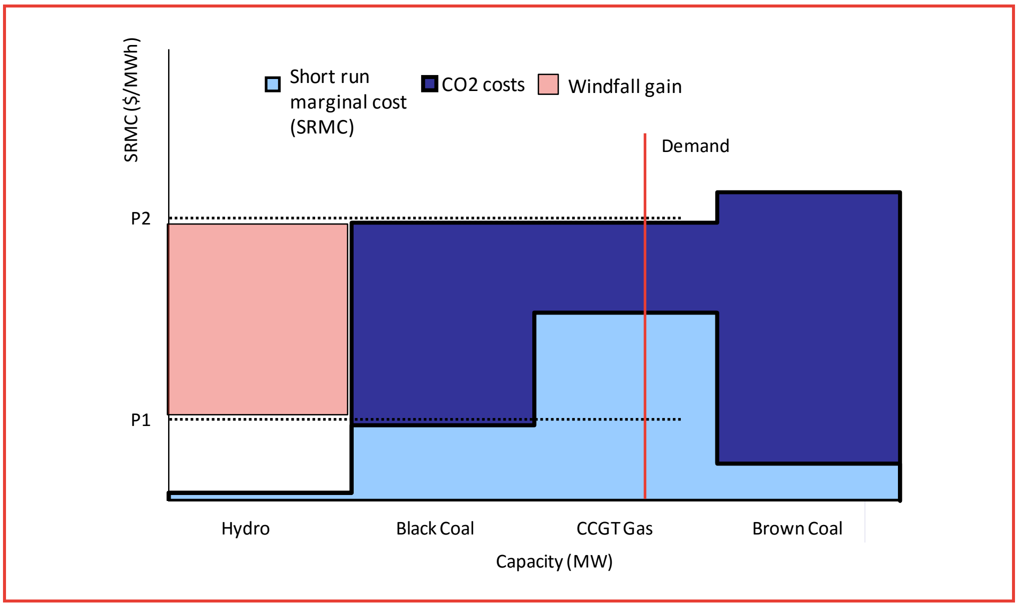
Under a standard ETS/cap and trade the carbon price will lead to spot price increases for the market as a whole as the cost of marginal generation increases. Existing hydro will not see any rise in (carbon) costs. Frontier Economics has previously advised the AEMC on the drivers of carbon cost pass-through.[8] This can lead to 'windfall gains' to existing hydro under a standard cap and trade (price and revenue increases but cost does not). Under an intensity approach, one option to consider could be to exclude legacy hydro from creating credits. Since marginal cost of existing hydro is low, this would make no change to their output (which is a function of rainfall longer-term, subject to shifts from year to year) or sector emissions. This would mean that existing hydro would be no worse than under BAU but would not earn the potential windfall gains that they would under a standard cap and trade (or an intensity target when they are eligible for credits). This could be similar to the exclusion of legacy hydro under the LRET.

Note, however, that hydro output still would be contributing to reducing the sector emissions intensity, and any credits generated (or excluded) would need to be considered in the target/price setting. If legacy hydro were to be excluded from certificate creation, this would reduce the supply of **credits** created which would result in a higher carbon price unless the sector intensity target were similarly adjusted (i.e. raised). If legacy hydro is to be excluded from eligibility, one alternative to adjusting the target might be for the Government to release/sell credits equivalent to the output from legacy hydro into the market. This would ensure that the supply/demand of certificates matches the actual emissions intensity of the market. But it would mean that the potential windfall gain to legacy hydro that would exist under a standard cap and trade (or intensity target with legacy hydro creating credits) could instead flow to Government or distributed to other parties (eg Emissions intensity trade exposed industries: EITEI).

This approach is less relevant to existing gas as they have a much higher marginal cost than existing hydro, so exclusion from eligibility would affect them differently and have a different impact on sector emissions.

8 Weblink: http://www.aemc.gov.au/Media/docs/Frontier%20Economics%20Report%20-%20%20Impact%20of%20Climate%20Change%20Policies%20on%20Electricity%20Retailers-e004f70d-67f4-413c-8736-4f4f0896c303-0.pdf

Figure 8: A stylised diagram: potential windfall gain for existing hydro



2.7 Interaction with existing LRET

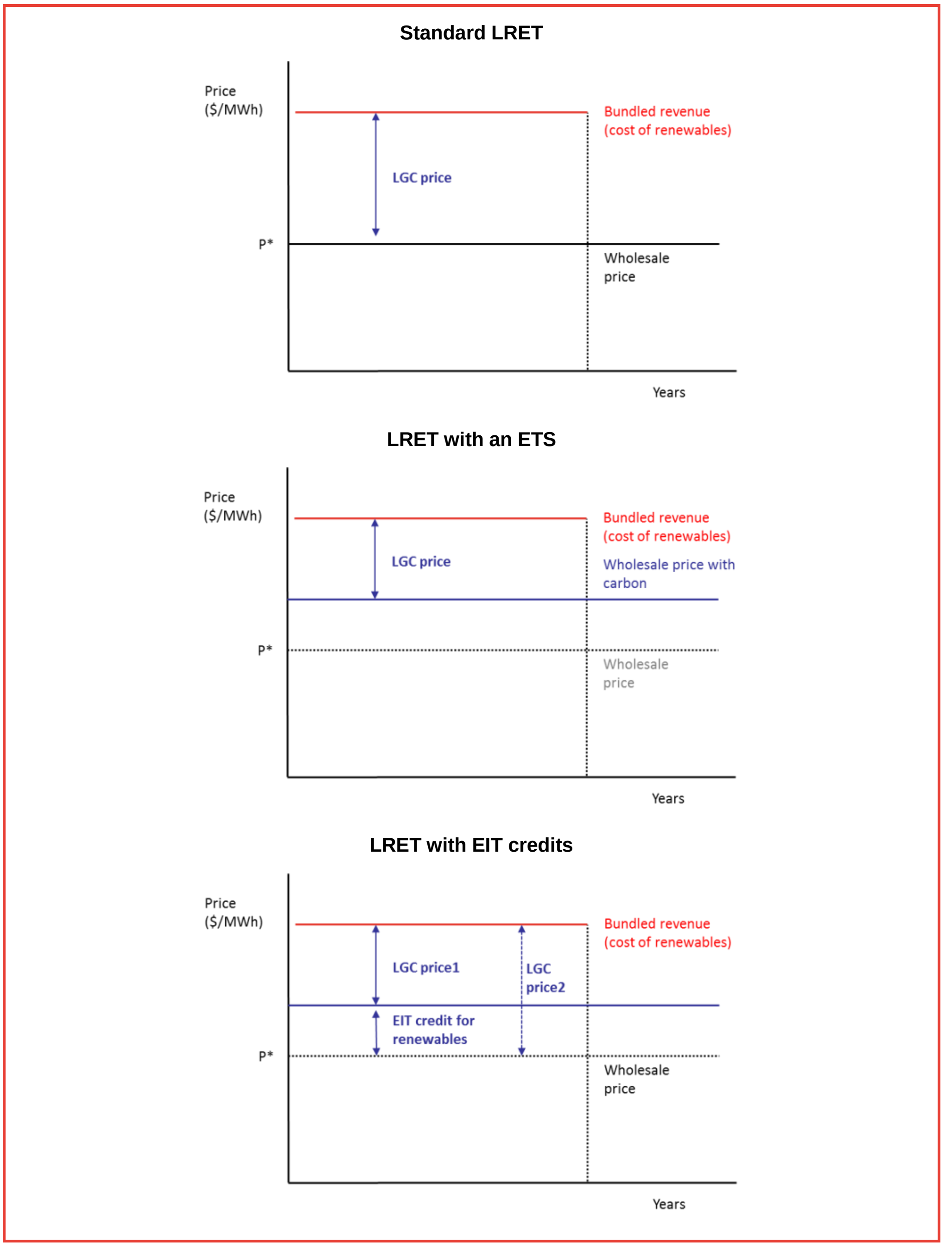
Figure 9 illustrates how an LRET would interact with an EIT. The first example shows that LGC prices are generally set by the difference between wholesale pool prices and the cost of renewables.

Under a standard cap and trade (ETS), a carbon price should lead to higher pool prices which should lead to lower LGC prices (diagram 2). Frontier Economics explained this interaction in a previous report for the AEMC.[9]

Under an EIT (diagram 3), one option would be for LRET eligible generation to be eligible to create credits under the EIT approach (as well as concurrent creation of LGCs). Under this approach the value of credits under this approach should lead to lower LGC prices (LGC price1). An alternative is to exclude LRET eligible generation from the EIT. This would not lead to a reduction in LGC prices (LGC price2). However, as per legacy hydro above, this would need to be considered in the setting of targets.

9 Weblink: http://www.aemc.gov.au/getattachment/1a21ab8c-49d5-462b-9cba-089be0efc9c3/Impacts-of-climate-change-policies-on-generation-i.aspx

Figure 9: A stylised diagram: interaction between LRET and EIT



Theoretical underpinnings and scheme design

2.8 EITEI

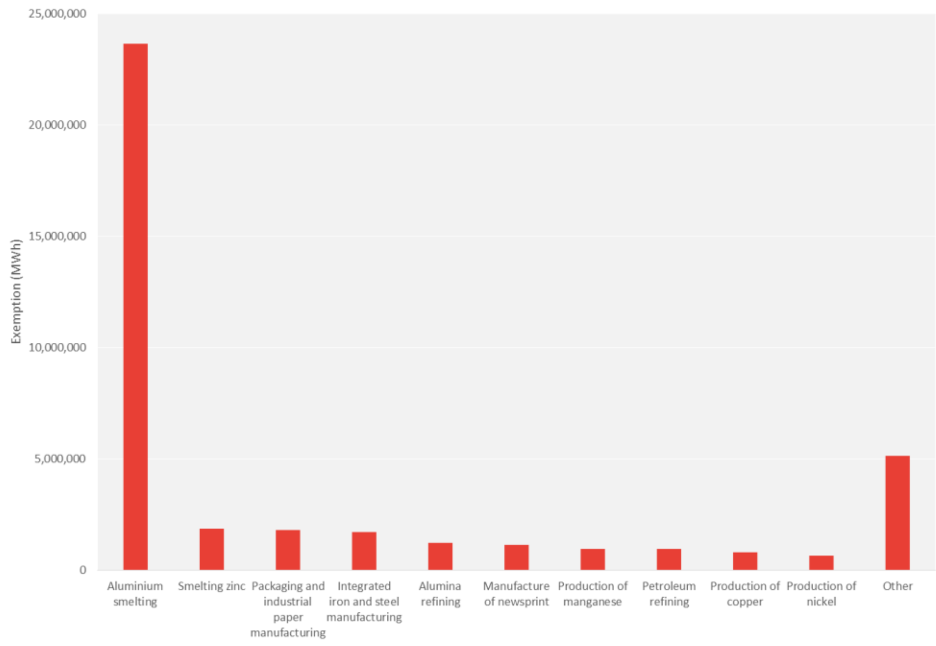
Theoretically, the legacy hydro EIT credits could be allocated for other purposes without affecting the efficiency of emissions abatement.

One option could be to compensate EITEI *directly* using the legacy hydro credits, however the EIT scheme should already provide some *indirect* compensation (via lower electricity prices than under an ETS).

On indicative figures, EITE consume around 39TWh of electricity (based on CER data on the RET, Figure 10).

Legacy hydro (that is excluded from the LRET baselines) is around 15TWh. Given our EIT pathway, this implies potential legacy hydro credits of around 11M per year (~117Mt from 2020-2030). Whether this is sufficient is an empirical question, though not all EITE consumption requires an EIT credit, as they need only be compensated for price increases (which the EIT is likely to limit).

Figure 10: EITE electricity use



http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/Industry-assistance/Industry-assistance-published-information/Emissions-intensive-trade-exposed-activity-summaries

3 Methodology

This section presents an overview of Frontier Economics' electricity market models, the inputs used in the models and detailed discussion of demand and retirements. Scenarios and assumptions are discussed in Section 4.

3.1 Modelling framework

Forecasting long term gas prices for both the eastern and western gas markets is undertaken in our gas market model – *WHIRLYGAS*. Coal prices are forecast using our detailed mining cost and netback price models. These are generally consistent with our approach and assumptions for the AEMC 2015 Retail Price trends[10], subject to more recently available information.

Our electricity modelling for this project uses our electricity market models: *WHIRLYGIG* and *SPARK*.

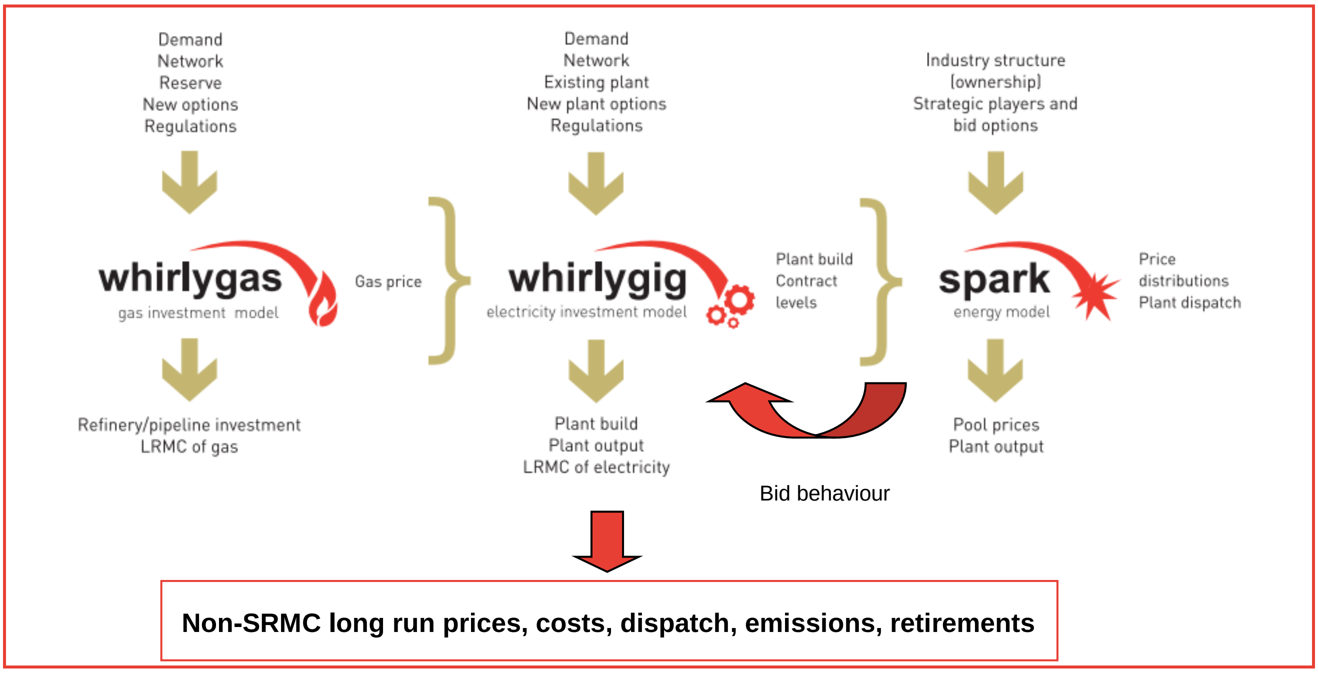
The key features of these models are as follows:

- *WHIRLYGAS* seeks to minimise the total cost – both fixed and variable costs – of supplying forecast gas demand for eastern Australia's major demand regions. This optimisation is carried out subject to a number of constraints that reflect the physical structure and the market structure of the east coast gas market. *WHIRLYGAS* has been structured to incorporate international LNG demand and to produce domestic price forecasts that reflect opportunity costs of exporting gas as LNG.
- *WHIRLYGIG* optimises total generation cost in the electricity market, calculating the least cost mix of existing plant and new plant options to meet load. *WHIRLYGIG* provides an estimate of LRMC, including the cost of any plant required to meet any regulatory obligation, as required under the scope of work for this consultancy.
- *SPARK* identifies optimal and sustainable bidding behaviour strategy for generators in the electricity market using game theoretic techniques. The model determines the optimal pattern of bidding by having regard to the reaction by competitors to a discrete change in bidding behaviour by each generator to increase profit (either by attempting to increase price or expand market share). Once the profit outcomes form all possible actions and reactions to these actions are determined the model finds the equilibrium outcome based on standard game theoretic techniques. An equilibrium is a point at which no generator has any incentive to deviate from because they will get pushed back to this point by competitor responses.

10 Frontier Economics – 2015 Residential Electricity Price Trends (wholesale modelling report)

These models are described in more detail in the text boxes below and their relationship to one another is summarised in Figure 11. For this long-term policy modelling, we iterate the strategic bid profiles from *SPARK* back into the long-term *WHIRLYGIG* modelling to derive non-SRMC prices and ensure consistency between pool prices, investment/retirement decisions and certificate prices.

Figure 11: Model inputs and outputs



3.2 Model inputs

The key input assumptions are:

- Demand
- Carbon policy assumptions
- RET assumptions
- Fuel costs
- Capital costs.

These are discussed in Section 4, however we provide detailed discussion of our approach to demand adjustments and retirements below.

3.2.1 Demand adjustments and elasticity

Our Base Case demand is derived from AEMO and IMO demand forecasts (Medium case). However, the Medium AEMO demand forecasts correspond to a price forecast which includes a moderate carbon price after 2020 (which raises pool prices). Strictly speaking, the AEMO demand forecasts correspond to those specific price forecasts and the AEMO demand should be adjusted to account for the removal of an assumed carbon price in our Base Case. Without the precise AEMO price forecasts, this adjustment is approximate and results in a marginal increase in Base Case demand (in the absence of a carbon price). This is shown in Section 4 but the difference only applies after 2022 (when the AEMO prices include a carbon price) and the change in demand is around only 1-2%.

Strictly speaking we could also iterate our price forecasts from the policy modelling scenarios (model outputs) with further revisions to demand (model inputs). However, none of the policy scenarios modelled result in net price increases (or falls) as large as would result from a traditional ETS and, given the results above, this is not a material driver of results.

3.2.2 Forecasting plant retirements

Plant retirement has an important bearing on emissions forecasts, particularly the exit of brown and black coal. This is especially relevant under conditions of weak demand growth, oversupply and/or policies that directly or indirectly increase costs or reduce revenue for high emissions generators.

Importance of retirements

In recent years, the NEM has experienced an unprecedented period of low or, in some cases, negative demand growth. These reductions have been driven by a number of factors, including:

- energy efficiency schemes
- structural changes to the economy (for example closures of industrial facilities like the Point Henry smelter) as part of long terms trends towards de-industrialisation
- residential Solar PV installations driven by state and Commonwealth subsidies and falling costs
- price elasticity of demand effects in response to rapid increases in retail tariffs (driven mostly by increased network tariffs).

These factors and others have acted to reduce the demand for electricity met by large thermal and renewable generators, which has resulted in wholesale prices close to SRMC, and low profitability for a number of generators. In some cases generation plant have been removed from the market temporarily (this is often referred to as mothballing or standby outages). In other cases, older generation plant have been retired permanently; for instance, the Munmorah coal-fired power station, Swanbank B and E, Collinsville, Playford, Wallerawang units 7 and 8, Torrens Island A and most recently Northern have permanently closed or announced intentions to close.

This is a significant quantity of capacity that has already exited the NEM. With weak demand growth and growing renewables entry to meet the RET, this will place further downward pressure on prices and generator profitability. As such, it is possible that further retirements may occur over the modelling period.

Difficulty in modelling power station retirements

Many factors impact on a particular participant's decision to retire a power station, including:

- for generation plant that is operating at a loss, the need to weigh up relatively certain short term losses against less certain long term profits when deciding whether to remain in the market
- decommissioning and site remediation costs that would be incurred on retirement
- dry storage costs (i.e. costs associated with temporarily closing a plant such that it can be easily returned to service)
- portfolio considerations:
  - stand-alone generators may not benefit from higher prices after exit.
  - stakeholders with a portfolio of assets may have stronger incentives to both retire plant (due to ability to capture any uplift in revenue via other assets) and to persist with struggling assets (as they can better support short term losses on one asset with profits on other assets).

The most complex aspect of forecasting retirements is that the decision to retire represents an economic game between participants in an electricity market involving a strong first-mover **disadvantage**. The exit of a plant may lead to higher prices for remaining participants. In the case where multiple large power stations are experiencing marginal profitability, this is likely to lead to an outcome where no plant retires and all make minimal profits or even some losses.

Modelling approach

There are a number of approaches to modelling power station retirements. These fall into three broad categories:

- **By assumption**. Specific plant are assumed to retire based on an assumed technical life. We include the announced retirement of Northern in our assumptions but do not include the announced retirements of Liddell and Bayswater.
- **On the basis of cost**. Retirement can be considered as part of any cost optimisation model: we include fixed operating and maintenance costs (FOM) for existing plant, which can be avoided through retirement of capacity. If it is cheaper to retire plant with sunk capital costs but ongoing FOM and invest in

new plant, then plant can be retired. This is determined from a system perspective, so it is possible that plant might continue to operate at a loss (not recover FOM) if this is cheaper than replacement with new investment.

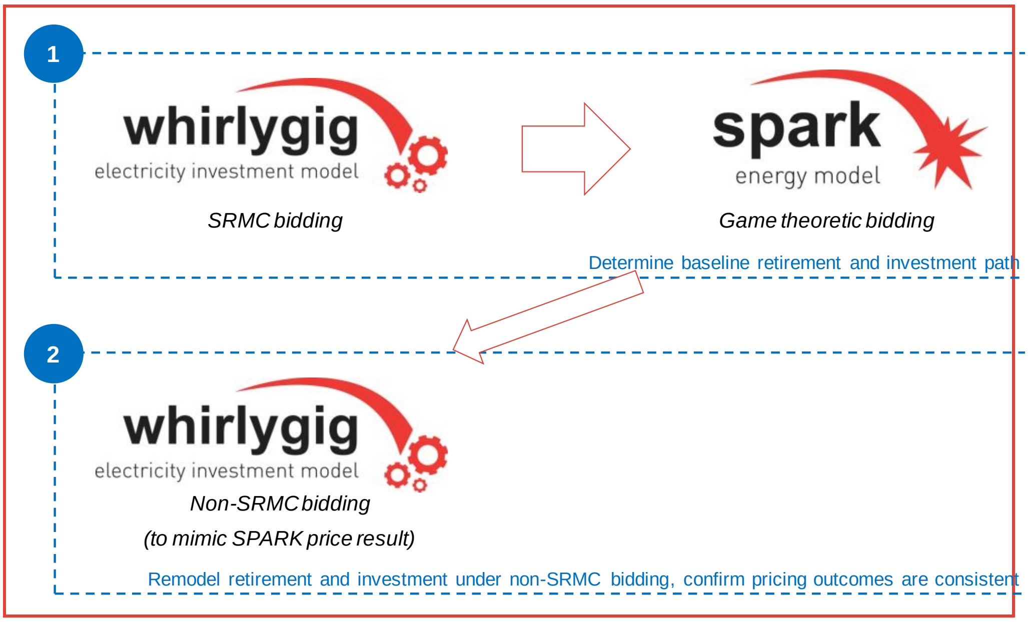
- **On the basis of expected profit**. This involves forecasting the profitability of various portfolios with and without specific combinations of retirements. This allows considerations of the strategic game between major NEM participants.

Our approach combines the least-cost, centralised optimisation approach used in *WHIRLYGIG* and the equilibrium bidding patterns forecast in *SPARK* in a two-step iterative process.

1. First, we forecast outcomes in *WHIRLYGIG*, assuming perfectively competitive, SRMC bidding. This is used to model both retirement and investment. We then model market outcomes in *SPARK* to determine bidding and pricing forecasts under more market reflective pricing.
2. Second, we relax the assumption of perfect competition in *WHIRLYGIG* by adopting profiled quantity offers for all strategic generators. These profiled offers are consistent with the bidding outcomes forecast in *SPARK* in our first step. We use this second *WHIRLYGIG* run as our forecast of both retirement and investment.

This approach is illustrated in Figure 12.

Figure 12: Overview of approach to modelling retirements



This approach has a number of benefits:

- Retirements occur based on outcomes in the market that reflect strategic bidding, which we think is a more realistic treatment of retirement than assuming SRMC bidding.[11]
- The approach maintains a centralised optimisation framework such that *all* combinations of retirements are investigated simultaneously, just as all combinations of new investment are captured in the approach.

The approach is still limited in some regards. Portfolio effects (first mover disadvantage and strategic considerations for large portfolios) are explicitly *not* considered in the approach. The optimisation also occurs with 'perfect foresight' on all model inputs. For example, for a given scenario the model 'knows' future price outcomes.

Remediation costs

Mine remediation costs can be viewed as a potential barrier to exit: if plant closure results in large remediation costs then it may encourage delayed retirement. We did not include this additional retirement cost in the modelling (for remediation) for the following reasons, all of which potentially reduce the extent to which mine remediation costs would act as a barrier to exit:

- Earlier retirement brings forward remediation costs that would otherwise be incurred in the future at some point, hence this is a question of time value of money (bringing forward a cost, as opposed to incurring a new additional cost);
- Generators could potentially mothball capacity to avoid FOM (and reduce emissions) while deferring remediation costs;
- Some generators already face remediation bonds. Remediation cost is already incurred in these instances; although there is a question of adequacy, in Victoria the bonds will be increased over the next 18 months.

11 Similar arguments apply to the marginal cost of meeting relevant policies, such as the LRET and/or other emissions schemes.

4 Scenarios and assumptions

This section provides an overview of the input assumptions that we use in our modelling.

The key input assumptions in terms of impact on modelling wholesale outcomes are:

- demand
- carbon assumptions
- RET assumptions
- fuel costs
- capital costs.

Each of these key assumptions is discussed below.

4.1 Scenarios and sensitivities

Table 4 summarises the scenarios and sensitivities considered in the modelling. We model four cases: BAU (no carbon price but with continuation of the RET) where emission cans rise above the target, plus three mechanisms to reduce emissions in line with the 2030 targets:

- an **EIT** that rewards low emitters and penalises high emitters,
- an **extended LRET**, with the target increased and extended to 2040 (to a level sufficient to meet the emission target given our assumptions on demand, fuel costs)
- **Regulatory closures (REG),** which assumes that existing plant can be forced into retirement (sufficient to meet the emissions targets). This policy option does not consider any costs associated with compensation for closed generators (or a levy to fund this).

In addition to a Base Case scenario reflecting our default assumptions, we also test each scenario under different assumptions, including **High Demand**, **High Gas** prices, **Low Demand, a 50PC emissions reduction target** and **lower utility solar costs**. However, the results of the Low Demand case were such that BAU emission were below the target, rendering the policy scenarios redundant. These results are not reported here.

The **Demand** sensitivity is intended to reflect a difference in **expected**/forecast demand, not an **unexpected** difference in demand, as the implications differ:

- If the difference is **expected** then this will require a different intensity target to meet a given sector emissions target, which will have an impact on the resulting carbon price. High Demand requires a lower emissions intensity target (higher LRET, more REG closures) to meet a given sector emissions target.

- If the difference is **unexpected** then the intensity target/LRET (and resulting carbon price) will be broadly the same but there will be a difference in total sector emissions. We adopt the former approach in the modelling scenarios

Table 4: Scenarios

Scenario	Sensitivities						
	Base Case (S5)	High demand (S6)	High Gas (S7)	Low Demand (S8)	50PC 2030 target (S9)	Lower solar PV costs (28PC target) (S10)	EITEI credits (28PC target) (S11)
BAU	✓	✓	✓	✓			
Emissions Intensity target (EIT)	✓	✓	✓	✓*	✓	✓	✓
Extended LRET (LRET)	✓	✓	✓	✓*	✓	✓	
Regulated closures (REG)	✓	✓	✓	✓*	✓		

Table 5 provides a high level summary of scenario design and assumptions. The scenarios test different mechanisms to meet the emissions reduction targets for a given set of costs/demand; we then test different demand/gas prices for each.

All scenarios include the existing national LRET and the ACT reverse auctions but **exclude** the recently proposed Victorian[12] and Queensland[13] Renewable Energy Targets.

12 40% by 2025

13 50% by 2030

Table 5: Key assumptions

Base Cases	LRET	Demand	Fuel	Capex	Retirement	CO2		
						Scheme	Target	Internation-al linkage
BAU	33 TWh	2015 medium NEFR/IMO (High/Low sensitivities)	Frontier Economics (High Gas sensitivity)	Frontier Economics	Cost recovery (FOM) (subject to a check on profitability)	None	n/a	n/a
Emissions Intensity target (EIT)	RET continues at 33TWh (interacts with EIT).					Declining **intensity** target	28% reduction pro rata **(sector only)** (50PC sensitivity)	No
Extended LRET (LRET)	Extended to meet 2020-30 emissions target (86TWh)					RET	To meet cumulative 2020-2030 emissions target	No
Regulated closures (REG)	33 TWh				Cost (FOM) + forced (by assumptions)	Forced retirements		No

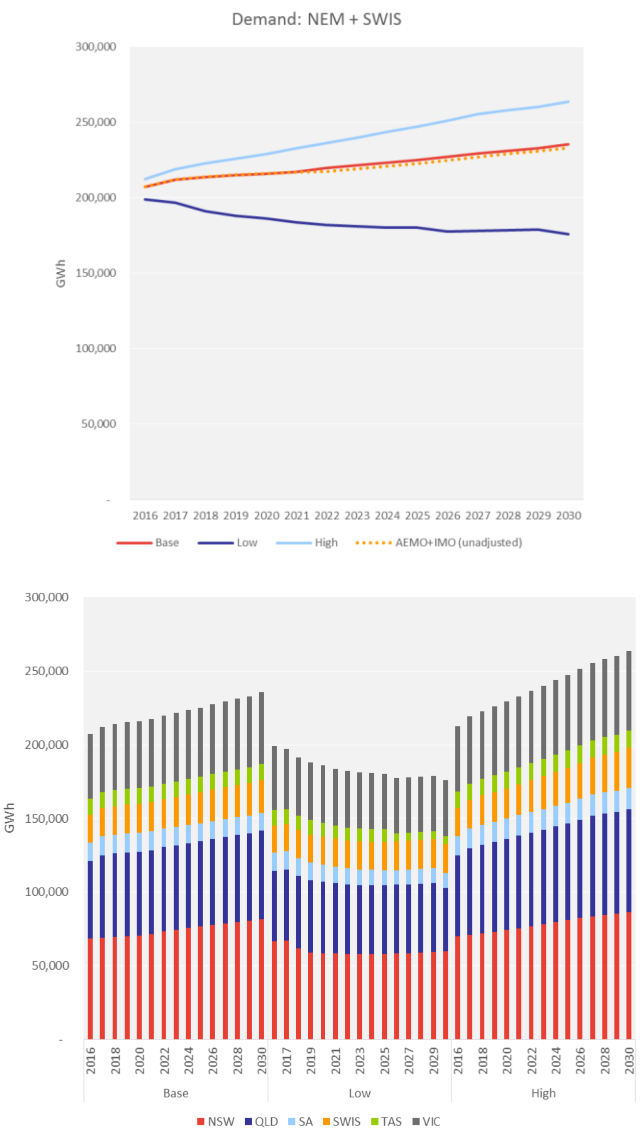
4.2 Demand

Figure 13 shows the demand inputs in the Base, High and Low sensitivities. These are largely based on AEMO 2015 NEFR[14] and the latest IMO ESOO (2014, published June 2015)[15]

14 http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report

15 http://wa.aemo.com.au/home/electricity/electricity-statement-of-opportunities

Figure 13: NEM + SWIS demand by sensitivity



Source: Frontier Economics, AEMO/IMO, Native Sent out energy (excludes rooftop PV)

Strictly speaking, the AEMO Medium case is based on future price forecasts that include the introduction of a carbon price from 2022 (based on EU ETS prices), whereas our BAU is intended to reflect no carbon price scenario. Although AEMO's demand forecasts depends on the precise price path forecasts used as inputs, we have approximately adjusted this price forecast to only account for the approximate difference in BAU carbon price assumptions. This implies a lower underlying price (without carbon from 2022) which implies a marginally higher demand in the BAU, though the difference is not material to our modelling results.

Theoretically we could undertake similar demand adjustments as a result of our policy price forecasts, iterating between **price** as a model **output** to adjust **demand** as a model **input**, to test whether this results in different final prices. However, given the slight difference in the adjusted demand (above), and given that our price results in the modelling scenarios are broadly close to the BAU results, we do not consider further iteration necessary. This is only required if the market is likely to be in disequilibrium.

4.3 CO2 and EI targets

Our target emissions reduction is a 28 per cent reduction on 2005 emissions by 2030. For the purpose of our Base Case modelling, we consider a closed sector, pro-rata target for Australian electricity (no international imports). Figure 14 illustrates how we derive this target, including translation to an emissions intensity target for the Base Case demand growth.

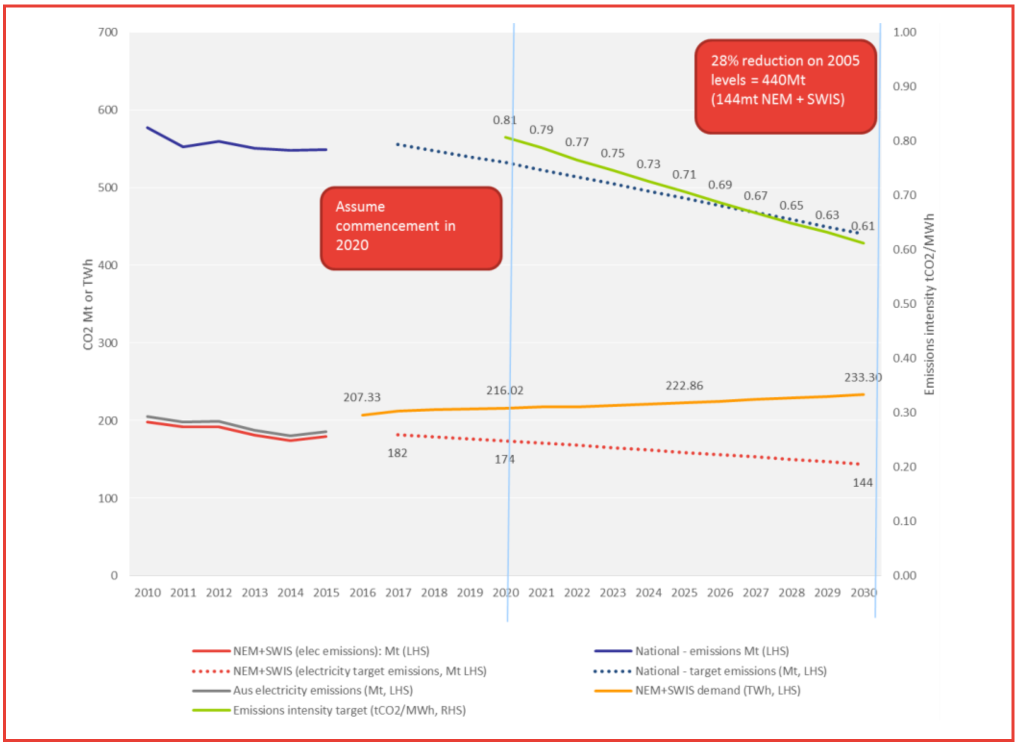
Total emissions (Mt)/electricity demand (TWh) are shown on the left hand axis; emissions intensity (tcO2/MWh) is shown on the right hand axis.

