Massively expanding behind-the-meter battery-backed photovoltaics (PV) on business properties

A policy proposal that offers a rare combination of potentially huge upside and easily managed downside risk

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Executive summary

This paper examines policy to encourage the uptake of large-scale battery-backed rooftop solar PV on the premises of Australia's commercial and industrial properties. The idea it examines is turning commercial and industrial properties located in and around Australia's cities, towns, villages and farms into major sources of electricity generation and storage, for supply to the grid.

The idea is motivated by the urgent need to expand emission-free electricity to replace coal generation that is scheduled to close over the coming decade, and in a way that presents little or no social and local environmental costs. Such social and local environmental costs are now plainly evident in some farmed wind and solar proposals and with their attendant transmission expansion requirement.

The "Business Power" policy discussed in this paper considers the merit of encouraging the development of large-scale battery-backed rooftop PV, capable of behind-the-meter trading in the electricity wholesale market, in supplying electricity to the grid. Suitably developed, this resource might be expected to supply at least a quarter of the electrical energy consumed in Australia each year, and much of that supply will occur when the sun is not shining.

The proposal that is assessed here involves floor prices for electricity that is fed into the grid at certain times of the day from rooftop solar PV and from behind-the-meter batteries:

- A "solar feed-in floor price" is proposed for feed-in before 11am and after 2pm.
- A "battery discharge floor price" is proposed for feed-in between 6pm and 9pm.

Such combination is likely to result in more electricity supplied to the grid before 11am and after 2pm, more electricity storage from rooftop PV between 11am and 2pm and more electricity supply to the grid between 6pm and 9pm, when the stored electricity is discharged to the grid.

The assessment of these proposals examines financial viability, policy cost as a proportion of revenues and costs, implicit greenhouse gas abatement cost, policy support yield, the cost-effectiveness of battery backed rooftop solar and the impact on electricity prices. The analysis concludes that a solar feed-in floor price of $100/MWh and battery discharge floor price of $200/MWh is likely to deliver financially viable battery-backed solar PV. While such floor prices would at times be higher than wholesale prices, it will deliver greenhouse gas abatement at a cost that is well below the levels determined pursuant to guidelines from the Ministerial Council on Energy.

The analysis also suggests this model of battery-backed rooftop solar is likely to be cost-effective compared to alternatives (recognising that such cost comparisons are nonetheless fraught) and that Business Power has a prospect of paying for itself in wholesale and retail price reductions. This might be expected even after taking account of the recovery of policy costs.

The analysis also finds that Business Power is likely to be more efficient than the existing certificate scheme (which is in the process of being phased out) in expanding emission-free electricity. Unlike existing policy, Business Power also provides incentives for behind-the-meter storage expansion.

Suggested implementation arrangements include establishing a “Business Power Authority” to disburse Business Power floor price payments and to recover the cost of this from consumers via regulated distribution network service providers. An alternative would be to recover some or all of the policy cost from taxpayers. There is no compelling economic reasoning to prefer one rather than the other.

There are many uncertainties here: are the floor prices too high or too low; will network service providers seek to support or undermine this; will the policy reduce electricity prices; will customers be attracted to it? Perhaps some uncertainties might be reduced through further study. However, there are many uncertainties in policy and technology. Trying to narrow such uncertainty through apparently sophisticated modelling often misdirects more than it enlightens. The most valuable learning here, as with many other energy policy ideas, will come by doing.

Policy makers should rightly be wary of unintended consequences and governments’ track record of picking losers. In this regard, it is notable that Business Power has a particular attraction, relative to most other energy policies, that customer and taxpayer risks can easily be managed by closing the scheme to new participants, if it becomes evident that the policy is not succeeding as hoped. Learning by doing will be inexpensive.

The cautious conclusions that characterise the analysis in this document should therefore not be misconstrued as equivocation as to the merits of Business Power. To the contrary, while success is not guaranteed, there is good reason to be optimistic, and that little will be lost by trying. Few energy policies offer this combination of potentially huge upside and easily managed downside risk. Policy makers, market participants and interest groups are encouraged to lose no time in their detailed consideration of this.

1. Introduction

This discussion paper explores the possibility of policy to encourage the uptake of large-scale battery-backed rooftop solar PV on the premises of Australia's commercial and industrial properties, not just for self-consumption but also in order to provide a major new source of firmed[1] zero-emission electricity to the grid.

While rooftop PV on commercial and industrial premises is becoming popular, policy currently encourages this to be sized for self-consumption, and there is no policy applicable to the industrial and commercial sector, to encourage PV production to be stored for later use, and for dispatch into the interconnected electricity grid.

The purpose of this document is to explore ideas and present analysis of them, for discussion. If these ideas find a receptive audience, more work will need to be done to consider their implementation. There is no reason that Business Power should necessarily be Australian Government rather than jurisdiction government policy, but the working assumption here is Australian Government policy. In addition, the analysis in this paper focusses on the National Electricity Market covering the south and eastern states. The conclusions of this analysis are likely to apply also in Western Australia and the Northern Territory, though feed-in floor prices will need to be tuned for their circumstances.

1.1 Context

The owners of 10 coal-fired power stations have issued notice of their intention to close them by 2040[2]. These power stations produced 87 TWh in 2023 of which 41 TWh in New South Wales (NSW), 23 TWh in Victoria and 23 TWh in Queensland.

The Australian Energy Market Operator (AEMO), in its latest Integrated System Plan (ISP) said it expects that all but a few coal generators will be closed by 2035, and all will be closed by 2040. AEMO's forecast requires replacing almost twice as much production as required to meet owners' announced closure dates, over the coming decade.

Market participants are not proposing to replace existing coal production with new coal, or other low marginal-cost base-load capable generation such as nuclear. Some gas generation capacity expansion is expected, but AEMO suggests that the share of electricity sourced from gas, measured annually, will be largely unchanged over the coming decade and when required at full capability during weather-dependent

[1] The term "firm" has found common use in the electricity industry to describe outcomes in which the variability of wind and solar generation is compensated for either through the addition of dispatchable energy or by storing variable renewable electricity for later consumption. There is no common understanding of just what, exactly, would qualify as "firmed". In this paper we refer to it as storing solar each day, particularly production between 11am and 2pm and then making that stored electricity available to the grid between 6pm and 9pm.

[2] https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information

renewable droughts, it is questionable whether there would be sufficient gas supply and gas pipeline and storage capacity to meet such infrequent demand. AEMO (and market participants) expect that renewable generation from farmed wind, solar PV and rooftop solar PV will dominate new supply.

Looking backwards, over the last four years to 2023, renewable generation grew on average by 7.8 TWh per year of which 2.2 TWh from farmed solar, 2.5 TWh from wind and 3.1 TWh from rooftop PV. Within the rooftop PV category, over this period rooftop systems larger than 15 kW but less than 100 kW and so mainly on commercial and industrial roofs, have grown on average by 500 MW per year, equivalent to approximately 1.4 TWh per annum while those smaller than 15 kW (mainly house household roofs) have grown on average by 2,500 MW per year, equivalent to approximately 4TWh per annum.

Nearly a decade ago, the Clean Energy Finance Corporation estimated rooftop solar production potential in 2016 of 38 TWh per year in commercial and industrial zones[3]. This is equivalent to a little under one quarter of end-use electrical demand in 2016. The CEFC also said that this was likely to underestimate the actual potential. Increases in rooftop space and in PV panel efficiency are also likely to substantially increase the CEFC's 2016 estimate.

In Victoria, electricity distributors Citipower/Powercor/United have estimated that Victoria alone has 56.3 TWh of rooftop solar potential, of which only 7% had been developed and of which only a small proportion was on the roofs of factories, warehouses and similar commercial and industrial buildings. By comparison the total end-use demand for electricity in Victoria in 2023 was 47 TWh. These distributors' therefore estimate that rooftop PV annual electricity production potential is more than the total end-use demand for electricity in Victoria in 2023

The future rate of renewable electricity expansion and the extent to which this is from farmed wind and solar rather than rooftop PV is far from certain. AEMO's most recent ISP predicts that more rooftop PV capacity will be added than either farmed solar or wind capacity. Their prediction of farmed wind and solar is however predicated on massive transmission capacity expansion, and therefore subject to the objections in relation to competing uses of land as well as the challenges of obtaining environmental approval for the development. All the transmission projects that AEMO has instructed for development are running far behind schedule and the latest cost estimates are several multiples of initial estimates. Transmission expansion – particularly of ultra-high voltage interconnectors - is encountering fierce opposition from affected communities.

Taken together, the demand for new (clean) generation to replace coal generation and evidence of challenges in the expansion of consequent transmission, suggests that

[3] https://www.cefc.com.au/insights/market-reports/how-much-rooftop-solar-can-be-installed-in-australia/

opportunities for electricity production (and storage) much closer to customers loads is likely to be particularly valuable.

The Australian Government has introduced a Capacity Investment Scheme (CIS) that seeks to expand renewable generation by 23 GW over the four years to 2027[4]. While this scheme does not specifically exclude behind-the-meter generation and storage, it is not likely to be useful to the expansion of rooftop PV and behind-the-meter storage in the commercial and industrial market segment. This is because the CIS will require that behind-the-meter generation and storage be aggregated and offered in large chunks, in competition with large scale front-of-meter generation and storage projects that do not need to be aggregated. The large transaction costs of such aggregation means that behind-the-meter opportunities cannot be expected to compete effectively in the CIS.

Furthermore, the Renewable Energy Target certificate scheme currently available for rooftop PV installations smaller than 100 kW is gradually phasing down to zero in 2030. Therefore, existing policy is tilting against what might be one of the easiest and most efficient sources of firmed clean energy, that can be delivered quickly.

The failure to prioritise decentralised production is also at odds with policy and developments in other countries/regions with similar solar potential and similarly ambitious decarbonisation objectives. For example, in Italy, a renewable energy communities decree[5] enacted in 2023 prioritises decentralised solar and storage particularly on rooftops. In Germany, rooftop solar accounted for 72% of PV expansion in 2023 and in Europe the Rooftop Solar Standard which currently applies to new non-residential and public buildings and to existing non-residential builds is expected to double rooftop solar capacity over the next four years[6].

In this context, this paper explores the merits of policy support for either rooftop PV, or behind-the-meter battery or the combination ("battery-backed solar") in the industrial and commercial premises (factories, warehouses, large farm sheds, shopping centres, offices, covered parking lots and so on). These are located mainly on the fringes of cities, towns, villages and on farms.

This policy – "Business Power" – encourages rooftop PV (and storage) to be sized so as to maximise the export of electricity to the grid. By contrast existing policy encourages rooftop solar sized for self-consumption, and there is currently no policy support for behind-the-meter storage.

