Sustainable Engineering Group

Over the Precipice: Transitional Pressures from Household PV Battery Adoption on Electricity Markets and the Potential for Decarbonisation

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Declaration

To the best of my knowledge and belief this thesis contains no material previously published by any other person except where due acknowledgment has been made.

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Kelvin Guisen Say

Signature: **Date: 10 November 2021**

ABSTRACT

Strategies to decarbonise the global energy system rely on the electricity sector to rapidly transition to sources of energy that do not emit greenhouse gases. The electricity sector has an important role to play as a growing source of energy for other energy sectors to also decarbonise. Climate and energy policies designed to transition the electricity sector to renewable energy resources have typically focused on using large-scale renewable energy generators to displace existing fossil fuel generators. Given economies of scale, large utility-scale solutions are generally considered as the least-cost transition pathway. However, an alternative pathway has begun to emerge over the last decade, one in which electricity customers (led by individual households) are beginning to force an alternative transition pathway by installing their own rooftop solar photovoltaic (PV) and battery energy storage systems (BESS) behind-the-meter. If the potential of these behind-the-meter energy systems and their adoption drivers are not well understood, there is a risk that these utility- and customer-scale transitions may disrupt one another. This thesis explores how the growth of customer PV battery adoption may drive the power sector to evolve, and how policymakers could use these evolutionary pressures to further electricity system decarbonisation.

A Western Australian context is used as behind-the-meter rooftop PV systems have already become widespread and affects not only the operation of the electricity system, but also the future outlook for its utility-scale generators. With residential BESS costs likely to decrease, existing PV-only households may transition to PV-battery systems as the economics improve. In a competitive wholesale market designed around utility-scale generation (and already having to cater for significant and growing rooftop PV) a subsequent transition towards PV-battery adoption is likely to further affect the structural frameworks of the liberalised electricity market and may undermine existing utility-scale renewable energy policies. As the Western Australian context is not unique, this research offers insights for other jurisdictions experiencing a rise in household PV battery adoption or developing strategies encouraging greater energy decarbonisation behind-the-meter.

This research develops technical modelling and analysis techniques to represent customer expectations, centred around their propensity to install PV battery systems, their impact on the electricity market, and their changing role within the power sector. As an emerging source

of renewable energy, this research improves the understanding of their energetic and market potential and how they could be leveraged to further decarbonise the electricity sector. The developed model and data have also been released as open-source to facilitate transparency and reproducibility of this research. This thesis focuses on the renewable energy transition at the customer level, to firstly understand the extent of change that residential PV battery systems may have on the wider power sector, and to secondly identify the policy levers that may influence the evolution of this customer-led transition and its trade-offs.

The research conducted in this thesis led to four published research papers that establishes:

- The relationship between time invariant two-part retail electricity tariffs and household PV battery adoption as technology costs improve and electricity prices rise.
- The lost revenue implications (both short and long-term) for electricity retailers from the continued use of time invariant two-part retail tariffs.
- The influence of PV battery households on the least-cost portfolio of utility-scale generation and storage technologies.
- The impact of growing PV battery adoption on the operation and planning of the electricity system, wholesale spot energy market, and flexibility of its generation assets within a liberalised electricity market framework.

This research showed that retail Feed-in Tariff (FiT) prices have significant influence on the cost-effectiveness of PV-battery systems and may be used as a policy lever to influence PV-battery adoption and how it operationally integrates with the rest of the electricity system. However, if FiTs are set and paid for by electricity retailers, the subsequent revenue impacts apply financial pressure to keep FiT prices low, which accelerates a household transition to PV-battery systems. Striking a balance between customer and retailer benefits remains an area of strategic tension which is further affected by PV battery adoption.

Observed household load profiles were used to assess the operational and economic impact of growing PV-battery adoption on the power sector. The research found average PV capacity installed per household increases with battery adoption and could exacerbate feed-in network congestion. However, as PV-battery households were also capable of significantly reducing their late-afternoon demand, wholesale prices over these typically high price hours were reduced, benefitting non-PV-battery households. With significantly reduced grid consumption and further increases in excess generation, PV-battery households were capable of becoming net-generators, with the potential to become a significant and growing source of new renewable energy generation and energy storage capacity. This would compete directly against utility-scale generation, and due to the similarities in generating hours, future utility PV capacity would be significantly more impacted than utility wind. Future utility-scale battery capacity was found to be less affected by household PV-battery adoption, but only because the economic dispatch of household batteries was underutilised.

The research has shown that customers (freely capable of installing their own PV-battery systems) have a growing competitive advantage over the rest of the power sector and could become a significant source of future renewable energy and energy storage. By self-generating and time-shifting demand, PV-battery households have a much greater ability (compared to PV-only households) to automatically respond to time-varying prices without requiring changes in energy consumption behaviour. Policymakers should therefore reconsider if PV-battery households (that are predominantly on flat tariffs) should remain insulated from the temporal dynamics of the wholesale electricity market. As increasing their exposure to the wholesale electricity market would likely increase the financial returns for PV-battery owners, while improving the market efficiency for all electricity users. Policy mechanisms may include time-of-export and time-of-use tariffs, to retail aggregators that pay customers to operate their PV-battery assets as a virtual power plant.

The research findings suggest that a transition towards widespread household PV battery adoption could significantly impact liberalised electricity market structures. However, this would also lead to significant behind-the-meter renewable energy generation and energy storage capacity. Left alone, these behind-the-meter energy assets would remain outside the electricity market and negatively affect large-scale renewable energy policies that rely on the growth of future electricity demand. Decision and policymakers should therefore consider a range of market and regulatory reforms that allow small- and large-scale renewable energy assets to complement one another, such that future growth in customer PV-battery systems is not considered as a threat, but as an asset that accelerates the transition towards a decarbonised energy system and economy.

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List of Publications

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Journal articles (peer-reviewed and included as part of the thesis):

1. **Say, K.**, John, M., Dargaville, R., Wills, R.T., 2018. The coming disruption: The movement towards the customer renewable energy transition. *Energy Policy* 123, 737–748. https://doi.org/10.1016/j.enpol.2018.09.026
2. **Say, K.**, John, M., Dargaville, R., 2019. Power to the people: Evolutionary market pressures from residential PV battery investments in Australia. *Energy Policy* 134, 110977. https://doi.org/10.1016/j.enpol.2019.110977
3. **Say, K.**, Schill, W.-P., John, M., 2020. Degrees of displacement: The impact of household PV battery prosumage on utility generation and storage. *Applied Energy* 276, 115466. https://doi.org/10.1016/j.apenergy.2020.115466
4. **Say, K.**, John, M., 2021. Molehills into mountains: Transitional pressures from household PV-battery adoption under flat retail and feed-in tariffs. *Energy Policy* 152, 112213. https://doi.org/10.1016/j.enpol.2021.112213

Conference papers (peer-reviewed):

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Statement of contribution and co-authorship declaration

I hereby declare that I have authored and co-authors the following publications. The level of my intellectual input to each publication is indicated in brackets as below. Signed verification statements from each of my co-authors are provided in Appendices 1 to 4.

Mr Kelvin Guisen Say | **Professor Michele John** | **Dr Roger Dargaville**

Dr Wolf-Peter Schill | **Professor Raymond Wills**

Say, K., John, M., Dargaville, R., Wills, R.T., 2018. The coming disruption: The movement towards the customer renewable energy transition. Energy Policy 123, 737–748. https://doi.org/10.1016/j.enpol.2018.09.026 (85% contribution by lead author/PhD candidate)

Say, K., John, M., Dargaville, R., 2019. Power to the people: Evolutionary market pressures from residential PV battery investments in Australia. Energy Policy 134, 110977. https://doi.org/10.1016/j.enpol.2019.110977 (85% contribution by lead author/PhD candidate)

Say, K., Schill, W.-P., John, M., 2020. Degrees of displacement: The impact of household PV battery prosumage on utility generation and storage. Applied Energy 276, 115466. https://doi.org/10.1016/j.apenergy.2020.115466 (60% contribution by lead author/PhD candidate)

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List of Abbreviations

(in order of appearance)

PV:	Photovoltaic
FiT:	Feed-in Tariff
DER:	Distributed Energy Resources
MLP:	Multi-Level Perspective
RES:	Renewable Energy Source
SWIS:	South-West Interconnected System
WA:	Western Australia
BESS:	Battery Energy Storage System
BEV:	Battery Electric Vehicle

CHAPTER 1.

Introduction

1.1 Background and motivation

The economies of scale benefiting customer-level decarbonisation

To address the significant challenge of global warming (COP21, 2015; Ricke et al., 2018; Sanderson and O'Neill, 2020), our modern energy systems need to undergo a rapid transformation (Bruckner et al., 2014). Human societies require energy to operate and function and will need to significantly decrease their reliance on fossil fuel as an energy resource in order to limit greenhouse gas emissions. With the energy sector responsible for the largest share of anthropogenic greenhouse gases, at 76.1% (Boehm et al., 2021), the sector as a whole has to find viable decarbonisation pathways. While the power sector[1] only accounted for 17% of total final energy consumption in 2018 (REN21, 2021), it has access to a wide range of low emission technologies. In order for countries to meet net-zero emission targets by 2050, it is necessary for their power sectors to be decarbonised well before 2050 (Bruckner et al., 2014; IEA, 2021). This allows the power sector to supply the energy required to decarbonise the other sectors of the economy (i.e., transport, heating and cooling). Significant reductions in the cost of wind and solar photovoltaic (PV) technologies over the last decade have made renewable energy technologies the cheapest source of new electricity generation in most countries (BNEF, 2021; IEA, 2020a; IRENA, 2020). Similarly, rapid cost reductions are expected for lithium-ion battery energy storage systems (BNEF, 2021; Schmidt et al., 2017), due to the rapid growth of electric vehicle production globally. As global manufacturing capacity increases, the modularity and scalability of both solar PV and lithium-ion battery technologies allow economies of scale to drive further cost reductions. This not only improves its competitiveness as a utility-scale technology, but their scalability allows these cost reductions (and their technical performance) to be transferrable at smaller scales. These cost savings not only benefit utility-scale installations but have also begun to extend to

[1] The term *power sector* is used to describe the electricity system, its various markets and market actors, and range of governance and policy institutions. The term *energy sector* is only one component of global energy system, which spans the heating, transport, and power sectors.

electricity customers themselves. As electricity customers gain cost-effective access to their own source of energy generation and storage, they also acquire the means to decarbonise their own energy use while changing how they interact with the rest of the power sector. Given that the power sector's operational and economic assumptions have been designed around large and centralised generation (Bouffard and Kirschen, 2008), customer self-generation and storage are new factors in the energy transition that have the potential to either disrupt or complement the wider energy system decarbonisation (Agnew and Dargusch, 2015).

The potential role of customers in the energy system decarbonisation

As a world leader in rooftop PV adoption (APVI, 2020; IEA, 2020b), Australia is currently experiencing a rapid transformation in the power sector. In the decade since 2010, the cumulative installed capacity of small-scale PV has increased from 0.3 GW to over 13 GW (Clean Energy Council, 2021). As the total potential of all rooftop PV capacity is estimated at 179 GW (Roberts et al., 2019) there remains significant spare capacity for continued expansion. Amounting to a potential annual energy output of 245 TWh (Roberts et al., 2019), this would exceed Australia's current electricity consumption of around 200 TWh (AEMO, 2020a, 2021a). From an energy system planning perspective, customer-level policies that may encourage the installation of rooftop PV systems, which also use predominantly private (rather than public) capital, has the potential to develop customer self-generation into a significant source of renewable energy for all energy users. Battery energy storage systems, which can store excess PV self-generation for later use, can further reduce the need for grid-sourced electricity and its associated greenhouse gas emissions. The availability of PV and battery technologies interact with residential electricity prices, underlying electricity demand, and customer expectations to influence their rate of adoption. While residential customers account for approximately 30% of total electricity consumption (AEMO, 2021a), they have become the largest source of PV generation in Australia (Clean Energy Council, 2021) and the primary cause of decreasing minimum demand during the midday (AEMO, 2021b). Therefore, a better understanding of the influencing factors, retail policies, and its business-as-usual progression, are critical to understanding how to utilise this novel pathway towards decarbonisation. While this research focuses on residential customers, commercial and industrial customers are presented with similar opportunities. This research aims to analyse how residential customer PV and battery adoption may be influenced by retail policy levers, and the extent to which the power sector (under a liberalised electricity market framework) may be forced to change in order to accommodate a growth in customer self-generation and energy storage. However, this first requires a background on the wider power sector and its current decarbonisation strategies.

Structural factors that have driven utility-scale decarbonisation

Historically, the range of available technologies that can generate and manage electricity have been long-lived and capital-intensive assets that operate more efficiently at larger scales, i.e., utility-scale. Planners, policy, and decision makers have traditionally favoured a top-down management perspective with the power sector, focussing on utility-scale solutions that offer the lowest cost of supply, while also considering changing technology costs, retirement of existing assets, and more recently carbon emission constraints (Finkel et al., 2016; Zappa et al., 2021). With electricity being an essential service for both society and the economy, it is an important government responsibility and utility-scale policies, such as renewable energy portfolio standards (RPS) (Jaccard, 2004), emission trading mechanisms (Pope and Owen, 2009), and reverse auctions for supply (Cozzi, 2012; Lackner et al., 2019) have been used by governments to manage the 'energy trilemma'. The term 'energy trilemma' is used to define the power sector's need to balance competing trade-offs between its *technical* (i.e., security of supply), *economic* (i.e., affordability and energy equity), and *environmental* dimensions (Finkel et al., 2016; Heffron et al., 2015; Oliver and Sovacool, 2017). As the costs of renewable energy generation and battery energy storage technologies continue to decrease, the *economic* and *environmental* dimensions are no longer in direct opposition with one another, opening new opportunities to navigate the 'energy trilemma'. However, as these technologies also come with new technical and economic considerations, the historical power sector market frameworks that determine the distribution of incentives and risks need to also adapt (Grubb and Newbery, 2018; Markard, 2018).

Electricity was traditionally supplied using vertically-integrated utilities operating as a regulated monopoly, with customer electricity demand at one end, and a single utility business responsible for the supply of electricity at the other end (IEA, 2005). From the 1980s onwards, privatisation and market reforms (also known as electricity market liberalisation) were introduced to improve the economic efficiency of the power sector, by increasing competitiveness and shifting financial risks away from customers (Blazquez et al., 2018). These liberalised electricity markets can be found in many national and sub-national jurisdictions, e.g., Australia,[2] Germany,[3] PJM in the US,[4] Japan.[5] The framework of liberalised electricity markets establishes competitive generation and retail markets, with transmission and distribution networks owned and operated as regulated monopolies. Market liberalisation separates vertically-integrated utilities into different structures: (i) an independent system operator that forecasts energy demand and manages market dispatch and system security; (ii) a competitive wholesale spot market that selects the lowest cost mix of generators to securely meet forecasted demand; (iii) a regulated network monopoly that ensures sufficient network capacity to meet the annual peak power demand of all customers; and (iv) a competitive retail market that manages the risk of wholesale electricity prices and offering simplified electricity tariffs for retail customers. As generators compete to supply energy for forecasted electricity demand, this market framework is one-sided and does not allow individual energy consumers to directly bid for generation capacity. Similarly, vertically-integrated utilities operate in a one-sided manner, by setting prices in line with expectations of consumer demand. Therefore, both liberalised electricity markets and vertically-integrated utilities are susceptible to disruption if consumer demand and futures expectations significantly change (Johnstone et al., 2020; Weigelt et al., 2021).

Australia as a front runner in distributed energy resources

Over 3 million Australian households have installed behind-the-meter rooftop PV (Kallmier and Egan, 2021) and tens of thousands of new battery systems are being installed each per year (Filatoff, 2021). This has begun to significantly transform day-to-day (AEMO, 2021c) and forecasted (AEMO, 2020a) electricity demand, and is emerging as a customer-led and bottom-up energy transition. Customers with their PV-only and PV-battery installations, also more generally known as Distributed Energy Resources (DER), are changing the way they interact with the grid and are challenging the dominant top-down approach to power sector decarbonisation. Over the last decade the installed costs of solar PV have fallen more than 60% both internationally (IRENA, 2019) and in Australia (Solar Choice, 2020). With discounted

[2] https://aemo.com.au/
[3] https://www.smard.de/en
[4] https://www.pjm.com/
[5] http://www.jepx.org/english/

payback times for rooftop PV systems under 5 years in most Australian capital cities (AEC, 2020), it has also become a cost-effective technology. As of the end of 2020 (Kallmier and Egan, 2021), cumulative rooftop PV (13 GW_P) exceeded utility PV capacity (7.4 GW_P). The average capacity of new rooftop PV installations across 2020 was above 8 kW_P. Over 31% of Australian freestanding and semi-detached dwellings have installed rooftop PV (Kallmier and Egan, 2021), making Australia the global front runner in rooftop PV penetration. At the state level Queensland and South Australia average more than 40% of dwellings with rooftop PV, while Western Australia averages more than 35% of dwellings. Aside from system costs reductions, the growth of rooftop PV has been driven by Australia's abundant solar resources, relatively high retail electricity tariffs (AEMC, 2019), falling consumer confidence in the electricity market (AEMC, 2018), retail Feed-in Tariffs (FiTs), and an increasing community concern for greenhouse gas mitigation.

With PV installations situated behind-the-meter, PV self-generation is consumed first by a customer's load and the remainder exported onto the grid. As customer grid exports are not managed as part of the economic dispatch process, they effectively have the highest dispatch priority on the network. During ideal daytime conditions, rooftop PV customers are increasingly capable of meeting all their own electricity demand and exporting any excess electricity onto the grid. This reduces the supply of grid-sourced electricity to these PV customers while also reducing demand across all other electricity customers. An observable result is a negative load pattern that mimics the diurnal solar radiation profile (AEMO, 2021c) known as the "duck curve" (Denholm et al., 2015; Maticka, 2019). The "duck curve" describes the effect of solar PV generation on electricity system operation, notably with diurnal peak network demand shifting slightly into the late afternoon (or early evening), significant reduction in demand over midday, and an increased ramp of capacity required between midday and the late afternoon peak. This demand profile requires generators to ramp faster and cycle more often, which disadvantages inflexible generation technologies (such as coal-fired power stations) by reducing their overall operational and economic efficiency, thus leading to early retirements (Maisch, 2019; Matich, 2020). To maintain system security, system managers have requested mitigation measures that can dynamically disable customer grid exports through remote system commands or distribution network voltage control (AEMO, 2020b). In addition, distribution network operators are generally limiting customer exports to 5 kW or lower (dependent on available hosting capacity). These changes to customer grid-utilisation are no longer immaterial and have becoming increasingly significant, e.g., rooftop PV has been recorded supplying over 60% of instantaneous underlying demand.[6] Therefore, the continued growth of customer PV generation would considerably affect how the electricity system, or more broadly the power sector, evolves and may open new pathways for decarbonisation. While the growth of customer self-generation is continually being revised and incorporated into longer term power sector scenario planning (AEMO, 2020a; Energy Transformation Taskforce, 2020; Stringer et al., 2020), further research is necessary to better understand how customers interact with and impact the power sector, and how they may be used to complement decarbonisation strategies and energy policies. This thesis wishes to investigate these interactions.

Contextualising the South-West Interconnected System for analysis

The South-West Interconnected System[7] (SWIS) in Western Australia (WA) offers researchers important real-world context for analysis on customer PV battery adoption and its market effects. The SWIS is a medium-sized electricity system with its own liberalised electricity market, which is also isolated (thus removing the need to make assumptions for interconnections). It has one major load centre based around the greater metropolitan region of Perth, Australia (which simplifies assumptions around representative household load profiles) and is undergoing a rapid growth of rooftop PV adoption. Rooftop PV capacity currently amounts to 1.4 GW in a power system with an average diurnal peak demand of around 2.5 GW and an annual peak demand of around 4 GW. Rooftop PV has also been recorded supplying 61.5% of total underlying demand and is expected to increase its contribution in the coming years (AEMO, 2021c). This has led to increasing concern for operational stability as new minimum demand records are broken each year (AEMO, 2019). A single retailer is responsible for all residential customers, resulting in a uniform set of retail tariffs applied across all households in the SWIS and with the majority of customers under flat

[6] On 20 October 2019, the combined generation of rooftop PV systems supplied 64% of the underlying demand in South Australia (AEMO, 2020b). This percentage contribution is currently forecasted by the independent system operator to continue increasing year-on-year (Graham and Havas, 2020).

[7] https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/about-the-wholesale-electricity-market-wa-wem

tariffs.[8] These conditions reduce the number of assumptions needed to model the consumer and utility perspectives within the SWIS. By contrast the larger National Electricity Market on Australia's eastern and southern coasts (AEMO, 2018), has a much larger geographical difference in its load and renewable energy resources, and has five interconnected markets, each with subtly different utility and retail market conditions. As the SWIS has to manage its own liberalised electricity market without interconnectors, any unexpected changes in future demand and grid-utilisation would have a greater impact on system and market operation, and long-term planning. Therefore, the SWIS offers researchers real-world conditions while simplifying the range of assumptions necessary to model the interactions between retail pricing, changes in customer demand and utility-scale generation. By better understanding these end-to-end implications, the results and analyses from this research may provide insights to other regions that are also expecting a significant growth in customer PV and/or battery adoption.

As this thesis dynamically evaluates the installation of rooftop PV systems (PV-only), battery systems (battery-only), and PV plus battery systems (PV-battery) a simplified terminology will be used to collectively describe all three configurations. Rather than referring to all of these combinations as the "the customer installation of ***PV and/or battery*** systems", it will be subsequently referred to as "the customer installation of ***PV battery*** systems".

1.1.1 Research motivation one: Evaluate customer PV battery adoption over the interrelated dimensions of generation and storage capacity.

With all PV generation tied to the available solar irradiance, rooftop PV customers generate at similar times. This aligns grid-utilisation at the aggregate level, even though individual consumption patterns differ, and this alignment becomes more pronounced as installed PV capacities behind-the-meter increases. With the addition of energy storage however, these effects are less generalisable, since the grid-utilisation from each customer becomes increasingly sensitive to profile differences in customer demand, the quantity of excess PV generation and the incentive structures from volumetric retail usage tariffs and FiTs. Therefore, customer investments in PV and battery systems have two interrelated dimensions

[8] A range of residential retail tariffs from time-of-use, peak time rebates, to time-of-export charges are being used in other Australian jurisdictions to improve cost-reflectivity (see Roberts et al., 2021). However, flat tariffs remain the dominant tariff structure in the SWIS and in other parts of the world.

(i) **generation capacity,** and (ii) **storage capacity**. As these two dimensions are interdependent, the first motivation is to develop a unified approach that does not consider each dimension independently but rather assesses their combined value. This would provide the means to establish scenarios of future outcomes and their respective sensitivities.

1.1.2 Research motivation two: Evaluate the bi-directional influence between customer PV battery adoption and retail tariff offerings.

Liberalised electricity markets were designed around the one-way flow of electricity with the resulting segregation of supply and value chains designed to provide incentives that improved economic efficiency between competitive generators and passive consumers. With customer self-generation and storage, customers are no longer passive consumers but have the means to reduce consumption and utilise the grid in a bi-directional manner. As all costs of the electricity system are expected to be borne by its customers, future changes to retailer revenues provide an indicator for the state of the electricity market. The tariff offerings provided by retailers (i.e., its structure and price) not only define the costs of grid imported electricity and revenue of grid exported electricity to customers, but also the potential cost savings from customer self-generation and storage. Therefore, as retailers decide upon their range of tariff offerings, they have to consider not only fixed and variable cost recovery, but also the extent to which it incentivises customers to reduce future demand (via PV battery adoption). This establishes a bi-directional relationship between retailers and customers with the retail tariff as its interface. With PV and battery prices expected to decrease, this research motivation aims to better understand how customers (with the ability to increasingly self-generate and self-consume over the longer-term) can affect how retailers set usage and feed-in tariffs in the shorter-term.

1.1.3 Research motivation three: Influence on utility-scale generation and storage.

Market participants that deploy utility-scale generation and storage systems require a clear understanding of future grid demand in both its magnitude and temporal characteristics. With utility assets being long-lived capital assets that provide different services, changes in grid demand creates the risk that the technology portfolio of future utility-scale generation and storage systems may be over- or under-capacity, leading to higher electricity prices. Furthermore, the relative value of pre-existing generation assets is dependent on present grid demand assumptions continuing into the future. With Australia's significant installed rooftop

PV capacity, the addition of battery systems will drive further changes in grid-utilisation. This leads to the third motivation, which aims to understand how utility generation and storage capacity is affected by changes in grid-utilisation from rooftop PV customers transitioning towards PV-battery customers, and the relative influence that retail tariff policies have on this change.

1.1.4 Research motivation four: Transitioning towards a customer-centric market design.

The framework of the liberalised electricity market is currently undergoing increasing pressure to change because of renewable energy technologies at both the utility- and customer-scale. The traditional approach has been to consider market frameworks from the top-down starting with the utility-scale. However, as the power sector is fundamentally designed to service customer electricity demand, it is vulnerable to disruption from the bottom-up. Therefore, there is a need to better to understand how traditional liberalised electricity market structures (that were designed around the one-way delivery of electricity) are impacted and challenged by customer PV battery adoption. This final motivation aims to evaluate the trajectory of change, and the steps that can be taken to pivot the electricity market towards a customer-centric system. With better understanding and awareness, policymakers may be able to utilise the adoption of PV and battery technology by customers (that uses private rather than public or corporate capital) to establish an alternative energy system and important decarbonisation pathway.

1.2 Scope, approach, and focus

This research evaluates the influence of customer PV battery adoption across the layers of the power sector under a liberalised electricity market framework. The South-West Interconnected System (SWIS) in Western Australia is used as a case study as it an isolated medium sized network with a single major load centre based near Perth, Australia. These characteristics eliminate the need for assumptions on adjacent interconnected markets, multiple major load centres, and time zone differences. The SWIS also has sufficient scale to justify a wholesale electricity market with competing market participants. The primary focus is on household electricity customers (as opposed to commercial and industrial customers), which constitutes around 30% of total electricity demand. With the power sector built upon expectations of future electricity demand, household electricity customers with PV battery systems may have a disproportionate effect on how electricity and revenue flows through a liberalised electricity market, while simultaneously disrupting the expected flow of incentives within the market framework. Due to the interdependent layers of the liberalised electricity market framework, the analyses are staggered to approach the problem at different scales. Figure 1 shows a representation of the interdependencies between the multiple layers of a liberalised electricity market, and how the research gradually develops towards a whole-of-system analysis using a combination of quantitative and qualitative methods. The bottom-up approach used in this thesis is necessary to capture the range of influencing factors and potential outcomes from growing customer PV battery adoption. Starting from the individual household and scaling up through the various electricity system layers, generalisations and contexts around sensitivity are established. This allows modelling assumptions to be further simplified at higher layers while also preserving the granularity of the overall analysis.

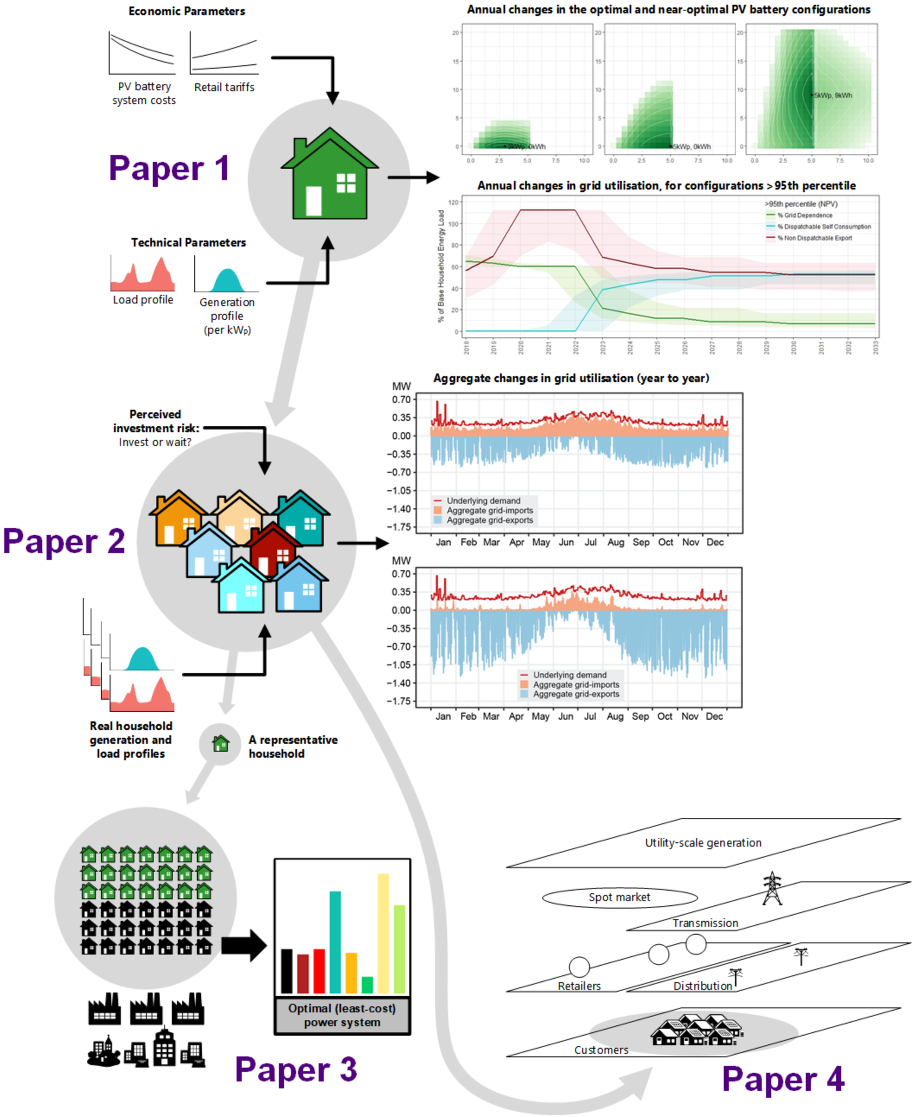

Figure 1. Bottom-up and multi-layered approach used in this thesis and the resulting publication strategy.

1.3 Research questions and objectives

A main research question is used as a guiding principle. By answering this question across different scales and layers of the power sector, the structure and objectives of the thesis are formed.

1.3.1 Guiding research question

How can the growth of customer PV battery adoption drive liberalised electricity markets to evolve; and how could policymakers use these evolutionary forces to further electricity system decarbonisation?

1.3.2 Research questions

The following four questions are used to address the guiding research question at different scales, from individuals through to the entire electricity system:

1. What is the relationship between electricity prices and household PV battery adoption?

This is the primary research question evaluated in Chapter 3, which was published in 2018 as a journal paper in *Energy Policy*, titled *"The coming disruption: The movement towards the customer renewable energy transition".* This paper will be subsequently referred to as '*The coming disruption'*. In this paper, a single synthesised household load and PV generation profile is used as the basis to evaluate the following sub-questions:

- *How do electricity prices, feed-in tariffs and system prices influence the adoption of PV battery systems over time?*
- *What changes in electricity demand can be expected from a future PV battery household?*

2. How does the prospect of future household PV battery adoption influence how retailers design their retail tariff offerings?

This is the primary research question evaluated in Chapter 4, which was published in 2019 as a journal paper in *Energy Policy*, titled *"Power to the people: Evolutionary market pressures from residential PV battery investments in Australia"*. This paper will be subsequently referred to as '*Power to the people'*. In this paper, 261 real household load and PV generation profiles are used as the basis to evaluate the following sub-questions:

- *To what extent can retailers adjust feed-in tariffs before households move from PV to PV-battery systems? How does this affect future retailer revenues?*
- *As an overall sector, how could PV battery adoption by households change the financial and technical relationship between liberalised electricity markets and their customers?*

3. What impact could household PV battery adoption have on utility-scale technology portfolios?

This is the primary research question evaluated in Chapter 5, which was published in 2020 as a journal paper in *Applied Energy*, titled "*Degrees of displacement: The impact of household PV battery prosumage on utility generation and storage"*. This paper will be subsequently referred to as '*Degrees of displacement'*. In this paper, 261 real household load and PV generation profiles are used to establish a representative PV battery adopting household in 2030 and under various FiT scenarios. This is used to quantify the influence of PV battery households on operational grid demand (i.e., the demand that is observable by utilities), which provided the foundation to analyse future utility-scale technology portfolios. More specially, the following sub-questions are evaluated:

- *To what extent are future least-cost utility portfolios affected by households remaining with PV-only systems as opposed to PV-battery systems? What effect may there be on wholesale electricity prices?*
- *Which classes of utility assets are vulnerable under household PV battery adoption?*

4. What influence could household PV battery adoption have on the individual layers of the power sector and its overall structure?

This is the primary research question evaluated in Chapter 6, which was published in 2021 as a journal paper in *Energy Policy*, titled "*Molehills into mountains: Transitional pressures from household PV-battery adoption under flat retail and feed-in tariffs".* This paper will be subsequently referred to as '*Molehills into mountains'*. In this paper, the results from the earlier paper, *'Power to the people',* are used as the numerical basis to establish changing trends in grid-utilisation. These trends are then used to qualitatively assess how various layers of the liberalised electricity market are susceptible to change. More specifically the following sub-questions are evaluated:

- *To what extent are traditional structural assumptions of liberalised electricity markets undermined by an ongoing growth of household PV battery systems? And how will entities within this system have to adapt?*
- *What are the transitions patterns that emerge from ongoing household PV battery investment under time-invariant tariffs? What additional responsibilities should be placed on PV battery households to improve energy equity?*

1.4 Research methodology

As the research questions span a wide range of system scales, a range of assessment methodologies are necessary for modelling and analysis. Following the bottom-up approach, the primary method involves simulating the technical operation of PV battery systems to determine changes in electricity bills, which are then used to inform the decision-making process of electricity customers. A techno-economic model, based on financial investment theory, is used to model PV battery adoption as a series of annual investment decisions, where a wide range of PV battery combinations are treated as competing investment opportunities. By simulating investments in a dynamic manner, this approach allows greater granularity to be incorporated into how the scenarios evolve. Furthermore, with the investment case for upgrades of existing PV battery systems being modelled, path dependence along with its sensitivity to retail electricity policies (e.g., FiT pricing) can also be assessed.

The core methodology simulates (each year) the investment decision process for an individual electricity customer and uses discounted cash flow analysis to answer the following questions:

i. What is the most appropriate PV capacity to install?
ii. What is the most appropriate battery capacity to install?
iii. Given i. and ii., should a PV battery system be installed this year?

If a PV battery system is installed, then the customer's electricity load profile is updated and the range of investment decisions in the following year are affected. By the end of the simulation, changes in grid-utilisation and the timing and capacity of PV battery investments may be observed. These technical and financial perspectives provide a methodological foundation to model customer PV battery adoption as a singular capacity expansion problem, rather than separate PV adoption and battery adoption problems. Changes in the value and range of these PV battery investment considerations over time are evaluated in Chapter 3 *'The coming disruption'*.

By applying this methodology to a wide range of real household demand profiles, a clearer representation of the household sector may be established, along with their PV battery adoption pathways under different scenarios. As these changes affect electricity bills paid by these households, retailers are exposed to lost revenues as PV battery adoption rises. At the same time, retailers are capable of influencing the economics of household PV battery systems by pricing retail FiTs. This leads to dynamic feedback that have short- and long-term trade-offs for retailers that set the price of their FiTs. These conditions and their feedbacks are evaluated in Chapter 4 *'Power to the people'*.

By simulating household PV battery adoption pathways under different scenarios, changes in grid-utilisation are calculated. By further assuming that these future grid-utilisation changes are representative of all prosumer households within an electricity system, future changes to the whole-of-system annual demand profile may also be calculated. This provides the means to evaluate the impact of household PV battery adoption on utility-scale technology portfolios (which depend upon the whole-of-system annual demand profile). Using a least-cost utility-scale investment and dispatch model coupled with the developed household PV battery adoption model, the influence of different PV battery adoption pathways on various utility-scale technologies may be established, including the impact to other renewable energy technologies and wholesale electricity prices. These impacts and observations are evaluated using counterfactual analysis in Chapter 5 *'Degrees of displacement'*.

With PV battery technology, households have gained the ability to significantly change their grid-utilisation in response to retail tariff price signals. This does not only affect future retailer revenues and utility-scale technology portfolios (i.e., Chapters 4 and 5), but also network capacity planning, the commercial relationship between customers and retailers, whole-of-system operation, and the flexibility requirements of utility generators. This results in a broad scope of change that evolves over time and across each layer of the liberalised electricity market framework. Using a purely quantitative approach to capture this scope faces significant challenges, due to the exponential increase in the number of assumptions. A mixed quantitative and qualitative approach provides an alternative method. As the core methodology in this thesis simulates ongoing PV battery adoption in response to retail tariff price signals, it provides the means to numerically establish how household grid-utilisation patterns may change over time (i.e., a trend). Trend analysis is then used as a foundation for a qualitative discussion on the sectors of the electricity market that are vulnerable to ongoing household PV battery adoption. The qualitative approach provides the flexibility to establish the breadth of change, and how different market sectors may be forced to transform as a consequence of changing household grid-utilisation. This mixed quantitative and qualitative approach is applied in chapter 6 *'Molehills into mountains'*.

1.5 Relevance and contributions to knowledge

The core role of the power sector is to provide society with the energy (in the form of electricity) that it needs to function. Due to its critical importance its stakeholders and decision makers span the technical, economic, social, and political domains. Over time, power sector responsibilities and participant incentives have transitioned (across many jurisdictions) into liberalised electricity market frameworks, with its various boundaries and layers of interconnection and absence of central planning. Transitional planning for the power sector has traditionally favoured a top-down approach, centred around an economic aim of incentivising the lowest cost of supply (from utility-scale generation), and internalising environmental and social externalities through centralised policies, such as renewable energy portfolio standards or carbon taxes and the design of fair and reasonable retail tariffs.

PV battery technologies are a relatively recent innovation that enables customers to actively participate in the power sector. With its long lived assets and need for long-term planning, power sector market design has focused primarily on the integration of utility-scale renewable energy technologies and as a result, underestimated the capacity of customers (in aggregate) to challenge long-term assumptions on grid demand and its utilisation (AEMO, 2018, p. 81). Previously with customers not being able to self-generate, it was sufficient for long-term top-down planning models to assume future grid demand as an exogenous input. However, with customers gaining the ability to react to retail price signals and technology costs, the evolution of the power sector is becoming increasingly affected by customer expectations.

This research develops modelling and analysis techniques to represent customer expectations, their propensity to install PV battery systems, their impact on the electricity market, and their changing role within the power sector. As an emerging source of renewable energy, this would improve the understanding of their energetic and market potentials and how they may be leveraged to encourage further decarbonisation of the electricity sector. This would provide policymakers with a greater degree of confidence to support a customer-led energy decarbonisation pathway and provide planners and decision markers with a better understanding of its implications. The developed model and data have also been released as open source to facilitate the transparency and reproducibility of this research. This thesis focuses on the renewable energy transition occurring at the customer level, to firstly understand the extent of change that residential PV battery systems can have on the wider power sector, and to secondly identify the policy levers that influence the evolution of this customer-led transition along with their trade-offs.

Across the range of published research papers in chapters 3, 4, 5, and 6, this thesis establishes:

- The relationship between time invariant two-part retail electricity tariffs and household PV battery adoption as technology costs improve and electricity prices rise.
- The lost revenue implications (both short and long-term) for electricity retailers from the continued use of time invariant two-part retail tariffs.
- The influence of grid-utilisation changes by PV battery households on the least-cost portfolio of future utility-scale generation and storage technologies.
- The impact of growing PV battery adoption on the operation and planning of the electricity system, the wholesale spot energy market, the flexibility of its generation assets within the liberalised electricity market framework.

These research contributions are designed to complement existing top-down studies on power sector decarbonisation. By understanding the potential scale and extent of changes from customer PV battery adoption along with their economic drivers, this research provides planners, policy, and decision makers with a better understanding of how to capitalise on private investments by customers into their own energy assets in order to accelerate the renewable energy transition.

1.6 Thesis outline

This thesis is intended to be read from the beginning to end. With four peer-reviewed publications included in chapters 3, 4, 5, and 6 each with their own introduction, methodology and conclusion.

Chapter 1 provides the scope, research questions, methodological approach, and significance of the research. It frames the research within the context of Australia's renewable energy transition and the potential lessons it offers to researchers in other jurisdictions.

Chapter 2 presents the literature review across three main themes. Firstly, the context in which energy system transitions take place and how they can be modelled and studied. This requires a review around the structure and complexity of the power sector, followed by a range of qualitative and quantitative analysis techniques. Secondly, the various methods used to model behind-the-meter PV battery adoption and the context in which modelling assumptions are established. Finally, a review on how the market design influences the deployment of customer energy assets and how customer energy assets in turn influence the market design.

Chapter 3 *'The coming disruption'* introduces the developed model. It is used to evaluate the influence of retail usage and feed-in tariffs on the dynamics of PV battery adoption across a household load profile. By assessing the effect of different feed-in tariff values, this research demonstrates that feed-in tariff policies influence the rate of adoption and transition point of PV battery systems, along with the span of possible system capacities that generate a positive return.

Chapter 4 *'Power to the people'* assesses the impact on future electricity retailer revenues from ongoing PV battery adoption. To better represent the adoption patterns of Australian households, the developed model is used to assess a wide range of customers with real-world demand profiles. This research establishes the relationship between setting the value of the feed-in tariff (that are a cost to the retailer) and subsequent electricity bill revenues.

Chapter 5 *'Degrees of displacement'* evaluates how changes in grid-utilisation from household PV battery adoption affects the least-cost utility generation and storage portfolios. This research assesses the extent to which different utility-scale technologies over the longer term are vulnerable to household PV battery adoption.

Chapter 6 *'Molehills into mountains'* uses a combined quantitative and qualitative analysis to evaluate how changes to aggregate grid-utilisation may affect the various layers within liberalised electricity markets (i.e., retailers, networks, and utility-scale generation). By evaluating changes in residual load as a systematic transition pattern, each market layer is assessed to determine the extent to which their underlying market design assumptions are challenged.

Chapter 7 summarises these four peer-reviewed publications with their limitations and how their analyses address the overarching research question and its four sub-objectives. The overall market design and policy implications are analysed followed by a set of policy recommendations to leverage customer PV battery adoption as a complement to power sector decarbonisation.

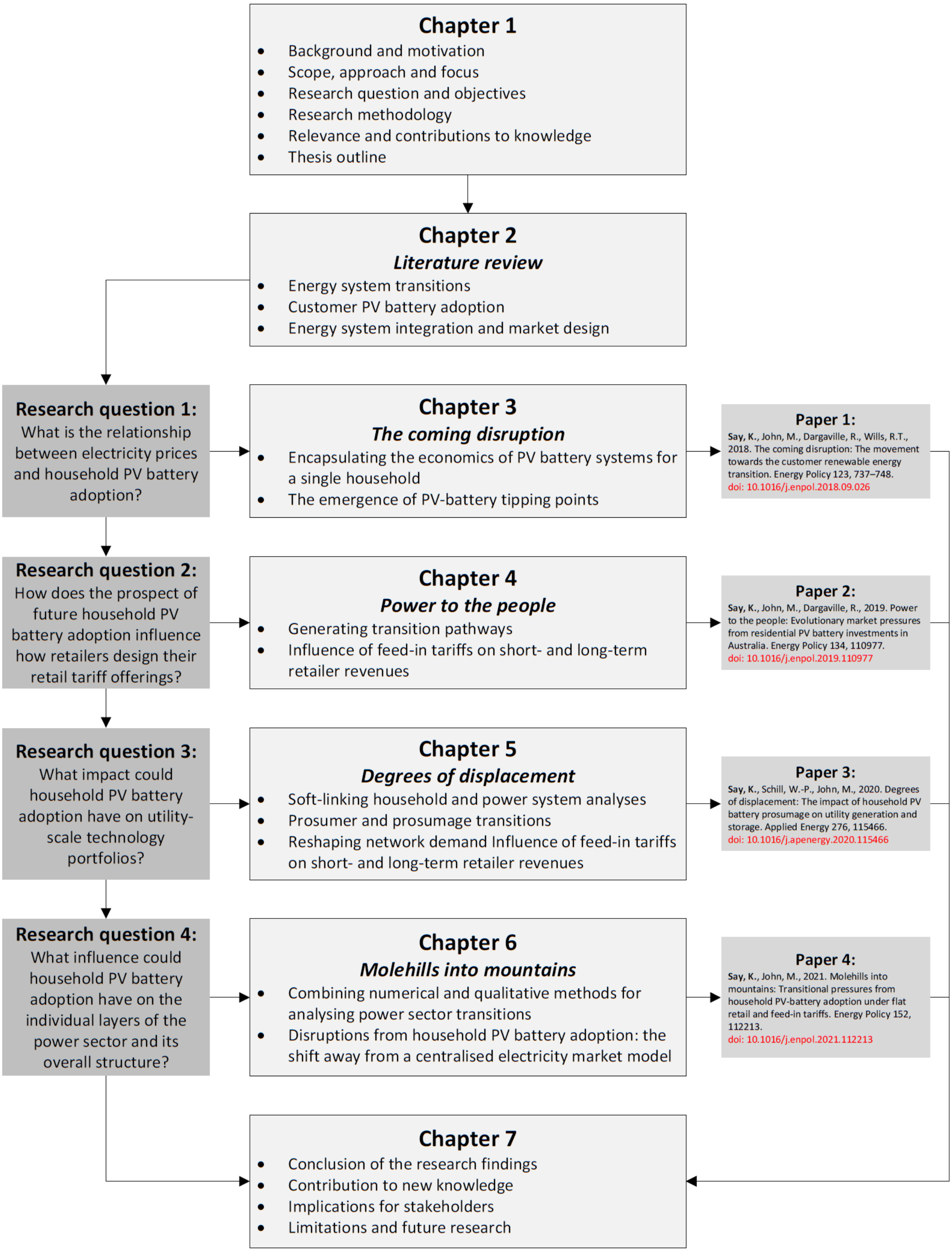

Figure 2. Thesis outline.

CHAPTER 2.

Literature review

This chapter reviews literature focused on the structural components of the electricity system and its socio-economic influences. The literature in subsection 2.1.1 establishes the interdependencies between the socio-economic, political, and technological domains and broadens an analysis of the 'electricity system' from a more generalised concept of an overall 'power sector'. From this perspective, the literature in subsection 2.1.2 shows the many inter-relationships and layers of the power sector are constantly co-evolving and reacting to both internal and external shocks. This suggests that the power sector is less deterministic, and more akin to a complex system. The literature on complex systems in subsection 2.1.3 is reviewed to establish a range of analytical methods and how they may be used analyse energy system transitions. As aggregate changes in customer demand affect the entire power sector, section 2.2 reviews the literature that combines socio-economic perspectives and techno-economic methodologies to model behind-the-meter PV and battery adoption. As the design of retail markets characterise the financial incentives available to customers with PV battery systems, section 2.3 evaluates their implications on market design as active customer participation increases. Shortcomings and gaps in the literature are identified in section 2.4. A more concise literature review is also provided within each peer-reviewed publication in chapters 3, 4, 5, and 6.

2.1 Energy system transitions

2.1.1 Influences on the electricity system

The electricity system is built on the principals of electromagnetics and technical engineering. Starting with rotating masses that generate electricity that are synchronised with one another, then transmitted across a high-voltage transmission network, before being stepped down at progressively lower voltages to be consumed by different electricity customer segments (i.e., industrial, commercial, and domestic). The build out of the electricity system requires significant physical infrastructure, from large-scale generators, fuel lines, import facilities and railways to transmission towers and wires, distribution poles and wires, that all branch out to millions of electricity customers.

A critical source of energy for society.

Bruckner et al. (2014) and Pfenninger et al. (2014) describe how the electricity system plays a critical function within society and requires a large amount of capital (to build, maintain, and operate), and the evolution of the electricity system is affected by more than its technical considerations. Firstly, the significant capital required to pay for generation and network infrastructure establishes the need to consider the long-term viability and strategic benefit of making an investment, along with the stability of economic incentives and policy settings that influence its financial returns. Secondly, as electricity is an essential service, there is a need to consider the socio-political implications of affordability and fairness across all electricity customers. Thirdly, as it is a critical source of energy for the economy, there is a need to ensure that it is both secure and reliable.[9,10] Finally, with electricity being the largest contributor of global greenhouse gas emissions, it is crucial that its energy sources are rapidly transitioned away from carbon emitting energy resources (Bruckner et al., 2014). These four factors continually influence the range of energy policies, the state of technological innovation, efficiency of energy markets, and project financing, which leads to the electricity system evolving over time. As described by DeCarolis et al. (2020), these factors span many fields of research and span a range of generation technologies with varying (and sometimes rapidly) changing costs, while utilising energy resources that physically depend on time and location while simultaneously being under the influence of public acceptance, behavioural change, and political decision making. Analysing electricity system transitions therefore shifts away from a technical evaluation towards a more general power sector perspective involving a wide range of stakeholders from consumer groups, electrical utilities, global manufacturing, value & supply chains, to political actors and organisations. These layers of influence subsequently increase the complexity of analysis, which draw parallels with the field of complex systems science.

A system of complex actors and interactions.

A complex system can be defined as any system that consists of a large number of heterogenous components (or agents), within an environment of limited resources that interact and learn (i.e., co-evolve) from one another (Carmichael and Hadžikadić, 2019;

[9] https://www.aemc.gov.au/energy-system/electricity/electricity-system/security
[10] https://www.aemc.gov.au/energy-system/electricity/electricity-system/reliability

Holland, 2006). A feature of complex systems is that these interactions lead to emergent behaviours that cannot be predicted by only analysing its individual components (Ottino, 2004). Cherp et al. (2011) extends earlier work from Axelrod and Cohen (1999) to further characterise a complex system as being *unpredictable* (i.e., past behaviour does not reliably predict future behaviour), *non-linear* (i.e., small changes can have major consequences), *path dependent* (i.e., historical decisions limit future choices), *open* (i.e., system boundaries cannot be explicitly defined and are constantly interacting with its environment), and is both *adaptable* and *resilient* (i.e., capable of adapting to external circumstances and maintaining its operation under external shocks). The science of complex systems has been applied in the fields of physics, biology (Kitano, 2002), ecology (Grimm et al., 2005), economics (Arthur, 2015), and social science (Epstein and Axtell, 1996). In the field of energy systems, Bale et al. (2015) in p. 152 contextualises the relationship between energy systems and complexity as:

> *"Energy systems exhibit complex social and technological dynamics, including the complexity inherent in the technological systems and infrastructure, by which energy is converted, transmitted and distributed in order to provide useful energy services to households, industry and businesses, and in the related actors and social institutions, policies and practices that influence these systems.*
>
> *[…] From a complexity perspective, energy systems are made up of (1)* ***agents****, interacting through networks under the influence of institutions, which gives rise to emergent properties and co-evolutionary dynamics, (2)* ***objects****, such as technologies and infrastructures, which are relatively stable in the short term, but whose adoption is dynamic, and (3)* ***the environment****, which provides resources and also establishes social, political, and cultural scenarios in which the energy system operates.*
>
> *The key agents in energy systems include household and business energy users, energy conversion and supply companies, economic and environmental regulators, and governments (local and central). These agents are able to adapt and respond to other agents and objects, but are heterogeneous and lack the perfect rationality and foresight of 'representative agents' in many economic models (Foster, 2005). They interact through physical and social networks, by sharing information or learning from one another, influenced by social norms and institutional rules. This may lead to self-organisation and emergent properties, such as common practices for energy use or particular market*

frameworks governing energy supply. These interactions change over time according to dynamical rules which emerge with the availability of new objects, policies and so on, but, as both technologies and institutions are subject to non-linear increasing returns (positive feedbacks) to adoption, change is path-dependent and systems are subject to lock-in (Arthur, 1989; North, 1990; Unruh, 2000). This means that potentially advantageous innovations may not be adopted if they do not fit with the current system."

Electricity customers are key agents in the energy system, which are increasingly gaining access to PV battery technology (as these mature and costs decrease). As stated by Bale et al. (2015), the market framework in which customers engage with is an *emergent* property of self-organisation (between agents, objects, and the environment), and reflects the technology available at the time and the expectations of customers. Therefore, as electricity customers become increasingly capable of generating and storing their own energy, the market framework itself comes under increasing pressure to adapt and change. However, before the future role of electricity customers is considered in this review, it is necessary to establish how the electricity market framework emerged.

2.1.2 The emergence of the liberalised electricity market framework

The roles within the structure.

The supply of electricity has traditionally relied upon large thermal generators, e.g., coal-fired power plants, and centralised networks to transmit electricity to customers, which were primarily dependent on grid-sourced electricity. With electricity supply being an essential service that involves significant costs with planning, expertise and infrastructure, which also cannot be easily duplicated, it is a form of natural monopoly. Joskow (2008) describes how power sector development predominantly started as vertically integrated monopolies (either a state- or privately-owned), subject to regulations on price and entry, and resided within separate geographic regions. As vertically integrated entities, the core components of electricity supply (i.e., generation, transmission, distribution, and retail services) were managed as a single regulated monopoly. By having a single organisation manage electricity provision and long-term planning, coordination can more easily directed however at the expense of competitive forces. However, over time, high retail electricity prices, high operating costs, and ongoing cost overruns persisted. As new technologies emerged that were more efficient (e.g., CCGT) and utilised lower cost fuel (i.e., natural gas), reforms were introduced to the power sector in order to create downward pressure on electricity costs and retail prices. The aim was to develop new institutional structures that would allow retail electricity prices to reflect the efficient economic cost of supplying electricity, and at the quality of service expected by customers. These reforms led to development of liberalised electricity markets that specifically introduced the following:

- A *competitive wholesale market* for generation. The purpose of the wholesale market is to improve incentives for controlling the operation and construction costs of existing and new power capacity, while encouraging further innovation of power supply technologies. The wholesale market effectively shifts the cost of mistakes (e.g., capacity, technology choice, construction) from electricity customers to the suppliers.
- *Retail competition* to provide customers with the freedom to choose a retail supplier with an appropriate price and quality of service, while creating space for retailers to introduce further pricing innovations (e.g., demand management) that better matched customer expectations and preferences.
- *Transmission and distribution* networks remain as regulated monopolies that operate under performance-based regulation that direct network owners to provide an appropriate quality of service for both customers and generators.
- Creation of *independent regulatory agencies* to ensure that market and regulatory structures are appropriately managed. These agencies need access to good quality information on costs, quality of service, and the comparative performance of other regulated network services, in order to enforce the regulatory requirements, and to set appropriate prices and the terms and conditions for transmission and distribution companies.

Under the liberalised electricity market framework (Figure 3), the electricity supply value chain is separated into different services that are either competitive markets (i.e., generation and retail) or regulated monopolies (i.e., transmission and distribution). Within the generation and retail markets, many private firms compete for market share and service quality, while in the transmission and distribution sector, spatially segregated portions of the network are owned and operated by different firms under a regulated monopoly model.

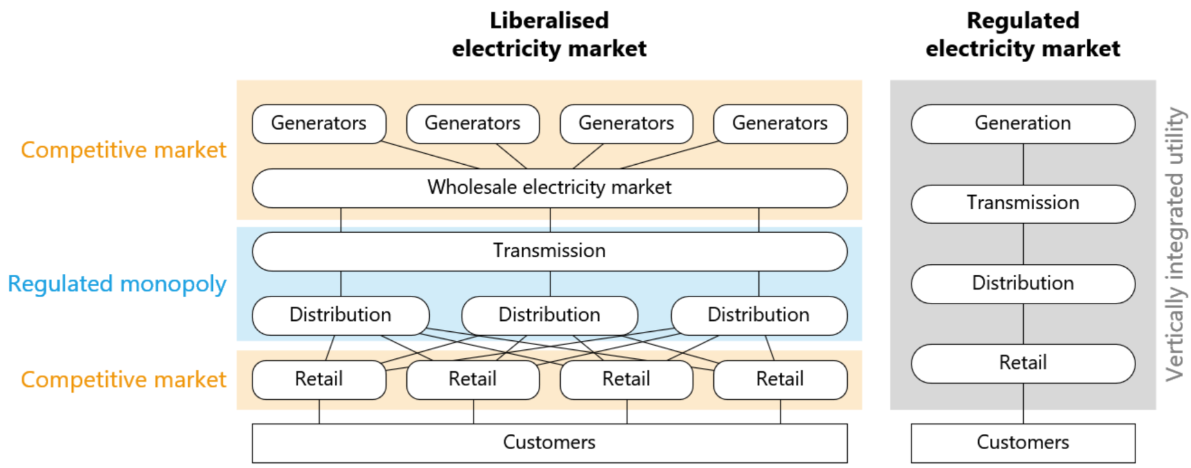

Figure 3. Liberalised electricity markets compared to regulated electricity markets with vertically integrated utilities.

This framework shifts governmental responsibility of electricity supply, away from a build, operate, and maintain model, towards one where it is responsible for creating and maintaining independent regulatory authorities that oversee its operation, which also allows previously vertically integrated state-owned enterprises to be privatised. This led to the phasing in of liberalised electricity markets (IEA, 2005) beginning with the United Kingdom in 1989, Nordic nations in 1991, Australia in 1994, and PJM in the United States in 1996 and extending into many other national or sub-national jurisdictions since then (IEA, 2017, p. 16).

Structurally, the process of market liberalisation separates responsibilities of the power sector into different market segments. Generation companies, retail companies, network owners, market operators, and regulators each become actors with their own responsibilities and objectives (Figure 4). To protect against market failure, it is further necessary to segregate flows of information and revenues between market participants and across market segments (i.e., ring fencing). This also prevents cross-subsidisation of services that can lead to unfair competition. For example, if network owners are able to control the dispatch of their own localised generators within their monopoly jurisdiction, they have significant market power over other generators. As jurisdictions have transitioned to liberalised electricity market frameworks, it has been crucial that rules are defined such that specific roles and revenue streams within each market segment are clearly prescribed for each participant.

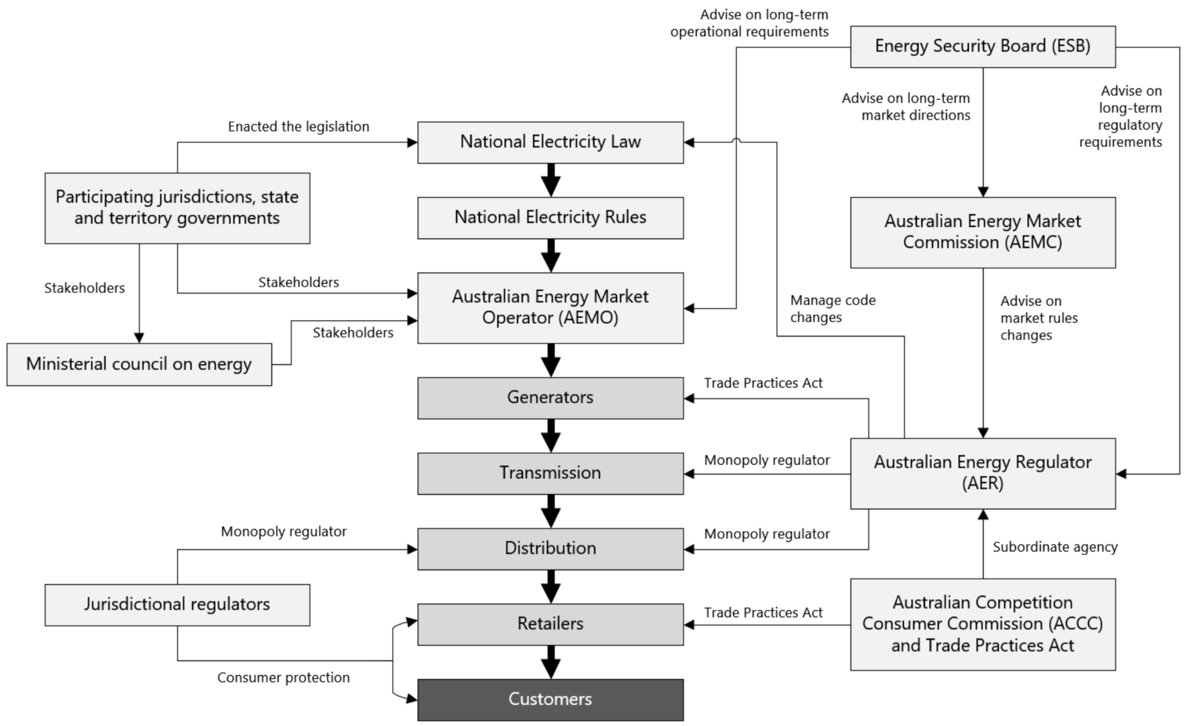

Figure 4. The range of actors within Australia's liberalised electricity markets. Adapted from Byrnes et al. (2013).

Integration of utility-scale renewable energy generation.

These boundaries of separation distribute the planning and operational responsibility of the power sector across many institutional actors and removes the role of a central coordinator or planner. From a systems perspective, this disaggregation creates further interdependencies and structural layers leading to additional system complexity, especially when evaluating the power sector over time. As noted by Bale et al. (2015), this market framework is a property of self-organisation that emerges from the state of technology, its users and the environment it resides within. As the state of technology changes, the market framework naturally comes under pressure to evolve. As electricity market liberalisation began before the arrival of cost-effective renewable energy generators, many of its design assumptions were based around the available technology. The competitive wholesale generation market was designed around conventional (i.e., non-renewable) power plants with fuel costs being the dominant cost of generating electricity. In the wholesale spot market, a competitive advantage was given to generators with lower operating costs (i.e., short-run marginal cost). Only the set of generators with the lowest short-run margin costs were allowed to collect revenues and dispatch onto the network to meet the capacity of forecasted demand. This market structure favoured a near constant (i.e., baseload) use of large capacity and low fuel cost generators (e.g., coal) coupled with the occasional use of smaller capacity but higher cost peaking generators (e.g., open-cycle gas turbines). To support these particular power plants, transmission networks were designed around providing capacity to a small number of large centralised thermal power plants. However, as utility-scale renewable energy generators entered the technology mix, its techno-economics began to challenge the base assumptions of the existing market framework and started to expose areas of weakness. As a new type of generator, wind and utility PV generators had weather-dependent generation capacity, but zero fuel costs. This meant that the short-run margin costs of wind and solar PV generators were near-zero, and they could dispatch ahead of conventional generators. Initially, this provided these renewable energy generators with a significant competitive advantage, while reducing wholesale energy prices in the process. This came to be known as the *merit order* effect (Sensfuß et al., 2008). Over the medium term, a system with wind and utility PV generators continued to rely upon complementary capacity to ensure that customer demand continued to be met by all generators. However, with wholesale electricity prices falling, the risk for new generators to enter the market increases, leading to an underinvestment in system capacity, i.e., the *missing money* problem (Hildmann et al., 2015; Newbery, 2016). Notably, there is also a paradox where the continued growth of renewable energy generation requires the continued presence of fossil fuel generation to ensure that spot prices remain high enough to recover long term costs for renewable energy generation (Blazquez et al., 2018). Furthermore, with wind and utility PV having very specific locational requirements that rarely overlap with existing topological network capacity, existing transmission networks have become increasingly congested leading to generator curtailments (Bird et al., 2016) and requiring further network expansion (Sun et al., 2018; Wang and Dargaville, 2019). However, with networks being a regulated monopoly, the regulator has to approve network expansion such that the economics benefits of providing access to complementary renewable energy resources outweighs any increase in overall network costs (Schaber et al., 2012). Due to significant uncertainties with future demand and renewable energy resource potential, this process has become especially challenging for regulators to forecast and has led to approval delays, impacting the ability of the electricity system to gain access to complementary renewable energy capacity (Schroeder et al., 2013; Wright, 2012). Furthermore, the degree of uncertainty with renewable energy generation and an overall reduction in system inertia, has increased the role for ancillary support services, e.g., frequency regulation and contingency management, leading to the growth in these support markets (Newbery et al., 2017; Rai and Nunn, 2020).

As electricity generation and energy storage technology continues to develop, the liberalised electricity market framework will need to continue evolving. This process however is neither linear nor straightforward, as it is the existing market framework that determines specific areas of opportunity for innovation to occur, at the same time the actual deployment of these innovations subsequently exposes weakness in the market framework that require further changes. It is through these cycles of change that the power sector evolves. Therefore, in order to analyse how a power sector may change over time and how different policies and decisions can influence this, it is necessary to develop the means to incorporate these dynamic adaptations.

2.1.3 Complexity of power sector transitions

Li et al. (2015) states that the dominant approach has been to focus on formal energy economic models that assume perfect information, utility and profit maximisation, and rational choices. Typically, techno-economic models are used to determine the least-cost solution for a future electricity system (e.g., Jeppesen et al., 2016; Ziegler et al., 2019). Socio-technical factors that are challenging to quantify and model endogenously are generally represented as exogenous input parameters and scenarios, e.g., future installed capacities of household PV battery systems and electric vehicle adoption (AEMO, 2020a). This approach is capable of capturing the constraints of a system to determine a numerically "best" solution but lacks the flexibility to derive a range of alternative solutions (Neumann and Brown, 2021; Trutnevyte, 2016) and structural factors that are also influencing the energy transition, such as the evolution of market design amid changing competitive behaviour and customer expectations. Li et al. (2015) notes that these broader political, social, and behavioural aspects have been typically left to the end-user to frame exogenously.

Numerically modelling complexity.

Many of the market framework components (i.e., technical, economic, and geospatial layers) can be quantified, while additional considerations, such as the socio-political expectations of leaders and customers, are more qualitative in nature. Together these threads and layers of influence continually interact and adapt (i.e., co-evolve) akin to a complex ecosystem. Methodological frameworks from the field of complexity science can help to compartmentalise, model, and evaluate how system level effects occur, what they are dependent upon and how they may emerge from the bottom-up. Bale et al. (2015) identifies a range of computational modelling frameworks beginning with,

- *Equation-based models* that translate the quantifiable portions of the electricity system into a set of numerical parameters and equations, which are then used to evaluate system-level outcomes, such as its dynamics, uncertainty, and sustainability. Examples include computable general equilibrium models (e.g., Crespo del Granado et al., 2018), system dynamic models (e.g., Agnew et al., 2019), and least-cost optimisation models (e.g., Schill and Zerrahn, 2018).
- *Agent-based models* that focus on defining the behaviour of different individuals and how they interact, which are used to simulate interactions from the bottom-up and how it may lead to emergent system-level outcomes (Bonabeau, 2002; Rai and Henry, 2016). This approach allows modellers to explicitly define and distribute different human behaviours and decision-making processes for analysis. It also allows spatial factors, feedback and rebound effects to emerge, rather than being approximated in equation-based models. Examples of agent-based models include Barazza and Strachan (2020); Boulaire et al. (2019); Chappin et al. (2017); and Kraan et al. (2019).
- *Network theory models* that focus on the relationship between the number of nodes and the number of edges between these nodes. By translating different aspects of the energy system as a node (e.g., network capacity, customer influence, information), it allows their structural dependencies and adjacencies to be analysed as the number of nodes increase or change. This approach has been used to evaluate the growth of smart grids (Pagani and Aiello, 2014), the robustness and resilience of real networks (Ezzeldin and El-Dakhakhni, 2019), the effect of social networks on technology diffusion (McMichael and Shipworth, 2013), and to identify the critical of components in an electricity system (Milanović and Zhu, 2018).

These computational modelling frameworks are built on numerical foundations and rely upon *all* parameters (and interactions) that influence the system in the future to be *explicitly* defined. As the level of detail increases, there is an exponential increase in the amount of computation resources required. This means that developing a single model that represents each and every dimension of the power sector quickly becomes computationally and analytically intractable.

Rather than a single model approach, DeCarolis et al. (2020) propose using a macro-energy systems framework that distributes the research problem across separate but collaborating modelling teams. These modelling teams provide the expertise to examine and combine the quantitative technical and economic and qualitative social and policy dimensions. Rather than limiting the research scope to fit within a specific expert community, this collective approach allows a broader analysis of power sector transitions. In addition, energy system models have traditionally relied upon propriety models and commercial datasets making it inaccessible to other researchers (Gardumi et al., 2018; Morrison, 2018). DeCarolis et al. (2020) further suggest that open-source models, tools, and datasets should be used to allow information to flow freely between teams and facilitate collaborative analysis.

Combining numerical and qualitative methods.

This macro-system energy approach builds on the meta-theoretical framework by Cherp et al. (2018), that considers transitions within the power sector as the result of three interrelated systems, namely (i) a **techno-economic** system based on energy system analysis and economics, (ii) a **socio-technical** system based on evolutionary economics and the sociology of technology, and (iii) a **political** system based on political science. Cherp et al., (2018) emphasises the importance of the third political dimension as it often sets the boundary conditions that define the environment of the socio-technical system. Compared to socio-technical systems research, political science contains a range of techniques that better explain political will, special interests, and public concerns, especially when energy policies begin to influence public concerns, e.g., NIMBY-ism (van der Horst, 2007).

These authors present modelling frameworks that reduce the power sector into a number of interacting subsystems, spanning both quantitative and qualitative models. These modelling frameworks are useful to evaluate explicit changes in input assumptions (e.g., technology costs) and system boundaries (e.g., emission constraints), but are less well suited to generating a wide range of future possibilities and pathways. This is because the power sector is an open system (Cherp et al., 2011) with future influencing factors remaining unknown at the time of analysis (e.g., the unexpected 90% reduction in PV costs between 2010 and

2020).[11] The alternative is to consider the power sector from a more general complex ecosystems perspective.

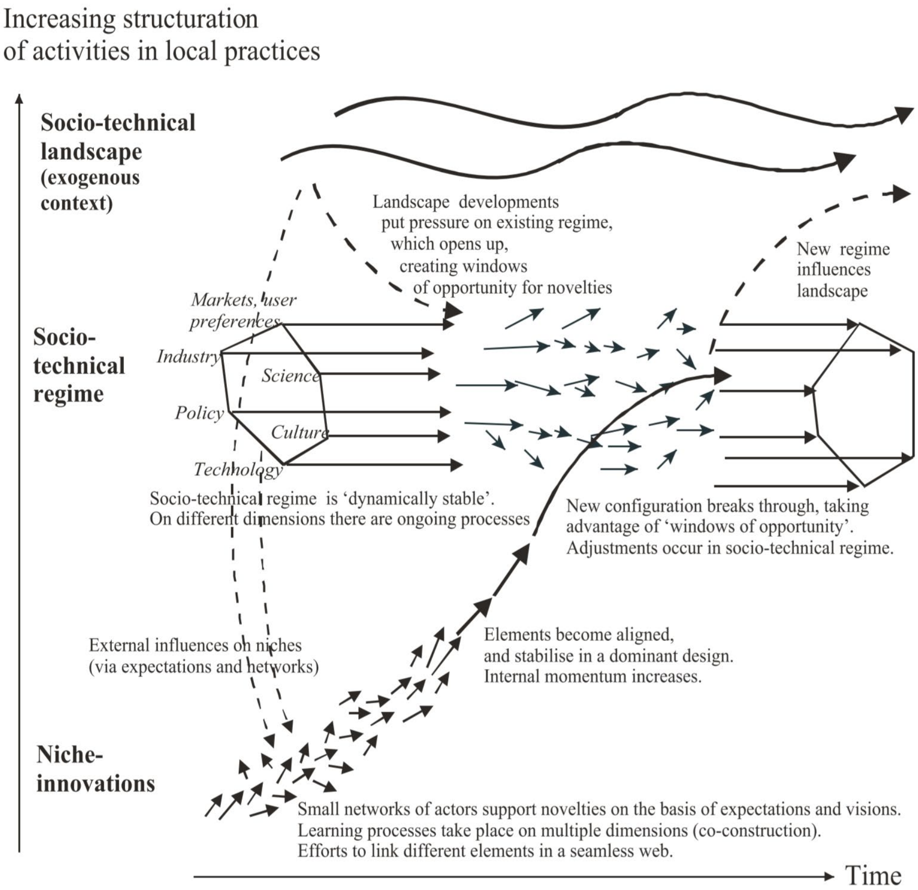

Figure 5. Multi-Level Perspective on Socio-Technical Transitions. Source (Geels, 2011).