The national target in 2030 is estimated at 440Mt (28% reduction on 611Mt in 2005)[16]; we pro-rate this target based on the approximate NEM+SWIS electricity sector emissions (which has varied between 32-34% of national emissions over the past decade) to derive a NEM+SWIS target of 144Mt by 2030. We assume that this commences from 2020 based on a pro-rata share of the national trajectory of 532Mt in 2020 (which is below actual projected emission in 2020). This equates to a cumulative 2020-2030 budget of 1751Mt.

We translate this to an intensity target by dividing the sector emissions target by forecast electricity demand each year (NEM+SWIS). This commences at 0.81tCO2/MWh in 2020 and falls to 0.61tCO2/MWh by 2030 **based on this forecast demand.**

16 The 2005 emissions were revised to 611Mt in late 2015 (http://www.environment.gov.au/climate-change/publications/factsheet-emissions-projections-2015-16)

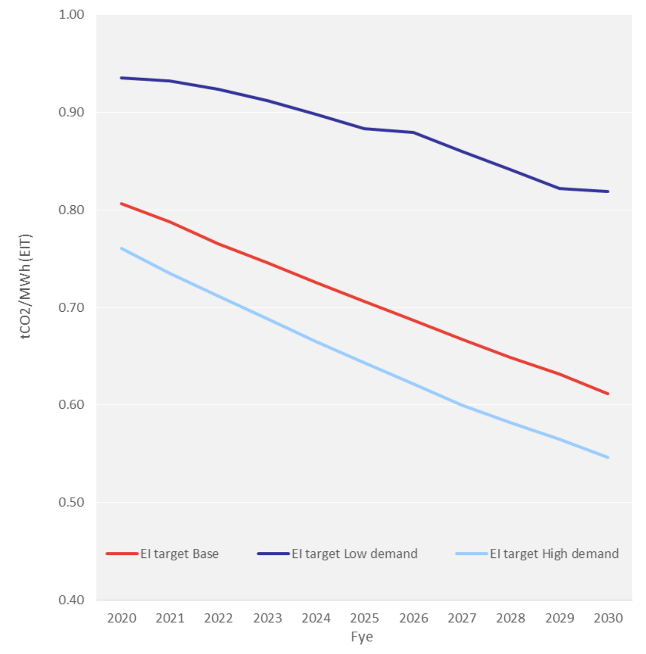
Figure 14: NEM + SWIS Emissions target



Source: Frontier Economics

Figure 15 shows the equivalent emissions intensity targets for the High and Low demand sensitivities. This assumes that these are **expected** changes in demand and the emissions intensity targets adjusted accordingly (or that targets are updated/adjusted very regularly).

Figure 15: NEM + SWIS Emissions intensity target by sensitivity



Source: Frontier Economics

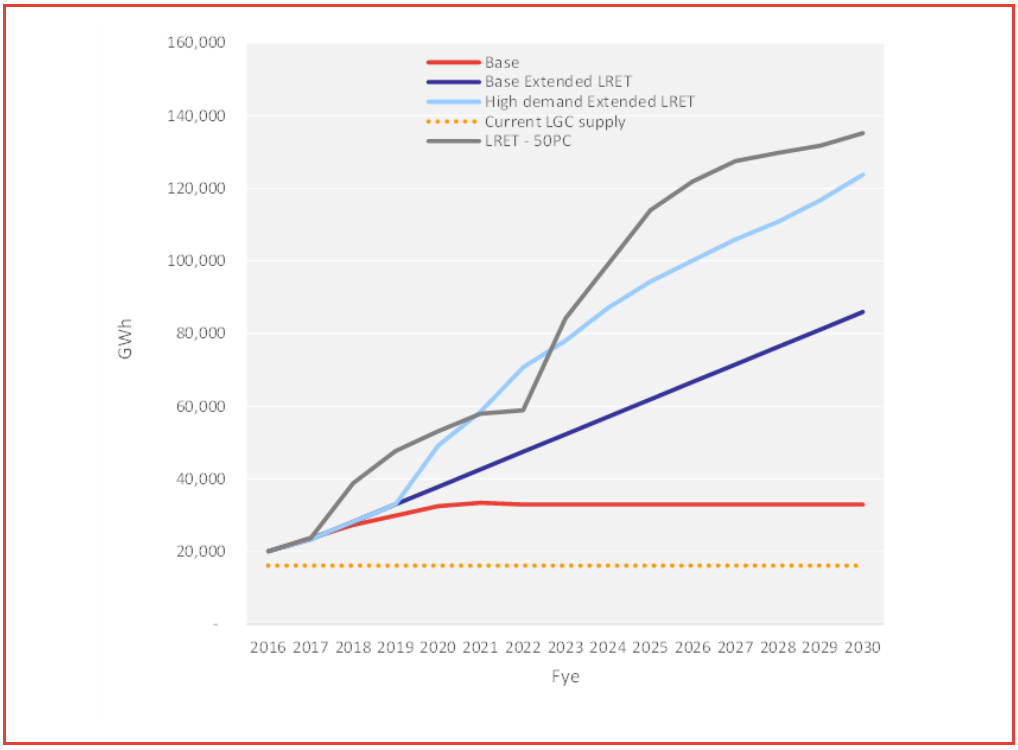
4.4 RET

The revised LRET target of 33,000 GWh, including the revised trajectory of the target to 2020, is modelled for the BAU across all cases. This is relative to current existing annual supply of LGCs of 16,000GWh. (This amount varies with annual hydro and wind output, which is uncertain but generally growing).

In the Extended LRET scenarios, the LRET is extended to ensure that the emissions target from 2020-2030 is met through the LRET alone without other policy support mechanisms. This is an iterative process requiring adjustment of the LRET and comparison of the resulting sector emissions against the target; the final results are within 2% in the forecasts.

The Extended LRETs to meet the 2030 target are 86,000GWh in the Base demand scenario, 124,000GWh in the High Demand sensitivity and 135,000GWh in the 50PC sensitivity. BAU emissions are actually lower than the target in the Low Demand sensitivity, which would suggest a reduction in the LRET (which is not modelled).

Figure 16: RET by case, sensitivity



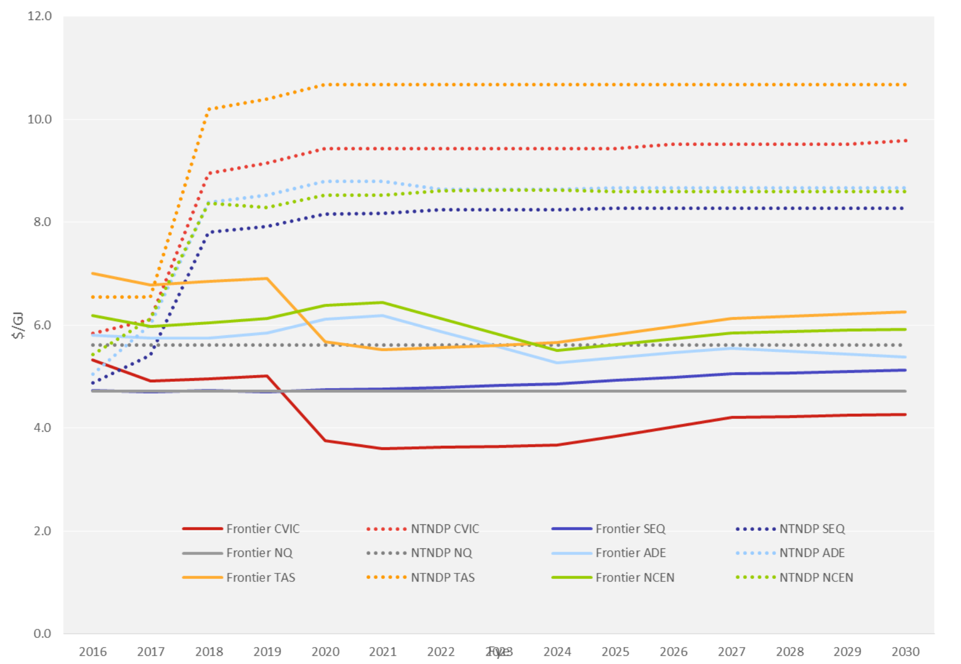
Source: Frontier Economics

4.5 Fuel

Gas prices

Gas prices are driven by demand for gas, international LNG prices, foreign exchange rates and underlying resource costs associated with gas extraction and transport. Frontier Economics' Base Case and High Case (NTNDP) forecasts are shown in Figure 17 for a selection of pricing zones across Australia.

Figure 17: Gas price by region ($/GJ, real 2016)



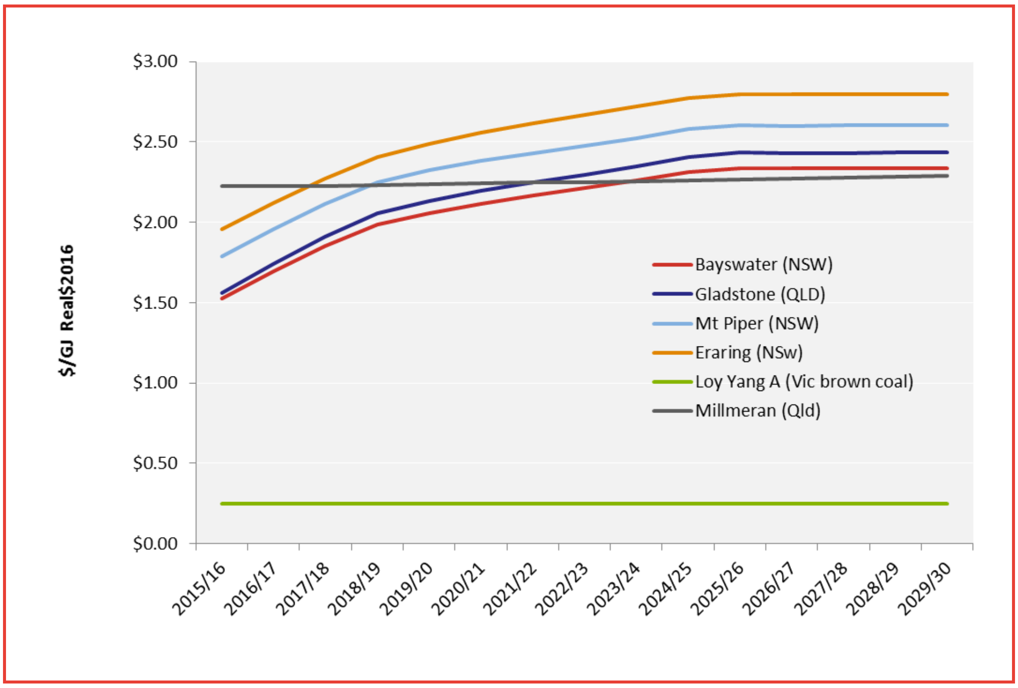
Frontier assumptions = Base Case. NTNDP = High Gas case (NQ gas limited to 400MW capacity)

Source: Frontier Economics

Coal prices

Coal prices are driven by demand for coal, international export coal prices (for export exposed power stations), foreign exchange rates and underlying resource costs associated with coal mining. Frontier Economics' forecasts are shown in Figure 18 for representative power stations both export exposed and mine-mouth stations.

Figure 18: Coal prices for representative generators ($2015/16)



Source: Frontier Economics

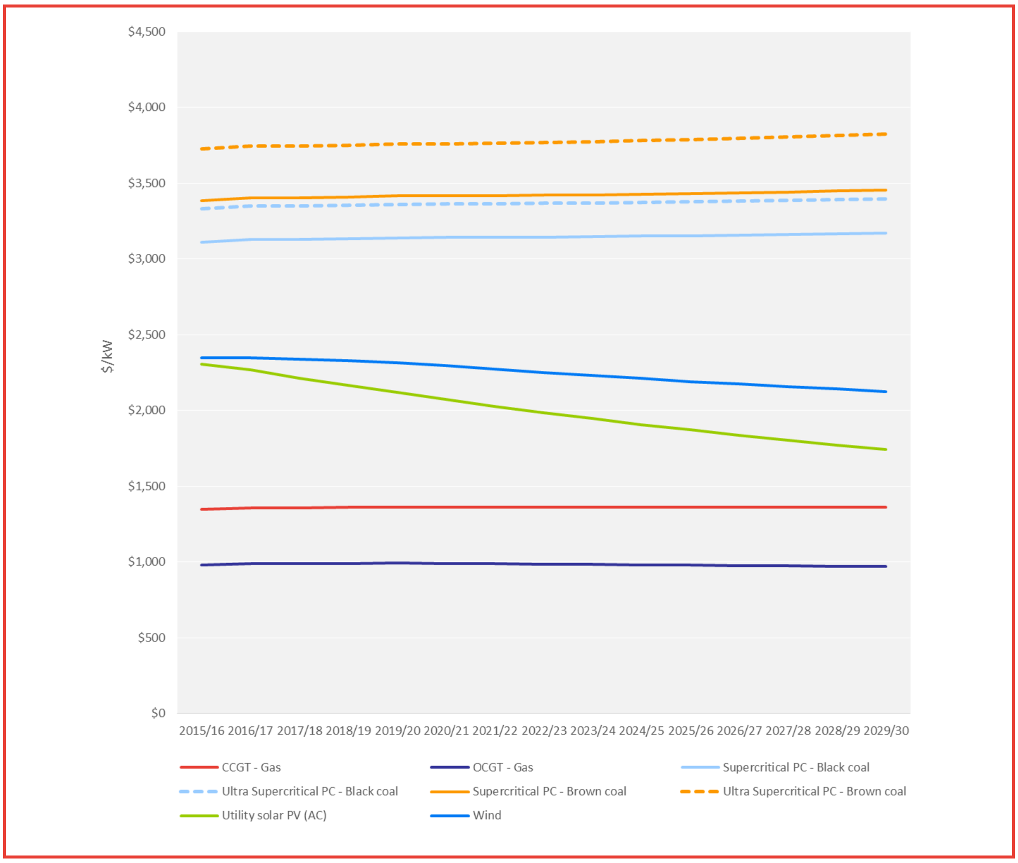
4.5.2 Capital

Frontier Economics' capital cost estimates are based on a detailed database of actual project costs, international estimates and manufacturer list prices.

Our approach relies on estimates from a range of sources – actual domestic and international projects, global estimates (for example, from EPRI [17]) and manufacturer list prices. These estimates are converted to current, Australian dollars. Our estimate is then taken as the mean over the middle two quartiles of the data (the 25th to 75th percentiles). The capital cost curves used in the modelling are shown in Figure 19 for key thermal and renewable technologies. The movements of capital cost over time are driven by factors such as real cost escalation, exchange rate movements and technological improvements (learning curves).

17 See http://www.epri.com.

Figure 19: Capital costs for new generation plant



Source: Frontier Economics

5 Results: Base case scenarios

This section presents Frontier Economics' modelling results for the Base Case scenarios. We report estimates of:

- Resource costs and cost of abatement;
- Certificate prices and emissions;
- Wholesale prices by region, with and without the additional of an LRET levy;
- Investment/capacity and output over time;
- Generator closures/retirements

Table 6: Scenarios

Scenario	Sensitivities							
	Base Case (S5)	High demand (S6)	High Gas (S7)	Low Demand (S8)	50PC 2030 target (S9)	Lower solar PV costs (28PC target) (S10)	EITEI credits (28PC target) (S11)	HZ retires pre-2020 (S12)
BAU	✓	✓	✓	✓				✓
Emissions Intensity target (EIT)	✓	✓	✓	✓*	✓	✓	✓	✓
Extended LRET (LRET)	✓	✓	✓	✓*	✓	✓		✓
Regulated closures (REG)	✓	✓	✓	✓*	✓			✓

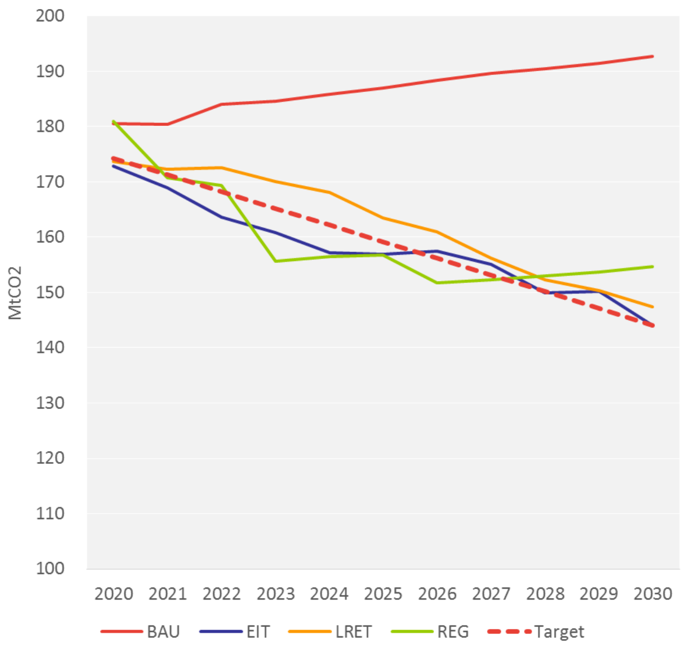
** In the Low Demand case, the emissions target was met in the BAU case, making the policy changes redundant*

5.1 Emissions comparisons

Figure 3 shows projected emissions over time. The BAU emissions grow with growth in electricity demand in the absence of further policy interventions.

The policy scenarios all broadly track the emissions target by design. In the EIT case the allowance for banking of permits between years means that actual emissions can fall below the target (initially) to offset emissions above the target in later years. The LRET and REG cases both involve some iteration between policy settings (increase in the LRET and assumed retirements in REG) and the resulting emissions.

Figure 20: Emissions pathways



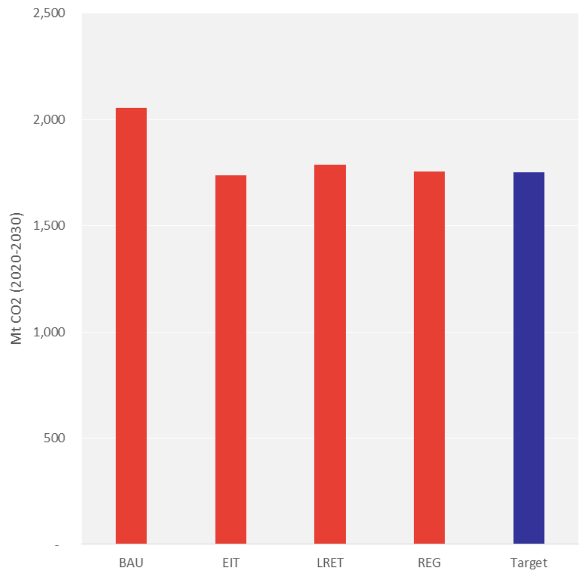
LRET 2% above target

Source: Frontier Economics

The cumulative emissions from 2020-30 are shown in Figure 21. The BAU is 304Mt above the target (under the Base Case assumptions), reflecting the cumulative abatement task.

- The EIT delivers emissions 1% below the target;
- the LRET emissions resulting from our assumed target are 2% over the target (which we assume is close enough for comparison without further iteration);
- The REG assumptions are 0.2% over the target,

Figure 21: Cumulative emissions: 2020-2030



LRET 2% above target

Source: Frontier Economics

5.2 Certificate prices

Figure 22 shows the EIT certificate (EITC) prices over time for the Base Case, including comparison with the equivalent certificates in the High Demand, High Gas and Low Demand sensitivities.

The Base EITC prices range from $28 (2020) to $40 (2030). This is sufficient to deliver fuel switching from existing coal to new gas (sufficient to meet the target).

Results from other sensitivity cases are as follows:

- The **High Demand** case ranges from $30 (2020) to $44 (2030). This is only marginally higher than the Base Case despite the higher abatement task. This suggests that further substitution of existing coal for new gas can be achieved at a similar marginal cost (for the target considered).
- The **High Gas** case has materially higher EITC prices of $45-66. This is directly driven by higher gas price assumptions, which results in higher abatement costs (switching from coal to gas).
- The **Low Demand** case has EIT prices of zero, as even the BAU policy setting is sufficient to meet the emissions target under the Low demand sensitivity (the EIT is redundant).
- The 50PC case has EIT prices ranging from $35 (2020) to $52 (2030). This is because a higher emissions abatement target generally requires incrementally higher cost abatement. For small emissions reduction targets (or where

demand growth is strong) it is relatively cheaper to change a **new** investment decision from new coal to new gas, as there is an additional capital cost associated with each. For harder targets (or where demand growth is slow) then meeting targets requires replacement of existing coal (with sunk capital cost) with new gas (with additional capital costs). Additionally, it becomes more expensive to replace existing coal with new gas to meet progressively harder targets as each retired plant has a different cost and emissions intensity.

Figure 22: EIT certificate prices by scenario: 2020-2030 (real FYe$2016)

Source: Frontier Economics

5.3 Resource cost comparisons

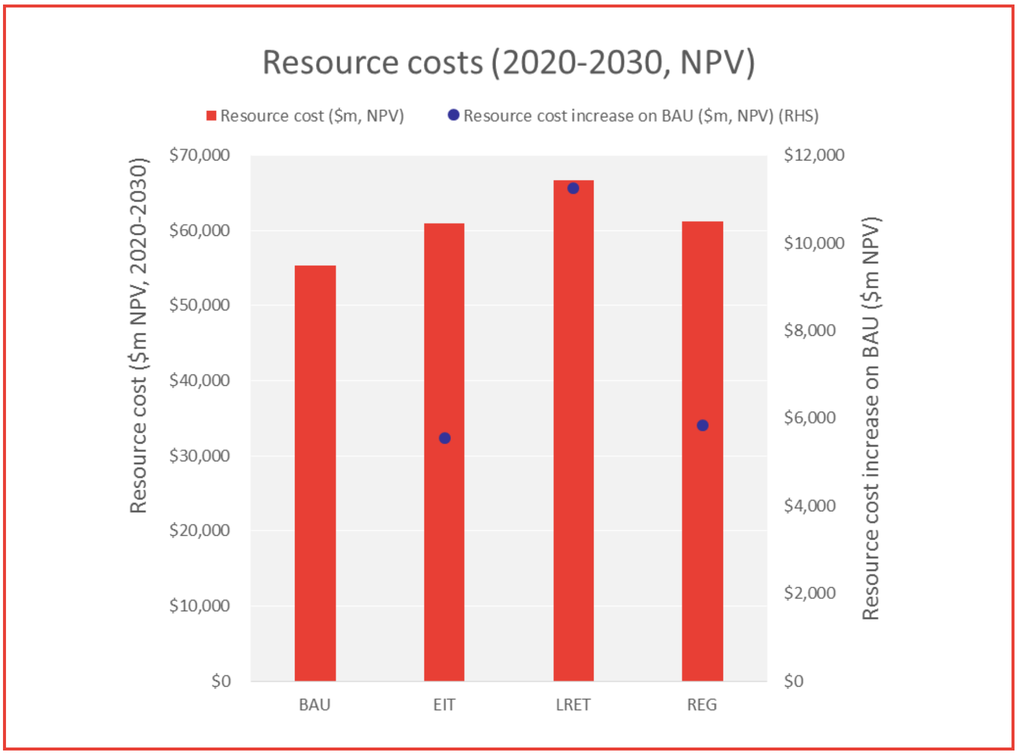
Figure 23 shows the NPV of resource costs from 2020-2030 for the different policy settings in the Base Case. These resource costs reflect fuel costs, operating and maintenance costs and capital costs (capex) for new plant only; they do not include a return on capital for existing plant, which is treated as a sunk cost. This cost (capex for existing plant) is equivalent across all scenarios and does not change relativities. The REG case does not include any cost associated with compensation for existing plant. Cumulative costs are discounted at 8.3%.

The blue dots on the chart (RHS) reflect the change in resource costs compared with the BAU policy settings. This reflects the incremental cost of each policy in meeting the emission constraint.

The results show:

- The EIT has the lowest incremental resource cost of meeting the target ($5.5b). This is to be expected as it is a technology neutral policy (no regrets): if closure of existing plant or replacement with renewables were efficient (lowest resource cost) then this should occur in the EIT scenario. This result should be robust to different cost assumptions: the other policy scenarios might delivery abatement at similar (but not lower) resource costs.
- The LRET has the highest incremental resource cost of meeting the target ($11.2b). This is because the LRET is technology specific, limiting abatement options only to renewable technologies. Under our assumptions, this is a higher cost option for abatement.
- The REG has a similar resource cost of meeting the target ($5.8b) as the EIT. This is because the assumed forced closure of existing plant is replaced with new gas plant. This is partly a result of our modelling approach: our starting point for targeting (assumed) closures is the retirement results observed from the EIT. This is not necessarily as robust to changes in assumption: our fuel cost assumptions suggest that closure of the emissions intensive brown coal plant (replaced with gas in Vic) is the cheapest option for abatement. This is not always the case for different gas price assumptions (discussed in the High Gas case). This resource cost does not include any potential costs associated with compensation for closures.

Figure 23: Resource costs: 2020-2030



Source: Frontier Economics

Table 3 summarises the estimated **average** cost per tonne abated between 2020-2030. This reflects the change in resource cost divided by the change in total emissions. This is not directly equivalent to the implied carbon price, which is based on the marginal cost of abatement (which is generally higher).

Discounted or undiscounted

Some analysts prefer to compare the change in discounted resource costs (above) against the change in total (undiscounted) emissions. The argument for this approach is that emissions (or abatement) now or in the future have the same impact on climate change. We report these figures here in the **Not Discounted** columns. However, this approach can imply that delayed abatement action should be relatively preferable (lower cost) to early abatement action for different trajectories: since costs are discounted but emissions are not, deferral of abatement will lower the estimated cost per tonne. It is also misleading to compare this to the implied carbon price path where cost per tonne is estimated each year.

We also report the **Discounted** cost per tonne, where emission reductions are also discounted. This is more comparable to an estimate/understanding of average abatement cost in a given year. The relativities between policy settings are robust to either approach.

Results

These results are consistent with the differences in resource costs (for the same reasons) given that each policy approach delivers an equivalent (or very similar) level of abatement. Results from other sensitivity cases are discussed in the relevant chapters.

Table 7: Cost per tonne abated (2020-2030), $/tCO2

Scen-arios	Base case		High Gas		High Demand		50PC		Hazelwood retire	
	Discounted	Not discounted	Discounted	Not Discounted	Discounted	Not discounted	Discounted	Not discounted	Discounted	Not discounted
EIT	$30.4	$17.5	$51.4	$28.4	$29.8	$17.7	$34.7	$20.5	$28.8	$16.2
REG	$34.2	$19.5	$73.9	$43.6	$35.5	$20.0	$37.9	$22.1	$35.2	$19.5
LRET	$75.7	$42.0	$72.0	$40.0	$93.6	$50.8	$85.3	$48.3	$85.1	$46.9

Source: Frontier Economics

5.4 Revenue comparisons (consumer impacts)

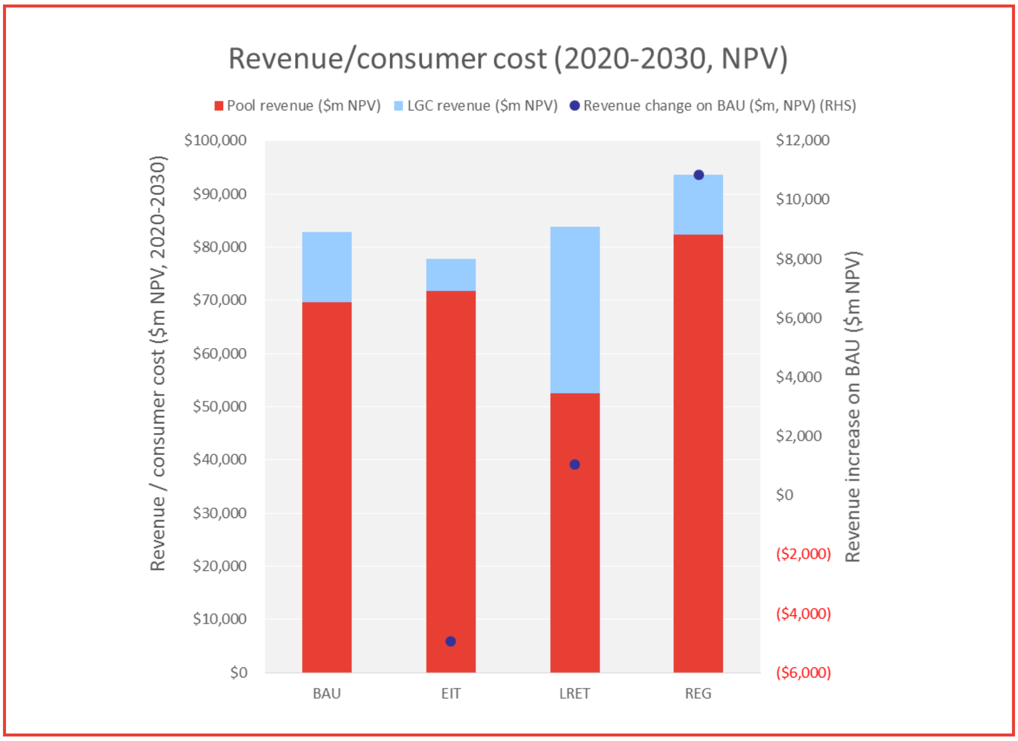
Figure 24 shows the NPV of generator revenue (or consumer cost) from 2020-2030. This is a function of the change in consumer prices, which determines how the change in resource costs is divided between generators and consumers. This can and does differ from the resource cost impact: where resource costs increase by more than the increase in consumer costs, this means that generators bear larger share of the increase in costs than consumers (and conversely).

In this chart, the **red bars** reflect the impact on wholesale pool prices (multiplied by total energy, discounted). We also estimate and report the impact of the LRET levy, which will separately affect consumer costs. This is most noticeable in the LRET scenario where although there is a merit order effect (increased supply from renewables actually reduces pool prices and imposes a cost on thermal generators), the increase in the LRET requires a substantial increase in the retail LRET levy (**light blue bars**), which results in a net increase in consumer costs.

As above, the blue dots reflect the change in consumer costs relative to the BAU.

- Under our Base Case scenario, although the **EIT** marginally raises total pool prices (red), the resulting fall in the required LRET levy (since renewables now earn EIT credits) means a net reduction in consumer costs of nearly $5b. As resource costs have increased but consumer costs have fallen, the difference is borne by generators.
- The **LRET** results in some merit order effect: increased renewable supply reduces pool prices. However, the higher target requires a higher LRET levy, which raises net consumer costs by $1b compared with the BAU. The reduction in pool prices reflects a relatively large burden on thermal generators.
- Although the **REG** case had relatively low resource costs, this has the highest consumer price impact ($10.8b above BAU). The closures of existing plant result in higher pool prices for existing plant. This increase in consumer costs is almost double the increase in resource costs, suggesting that generators benefit under this scenario (at the expense of consumers).

Figure 24: Revenue: 2020-2030



Source: Frontier Economics

5.5 Pool price impacts

Figure 25 shows weighted average national pool prices over 2020-2030, with and without the addition of the relevant LRET levy in each case. These results reflect the same results as Figure 24 but expressed differently.

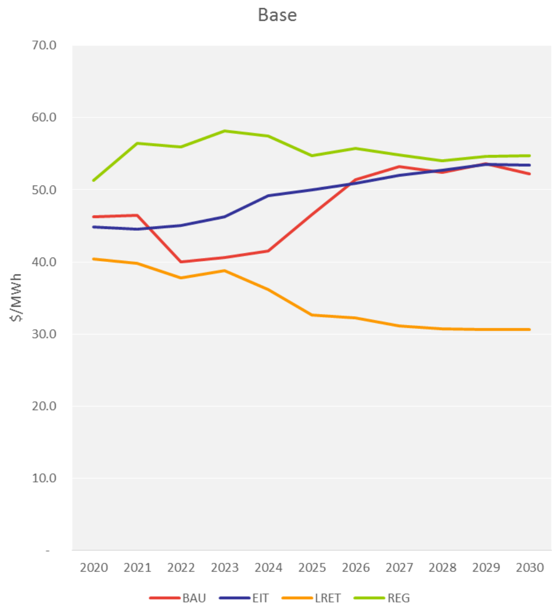
- The EIT results in similar pool prices to the BAU: the net effect of EIT penalties and credits results in flattening of the merit order (fuel switching) with only minimal change in consumer costs. This is because the implied **marginal** emissions intensity of the sector (which affects prices) is falling at a similar rate to the **average** emissions target. Although there is an increase in resource costs to generate with a lower emission mix, the shift in merit order (due to the mix of credits and penalties) means that existing generators bear more of this cost than consumers in our modelling results.
- The REG case results in higher pool prices: the withdrawal of supply eventually leads to new investment and prices converge on BAU (around 2026-7), but this suggests that BAU prices are currently below the level required to deliver new investment for many years. This is largely due to the effects of the existing LRET from 2018-2022 increasing supply faster than growth in demand, which contributes to the dip in BAU prices from 2022-2026. The REG approach more than offsets this effect from the BAU.