[4] https://www.dcceew.gov.au/energy/renewable/capacity-investment-scheme

[5] https://cms.law/en/ita/publication/green-light-from-the-eu-for-the-italian-cer-renewable-energy-communities-decree

[6] https://www.solarpowereurope.org/press-releases/eu-rooftop-solar-standard-alone-could-solar-power-56-million-homes

1.2 Layout

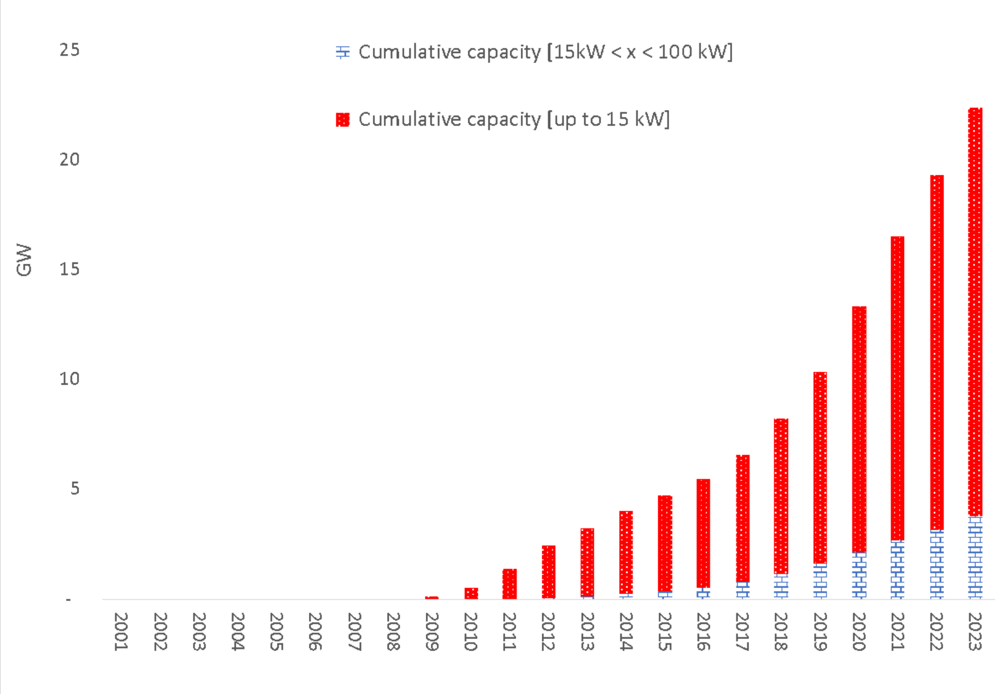
The second section provides a history of rooftop PV outcomes and of the policy support that the sector has enjoyed. Rooftop PV is one of Australia's energy policy success stories and a reasonable review of that is important in setting the context to the Business Power proposal. Section Three examines the economics of solar and storage. It is widely known that solar PV costs have declined steeply over the last 20 years and that (electrochemical) battery costs are declining rapidly too. Why then is policy support needed? This section answers this question. Section Four defines and then evaluates Business Power policy options and Section Five discusses the analysis and other issues that arise from it. Section Six briefly examines implementation issues.

2. A history of rooftop PV outcomes and policy in Australia

Australia already has, per capita, the highest penetration of rooftop PV of any country[7]. In 2023 rooftop PV provided 11% of the electricity produced in the National Electricity Market (NEM). By comparison wind farms provided 13%, hydro 7% and farmed (ground based) solar 7%[8]. This section presents relevant information about rooftop PV outcomes and about the policy support that has contributed to those outcomes.

Figure 1 shows the cumulative installed PV capacity to end 2023. It shows total capacity of 23 GW by end 2023 of which 7GW in rooftop systems bigger than 15 kW and smaller than 100 kW on commercial and industrial customers' rooftops, and the remaining 18 GW in systems smaller than 15 kW, almost all of which are on household roofs. Larger systems started to grow later than household systems but are now an increasing proportion of the total.

Figure 1. Cumulative installed Australian rooftop PV capacity (GW) to end 2023



Source: Data from Clean Energy Regulator, author's analysis.

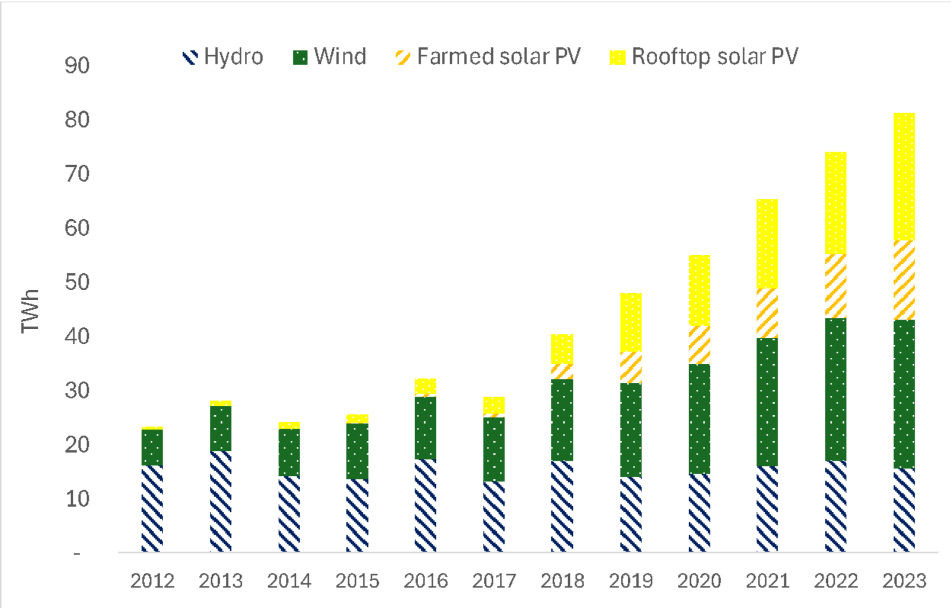
The mix of rooftop solar on household rooftops and business premises rooftops in the Australia (4 to 1) can be compared with that in the EU (1 to 1.5)[9]. So, rooftop solar on business premises in Australia is just 1/6th as large relative to households in Australia, it is on business premises relative to households in Europe. The relative proportion of

[7] https://iea-pvps.org/wp-content/uploads/2023/04/IEA_PVPS_Snapshot_2023.pdf
[8] https://www.v-nem.org
[9] https://www.solarpowereurope.org/insights/outlooks/eu-market-outlook-for-solar-power-2023-2027/detail

rooftop to ground-mounted solar in Australia (1.5 to1) is however not too dissimilar to this ratio in Europe (2 to 1)[10].

Figure 2 presents data on the average annual production (MW/year) of renewable electricity in the NEM, distinguishing hydro, wind, large scale (farmed) solar and small scale (mainly rooftop) solar. The more rapid expansion of rooftop PV relative to the other three is evident from this.

Figure 2. Electricity production (TWh per year) from renewable sources in the NEM, 2012 to 2023

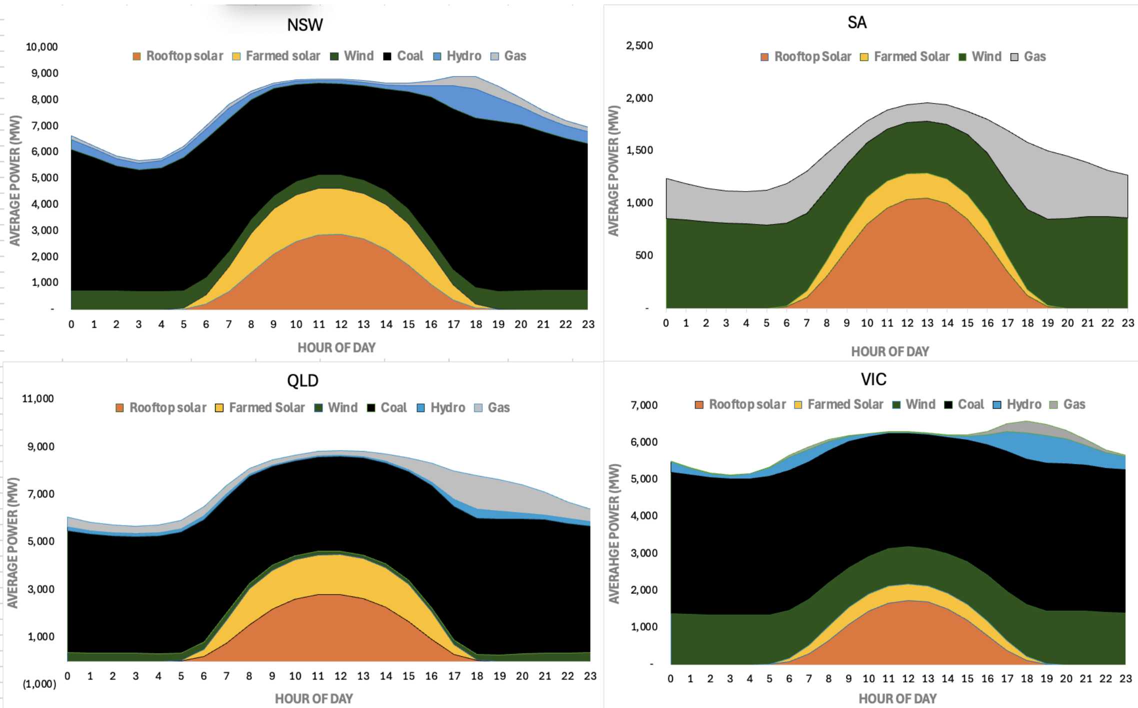


Source: www.v-nem.org

Figure 3 shows the average hour-of-day profile of electricity production of rooftop PV in the four mainland states of Australia compared to the other main sources, in 2023. It shows that, proportionately, rooftop PV is bigger in South Australia than the other states where, in the middle of the day, rooftop PV accounts for around a half of electricity production.

[10] https://www.solarpowereurope.org/press-releases/eu-rooftop-solar-standard-alone-could-solar-power-56-million-homes

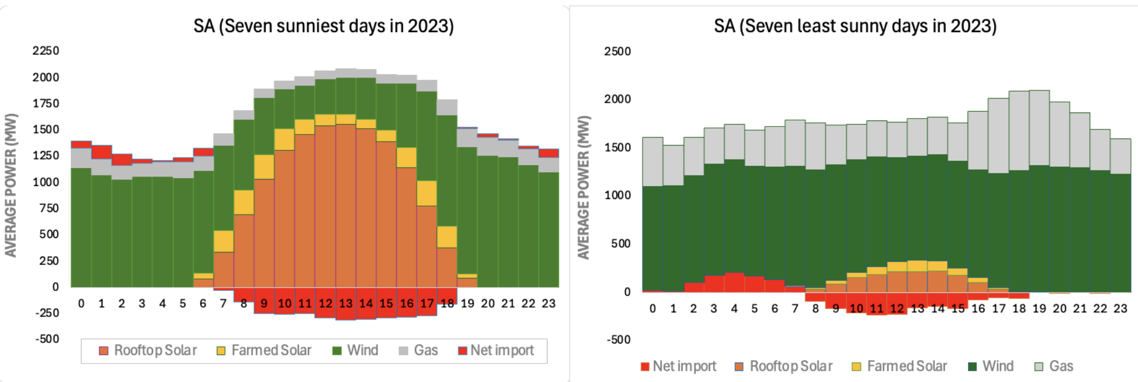
Figure 3. Average power (MW) by fuel type by hour of day in 2023 in mainland NEM regions



Source: www.v-nem.org, author's analysis

Figure 4 narrows the focus to the seven sunniest days (left hand chart) and seven least sunny days in South Australia in 2023 to show the average hourly production by fuel type. On the sunniest days, rooftop PV provides most of the energy between 7am and 5pm, gas generation was reduced to a small sliver (which was constrained on) and reasonable exports occurred over much of the day. On the least sunny day, gas plays a bigger role, but wind generation a much bigger role and SA was again exporting during the day, albeit less than on the sunniest days. In fact, in 2023, there were 34 five-minute time intervals in which rooftop PV production exceeded South Australia's entire electrical demand. The average excess at these times (15 MW) was exported.