Geels et al. (2017) builds upon concepts from ecosystem research to define the Multi-Level Perspective (MLP). This is a qualitative socio-technical framework (Figure 5) used to describe the power sector as a dynamic landscape, with new innovations constantly attempting to find a niche within an existing regime. Occasionally, some of these innovations are able to establish a niche which then grows to such a point that it changes the existing rules. It then continues to grow and until it eventually destabilises and supplants the previously dominant regime. This framework allows an evaluation of power sector transitions from a purely qualitative perspective, and does not limit the examination of future pathways to only those that are currently quantifiable. Wainstein and Bumpus (2016) considers how renewable energy technologies are enabling business model innovations that in turn create niches that

[11] https://www.greentechmedia.com/articles/read/solar-pv-has-become-cheaper-and-better-in-the-2010s-now-what

drive further renewable energy adoption. For example, they examine a new retailer business model that installs rooftop PV systems at no cost to the household in exchange for a commitment by the household to purchase electricity only from this retailer (priced lower than from the grid) over the next 20 years. From a single upfront cost investment, this business model allows the retailer to continually collect credits from rooftop PV generation (some of which is returned to the customer through lower electricity prices) while securing a long-term customer. This scheme reduces the capital required for households to install rooftop PV systems and may accelerate its wider adoption. Wilkinson et al. (2020) evaluate Western Australia's electricity system between 1880 and 2016 to characterise the time periods in which the system was under different transformative pressures. They explain that the rapid adoption of rooftop PV and growing potential of household battery systems is creating a niche around customer DER. They conclude that the overall landscape of the electricity system is at a critical juncture. If the system is able to develop integration strategies for customer DER, it would likely reconfigure itself to take advantage of these resources. However, if it does not, the system would likely enter a period of de-alignment before developing the means to realign itself. The qualitative evaluations from the MLP provide a broader understanding of the commercial, socio-technical, and policy conditions necessary to enable and drive transformative change. This differs from explicit modelling frameworks that, by design, focus on specific outcomes rather than the range of available pathways and their contingent factors.

Evaluating power sector transitions through the sole use of computational modelling frameworks is limited by the inability to completely quantify all future influencing factors. However, models can provide researchers with the means to establish a range of plausible future scenarios that can then be qualitatively evaluated. Approaches such as the MLP qualitatively examine how the growth of niche processes may reshape the power sector in the future. These two approaches may be coupled through scenario planning and analysis (Cornelius et al., 2005). The strength of a computational modelling framework lies in its ability to retain the quantitative constraints of a system while achieving one or more objectives (e.g., lowest cost). However, this outcome results from a set of input parameters that are exogenous to the model. This is where scenario planning and analysis can strengthen computational modelling frameworks, by refining these exogenous input parameters through a qualitative process of developing narratives that describe future operating states, with each storyline corresponding to a distinct scenario for analysis (Swart et al., 2004).

Moallemi and Malekpour (2018) utilised a participatory process, aided with computational models, to improve the robustness of long-term power sector decarbonisation policies. The first step involved collecting qualitative storylines from participants to determine the requirements and granularity of a computational electricity system transitions model. The next step required participants to answer problem-focused, exploratory, and forward-thinking questions to identify a range of distinct scenarios to be evaluated by the model. The model was run for each of these scenarios and results used by participants to evaluate policy outcomes and improve its overall robustness. With the electricity system being quantitively constrained while spanning a wide range of knowledge disciplines, this process provided policymakers with tangible feedback of their policy intentions and the dependencies that these policies relied upon. This participatory process moved away from exact solutions and focused on creating an environment to facilitate contingency planning and robust policy creation. Similarly, Chilvers et al. (2017) developed three narrative storylines through the collaboration between policy analysts, engineers, and social scientists for the low-carbon transition of United Kingdom's economy and society. These three energy transition scenarios were then used to define modelling input parameters for an integrated least-cost optimisation of the UK electricity system. This combined social science and energy systems approach provided a baseline for developers, policymakers and other stakeholders to understand the cost, environmental footprint, and technological implications for each of the low-carbon transition pathways. This approach has been applied in Germany (Witt et al., 2020), Canada (Dolter, 2021), Denmark (Venturini et al., 2019), and also used by Australia's independent market operator for future system operation and renewable energy resource planning (AEMO, 2020a; Energy Transformation Taskforce, 2020). However, with cognitive biases playing a role (Morgan and Keith, 2008) the actual process of selecting scenarios may increase the perceived plausibility of the scenarios selected (which are designed to be mutually exclusive rather than comprehensive) with its participants and audience while discounting the larger number of scenarios not selected for analysis. This approach therefore requires careful consideration when interpreting and discussing results in order to ensure that model-based insights are being communicated to policy and decision makers, rather than creating an expectation that exact solutions have been found.

The complexity of power sector transitions arises from both (i) the external techno-economic, socio-technical, and political landscape, and (ii) its continually adapting internal structure and configuration. By integrating the quantitative and qualitative factors into power sector transition analysis (Cherp et al., 2018; Hof et al., 2020; Turnheim et al., 2015), researchers improve the advice and information provided to policy and decision makers. Given that the decarbonisation of the global energy system needs to continue accelerating (COP21, 2015), it increasingly requires as many plausible transition pathways to be considered and evaluated.

2.2 Customer PV battery adoption

The ability of electricity customers to install their own PV and battery systems provides them with the operational capability to generate and store their own energy. It also enables customers to directly participate in the decarbonisation of the energy system and has created a new market niche within the power sector. Presently, the continued development and deployment of utility-scale renewable energy technologies is forcing the power sector to adapt. A widespread adoption of customer-scale PV and battery technologies further affects the power sector by redefining the quantity and profile of future electricity demand and the way in which customers engage with the electricity network. This change directly challenges a traditional electricity supply service model (with electricity customers only consuming energy). The power sector is therefore under increasing pressure to adapt simultaneously at both the utility and customer scales. The high and growing levels of rooftop PV adoption in Australia places it at the forefront of this transition (APVI, 2020).

As changes in generation technology adapts at the utility-scale, prices and costs continue to propagate through the supply chain. This is especially relevant within a liberalised electricity market framework, with its formal service layers (i.e., generation, networks, retail) and expectation that the remuneration of efficient service costs are borne by all customers. Therefore, as the power sector undergoes significant changes with utility-scale generation, customers become indirectly involved due to changes in retail electricity prices, tariff structures, policy incentives, and regulatory constraints. These changes affect customer expectations and shape their motivations to install their own PV battery systems. In subsection 2.2.1, the literature on the socio-economic and motivating factors is reviewed to establish the influencing factors that drive the adoption of customer PV battery systems. In subsection 2.2.2, the literature on techno-economic modelling of customer PV battery systems is reviewed to evaluate the breadth of research questions and supporting methodologies. In subsection 2.2.3, the literature on customer adoption dynamics is reviewed to establish the mechanisms used to model transitions in customer demand and then incorporated into wider power sector transition analyses. These subsections establish the qualitative and quantitative context for customer PV battery adoption and the methodologies that underpin the modelling research in this thesis.

2.2.1 Socio-economic and motivating factors

Before evaluating the mechanisms to model the adoption of PV battery systems, it is necessary to first consider the factors that drive their adoption. This can be broadly characterised as either socio-economic factors (i.e., situational context) or motivational factors (i.e., intentions and expectations).

Sommerfeld et al. (2017) utilised postcode and census data with regression tree analysis to quantify the influence of demographic variables on the adoption of rooftop PV within the greater Brisbane area (population of 2 million people) in Australia. They found that home ownership has a strong influence on rooftop PV adoption, while education and income were less significant. These observations are consistent with studies in other countries, e.g., Germany (Schaffer and Brun, 2015) and Malta (Briguglio and Formosa, 2017). Further analysis of Australian postcode data by Best et al. (2019a) also indicated that mortgage holders have higher rooftop PV adoption rates. These studies highlight the importance of home ownership on rooftop PV adoption where monthly bill savings can be used to recoup the cost of an upfront DER investment. Rental properties remain at a disadvantage, as the beneficiaries of a DER investment remain its tenants rather than the owners of the property.

Further research on the motivational factors of rooftop PV adoption identifies the importance of financial factors. Rai et al. (2016) surveyed the decision-making process of 380 residential PV adopters in northern California and found that the main determining factors were ‘expected financial returns’ and ‘concerns about operations and maintenance’. Bondio et al. (2018) evaluated survey results from over 8,000 households that were either intending to or have already installed rooftop PV systems in the state of Queensland, Australia. The primary motivators from this research were, 'reducing electricity bills' and 'concern over future electricity prices'. Further studies continue to reinforce the importance of financial outcomes and self-sufficiency (Abreu et al., 2019; Figgener et al., 2019; Sigrin et al., 2015; Vasseur and Kemp, 2015). Considering that the scale of electricity bill savings is dependent on the price of electricity, research by Best et al. (2019b) establishes empirical evidence that postcode regions with higher electricity prices also have higher rates of rooftop PV adoption. As customers PV-battery installations are at the early stages of growth, very few studies have been able to collect sufficient empirical data to analyse the motivational factors for PV-battery adoption. Recent research by Best et al. (2021) surveyed 1,821 Australian rooftop PV households and evaluated the role of access to capital and feed-in tariffs on battery adoption. They found households with smaller PV systems and lower access to capital were less likely to install a battery system, while households with lower feed-in tariffs (that improve battery returns) were more likely to install a battery system. These empirical studies support the perspective that financial outcomes remain a primary motivator for the installation of PV battery systems by offering electricity customers the means to 'achieve electricity bill savings' and 'protect against future electricity price increases'.

2.2.2 Techno-economic modelling and financial assessment metrics

PV and battery systems have the technical capability to modify customer electricity demand and grid-utilisation, such that a financial benefit can be derived. The techno-economic literature provides a methodological foundation to evaluate the financial opportunity of various PV and battery system configurations. The literature has predominantly focused on the determination of optimal system capacities given different exogenous input parameters, such as future PV and battery costs, future electricity prices, and changes in policy incentives (e.g., feed-in tariffs). The general techno-economic modelling approach uses a foundation of energy flow modelling consisting of four basic elements (i.e., solar PV generator, battery energy storage system, customer load profile and access to grid-sourced electricity) to establish the financial impact on customer electricity bills. Financial valuation metrics are then used to quantify reductions in electricity bills across different PV battery system configurations in order to ascertain an optimal configuration, given the context in the studies' location. The results of this bill minimisation problem are subsequently extended to PV battery adoption by making an assumption that customers are rational investors.

For example, Hoppmann et al. (2014) presented a simulation model that performed a techno-economic assessment of different PV and battery system configurations on a single residential electricity customer. By determining the economically optimal size of the PV and battery system between 2013 and 2022, the authors established that increasing flat retail electricity prices improved the viability of investing in battery systems, and that in the German case study, small PV-battery systems were already profitable in 2013. The model separated the analysis into technical and financial layers. In the first layer the electricity flows were systematically simulated across a range of 35 PV and 41 battery system capacities, resulting in 1435 combinations. In the second financial layer, these 1435 residual load profiles were used to calculate the next 25 years of electricity bills. Annual bill savings were quantified by comparing electricity bills with a PV battery system against the electricity bill without. Using a 4% discount rate, upfront system costs and expected annual bill savings over 25 years, the Net Present Value (NPV) for each of the 1435 PV battery combinations was calculated and ranked to determine the optimal PV battery capacity for that given evaluation year. This approach was re-evaluated over 10 years of decreasing PV battery system costs to establish changes in the optimal PV battery configuration over time. The authors determined that declining PV battery system costs alleviated the requirement for policy incentives to support battery adoption over the mid- to long-term. They also established those future customers with PV battery systems have the potential to become net generators, which has significant implications for electricity retailer business models.

Ren et al. (2016) evaluated the influence of different retail tariffs and tariff structures on a limited number of PV battery configurations located in three Australian capital cities. Using seven PV battery system configurations, they determined that flat tariffs favoured PV-only systems, while time-varying tariffs favoured PV-battery systems. Compared to PV-only systems, PV-battery systems doubled reductions in diurnal peak demand, which would alleviate network congestion and directly benefit distribution network owners. Expected bill savings over 20 years and a discount rate of 3.7%, along with 2015 prices of PV and battery systems was used. The NPV was calculated for each PV battery configuration and in each capital city. While they found that the NPV was positive for all PV-battery configurations (more so in cities with higher quality solar resources), it was only financially better than PV-only systems under time-varying tariffs. The focus of this research was on the effect of tariff structure on customer profitability and distribution network owner outcomes, rather than the implications from declining PV and battery costs.

Schopfer et al. (2018) considered the influence of heterogeneous household electricity load profiles on the optimal PV battery system configuration. Rather than utilising a simulation approach, the authors used a mathematical optimisation model to determine the PV and battery capacities that achieved the highest NPV (based on electricity bill savings) per household. A 20 year project lifetime was used with a 4% discount rate. In their analysis, real load profiles (one year with a 30 min resolution) from 4190 households in Ireland were evaluated under the retailer and weather conditions in Zurich, Switzerland. With privacy laws limiting the capability of researchers to utilise real customer data in the region of study, it is common practice for researchers to utilise load profiles from one region and apply it to another, but only if the two regions are sufficiently similar (e.g., Parra et al., 2015; Parra and Patel, 2016; Quoilin et al., 2016). The results from Schopfer et al. (2018) showed significant NPV variability between different households, and even those with similar annual electricity demand. By evaluating across heterogenous load data and using PV and battery system costs in 2018 (2 €/kW_P and 1 €/kWh respectively), this study showed that it was profitable for 40% of these households to install PV-only systems and that PV-battery systems were not yet profitable for 99.9% of these households. For PV-battery system to become the predominant optimal configuration, the authors determined that PV costs were required to reduce to 1 €/kW_P and battery costs to 0.25 €/kWh. By using a large number of real load profiles that also provide heterogeneity, this study was able to evaluate the distribution of optimal PV battery configurations over time, which allowed the authors to establish the cost tipping points necessary to shift the optimal configuration from PV-only to PV-battery systems.

Role of different financial metrics.

These research papers and many others (e.g., Barbour and González, 2018; Khalilpour and Vassallo, 2015; Shaw-Williams et al., 2018; von Appen and Braun, 2018) utilised NPV as the primary financial valuation metric. NPV is based on the summation across a series of annual net cash flows (limited by the life span of the project) and discounted by the annual cost of capital (i.e., discount rate). By making assumptions around future revenues and costs, the

NPV represents the overall profitability (in real dollars) at the end of a project, while also allowing the relative financial performance of many projects to be assessed together. A positive NPV indicates that a project is profitable and a higher NPV indicates greater project returns. However, NPV is only one type of financial valuation metric utilising discounted cash flows. Another is the Internal Rate of Return (IRR), which equates to the discount rate necessary to achieve profitability by the end of a project's lifespan. This provides a comparison between a project's profitability and its cost of capital (e.g., López Prol, 2018; Parra and Patel, 2016). If the IRR is greater than a project's cost of capital, then the project is profitable. Furthermore, projects with the higher IRR are more profitable than projects with lower IRR. Both the NPV and IRR metrics rely upon long-term assumptions on how revenue and costs are attributed. The number of years required for a project to payback its upfront cost (while factoring its discount rate) equates to the Discounted Payback Period (DPP) (e.g., Akter et al., 2017; Zhang et al., 2018), which can also be used to quantify a project's future cash flow risk. Projects with a shorter DPP are able to achieve profitability earlier than projects with a higher DPP and are therefore less dependent on long-term assumptions on revenue and cost. Alternatives to discounted cash flows are also used by researchers, such as Simple Payback Periods (e.g., Palmer et al., 2015; Pearce and Slade, 2018; Young et al., 2018) and Return on Investment (e.g., Dharshing, 2017). Together these financial metrics provide the means to rank (via profitability) and determine what is deemed as an optimal customer PV battery system configuration.

A need to move beyond a single snapshot of profitability.

The general approach utilises techno-economic models to objectively rank (via a financial valuation metric) and compare different PV and battery system configurations. This process considers each configuration as a competing investment opportunity (or an investment option). By further considering customers as economically rational investors, these financial metrics provide the mechanism to estimate future configurations of customer PV battery systems under different scenarios and assumptions. By further assuming that only optimal system configurations are installed by customers, PV battery adoption pathways can also be modelled along with the relative impact of policy and market settings. This approach has been used to establish technology cost tipping points (e.g., Hoppmann et al., 2014; Schopfer et al., 2018; Weniger et al., 2014), measure the effectiveness of different tariff structures (e.g., Ren et al., 2016), and assess the impacts on distribution networks (von Appen and Braun, 2018). Aniello et al. (2021) noted however, that the optimal system configuration significantly varied across different financial metrics (e.g., NPV vs ROI). Utilising only one of these financial metrics as part of modelled decision-making process may inaccurately capture the overall financial opportunity and subsequent adoption pathways available to customers. In addition, this approach of tracking the optimal configuration over time uses a *greenfield* investment perspective, which baselines future customer investment opportunities with respect to an absence of any PV battery system having been installed. Analytically, this makes the implicit assumption that customers are continually expanding their PV battery systems to match the optimal configuration year-on-year, and are thus ignoring the lumpiness of high upfront cost investments (Reuter et al., 2012). Furthermore, a *greenfield* perspective does not consider the potential of retrofitting existing PV battery systems, or the impact of changing financial conditions on future retrofits. This perspective is especially important when conducting techno-economic assessments in regions with significant pre-existing PV battery capacity, such as in Australia (AEMO, 2020b; APVI, 2020). Therefore, an alternative to the *brownfield* investment perspective is required, which considers the impact of past investment decisions on future investments in order to model customer PV battery adoption pathways.

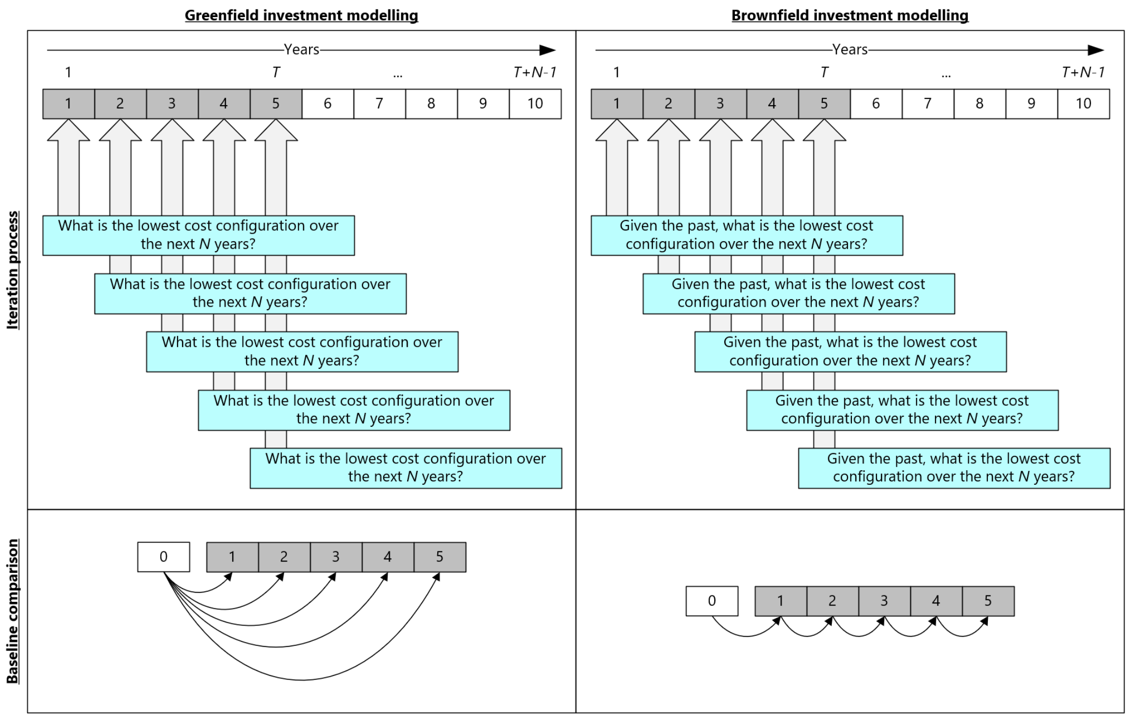

Figure 6. Differences between modelling greenfield and brownfield investments over 5 years (*T*) using a discounted cash flow horizon of 6 years (*N*).

2.2.3 From customer adoption dynamics towards power sector transitions

A brownfield perspective using iterative investments.

As past decisions are able to influence future decisions, a *brownfield* approach allows path dependence to be explicitly modelled (Cherp et al., 2011). Under a *brownfield* framework, adoption modelling becomes an iterative process, where the overall result emerges from many small decisions being made over time, as opposed to a single overarching objective applied each year over the same time period (Figure 6). A *brownfield* approach provides researchers with the opportunity to further model the customer decision making process, which leads to a more typical representation of customer PV battery adoption. It also allows researchers to further evaluate the influence of the customer decision making process, and its evolving bottom-up influence on power sector transitions.

While a *greenfield* perspective requires the technical evaluation and financial valuation of different PV battery configurations, a *brownfield* perspective also requires, (i) a decision whether or not to make an investment, and (ii) a financial valuation with respect to previous investment decisions. Wüstenhagen and Menichetti (2012) provide a useful framework by describing investments in renewable energy technology as a strategic choice, requiring a commitment of significant capital that cannot be easily reversed and that are under the influence of cognitive factors. This incorporation of cognitive factors, along with prior investments, and the type of investor, provides policymakers with additional levers to encourage renewable energy investments (Figure 7). By incorporating an investor's cognitive expectations into an investment decision, it respectively replaces financial risks and returns with *perceived* risks and *expected* returns. These cognitive aspects are important factors that influence how investments in renewable energy technologies are made. This framework can be similarly applied at the customer-scale, where electricity customers are continually presented with a strategic choice to invest in a PV battery system. The choice of investing in new PV and/or battery capacity is influenced by the *perceived risk* of the investment opportunity (e.g., confidence in profitability, continued access to financial incentives), the structure in which customers obtain their financial returns (e.g., stable feed-in tariff pricing and retail tariff structures, access to capital), and earlier investments in PV battery capacity.

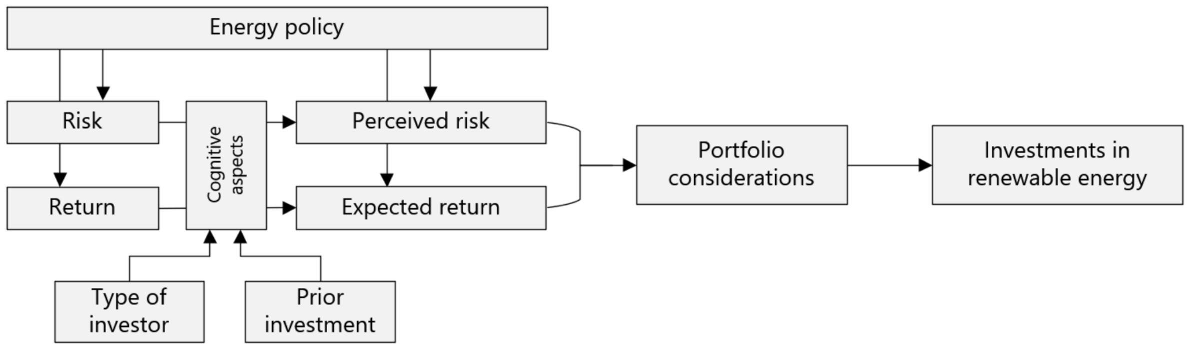

Figure 7. Incorporating cognition into renewable energy investment modelling. Adapted from (Wüstenhagen and Menichetti, 2012).

Boomsma et al. (2012) highlights the potential value of postponing an investment, as renewable energy technologies are exposed to high degrees of financial uncertainty (from changing technology costs, regulations, and incentives to intermittency of generation). For example, it may be more profitable to delay an investment if technology costs are expected to decrease. In the finance literature, this type of problem has been approached as a form of real options analysis (Boomsma et al., 2012; Fernandes et al., 2011; Fleten et al., 2007; Martínez Ceseña et al., 2013; Reuter et al., 2012), which focuses on the expanding scope of financial returns to incorporate delays to an investment. However, at the customer-scale the level of financial knowledge is lower and cognitive aspects begin to play a greater influence on PV battery adoption, such as the socio-economic and motivating factors reviewed in subsection 2.2.1. Therefore, in order to model customer PV battery adoption, there is a need to incorporate these socio-economic and motivating factors into the decision-making process.

Agent based adoption models.

By being able to represent the individual rather than the aggregate, Agent-Based Models (ABMs) are well suited to represent *brownfield* customer-scale adoption dynamics (Rai and Henry, 2016). ABMs allow customers to be modelled as autonomous decision makers, continually presented with opportunities to invest in a PV battery system, while retail electricity tariffs, policy incentives and system costs change year-on-year (Klein, 2020). ABMs are able to incorporate cognitive factors (Wüstenhagen and Menichetti, 2012) into its decision logic, while the iterative decision making process allows it to model path dependence (Li et al., 2015).

Adepetu et al. (2018) surveyed electricity customers in Ontario, Canada and Bavaria, Germany to establish and fit a range of ABM decision parameters (i.e., environmental, social, and economic factors) that influence the purchase of PV battery systems in each country. Using customer load profiles, retail electricity prices, system costs, and social influence, the study found national differences in customer attitudes affected the effectiveness of incentive programs. In Ontario reductions in PV prices were the most effective policy option to increase PV adoption, while in Bavaria electricity price increases would be more effective. Muaafa et al. (2017) developed an ABM that simulated rooftop PV adoption in two cities in the United States. Agents were owner-occupied households presented with an annual choice to install rooftop PV over a 20-year period. The decision to install utilised a logistic curve probability function based on the perceived payback period. Under their scenario, the authors determined that the 'utility death spiral' was unfounded under current retail electricity prices and United States policies. Rai and Robinson (2015) developed an ABM that dynamically modelled social influences, expected payback periods, and PV system awareness using the Theory of Planned Behaviour. The ABM was calibrated to reflect real-world rooftop PV adoption between 2004-2013 in Austin, Texas, USA and used to evaluate policy choices. The authors established that improving rooftop PV adoption by low-income households would require high solar PV rebates, and that as the number of rooftop PV households increased further PV adoption would be increasingly sensitive to changes in the solar PV rebate. Palmer et al. (2015) modelled the adoption of rooftop PV systems across single- or two-family households based on various Italian rooftop PV support schemes. Using an ABM, the study modelled individual household agents with their own income levels, perceived environmental benefit, communication with other agents, and discounted payback periods. These factors were calibrated with individual weightings to determine if rooftop PV system was to be installed. They found that economic profitability remained a key driver for rooftop PV adoption and adoption could be accelerated through the use of stronger policy incentives or reductions in installed system costs.

Alternative approaches for adoption.

Other approaches used by scholars to model customer DER adoption have focused on analysing the diffusion of technology over time through aggregate (rather than individual) methods, such Bass diffusion (Cai et al., 2013; Darghouth et al., 2014), logistic regression models (Bondio et al., 2018), and system dynamics (Agnew and Dargusch, 2017). Klein and Deissenroth (2017) utilised prospect theory, from behavioural economics (Tversky and Kahneman, 1992), to incorporate aggregate customer loss aversion from changes in FITs. The authors developed a residential rooftop PV adoption model that not only considered profitability (in the form of NPV), but also the magnitude of changes in profitability over time. Using Germany as an example, the authors applied a value function with differing expectations between gains and losses to reproduce German rooftop PV adoption between 2006 and 2014. Their study showed that prospect theory could be applied at the national scale and that loss aversion (or the fear of missing out) was an important factor in rooftop PV adoption. Dharshing (2017) utilised spatial econometric modelling to analyse German rooftop PV adoption between 2000 and 2013 focusing on socio-economic characteristics, rooftop PV profitability and regional settlement structure. While they reaffirm the importance of system profitability, access to solar resources, high income levels, and regional policy incentives to improve rooftop PV adoption, the spatial analysis was capable of establishing the positive influence of adjacent counties on rooftop PV adoption.

These ABM and diffusion models are able to represent respectively, the individual or aggregate, dimensions of the customer decision making process. By using them to reproduce historical adoption dynamics, these models have allowed researchers to quantify the factors that influence technology adoption. However, when addressing research questions focused on the future adoption of customer PV battery systems, the methodologies need to be forward looking. Klingler (2017) developed a hybrid ABM-diffusion model for household PV battery adoption, that simulated many individual investment decisions to determine the aggregate technology diffusion. This study incorporated 'consumer preferences and behaviour' from survey data, 'adopter characterisation' based on an estimated willingness-to-pay, and a 'techno-economic simulation model' utilising 415 individual load profiles and meteorological data to evaluate changes in profitability of various PV battery configurations. This approach formed the basis of an individual PV battery investment decision in a given year. This model was iteratively run over 40 years to simulate the adoption of PV battery technology by households. The results indicated that that PV battery adoption was favoured by households with higher electricity consumption, but the heterogeneity of consumption profiles strongly influenced optimal system capacities. While the study found only moderate growth of PV battery capacities by 2040 (with average capacity of 4 kW_P PV and 3 kWh of battery storage), the results remained highly sensitive to changes in electricity prices and system costs.

Klingler (2017) utilised *brownfield* investment methodologies to model the adoption of PV battery systems. At the centre of this approach is a representation of a customer's decision to invest. This allows the motivating factors and socio-economic characteristics of customers to be incorporated into the adoption dynamics. By further assessing the techno-economic opportunities at the individual level, further layers of heterogeneity are incorporated, such as differences in load profiles, solar resources, policy incentives, and retail electricity prices. However, as the power sector is tightly coupled with future grid-utilisation expectations, PV battery adoption fundamentally changes how customers utilise the grid and its growing adoption has significant implications for the power sector and associated market design. This is especially relevant in liberalised electricity markets that have market frameworks initially designed around one-way centralised generation with passive electricity consumers.

2.3 Energy system integration and market design

There is growing literature that analyses the co-dependent relationship between the liberalised electricity market design and customer PV battery adoption (Figure 8). The literature considers how changes in customer demand influence the operational, financial, and planning outcomes of the power sector, while also determining how the cost recovery mechanisms of the liberalised electricity market influence how customers decide upon the sizing and operation of their PV battery systems and their resulting market share. These interdependencies make the modelling and analysis of future states especially challenging and require a range of methods that can tailor the level of complexity necessary to address the specific research question.

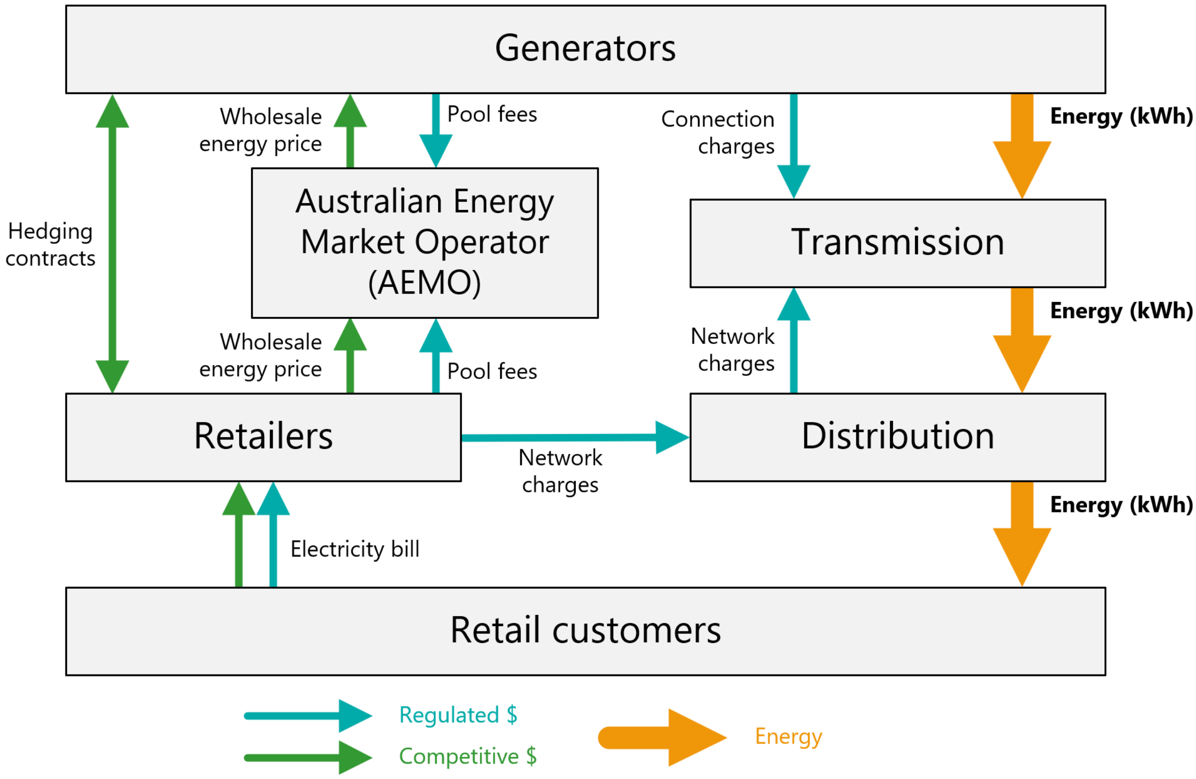

Figure 8. The co-dependent relationship between customers and the liberalised electricity market. Source (Simshauser, 2014).

MacGill and Esplin (2020) describe how the continued growth of DER behind-the-meter is requiring the liberalised electricity market to transition away from a one-way centralised generation market with passive electricity consumers towards an end-to-end customer-centric electricity market. This raises a range of market design challenges from determining how to manage greater supply and demand uncertainty with market or regulatory mechanisms, how different market layers may integrate with one another to improve system robustness and resilience, to how the rules of customer market participation need to be managed along with its risks. By fundamentally changing how customers interact with the power sector, PV and battery technologies are rewriting the rules of the liberalised electricity market, notably with Australia at its forefront.

Households and the electricity system.

A report by Rocky Mountain Institute (2015) applied an optimal PV battery sizing model to five cities in the United States and (annually) modelled the optimal system configuration between 2014 and 2050. The analysis utilised median load profiles for each city and their associated retail tariffs, tariff structures (three-part), expected price inflation, and forecasted PV battery system costs. Across each scenario, the report highlighted that the optimal system configuration in each city generally shifted initially to PV-only systems before becoming PV-battery systems by 2050. If this were to occur in 2050, it would lead to significant load defection[12] that eventually amounts to a reduction of 80-97% of electricity volume by 2050. The report further assessed the impact of retail tariff structures on the timing of this PV-battery transition and found that fully volumetric tariffs accelerated PV-battery adoption, while fully fixed tariffs (i.e., no usage charges with a high daily charge) delayed PV-battery adoption until off-grid solutions were cost-effective.

Schill et al. (2017) provided a qualitative and quantitative system assessment of customer PV-battery adoption. Notably, the authors utilise the term ‘prosumage’ (Green and Staffell, 2017) to differentiate PV-battery customers as opposed to ‘prosumers’ with PV-only systems. ‘Prosumers’ are only able to consume and produce electricity, while ‘prosumagers’ are able to store and release energy from self-generation or from the grid, which significantly changes how they can participate in the electricity market. The authors begin with a qualitative discussion around the pros and cons of ‘prosumage’ describing the way in which customers and the power sector may interact in a mutually beneficial or one-sided manner. They explain that ‘prosumage’ allows customers to utilise their own private capital to directly participate in electricity decarbonisation, while simultaneously establishing their own political representation at the institutional level (IEA, 2014). However, it can also reduce the economic efficiency of the power sector and unequally distribute costs and benefits across different customers. Utilising a brownfield least-cost optimisation model of the German electricity system with prosumagers, the study found that increased customer PV generation also drove increased behind-the-meter battery capacity. Furthermore, in order to maintain the overall economic efficiency of the electricity system it was necessary for customers’ battery capacity

[12] Load defection is the amount of customer load being supplied from behind-the-meter generation and storage rather than from the grid.

to be fully available to participate in the market. If customer batteries were only limited to improving customer self-consumption, significant utility storage capacity continued to be required, resulting in higher overall system costs. The authors concluded that policymakers should takes steps to ensure that the demand flexibility from customer battery systems is accessible to the electricity market.

Bustos et al. (2019) considered the influence of retail tariff structures on customer PV battery adoption and its impact on the optimal capacity mix within separate regional microgrids across Chile. The retail tariff structures considered were a *flat bundled volumetric tariff* that had no daily charge and the highest usage charges, a *two-part tariff* with a daily network charge and lower usage charges, and a *three-part tariff* with a daily network charge, per kW demand charges and the lowest usage charges. Using the United States net-metering approach (Darghouth et al., 2011), grid exports were remunerated at the same value as consumption. The costs of supplying the residual demand in each regional microgrid was used to define how the individual tariff charges changed over time. Individual learning rates for PV and battery technologies were used to establish future system costs. By analysing the progression of customer PV battery adoption and the utility costs, the authors establish that *flat bundled volumetric tariffs* drove the highest rate of PV-only adoption that could result in a 'utility death spiral'. The *two-part tariff* on the other hand allowed the utility to maintain a fixed revenue stream and avoid a 'utility death spiral', however it also delayed PV-only adoption. The *three-part tariff* allowed the utility to recoup many of their costs but resulted in negligible PV battery adoption.

Günther et al. (2021) considered the impact of different feed-in tariff rates and retail usage charges on household PV battery prosumage. In order to further analyse the impact on power sector cost recovery, they developed an equilibrium problem between prosumage households (that can invest in PV and storage capacity) and a centrally planned power sector operator (that determine the least cost wholesale generation and storage operation) for the German power sector in 2030. The authors utilise a *flat bundled volumetric tariff*, a *two-part tariff*, and a *real-time pricing tariff* and further consider different feed-in tariff rates. Given an expected market penetration of one million prosumage households in 2030, changes to the standard German load profile[13] from prosumage were scaled accordingly. Their analysis showed that a lowered feed-in tariff reduced the optimal capacity of rooftop PV, however the optimal battery capacity remained relatively robust. The use of a two-part tariff further reduced optimal PV and battery capacities, leading to reduced self-generation while requiring prosumage households to contribute more to fixed power sector costs. The authors conclude that policymakers that choose retail tariff designs need to carefully balance the incentives between utility- and household-scale renewable energy capacity expansion and the customer contribution to power sector system costs.

Gissey et al. (2019) utilised an agent-based model to evaluate the United Kingdom power sector impacts from either an aggregator-led or consumer-led coordination of flexibility assets. The authors utilised four UK transition scenarios based on National Grid's Future Energy Scenarios[14] to establish the portfolio capacities at the utility-scale and consumer-scales (industrial, commercial, domestic). Under aggregator-led coordination, flexible consumer resources were operated with a primary aim to reduce wholesale electricity costs. Under consumer-led coordination, these same consumer resources were operated to minimise temporal differences in demand. While both strategies reduced electricity prices faced by consumers, aggregator-led coordination reduced electricity prices by an additional 4-7%. However, as this benefit remained small, the authors suggest that it would be unlikely that consumers would allow an aggregator to fully operate their energy resources without further incentives.

Households and distribution networks.

Young et al. (2018) utilised two (exogenous) scenarios to determine the influence of PV battery households on the electricity network in Sydney, Australia. The first scenario considers if 25% of households had rooftop PV installed along with 5% of households having batteries installed. The second scenario considers if 40% of households had rooftop PV installed along with 20% of households having batteries installed. Utilising individual load profiles from the Smart Grid, Smart City trial (Ausgrid, 2014) and PV generation profiles from 300 real households (Ausgrid, 2018), the authors analysed the network business and operational impacts from different retail tariff structures. Compared to a PV-only system, the

[13] https://www.stromnetz.berlin/netz-nutzen/netznutzer
[14] https://www.nationalgrideso.com/future-energy/future-energy-scenarios

results showed that PV-battery households more than doubled their reduction in volumetric network charges, regardless of whether flat, time-of-use, or demand-based tariffs were used. This reduction in network charges has significant revenue implications for network businesses dependent volume-based usage charges. The study also noted that while flat tariffs do not explicitly disincentivise consumption during peak demand, peak demand continued to be reduced due to the coincidence between excess PV generation over the day and the diurnal demand peak in the early evening. Furthermore, flat charges had an overall flatter diurnal demand profile, compared to a time-of-use or demand-based tariff that led to the temporal alignment of household grid imports (and exports) as tariffs entered and exited their peak hours.

Neetzow et al. (2019) evaluated the influence of different retail policy scenarios on the interactions between distribution networks and households with PV battery systems. The case study was calibrated to the German electricity system and optimised the dispatch of utility-scale generation, prosumage households, and distribution capacity within the constraints of the transmission network. Different policy scenarios were analysed including, a capacity tariff based on the time varying costs of distribution network utilisation (with or without storage) and maximum or relative grid feed-in limits. By analysing overall system costs and distributional effects between distribution owners and prosumage households, the authors conclude that distribution network *export* constraints could be cost-effectively managed using fixed feed-in limits. However, they caution that distribution network *load* constraints could be exceeded as customers installed battery storage due to simultaneous consumption and charging occurring during peak periods. They suggest that *load* (rather than *export*) policies are necessary to manage distribution network *load* constraints, for example by disincentivising battery charging during peak periods.

Distributional effects

Nelson et al. (2011) considered the distributional impact of gross and net feed-in tariffs (priced above retail usage charges and were in use during this period of time in Australia) used to accelerate the customer rooftop PV adoption. By utilising the number of installed PV systems in New South Wales (NSW), Australia in 2010 and the associated average PV capacity of 1.5 kW_P, they determine the total cost of the gross and net feed-in tariff policies at $360 million and $79 million respectively. By utilising survey and household income vs annual electricity consumption data, the authors determined how the weighted average annual cost per household differs by household income. While the weighted costs per household were greater for higher income households, the implied rate of taxation (that considers income) for households in the lowest income bracket was more than double of those in the highest income bracket, making it a highly regressive policy. The authors suggest that feed-in tariffs should be gradually reduced and eliminated. Since the study feed-in tariffs in NSW have fallen from 60 c/kWh in 2010 to around 7-16 c/kWh in 2021.[15]

2.4 Shortcomings of the literature and gaps in knowledge

As presented in subsection 2.1.2, the liberalised electricity market framework is an emergent property of the interactions between different actors in the power sector. Prior to wind and PV becoming cost-effective, large-scale centralised generators were economically efficient, leading to a market framework designed around the one-way flow of energy and its costs borne by all electricity customers. However, as the investment costs of PV and battery systems decrease, electricity customers are capable of responding to electricity prices by installing their own generation and energy storage. At sufficient scale, PV battery customers could challenge the fundamental design assumptions of the liberalised electricity market framework. The existing literature highlights the need for further research on how customer PV battery adoption may affect the structural frameworks of liberalised electricity markets. The following shortcomings were identified and specifically addressed in subsequent chapters:

- Further research should be conducted on the effect of retail and feed-in tariffs on the business case for customer PV battery systems (von Appen and Braun, 2018) and their effect on technology diffusion (Bustos et al., 2019). Chapters 3 and 4 extends the literature analysis by simulating the business case of PV battery systems and their potential adoption pathways under different feed-in tariffs rates and electricity prices.
- A broader cost-benefit analysis of PV battery systems and the wider power sector should be considered (O'Shaughnessy et al., 2018). Chapter 4 analyses the cost-benefit to retailers of PV battery adoption since retailers have to decide the price and structure of retail tariffs. Chapter 4 also considers the short- and long-term implications on retailer

[15] https://www.solarchoice.net.au/solar-rebates/solar-feed-in-rewards

revenues under these different tariffs to better understand its strategic implications and the range of trade-offs necessary under the retailer business model.

- The evaluation of PV battery systems and retail tariffs on distribution networks should consider changes in peak demand beyond a single week (Young et al., 2018). Chapters 4, 5 and 6 expands upon their analysis by utilising annual load profiles to evaluate the impact of feed-in tariffs on PV battery operation, and with a particular focus in Chapter 6 on its impact on peak network demand.
- Further research should evaluate the distributive effects between those with PV battery systems and those without (Schill et al., 2017). Chapter 5 determines the effect of a segment of customers in the household sector installing their own PV battery systems on the least-cost utility-scale portfolio in 2030, and its impact on future electricity prices. This provides the basis to assess the cost of supplying electricity to households with and without PV battery systems and establish the distributive implications on different sectors of customers.
- The regulatory framework of the power sector should be further explored to balance the benefits between prosumers and the electricity market (Schill et al., 2017). Chapter 6 considers how PV battery adoption may change grid demand over time and how it subsequently affects competitive retailers and generators, and regulated monopoly network owners. By qualitatively analysing these changes within the market and regulatory framework of a liberalised electricity market, areas that require improvement are identified to policy and decision makers.

There remains a broad range of analyses around the integration of customer DER systems into the electricity market and its role as a potentially significant source of renewable energy that policymakers may use to accelerate energy system decarbonisation. This thesis addresses some of the gaps in the literature by evaluating the extent of change from multiple perspectives and scaling its analysis from the individual through to an increasingly significant proportion of all electricity customers within the SWIS in Western Australia. The SWIS provides a suitable basis to model the customer transition as its isolation means any market impacts would occur earlier and also be more pronounced, while reducing the number of assumptions required to capture its power sector dynamics.[16]

[16] As a medium-sized electricity system, centred around the Perth metropolitan region, there is less spatial and renewable energy resource variation in the SWIS, and also less variation in household load and PV generation due to the majority of electricity customers having similar climatic conditions.

CHAPTER 3.

The coming disruption: The movement towards the customer renewable energy transition

3.1 Objective

The objective of this chapter is to evaluate the influence of increasing retail electricity prices and the relative value of the feed-in tariff on the timing and scale of PV battery adoption by households. With two degrees of freedom[17] and many techno-economic factors affecting the economics of PV battery systems, a developed model is used to assess the impact of cost and price trends on tipping points and grid-utilisation, and the extent that electricity consumption could be moderated by retail tariffs. A model was developed to address motivation one (Section 1.1.1), by evaluating customer PV battery adoption over the interrelated dimensions of generation and storage capacity.

This chapter was published as a journal article (Say et al., 2018) titled "The coming disruption: The movement towards the customer renewable energy transition" in the journal *Energy Policy* (see **Appendix 1 – Paper 1**).

3.2 Encapsulating the economics of PV battery systems for a single household

The barrier to entry for households to self-generate and store energy lowers as the price of PV and battery technologies decrease. However, this transition does not occur equally between PV adoption and battery adoption since they are co-dependent systems, which are also dependent on the structure and expected prices of a household's electricity bills. Future system cost and electricity price expectations however can be used to assess the profitability of PV battery systems in the future (e.g., Hoppmann et al., 2014), and in doing so, encapsulate the economic factors that influence householders' adoption of PV battery systems and how they change over time.

In this paper, a model was developed based on two primary motivators for installing self-generation and storage, namely the 'reduction of electricity bills' and 'protection against

[17] i.e., PV generation capacity (kW_P) and battery energy storage system capacity (kWh)

future electricity price increases'. A synthetic 'double hump' household load profile (Martin, 2016) was used to represent the daily household demand (at an hourly resolution) and repeated 365 times to represent a single year. The scenario parameters were aligned to expected price and policy conditions in Perth, Australia and simulated for each year between 2018 and 2033.

The model comprised of two layers. A technical layer simulated changes in electricity demand if a given PV and battery capacity was installed, and a financial layer calculated the subsequent annual electricity bill savings. By systematically evaluating each PV battery combination within a PV capacity range of 0 to 10 kW_P (step size of 0.5 kW_P) and battery capacity range of 0 to 20 kWh (step size of 1 kWh), the model assessed 441 PV battery combinations in each simulation year over 15 years.

NPV was used as a financial metric to quantify 'electricity bill reduction' and 'protection against future electricity price increases' for each PV battery combination. More specifically, the NPV calculation was based on: (i) 10 years of expected annual electricity bill savings; (ii) upfront installed system costs in the particular simulation year; and (iii) a discount rate reflecting the average owner-occupied standard variable home loan. The end result was a set of NPVs corresponding to each PV battery combination that changed over time as installed system costs decreased and electricity prices increased (Figure 9). Electricity bill savings were calculated by comparing the cost of using grid-sourced electricity to meet the household demand compared to having the PV battery system installed behind-the-meter and with any excess PV generation remunerated at the Feed-in Tariff (FiT) rate. Matching the regulatory environment in Perth, Australia, FiTs are only eligible for households with PV capacity at 5 kW_P or under.

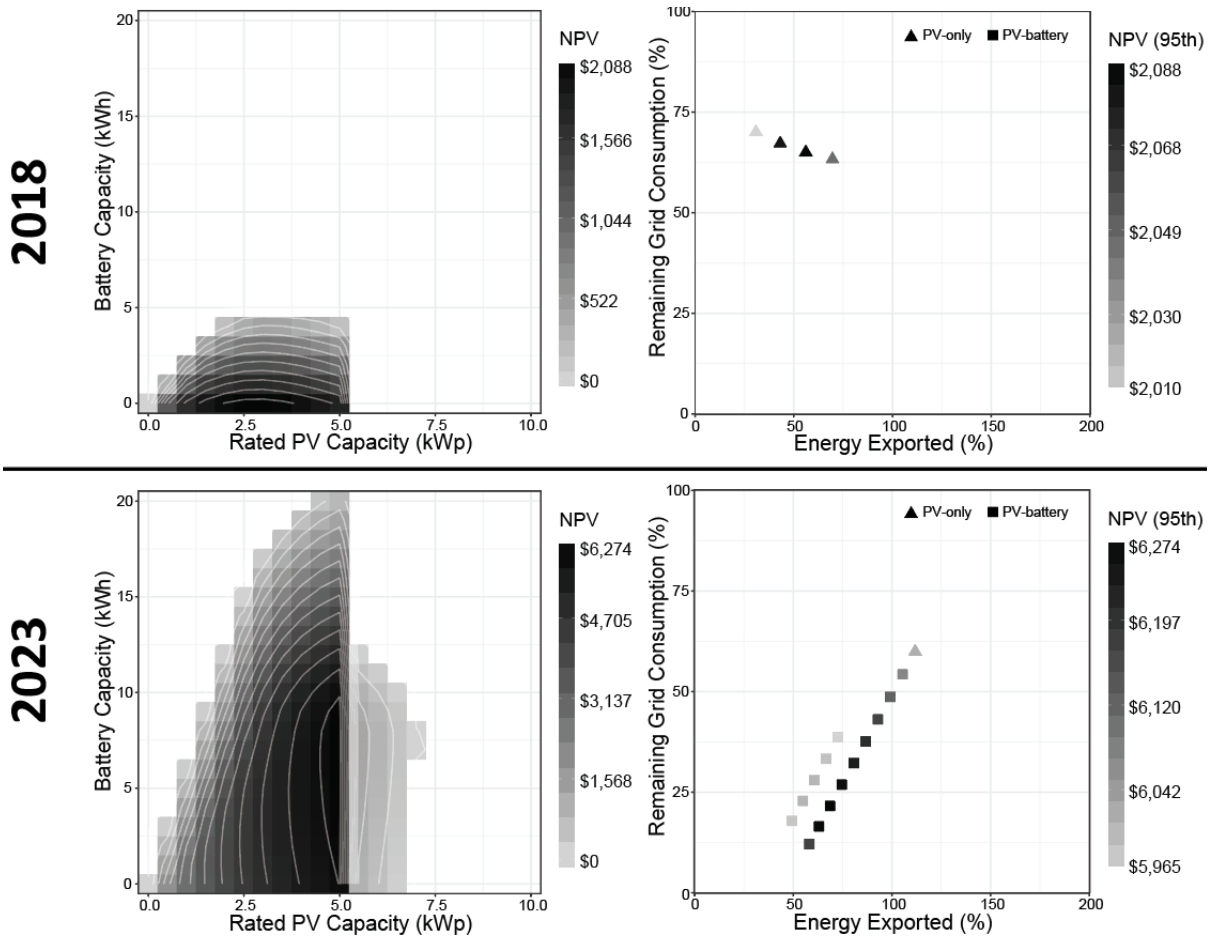

Figure 9. The spectrum of positive NPVs for each PV battery configuration in 2018 (upper) compared to 2023 (lower) and the set of near-optimal PV battery configurations (i.e., 95th percentile) on the remaining grid consumption (left) and energy exported (right). Source (Say et al., 2018).

The PV battery configuration with the highest NPV represents the optimal solution in any given simulation year. However, there remains additional PV battery configurations that could offer comparable returns. In this paper, the PV battery configurations in the 95th percentile of maximum NPV were also included in the analysis, which expands the optimal-only approach that is commonly used in the literature (e.g., Hoppmann et al., 2014). The consideration of the range and span of near-optimal PV battery configurations was used to establish a baseline level of uncertainty, which was subsequently analysed over time (Figure 9 right hand side). This provided the basis from which to assess how a variety of cost-effective PV battery capacities could emerge, and how they could drive a range of changes to annual grid consumption and energy exports as PV battery system costs decreased, retail electricity prices increased and across different feed-in tariff options.

3.3 The emergence of PV-battery tipping points

Aligning with real world conditions in 2018 (and with a FiT rate set at 26% of the volumetric retail tariff), the results at the start of the simulation showed that PV-only systems were the most cost-effective configuration. Over the following 15-years however, PV-battery systems eventually become more financially attractive across the three retail tariff inflation scenarios evaluated (Figure 10a). By comparing PV-battery tipping points with respect to different annual rates of tariff inflation, the results indicated that higher rates of tariff inflation accelerated the cost-effective tipping point of PV-battery systems (Figure 11a and Figure 11c). Furthermore, even if tariff inflation were kept at zero (i.e., flat), PV-battery systems would still become more cost-effective than PV-only systems due to declining system costs (Figure 10a). As the relative value of the FiT (with respect to the volumetric usage charge) determines the value of self-consumption, the research also found that the removal of FiT payments accelerated the tipping point for PV-battery adoption (Figure 11c). Raising the FiT to match usage charges[18] negated the value of self-consumption and completely disincentivised PV-battery adoption (Figure 11c). However, this would come at significant financial cost to the retailer as they are responsible for FiT payments. These PV-battery tipping points indicated that under decreasing PV battery system costs and low relative FiT rates, the power system was likely to experience growing behind-the-meter PV-battery adoption within the next decade.

By considering near-optimal solutions, as the range of PV battery configurations within the 95th percentile of maximum NPV, the paper also assessed the potential scope of changes to grid consumption and exported energy. The modelling results found that as the cost-effectiveness of PV battery systems increased (i.e., under high tariff inflation or lower FiTs), the potential range of viable battery capacities was also increased, resulting in the remaining grid consumption reducing below 10% (Figure 10d and Figure 11d). These potential reductions in grid consumption are much more significant when compared to PV-only systems and could have substantial implications for retailers that assume household demand will continue to remain constant.

[18] The is equivalent to the *net-metering* policy utilised in the U.S. (Barbour and González, 2018).

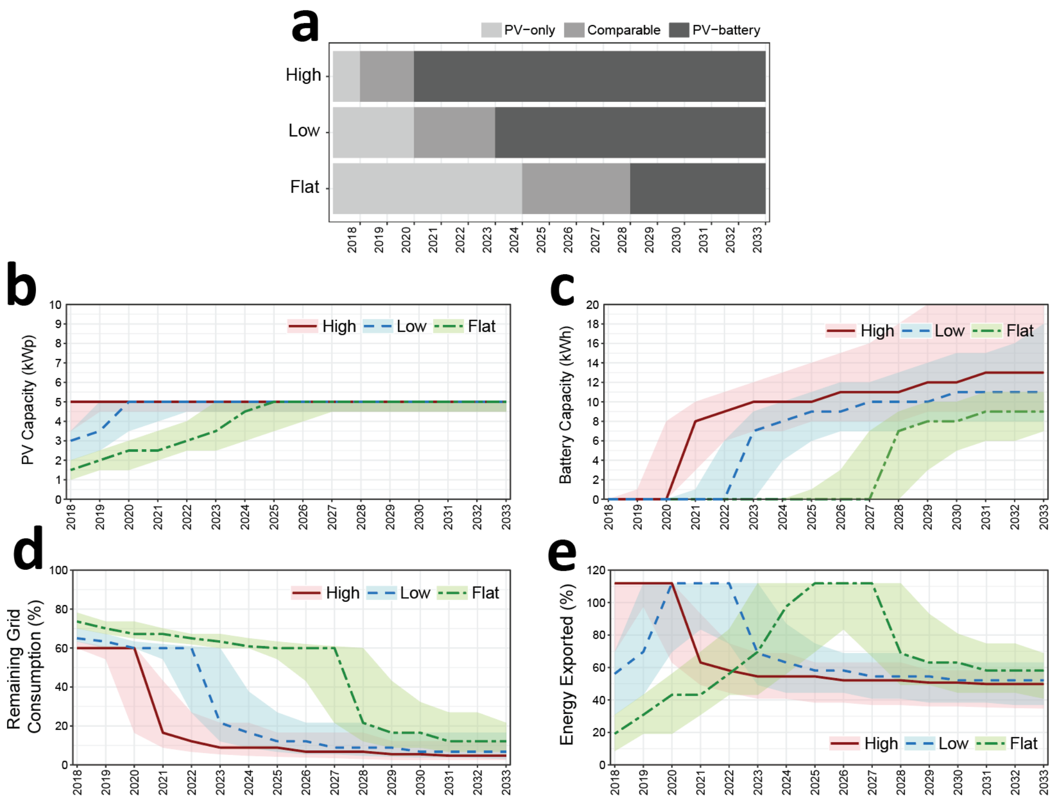

Figure 10. The influence of different retail electricity price trajectories under High (+10%pa), Low (+5%pa), and Flat (0%pa) scenarios on the optimal and near-optimal PV battery configurations, and the resulting grid utilisation. (a) The type of configuration in the near-optimal set (95th percentile of maximum NPV). (b) The optimal and near-optimal PV capacities. (c) The optimal and near-optimal battery capacities. (d) The impact on remaining grid consumption. (e) The impact on energy exported with respect to underlying consumption. Source (Say et al., 2018).

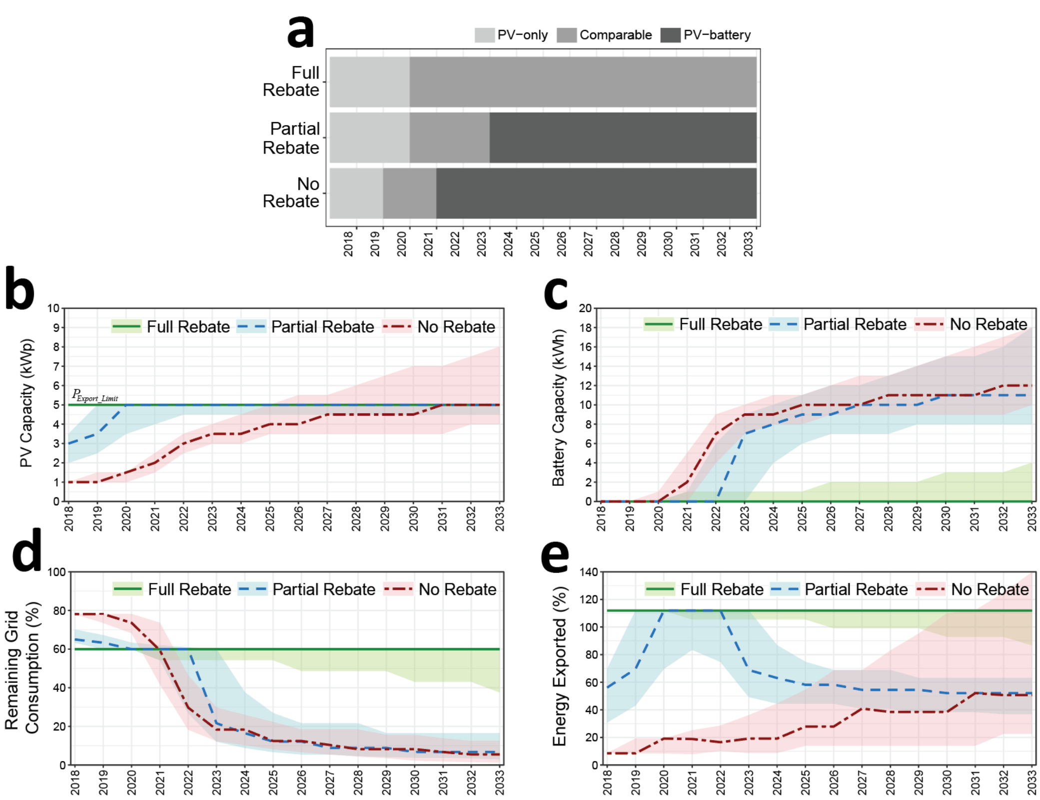

Figure 11. The influence of the FiT with Full Rebate (100% of the volumetric retail tariff), Partial Rebate (26%), and No Rebate (0%) on the optimal and near-optimal PV battery configurations, and the resulting grid utilisation. (a) The type of configuration in the near-optimal set (95th percentile of maximum NPV) (b) The optimal and near-optimal PV capacities. (c) The optimal and near-optimal battery capacities. (d) The impact on remaining grid consumption. (e) The impact on energy exported with respect to underlying consumption. Source (Say et al., 2018).

3.4 Research outcomes and policy implications

Using a synthetic household load profile and techno-economic simulation, this research evaluated the influence of different rates of tariff inflation and the impact of the relative value of the FiT on the cost-effective tipping point between PV-only and PV-battery systems. This study considered how the optimal sizing and range of near-optimal PV battery systems are affected under increasing retail usage charges and decreasing PV battery system costs. The results were used to establish how household investment behaviour may change over time. The findings of this research established the following policy implications:

The relative value of the FiT has significant leverage on PV-battery adoption.

FiT payments play a key role in how PV battery systems are valued. This relationship exists because the value of self-consumption is defined by the difference between the usage charge and FiT. Low FiTs increase the value of self-consumption and decrease the value of exports, which incentivises households to install DER systems that focus on grid import reductions. In the short term as batteries are cost prohibitive, this leads to smaller capacity PV-only systems that have higher self-consumption ratios. As batteries become cheaper, they begin to be paired with increasingly larger capacity PV systems, as they are able to store and increase the financial value of excess generation. In the *No Rebate* scenario, this eventually leads to more PV capacity being installed than in the *Full Rebate* scenario. This is because high FiTs (such as in the *Full Rebate* scenario) reward excess generation, which incentivises households to install PV-only systems that maximise feed-in over self-consumption (but only up to the 5 kW_P eligibility limit and no more).[19] However, in the *No Rebate* scenario there is a much higher value for self-consumption, since there is no feed-in value (and no penalty for installing PV systems larger than the 5 kW_P). Therefore, as system costs decline, households with batteries can cost-effectively install PV systems larger than the 5 kW_P. Overall, lower FiTs have a lower policy cost but simultaneously accelerate the cost-effective tipping point for PV-battery systems. This means that policy and decision makers need to be aware that FiTs are not just a lever for encouraging renewable energy generation (by raising FiTs) but are also a lever for accelerating PV-battery adoption (by lowering FiTs).

PV-battery systems can lead to significant load defection.

With PV-battery systems not being constrained by the setting sun, much higher grid consumption reductions can be achieved (compared to PV-only systems) by repurposing excess daytime generation. As system costs improve and optimal PV-battery capacities subsequently increase, this could result in even further reductions in grid consumption. In the *No Rebate* and *Partial Rebate* scenarios, this eventually led to grid consumption reductions of above 90% (Figure 10d and Figure 11d). This is signal withdrawal of load from the grid, and if PV-battery systems become as widely adopted as rooftop PV in Australia, it could severely reduce the size of the electricity market.[20] Conversely, households are capable of installing

[19] Households with more than 5 kW_P of behind-the-meter PV capacity lose any FiT payments. This eligibility policy is in place in Perth, Australia under the *Renewable Energy Buyback Scheme*.

[20] As defined by the volume of energy traded.

significant renewable energy generation and storage capacity using private rather than public capital. From an energy policy perspective, this means that there could be a significant role for customers to directly contribute and participate in the energy transition which could also lead to direct competition between customers and the electricity market.

The changing role of electricity customers.

With improving access to PV and battery technologies, customers can no longer be considered as passive price takers within the electricity market. This study showed the relationship between retail tariffs and potential installations, which could result in at least a decade of adjusted demand and the means to reshape the long-term trajectory of the electricity market. Since the electricity market and the potential for customer PV battery adoption are inter-dependent and co-evolving, policymakers need to carefully consider the future role of customers in the electricity system. However, this first requires more detailed analysis of the extent to customer PV battery adoption can affect different elements of the power sector, from retailers that interact with customers, to system operators and market participants within the electricity market, through to whole-of-system utility portfolios. By understanding how these elements are affected, policymakers can develop more targeted strategies that take advantage of the benefits of customer PV battery systems, while managing areas of weakness. Policymakers would then be able to utilise customer PV-battery adoption as a complementary strategy to accelerate the renewable energy transition.

CHAPTER 4.

Power to the people: Evolutionary market pressures from residential PV battery investments in Australia

4.1 Objective

The objective of this chapter is to use transition analysis to quantify the potential electricity market impacts of various retail tariff policy and household investment conditions. These impact the capacity of PV battery systems installed behind-the-meter, which then affect future electricity demand and electricity market revenues. This chapter considers retailers as both an agent that collects customer revenues (at a premium that covers the majority of electricity market costs), and a decision maker that determines retail tariff pricing which influences the financial value of behind-the-meter PV battery systems. These perspectives are of interest as they create conflicting business objectives that can constrain the range of feed-in tariffs (FiTs) offered to customers. The model from Chapter 3 was extended to address motivation two (Section 1.1.2), by evaluating the bi-directional influence between customer PV battery adoption and retail tariff offerings.

This chapter was published as a journal article (Say et al., 2019) titled "Power to the people: Evolutionary market pressures from residential PV battery investments in Australia" in the journal *Energy Policy* (see **Appendix 2 – Paper 2**).

4.2 Generating transition pathways: iterating PV battery investments over time and across households

In the previous chapter the analysis was conducted on a single synthetically generated household load profile. The research was based on how the optimal PV and battery size changes each year, with respect to the household not previously having any DER systems installed. While this was useful to assess the potential of future PV battery investments for non-DER households, it does not represent how existing rooftop PV households approach investments in additional PV battery capacity. Neither does it evaluate the range of optimal solutions that can come from variations in real household demand. The techno-economic model therefore could be further improved.

Using agent-based modelling principles (e.g., Chappin et al., 2017), the greenfield investment model from Chapter 3 was adapted into a brownfield investment model. This involved incorporating history by changing the baseline reference from 'a household that does not have any previously installed PV battery systems' to 'a household that may have previously installed PV battery systems'. This change expanded the investment assessment from 'what is the optimal PV battery size for a non-DER household' to 'what is the optimal PV battery retrofit'. Furthermore, an additional step was required to determine if the optimal investment option was or was *not* to be made in a given year. The approach taken was to represent this as an investor's strategic choice (Wüstenhagen and Menichetti, 2012) that had to overcome a base level of perceived risk. In this paper, it was represented by an awareness that it was possible for a PV battery system to have a discounted payback under 5 years, which is in line with the rooftop PV reporting by the Australian Energy Council, AEC (2020). This additional step enabled the model to represent lumpy investment behaviour. By starting the analysis with a non-DER household and iterating the investment assessment each year, the developed methodology simulated investments as a series of discrete events occurring dynamically over time in response to annual changes in systems costs and electricity prices. This process allowed the research to generate pathways of household PV battery investments and then evaluate the impact of different policy options, such as the *relative value of the FiT*.

Due to strict privacy laws, publicly accessible customer load and PV generation profiles for Perth, Australia are not available. Instead, this study utilised real household load and PV generation data from Sydney, Australia that was collected between 1 July 2012 and 31 June 2013 from 300 gross utility meters (Ausgrid, 2018; Ratnam et al., 2017). This information was used to represent the annual household load and PV generation profiles in Perth, Australia, as both cities had comparable solar resources (NREL, 2018), annual electricity consumption (ABS, 2013) and climatic conditions. The use of real data allowed seasonal changes in demand to be incorporated into the analysis along with the real-world variation of demand and PV panel orientation between different households. By using the model to generate individual transition pathways of PV battery installations for each household, the results could be aggregated to better represent real world technology adoption and further used to assess its sensitivity to different system costs, retail electricity prices and policy options.

4.3 Influence of feed-in tariffs on short- and long-term retailer revenues

As the costs of the electricity system are covered by the customers that use it, any significant changes to future electricity bills can impact the long-term revenue outlook by retailers, and by extension the entire electricity market. Due to the way that costs are allocated, this can drive tensions between market actors[21] and across each of layer of the market framework.[22]

As retailers serve as the interface between customers and the electricity market, they are the means to which wholesale generation and network costs are recovered (i.e., through simplified retail tariff structures and pricing). However, by explicitly defining the fixed and variable costs that customers face, retailers also implicitly determine how customers derive financial returns from their own PV battery investments. The findings from Chapter 3 showed that the cost-effective transition from PV-only to PV-battery systems results in much greater reductions in grid demand and that its timing is highly sensitive to the *relative value of the FiT* (i.e., with respect to the volumetric usage charge). Therefore, retailers are faced with conflicting outcomes, firstly because setting the volumetric usage charge too high improves the expected bill savings from any PV battery system; and secondly because setting the price of the FiT too low accelerates the cost-effectiveness of PV-battery over PV-only systems.

This study utilised the brownfield investment model to assess the impact of the *relative value of the FiT* on subsequent PV battery adoption by households and their future electricity bills. By systematically applying this model to a large number of real household profiles, their future electricity bills could be aggregated, and an estimate of future revenues collected by the retailer can be established. Since retailers also cover the cost of FiT payments, their net-revenue is the difference between the 'sum of all household usage (volumetric) and daily (fixed) charges' and the 'sum of all payments made to households at the FiT rate (volumetric)'. The study in this chapter evaluates the short- and long-term revenue ramifications for retailers under different FiT rates while household PV and battery system costs decline.