- The extended LRET case has a relatively strong merit order effect that suppressed pool prices, but this effect is limited. Further increases in the merit order effect should not lead to larger declines in pool prices: it should hit something of a price floor whereby existing generators begin to withdraw from the market (crowding out). At the same time, the increase in the target should lead to higher LGC prices and a higher target (more certificates) means an increase in the LRET levy. The net effect in this modelling is a slight increase in net prices for consumers.

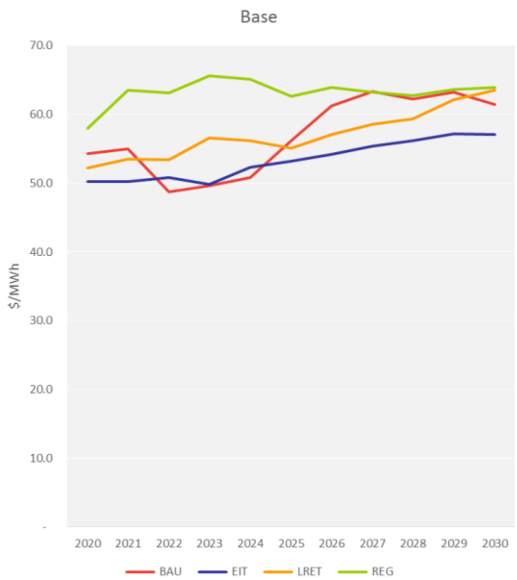
Regional prices are reported in the appendices.

Figure 25: Pool prices: 2020-2030 (weighted national average, $/MWh, realFYe2016)

Without RET levy



With RET levy

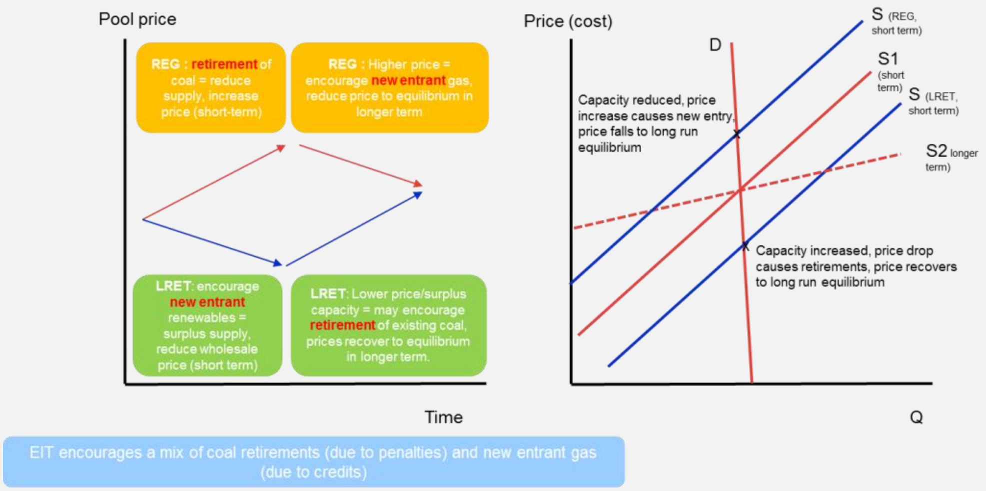


Source: Frontier Economics

Box 1: Drivers of relative **price** changes between cases

The intuition behind the relative prices changes over time is as follows:

- The **REG** approach is essentially to withdraw high emissions capacity from the market, which should result in a price signal for new low emissions generation to replace it. This suggests that prices should **rise** in the short/medium term before reverting to long run equilibrium.
- The **extended LRET** approach is largely the opposite: this encourages entry of new low emissions generation via subsidies. This should lead to excess capacity, short-term (wholesale) price falls, which should encourage retirement of existing plant (crowding out). This suggests that wholesale prices should **fall** in the short/medium term before reverting to long run equilibrium.
- The **EIT** involves a mix of credits (encouraging low emissions entry) and penalties (encouraging high emission exit), which suggests that short term wholesale prices should be between the other policy options.

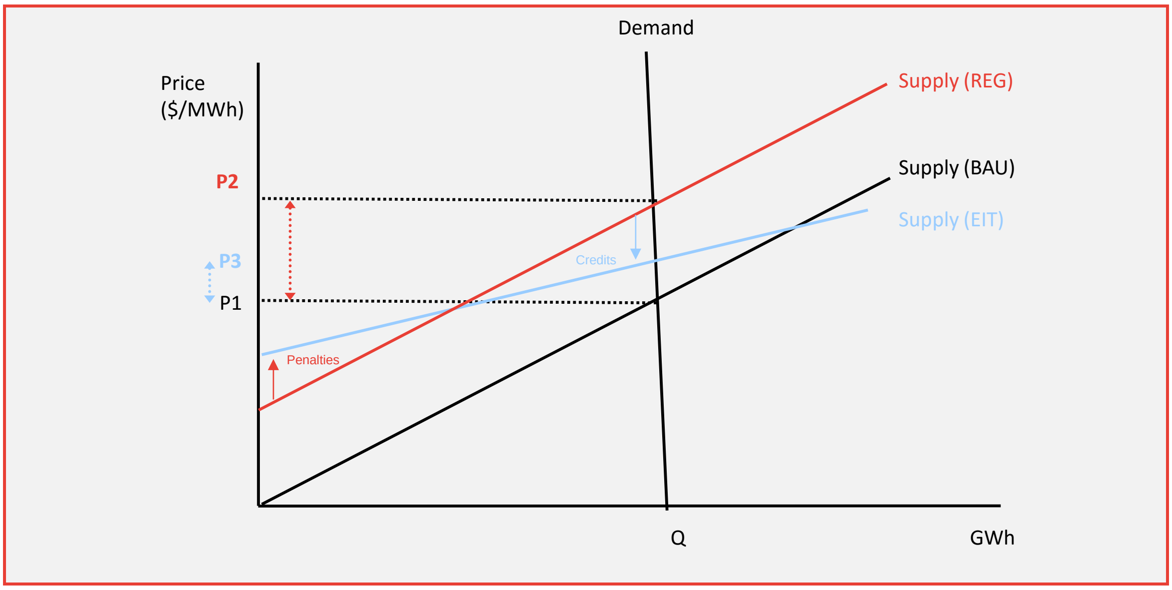


The chart below explains differences in price effects between an EIT and REG approach, despite both schemes resulting in similar closures and withdrawal of capacity.

Under a REG approach there is a simple withdrawal of capacity, which shifts the supply curve (merit order) up/left. Under this approach, there is no other change in the merit order, or relative costs between coal and gas: there is no additional incentive to lower the cost of new entrant gas, for example. This leads to a relatively larger price increase.

The EIT approach not only encourages the retirement of existing high emissions capacity, it also imposes penalties on the operation of high emissions plant that continues to operate and transfers these as a credit (subsidy) to existing and new entrant low emissions generation. This penalty/credit approach results in a flattening of the supply curve which lowers the cost of new entrants at the expense of reduced margins for higher emissions generators (and means relatively slower retirements/capacity withdrawal). This should ensure a relatively smoother price path in transitioning to a lower emissions plant mix: prices increase post-retirements should be reduced as new entrants are also subsidised.

Results: Base case scenarios



5.5.1 LRET effects

This subsection provides a brief high level overview of LRET market effects as context for the price and output results.

Merit order effect

Figure 26 provides a stylised example of the LRET effects on the wholesale and retail markets, with prices on the vertical axis and quantity (output, demand) on the horizontal axis. The thermal supply curve (merit order) is the original supply curve (in Black). Renewable supply (red) is more costly. Wholesale prices are originally at the intercept of supply and demand (Q* P*).

The LRET target requires Qr2 to be met through new renewables. This requires subsidy to renewables is the difference between wholesale prices and renewable costs. The subsidised entry of new renewables shifts the existing thermal supply curve to the right (navy blue). Where the growth in renewables is greater than the growth in demand (or where there is already an excess of supply over demand), this reduces wholesale prices to P2. This is the merit order effect on wholesale prices, which reflects excess supply. This does not necessarily persist long-term to suppress wholesale prices if this leads to retirements of thermal plant. If demand growth is strong (Demand2 – light blue), the RET crowds out new entrant investment as opposed not existing, and the wholesale price remains at P*.

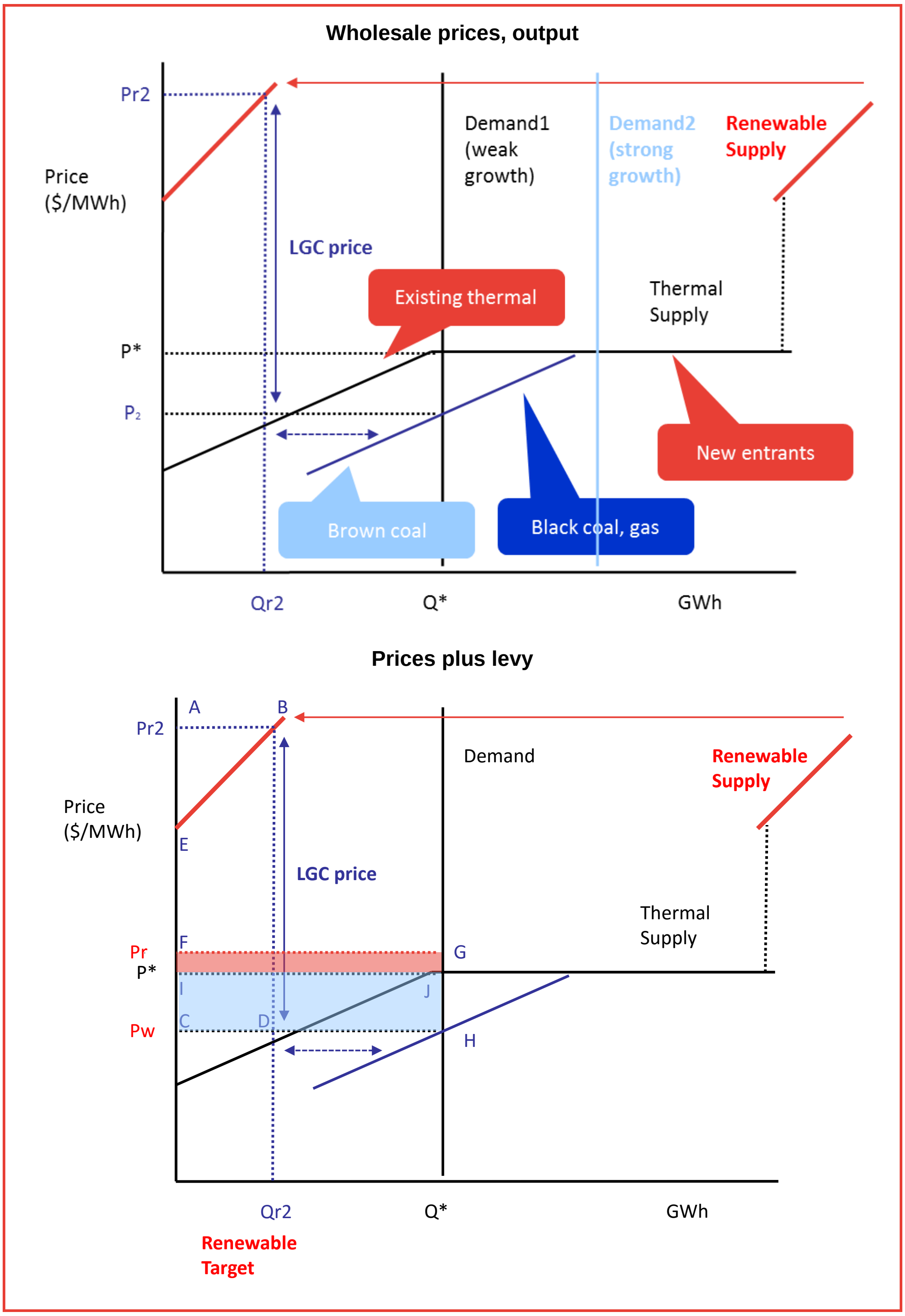
Generation mix

The other result of this shift in the supply curve due to the LRET is that higher cost plant (gas, black coal) will tend to be crowded out ahead of higher emissions/lower cost plant (brown coal). Some of this is limited by regions (brown coal is in Vic while black coal is in NSW, QLD), but in general much of the expected opportunity for new wind is in Vic or NSW.

Retail impacts

The second diagram shows the price effect once the LRET levy is accounted for. The subsidy value (LGC price x LRET target) is the area ABCD. This must be funded by a levy on all consumption (area FGCH). In this example, although there is a merit order effect causing a fall in wholesale price, the levy results in an increase in net consumer prices (to Pr). The burden on consumers is greater for larger LRET targets, or if the merit order effect does not persist.

Figure 26: Stylised example of LRET: wholesale, retail, output



Source: Frontier Economics

5.6 Output

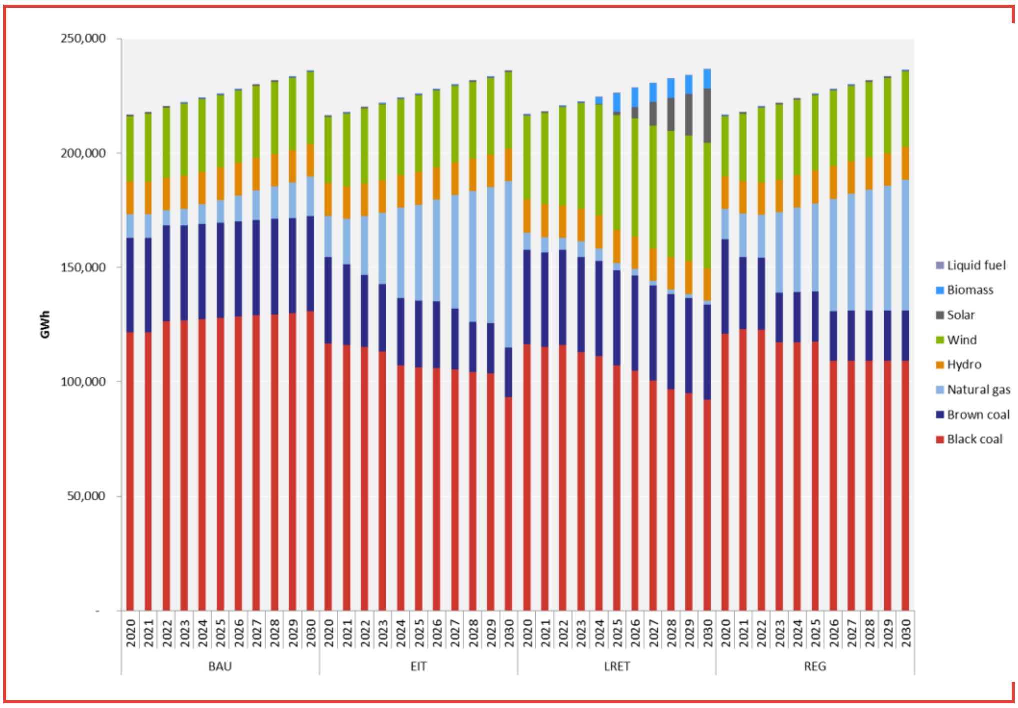
Figure 27 shows the projected output mix by scenario. The BAU shows continued output from brown and black coal, with some moderate growth in gas and renewables.

The EIT (and REG) show declines in brown and black coal, either by economic retirements (EIT) or by assumption (REG). In both cases this is replaced by strong growth in new gas output as the cheaper supply-side generation option.

The LRET shows declines in black coal and gas for the reasons explained in section 5.5.1. There is very little displacement of lower cost (high emissions) brown coal. There is strong growth in renewables (wind and solar) to deliver emissions abatement.

Regional output is reported in the appendices.

Figure 27: Output: 2020-2030



Source: Frontier Economics

5.7 Investment

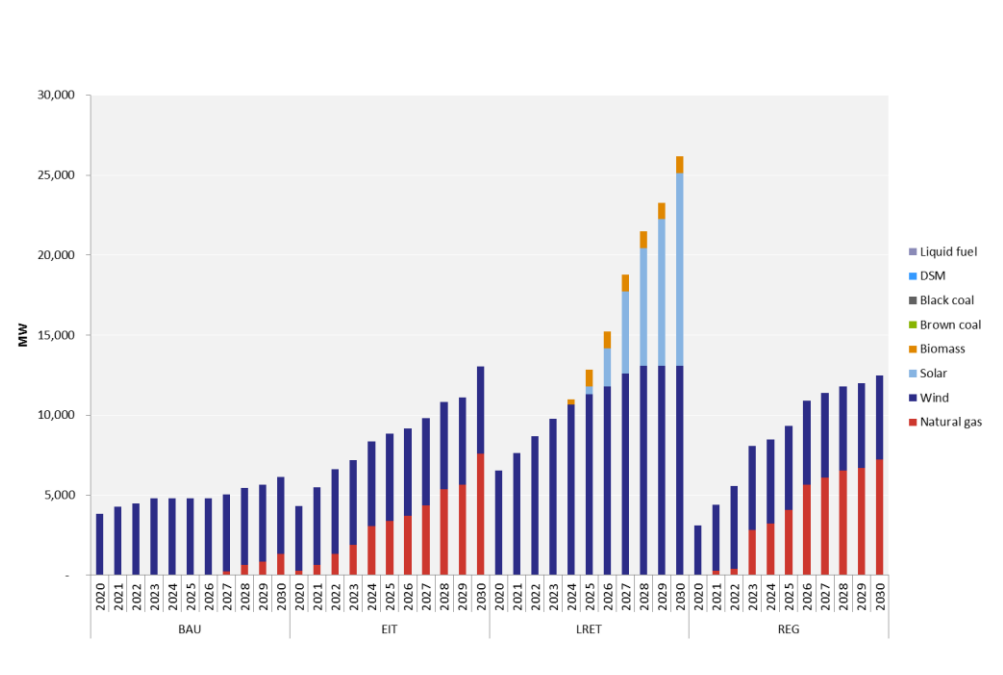
Figure 28 shows only **new** investment in capacity from 2020-2030 (relative to current/committed capacity mix). In the BAU, there is new investment in wind to meet growth in the LRET. Most of this investment occurs prior to 2020. There is around 5000MW of new wind (around 1000MW/year) required to meet the existing LRET, and some new gas plant later in the decade to meet demand growth.

In the EIT case there is a similar level of new wind driven by the existing LRET but a larger share of investment in new gas. This displaces existing coal, which is forecast to retire by the EIT scheme (to reduce emissions). The REG investment mix shows a similar pattern with rising wind to meet the existing LRET and new gas required to replace assumed forced coal retirements.

The expanded LRET requires around 13000MW of new wind by 2030; this is around 1000MW/yr from 2018-2030, though around 1500MW/yr from 2018-2024. This also requires around 12000MW of utility scale solar by 2030 (growing at around 2000MW/yr from 2024).

Regional investment is reported in the appendices.

Figure 28: Investment: 2020-2030



Source: Frontier Economics

5.8 Retirements

Table 8 shows the retirements of existing coal that occur in each policy scenario of the Base Case. Northern (SA) is assumed to retire from the outset in all circumstances (by assumption).

Under the EIT, Hazelwood (Vic), Liddell (NSW) and Muja (WA) are forecast to close almost from the outset of the scheme. Yallourn (Vic) is forecast to retire toward the end of the decade as is Gladstone (Qld), though it is assumed that Gladstone cannot retire sooner for contractual reasons.

All retirements in the REG scenario are assumed and largely reflect the EIT results, plus some additional/earlier retirements to offset the fact that this scenario does not obtain any abatement benefits from fuel switching of existing plant (as occurs in the EIT).

The extended LRET shows a different mix of retirements, with higher cost plant (as opposed to higher emissions plant) being crowded out early. There are also relatively fewer retirements required in this scenario: where the new entrants are zero emissions (renewables) this requires fewer plant to be displaced (retired) than where new entrants are low emissions (gas).

Table 8: Retirements

	BAU	EIT	LRET	REG
Gladstone		2030		
Hazelwood		2021-22		2021
Liddell		2022-24		2022-23
Muja AB (1&2)		2020	2028	2019
Muja AB (3&4)			2029	2019
Northern	2017	2017	2017	2017
Vales Point			2023	2026
Yallourn W		2028		2023

Source: Frontier Economics

5.9 Summary

Table 9 provides a high level summary of the change in resource costs and consumer costs relative to the BAU. In brief, the LRET involves the highest estimated resource cost (as it is technology specific) while the REG approach involves the highest consumer costs. The EIT has the lowest resource and consumer cost. The fall in consumer cost suggests that thermal generators bear a larger share of the resource costs under this policy.

Table 9: Change in resource cost/revenue versus BAU (NPV, Real2016$m, 2020-2030)

	EIT	LRET	REG
Resource costs			
Base	$5,546	$11,248	$5,838
High Demand	$7,961	$22,079	$8,408
High Gas	$7,204	$9,870	$10,232
50PC	$14,565	$33,900	$15,711
Hazelwood retires	$3,449	$10,115	$3,816
Revenue/consumer costs			
Base	($4,945)	$1,062	$10,843
High Demand	($15,014)	$9,714	$3,654
High Gas	($14,049)	($14,934)	$24,143
50PC	($3,372)	$28,085	$14,696
Hazelwood retires	($11,216)	($1,768)	$5,244

Source: Frontier Economics

6 Results: High Demand scenarios

This section presents Frontier Economics' modelling results for the High Demand scenarios:

Table 10: Scenarios

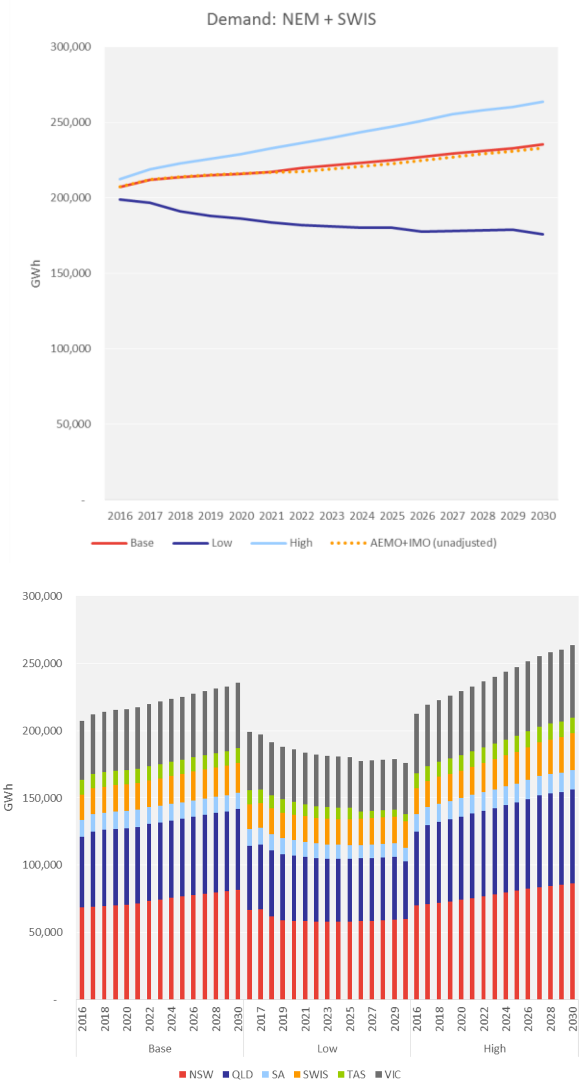
Scenario	Sensitivities							
	Base Case (S5)	High demand (S6)	High Gas (S7)	Low Demand (S8)	50PC 2030 target (S9)	Lower solar PV costs (28PC target) (S10)	EITEI credits (28PC target) (S11)	HZ retires pre-2020 (S12)
BAU	✓	✓	✓	✓				✓
Emissions Intensity target (EIT)	✓	✓	✓	✓*	✓	✓	✓	✓
Extended LRET (LRET)	✓	✓	✓	✓*	✓	✓		✓
Regulated closures (REG)	✓	✓	✓	✓*	✓			✓

** In the Low Demand case, the emissions target was met in the BAU case, making the policy changes redundant*

6.1 Demand comparisons

Figure 29 provides a comparison of demand by sensitivity. This High Demand sensitivity results in higher BAU emissions projections and larger emissions abatement required to meet the 2030 target.

Figure 29: Demand



Source: Frontier Economics

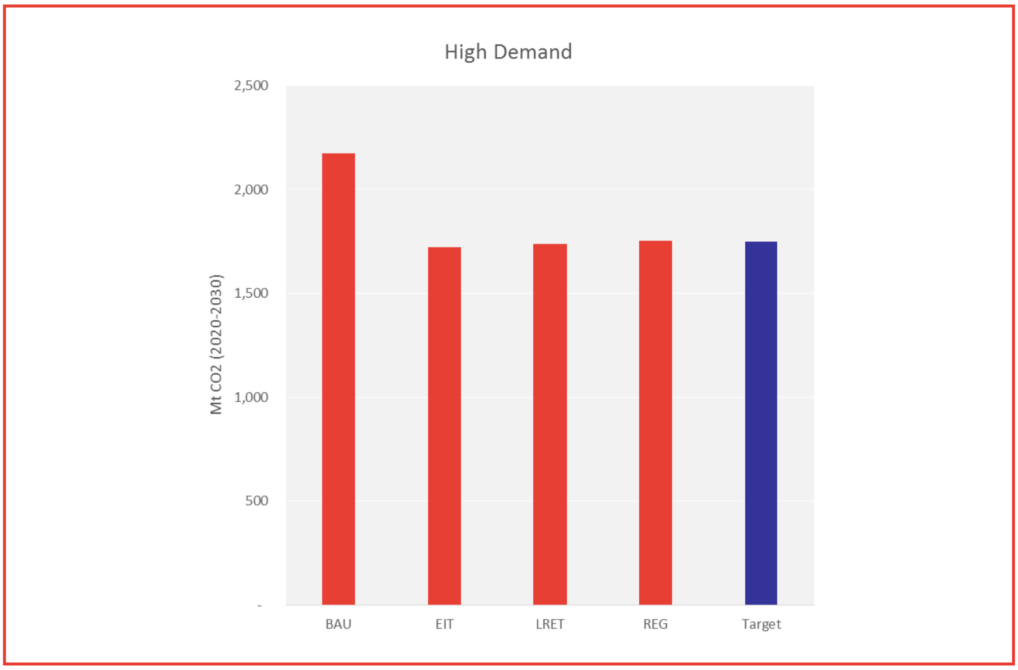
6.2 Emissions comparisons

Figure 30 shows cumulative emissions from 2020-2030. The BAU emissions are 2173Mt, implying a sector abatement task of 422Mt (compared with 304Mt in the Base Case).

This change in demand growth is assumed to be expected and all policy options are adjusted to ensure that the cumulative emission target is met. The EIT requires a lower EIT to compensate for higher demand growth (see Figure 15). The REG case requires more (earlier) assumed retirements. The LRET case requires an increased target (Figure 16).

The REG approach modelled is 2Mt over; the EIT is 1.6% under due to some small banking of credit for after 2030; the extended LRET is 0.7% under.

Figure 30: Cumulative emissions: 2020-2030



Source: Frontier Economics

6.3 Resource cost comparisons

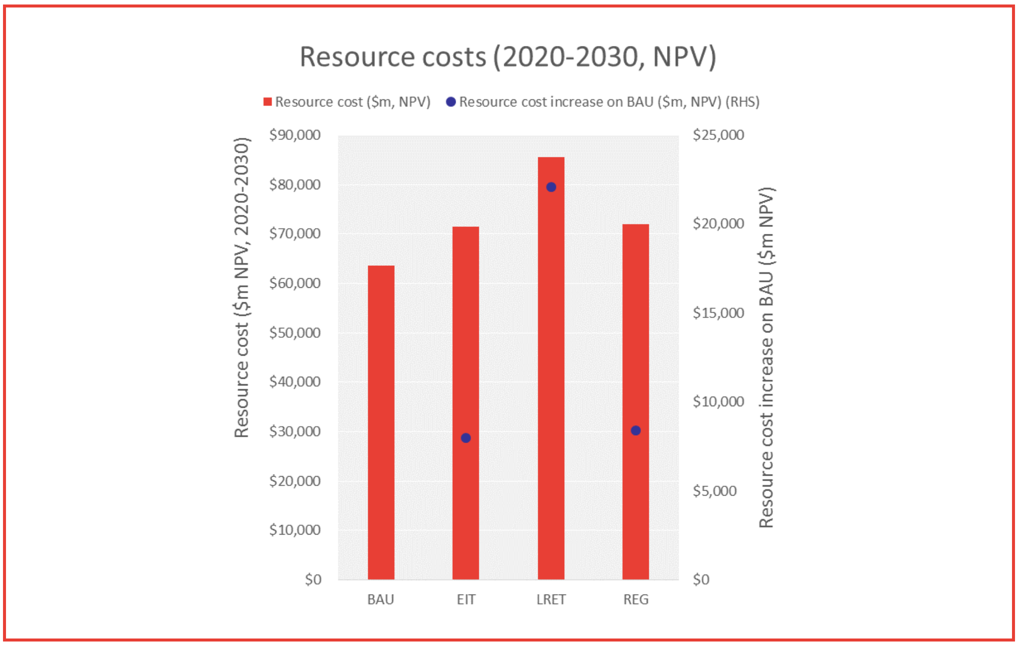
Figure 31 shows the Resource costs of each policy in the High Demand case. The BAU cost increases compared with in the Base Case, as expected due to meeting higher demand.

The RHS of the chart shows the change in resource cost for each policy relative to the **High Demand** BAU (comparing on the same basis).

The EIT cost increase on BAU is $7.9b, a 44% increase on the equivalent measure in the Base Case. The REG cost increase on BAU is $8.4b (also 44% increase compared with the Base Case). The average cost **per tonne** for EIT and REG (Table 11) only slightly increases in the High Case compared with the BAU, which suggests that the total costs rise almost linearly with the higher abatement task due to High Demand. (It actually decreases slightly in the EIT /discounted: high demand growth can provide cheaper ***relative*** abatement opportunities).

The LRET cost increase compared with the BAU is $22b under High Demand (96% higher than in the Base Case); the average cost per tonne also increases, most likely because of the upward slope of the renewable supply curve (requiring more expensive options).

Figure 31: Resource costs: 2020-2030



Source: Frontier Economics

Table 11: Cost per tonne abated (2020-2030), $/tCO2

Scen-arios	Base case		High Gas		High Demand		50PC		Hazelwood retire	
	Discounted	Not discounted	Discounted	Not Discounted	Discounted	Not discounted	Discounted	Not discounted	Discounted	Not discounted
EIT	$30.4	$17.5	$51.4	$28.4	$29.8	$17.7	$34.7	$20.5	$28.8	$16.2
REG	$34.2	$19.5	$73.9	$43.6	$35.5	$20.0	$37.9	$22.1	$35.2	$19.5
LRET	$75.7	$42.0	$72.0	$40.0	$93.6	$50.8	$85.3	$48.3	$85.1	$46.9

Source: Frontier Economics

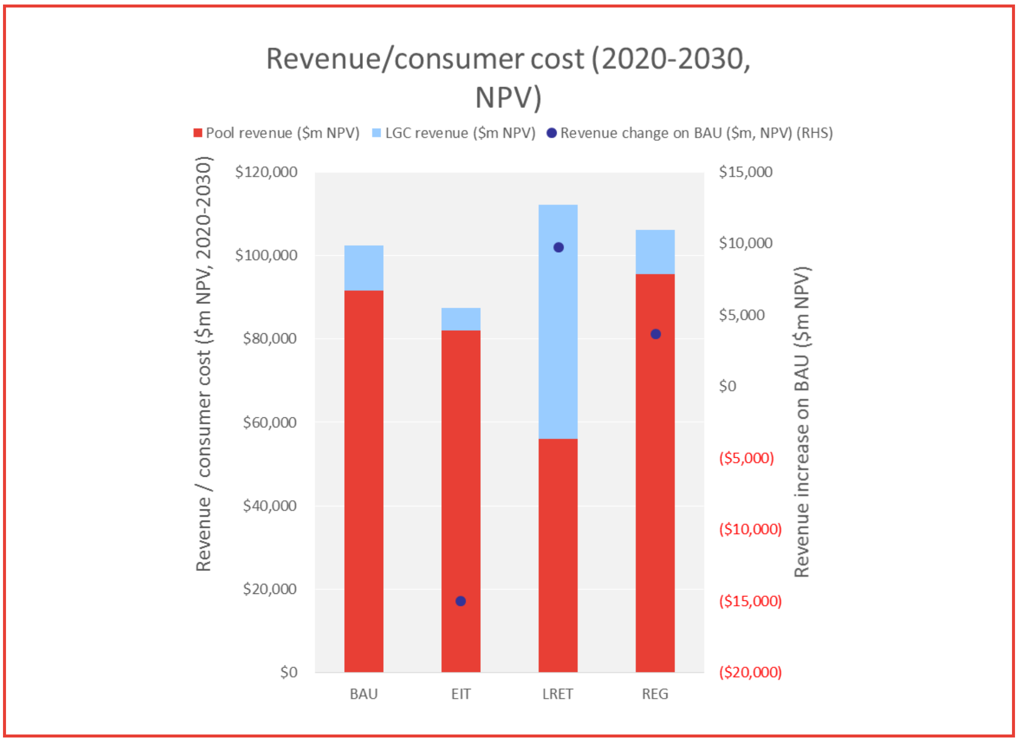
6.4 Revenue comparisons (consumer impacts)

Figure 32 shows the revenue by case for the High Demand scenario, including the change in revenue relative to the High Demand BAU case (not the Base Case BAU).

The EIT case and REG cases project a larger **relative** fall in total revenue/consumer costs (relative to the BAU) in the High Demand case than in the Base Case. This is because the High Demand case increases revenue by more in the BAU case.

In the LRET case the revenue (consumer cost) increases by more in the High Demand case than in the Base Case (Table 13 below). Although LRET was better for consumers than REG in the Base Case, this result reverses in the High Demand case. This is because higher demand growth leads to a linear increase in resource costs but any merit order effects (lowering wholesale price effects) do not last as long under high demand growth, meaning that consumers bear a larger share of the increase in costs.