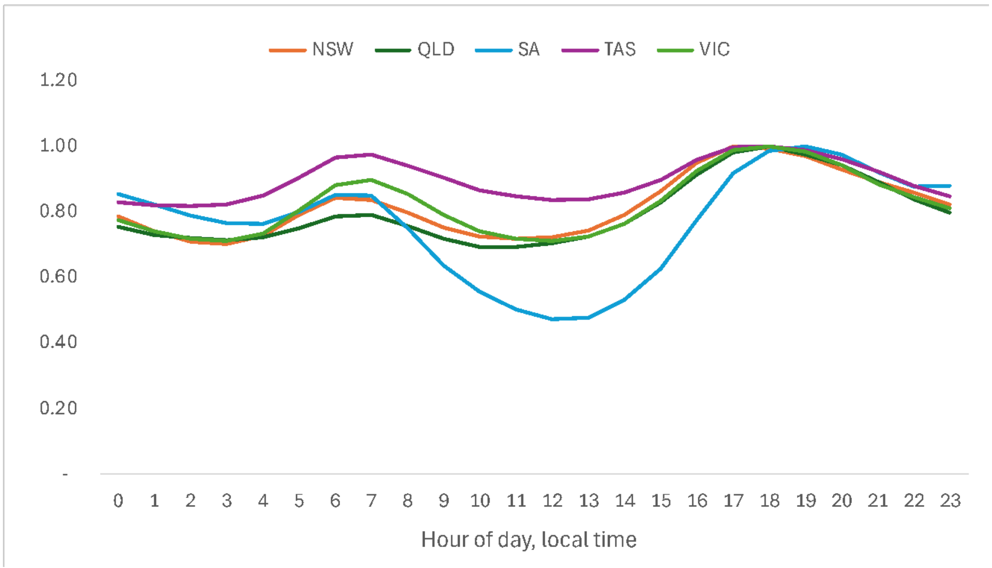
Figure 4. Average power (MW) by fuel type by hour of day for the seven sunniest days (left hand) and seven least sunny days (right hand) in South Australia in 2023



Source: www.v-nem.org, author's analysis.

The previous charts have shown the pattern of production across the day. Another perspective is provided by looking at the time profile of demand as measured on the transmission system (rooftop solar is almost always fully absorbed on the distribution system). Figure 5 shows the average demand by hour of day normalised relative to the peak demand, for the five NEM regions in 2023. Comparing Tasmania and South Australia, the effect of the difference in the state with the lowest and highest market share of rooftop PV is evident in the much greater dip in demand as measured on the transmission system in South Australia during the middle of the day.

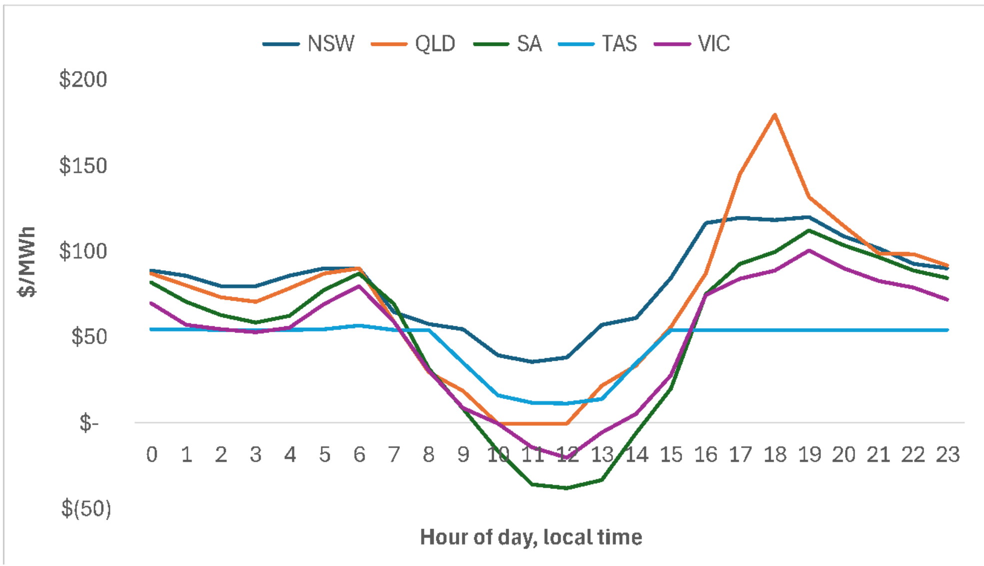
Figure 5. Normalised average hourly demand measured on the transmission system in mainland NEM region by hour of day in 2023



Source: www.v-nem.org, author's analysis.

How has rooftop PV affected prices in the mandatory wholesale market? Econometric studies can shed light on this at points in time, but the effect changes over time depending on many factors. However, the picture is sufficiently stark as to confidently conclude that rooftop solar is likely to have played a big role in reducing wholesale prices so far. Figure 6 shows the average of the median of the 12 five-minute wholesale (spot) electricity market price by hour of day in 2023 in the mainland NEM regions. It shows that in South Australia this hourly price was negative between 9.30am and 2.30pm. In Victoria it was negative between 10.30am and 1.30pm and in Queensland and NSW it was small or close to zero in the hours either side of the middle of the day. The large supply of rooftop PV in the middle of the day is likely to have been the main factor in explaining this outcome.

Figure 6. Average of the median of the 12 five-minute spot prices by hour of day in each NEM region in 2023

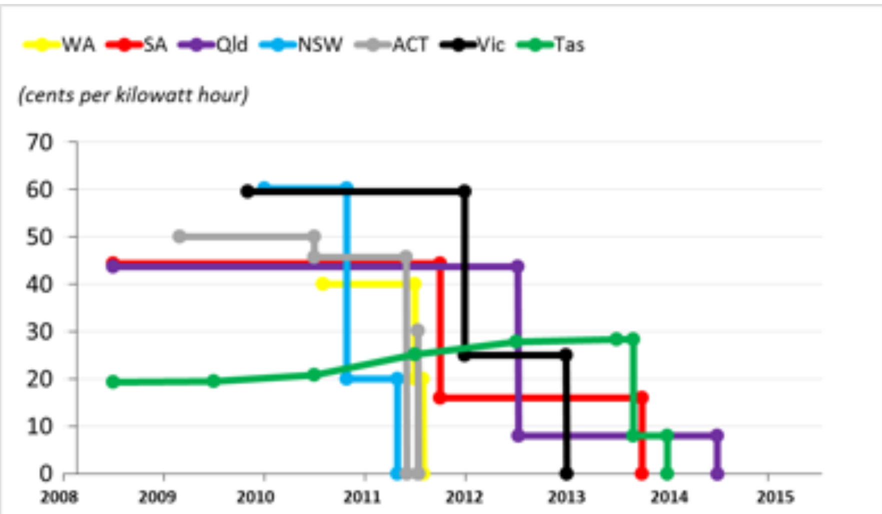


Source: www.v-nem.org, author's analysis.

2.1 Policy

Australia's rooftop PV outcomes have been supported by policy by state governments and more so through federal government renewable electricity policy. Figure 7 shows the premium feed-in tariffs (cents per kWh) available to households for the export of rooftop PV to the grid (or for total rooftop solar generation as was the case in NSW) offered by the seven jurisdictional governments that offered them. It shows that by June 2015 premium feed-in rates were no longer available in any jurisdiction.

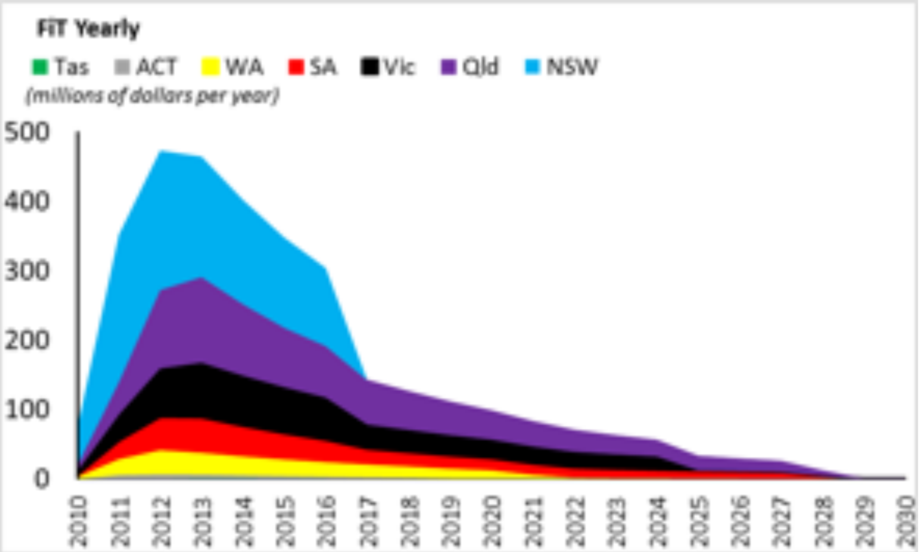
Figure 7. Jurisdiction government rooftop solar feed-in rates



Source: Mountain B.R and Szuster, P. 2015 "Solar, Solar Everywhere: Opportunities and Challenges for Australia's Rooftop PV Systems". IEEE Power and Energy, Vol 13, Issue 4, p.53-60.

The cost of these feed-in tariff policies were recovered mainly from consumers through regulated charges applied to all households and in some cases to all customers. Figure 8 shows the estimated annual cost (2014 dollars) of these policies in each jurisdiction. Mountain and Szuster (2015) estimate the aggregate value of these subsidies to be $4.5bn (2014 dollars).