[21] E.g., since retailers pay households for their excess PV generation through the FiT. This can be greater than the wholesale electricity price, which penalises the retailer while also reducing the size of the utility-scale generation market.
[22] E.g., if fixed network costs are charged volumetrically by the retailer, PV battery households that reduce their energy usage are able to avoid paying for network costs which may no longer become cost-reflective and lead to inequitable outcomes.

Reflecting the range of time-invariant FiTs used by retailers, five FiT scenarios were chosen that corresponded to 0%, 25%, 50%, 75% and 100% of the retail usage charge ($/kWh) and with FiT payments only eligible to households with a cumulative PV capacity of 5 kW$_P$ and under.[23] Under the assumption that electricity prices (fixed and volumetric)[24] increased at 5% per annum, and PV and battery system costs decreased respectively at -5.9% and -8% per annum, the brownfield investment model was used to simulate the timing of PV battery investments over 261 real household load and normalised PV generation profiles.[25] The average installed PV and battery capacity per household, remaining grid consumption and net retailer revenues (i.e., after FiT payments) over the next 20 years were calculated to establish the changes that a retailer may experience in the future. With each of these dimensions presented simultaneously (Figure 12), the study was able establish the short- and long-term trade-offs that retailers have consider when deciding upon their FiT rates.

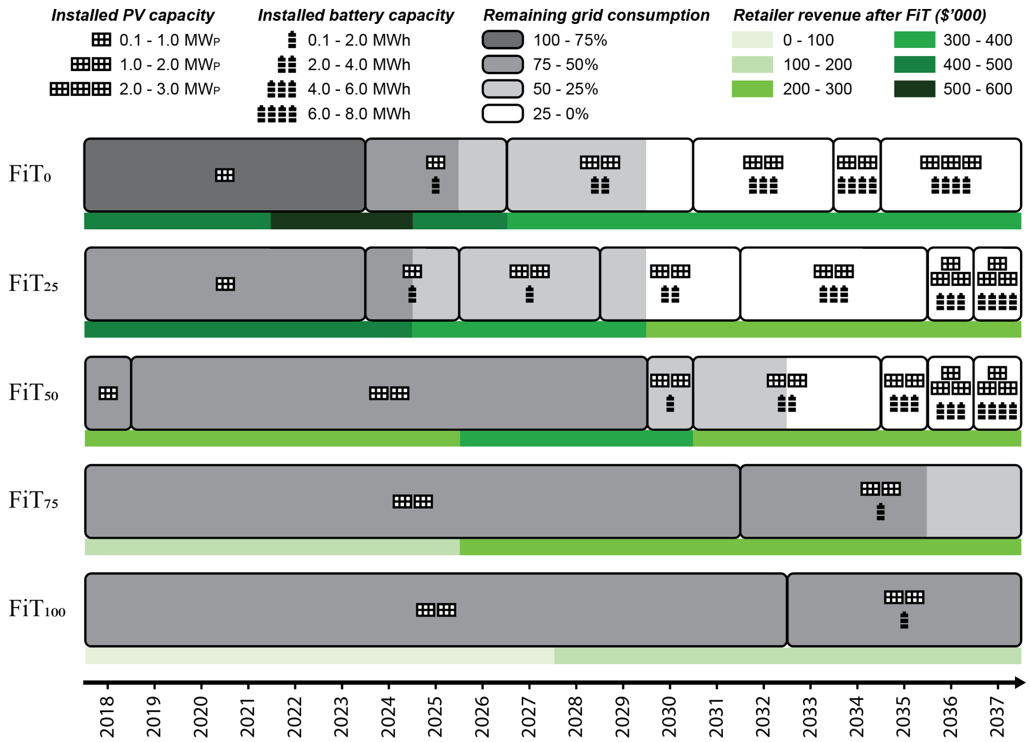

Figure 12. Strategic overview from each feed-in tariff scenario over 20 years. Source (Say et al., 2019).

[23] Which means that households with more than 5 kW$_P$ of behind-the-meter PV capacity lose any FiT payments. This eligibility policy is in place in Perth, Australia under the *Renewable Energy Buyback Scheme*.
[24] Between 1980 and 2007 Australian electricity prices increased by 5.3% per annum, and between 2007 and 2017 it increased by 9.4% per annum (ABS, 2018).
[25] 261 out of 300 remained after removing households with missing data.

By the end of the 20-year period, decreasing system costs meant that PV-battery systems were cost effective across all scenarios, and even more so with lower FiT rates. Evaluating over the 20-year timespan, FiTs *'above 50% of usage charges'* led to a widespread adoption of 5 kW_P PV systems (that maximised FiT payments) initially while delaying the cost-effective tipping point for PV-battery systems. However, it also had the lowest net retailer revenues due to the high cost of FiT payments. FiTs '*below 50% of usage charges'* initially discouraged 5 kW_P PV systems but brought forward the cost-effective tipping point for PV-battery systems. Notably lower FiTs also maintained higher levels of net retailer revenues.

The results also showed that the FiT eligibility policy (that restricted FiT payments to households with PV systems 5 kW_P and under) was only able to temporary disincentivise households from installing >5 kW_P capacity PV systems. At the beginning of the simulation, the 5 kW_P limit meant that higher consumption households were disincentivised from installing PV capacities beyond 5 kW_P (which also meant significant grid consumption remained). As electricity prices increased, the cost to supply the remaining grid consumption became ever more expensive. As PV battery system costs also decreased, they eventually reach a tipping point when the bill savings from upgrading to a larger PV plus battery system becomes greater than the opportunity cost of losing FiT revenues. Importantly, higher FiTs do not entirely remove the cost-effective tipping point of PV-battery systems, but rather raises the opportunity cost thereby delaying the transition. This is exemplified in the FiT_{50} scenario, which initially follows a similar trajectory as the FiTs *'above 50% of usage charges'* scenarios, but then switches to the trajectory of FiTs '*below 50% of usage charges'* once the opportunity cost to switch to PV-battery systems is overcome. This transition also occurs in the FiTs *'above 50% of usage charges'* scenarios, but to a lesser extent during the simulation period.

4.4 Research outcomes and policy implications

This study simulated household PV battery adoption using an iterative approach to generate transition pathways of the household sector under various 'relative values of the FiT'. The optimal PV battery capacity model from Chapter 3 'The coming disruption' was expanded to assess load and PV generation profiles from 261 real households and also simulate annual purchasing behaviour using a perceived risk evaluation. The adoption pathways that emerged showed that PV battery adoption was highly sensitive to the 'relative value of the FiT' which suggests that retailers have significant leverage to direct how households invest in PV battery capacity. However, as retailers are also responsible for FiT payments, they have to carefully consider which FiT price is eventually set. By assessing these two factors simultaneously and quantifying their impact on net retailer revenues, this study showed that retailers are incentivised to set low FiTs, as it discourages larger PV systems (thus reducing overall FiT payments) in the short-term. However, this also accelerates the cost-effective tipping point for batteries and sets the economic conditions for a faster transition to PV-battery systems that leads to higher installed PV and battery capacities per household (as compared to the higher FiT scenarios).

This relationship between customers and electricity retailers creates a co-dependency that has the following policy implications:

Maintaining net retailer revenues places a downward pressure on FiT rates.
With installed PV and battery costs driven by global supply chains[26,27] and retail tariffs structured around annually revised daily fixed charges, time-invariant volumetric usage charges, and a time-invariant FiT (CME, 2017), there are limited degrees of freedom for retailers to constrain the economics of household PV battery adoption. This study showed that retailers could delay PV-battery adoption if the FiT is raised '*above 50% of usage charges*', but this would come at a significant cost of future revenue (since larger PV systems are incentivised leading to higher FiT payments to customers). Retailers would also be paying customers more for their generation than from the grid, as daytime future wholesale electricity prices are likely to decrease further as more utility wind and PV capacity enters the market. As a result of these cost dynamics, retailers cannot sustain high FiT rates and would be under financial pressure to keep FiT rates as low as possible. These financial constraints on retailer margins therefore lock-in a low FiT trajectory, which improves the financial returns of PV-battery systems and subsequently accelerates its adoption. As long as battery costs continue to decrease, and two-part and time-invariant tariffs remain dominant, retailers will be unable to prevent PV-battery economics from improving and driving its widespread adoption.

[26] https://www.solarchoice.net.au/blog/solar-power-system-prices/
[27] https://www.solarchoice.net.au/blog/battery-storage-price

PV-battery adoption shifts 'two-part time-invariant' retail tariffs from volumetric to fixed charges.

In the longer term, if 'two-part time-invariant' tariffs are maintained, the prospect (and actual adoption) of PV-battery systems would drive retailers to increasingly rely upon fixed over volumetric charges in order to recover wholesale generation and network costs.

Firstly, the actual deployment of PV-battery systems by households would result in significant reductions in the volume of energy imported from the grid. This would lead to significant reductions in usage charges, and fixed charges becoming the dominant portion of the electricity bill. Secondly, using higher usage charges to recoup wholesale generation and network costs improves the economics of self-consumption and would likely accelerate future PV-battery adoption. A preferred strategy would therefore be to increase fixed over volumetric charges. Thirdly, if fixed network capacity costs are charged through a volumetric rate, those with PV-battery systems would be able to disproportionally avoid contributing to these fixed costs. Finally, as the wholesale electricity market integrates even more renewable energy generators with near-zero marginal costs (i.e., wind, utility PV, and rooftop PV), the average cost for wholesale energy generation is expected to decrease, reducing the reliance on usage charges, and leaving fixed costs proportionally higher.

These four co-dependent factors place strategic constraints around the degree to which retailers that use "two-part time-invariant tariffs" can rely on volumetric usage charges to recover costs. As PV battery prices continue to improve, retailers would therefore come under increasing financial pressure to raise fixed over volumetric charges. However, there is a limit to how much retailers can rely on fixed charges as they are regressive[28] and can worsen energy equity. Moreover, it also reduces the financial incentive of energy efficiency and can lead to unexpected consequences (e.g., increased rather than decreased energy consumption). For policymakers, this means that 'two-part time-invariant' retail tariffs may no longer be capable of recouping power system costs in a socially equitable manner as PV-battery systems become more cost-effective. This requires careful consideration by policymakers to develop and trial new tariffs that can segregate the opportunity and risk between customers with PV battery systems and those without.

[28] Since both high- and low-income households are charged the same amount.

Cost-effective battery storage allows time-varying retail tariffs to be socially equitable.

These structural tensions, between components of the 'two-part time-invariant' tariff, suggest that it may become increasingly incompatible with market efficiency and energy equity as more households install PV-battery systems. The 'two-part time-invariant' tariff has the advantage of reducing complexity, as consumers only need to consider how much electricity they consume, and not when. Time-varying tariffs rely upon consumers to adjust their electricity consumption in response to lower prices (in times of excess generation) and higher prices (in times of shortage). However, empirical research continues to find that household electricity consumption behaviour remains highly inelastic (e.g., Li et al., 2021), which weakens the advantage of moving to time-varying tariffs (Toner, 2019). Those with PV-only systems would still require behavioural change to respond to time-varying prices, as PV generation itself cannot dynamically respond to price signals. Conversely, those with PV-battery systems are capable of operating the battery to dynamically respond to price signals, without requiring behavioural change. Therefore, as battery systems approach cost-effectiveness, policymakers have greater freedom to apply time variance to feed-in and retail tariffs. Time-varying FiTs that reflect the reduction in generation value during daylight hours would encourage PV-only households to install battery systems in response to an excess of PV capacity (e.g., Energy Policy WA, 2021; Victorian Essential Services Commission (ESC), 2018). Time-varying retail tariffs would go further and incentivise these PV-battery systems to operate in such a way that complements wholesale electricity supply and demand. This should improve the financial performance of the PV-battery system (e.g., Ren et al., 2016; Sepúlveda-Mora and Hegedus, 2021) and contribute to the reduction of wholesale electricity prices which would benefit others (e.g., Ansarin et al., 2020; Simshauser and Downer, 2016). This means that PV-battery owners that use time-varying retail tariffs would, at a large-scale, be increasingly capable of improving energy equity, by better matching their grid utilisation with the operational needs of the power system.

Behind-the-meter PV-battery systems are further developing customers into new market actors that have the capability to disrupt liberalised electricity market frameworks that focus on centralised generation. This study breaks down how the retailer is exposed to changes in consumption and the limited degrees of freedom they have to mitigate this. As retailers are designed to recoup the operational and service costs across the entire power sector, any changes in retailer revenues and overall consumption directly impacts the size and scope of the electricity market and inherent profitability of the centralised power sector.

CHAPTER 5.

Degrees of displacement: The impact of household PV battery prosumage on utility generation and storage

5.1 Objective

The objective of this chapter is to determine the impact that widespread household PV battery adoption may have on least-cost utility generation and storage portfolios. The installed capacities of utility-scale generation and storage technologies are designed to meet expectations of future network demand;[29] however, household PV battery systems are capable of sufficiently reshaping grid-utilisation at the aggregate level such that this assumption is significantly impacted. This raises the importance of analysing the influence that retail tariff structures and prices may have on profile of future network demand and how it impacts different classes of technologies within utility-scale portfolios. The household PV battery investment *simulation* model developed in Chapter 4 was soft-linked to a least-cost utility-scale dispatch and investment *optimisation* model that was parameterised to the South-West Interconnected System (SWIS). Using residual network demand as a link between these two models, this study addresses motivation three (Section 1.1.3) and assesses the influence of household PV battery adoption on the least-cost portfolio of utility-scale generation and storage technologies using counterfactual analysis.

This chapter was published as a journal article (Say et al., 2020) titled "Degrees of displacement: The impact of household PV battery prosumage on utility generation and storage" in the journal *Applied Energy* (see **Appendix 3 – Paper 3**).

5.2 Soft-linking household and power system analyses

In Chapter 4, the household PV battery investment simulation model (henceforth named *Electroscape*) was used to assess the impact on retailer revenues under FiT rates. This approach yielded not only the annual electricity bills for each household, but also changes to hourly grid-utilisation in each year of the simulation. In this chapter, the projected conditions

[29] The term *network demand* is used to denote electricity demand managed by the grid. It does not include the underlying demand of customers but instead consists of residual grid imports and exports after the operation of behind-the-meter PV battery systems.

in 2030 was analysed, with *Electroscape* used to generate (using the real data from 261 households as a representative) the average changes in hourly grid-utilisation from prosuming households[30] within the SWIS. By superimposing these changes on actual SWIS operational demand, the residual network demand in 2030 was synthesised (Figure 13). The residual network demand was then used by the power system optimisation model (henceforth named *DIETER-WA*) to determine the optimal (least-cost) utility generation and storage technology portfolios in the SWIS.

As the installed capacities and future operation of household PV battery systems are highly sensitive to the relative value of the FiT, this study evaluated three specific FiT scenarios. The first with no FiT (i.e., FiT_0), the second with the FiT set to 25% of the retail usage tariff (i.e., FiT_{25}), and the third with the FiT set to 50% of the retail usage tariff (i.e., FiT_{50}). By evaluating these scenarios between 2019 and 2030 through *Electroscape*, different average PV and battery capacities were installed across the representative households by 2030. The FiT_0 scenario resulted in a 'PV-battery plus' (PVB+) outcome with an average PV capacity of 4.7 kW_P and battery capacity of 8.7 kWh. The FiT_{25} scenario resulted in a 'PV-battery' (PVB) outcome with an average PV capacity of 5.3 kW_P and battery capacity of 5.9 kWh. The FiT_{50} scenario resulted in a 'PV-only' outcome with an average PV capacity of 5 kW_P. These three outcomes led to different residual network demand profiles and provided the numerical foundation to assess households transitioning through a *PV-only* or *PV-battery* adoption pathway. By comparing these results against the counterfactual scenario (which assumed no prosuming households in the SWIS) the range of potential portfolio impacts from PV battery households was then established.

[30] Prosumers were assumed to be half of the 1 million households in the SWIS according to projections of rooftop PV adoption in 2030 (AEMO, 2019).

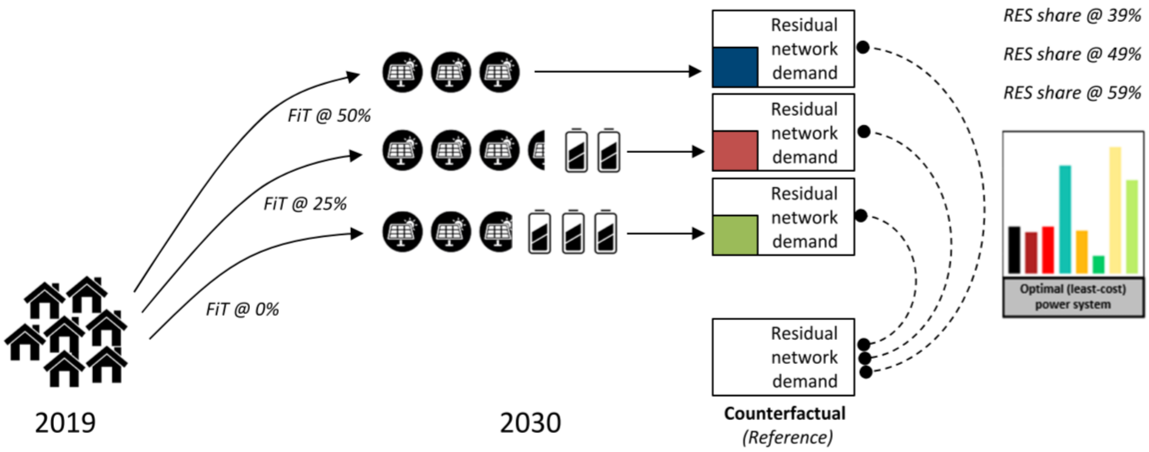

Figure 13. FiT scenarios and an overview of the analytical approach used to assess the impact of FiTs on future utility-scale portfolios.

As the SWIS is a medium-sized isolated network with a single major metropolitan load centre, the number of assumptions (Figure 14) necessary to represent both the household and utility sectors was greatly simplified.[31] To ensure that the results remained representative, each model evaluated its sensitivities across a small set of scenarios. As described above, the household perspective considered three FiT scenarios, while the power system perspective considered three Renewable Energy Source (RES) shares in 2030, namely 39%, 49% and 59% (with the 49% corresponding to the linear extrapolation in 2030 of the SWIS reaching 100% renewable energy by 2050). By including the counterfactual, this resulted in 12 scenarios being evaluated in this study.

[31] National Electricity Market (NEM) on the south and east coasts of Australia has ten times the operational consumption (compared to the SWIS) and consists of 5 interconnected markets spanning a much larger regional area and multiple time zones (AEMO, 2019, 2018).

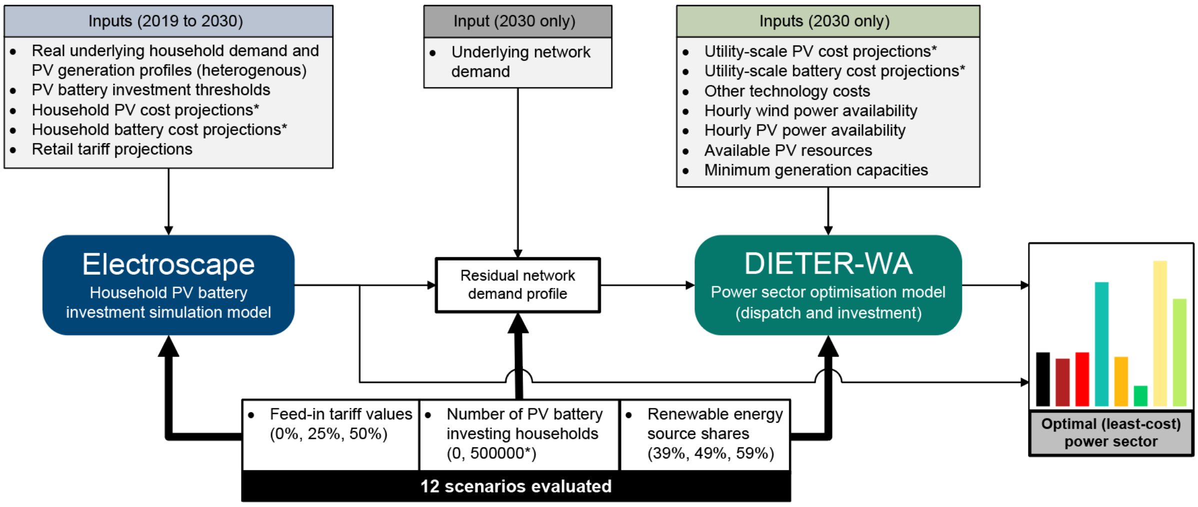

Figure 14. Overview of the modelling integration that soft-links Electroscape with DIETER-WA. Source (Say et al., 2020).

5.3 Prosumer and prosumager transitions

This study explicitly analysed differences in utility-scale portfolios and their operation if households install DER systems in line with a *prosumer* (i.e., PV-only) or *prosumager* (i.e., PV-battery) transition pathway. This distinction is required as there are significant operational differences between these transition pathways. If households continue to install PV-only systems, then they have limited capacity to manage their grid-utilisation beyond increasing or decreasing the *pro*-duction of electricity and continuing to con-*sume* electricity. With PV-battery systems however, there is a greater degree of flexibility that allows the *pro*-duction of electricity to temporally decouple from its con-*sum*-ption through the use of energy stor-*age*. The degree to which consumption could be moderated is further influenced by the retail tariffs that households are exposed to. In this study, flat tariffs (i.e., time-invariant) were used as they were the most common retail tariff in the SWIS, and also abroad. Flat tariffs encourage batteries to be used only[32] as storage for excess PV generation (until it is full) and to match any remaining grid demand (until it is empty).

These operational differences in *prosumer* and *prosumager* transition pathways impact residual network demand differently and may have a tangible impact on the required capacity of utility-scale generation and storage technologies and how they are dispatched into the

[32] Flat tariffs provide no financial incentive to shift demand in time, hence the study did not implement energy arbitrage or grid charging/discharging strategies.

power system. By understanding the extent to which utility-scale technologies are affected by different household transition pathways, this research provides information to market participants and institutional actors to better prepare for and take advantage of the energy resources and operational dynamics that customers may bring into the electricity market.

5.4 Reshaping of network demand and displacement of generation capacity

5.4.1 Changes to residual network demand

In all FiT scenarios the annual residual network demand was reduced by a similar amount. In the baseline scenario with no PV battery households the annual network demand totalled 18 TWh. The PV-only, PVB and PVB+ scenarios reduced this by 16.7%, 17.9% and 15.6% respectively. At the annual resolution, the impact of PV battery changes was less noticeable, however at the diurnal scale differences were more evident (Figure 15). Across each FiT scenario, the timing of minimum demand shifts from the night to midday due to excess PV generation, however in the PV-battery scenarios the degree of this midday reduction is reduced as the battery is charged. It can be seen in Figure 15 that in summer the evening peak is only reduced in the PVB scenarios, as batteries and their discharge provide the means to drive meaningful reductions in the diurnal peak. These operational impacts are more pronounced in the summer months when compared to winter and would have further ramifications for the required utility-scale ramping capacity.

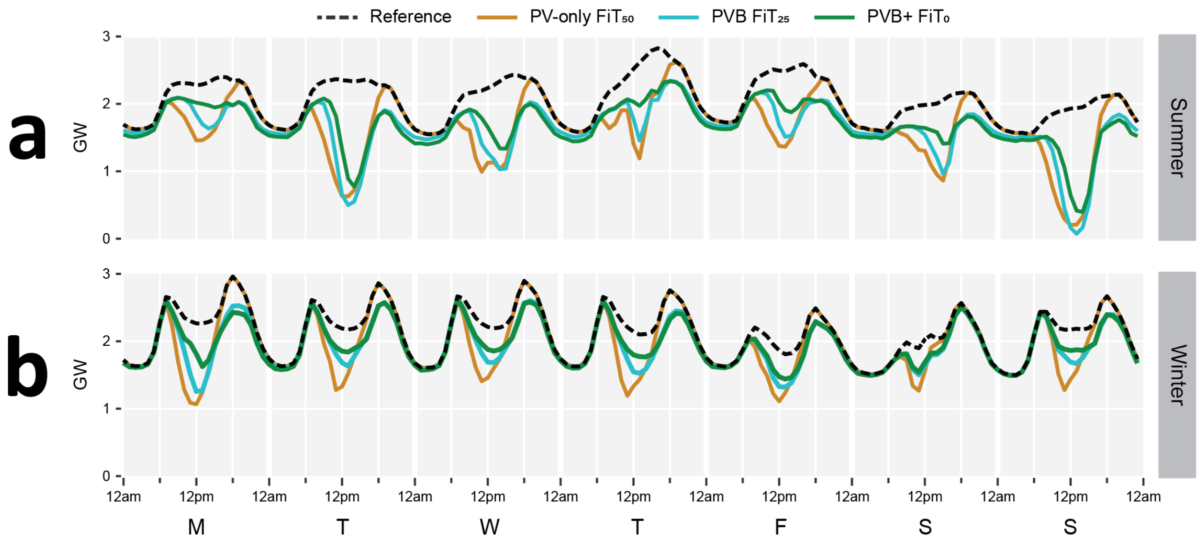

Figure 15. Influence of the FiT scenarios on the SWIS residiual network demand for 500,000 prosumage households across a week in (a) summer and (b) winter. Source (Say et al., 2020).

5.4.2 Impact on optimal utility capacities

Utility PV significantly affected, wind less impacted, and utility batteries still required.

With approximately 2.5 GW_P of PV capacity installed behind-the-meter in each FiT scenario, the household PV capacity generally substituted more utility PV capacity over wind capacity. This was due to household PV generating at similar times to utility PV and discouraging further investments in PV capacity. Furthermore, as household generation also contributes to the RES share, it also reduced wind capacity (Figure 16). The absence of battery storage in the PV-only scenario also resulted in additional investments in utility battery capacities, as the diurnal spread of demand between midday and the late-afternoon peak was further exacerbated. However, in the PV-battery scenarios, optimal utility battery capacity was only marginally impacted, even though significant storage capacity was deployed behind-the-meter. Comparisons between the PV battery scenarios and the counterfactual also reveal that the optimal capacities for conventional generation technologies were only marginally affected with PV battery households.

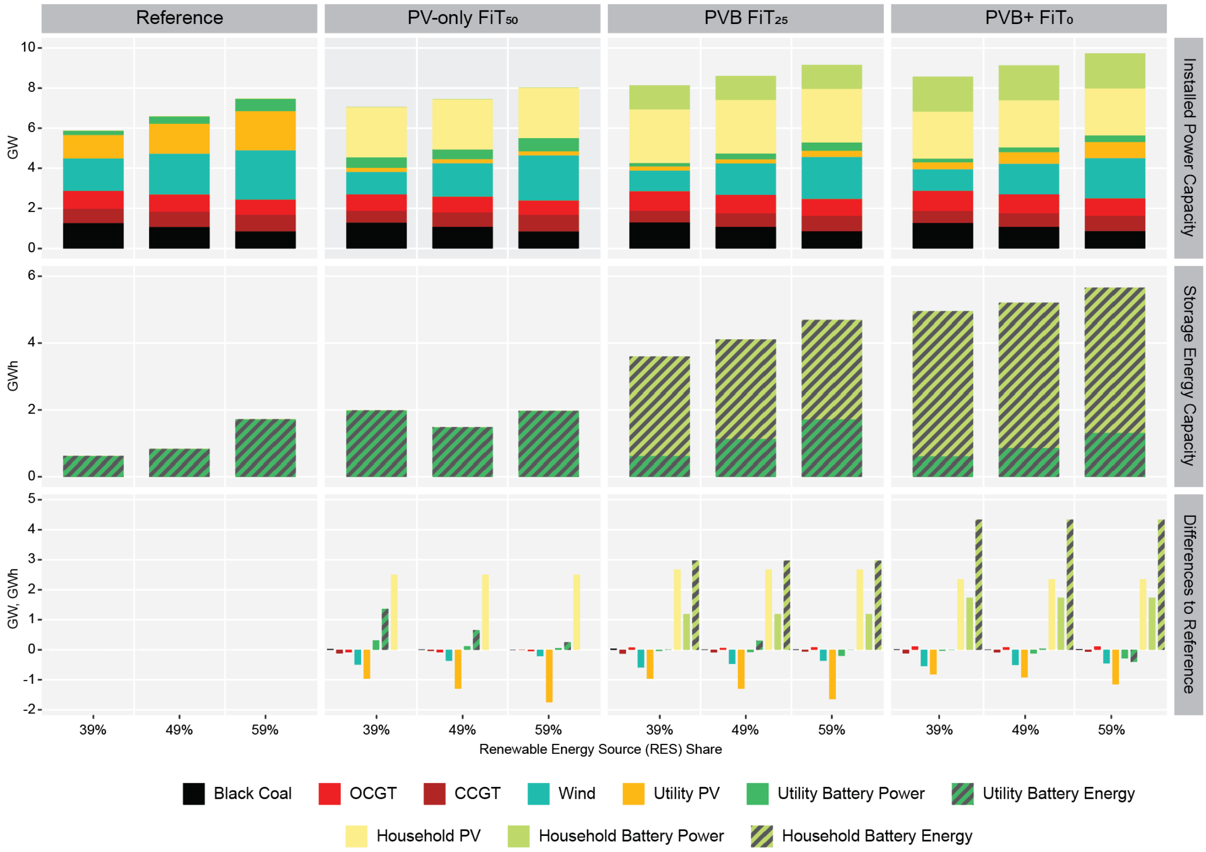

Figure 16. Installed power and storage energy capacity for varying FiT and RES shares (500,000 households) and the change in capacity with respect to the equivalent reference scenario (i.e., without prosumage household investments). Source (Say et al., 2020).

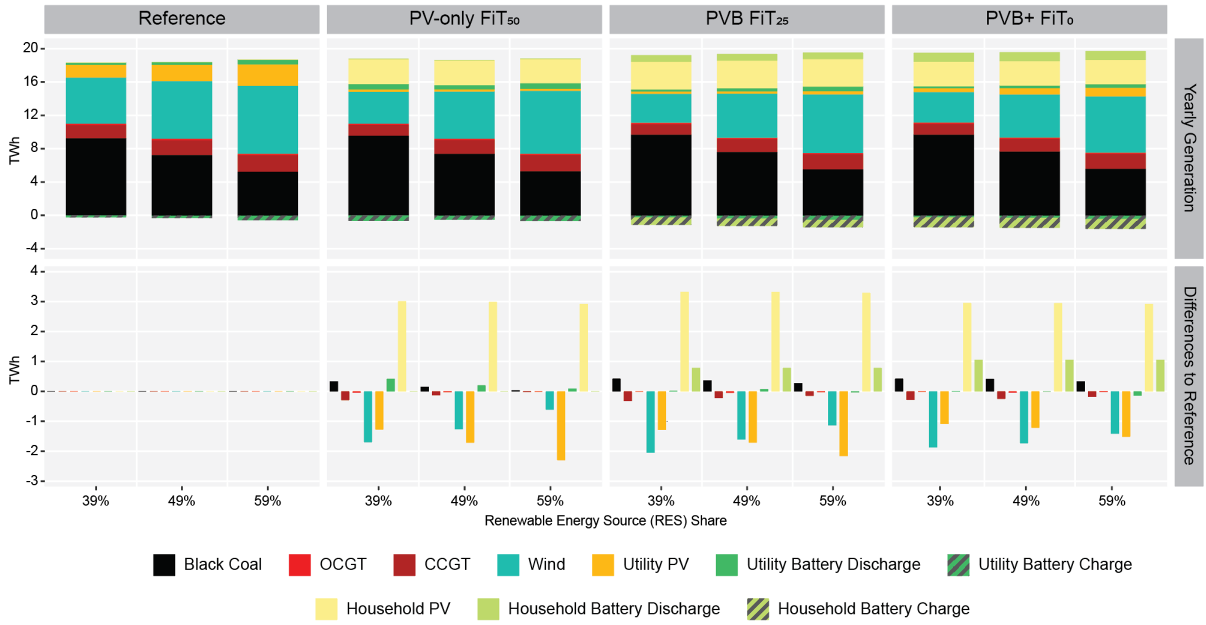

Figure 17. Yearly generation for varying FiT and RES shares (500,000 households) and the change in generation with respect to the equivalent reference scenario (i.e., without prosumage household investments). Source (Say et al., 2020).

5.4.3 Impact on optimal utility operation

Wind remains the largest contributor to the renewable energy share.

As the wind resources in the SWIS had a higher capacity factor than solar PV, wind provided the majority of the system's RES share even though its installed capacity was lower (Figure 17). As the RES share increased, wind consistently supplied more generation than solar PV, while coal generation experienced the greatest reductions in output.

Slight coal enhancing effect.

When comparing the scenarios against the counterfactual (i.e., without PV battery households) there was a slight increase in coal generation that led to a slight increase in carbon emissions. This was because the capacity of household PV reduced the amount of wind generation required,[33] resulting in an overall reduction in the amount of flexibility required from conventional generators. As a result, coal generation was able to dispatch slightly more effectively. In the PVB and PVB+ scenarios, the deployment of household batteries further reduced the amount of flexibility required, which also enhanced the overall

[33] That is, to meet the RES share.

coal generation slightly. However, this slight coal enhancing effect is mitigated as the RES share was increased, and the overall coal generation capacity only increased marginally. This meant that coal generators had a slightly higher capacity factor, but further investments in coal capacity were not warranted.

5.4.4 Impact on wholesale prices and system costs

Differences in costs faced by different customer sectors.

An approximation of the hourly wholesale electricity market price was established by utilising the shadow price of the *DIETER-WA* model's energy balance. The weighted yearly average wholesale market price required to supply electricity to 'commercial and industrial customers', 'non-prosumage households' and 'prosumage households' was calculated and compared to the reference scenario with no 'prosumage households'. Without prosumage households, the wholesale electricity price continues to significantly rise in the late afternoon. However, the reshaping of network demand by prosumage households resulted in a wholesale electricity price that had two local peaks, one in the early-morning and one in the late-afternoon (Figure 18b). This led to reductions in wholesale electricity costs for 'prosumage households' as their demand was able to avoid peak wholesale prices (Figure 18c). Interestingly, the wholesale electricity cost for 'non-prosumage households' was reduced even further as they were no longer exposed to significant price increases during their late-afternoon demand peak. 'Commercial and industrial customers' were slightly worse off as their savings from reduced late-afternoon wholesale prices could not offset the increased early-morning wholesale prices. Overall, the household sector saw a net-reduction in wholesale electricity costs, while the commercial and industrial sector had a slight increase.

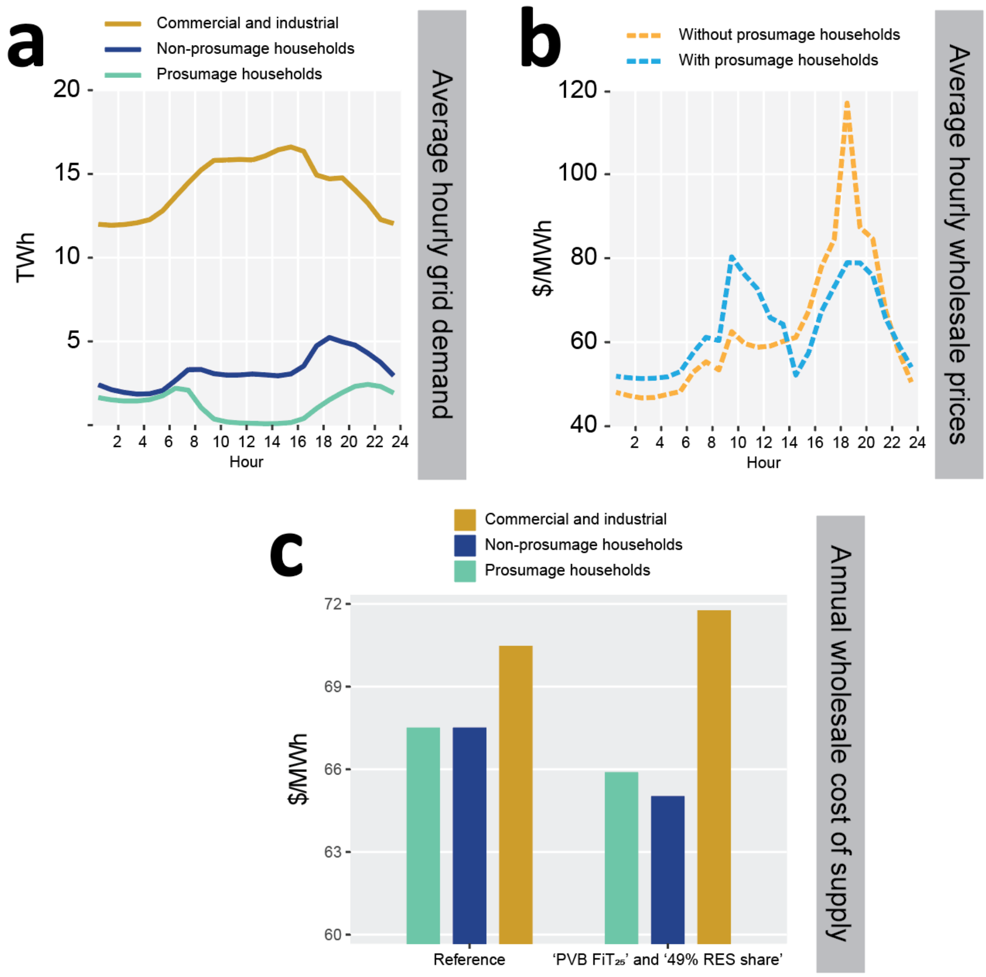

Figure 18. Effect of household PV-battery adoption in the 'PVB FiT25' and '49% RES share' scenario. (a) The average hourly grid demand for each customer sector. (b) The average hourly wholesale price of the least-cost portfolio. (c) The wholesale costs of supplying energy to each customer sector with and without prosumage. Source (Say et al., 2020).

Higher overall system costs, particularly from household battery adoption.

The total system costs were also affected by the capacity installed behind-the-meter and the utility-scale capacity necessary to service the remaining network demand. In the PV-only scenario, with the installation costs of household PV being greater than utility PV, the overall system costs were increased by approximately +6% (Figure 19). In the PVB and PVB+ scenarios, the overall system cost increases were much higher (+18% to +23%) as the addition of household battery capacity did not lead to an equivalent displacement of utility battery capacity. Instead, the utility battery capacity remained, while the household battery capacity increased significantly. This occurred since household batteries were limited to only improving PV self-consumption, while utility batteries continued to be required to provide balancing services to the wholesale market. The net effect was that overall system costs increased significantly, especially considering that households pay a price premium for their battery capacity. This finding suggests that household battery adoption when driven by flat retail tariffs, remains underutilised at the power system level, which would create an opportunity for new market mechanisms to better integrate the spare storage capacity into the wholesale market, e.g., via retail aggregators.

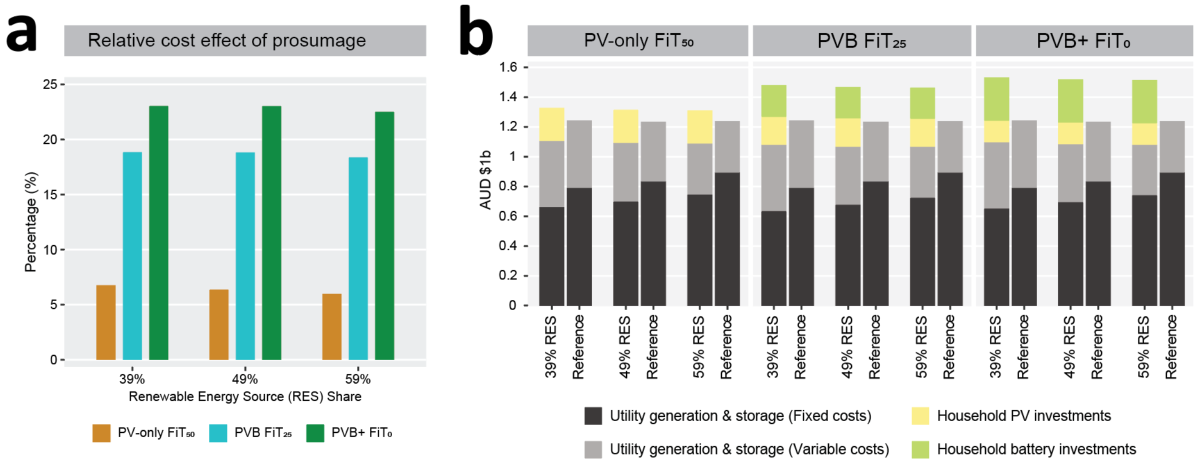

Figure 19. Relative effects of prosumage on overall system costs for each FiT and RES share scenario. (a) Overall change in system cost with respect to RES. (b) Breakdown comparison of each cost component with respect to the counterfactual reference. Source (Say et al., 2020).

5.5 Research outcomes and policy implications

This study coupled changes in customer demand with optimal utility portfolios to evaluate the overall power system impacts in 2030. The residual network demand was used to soft-link the household-focused *Electroscape* model with the utility-focused *DIETER-WA* model. The analysis focused on the relative differences from households installing PV-battery systems over PV-only systems. This research provided policy and decision makers with information on which utility-scale technologies were more resilient to PV-battery adoption, and their combined influence on wholesale electricity prices and carbon emissions intensity. This study adds to the energy modelling literature by combining customer and utility market models, that remain rare in the literature due to the significant parameterisation and modelling assumptions required. In this case, the SWIS network in Western Australia provided a useful system for analysis, as the power system was sufficiently large enough to have a competitive wholesale electricity market, but without interconnected regional markets that would otherwise increase the modelling complexity.

With the study driven by changes in the 'relative value of the FiT' and 'RES shares' amid changing system costs, the following policy implications were identified:

Wind capacity is more resilient.

Future utility PV capacity was the most vulnerable to substitution by household PV adoption. This was because households effectively dispatch ahead of utility PV and are usually generating at the same time. While this substitution was improved slightly when households installed their own batteries, utility PV remains significantly exposed to direct competition from households. By contrast, wind resources are capable of generating at different times of day and are thus better suited to complement customer-sited PV. From a whole-of-system planning perspective, the continued growth of PV capacity by prosumage households means that long lived assets, such as transmission networks, should be built to access renewable energy resources that are not just least cost but are also not temporally correlated with local solar resources. This outlook means that renewable energy developers would likely shift investments towards wind and firming resources over utility PV due to the long-term market risk (Mazengarb, 2021). Policymakers in regions with high solar radiation should therefore consider utility generation and storage capacity that complements customer-sited PV, rather than ignoring their potential.

Non-prosumage households can benefit from reduced prices.

Even though PV-battery households on flat tariffs lack temporal price signals, the default operation by household batteries directly reduces peak diurnal demand (which generally occurs between the late-afternoon and evening). In this study, this led to wholesale electricity price reductions over this period of time, which reduces the wholesale electricity costs for not just households with PV-battery systems, but also those without. This means that policies that encourage further household PV battery adoption (e.g., capital subsidies)[34,35] have a wider energy equity benefit to all other residential customers.

[34] https://www.solar.vic.gov.au/

[35] https://homebatteryscheme.sa.gov.au/

Underutilisation of overall battery capacity.

Under both PV-battery scenarios, the amount of household battery capacity did not significantly reduce the optimal utility battery capacity that would otherwise have been installed. This means that the operation of household batteries (driven by flat tariffs) considerably underutilises their technical capability to store and dispatch low-cost energy within the wholesale electricity market. These results indicate that policymakers should consider further exposing PV-battery households to wholesale market prices (either individually through temporal pricing, or through aggregation) to encourage their active market participation. By doing so, household PV-battery adoption can provide energy arbitrage that can improve the contribution (by reduce curtailments) of low-cost wind and utility PV generation, leading to additional wholesale cost reductions in the electricity market.

CHAPTER 6.

Molehills into mountains: Transitional pressures from household PV-battery adoption under flat retail and feed-in tariffs

6.1 Objective

The objective of this chapter is to identify transitional tipping points for household PV battery adoption that may challenge future electricity system management, market participation and energy policies. As electricity customers change how they interact with the grid, they apply transitional market pressures by undermining assumptions of traditional liberalised electricity market frameworks. By analysing these transitional pressures qualitatively, this research identifies particular structures in liberalised electricity market frameworks that are vulnerable to change and require further adaptation. The quantitative approach from Chapter 4 was analysed qualitatively to address the fourth research motivation (Section 1.1.4) through the identification and characterisation of a range of interlinked transitional pressures, which together may drive a liberalised electricity market towards greater renewable energy adoption through a customer-centric market design.

This chapter was published as a journal article (Say and John, 2021) titled “Molehills into mountains: Transitional pressures from household PV-battery adoption under flat retail and feed-in tariffs” in the journal *Energy Policy* (see **Appendix 4 – Paper 4**).

6.2 Combining numerical and qualitative methods for analysing power sector transitions

The power sector is continually influenced by changes in the technical, economic, environmental, social, and political dimensions. As noted by Bale et al. (2015), the framework of the liberalised electricity market is an emergent property of self-organisation that arises from the interactions between these dimensions. Each of these dimensions are therefore continually influencing the range of opportunities in the market framework and how they evolve over time.

Power sector transition analysis has to consider not only how individual entities within the framework of the market change, but also how the structure of the market framework itself comes under pressure to change. As reviewed in the Section 2.1.3, numerical methods are well suited to the analysis of the former, and qualitative methods with the latter, since many of the influencing factors that affect the framework of the liberalised electricity market are non-numerical (e.g., definition of fairness, appropriate allocation of risk, future climate and energy policies). In the context of household PV battery adoption, these prosuming households are individual entities that are able to take advantage of opportunities within the existing market framework, which may challenge and undermine the market's original design and assumptions around economic efficiency, subsequently leading to structural change. This interface between prosuming households and market structures creates the opportunity to couple numerical modelling with qualitative methods for transition analysis.

In this study, the *Electroscape* model was used to simulate a general trajectory of future grid-utilisation patterns (Figure 20 and Figure 21). This approach builds on the numerical modelling in Chapter 4 by evaluating across a range of FiT scenarios on future household PV battery investment behaviour. This not only generated installed PV battery capacities over time, but also its associated annual grid-utilisation profiles (with a 30-min resolution). By categorising these aggregate grid-utilisation profiles with the average PV battery installed capacities per household, a set of generalised *grid-operation stages* emerged that were used to represent a trajectory of change. This created the interface between the numerical modelling and the qualitative analysis in this study.

These *grid-operation stages* were qualitatively analysed (Figure 21) to establish how different operational qualities may change over time (e.g., residual demand becoming increasingly winter dominant) and then further broadened (by considering PV battery households as a segment of overall grid demand) to evaluate their impact at the system and market levels. This approach uses a range of FiT scenarios to establish how a general pattern of change emerges, and its impact on a liberalised electricity market that is based on large, centralised generation. By qualitatively evaluating changes in grid operation, this research determined the transitional pressures that are placed on the structure of the market framework from household PV battery adoption. This study provides system operators and planners, market participants, and decision and policymakers with the context and scope of changes that may result from households continuing to invest in PV battery systems and the transitional pressures they could face.

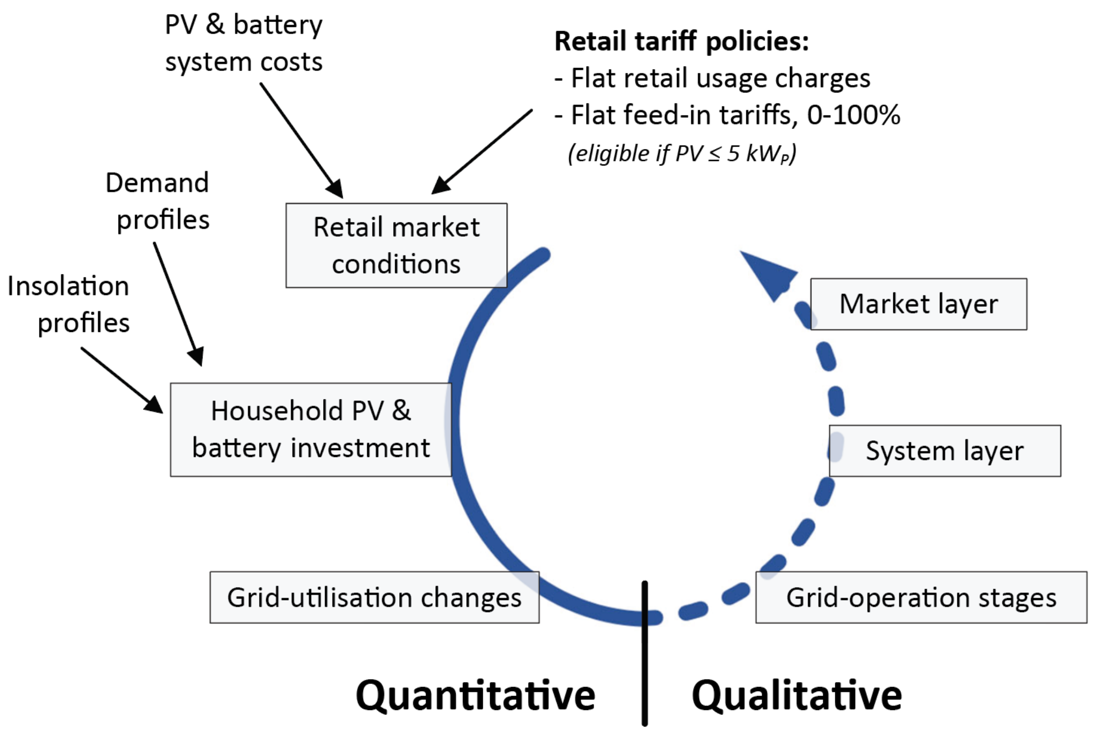

Figure 20. Overall quantitative and qualitative analytical framework used in the system and market transition analysis. Source (Say and John, 2021).

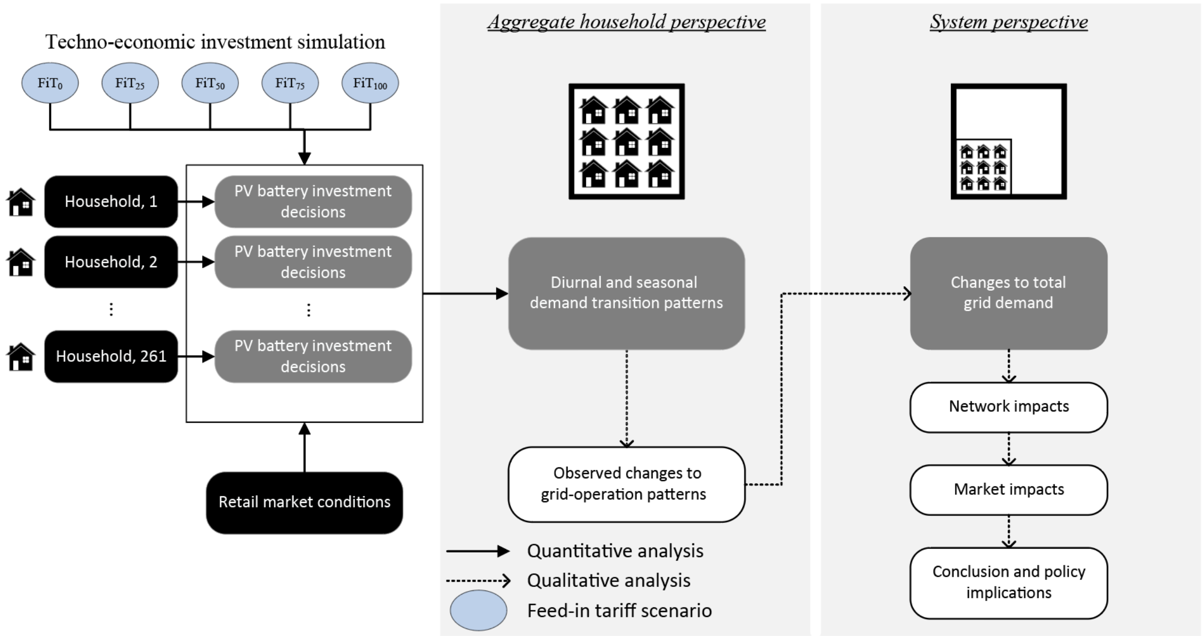

Figure 21. Detailed quantitative and qualitative analytical framework used in the system and market transition analysis. Source (Say and John, 2021).

6.3 Disruptions from household PV battery adoption: the shift away from a centralised electricity market model

Overall, outputs from 5 FiT scenarios were correlated to generate 7 grid-operation stages that represented a transition pathway as households switched from PV-only to PV-battery systems. The changes in aggregate operational characteristics over time (e.g., variation in the timing of diurnal peak demand, reduction in annual grid imports) formed the basis for the qualitative transitional pressures analysis. These transition pressures were evaluated at specific layers of the liberalised electricity market framework, namely at the aggregate household, system operation, and market level.

6.3.1 Aggregate household perspective

For utility-scale generators and network owners their operation and financial incentives are directly tied to customer electricity demand and quality of service. If grid demand is low, many of the available generators are not permitted to dispatch onto the grid. Customer behind-the-meter exports are exempt from this rule and can feed-in at any time regardless of current grid demand.[36] This effectively awards customer generation with the highest dispatch priority in the wholesale electricity market, without granting the system operator any visibility or control. This means that changes in grid utilisation by the household-sector can have an outsized effect on operational and market assumptions within a liberalised electricity market based on centralised generation.

At the aggregate level, the change in grid-utilisation showed that the transition to PV-battery households under flat tariffs resulted in:

Higher annual peak feed-in.

Once household battery systems became cost-effective, the economics of PV-battery systems incentivised households to not only install batteries, but also expand their existing PV capacity. This additional generation capacity was needed to supply enough energy for the battery to be used effectively. Furthermore, as the economic efficiency of household batteries are driven by its utilisation rate, they are sized to the average PV generation across the year

[36] This automatic right to dispatch has only recently started to change in Australia with new inverter standards being introduced to allow the system operator to control (i.e., de-rate or disable) the output of customer inverters if the overall grid demand becomes too low to maintain the electromagnetic stability of the power system (AEMC, 2021).

rather than peak insolation hours. As a result, during months with the highest rates of insolation (i.e., summer), installed battery capacities could not completely store all excess PV generation and were generally full before midday. This resulted in excess midday PV generation being fed into the grid without any storage capacity to act as a load. Since PV capacity was expanded, the annual peak feed-in from PV-battery households was also increased (compared to when they were PV-only households).

Diurnal peak demand shifting towards the early morning.

With flat tariffs, there is no financial incentive to shift demand and grid exports in response to higher or lower electricity prices across the day. As a result, the operation of the battery is incentivised to maximise self-consumption by storing any excess self-generation until full and discharging to fill any shortfalls in demand from PV generation until empty. This battery dispatch behaviour automatically leads to the reduction of demand during the late-afternoon peak (Figure 22a to Figure 22b). With batteries typically becoming empty overnight, they are less capable of reducing demand in the early-morning, which leads to early-morning demand becoming the new peak diurnal demand (Figure 22b). As system costs decreased and PV battery capacities increased, there was a continued reduction in the late-afternoon peak while the early-morning demand was more persistent. This eventually leads to peak diurnal demand increasingly occurring during the early-morning rather than late-afternoon (Figure 22c and Figure 22d). With the additional PV battery capacity, the batteries are able to continue operating further into the next morning, for more days of the year and for more households, which also leads to early-morning demand gradually reducing but at a lower rate (Figure 24).

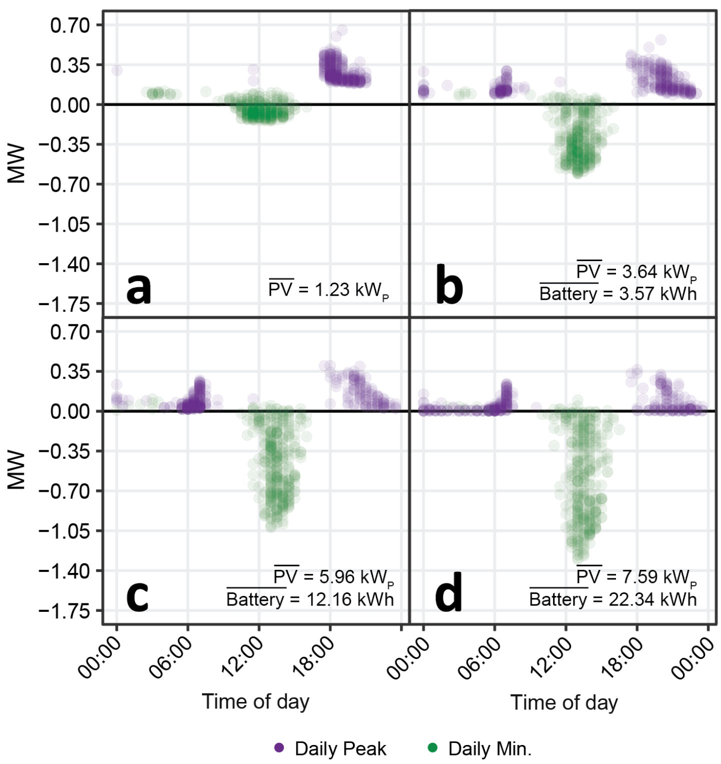

Figure 22. Timing and occurrence of the aggregate diurnal demand peak and minimum as installed PV battery capacity increases over time. (a) Average PV-only capacity of 1.23 kWP per household. (b) Average PV capacity of 3.64 kWP and battery capacity of 3.57 kWh per household. (c) Average PV capacity of 5.96 kWP and battery capacity of 12.16 kWh per household. (d) Average PV capacity of 7.59 kWP and battery capacity of 22.34 kWh per household. Source (Say and John, 2021).

Peak and operational demand becoming increasingly winter dominant.

Peak electricity demand in the Perth region generally occurs during the late afternoon in summer due to significant cooling demand during heat waves. However, summer months also have the highest levels of solar insolation which provide enough energy for PV-battery systems to reduce both peak and operational demand. While the spring and autumn months have lower solar resources, that also have the lowest electricity demand (due to the mild weather not requiring significant heating or cooling). This meant that the PV-battery systems were capable of even deeper reductions in peak and operational demand during these months (Figure 23). During the winter months, heating demand is more persistent and continues into the night. As solar resources are also at their lowest, PV-battery systems were much less capable of reducing peak and operational demand. Overall, this meant that as more

PV battery capacities were installed, peak summer demand eventually became less than peak winter demand. Operational consumption also become increasingly winter dominant as PV-battery systems were less effective during these months.

6.3.2 System operational challenges and opportunities

By considering the trajectory change across the grid-operation stages as being representative of the segment of the household sector willing to install PV battery systems, this study qualitatively analysed their operational impact on the wider entire electricity system.

Households gradually becoming net-generators.

As installed battery capacities were economically driven to reduce the total amount of grid consumption, a significant amount of electricity continued to be generated during non-winter months (Figure 23). As PV-battery capacities increased, this eventually led to annual grid consumption falling below annual grid exports (Figure 23c and Figure 23d). This effectively changes the role of households from consumers to net-generators. With fixed cost recovery commonly charged through the (volumetric) retail usage tariff, PV-battery households under fixed tariffs are able to avoid a significant proportion of these costs. Furthermore, this means that a transition to PV-battery household will further reduce total grid demand while further displacing utility-scale generation during daytime hours.

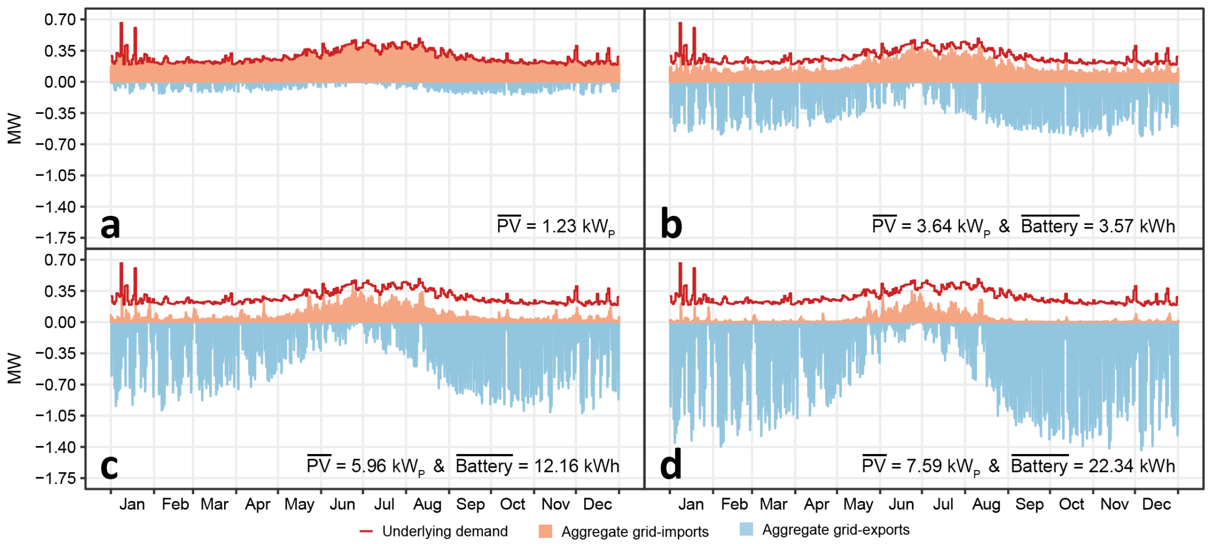

Figure 23. Change in half hourly grid utilisation (aggregate of 261 households) as installed PV battery capacity increases over time. (a) Average PV-only capacity of 1.23 kW$_P$ per household. (b) Average PV capacity of 3.64 kW$_P$ and battery capacity of 3.57 kWh per

household. (c) Average PV capacity of 5.96 kW_P and battery capacity of 12.16 kWh per household. (d) Average PV capacity of 7.59 kW_P and battery capacity of 22.34 kWh per household. Source (Say and John, 2021).

Reshaping of utility-scale generation.

Continued growth in grid exports during daytime hours and the reduction of demand during the late afternoon (and into the night) reshapes the demand profile exposed to the wholesale electricity market (Figure 24). The net result is that minimum network demand continues to decline under household PV-battery adoption. Furthermore, ramping requirements are affected as the ramp rate between midday and the late-afternoon becomes less steep than between early-morning to midday. This drives an operational shift towards the fast reduction of generation capacity, rather than fast starting.

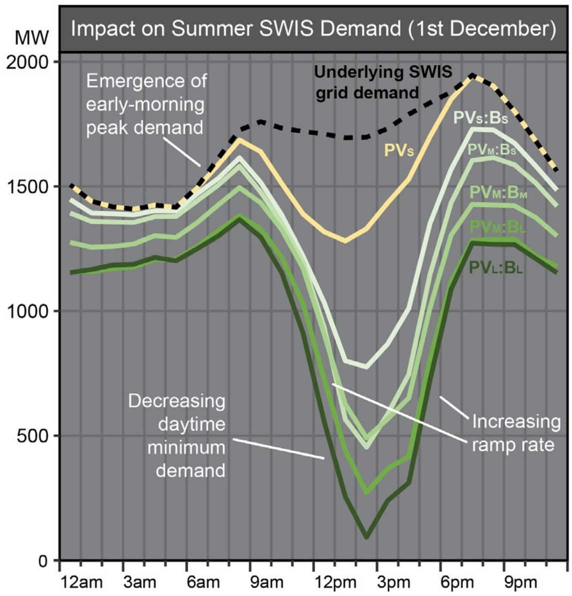

Figure 24. Impact on summer diurnal demand as 270,000 households transition from PV-only to PV-battery systems. Source (Say and John, 2021).

Increased need to coordinate customer DER.

The absence of time-varying prices limits any incentive for households to align their demand with low-cost and renewable energy generation. Rather than investing in capital intensive generation capacity to match these changes in customer demand from ongoing PV-battery adoption, there is an opportunity for system and market operators to coordinate customer energy assets instead. This could be achieved through pricing signals (e.g., time-of-use or real-time pricing) or dynamically controlling customer DER assets, via direct methods (AEMC, 2021) or via an intermediary (e.g., aggregators). By doing so, the electricity system gains not only an operational tool to manage operational risks, but also a technical foundation for a new range of market services that can provide demand flexibility through customer participation and remuneration.

6.3.3 Electricity market challenges and opportunities

Falling retailer revenues to drive DER market integration.

Considering that changes in customer grid-utilisation directly impact electricity bills, retailers are exposed to significant lost revenues if they continue to focus solely on supplying customers with electricity. As PV-battery adoption in the long term obtains most of its financial benefit from self-consumption over FiT revenues, PV capacities eventually exceeded the FiT eligibility limit. This means that retailers no longer have to pay for household grid exports, and since these household PV-battery systems are already sunk costs, any grid services that households could provide (e.g., peak shaving, network congestion management) from their spare capacity could have near-zero marginal costs for the retailer. This creates the necessary conditions for retailers to shift their primary focus away from supplying electricity *to* customers, to supplying grid services *from* customers.

Increasing role for flexible demand.

The reshaping of grid demand by ongoing PV-battery adoption leads to increased ramping while overall grid consumption continues to decline. Traditionally, this would be supplied by increasing the capacity of flexible generation technologies (e.g., open-cycle gas turbines, pumped hydro). But as these technologies have higher marginal costs than baseload generators, there is a risk that these changes in customer demand from ongoing PV-battery adoption can lead to increased electricity prices. However, if communication and coordination of customer DER assets are established with the electricity market, their demand flexibility and spare storage capacity could provide a competitive alternative to utility-scale peaking plants and load balancing facilities.

6.4 Research outcomes and policy implications

This research combined numerical modelling with qualitative analysis to evaluate the impact of household PV battery adoption on liberalised electricity market frameworks. Under pure numerical modelling (e.g., Chapter 5 'Degrees of displacement'), the level of analysis is constrained by the model's explicit capabilities, input parameters, and structural assumptions, which limits its overall breadth of discussion to its inputs and outputs, rather than the structure itself. In a time of rapid change, numerical models are at a disadvantage as many of these structural assumptions are being rewritten. This study addresses this issue by developing an analytical framework that uses a numerical model to establish trajectories (i.e., patterns) of changing demand that are the foundation the electricity market is built upon. By qualitatively evaluating how these patterns of change affect the structural elements of the power sector, this study provided the context and broadened the analysis on how liberalised electricity markets may come under bottom-up pressure from households to change. Moreover, as liberalised electricity markets have many common components, this analysis may not only apply to Western Australia, but also more broadly to other regions and markets.

By evaluating the structural elements of the market framework that are affected by household PV battery adoption, the following policy implications are identified:

Low FiTs reduce marginal costs to access household DER.

Even though the household sector only constitutes a segment of all electricity customers, the ability of PV-battery systems to further reduce demand and increase exports onto the grid[37] will significantly change the shape and quantity of future grid demand. As system operators cannot directly curtail or shape household exports in response to market prices,[38] households will continue to have a sizable impact on future wholesale electricity prices. As policymakers have limited leverage on household PV battery adoption (since PV-battery systems will eventually become economic even if FiTs were entirely removed) they will need to carefully consider how to integrate growing behind-the-meter capacity into the electricity market, rather than primarily focusing on utility-scale generation and storage solutions. As behind-the-meter generation and storage capacity are sunk costs, any additional services that can make use of the spare capacity would likely have low marginal costs. This presents an opportunity to capitalise on the growth of spare behind-the-meter PV and battery capacity to

[37] As the economics of battery adoption also drive further PV capacity to be installed.

[38] In Australia, the system operators have recently been permitted to curtail household exports in order to maintain grid stability during minimum grid demand events (AEMC, 2021).

provide a competitive and renewable alternative to grid services (particularly if the grid services are sourced from fossil fuel generators).

Growing scope for temporal pricing.

In this study, the path of adoption was driven by flat tariffs, which lack the temporal price signals that would allow household battery energy storage systems to respond to supply and demand fluctuations in the wholesale electricity market (and collect additional revenue through price arbitrage). While the behavioural inelasticity of household energy demand (e.g., Li et al., 2021) has impeded widespread temporal pricing in the past, battery energy storage systems offer the means to react to temporal price signals without requiring significant behavioural change. Therefore, as battery systems become more widespread, policy and decision makers would have greater capacity to encourage temporal pricing that improves the market integration of behind-the-meter generation and storage.

Customers as energy assets.

As future FiT rates decline,[39] the economics of household PV battery adoption favours installed capacities that minimise behind-the-meter electricity use over maximising electricity exports. However, the net result also leads households to export to the grid significantly more energy than they consume from the grid.[40] This means that households are in the process of transitioning from consumers into net-generators (even though energy exports are not the main value stream). From a transition's perspective, the existing market structures (i.e., retailer and network owner separation) and retail tariffs (i.e., time-invariant) are only able to offer limited alternate economic pathways as PV battery costs decrease. As more households become net-generators, the liberalised electricity market framework comes under increasing pressure to adapt, since its market share is effectively transferred from utilities to customers. This would result in greater responsibility and system awareness[41] being placed on customer generation and storage, which would also make it more capable of contributing grid services.

[39] Funded by retailers, FiTs approximate the average wholesale cost of utility PV in the electricity market. As further renewable energy capacity is installed, the average wholesale cost of energy during the daylight hours decreases further due to the merit order effect and near-zero marginal costs of wind and solar technologies, leading to lower FiT rates.

[40] With more PV capacity required to cover energy demand in the winter months, there is a growing excess of PV generation during the non-winter months.

[41] For example, adhering to dynamic export limits, incurring costs for participation, providing status information to the system operator.

With the reducing need for utility-scale capacity (from the withdrawal of customer demand) coupled with the growth of capacity behind-the-meter, the Western Australian liberalised electricity market is likely to undergo significant transitional pressure to change from a centralised market (that considers customers as consumers) to a decentralised market (where customer energy assets are market participants).

CHAPTER 7.

Conclusions

The growth of customer DER systems is challenging and beginning to transform many layers of the power sector. This is not just specific to Western Australia (AEMO, 2021a, p. 40), but also applies across Australia (AEMO, 2021c) and abroad.[42] The factors that have contributed to its growth have been shaped by the way customers interact with the power system, which has primarily been through their retail tariffs and feed-in tariff incentives. This research evaluated a potential range of transitional impacts that can arise from the continued use of 'two-part time-invariant' retail tariffs within a liberalised electricity market. This analysis resulted in 4 peer-reviewed journal articles.

Paper 1 *'The coming disruption'* developed a techno-economic model to evaluate the impact of retail tariff inflation and the relative value of the FiT on optimal and near-optimal PV battery capacities over time. The consideration of near-optimal solutions expanded the level of analysis by considering how the range of potential configurations are shaped by different tariff progression scenarios. This led to a broader understanding of the potential futures and the breadth of potential deployment strategies from residential customers. It also highlighted the growing possibility of an energy transition centred around prosumage energy production.

Paper 2 *'Power to the people'* extended the model in paper 1 by adding path dependency (through iterative investments) and by using real household data. The numerical results were then used to establish future retailer revenues by simulating the effect between retailer FiT pricing and subsequent PV battery adoption. This research showed the strategic considerations that can influence retailers to choose a particular FiT rate over another.

Paper 3 *'Degrees of displacement'* focused on three potential PV battery transition scenarios in 2030 and how they could influence the optimal mix of utility-scale technologies under different renewable energy portfolio standards. To achieve this, the developed model was soft-linked with a least-cost portfolio optimisation model of the SWIS power system. The results were then used to establish the extent to which the household sector could influence

[42] https://about.bnef.com/blog/henbest-energy-2040-faster-shift-clean-dynamic-distributed/

what was installed by the utilities, how it could operate, changes to wholesale electricity prices and the overall carbon emission intensity.