Figure 32: Revenue: 2020-2030



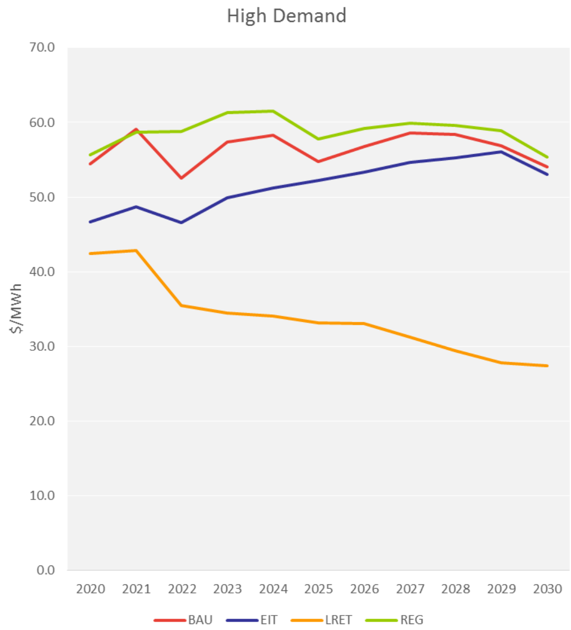
Source: Frontier Economics

6.5 Pool price impacts

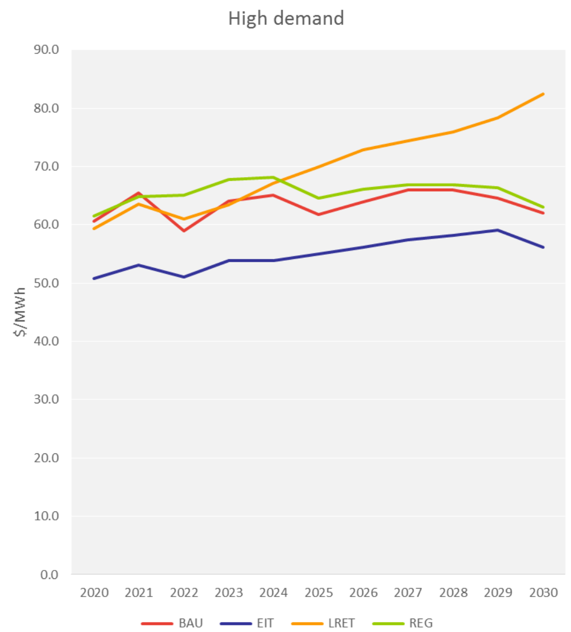
Figure 33 show pool prices over time, with and without the RET levy. These results are consistent with the results in Figure 32.

Figure 33: Pool prices: 2020-2030 (weighted national average, $/MWh, realFYe2016)

Without RET levy



With RET levy

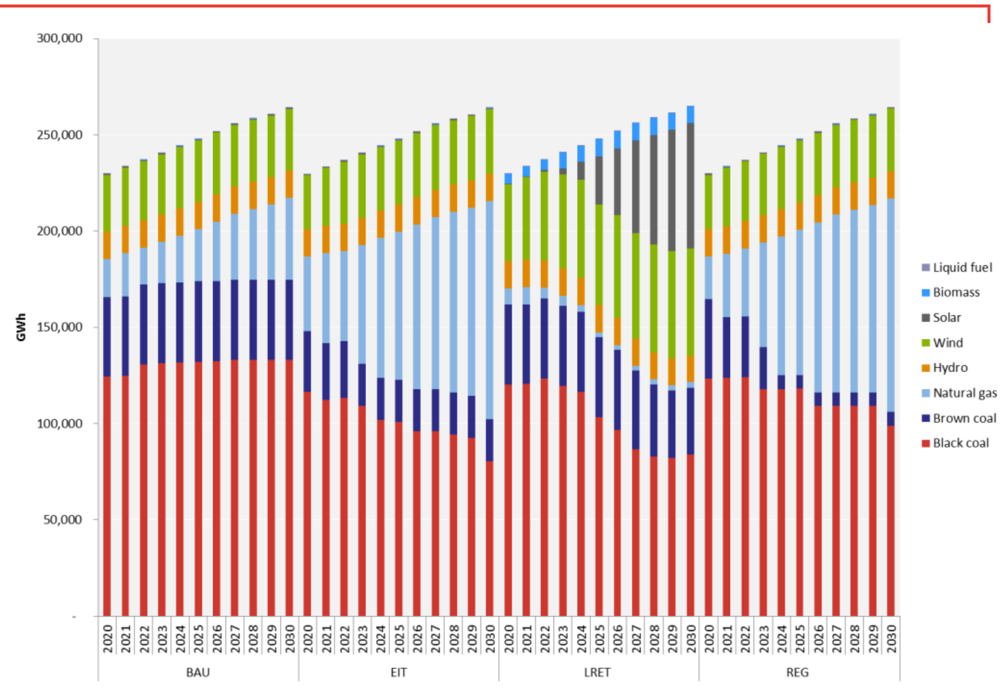


Source: Frontier Economics

6.6 Output

Figure 34 shows output by policy case in the High Demand scenario. The change in output patterns are consistent with the results in the Base Case scenario but more extreme: EIT and REG result in greater shifting from coal to gas generation; the LRET results in greater switching to new renewables.

Figure 34: Output: 2020-2030

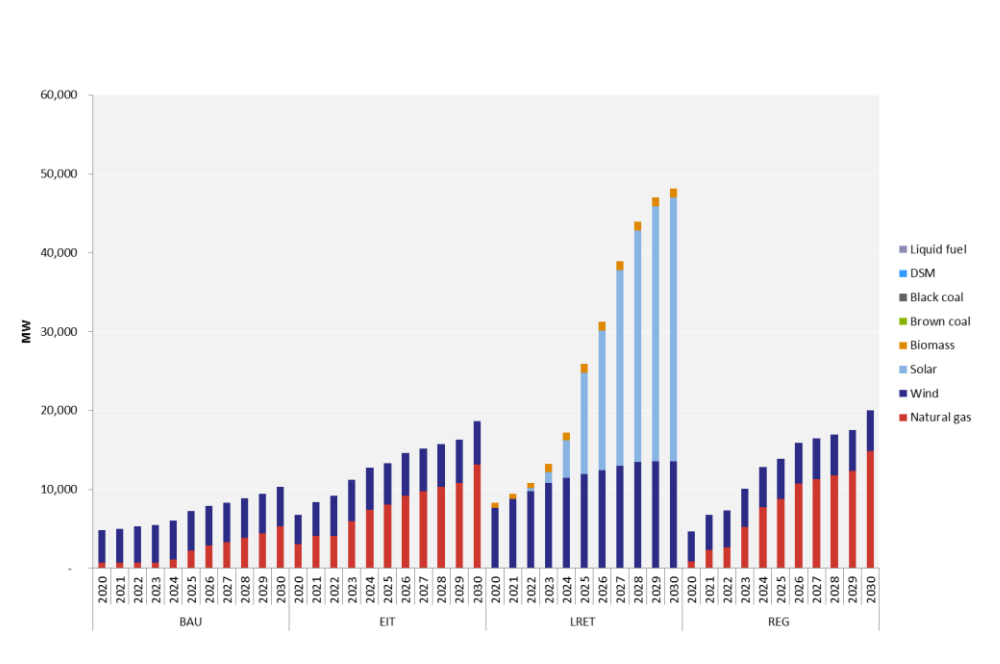


Source: Frontier Economics

6.7 Investment

Figure 35 shows new investment by policy case in the High Demand scenario. As for output, the change in investment patterns are consistent with the results in the Base Case scenario but more extreme: EIT and REG result in greater investment in new gas generation; the LRET results in greater investment in new renewables.

Figure 35: Investment: 2020-2030



Source: Frontier Economics

6.8 Retirements

Table 12 shows the plant retirements in the High Demand case. This requires more aggressive (earlier) retirements than in the Base Case.

Table 12: Retirements

	BAU	EIT	LRET	REG
Gladstone		2030		2030
Hazelwood		2020		2021
Liddell		2023-24		2022-23
Loy Yang A				2024
Muja AB (1&2)		2028	2026	2019
Muja AB (3&4)			2026	2019
Northern	2017	2017	2017	2017
Vales Point		2026		2026
Yallourn W		2023		2023

Source: Frontier Economics

6.9 Summary

Table 13 shows the relative change in resource costs and revenue (consumer costs), comparing both the change across policy scenarios and a comparison with the Base Case results.

Similar to the Base Case, the EIT is the lowest cost option, with the REG approach a little higher. The High Demand case has a strong effect on LRET: costs almost double compared with the Base Case (EIT and REG costs increase by less than 50%).

Revenue (relative to the BAU) decreases in the EIT and REG cases: this is because BAU revenue increases by more (in the High Demand case) than the EIT and REG revenue increases. In contrast, the LRET approach sees a larger increase in revenue/consumer costs (more than the REG approach).

Table 13: Change in resource cost/revenue versus BAU (NPV, Real2016$m, 2020-2030)

	EIT	LRET	REG
Resource costs			
Base	$5,546	$11,248	$5,838
High Demand	$7,961	$22,079	$8,408
High Gas	$7,204	$9,870	$10,232
50PC	$14,565	$33,900	$15,711
Hazelwood retires	$3,449	$10,115	$3,816
Revenue/consumer costs			
Base	($4,945)	$1,062	$10,843
High Demand	($15,014)	$9,714	$3,654
High Gas	($14,049)	($14,934)	$24,143
50PC	($3,372)	$28,085	$14,696
Hazelwood retires	($11,216)	($1,768)	$5,244

Source: Frontier Economics

7 Results: High Gas scenarios

This section presents Frontier Economics' modelling results for the High Gas Case scenarios:

Table 14: Scenarios

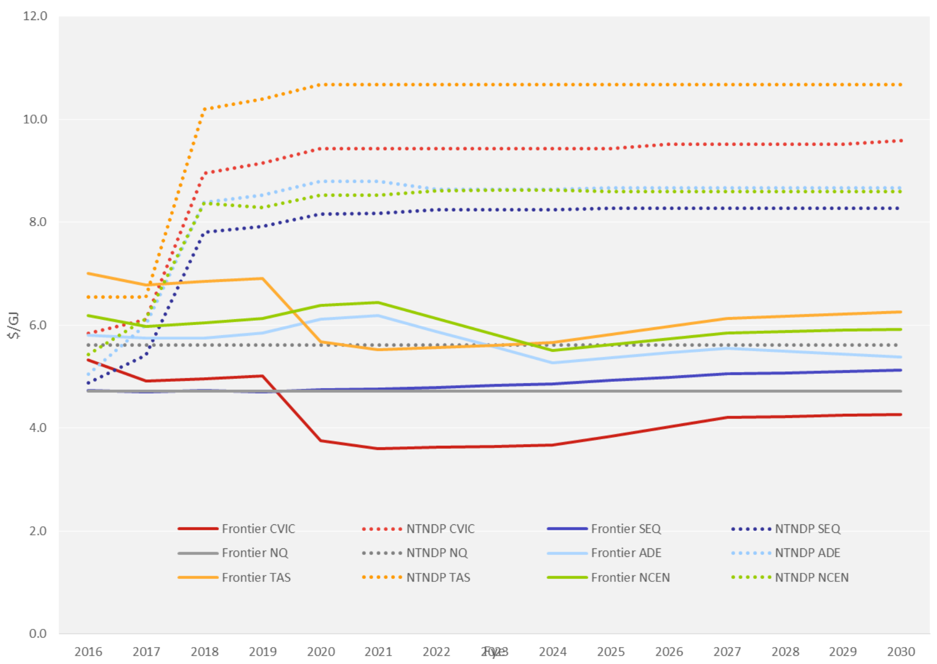
Scenario	Sensitivities							
	Base Case (S5)	High demand (S6)	High Gas (S7)	Low Demand (S8)	50PC 2030 target (S9)	Lower solar PV costs (28PC target) (S10)	EITEI credits (28PC target) (S11)	HZ retires pre-2020 (S12)
BAU	✓	✓	✓	✓				✓
Emissions Intensity target (EIT)	✓	✓	✓	✓*	✓	✓	✓	✓
Extended LRET (LRET)	✓	✓	✓	✓*	✓	✓		✓
Regulated closures (REG)	✓	✓	✓	✓*	✓			✓

** In the Low Demand case, the emissions target was met in the BAU case, making the policy changes redundant*

7.1 Gas price comparisons

Figure 36 shows a comparison of Frontier Economics' gas price forecasts (used as inputs in the Base Case) compared with the NTNDP Medium Gas prices, which are used for our High Case. Broadly, the NTNDP assumptions forecasts higher/more rapid escalation of prices which raises the relative cost of coal to gas fuel switching (and hence increases abatement costs).

Figure 36: Gas prices



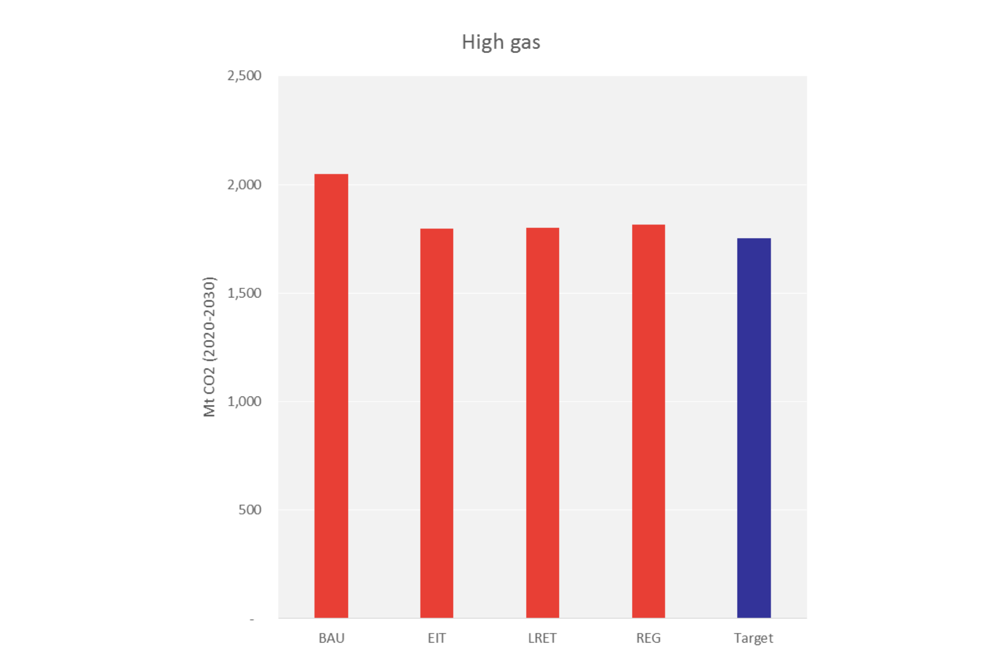
Frontier assumptions = Base Case. NTNDP = High Gas case (NQ gas limited to 400MW capacity)

Source: Frontier Economics

7.2 Emissions comparisons

Figure 37 shows a comparison of cumulative emissions by policy scenario. The abatement task is similar to the Base Case (given the same demand forecast).

Figure 37: Cumulative emissions: 2020-2030

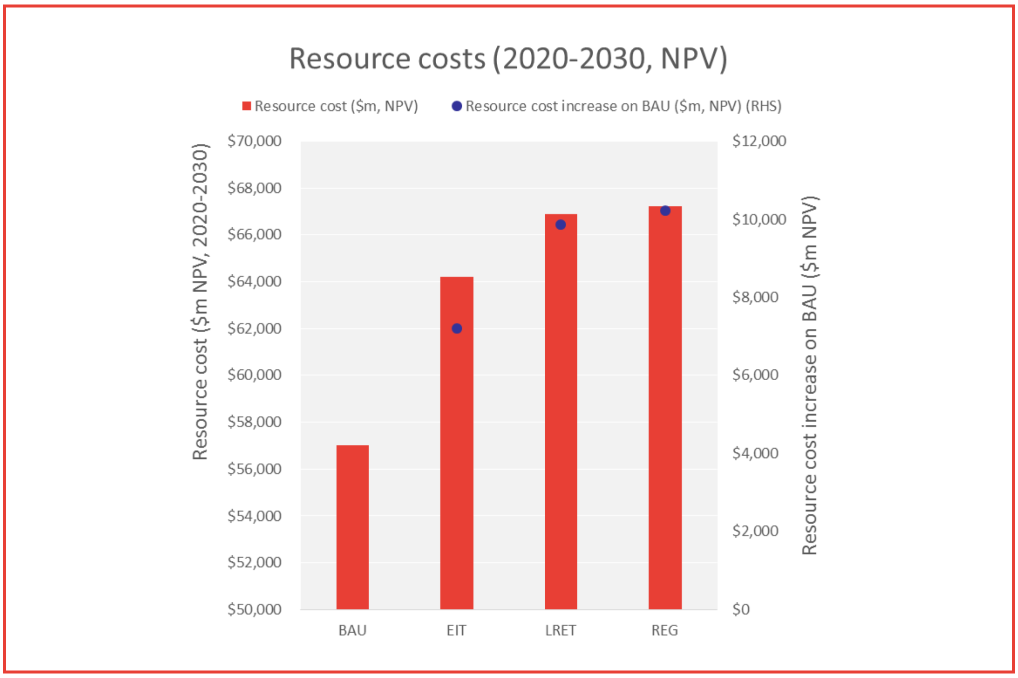


Source: Frontier Economics

7.3 Resource cost comparisons

Figure 38 shows a comparison of resource costs in the High Gas cases. EIT is still the lowest cost option relative to the BAU, however in this case LRET is forecast to be a lower (resource) cost option than REG. The relative cost of the LRET (versus BAU) in this case is actually lower than in the Base Case, since higher gas prices increase the BAU costs by more than the LRET costs (and the higher gas costs narrow the relative gap in cost of abatement from gas versus renewables.)

Figure 38: Resource costs: 2020-2030



Source: Frontier Economics

Table 15 shows the relative cost per tonne of abatement, which confirms the trends described above: the relative abatement cost for EIT and RET increase compared with the Base Case as these rely mostly on abatement from switching to gas; the relative abatement cost of the LRET actually falls in this case because the relative cost between gas and renewables narrows.

Table 15: Cost per tonne abated (2020-2030), $/tCO2

Scen-arios	Base case		High Gas		High Demand		50PC		Hazelwood retire	
	Discounted	Not discounted	Discounted	Not Discounted	Discounted	Not discounted	Discounted	Not discounted	Discounted	Not discounted
EIT	$30.4	$17.5	$51.4	$28.4	$29.8	$17.7	$34.7	$20.5	$28.8	$16.2
REG	$34.2	$19.5	$73.9	$43.6	$35.5	$20.0	$37.9	$22.1	$35.2	$19.5
LRET	$75.7	$42.0	$72.0	$40.0	$93.6	$50.8	$85.3	$48.3	$85.1	$46.9

Source: Frontier Economics

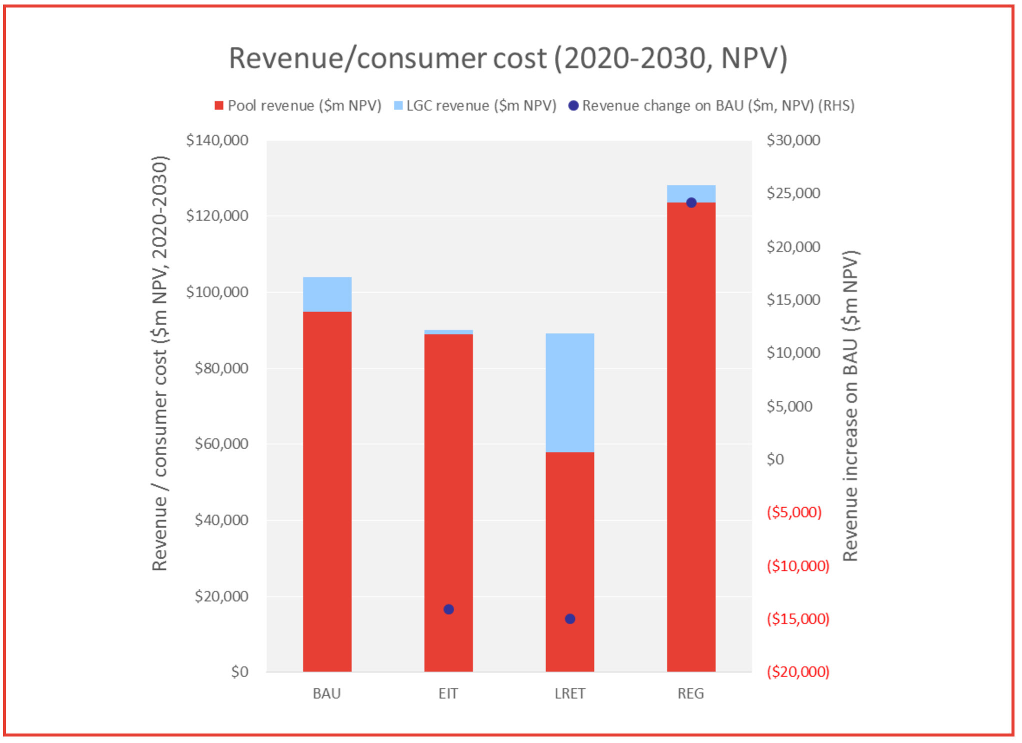
7.4 Revenue comparisons (consumer impacts)

Figure 39 compares the revenue (consumer cost) by case for the High Gas cases.

The REG has the largest impact, and revenue increases by more than resource cost, suggesting a net benefit to existing generators.

The EIT and LRET have a similar negative impact on revenue (LRET marginally greater), suggesting a benefit to consumers while generators bear more than the resource cost increase.

Figure 39: Revenue: 2020-2030



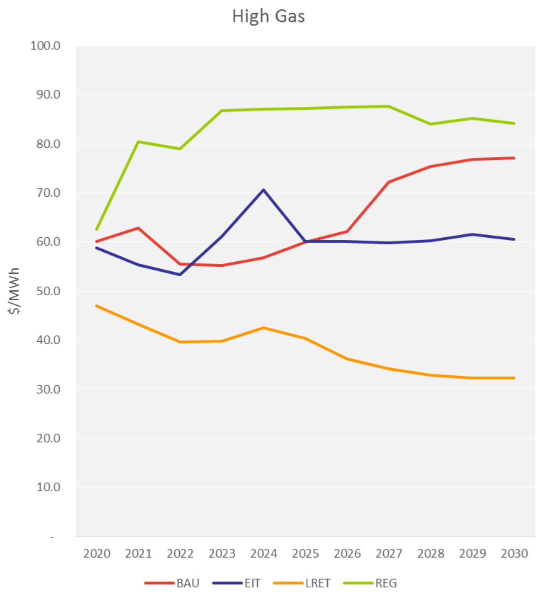
Source: Frontier Economics

7.5 Pool price impacts

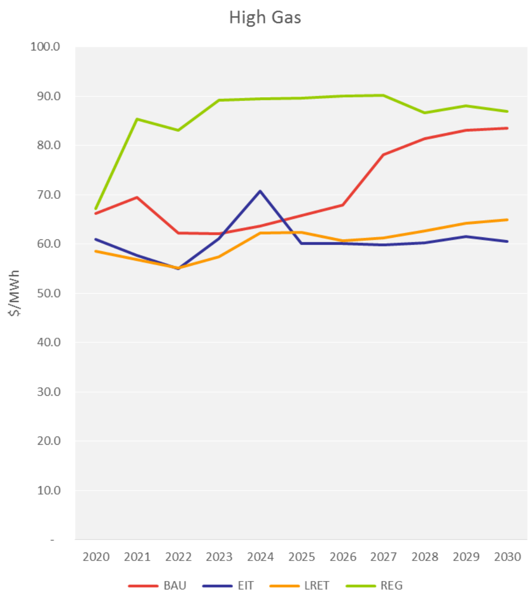
Figure 40 shows weighted average pool prices over time, which confirm the results from Figure 39: the LRET and EIT have a similar forecast impact on net prices (with RET levy) which are forecast lower than the BAU; the REG forecasts higher prices.

Figure 40: Pool prices: 2020-2030 (weighted national average, $/MWh, realFYe2016)

Without RET levy



With RET levy

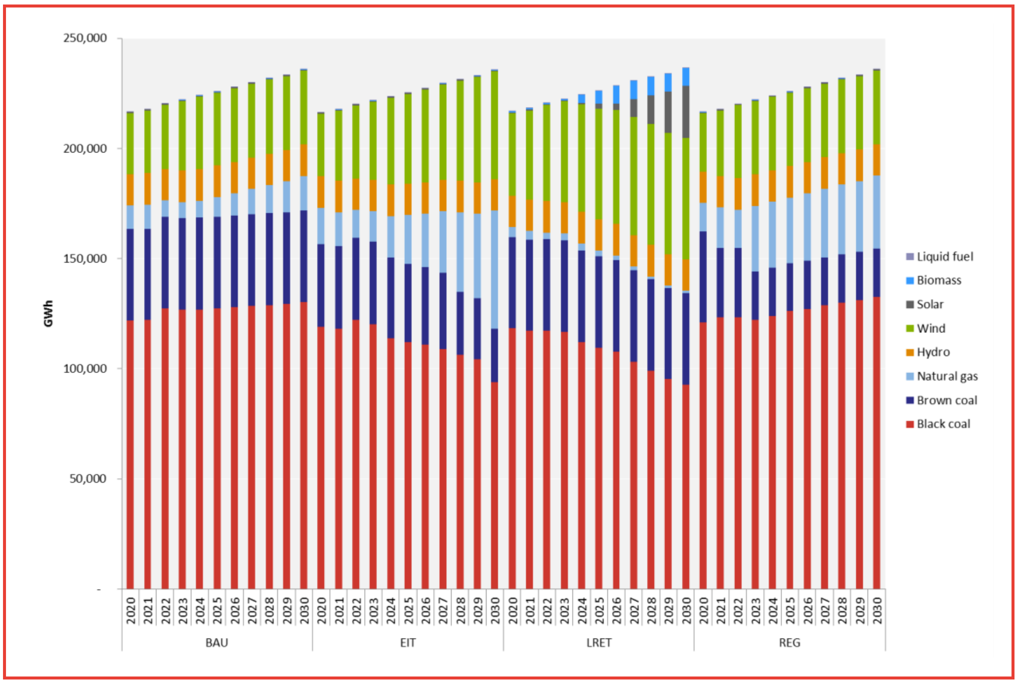


Source: Frontier Economics

7.6 Output

Figure 41 shows forecast output by scenario, which is consistent with other cases: EIT and REG rely on switching from coal to gas; LRET relies on switching from coal (and gas) to increased renewables.

Figure 41: Output: 2020-2030

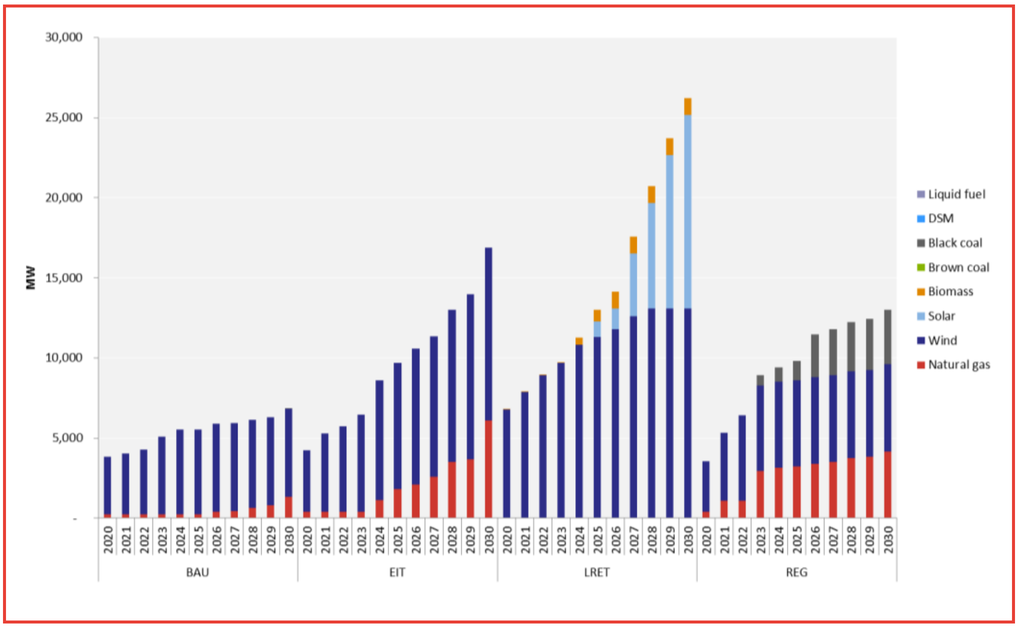


Source: Frontier Economics

7.7 Investment

Figure 42 shows the investment in new capacity by scenario, which is consistent with other scenarios.

Figure 42: Investment: 2020-2030



Source: Frontier Economics

7.8 Retirements

Table 16 shows the forecast (or assumed) retirements in the High Gas case. This EIT case projects a much more gradual retirement path for Hazelwood (and no closure of Yallourn), despite the higher carbon price in this scenario. On the other hand, this now includes retirements of Callide B and Tarong (Qld). This is driven by the relatively higher Vic gas prices in this scenario, and (relatively) lower Qld gas prices, which appears to make it more efficient to retire Qld black coal ahead of higher emissions Vic brown coal.

The REG case here has not been optimised for this change in relative assumptions, and continues to assume closure of Vic brown coal (at the expense of the relative efficiency of this policy in this scenario).

Table 16: Retirements

	BAU	EIT	LRET	REG
Callide B		2028		
Gladstone		2030		
Hazelwood		2020-2030*		2021
Liddell		2022-24		2022-23
Muja AB (1&2)				2019
Muja AB (3&4)				2019
Northern	2017	2017	2017	2017
Tarong		2028		
Vales Point			2023	2026
Yallourn W				2023

*Source: Frontier Economics * HZ progressively retires units over this period.*

7.9 Summary

Table 17 shows the change in resource costs and revenue by scenario.

The EIT is the lowest **cost** option of the three, though the higher gas prices narrows the relative gap between the EIT and the LRET. The REG approach is materially higher cost in this case, which illustrates that the efficiency of the REG approach depends on closure assumptions (administrative decisions) relative to assumptions regarding fuel prices and other costs. Although the EIT is more market based (adapting to market conditions for relative fuel costs between regions), the REG is dependent on forecasts/administrative decisions, which may not be as efficient if cost assumptions differ from forecast. For example, high Victoria gas prices / low NSW/Qld gas prices might mean that it is relatively more efficient to retire NSW/Qld black coal as opposed to higher emissions Vic brown coal.

Both the EIT and LRET forecast lower revenue than BAU, suggesting a benefit to consumers (*relative to BAU*); this means that generators bear more that the resource cost in these cases. Conversely, the REG approach sees a much larger increase in revenue than in costs, suggesting that generators are actually better off under this approach than under BAU (at the expense of consumers).

Table 17: Change in resource cost/revenue versus BAU (NPV, Real 2016 $m,2020-2030)

	EIT	LRET	REG
Resource costs			
Base	$5,546	$11,248	$5,838
High Demand	$7,961	$22,079	$8,408
High Gas	$7,204	$9,870	$10,232
50PC	$14,565	$33,900	$15,711
Hazelwood retires	$3,449	$10,115	$3,816
Revenue/consumer costs			
Base	($4,945)	$1,062	$10,843
High Demand	($15,014)	$9,714	$3,654
High Gas	($14,049)	($14,934)	$24,143
50PC	($3,372)	$28,085	$14,696
Hazelwood retires	($11,216)	($1,768)	$5,244

Source: Frontier Economics

8 Results: Low demand scenarios

This section presents Frontier Economics' modelling results for the Low demand Case scenarios:

Table 18: Scenarios

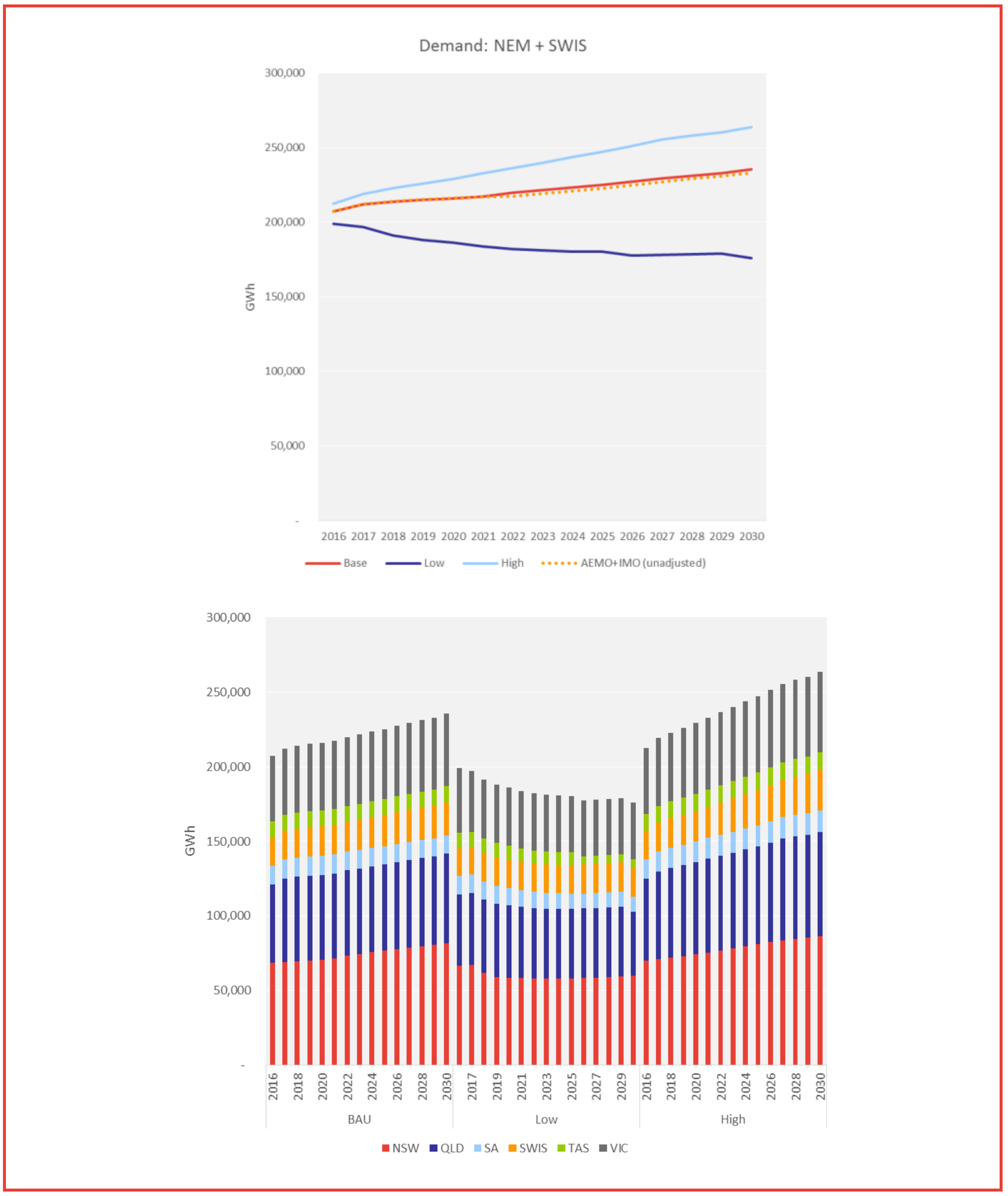
Scenario	Sensitivities							
	Base Case (S5)	High demand (S6)	High Gas (S7)	Low Demand (S8)	50PC 2030 target (S9)	Lower solar PV costs (28PC target) (S10)	EITEI credits (28PC target) (S11)	HZ retires pre-2020 (S12)
BAU	✓	✓	✓	✓				✓
Emissions Intensity target (EIT)	✓	✓	✓	✓*	✓	✓	✓	✓
Extended LRET (LRET)	✓	✓	✓	✓*	✓	✓		✓
Regulated closures (REG)	✓	✓	✓	✓*	✓			✓

** In the Low Demand case, the emissions target was met in the BAU case, making the policy changes redundant*

8.1 Demand comparison

Figure 43 shows assumed demand by scenario: the Low demand case projects falling demand over time.