Figure 8. Jurisdiction government mandated premium feed-in tariff aggregate payments from 2010 to 2030 ($million, 2014)

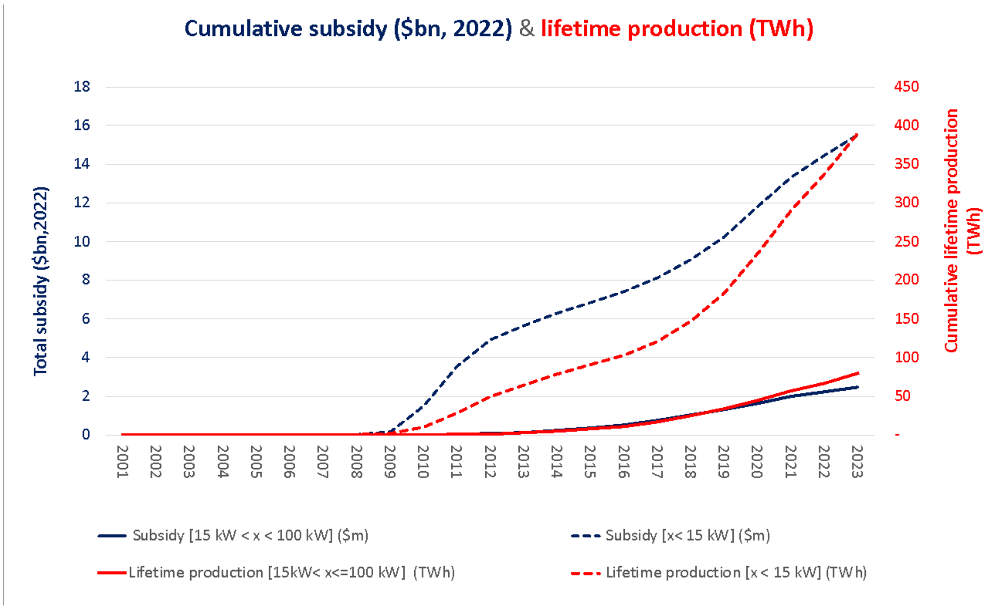


Source: Mountain B.R and Szuster, P. 2015 “Solar, Solar Everywhere: Opportunities and Challenges for Australia's Rooftop PV Systems”. IEEE Power and Energy, Vol 13, Issue 4, p.53-60.

Much greater policy support for rooftop PV (about 4 times more) has been provided through federal policy than through state governments. Both state and federal policy costs have been paid by consumers (not taxpayers) through regulated charges in the case of feed-in tariffs or through certificate obligations that retailers are likely to have fully recovered from their customers.

Figure 9 shows our estimate of the total value of the subsides (left hand axis) and life-time electricity production (right hand axis) of rooftop PV systems smaller than 15 kW (the dotted lines) and rooftop PV systems between 15 kW and 100 kW (the solid lines). The cumulative total lifetime production (TWh) from the subsidised systems is shown on the right-hand axis. The chart shows that by 2023, the sub-15kW systems will have lifetime production of just under 400 TWh and that just under $16bn of subsidy has been paid for this. For the 15 to 100 kW systems, lifetime production for the systems installed by the end of 2023 is about 75 TWh and a little over $2bn subsidy has been paid for this. The much lower subsidy for the 15-100 kW systems is explained in Figure 10.

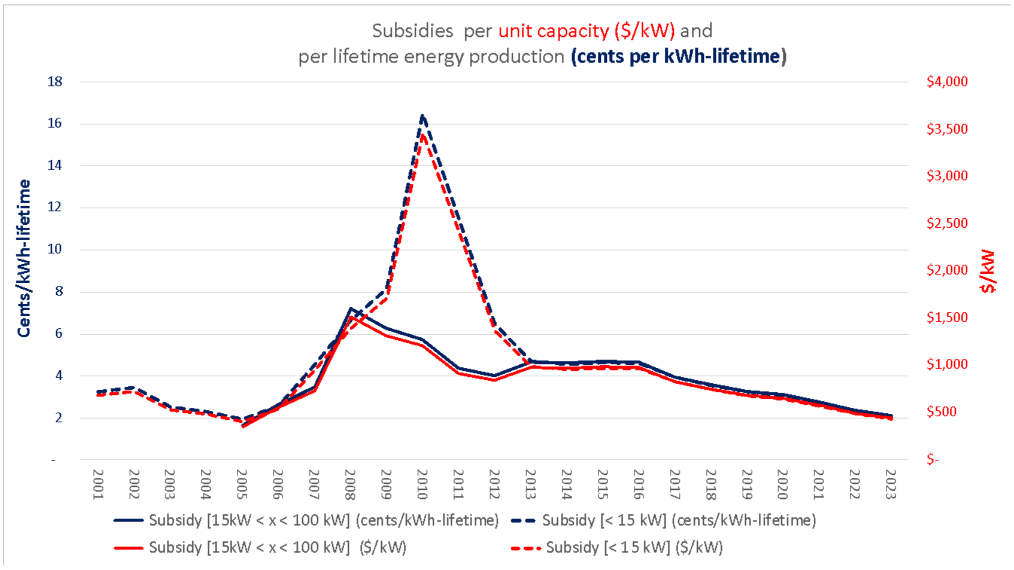
Figure 9. Cumulative federal government policy support and lifetime production of rooftop PV ($million, TWh 2022)



Source: Dated supplied by Clean Energy Regulator, author's analysis.

Figure 10 shows our estimate of the value of the certificate subsidy per kWh-life (coloured in blue and measured on left hand axis) and per kW of additional capacity (coloured in red and measured on right hand axis) of rooftop PV systems smaller than 15 kW (dotted) and between 15 kW and 100 kW (solid). It shows that by 2023, the value of the subsidy had become 2 cents per kWh-lifetime or expressed per kW, $500/kW. The surge in the subsidy for sub 15 kW systems between 2009 and 2013 was the result of an explicit subsidy push that multiplied the eligible certificates by a factor 5 times their base level. As the chart shows, this peaked in 2010 but then quickly dissipated.

Figure 10. Rooftop PV subsidy ($ per kW) and (cents per kWh-lifetime)



Source: Dated supplied by Clean Energy Regulator, author's analysis.

In summary, the relative lag in the development of rooftop solar in the business sector, relative to households might be explained in part by business-scale users never being eligible for the super-high federal or state incentives; business electricity prices being somewhat lower than households thus reducing the savings available from self-generation and businesses less subject able to respond to the impulse for early adoption for environmental action that motivated many early household installers.

3. The economics of behind-the-meter electricity production and storage: Is policy needed?

If the model of Business Power explored in this paper is financially attractive to investors and customers there is no need to consider policy support for it. It is therefore necessary first to establish the economics to demonstrate that support is likely to be needed if there is a desire to rapidly expand grid-oriented battery-back solar. If policy support is needed (and the first part of this section concludes it is) then it is necessary also to make the case for considering policy support: why not leave decisions on behind-the-meter solar and storage to the market? The last part of this section considers that.

3.1 Rooftop PV

We start by estimating the levelised cost of electricity (LCOE) of rooftop PV mounted on factory roofs. The method and assumptions used in the estimate are set out in Appendix A. LCOE measures the average cost of production, taking account of the opportunity cost of money at the assumed discount rate.

Table 1 shows our estimate of the LCOE of Business Power ranging between $81 and $99/MWh in the five regions of the NEM based on contemporary cost estimates (Appendix A for details). The state variation is explained by differences in the extent of solar irradiance. This estimate does not account for the subsidies available under the Australian Government's Renewable Energy Target (RET) policy[11]. The after-subsidy LCOE is likely to be about $10-$15/MWh lower.

Table 1. Levelised cost of electricity of rooftop solar PV ($/MWh)

	NSW	QLD	SA	TAS	VIC
Levelised cost of electricity (S/MWh)	$88	$81	$81	$99	$95

This LCOE is below the variable consumption rate that most customers in the commercial and industrial sector pay for grid-supplied electricity. This suggests that self-consumption will reduce electricity bills and so rooftop PV sized for self-consumption is likely to continue to grow even if existing policy support is ended.

What about the economics of rooftop PV focussed on the export of electricity to the grid? Comparing the average cost with the price received for rooftop PV grid sales informs this. Table 2 shows the volume-weighted average spot price value of rooftop PV for the last six full years, and the first four months of 2024 (Appendix B presents the methodology for the calculation). The table shows that the weighted-average spot price value over this period ranges between $31 and $68 per MWh (in South Australia and NSW respectively). Excluding 2022 (during which period wholesale prices were heavily affected by the Russian invasion of Ukraine and the consequential increase in wholesale market prices)

[11] https://cer.gov.au/schemes/renewable-energy-target

the spot price value of rooftop solar has declined over the period. This is consistent with the impact of rooftop solar on wholesale prices as shown in Figure 6 and discussed earlier. Comparing the spot price value of rooftop solar in Table 2 with the LCOE in Table 1, it is evident that selling rooftop PV electricity into the wholesale market at the spot price is unlikely to be profitable. Of course, in practice very little rooftop PV that retailers will buy from customers is likely to be transacted at the spot price. Instead, most will be priced at a flat feed-in rate that is likely to be fixed for reasonably long periods (a year or more). Such rates might in some cases be more attractive than volume-weighted spot prices, but this is unlikely to be such as to make up the gap to the LCOE. Flat feed-in rates may come to reflect volume-weighted spot prices albeit lagged.

Table 2. Volume-weighted average spot price of rooftop solar ($/MWh)

	Volume-weighted average spot price value of rooftop PV ($/MWh)				
	NSW	**QLD**	**SA**	**TAS**	**VIC**
2018	$84	$74	$91	$83	$99
2019	$77	$56	$43	$94	$104
2020	$65	$30	$25	$44	$43
2021	$41	$38	$25	$29	$14
2022	$103	$93	$51	$95	$50
2023	$47	$24	$2	$40	$ (4)
To 30 April 2024	$56	$51	$1	$45	$18
Average	$68	$52	$31	$61	$46

3.2 Behind-the-meter batteries

Are behind-the-meter batteries financially viable? To answer this we start by establishing the LCOE of such batteries. We assume a two-hour battery (i.e. one able to discharge at its peak power rating for two hours). This is a common duration for behind-the-meter batteries in the commercial and industrial sector. Our estimate is $395/MWh (assuming the battery is charged from the grid) or $335/MWh assuming the battery is charged from behind-the-meter PV, based on the assumptions and method set out in Appendix D. Battery costs, like solar PV costs, have declined quickly and are expected to continue to do so, and so this estimate is likely to decline in future.

What income might the battery expect to receive in providing energy market arbitrage services[12]? This depends on the difference between the price paid for electricity to charge and the price received when discharging. In some cases, these prices might be known, for example if a battery charges at tariff rates for off-peak electricity and then provides electricity for self-consumption at peak tariff rates. However, the Business Power proposal

[12] Other possible sources of income include the provision of network support, demand tariff optimisation, the provision of ancillary services to the wholesale market. We do not focus on these sources of income in our evaluation since these are niche services with a relatively small demand, although network support might become more significant in future. We are focussed on the dominant service that batteries will be asked to provide: shifting energy from one time period to another.

is a battery or battery-backed solar focussed on export to the market, not only for self-consumption. Accordingly, the relevant calculation is of the price paid when charging from the grid and price received when discharging to the grid.

To estimate such prices, we use five-minute wholesale market prices. This implicitly assumes that even if the rooftop PV is charging the battery, such electricity is priced at its opportunity cost, which is assumed to be the five-minute spot market price of electricity.

In addition, we allow 6 cents per kWh as the network charge to be paid when withdrawing electricity from the grid. The actual price paid might vary from this but is more likely to be lower than higher than this, assuming distributors seek to encourage charging at times when solar production is plentiful (when batteries are most likely to be charging). The allowance for network costs when charging the battery is likely to under-state revenues to the extent that the battery is mostly charged from rooftop PV rather than the grid.