Paper 4 *'Molehills into mountains'* utilised qualitative analysis to assess how transitional changes in residual load (as households transition from PV-only to PV-battery systems) affect each layer of the power sector. The qualitative approach taken was used to evaluate how structural weaknesses are exposed by ongoing customer PV-battery adoption within the framework of a liberalised electricity market based on centralised generation.

This chapter shows how the four research questions (subsection 1.3.2) were addressed and how they answer the overall guiding research question (subsection 1.3.1).

7.1 Influence of retail tariffs and feed-in tariffs on subsequent household PV battery adoption

Using the model developed in Paper 1 *'The coming disruption'* (Chapter 3; Appendix 1 – Paper 1) and with further analysis conducted in Paper 2 *'Power to the people'* (Chapter 4; Appendix 2 – Paper 2), different rates of retail tariff inflation and FiT values were assessed. As 'two-part time-invariant' tariffs have limited degrees of freedom, these studies were able to evaluate the boundary and intermediary conditions to establish their general influence on household PV battery adoption.

Using NPV (based on 10 years of expected electricity bill savings) as a financial valuation metric, the results found that rooftop PV systems in 2018 were the most profitable system configuration. Over the next decade however, decreasing PV and battery system costs would eventually lead to PV-battery systems becoming more profitable, even if retail electricity prices stayed the same. Increasing the tariff resulted in the cost-effective PV-battery tipping point occurring earlier, which suggests that passing increased wholesale costs via retail usage charges would accelerate PV-battery adoption. Furthermore, raising the FiT to a higher proportion of retail usage charges reduced the value of self-consumption and slowed down PV-battery adoption. While reducing the FiT raised the value of self-consumption, which initially suppressed the installation of large capacity PV-only systems, but as the PV-battery tipping point was brought forward, it also eventually resulted in the largest PV and battery capacities being installed.

Further analysis of the annual grid-consumption showed that households with PV-only systems would still require the grid for approximately 60% of their underlying energy demand. However, once cost-effective PV-battery systems were installed, near-optimal configurations would eventually result in the household grid-consumption falling to under 10% of their underlying energy demand. Such a decrease in grid-consumption, if widely adopted, signifies substantial load defection out of the electricity market, and when coupled with the rise in grid-exports, would considerably impact future electricity demand and system planning expectations across the entire power sector.

Notably, the analysis of the economics of PV battery system in Paper 1 and Paper 2 showed that the arrival of cost-effective batteries simultaneously incentivised additional PV capacity. Therefore, as the cost-effective tipping point of PV-battery systems nears, policymakers have an opportunity to further accelerate the decarbonisation of the power sector by using retail tariff policies that encourage battery adoption. This would indirectly increase the amount of PV capacity deployed behind-the-meter, and further increase the amount of renewable energy capacity in the power sector.

7.2 Household PV-battery adoption and its influence on retailer tariff prices and structure

This relationship between the 'relative value of the FiT' and the resulting reduction in grid consumption, plus increases in grid exports, leads to fundamental changes between customers and electricity retailers. At the individual household level, customers are able to reduce their annual electricity bills as a consequence of retail electricity prices and incentives. At the whole of system level, these reductions in electricity bills change consumption and future net retailer revenues. As retailers are responsible for setting the 'relative value of the FiT' and paying for it, they are capable of influencing the rate and timing of household PV-battery adoption in accordance with their own financial motivations.

With the addition of the iterative investment approach, which yields path dependency, and the use of real household load and generation profiles, the study in Paper 2 *'Power to the people'* (Chapter 4; Appendix 2 – Paper 2) evaluated the effect of changing the 'relative value of the FiT' on future net retailer revenues. The results found that higher FiTs were unsustainable (and discouraged PV-battery adoption), as it encouraged too many households in the short-term to install large capacity PV-only systems, which significantly raised the cost of FiT payments and led to the lowest future net retailer revenues. Conversely, lower FiTs yielded the highest net retailer revenues since FiT payments were also drastically reduced (even though households were incentivised to install PV-battery systems earlier). Overall, the findings suggest that retailers would be under continuous financial pressure to protect their overall net retailer revenues by keeping FiTs as low as possible, which increases the likelihood that household PV-battery adoption could become more widespread.

The study also found that the continued use of 'two-part time-invariant' retail tariffs would lead to fixed charges gradually becoming the dominant component for recovering wholesale generation and network costs. This would have negative consequences for energy equity as it applies equally to low- and high-income households, and higher income households would still retain some limited capability[43] to avoid contributing to overall power sector costs. This suggests that a re-evaluation of retail tariffs for PV-battery households should be considered to encourage the wider use of time-varying usage and export charges. With batteries being able to operate without requiring customers to change their energy consumption behaviours, time-varying tariffs provide an incentive for PV-battery households to align their grid-utilisation with the supply and demand needs of the electricity market, thus improving the economic efficiency of its assets. This should result in reduced electricity prices that would benefit all customers rather than just PV-battery owners.

7.3 Households reshaping utility generation portfolios and the operation of the power system

Changes in grid-utilisation from solar PV are already affecting electricity markets worldwide, e.g., solar duck curve (Denholm et al., 2015; Maticka, 2019). The widespread use of PV-battery systems by households are likely to further change utility-scale investment and dispatch assumptions. This will have repercussions not only on day-to-day operations, but also on the optimal mix of utility-scale technologies. Two models were soft-linked in Paper 3 *'Degrees of displacement'* (Chapter 5; Appendix 3 – Paper 3) using the expected residual network demand from three 2030 household PV battery transition scenarios. This allowed changes in grid-utilisation from the household-sector to influence the least-cost portfolio in the SWIS power

[43] Through PV battery investments

system under three different renewable energy shares. By comparing how the least-cost portfolio changed with respect to a counterfactual scenario (in which households did not install any PV battery systems), the relative impact from different household PV battery transition states could be established.

Under either a PV-only or PV-battery transition, the results showed that household PV capacity significantly reduced utility PV capacity, as they share similar generation hours. Furthermore, as overall generation was constrained to match a fixed annual renewable energy source (RES) share, wind capacity was also reduced but to a lesser extent. This led to a slight increase in coal generation, as the remaining network demand faced by conventional generators was slightly less variable due to reductions in wind generation. This coal enhancing effect however could be reduced by increasing the required RES share. The remaining conventional generators, i.e., open-cycle gas turbines and combined-cycle gas turbines, were largely unaffected by household PV battery transitions.

Under a PV-only transition, additional utility-scale batteries were installed to make use of excess rooftop PV generation. Under a PV-battery transition however, there was no corresponding reduction in utility-scale battery capacity. This meant that the operation of household batteries (under 'two-part time-invariant' retail tariffs) did not sufficiently improve the economic dispatch of the power system and were largely underutilised. Furthermore, as all this additional household battery capacity that did not decrease utility-scale battery capacity, total system costs were also much higher.

Notably, average hourly wholesale electricity prices were reshaped under PV-battery transitions, where high peak prices in the late-afternoon were redistributed into two lower peak prices during the morning and late-afternoon (as a consequence of PV-battery households reducing their own late-afternoon peak demand). These hourly changes in wholesale prices meant that the average wholesale cost for non-DER households was reduced, since their late afternoon demand was no longer exposed to very high peak prices. However, commercial and industrial (C&I) customers faced slightly higher average wholesale costs as their annual demand profile remained more exposed to higher morning wholesale prices than lower late-afternoon wholesale prices.

This research evaluated a renewable energy transition occurring simultaneously at the utility- and household-scale, but with the household-sector leading the transition. The overall findings suggest that utility PV would continue to face increasing competition from household PV, even in the presence of utility-scale batteries. Wind was more economically robust, as it is less affected by household PV. This means that transmission planning should prioritise access to wind over solar resources, especially in regions where the wind profile complements the diurnal solar profile. Utility-scale battery capacities remained relatively unaffected, as they do not face meaningful competition from households with time-invariant retail tariffs. Coal continues to face significant operational and capacity reductions, while the more flexible OCGT and CCGT generators were much less affected.

7.4 The emergence of customer generation and storage assets in power sector decarbonisation

Liberalised electricity market frameworks were traditionally designed around centralised generation, with the burden of risk and uncertainty gradually being lowered across its supply chain. The highest risks (and rewards) reside within wholesale electricity markets (i.e., energy, capacity/reserve, ancillary services), then to regulated monopolies for network expansion and maintenance, and finally retail markets that compete to simplify customer electricity pricing (by averaging costs components such as spatio-temporal variations in pricing, to maintaining a certain degree of capacity and reliability). In exchange, all customers are required to pay for the operating and maintenance costs across the entire power sector. As a result, customer retail tariff structures and pricing are designed to be as simple as possible in order to recover these fixed and variable costs, with 'two-part time-invariant' structures being the most common example in Australia (CME, 2017). However, by insulating customers from the power sector's operational and transitional risks, customers have limited influence on the pace of transition, while also being excluded from directly participating.

The improving cost-effectiveness of behind-the-meter PV battery systems enable customers to make their own decisions, where they have a competitive advantage over the electricity market with a guaranteed level of future energy demand (i.e., their own) while also having the lowest exposure to operational and pricing risks. Given that design of the electricity market depends not only upon the amount of customer electricity demand but also how the grid is utilised, these changes mean that the market framework needs to adapt to how customers install and utilise their own generation and storage systems. Therefore, a better understanding of how the liberalised electricity market framework is gradually affected by ongoing household PV battery adoption (under flat retail tariffs) is needed to provide policymakers with both the extent and scope of changes possible. This would allow them to develop policies that improve the alignment between household PV battery adoption and liberalised electricity markets. That way the growth of customer PV generation and storage may be used as a complementary pathway for the decarbonisation of the power sector and the wider energy system.

This process was studied in Paper 4 *'Molehills into mountains'* (Chapter 6; Appendix 4 – Paper 4), which simulated a range of PV battery adoption scenarios using real household profiles and across a range of different retail usage and FiT prices. Annual changes in grid-utilisation were then characterised into a series of grid-operation patterns that together represented a generalised transition pathway. Furthermore, this captured the magnitude and timing of how energy flows could be impacted by PV battery customers, and also provided the numerical foundation for a qualitative analysis on how gradual changes in aggregate household grid-utilisation may subsequently challenge each layer of a traditional liberalised electricity market framework.

Under time-invariant tariffs, households focused on minimising their overall grid demand, which required the installation of further PV and battery capacity to minimise demand during the winter months. While this significantly reduced the late-afternoon diurnal demand peak over the summer months, it inadvertently also led to the continued increase in the amount of excess PV generation being exported during midday,[44] even after households were no longer eligible to receive FiT payments. This would likely lead to: (i) greater network congestion resulting from peak feed-in rather than peak demand which necessitates remote feed-in management; (ii) a continued decrease in minimum daytime demand leading to further reductions in the value of daytime wholesale generation; (iii) steeper ramping

[44] Since the battery capacities installed by households were could not store the entire day's excess generation, thus becoming full before midday. This consistently led to all excess PV generation being exported during the midday.

requirements between morning and midday requiring more flexible utility generation; and (iv) a transformation of customers from consumers into net-generators.

These results show that PV-battery households would continue to increase their grid exports even though they are not paid for it,[45] and become a growing source of zero-marginal cost generation. This creates an opportunity for new business models to emerge that manage how these exports are used within the rest of the electricity market. From a retailer perspective, PV-battery households that consume much less energy than they export would mean retailers may have to shift their business models away from selling electricity to these customers, to selling their electricity exports and demand flexibility into other sectors of demand (e.g., commercial and industrial). Furthermore, as PV-battery households have a greater ability to react to temporal and demand charges without behavioural changes, it creates the space to encourage more dynamic retail pricing, especially if it improves customer financial returns. The increasing magnitude of excess daytime generation means that new investments in utility-scale generation would increasingly have to avoid competing directly with households[46] and develop utility-scale resources that generate at different times (e.g., wind) or provide the system with additional flexibility (e.g., utility batteries, aggregators). This suggests that transmission planning should focus on wind over solar resources, and the overall electricity market has to contend with continually decreasing demand from the household sector.

These changes in grid-utilisation compete directly with the centralised generation paradigm that has dominated the design of liberalised electricity markets. As PV-battery households are able to utilise their own capital to withdraw significant demand and contribute to generation, they are capable of becoming new decentralised market actors and should be considered as an integral part of the future electricity market, or else they may continue to undermine the investment confidence of wholesale market participants and network owners.

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[45] Since more value could be obtained from reducing grid imports than exporting energy, households were still incentivised to exceed the 5 kW_P FiT eligibility limit and lose their FiT payments.

[46] Especially since households would always have a higher merit order for their own demand.

7.5 Contribution to new knowledge

By addressing each of the four research questions, this research filled the following knowledge gaps:

- The relationship between the feed-in tariff pricing and retail tariff inflation for flat time-invariant tariffs on future PV battery adoption was established. This research used a near-optimal investment perspective to develop a techno-economic simulation model that used NPV profitability as the evaluation metric.
- This research identified the short- and long-term strategic considerations that retailers face when deciding upon the price of the FiT. By quantifying the impact of subsequent PV battery adoption on future retailer revenues, this research determined the financial considerations that pressure retailers to choose low FiT rates, even though it would lead to an acceleration of PV-battery adoption.
- This research quantified the impact that different household adoption pathways (i.e., PV-only or PV-battery) have on optimal utility-scale technology portfolios (using least-cost dispatch and investment optimisation). Using counterfactual analysis, the potential impacts on future capacity investments in generation and storage, system operation and planning, wholesale electricity prices, and carbon emission intensities were established.
- The structural foundations of the traditional liberalised electricity market framework were qualitatively analysed by using changes in grid-utilisation from PV battery investing households over time to represent a general PV battery investing household transition pathway. This research found a range of vulnerabilities in the retail, network, system operation and wholesale market sectors that currently remain exposed to ongoing PV battery adoption.
- The dynamic techno-economic investment simulation model developed in each of the studies was made open source to contribute a set of modelling tools to the energy transitions research community. It also enables other researchers to more easily apply the same methodology to their own case studies.

Overall, this research quantified and qualified how ongoing household PV battery adoption may impact the current state of the power sector. These studies establish a range of system benefits and structural weakness to provide decision and policymakers with more detailed information on specific areas of the liberalised electricity market framework that should be re-examined in order to take advantage of and embrace the growth in customer energy resources.

7.6 Implications for stakeholders

Customers have the competitive advantage

Decreasing costs of solar PV and lithium-ion battery technologies are not only creating new opportunities for large-scale renewable energy generation and electric vehicles but are in the process of establishing new technological niches for customers to actively participate in the decarbonisation of the power system. When deploying private capital and collecting returns, customer PV battery systems have many competitive advantages, namely, having their own electricity demand, the right to self-consume, not needing to purchase/lease land for PV panels, and the ability to export into the grid without market coordination or additional expenses. In the broader sense, there is a paradigm shift occurring in the power sector where customers are capable of exercising increased bargaining power.

Time-invariant tariffs lock-in customer PV-battery adoption

For retailers, the traditional mechanisms for recouping power systems costs and reducing price volatility through hedged contracts and time-invariant retail pricing, places them at a disadvantage as they have to determine relatively uniform prices that cover the cost of aggregate household demand. This means retailers have to compromise with some customers better off while others are not. However, individuals are not similarly constrained and may invest in generation and storage capacity catered to their own electricity demand while capitalising on the price certainty offered by the retailer's tariffs. Continued investment by a growing number of individuals into self-generation and storage means those that do not install their own systems may become gradually worse off, which then encourages more customers to install their own systems, while potentially worsening energy equity. The research conducted in this thesis has shown that time-invariant tariffs favoured by many retailers do not have sufficient degrees of freedom to prevent PV-battery systems becoming cost-effective.

With regards to FiTs, raising their value delays PV-battery adoption but comes at a higher policy cost. Lowering their value reduces PV-only adoption in the short-term but brings forward the cost-effective PV-battery tipping point and the subsequent magnitude of adoption. It also has a lower policy cost, while maintaining higher retailer revenues, which suggests that lower FiT rates would be the more likely outcome, along with the accelerated PV-battery adoption.

With regards to usage charges, higher prices bring forward the cost-effective tipping point for PV-battery systems which discourages retailers from raising usage charges over fixed charges to recover supply chain costs. Though raising fixed charges does not improve the economics of PV battery systems, it may encourage a greater number of non PV battery households to consider installing it.

Since customers are able to adjust PV battery investments in response to changing retail tariff and FiT prices, while taking advantage of decreasing installation costs, the widespread adoption of PV-battery systems by the household sector is unlikely to be prevented and will continue to grow unabated. The wider power sector and its market framework therefore need to prepare for their integration.

A disruptive transition towards a customer-centric electricity market

The top-down operating paradigm of the liberalised electricity market is fundamentally being challenged by its customers. The retail market mechanisms designed to minimise risk and simplify the cost of electricity for customers, are in turn used by the very same customers to justify their investments in self-generation and storage, that then reduce the size of the electricity market. Since the electricity market fundamentally remains dependent upon customer demand, it has no alternative but to evolve.

This research shows that potential disruption from household PV battery adoption stretches across the entire supply chain (e.g., depressing future retailer revenues, exacerbating network congestion with bidirectional electricity flows, displacing other utility-scale renewable energy generators (especially utility PV) and the wider cost-optimal technology mix, to reshaping wholesale electricity price dynamics). The results also suggest that PV-battery customers will have a greater capacity to manage retail tariff pricing risks (e.g., time-of-use, demand charges, real time pricing) and should therefore be increasingly exposed to them. This would allow customer PV-battery systems to react and capitalise on wholesale market supply-demand dynamics (e.g., energy arbitrage) and grid services (e.g., ancillary services, network decongestion), while simultaneously providing a form of support for the overall power system as it undergoes an unprecedented rate of transition.

The liberalised electricity market therefore needs to become increasingly customer-centric and to provide the bottom-up cost signals and market structures that can allow customer supply and demand to dynamically adapt and respond.

An emerging and complementary pathway to accelerate energy system decarbonisation

As disruptive as the growth in household PV battery adoption may be to the power sector, it is also a new and significant source of renewable energy that allows customers to directly contribute to the decarbonisation of the energy system. Decision and policymakers should therefore embrace this opportunity and consider how this behind-the-meter capacity may be better leveraged to accelerate the renewable energy transition. The rate of decarbonisation necessary to avoid climate change has to occur at such a pace that there is likely to be a high degree of policy and implementation risk, which is magnified in any system with rigid structures and long-lived assets.

By transitioning to a customer-centric electricity market, the range of decision makers and participants in this transition is widened and becomes less homogenous. It introduces a new range of operational and economic levers to manage supply and demand variability and may increase the flexibility of the power sector to respond to unforeseen risks over the course of the energy transition (e.g., automatically reducing customer demand to prevent shortfalls in generation capacity, to providing storage capacity for excess daytime generation). As small-scale solutions to the energy transition, customer PV battery systems can more readily react to changing market conditions than much larger utility-scale solutions, which have higher capital requirements, greater lead times and longer economic lifespans. It may also lower the costs of the transition since customer PV battery systems compete against utility-scale solutions. Furthermore, as behind-the-meter generation and storage capacity comes primarily from private rather than public funds, it allows public capital to be reallocated into other decarbonisation strategies.

Overall, customer PV battery systems provide policymakers with additional leverage to manage the transition of the energy system. While the decentralisation of the electricity market may be disruptive in the short-term, it has the potential to drive long-term structural changes across the power sector and enable new frameworks that allow both customers and utilities to complement one another.

Implications for the future

This research shows that electricity customers are unlikely to remain as passive actors within the power sector and have the potential to become a significant source of new renewable energy generation and energy storage capacity. In 2021, customer rooftop PV generation capacity in Australia has reached the point that it has become the largest generator in the middle of the day. In the states of South Australia and Victoria, this has affected wholesale prices over summer such that the average price around midday was negative (AEMO, 2021b). With operational lifespans over 20 years, customer PV generation will continue to persist and as the economics of battery systems continue incentivise further PV generation capacity, it is the electricity market that has to adapt to customer generation and storage. This creates an opportunity not just for power sector decarbonisation, but also the larger energy sector.

Every unit of energy generated behind-the-meter using PV systems reduces the need to rely upon the grid and its operational emissions. As the economics of customer PV battery systems is focused on maximising the value of self-consumption, the PV generation that leads to avoided grid consumption and rising excess energy exports subsequently comes at zero-marginal cost. Furthermore, as customer batteries tend to be underutilised when maximising self-consumption, access to their spare capacity could come at near-zero marginal cost. Therefore, excess customer PV generation is likely to become the cheapest form of renewable energy generation and source of power sector carbon abatement, while underutilised battery capacity has the potential to become the cheapest form of short-term energy storage.

Given that the decarbonisation of the energy system relies largely on the power sector becoming the main source of low-cost renewable energy, the widespread adoption of customer PV battery systems is capable of significantly contributing to this outcome. The research in this thesis has shown that it has the energetic and economic potential to do so and should therefore not be discounted as a viable strategy for decarbonisation. With PV battery costs expected to continue decreasing worldwide, other countries are likely to experience a similar growth in their adoption. The Western Australian context in this research offers other jurisdictions insights on its techno-economic drivers, the policies that enable its growth, and how the wider power sector may be impacted. Decision and policymakers should therefore consider the widespread adoption of customer PV battery systems not as a threat, but rather as an asset to accelerate the transition towards a decarbonised energy system and economy.

7.7 Limitations and future research

The research conducted in this thesis was based on numerical modelling of customer PV battery investment behaviour. Models however remain simplifications of reality and are unable to accurately represent non-numerical factors used in decision making processes. They therefore remain a tool for exploring system boundaries, transition pathways and informing policymakers on the potential range of consequences, rather than generating accurate forecasts.

The assumptions used in this research reflect the available information and degree of confidence about future financial and technical parameters. These assumptions lead to the range of limitations that follow while also providing opportunities for future research:

- The **retail tariff structure** used in this research was based on ‘two-part time-invariant’ tariffs. While it is the predominant tariff structure in use in Australia, it does not evaluate other tariff structures offered by retailers. The research findings showed that the lack of temporal prices prevented customers from actively reshaping their grid-utilisation in response to supply and demand shortfalls in the wholesale market. Future research that can develop a clearer understanding of the impact of time-varying import and export tariffs on the operation patterns of PV battery systems and their subsequent adoption could offer policymakers the information necessary to further encourage retail tariff reforms.
- **Battery electric vehicles (BEVs)** were not part of the analysis but are emerging as a new source of electricity demand with its own energy storage capacity. Together household PV, household batteries and BEVs encompass the range of currently available behind-the-meter energy resources. The inclusion of BEVs into future analyses would create new opportunities and incorporate an additional energy sector, i.e., mobility. The ways in which BEVs dynamically interact with household PV battery systems and the grid shares similarities with energy transition research on utility-scale sector coupling (e.g., Fridgen et al., 2020). Developing an iterative customer-scale PV, battery, and EV energy transition

model that can be applied across many heterogeneous customers, may lead to the development of addition customer-centric decarbonisation strategies.

- **Retail electricity price increases** were based on the historical growth rate of household electricity prices over the last 5 to 10 years (Australia Bureau of Statistics, ABS, 2018) and then extrapolated over the simulation period. However, the power sector is currently undergoing significant transformation from the deployments of large-scale renewable energy generators, accelerated retirement of coal power stations, to the ongoing growth of rooftop PV, all of which would lead to non-linear price dynamics. Moving beyond the fixed growth rate approach for future retail electricity prices would require decarbonisation policy strategies (e.g., carbon pricing, renewable energy source shares) to be integrated into the research, since they heavily affect future wholesale and thus retail electricity prices. This may lead to future research that evaluates the second order effects of utility-scale decarbonisation policies, by combining future wholesale electricity price projections with a trajectory and magnitude analysis of household PV battery adoption, to determine the overall power system outcomes and effectiveness of the decarbonisation policy.
- A **single investment decision process** (based solely on financial performance) was applied to each household. The heterogeneity in this research was based on the unique load and generation profiles from each household rather than the decision-making process itself. While this simplified the number of assumptions, future research could utilise behavioural economics research to develop investment decision processes that are heterogeneous and capable of incorporating non-financial parameters, such as motivation and perception. This would provide the researchers with a means to evaluate the robustness of potential energy policies by moving away from a perfectly rational economic actor.
- **Spare generation and storage capacity** was not explored in this thesis. The results from Paper 3 *'Degrees of displacement'* suggest that the significant amount of installed household battery capacity was not being utilised in a power system friendly manner (as utility-scale batteries were still being built to a similar capacity without household batteries). This spare generation and storage capacity can be used locally to improve overall self-consumption within a community, alleviate network congestion, or participate in the wholesale electricity market and reduce renewable energy curtailment. Future research can consider how the growth and magnitude of spare behind-the-meter capacity

can be used across the various layers of the liberalised electricity market. Quantifying these potential revenue opportunities would begin to explore the viability of aggregation services that have to pay customers to utilise their spare capacity.

- The **region of analysis** was centred on the isolated SWIS network in Western Australia. While this simplified the number of assumptions required to conduct an end-to-end analysis, it also limited the analysis to this region. Applying the same methodology to other national or sub-national power systems would allow researchers to compare regional differences and develop more robust customer-centric renewable energy transition policies and strategies.

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Appendices

Appendix 1 – Paper 1

Say, K., John, M., Dargaville, R., Wills, R.T., 2018. The coming disruption: The movement towards the customer renewable energy transition. Energy Policy 123, 737–748. https://doi.org/10.1016/j.enpol.2018.09.026

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Conception and design, acquisition of data and method, data conditioning and manipulation, analytical method, interpretation and discussion, and final approval

Signature of candidate: **Date:** **10 November 2021**

I, as a Co-Author, endorse that this level of contribution the candidate indicated above is appropriate.

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Signature: **Date:** *9 December 2021*

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Signature: **Date:** **8 December 2021**

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The coming disruption: The movement towards the customer renewable energy transition

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ABSTRACT

The technical and financial influences that shape customer investment in behind-the-meter PV and battery systems, provide the means to forecast and quantify customer energy transitions. By utilising techno-economic scenario analysis, this research assists policymakers to understand the impacts of their decisions on future energy market relationships between the customer and utilities. Two case studies are presented, firstly to evaluate the influence of annual increases in usage charges, and secondly the level of feed-in tariff compensation on customer PV and battery investment over a 15-year forecast period located in Perth, Australia. The findings indicate that even without annual increases in usage charges, the falling installation costs of PV and battery technologies will make customer PV-battery systems financially viable within the 15-year forecast period. Additionally, the removal of the feed-in tariff leads to greater reductions in eventual grid consumption. By the end of the forecast period, customer PV-battery systems with the highest financial performance are able to reduce grid consumption above 90% resulting in significant energy resources being transferred out of the energy market. This necessitates the market integration of customer energy resources and provides an opportunity to leverage a combination of customer and utility energy resources for the renewable energy transition.

1. Introduction

Continuous innovations in renewable energy technologies, in particular wind and solar, has resulted in significant cost reductions that have made them economically competitive with fossil fuel generation (BNEF, 2017; IEA, 2017a; IRENA, 2018). Furthermore, as a consequence of significant capital investment and increases in global battery production capacity, battery energy storage system costs have continued to fall (BNEF, 2017). In 2016, renewable energy technologies accounted for the majority of new generation capacity and is expected to continue, with renewable energy technologies becoming the lowest cost source of bulk energy generation (IEA, 2017b). Similarly, change is occurring at the customer level with solar PV and battery energy storage systems. Their modularity allows capacity cost reductions at the utility-scale to be correspondingly applied to electricity customers and facilitates the customer adoption of solar PV and battery technologies on electricity networks.

With their own PV-only or PV-battery systems, customers have a choice to be grid reliant or self-sufficient. The ability for customers to supply their own energy can be considered as a *customer energy resource* that also results in load-defection (RMI, 2015). As the technical configuration of a customer's PV-only or PV-battery system affects the amount of energy customers import from (and export to) the grid, it becomes increasingly important to understand the aggregate effect of these individual decisions, as they determine the amount of grid electricity that is supplied, and by extension, the operation and economics of the energy market. As the fundamentals change with the customer, policy and utility decision makers face considerable uncertainty to address future requirements, from funding of renewable energy policies to the setting of electricity prices and network supply charges.

In Australia, the falling price of solar PV (Ardani et al., 2018; BNEF, 2017; Solar Choice, 2018a) coupled with the Feed-in Tariff (FiT), solar rebates, rising electricity prices and abundant solar radiation, has seen small-scale solar PV become the dominant form (87%) of solar PV generation (Clean Energy Council, 2017) and has also resulted in the highest penetration rate of household PV in the world (Australian Energy Council, 2016). As the cost of battery storage falls (IRENA, 2017), battery energy storage systems are being increasingly adopted in Australia. In 2017, 12% of solar installations included batteries, which was a three-fold increase from the previous year (SunWiz, 2018).

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The choice of customers to install a PV-only or PV-battery system requires an investment of financial resources that cannot be easily reversed (Wüstenhagen and Menichetti, 2012). The technical and financial influences that shape this investment, provide the means to forecast and quantify the potential adoption of customer energy resources. Furthermore, as the market conditions change, rational economic investment choices will adapt in response. This dynamic behaviour provides an opportunity to quantitatively evaluate customer responses to future market conditions and to assess the potential impacts from specific energy policies on the wider energy market.

This research aims to evaluate customer energy transitions and assist policymakers to understand the impacts of their decisions on future energy market relationships between customers and utilities. Two case studies are presented, the first estimates customer load-defection as a result of long-term increases in electricity usage charges. The second case study evaluates customer load-defection as a result of changing the level of feed-in tariff compensation. A techno-economic approach is utilised to incorporate a range of technical, financial, economic and policy inputs. The paper provides a strategic overview and literature review, then describes the modelling methodology and data sources. The results from the two case studies follow in Section 4 and are discussed in Section 5 within the wider context of energy policies and the energy market. The paper concludes with policy implications and future research directions.

2. Strategic overview and literature review

Potential electricity bill savings financially incentivise customers to install their own PV-only or PV-battery systems. A positive return on investment requires future bill savings over the lifetime of the investment to exceed upfront costs. Under economic rationality, customers that are driven to maximise their return on investment have to decide upon a specific PV-only or PV-battery configuration with respect to technical and financial trade-offs. Dependent upon the underlying customer energy consumption profile, each PV-only or PV-battery configuration results in differing amounts of imported and exported energy, and consequentially different levels of bill savings and installation costs.

As each PV-only and PV-battery configuration is a strategic investment opportunity, Net Present Value (NPV) can be used to determine the range of configurations that deliver the highest financial returns over time. NPV is a financial calculation that utilises projected cash flows and upfront costs to quantify the profitability of an investment. NPV has been used to evaluate many strategic renewable energy investments (Klein and Deissenroth, 2017; Laws et al., 2017; Satchwell et al., 2015a). Utilising bill savings as projected cash flows, NPV evaluates and compares the range of customer PV-only and PV-battery systems that are incentivised under various energy policy scenarios.

The majority of energy metering in Australia utilise 'net-metering' (Poruschi et al., 2018), where behind-the-meter generation is initially consumed by the customer load. Generation in excess of the customer load is exported to the grid and is entitled to a Feed-in Tariff (FiT) that provides customers with a small rebate, promoting customer self-consumption over exporting energy. Australian residential customers are typically charged a two-part electricity tariff that consists of a fixed daily network charge (T_{Daily}) and a volumetric usage charge (T_{Import}). Volumetric usage charges are the dominant factor in average electricity bills (AEMC, 2017). With time-of-use usage charges, the inability for customers to shift loads to shoulder or off-peak periods exposes customers to high peak period usage charges. Self-generation and energy storage allow customers to take advantage of off-peak periods for grid charging of energy storage while reducing their energy demand during peak periods. However, flat rate usage charges, that are time independent, do not offer this added financial incentive.

Solar PV installation costs in Australia are comparable to Germany but less than half of those in the USA (Barbose and Darghouth, 2016). Australia's high solar radiation, low solar PV prices, relatively high electricity prices, FiT and solar rebates has resulted in significant household adoption of solar PV with an average penetration of 20% across all Australian houses (APVI, 2017) and with many new installation PV capacities above 5 kW_P (Vorrath, 2018). This trend is likely to continue solar PV prices continue to fall (BNEF, 2017).

From the perspective of the electricity network, a high penetration of customers with PV-only systems reduces daytime electricity demand before a rapid ramp up of generation is required to meet the electricity demand during the late afternoon (Denholm et al., 2015). The overall consumption of grid-supplied electricity and subsequent revenue from each customer is reduced (AEMO, 2016, 2017a). However, grid-sourced energy is still required to supply customer electricity through the night.

The addition of customer energy storage leads to more dramatic changes on the electricity network. Customers can be almost entirely self-sufficient while maintaining network access for energy security. Under existing (predominantly volumetric) tariff structures, utility revenues would be severely impacted, leading to reduced cost recovery for maintenance and operation costs in the electricity network (Costello and Hemphill, 2014; Laws et al., 2017; Passey et al., 2017; Severance, 2011). However, increasing electricity prices to recuperate network investment improves the financial advantage of customer energy storage. This marks a shift in bargaining power in the electricity market towards the customer. As electricity prices define the financial incentives for the customer, it becomes a strategic choice for utilities to either embrace or compete against the customer (MacGill and Smith, 2017). As retail electricity prices continue increasing and the costs of solar PV and battery storage continue to fall, it becomes necessary to understand how customers are incentivised.

2.1. Solar PV only

Pairing energy storage with solar PV generation considerably changes how a customer interacts with the grid, impacting the energy market and its policies (DiOrio et al., 2015). There exists a rich literature on PV-only market impacts and policy outcomes. While energy storage changes the results from PV-only studies, it is beneficial to understand the range of methodologies utilised by PV-only literature to reapply to PV-battery research.

At the grid scale, solar PV generation has zero marginal costs and when used as a generation asset in energy spot markets, results in a reduction in wholesale energy prices due to the merit order effect (Sensfuß et al., 2008). Moreover, traditional generation assets, such as coal and gas, may pay to continue generating during daylight hours resulting in negative energy prices (Denholm et al., 2015).

From the customer perspective, electricity bill savings under various scenarios are used to quantify the financial incentives for PV-only systems under different FiT and metering schemes (Darghouth et al., 2011; Haapaniemi et al., 2017; Yamamoto, 2012). Large-scale customer solar PV adoption dynamics are necessary for network planning and policy management. Researchers utilise a range of techniques, from prospect theory (Klein and Deissenroth, 2017), statistics (Briguglio and Formosa, 2017), system dynamics (Castaneda et al., 2017; Hsu, 2012) to agent-based modelling (Palmer et al., 2015; Rai and Robinson, 2015). Using empirical analysis of census data, Sommerfeld et al. (2017) reaffirmed that home ownership significantly influences solar PV adoption.

Satchwell et al. (2015a, 2015b) utilise an energy model, while Oliva et al. (2016) utilise meter and solar insolation data, to quantify the financial impacts on utilities from various tariff and rate designs. Passey et al. (2017); Simshauser (2014) evaluate cross-subsidisation from tariff structures that reward solar PV customers at the expense of others. Their findings suggest that demand tariffs would reduce the level of cross-subsidisation. Similarly, Prata and Carvalho (2017) attempt to balance the competing demands of customer self-supply and network cost sustainability by evaluating the impact of increasing daily network charges. Their findings indicate that a gradual transition to higher fixed

Table 1
Input parameters and data used in the study.

Input parameter	Abbreviation	Unit	Values	Derived from
Rated PV capacity sizes	p	kW_P	0–10	Model assumption
Battery energy storage capacity sizes	b	kWh	0–20	Model assumption
Initial flat-rate electricity usage charges	T_{Import_Start}	AUD / kWh	0.27	Model assumption
Initial flat-rate feed-in tariff rebate	T_{Export_Start}	AUD / kWh	0–0.27	Model assumption
Change in flat-rate electricity usage charges	R_{Import}	% / a	0–10	Model assumption
Change in flat-rate feed-in tariff rebate	R_{Export}	% / a	0–10	Model assumption
Feed-in tariff rebate limit	P_{Export_Limit}	kW	5	(Synergy, 2017)
Initial installed PV system cost	C_{PV_Start}	AUD / kW_P	1400	(Solar Choice, 2018a)
Initial installed battery system cost	$C_{Battery\_Start}$	AUD / kWh	900	(Tesla, 2018)
Change in installed PV system costs	R_{PV}	% / a	−5.9	(Ardani et al., 2018)
Change in installed battery system costs	$R_{Battery}$	% / a	−8	(IRENA, 2017)
Annual household energy consumption	$E_{Household}$	MWh / a	5.2	(AEMC, 2017)
Discount rate	R_d	% / a	6	(RBA, 2018)
Solar PV generation profile	H	W	Time series	(NREL, 2018)
Underlying household load profile	L	Wh	Time series	(Martin, 2016)
NPV financial investment period	N	years	10	Model assumption
Scenario forecast period	T	years	15	Model assumption

network charges does not discourage solar PV adoption.

2.2. Solar PV coupled with energy storage

Energy storage systems provide many services to the electricity network (IRENA, 2017; Schill et al., 2017; Stock et al., 2018) from ancillary (e.g. frequency regulation) to bulk-energy services (e.g. time-shifting and capacity firming). However, from the customer's perspective, only those services that lead to electricity bill savings are financially rewarded. Hence, energy storage systems that increase self-consumption allow customers to reduce overall energy consumption while improving the financial returns from excess solar PV generation.

Determining the optimal PV-battery system capacities to maximise the financial returns on a customer's load profile depends upon a wide range of technical and economic parameters, such as location, solar insolation, system costs, electricity rates and the FiT. Typically, numerical simulation (Cucchiella et al., 2016; Hoppmann et al., 2014; Mulder et al., 2013; Weniger et al., 2014) and mathematical optimisation techniques (Every and Dorrell, 2017; Linssen et al., 2017; Sani Hassan et al., 2017) are used to determine the financially optimal PV and battery configuration.

Parra and Patel (2016); Ren et al. (2016) utilise a techno-economic model on a predetermined set of PV-battery system capacities to evaluate financial performance across a range of tariff structures for a specific customer investment.

From an energy market perspective, Higgins et al. (2014); Laws et al. (2017) apply a diffusion model to forecast the rate of adoption between different customer PV-battery systems under various tariff structures. Agnew et al. (2017) developed a system dynamics model of the Queensland energy market and finds that mass-market adoption of PV-battery systems will erode traditional utility business models. Fridgen et al. (2018) utilised a series of numerical simulation models to evaluate the impact of tariff structures on incentivising different network behaviours within a community microgrid. Their findings suggest that a combination of capacity charges and daily network charges would incentivise stable demand and generation profiles from customers and sufficiently cover utility costs.

Electricity prices and feed-in tariffs provide leverage points for decision makers to influence customer decisions in the electricity market; and incentivise or disincentivise cooperative behaviour. The electricity network consists of customers and suppliers in constant balance, with the costs ultimately borne by all users. To develop a mutually beneficial relationship with the customer, it is important to understand how customers react to a range of market conditions and scenarios.

Many studies have investigated the impact of changing financial conditions on the profitability of customer solar PV and energy storage choices, but none to date have studied the transitional impact of electricity prices and FiT compensation on the future energy and market relationship between utilities and its customers as solar PV and battery costs continue to decline.

3. Methodology

From the customer's perspective, competing value propositions exist between, (i) purchasing and installing a behind-the-meter PV-only or PV-battery system; and (ii) continuing to source electricity from the grid. If electricity bill savings from (i) exceed the costs of (ii), it becomes financially attractive for customers to install their own generation assets. As the value of imported and exported energy changes over time, while the costs of solar PV and battery systems continue to fall, the financial incentives for different system configurations will change accordingly.

This paper's analysis utilises three components written in the statistical programming language R. Firstly, a *technical model* determines the technical operational performance over a range of PV and battery system combinations, for a specific electricity consumption profile. Secondly, a *financial model* evaluates the potential electricity bill savings from each PV and battery system configuration. The PV-only and PV-battery combinations that provide the highest financial returns over a 10-year investment period (N), represent the system configurations that would be most attractive under the input financial assumptions. Thirdly, to develop *potential customer energy scenarios,* the financial conditions are adjusted, and the financial model is re-evaluated for each year in the 15-year forecast period (T). Using the input parameters in Table 1, scenario analysis is used to evaluate the potential impact of economic and policy decisions on future customer energy demand. For each scenario, the changing shape and size of profitable PV and battery systems quantifies a range of potential grid impacts and requires the use of Monte-Carlo simulation rather than numerical optimisation.

3.1. Technical model

The technical model consists of an underlying household electricity consumption load profile, solar electricity generation profile and battery energy storage system, residing behind the utility energy meter. A range of PV and battery system capacities are simulated over a 10-year financial investment period (N). The solar PV system capacities (p) range from 0 to 10 kW_P with a step-size of 0.5 kW_P. The battery system capacities (b) range from 0 to 20 kWh with a step-size of 1 kWh. This results in 441 PV and battery system combinations.

The underlying household electricity consumption (L) load profile (Fig. 1) is modelled based on a daily 'double hump' curve (Martin,

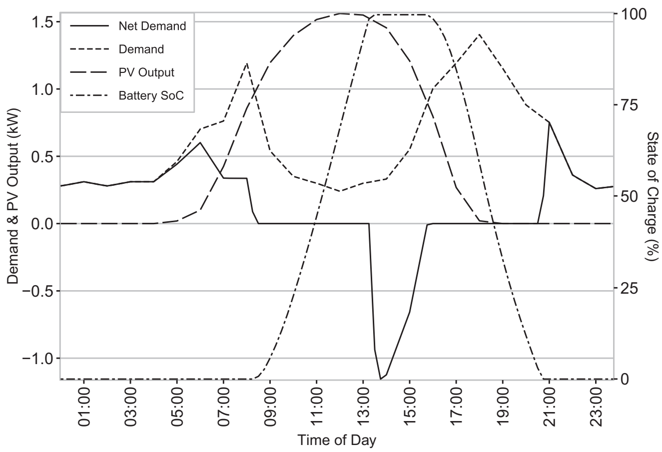

Fig. 1. Example summer day (February 11) net-demand profile from a 5.2 MWh per year 'double hump' annual energy consumption pattern with a 2 kW_P and 5 kWh PV-battery system located in Perth, Australia.

2016) repeated across the entire year and scaled to an average Western Australian household's consumption of 5.2 MWh per annum (AEMC, 2017). The 'double hump' curve is consistent with the daily aggregate electricity demand on the SWIS network (AEMO, 2017a).

Hourly solar electricity generation (*H*) data was obtained from the PVWatts Calculator (NREL, 2018) in Perth (31.95°S 115.77°E) using a 1 kW_P fixed roof mounted array on a 20° tilt facing north, 14% system losses and 96% DC-AC inverter efficiency. The average solar radiation is 5.82 kWh/m^2/day. The solar generation data is multiplied by the PV system capacity (*p*) to determine the power generation profile. A linear degradation of PV generation is modelled that assumes 80% of the generation capacity remains after 25 years.

The battery energy storage system model stores energy when solar generation exceeds the household load and there is available battery storage capacity. Once the storage capacity is reached, excess self-generation is exported to the grid. As solar generation falls below the household load, energy is extracted from the battery storage capacity in place of grid electricity, until the storage capacity is fully discharged. Based on the Tesla Powerwall 2, the battery model assumes a round trip efficiency of 89%, charge and discharge limit of 5 kW, 100% depth-of-discharge and 30% linear degradation of storage capacity after 10-years (Tesla, 2018).

The technical simulation model utilises a 15-min temporal resolution. The model uses resampled household electricity consumption and PV generation data for numerical analysis. Subtracting the PV generation from the underlying electricity consumption results in an intermediate net-energy profile. The intermediate net-energy profile is used by the battery system model to determine the charging and discharging dynamics, before producing the final net-energy profile. The technical model calculates the annual energy import and export quantities over the 10-year financial investment period (*N*) for 441 different PV and battery configurations.

3.2. Financial model

For each of the 441 PV and battery configurations the technical model data is used by the financial model to calculate the NPV over the 10-year financial investment period (*N*). The financial model determines the installation costs in the forecast year (*t*) and the bill savings received during each investment year (*n*) thereafter. The financial assumptions are based on an owner-occupied household, as they are the most capable of recouping the cost of investment, as opposed to landlords (that do not benefit from the bill savings) or tenants (that do not have the right to utilise the roof area for their own PV panels). Empirical analysis from Sommerfeld et al. (2017) supports this assumption. For clarity reasons, the equations are presented in Appendix A.

The NPV is used to quantify the financial performance from each PV and battery combination, allowing each investment opportunity to be evaluated and compared. The PV and battery configurations with the highest NPV signify the type of systems that would be most attractive to the customer. As the average Australian household in a capital city is owned for 10.5 years before being sold (CoreLogic, 2015), a 10-year financial investment period (*N*) is used to represent when customers will expect to make a profit on any PV-only or PV-battery investment. Additionally, as operational warranties for solar PV and battery systems are typically 20 and 10 years respectively (Lesourd, 2001; Tesla, 2018), PV and battery replacements are not considered in this study.

A two-part fixed-rate electricity tariff with net-metering is used that is consistent with the rate structure in Perth, Australia. The rate structure consists of a volumetric fixed-rate electricity usage tariff (T_{Import}), a daily network charge (T_{Daily}) and a fixed-rate volumetric FiT (T_{Export}) for customers with solar PV systems up to 5 kW_P (P_{Export_Limit}). This FiT limit is consistent with the local electricity retailer's tariff structure (Synergy, 2017). The FiT limit is modelled in Eq. (7) by zeroing the FiT once the solar PV capacity (*p*) exceeds 5 kW_P.

Eq. (1) in Appendix A represents the NPV calculation for a customer to invest in a particular PV system capacity (*p*) and battery energy storage system capacity (*b*) in the forecast year (*t*). The NPV calculation considers the cost of capital (R_d) and the expected cash flow over the 10-year investment horizon (*N*). This study makes the assumption that a householder's access to capital financing is likely obtained by extending their home loan. Hence, the weighted average cost of capital or discount rate (R_d) is set to 6% over the course of the forecast period (*T*). This aligns with the 6.4% historical average over the last 10 years for Australian owner-occupied standard variable home loans (RBA, 2018).

The yearly cash flow is considered as the difference in electricity bills as a consequence of installing a PV-only or PV-battery system. By substituting the flat rate two-part electricity tariff and FiT into Equation (2), the daily network charge (T_{Daily}) is nullified and the cash flow depends solely on the technical system performance and volumetric tariffs, see Equation (5).

The system cost in forecast year (*t*) is presented in Eq. (8) and is equal to the PV capacity (*p*) multiplied by the predicted PV costs in the forecast year (*t*) and the battery capacity (*b*) multiplied by the predicted battery costs in the forecast year (*t*).

The financial model addresses the customer question, 'In year *t*, which PV-only and/or PV-battery system configurations provide the highest NPV after 10 years?'. The financial results are used to generate the NPV contour plots from each PV and battery combination (Fig. 2a and Fig. 2c). Only the system configurations that have a positive NPV are shown. Worth noting are the set of system configurations within the '95th percentile of maximum NPV', as these system configurations offer comparable returns to the customer. The size and shape of this set reveals a range of possible system configurations that the customer may be motivated to install. These technical and financial outcomes are utilised in the scenario analysis to evaluate future customer energy demand and assess energy policy impacts.

3.3. Potential customer energy scenarios

The techno-economic simulation model identifies a profitable subset of PV-only and/or PV-battery system configurations that respond to the changing financial conditions. To evaluate potential customer energy futures, economic conditions and policy decisions are translated into a set of financial conditions in each forecast year (*t*) and extrapolated across the 10-year investment period (*N*). These include the falling installation costs of solar PV capacity (C_{PV}) and storage capacity ($C_{Battery}$) and the changing volumetric import (T_{Import}) and export (T_{Export}) electricity tariffs.

The price of installed solar PV panels has been modelled with a

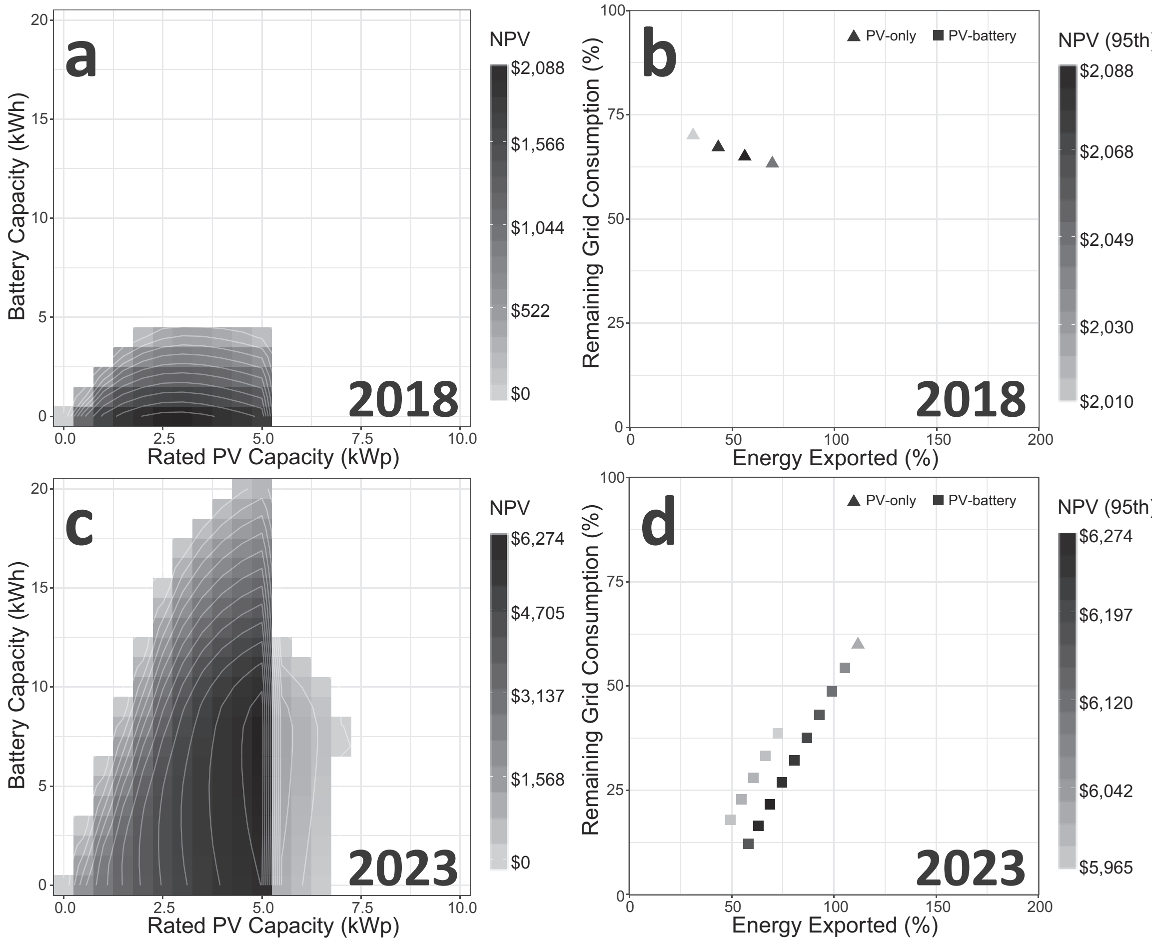

Fig. 2. Financial performance of PV and battery system configurations in 2018 and 2023. (a) 2018, NPV comparison. (b) 2018, remaining grid consumption and energy exported (% of household load) from systems in the 95th percentile of maximum NPV. (c) 2023, NPV comparison. (d) 2023, remaining grid consumption and energy exported (% of household load) from systems in the 95th percentile of maximum NPV.

starting base (C_{PV_Start}) of \$1400/kW$_P$ (Solar Choice, 2018a) and reducing (R_{PV}) at a rate of −5.9% per annum (Ardani et al., 2018). The price of installed battery energy storage systems has been modelling with a starting base ($C_{Battery\_Start}$) of \$900/kWh (Tesla, 2018) and reducing ($R_{Battery}$) at a rate of −8% per annum (IRENA, 2017).

The electricity prices used in the modelling are comparable to retail electricity rates in Perth, Australia with a daily network charge of 95c/day, fixed rate volumetric usage charges of 27c/kWh (Department of Treasury, 2017) and fixed rate FiT of 7c/kWh (Synergy, 2017). Due to the complex nature of the energy market, decision makers are faced with considerable uncertainty when setting electricity prices and energy policies each year (Pfenninger et al., 2014).

To address this uncertainty, the financial model determines the range of PV and battery system configurations that are most profitable for each forecast year (t) (Fig. 2b and Fig. 2d). By collating these results across the 15-year forecast period (T) a forecast of the customer renewable energy transition can be generated. This allows the economic and policy impacts to be evaluated from both the customer and utility perspectives. Five plots are generated to illustrate the customer energy transition:

- *The general system configurations in the 95th percentile of maximum NPV*. This plot illustrates the potential tipping points when (or if) *PV-battery* systems become more cost competitive than *PV-only* systems, the *comparable* transition period (see Fig. 3a or Fig. 5a) occurs when both PV-only and PV-battery systems are within the 95th percentile of maximum NPV.
- *The solar PV system capacities in the 95th percentile of maximum NPV*. This plot illustrates the potential tipping points or limits when particular solar PV system capacities are incentivised (Fig. 3b or Fig. 5b).
- *The battery energy storage system capacities in the 95th percentile of maximum NPV*. This plot illustrates the potential tipping points or limits when particular battery energy storage system capacities are incentivised (Fig. 3c or Fig. 5c).
- *Incentivised remaining grid consumption*. These results (Fig. 4a or Fig. 6a) are useful for energy planners to determine the range of *remaining grid consumption* as the financial conditions change each year. As each scenario generates a different profile, the relative influence of the scenario parameters can be compared.
- *Incentivised (solar PV) energy exported*. These results (Fig. 6b or Fig. 6b) are useful for energy planners to determine the range of exported energy as the financial conditions change each year. In particular, any reductions in the amount of exported solar PV energy would improve the predictability when managing the operation of the energy network.

3.4. Assumptions

The techno-economic simulation model used in this study makes the following assumptions:

a) *Customer energy demand remains constant*. The customer energy consumption pattern does not change over the 15-year forecast period and is consistent with observations from the system operator (AEMO, 2017b). The impact of electric vehicles on customer energy demand has not been modelled, as the timing and potential impacts currently remain uncertain.

b) *Financial assumptions continue year-after-year.* In reality energy market actors constantly interact and co-evolve, resulting in an ever changing and dynamic financial environment. However, the purpose of this paper is to highlight the impact of making a single financial decision on the range of possible customer responses. By keeping all other parameters consistent, it isolates the impact of the financial decision and provides a clearer illustration of its influence on the customer.

c) *The battery energy storage system model does not charge from the grid.* Flat-rate volumetric usage charges do not provide any financial incentive to charge during off-peak hours, hence grid-charging of batteries is not utilised in this study.

The results from the customer scenario analysis provide the means to test various economic and policy impacts. The customer energy scenarios discussed in this paper rely upon customers making rational economic decisions. This transitional analysis is an estimation of the potential of change, rather than the forecasting of actual network changes. To prevent overestimation of the results, the modelling has been deliberately conservative in the choice of parameters and assumptions. The dynamics observed are a consequence of the interactions and inter-dependencies between technological innovation and economics. The findings serve as a guide for economic and energy policy decision-making.

Two case studies are evaluated over a 15-year forecast period. The first case study evaluates customer load-defection from long-term increases in electricity usage charges. The second case study evaluates customer load-defection from the level of feed-in tariff compensation.

4. Results

4.1. Case Study 1: customer load-defection from long-term increases in electricity usage charges

Between 1980 and 2007 Australian electricity prices increased on average 5.3% per annum. From 2007–2017, the average electricity price increase rose to 9.4% per annum, as a result of increases in fuel prices and network charges (ABS, 2017; AEMC, 2017). As the global renewable energy transition provides customers with an increasingly cost-effective alternative to grid-sourced energy, this case study analyses how customer PV and battery investments might change over 15 years, to different rates of increasing electricity prices while solar PV and battery energy storage system costs continue to fall.

Three scenarios are presented in Table 2 using different rates of increasing electricity prices (and corresponding FiT) over the 15-year forecast period. The *High* scenario corresponds with the 2007–2017 average electricity price increases and raises both the volumetric usage charge and FiT at 10% per annum. The *Low* scenario corresponds with the historical 1980–2007 average electricity price increases and raises both the volumetric usage charge and FiT at 5% per annum. The *Flat* scenario is a boundary condition that holds the volumetric usage charge and FiT across the entire forecast period.

To maintain consistency with 2017–18 electricity rates in Perth,

Table 2
Input parameters for case study 1.

Scenario	R_{Import}	R_{Export}	T_{Import_Start}	T_{Export_Start}
High	10%/a	10%/a	27 c/kWh	7 c/kWh
Low	5%/a	5%/a	27 c/kWh	7 c/kWh
Flat	0%/a	0%/a	27 c/kWh	7 c/kWh

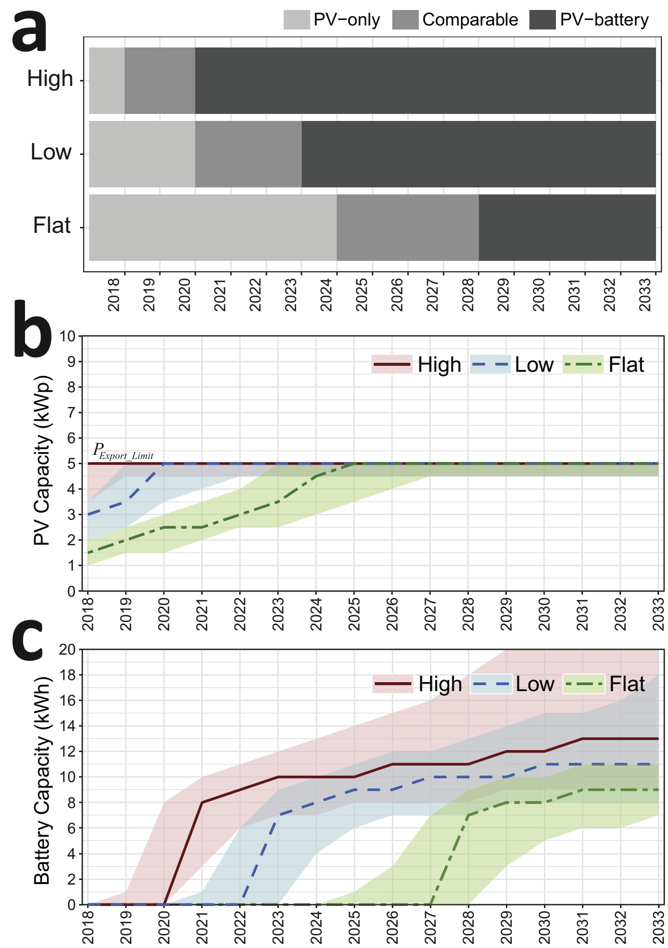

Fig. 3. Changing customer PV and battery investment incentives under different long-term electricity price increases. (a) General system configurations in the 95th percentile of maximum NPV. (b) PV system capacities in the 95th percentile of maximum NPV. (c) Battery energy storage system capacities in the 95th percentile of maximum NPV.

Australia, the flat rate volumetric usage charge (T_{Import}) is initially set to 27c/kWh and FiT (T_{Export}) to 7c/kWh. All other technical and financial parameters are as described in Section 3. This includes the 5 kW_P solar PV capacity limit (P_{Export_Limit}) to receive the FiT and for solar PV and battery installation costs to fall at −5.9% per annum and −8% per annum respectively.

The technical model generates the operational data for each of the 441 solar PV and battery system configurations analysed. This data is used by the financial model to determine the NPV of each investment for every year within the 15-year forecast period. The range of PV-only and/or PV-battery system configurations in the 95th percentile of maximum NPV are then used to generate the series of plots Fig. 3 and Fig. 4. The numerical results at the start and end of the forecast period are presented in Table 3.

In a market with falling solar PV and battery costs, the results indicate that higher increases in volumetric usage charges accelerates a transition to PV-battery systems. Even if usage charges were to remain flat over 15-years, it would delay but not remove the financial incentive for customers to install PV-battery systems. It is evident that higher long-term increases in volumetric usage charges shortens the transition period to PV-battery systems and the time frame over which PV-battery systems become more economic (Fig. 3a).

The transition from PV-only to PV-battery systems leads to significant changes in grid consumption. During the time when PV-only systems are more economic, the remaining grid consumption remains above 60% due to the need for the grid to supply energy during non-daylight hours

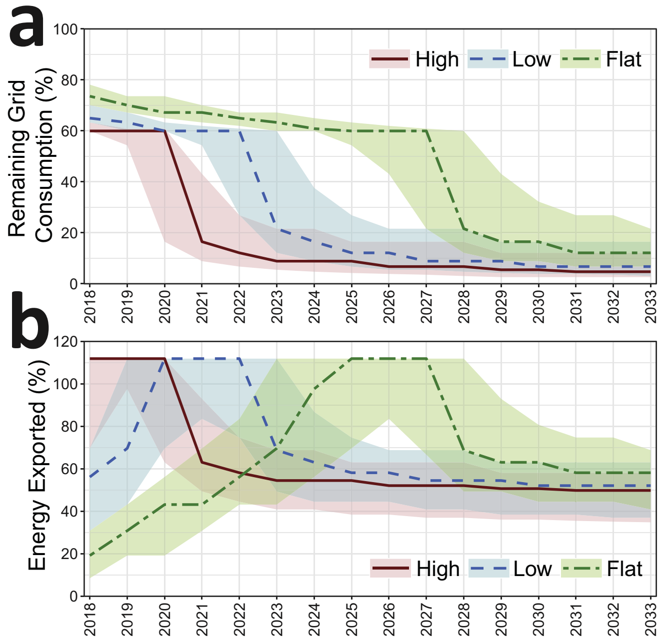

Fig. 4. Grid impacts from changing customer PV and battery investment incentives under different long-term electricity price increases. (a) Incentivised remaining grid consumption (% of household load). (b) Incentivised energy exported (% of household load).

Table 3
Results from case study 1.

Results	*High*	*Low*	*Flat*
2018			
Remaining Grid Consumption:			
Highest NPV configuration	60%	65%	74%
Within 95th NPV percentile	60–63%	63–70%	70–78%
Exported Energy:			
Highest NPV configuration	112%	56%	19%
Within 95th NPV percentile	70–112%	31–70%	9–31%
Highest NPV configuration:	5 kW_P	3 kW_P	1.5 kW_P
2033			
Remaining Grid Consumption:			
Highest NPV configuration	5%	7%	12%
Within 95th NPV percentile	3–12%	3–16%	7–22%
Exported Energy:			
Highest NPV configuration	50%	52%	58%
Within 95th NPV percentile	35–58%	37–63%	41–69%
Highest NPV configuration:	5 kW_P, 13 kWh	5 kW_P, 11 kWh	5 kW_P, 9 kWh

(Fig. 4a). Additionally, during the PV-only phase, 5 kW_P solar PV capacities are the most profitable, as system capacities above 5 kW_P (P_{Export_Limit}) removes the FiT. However, once PV-battery systems become more economic, the remaining grid consumption falls below 10%. During the transition between PV-only and PV-battery systems, small capacity energy storage is initially incentivised, but as the costs continue to fall, larger energy storage systems become economic resulting in greater gains in self-sufficiency. Additionally, the adoption of energy storage lead to reductions in exported solar PV generation (Fig. 4b). While maintaining the FiT compensation level, the results indicate that PV-battery systems will eventually become more economic than PV-only systems, even if electricity prices where to remain the same.

4.2. Case Study 2: customer load-defection from the level of feed-in tariff compensation

The introduction of the FiT in Australia contributed to significant growth in customer solar PV adoption. However, funding the FiT is a contentious issue. At its introduction, it was initially funded by the government, but due to rapid solar PV uptake and rising policy costs, the funding was transferred to electricity retailers (Poruschi et al., 2018). However, by spreading the cost burden across all electricity customers, cross-subsidisation is introduced between those with self-generation and those without (Simshauser, 2014). It is difficult to determine a fair level of FiT compensation, as it has to balance multiple objectives between (i) customers with and without self-generation, (ii) customers and utilities, and (iii) utilities and energy policy objectives. This case study evaluates the influence of the FiT compensation on the relationship between the customer and utility.

Three scenarios are presented using different levels of FiT compensation (Table 4) over the 15-year forecast period. The *Full Rebate* scenario sets the FiT at 100% of the volumetric usage charge and is equivalent to many states in the US where exported energy is compensated at the same value as imported energy (Darghouth et al., 2016). The *Partial Rebate* scenario of 26% is consistent with the 2017–18 FiT in Perth, Australia with a FiT of 7c/kWh and volumetric usage charge of 27c/kWh. Across Australia, the FiT compensation levels in 2017–18 vary between 17% and 39% (Solar Choice, 2018b). The *No Rebate* scenario removes the FiT to evaluate the PV and battery system incentives in the absence of policy support. All other technical and financial parameters are as described in Section 3. This includes the 5 kW_P FiT limit and for solar PV and battery installation costs to fall at −5.9% per annum and − 8% per annum respectively. To isolate the effect of evaluating different levels of FiT compensation, the growth rates for the volumetric usage charges and FiT are fixed at 5% per annum.

The FiT scenarios result in three divergent customer load-defection outcomes (Fig. 5 and Fig. 6). In the *Full Rebate* scenario, where the volumetric usage charge matches the FiT, there is a greater incentive to maximise exported energy. Due to the 5 kW_P FiT limit (P_{Export_Limit}), the most profitable PV-only system capacity remains at 5 kW_P. As time shifting from energy storage provides no additional revenue, while incurring additional capital expenses and round-trip energy losses, PV-battery systems are initially at a financial disadvantage. However, as battery costs continue to fall, the financial disadvantage from 2021 onwards is reduced to the point where both PV-only and PV with small battery systems are within the 95th percentile of maximum NPV (Fig. 5a). This results in small reductions in both grid consumption (Fig. 6a) and exported energy (Fig. 6b). The findings suggest by the end of the 15-year forecast period, it is most economical for the customer to install 5 kW_P of solar PV panels and remain mostly reliant on the electricity network (Table 5).

In the *Partial Rebate* scenario there is an incentive to increase self-consumption within the 5 kW_P FiT limit. As shown in Fig. 5a, PV-only systems initially remain the most profitable, before a transition period where both PV-only and PV-battery systems are comparable. From 2024 onwards, PV-battery systems are the leading system configuration. Remaining grid consumption (Fig. 6a) and energy exports (Fig. 6b) fluctuate as different system configurations compete to be the most profitable. While PV-only systems are favoured, there is an initial decrease in grid consumption (from 65%) before it plateaus (to 60%). During this time, the PV capacity that is most profitable rises from 3 kW_P to 5 kW_P. The 5 kW_P FiT limit disincentivises further PV capacity increases, resulting in the initial plateau of grid consumption and energy exports. During the transition period between 2021 and 2023,

Table 4
Input parameters for case study 2.

Scenario	R_{Import}	R_{Export}	T_{Import_Start}	T_{Export_Start}
Full Rebate (100%)	5%/a	5%/a	27c/kWh	27c/kWh
Partial Rebate (26%)	5%/a	5%/a	27c/kWh	7c/kWh
No Rebate (0%)	5%/a	5%/a	27c/kWh	0 c/kWh

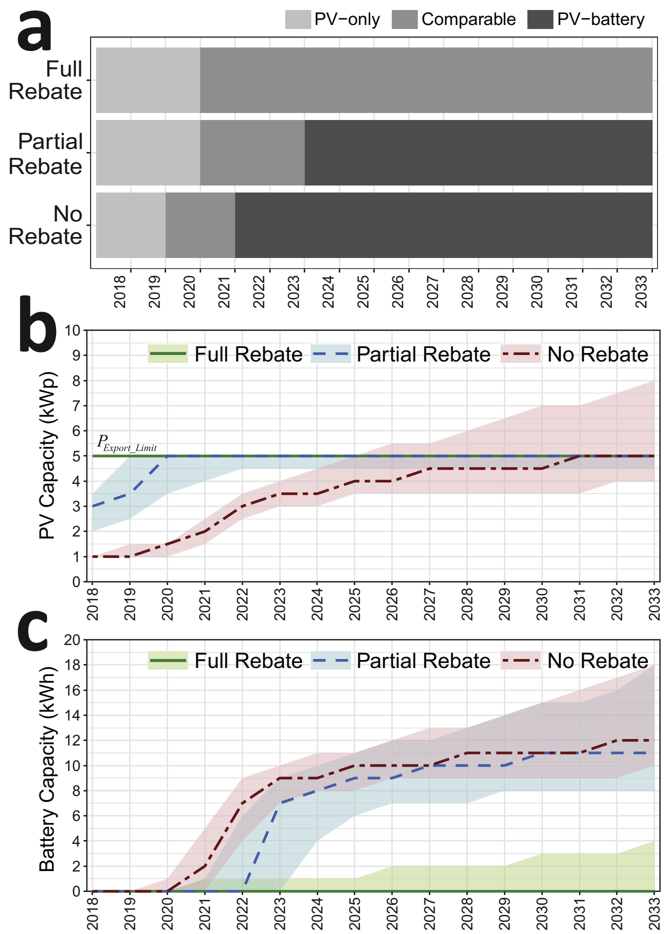

Fig. 5. Changing customer PV and battery investment incentives under different levels of feed-in tariff compensation. (a) General system configurations in the 95th percentile of maximum NPV. (b) PV system capacities in the 95th percentile of maximum NPV. (c) Battery energy storage system capacities in the 95th percentile of maximum NPV.

pairing 5 kW$_P$ solar PV panels with increasing battery capacities becomes profitable and the associated grid consumption and energy exports fall from 60% to 22% and 112–69% respectively. After the transition period, falling PV and battery costs continue to favour pairing 5 kW$_P$ solar PV systems with increasing levels of storage capacity, eventually reducing the grid consumption to 7% and energy exports to 52% by the end of the 15-year forecast period. In the *Partial Rebate* scenario, it eventually becomes economical to minimise energy exports and capture the majority (93%) of the underlying energy load with 5 kW$_P$ solar PV panels and 11 kWh of battery storage (Table 5).