Figure 43: Demand



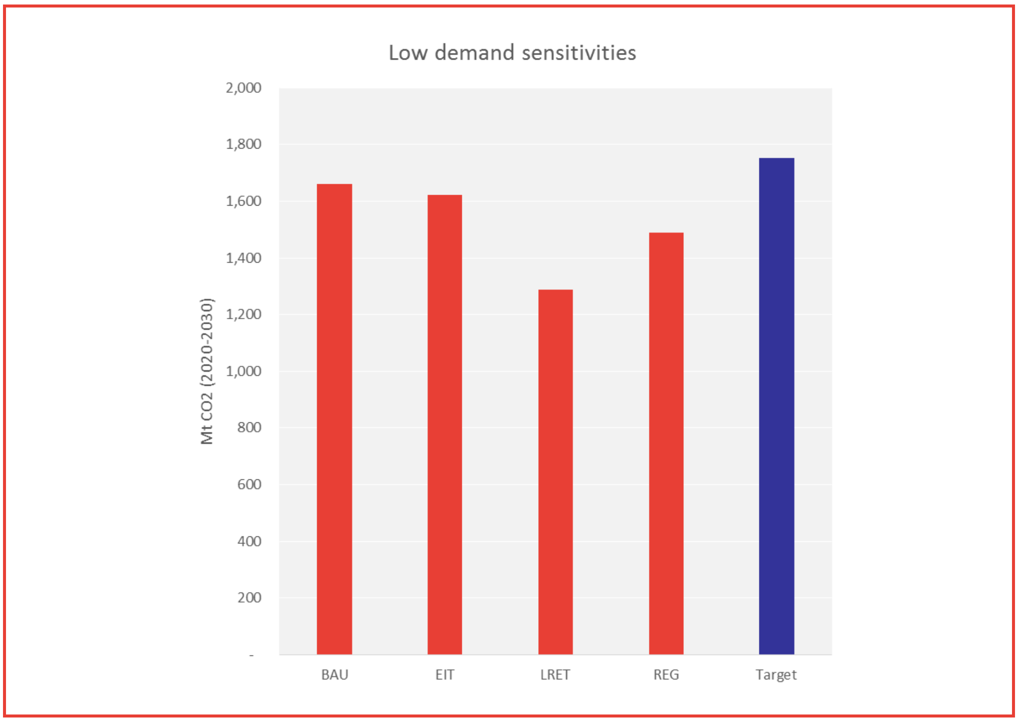
Source: Frontier Economics

8.2 Emissions comparisons

Figure 44 shows the cumulative emissions for each scenario. Critically, the BAU emission are forecast to be below the target emissions (by 90Mt), which suggests that all of the policy options are redundant. The LRET and REG options reported here are based on the first iteration of attempted policy settings, **however they were not further updated as the BAU results imply that no increase in the LRET, and no assumed REG retirements would be required to meet the target.**

Although these adjustments to policy are based on changes in **expected demand,** this result does highlight that **unexpected** changes to demand (which necessitate iteration that include policy changes/adjustments) will mean that emissions may be higher/lower than targets without some form of policy updating.

Figure 44: Cumulative emissions: 2020-2030

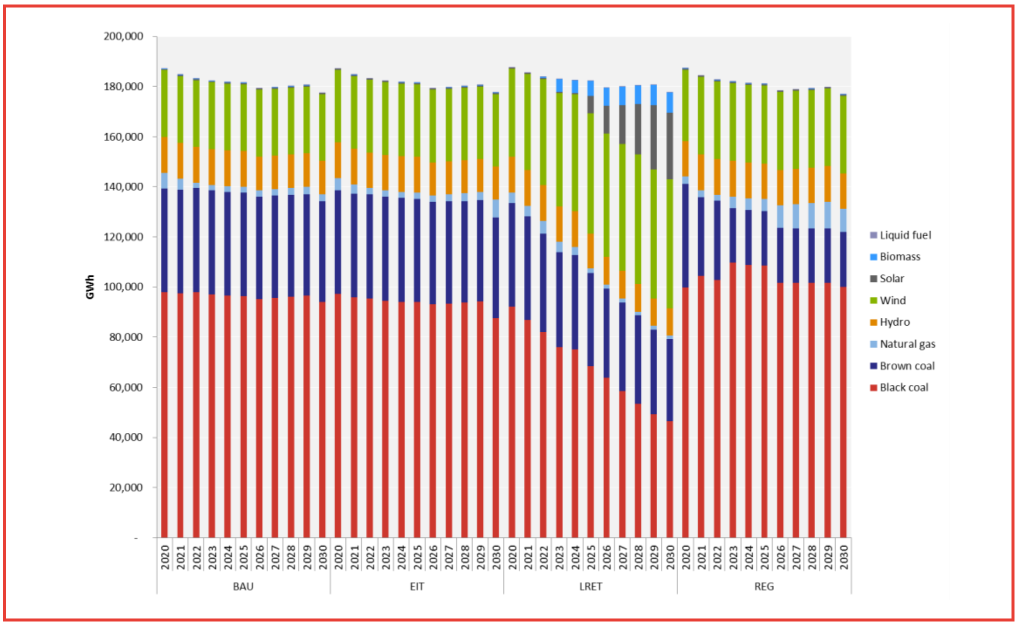


Source: Frontier Economics

8.3 Output

Figure 45 shows output by scenario. The BAU and EIT shows some decline in output (in response to demand) but this reduces the need for any major fuel switching to meet the emissions targets. The LRET shows renewables displacing gas/black coal, noting that this policy was not adjusted for a further iteration (the target modelled delivery emissions well below the target).

Figure 45: Output: 2020-2030

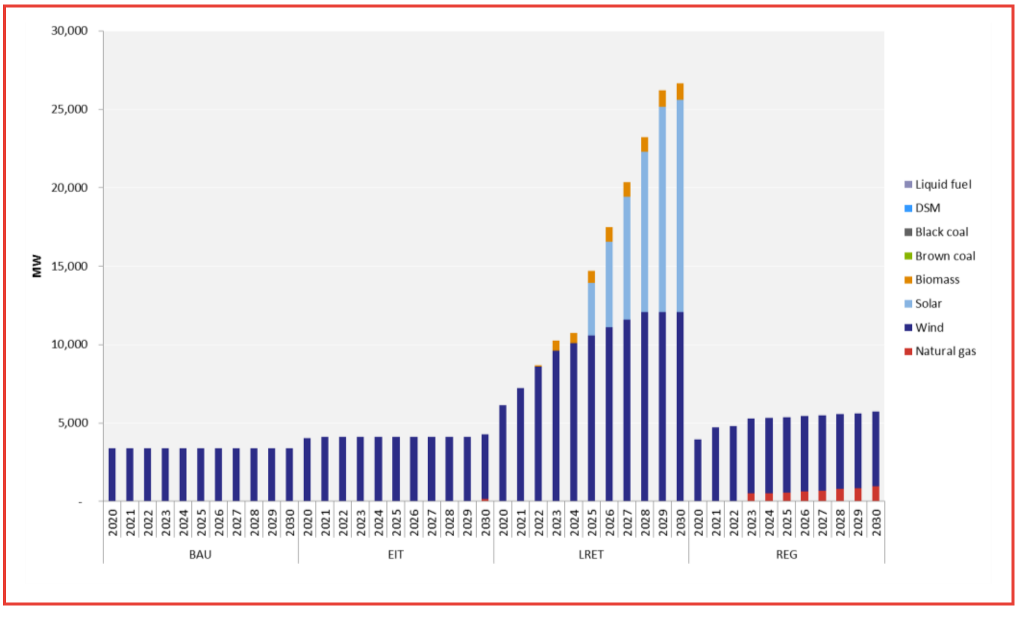


Source: Frontier Economics

8.4 Investment

Figure 46 shows the new investment. In the BAU and EIT this is mainly wind to meet growth in the existing LRET.

Figure 46: Investment: 2020-2030



Source: Frontier Economics

8.5 Other

Other results (costs and revenue) and not reported for this scenario, as the BAU case alone meets the emission targets without any other policy interventions when demand is this low.

9 Results: 50PC target

This section presents Frontier Economics' modelling results for the 50PC 2030 target scenarios, reflecting a 50 per cent reduction on 2005 emissions by 2030.

Table 19: Scenarios

Scenario	Sensitivities							
	Base Case (S5)	High demand (S6)	High Gas (S7)	Low Demand (S8)	50PC 2030 target (S9)	Lower solar PV costs (28PC target) (S10)	EITEI credits (28PC target) (S11)	HZ retires pre-2020 (S12)
BAU	✓	✓	✓	✓				✓
Emissions Intensity target (EIT)	✓	✓	✓	✓*	✓	✓	✓	✓
Extended LRET (LRET)	✓	✓	✓	✓*	✓	✓		✓
Regulated closures (REG)	✓	✓	✓	✓*	✓			✓

** In the Low Demand case, the emissions target was met in the BAU case, making the policy changes redundant*

9.1 Emissions target setting and comparisons

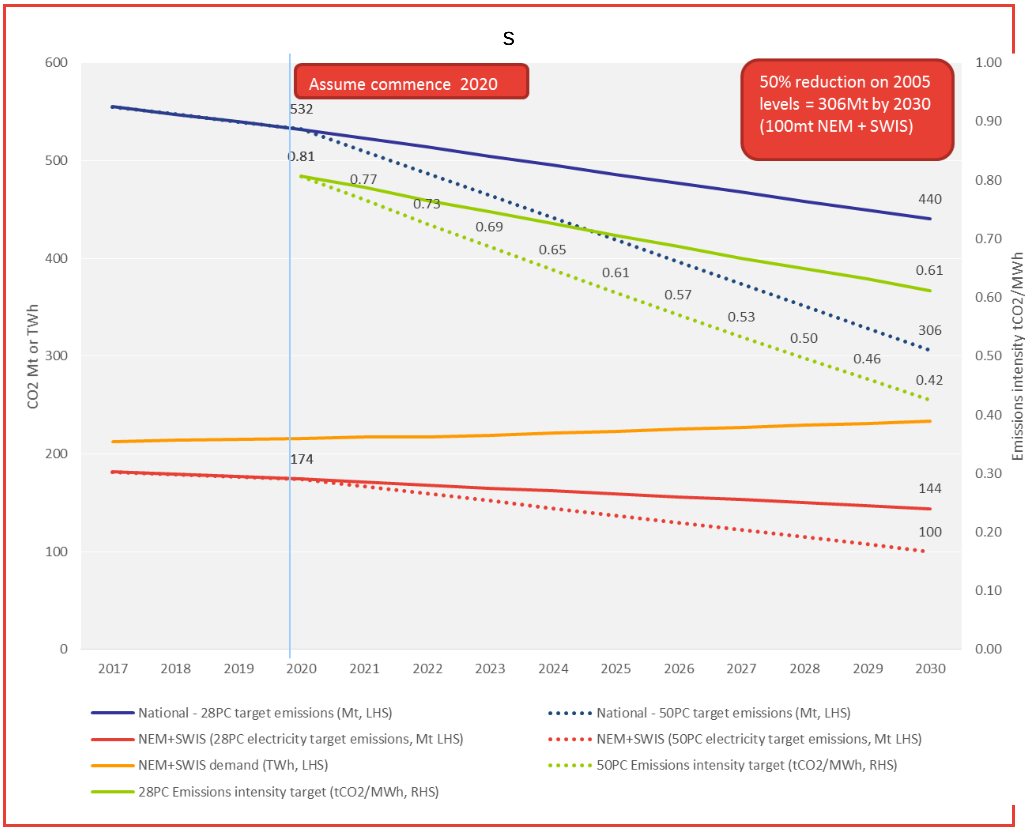
Figure 36 shows a comparison of our assumed emissions targets for a national target of 50 per cent reduction on 2005 emissions by 2030. Our estimate for allocating a 2030 target for NEM+SWIS emissions is based on pro-rating electricity sector share of national emissions as at 2015:

- A 50PC reduction on **national** 2005 emissions (611MtCO2e) by 2030 equals 306Mt.
- National **electricity** sector emissions in 2015 were 34% of national emissions.
- We estimate NEM plus SWIS emissions recently are around 96% of national electricity sector emissions.
- 306Mt x 34% x 96% equals **100Mt** NEM+SWIS target by 2030.

An alternative approach would be to apply a 50PC reduction on 2005 electricity sector emissions (197Mt). This approach would imply a national sector target of 98Mt and an implied NEM+SWIS target of 95Mt.

This implies an EIT of 0.42tOC2/MWh by 2030.

Figure 47: Emissions target comparisons



Source: Frontier Economics

9.2 Emissions comparisons (model outputs)

Figure 37 shows a comparison of cumulative emissions by policy scenario. The 50PC target reflects a NEM+SWIS annual target of 100Mt by 2030 under our pro-rate methodology. This implies a cumulative 2020-30 target of **1508Mt.** Our BAU projection is **2054Mt** cumulative emissions in the NEM+SWIS from 2020-30, reflecting a cumulative abatement task of **546Mt** (for the NEM+SWIS). This BAU projection reflects:

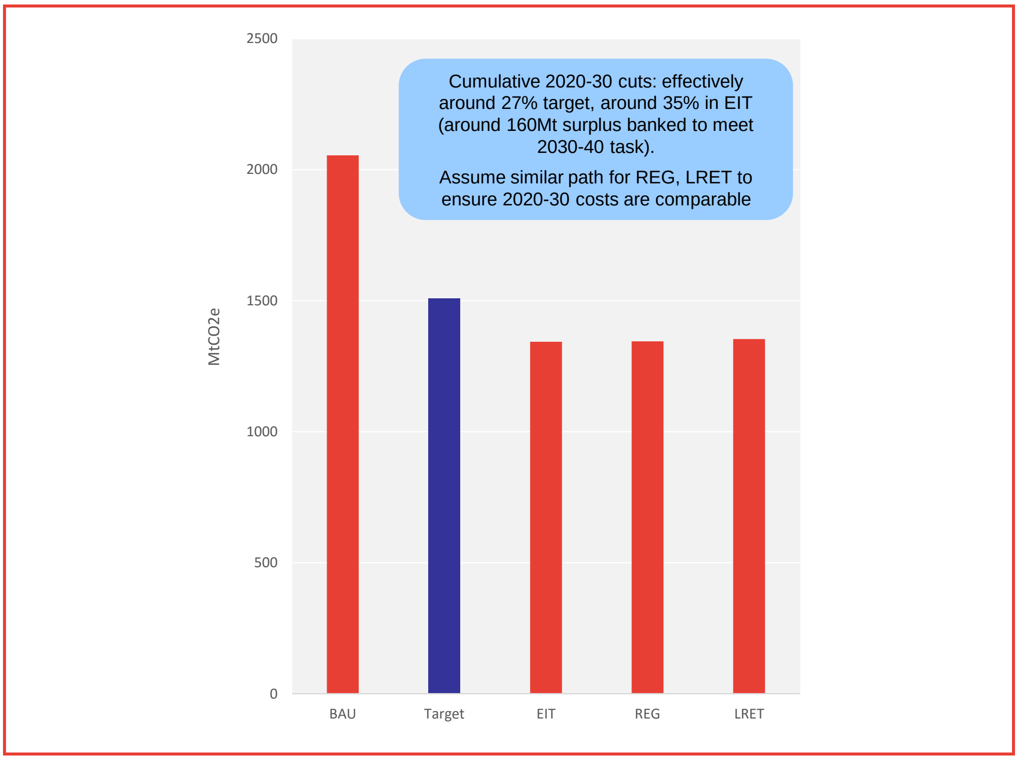
- AEMO's 2015 NEFR demand: the more recent 2016 demand projection forecasts slower growth;
- Information prior to the proposed Victorian 40% RET by 2025 or the Queensland 50% RET by 2030.

Each of these factors would reduce the BAU emissions projections.

The emissions projections for the policy cases reflect cumulative 2020-2030 emissions of **1343-1353Mt**, which is around 90% of the cumulative target. This equals cumulative abatement achieved of 700-710Mt. Our modelling to 2040 suggests that it is lower cost (more efficient) to outperform the 2020-30 target (emit less/abate more) and bank surplus credits for use to meet the 2030-40 target given the target trajectory. The implied emissions intensity by 2030 is 0.42tCO2/MWh, which can be met with gas-fired plant, however a linear trajectory would imply a 2040 EIT of 0.1tCO2/MWh. This is lower emissions intensity than gas and would require either carbon capture and storage (CCS) or a combination of renewables with storage. Our modelling results suggest that the lower cost option to meet this trajectory is to pursue an earlier transition to gas plant than required (to bank surplus credits), which would enable recovery of their capital costs over an approximate 20 year period before a subsequent transition to zero emissions generation is required closer to 2040. The alternative is to pursue a slower transition to gas from 2020-30, however this would require a much more rapid transition to near zero emissions generation between 2030-40, which appears to be more costly.

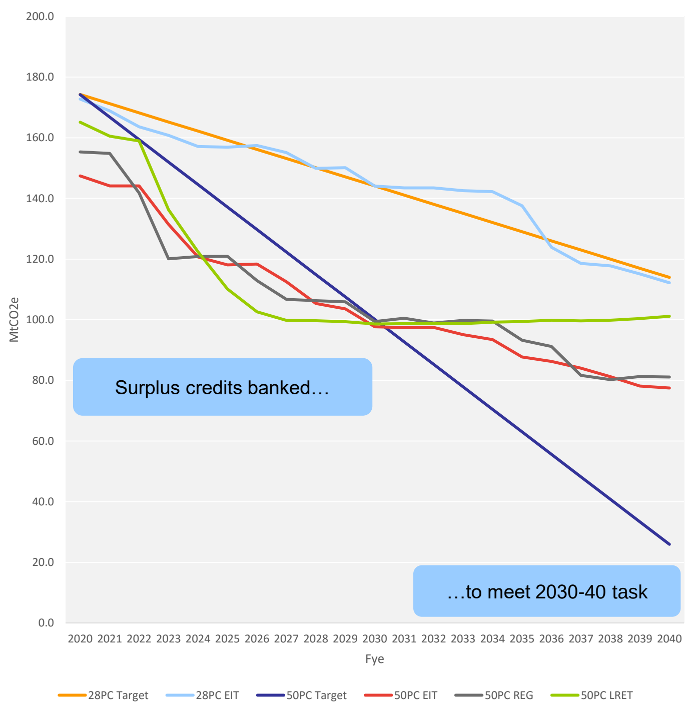
Figure 49 compares the annual emissions projections against the targets, reflecting this trajectory. The EIT emissions trajectory reflects an optimal (least cost) path; the LRET and REG emissions paths were assumed to reflect a similar trajectory to ensure that the results are comparable. A slower 2020-30 pathway might reflect lower resource costs from 2020-30 but much higher resource costs from 2030-40, which may distort the results.

Figure 48: Cumulative emissions: 2020-2030



Source: Frontier Economics

Figure 49: Annual emissions: 2020-2040

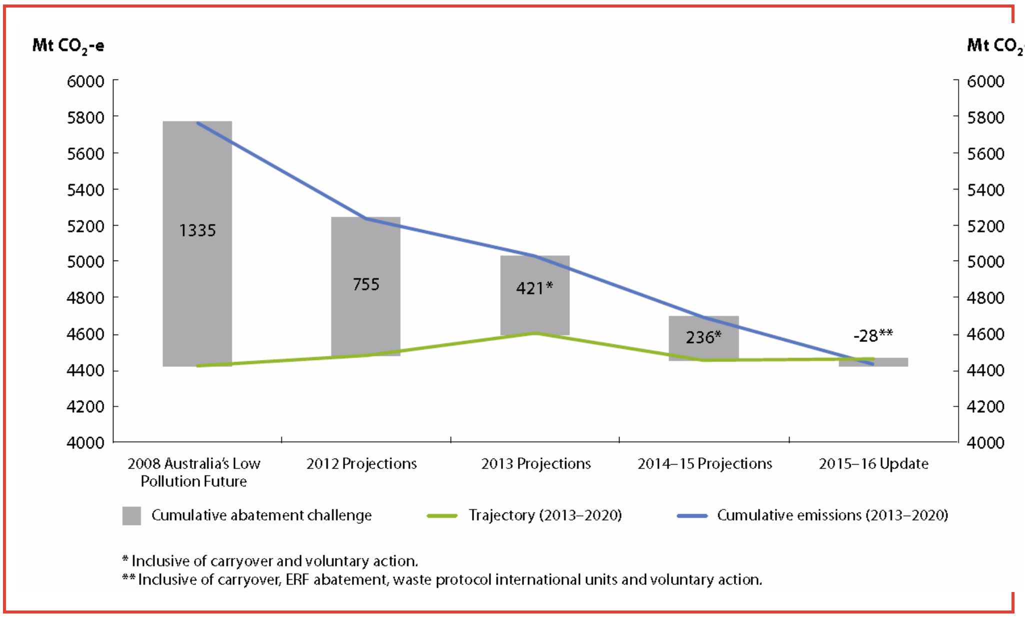


Note: the resulting trajectory allows cumulative emissions in the policy cases to exceed the cumulative 2020-40 target by around 5%.

Source: Frontier Economics

For context, the national cumulative abatement task from 2013-2020 was initially estimated at 1335Mt (in 2008), and revised down to 755Mt (2012), 421Mt (2013), 236Mt (2014/15), and -28Mt by December. 2015: Figure 50. This is not directly comparable as it reflects a national target (with larger abatement opportunities).

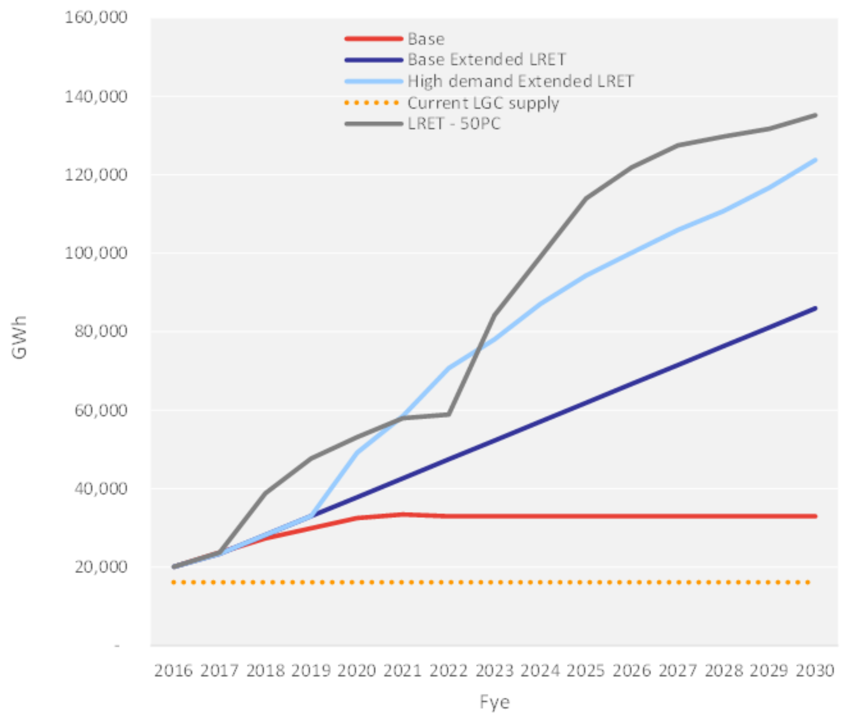
Figure 50: Cumulative abatement task: 2013-2020



Source: https://www.environment.gov.au/system/files/resources/d46b4104-0a04-4efb-9e83-df97e58eb2ff/files/tracking-to-2020-interim-update-emissions-projections.pdf

As per the Base Case, the required LRET to meet the 50PC emissions target was estimated through iteration of the modelling. The LRET is a model input and emissions are a model output in this scenario, with the LRET adjusted to achieve emissions close to the pathway from the EIT. Figure 51 shows the LRET for each sensitivity, including for the 50PC case. This implies that LRET eligible renewables would meet approximately 57% of grid demand by 2030 (excluding rooftop PV and non-LRET eligible hydro). This compares with an equivalent BAU renewable share of grid demand of 14%, or 36% in the 28PC case. The LRET penalty levels were also increased to ensure compliance with the assumed target.

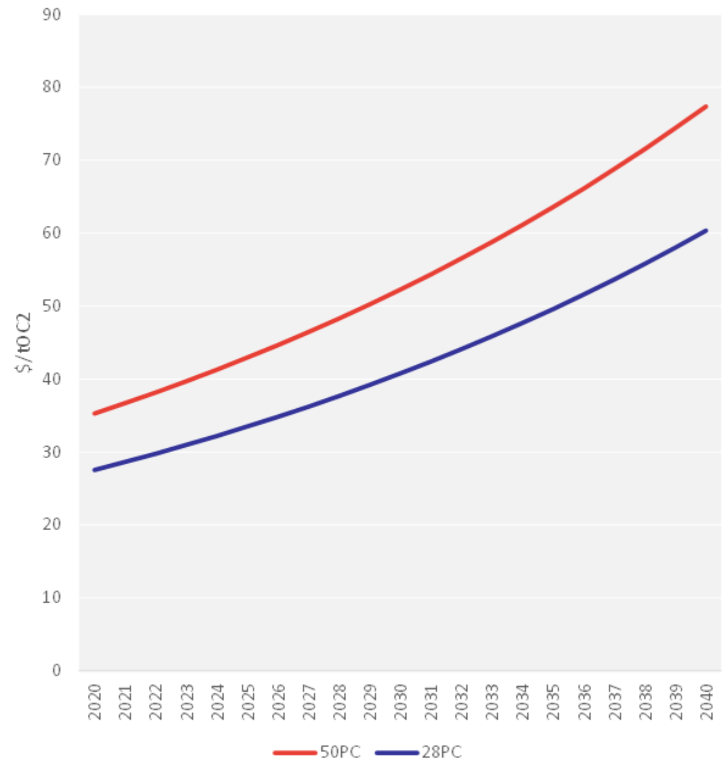
Figure 51: LRET targets



Source: Frontier Economics

Figure 52 shows the EIT certificate prices (the carbon price) under the 28PC and 50PC targets: the increase is from around $27/tCO2 (2020, 28PC) to around $35/tCO2 (2020, 50PC). This reflects an increase in the **marginal** cost of abatement of around 30% under our assumptions. This is larger than the increase in **average** cost of abatement, which is discussed under resource costs.

Figure 52: EITC prices

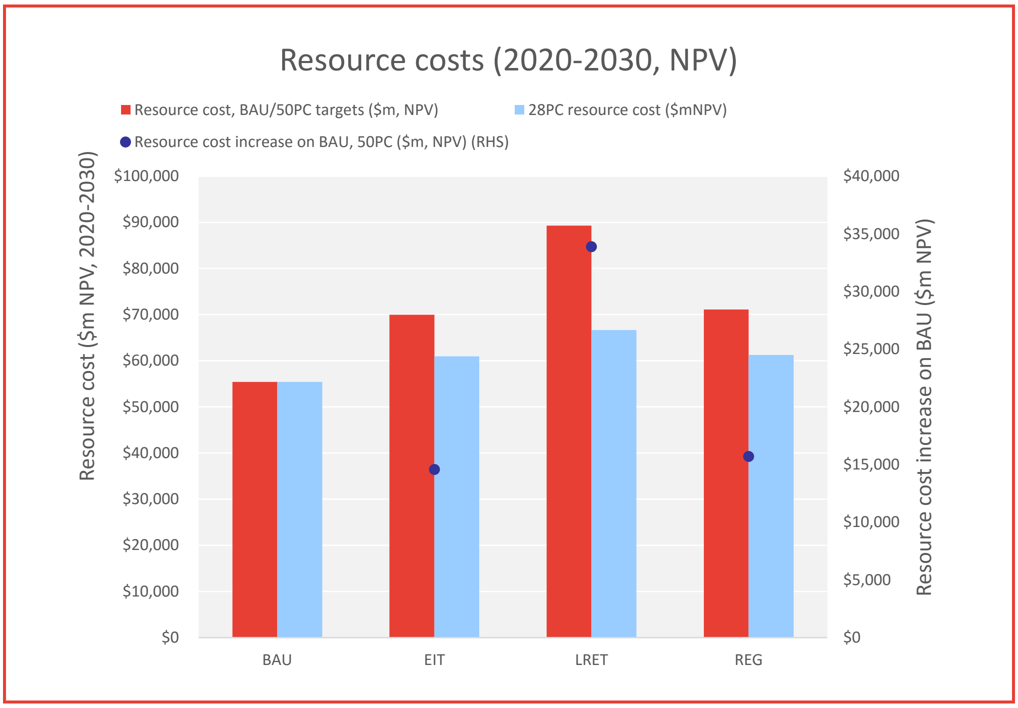


Source: Frontier Economics

9.3 Resource cost comparisons

Figure 38 shows a comparison of resource costs in the 50PC emissions target cases. EIT is still the lowest cost option relative to the BAU (a $14.5B increase, NPV 2020-30) and the LRET is the highest relative cost ($33.9B NPV). The REG case is $15.7B higher cost than BAU, though as per the BAU cases this option (the retirement decisions) is based on the known results from the EIT case, which arguably overstates the relative efficiency (or understates the likely cost) of this option.

Figure 53: Resource costs: 2020-2030



Source: Frontier Economics

Table 20 shows the relative cost per tonne of abatement which confirms the trends described above: the relative abatement cost for EIT and REG increase compared with the Base Case due to the increase in the abatement task (reduction in the target). Although these cases achieve greater abatement from 2020-30 than required, this increases overall abatement and resource costs. On a cost per tonne basis this increase is marginal, as switching from coal to gas is still the main path to reducing emissions.

The relative increase in the cost of abatement under the LRET increases by more as it relies more heavily on lower quality wind sites and a greater share of solar to meet the harder target.

Table 20: Cost per tonne abated (2020-2030), $/tCO2

Scen-arios	Base case		High Gas		High Demand		50PC		Hazelwood retire	
	Discounted	Not discounted	Discounted	Not Discounted	Discounted	Not discounted	Discounted	Not discounted	Discounted	Not discounted
EIT	$30.4	$17.5	$51.4	$28.4	$29.8	$17.7	$34.7	$20.5	$28.8	$16.2
REG	$34.2	$19.5	$73.9	$43.6	$35.5	$20.0	$37.9	$22.1	$35.2	$19.5
LRET	$75.7	$42.0	$72.0	$40.0	$93.6	$50.8	$85.3	$48.3	$85.1	$46.9

Source: Frontier Economics

9.4 Revenue comparisons (consumer impacts)

Figure 39 compares the revenue (consumer cost) by case for the 50PC cases.

The LRET has the largest increase in consumer costs: despite driving wholesale prices lower, this is more than offset by a large increase in the LRET quantity and certificate prices. The net increase in consumer costs is a little less than the increase in resource costs, suggesting that consumers bear around 80% of the cost under this scheme.