In addition, for these calculations it is necessary to make assumptions on how effectively the battery will be operated: to what extent will operators be able to charge at the cheapest price and discharge at the highest? This can’t be known with certainty. We have chosen two cases to illustrate the likely range:

- The first assumes that batteries are set to charge between 11am and 2pm when prices are most likely to be at their lowest (see Figure 6), and discharge between 6pm and 9pm when prices are most likely to be at their highest. This is repeated daily and the battery is assumed to be fully charged and discharged once each day.
- The second also assumes that the battery charges and discharges once each day but that the operator has perfect foresight of prices each day so that the battery is charged at the average of the cheapest prices each day with the total charge volume equal to the battery capacity and that it is fully discharged at the average of the most expensive prices each day. [13]

The results of this analysis (using five-minute prices over all days in the four years from 2020 to 2023 and then taking the average of the result) is shown in Table 3. Comparing the estimated LCOE of the battery ($395/MWh) with the gross trading margins suggests that a market-focused behind-the-meter battery is unlikely to be profitable if the battery is operated passively. Queensland comes the closest to profitable operation, but with trading margins that are still only about half as high as the LCOE. However, Table 3 also shows that in South Australia, NSW and Queensland a trading strategy assuming perfect foresight delivers trading margins above the levelised average cost and so on this measure, a grid-export oriented behind-the-meter battery is likely to be profitable.

[13] The average of the cheapest and most expensive is the average of the lowest 24 five minute and highest 24 five minute prices respectively each day.

Table 3. Average trading margin assuming passive operation and perfect foresight operation in each NEM region ($/MWh)

	Trading margins ($/MWh) using 2020-2023 spot prices				
Battery operating assumptions	**SA**	**VIC**	**NSW**	**QLD**	**TAS**
Passive: charge each day at average price between 11am & 2pm; discharge at average price between 6pm & 9pm	$160	$112	$107	$191	$34
Perfect foresight: charge each day at average of 24 lowest 5-minute prices; discharge at average of 24 highest 5-minute prices	$596	$275	$400	$709	$210

A passive trading strategy is likely to be too pessimistic about the ability of a competent battery operator to predict market prices. But perfect foresight is almost certainly too optimistic (if it was not then the consequent storage investment might be expected to compete the profits away in which case these trading margins would not be sustainable anyway). The conclusion from this is that, behind-the-meter storage oriented to grid-supply is likely to require policy support if it is to expand quickly.

3.3 Why does business power merit consideration?

Analysis in the next section considers the extent to policy support needed to make battery-backed solar financially attractive. Before proceeding there, it is helpful first to survey possible arguments for why such support might be considered. We suggest ten arguments:

1. First, with a few exceptions almost all electricity production in the NEM has relied on policy support for its development. This was true for coal generation (all developed by governments, albeit in a few cases in partnership with private investors/operators); almost all gas generation (invariably developed by government-owned corporations or where not supported through obligation schemes or government grants); all hydro capacity of any consequence (owned and developed by government-owned corporations); all pumped hydro (either developed by government-owned corporations and in the single case where not supported by grants and concessions); and almost all renewable generation and storage (whether in-front or behind customers' meters). It might be argued that it was a mistake that policies had driven such investment and that it should have been left to private investors and rivalrous processes to determine investment. It would be consistent with this argument to suggest that two wrongs don't make a right and so policy support for Business Power is not justified. However, this ignores the reality that there is cross-party and crossbench political support for continued intervention to support investment in electricity production. The reality is that such intervention will occur and so the issue to be grappled with in pursuit of customers' and the public's best interest, is the appropriate allocation of public resources recognising this reality.

2. Second there is cross-party and almost unanimous crossbench support in Australia's national and jurisdictional parliaments for policy to reduce greenhouse gas emissions. This consensus has developed over time and is now well established (albeit that differences remain on the urgency and the price that taxpayers and electricity consumers are willing to pay for reductions). Yet our governments have chosen not to charge emitters for their greenhouse gas emissions. This leaves no alternative other than to pursue policies that support the expansion of zero or low emission electricity production. Business Power is one such approach. This does not mean that Business Power is necessarily justified, but rather that its consideration and evaluation is justified on the grounds of its contribution to emission reductions.

3. Third, social and environmental costs associated with farmed wind and solar are, evidently, significant. Such costs are now a major political, social and economic concern. Business Power expands clean energy (and storage) in a way that presents no social or local environmental costs.

4. Fourth, the electricity market is a final-price mandatory spot market. When variable renewable generation is at or close to the last generating unit to be dispatched to meet demand, market prices can be close to zero or negative. All dispatched generators receive this price and all electricity sourced from the wholesale market pays this price. While producers and retailers can (and do) swap volatile 5-minute spot prices for longer term fixed prices, spot market outcomes ultimately drive such fixed prices. It might be suggested that market prices are signalling abundant supply in the middle of the day and hence it would be inappropriate to provide policy support to increase the supply of rooftop solar even if, backed by battery, some large part of that solar is likely to be stored for later use when the demand/supply balance is tighter. The counter to this argument is that almost all generation (and storage) capacity expansion in the NEM is supported by policy outside the wholesale market. As such, investors do not actually rely exclusively or even heavily on spot prices to motivate investment. In other words, the spot market has become a mechanism for scheduling and dispatch, not a mechanism that is expected to fully reward investment. To disregard this in considering the merit of Business Power will be to deny the possibility of investment opportunities that may have a higher policy yield than alternatives. Again, this is not to suggest that Business Power is necessarily deserving of policy support, but it does suggest it should be considered for this reason.

5. Fifth, Business Power is likely to result in a flatter (less peaky) load profile on both transmission and distribution networks. This is likely to defer or permanently avoid network augmentation expenditure[14], thus reducing network charges for all customers.

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[14] There are many examples around the various distribution grids. For one example see https://www.energex.com.au/__data/assets/pdf_file/0011/1079336/Pimpama-East-and-Stapylton-Notice-of-No-Non-Network-Options.pdf

6. Sixth, the flatter load profile that Business Power will deliver is likely to reduce demand-weighted average prices in regulated default offers, and in retailers' market offers.

7. Seventh, decentralisation of energy production pursuant to Business Power will reduce network losses on both distribution and transmission networks, thus reducing both grid-supplied energy charges and network charges.

8. Eighth, locating storage low down in the network, as Business Power does, is likely to reduce solar curtailment on feeders thus reducing energy losses and distribution network augmentation needs.

9. Ninth, Business Power is likely to facilitate the installation of EV chargers at places of work, so providing a co-benefit for the decarbonisation of private transport.

10. Tenth, Business Power can easily be closed to new participants. If the policy is not working as hoped it can be quickly turned off. This means taxpayers and consumers only face a small downside if Business Power turns out to be a loser.

4. Policy options and their evaluation

This section proposes options for policy support and then evaluates them. It works through policy design options and then evaluates the chosen options.

4.1 Policy support options

In the suite of possible policies, should support be considered only for behind-the-meter solar or only for behind-the-meter storage or only for battery-backed solar? Taking account of the central objective – the rapid replacement of coal generation scheduled to close – expanding both production and storage will be valuable. A valid case for policy support for all three exists and so we develop and evaluate options for all three in this sub-section.

Should policy support be paid out up-front at the time a facility is commissioned or over time based on production? Existing policy provides capital support for behind the meter production smaller than 100 kW or production support for systems bigger than this. The origin of the distinction lies largely in the administrative cost of administering a production subsidy. We suggest that with the evolution of the electricity market, specifically the very large role that rooftop solar plays (and is expected to continue to play), it has become more important to focus policy on production even for smaller systems. Production subsidies can ensure quality and reliability (the support is not collected unless the system produces) and with production support, it is possible to focus on the time of day that production will be most valuable.

Market prices suggest that policy support to increase supply between 11am and 2pm is not warranted. Although the market is still far from fully supplied at these times (even in South Australia), continued organic growth[15] of rooftop PV is likely to mean a market that is fully supplied for almost all days between 11am and 2pm in due course. Outside of these hours, the market is still not well supplied. Policy support for rooftop solar production outside the 11am to 2pm period can provide incentives for easterly and westerly panel orientation.

With respect to storage, the profile of hourly demand and market prices shows that storage discharge between 6pm and 9pm is more likely to be valuable than at other times of the day. Accordingly, we assess policy to support discharge between 6pm and 9pm.[16]

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[15] See for example: https://www.sunwiz.com.au/a-closer-look-at-some-record-breaking-commercial-pv-market-segments/?utm_campaign=a-closer-look-at-some-record-breaking-commercial-pv-market-segments&utm_medium=email&_hsenc=p2ANqtz-9yLvppEQWbC7nb3uTXNicxuuoTLw37gaxDNoQwOGHKcThxvBV0pCmAJ0UQgIzo1jHlb_7SENYHHL0b_GZJ6lenRIjpG6zNu7z4SmFOfooyUO5tdhc&_hsmi=316253875&utm_content=316253875&utm_source=hs_email

[16] There is no need to establish incentives to find the cheapest charge times: if exposed to spot prices, battery operators have a powerful incentive to find such times themselves.

Finally, what form should production support take: a fixed feed-in price or a floor price? Fixed (i.e. non time-varying) feed-in prices have been the norm for rooftop PV policy so far. Feed-in prices have the advantage of simplicity. However, it is now increasingly important that the operation of behind-the-meter production and storage faces similar incentives to ensure efficient dispatch as large scale (front of meter) production and storage. Accordingly, taking on the additional complexity of market price exposure – by providing policy support in the form of a time-dependent floor price - is merited[17]. A floor price provides incentives for efficient dispatch.[18]

We note also the developments in electricity retailing mean that it is now easily possible to provide retail consumers with exposure to spot market prices (many thousands of households have chosen such retail arrangements) and so the additional complexity is likely to prove easy to surmount in the target market of even more sophisticated commercial and industrial consumers. We note however, that adoption of the proposals here do not require that business customers be exposed to spot prices. The operation of the policy does not require customer exposure to spot price structures.

It might be suggested that feed-in floor prices and the times they apply should vary over the seasons, and between the states. This will however greatly increase the complexity of the scheme. Such additional complexity is unlikely to be worthwhile. The objective of the floor prices is to increase supply when the balance between supply and demand is more likely to be tight, and to provide policy support that is likely to make Business Power bankable. The objective is not to optimise battery backed behind the meter solar dispatch in each five-minute interval. This can be left to the market through the prices that participants will see.

The next issue to consider is how long (for how many years) floor prices should be available for? Shorter periods will require relatively higher floor prices to achieve the same level of policy support as longer periods. We have assumed 20 years for solar and 10 years for batteries, based on the likely operating life of solar/batteries before refurbishment or life extension is contemplated. Shorter periods may be preferable to some customers. Further consideration of this can be left to detailed implementation.
In summary, three policy support options are considered and evaluated:

1. Rooftop PV floor price ($/MWh) for production before 11am or after 2pm for 20 years.
2. Battery discharge floor price ($/MWh) for battery discharge between 6pm and 9pm for 10 years.