In the *No Rebate* scenario, the FiT is removed, incentivising customers to maximise self-sufficiency while removing the influence of the 5 kW$_P$ FiT limit. As shown in Fig. 5b, small PV-only systems are initially more profitable, as they are able to achieve a higher level of self-sufficiency given their capital investment. However, falling PV and battery costs result in small PV-battery systems becoming more profitable, steadily increasing both the PV and storage capacity over the 15-year forecast period (Fig. 5b and Fig. 5c). This contrasts with the *Full Rebate* and *Partial Rebate* scenarios, where PV systems greater than 5 kW$_P$ are disincentivised. Additionally, over the 15-year forecast period, the amount of exported energy (within the 95th percentile of maximum NPV) continually increases and eventually overtakes the levels observed in the *Full Rebate* and *Partial Rebate* scenarios (Fig. 6b). With increasingly affordable PV-battery systems, the customer is able to obtain sufficient financial returns by sizing the PV-battery system to increasingly cover their worse performing solar insolation days. As a result, remaining grid consumption falls to 5% by 2033 and there is an increasing amount of excess self-generation at other times of the year. By the end of the 15-year forecast period, it is most economical to capture the majority (95%) of the underlying energy load with 5 kW$_P$ solar PV panels and 12 kWh of battery storage. However, there are a large number of alternate system configurations within the 95th percentile of maximum NPV, with larger PV and battery capacities that result in a wide range of exported energy levels between 23% and 140% and a narrow range of remaining grid consumption between 1% and 12% (Table 5).

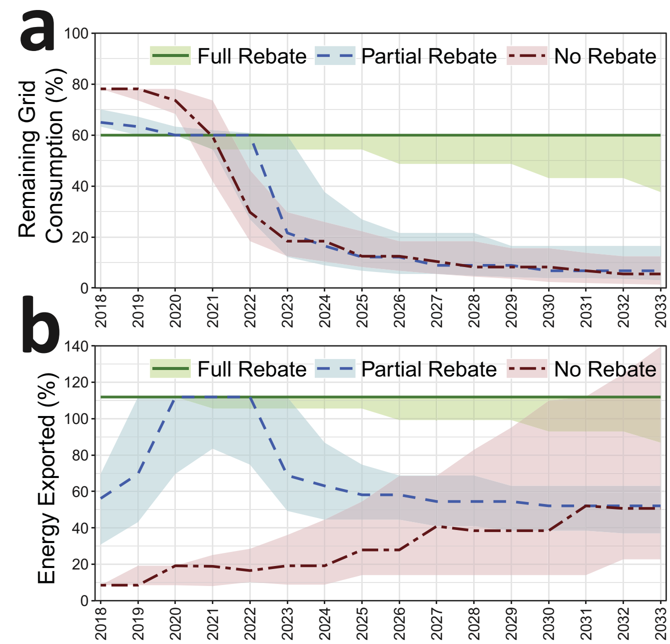

Fig. 6. Grid impacts from changing customer PV and battery investment incentives under different levels of feed-in tariff compensation. (a) Incentivised remaining grid consumption (% of household load). (b) Incentivised energy exported (% of household load).

Table 5
Results from case study 2.

Results	*Full Rebate*	*Partial Rebate*	*No Rebate*
2018			
Remaining Grid Consumption:			
Highest NPV configuration	60%	65%	78%
95th NPV percentile range	60–60%	63–70%	78–78%
Exported Energy:			
Highest NPV configuration	112%	56%	9%
95th NPV percentile range	112–112%	31–70%	9–9%
Highest NPV configuration	5 kW$_P$	3 kW$_P$	1 kW$_P$
2033			
Remaining Grid Consumption:			
Highest NPV configuration	60%	7%	5%
95th NPV percentile range	38–60%	3–16%	1–12%
Exported Energy:			
Highest NPV configuration	112%	52%	51%
95th NPV percentile range	87–112%	37–63%	23–140%
Highest NPV configuration	5 kW$_P$	5 kW$_P$, 11 kWh	5 kW$_P$, 12 kWh

5. Discussion

To prevent the overestimation of results, the modelling analysis has been deliberately conservative in its choice of parameters and assumptions. Fixed rate electricity tariffs were chosen as it offered the least advantageous and most conservative rate structure for PV-battery adoption, whereas time-of-use tariffs facilitated additional electricity bill savings obtained through time-shifting and grid battery charging services. The modelling results are indicative only and should be evaluated as a comparative assessment between scenarios, rather than an exact market forecast.

In the first case study, the influence of annual increases of 0%, 5% and 10% in volumetric usage charges and FiT rebates (at 26% compensation and limited to PV system capacities 5 kW_P and below) was investigated. The results across all scenarios, indicate that after 15 years, customers would be incentivised to reduce their grid consumption beyond 90% with PV-battery systems (Table 3). As the rate of annual increases was raised, an accelerated transition from PV-only to PV-battery systems occurred (Fig. 3a) and resulted in greater overall reductions in grid consumption (Fig. 4a).

As the majority of electricity retailer revenues in Australia are obtained from volumetric usage charges, rapid falls in grid consumption would result in significant losses to future revenue. These results exemplify the challenges facing the energy market from customer load-defection: increasing electricity prices improves market revenues in the short-term but leads to an acceleration of customer load-defection and significant losses in sales revenue; while reducing electricity price increases delays customer load-defection, preserving existing market revenues but disincentivises future energy market investment. Moreover, the economic feasibility of PV and battery systems are not eliminated and ultimately, the energy market still has to respond to significant reductions in customer energy demand. These findings suggest that increasing the volumetric usage charge in retail electricity tariffs carries significant risks for the rate of customer PV-battery adoption that can lead to significant load-defection and losses in future electricity retailer revenues.

The second case study evaluated the influence of the level of FiT compensation at 0%, 26% and 100% of usage charges (limited to PV system capacities 5 kW_P and below). The modelling results led to three notably different outcomes (Fig. 5 and Fig. 6). At 100% FiT compensation, customers retained the highest level of grid consumption by incentivising PV systems to the 5 kW_P limit without encouraging large capacity energy storage. However, it is also the most expensive policy option with the highest levels of cross-subsidisation (Darghouth et al., 2016; Simshauser, 2014). Conversely, the removal of the FiT (while being the cheapest policy option) negated the influence of the 5 kW_P FiT limit and incentivised customers to minimise grid consumption with solar PV systems beyond 5 kW_P paired with large energy storage capacity (Fig. 5b and Fig. 5c). This scenario resulted in the highest levels of exported solar PV energy at the end of the 15-year forecast period (Fig. 6b). From the grid perspective, significant quantities of uncontrolled solar PV exports would lead to system wide operational risks, such as the reversal of flows on the distribution network, reduction of grid inertia, increased rates of redispatch and raising the level of operational uncertainty. This would necessitate mitigation strategies, such as additional capital expenditure to strength the distribution grid, remote operation of customer inverters, and solar PV installation limits in weak grids. However, with a 26% FiT compensation, customers are offered a compromise that provides some value for exported energy within the 5 kW_P limit. This creates a disincentive for PV installations greater than 5 kW_P (Fig. 5b) and promotes the sizing of battery systems that take advantage of excess solar PV energy up to 5 kW_P of solar PV. When compared to the other two scenarios, the 26% FiT compensation results in the lowest levels of exported energy (Fig. 6b) and reduces the economic incentive to leave the grid.

The falling costs of solar PV and battery energy storage systems offer customers a cost-effective means to acquire energy resources. The results from both case studies illustrate the potential for customers to economically self-generate the majority of their own energy supply, and at the expense of the utility. Incumbent stakeholders in the electricity market face a challenging future operating environment. While the renewable energy transition is transforming the energy market at the utility-scale, customer PV and battery systems have the potential to withdraw significant energy resources from the network, leading to further market transformations. From the wider electricity market perspective, the competition for customer revenue between different utilities has broadened to include competition between the customer and utilities. Existing tariff structures that are heavily weighted to volumetric usage charges are the most exposed to future reductions in customer grid consumption and will require a shift towards increased cost reflectivity.

To prevent the withdrawal of significant energy demand from the energy market, there will be a need to integrate customer energy resources into a more competitive energy market. It will become increasingly essential for the energy market to embrace customer energy resources as PV and battery costs continue to fall. This creates an opportunity for new market concepts that unlock the benefits of customer PV-battery energy resources to capture future market value. At present a number of trials are being developed that establish mutual business relationships with customers to permit operational access to their PV-battery energy resources to provide grid services. These include, but are not limited to, virtual power plants that aggregate customer supply and demand to participate in the energy market (SA State Government, 2018; Reposit, 2018), no-upfront financing with long-term lease agreements (Wainstein and Bumpus, 2016), and peer-to-peer energy trading systems that facilitate direct financial agreements between different customers (Sonnen, 2018; PowerLedger, 2018; WePower, 2018). Alternative tariff designs are also being trialled, such as peak-demand-weighted fixed network charges with low volumetric usage charges (Horizon Power, 2018) and time varying FiTs (ESC, 2018). Each of these trials are attempting to set the terms for a mutually beneficial relationship between customers, the electricity grid and the energy market.

These initiatives are creating new markets and revenue streams for customers to utilise and integrate their energy resources into the energy market. The parameters used in this study did not consider additional revenue streams from PV-battery market integration. Therefore, any additional value that is created by new market concepts would improve the cash flow, further increasing the adoption of customer PV-battery installations and accelerating the energy transition results presented in this study.

However, the challenge lies in understanding the time and potential for stakeholders to transition. The results presented in this paper can aid decision makers in the energy market to understand the impact of existing electricity tariffs and that continuous increases in electricity prices and the level of FiT compensation can influence the customer PV-battery transition. By managing these economic levers while introducing new market concepts, policy makers are able to create a window of opportunity for the energy market to adjust. In the longer-term, the energy market and its customers will continue to evolve and challenge the underlying assumptions used in this study, and this would necessitate a re-evaluation of these results as the market conditions shift.

6. Conclusions

Utility-scale renewable energy technologies have diversified the operation of energy markets worldwide, and solar PV and battery technologies are evidently also creating change. Decision makers require projections of future market conditions to make better choices. However, energy systems are complex systems that are continually interacting and co-evolving (Cherp et al., 2018) making decision-making especially challenging.

A techno-economic model was developed to simulate the interactions between electricity rate structures and customer financial incentives for PV-only and PV-battery adoption. The results provide an assessment of future customer energy demand and its impacts on the energy market.

6.1. Policy implications

Even without increases in volumetric usage charges, the research suggests that customer PV-battery systems will become financially viable well within the 15-year forecast period. Raising the average long-term increases in usage charges leads to an accelerated transition from PV-only to PV-battery systems. Furthermore, the removal of the FiT did not prevent the adoption of PV-battery systems, rather the self-sufficiency improvements eventually justified the financial investment leading to the lowest levels of customer grid consumption and highest levels of solar PV exports. Raising the FiT rebate to 100% of volumetric usage charges discouraged the adoption of storage but at a high policy cost. Offering a partial FiT rebate provided a compromise that incentivised customers to remain on the grid with their PV-battery systems.

The research findings suggest that under existing electricity tariff structures, the falling PV and battery costs will incentivise customers to install PV-battery systems in 15-years with a 93% reduction in grid consumption (Table 3 and Table 5). This would transfer significant energy resources from the network to the customer, resulting in lost energy market revenues and a re-evaluation of network and generation assets. However, by developing new market concepts that integrate customer energy resources into the competitive energy market, the customer relationship with the grid can be re-established by commoditising spare supply- and demand-capacity from customers to match the energy needs of the network. This provides customers an opportunity to become an integral component in the renewable energy transition.

6.2. Future research and concluding comments

Further research could extend the analysis beyond a single customer to many individuals and quantify the impact of rising customer energy resources on the operation of existing energy markets, utility generation and energy prices. This bottom-up methodology offers the means to evaluate the energy resource potential for any customer load profile and with further research can be integrated into larger energy system models.

The global imperative and commitment to reduce greenhouse gas emissions has given rise to a rapid emergence of renewable energy technologies that continue to challenge and disrupt the operation of energy markets. The economics for customer PV-battery systems are fast approaching cost-effectiveness. Without change, energy markets stand to lose significant energy resources to customers, forcing policy-makers into a ‘no-win’ situation. It becomes necessary to integrate customer energy resources into a future customer-oriented energy market. As new market initiatives are being developed to service this growing niche, further opportunities are created for energy markets to lower greenhouse gas emissions and reach emission reduction targets by embracing a customer-oriented renewable energy transition

Acknowledgements

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Appendix A. Financial equations

A.1 Net present value

As stated in Section 3, the NPV defines the economic incentive to install a PV and battery system and consists of two main components. Firstly, the upfront installed system cost, and secondly the cash flow from the investment over the 10-year investment period (N), while considering the cost of capital or discount rate (R_d). For each year of the forecast period (T), the changing electricity usage charges, FiT rebate and install costs for PV and battery systems, influence the economic incentives, hence the NPV is given as a function of the forecast year (t), PV capacity (p) and battery capacity (b):

$$NPV(p, b, t) = \sum_{n=1}^{10} \frac{Cash\ Flow(p, b, n, t)}{(1+R_d)^n} - System\ Cost(p, b, t) \tag{1}$$

where,

p = Rated PV capacity (kW_P)
b = Energy storage capacity (kWh)

A.2 Cash flow

The cash flow is defined as the electricity bill cost savings that arise from installing a particular PV capacity (p) and battery capacity (b) system from each year of the investment period (n) starting from the forecast year (t):

$$Cash\ Flow(p, b, n, t) = Electricity\ Cost_{Base}(n, t) - Electricity\ Cost_{System}(p, b, n, t) \tag{2}$$

where,

Base is the cost of electricity without any PV or battery system; and
System is the cost of electricity with a particular PV and/or battery system

The *Base* and *System* electricity costs for each n-th year from the t-th forecast year are given by:

$$Electricity\ \ Cost_{Base}(n, t) = E_{Import}(0, 0, n)\cdot T_{Import}(n, t) - \ E_{Export}(0, 0, n)\cdot T_{Export}(0, n, t) + 365\cdot T_{Daily}(n, t) \tag{3}$$

$$Electricity\ Cost_{System}(p, b, n, t) = E_{Import}(p, b, n)\cdot T_{Import}(n, t) - \ E_{Export}(p, b, n)\cdot T_{Export}(p, n, t) + 365\cdot T_{Daily}(n, t) \tag{4}$$

and substituting (3) and (4) into (2) yields:

$$Cash\ \ Flow(p, b, n, t) = [E_{Import}(0, 0, n) - E_{Import}(p, b, n)]\cdot T_{Import}(n, t) + [E_{Export}(p, b, n) - E_{Export}(0, 0, n)]\cdot T_{Export}(p, n, t) \tag{5}$$

where,

$$T_{Import}(n, t) = T_{Import\_Start} \bullet (1+R_{Import})^{n+t-2} \tag{6}$$

$$T_{Export}(p, n, t) = \begin{cases} T_{Export\_Start} \bullet (1+R_{Export})^{n+t-2}, & p \leq P_{Export\_Limit} \\ 0, & p \leq P_{Export\_Limit} \end{cases} \tag{7}$$

A.3 System cost

The install cost of each PV and battery system combination changes for each forecast year (t) according the following equation:

$$System\ Cost(p, b, t) = p \cdot C_{PV_{Start}} \cdot (1 + R_{PV})^{t-1} + b \cdot C_{Battery\_Start} \cdot (1 + R_{Battery})^{t-1} \tag{8}$$

Appendix B. Research data

The R source code, demand profile data, insolation data and computational results are publicly accessible from doi:10.25917/5b3dc6bb7bb70.

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Appendix 2 – Paper 2

Say, K., John, M., Dargaville, R., 2019. Power to the people: Evolutionary market pressures from residential PV battery investments in Australia. Energy Policy 134, 110977. https://doi.org/10.1016/j.enpol.2019.110977

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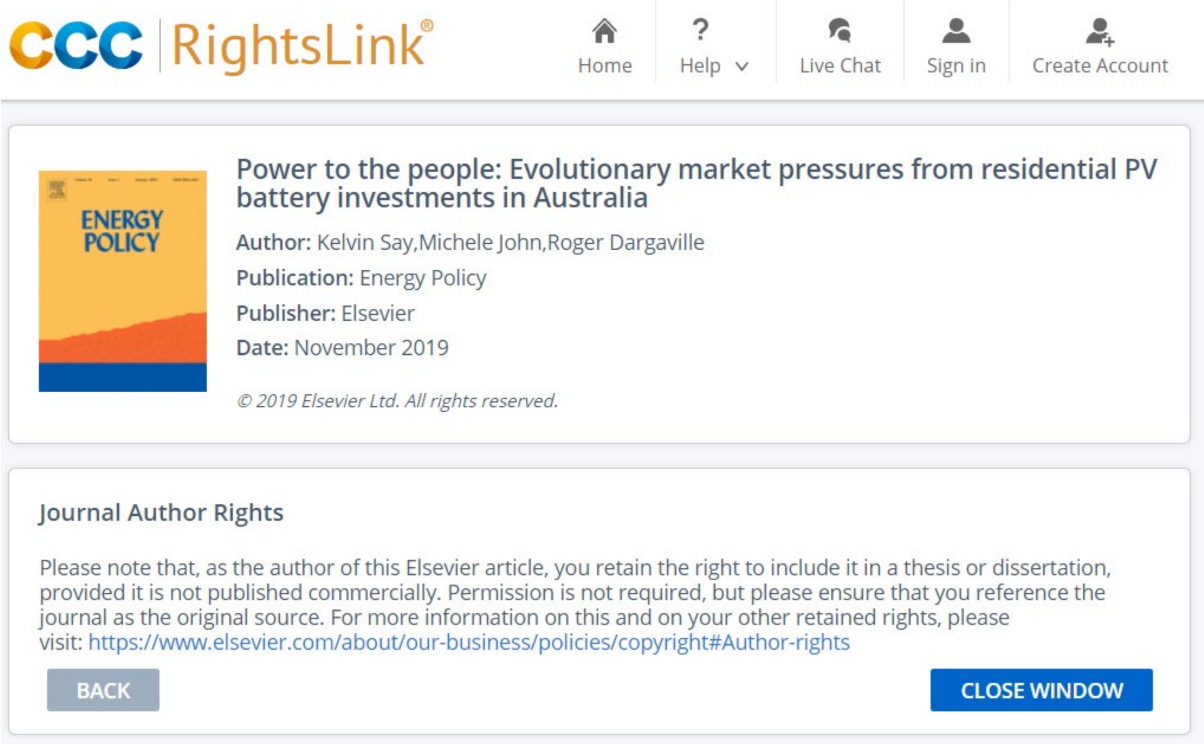

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Statement of Contribution

I, Kelvin Guisen SAY, contributed to the 85% of the paper/publication entitled:

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Specifically, I contributed to the following:

Conception and design, acquisition of data and method, data conditioning and manipulation, analytical method, interpretation and discussion, and final approval

Signature of candidate: **Date:** **10 November 2021**

I, as a Co-Author, endorse that this level of contribution the candidate indicated above is appropriate.

Michele John

Signature: **Date:** *9 December 2021*

Roger Dargaville

Signature: **Date:** **8 December 2021**

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Power to the people: Evolutionary market pressures from residential PV battery investments in Australia

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ABSTRACT

Falling costs of solar PV and battery technologies are continuously changing the customer relationship with their electricity network. By managing their own self-generation, customers are able to place natural selection pressure on utilities to evolve. The devised techno-economic simulation model projects residential PV and battery investment decisions over 20 years in Perth, Australia to quantify the potential market impacts from policy and customer investment conditions. Using real-world demand and insolation profiles from 261 households, this research evaluates how cumulative customer PV and battery investments changes the network and market operating conditions, while under the influence of various feed-in tariff values. The results indicate that high feed-in tariff policy costs in the short-term, make it economically challenging to prevent or restrain significant residential PV-battery adoption in the longer-term. Moreover, continuous increases in residential PV-battery system installations eventually lead to annual net-exports substantially exceeding net-imports on the distribution network. This significant shift in network operation provides an opportunity for policymakers to utilise behind-the-meter PV-battery investments and decentralised energy markets to meet wider renewable energy and decarbonisation goals.

1. Introduction

The provision of electricity is a complex problem that involves many competing and cooperating institutions. The liberalisation of electricity markets has led to clearly defined governance and operational roles, of which generation companies, network owners, and electricity retailers, provide particular electricity services in exchange for financial gain. The segregation of responsibilities gives rise to co-evolving dependencies and feedbacks that have similarities to complex adaptive systems in natural ecosystems (Miller and Page, 2009). Energy decarbonisation is vital for reducing global greenhouse gas emissions (Blanco et al., 2014) and thus electricity markets are faced with the challenge of delivering affordable, secure and low-emissions electricity (Commonwealth of Australia, 2017). Behind-the-meter PV and battery systems allow customers to affordably source their own low-emissions electricity, which inevitability leads to the withdrawal of demand from the electricity market and an increasing quantity of distribution network exports. Hence, these changes in how a customer engages with the electricity network places natural selection pressure (both financial and technical) on incumbent utilities to evolve. As the financial and technical flows adjust to customers' changing needs from the grid, tipping points and regime shifts begin to emerge that places pressure on all market participants to change (Walker and Salt, 2012).

Using a developed bottom-up techno-economic simulation model and scenario analysis, this paper estimates the influence of customer PV and battery investments in the electricity system over a 20-year timeframe. Heterogeneity of demand and solar insolation are sourced from 261 real household gross utility meters (Ausgrid, 2018; Ratnam et al., 2017). The aim of this research is to determine the influence of the Feed-in Tariff (FiT), decreasing systems costs, and increasing electricity prices on the adoption of these technologies and their subsequent impacts on the retail energy market and wider distribution network. Perth, Australia is used in the case study as its retail conditions are consistent with other states (Australian Energy Market Commission, AEMC, 2018a), while its isolated network heightens the operational risks that would otherwise be delayed in other interconnected regional networks. This research illustrates the economic potential for customer PV-battery investments in Australia to drive further energy system decarbonisa-

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tion, whilst offering new opportunities for different roles and services in the electricity market.

Section 2 describes the current situation in Australia followed by a literature review and main contributions. Section 3 presents the developed modelling framework. The case study and results are presented in Section 4 with a sensitivity analysis. Section 5 uses scenario analysis within the wider context of the energy market to discuss how these results would impact future energy policies. Section 6 concludes with key findings and policy implications.

2. Background and literature review

2.1. Household PV battery adoption in Australia

Australia's solar PV generation is currently dominated by small-scale solar PV (Clean Energy Council, 2018). Bloomberg New Energy Finance, BNEF (2018) expects Australia to have one of the most decentralised energy systems in the world with 44% of capacity sourced from behind-the-meter by 2050. Australian Energy Council, AEC (2019) reports that the Discounted Payback Period (DPP) for residential solar PV has fallen below 5 years in most capital cities and average newly installed solar PV capacities have risen past 6.5 kW_p. As the economics of these systems continue to improve, commercial and industrial customers are also investing in their own medium and large-scale solar PV systems (Puddy, 2018; Stockland, 2018; Verdia, 2018; Vorrath, 2018).

Australia currently has the world's highest rate of rooftop PV penetration (AEC, 2016; Australian Photovoltaic Institute, APVI, 2018b), with homeowners the largest demographic (Sommerfeld et al., 2017). Australian Energy Market Operator, AEMO (2018a) reports that rooftop PV has contributed to a flattening of peak demand and energy consumption, a shifting of peak periods to later in the afternoon and a decline of demand in the middle of the day. At the end of 2018 over 2 million, or 20% of all Australian households have rooftop PV installed, and the average system capacity for new PV installations continue to increase (AEC, 2019; APVI, 2018a; Roberts et al., 2018). The rise of customer PV has already led to numerous revisions in operational load forecasts (AEMO, 2018b). Household PV-battery systems are increasingly being installed, with 12% of PV installations in 2017 including a battery (up from 5% in 2016) (Solar Choice, 2018d; SunWiz, 2018). In 2018, 300 MWh of distributed storage is expected to be installed (an increase of 56% from the previous year) (Clean Energy Council, 2018). Sufficient capacity is being installed behind-the-meter (that is not centrally monitored or controlled) such that system operators are becoming increasingly concerned that system security may be threatened (AEMO, 2019; AEMO, 2018d).

2.2. Tariff and cost factors for household PV battery systems

A significant driver for household PV and battery investment has been the ability to hedge against future electricity prices increases while reducing existing electricity consumption costs (Williams, 2018). These investments offer an implicit income gained from the expected electricity bill savings and can be considered as an investment cashflow (Darghouth et al., 2016; Schopfer et al., 2018; von Appen and Braun, 2018a). The investment returns are therefore characterised by the financial value of (i) the structure of the retail electricity bill, (ii) volumetric usage charges, (iii) feed-in tariffs and (iv) upfront system costs.

i) Australian retail electricity bills consist of two-parts, a volumetric usage charge (AUD/kWh) and fixed network charge (AUD/day). Demand charges (AUD/kW) are reserved for commercial and industrial customers. Household solar PV energy generation is predominantly credited using a net-meter configuration,[1] [2] where energy generated is initially consumed by the customer's load before being exported onto the grid.
ii) The volumetric usage charge is applied to the quantity of energy not met by self-generation and is typically the largest contributor to retail electricity bills. In 2018, the volumetric usage charge was between $0.24-0.38 AUD/kWh across electricity retailers (AEMC, 2018a; APVI, 2018a) and has been rising at an average of 7.86% per annum between 2007 and 2018 (Australian Bureau of Statistics, ABS, 2018).
iii) The FiT policy applies a credit (AUD/kWh) to the quantity of self-generated energy that is not consumed by the household and is subsequently exported to the grid. The 2018 FiTs ranged between $0.07-0.17 AUD/kWh across electricity retailers (Solar Choice, 2018a), which correspond to a relative value between 24 and 82% of their respective volumetric usage charges.[3] To be eligible to receive the FiT, customers typically have to remain under an inverter capacity limit (Solar Choice, 2018a), such as 5 kW on the SWIS network[4] (Synergy, 2017a). With FiT rates being lower than their volumetric usage charges, customers are therefore incentivised to minimise imported energy by prioritising self-consumption over grid exports. In addition, as retailers are paying for customer-sourced electricity at the FiT rate, it is likely that FiTs will remain lower than usage charges and eventually reflect daytime wholesale electricity prices.
iv) Between 2012 and 2018, residential PV system costs have been falling at an average of 10% per annum with median prices currently around $1250 AUD/$kW_P$ (Solar Choice, 2018b) including policy discounts. At present, battery system installations are less common (and have limited historical pricing data). Battery system costs have a greater variation and are currently between $710–2500 AUD/kWh (Solar Choice, 2018c).

2.3. Literature review

2.3.1. Investment modelling and adoption

Over time, declining PV and battery system prices, increasing electricity costs and different FiT values change the PV battery configurations that provide positive investment returns. Further variation occurs due to differences in customer energy consumption and solar insolation. By incorporating the span of technical and financial considerations into a model, projections of household PV and battery investments can be generated. However, when using a modelling approach, care must be taken when interpreting results, since energy systems are open and complex in nature and all models are simplifications of reality (Pfenninger et al., 2014). However, by systematically evaluating the parameter space between boundary conditions, modelling results can represent a range of possible scenario outcomes that together can improve the robustness of the evaluation (Lempert et al., 2006; Winskel, 2018). This paper's case study and scenario analysis has been developed in consideration of this approach.

[1] Net-metering in Australia differs to the U.S. terminology where customers are credited for net-exported energy at the same value of the retail tariff (Satchwell et al., 2015a).

[2] Many early Australian FiTs were gross-metered with generation and consumption separately credited and billed, and with FiT rates exceeding volumetric usage charges. Due to oversubscription and falling PV costs, gross-FiTs are being phased out for net-metered bills that have much lower FiT rates (Poruschi et al., 2018).

[3] Australian FiTs are revised annually by their retailers or regulators and not fixed-term contracts. Poruschi et al. (2018) provides a review on the evolution of Australian FiT policies.

[4] The South West Interconnected System (SWIS) network is an isolated network in Western Australia that covers Perth and surrounding cities (255,000 km^2), and operates as an energy and capacity market (AEMO, 2018c).

The extensive literature on renewable energy investment dynamics offer a range of methods to evaluate the influence of energy policies, tariffs and system costs on future energy markets. Wüstenhagen and Menichetti (2012) make an important contribution that investment decisions are not simply continuous acts of profit maximisation but require commitment of limited financial capital and are not easily reversed. Therefore, customers are faced with a 'strategic-choice' that has to consider the perceived risks and opportunities before an investment decision is made. Niamir et al. (2018) implemented Normative Activation Theory (De Groot and Steg, 2009; Schwartz, 1977) within an agent-based computational model to examine the influence of behavioural triggers and barriers on customer adoption of low carbon energy. Separating renewable energy investment decision-making into various stages (awareness, responsibility, personal norms and behaviours) with influences (subjective norms and perceived behaviour control) allowed customer survey data to be computationally modelled to evaluate customer behaviour on energy, economic and emission objectives. Similarly, Klein and Deissenroth (2017) utilised financial investment metrics coupled with prospect theory to reproduce solar PV adoption dynamics in Germany between 2006 and 2014.

Bottom-up studies quantify the profitability from customer renewable energy investments using financial investment metrics, such as Net Present Value (NPV) (Barbour and González, 2018; Hoppmann et al., 2014; Khalilpour and Vassallo, 2015; Schopfer et al., 2018; Shaw-Williams et al., 2018; von Appen and Braun, 2018b), internal rate of return (López Prol, 2018; Parra and Patel, 2016) and payback period (Palmer et al., 2015; Pearce and Slade, 2018). To evaluate system effects both optimisation and simulation methods are commonly used, however various trade-offs exist. As described by Pfenninger et al. (2014), optimisation models are able to evaluate a wide variety of parameters to determine likely futures but are unable to evaluate path dependencies. Simulation models can evaluate incremental changes and path dependencies by making use of higher resolution data but do not easily handle uncertainty and transparency. Each approach however can be used effectively to address different research questions.

2.3.1.1. Bottom-up optimisation. Schopfer et al. (2018) utilised real-world load profiles from 4190 households with electricity rates and weather conditions in Zurich, Switzerland to determine the percentage of households that would find PV-battery systems profitable over a range of PV and battery cost scenarios. von Appen and Braun (2018a) evaluated the business case for PV-battery systems and found that once battery storage systems become cost-effective, German households are incentivised to install additional PV capacity. Schill et al. (2017) used an electricity sector optimisation model and evaluated the system advantages and disadvantages of customer PV-battery systems in the German energy market. They found the flexibility offered by coordinating customer PV-battery systems could benefit the energy market and highlighted the need for further regulatory reform. Linssen et al. (2017) evaluated the influence of aggregate load profiles over individual load profiles on dimensioning of PV-battery systems. They found that aggregate load profiles result in an over-estimation of self-consumption and over-optimistic profitability. They recommended the use of individual real-world load profiles for economic analysis. Barbour and González (2018) utilised real-world demand and insolation profiles from 369 customers using a battery scheduling optimisation model and determined the NPV for PV-only and PV-battery investments under various U.S. electricity rates, FiT policies and future system costs. They found that PV-only systems are currently profitable, but for PV-battery systems to be profitable it would require electricity prices to increase above $0.40 USD/kWh and FiT rates fall below $0.05 USD/kWh.

2.3.1.2. Bottom-up simulation. Hoppmann et al. (2014) developed a simulation model to evaluate a range of electricity price projections to find the most profitable dimensions of PV and battery systems for a three-person household in Stuttgart, Germany. They found that as electricity prices increase, both the PV and battery capacities also increase. Shaw-Williams et al. (2018) evaluated a fixed set of residential PV-only and PV-battery configurations for 700 households in Sydney and Newcastle, Australia to determine the profitability for both householders and network operators. Their findings reaffirm that PV-only systems are currently the most profitable option for individual householders. However, by considering savings in network operation costs, residential PV-battery systems are more advantageous overall. Ren et al. (2016) evaluated the impact of various electricity rate and FiT scenarios on a fixed set of PV-only and PV-battery systems across three Australian cities. The impact on individual NPV profitability and reductions to peak demand and energy consumption was quantified. The results indicated that tariffs with time-of-use and critical peak pricing improved the economics of PV-battery systems over PV-only systems. Rocky Mountain Institute (2015) utilised low-cost economics to generate projections of customer PV-only and PV-battery adoption and determined the potential quantity and timing of customer load-defection in five U.S. cities. As opposed to grid-defection (i.e., customers leaving the grid), load-defection refers to households remaining connected to the grid but reducing their grid imports. Thus, retailer revenues per household are reduced (if volumetric dominant) and it further exacerbates lost revenues from any cross-subsidisation between variable and fixed costs. The report's findings highlighted the need for pricing reform, new business models and regulations to transition energy markets towards an integrated grid and avoid customer grid defection.

2.3.2. Market and policy tensions

Supported in part by FiT policies, the increasing quantity of behind-the-meter solar PV has changed the energy and monetary flows in the energy market and led to policy tensions concerning sources of FiT funding (Poruschi et al., 2018) and its distribution of benefits across the socio-economic spectrum (Cassells et al., 2017). Nelson et al. (2011), Satchwell et al. (2015a) and Simshauser (2014) evaluated the regressive nature of FiT policies and quantified how the financial benefits largely reward customers with self-generation (due to avoided costs) while those without the financial capacity to invest in their own systems, have to bear a greater proportion of electricity system costs. Khalilpour and Vassallo (2015) and von Appen and Braun (2018b) evaluated the potential costs required for households to leave the grid and found that while a decreasing marginal gain from additional PV battery capacity disincentives grid-defection, significant load-defection still remains. These issues have led to further research on regulation, FiT policy and rate design to evaluate trade-offs and dependencies in order to improve the exchange of energy and value that is both fair and reasonable for all stakeholders (Ayompe and Duffy, 2013; Fridgen et al., 2018; Martin and Rice, 2018; Passey et al., 2017; Satchwell et al., 2015b; Timilsina et al., 2012).

2.4. Main contributions and approach

Many existing studies have evaluated the profitability of PV and battery systems, but none to date have coupled an investment model with the determination of household PV and battery profitability to illustrate the sensitivity that the FiT has on the adoption of these technologies. The potential impacts on retailer revenues are used to show how PV and battery investing households constrain short-term FiT policy options that then lead to high PV and battery adoption in the longer-term. The subsequent changes to the wider distribution network and utility revenues drive natural selection pressures on energy markets.

A bottom-up techno-economic simulation[5] model was developed with scenario analysis to illustrate the influence of customers on the evolution of the electricity system. The case study and scenarios are designed to address the following questions in the Australian context:

- What influence does the FiT have on household PV and battery adoption?
- How does grid utilisation on the wider distribution network change as households install increasing PV and battery capacity?
- How is the retail energy market affected by changes to grid consumption and FiT payments?

The proposed approach evaluates household PV and battery investments under current electricity tariff and system cost trends. Potential reactions from utilities to increase tariffs are evaluated in the sensitivity analysis. The numerical results are not intended as exact forecasts, but rather as indications of the evolutionary market pressures that energy markets could face from their own customers.

3. Methodology

3.1. Techno-economic simulation to project customer PV and battery investment

The developed bottom-up techno-economic simulation evaluates individual customer investment decisions. Prior research by Say et al. (2018) evaluated how the range of profitable PV and battery configurations change in response to market for a single hypothetical customer. This paper extends this previous work by utilising real-world demand and insolation profiles while iteratively considering previous installations PV and battery systems before making further investment decisions (Say and Rosano, 2019). Consideration of previous PV battery installations are required as their finite operational lifespans constrain investment cash-flows, thereby affecting future PV battery investments. The model evaluates each customer independently and only considers PV and battery investments that are suited to each customer's demand profile, solar resource and previously installed PV and battery systems. By simulating a customer's investment decisions, the developed R numerical simulation model computationally generates PV and battery investment dynamics, over a range of customers, to investigate the potential impact on network and market operators. The techno-economic modelling framework (Fig. 1) consists of three interconnected modules that evaluate each customer annually over the next 20 years (T). As the economic conditions change and the operational performance of previously installed systems degrade, the model dynamically determines how a customer would continue to invest in PV and battery systems. As a customer's underlying electricity demand, solar insolation, electricity rates and FiT are exogenous parameters, the model is able to evaluate a wide range of economic scenarios to generate future operational scenarios and compare their relative influence.

The customer simulation model consists of (i) *technical*, (ii) *financial*, and (iii) *investment decision* modules. Each customer is evaluated independently to generate their net-import and net-export energy profiles for each year over the 20-year projection (T). The model uses a semi-constrained *Monte Carlo* approach to determine the *technical* implications of a given customer installing each PV and battery combination (within the semi-constrained range of PV and battery capacities) and the resulting *financial* cash-flow that is generated from electricity bill savings. These cash-flows create a set of distinct investment opportunities for each PV and battery combination that the *investment decision* module uses in a two-stage decision tree to determine firstly if a customer should invest, and secondly which PV and battery combination to invest into. If a PV battery system is installed, the customer's net-energy profile is updated from the following year onwards, and any subsequent PV and battery investments have to consider the recently installed system. Each module is further described in the following subsections.

3.1.1. Technical module

The purpose of the *technical* module is to supply time-series net-energy profiles to the *financial* module to determine the attractiveness of a given PV battery investment over the 10-year financial investment horizon[6] (N). Hence, this module determines, for each simulation year (t) using half-hourly time intervals (Δ_{Step}), how a customer's net-energy imports and exports changes for each PV battery combination over 10 years. In the first simulation year, the range of PV and battery combinations are initially evaluated between 0 and 10 kW_P ($p \varepsilon P$) using a step size of 0.5 kW_P and 0–18 kWh ($b \varepsilon B$) using a step size of 1 kWh respectively. This results in an initial *technical* evaluation of 399 PV battery combinations. However, the most profitable systems may reside outside the initial PV battery evaluation range, therefore it is important to allow the range of PV battery capacities to expand if required. The model uses a semi-constrained evaluation range that reruns the simulation year with increased PV battery capacities, if the most profitable PV battery system resides on the evaluation boundary. To maintain computational tractability the PV (P) or battery (B) capacity range is expanded iteratively by 40% until the most profitable system configuration resides within the evaluation boundaries (Equation (A.10) and Equation (A.11)).

For each PV and battery combination, (i) a PV generation profile is created using the customer's own solar insolation profile (H_S) and scaled to the PV capacity (p) with a linear degradation (80% capacity remaining after 25 years), and (ii) a battery energy storage model is scaled to the battery capacity (b) and modelled after the Tesla Powerwall 2 (Tesla, 2018) with an 89% round trip efficiency, 100% depth of discharge, 70% end-of-life capacity, and a 10-year operational lifespan. The PV generation profile is first subtracted from the customer's load profile (L_S) to obtain an intermediate net-energy profile. The intermediate net-energy profile is then evaluated by the battery energy storage model to utilise any excess energy for later self-consumption (within operational constraints). The resulting net-energy profile is then used by the *financial* module to calculate investment cash-flows.

3.1.2. Financial module

The *financial* module calculates the annual investment cash-flow for each PV battery combination over the 10-year investment horizon (N) by the amount of annual electricity bill savings achieved. In this study, a net-metered electricity bill structure and FiT is used, consisting of a flat volumetric usage charge (T_{Import}), a fixed network charge (T_{FNC}) and a flat FiT (T_{Export}) increasing at the tariff annual growth rate (R_{Tariff}). The bill structure with annual imported and exported energy quantities are combined to calculate the electricity bills over the next 10 years (N). By taking the difference in electricity bills between the pre-existing configuration and the system with additional PV battery capacity, the annual investment cash-flow is calculated (Equation (A.2)). The cost of capital equates to the PV capacity (p) multiplied by the PV system cost (C_{PV}) plus the battery capacity (b) multiplied by the battery system cost ($C_{Battery}$) in the given simulation year (Equation (A.8)). The *financial* module generates a set of cash-flows for each PV battery combination that are used by the *investment decision* module to determine the suit-

[5] A simulation modelling approach was taken as it allows path-dependency and transition analysis to be more readily evaluated when compared to an optimisation approach (Pfenninger et al., 2014).

[6] Justification for the 10-year financial investment horizon is provided within Criteria 2 in Section 3.1.3.

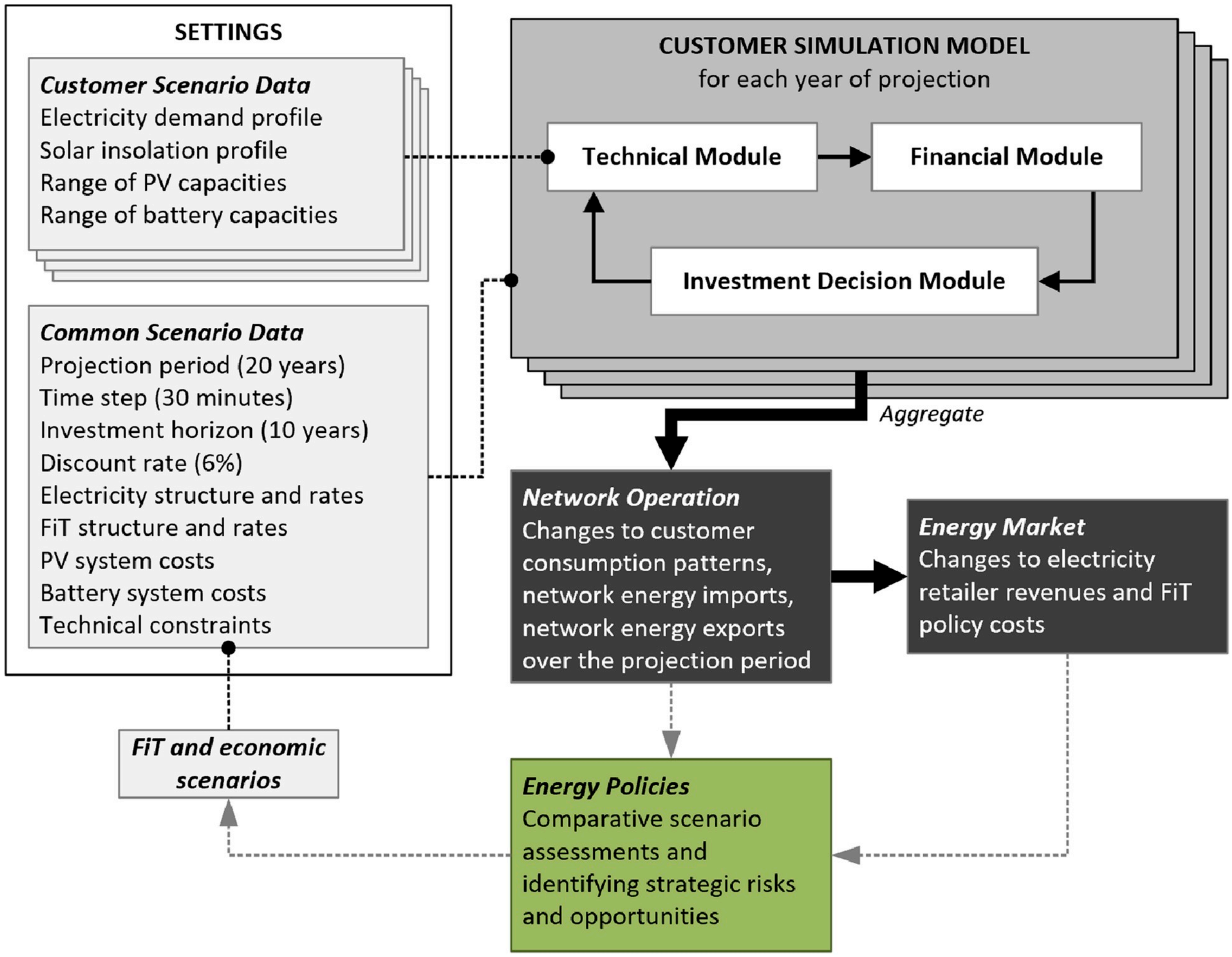

Fig. 1. Techno-economic simulation modelling framework to project customer PV and battery investment.

ability of each investment option. The financial equations used are provided in Appendix A.

3.1.3. Investment decision module

The *investment decision* module is responsible for evaluating the perceived risks and expected returns, in each year of the simulation (t), across the range of investment opportunities presented by each new PV battery combination and with respect to previous installations. A two-stage investment decision tree is used that requires the customer to be firstly certain that a sufficiently valuable investment opportunity exists (evaluating perceived risk), before making an economically rational decision to invest (by evaluating expected returns). The *investment decision* module makes the same considerations for every customer, but as each customer has a different demand and solar insolation profile, the resulting PV battery investment decisions differ. Furthermore, additional differences occur as the investment simulation progresses, as limited operational lifespans from earlier installations are factored into subsequent investment decisions. The upfront capital costs and projected cash-flows provided by the *financial* module form the basis of investment decisions. As the DPP is already used to compare and evaluate solar PV investment opportunities (AEC, 2019), the *investment decision* module uses the DPP to evaluate perceived risk. Once the perceived risks are acceptable, the module will select the most profitable PV battery combination. This leads to the following criteria:

Criteria 1 (perceived risk): *If at least one PV battery investment option (within the customer's evaluation range) has a DPP of less than 5 years then the customer is ready to make an investment.* It is assumed that the customer will not invest unless the perceived risks are sufficiently reduced. Once becoming confident that viable investment opportunities exist, the customer attempts to maximise their financial returns in the next stage.

Criteria 2 (expected returns): *Invest in the PV battery combination that provides the highest NPV over the next 10 years.* The 10-year financial horizon aligns with the 10.5 years of average household ownership turnover in Australia (CoreLogic, 2015). Using the NPV financial metric, each PV battery combination is assessed as a competing investment opportunity and the system with the highest NPV is selected.

As the *investment decision* module is bound by the range of PV and battery combinations that it evaluates, the range needs to expand to ensure that ***Criteria 2*** continues to be met (more detail provided in Section 3.1.1 and Equation (A.9)). Once a decision has been made to invest in a particular PV battery system, the underlying customer net-energy profile is updated with the expected technical operation from this system. As the operational lifespan of the newly installed system is embedded into the customer's net-energy profile, the customer simulation model is able to determine when it is economical to replace aging systems with larger or equivalent system capacities. The implementation of ***Criteria 1*** and ***Criteria 2*** allow the customer simulation model to generate lumpy investment decisions that dynamically react to changing market conditions and limited lifespans of installed PV battery systems. These modules allow the customer simulation model to generate projections of PV and battery installations, network utilisation, and future electricity bills, for each customer's unique demand and solar insolation profiles.

3.2. Operational, market and policy outcomes

This methodology allows researchers to study the effect of many customers making their own investments in PV and battery systems that in turn drive the emergence of market level effects, such as changes to network energy demand, lost market revenues or unsustainable policy costs. Analysing the relative differences between a range of economic and policy scenarios allows researchers to quantify the influence of micro-economic policy levers, such the value of the FiT.

For each economic scenario, the modelling results across the set of representative customers ($s \varepsilon S$) are aggregated. This creates a projection of network energy imports and exports (Fig. 2), installed household PV and battery capacities (Fig. 3) and expected retailer revenues and FiT policy costs (Fig. 4). As Australian FiT costs are primarily funded by electricity retailers (AEMC, 2018a; Poruschi et al., 2018), this means that retailers are financially exposed to increasing customer grid exports and decreasing customer grid imports. As retailer revenues are also the main source of liquidity for Australian energy markets, any significant reduction in retailer revenue streams would impact the operating margins of the entire electricity sector. Hence, retailer revenues (Fig. 4) are used to illustrate potential cash-flow risks facing the energy market and how this may constrain the range of acceptable FiT values for policymakers.

3.3. Key assumptions

- *Underlying customer demand and solar insolation profiles are repeated for each year of the simulation.* By maintaining underlying customer energy demand, the relative influence from exogenous parameters (e.g. FiT) are more clearly presented in scenario analyses. However, the influence of energy efficiency improvements (AEMO, 2017a; 2018b) on reducing future energy demand is disregarded. Furthermore, electric vehicle loads were not included as significant uncertainty exists with their timing and potential impacts.
- *Economic scenario assumptions continue year-on-year.* The energy market is a complex system that constantly reacts to internal and external forces. However, by externalising the economic parameters and limiting feedbacks to the path-dependence in customer PV battery investments, the results provide a clearer presentation of the evolutionary market pressures that emerges from customer investment behaviours.
- *Each customer invests with the same perceived risk and financial return expectations.* Variations in customer expectations are not modelled in the investment decision module, but rather the differences in demand and solar insolation profiles drive the variation in installed PV battery system capacities.
- *PV and battery system price reductions are independent of the installation rate.* The prices of PV battery systems (predominantly imported) in Australia are driven by global prices. In consideration of Australia's small energy market (compared to global scale), the rate of PV battery adoption involved is unlikely to induce shortages that raise prices. Larger regional studies that can measurably impact global demand may need to reconsider this assumption.
- *Unconstrained roof space for solar PV.* The simulation does not take in to account limitations on rooftop space for maximum installed solar PV capacities. However, the average solar PV system capacity remains below 11 kW_P across all scenario projections (Fig. C.2).
- *The battery energy storage system does not operate beyond their 10-year warranty period.* In this model, the battery energy storage system is removed from operation after the warranty period. However, a significant quantity of residual energy storage capacity remains at the end-of-life that could continue be repurposed for second life applications (Minter, 2018).
- *The battery energy storage system does not utilise grid charging.* As time-invariant volumetric usage rates and FiTs in the case study eliminates any financial incentive from grid charging the battery, grid charging is not considered.

4. Case study: influence of feed-in tariffs on the energy market from residential customer PV and battery investment

The case study evaluates a range of customer, network and market outcomes in Perth, Australia that are driven by customer PV battery investments and influenced by different FiT values. The input parameters are presented in Table 1. Five scenarios are evaluated (Table 2) to determine the influence of valuing the FiT at 0%, 25%, 50%, 75% and 100% of the volumetric usage charge over the next 20-years (T) between 2018 and 2037. To illustrate how customer PV and battery investments can force energy markets to evolve under minimal policy support, the parameters were conservatively chosen to remove additional PV battery economic incentives, such as time-of-use tariffs and battery subsidies, that would otherwise hasten adoption.[7]

A two-part electricity tariff structure is used, consisting of a flat volumetric usage charge (T_{Import}) and a daily fixed network charge (T_{FNC}). Flat volumetric usage charges were chosen as they do not financially reward time-shifting of loads. The flat FiT (T_{Export}) only rewards customers for each kWh of net-exported energy rather than considering temporal grid demand. Based on these tariff structures, financial incentives for residential customers are obtained from self-consumption improvements and increases in net-exports. The initial parameters are based on 2018 market conditions in Perth. The initial volumetric usage charge (T_{Import_Start}) is \$0.27 AUD/kWh and the initial fixed network charge is \$0.95 AUD/day (T_{FNC_Start}). Consistent with local conditions (Synergy, 2017a), FiTs are only eligible for customers with combined installed PV capacities up to 5 kW_P (P_{Export_Limit}). Beyond 5 kW_P, customers no longer receive any FiT payments for any excess PV generation. In each FiT scenario, the initial FiT is valued according to T_{Export_Start} in Table 2.

The volumetric usage charge (T_{Import}), FiT (T_{Export}) and network charge (T_{FNC}) all increase at 5% per annum ($R_{Tariffs}$). The 5% rate was chosen to minimise the influence of electricity prices changes on the results. Australian electricity prices have had two distinct growth rates since 1980, with an average increase of 5.07% per annum between 1980 and 2007 and an average increase 7.86% per annum between 2007 and 2018 (AGL, 2018). Hence, 5% per annum corresponds to the 1980–2007 growth rate. Installation costs for PV and battery systems are initially priced at \$1400 AUD/kW_P (Solar Choice, 2018b) and \$900 AUD/kWh (Tesla, 2018) respectively and reduce at −5.9% per annum (Ardani et al., 2018) and −8% per annum (IRENA, 2017) respectively.

This research assumes that the likely source of capital for a residential homeowner is their existing home loans. Hence, the discount rate (R_d) is set to an average home mortgage interest rate of 6% per annum.[8] Commercial entities that choose to supply PV and battery systems to homeowners would likely have higher costs of capital. A sensitivity analysis with a discount rate of 12% is provided in Section 4.2.1.

Heterogeneity of customer demand and solar insolation profiles are sourced from 300 residential customers in Sydney, Australia (Ausgrid, 2018; Ratnam et al., 2017) which has similar weather conditions to Perth. The data consists of 30-min load and solar insolation profiles

[7] With PV-battery systems capable of time-shifting both household load and supply, a wide range of value streams are available to system owners (Rocky Mountain Institute, 2015; Schill et al., 2017) for, (i) owner-friendly services (e.g., reduced electricity bills, increasing PV self-consumption) (ii) grid-friendly services (e.g., reducing peak demand, congestion management, frequency balancing); that would require time-varying tariffs and remuneration mechanisms; and (iii) policy incentives (e.g., capital subsidies, low cost finance, co-sharing). To establish a base case for PV battery transitions, only the ‘reduction of electricity bills’ from (i) are considered in this paper. However, access to additional value streams from (ii) and (iii) should improve investment returns and thus hasten the transition results presented in this paper.

[8] This is consistent with the 10-year historical average for owner-occupied standard variable mortgage home loans in Australia of 6.4% (RBA, 2018).

(recorded separately using gross utility energy meters) between 1st July 2012 and 31st June 2013. After removing customers with incomplete meter data, 261 households remain, with an average annual energy demand per household of 5.62 MWh, consistent with the Australian average of 6.43 MWh and Perth average of 5.83 MWh (ABS, 2013). The respective 261 solar insolation profiles are scaled to their nominal PV capacities and have an average PV capacity factor of 14.8%, consistent with Perth.[9] Further details of the customer data are provided in Appendix C. All other technical and financial parameters are as described in Section 3 and presented in Table 1.

4.1. Results

The customer simulation model independently evaluates each of the 261 households to generate a 20-year projection of household PV and battery investments. In each simulation year, electricity rates, FiT, and PV battery system costs are updated, and any new PV battery investments considers previously installed PV battery systems. By aggregating the subsequent impacts on network demand and retailer revenues from all households, a distribution network projection of operational and market changes is produced, including changes to grid imports and exports (Fig. 2), installed PV and battery capacities (Fig. 3), retailer revenues (Fig. 4a and b) and FiT policy costs (Fig. 4b). As opposed to an exact market forecast, this research evaluates across the scenarios to illustrate how tensions between customers and the energy market can develop and lead to various futures.

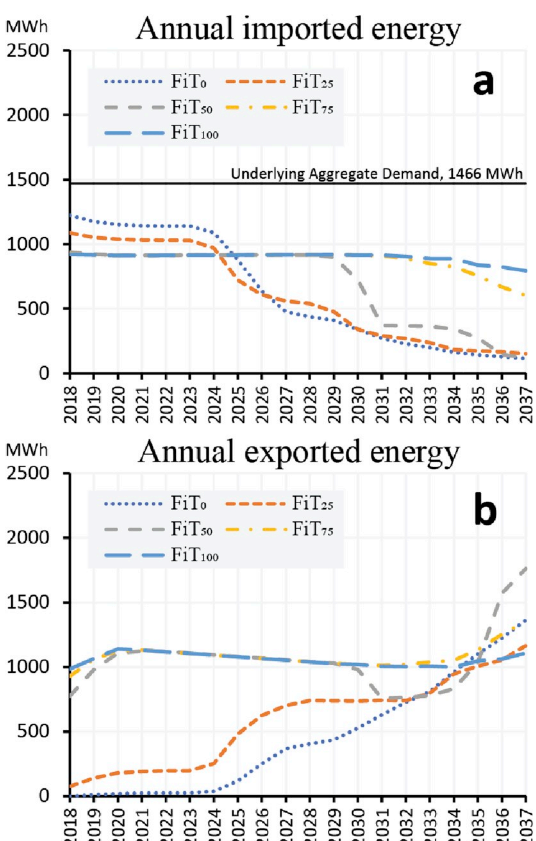

Fig. 2. Projected changes to customer network demand over 20 years (aggregate of 261 households) for each feed-in tariff scenario. (a) Annual imported energy. (b) Annual exported energy.

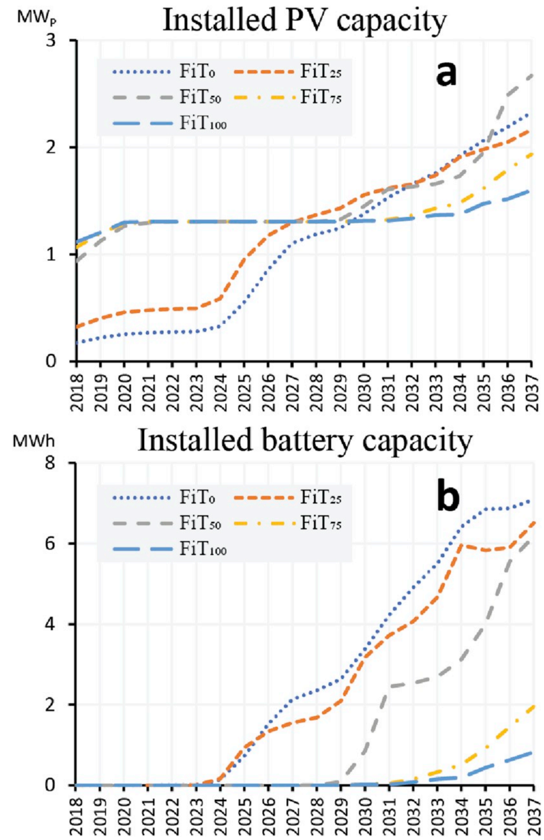

Fig. 3. Projected changes to cumulative installed PV and battery capacities over 20 years (aggregate of 261 households) for each feed-in tariff scenario. (a) Installed PV capacity. (b) Installed battery capacity.

In the first 6 years of the simulation (2018–2023), FiT values above 50% (FiT_{50}, FiT_{75} and FiT_{100}) have the lowest levels of annual grid imports (Fig. 2a) and the highest levels of installed PV capacity (Fig. 3a). With a high value in exported energy, the majority of households install 5 kW_P PV systems (remaining within the FiT limit) and prioritise self-generation over self-consumption, resulting in comparatively higher levels of exported energy (Fig. 2b) when compared to FiT_{25} and FiT_0. As the value of the FiT decreases to FiT_{25} and FiT_0, self-consumption increasingly becomes more economic over self-generation, and excessively large PV systems are disincentivised. As small PV systems provide higher levels of self-consumption, they are able to remain cost-effective. Hence in the FiT_{25} and FiT_0 scenarios, there are correspondingly lower levels of installed PV capacity (Fig. 3a) and higher levels of grid utilisation (Fig. 2a). Even when FiTs are removed (FiT_0) and exported energy is not credited, small PV system capacities remain cost-effective and network demand is still reduced by 17% in 2018 (Fig. 2a). With negligible levels of installed battery capacity, battery systems prior to 2024 are not yet cost-effective (Fig. 3b). While PV-battery systems remain more expensive than PV-only systems, the simulation results suggest that lower FiT maintain higher grid consumption and lowers grid exports.

As battery costs decline, the cost-effectiveness of PV-battery systems begins to supersede PV-only systems and three observations become evident. Firstly, lower FiTs bring forward the time at which PV-battery systems become more cost-effective (Fig. 3b), in FiT_{25} and FiT_0 batteries are cost-effective around 2024, in FiT_{50} from 2029, and in FiT_{75} and FiT_{100} from 2032. Secondly, the simulation finds it is more economic for customers installing battery systems to also install additional PV capacity (Fig. 3a). Across all five FiT scenarios, as the installed battery capacity increases there is a corresponding increase in PV

[9] The PVWatts calculator from National Renewable Energy Laboratory, NREL (2018) reports a 14.1% capacity factor for Perth, while AEMO's (2018b) forecasting analysis uses an empirically derived 15.8% capacity factor, the 14.8% capacity factor used in this study (Ausgrid, 2018) is consistent these values.

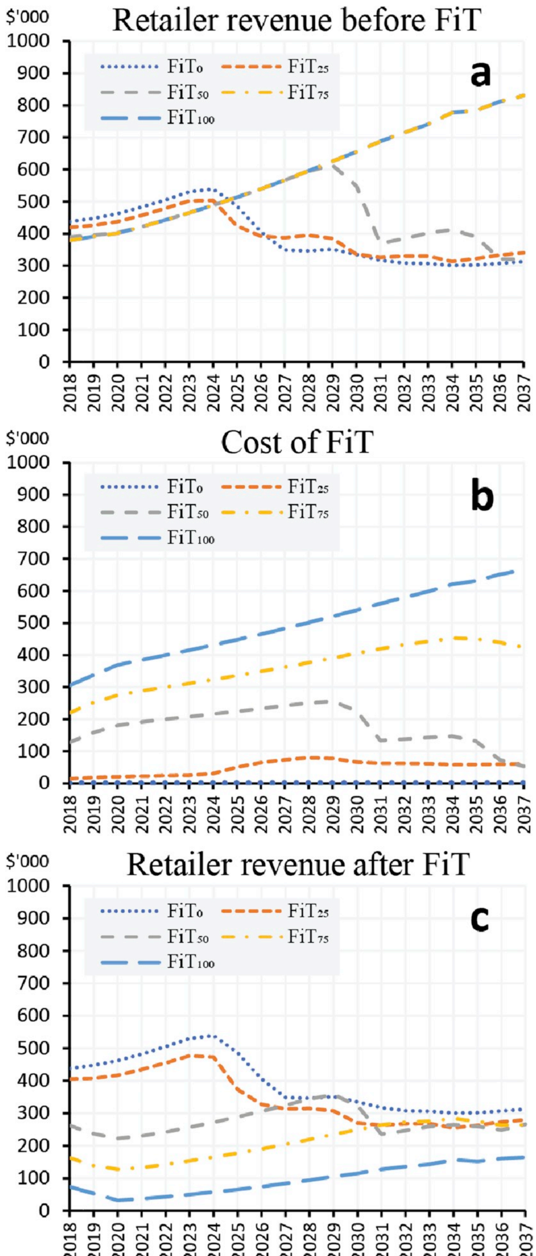

Fig. 4. Projected changes to electricity retailer revenues over 20 years (aggregate of 261 households) for each feed-in tariff scenario. (a) Retailer revenue before FiT. (b) Cost of FiT. (c) Retailer revenue after FiT.

capacity. That is, rather than sizing batteries to only time-shift energy from the existing PV system, it is more cost-effective to increase the level of self-generation (with additional PV capacity) to utilise larger battery capacities and obtain greater levels of self-consumption (Fig. 2a). This result aligns with previous research findings (Hoppmann et al., 2014; von Appen and Braun, 2018a; von Appen and Braun, 2018b). Thirdly, as more PV battery systems are installed, the amount of energy exported also increases (Fig. 2b). Only in the FiT_{50} scenario does exported energy (Fig. 2b) decline initially between 2030 and 2032. During this time a significant number of households with 5 kW_P of PV would rather use a smaller battery (utilising pre-existing PV self-generation capacity) than lose their FiT (by installing additional PV capacity for a larger battery system). However, as PV battery costs continue to decline and electricity rates increase, the economic case for keeping within the 5 kW_P FiT limit erodes, and households eventually find it more cost-effective (2032 and onwards) to relinquish the FiT and pursue greater self-consumption savings with larger PV-battery systems.

Electricity retailers in Australia are responsible for making FiT payments (Poruschi et al., 2018). Therefore, retailer revenues are impacted by changes to the quantity of imported and exported energy. Fig. 4 illustrates the impact to retailer revenues in each FiT scenario by aggregating the electricity bills and FiT payments across all residential customers. As the value of the FiT is reduced, the *retailer revenues after FiT* payments (Fig. 4c) generally increase. As discussed previously, higher FiTs (FiT_{75} and FiT_{100}) incentivise larger PV systems (within the FiT capacity limit) with a greater emphasis on exported energy. This leads to high FiT policy costs (Fig. 4b) that reduces retailer revenues below that of other FiT scenarios. As the value of the FiT is reduced (from FiT_{50} to FiT_0) the incentive for exported energy shifts towards increased self-consumption, disincentivising grid exports and reducing FiT payments (Fig. 4b). Notably, once PV-battery systems are installed (FiT_0 and FiT_{25} from 2024 and FiT_{50} from 2029), the significant reductions in imported energy lead to significant falls in *retailer revenues after FiT* payments (Fig. 4c) even though electricity usage and network charges increase at 5% per annum (R_{Tariff}). By 2037 the continued reduction in the volume of energy imports naturally leads to network charges becoming the dominant component in electricity bills.

As the energy market cash-flows are primarily sourced from electricity retailer revenues, the revenue results provide an important indicator of the financial vulnerability of the energy market. The increases in retailer revenue as the FiT value is lowered (Fig. 4c) implies that retailers would be naturally incentivised to lower FiT values to protect existing operating margins, however this accelerates PV-battery adoption (Fig. 3) and still exposes the market to significant falls in revenue (Fig. 4c). For policymakers, deciding upon the FiT value has subsequent impacts on customer PV-battery adoption that adds additional tension between electricity retailers, network owners, generators and customers.

4.2. Sensitivity analysis

4.2.1. Increasing the discount rate

Commercial entities typically require higher rates of return to cover higher costs of capital. Increasing the discount rate from 6% to 12% (Table B.1) the installation of battery systems is delayed by 1 year for S_1-FiT_0 and S_1-FiT_{25} and 2 years for S_1-FiT_{50}, S_1-FiT_{75} and S_1-FiT_{100} (Fig. B.1d). In the first year, the quantity of installed PV capacity (Fig. B.1c) is reduced by over 40% but promptly converges with a delayed trajectory to the base case results. Increases in installed PV capacity continues to coincide with the arrival of battery installations (Fig. B.1c and d). The annual imported (Fig. B.1a) and exported energy (Fig. B.1b) quantities are similarly delayed along with the financial impacts (Fig. B.2). Overall retailer revenues in the first three years are higher than the base case, as the lower incentives to install PV holds FiT costs down and retains higher imported energy quantities (Fig. B.2c). In S_1-FiT_0 and S_1-FiT_{25}, peak revenue is delayed by 2 years, but still leads to reductions in overall revenue but at a lower rate of decline. By doubling the discount rate, the transition from PV-only to PV-battery systems continue to occur but are delayed by 1–2 years.

4.2.2. Increasing tariff inflation

The tariff inflation of 5% in the base case is consistent with the 1980–2007 rate of change in electricity prices (AGL, 2018). However, electricity costs between 2007 and 2018 have increased at an average annual rate of 7.86%. The second sensitivity analysis increases the tariff inflation from 5% to 10% per annum (Table B.2). The results indicate that PV-battery installations are brought forward by 1–4 years (Fig. B.3) while overall retailer revenues are increased (Fig. B.4). In S_2-FiT_0 and S_2-FiT_{25} battery systems become cost effective 1 year earlier, while in S_2-FiT_{50}, S_2-FiT_{75} and S_2-FiT_{100} this occurs 4 years earlier (Fig. B.3d).

Table 1
Input parameters and data used in the study.

Input parameter	Abbreviation	Unit	Values	Derived from
Starting solar PV capacities	p	kW_P	0–10	Model assumption
Starting battery energy storage capacities	b	kWh	0–18	Model assumption
Scenario forecast period	T	years	20	Model assumption
Simulation time step	Δ_{Step}	minutes	30	Model assumption
NPV investment horizon	N	years	10	Model assumption
DPP evaluation criteria	D	years	5	Model assumption
Initial flat-rate feed-in tariff rebate	T_{Export_Start}	AUD/kWh	$0-0.27$	Model assumption
Initial flat-rate electricity usage charges	T_{Import_Start}	AUD/kWh	0.27	Synergy (2017b)
Initial daily fixed network charge	T_{FNC}	AUD/day	0.95	Synergy (2017b)
Change in tariffs charges/rebates	$R_{Tariffs}$	%/a	5	ABS (2018)
Feed-in tariff rebate limit	P_{Export_Limit}	kW_P	5	Synergy (2017a)
Discount rate	R_d	%/a	6	RBA (2018)
Initial installed PV system cost	C_{PV_Start}	AUD/kW_P	1400	Solar Choice (2018b)
Initial installed battery system cost	$C_{Battery\_Start}$	AUD/kWh	900	Tesla (2018)
Change in installed PV system costs	R_{PV}	%/a	-5.9	Ardani et al. (2018)
Change in installed battery system costs	$R_{Battery}$	%/a	-8	IRENA (2017)
Number of households	S	household	261	Ausgrid (2018)
Solar PV generation profile (per household)	H_s	Wh	Time series	Ausgrid (2018)
Underlying load profile (per household)	L_s	Wh	Time series	Ausgrid (2018)

Table 2
Case study input parameters.

Scenario	T_{Export_Start}	T_{Import_Start}	P_{Export_Limit}
FiT_0	0.0000 AUD/kWh	0.27 AUD/kWh	n/a
FiT_{25}	0.0675 AUD/kWh	0.27 AUD/kWh	5 kW_P
FiT_{50}	0.1350 AUD/kWh	0.27 AUD/kWh	5 kW_P
FiT_{75}	0.2025 AUD/kWh	0.27 AUD/kWh	5 kW_P
FiT_{100}	0.2700 AUD/kWh	0.27 AUD/kWh	5 kW_P

The average growth rate of installed PV and battery capacities are also increased, leading to approximately 40% more PV capacity and 60% more battery capacity by 2037. The higher levels of installed PV and battery capacities significantly raise the quantity of exported energy (additional 60–120% by 2037) whilst further reducing grid imports (Fig. B.3). When compared to the base case, the retailer revenue after FiT is higher as the increased value of fixed network charges outweigh the reductions in grid imports (Fig. B.4c). Furthermore, the installation rate of PV-battery systems increases, resulting in significantly greater quantities of exported energy.

5. Discussion

The case study quantitatively evaluated the influence of the FiT value on customer PV battery investments (Fig. 3) and the subsequent changes to grid imports and exports (Fig. 2), load defection and retailer revenue margins (Fig. 4). However, the results from this research are not intended to be used as exact forecasts but rather to illustrate how FiTs and falling PV battery costs apply demand-side pressure on the energy market, creating operating conditions that in turn pressure the market to evolve. As FiTs allow policymakers to influence future customer PV and battery investments, it is important to assess the range of potential trade-offs involved. Presently, retailer revenues are vulnerable to customer PV-battery adoption which has long-term implications for the economic operation of the energy market.

The case study results are now summarised as follows: While battery systems are too expensive and PV-only systems are common, lower FiTs maintain higher grid consumption and lower the quantity of grid exports. However, lowering FiTs further brings forward the time in which PV-battery systems become cost-effective. Once this occurs, customer battery installations encourage further PV capacity to be installed, resulting in further reductions in distribution grid imports and additional increases in grid exports. Attempts to slow down the rate of customer battery adoption with higher FiTs result in higher FiT policy costs that subsequently erode electricity retailer revenues.