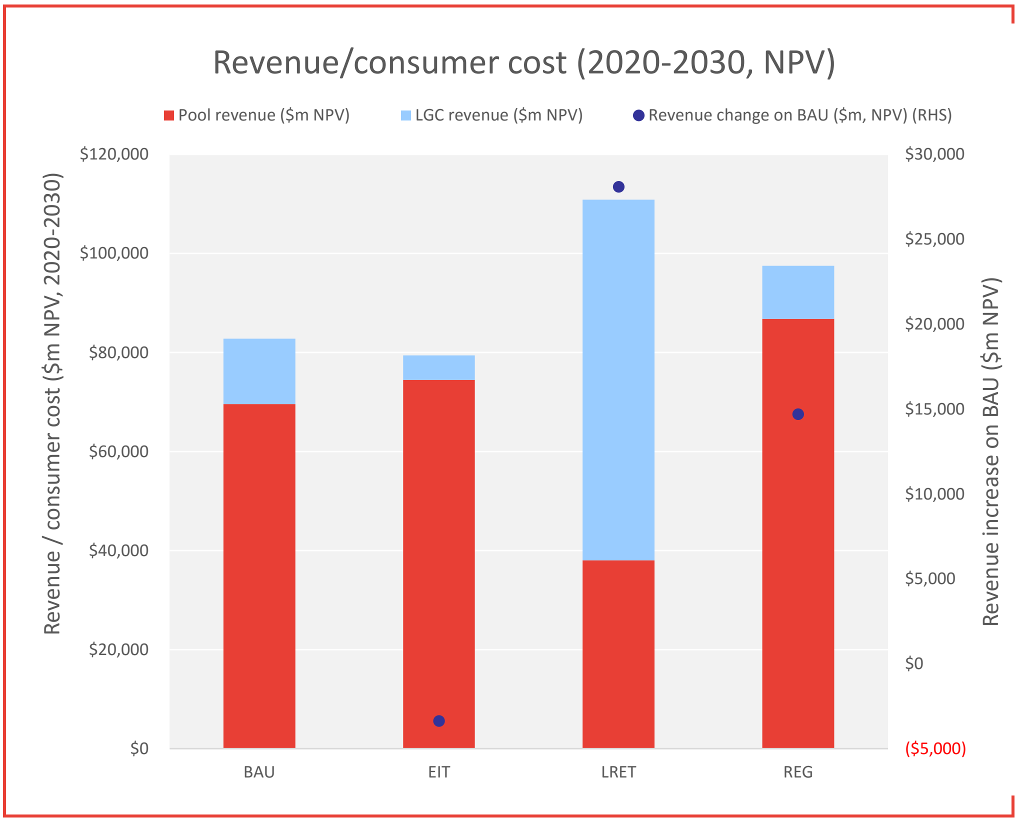
The EIT continues to result in lower overall consumer costs (compared with BAU), even for the 50PC target. This is not immediately evident from wholesale prices alone (the red bars are higher under EIT than in BAU), however once the effect of EIT credits to renewables are taken into account, this lowers the cost of the existing LRET to consumers (light blue) as it drives LGC prices down.

As before, this is driven by the flattening of the merit order: lower cost/higher emissions coal is penalised and higher cost/low emissions gas is rewarded and because gas is more frequently the marginal price setting plant, this results in a lower impact on pool price / higher negative impact on coal generator margins. The net effect is that (coal) generators bear more than 100% of the resource cost of reducing emissions to meet the 50PC target.

The REG impact on consumers falls between the other two policy cases: it has the highest impact on wholesale pool prices (red bars) due to the withdrawal of capacity. However, this does not reduce LGC costs by as much as the EIT case as there are no additional EIT credits for renewables, as there are under the EIT. Under this policy (and target setting), consumers bear around 94% of the resource cost of emissions reductions.

As an aside, although the EIT has a similar withdrawal of supply as the REG (an upward shift of the merit order), it does not have the same impact on pool prices. This is because of the penalty/reward mechanism embedded in the EIT system, which flattens the merit order (described above). The EIT transfers penalties from infra-marginal (non-price setting) coal to rewards for marginal (price setting) gas, which results in lower pool price effects, shifting more of the cost of meeting emissions targets to existing coal generators as opposed to consumers.

Figure 54: Revenue: 2020-2030 (50PC policy cases)



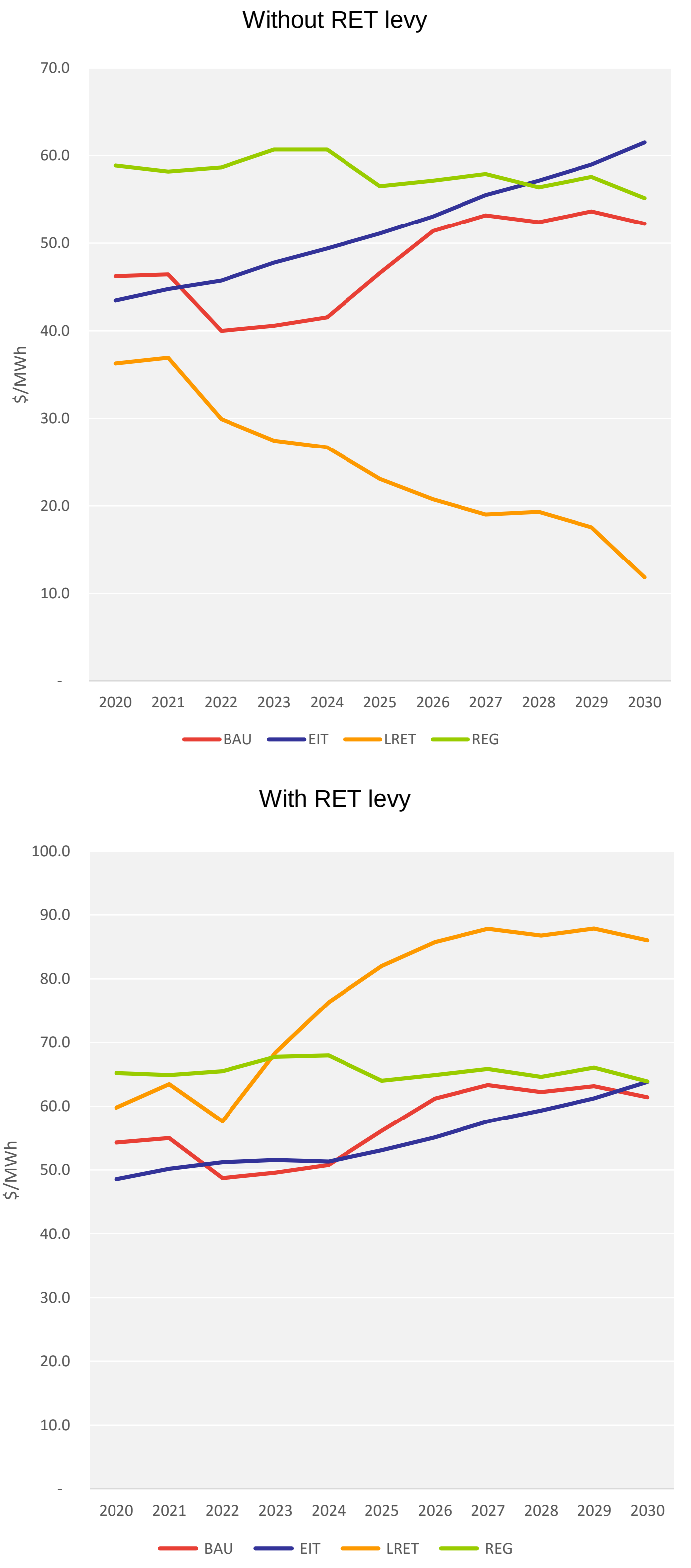
Source: Frontier Economics

9.5 Pool price impacts

Figure 55 shows weighted average pool prices over time, which confirm the results from Figure 54.

- The LRET results in lower wholesale prices but the highest impact on consumers once the LRET levy is taken into account;
- The REG results in higher wholesale prices, which is not offset by a lower LGC levy;
- The EIT results in marginally higher wholesale prices, though this is offset by a lower LGC levy, resulting in lower overall consumer costs.

Figure 55: Pool prices: 2020-2030 (weighted national average, $/MWh, realFYe2016), 50PC

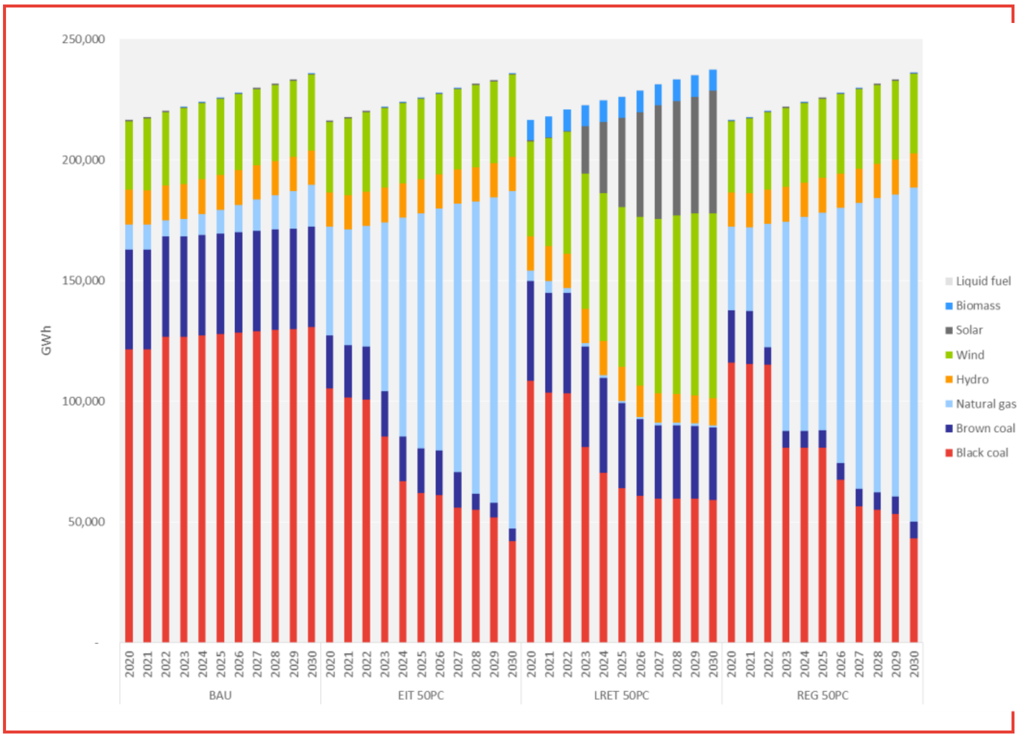


Source: Frontier Economics

9.6 Output

Figure 41 shows forecast output by scenario, which is consistent with other cases: EIT and REG rely on switching from coal to gas but the shift is more substantial under the 50PC target; LRET relies on switching from coal (and gas) to increased renewables (wind, solar).

Figure 56: Output: 2020-2030



Source: Frontier Economics

9.7 Investment

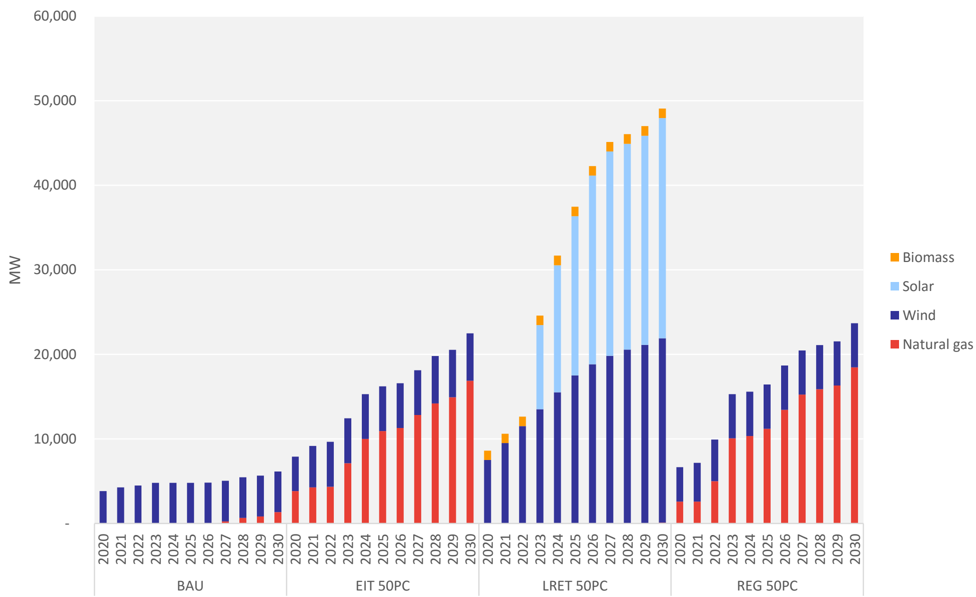
Figure 57 shows only **new** investment in capacity from 2020-2030 (relative to current/committed capacity mix). In the BAU, there is new investment in wind to meet growth in the LRET. Most of this investment occurs prior to 2020.

In the EIT case there is a similar level of new wind driven by the existing LRET but a larger share of investment in new gas. This displaces existing coal, which is forecast to retire by the EIT scheme (to reduce emissions). Under the 50PC target there is around 17,000MW of new gas required to replace existing coal, or around 1300MW/year from 2018-2030. The REG investment mix shows a similar pattern with rising wind to meet the existing LRET and new gas required to replace assumed forced coal retirements.

The extended LRET under the 50PC case requires around 22,000MW of new wind by 2030, or around 1700MW/year from 2018-2030, mostly at the start of the decade. This also requires around 26000MW of utility scale solar by 2030, which would require around 3,000MW per year from 2023-30, if possible.

Regional investment is reported in the appendices.

Figure 57: Investment: 2020-2030



Source: Frontier Economics

9.8 Retirements

Table 16 shows the forecast (or assumed) retirements in the 50PC cases.

In the EIT and REG cases this would require early retirements and replacement with equivalent gas capacity of Hazelwood, Yallourn and Vales Pt (around 2020), along with closures of Eraring, Liddell and Tarong early in the decade.

The LRET 50PC results in early retirements of Vales Pt and Eraring (displaced by new NSW wind and solar) but this does not drive the retirement of Hazelwood, which is low cost but not penalised for higher emissions under this policy.

Table 21: Retirements (to 2030)

	BAU	EIT	LRET	REG
Bayswater				2028/9
Bluewater A				2029
Callide B		2025		2026
Eraring		2024	2023	2023
Gladstone		2030		2030
Hazelwood		2020		2020
Liddell		2022-23		2022-23
Loy Yang A		2028		2022
Muja AB		2020	2022	2019
Muja C			2023/4	2027/8
Muja D			2026-9	
Northern	2017	2017	2017	2017
Tarong		2024		2023
Vales Point		2020	2023	2020
Yallourn W		2020		2020

Source: Frontier Economics

9.9 Summary

Table 22 shows the change in resource costs and revenue by scenario.

For the 50PC case, the EIT remains the lowest **cost** option of the three, with the LRET costs remaining the highest cost option. The REG approach is marginally higher cost than the EIT, though the REG cost is likely understated as it relies on the outputs of the EIT case to assume a highly efficient retirement path. Although the EIT is more market based (adapting to market conditions for relative fuel costs between regions), the REG is dependent on forecasts/administrative decisions, which may not be as efficient if cost assumptions differ from forecast.

Even for the harder 50PC target, the EIT forecasts lower revenue (consumer cost) than BAU, suggesting a benefit to consumers relative to BAU; this means that generators bear more that the resource cost in these cases. Conversely, the REG and LRET approaches see a similar increase in revenue compared to costs, suggesting that consumers bear almost all of the resource cost of reducing emissions.

Table 22: Change in resource cost/revenue versus BAU (NPV, Real2016$m, 2020-2030)

	EIT	LRET	REG
Resource costs			
Base	$5,546	$11,248	$5,838
High Demand	$7,961	$22,079	$8,408
High Gas	$7,204	$9,870	$10,232
50PC	$14,565	$33,900	$15,711
Hazelwood retires	$3,449	$10,115	$3,816
Revenue/consumer costs			
Base	($4,945)	$1,062	$10,843
High Demand	($15,014)	$9,714	$3,654
High Gas	($14,049)	($14,934)	$24,143
50PC	($3,372)	$28,085	$14,696
Hazelwood retires	($11,216)	($1,768)	$5,244

Source: Frontier Economics

10 Results: Lower solar PV costs

This section presents Frontier Economics' modelling results for the lower solar PV cost scenarios.

Table 23: Scenarios

Scenario	Sensitivities							
	Base Case (S5)	High demand (S6)	High Gas (S7)	Low Demand (S8)	50PC 2030 target (S9)	Lower solar PV costs (28PC target) (S10)	EITEI credits (28PC target) (S11)	HZ retires pre-2020 (S12)
BAU	✓	✓	✓	✓				✓
Emissions Intensity target (EIT)	✓	✓	✓	✓*	✓	✓	✓	✓
Extended LRET (LRET)	✓	✓	✓	✓*	✓	✓		✓
Regulated closures (REG)	✓	✓	✓	✓*	✓			✓

** In the Low Demand case, the emissions target was met in the BAU case, making the policy changes redundant*

10.1 Solar PV cost comparisons

Figure 58 shows a comparison of estimated utility scale solar PV costs under our Base Case assumptions and Low solar. Frontier Economics' original solar PV costs (**Base Case**) reflect LCOE of around $117/MWh from FYe2016 (real $2016), declining to near $80/MWh by 2040.

This is consistent with our estimates of successful ARENA projects (announced Aug 2016), which average around $2200/kW (AC), which by our calculations translates to around $114/MWh[18]. Most of these projects are due to comment in 2018.

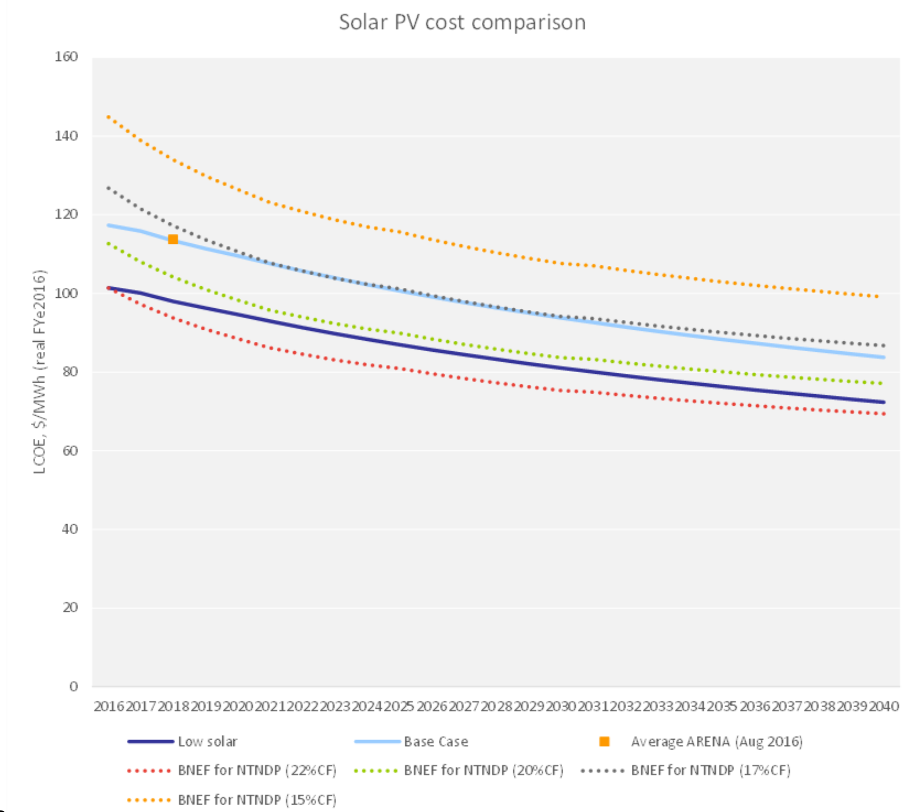
The BNEF for NTNDP 2015 estimates for Fixed axis solar PV are $1800/kW nominal. It is not clear whether this is AC or DC basis but they include tiers for CF based on 22%, 20%, 17% and 15%. The chart includes estimates of the LCOE

18 Assumes 8.3% WACC, 30 year life, $20/MWh average O&M.

of these price paths, converted to real $2016 (assuming 8.3% WACC over 30 years).

For the **Low Solar** case we scale down our costs to match the lowest cost tier in BNEF (the highest CF). This commences at around $100/MWh, falling to $72/MWh by 2040.

Figure 58: Solar cost comparisons



s

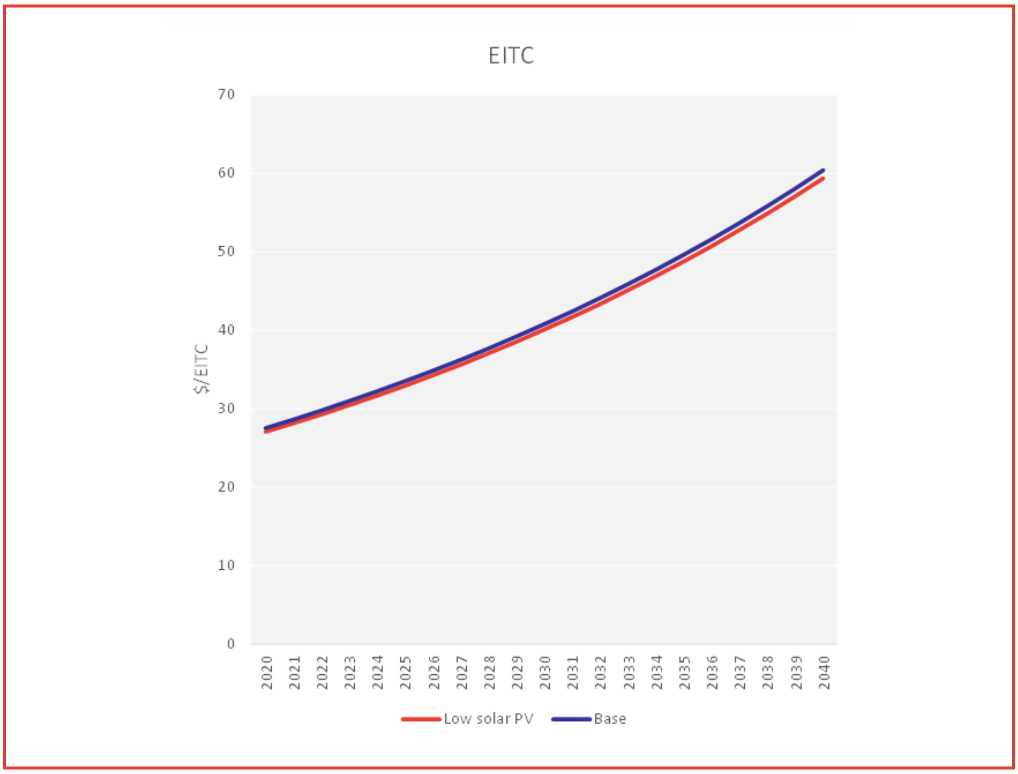
Assumes WACC of 8.3%, 30 year life, $20/MWh O&M

Source: Frontier Economics, http://arena.gov.au/programs/advancing-renewables-program/large-scale-solar-pv/, BNEF for NTNDP 2015

10.2 Certificate price comparison

Figure 52 shows the EIT certificate prices (the carbon price) under the Base 28PC EIT and under the lower solar PV costs. The lower solar costs result in a marginal reduction in certificate price.

Figure 59: EITC prices

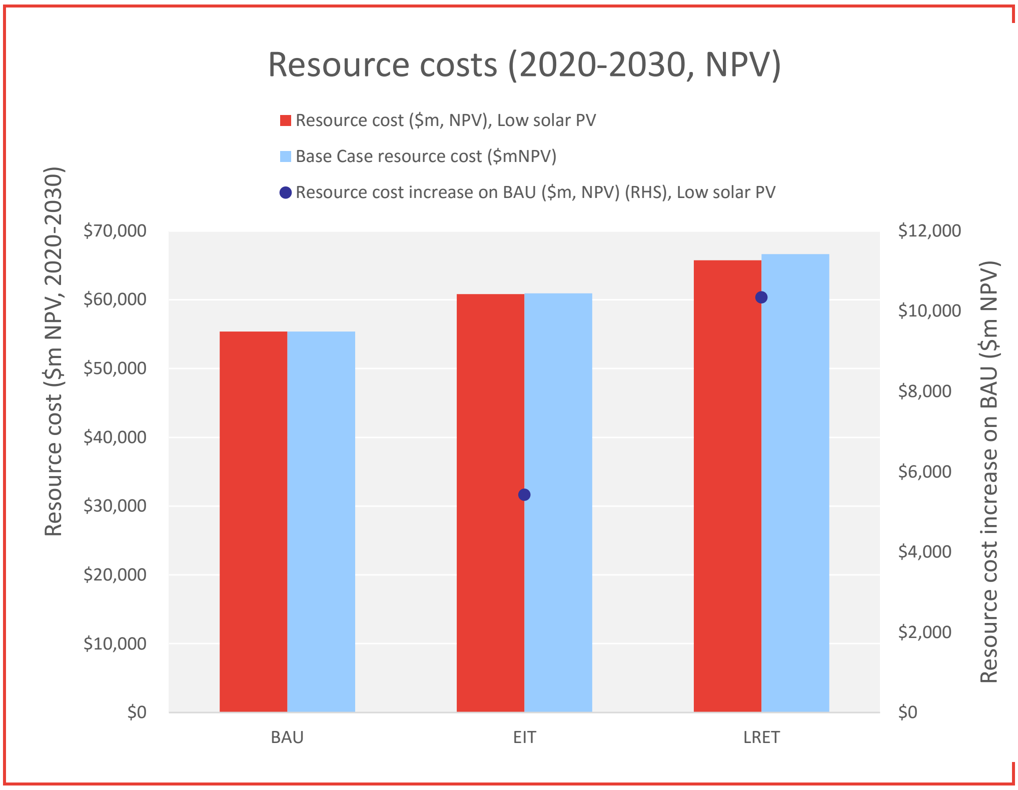


Source: Frontier Economics

10.3 Resource cost comparisons

Figure 60 shows a comparison of resource costs in the Base 28PC against the Low solar 28PC cases. The EIT change in costs is insignificant. The LRET costs are reduced by around $900m (1.5%).

Figure 60: Resource costs: 2020-2030



Source: Frontier Economics

Table 24 shows the relative cost per tonne of abatement. There is very little change in the EIT costs, as this case relies mostly on coal-gas switching. The LRET case sees a larger reduction in average abatement costs.

Table 24: Cost per tonne abated (2020-2030), $/tCO2

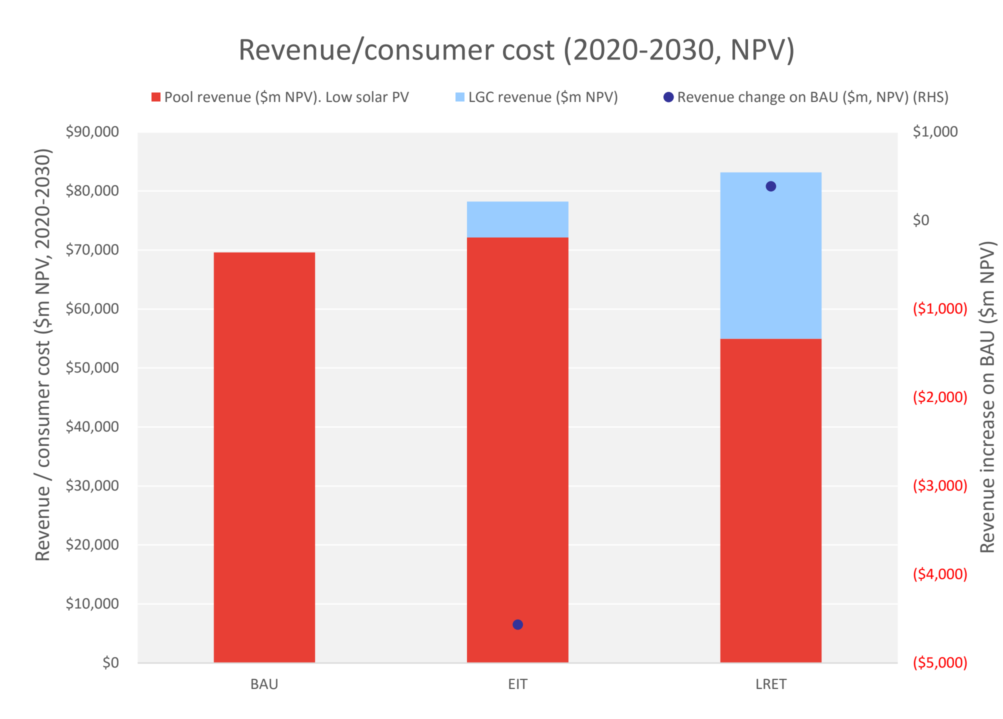
Scenarios	28PC, Base		28PC, Low solar	
	Discounted	Not discounted	Discounted	Not discounted
EIT	$30.4	$17.5	$30.3	$17.4
LRET	$75.7	$42.0	$67.5	$37.2

Source: Frontier Economics

10.4 Revenue comparisons (consumer impacts)

Figure 61 compares the revenue (consumer cost) by case for the Low solar PV cases (28PC). The EIT costs are largely unchanged from the Base Case 28PC, while the LRET consumer costs are reduced by around 0.8% ($670m NPV, 2020-30) compared with the Base Case 28PC. This does not change any relativities between policies.

Figure 61: Revenue: 2020-2030 (28PC, Low solar PV)

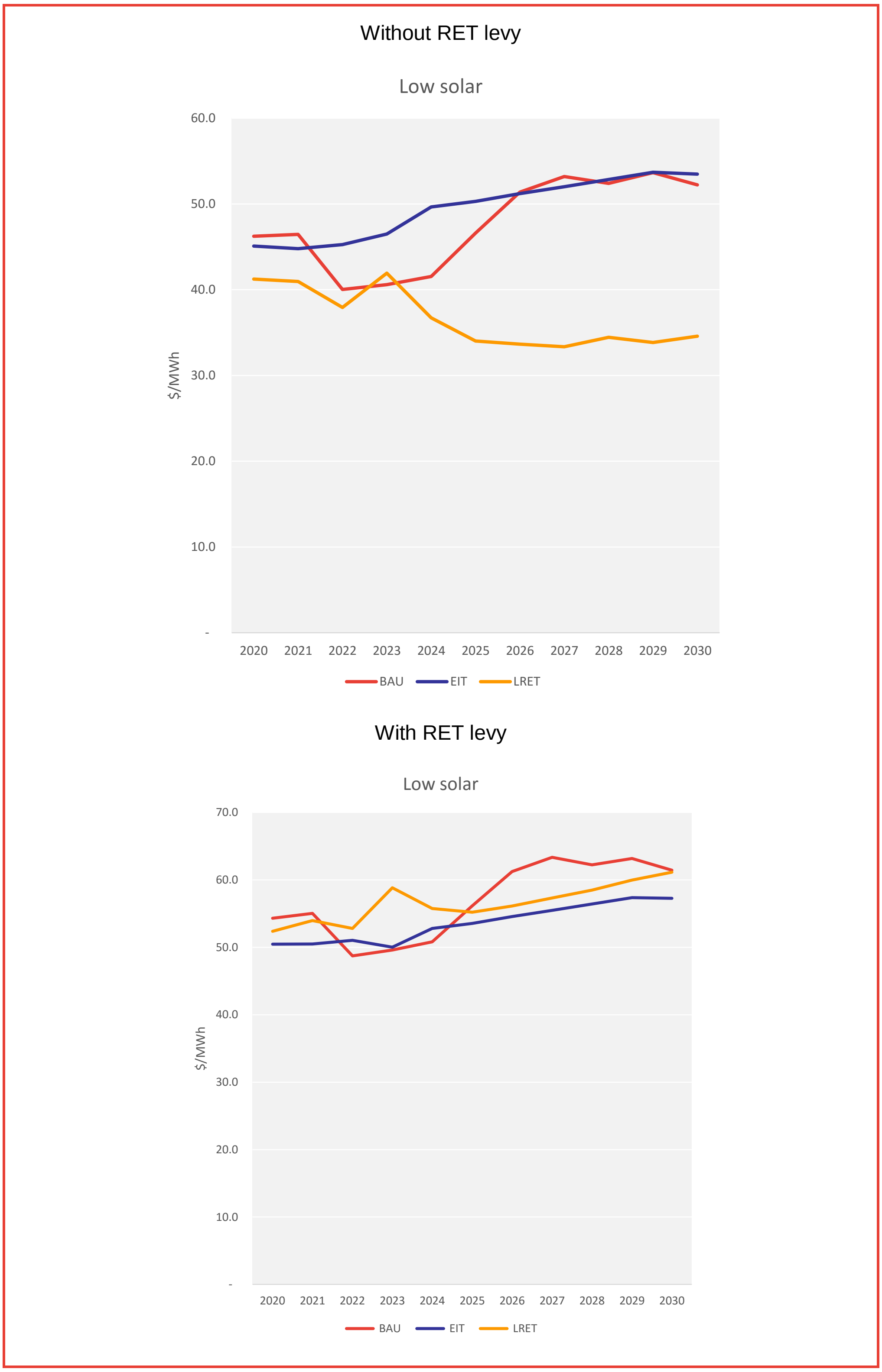


Source: Frontier Economics

10.5 Pool price impacts

Figure 55 shows weighted average pool prices over time. There is generally insignificant change from the Base 28PC case.

Figure 62: Pool prices: 2020-2030 (weighted national average, $/MWh, realFYe2016), Low solar PV, 28PC



Source: Frontier Economics

10.6 Other

Output, investment and retirements are largely unchanged relative to the 28PC Base Case and are not reported separately

10.7 Summary

Table 25 shows the change in resource costs and revenue by scenario. As discussed above, there is only marginal change in results compared with the Base Case 28PC, though as expected the LRET resource/consumer costs fall by relatively more than the EIT.

Table 25: Change in resource cost/revenue versus BAU (NPV, Real2016$m,2020-2030)

	EIT	LRET	REG
Resource costs			
Base	$5,546	$11,248	$5,838
High Demand	$7,961	$22,079	$8,408
High Gas	$7,204	$9,870	$10,232
50PC	$14,565	$33,900	$15,711
Low solar (28PC)	$5,429	$10,349	n/a
Revenue/consumer costs			
Base	($4,945)	$1,062	$10,843
High Demand	($15,014)	$9,714	$3,654
High Gas	($14,049)	($14,934)	$24,143
50PC	($3,372)	$28,085	$14,696
Low solar (28PC)	($4,566)	$388	n/a

Source: Frontier Economics

11 Results: EITEI Credits

This section presents Frontier Economics' modelling results for an EITEI credit scenario.

The Base Case scenario assumes that **either:**

- pre-existing hydro are eligible to earn EIT credits for all output **or**
- the credits that would be earned by hydro are sold by a scheme administrator and funds allocated to EITEI as compensation for rising pool prices.

The rationale for this is discussed in sections 2.6 and 2.8: as hydro has a low marginal cost and should produce with or without EIT credits, the allocation of credits to hydro might be viewed as a windfall gain. The modelling results under the Base Case EIT are unchanged whether the credits are allocated to pre-existing hydro or sold for the benefit of EITEI.