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[17] We note also strong regulatory support for behind-the-meter participation in wholesale markets. See for example: https://www.aemc.gov.au/rule-changes/integrating-price-responsive-resources-nem

[18] The floor price policy does not limit whatever commercial arrangements service providers and commercial/industrial customers might agree. The floor price relative to the 5-miute spot price is the basis of Business Power top-up policy payments but does not prescribe that the entity that receives the top-up payments has to contract with customers using five-minute prices.

3. Battery-backed solar with floor price for rooftop PV production before 11am or after 2pm for 20 years as well as floor price for battery discharge between 6pm and 9pm for 10 years.

4.2 Evaluation

How should the policy support options be evaluated? We consider four measures here:

1. **Viability:** for the modelled level of support**,** is the present value of revenues less costs likely to be positive, and so will pursuit of that Business Power option be investable?
2. **Value-for-money Criterion 1**: how much of the spot market revenue is accounted for by policy support? This measures how dependent revenues are on policy support. But Criterion 2 also matters (policy support might be a large proportion of revenues but a lower proportion of costs).
3. **Value-for-money Criterion 2:** how does the policy support compare to the cost of the rooftop solar/battery/battery-backed solar? This measures much of the cost is met through policy support.
4. **Implied greenhouse has (GHG) abatement cost:** what is the value of the policy support per tonne of GHG emissions abated as a result of the policy? Since the main rationale for a Business Power policy is to decarbonise electricity supply, the assessment of policy proposals in terms of their GHG abatement costs is an important metric in policy assessment.

In the Discussion (next section) we also introduce “policy yield” (how much investment per dollar of policy support) in evaluating alternatives.

4.2.1 PV-only policy support assessment

Table 4 presents the results of the assessment, using the calculations set out in Appendix E.

Table 4. PV-only floor price evaluation

Average sales price ($/MWh)					
Floor	**NSW**	**QLD**	**SA**	**TAS**	**VIC**
No floor	59	30	26	43	17
$100	88	73	77	77	65
$130	103	89	92	94	80
$150	114	101	103	105	91
NPV ($m)					
Floor	**NSW**	**QLD**	**SA**	**TAS**	**VIC**
No floor	$0.20	$0.39	$0.42	$0.35	$0.51
$100	$0.00	$0.06	$0.04	$0.14	$0.20
$130	$0.10	$0.06	$0.08	$0.03	$0.10
$150	$0.18	$0.15	$0.16	$0.04	$0.03
Policy support as % of revenue					
	NSW	**QLD**	**SA**	**TAS**	**VIC**
$100	33%	59%	66%	45%	74%
$130	43%	67%	71%	54%	79%
$150	48%	71%	74%	59%	82%
Policy support as % of levelised cost					
	NSW	**QLD**	**SA**	**TAS**	**VIC**
$100	32%	53%	62%	35%	51%
$130	50%	73%	80%	51%	66%
$150	62%	88%	93%	63%	78%
Implied carbon price ($/tonne$CO_{2-e}$)					
Floor	**NSW**	**QLD**	**SA**	**TAS**	**VIC**
$100	$29	$43	$39	$27	$37
$130	$44	$60	$51	$39	$49
$150	$55	$71	$59	$48	$57

The first block of numbers shows the effect of different floor prices on the average annual price received. For example, a $100/MWh floor price for production before 11am and after 2pm raises the average sales price by around $30/MWh to $40/MWh in each state, relative to the "No floor" case.

The second block of numbers (NPV) tables shows that grid-oriented rooftop solar (i.e. excluding the value from self-consumption) would not be profitable in any NEM region without policy support. At a floor of $100/MWh, rooftop solar would be close to viable (assuming a 7% discount rate) in all NEM regions except Tasmania and Victoria.

Focussing further on the $100/MWh floor (again only payable for PV injected to the grid before 11am or after 2pm) the third block reveals that such floor would provide support that adds up to between 33% (NSW) and 74% (in VIC) of the spot market revenue of solar. This level of policy support accounts for a similar level of the total cost of rooftop PV. The last set of numbers (Implied carbon price) shows that, when expressed per tonne of greenhouse gas abated, a $100/MWh floor would deliver abatement at a cost of between $27 and $43 per tonne of carbon-dioxide equivalent abated.

4.2.2 Battery-only policy support evaluation

Table 5 presents the results of the evaluation of a floor price for battery discharge between 6pm and 9pm using the calculations set out in Appendix F. The first set of numbers show the “gross arbitrage margin” which is the difference between the average price received when discharging and price paid when charging, per MWh discharged. This analysis assumes that battery operators achieve gross margins halfway between the high point (which assumes they have perfect foresight of spot prices) and the low point (which assumes batteries are charged at the average price each day between 11am to 2pm and discharged at the average price between 6pm and 9pm).

The table shows that adding a floor price of $200 for discharge between 6pm and 9pm will deliver margins in SA and QLD that are above the levelized cost of electricity of $335/MWh (assuming the battery is charged from behind the meter solar or $395/MWh (assuming the battery is charged from electricity drawn from the grid).

The second group of numbers (NPV) shows that with a floor price of $200/MWh for discharge between 6pm and 9pm, a behind-the-meter battery (but which is assumed to be charged from the grid) is likely to be profitable or close to profitable in all NEM regions (assuming a 7% discount rate).

The third set of numbers shows that a $200/MWh floor price provides support that is a small proportion of revenues (21% or less) in the mainland NEM region (it is a higher proportion in Tasmania where hydro storage already smooths daily prices and so arbitrage margins are less attractive).

Table 5. Battery-only floor price evaluation

Gross arbitrage margin ($/MWh)					
Floor	**NSW**	**QLD**	**SA**	**TAS**	**VIC**
No floor	$254	$351	$378	$122	$194
$100	$263	$458	$392	$148	$210
$200	$311	$495	$442	$219	$267
$300	$379	$558	$511	$304	$342
$400	$469	$642	$596	$398	$434
NPV ($m)					
Floor	**NSW**	**QLD**	**SA**	**TAS**	**VIC**
No floor	$0.08	$0.02	$0.04	$0.22	$0.15
$100	$0.07	$0.13	$0.06	$0.19	$0.13
$200	$0.03	$0.17	$0.11	$0.12	$0.07
$300	$0.05	$0.23	$0.18	$0.03	$0.01
$400	$0.14	$0.32	$0.27	$0.07	$0.10
Policy support as % of revenue					
Floor	**NSW**	**QLD**	**SA**	**TAS**	**VIC**
No floor	0	0	0	0	0
$100	4%	23%	4%	18%	8%
$200	15%	7%	11%	32%	21%
$300	18%	11%	14%	28%	22%
$400	19%	13%	14%	24%	21%

4.2.3 Battery-backed solar policy support evaluation

Table 6 presents the evaluation of battery-backed solar using the calculations set out in Appendix G. Two different combinations of feed-in prices for battery and solar are used. The first combination is a $200/MWh floor for battery discharge between 6pm and 9pm and a solar feed-in floor for solar fed-in before 11am and after 2pm.

The second combination is a $300/MWh battery floor and a $130/MWh PV floor. This combination reveals a positive NPV, or close to, it in all regions. This policy support expressed as a percentage of revenue is between 28% and 56% in the mainland states, and expressed as a percentage of cost is 31% to 57%. While these are relatively high, the implied GHG abatement cost (between $22 and $37/MWh abated is well below the Australian Energy Market Commission's estimate of the value of emission reduction in the electricity, calculated according to the Ministerial Council of Energy's methodology ($70 per tonne of $CO_{2\text{-}e}$ in 2024 rising to $146 per tonne $CO_{2\text{-}e}$ in 2034[19]).

Table 6. Battery-backed solar floor price evaluation

$200 Battery floor, $100 PV floor	NSW	QLD	SA	TAS	VIC
NPV	$0.03	$0.10	$0.08	$0.26	$0.27
Policy support as % of revenue	28%	45%	43%	52%	56%
Policy support as % of cost	27%	49%	46%	33%	40%
Implied carbon price	$19	$32	$23	$23	$23
$300 Battery floor, $130 PV floor	**NSW**	**QLD**	**SA**	**TAS**	**VIC**
NPV	$0.15	$0.29	$0.26	$0.07	$0.09
Policy support as % of revenue	39%	53%	52%	56%	65%
Policy support as % of cost	45%	69%	66%	52%	58%
Implied carbon price	$32	$45	$33	$32	$34

[19] https://www.aemc.gov.au/sites/default/files/2024-03/AEMC%20guide%20on%20how%20energy%20objectives%20shape%20our%20decisions%20clean%20200324.pdf

5. Discussion

The analysis in the previous subsection concluded that a floor price for rooftop PV of \$100/MWh for feed-in before 11am and after 2pm is likely to yield profitable investment and although such floor delivers income that is a reasonably large proportion of total income and total cost, it is nonetheless cheap in greenhouse gas abatement terms.
The analysis also revealed that a \$200/MWh floor for battery discharge from 6pm to 9pm also likely leads to profitable investment, and policy support that is a small proportion of revenues and costs.

The combination of these two floors and a battery sized so that 1kW of solar is required to be matched with at least 2 kWh of storage delivers investment that is likely to be profitable and at a GHG abatement cost that is well below the AEMC's estimate (\$70 per tonne of $CO_{2\text{-}e}$ in 2024 rising to \$146 per tonne $CO_{2\text{-}e}$ in 2034[20]).

The suggested combination of storage capacity and rooftop PV capability is likely to result in almost all the Business Power rooftop PV production during winter being stored for discharge to the market in the evening. In summer, the combination will result in about half the solar production being consumed during the day and half being stored for later discharge. This pattern of operation can be expected to bring downward pressure on wholesale prices during the day and even more so during the evening peak periods, when supply is maximised.

Five further aspects are considered in assessing the Business Power proposals:

- Policy support yield;
- Average cost;
- Impact on electricity prices;
- The recovery of policy support costs; and
- Uncertainty.

5.1 Policy support yield

What is the likely "policy support yield" i.e. what is the amount of additional production or storage (or both) that is likely to be delivered per dollar of policy support? This is quantified in Table 7 which shows that \$1bn of policy support for battery-backed solar can be expected to deliver 2.7 TWh of additional electricity production per year, and 2 GWh of additional storage capacity. This calculation assumes that \$1 of public subsidy leverages a further \$3 of private investment (so \$4 in total) as appears to be the case under the existing small-scale certificate scheme.

[20] https://www.aemc.gov.au/sites/default/files/2024-03/AEMC%20guide%20on%20how%20energy%20objectives%20shape%20our%20decisions%20clean%20200324.pdf

The table also shows that the battery-only policy delivers more storage and the PV-only policy delivers more production than the battery-back solar policy (as would be expected because the battery-backed solar policy support is helping to fund both storage and solar production).