Rather than evaluating each of these outcomes independently, Fig. 5 presents a strategic overview of the technical and economic outcomes across all the FiT scenarios. By categorising the numerical results, it allows the technical and economic trade-offs across all FiT scenarios to be visually compared and facilitates a broader understanding of the market conditions that lead to opportunities, risks and policy constraints. Note, the categorisation of the *remaining grid consumption* is calculated with respect to the underlying annual energy demand of 1466 MWh. The following policy implications become evident:

1) *Higher FiTs place downward pressure on electricity retailer profits.* Higher FiTs make it more cost-effective for customers to deliberately oversize their PV systems (within the FiT eligibility limit) resulting in larger amounts of exported energy (that has to be credited) with a simultaneous reduction in grid consumption (leading to lost sales). The higher the FiT, the greater the reduction in electricity revenues. Electricity bill structures that are heavily weighted towards volumetric usage charges over fixed network charges will exacerbate this issue.
2) *It will be economically challenging to prevent substantial customer PV-battery adoption.* While the higher FiT scenarios (FiT_{75} and FiT_{100}) are able to disincentivise significant customer PV-battery adoption, they also resulted in the lowest retailer revenues. As retailers are the primary source of revenue in the energy market, having low retailer revenues would place significant pressure on the operating margins of utility generators and networks. Therefore, high FiTs place significant financial risks upon the energy market and would (in the short-term) incentivise retailers to reduce FiTs that subsequently leads towards greater customer PV-battery adoption. In addition, efforts by retailers to increase electricity tariffs (to recoup lost revenue) would also accelerate the transition process (Section 4.2.2).
3) *As customer PV-battery adoption continues to rise, customer grid exports will become much greater than grid imports.* Under low FiT conditions (FiT_0, FiT_{25} and FiT_{50}), customers are economically driven to raise

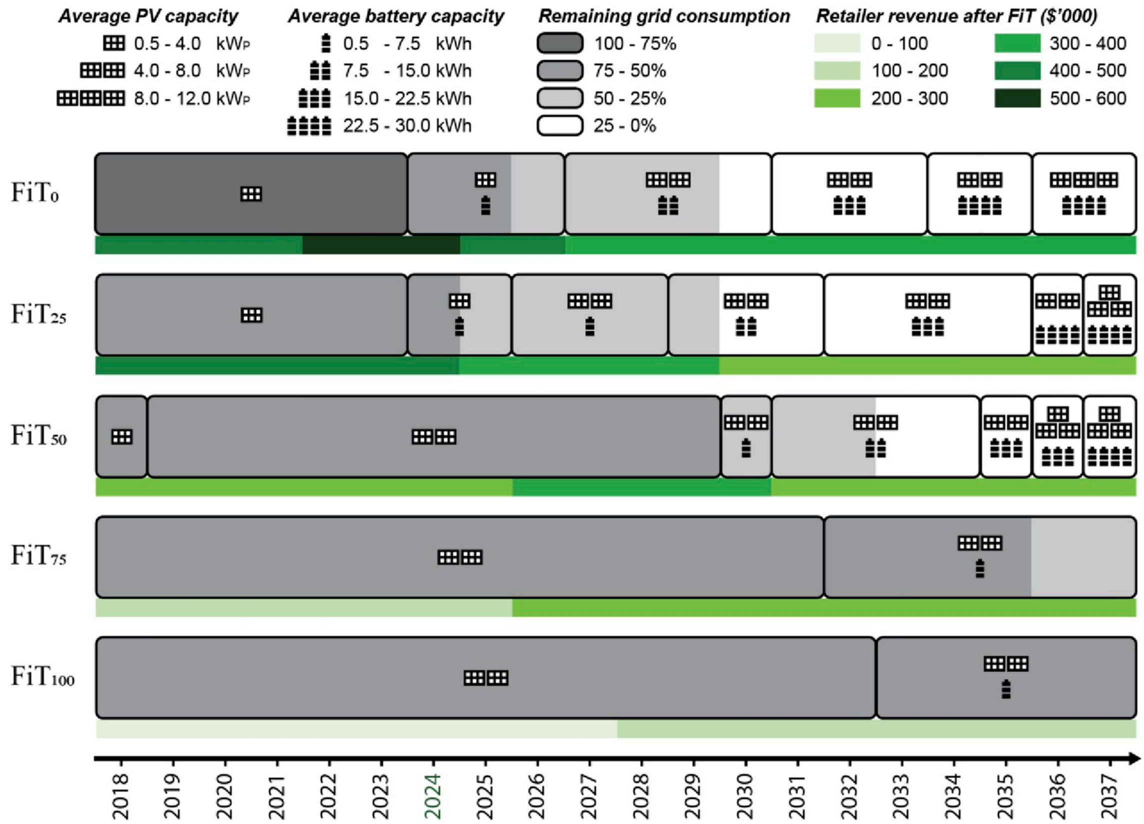

Fig. 5. Strategic overview from each feed-in tariff scenario simulated over 20 years.

their level of self-consumption. With continual reductions in PV battery system costs, it becomes increasingly more cost-effective to use larger PV-battery systems that have higher self-consumption rates and targeted towards the winter months. This results in excess solar energy generation in all other months. For example, in the 20th year of the FiT_{25} scenario (Fig. 2) annual grid imports fall to 150 MWh (10.3% of underlying energy demand) while annual grid exports rise to 1165 MWh (over 7.7 times grid imports). Similar observations occur in the FiT_0 and FiT_{50} scenarios. The considerable fall in annual grid imports coupled with a significant quantity of excess PV generation marks a significant shift, with households effectively becoming net generators over the year. This outcome would challenge and threaten the underlying technical and economic assumptions of existing centralised energy markets, resulting in changes to retail tariff structures. For example, retailers may increase fixed network changes while reducing volumetric changes for PV battery households, thus disincentivising further increases in capacity.

These policy implications suggest that, as the cost of PV and battery technologies decline, coupled with Australia's high availability of solar resources, and under existing electricity rate and FiT structures, growing installations of customer PV-battery systems have the potential to become a disruptive force in the energy market over the next 20 years. While flat tariff structures were used in this study, alternative tariff structures (e.g. time-of-use charges, time-of-export FiTs, real-time pricing) would provide additional revenue streams to PV-battery systems (Young et al., 2019) and accelerate their cost-effective tipping points. Tariff structures that raise fixed network charges and lower variable charges, could delay PV-battery adoption (by reducing the value of self-consumption) but their regressive effects (Schlesewsky and Winter 2018) in a sector with low consumer trust (AEMC, 2018b) would make it challenging to implement. Therefore, customer PV-battery adoption will continue to grow and become increasingly difficult for utility generators and networks to ignore. Centralised energy markets will face increasing market pressures if customers (utilising their own capital) transition from being net-consumers of energy to net-exporters of energy. However, rather than perceiving this as a market risk, it presents policymakers an opportunity from a decarbonisation perspective to utilise the increasing availability of customer self-generation and storage to reduce emissions and lower costs across society. Policies that support the market integration of customer PV and battery systems could encourage this alternative energy system decarbonisation pathway. These research findings add to existing energy transitions studies from CSIRO and Energy Networks Australia (2017) and Barton et al. (2018) that also highlight that customers have the means to play a major role in achieving emission reduction targets.

The integration of customers as distributed energy resources into the energy market would take advantage of spare customer generation and storage capacity to provide wider energy market services. However, this would necessitate changes to existing regulations and policies. By utilising the scenario analyses from this research and existing distributed energy resource literature, a number of policy recommendations are now proposed that are necessary for the integration of customer PV and battery energy resources into existing energy markets.

- *Smart energy meter standards.* The scenario results (FiT_0, FiT_{25} and FiT_{50}) suggest that customer grid exports are likely to rise well beyond grid imports. Therefore, it will become increasingly necessary for behind-the-meter grid exports to be controllable by the system operator (or an intermediary) via two-way communications to the smart meter. In addition, Australian smart energy meters do not typically measure all four quantities of (i) onsite generation, (ii) underlying consumption, (iii) net-imports and (iv) net-exports (Ayompe and Duffy, 2013). With gross metering, only (i) and (ii) are measured. With net-meters, only (iii) and (iv) are measured. As net-meters are the predominant configuration in Australia, the inability to obtain onsite generation and underlying consumption profile data limits operational visibility for system operators, and affects the accuracy of grid forecasts and operation planning (AEMO, 2018d). Another concern is the socially regressive nature of usage charges and FiTs, based only (iii) and (iv) respectively, that imposes cross-subsidies on households that are unable to afford their own PV battery systems (Brown and Bunyan, 2014; Nelson et al., 2011). With higher income households generally consuming more electricity, being able to read (i) and (ii) offers the means to consider more socially progressive tariff reform, such a levying the quantity self-consumed[10].

- *Cost reflective electricity rates and FiTs.* From an economic perspective, the structure of electricity tariffs and FiTs have to better reflect the cost of electricity provision while adapting to changes in customer consumption and generation patterns. Time-of-use tariffs are already used to encourage customers to reduce their grid demand during the afternoon peak periods. Furthermore, it encourages PV-battery adoption by incentivising grid charging during night time off-peak periods to boost overall self-consumption. As observed by Australian Energy Market Operator (AEMO) (2017a), the minimum demand period has begun to occur in the middle of the day, which will eventually require the off-peak period to also change. The introduction of time-of-export FiTs by the Victorian Essential Services Commission, ESC (2018) has introduced an additional financial incentive for customers to supply energy during the peak demand period (3pm–9pm on weekdays). While this reduces the value of self-consumption (during this time) for PV-only households, it creates an additional income stream for PV-battery customers by rewarding them for discharging their batteries (beyond their own energy demand) to assist with peak demand shaving. The adjustment of tariff structures as economic policy levers can help reduce grid balancing system costs while incentivising additional customer PV-battery adoption.
- *Decentralised energy markets.* Smart energy meters offer the technical means to utilise behind-the-meter energy resources in the wider energy market. The development of decentralised energy markets permits these distributed energy resources (with low marginal costs) to compete for grid services. Aggregators or virtual power plants (VPPs) pool together customer variable energy resources to bid for available grid services (AGL, 2018; Powershop, 2018; Sonnen, 2018). Therefore, it becomes necessary for regulators and policymakers to increase the range of grid service markets and shorten trading periods to allow VPPs (and other short-term grid balancing technologies) to compete effectively. However, at the local distribution-level, network issues such as congestion, line losses and constraints and redispatch cannot be addressed by common pool aggregators. Rather localised energy markets or separate nodal prices are required. However, as localised energy prices are not permitted in Australia under traditional liberalised energy markets (that have a single market price) significant regulatory changes are required.[11]

To take advantage of the technical and economic opportunities provided by future residential PV and battery investments, energy markets and regulators need to be flexible and innovative in working together with these evolutionary pressures from their own electricity customers.

6. Conclusion and policy implications

Continued cost reductions in solar PV systems have already changed how customers interact with the electricity grid and have forced energy markets to adapt with the emergence of the 'duck curve' (Denholm et al., 2015), negative daytime energy prices (AEMO, 2017b) and lost electricity sales (Rocky Mountain Institute, 2015). With continued falls in battery energy storage system costs, another phase of market evolution is likely to occur. These changes are being brought about by residential customer investment in PV and battery systems that are shaped by expected market conditions and in particular, the value of the FiT.

A techno-economic simulation model was developed to project customer PV and battery investments in Australia over 20 years and to evaluate the influence of the FiT to shape future energy market conditions. Utilising real-world demand and insolation profiles from 261 Australian households and economic conditions consistent with Perth, Australia, projections of annual grid imports and exports, installed PV and battery capacities, and retailer revenues were generated for five FiT scenarios, FiT_0, FiT_{25}, FiT_{50}, FiT_{75} and $FiT1_{100}$ respectively set at 0%, 25%, 50%, 75% and 100% of the volumetric usage charge.

For FiTs below 50% of the volumetric usage charge (FiT_0, FiT_{25} and FiT_{50}), the results indicate that by the end of the 20-year period, residential customers are able to cost-effectively install significant PV and battery capacities and reduce grid imports by over 92%. Higher FiT values (FiT_{75} and FiT_{100}) disincentivise battery investments and maintain higher levels of grid consumption, however electricity retailers would likely incur significantly reduced revenues due to high FiT policy costs (Fig. 4). Therefore, policymakers would be under market pressure to reduce FiT values which in turn accelerates the tipping point towards cost-effective PV-battery systems (Fig. 3b). As a result, it could be economically challenging to prevent or restrain customer PV-battery adoption. As batteries are installed, additional PV capacity is also installed (Fig. 3a) and by the end of 20-year period, the results from FiT_0, FiT_{25} and FiT_{50} indicate that residential customers have the potential to export greater than 7.7 times their annual imports (Fig. 5). These findings illustrate how ongoing customer investment in PV-battery systems gradually changes the technical operation of the network and places pressure on retailer revenues that constrain future FiT policy options. This would result in a lock-in of customer PV-battery adoption and the shifting of the system towards a market based on behind-the-meter electricity generation. These evolutionary market pressures will require the energy market to integrate a growing quantity of distributed energy resources into its technical and financial operations, beginning with smart meter standards, cost-reflective tariff reform and distributed energy market mechanisms.

Further research could evaluate how the changes to customer grid utilisation affects the economics of current utility-scale generation and storage technologies. By extending this analysis to different regions, we

[10] The German self-consumption levy (Fraunhofer ISE, 2018) was introduced for large PV system owners and applies 40% of the (Renewable Energy Sources Act) EEG surcharge to PV self-consumption. This policy is used to lower the regressive nature of net-metered volumetric usage charges and FiTs, by spreading EEG policy costs across a wider range of customers. At present, this policy option is not feasible in Australia as existing net-meters are unable to read 'onsite generation' and 'underlying consumption'.

[11] Vertically-integrated utilities are exempt from this regulatory limitation, as they operate without liberalised energy markets. In Australia, small-scale trials are being performed in the regional areas of Bruny Island, Tasmania (Consort, 2018) and Onslow, Western Australia (Horizon Power, 2018). In the U.S., the New York State microgrid initiative is developing the market rules to facilitate interoperability of local energy markets (NYS SmartGrid Consortium, 2018).

can evaluate the capacity for residential PV customers to influence energy markets. The developed simulation model can also help determine cost distribution and socio-economic trade-offs in evaluating FiT and electricity tariff structural designs.

This research shows that ongoing residential PV-battery investments place significant natural selection pressure on existing energy markets. However, the lowering of demand for large-scale generation capacity and the provision of significant quantities of low carbon energy from customers, provides an alternative and evolutionary pathway for energy decarbonisation. These research findings strengthen the case for policymakers to continue developing strategies that position customer distributed energy resources at the centre of the renewable energy transition.

Acknowledgements

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Appendix A. Financial and investment equations

The profitability of each PV and battery investment in the t-th simulation year can be expressed using the NPV that depends on discounted annual cash flows over the 10-year investment horizon (N) and upfront system costs.

$$NPV(p, b, t) = \sum_{n=1}^{10} \frac{Cash\ Flow(p, b, n, t)}{(1 + R_d)^n} - Cost(p, b, t) \tag{A.1}$$

where,

p = Rated PV capacity (kW_P)
b = Battery energy storage capacity (kWh)

$$Cash\ Flow(p, b, n, t) = Bills_{Base}(n, t) - Bills_{System}(p, b, n, t) \tag{A.2}$$

where,

Base is the cost of electricity without any PV or battery system; and
System is the cost of electricity with a particular PV battery system

The *Base* and *System* electricity costs for each n-th year from the t-th forecast year are given by:

$$Bills_{Base}(n, t) = E_{Import}(0,0, n)\cdot T_{Import}(n, t) - E_{Export}(0,0, n)\cdot T_{Export}(0, n, t) + 365\cdot T_{FNC}(n, t) \tag{A.3}$$

$$Bills_{System}(p, b, n, t) = E_{Import}(p, b, n)\cdot T_{Import}(n, t) - E_{Export}(p, b, n)\cdot T_{Export}(p, n, t) + \ + 365\cdot T_{FNC}(n, t) \tag{A.4}$$

where,

$$T_{Import}(n, t) = T_{Import\_Start}\cdot(1 + R_{Tariffs})^{n+t-2} \tag{A.5}$$

$$T_{Export}(p, n, t) = \begin{cases} T_{Export\_Start}\cdot(1 + R_{Tariffs})^{n+t-2}, & p \le P_{Export\_Limit} \\ 0 & , otherwise \end{cases} \tag{A.6}$$

$$T_{FNC}(n, t) = T_{RNC\_Start}\cdot(1 + R_{Tariffs})^{n+t-2} \tag{A.7}$$

The system cost is given by:

$$Cost\ (p, b, t) = p\cdot C_{PV\_Start}\cdot(1 + R_{PV})^{t-1} + b\cdot C_{Battery\_Start}\cdot(1 + R_{Battery})^{t-1} \tag{A.8}$$

The PV and battery configuration with the highest NPV in the t-th year is chosen (Criteria 2) according to the equation following, with the PV and battery capacities defined as p_c and b_c respectively:

$$Investment\ Decision(t) = Maximum\ [NPV\ (p, b, t)] \tag{A.9}$$

where,

$$0 \le p \le P^{*}\ and\ P'' = \begin{cases} 10\ kWP & , initial \\ P'\cdot(1 + 40\%) & , if\ Investment\ Choice(t) = (P', bc) \\ P' & , otherwise \end{cases} \tag{A.10}$$

$$0 \le b \le B^{*}\ and\ B'' = \begin{cases} 20\ kWh & , initial \\ B'\cdot(1 + 40\%) & , if\ Investment\ Choice(t) = (pc, B') \\ B' & , otherwise \end{cases} \tag{A.11}$$

Appendix B. Sensitivity analysis

B.1 Increasing the discount rate to 12% per annum

The discount rate used in the paper's case study is based on the 10-year historical average for owner-occupied standard variable mortgage home loans (RBA, 2018). Commercial entities require higher rates of return to justify an investment opportunity. Sensitivity analysis 1 evaluates a commercial perspective by raising the discount rate (R_d) from 6% to 12% (Table B.1) and presents the impact on network energy flows (Fig. B.1) and retailer revenues (Fig. B.2).

Table B.1
Sensitivity analysis 1 input parameters

Scenario	T_{Export_Start}	T_{Import_Start}	P_{Export_Limit}	R_d	$R_{Tariffs}$
S_1-FiT$_0$	0.0000 AUD/kWh	0.27 AUD/kWh	n/a	12%	5%
S_1-FiT$_{25}$	0.0675 AUD/kWh	0.27 AUD/kWh	5 kW$_P$	12%	5%
S_1-FiT$_{50}$	0.1350 AUD/kWh	0.27 AUD/kWh	5 kW$_P$	12%	5%
S_1-FiT$_{75}$	0.2025 AUD/kWh	0.27 AUD/kWh	5 kW$_P$	12%	5%
S_1-FiT$_{100}$	0.2700 AUD/kWh	0.27 AUD/kWh	5 kW$_P$	12%	5%

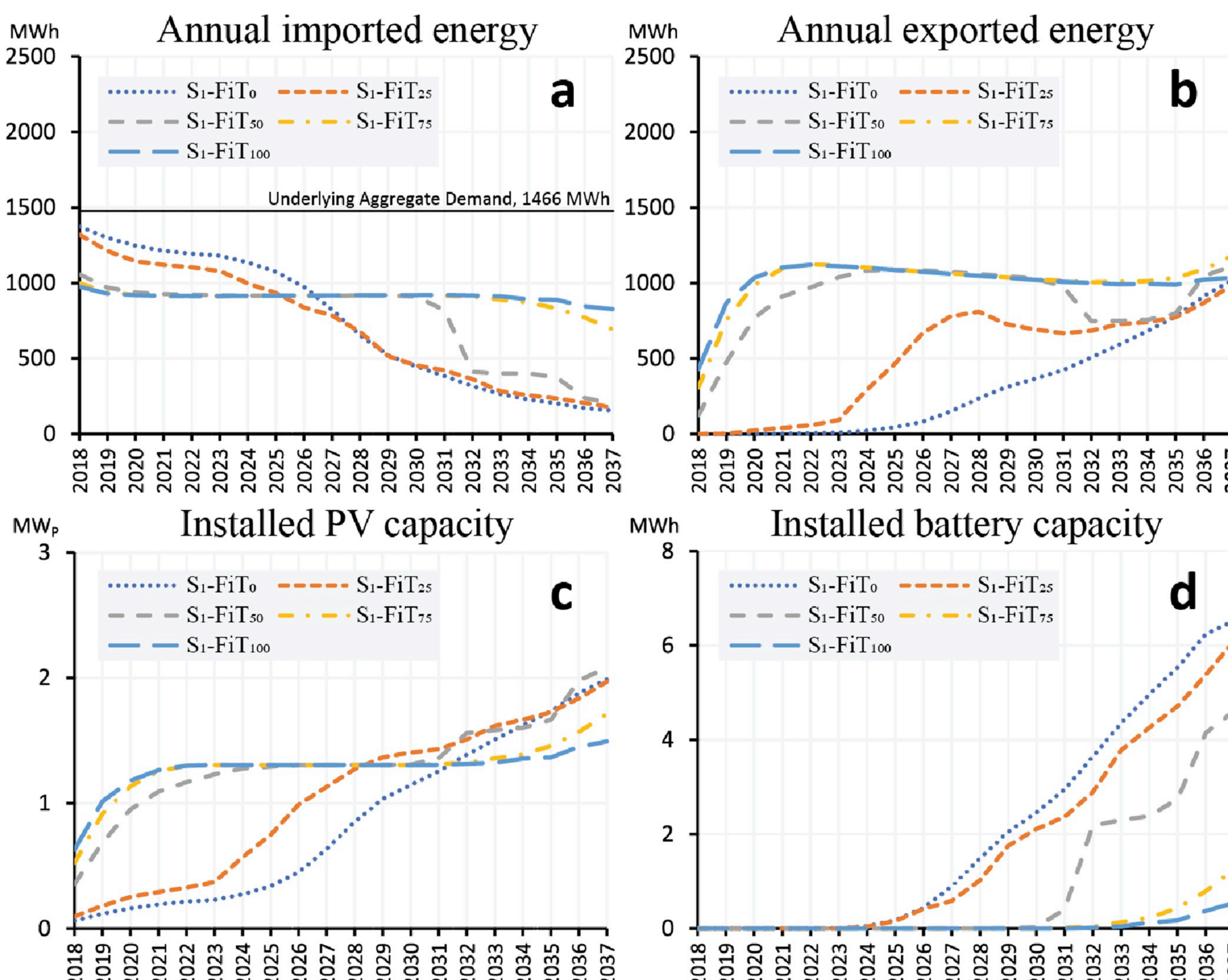

Fig. B.1. Projected import, export and cumulative installed capacity changes over 20 years (aggregate of 261 households) for each feed-in tariff scenario with a 12% discount rate. (a) Annual imported energy. (b) Annual exported energy. (c) Installed PV capacity. (d) Installed battery capacity.

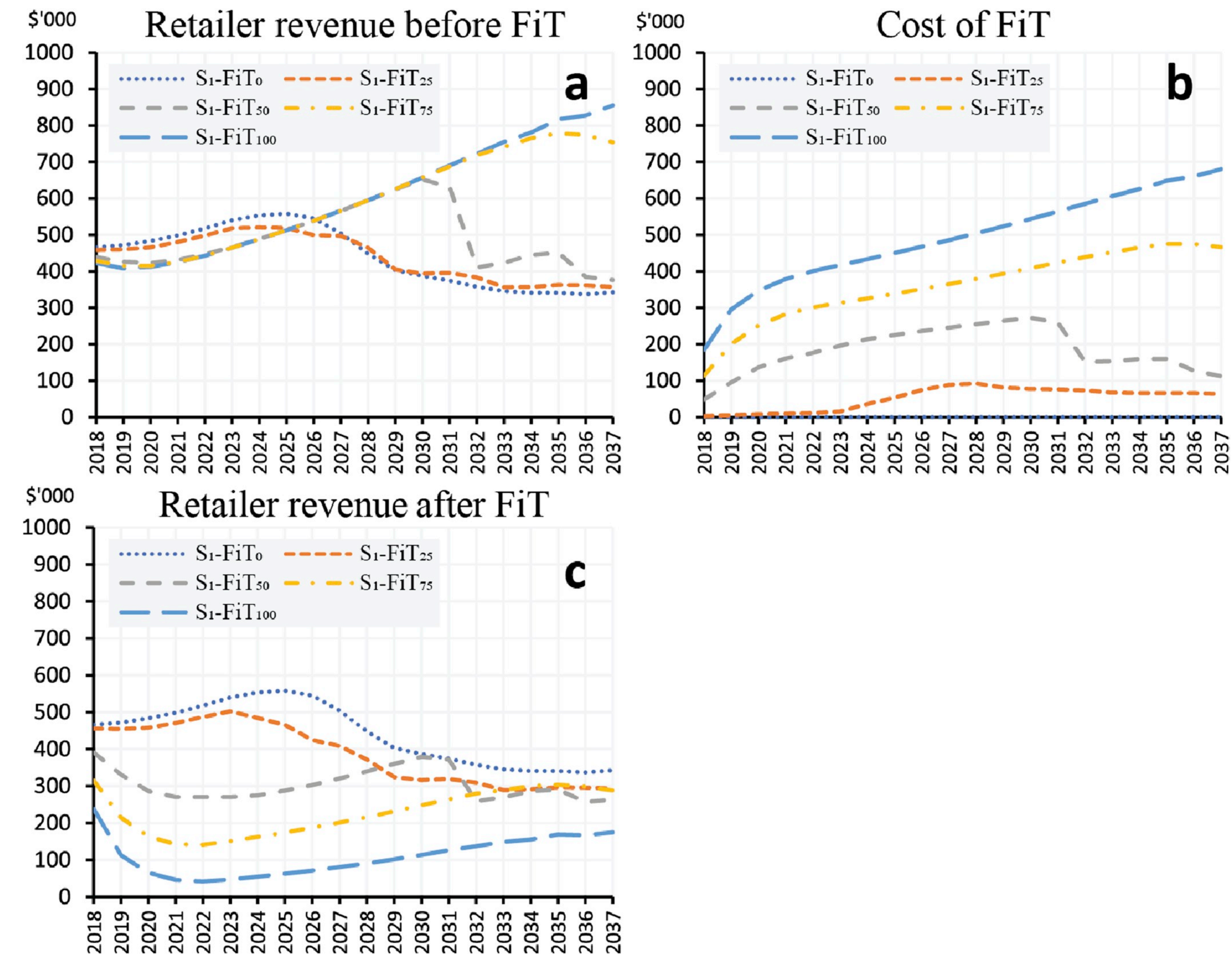

Fig. B.2. Projected changes to electricity retailer revenue over 20 years (aggregate of 261 households) for each feed-in tariff scenario with a 12% discount rate. (a) Retailer revenue before FiT. (b) Cost of FiT. (c) Retailer revenue after FiT.

B.2 Increasing tariff inflation to 10% per annum

Australian electricity prices have had two distinct growth rates since 1980, with an average increase of 5.07% per annum between 1980 and 2007 and an average increase 7.86% per annum between 2007 and 2018 (AGL, 2018). An average tariff inflation rate of 5% per annum is used in the case study, representing the pre-2007 rate of increase. Sensitivity analysis 2 evaluates the post-2007 rate of tariff increases with an average tariff inflation rate ($R_{Tariffs}$) of 10% per annum (Table B.2) and presents the impact on network energy flows (Fig. B.3) and retailer revenues (Fig. B.4).

Table B.2
Sensitivity analysis 2 input parameters

Scenario	T_{Export_Start}	T_{Import_Start}	P_{Export_Limit}	R_d	$R_{Tariffs}$
S_2-FiT_0	0.0000 AUD/kWh	0.27 AUD/kWh	n/a	6%	10%
S_2-FiT_{25}	0.0675 AUD/kWh	0.27 AUD/kWh	5 kW_P	6%	10%
S_2-FiT_{50}	0.1350 AUD/kWh	0.27 AUD/kWh	5 kW_P	6%	10%
S_2-FiT_{75}	0.2025 AUD/kWh	0.27 AUD/kWh	5 kW_P	6%	10%
S_2-FiT_{100}	0.2700 AUD/kWh	0.27 AUD/kWh	5 kW_P	6%	10%

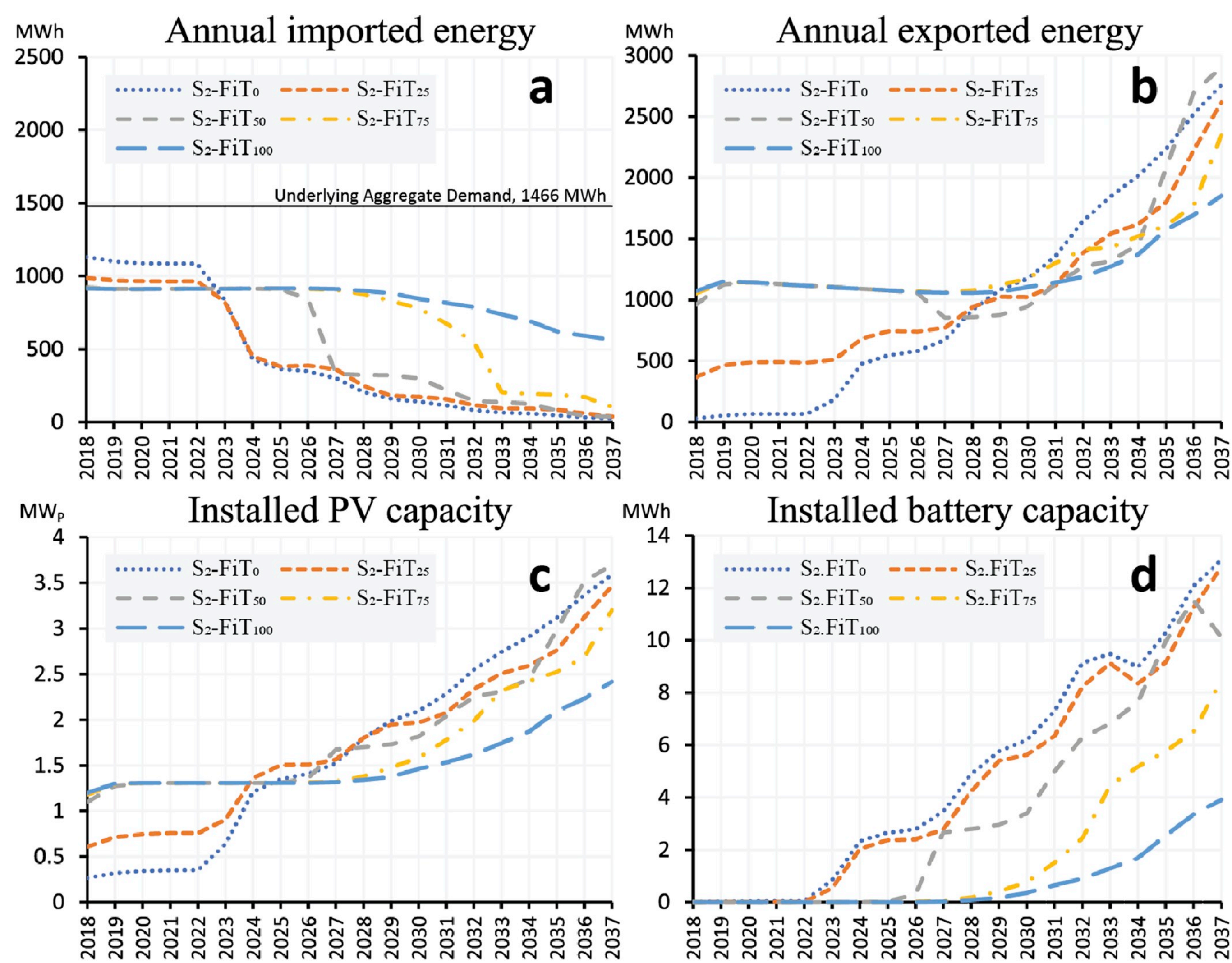

Fig. B.3. Projected import, export and cumulative installed capacity changes over 20 years (aggregate of 261 households) for each feed-in tariff scenario with a 10% tariff inflation rate. (a) Annual imported energy. (b) Annual exported energy. (c) Installed PV capacity. (d) Installed battery capacity.

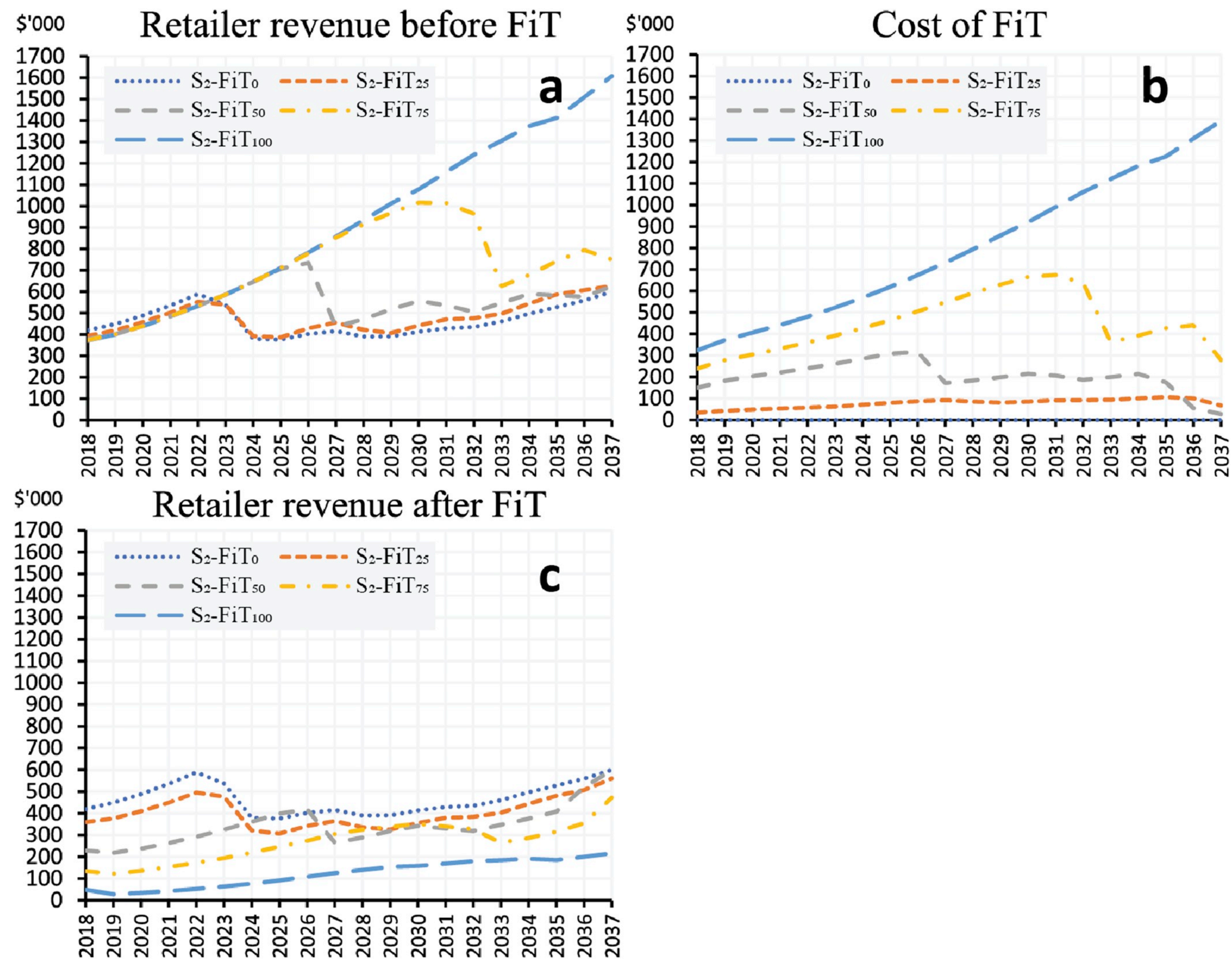

Fig. B.4. Projected changes to electricity retailer revenue over 20 years (aggregate of 261 households) for each feed-in tariff scenario with a 10% tariff inflation rate. (a) Retailer revenue before FiT. (b) Cost of FiT. (c) Retailer revenue after FiT.

Appendix C. Characteristics of the underlying household demand and projected PV and battery installation capacities

The underlying aggregate demand was obtained from real-world gross utility-meter data from 261 individual households in Sydney, Australia between 2012 and 2013 (Ausgrid, 2018). The data consists of 261 individual demand profiles and 261 individual solar insolation profiles with an average annual household consumption of 5.62 MWh and average PV capacity factor of 14.8% (Fig. C.1). These characteristics are consistent with the case study location of Perth, Australia that has an average annual household consumption of 5.83 MWh (ABS, 2013) and average PV capacity factor between 14.1% (NREL, 2018) and 15.8% (AEMO, 2018b). Sydney's publicly accessible utility gross-energy meter data was used since state privacy laws in Perth prevent the public release of household consumption and generation data. Furthermore, as utility net-energy meters are predominantly installed in the Perth region, separated underlying demand and PV generation timeseries data are not available from the existing smart meter infrastructure.

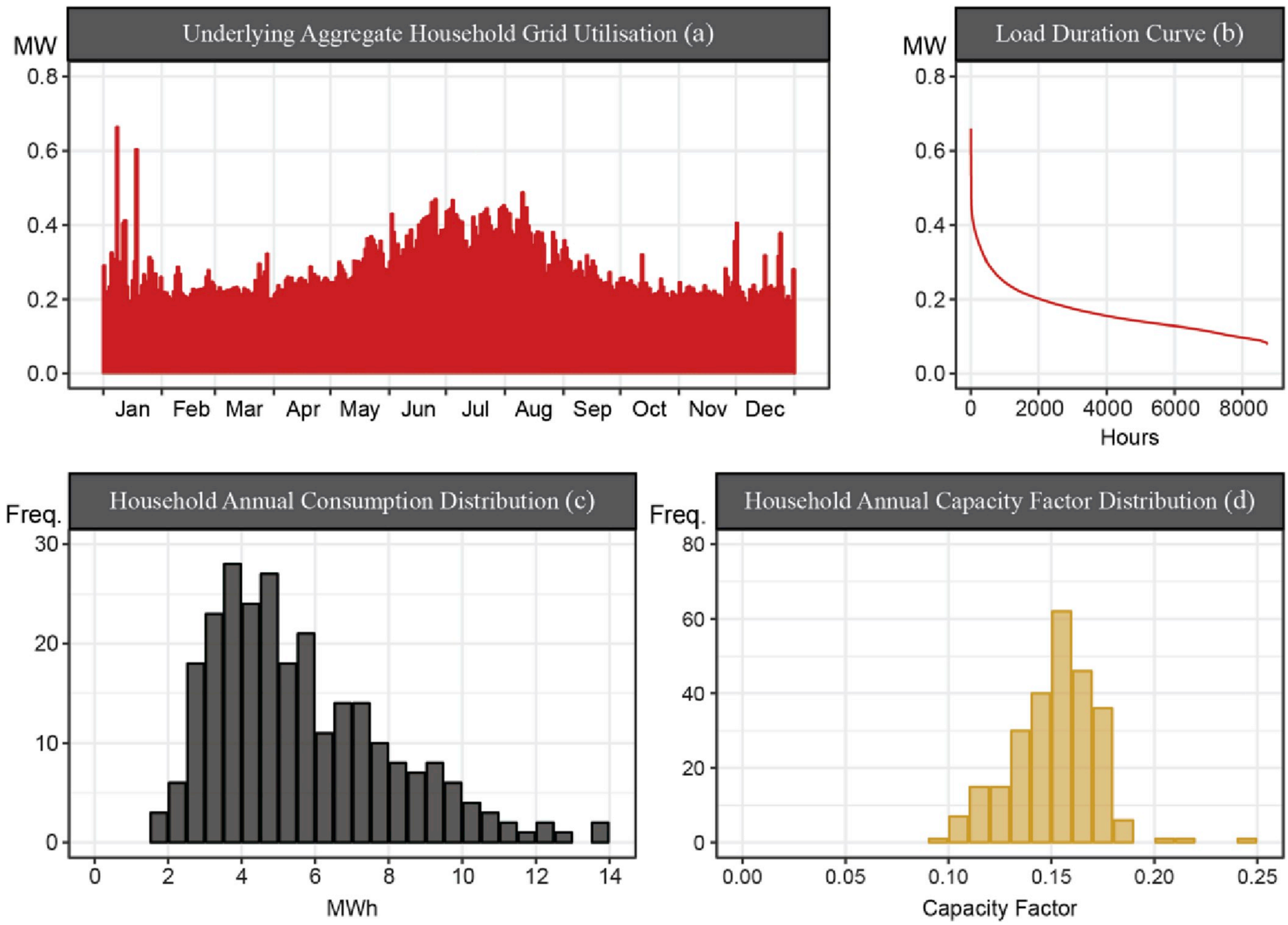

Fig. C.1. Characterisation of underlying household demand profiles. (a) Half-hourly grid utilisation (aggregate of 261 households) of the underlying demand. (b) Load duration curve of the aggregate underlying demand. (c) Distribution of annual underlying consumption of the 261 households. (d) Distribution of the household annual solar capacity factor.

The distribution of total installed PV and battery capacity for each individual household, across each scenario and for each year of the simulation, is used to illustrate the types of systems installed across all 261 households (Fig. C.2).

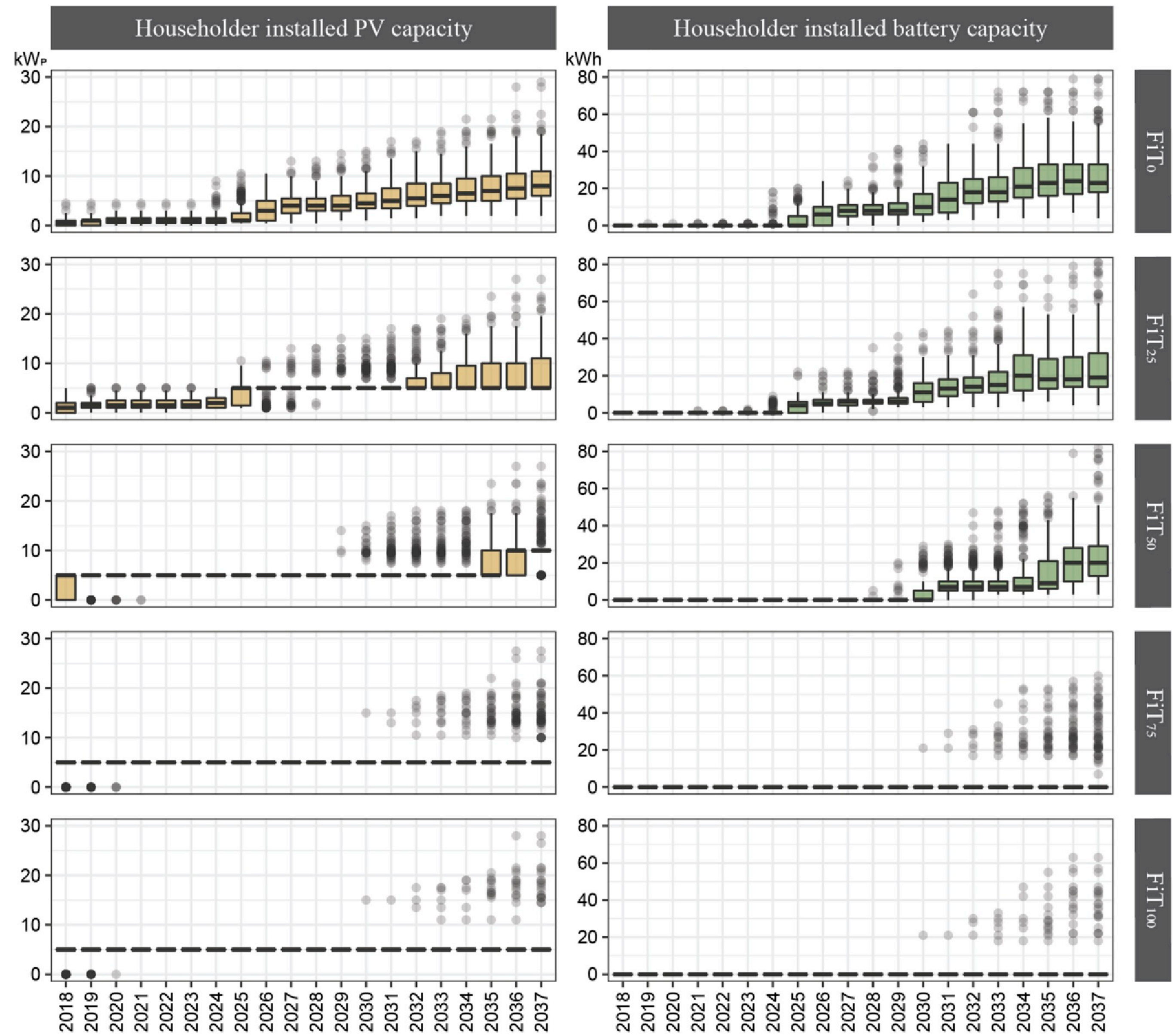

Fig. C.2. Projected distribution of 261 household PV and battery installation capacities for each FiT scenario in the case study.

Appendix D. Research data

The R source code, demand profile data, insolation data and computational results are publicly accessible from https://doi.org/10.25917/5bf501113063f.

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Appendix 3 – Paper 3

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Statement of Contribution

I, Kelvin Guisen SAY, contributed to the 60% of the paper/publication entitled:

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Specifically, I contributed to the following:

Conception and design, acquisition of data and method, data conditioning and manipulation, analytical method, interpretation and discussion, and final approval

Signature of candidate: **Date: 10 November 2021**

I, as a Co-Author, endorse that this level of contribution the candidate indicated above is appropriate.

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Degrees of displacement: The impact of household PV battery prosumage on utility generation and storage

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HIGHLIGHTS

- Power sector effects in WA of household PV battery systems using open-source models.
- Household PV mainly substitute utility PV, slightly reduced with household batteries.
- Wind power is less affected, especially in scenarios with higher shares of renewables.
- Household batteries hardly substitute utility storage if maximising self-consumption.
- Prosumage decreases average wholesale prices for households and increases for others.

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Abstract: Reductions in the cost of PV and batteries encourage households to invest in PV battery prosumage. We explore the implications for the rest of the power sector by applying two open-source techno-economic models to scenarios in Western Australia for the year 2030. Household PV capacity generally substitutes utility PV, but slightly less so as additional household batteries are installed. Wind power is less affected, especially in scenarios with higher shares of renewables. With household batteries operating to maximise self-consumption, utility battery capacities are hardly substituted. Wholesale prices to supply households, including those not engaging in prosumage, slightly decrease, while prices for other consumers slightly increase. Given the power sector repercussions modeled here, we conclude that the growing adoption of prosumage needs to be carefully considered by power system planners and investors of long-lived utility-scale renewable generation and storage assets to prevent overinvestment. Likewise, regulators should encourage greater system-oriented use of battery flexibility from prosumagers in the energy transition.

1. Introduction

To mitigate the effects of climate change it is necessary to take advantage of renewable energy sources and decarbonise energy use [1]. Continued investments in research and development as well as the massive deployment of renewable energy technologies has reduced the Levelised Costs of Energy of PV and wind power in many regions to or below those of conventional fossil fuel generation [2–4]. These ongoing cost reductions have not only changed how utilities generate their electricity, but have also opened new opportunities for electricity customers [5]. In combination with favourable regulatory settings, it has become increasingly attractive for households to install their own PV systems in many countries. This not only allows households to reduce their electricity bills but also decarbonises their energy consumption [6].

A similar transition is occurring in the lithium-ion battery sector with global manufacturing capacity expanding to supply the expected growth in the battery electric vehicle market [7]. This is driving significant cost reductions, which are expected to continue decreasing at a lower rate over the next 20 years [8–10]. These battery cost reductions have led to a growing number of utility and domestic-scale battery installations in electricity markets worldwide [11–13]. By storing excess PV generation for later use, PV-battery systems enable households to increase their overall share of self-generation. This concept, referred to as prosumage [14–16], can also significantly reshape grid consumption and retailer revenues [17].

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Australia currently leads the world in household PV adoption. The substantial existing PV capacity situated behind-the-meter raises the potential for an accelerated PV-battery transition, especially as the financial benefits from PV-battery systems begin to outweigh PV-only systems. While PV-only and PV-battery systems are both considered as behind-the-meter Distributed Energy Resources (DER), their grid utilisation and economic drivers considerably differ and require more detailed analysis. The term prosumage, in this paper, covers both household PV-only and PV-battery adoption.[1]

In this paper we aim to quantitatively explore the influence that residential PV systems with or without batteries could have on the power sector, in particular on utility-scale generation and storage technologies. We do so by applying two soft-coupled open-source models to 2030 scenarios in the South West Interconnected System (SWIS) located in Western Australia. This serves as a particularly suitable case study, as household PV penetration rates here are amongst the highest in the world [18] and household PV-battery installations are also beginning to rise [19]. As it is an island network,[2] the power sector effects from prosumage become evident earlier than in larger and interconnected networks. Firstly, we use a techno-economic simulation model of household prosumagers, *Electroscape* [20], in which a set of heterogeneous households are driven by economic self-interest to invest in additional PV and battery capacity while retail price conditions change under different Feed-in Tariff (FiT) values. By using these households as representatives for the segment of customers investing in prosumage, we quantify the changes to the 'residual network demand', also known as 'operational demand' [21] or 'net load' [22]. This serves as an input for a dispatch and investment model, which determines cost-minimal utility-scale generation and storage capacity while meeting different exogenous renewable energy targets.

This paper is structured as follows: Section 2 presents a literature review. Section 3 introduces the underlying methodology and modelling framework. Section 4 describes the case study and input data. Section 5 presents the results and discusses its wider implications on the power sector. Section 6 highlights the limitations of the study and the qualitative impacts of key assumptions on results. Section 7 concludes with policy implications and avenues for future research.

2. Literature review

With household PV-only systems, the timing of all self-generation is tied to the sun without the ability to store and buffer energy. This means that changes in residual grid consumption begin to coincide with other households, thus driving observable grid demand patterns such as the 'duck curve' [23,24]. The use of energy storage, changes the level of coincidence by making excess PV generation available for later use and increasing the system's sensitivity to the type of economic incentives and differences in household demand. This not only changes the overall residual grid consumption, but also the effectiveness of existing FiT policies to guide PV battery adoption [25,26].

By adopting battery storage, households become technically capable of providing further services to the rest of the power sector. Since the supply and demand of energy must always be in balance, spare household battery capacity could be used as a form of dispatchable load or generation to provide quantifiable system benefits [27,28]. However the use of time-invariant volumetric residential tariffs remains common in many regions, including Australia [29,30], Europe [31], UK [32], and China [33]. The time-invariant nature of these tariffs do not give households an incentive to consider wholesale market price signals when operating their PV battery systems, thus leaving increased PV self-consumption as the largest financial incentive for households to invest in PV battery capacity [34].

At the household-scale, techno-economic models and electricity bill savings are commonly used to determine the appropriate sizing of household PV-battery systems. Using project finance metrics, such as Net Present Value (NPV) [35,36], Internal Rate of Return [37] and Discounted Payback Periods [38], optimal system capacities can be calculated. At the utility-scale, techno-economic models are commonly used for long term energy planning and renewable energy integration. Using numerical optimisation, many different objectives can be evaluated, such as least-cost utility-scale renewable energy portfolios [39], coordinating renewable generation, network and storage expansion [40], through to establishing optimal utility-scale energy storage capacities [41]. The objectives of these household and power sector models differ, with households aiming to reduce electricity bills, and power sector models aiming to reduce the overall cost of supplying energy. As both perspectives interact and depend on one another, electricity system planners must consider how customers in the future affect electricity markets [42] and its subsequent evolution. However, there remains a gap in the literature that resolves the complexity and optimisation across these perspectives [43]. We aim to contribute to filling this gap with this analysis. A range of methods have been previously used, from system dynamics [44] and agent-based models [45] to least-cost pathways [46] and dispatch and scenario modelling [47]. The combination of household and utility-scale perspectives remains rare in the literature, but by coupling their analyses using the dispatch and modelling approach, we are able to evaluate interdependencies between the policy and economic trade-offs within each of their respective scales.

This paper uses two open-source models to link household PV battery investment decisions and optimal utility-scale generation and storage decisions from a social planner perspective. A counterfactual comparison is used to provide quantitative insights into the range of utility-scale system impacts from household prosumage, including generation and storage capacities, their dispatch and wholesale price impacts. With an islanded network and liberalised electricity market, the Western Australian context allows the derivation of relatively undistorted insights into the effects of prosumage. Given the real-world conditions that are currently driving Western Australia's significant household PV and growing battery adoption, these scenario analyses provide a front-runner case of what other markets could expect in the future. Moreover, the development and provision of the two open-source models also contribute to the literature by providing transparency and enabling reproducibility for subsequent research.

3. Methods

3.1. General setup

We soft-link two open-source techno-economic models to represent the differing objectives between PV battery investing prosumage households and central planner investments in utility-scale generation and storage capacity (Fig. 1). The first model *Electroscape* reflects the financial objectives of prosumage households as retail conditions change over time. These households consider investing annually in PV and battery systems, given exogenous assumptions on retail price conditions, installed system costs and three FiT scenarios (0%, 25%, 50% of volumetric usage charges) between 2019 and 2030. The second model *DIETER-WA* adopts a central planner perspective for the overall power sector, i.e., it determines least-cost utility-scale investment and dispatch decisions over a range of locally available technologies in 2030. *DIETER-WA* uses outcomes from *Electroscape* and its three FiT scenarios to also assess the additional impact of varying the Renewable Energy Source (RES) share between 39%, 49%, and 59% of gross

[1] We slightly expand the narrower definition of prosumage used in [16] to avoid lengthy verbal differentiations when describing results for PV-only and PV-battery cases.

[2] Island networks face more challenges in matching variable renewable energy supply with demand compared to interconnected networks, as they lack the ability of balancing over larger regions.

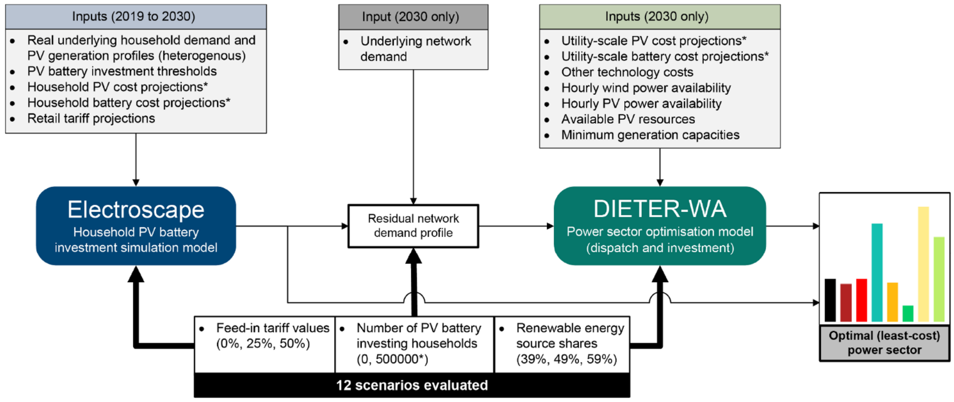

Fig. 1. Developed methodology that integrates household prosumage and utility-scale investment and dispatch decisions. Starred parameters are varied in sensitivity analyses.

electricity demand, where 49% is a linear interpolation between Australia's 2020 renewable energy target of 23.5% [48] and an assumed 100% target for 2050.[3] By comparing each of these results against reference counterfactual scenarios (without household PV battery investments) the effects of household prosumage on the overall system are quantified and separated.

Both models are soft-linked through an hourly time series of the residual network demand profile and household prosumage investments. *Electroscape* is solved annually for each of the FiT scenarios between 2019 and 2030 to determine the resulting net grid utilisation profile in the year 2030 for each individual prosumage household. These profiles are normalised and scaled to an assumed number of 500,000 prosumage households, which builds on the independent system operator's PV installation estimates for 2030 [50]. By subtracting the net grid utilisation changes from prosumage households from actual SWIS network demand data [51], we determine the overall impact of household PV and battery investments on the residual network demand. To isolate the effect of prosumage household investments, all other customers of the SWIS electricity network are assumed to consume the same amount of energy each year without investing in self-generation or energy efficiency.

3.2. Household PV battery investment modelling (Electroscape)

To determine PV battery investment decisions for residential households, *Electroscape* [20] uses the time-series of underlying household demand and insolation profiles with projections of retail tariffs, FiTs and PV battery installation costs and takes into consideration previous PV battery investments. By evaluating households individually and with real-world energy meter data, the model avoids biases that can be introduced when using aggregated or synthesised data [52,35]. This model was first introduced in [53] and subsequently used to evaluate the relationship between household PV battery investments and future electricity retailer revenues [20]. The model is implemented in R with its source code and data available under permissive open-source license [54].

Assuming that prosumage households are economically rational, the model starts in the first year without any previous PV battery systems installed and simulates the installation of each and every PV and battery combination (using a step size of $0.5\ kW_P$ and $1\ kWh$ respectively) on a household's underlying demand to determine the net grid utilisation and annual electricity bills. By comparing against a 'no installation' case, the expected savings in electricity bills are calculated and form the basis of a discounted cashflow for each and every combination. This model assumes a fixed investment horizon and uses Net Present Value (NPV) to compare each PV battery configuration as competing investment opportunities. The configuration with the highest NPV becomes a prime candidate for installation, pending a real options valuation [55] based on Discounted Payback Periods (DPPs),[4] the model determines if sufficient financial returns can be realised to warrant making an actual investment. If an investment is made, the underlying household demand is updated, and subsequent PV battery investments must now consider these newly installed systems. Repeating this process annually allows *Electroscape* to simulate sequential and lumpy PV battery investment behaviour (i.e., retrofitting existing PV with battery-only systems, or installing additional PV with a larger battery capacity) that reacts to changing retail conditions, namely retail tariffs, FiTs and PV battery installation costs. The model provides the means to model PV battery investment choices catered to the energy use and solar resources of individual households. By applying *Electroscape* across a set of real and heterogeneous household data, the normalised results are able to provide an approximate of the net grid utilisation from an average prosumage household.

3.3. Power sector dispatch and investment modelling (DIETER-WA)

To investigate the power sector effects of increased prosumage, we devise the open-source model *DIETER-WA*. It represents a simplified and adjusted version of the dispatch and investment model *DIETER*, which has been first introduced by [56]. The model has a long-run equilibrium perspective and minimises the total cost of utility-scale electricity generation for all subsequent hours of a whole year. Its results may be interpreted from a central planner perspective, or as an outcome of a frictionless market with perfect competition. The model assumes perfect foresight and is solved for all consecutive hours of an entire year. It is implemented in the General Algebraic Modelling System (GAMS). Source code and input data are available under a permissive license [57].

The model's objective function covers operational costs which consist of fuel and other variable costs, as well as annualised investment costs of all utility-scale generation and storage technologies. An energy balance ensures that electricity supply satisfies demand in each hour. Generation technologies comprise both dispatchable thermal and variable renewable generators. The model is also capable of representing various energy storage technologies and their respective intertemporal restrictions. In the model version used here, we ensure that a specified share of yearly gross electricity demand is met by renewable energy sources, including household PV installations.

Model inputs comprise specific fixed and variable costs of all

[3] Based on Australia's commitment to the COP21 Paris Agreement [49].

[4] The DPP is used to publicly track potential PV system financial performance in Australia [19] which is mirrored in this model.

technologies, hourly renewables availability factors, as well as the residual network demand profile, which considers the net grid utilisation profiles of prosumage households determined by *Electroscape*. Prosumage PV and battery investments also enter as exogenous inputs. Endogenous variables include investments in utility-scale generation and storage technologies and their hourly use. Further model outputs comprise the total cost of providing electricity and the shadow prices of the energy balance equation, which we interpret as wholesale prices.

4. Case study and input data

4.1. Western Australia as a prosumage front-runner

High levels of solar insolation, relatively high volumetric retail tariffs [58], and residential FiT policies[5] have resulted in over 2 million Australian households (or 20% of all free-standing households) installing solar PV systems [18]. As of the end of 2018, combined household PV capacity (7 GW_P) accounted for 62% of the nation's installed solar PV capacity [18]. The SWIS network[6] in Western Australia is similarly affected with household PV penetration rates above 27% [19,18]. The collective household PV capacity already exceeds the largest utility-scale generator on the network (854 MW) and is expected to more than double to 2 GW_P in 2030 [50]. In 2019, behind-the-meter PV has already been recorded supplying 45% of the underlying network demand [60]. With discounted payback periods falling below 5 years [19], household PV installations are expected to continue rising [61]. These behind-the-meter household PV systems (that are neither centrally monitored or controlled) are no longer insignificant and have begun to reshape residual network demand and system operation [62,63,60]. The inability to control DER systems behind-the-meter [62] effectively grants household generation the highest dispatch priority on the network, followed by zero-marginal cost and non-dispatchable utility PV and wind, then conventional baseload and peaking generation.

As battery energy storage costs decrease [10], both utility [64] and household [65] installations have begun to rise in Australia and abroad [13]. From 2015 onwards, Australian household battery adoption has increased year-on-year and is expected to continue growing at an accelerated rate [19,50]. As installed PV and battery capacities grow within the islanded SWIS network, prosumage households in the future could have considerable influence on the optimal mix of remaining utility-scale generation and storage technologies. Hence, the input data and assumptions have been chosen to reflect the local conditions in the SWIS network.

4.2. Input data for Electroscape

The main input parameters and data used in *Electroscape* are summarised in Table 1.

One year of real utility energy meter measurements of half-hourly resolution 'underlying household demand' and 'insolation' profiles are used to establish an average representative prosumage household within the SWIS network. This data was collected from 300 households in Sydney, Australia between 1st July 2012 and 31st June 2013 [73,74] and has been used in other Australian electricity market studies [75–78]. Due to similar latitudes and climate conditions, the average annual consumption and PV generation profiles in Sydney remain consistent with those of Perth, Australia (which is the primary source of residential demand in the SWIS network). After removing households with missing time series data, 261 households remain for analysis. Data from Sydney households was necessary as strict privacy laws prevent SWIS household data from being publicly available.

The battery model is based on lithium-ion residential systems designed for PV applications, similar to those sold by Tesla,[7] LG Chem,[8] and Sonnen,[9] with a round-trip efficiency of 92% and 70% storage capacity remaining at the end of a 10-year operational lifespan. A fixed energy-to-power ratio of 2. 5 is used based on the average of these residential battery systems. Battery systems cost reduction curves are derived from [10] and have been scaled with a factor of 0.73 to fit local price conditions [71].

The PV generation model assumes a 25-year operational lifespan with 80% generation capacity remaining. We assume a financial investment horizon of 10 years, reflecting expectations that homeowners typically require profitability before moving to another residence.[10] We further assume that households extend their home mortgage to access financial capital and a discount rate of 5% is used, consistent with the average standard variable home mortgage interest rate over the last 5 years [69]. PV cost reduction curves are derived from [72] and have been scaled with a factor of 0. 78 to fit local price conditions [70].

Corresponding to 2019–20 SWIS retail tariffs, volumetric usage charges begin at 0. 29 AUD/kWh [66] and increase at 4% per annum, based on the average annual growth rate of Australian electricity prices over the previous 10 years [67]. The real options evaluation requires that at least one investment opportunity has a Discounted Payback Period of under 5 years for an investment to be made.

The value of the FiT plays a significant role in incentivising various configurations of household PV battery systems,[11] thus three FiT scenarios are evaluated using time-invariant FiTs valued at 0%, 25% and 50% of volumetric usage charges (i.e., it only applies to the quantity of excess PV generation exported to the network). This range is consistent with Australian retail FiTs in 2019 [80]. As is standard practice to maintain hosting capacity on the SWIS network [68], a 5 kW_P FiT eligibility limit is used, such that PV systems above 5 kW_P lose all excess PV generation payments.[12]

4.3. Input data for DIETER-WA

The residual network demand profile used in *DIETER-WA* is derived from SWIS network demand data provided by [51] combined with the scaled net grid utilization of prosumage households as determined by *Electroscape*. Historical time series of hourly wind power availability in the SWIS are provided by [82]. To ensure utility-scale PV generation remains temporally consistent with household PV generation, the utility PV availability profile equals the average PV generation across each of the 261 households.

As for conventional utility-scale generation technologies, we include coal- and natural gas-fired plants, i.e., combined cycle gas turbines (CCGT) and open cycle gas turbines (OCGT), as well as bioenergy, onshore wind power, and utility PV. We further allow for investments in utility-scale batteries and hydrogen storage.[13] Key techno-economic

[5] The FiT is only applied to the amount of excess solar PV energy generated after subtracting the customer's underlying electricity demand. Australian FiTs are typically valued well below volumetric retail tariffs [19]. FiT payments are funded by electricity retailers and revised annually (as opposed to fixed-term contracts) [59].

[6] The SWIS network has a typical peak demand of 4.4 GW and 18 TWh of annual operational consumption [50].

[7] https://www.tesla.com/en_AU/powerwall

[8] https://www.lgenergy.com.au/products/battery

[9] https://sonnen.com.au/sonnenbatterie/

[10] 10.5 years is the typical duration that a home is owned before being sold [79].

[11] Generally higher FiTs accelerate the adoption of PV but delay the cost-effective tipping point of PV-battery systems. While lower FiTs initially reduce PV adoption, it also brings forward the tipping point for PV-battery systems that simultaneously drive further growth in additional PV capacity [20].

[12] On other Australian networks, special approval is typically required to connect PV inverters greater than 5 kW to the grid [81].

[13] Under the parameterisation used here, we find that bioenergy and 'power-to-gas-to power' hydrogen storage are never part of the least-cost portfolio. We accordingly do not report on these technologies in the following.

Table 1
Input parameters and data used in *Electroscape*.

Input parameter	Unit	Values	Source
Scenario forecast period	years	12	Own assumption
Simulation time step	minutes	30	Own assumption
Financial horizon	years	10	Own assumption
DPP evaluation criteria	years	5	Own assumption
Initial PV evaluation range	kW_P	0–10	Own assumption
Initial battery evaluation range	kWh	0–18	Own assumption
Battery energy-to-power ratio	ratio	2.5	Own assumption
Initial FiT rebate	AUD/kWh	0–14.5	Own assumption
Initial volumetric usage charges	AUD/kWh	0.29	[66]
Yearly change in tariff charges/rebates	%	4	[67]
FiT eligibility limit	kW_P	5	[68]
Yearly discount rate	%	5	[69]
Initial installed PV system cost (residential)	AUD/kW_P	1292	[70]
Initial installed residential battery system cost	AUD/kWh	1172	[71]
PV cost reduction curves	AUD/kW_P	Time series	[72]
Battery cost reduction curves	AUD/kWh	Time series	[10]
Number of unique household profiles	household	261	[73]
Underlying household demand profile (per household)	Wh	Time series	[73]
Household available insolation profile (per household)	Wh	Time series	[73]

input parameters for these technologies are summarised in Table 2.[14] We ensure that both utility-scale and household PV and battery storage technologies utilise the same relative cost reduction curves mentioned in Section 4.2. We also include a lower bound for wind power and utility PV investments corresponding to the capacity already in place [83].

5. Results and discussion

5.1. Changes in residual network demand from investments in PV battery prosumage

Investments by prosumage households in PV and battery capacity are heavily influenced by the value of the FiT (Fig. 2). Higher FiTs provide greater returns for excess PV exports, encouraging larger PV systems (up to the 5 kW_P FiT eligibility limit), while lowering returns for self-consumption and discouraging the use of battery energy storage. As a result, the scenario with a FiT equalling 50% of volumetric usage charges drives all 261 households by 2030 to invest in 5 kW_P PV systems with no battery storage. As the value of the FiT lowers, the value of self-consumption increases and the cost-effectiveness of battery storage is improved. In the scenario with a 25% FiT, the increased value of self-consumption results in 7.3% of households (with above average electricity consumption) foregoing their FiT revenue and installing PV systems above the 5 kW_P FiT eligibility limit. This raises the average PV capacity per household to 5. 3 kW_P with 5. 9 kWh of accompanying battery storage. In the scenario without a FiT (or 0% FiT), the lack of financial incentive to export excess PV generation discourages excessively large PV systems while maximising the value of household self-consumption. This results in households investing in slightly smaller PV systems but with even larger battery capacities. The overall average PV capacity per household is 4. 7 kW_P with 8. 7 kWh of accompanying battery storage.[15]

Each of the FiT scenarios (0%, 25%, 50% of volumetric usage charges) results in different average configurations of PV battery systems. To assist with readability, these three FiT scenarios will be respectively referred to as the 'PVB + FiT_0', 'PVB FiT_{25}' and 'PV-only FiT_{50}' scenarios.

The installed PV battery systems affect residual network demand by removing a household's load from the network (during self-consumption) and acting as a negative load (during excess PV exports). In the reference case without household PV battery investments, the annual residual network demand is 18. 1 TWh. Normalising the 261 households evaluated in *Electroscape* to a single representative household and then scaling to 500, 000 households leads to the following reductions in annual residual network demand. In the 'PV-only FiT_{50}' scenario, with an average of 5 kW_P of PV and no batteries, the annual residual network demand is reduced to 15. 1 TWh (or − 16. 7%). In the 'PVB FiT_{25}' and 'PVB + FiT_0' scenarios, the annual residual network demand is respectively reduced to 14. 7 TWh (− 17.9%), and 15. 2 TWh (− 15.6%). Since household PV generation is either self-consumed, exported, or time shifted (minus round-trip efficiency losses), these annual residual network demand reductions are predominantly driven by installed household PV capacity.

While annual residual network demand does not significantly differ between the FiT scenarios, their influence becomes much more evident at the diurnal scale (Fig. 3). Generally, the minimum residual network demand each day begins to occur increasingly over midday due to the timing of excess PV generation. Potential reductions in the early evening peak depend upon the presence of a battery system. In the 'PV-only FiT_{50}' scenario, the peak residual network demand is delayed until sunset. In absolute terms, the diurnal peak demand can only be reduced slightly, and only during the summer months with long daylight hours. In the 'PVB FiT_{25}' and 'PVB + FiT_0' scenarios, the household battery systems (that operate only to maximise self-consumption) are able to reduce peak residual network demand more strongly, and for a longer period of time. As it uses the PV generation stored during the day, larger battery systems (for a similar PV capacity) lead to a greater reduction of midday PV exports, thus reducing the down ramp of demand between the morning and midday, and the up ramp between midday and the early evening (comparing 'PVB + FiT_0' and 'PVB FiT_{25}' in Fig. 3 with 'PV-only FiT_{50}').

5.2. Impacts on optimal utility-scale generation and storage capacity

In the reference '39% RES share' scenario (i.e., without prosumage household investments), 1. 16 GW_P of utility PV and 1. 61 GW of wind power are optimal, along with relatively small utility battery storage of 0. 21 GW and 0. 62 GWh (Fig. 4, upper left panel). As the RES share rises to 59%, utility PV and wind capacity increases to 1. 95 GW_P and

[14] The complete input data is available in the open-source spreadsheet provided with the model.

[15] Similar effects should be observed in other regions where FiTs and retail tariffs share similar proportions and remain time-invariant. As markets mature, there is a trend towards lower FiTs, which are reflected in the chosen FiT scenarios. Qualitatively similar outcomes have also been found to apply in other countries, e.g., Germany [25].