This section considers a case where credits are allocated to **both** legacy hydro **and** EITEI.

Table 26: Scenarios

Scenario	Sensitivities							
	Base Case (S5)	High demand (S6)	High Gas (S7)	Low Demand (S8)	50PC 2030 target (S9)	Lower solar PV costs (28PC target) (S10)	EITEI credits (28PC target) (S11)	HZ retires pre-2020 (S12)
BAU	✓	✓	✓	✓				✓
Emissions Intensity target (EIT)	✓	✓	✓	✓*	✓	✓	✓	✓
Extended LRET (LRET)	✓	✓	✓	✓*	✓	✓		✓
Regulated closures (REG)	✓	✓	✓	✓*	✓			✓

** In the Low Demand case, the emissions target was met in the BAU case, making the policy changes redundant*

11.1 Theory/rationale

Under a Base Case, actual emissions intensity should equal the target emission intensity (subject to banking/borrowing between years), as all credits allocated reflect actual abatement produced. This is true whether the credits are allocated to hydro or sold by a scheme administrator on behalf of EITEI, so long as the supply of credits issued matches actual hydro output.

Under the proposed alternative considered here, equivalent credits are allocated to both legacy hydro and EITEI. This would create "phantom credits": supply of credits will be increased above the actual supply of abatement delivered. If the EIT target remains unchanged, this increase in supply of credits will lead to oversupply, which should reduce the EIT certificate price until the market balances. However, given that some of the EIT credit supply does not reflect actual abatement, a balanced market in this case would mean a shortfall of actual abatement.

To account for this and still meet actual emissions targets, the EIT would have to be reduced to offset the excess "phantom credits" allocated to EITEI. To supply an equivalent amount of legacy hydro credits (assume 15TWh) to EITEI, and allowing for some growth in demand, this would result in a reduction in the EIT of between 0.04 and 0.05tCO_2/MWh (about 6-7%). This should result in fewer credits/more penalties for a given MWh output, and this should be sufficient to offset an increase in supply of 15TWh of "phantom credits", such that the actual emissions targets should be met. For the purpose of certificate trading (to balance the market), the target EIT will be less than actual emissions intensity due to the excess phantom credits sold for the benefit of EITEI.

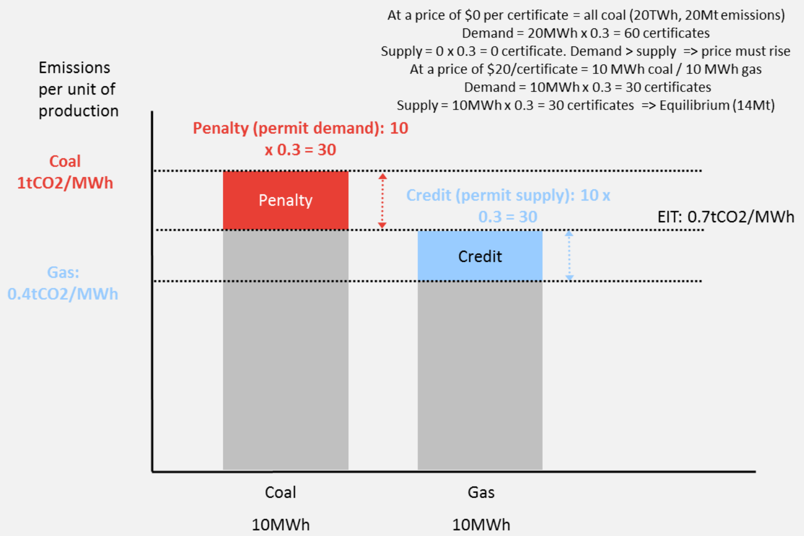
The reduction in the EIT is simply to offset the creation of phantom credits to EITEI. In practice, this should deliver the same certificate price, actual emissions intensity and resource costs as the Base Case 28PC. See Box 2 for a stylised example of why the EIT must be adjusted to account for any EITEI phantom credits to deliver the same fuel mix to meet a given emissions target.

The difference will be that a lower EIT should mean higher pool prices for all consumers, as there are fewer credits/more penalties per MWh produced, with the excess of credits being transferred (or sold for the benefit of) EITEI. Effectively, this approach could be considered equivalent in effect to a separate scheme that imposes a flat levy on all electricity consumption to raise funds to compensate EITEI or legacy hydro.

Box 2: Simple example of EIT adjustment for EITEI (phantom) credits

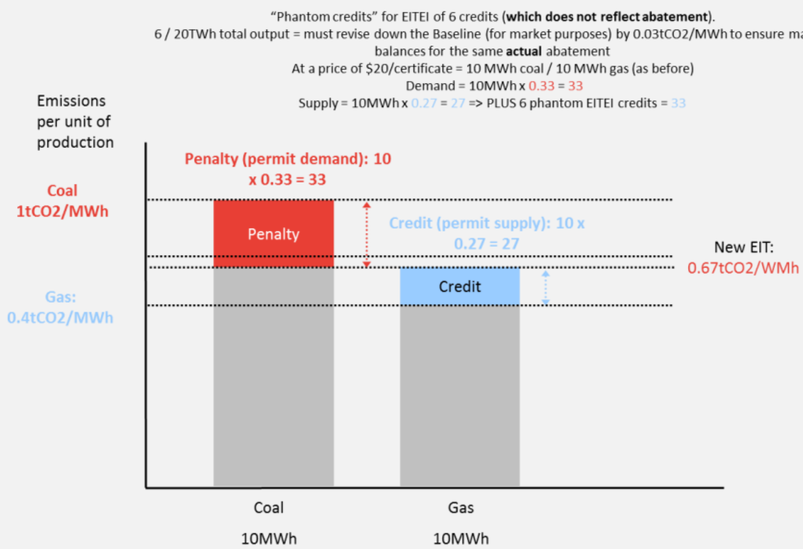
Case 1: Standard EIT with no EITEI credits, coal/gas options, 20TWh demand. For no EIT this might mean 20TWh of coal for 20Mt emissions. If we impose an emissions target of 14Mt this implies an EIT Baseline of 0.7tCO2/MWh which requires a mix of 10MWh coal and gas such that actual market emissions intensity (for that generation mix) equals the EIT (meeting the 14Mt sector target)

On these assumptions, coal faces a penalty of $6/MWh ($20 x 0.3) and gas faces a subsidy of $6/MWh; the relative change in costs between coal and gas is $12/MWh.



Case 2: EIT with 6 EITEI "phantom" credits (that don't reflect actual abatement). The EIT must be reduced to 0.67tCO2/MWh to ensure that the market balances for the same mix of generation (which is necessary to meet the actual emissions abatement target). But this still results in a mix of 10MWh each of coal/gas and actual market emissions intensity of 0.7tCO2/MWh despite the lower EIT. Without this adjustment there would be a surplus of credits, driving EIT prices lower and reducing abatement.

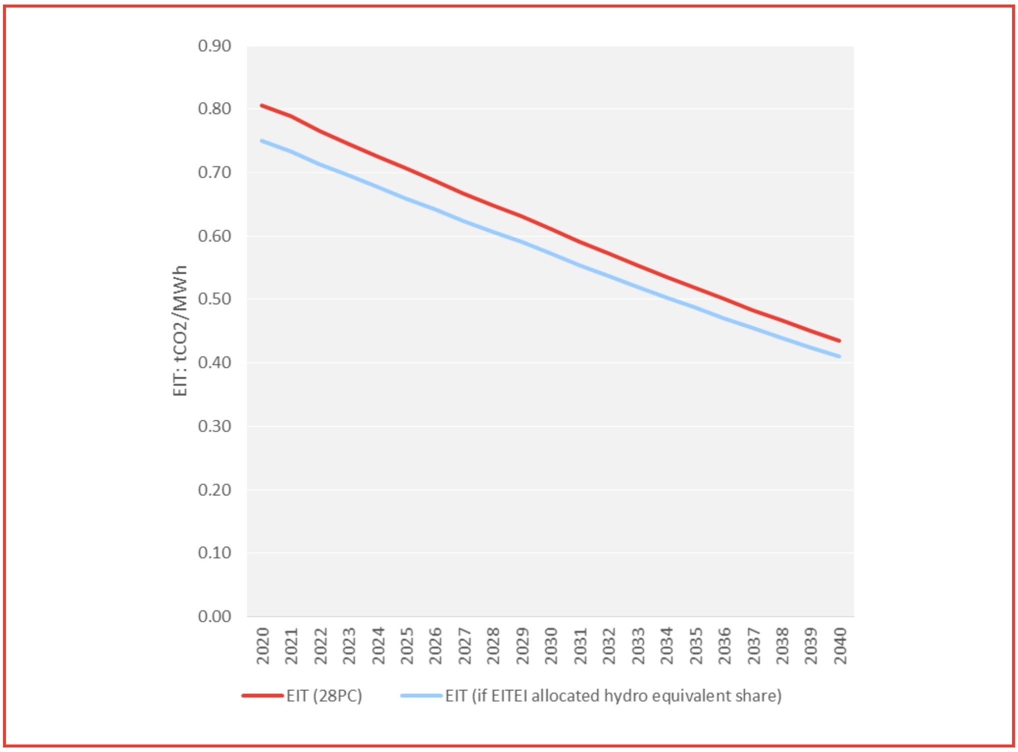
However, on these assumptions, coal now faces a penalty of $6.6/MWh ($20 x 0.33) and gas faces a subsidy of $5.4/MWh ($20 x 0.27). The relative change in costs between coal and gas is still $12/MWh (delivering the same fuel mix/sector emissions) but this involves a higher penalty for coal/lower subsidy for gas, which means marginally higher wholesale prices than under Case 1.



Source: Frontier Economics

Results: EITEI Credits

Figure 63 Comparison of EIT Base Case 28PC, or to offset EITEI phantom credits



Source: Frontier Economics

11.2 Sufficient compensation

EITEI energy use is approximately 40TWh (see s2.8), but they don't require 1:1 compensation/allocation of permits as any damages depends on the level of carbon cost pass-through relative to a counterfactual (BAU). The EIT effectively provides compensation in the form of lower pool prices. Under our Base Case 28PC results, EIT prices are comparable to (or even lower than) the BAU. This would suggest that the EIT mechanism itself is arguably sufficient to compensate EITEI. Alternatively, we could consider an allocation equivalent to the credits that would be created by legacy hydro (around 15TWh), which is what we analyse here.

11.3 Resource cost comparisons

As discussed above, the certificate prices and resource costs of meeting the targets should be equivalent to the Base Case 28PC. The differences should be in consumer costs/pool prices, which are reported below.

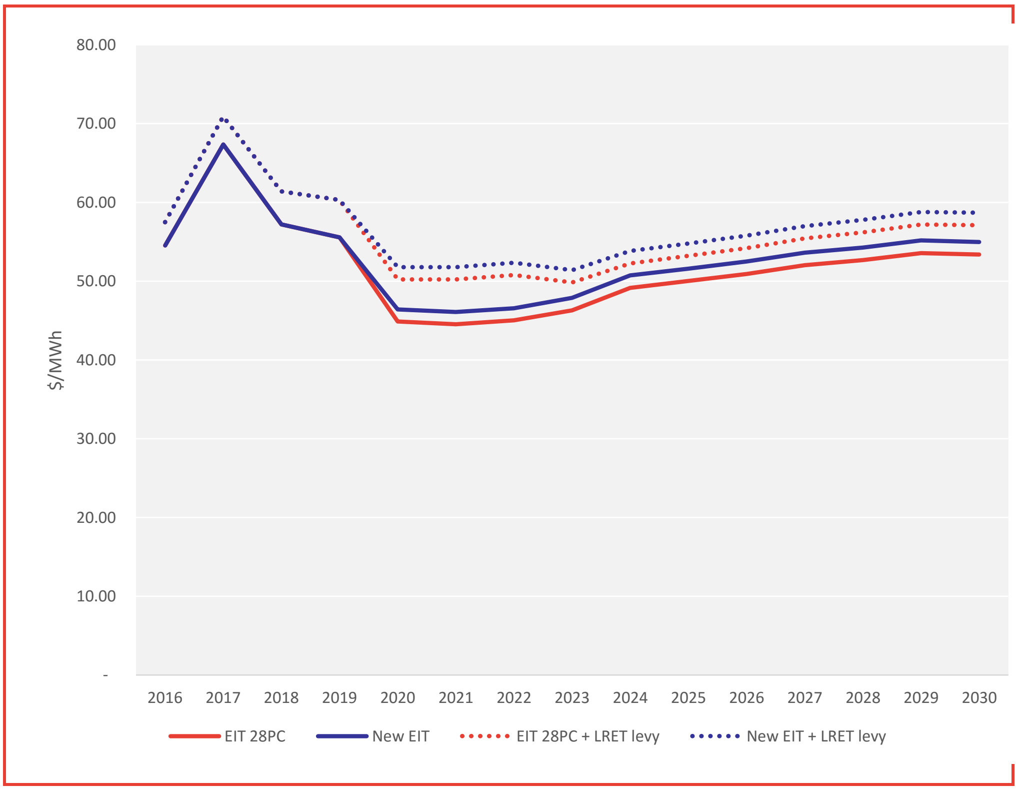
11.4 Pool price impacts

Figure 62 shows weighted average pool prices over time. The red line reflects national average pool prices under the Base Case 28PC EIT. The blue line reflects the same, but for the lower EIT (to account for EITEI phantom credits).

The dashed line reflects the same, but including the LRET levy.

The difference is an increase in average prices of around $1.5/MWh from 2020. This implies an effective value of the phantom credits (sold for EITEI or legacy hydro) of around $1.8B (NPV to 2030) to $2.5B (NPV to 2040).

Figure 64: Pool prices: 2020-2030 (weighted national average, $/MWh, realFYe2016)



Source: Frontier Economics

11.5 Other

Output, investment and retirements are unchanged relative to the 28PC Base Case and are not reported separately.

12 Results: Hazelwood retirement

The Base Case scenario modelling was undertaken prior to speculation regarding the early retirement of Hazelwood power station. On 3 November 2016, ENGIE, announced that the Hazelwood power station in Victoria would be closed in March 2017[19]. This section presents Frontier Economics' modelling results accounting for the recently announced early retirement of Hazelwood. This has only marginal effects on the results of the EIT and REG cases, as Hazelwood was projected to retire shortly after 2020 in those scenarios. It has a more material effect on BAU, and to a lesser extent LRET, as Hazelwood was projected to continue operation until after 2030 in those scenarios.

Table 27: Scenarios

Scenario	Sensitivities							
	Base Case (S5)	High demand (S6)	High Gas (S7)	Low Demand (S8)	50PC 2030 target (S9)	Lower solar PV costs (28PC target) (S10)	EITEI credits (28PC target) (S11)	HZ retires pre-2020 (S12)
BAU	✓	✓	✓	✓				✓
Emissions Intensity target (EIT)	✓	✓	✓	✓*	✓	✓	✓	✓
Extended LRET (LRET)	✓	✓	✓	✓*	✓	✓		✓
Regulated closures (REG)	✓	✓	✓	✓*	✓			✓

** In the Low Demand case, the emissions target was met in the BAU case, making the policy changes redundant*

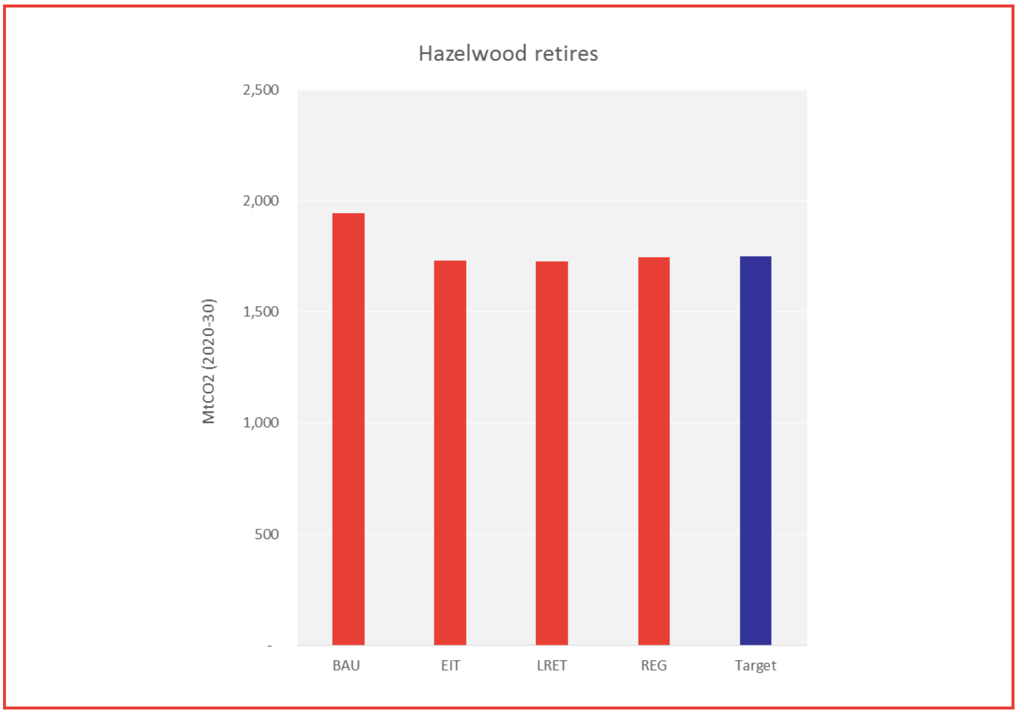
12.1 Emissions comparisons

Figure 65 shows a comparison of cumulative emissions by policy scenario, where Hazelwood retires in 2017 (before FYe2018) as recently announced. The most

19 ENGIE Media Release, Hazelwood to close in March 2017, 03 November 2016. Available at http://www.gdfsuezau.com/media/UploadedDocuments/News/Hazelwood%20Clousure/Hazelwood%20closure%20-%20Media%20release.pdf

material change is a reduction in BAU emissions due to the Hazelwood retirement, which reduces the incremental abatement task for each policy.

Figure 65: Cumulative emissions: 2020-2030

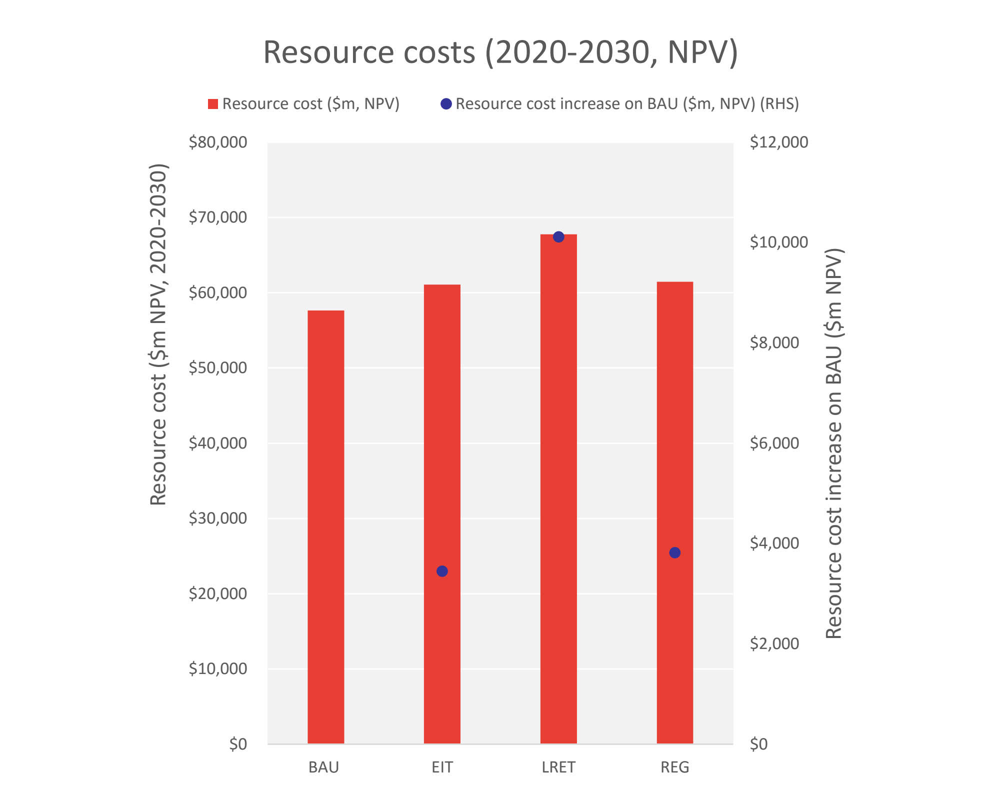


Source: Frontier Economics

12.2 Resource cost comparisons

Figure 66 shows a comparison of resource costs in the Hazelwood Retirement cases. The resource costs of all options increase to varying degrees, relative to the Base Case. Resources costs increase only marginally in the EIT and REG cases relative to the Base Case modelling (without Hazelwood retirement), as Hazelwood was otherwise projected to retire very early on even before the announced retirement. The resource costs increases are more substantial in the BAU case. This means that the incremental costs of each policy (the change in costs relative to BAU) is reduced as a result on the early Hazelwood retirement. The ranking of policies by resource cost impact are unchanged from the Base Case results.

Figure 66: Resource costs: 2020-2030



Source: Frontier Economics

Table 28 shows the relative cost per tonne of abatement, which confirms the trends described above: the relative abatement cost for EIT and RET increase compared with the Base Case as these rely mostly on abatement from switching to gas; the relative abatement cost of the LRET actually falls in this case because the relative cost between gas and renewables narrows.

Table 28: Cost per tonne abated (2020-2030), $/tCO2

Scen-arios	Base case		High Gas		High Demand		50PC		Hazelwood retire	
	Discounted	Not discounted	Discounted	Not Discounted	Discounted	Not discounted	Discounted	Not discounted	Discounted	Not discounted
EIT	$30.4	$17.5	$51.4	$28.4	$29.8	$17.7	$34.7	$20.5	$28.8	$16.2
REG	$34.2	$19.5	$73.9	$43.6	$35.5	$20.0	$37.9	$22.1	$35.2	$19.5
LRET	$75.7	$42.0	$72.0	$40.0	$93.6	$50.8	$85.3	$48.3	$85.1	$46.9

Source: Frontier Economics

12.3 Revenue comparisons (consumer impacts)

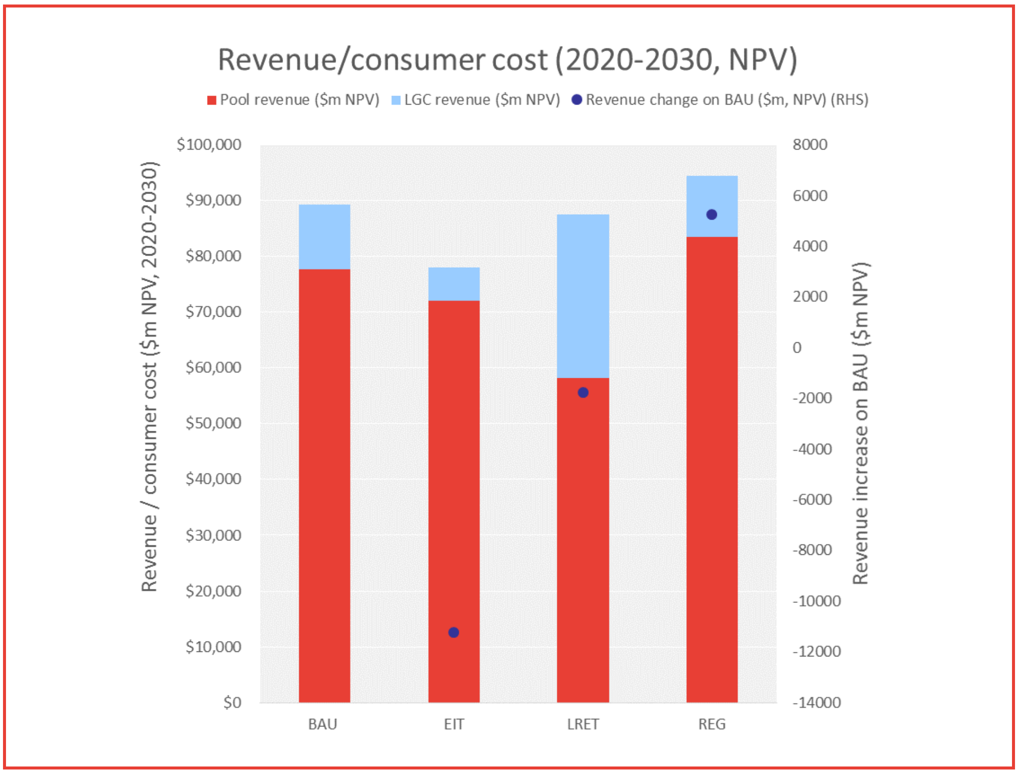
Figure 67 compares the revenue (consumer cost) by case for the Hazelwood Retirement cases.

The increase in revenue (consumer cost) compared with the Base Case results is very marginal in the EIT and REG cases, as Hazelwood was projected to retire in 2020 even prior to the announced retirement. However, revenue/consumer costs increase by more in the BAU case in particular, and to a lesser extent LRET.

In relative terms, the ranking of policies is unchanged from the Base Case results:

- EIT is most favourable for consumers: it reduces consumer costs relative to BAU, and by a considerably greater margin once the Hazelwood retirement is included in the revised BAU.
- REG is least favourable for consumers: it still raises costs relative to the BAU, though the difference is considerably reduced once Hazelwood's retirement is included in the revised BAU.
- LRET has a consumer impact between the other two policies: in the Base Case, LRET was projected to marginally raise consumer costs but once Hazelwood retirement is factored into the BAU, this now projects a marginal reduction in consumer costs as a result of the LRET.

Figure 67: Revenue: 2020-2030

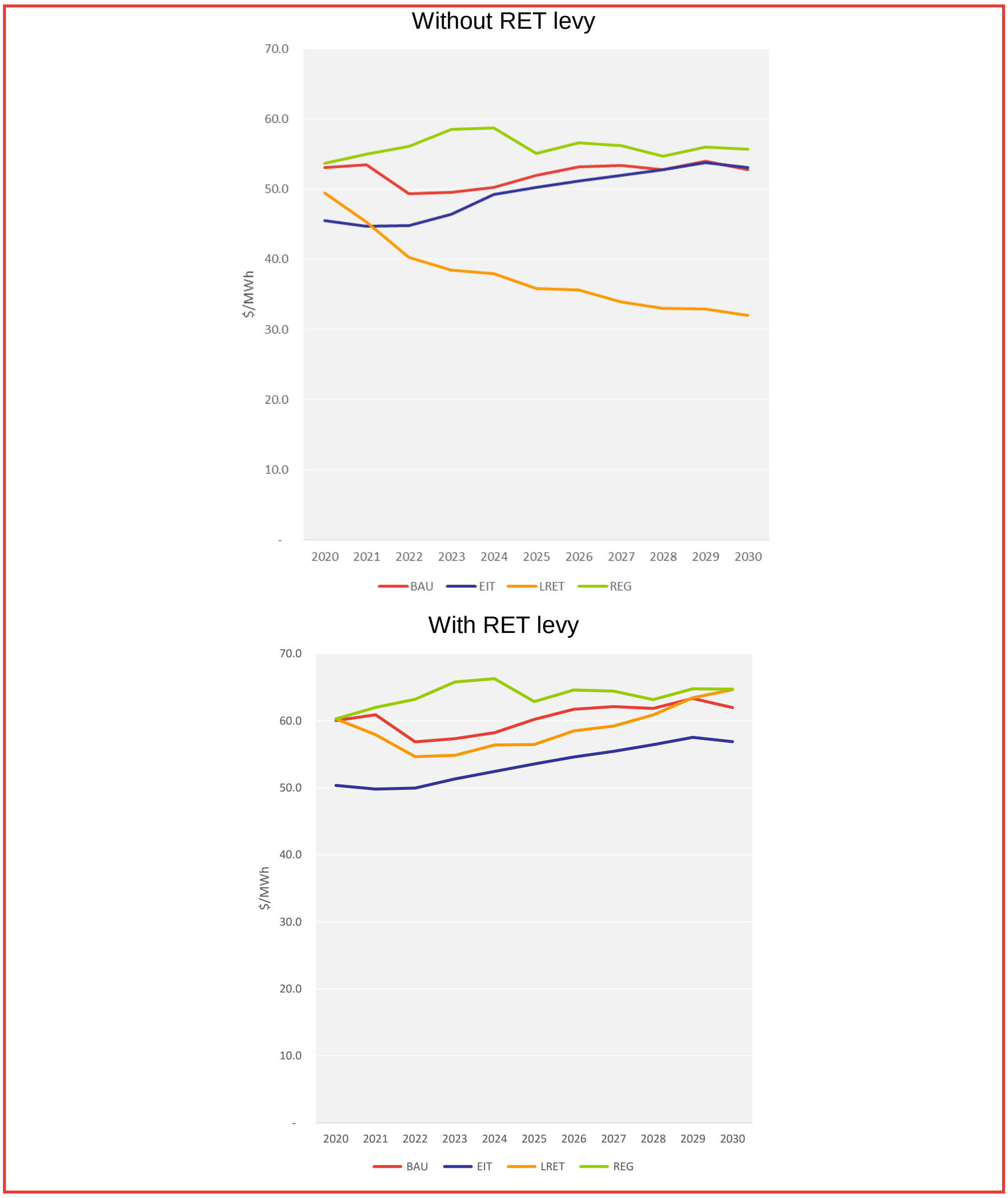


Source: Frontier Economics

12.4 Pool price impacts

Figure 68 shows weighted average pool prices over time, which confirm the results from Figure 67: the REG forecasts the highest price impacts and the EIT forecasts the lowest price impacts once LGC costs are accounted for. The LRET drives lower pool prices, but much of this is offset by LGC costs. The price effects presented are from 2020 only, which allows for some investment response to moderate the price increases in all cases. In the short-term (FYe2018/19) the wholesale price increases from the sudden withdrawal of Hazelwood are more severe across all cases.

Figure 68: Pool prices: 2020-2030 (weighted national average, $/MWh, realFYe2016)

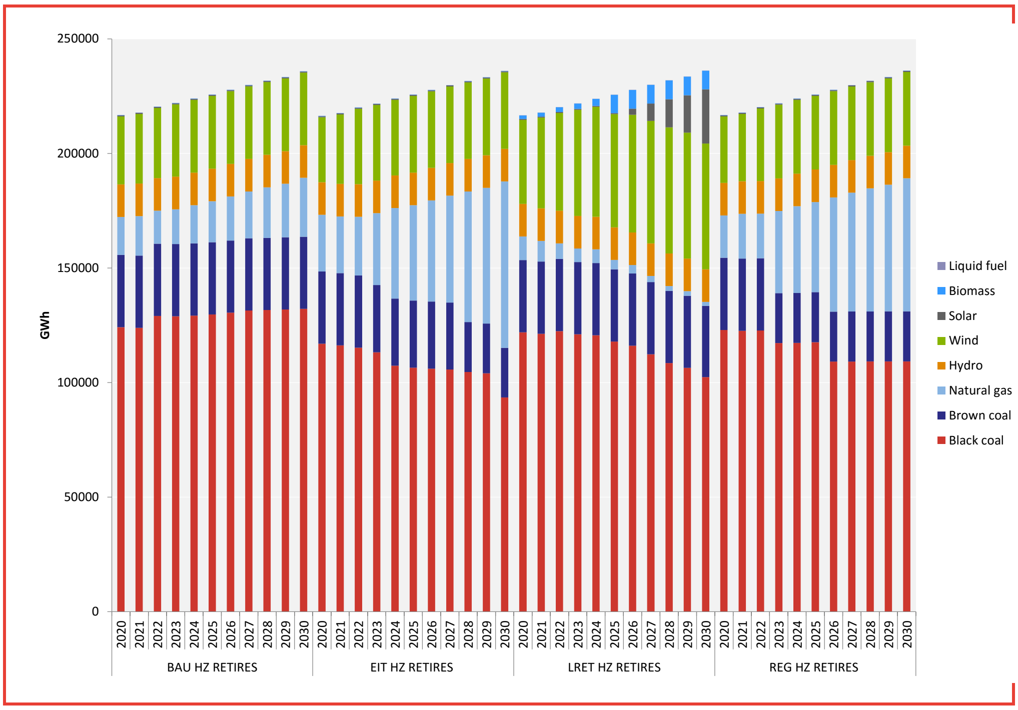


Source: Frontier Economics

12.5 Output

Figure 69 shows forecast output by scenario, which is consistent with other cases: EIT and REG rely on switching from coal to gas; LRET relies on switching from coal (and gas) to increased renewables. The main difference is reduced brown coal output due to the Hazelwood retirement. In the EIT and REG cases, this was also evident in the Base Case, as Hazelwood output was largely replaced with gas output very early in the decade. In the BAU and LRET cases, the brown coal output is replaced through a mix of increased gas and black coal output.