Are these good numbers or not? It is possible to get a sense of this by comparing the policy support yield under the existing small-scale certificate scheme. As is shown in Figure 10, two cents per kWh of policy support is being paid per kWh-lifetime of rooftop solar production. Re-stated, one dollar of policy-support is delivering 50 kWh-lifetime of new rooftop production. Table 7 shows that $1 of policy support for battery-backed solar is likely to deliver 67 kWh-lifetime of new solar production *as well as* 2-Watt-hours of storage capacity. On renewable production alone, the battery-backed solar policy support is therefore appreciably more efficient than the existing small-scale certificate scheme.

Table 7. Policy support yield

	Battery and solar	Battery only	PV only
Additional direct annual renewable generation (MWh)	2,679,002		4,816,097
Annual GHG emission reduction (tCO_{2-e})	2,679,002		4,816,097
Additional storage (energy) capacity (MWh)	2,059	2,633	

Another way to understand Business Power policy yield compared to existing rooftop solar policy is to compare the outcomes under the existing policy, with the outcomes that this analysis of Business Power predicts. Taking NSW as an example, in 2023 the total installed rooftop PV capacity of 5,560 MW produced 7,800 GWh of production. We estimate a total of $4.2bn of policy support was paid in getting to the 5,560 MW of installed rooftop PV. Under Business Power, our analysis suggests that $4.2bn of policy support would deliver 11.3 GW of additional rooftop PV capacity as well as 8,650 MWh of additional storage. This suggests that, by comparison, Business Power is likely to be twice as efficient as existing policy has been in expanding behind-the-meter renewable electricity, and will expand storage at (in relative comparisons, no additional cost).

5.2 Average cost

The assessment has assumed a hypothetical 490kW PV system and 245 kW (490 kWh) battery. The present cost of this we estimate to be $0.96m and the present value of production over its useful life is 8,175 GWh. With a 10-year battery life, it will be necessary to be replaced after 10 years and so to ensure 20 years of battery-backed solar, the present cost is $1.2m and the levelised cost of electricity (LCOE) of this battery-backed solar system is $134/MWh.

In this specific case, this will deliver a device capable of firm supply (charging from the grid is possible when solar is inadequate) equal to 490 kWh per day for 20 years (or a little less than 12 times as much per day) for a commensurately shorter number of years. It is also capable of variable supply of around 700 MWh per year, from the rooftop solar.

How can this functionality and levelised cost be compared to alternatives? There is no certain way to do this, but comparing the levelised costs of other technologies helps to provide a sense of comparative cost-effectiveness.

For example, CSIRO[21] says that the LCOE of open cycle gas turbines (which are capable of firm continuous supply at peak capacity typically for at least eight hours) is $140-$240/MWh (before accounting for emission costs).

The average cost of supply by Stanwell Corporation (which has a portfolio of 3,300 MW of coal and another 700 MW of gas and hydro) provides another point of comparison. Information from Stanwell's annual report suggests $180/MWh[22] (again, no emission costs are charged).

Another point of comparison is a recently approved windfarm in NSW, which a reported LCOE of $110/MWh.[23]

The functionality of each of these alternatives, differ from each other and from Business Power. This is unavoidable. Nevertheless, these comparisons lend weight to a suggestion that battery-backed solar is a cost-effective option considering the functionality it provides[24].

In addition, we note that in this cost comparison we have not accounted for the very large (positive) externalities associated with Business Power relative to large scale front-of-meter alternatives (i.e. the avoidance of social and environmental costs, transmission expansion costs and greenhouse gas emission costs).

5.3 Impact on electricity prices

It is impossible to be certain about the impact of the battery-backed solar (or the rooftop PV only or battery-only) options on electricity prices. Policy makers might choose to recover some or all policy costs from taxpayers. But even if they choose to recover policy costs from consumers, the effect on prices will still be uncertain. This uncertainty can be attributed in large part to the changing context of the industry particularly the rate of new generation and storage entry and the rate of coal generation closure. Even if coal generators close at the rate their owners have said they will close them (which as noted

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[21] https://www.csiro.au/en/research/technology-space/energy/gencost

[22] Derived from cost information reported on page 76 of financial statements: https://www.stanwell.com/wp-content/uploads/Stanwell-ANNUAL-REPORT-2022-23-FINAL.pdf

[23] https://reneweconomy.com.au/fate-of-contested-hills-of-gold-wind-project-delayed-again-as-developer-fights-for-more-turbines/

[24] Business Power applications – assuming the policy support requirement of 2 kWh of storage per kW of rooftop PV, is likely to result in around 50% of solar production (i.e. the amount produced between 11am and 2pm) being transferred from the middle of the day to the evening, annually. Effectively all of the solar production from mid-autumn to mid spring is likely to be transferred to the evening and about half of the summer PV production between 11am and 2pm is likely to be transferred to the evening.

is much slower than the rate that AEMO assumes) there will still be a huge demand for new generation (and storage).

However, the evaluation has concluded that Business Power is likely to have a higher policy yield than existing renewable electricity policy; it found low implied GHG abatement costs and levelised costs that are competitive with alternatives, including existing coal-fired generation (even without counting avoided externalities). Taken together, these conclusions suggest that even if the Business Power cost is fully recovered from consumers (rather than taxpayers) the policy may be expected to pay for itself in offsetting wholesale price reductions.

5.4 The recovery of policy support costs

As discussed earlier, Business Power is motivated by several policy objectives of which the two most important are reducing GHG reductions from the electricity sector at a greater rate than would happen if the sector was left to itself; and stimulating electricity supply, particularly in the evening.

The first objective originates in Australia's contribution to solving a global problem. This might suggest that the public in general, not electricity consumers, should pay for policy support in pursuit of this objective.

On the other hand, Business Power will benefit electricity consumers and, in this respect, consumers should pay for it, as they have for almost all renewable electricity policy support hitherto. Considering that consumers (and voters) seem to have (largely) supported arrangements for the recovery of renewable electricity policy support hitherto (or at the least do not seem to be trenchantly opposed to it) it might be suggested that Business Power payments might be recovered in the same way.

There would be many ways to recover costs from electricity consumers. We suggest the creation of a Business Power Administrator that would make floor price payments to Business Power recipients. The Business Power Administrator would then recover the cost of these payments in charges to regulated distribution network service providers (DNSPs). This could be calculated as a single region-wide price (distinguishing the regional markets across Australia) price per customer or per MWh distributed, or the charges could be specified per distributor based on the payments to the Business Power recipients served by that distributor.

5.5 Uncertainty

Finally, this discussion of the evaluation and the conclusions that arise from it, should be mindful of the unavoidable uncertainty of this analysis. The evolution of technology costs in future; the extent to which battery operators will make the most of market prices and how wholesale prices might evolve are particularly uncertain.

It also impossible to be certain how receptive building owners will be to the opportunity to develop grid-oriented batteries and rooftop PV on their premises. Some owners may particularly value the opportunity to export electricity to the grid by way of demonstrating (to their customers) contributions that they are making to their communities in the provision of clean electricity. It will also further their own emission reduction objectives. But it is not clear just how valuable building owners will consider this.

Some (probably most) Business Power participants may extract value from battery-backed solar in allowing them to reduce network demand charges and substitute more expensive grid supply for their own consumption. But again, the value that building owners see in these will vary greatly from one to the other and this will only be revealed once the policy is implemented. We have not formally accounted for this in our analysis, other than to the extent that the policy support levels implicitly assume some amount of value will be extracted through self-use of some of the capacity offered by the battery-backed solar.

We note in a recent release[25] that the Energy Network Association has called for policy support for expansion of rooftop solar in the commercial and industrial sector. To the extent the Association represents the views of its members this might suggest distributor support for Business Power. On the other hand, the Association is also lobbying for distribution level storage to be in front of customers' meters. Such preference is consistent with the incentives provided through their regulation. This might suggest that in practice at least some distributors will be ambivalent about Business Power and others might be hostile to it, as some have been to residential rooftop solar and behind-the-meter batteries. Such antipathy will require an effective regulatory response and to the extent that such response is not forthcoming, it will undermine the prospects for Business Power.

Finally, many of the calculations here are complicated and intricate. Different analytical approaches can result in different conclusions. All formulas are in the appendices and to allow detailed review of this analysis by others all data, code and post-processing is available on reasonable request.

[25] https://www.energynetworks.com.au/assets/uploads/The-Time-is-Now-Report-ENA-LEK-August-2024.pdf

6. Implementation and suggested next steps

Implementation details and next steps are suggested here.

6.1 Feed-in floor price eligibility and conditions

1. Recipients must be located in a NEM-region and their supply must be three-phase (variations of this proposal for the Southwest Interconnected System and North-West Interconnected System will need to be considered separately).
2. Minimum of 15 kW rooftop PV; no upper limit.
3. Battery (kWh) storage capacity must be at least twice the battery's continuous peak power (kW) rating, per day (i.e. "two-hour" battery).
4. Battery (power) capacity must be at least equal to rooftop PV DC inverter capacity.
5. Batteries must have a minimum storage power/energy capacity of 15kW/30 kWh. No upper limit on battery power/energy capacity.
6. Business Power floor price recipients are required to forego RET subsidies by voluntarily surrendering certificates that they may be entitled to.
7. Floor price rates are not subject to ex-post adjustment over their term.
8. Recipients are required to start production within 24 months of their eligibility for feed-in floor prices.

6.2 Payments and cost recovery

1. Floor price payments made by retailer/agent to customer, with back-to-back recovery of the gap between spot prices and floor prices charged to the "Business Solar Administrator".
2. Business Power Administrator to recover its costs in charges to be recovered from all customers through distribution network service providers.

6.3 Business Power Administrator

It is anticipated that if Business Power is to be established as a Commonwealth policy, primary legislation will be needed. The Business Power Administrator (BPA) will need to be established through this legislation. Further investigation should consider whether BPA should be stand-alone or whether the Clean Energy Regulator be tasked with the BPA's obligations. Regardless, it is suggested the legislation oblige BPA to publish an annual report which should include information on:

1. Market and customer outcomes and value for money
2. Market and non-market barriers with particular regard to the actions of regulated network service providers.

6.4 Worked example

This worked example illustrates the operation of the feed-in floor price.

- ABC Pty Ltd in Brisbane takes up the Business Power incentive for on-site solar battery and installs a 500 kW PV system and a 500kW/1,000kWh battery. ABC has very little daytime load and so self-consumes very little of its own solar. The battery shifts 1000 kWh from the day to the evening. This is equal to about half the solar system's daily production in summer and more than all of the solar system's daily production in winter.
- The $100/MWh PV floor price kicks in whenever Queensland spot prices dip below $100/MWh and the effect of this is to raise ABC's PV income in 2025 from $22.8k to $55.5k for the rooftop solar production that it exports to the grid. ABC's retailer pays $55.5k to ABC and charges the Business Power Administrator $32.7k ($55.5k-$22.8k).
- The $200/MWh Battery floor price kicks in when QLD spot prices dip below $200/MWh and the battery is discharging between 6pm and 9pm. The battery discharges fully once each day during the year and the floor price raises ABC battery's income from $128.1k to $167.2k.
- ABC's retailer (who has been contracted by ABC to operate their PV and battery) pays $167.2k to ABC and charges the Business Power Administrator $39.1k ($167.2k - $128.1k).
- The Business Power Administrator add the $32.7k and $39.1k along with all other payments in the area of supply of ABC's distribution network service provider and invoices the DNSP for this.
- The DNSP recovers the total payment to the Business Power Administrator in charges the regulator allows it to include in its regulated distribution use of system tariffs.