Table 2
Input parameters and data used in *DIETER-WA*

Input parameter	Unit	Hard coal	CCGT	OCGT	Bioenergy	Wind power	PV	Li-ion storage	Hydrogen storage	Source
Overnight investment costs	AUD/MW	3,195,000	1,254,000	877,000	12,432,000	1,874,000	817,000	115848	2384615	[72,10,84]
Overnight investment costs (energy)	AUD/MWh	–	–	–	–	–	–	173773	308	[10,84]
Annual fixed cost	AUD/MW	53200	10500	4200	131600	36000	14400	2027	16694	[72], own assumptions
Variable OM costs	AUD/MWh	4.2	7.4	10.5	8.4	2.7	0	0.5	0.5	[72], own assumptions
Thermal efficiency or roundtrip efficiency	%	40	48	31	23	–	–	92	41.9	[72,84]
Fuel costs	AUD/MWh$_{th}$	12.06	31.68	31.68	4.5	0	0	–	–	[72]
Technical Lifetime	years	25	25	25	25	25	25	15	22.5	[72,84]
Lower bound for investment	MW	0	0	0	0	419	202	0	0	[83]

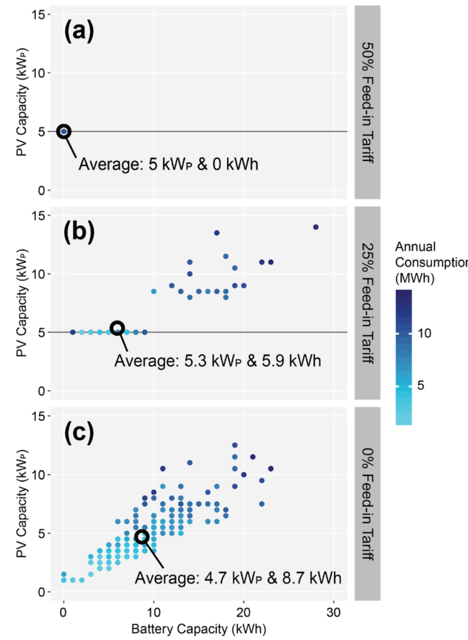

Fig. 2. Individual and average installed PV and battery capacities for each FiT scenario in the year 2030. (a) FiT valued at 50% of volumetric usage charges, if ⩽ 5 kW$_P$. (b) FiT valued at 25% of volumetric usage charges, if ⩽ 5 kW$_P$. (c) Without any FiT.

2. 45 GW respectively, while conventional generation capacity is reduced. The capacity of utility batteries raises disproportionately to 0. 62 GW and 1. 72 GWh.

In the scenarios with prosumage, however, household PV capacity generally substitutes for utility-scale renewable energy generation capacity. The nature of this substitution depends upon the FiT values that incentivise different types of household PV-only or PV-battery investments that subsequently impact the timing of excess PV exports and the required contribution of utility-scale generation to the RES share.

In the 'PV-only FiT$_{50}$' scenario and across each RES share, utility PV experiences the largest reduction in capacity. Here, the cumulative PV capacity of PV-only prosumage households (2. 50 GW$_P$) causes utility PV capacity to drop to the assumed lower bound of 202 MW$_P$. In the 39% RES share scenario, each MW$_p$ of household PV substitutes for 0. 38 MW$_P$ of utility PV and 0. 20 MW of wind capacity, respectively. By generating at similar times, household PV capacity generally discourages additional utility PV capacity. As the RES share rises, relatively more utility PV and less wind power are substituted, as the respective utility-scale PV capacity in the reference is also larger. In the 59% RES share scenario, each MW$_p$ household PV accordingly substitutes for 0. 70 MW$_P$ of utility PV and only 0. 08 MW of wind power. The significant installed household PV capacity and absence of installed household battery systems in 'PV-only FiT$_{50}$' also causes an increase of optimal utility battery power and energy storage capacity. This is because the increase in overall PV capacity and the corresponding decrease in wind power leads to larger diurnal variations between the midday and early evening residual network demand (compare Fig. 3). This effect is particularly strong in the 39% RES share scenario, which has the highest PV capacity share, with 0. 12 MW and 0. 55 MWh of additional utility battery capacity per MW$_p$ of household PV capacity. Conventional generation capacity hardly changes, except for a slight decrease in gas-fired generation capacity that corresponds to the increase in utility battery capacity.

In both the 'PVB FiT$_{25}$' and 'PVB + FiT$_0$' scenarios, most effects are qualitatively similar. The substitution of utility-scale PV is slightly less pronounced because household battery systems partially balance the daily export of excess PV generation from household PV installations.

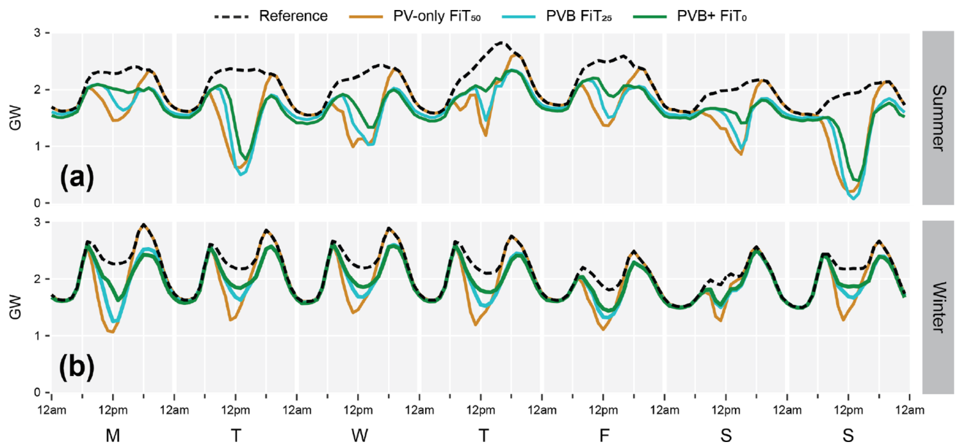

Fig. 3. Influence of the FiT scenarios on the SWIS residual network demand for 500,000 prosumage households across a week. (a) Week of the summer solstice (17 to 23 December). (b) Week of the winter solstice (18 to 24 June).

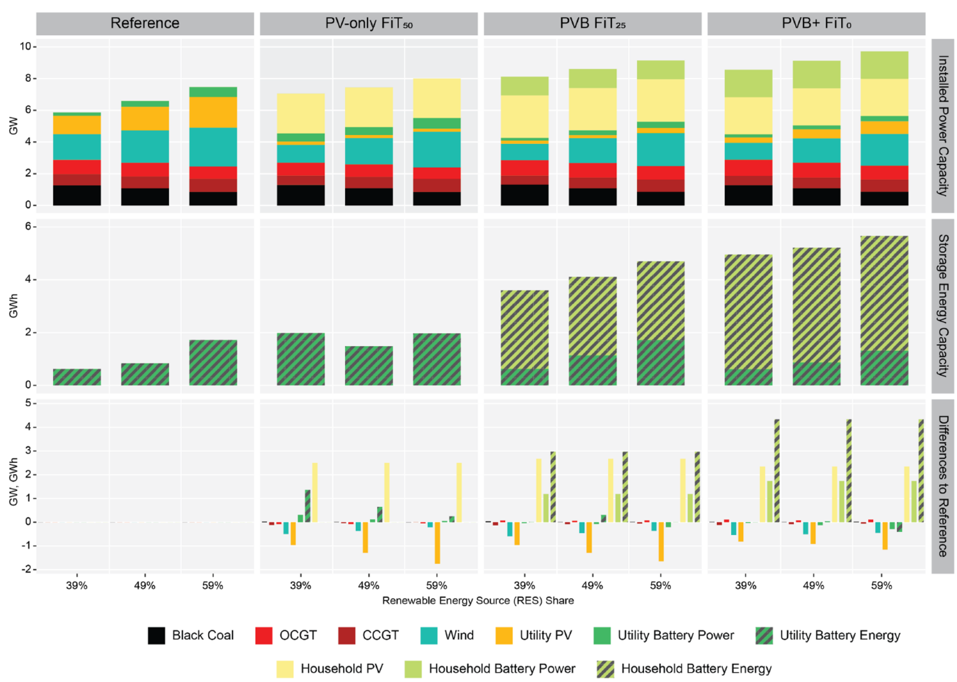

Fig. 4. Installed power and storage energy capacity for varying FiT and RES shares (500,000 households) and the change in capacity with respect to the equivalent reference scenario (i.e., without prosumage household investments).

Accordingly, this also slightly reduces the optimal amount of wind capacity. The only qualitative difference relates to utility batteries. Prosumage now slightly decreases the installed utility battery power capacity. Utility battery energy storage capacity, in contrast, remains constant or even increases. Overall, the substitution of utility batteries by household batteries is very incomplete, due to their operational focus on maximising self-consumption rather than wholesale energy arbitrage. Across RES shares, 1 MW of prosumage battery power capacity only substitutes for 0. 02 MW to 0. 17 MW of utility battery capacity; and 1 MWh of prosumage battery energy capacity substitutes for at most 0. 09 MWh utility battery capacity ('59% RES share' & 'PVB + FiT_0' scenario), but may also trigger an increase of up to 0. 10 MWh ('49% RES share' & 'PVB FiT_{25}' scenario). Conventional generation capacity again hardly changes, aside from a minor substitution between CCGT and OCGT capacity.

5.3. Impacts on optimal yearly utility-scale generation and storage

As the RES share rises in the reference scenario (upper left panel of Fig. 5), wind power becomes an increasingly important resource in terms of yearly energy provided (30% contribution at a 39% RES share) and eventually begins to dominate the generation mix (45% contribution at a 59% RES share). The contribution of utility PV also slightly rises (9% to 14% between 39% and 59% RES shares). Coal generation has the greatest reduction (51% to 29%) while CCGT increases its share slightly, and OCGT generation remains generally unaffected.

In the scenarios with prosumage, wind generation generally experiences a larger overall reduction in terms of yearly generation when compared to the capacity effects described above, as wind power's higher full load hours mean that capacity reductions have a larger energy impact. Raising the RES share again leads to a lower substitution of wind generation and a higher substitution of utility PV generation, slightly tempered with increasing deployment of household batteries (columns two, three and four of Fig. 5).

Overall power generation from coal increases slightly in the cases with prosumage (Fig. 6). This is most pronounced in the 'PVB FiT_{25}' and 'PVB + FiT_0' scenarios, where household batteries are also deployed. The increase in coal-fired power generation, combined with a

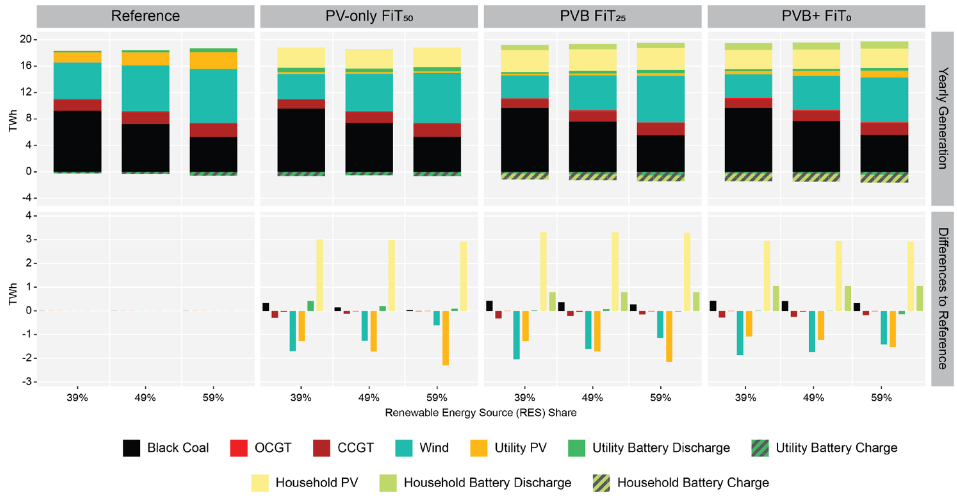

Fig. 5. Yearly generation for varying FiT and RES shares (500,000 households) and the change in generation with respect to the equivalent reference scenario (i.e., without prosumage household investments).

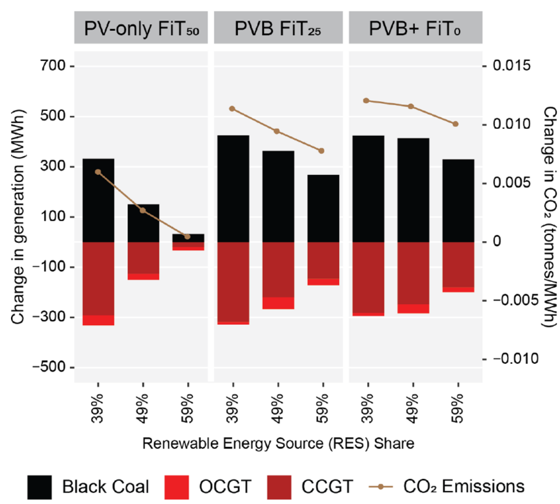

Fig. 6. Change in power generation from coal and natural gas for varying FiT and RES shares and effects on specific CO_2 emissions compared to reference scenario.

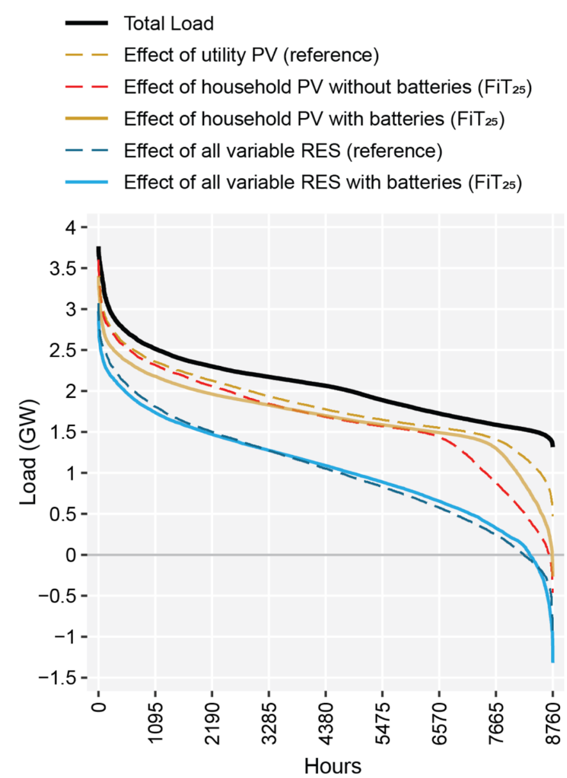

Fig. 7. Total load and residual load duration curves for the reference scenario and 'PVB FiT_{25}' for a RES share of 49%.

corresponding decrease of natural gas-fired generation, also causes CO_2 emissions to slightly increase.[16]

Although the coal-enhancing effect of prosumage is small, an exploration of its drivers raises complementary insights. To do so, we look at Residual Load Duration Curves (RLDCs) of the reference scenario and the 'PVB FiT_{25}' scenario with a 49% RES share (Fig. 7).[17] The blue curves show the residual load that remains to be served by utility-scale dispatchable generators and utility storage after the feed-in of all variable renewables. Here, the dashed blue line for 'PVB FiT_{25}' considers the net grid interaction of prosumage households, i.e., it takes not only household PV generation into account, but also the smoothing effect of behind-the-meter batteries. Comparing the two blue curves shows that PV-battery prosumage leads to an overall flatter residual load. While this is generally beneficial from a power sector perspective, it also allows coal-fired generators that have the lowest variable costs of non-renewable generators in our case study to slightly increase their production.

The changes in the residual load curve are driven (i) by an increasing overall solar PV capacity, and (ii) by the smoothing effect of household batteries. The dashed orange line shows the RLDC if only the utility-scale PV generation is taken into account in the reference scenario. The dashed red line then shows a counterfactual where this PV capacity grows to the size of prosumage household PV in the 'PVB FiT_{25}' scenario, but assuming that it would feed into the grid as utility-scale PV. That is, we counterfactually abstract from the smoothing effect of household batteries. The difference between these two curves thus shows the influence of having more PV in the power sector, triggered by prosumage. The solid orange curve then illustrates the smoothing effect of household batteries, i.e. a decrease in residual load on the left-hand side, and an increase on the right-hand side.

[16] Additional model runs show that this finding disappears if the binding RES share constraint is relaxed.

[17] For earlier and more detailed applications of residual load duration curves in the context of renewable energy integration and energy storage, see [85].

Fig. 7 further shows a slightly increasing renewable surplus generation in the prosumage scenario on the very right-hand side. This is a consequence of the sub-optimal (i.e., oversized compared to the reference) overall PV capacity. It also explains why the optimal utility-scale storage energy capacity does not decrease further, or even increases, as this capacity is used for shifting surplus energy to other hours. Utility storage power, in turn, does not decrease further because it is still required for contributing to peak residual load coverage. Note that the RLDC hardly changes on the very left-hand side, i.e., the peak residual load stays high. We find that the utility-scale battery power is optimized such that it exactly covers the difference between the peak residual load and other dispatchable generators.

5.4. Impacts on wholesale prices and system costs

The use of household PV-battery systems not only benefits prosumage households (by significantly reducing the total amount of grid-imported energy) but also reshapes the overall residual network demand. This affects wholesale electricity prices and has implications for the cost of supplying electricity to different types of customers that have their own specific grid utilisation profiles. In cost minimisation modelling, the shadow price of a model's energy balance is often interpreted as a wholesale electricity market price, which is for example used for market value analyses of renewable energy sources.[18] We use this approach to calculate the weighted yearly average wholesale market prices for three customer types, using their respective grid utilisation profiles: (i) 500,000 prosumage households, (ii) 500,000 non-prosumage households,[19] and (iii) the remaining Commercial and Industrial (C&I) demand. We assume both prosumage and non-prosumage households to have the same underlying grid demand as derived from [73].[20] For clarity, we focus on the central '49% RES share' and 'PVB FiT_{25}' scenario.

By comparing the average hourly grid demand profiles (Fig. 8) between prosumage households, non-prosumage households and C&I, it can be observed that residential households have a typical double peak profile (with a larger peak in the early evening, a much smaller peak in the morning and minimum demand during the night). With PV-battery systems, prosumage households on average are able to reduce the majority of their grid demand during the day with PV self-generation while continuing to reduce their grid demand past the early evening peak and partly into the night with their energy storage. C&I demand has a relatively more constant profile with higher demand occurring over the day. In the absence of prosumage households, wholesale electricity prices are, on average, highest in the early evening as household peak demand overlaps with declining C&I demand. With prosumage households, the early evening price peak reduces significantly, while an additional price peak during the mid-morning emerges. Night-time prices are also increased slightly on average, due to the reduced contribution of zero marginal cost wind power in the overall portfolio.

Average wholesale prices per *MWh* of electricity decrease for prosumage households, but even more so for non-prosumage households, as they are able to benefit more from the large reduction in prices over their early evening peak (Fig. 9). Since prosumage households are generally discharging their battery systems during this time, they receive less advantage from this effect. But as prosumage households already benefit from significant reductions in their total net grid utilisation, they are able to obtain much greater overall wholesale market

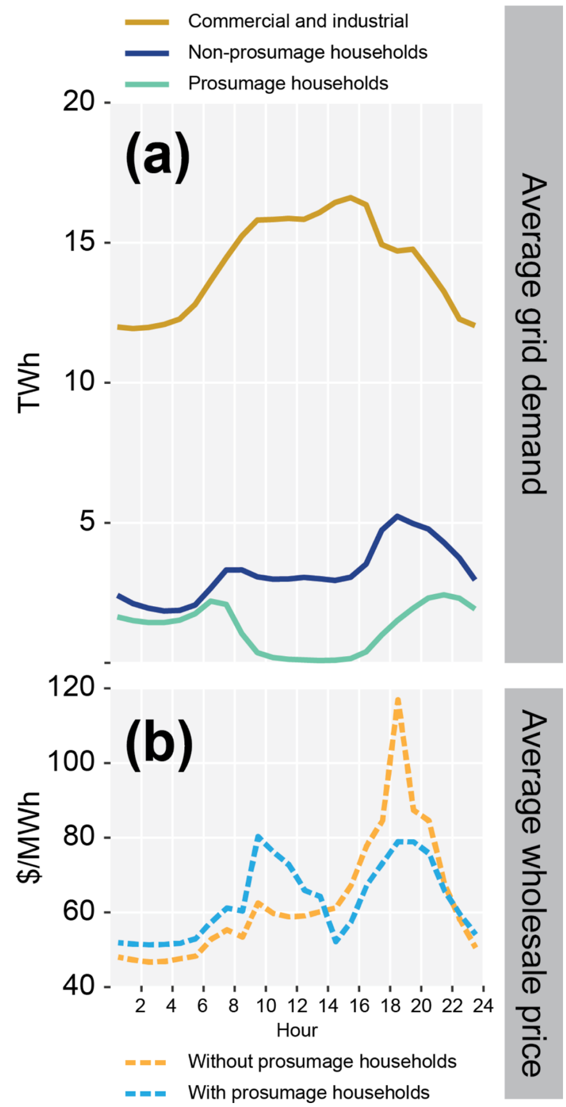

Fig. 8. Effect of household PV-battery adoption in the 'PVB FiT_{25}' and '49% RES share' scenario on: (a) Average grid demand per hour for each customer segment. (b) Average wholesale electricity prices per hour.

bill savings than non-prosumage households. Conversely, the wholesale prices for C&I demand increase slightly, as they are relatively more exposed to the moderate rise of wholesale electricity prices in mid-morning and at night-time, and benefit less than households from the reduction of the evening price peak.

Overall system costs always increase with prosumage compared to the reference scenario (Fig. 10). This is mainly driven by additional battery deployment, and also by the fact that household investments in small-scale PV and battery capacity have higher specific investment costs compared to utility-scale investments. More generally speaking, prosumage households' aim to reduce electricity bills by optimising self-consumption against the regulatory setting, which leads to a sub-optimal allocation of capital across the power sector. This is particularly visible in the 'PVB FiT_{25}' and 'PVB + FiT_0' scenarios where installations of household batteries are high. Remember that these household batteries are not designed to assist with overall grid operation and thus hardly substitute utility-scale batteries. Additional information on system cost calculations are included in A.1.

5.5. Sensitivity analyses

The sensitivity of results to changes in PV system costs, battery

[18] See [86] for a recent discussion on this.

[19] As the Western Australian SWIS network has approximately 1 million residential customers at the end of 2018 [87] and we have assumed 500,000 prosumager households previously.

[20] In this setup, residential household demand equates to 31% of total network demand and remains consistent with SWIS conditions in 2018 [87].

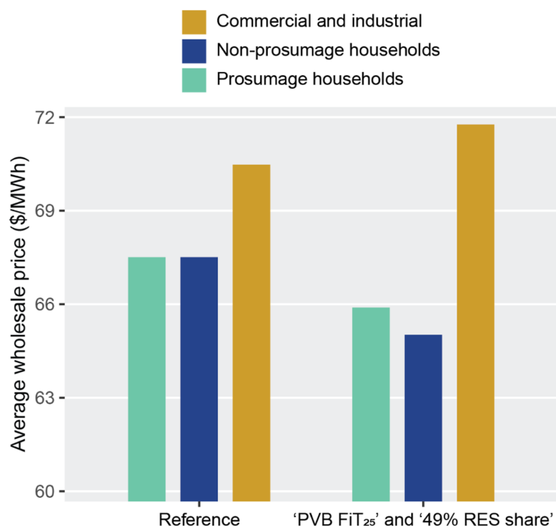

Fig. 9. Comparison of average wholesale electricity prices for the three customer types with and without prosumage for the '49% RES share' and 'PVB FiT_{25}' scenario.

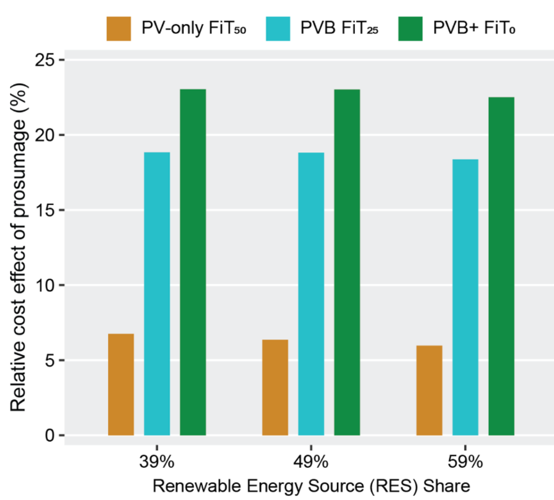

Fig. 10. Relative effects of prosumage on overall system costs for each FiT and RES share scenario.

system costs and the number of prosumage households was also evaluated by independently varying each parameter value by ± 20%. These results are presented separately as online supplementary material in Appendix B, however they did not qualitatively change the observed system effects.

6. Limitations

In the following, we discuss important limitations of the analysis and how certain key assumptions may qualitatively impact the results.

First, our retail price assumptions are independent of the modelled power sector changes and wholesale market outcomes. This is a consequence of the research design that soft-links *Electroscape* with *DIETER-WA*. In *Electroscape*, households' PV battery investments are driven by an assumed constant increase in retail electricity prices that is independent of the renewable energy share and the number of prosumage households. This assumption mirrors a long-running empirical trend in Australia [67]. If retail price increases were lower than the 4% per year assumed here, the uptake of household PV-battery systems would be slower and the accompanying system effects would be smaller (and vice versa). Increasing RES shares generally imply a greater penetration of zero-marginal cost generators, such that the wholesale cost of electricity may also decrease. Yet these savings may not be reflected in retail electricity prices. Wholesale electricity costs contribute to less than half of retail charges [58], and an increasing penetration of variable renewable energy often requires significant transmission and distribution network upgrades, that (though not explicitly modelled here) are usually recovered via increases in retail prices. Likewise, the financing of renewable energy remuneration schemes may also lead to further increases in retail prices. Accordingly, it appears justified to assume that the recent trend of increasing retail prices continues even if RES shares increase. Future research may aim to relax this assumption by further integrating both model approaches.

Second, we assume economic rationality for households' investments into PV and battery capacities. That is, households invest such that future electricity bills are minimised with respect to upfront system costs, and each household invests with the same criteria. This abstracts from other socio-technical motivations for PV battery adoption, from personal sustainability objectives and poor relationships with incumbent utilities through to securing a source of backup power. Incorporating socio-technical factors may lead to further increases in installed battery capacity beyond the results presented. This should be particularly relevant in the PV-only FiT_{50} scenario (Fig. 2a), where the system impact results would approach the PVB FiT_{25} outcomes (i.e., higher overall system costs from household battery installations but limited impacts on utility-scale generation and storage capacity).

Third, underlying household demand profiles remain constant across the years of the analysis. For example, we do not consider the additional impacts of electric vehicle energy demand or increased air conditioning cooling loads. However, additional energy demand would likely result in further increases in residential PV battery capacity beyond the results presented, leading to further displacement of utility-scale wind capacity.

Fourth, we assume that FiTs are only eligible for PV system installations under 5 kW_P. This mirrors the conditions in the SWIS network [68], with similar arrangements occurring in other Australian networks [81]. The 5 kW_P threshold is likely to become even more prevalent amid concerns with reverse power flows [88] and revised inverter standards [89]. Higher thresholds would result in higher household PV capacities being installed, and accordingly larger power sector effects, particularly in the 'PV-only FiT_{50}' scenario.[21]

Next, we adopt a long-run equilibrium 'greenfield' perspective in *DIETER-WA*.[22] Accordingly, the optimal solution accounts for the full costs of all generators, both fixed and variable, without explicitly modeling transmission and distribution network limits and expansion costs. In reality, existing conventional plants may not have to recover their full costs, but only the costs of going forward with the existing capacity. We may therefore underestimate the capacity of coal-fired power plants, which come with relatively high fixed costs, and conversely overestimated the capacity of OCGT plants. At the same time, an opposite distortion may be present, as we implicitly assume that the overall setting remains stable over time in our 2030 parameterisation. In the real world, investors may expect an ongoing transition toward higher shares of renewable energy sources or tighter carbon constraints beyond 2030, such that investments in coal- or gas-fired plants could be lower.

We further assume that certain shares of renewable energy sources are exactly met by including respective binding conditions in the model. This allows for meaningful comparisons of different scenarios

[21] Compare, for example, the German setting modelled by [25], where household PV installations are always at a 10 kW_P threshold whenever the FiT is sufficiently high.

[22] It is not a pure greenfield assumption, as we include a small lower bound for utility wind and solar power, and the PV lower bound is binding in some cases (202 MW).

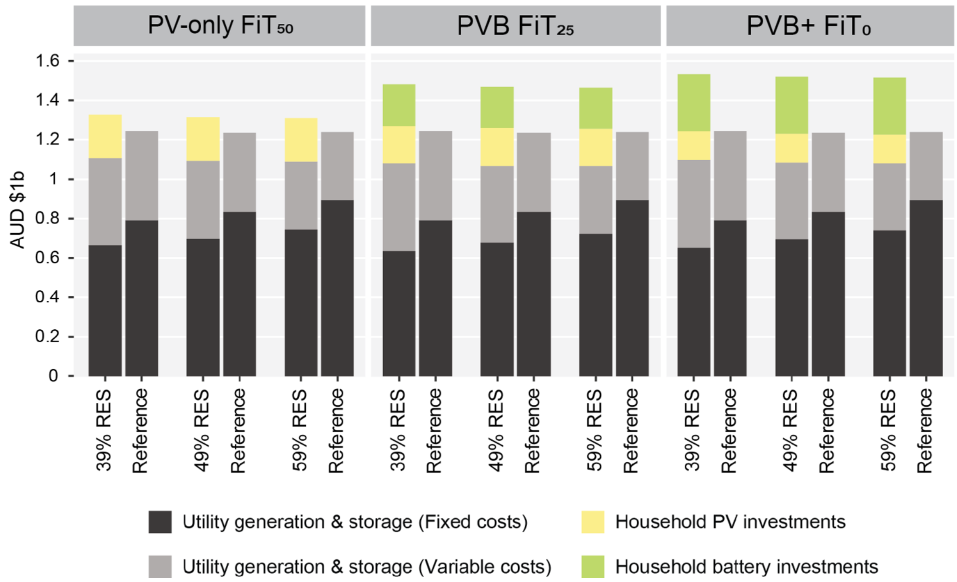

Fig. 11. Comparison of total annual system costs.

and is relevant from an energy policy perspective, as relative renewable energy targets are common in many countries. Yet we force the model to deviate from an endogenous, cost-optimal renewable share. To explore this, we carry out additional model runs with an endogenous share of renewable energy sources. Given our parameterisation, we find an optimal[23] share of renewables just below 59%, which slightly decreases with higher FiT values. Qualitatively, most results do not change compared to our setting with exogenously fixed renewable shares. Yet the coal-enhancing effect of prosumage described earlier disappears, as prosumage always increases the renewable penetration compared to the reference scenario, and accordingly substitutes more electricity from coal compared to the scenarios with fixed renewable shares.

Next, we abstract from technical limitations or additional costs related to ramping up and down power generation from conventional plants between one hour and the next in the *DIETER-WA* model used here. Thus, we may have not fully captured the potential system benefits of the 'PVB + FiT_0' scenario, which generally leads to a smoother residual load duration curve and lower ramps for thermal generators.

We further abstract from including a CO_2 price. While this is a meaningful policy assumption for the Western Australian case modelled here, it somewhat limits the interpretability of results for other jurisdictions where CO_2 pricing is present. In case a sufficiently high CO_2 price was introduced, coal-fired power plants would be substituted by natural gas. Accordingly, the minor coal-enhancing effect of prosumage would also disappear. Yet overall results are unlikely to change as the share of renewable energy sources is by assumption fixed.

Finally, our research design ignores the possibility that residential batteries could be used for further market or grid services, rather than only increasing the self-consumption of households' PV generation. While this adequately reflects the current setting in Western Australia and many other markets, household batteries may increasingly become available for additional uses in the future, enabled by aggregators and new technologies. If residential batteries became available for such applications, they may substitute utility-scale storage to a greater extent and thus mitigate the overall system cost increase from prosumage. Exploring the potentials and preconditions for this in more detail appears to be a promising avenue for future research.

[23] Note that this is not the optimal share of renewable energy sources from a social welfare perspective, i.e., if all external costs were internalised.

7. Conclusions

Using two open-source models, we first determine optimal investments into residential PV and battery capacities from a financial household perspective and then analyse their wider power sector effects. Using different FiT values and RES shares, we illustrate how prosumage changes the residual network demand and overall utility-scale generation and storage capacity investments and dispatch. We do so for the Western Australian SWIS island network, which serves as an example of what many other countries may experience in the future. Accordingly, the following general outcomes, which are evident across the range of scenarios and results, should also be of interest to many other geographical settings.

First, residential PV generally displaces utility-scale PV over wind capacity. This effect is less pronounced if more residential batteries are deployed, and more pronounced for higher RES shares. This should also apply to other regions, since residential PV generation, in general, temporally coincides with utility PV generation. Accordingly, future investments in utility PV capacity will have to consider the growth of prosumage as it directly competes against their market dispatch. Therefore, the use of utility PV capacity in the future may require additional financial certainty by engaging in hedging agreements, such as contracts-for-difference, rather than relying solely upon market dispatch revenues from the wholesale energy market.

Second, the optimal wind capacity, in contrast, is generally less affected by prosumage. As self-generation by prosumage households contributes to the RES share, it naturally displaces the remaining share of renewable energy required from utility-scale generators. Across each of the FiT and RES share scenarios however, reductions in wind capacity are less pronounced than with utility PV capacity. Furthermore, raising the RES share drives additional wind capacity over utility PV capacity. From a central planner perspective, investments in wind capacity may be more resilient to different degrees of prosumage adoption.

Third, even if a substantial residential battery capacity is deployed, utility battery power capacity is only displaced slightly while utility battery energy capacity may even increase. This is driven by the fact that we have assumed prosumage batteries to only be operated with the objective of minimising the households' energy costs, which maintains the diurnal ramping between midday and evening across the residual network demand. There is therefore a very imperfect substitution of utility storage by residential batteries. This is also a major source of increasing overall system costs. These findings should also apply beyond the Western Australian context, as the battery operation and cost premiums remain consistent with many other jurisdictions. Though not analysed in this study, alternative regimes that can reduce the cost premium of residential battery deployment compared to utility-scale storage and provide system integration incentives may be more economically efficient (e.g., community-scale energy storage [90]).

Fourth, prosumage causes average wholesale prices to slightly decrease for both prosumage and non-prosumage households and slightly increase for other consumers. These distributive implications of prosumage may be of interest from a policy perspective; yet the overall effects are also dependent on the design (and potential design changes) of retail tariffs and the pass-through by retailers to consumers.

Overall, we conclude that prosumage can have substantial impacts on the overall power sector, which has to be considered by system planners, investors and regulators alike. System planners and investors of long-lived utility-scale renewable generation and storage assets may be exposed to over or under investment, if they do not take into account prosumage investment behaviours. Likewise, an increasing uptake of prosumage presents an opportunity for regulators to offer retail incentives that can better incorporate and utilise these behind-the-meter PV battery systems as a source of additional power sector flexibility.

The development and provision of the two open-source models also contribute to the literature by providing transparency and enabling reproducibility for subsequent research. Future work may explore in more detail the distributive impacts of prosumage and potential grid tariff reform options to mitigate these. Moreover, a further integration of the two models appears desirable, which would also allow the incorporation of retail price feedbacks from increased prosumage as well as investigating the effects of making additional use of prosumage batteries for grid storage purposes.

8. Research Data

Source code and input data are publicly accessible from Zenodo repositories http://doi.org/10.5281/zenodo.3693308 for *Electroscape* and http://doi.org/10.5281/zenodo.3693287 for *DIETER-WA*.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Additional results

A.1. System costs

Although not in the focus of this analysis, we also compare overall system costs. As for all non-prosumage parts of the power sector, this is straightforward, as respective fixed and variable costs are direct outcomes of the *DIETER-WA* model. On the prosumage side, we re-calculate the costs of investments in household PV and battery capacity determined by *Electroscape* in a way that they are comparable to system cost calculations in *DIETER-WA*. We do this by summing up the annuities of respective investments in every year between 2019 and 2030, using a discount rate of 4% (the same as for utility-scale assets in *DIETER-WA*) and lifetimes of 10 years for batteries and 25 years for PV installations. In doing so, we consider the higher specific investment costs of household PV and battery installations compared to their utility-scale counterparts.

We find that overall system costs in the scenarios with prosumage are always higher than in the reference scenario. Generally speaking, this is because the inclusion of household PV battery systems forces the model to deviate from the least-cost generation and storage portfolio achieved in the reference scenario. In particular, prosumage batteries substitute utility battery storage only to a minor extent (compare Section 5.2), so overall battery-related investments increase substantially.[24] Accordingly, system costs increase most in the FiT_0 scenario, where we find the highest prosumage battery investments (Fig. 11). Depending on the renewable share, yearly system costs increase by around 23% in the FiT_0 scenario compared to the reference, but only by 6–7% in the FiT_{50} scenario without batteries. Another factor that contributes to increasing overall system costs relates to higher specific investment costs of households' PV and battery installations compared to their utility-scale counterparts.

Appendix B. Sensitivity analyses

Sensitivity analyses associated with this article can be found, in the online version, at https://doi.org/10.1016/j.apenergy.2020.115466.

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Appendix 4 – Paper 4

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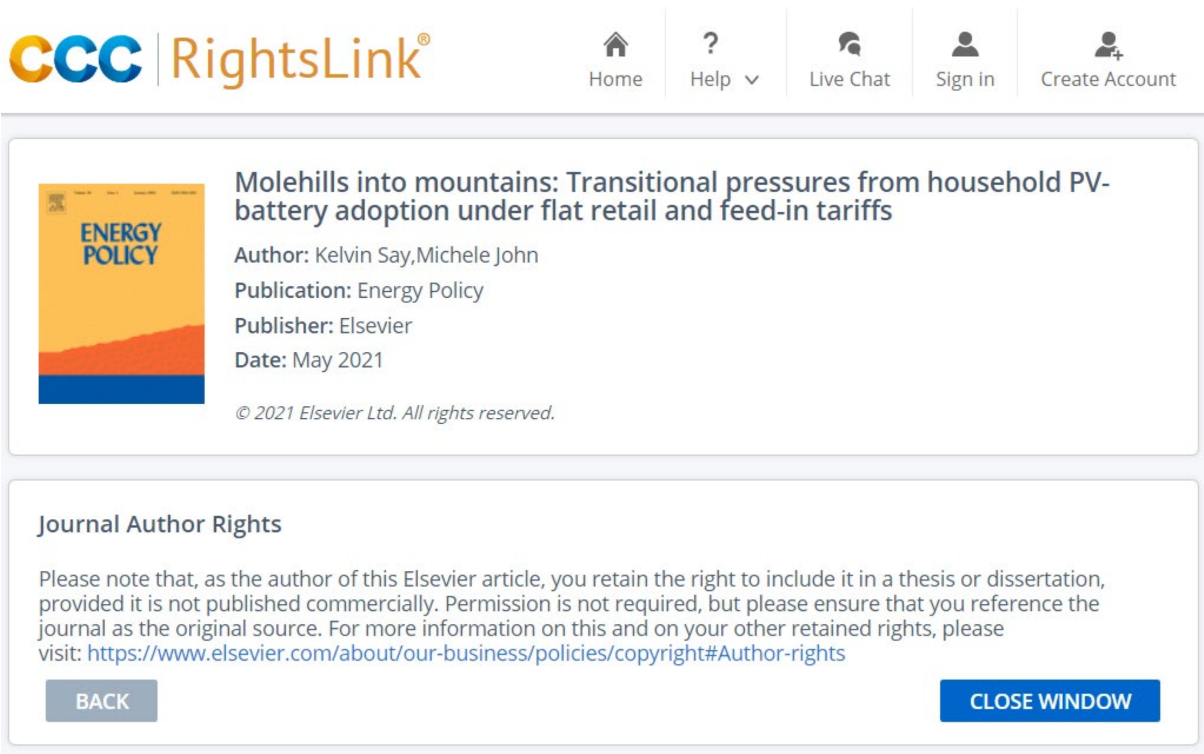

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Molehills into mountains: Transitional pressures from household PV-battery adoption under flat retail and feed-in tariffs

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I, Kelvin Guisen SAY, contributed to the 90% of the paper/publication entitled:

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Specifically, I contributed to the following:

Conception and design, acquisition of data and method, data conditioning and manipulation, analytical method, interpretation and discussion, and final approval

Signature of candidate: **Date: 10 November 2021**

I, as a Co-Author, endorse that this level of contribution the candidate indicated above is appropriate.

Michele John

Signature: **Date:** 9 December 2021

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Molehills into mountains: Transitional pressures from household PV-battery adoption under flat retail and feed-in tariffs

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ABSTRACT

With Australia's significant existing household PV capacity, decreasing battery costs may lead to widespread household PV-battery adoption. As the sizing of these systems are heavily influenced by retail tariffs, this paper analyses the effect of flat retail tariffs on households free to invest in PV battery systems. Using Perth, Australia for context, an open-source model is used to simulate household PV battery investments over a 20-year period. We find that flat usage and feed-in tariffs lead to distinct residual demand patterns as households' transition from PV-only to PV-battery systems. Qualitatively analysing these patterns from the bottom-up, we identify transitional tipping points that may challenge future electricity system management, market participation and energy policies. The continued use of flat tariffs incentivises PV-battery households to maximise self-consumption, which reduces annual grid-imports, increases annual grid-exports, and shifts residual demand towards winter. Diurnal and seasonal demand patterns continue to change as PV-battery households eventually become net-generators. Unmanaged, these bottom-up changes may complicate energy decarbonisation efforts within centralised electricity markets and suggest that policymakers should prepare for PV-battery households to play a more active role in the energy system.

1. Introduction

As set out by the Paris agreement, the decarbonisation of the power sector is necessary to mitigate the effects of global warming. The growth and integration of utility-scale renewable energy technologies has changed the economic and operational dynamics that have traditionally underpinned power sector management and planning. Reductions in the cost of photovoltaic (PV) technology have also benefited households by reducing cost barriers for customers to self-generate and reduce future electricity bills. Over the past decade, the rapid and widespread rise of household PV in Australia (Australian Photovoltaic Institute, APVI, 2019a; 2019b) has noticeably impacted whole-of-system operation and wholesale electricity market dynamics (Australian Energy Market Operator, AEMO, 2019b). With lithium-ion battery energy storage costs decreasing (Schmidt et al., 2017) there has been increased use within the utility-scale power sector (International Renewable Energy Agency, IRENA, 2019) and early-adoption at the household-scale (Graham et al., 2019; Porteous et al., 2018; SunWiz, 2020). As widespread household PV-battery adoption has the potential to further erode centralised electricity supply markets (Agnew and Dargusch, 2015), it is necessary to better understand the extent of their changes within the power sector.

The aim of this paper is to assess how maintaining flat retail usage charges and Feed-in Tariffs (FiTs) (which influence household investments in PV and battery systems) affect residual demand and influence the interconnected layers of a traditional liberalised electricity market, including its distribution network, market dispatch, and electricity retailing. By identifying transition patterns from household PV battery adoption and their qualitative effects on the power sector, system managers and policymakers may better understand (and prepare for) their wider adoption.

In this paper we analysed changes in aggregate household grid-utilisation within the context of an islanded electricity system and liberalised energy market in Perth, Western Australia, and assessed the power sector challenges and opportunities afforded from the growth of household PV battery adoption. In this system, cumulative household PV capacity (1 GW_P at the end of 2019) significantly exceeds the capacity of utility PV and wind (10 MW_P and 478 MW respectively) (AEMO, 2019d). With 4 GW of peak network demand, households have an outsized ability to influence the operational and market layers within this system. We utilised an open-source PV battery investment model

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(Say et al., 2019) applied to 261 real household underlying demand and insolation profiles. The aggregate grid-utilisation changes (at a half-hour resolution) were used to establish a pattern of diurnal and seasonal transitions across a range of proportional FiTs (valued at a fixed percentage of retail usage charges). The research focused on the household sector with business-as-usual retail conditions, that maintained flat and increasing retail tariffs, decreasing PV and battery system costs, and a 5 kW_P FiT eligibility limit. As flat tariffs do not value the timing of consumption and exports, grid-charging and grid-discharging from the battery was not evaluated. These retail market conditions for the household sector were simulated over a 20-year period to analyse emerging power sector tensions from the continued use of flat retail tariffs. This analysis may apply more broadly in other regions that use flat retail tariffs and are also experiencing growing household PV battery deployment. The provision of the open-source model also contributes to the literature by providing transparency and reproducibility for subsequent research.

In summary this paper reviews the critical impacts that household PV-battery adoption may have on the Western Australian electricity market. The influence of flat retail tariffs on household PV battery investments drive transitional changes in grid-utilisation, such as a movement towards early morning diurnal peak demand and a shift towards winter dominant residual demand, that affect all utility-scale generators. This transition leads to a number of significant changes in the Western Australian energy market. Firstly, PV-battery households becoming net-generators. Secondly, changes to the diurnal timing and increased ramping of utility-scale generation. Thirdly, the increased potential for retailers to capitalise on under-utilised flexibility from PV-battery households. However, this transition also leads to certain tipping points for incumbent retailers, with wfalling revenues accelerating the need to find additional value streams through customer energy market participation.

This paper is structured as follows: Section 2 presents the background and literature review. Section 3 describes the modelling and analytical approach. Section 4 characterises the modelling results into various grid-operation stages and determines the overall transition behaviour. Section 5 discusses the transition patterns that emerge, starting from the aggregate household level through to their wider power sector effects, along with the limitations and outlook. Section 6 concludes with key findings and policy implications.

2. Background and literature review

2.1. The growth of household PV in Australia

With over 1 GW_P of cumulative PV capacity installed behind-the-meter across 27% of free-standing households (Australian Photovoltaic Institute, APVI, 2019a), the South West Interconnected System (SWIS) in Western Australia has experienced a fundamental shift in how electricity is used over the last decade. Cumulatively, behind-the-meter household PV (or rooftop PV) capacity has become the largest generator on the network,[1] outstripping commercial and industrial customer-sited PV capacity (APVI, 2019b), and has been recorded supplying over 45% of instantaneous network demand (AEMO, 2019b) on the SWIS.[2] Over the next decade, the amount of energy generated from rooftop PV is expected to more than double from 1657 GWh in 2019 to 3432 GWh in 2028 (AEMO, 2019d). Currently rooftop PV only contributes to less than 10% of the overall energy demand on the SWIS, but new minimum network demand records are being exceeded such that system stability has become an increasing concern (AEMO, 2019a) such that mechanisms are being considered that can remotely curtail household generation (AEMO, 2020) or encourage the use of front-of-the-meter energy storage systems (Mercer, 2019). As a small-to medium-sized islanded electricity system, the SWIS lacks the ability to export excess generation, making it more sensitive to changes in grid-utilisation when compared to larger interconnected electricity systems. This heightens the need for a better understanding of how future PV battery customers may interact with the grid, while providing context for what larger systems may experience in the future.

The high penetration of rooftop PV is not unique to Western Australia and applies across most Australian states and territories.[3] This has been driven by continued reductions in installed system costs (Solar Choice, 2019a), abundant solar resources (World Bank Group, 2019), relatively high retail electricity tariffs (Australian Energy Market Commission, AEMC, 2018a) with low consumer trust (AEMC, 2018b) and increasing community concern for greenhouse gas mitigation. With behind-the-meter Distributed Energy Resources (DER) being unmonitored and uncontrolled (Australian Energy Market Operator, AEMO, 2019a, 2018), system operation remains highly reactive and sensitive to aggregate changes in household grid-utilisation.

The declining costs of batteries (Schmidt et al., 2017) may lead to a widespread adoption of household PV-battery systems (Parkinson, 2018) that further change how households utilise and interact with the grid. With household PV-only systems, all behind-the-meter generation across the network use the same solar resource simultaneously, which aligns their temporal effects and leads to observable system level patterns like the *duck curve* (Denholm et al., 2015; Maticka, 2019). With PV-battery systems, an additional degree of freedom is provided by the choice of battery capacity. This choice further depends on financial factors (such as retail tariff structures and feed-in tariffs) and technical factors (such as underlying household demand) that influence the installed level of self-generation and storage capacity, along with how it is dispatched. These dependencies make anticipating changes to grid-utilisation with PV-battery adoption less certain (e.g., retail tariff incentives may influence an existing PV-only household to install a large capacity battery with additional PV capacity or install a smaller capacity battery and maintain the existing PV capacity). As each choice leads to different household grid-utilisation profiles, understanding how retail tariffs influence this process (and consequently the underlying layers of the power sector) becomes critically important for the design of retail energy policies and suitable market design.

Though electricity systems remain region specific, similar processes underpin liberalised electricity markets, namely wholesale energy markets that competitively dispatch from the lowest marginal cost generators, regulated transmission and distribution network monopolies and retailers that hedge wholesale prices to provide simpler tariffs to customers. These similarities allow qualitative analyses from the SWIS to apply more broadly to other markets with similar structural designs.

2.2. Literature review

As greater amounts of renewable energy generation are incorporated into liberalised electricity markets, operation patterns begin to emerge from interactions between the system and market layers, such as the

[1] The SWIS has a peak network demand of 4.4 GW. The largest utility-scale generator on the network is the Muja coal power station with a nameplate capacity of 854 MW (AEMO, 2019d).

[2] This was over a 30-min trading interval and occurred on 29 September 2019.

[3] Over 2 million households (or 20% of all free-standing households) have installed rooftop PV systems (APVI, 2019a; 2019b). As of the end of 2018, rooftop PV systems under 10 kW_P accounted for more than half of the nation's cumulative installed PV capacity (APVI, 2019b). Average system capacity continues to rise and exceeded 7 kW_P in 2018 (AEC, 2019).

merit-order effect[4] from zero-marginal cost generators (Sensfuβ et al., 2008), and the *duck curve*[5] from growing PV generation (Denholm et al., 2015). While each electricity system is unique, similar technical and economic foundations have meant that the *merit-order effect* and *duck curve* have been widely generalisable. By considering households as rational investors that affect the various layers of the electricity system, we are able to build upon the extensive literature on financial investment modelling with renewable energy technologies, and analytical frameworks used to analyse energy transitions.

2.2.1. Household PV battery investment modelling

With Australia's current leadership in behind-the-meter PV adoption (Australian Energy Council, AEC, 2016; APVI, 2019a) and early PV-battery adoption, there remains insufficient information for *ex-post* analysis. However, an *ex-ante* financial investment perspective provides a techno-economic foundation to frame future investment decisions that can be useful to evaluate potential futures (Wüstenhagen and Menichetti, 2012). At a household-scale the financial investment perspective allows a range of possible PV battery system capacities to be framed as a set of competing investment opportunities based upon their expected electricity bill savings and upfront costs. Financial metrics using discounted cash flows, such as Net Present Value (NPV), Internal Rate of Return (IRR), and Discounted Payback Period (DPP) are commonly used to assess the value of each investment opportunity. The PV battery configuration with the highest financial value provides an indication of the systems that households may choose to install in the future and the costs necessary to achieve this.

Schram et al. (2018) used real utility net-meter data from 79 PV-only households in Amersfoort, Netherlands and determined potential electricity bill savings across a range of battery capacities. With a battery simulation model (that maximised PV self-consumption) under flat retail and feed-in tariffs, the cost-optimal battery capacity for each household was calculated using NPV analysis. Using these cost-optimal battery capacities, they found alternative battery operating modes could significantly reduce winter peak demand and that increasing battery capacities beyond the cost-optimal configuration only slightly reduced overall profitability. This suggests there is an opportunity for joint investment between households and utilities to further improve peak demand reduction. Schopfer et al. (2018) calculated NPV across a range of predetermined PV battery combinations and system costs using real energy consumption data from 4190 households in Zurich, Switzerland with a PV battery simulation model (also maximising self-consumption) and time-of-use retail tariffs and flat FiTs. With 2018 PV and battery system costs of 2000 €/kW$_P$ and 1000 €/kWh respectively, PV-only systems were profitable for less than half of the households and PV-battery systems remained unprofitable; however as battery costs decreased to 250 to 500 €/kWh, a tipping point emerged with the majority of households having profitable PV-battery systems. The use of real energy consumption data was the focus of Linssen and Stenzel (2017) that showed aggregate or synthetic data could lead to an overestimation of economic feasibility. Other examples utilising a cost-optimal household PV battery perspective, include Dietrich and Weber (2018), Hoppmann et al. (2014), Talent and Du (2018), von Appen and Braun (2018), and Weniger et al. (2014). Each of these bottom-up PV battery studies however, have used a 'greenfield' (or one-shot investment perspective), while 'brownfield' perspectives that focus on incremental investments to assess the path of cost-optimality are rarely evaluated in household PV battery literature. Real options models have been used previously to assess the effect of different policy conditions on the timing and scale of renewable energy investment decisions at the utility-scale (Reuter et al., 2012), but only recently used to evaluate PV battery investments (Ma et al., 2020).

2.2.2. Electricity system transitions

By being able to consume, self-generate and store energy, customers with PV and battery systems are not passive actors in the electricity system, but rather active participants that react to prices and expectations (Klein and Deissenroth, 2017) with the ability to influence broader energy system transitions. Energy transitions are described as co-evolving relationships between techno-economic, socio-technical, and political perspectives with transition pathways being a series of reconfiguring systems driven by a multitude of competing actors (Bolwig et al., 2019; Cherp et al., 2018; Geels et al., 2017; Pfenninger et al., 2014). Due to the complex interactions between different layers of the energy system, that extend beyond purely numerical assumptions, these studies highlight the importance of using combined qualitative and quantitative analysis to evaluate the energy system transitions. For example, Schill et al. (2017) modelled the implications of direct and indirect support mechanisms with various PV-battery operating strategies. Numerical data was used as a basis for a qualitative evaluation on the potential role of household PV-battery adoption in the German electricity sector. A range of qualitative system-level arguments for and against household PV-battery adoption were established, such as private rather than public capital can be used to increase renewable energy penetration, through to increased data protection amid rising security concerns. The authors also highlighted the potential of reducing system operation costs by encouraging system-friendly household battery operation. Neetzow et al. (2019) analysed various policy mechanisms that incentivise market friendly household PV-battery operation while reducing the need for network capacity expansion. They find that grid feed-in policies should be complemented by load policies to incentivise households to operate PV-battery systems in a system-friendly manner (i.e., utilising the spare capacity of the electricity system, rather than exacerbating its constraints). They caution policymakers that careful policy design is necessary as battery systems can (if unchecked) exacerbate both load and supply issues across the distribution network. Eid et al. (2016) constructed a framework of various local energy management market designs from European case studies. By evaluating the socio-economic constructs and regulatory environments, they qualitatively discussed the range of changes necessary to integrate DER systems in a system-friendly manner, along with the challenges and opportunities with this transition. By using a combination of quantitative and qualitative approaches, these studies analyse a broader range of energy system integration outcomes and offers further context to be applied in other regions.

2.2.3. Modelling approach

Analysing the interactions between retail tariffs, household installations of PV and battery capacity, aggregate residual demand, the distribution network, wholesale market dynamics, and existing utility-scale generators requires an ever-increasing number of parameters and assumptions (Bale et al., 2015). Many of these elements depend on socio-political factors that cannot be entirely represented numerically (e.g. householders' personal decisions to install PV battery systems, to political pressure to maintain favourable policy mechanisms such as flat feed-in tariffs). This paper addresses this modelling gap by using a range of scenarios with a bottom-up and combined quantitative and qualitative approach. This approach analyses how PV battery investing households (under flat retail and feed-in tariffs) may qualitatively influence various power sector layers. Energy transition pathways for individual households are generated by considering PV battery adoption

[4] The reduction in wholesale electricity prices occurs as the capacity of near-zero short run margin cost generation (namely wind and solar PV) increases within an electricity market, due to the merit order and dispatch price determination.

[5] The *duck curve* describes how network operations may be impacted by increasing solar PV capacity. Operationally, minimum demand moves into the middle of the day and gradually declines, resulting in a risk of overgeneration. Furthermore, as the late afternoon peak persists, the ramping required to meet the peak increases for all remaining generators.

as a series of discrete and incremental investment opportunities. This brownfield approach focuses on how household PV battery investment pathways change over time, and how they can lead to aggregate changes in grid-utilisation. With different grid-operation stages emerging, their transitions form a basis to qualitatively assess (i.e. describe the important inter-relationships and dependencies) the power sector impacts. To the best of the authors' knowledge, no studies to date have modelled and characterised how decreasing PV and battery costs combined with the continued use of flat retail and feed-in tariffs leads to transitional pressures from household residual demand on the power sector's system operation, market and retail energy policies.

3. Methodology and case study

3.1. Analytical framework

This study uses a techno-economic investment simulation model used in previous studies (Say et al., 2019, 2020) called Electroscape. The model considers the range of PV and battery configurations available to a household as a set of competing investment opportunities (based on electricity bill savings). By utilising an investment decision tree (based on real options evaluation), projections of annual PV battery installed capacities are simulated across a range of households using their own underlying demand and insolation profiles. This numerical model establishes how household grid-utilisation may change under (exogeneous) retail market conditions. By categorising and framing these changes as a series of grid-operation transition stages, the qualitative effect on the wider power sector is evaluated.

With a focus on flat retail tariffs, this paper evaluates five scenarios that vary the relative value of the FiT with respect to the retail usage tariff (volumetric), along with additional high and low growth scenarios in the sensitivity analysis (Appendix B). FiT payments are only applied to the amount of energy exported after first being consumed by underlying demand. Using FiT conditions that are representative of flat FiTs in Australia (AEC, 2018; AEMC, 2018a) and abroad,[6] five FiT scenarios are modelled that correspond to setting the FiT between 0% and 100% of the retail usage charge (using steps of 25%) and are only eligible for households with PV systems 5 kW_P and under. These five FiT scenarios are named FiT_0, FiT_{25}, FiT_{50}, FiT_{75} and FiT_{100}, and value the FiT respectively at 0%, 25%, 50%, 75% and 100% of the retail usage charge. Therefore, in the FiT_0 scenario households are not paid for excess energy exports. In the remaining FiT scenarios, the value of energy exports increases but only applies to households with PV systems 5 kW_P and under (AEMC, 2018a; Solar Choice, 2019c). By independently simulating the five scenarios, we broadly capture situations where FiTs change over time. For example, if the FiT is initially valued at 50% of the retail usage tariff (i.e., \$0.20/kWh for a \$0.40/kWh usage charge) and then gradually reduces to 25% of an increasing retail usage tariff over the next 10 years (i.e., \$0.125/kWh for a \$0.50/kWh usage charge), then the transitional pathwayis likely to reside within the simulation results from the FiT_{50} and FiT_{25} scenarios.

Based on business-as-usual conditions, this paper's analysis assumes that PV and battery system prices continue to decrease, and retail usage charges continue to increase. The first part of the analysis (Fig. 1) establishes how different FiT values and flat tariffs, shape and affect household grid-utilisation from household PV battery investments over 20 years. Using a set of representative households, aggregate changes in residual demand affects a range of operational parameters (e.g. the timing and magnitude of annual peak demand) that are then used to quantify how household grid-utilisation changes over time in each FiT scenario. In the second part of the analysis (Fig. 1), common patterns between these grid-utilisation changes are characterised into a set of representative grid-operation transition stages. The trajectory of these transitions provides the foundation for a qualitative assessment on how growing PV battery households may place bottom-up pressure on the power sector's system and market layers. Together the two-part analytical framework (Fig. 2) assesses the policy implications on the power sector from the continued the use of flat retail tariffs. By evaluating market effects from the bottom-up, this paper identifies areas of weaknesses in traditionally centralised liberalised electricity markets and the limitations of using flat retail and feed-in tariffs to manage households' grid-utilisation.

3.2. Modelling PV battery adoption

3.2.1. Household PV battery investment decision model

Electroscape is a techno-economic simulation model used to model the timing and capacity of household investments into PV battery systems between 2018 and 2037. Electroscape simulates the investment decisions for each household annually using a 10-year financial horizon. In each year of the simulation, electricity tariffs increase, PV battery system costs decrease, and each household calculates the expected bill savings from installing a range of additional PV and/or battery combinations.[7] As underlying household demand remains constant, these retail market conditions are the sole driver of adoption. NPV of each PV battery combination is calculated by considering expected bill savings over the next 10-years as the *investment cash flow*, system installation costs as *upfront capital costs* and using the average owner-occupied standard variable home loan interest rate as the *discount rate*. This allows each PV battery configuration to be considered as competing investment opportunities. If the financial returns are sufficient to *reduce the uncertainty risk* of making an investment (i.e., requiring a shorter discounted payback period of less than 5 years), the system configuration with the highest NPV is chosen and installed in the given simulation year. This updates the household's future grid-utilisation and subsequent PV battery investments in later years must consider the installed system configuration.[8] Additional detail on the financial and investment modelling assumptions and equations are provided in Appendix C.

This iterative approach allows new PV battery investments to dynamically respond to changing retail conditions while considering previous investments. As the model applies the same investment methodology to each household, variations in installed PV battery system capacities between households are driven by differences in underlying demand and solar insolation profiles. At the end of the simulation, each household produces a half-hourly resolution grid-utilisation profile over 20 years. By aggregating the grid-utilisation across all simulated households, a representation of the grid-utilisation changes at the distribution network level is generated.

3.2.2. Technical PV and battery simulation model

The technical modelling of PV and battery operation follows the simulation framework described by Hoppmann et al. (2014) and uses an AC coupled PV-battery system residing behind-the-meter. The purpose of the technical model is to evaluate, with respect to a household's unique underlying demand and insolation profile, the effect of different

[6] Germany (Engelken et al., 2018), United Kingdom (Pearce and Slade, 2018), Japan (Kobashi et al., 2020).

[7] This is determined by simulating the technical operation from installing additional PV and/or battery system on top of the household's expected grid-utilisation (that considers previously installed PV and/or battery systems). The simulated PV and battery models consider performance degradation, finite operational lifespans, system losses and capacity limits. The resulting differences in annual grid-imports and grid-exports are then valued using the electricity tariffs and FiTs to determine the expected bill savings. More detail is provided in Appendix C.

[8] This sequential investment approach models 'brownfield' investments and allows the economics around the retrofit of existing systems to be modelled explicitly.

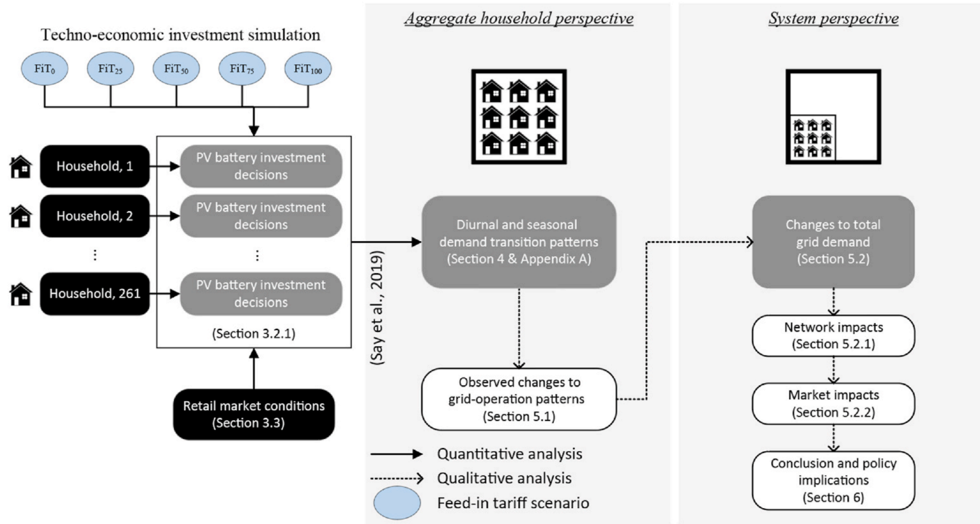

Fig. 1. The detailed analytical framework, components, and relationships between the quantitative and qualitative analyses.

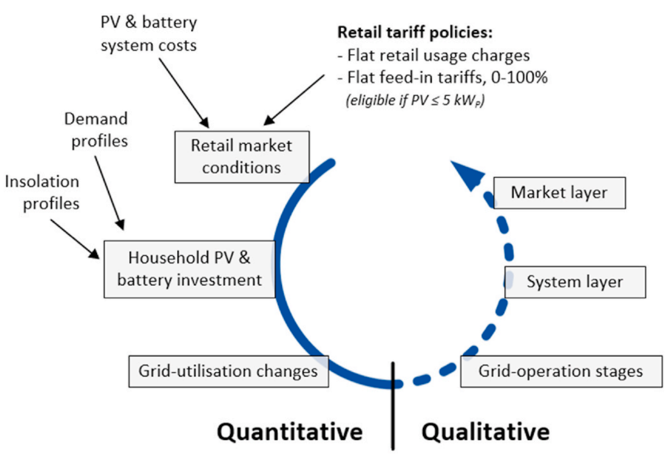

Fig. 2. The overall bottom-up analytical framework.

PV and battery capacity combinations on a household's grid-utilisation profile over the 10-year financial horizon, which establishes it potential electricity bill savings. The PV generation profile is derived by scaling the household's (kWh/kWP) insolation profile with the PV capacity. By subtracting the PV generation profile from the household demand an intermediate net-demand profile is calculated. The battery simulation model uses this intermediate net-demand profile within its battery capacity constraints to determine the resulting residual demand profile. Grid-charging and grid-discharging is not modelled, as the time-invariant tariffs remove the financial incentive of energy arbitrage. Therefore, the battery dispatch algorithm only aims to maximise PV self-consumption, by charging with excess PV generation until full and discharging to avoid grid-imports until empty (and remaining within the battery inverter limits). Additional detail on the technical modelling assumptions are provided in Appendix C.

3.3. Case study parameters and conditions for Perth, Australia

The largest load centre on the SWIS network is the region encompassing the state capital of Perth, Australia. The islanded SWIS network and its liberalised electricity market provides an ideal case study, as it naturally limits the number of external factors. The SWIS has approximately 1.1 million customers with residential, commercial, and industrial sectors consuming 27%, 55% and 18% respectively of its 18 TWh of total annual energy demand (AEMO, 2019d). The vast majority of installed PV capacity resides behind-the-meter on owner-occupied households and the independent market operator continues to expect the household sector to remain as the predominant source of PV capacity growth in the SWIS (Energy Transformation Taskforce, 2020; Graham et al., 2019).

A set of retail market conditions are chosen to reflect business-as-usual conditions in Perth, Australia (Table 1). Household demand and PV generation data was sourced from 261 real households. As disaggregated underlying household demand and insolation profiles are not measured by the utility net-energy meters in Perth, Australia or the wider SWIS network, comparable data[9] from 261 households in Sydney, Australia are used in its place. The dataset (Ausgrid, 2018) was obtained via utility gross-energy meters that separately measured underlying household demand and PV generation. The Sydney dataset is used to represent Perth households as both regions share similar latitudes, climatic conditions, annual energy consumption and solar resources.[10] In addition, household demographics (ABS, 2017a; 2017b) between Perth and Sydney are comparable (average household sizes of 2.6 and 2.8 people respectively) along with median weekly incomes ($1643 and $1750 per household respectively). While Sydney has a lower proportion of owner-occupied dwellings (64%) compared to Perth (73%), the Sydney utility meter data was obtained from owner-occupied and free-standing households (Ausgrid, 2018), reflecting the housing demographic in Perth most likely to invest in PV battery systems (APVI, 2019b). Due to these similarities the Sydney dataset is used to represent the underlying demand and PV generation of Perth households. The aggregate characteristics of the underlying demand data is provided in Appendix A.1.

Reflecting SWIS retail conditions, a two-part retail electricity tariff structure is used with an initial usage charge of AU$0.27/kWh (Infinite Energy, 2017) and fixed daily charge of AU$0.95/day. Using historical

[9] Half-hourly timeseries data was obtained from 300 gross-metered PV households in Sydney, Australia between 1st July 2012 and 31st June 2013. After removing households with missing timeseries data, 261 households remain. The insolation profile (kWh/kWP) for each household was obtained by normalising the solar PV generation profile by their declared PV capacity. Further information on collection of the dataset is documented by Ratnam et al. (2017).

[10] From the Sydney data set, the average annual energy demand per household is 5.62 MWh and average PV capacity factor is 14.8%. This is consistent with Perth that has an average annual energy demand per household of 5.83 MWh (ABS, 2013) and average PV capacity factor of 14.1% (NREL, 2018).

Table 1
Input parameters and data used in the study.

Input Parameter	Unit	Values	Derived from
Scenario forecast period	years	20	Model assumption
Simulation time step	minutes	30	Model assumption
Initial flat FiT rebate	AUD/kWh	0–0.27	Model assumption
Initial flat usage charge	AUD/kWh	0.27	Infinite Energy (2017)
Change in tariff charges/rebates	%/a	5	ABS (2018)
FiT rebate installed capacity limit	kW_P	5	Synergy (2017)
Discount rate	%/a	6	RBA (2018)
Initial installed PV system cost	AUD/kW_P	1400	Solar Choice (2019a)
Initial installed battery system cost	AUD/kWh	900	Tesla (2018)
Change in installed PV system costs	%/a	−5.9	Ardani et al. (2018)
Change in installed battery system costs	%/a	−8	BNEF (2019b)
Number of households	household	261	Ausgrid (2018)
Solar PV generation profile (per household)	Wh	Time series	Ausgrid (2018)
Underlying demand profile (per household)	Wh	Time series	Ausgrid (2018)

electricity price increases between 2008 and 2018 (ABS, 2018), retail tariffs are assumed to increase at a fixed rate of 5% per annum.[11] The FiT payments reflect the incumbent retailer conditions (Synergy, 2017) and are only applicable for household PV capacities 5 kW_P and under. PV system costs start at AU\$1400/kW_P[12] (Solar Choice, 2019b) and decrease at −5.9% per annum (Ardani et al., 2018). Linear degradation of PV generation was modelled, with 80% remaining at the end of a 25-year operational lifespan. Battery system costs start at AU \$900/kWh[13] (Solar Choice, 2018; Tesla, 2018) and decrease at −8% per annum (BNEF, 2019b). Technical specifications of the battery model are based on currently available residential lithium-ion battery systems, such as the Tesla Powerwall2[14] and sonnenBatterie.[15] Batteries are simulated with a 100% depth-of-discharge, 5 kW charge and discharge limit, round-trip efficiency of 92% (reflecting warranted performance) and assumes a linear degradation with 70% energy storage capacity remaining at the end of a 10-year operational lifespan. As flat retail tariffs are used, grid-charging and grid-discharging is not simulated. By assuming that households finance the cost of investments using their home loan, a discount rate of 6% is applied, reflecting the 10-year historical average of Australian owner-occupied standard variable home loans (Reserve Bank of Australia, RBA, 2018).

These case study parameters (Fig. 3) reflect constantly increasing retail tariffs, decreasing PV and battery system costs and an adherence to the existing two-part tariff structure over 20-years. The highly interconnected nature of the electricity market means that growing household PV battery adoption would likely drive further structural and financial changes (such as, new retail tariff structures, reducing wholesale energy costs with greater zero-marginal cost renewable generation, distribution and transmission network upgrades, new decentralised energy markets) that have implications on the future value of DER. Explicitly modelling these future power sector reactions remains outside the scope of analysis. Rather we focus on the current business-as-usual expectations to assess the layers of the power sector susceptible to growing household PV battery adoption, thus highlighting to policy makers the parts of the electricity market that may require further energy policy reform.