Figure 69: Output: 2020-2030

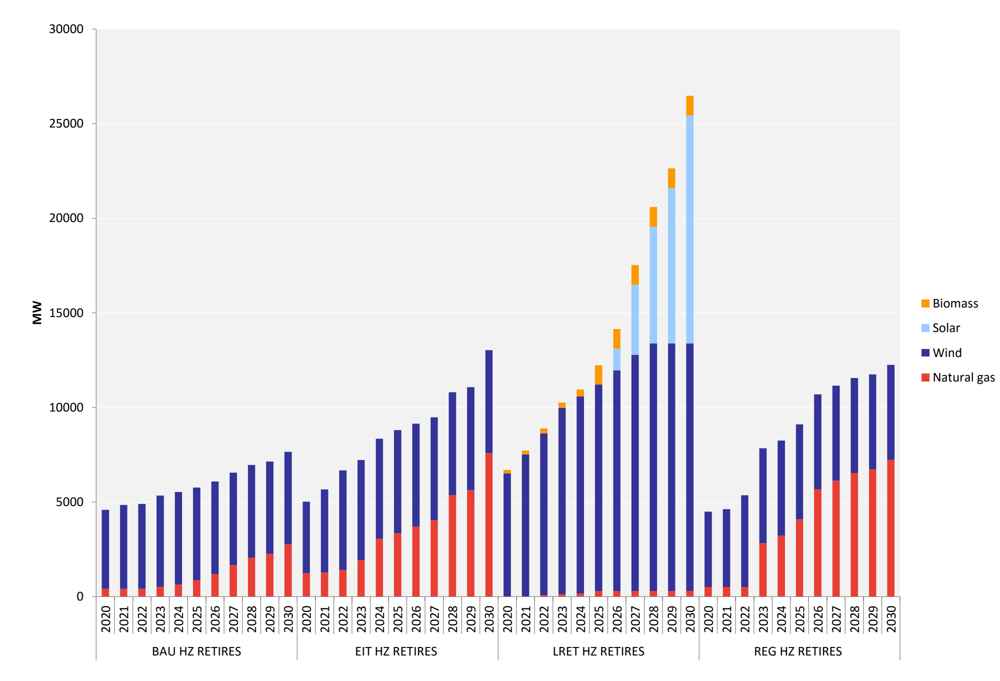


Source: Frontier Economics

12.6 Investment

Figure 70 shows the investment in new capacity by scenario, which is consistent with other scenarios. The level of new gas investment in the BAU and LRET cases from 2020 is only around 200-400MW initially, which is less than the withdrawal in capacity due to Hazelwood retirement (1600MW). This is largely because the Hazelwood capacity is effectively replaced (crowded out) by mostly new wind entrants to meet the existing LRET, with much of this occurring after FYe2017.

Figure 70: Investment: 2020-2030



Source: Frontier Economics

12.7 Retirements

Table 29 shows the forecast (or assumed) retirements in the Hazelwood Retirement cases. Other than the early Hazelwood retirement these are almost identical to the Base Case. The main difference is that Vales Point no longer retires in the LRET case if Hazelwood is already retired.

Table 29: Retirements

	BAU	EIT	LRET	REG
Gladstone		2030		
Hazelwood	2017	2017	2017	2017
Liddell		2022-24		2022-23
Muja AB (1&2)		2020	2029	2019
Muja AB (3&4)			2029	2019
Northern	2017	2017	2017	2017
Vales Point				2026
Yallourn W		2028		2023

12.8 Summary

Table 30 summarises the change in resource costs and revenue by scenario. The cost of all of policy options increase by less than the increase in costs under BAU, which reduces the incremental costs of all options. As before, the EIT is the lowest **cost** option of the three and LRET is the highest.

Both the EIT and LRET forecast lower revenue than BAU, suggesting a benefit to consumers (*relative to BAU*); this means that generators bear more that the resource cost in these cases. This is mostly because forecast prices are relatively much higher under BAU as a result of the withdrawal of Hazelwood, compared with the Base Case. The REG approach is still higher cost to consumers than BAU but the gap is reduced once Hazelwood retirement is factored into the BAU. The relative rankings of each policy are the same as under the Base Case on both a resource cost and consumer cost basis.

Table 30: Change in resource cost/revenue versus BAU (NPV, Real 2016 $m2020-2030)

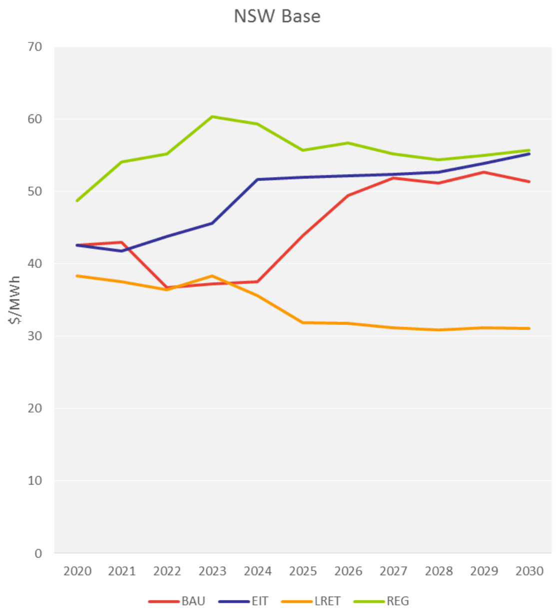
	EIT	LRET	REG
	Resource costs		
Base	$5,546	$11,248	$5,838
High Demand	$7,961	$22,079	$8,408
High Gas	$7,204	$9,870	$10,232
50PC	$14,565	$33,900	$15,711
Hazelwood retires	$3,449	$10,115	$3,816
	Revenue/consumer costs		
Base	($4,945)	$1,062	$10,843
High Demand	($15,014)	$9,714	$3,654
High Gas	($14,049)	($14,934)	$24,143
50PC	($3,372)	$28,085	$14,696
Hazelwood retires	($11,216)	($1,768)	$5,244

Appendix A - Regional results for Base Case

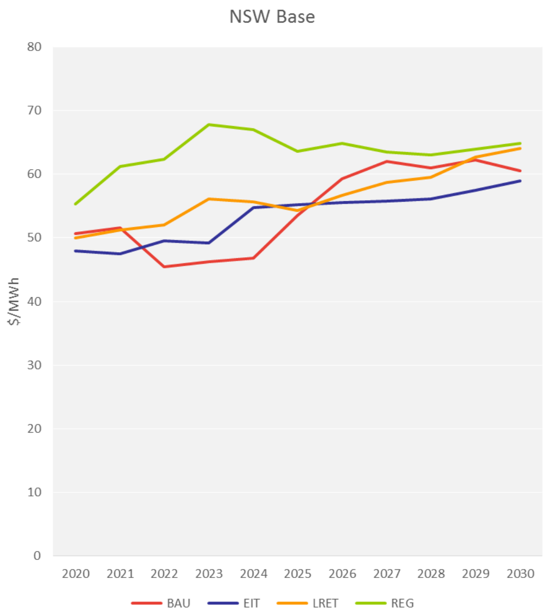
NSW - Pool price impacts

Figure 71: Pool prices: 2020-2030

Without RET levy



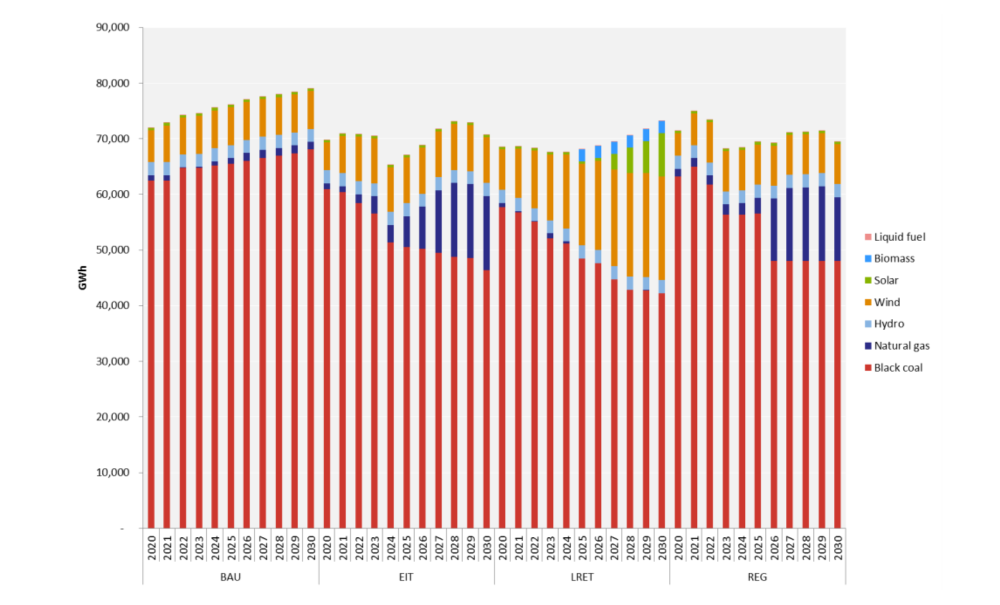
With RET levy



Source: Frontier Economics

NSW - Output

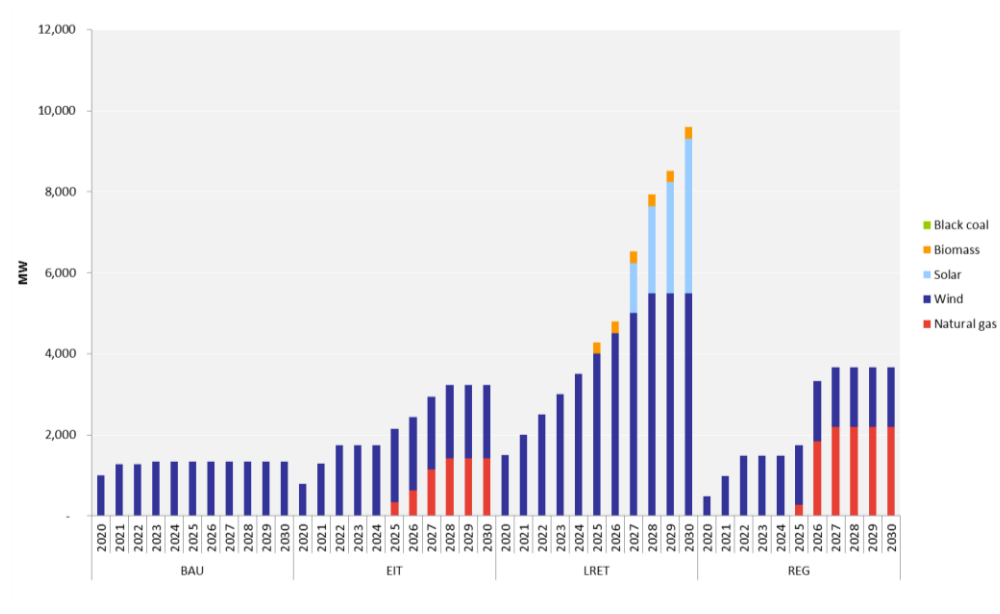
Figure 72: Output: 2020-2030



Source: Frontier Economics

NSW - Investment

Figure 73: Investment: 2020-2030



Source: Frontier Economics

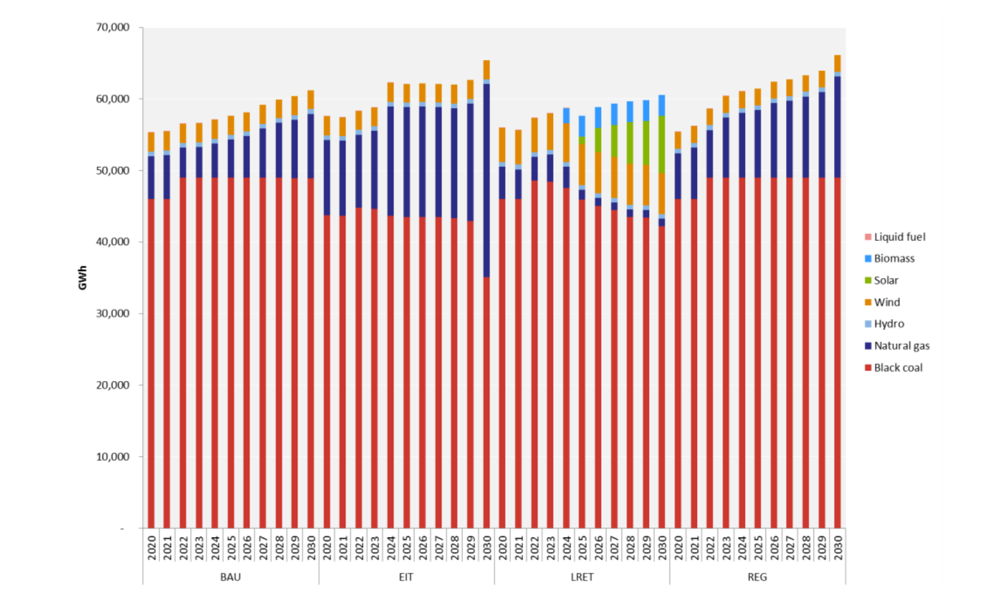
QLD - Pool price impacts

Figure 74: Pool prices: 2020-2030

Source: Frontier Economics

QLD - Output

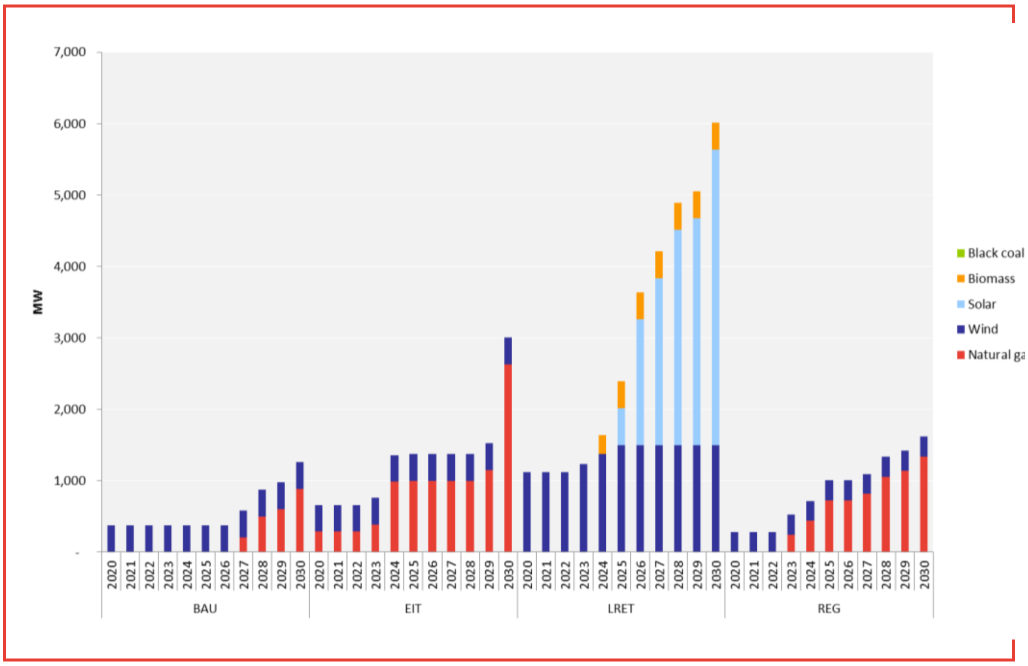
Figure 75: Output: 2020-2030



Source: Frontier Economics

QLD - Investment

Figure 76: Investment: 2020-2030

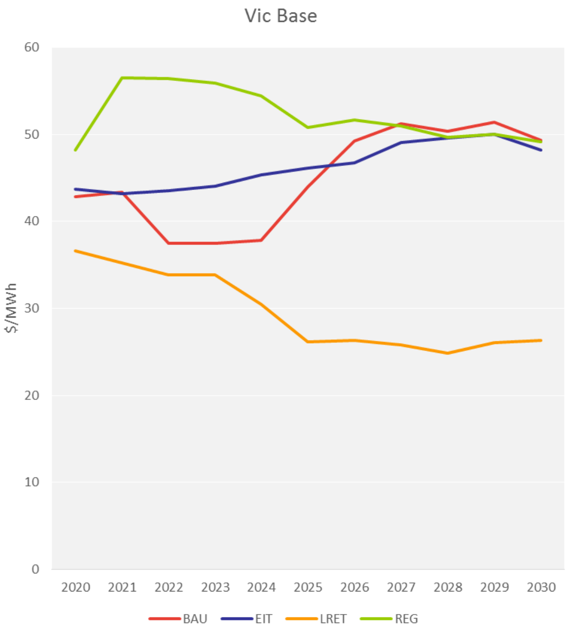


Source: Frontier Economics

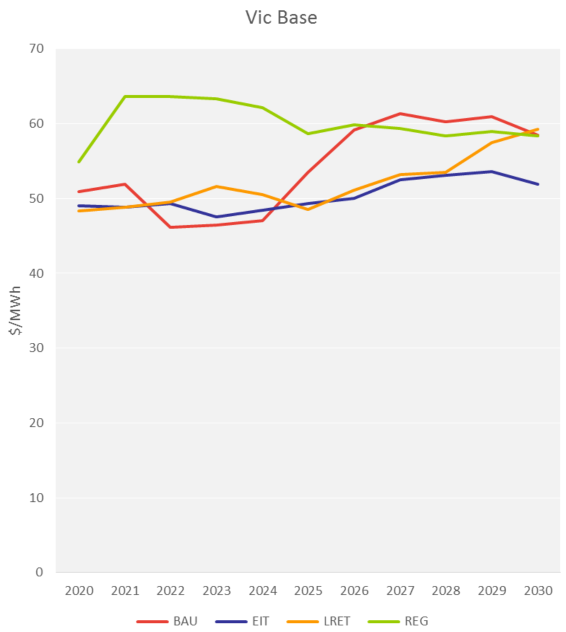
VIC - Pool price impacts

Figure 77: Pool prices: 2020-2030

Without RET levy



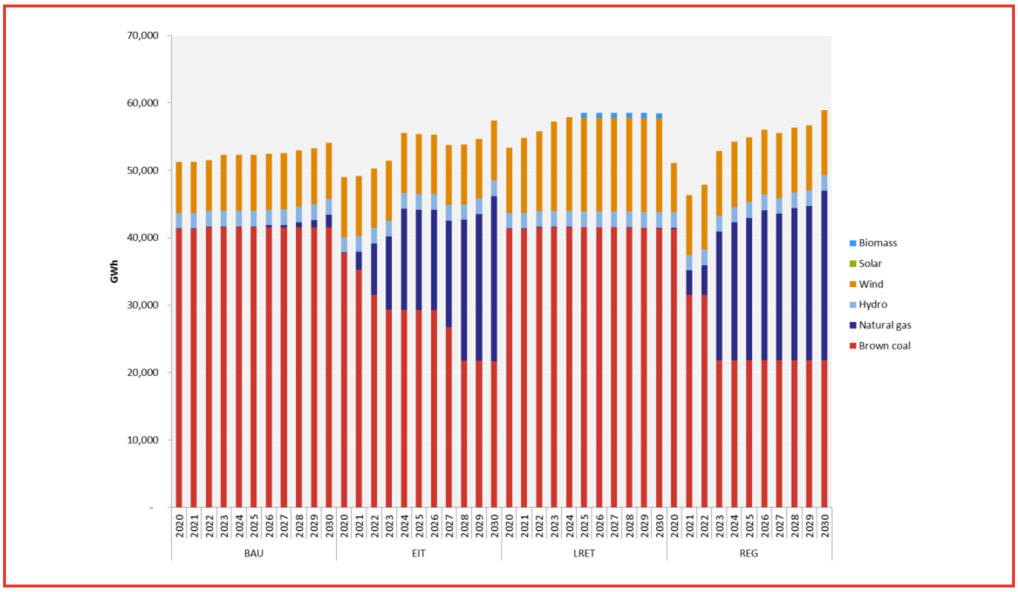
With RET levy



Source: Frontier Economics

VIC - Output

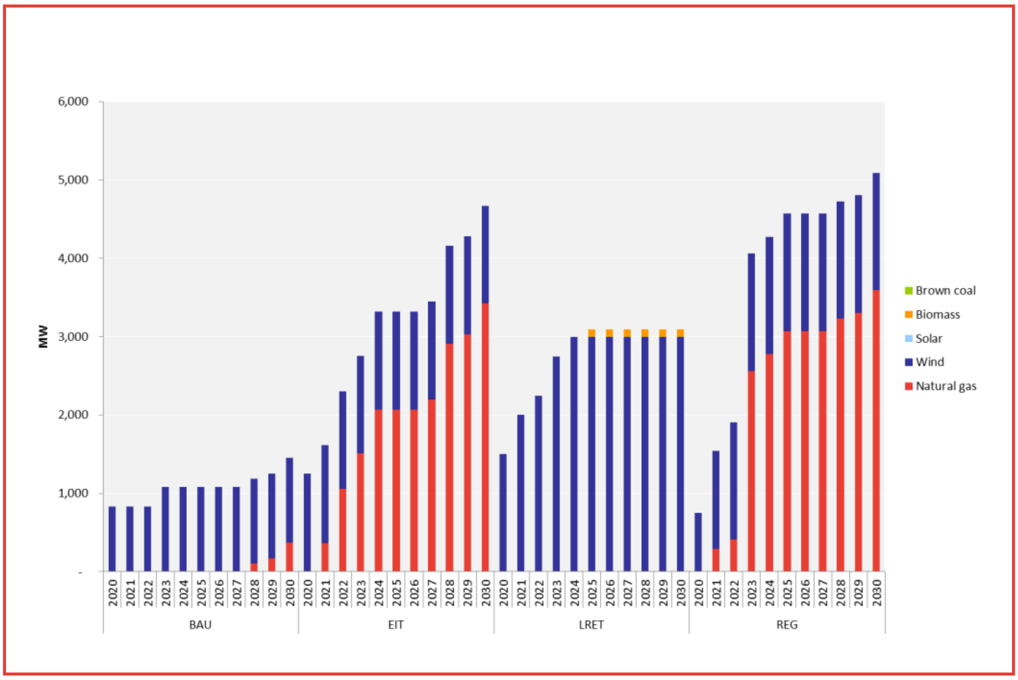
Figure 78: Output: 2020-2030



Source: Frontier Economics

VIC - Investment

Figure 79: Investment: 2020-2030

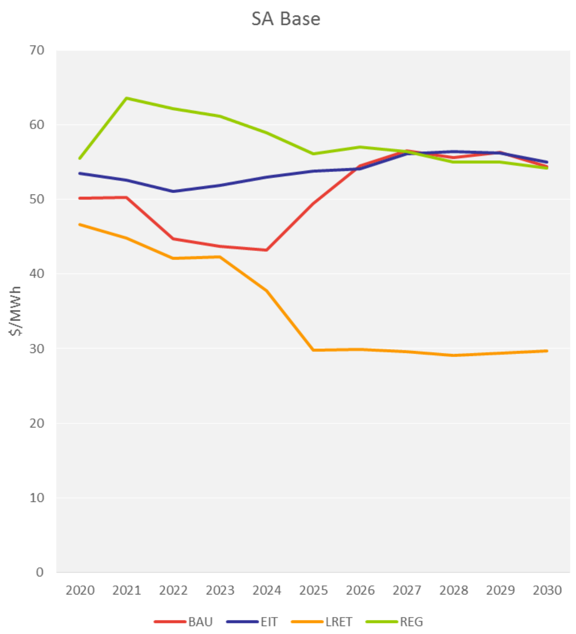


Source: Frontier Economics

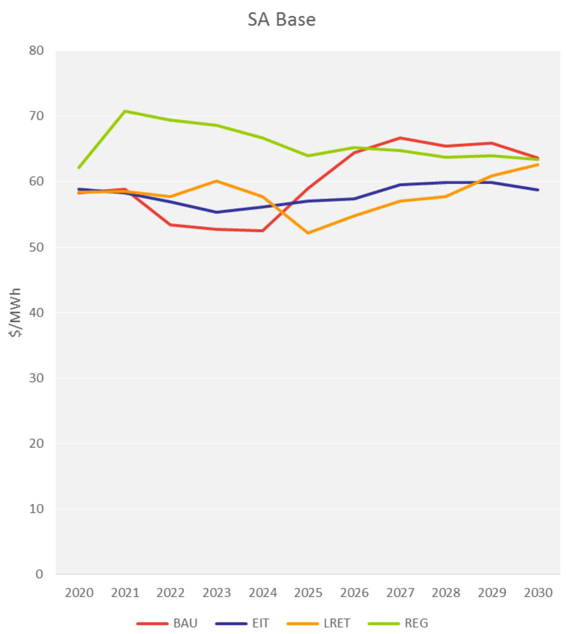
SA - Pool price impacts

Figure 80: Pool prices: 2020-2030

Without RET levy



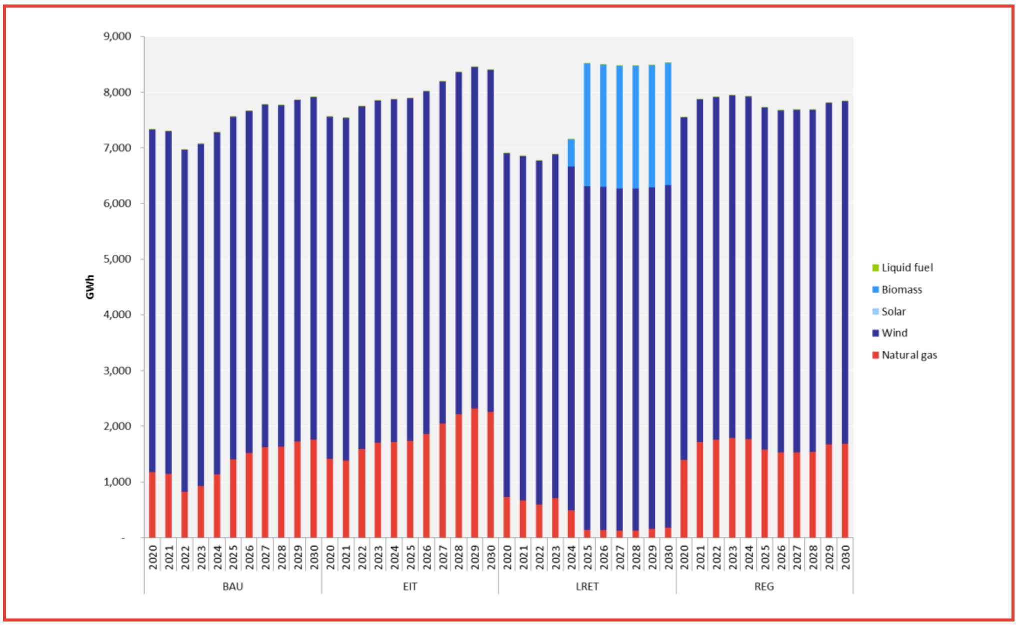
With RET levy



Source: Frontier Economics

SA - Output

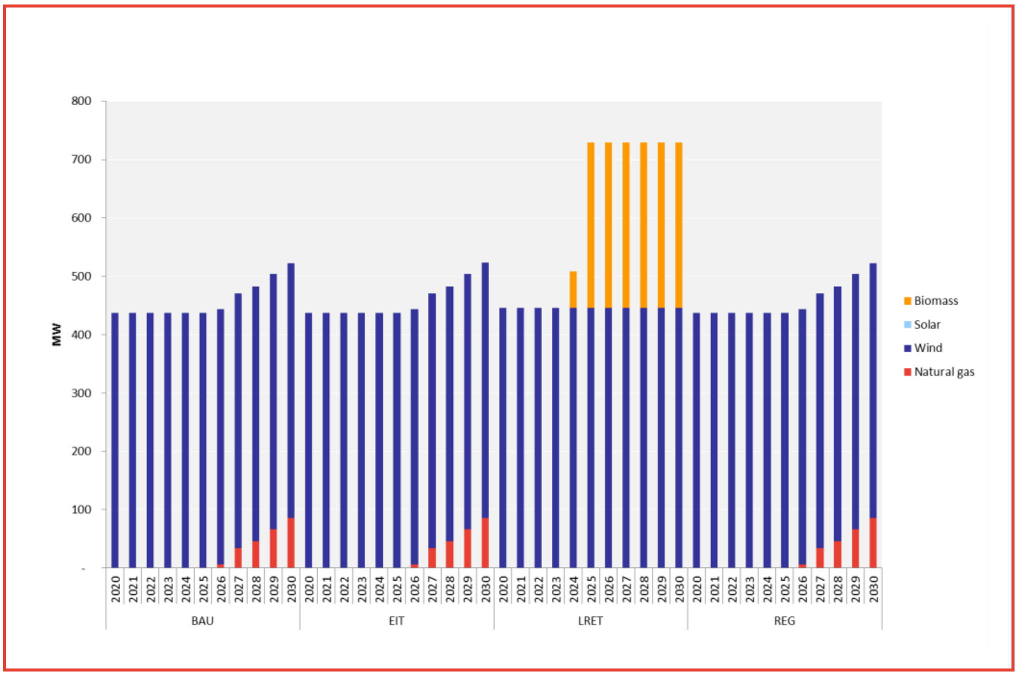
Figure 81: Output: 2020-2030



Source: Frontier Economics

SA - Investment

Figure 82: Investment: 2020-2030



Source: Frontier Economics

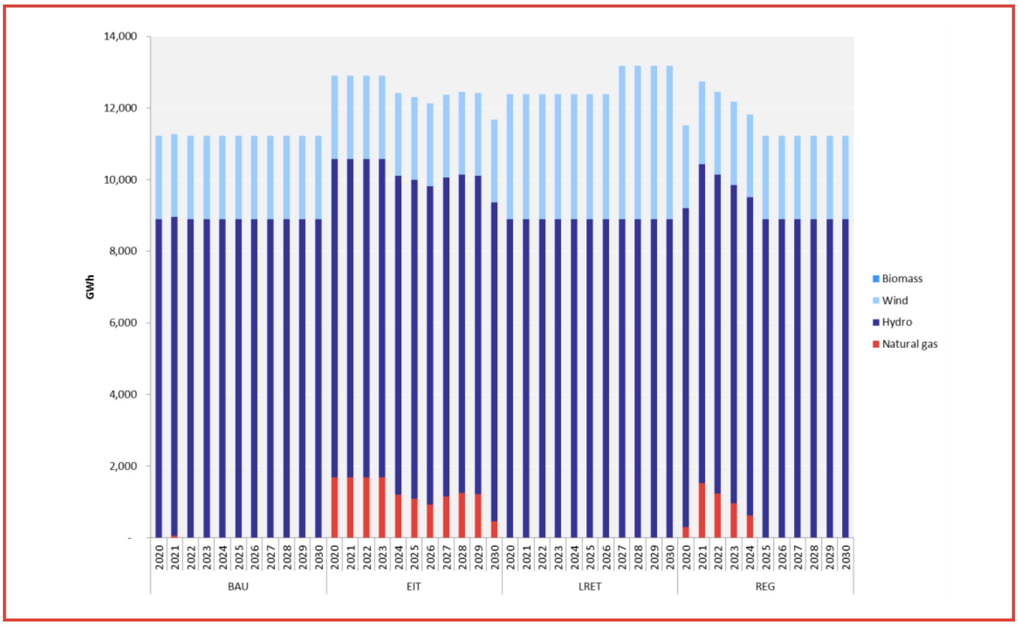
TAS - Pool price impacts

Figure 83: Pool prices: 2020-2030

Source: Frontier Economics

TAS - Output

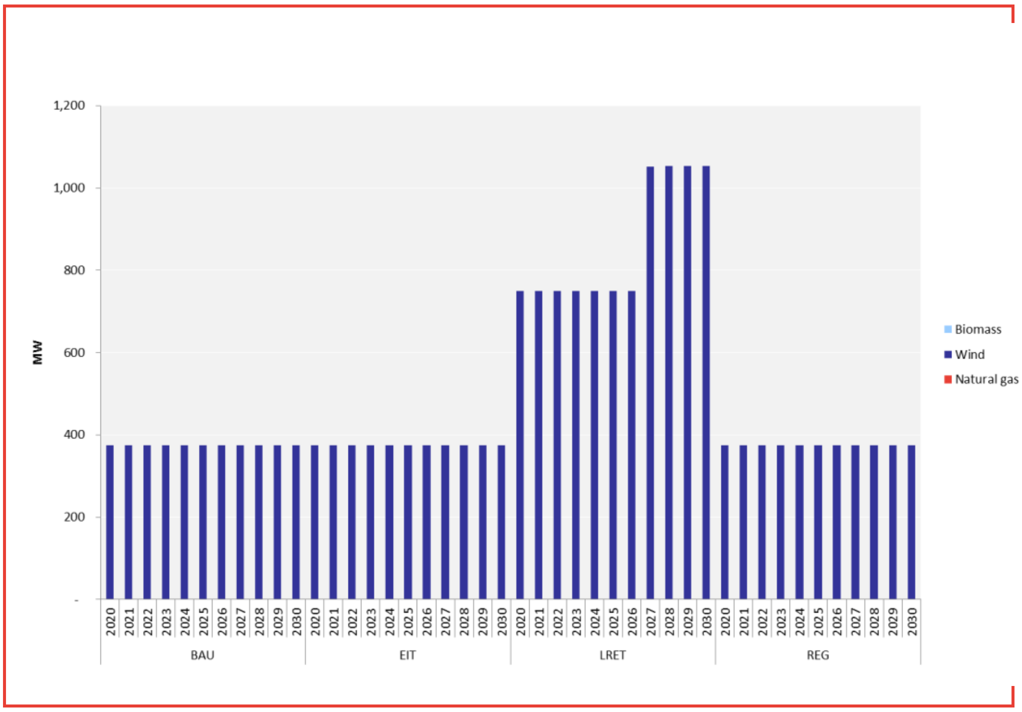
Figure 84: Output: 2020-2030



Source: Frontier Economics

TAS - Investment

Figure 85: Investment: 2020-2030



Source: Frontier Economics

Results: Hazelwood retirement

Glossary

This section details the acronyms used in the report

AEMO	Australian Electricity Market Operator
BREE	Bureau of Resources and Energy Economics (now the Office of the Chief Economist – Department of Industry)
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CER	Clean Energy Regulator
COAG	Council of Australian Governments
EIT	Emissions Intensity Target
EITEI	Emissions intensive trade exposed industries
EOR	Expected outage rate
FOM	Fixed operating and maintenance costs
GJ	Gigajoule
GT	Generator terminal
GWh	Gigawatt hours
IMF	International Monetary Fund
IMO	Independent Market Operator of the SWIS
IPART	Independent Pricing and Regulatory Tribunal
LGC	Large-scale Generation Certificates
LNG	Liquid Natural Gas
LRET	Large-scale Renewable Energy Target
LRMC	Long run marginal cost
MW	Megawatt
MWh	Megawatt hour
NEFR	National Electricity Forecast Report
NEM	National Electricity Market
NTNDP	National Transmission Network Development Plan
O&M	Operating and Maintenance

OCGT	Open Cycle Gas Turbine
PV	Photovoltaic (solar)
RET	Renewable Energy Target
SO	Sent-out
SRES	Small-scale Renewable Energy Scheme
SRMC	Short run marginal cost
SWIS	South West Interconnected System
VOM	Variable operating and maintenance
WACC	Weighted average cost of capital
WEM	Wholesale Energy Market

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