Appendix A. Levelised cost of electricity of rooftop solar

$$LCoE\_solar_s = \sum_{y=1}^{20} \frac{\frac{O\_solar_y}{(1+r)^y} + C\_solar_0 . A}{\frac{P_s . A}{(1+r)^y . (1+d)^y}}$$

Where,

C_solar_0	Installed cost ($ per kW) before STC subsidy	$1,168				
r	Discount rate (%)	7%				
A	Capacity (kW)	490				
d	Annual panel degradation (%)	1%				
O_solar	Operating costs (percentage of C_solar_0.A) per annum	1%				
y	Life (years)	20				
P_s	PV production (MWh p.a. per kW)	NSW	QLD	SA	TAS	VIC
		1.40	1.52	1.50	1.24	1.29

Appendix B. Volume-weighted average price (VWAP) of rooftop solar production in the NEM from 2018 to 2023

$$VWAP\_NEM_{s,y} = \frac{\sum_{i=1}^{n} (V_{s,y,i} . P_{s,y,i})}{\sum_{i=1}^{n} V_{s,y,i}}$$

Where,

s is State (NSW, VIC, QLD, SA, TAS),
y is Year (2018 to 2023),
i is the 5-minute trading intervals in year, y
$V_{s,y,i}$ is the number of 5-minute trading periods from period starting 00h00 on 1 January 2018 to period ending 24h00 on 31 December 2023.
$P_{s,y,i}$ is the 5-minute price ($/MWh) at the Regional Reference Price in each State
$V_{s,y,i}$ is rooftop solar generation (MWh) in each 5-minute period trading period

All data sourced from www.v-nem.org, originally published by AEMO.

Appendix C. Calculation of storage arbitrage margin

Passive strategy

$$AMPS_s = \sum_{d=1}^{1096} \frac{\left(DP_{s,d} - CP_{s,d}\right)}{1096}$$

$AMPS_s$ *is the arbitrage margin in state*, S, *assuming the passive arbitrage strategy.*

Where,

$$CP_{s,d} = \sum_{i=132}^{168} \frac{P_{s,d,i}}{36}$$

$$DP_{s,d} = \sum_{i=216}^{252} \frac{P_{s,d,i}}{36}$$

P is the 5-minute price ($/MWh) at the Regional Reference Price in each State
d is the 1096 days from 1 January 2020 to 31 December 2023 inclusive
S is State (NSW, VIC, SA, QLD TAS)
i is 5-minute trading intervals from 133(11h00) to 168(14h00) and 217(17h00) to 252(21h00) in each day, *d.*

Perfect foresight

$$AMPF_{s,d} = \sum_{d=1}^{1096} \frac{\left(DPF_{s,d} - CPF_{s,d}\right)}{1096}$$

$AMPF_s$ *is the arbitrage margin in state*, S, *assuming perfect foresight.*
Where,

$$CP_{s,d} = \sum_{x=1}^{24} \frac{PL(x)_{s,d}}{24}$$

$$DP_{s,d} = \sum_{y=1}^{24} \frac{PH(y)_{s,d}}{24}$$

$PL(x)$ *and* $PH(y)$ are the lowest and highest 24 5-minute prices in each day for x, y = 1 to 24
d is days from 1 January 2020 to 31 December 2023 inclusive
S is State (NSW, VIC, SA, QLD TAS)

Appendix D. Levelised cost of electricity per MWh discharged from storage

$$LCoE_{Battery} = \sum_{i=1}^{10} \frac{\frac{O\_battery_i + N_i}{(1+r)^i} + C\_battery_0 . E + \frac{RV}{(1+r)^{10}}}{\left(\frac{E * 365}{(1+R_t).(1+r)^i.(1+d)^i}\right)}.$$

Where

$LCoE_{Battery}$ is the levelised of cost of electricity, $ per MWh discharged from the battery which is assumed to be fully discharged once per day for 10 years.

$C\_battery_0$	Installed cost per kWh of storage capacity	775	$/kWh
E	Storage (Energy) capacity	490	kWh
P	Storage (Power) capacity	245	kW
i	Life (years)	10	numbe r
RV	Residual value at the end of life (% of installed cost)	30%	%
r	Discount rate	7%	%
d	Annual degradation	1%	%
R_t	Round-trip loss	15%	%
$O\_battery$	Annual operating cost (% of capital outlay)	1%	%
N_i	Network use of system charge if importing from the grid	$ 60.00	$/MWh

Appendix E. Policy evaluation: rooftop PV policy support

Net Present Value (NPV_Solar)

$$NPV\_Solar(f\_solar)_s = VWAP(f\_solar)_s * C_{solar_0}.A - \left(\sum_{y=1}^{20} \frac{O_{solar_y}}{(1+r)^y} + C_{solar_0}.A\right)$$

Policy Support as % of Revenue (PSR)

$$PSC_s\ (f\_solar = 0) = 0$$

$$PSC_s = \frac{VWAP(f\_solar)_s - VWAP(f\_solar = 0)_s}{VWAP(f\_solar)_s} * 100$$

Implied Carbon Price (\$ / tCO_2-e)

$$ICP_s = \frac{(NPV\_Solar(f\_solar)_s \; - NPV\_Solar(f\_solar = 0)_s\,) * GF_s}{y.A.P_s}$$

Where:

A	Capacity (kW)	490				
y	Life (years)	20				
P_s	PV yield (MWh p.a. per kW)	NSW	QLD	SA	TAS	VIC
		1.40	1.52	1.50	1.24	1.29
GF_s	Greenhouse intensity tCO_2-e per MWh	1	1	1.3	1.3	1.3

$$VWAP(f_{solar})_s = \frac{\sum_{h=1}^{24} V_{s,h}.P(f_{solar},h)_{s,h}}{\sum_{h=1}^{24} V_{s,h}}$$

$$P(f\_solar)_{s,h} = \sum_{i=1}^{4380} \frac{P(f_{solar},h)_{s,h,i}}{4380}$$

$P(f_{solar},h)_{s,h,i}$ is the higher of the 5 minute Regional Reference Price in each state, S, and f_solar (the solar floor price) which can take the value {0, 100, 130, 150} for all i in 2023 before 11h00 and after 14h00. For all other trading intervals, i in 2023, it is the Regional Reference Price in each State. All prices are adjusted from NEM-time to the local time in each State.

h takes the value 0 to 23 corresponding to the 24 hours of a day starting at 0h00 and ending at 24h00
is the 365 days in 2023

$V_{s,h}$ is obtained from the https://pvwatts.nrel.gov/ based on the latitude and longitude of the capital city in each state and using the following input assumptions:

Module Type	Standard
Array Type	Fixed (open rack)
Array Tilt (deg)	20
Array Azimuth (deg)	0
System Losses (%)	14.08
DC to AC Size Ratio	1.2
Inverter Efficiency (%)	96
Albedo	From weather file
Bifacial	No
Monthly Irradiance Loss (%)	0

Appendix F. Policy evaluation battery policy support

Gross Arbitrage Margin (GAB)

$$GAB(f\_battery)_s = \frac{(AMPS(f\_battery)_s + (AMPF(f\_battery)_{s,d})}{2}$$

Where,

$$AMPS(f\_battery)_s = \sum_{d=1}^{1096} \frac{\left(DP(f\_battery)_{s,d} - CP_{s,d}\right)}{1096}$$

$$CP_{s,d} = \sum_{i=133}^{168} \frac{P(c)_{s,d,i}.(1 + R_t)}{132}$$

$$DP(f\_battery)_{s,d} = \sum_{i=217}^{252} \frac{P(f\_battery)_{s,d,i}}{132}$$

$P(c)$ is spot price

$P(f)$ is the higher of the 5 minute price at the relevant Regional Reference Node and f if $132 < i < 252$

d is days from 1 January 2020 to 31 December 2023 inclusive

s is State (NSW, VIC, SA, QLD TAS)

i is 5-minute trading intervals ending 133 (11.05am) to 168 (2pm) and 217 (6.5pm) to 252 (9pm)

R_t is round-trip losses and takes the value of 15%

$$AMPF(f\_battery)_{s,d} = \sum_{d=1}^{1096} \frac{\left(DPF(f\_battery)_{s,d} - CPF_{s,d}\right)}{1096}$$

Where,

$$CP_{s,d} = \sum_{x=1}^{24} \frac{PL(x)_{s,d}}{24}$$

$$DPF(f\_battery)_{s,d} = \sum_{y=1}^{24} \frac{PH(y, f\_battery)_{s,d}}{24}$$

$PL(x)$ is the lowest 24 (x = 1 to 24) 5 minute prices in each day

$PH(y, f_battery)$is the higher of each of the 24 (y = 1 to 24) highest 5 minute prices, and $f\_battery$, for each day

d is all days from 1 January 2020 to 31 December 2023 inclusive

s is State (NSW, VIC, SA, QLD TAS)

$f\_battery$ can take the value {0, 100, 200, 300, 400}

Net Present Value (NPV)

$$NPV(f\_battery)_s = GAB(f\_battery)_s * E - LCoE_{Battery} * \sum_{i=1}^{10}\left(\frac{E*365}{(1+R_t).(1+r)^i.(1+d)^i}\right)$$

Policy Support as % of Revenue (PSR)

$$PSR(f\_battery)_s = \frac{(NPV(f\_battery)_s - NPV(f\_battery = 0)_s +}{NPV(f\_battery)_s + \sum_{i=1}^{10}\frac{O_i + N_i}{(1+r)^i} + C_0.E + \frac{RV}{(1+r)^{10}}} * 100$$

Appendix G: Policy evaluation battery+rooftop PV policy support

NPV

$$NPV(f\_solar\_battery)_s = NPV(f\_battery)_s + NPV\_Solar(f\_solar)_s$$

Policy Support as % of Revenue (PSR)

$PSR(f\_solar\_battery)_s =$

$$\frac{NPV(f\_solar\_battery)_s - NPV(f_{solar} = 0)_s - NPV(f\_battery = 0)_s}{NPV(fsolar\_battery)_s + \sum_{y=1}^{10}\frac{O_y + N_y}{(1+r)^y} + C_0.E - \frac{RV}{(1+r)^{10}} + \sum_{y=1}^{20}\frac{O_y}{(1+r)^y} + C_0.A}$$

Implied Carbon Price (\$ / tCO_2-e)

$ICP(f\_solar\_battery)_s =$

$$PSR\left(f_{solar_{battery}}\right)_s . \frac{NPV(f_{solar})_s + NPV(f_{battery})_s + \sum_{y=1}^{10}\frac{O_y + N_y}{(1+r)^y} + C_0.E - \frac{RV}{(1+r)^{10}} + \sum_{y=1}^{20}\frac{O_y}{(1+r)^y} + C_0.A}{10.E + 20.A.P_s}$$