4. Results

Across all five FiT scenarios, with changing retail market conditions (Fig. 3) and the continued use of two-part (and time-invariant) retail tariffs, progressive investments by households eventually lead to PV-battery systems becoming more cost-effective than PV-only systems (Fig. 4). The proportional value of the FiT however influences the timing and magnitude of this transition. With higher FiT scenarios, the installation of PV-only systems begins earlier (and at a higher average capacity) than the lower FiT scenarios, and eventually plateaus at the 5 kW_P per household FiT eligibility limit. Investments in battery capacity occurs, but later than the lower FiT scenarios. In all FiT scenarios, increases in battery storage capacity also coincides with additional PV capacity which indicates that the arrival of cost-effective batteries drives further growth in installed PV capacity. Furthermore, as households increasingly install PV-battery systems, there is an accelerated reduction in annual grid-imports while annual grid-exports continues to increase. This indicates that, under the assumed retail market conditions, households do not find it cost-effective to install battery capacity such that all PV generation is self-consumed. These overall PV battery adoption patterns are a result of differences in investment behaviour, driven by the use of flat usage charges and FiTs.

Under flat tariff structures, PV battery systems offer households two revenue streams (Fig. 5), a value of self-supply ($\$_{SS}$) and a value of excess generation ($\$_{FiT}$). As these are derived from the difference between the retail usage charge and FiT (Fig. 5a): higher FiTs increase the value of excess generation and decrease the value of self-supply (i.e., prioritising grid-exports); lower FiTs decrease the value of excess generation and increase the value of self-supply (i.e., prioritising self-consumption). With PV-only systems, excess energy is valued at $\$_{FiT}$ while self-consumed generation is valued at $\$_{SS}$ (Fig. 5b). With PV-battery systems however, the amount of energy time-shifted is revalued from the $\$_{FiT}$ to $\$_{SS}$ (Fig. 5c) minus round-trip efficiency losses. Furthermore, the 5 kW_P FiT eligibility limit disincentivises increasing PV generation beyond 5 kW_P and limits the ability of high consumption households to reduce their overall grid-imports. Under each of these FiT scenarios, the various price signals interact and incentivise different investment patterns in the short-term, but collectively begin to follow a similar trajectory over the long-term.

In low-FiT scenarios (FiT_0 and FiT_{25}), the value of self-supply is greater than the FiT (i.e., $\$_{SS} > \$_{FiT}$), hence households are incentivised to dimension their systems to maximise self-consumption while minimising excess PV generation (with respect to overall system costs). During the time that battery systems remain cost-prohibitive a lower average PV capacity is installed, as low FiTs disincentivise the installation of excessively large PV systems due to decreasing marginal benefits with increasing PV capacity. However, once battery systems become cost-effective, households have an option to either, (i) size the battery capacity to utilise existing PV generation, or (ii) upgrade to a larger PV system providing further generation that can utilise a larger capacity battery. Since excess PV generation was previously disincentivised, option (ii) becomes the more cost-effective option. This drives an increase of PV capacity with the installation of battery systems (Fig. 4). Furthermore, low FiT values mean that the loss of FiT revenue (by

[11] This is a simplified assumption that is used to illustrate the effect on household PV battery investments. The low and high sensitivity analyses respectively evaluate inflation rates of 2% and 8% per annum. Significant uncertainty still remains with the trajectory of future electricity prices, with Western Australian wholesale electricity and network costs respectively contributing to approximately 40% and 45% of usage charges (AEMC, 2018a). The attribution of costs between these two components, in a rapidly changing policy and economic environment makes predictions difficult. We therefore utilise the simplified parameter and sensitivity analysis to bound the results within an analysis envelope.

[12] These PV system costs includes the small-scale technology certificate that provides an upfront capital subsidy as part of the federal Renewable Energy Target policy.

[13] As no uniform support mechanisms are currently in place these battery system costs do not include any subsidies.

[14] https://www.tesla.com/en_AU/powerwall.

[15] https://sonnen.com.au/sonnenbatterie/.

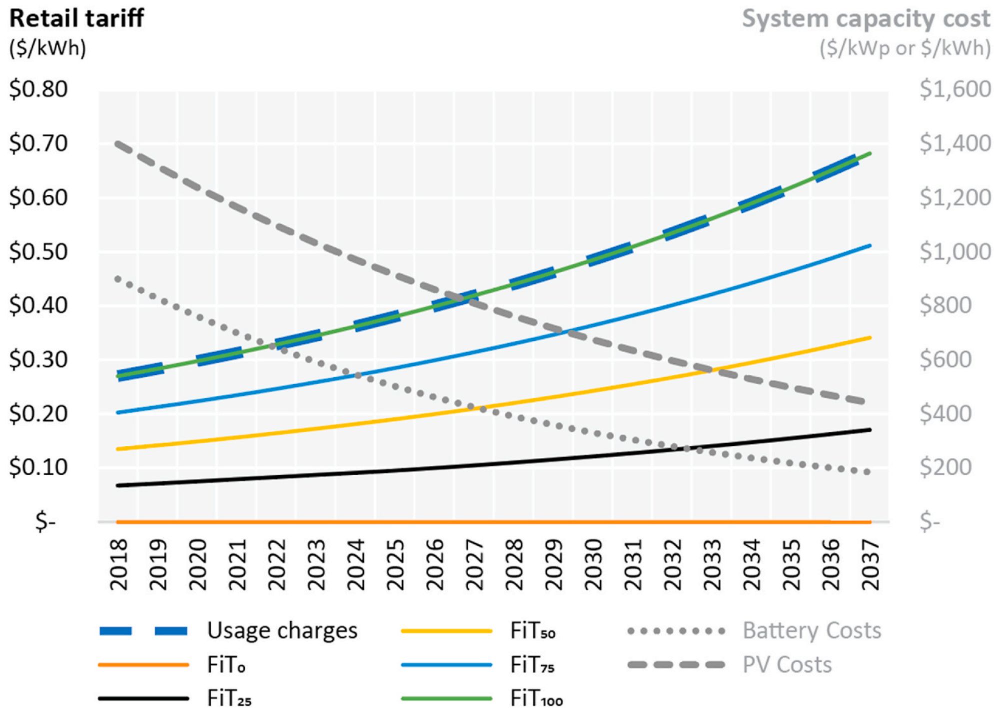

Fig. 3. Changes in retail market conditions over the 20-years of the case study.

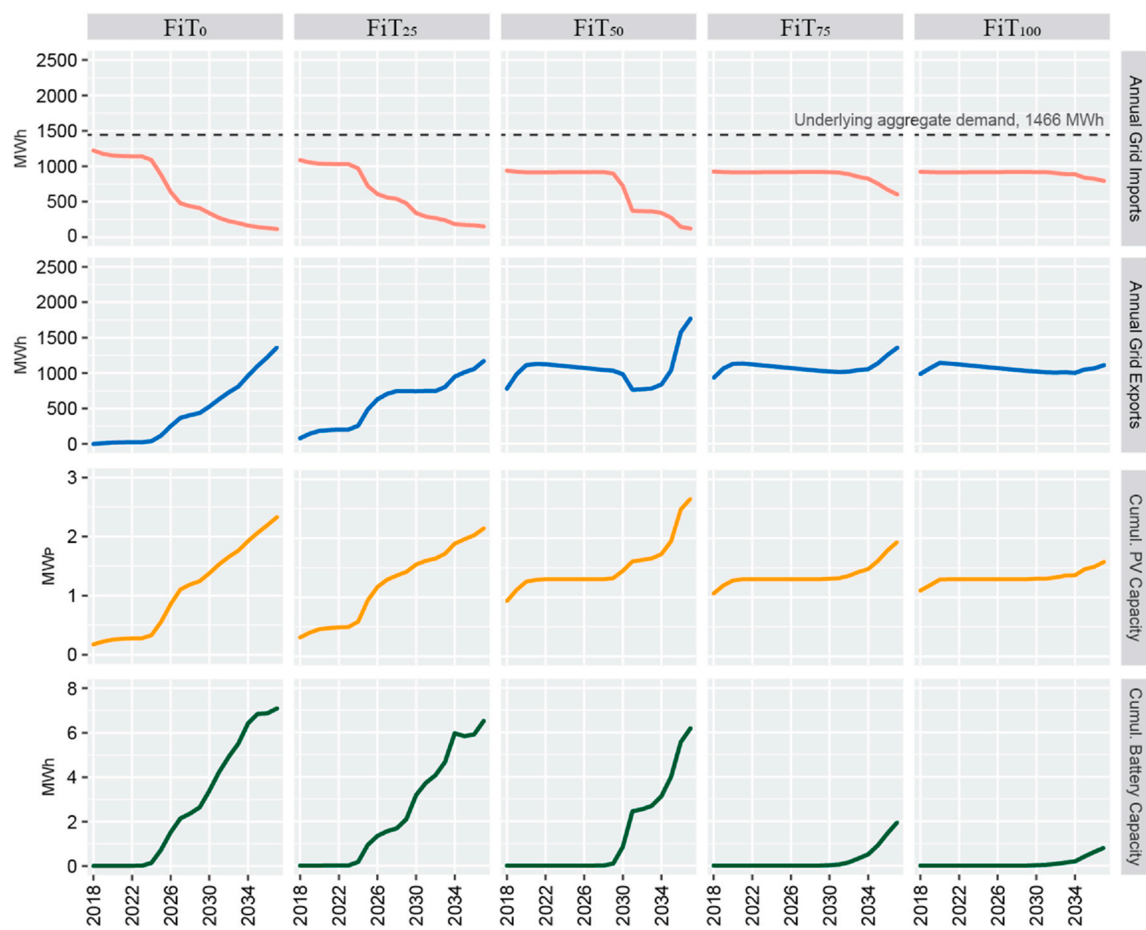

Fig. 4. Comparison of operational results (aggregate of 261 households at an annual resolution) projected over 20-years. The feed-in tariff scenarios (FiT_0, FiT_{25}, FiT_{50}, FiT_{75} and FiT_{100}) respectively value the FiT at 0%, 25%, 50%, 75% and 100% of the retail usage tariff. FiTs are only eligible for households with PV systems 5 kW_P and under.

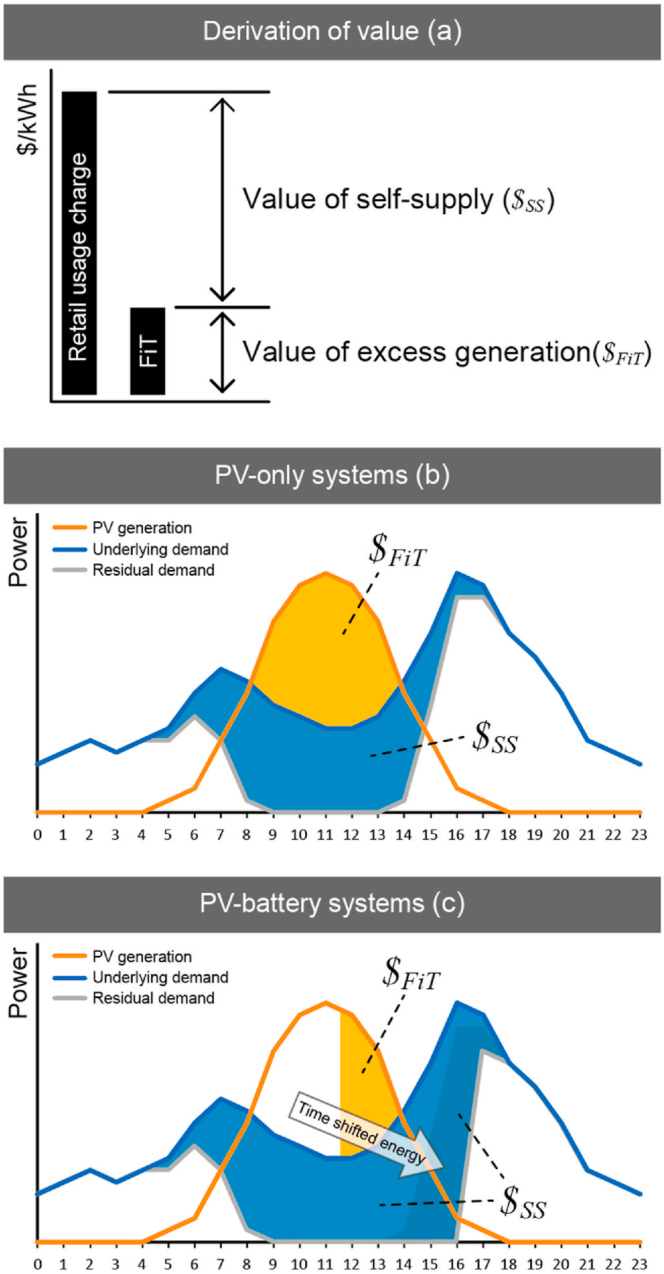

Fig. 5. Value stream (stylised) from household self-generation and energy storage using a utility net-energy meter. (a) Derivation of value. (b) Remuneration from PV-only systems. (c) Remuneration from PV-battery systems.

exceeding the 5 kW$_P$ FiT eligibility limit) does not significantly disincentivise households from installing PV systems > 5 kW$_P$. This results in an earlier transition to PV-battery systems, with continued increases in generation and storage capacity even beyond the high-FiT scenarios. The net-effect with low-FiTs are that households remain economically driven to install PV-battery system capacities that maximise their value from self-consumption as system costs decline.

In high-FiT scenarios (FiT$_{75}$ and FiT$_{100}$), the FiT value is greater than the value of self-supply (i.e., $\$_{FiT} > \$_{SS}$). With FiTs being more

Table 2
Classification ranges of average PV and battery system capacities per household.

Range label	Capacity range
Average installed PV capacity per household (kW$_P$)	
PV-small (PV$_S$)	0.5–4
PV-medium (PV$_M$)	4–8
PV-large (PV$_L$)	8–12
Average installed battery capacity per household (kWh)	
Battery-small (B$_S$)	0.5–10
Battery-medium (B$_M$)	10–20
Battery-large (B$_L$)	20–30

valuable, exceeding the 5 kW$_P$ FiT eligibility limit becomes a stronger disincentive, as losing all FiT revenue becomes more financially significant. Energy storage has limited financial advantage, as it would swap higher valued excess generation ($\$_{FiT}$) for lower valued self-consumption ($\$_{SS}$). The higher value of grid-exports means that low consumption households can cost-effectively invest in a larger PV system (beyond their self-consumption needs) up to 5 kW$_P$ eligibility limit. Conversely, high consumption households are disincentivised from installing systems larger than 5 kW$_P$ (or they would lose FiT revenue) while also receiving proportionally less revenue from excess generation. These conditions cause the average installed PV capacity per household to rapidly converge towards 5 kW$_P$. As retail tariffs increase and system costs decrease, an increasing number of high consumption households (that have higher electricity bills) eventually find it more cost-effective to reduce their electricity bills by increasing self-consumption (with additional PV capacity and large capacity batteries), over artificially limiting their excess generation with a 5 kW$_P$ system. A higher cost of energy and lower system cost is needed to breakeven, thus delaying the transition towards PV-battery systems (Fig. 4). The net-effect with high FiTs, is that households are initially driven to maximise grid-exports up to the 5 kW$_P$ FiT eligibility limit, but eventually (as system costs decline) a growing percentile of high consumption households find it more cost-effective to forego FiT revenue and maximise their value from self-consumption as system costs decline.

In the FiT$_{50}$ scenario, the value of self-supply is equal to the FiT (i.e., $\$_{SS} = \$_{FiT}$) and the resulting investment dynamics comprise of a mix of the high- and low-FiT scenarios (Fig. 4). The first decade of the simulation mirrors the high-FiT scenarios, where the FiT and eligibility limit is sufficient to incentivise the majority of households to invest in 5 kW$_P$ PV systems, while the final decade of the simulation generally mirrors the low-FiT scenarios with a larger amount of pre-installed PV capacity. A transition period between 2030 and 2034 occurs where more households that invest in battery systems choose to retain (rather than increase) their existing PV capacity, leading to a temporary reduction of annual grid-exports. However, from 2035 onwards an increasing majority of households find it more cost-effective to forego FiT revenue with larger PV and battery systems that maximise their value from self-supply over grid-exports.

Across all five FiT scenarios, the flat tariff structure with decreasing PV battery costs and increasing retail electricity tariffs, eventually incentivises households to invest in PV-battery systems (Fig. 4) that maximise the value of self-consumption over excess generation. This leads to households foregoing FiT revenue and gradually investing in PV capacities above 5 kW$_P$ with associated battery storage. This common outcome aligns each FiT scenarios' transition pathways into a set of corresponding grid-operation stages that are used in Section 5 to

Table 3
Grid-operation stages (based on the average PV and battery system capacities per household) for each FiT scenario. Starred scenario-years (*) are used as the representative for each grid-operation stage.

Year	FiT_0	FiT_{25}	FiT_{50}	FiT_{75}	FiT_{100}
2018	PV_S	PV_S*	PV_S	PV_M	PV_M
2019	PV_S	PV_S	PV_M	PV_M	PV_M
2020	PV_S	PV_S	PV_M	PV_M	PV_M*
2021	PV_S	PV_S	PV_M	PV_M	PV_M
2022	PV_S	PV_S	PV_M	PV_M	PV_M
2023	PV_S	PV_S	PV_M	PV_M	PV_M
2024	PV_S:B_S	PV_S:B_S	PV_M	PV_M	PV_M
2025	PV_S:B_S	PV_S:B_S*	PV_M	PV_M	PV_M
2026	PV_S:B_S	PV_M:B_S	PV_M	PV_M	PV_M
2027	PV_M:B_S	PV_M:B_S*	PV_M	PV_M	PV_M
2028	PV_M:B_S	PV_M:B_S	PV_M	PV_M	PV_M
2029	PV_M:B_M	PV_M:B_S	PV_M	PV_M	PV_M
2030	PV_M:B_M	PV_M:B_M*	PV_M:B_S	PV_M	PV_M
2031	PV_M:B_M	PV_M:B_M	PV_M:B_S	PV_M	PV_M
2032	PV_M:B_M	PV_M:B_M	PV_M:B_S	PV_M:B_S	PV_M
2033	PV_M:B_L	PV_M:B_M	PV_M:B_M	PV_M:B_S	PV_M:B_S
2034	PV_M:B_L	PV_M:B_L	PV_M:B_M	PV_M:B_S	PV_M:B_S
2035	PV_M:B_L	PV_M:B_L*	PV_M:B_M	PV_M:B_S	PV_M:B_S
2036	PV_L:B_L	PV_M:B_L	PV_L:B_L	PV_M:B_S	PV_M:B_S
2037	PV_L:B_L	PV_L:B_L*	PV_L:B_L	PV_M:B_S	PV_M:B_S

qualitatively assess the impact of household PV-battery investments on the wider power sector. Two additional sensitivity cases, higher and lower growth retail conditions (Appendix B), were evaluated to assess the robustness of this outcome. The overall qualitative patterns were maintained but with a slower rate of transition in the low growth case and a faster rate of transition in the high growth case.

4.1. *Emergence of grid-operation stages*

Each FiT scenario leads to a different amount of installed PV and battery capacity within each year of the simulation (Fig. 4), but all scenarios lead to a transitional tipping point from household PV-only to PV-battery adoption. As underlying demand for each household is assumed to remain consistent each year, grid-utilisation changes are therefore driven by installed PV and battery capacities. Using the average installed PV and battery capacity per household as independent classifiers (Table 2), we characterise changes in grid-utilisation into a series of distinct grid-operation stages (Table 3). For example, if the average installed PV capacity is 3.5 kW_P (PV-Small) and the average installed battery capacity is 14.5 kWh (Battery-Medium) per household, the resulting grid-operation stage is categorised as 'PV_S:B_M'. If the average installed PV capacity increases to 5 kW_P (PV-Medium), then the subsequent grid-operation stage becomes 'PV_M:B_M'. Changes between these grid-operation stages establishes a broader transition pathway from PV-only to PV-battery households (Fig. 6). As the electricity system and its market operates higher resolution timescales, these grid-operation stages also provide a set of high resolution (30-min time-step) grid-utilisation profiles that establish changes in diurnal and seasonal grid demand. The combination of the broader transition pathway with the diurnal and seasonal changes, provides the numerical

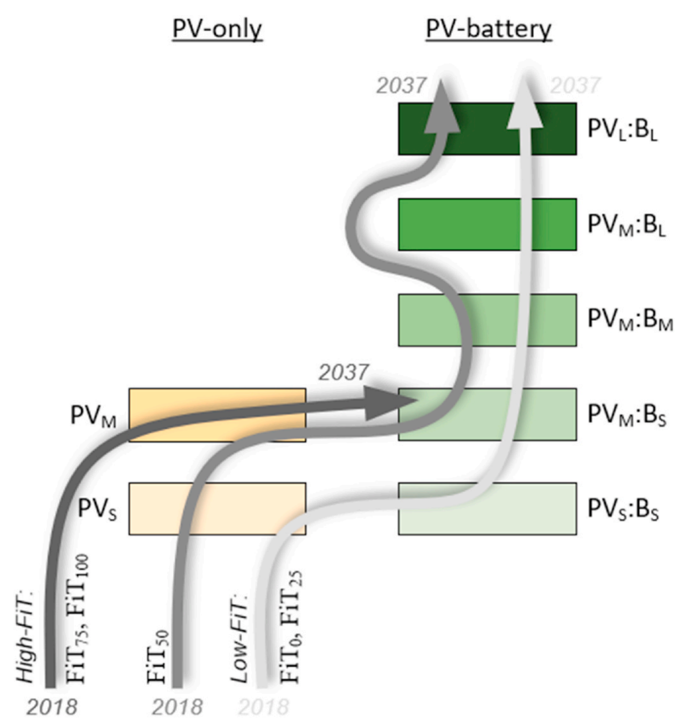

Fig. 6. Transition paths (2018–2037) for each FiT scenario across the various grid-operation stages.

foundation for a qualitative discussion on its wider power sector effects (Section 5).

In total, seven grid-operation stages are identified (Table 3) that range from two PV-only stages (PV_S and PV_M) through to five PV-battery stages (PV_S:B_S, PV_M:B_S, PV_M:B_M, PV_M:B_L and PV_L:B_L). As each grid-operation stage corresponds to a range of PV and battery capacities, specific scenario-years are selected in Table 3 as representatives for each grid-operation stage. The grid-operation stages are evaluated and illustrated individually in Appendix A to determine their diurnal and seasonal operational characteristics. These quantitative changes in grid-operation at the diurnal and seasonal scales are summarised in Table 4. The results show that ongoing investments by households in PV battery systems can significantly change grid-utilisation across a range of operational dimensions that affect the electricity system and its wholesale market.

5. Discussion

By characterising the grid-operation stages, a pathway of transition (Fig. 6) is identified that leads a range of operation effects (Table 4) at the aggregate household level. From the use of real underlying demand and PV generation data from 261 households, the aggregate changes in grid-utilisation are assumed to be representative of PV and battery investing households in the SWIS network. As the paper focuses on transition pathway patterns (rather than forecasts), we use the trajectory of operational changes (Table 4) to qualitatively assess the how layers of the power sector are affected starting from an aggregate household perspective through to the system and market layers.

5.1. Aggregate household perspective

5.1.1. Rising annual peak feed-in with household PV-battery adoption

During the period of PV-only adoption, both the PV_S and PV_M stages (Appendix A.2 and A.3 respectively) exhibit demand-side changes consistent with the "duck curve" (Denholm et al., 2015; Maticka, 2019). At the diurnal scale, minimum demand shifts from night into midday and becomes increasingly negative (Fig. A2d and Fig. A3d). At the seasonal scale, net-exports increase in magnitude over the summer months (Fig. A2a and Fig. A3a). As households' transition from PV-only to PV-battery systems, further changes become evident. Notably, from PV_M:B_S onwards, the average PV capacity per household increases past the 5 kW_P FiT eligibility limit (Table 4), meaning that grid-exports no longer have financial value (increasing the value of self-consumption) which then drives further PV and battery capacity growth. Considering the gradual changes in grid-utilisation from the PV_S:B_S (Fig. A4a) through to the PV_L:B_L (Fig A8a) stage, there is a gradual reduction in the amount of grid consumption over winter, which indirectly causes grid-exports to rise significantly across the summer months. The use of flat tariff structures leads to a series of economically rational decisions. Firstly, underlying energy demand in winter is higher than summer due to more consistent occurrences of night-time heating demand (Fig. A1a). Secondly, reduced solar resources and increased night-time demand over winter requires larger PV capacities to raise self-generation during these months. Thirdly, installing battery capacities larger than would be regularly utilised over the entire year leads to diminishing returns that disincentivise households from installing larger storage capacities. During the summer months, this leads to many household batteries becoming full before midday and allowing peak PV generation to continue feeding into the grid at noon. With PV capacities rising to cover a growing portion of winter demand, peak feed-in during the summer months eventually exceeds the underlying annual peak demand of 663 kW from the PV_M:B_S stage onwards (Table 4).

As flat tariffs do not provide an incentive to change the timing of grid-exports, peak feed-in across the majority of households temporally coincide around noon. As the capacity of the distribution network is designed around the expected annual peak demand plus a reserve margin, increasing peak feed-in from further PV-battery investments exacerbates existing hosting capacity limitations and can lead to reverse power flows beyond the capacity of the distribution network. As system and network operators do not currently have the ability to control behind-the-meter generation, risk mitigation and management strategies would have to be taken, such as restricting grid exports, further network augmentation, installing distribution-scale energy storage, or providing dynamic export limits.

5.1.2. Emergence of an early-morning diurnal peak demand

As is typical of Australian households (AEMO, 2018), the underlying diurnal peak demand occurs most frequently during the late-afternoon between 17:30 and 21:00 (Table 4 and Fig. A1d). Household PV-only and PV-battery systems affect the timing and magnitude of the diurnal peak demand. In the PV-only stages (PV_S and PV_M) the setting sun limits the ability of PV generation to reduce diurnal peak demand, and the late-afternoon peak can only be delayed and reduced slightly (Fig. A2d and Fig. A3d). In the PV-battery stages the timing of diurnal peak demand becomes much more sensitive to variations in insolation and installed PV battery capacities. Starting from the PV_S:B_S stage, the lower generation and storage capacity means that on days with less than ideal insolation, the energy self-generated and stored only delays the late-afternoon peak to around 20:00 (Fig. A4d). But on days with higher insolation, there is sufficient energy self-generated and stored that households are able to self-supply past the underlying late-afternoon peak and into the night, thus temporarily eliminating the late-afternoon diurnal peak demand in the process. Once battery storage capacity is exhausted however, grid-imports are required overnight and into the next morning. These factors lead to the first occurrences of an early-morning diurnal peak demand (Table 4). As PV-battery investments progress from the PV_M:B_S to the PV_M:B_L stage, battery storage capacity increases more than PV capacity. Therefore, on more days of the year, households are able to self-supply further into the night, resulting in an increasing occurrence of the early-morning diurnal peak demand (Fig. A.5d, Fig. A6d and Fig. A7d). By the PV_L:B_L grid-operation stage however, the much larger self-generation and storage capacity allows households to increasingly self-supply through the night and into the next morning, which then removes grid demand over a diurnal cycle and begins to reduce the occurrence of the early-morning diurnal peak demand (Fig. A8d).

5.1.3. Shifting into winter dominant residual demand

Compared to the winter months, the higher levels of summer insolation increase the capability of households to self-supply. Up until the PV_M:B_S stage the annual peak demand remains in summer (Table 4). With increasing household PV battery capacities however, the residual demand profile becomes increasingly winter dominant (e.g. Fig. 6a). From PV_M:B_M onwards, the summer peak is reduced sufficiently that the annual maximum is replaced by the winter peak (Table 4). Considering monthly grid consumption (Fig. 7), the high insolation levels over summer (Dec to Feb) allow households to reduce a significant portion of their overall grid-imports. In the autumn (Mar to May) and spring (Sep

Table 4
Summarised operational results from each representative grid-operation stage.

Description	Underlying	PV_S	PV_M	$PV_S:B_S$	$PV_M:B_S$	$PV_M:B_M$	$PV_M:B_L$	$PV_L:B_L$
Representative scenario *(Year)*	n/a	FiT_{25} (2018)	FiT_{100} (2020)	FiT_{25} (2025)	FiT_{25} (2027)	FiT_{25} (2030)	FiT_{25} (2035)	FiT_{25} (2037)
Average PV capacity per household (kW_P)	0	1.23	4.98	3.64	4.97	5.96	7.59	8.29
Average battery capacity per household (kWh)	0	0	0	3.57	5.94	12.16	22.33	24.94
Annual grid-imports (MWh) *(% grid dependency)*	1466 *(100%)*	1086 *(74%)*	912 *(62%)*	721 *(49%)*	559 *(38%)*	340 *(23%)*	174 *(12%)*	151 *(10%)*
Annual peak demand (kW) *(Season)*	663 *(Summer)*	654 *(Summer)*	643 *(Summer)*	565 *(Summer)*	519 *(Summer)*	400 *(Winter)*	364 *(Winter)*	349 *(Winter)*
Timing of diurnal peak demand *(% occurrence)*	Late afternoon: 17:30–21:00 *(97%)*	Late afternoon: 17:30–21:00 *(97%)*	Late afternoon: 17:30–21:00 *(97%)*	Evening: *Main peak* 20:00–21:30 *(35%)* *distributed over* 18:30–23:00 *(63%)* + Early morning: 06:00–07:30 *(26%)*	Early morning: 05:30–07:30 *(53%)* + Evening/night: 20:00–23:00 *(31%)*	Early morning: 05:30–08:00 *(64%)* + Evening/night: 20:00–23:00 *(24%)*	Early morning: 05:30–07:30 *(40%)* + Evening/night: 19:30–00:30 *(37%)*	Evening/night: 19:30–01:00 *(43%)* + Early morning: 05:30–07:30 *(35%)*
Annual grid-exports (MWh)	0	75	1139	480	701	737	1007	1166
Annual peak feed-in (kW) *(% of underlying annual peak demand)*	0 *(0%)*	145 *(22%)*	914 *(138%)*	611 *(92%)*	865 *(130%)*	1021 *(154%)*	1303 *(196%)*	1438 *(217%)*
Timing of diurnal minimum demand *(% occurrence)*	Early morning: 02:30–05:30 *(96%)*	Midday: 10:30–14:30 *(86%)*	Midday: 10:30–15:00 *(94%)*	Midday: 11:30–15:00 *(92%)*	Midday: 11:30–15:30 *(94%)*	Midday: 11:30–16:00 *(96%)*	Afternoon: 12:00–16:00 *(94%)*	Afternoon: 12:00–15:30 *(91%)*
Peak ramp up rate (kW/min)	3.55	3.65	10.53	6.62	8.85	9.67	12.67	14.49
Peak ramp down rate (kW/min)	−3.43	−3.43	−9.62	−4.87	−6.52	−6.49	−7.28	−8.17

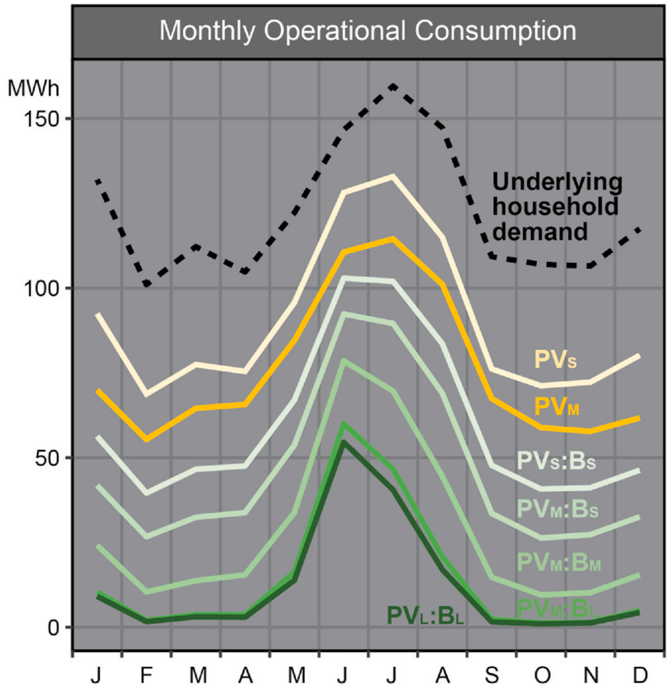

Fig. 7. Monthly grid-imports (aggregate of 261 households) of the underlying household and residual demand from each grid-operation stage.

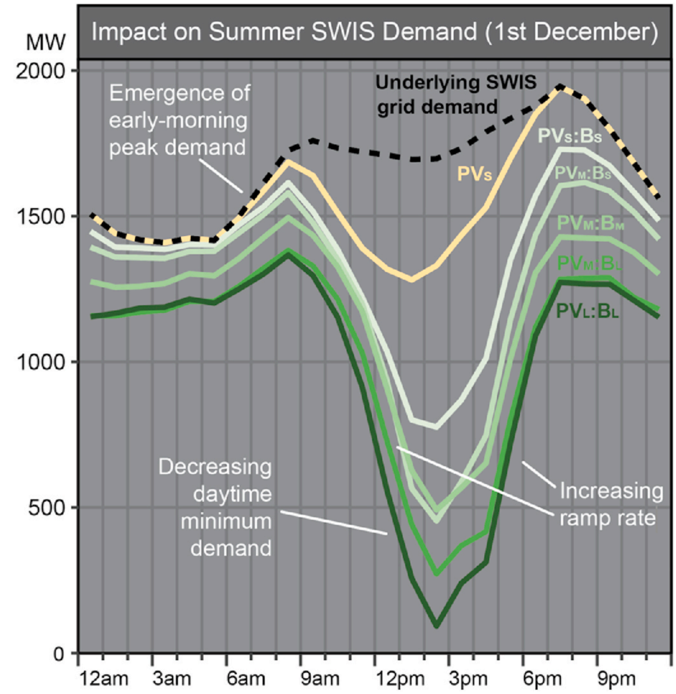

Fig. 8. Impact on summer diurnal demand (1st December) from 270,000 PV-only households transitioning to PV-battery households in the FiT_{25} scenario and using real SWIS network demand (AEMO, 2019c).

to Oct) months, milder weather conditions reduce heating and cooling demand and when coupled with moderate insolation levels, households are able to reduce their grid-imports beyond the summer months. Low insolation levels in the winter months (Jun to Aug) prevents PV-battery systems from operating as effectively, hence grid-imports remain highest over the winter period.

5.2. System and market perspectives

Even though households are only one segment of customers contributing to the total grid demand, growing household investments into PV battery systems are still capable of significantly reshaping how the electricity system and market operates. Using the qualitative impacts from the aggregate household analyses in Section 5.1 and contextualising it as a proportion of customers within the total grid demand, we further analyse how the operational and market layers are affected as households transition from PV-only to PV-battery systems under flat retail tariffs (Fig. 6).

5.2.1. Operational challenges and opportunities

5.2.1.1. PV-battery households becoming net-generators. PV-only systems must continue to rely on grid-sourced energy at night, ensuring a minimum level of grid demand is always maintained. PV-battery systems however can continue to self-supply much further into the night, leading to additional reductions in annual grid-imports (Fig. 4). Furthermore, annual grid exports continue to rise with household PV-battery adoption (Table 4). The net effect is that annual grid-exports from PV-battery households eventually exceed annual grid-imports, making these households become net-generators and a growing source of renewable energy generation. Such an outcome, if widespread, fundamentally challenges traditional liberalised electricity markets, with PV-battery households competing with and displacing utility generation while avoiding fixed electricity system costs. Continued reductions in annual grid-imports also places downward pressure on any growth of total grid demand, which disincentivises future investments into additional bulk-energy utility generation.

5.2.1.2. Changes in timing and ramping of utility-scale generation. As household PV-battery investments progress through each grid-operation stage (Fig. 6), daytime grid feed-in continues to rise (Section 5.1.1), the late-afternoon diurnal peak demand subsides and is gradually replaced by an early-morning diurnal peak (Section 5.1.2). A representation of these residual demand changes on the total grid demand in summer[16] is shown in Fig. 8. Using a rooftop PV penetration rate of 27% (of 1 million households) in the SWIS network (APVI, 2019a), changes in residual demand become clearly capable of affecting the total grid demand:

(i) Overall minimum demand continues to decline as daytime feed-in from PV-battery households increase (with household batteries unable to store all excess PV generation);
(ii) The reduction and shift of diurnal peak demand from the late-afternoon to early morning, by PV-battery households, become capable of affecting the whole system and driving similar changes in the diurnal profile of the total grid demand.

Even though overall diurnal peak demand is reducing, the minimum demand during noon continues to decline, leading to ramp rate increases (Fig. 8). This suggests that as household PV-battery systems become more widespread, the appropriate types of utility generation may be affected. With decreasing annual grid demand (Section 5.2.1) and reductions in diurnal peak demand, there is a reduced need for additional utility generation capacity. However, with increasing ramp rates, flexible generators have an increasing advantage over inflexible baseload generators.

5.2.1.3. Coordination increasingly necessary for household PV-battery assets. These changes in total grid demand are influenced by the continued use of flat retail tariffs. Without a temporal value, there is no

[16] The diurnal SWIS grid profile was obtained via SCADA records (AEMO, 2019c) on 1st December 2012, as it best matches the household data profiles (Ausgrid, 2018) collected between 1st July 2012 and 30th June 2013.

financial benefit for households to operate their DER systems according to the dynamic needs of the electricity system. Currently household DER systems are not centrally monitored or controlled (AEMO, 2019a); hence system and market operations are reactive to household PV-battery adoption and dispatch. Addressing system limitations at the utility-side (e.g. additional peaking generation, utility-scale energy storage, network augmentation) may be more costly than managing household energy resources directly. By developing the capability for system coordination behind-the-meter, not only are operational risks and mitigation costs reduced but a pathway for customers to provide a wider range of energy services becomes available. Furthermore, as household PV battery capacities increase, underutilised generation and storage capacity becomes available behind-the-meter to supply and manage a growing share of overall electricity demand. These changes are likely to involve significant regulation, privacy, and market reforms (AEMC, 2019; AEMO and Energy Networks Australia, 2018) before these behind-the-meter services can be integrated into the electricity network and market.

5.2.2. Electricity market challenges and opportunities

5.2.2.1. Falling retailer revenues necessitates DER market integration. As PV-battery systems can achieve much greater grid-import reductions than PV-only systems,[17] retailers that collect revenues primarily from volumetric usage charges are exposed to significant lost sales from widespread household PV-battery adoption. The transition from PV-only to PV-battery systems also leads to many households foregoing FiT revenues and investing in PV-battery systems with PV capacities above the 5 kW_P FiT eligibility limit (Section 4). As retailers no longer have to pay for household grid-exports, and household PV-battery systems are already sunk costs, any grid services that could be provided by these DER assets (e.g., peak shaving, frequency response, load shifting) has near-zero marginal costs. This creates an opportunity for retailers to reposition themselves from managing the risk of wholesale electricity prices to becoming an agent for DER market participation and encouraging their integration into the wholesale electricity market. However, considerations have to be made within electricity market rules to allow household DER systems to effectively compete for grid services and to allow their potential system and operational savings to be realised across the system (AEMC, 2019).

5.2.2.2. Increasing role for flexible demand. Changes in residual demand from household PV-battery systems (Fig. 8) leads to increased ramping of network demand (Section 5.2.1.2) while reducing overall grid consumption (Section 5.2.1.1). Flexible generation technologies that can respond rapidly to these changes in demand, such as peaking and load balancing facilities, should gain a competitive advantage over inflexible baseload generators. But as their levelised costs of electricity are typically higher than baseload generators (Bloomberg New Energy Finance, BNEF, 2019a; Graham et al., 2018), the increased use of flexible generators may place upward pressure on wholesale electricity prices. However, the integration of household DER systems into the electricity market as a form of flexible demand (with near-zero marginal costs) may provide a competitive alternative to utility-scale peaking and load balancing facilities.

5.3. Limitations and outlook

The results remain dependent on the choice of input parameters and modelling assumptions. A business-as-usual perspective was taken to assess the range of impacts that may emerge from households PV battery investments without endogenous feedback on the potential changes in the wholesale energy market and associated retailer and network costs. This leads to a range of limitations to be considered when interpreting the results.

Underlying electricity demand and solar insolation profiles are repeated year-on-year. By keeping these parameters constant, the results can more clearly show the influence of the retail conditions on household PV battery adoption. However, it also discounts future changes in energy demand, energy efficiency, climatic conditions and ignores the potential of electric vehicles to further reshape the underlying electricity demand. As the demand and solar insolation profiles reflect the specificities of the region, caution is required when transposing results into other regions with different demand and insolation profiles.

Flat usage charge and feed-in tariffs and the default battery operation. Australian retail electricity tariffs are predominantly time-invariant, consisting of a usage and fixed charge (without demand charges). Without a temporal value of energy, batteries are not incentivised to operate beyond improving self-consumption (i.e., default battery operation[18]), as additional layers of operational complexity (e.g., deciding when to grid-charge and grid-discharge) would incur additional costs without further remuneration. The use of time-varying tariffs (that would encourage different operational behaviour) remains outside the scope of this paper.

Uniform household PV battery investment methodology. Results were generated by applying a single investment methodology (based on discounted cash flows from bill savings) to each household. The decision process reflects economically rational homeowners with sufficient income that can finance PV battery investments by extending their existing home loans. With a uniform investment methodology, these results cannot reflect the full spectrum of factors influencing customer PV battery adoption, nor the wide range of financial valuation metrics that households may use to make their investment decisions. However, empirical evidence continues to reaffirm that bill savings (Agnew and Dargusch, 2017; Bondio et al., 2018; Figgener et al., 2019) and home-ownership (Sommerfeld et al., 2017) are significant factors that influence the installation of behind-the-meter energy systems, and discounted cash flows remain widely used in the literature (e.g., Schram, 2018; Schopfer; 2018).

Focus on households. As households remain the largest customer sector installing behind-the-meter PV systems (AEMO, 2019d), this paper focuses on the retail market conditions that affect their PV battery investments. With ownership being a significant influencing factor (Sommerfeld et al., 2017), commercial and industrial (C&I) customers (that are largely tenanted) are disadvantaged from installing DER assets, since risk and benefit sharing between landlords and tenants need to be first established. However, if electricity prices continue to increase, the C&I sector may encourage additional DER growth to reduce their exposure to future price increases and drive another set of electricity system transition patterns.

Future electricity prices and PV battery system costs. Projected electricity prices and PV battery system costs are represented using exogenous scenario parameters and change at a fixed rate each year. With rising (time-invariant) electricity prices and declining system costs, these cost projections only reflect historical Australian business-as-usual conditions and industry price expectations. This paper does not consider further cost dynamics, such as continued changes to the electricity

[17] In the PV_M stage only 38% of grid consumption could be self-supplied, however in the PV_L:B_L stage, over 90% of household grid consumption could be self-supplied (Table 4).

[18] The default mode of battery operation maximises PV self-consumption by, only charging using excess PV generation until full, and only discharging to avoid grid-imports until empty (while remaining within the 5 kW battery inverter limit). As a result, grid-charging and grid-discharging operation is not utilised.

system,[19] introduction of new support policies or further expansion of global PV battery supply chains. Exploring how these dynamics interact and affect subsequent policy decisions may be a promising area for future research.

Access to high resolution and disaggregated household consumption and generation profiles would allow researchers and energy analysts to provide further more extensive analysis to policymakers and system managers, allowing them to be better informed on the expected growth of behind-the-meter PV battery systems and their potential to provide grid services. Further research is required to understand the influence of a broad range of retail tariff structures on household PV battery investment behaviours over time and their system integration impacts. Additional research is required to evaluate and quantify the suitability of various utility-scale generation technologies as households adopt PV battery systems. Future research could also assess the policy costs and carbon abatement potential from household PV battery investments over utility-scale solutions.

6. Conclusions and policy implications

With behind-the-meter PV battery systems, households effectively have the highest dispatch priority on the network. By changing their grid consumption and freely exporting energy into the grid, these prosuming households have the ability to reshape grid demand, revenue streams and displace utility-scale generation. As households are capable of reacting to retail electricity costs by investing in additional PV and battery capacity, policymakers have to carefully consider how future households should interact with the grid and its role in the electricity system.

With flat retail tariffs the temporal value of energy is not exposed to households, thus obsfucating time sensitive price signals for the investment and dispatch of PV battery systems. As these households shift from PV-only to PV-battery systems their aggregate impact significantly reduces grid-imports and increases grid-exports such that households eventually become net-generators. By avoiding system costs that may be incurred from additional operational and market responses necessary to accommodate changes in grid-utilisation, these net-generator households may exacerbate socio-economic inequality by, increasing the cost burden on all other customers, and introducing market inefficiencies by displacing lower cost generation. Government policymakers may be able to avoid making changes at low penetration rates, but as PV-battery households become more widespread (as is the potential on the SWIS) their power sector impacts can no longer be ignored, which would require action from both government policymakers and power system regulators.

PV-battery households should eventually be treated like other generators that supply electricity to the grid, with responsibilities to provide firm and reliable power when it is required. Either proscriptive or price-based policies can be used. Households that want to supply electricity to the grid should accept a common grid code that provides system-level visibility, aligns their operational dynamics, and allows remote feed-in management. This would allow critical system operation or market prices to determine when electricity can be exported. Recouping costs associated with the negative externalities from PV-battery households (e.g., extra costs imposed on the distribution network, lost retailer revenues) will also be necessary. Increasing fixed daily charges over volumetric usage charges, potentially limits the incentive for further PV battery adoption, but applies to all customers and is thus regressive. An access fee could be applied when exporting to the grid, which places the cost burden only on prosuming households, but discourages PV exports with their carbon abatement potential. Another approach is to reduce these negative externalities by changing when PV exports occur. For example, by introducing time-varying FiTs[20] that reflect the temporal value of grid-exports (i.e., significantly reducing the value of midday grid-exports and increasing their value during peak hours). Over the short-term this should discourage further increases in PV capacity while also bringing forward the timing and scale of battery systems. By better aligning grid-exports with peak demand rather than midday minimum operational demand, there is less pressure on wholesale electricity prices. Finally, using retail aggregators[21] to manage household grid-exports and grid-imports in line with the wholesale electricity market should increase competition for flexible generation and demand, and improve the market's economic efficiency, further lowering prices for all electricity customers. As our analysis has shown, reducing the value of the FiT accelerates PV-battery adoption which improves the capability of households to provide firm capacity. This provides policymakers with an opportunity to provide the price signals that encourage prosuming households to better align their load and generation with the needs of the wider electricity system.

This paper illustrates the potential magnitude of changes and challenges that continuous investments by households into PV-battery systems, under flat retail tariffs, may have on the electricity system. These households are effectively using private capital to invest into the power sector, and as the cost-effective tipping point for PV-battery systems approaches, it becomes increasingly important to develop policy strategies that encourage future household investments to complement the electricity system and allow customers to play a bigger role in decarbonising the power sector.

CRediT authorship contribution statement

Kelvin Say: Conceptualization, Methodology, Software, Formal analysis, Writing – original draft, Writing – review & editing, Visualization. **Michele John:** Supervision, Writing – review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Representative grid-operation stages

For each representative stage, the following sub-sections describe the changes to annual grid-operation at a 30-min resolution. The values are

[19] Such as, the wider integration of zero-marginal cost generation that can reduce wholesale electricity prices, or the modernisation of distribution networks that may raise network and operation costs.

[20] https://www.esc.vic.gov.au/electricity-and-gas/electricity-and-gas-tariffs-and-benchmarks/minimum-feed-tariff.

[21] https://homebatteryscheme.sa.gov.au/join-a-vpp.

summarised and presented in Table 4 with the transitional implications discussed in Section 5.

A.1. Underlying aggregate household demand

The annual grid-imports from the 261 household customers (Ausgrid, 2018) is 1466 MWh with an annual peak demand of 663 kW (Fig. A1a and Fig. A1b) that occurs in summer due to high cooling loads. The average annual consumption is 5.62 MWh per household with an average solar PV capacity factor of 14.8%. The diurnal peak demand typically occurs in the late-afternoon between 17:30 and 21:00 and the diurnal minimum demand typically occurs in the early-morning between 02:30 and 05:30 (Fig. A1c and Fig. A1d).

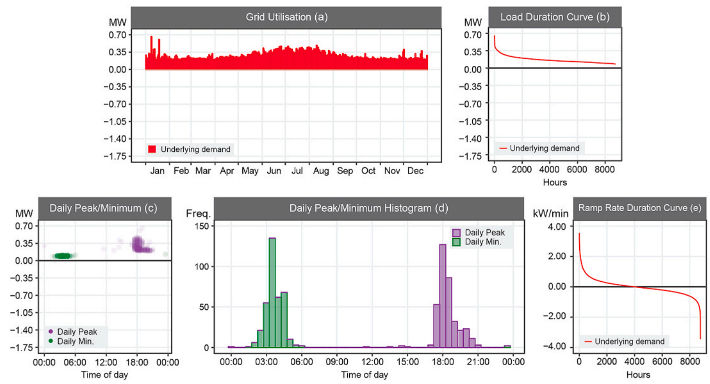

Fig. A.1. Annual grid-utilisation (aggregate of 261 households) of the underlying demand. (a) Half-hourly grid-imports. (b) Load duration curve. (c) Capacity and timing of diurnal demand peaks and minimums. (d) Histogram of diurnal demand peaks and minimums across each time interval. (e) Ramp rate duration curve.

A.2. PV-small only (PV_S) stage

The PV_S stage is represented with the time-series residual grid-utilisation from the FiT_{25} scenario in the year 2018 (Table 3) with an average PV capacity of 1.23 kW_P and no installed battery capacity (Fig. 4).

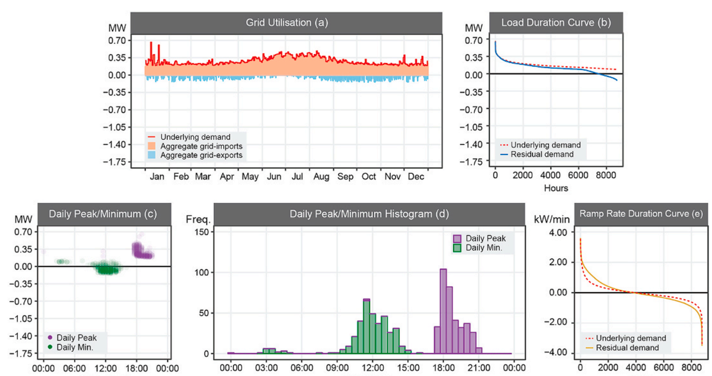

Fig. A.2. Annual grid-utilisation (aggregate of 261 households) at the PV_S (PV-small) operational stage. (a) Half-hourly grid-imports and grid-exports of residual and underlying demand. (b) Load duration curve of residual and underlying demand. (c) Capacity and timing of diurnal demand peaks and minimums. (d) Histogram of diurnal demand peaks and minimums across each time interval. (e) Ramp rate duration curve of residual and underlying demand.

The grid-utilisation (Fig. A2a) shows significant grid-imports remaining over the year and annual grid-imports of 1086 MWh. Compared to underlying demand, annual peak demand is slightly reduced to 654 kW (Fig. A2b) while continuing to occur in summer. Customer annual grid-exports total 75 MWh and peaks at 145 kW (Fig. A2b). The diurnal peak demand remains predominantly in the late-afternoon between 17:30 at 21:00 (Fig. A2c) but with 56% more peak demand periods occurring between 19:30 and 21:00 (Fig. A2d). More significantly, the diurnal minimum demand period moves from a positive value in the early-morning (Fig. A1c) to an increasingly negative value around midday (Fig. A2c), the implications of which are discussed in Section 5.1.1.

A.3. PV-medium only (PV_M) stage

The PV_M stage is represented with the time-series residual grid-utilisation from the FiT_{100} scenario in the year 2020 (Table 3) with an average PV capacity of 4.98 kW_P and no installed battery capacity (Fig. 4).

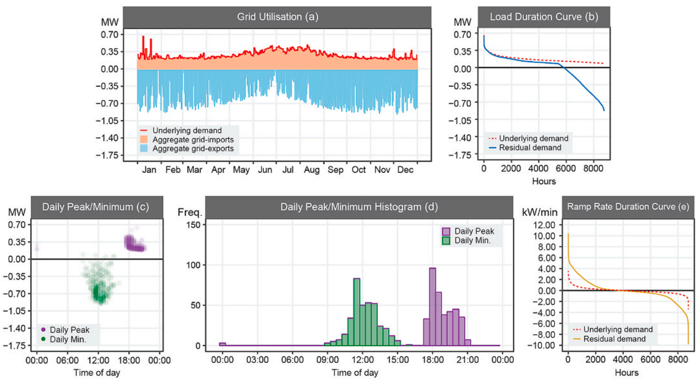

Fig. A.3. Annual grid-utilisation (aggregate of 261 households) at the PV_M (PV-medium) operational stage. (a) Half-hourly grid-imports and grid-exports of residual and underlying demand. (b) Load duration curve of residual and underlying demand. (c) Capacity and timing of diurnal demand peaks and minimums. (d) Histogram of diurnal demand peaks and minimums across each time interval. (e) Ramp rate duration curve of residual and underlying demand.

Compared to PV_S, the greater installed PV capacity in PV_S has further reduced annual grid-imports to 912 MWh (Fig. 4). The grid-utilisation (Fig. A3a) shows that the majority of grid-imports continues and annual peak demand only slightly reduces to 643 kW (and occurs in summer). The diurnal peak demand period remains predominantly in the late-afternoon between 17:30 at 21:00 (Fig. A3c) but with a further increase in the evening periods between 19:00 and 21:00 (Fig. A3d). The additional PV capacity (compared to PV_S) significantly increases customer annual grid-exports to 914 MWh (Fig. A3a) that peaks at 914 kW (Fig. A3b). This grid-export peak exceeds the underlying peak demand of 663 kW, which has implications for network capacity design (discussed in Section 5.1.1).

A.4. PV-small and battery-small (PV_S:B_S) stage

The PV_S:B_S stage is represented with the time-series residual grid-utilisation from the FiT_{25} scenario in the year 2025 (Table 3) with an average PV capacity of 3.64 kW_P and an average battery capacity of 3.57 kWh per household (Fig. 4).

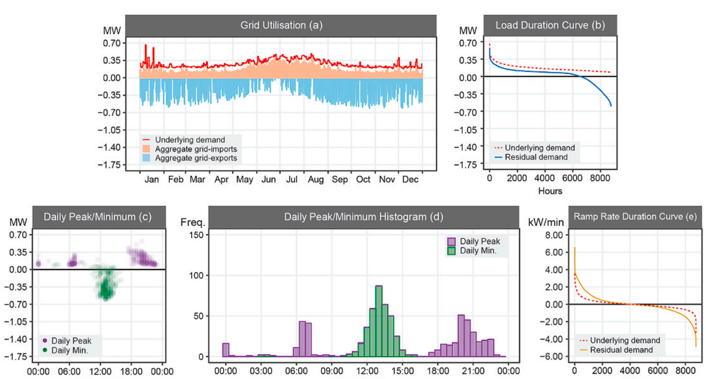

Fig. A.4. Annual grid-utilisation (aggregate of 261 households) at the PV_S:B_S (PV-small and battery-small) operational stage. (a) Half-hourly grid-imports and grid-exports of residual and underlying demand. (b) Load duration curve of residual and underlying demand. (c) Capacity and timing of diurnal demand peaks and minimums. (d) Histogram of diurnal demand peaks and minimums across each time interval. (e) Ramp rate duration curve of residual and underlying demand.

Compared to PV_S, the widespread adoption of low-capacity battery systems leads to a more consistent reduction in annual grid-imports (Fig. A4a). Annual grid-imports fall to 721 MWh while annual peak demand reduces more sharply to 565 kW (Fig. A4b) (remaining in summer). The installation of low-capacity battery systems also raises the average level of installed PV capacity from 1.23 kW_P to 3.64 kW_P per household that increases PV self-generation and improves the overall self-consumption and financial benefits from the PV-battery system (discussed in Section 4). The net effect of the higher installed PV capacity per household is an increase in annual grid-exports to 480 MWh that peaks at 611 kW in summer (Fig. A4a and Fig. A4b). The timing of diurnal peak demand shifts from the late-afternoon into two separate time intervals, firstly a wider evening peak (concentrated between 20:00 and 21:30 but distributed over 18:30 and 23:00), and a second early-morning peak (between 06:00 at 07:30). Furthermore, the timing of the diurnal minimum demand is generally delayed by an hour (between 11:30 and 15:00). These changes to diurnal peak and minimum demand are discussed in Section 5.1.2.

A.5. PV-medium and battery-small (PV_M:B_S) stage

The PV_M:B_S stage is represented with the time-series residual grid-utilisation from the FiT_{25} scenario in the year 2027 (Table 3) with an average PV capacity of 4.97 kW_P and an average battery capacity of 5.94 kWh per household (Fig. 4).

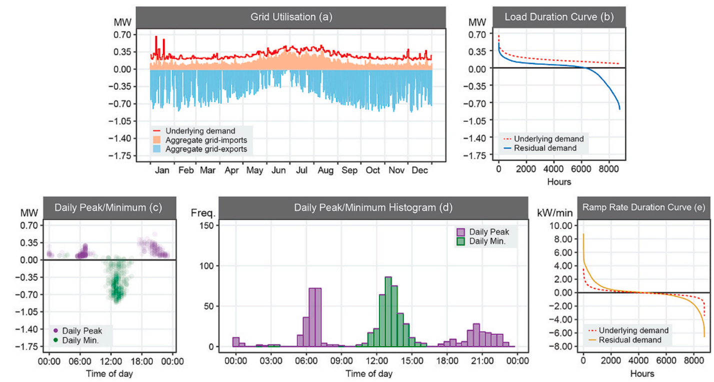

Fig. A.5. Annual grid-utilisation (aggregate of 261 households) at the PV_M:B_S (PV-medium and battery-small) operational stage. (a) Half-hourly grid-imports and grid-exports of the residual and underlying demand. (b) Load duration curve of residual and underlying demand. (c) Capacity and timing of diurnal demand peaks and minimums. (d) Histogram of diurnal demand peaks and minimums across each time interval. (e) Ramp rate duration curve of residual and underlying demand.

Compared to PV_S:B_S, the increase in installed PV capacity further reduces grid-imports across non-winter months (Fig. A5a) with annual grid-imports falling to 559 MWh that peaks at 519 kW in the summer (Fig. A5b). The increase in self-generation also leads to an increase in annual grid-exports to 701 MWh (Fig. A5a) that peaks at 865 kW (Fig. A5b). This grid-export peak exceeds the underlying peak demand of 663 kW, which has implications for network capacity constraints (discussed in Section 5.1.1). Moreover, annual grid-exports (701 MWh) exceeds annual grid-imports (559 MWh) leading to further grid and market implications (discussed in Section 5.2.1.1). The diurnal demand profile continues to shift, with peak demand in the evening between 20:00 and 23:00 diminishing, and occurring more consistently during the early-morning between 05:30 and 07:30 (Fig. A5d). The diurnal minimum demand remains between 11:30 and 15:30 and continues to decrease in magnitude (Fig. A5c).

A.6. PV-medium and battery-medium (PV_M:B_M) stage

The PV_M:B_M stage is represented with the time-series residual grid-utilisation from the FiT_{25} scenario in the year 2030 (Table 3) with an average PV capacity of 5.96 kW_P and an average battery capacity of 12.16 kWh per household (Fig. 4).

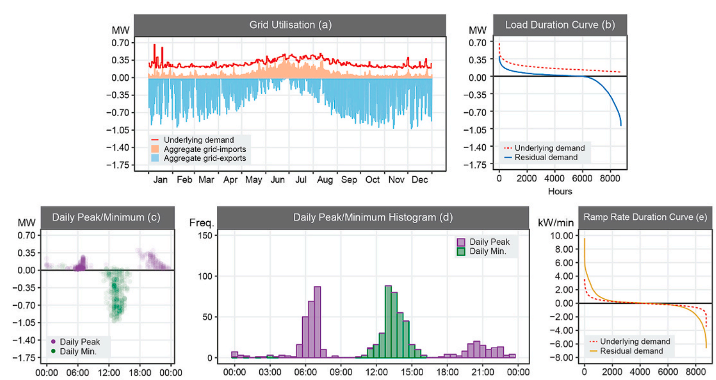

Fig. A.6. Annual grid-utilisation (aggregate of 261 households) at the PV_M:B_M (PV-medium and battery-medium) operational stage. (a) Half-hourly grid-imports and grid-exports of the residual and underlying demand. (b) Load duration curve of residual and underlying demand. (c) Capacity and timing of diurnal demand peaks and minimums. (d) Histogram of diurnal demand peaks and minimums across each time interval. (e) Ramp rate duration curve of residual and underlying demand.

Compared to PV_M:B_S, the additional installed battery capacity leads to further reductions in grid-imports in the non-winter months (Fig. A6a). Annual grid-imports falls significantly to 340 MWh, which means only 23% of the underlying aggregate demand is supplied by the grid. Annual peak demand also falls to 400 kW (Fig. A6b) and occurs in the winter (Fig. A6a) indicating that network demand has become winter dominant (discussed in Section 5.1.3). Annual grid-exports increases slightly to 737 MWh (Fig. A6a) with a higher peak of 1021 kW (Fig. A6b). The diurnal demand profile also changes slightly, with the occurrence of the evening peak further diminishing between 20:00 and 23:00 and increasing in the early-morning between 05:30 and 08:00 (Fig. A6d). The timing of diurnal minimum demand widens slightly to between 11:30 and 16:00 (Fig. A6d).

A.7. PV-medium and battery-large (PV_M:B_L) stage

The PV_M:B_L stage is represented with the time-series residual grid-utilisation from the FiT_{25} scenario in the year 2035 (Table 3) with an average PV capacity of 7.59 kW_P and an average battery capacity 22.34 kWh per household (Fig. 4).

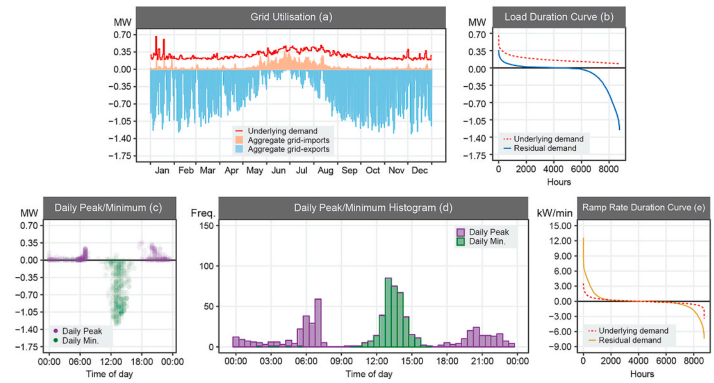

Fig. A.7. Annual grid-utilisation (aggregate of 261 households) at the PV_M:B_L (PV-medium and battery-large) operational stage. (a) Half-hourly grid-imports and grid-exports of the residual and underlying demand. (b) Load duration curve of residual and underlying demand. (c) Capacity and timing of diurnal demand peaks and minimums. (d) Histogram of diurnal demand peaks and minimums across each time interval. (e) Ramp rate duration curve of residual and underlying demand.

Compared to PV_M:B_M, the additional installed battery capacity leads to even further reductions in grid-imports across the non-winter months (Fig. A7a) with annual grid-imports almost halving to 174 MWh, which means only 12% of the underlying aggregate demand is supplied by the grid. Annual peak demand reduces to 364 kW (Fig. A7b) and continues to occur in the winter (Fig. A7a). Annual grid-exports increases to 1007 MWh (Fig. A7a) that peaks at 1303 kW (Fig. A7b). The timing of diurnal demand changes, with the early-morning peak between 05:30 and 07:30 reducing in occurrence, while the evening peak further widening to be between 19:30 and 00:30 (Fig. A7d). The timing of diurnal minimum demand also shifts into the afternoon between 12:00 and 16:00 (Fig. A7c and Fig. A7d) as higher average battery capacities are able to store more self-generation.

A.8. PV-large and battery-large (PV_L:B_L) stage

The PV_L:B_L stage is represented with the time-series residual grid-utilisation from the FiT_{25} scenario in the year 2037 (Table 3) with an average PV capacity of 8.30 kW_P and an average battery capacity between 24.94 kWh per household (Fig. 4).

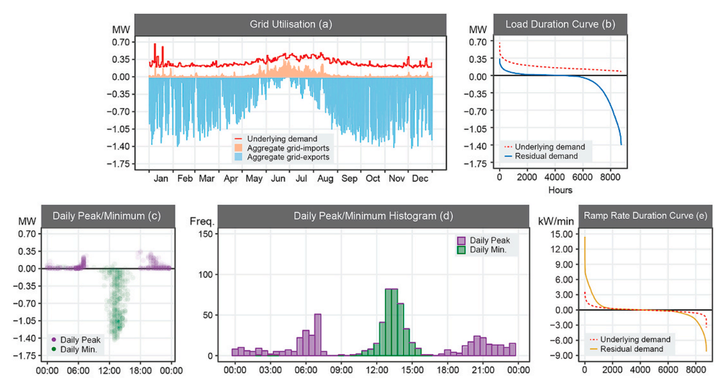

Fig. A.8. Annual grid-utilisation (aggregate of 261 households) at the PV_L:B_L (PV-large and battery-large) operational stage. (a) Half-hourly grid-imports and grid-exports of the residual and underlying demand. (b) Load duration curve of residual and underlying demand. (c) Capacity and timing of diurnal demand peaks and minimums. (d) Histogram of diurnal demand peaks and minimums across each time interval. (e) Ramp rate duration curve of residual and underlying demand.

Compared to PV_M:B_L, the increased installed PV capacity further reduces annual grid-imports to 151 MWh that peaks at 349 kW in winter (Fig. A8a and Fig. A8b). Annual grid-exports continues to increase to 1166 MWh (Fig. A8a), which significantly exceeds annual grid-imports (discussed in Section 3.2). The grid-export peaks at 1438 kW (Fig. A8b) which is more than double the underlying demand peak of 663 kW. The timing of the diurnal demand mostly remains the same, with the early-morning peak remaining between 05:30 and 07:30 and the evening peak further widening to between 19:30 and 01:00 (Fig. A8d). The timing of diurnal minimum demand remains in the afternoon between 12:00 and 15:30 (Fig. A8c and Fig. A8d).

Appendix B. Sensitivity analysis

The low and high growth retail conditions assume the following parameters in Table B1. All other parameters remain as defined in Table 1. In both sensitivity cases, the full range of FiT scenarios between 0% and 100% are evaluated. More detailed numerical results are included as part of the Research Data (Appendix D).

Table B.1
Additional low and high sensitivity cases with respect to the reference.

Scenario parameter	Unit	Low	Reference	High
Discount rate	%/a	10	6	2
Change in tariff charges/rebates	%/a	2	5	8
Change in installed PV system costs	%/a	−3	−5.9	−9
Change in installed battery system costs	%/a	−4	−8	−12

B.1. Low growth case

Under the low growth case, the discount rate, projected reduction in PV and battery systems costs, retail tariffs and associated feed-in tariffs are reduced (Table B1). This reduces the expected electricity bill cost savings while also raising upfront costs. Using the same capacity categories as from Table 2, the transition to PV-only and PV-only to PV-battery households occurs later while the average installed capacities are also reduced in each FiT scenario (Table B2). Furthermore, the transition from PV-only to PV-battery systems in the FiT_{75} and FiT_{100} scenarios are delayed beyond the 20-year evaluation period. However, the PV battery adoption pattern across each FiT scenario remained qualitatively similar when compared to the reference case (Table 3) but with a decelerated transition between each representative grid-operation stage. Numerical values are provided in the research data.

Table B.2
Grid-operation stages (based on the average PV and battery system capacities per household) for each FiT scenario in the low growth sensitivity scenario.

Year	FiT_0	FiT_{25}	FiT_{50}	FiT_{75}	FiT_{100}
2018	-	-	PV_S	PV_S	PV_S
2019	-	-	PV_S	PV_S	PV_S
2020	-	PV_S	PV_S	PV_S	PV_S
2021	PV_S	PV_S	PV_S	PV_S	PV_M
2022	PV_S	PV_S	PV_S	PV_M	PV_M
2023	PV_S	PV_S	PV_S	PV_M	PV_M
2024	PV_S	PV_S	PV_S	PV_M	PV_M
2025	PV_S	PV_S	PV_S	PV_M	PV_M
2026	PV_S	PV_S	PV_S	PV_M	PV_M
2027	PV_S	PV_S	PV_S	PV_M	PV_M
2028	PV_S	PV_S	PV_S	PV_M	PV_M
2029	PV_S	PV_S	PV_M	PV_M	PV_M
2030	PV_S	PV_S	PV_M	PV_M	PV_M
2031	PV_S	PV_S	PV_M	PV_M	PV_M
2032	PV_S	PV_S	PV_M	PV_M	PV_M
2033	PV_S	PV_S	PV_M	PV_M	PV_M
2034	PV_S:B_S	PV_S:B_S	PV_M	PV_M	PV_M
2035	PV_S:B_S	PV_S:B_S	PV_M	PV_M	PV_M
2036	PV_S:B_S	PV_M:B_S	PV_M	PV_M	PV_M
2037	PV_S:B_S	PV_M:B_S	PV_M	PV_M	PV_M

B.2. High growth case

Under the high growth case, the discount rate, projected reduction in PV and battery systems costs, retail tariffs and associated feed-in tariffs are increased (Table B1). This increases the expected electricity bill cost savings while also lowering upfront costs. As average PV and battery capacities in the later years exceeded the capacity categories from Table 2, PV capacities greater than 12 kW_P and battery capacities greater than 30 kWh are respectively categorised as PV_{XL} and B_{XL}. The transition from PV-only to PV-battery households occurs earlier while also increasing the average installed capacities in each FiT scenario (Table B3). Furthermore, FiT_{75} exhibited a transition pattern similar to FiT_{50}, where it quickly catches up to the average installed PV battery capacities in lower FiT scenarios. The PV battery adoption pattern across each FiT scenario remained qualitatively similar to the reference case (Table 3) but with an accelerated transition between each representative grid-operation stage. Numerical values are provided in the research data.

Table B.3
Grid-operation stages (based on the average PV and battery system capacities per household) for each FiT scenario in the high growth sensitivity scenario.

Year	FiT_0	FiT_{25}	FiT_{50}	FiT_{75}	FiT_{100}
2018	PV_S	PV_S	PV_M	PV_M	PV_M
2019	PV_S	PV_S	PV_M	PV_M	PV_M
2020	PV_S	PV_S	PV_M	PV_M	PV_M
2021	PV_S:B_S	PV_S	PV_M	PV_M	PV_M
2022	PV_S:B_S	PV_S	PV_M	PV_M	PV_M
2023	PV_M:B_S	PV_M:B_S	PV_M	PV_M	PV_M
2024	PV_M:B_M	PV_M:B_S	PV_M	PV_M	PV_M
2025	PV_M:B_M	PV_M:B_S	PV_M:B_S	PV_M	PV_M
2026	PV_M:B_M	PV_M:B_M	PV_M:B_M	PV_M:B_S	PV_M
2027	PV_M:B_L	PV_M:B_M	PV_M:B_M	PV_M:B_S	PV_M:B_S
2028	PV_L:B_L	PV_M:B_L	PV_M:B_M	PV_M:B_S	PV_M:B_S
2029	PV_L:B_L	PV_M:B_L	PV_M:B_M	PV_M:B_S	PV_M:B_S
2030	PV_L:B_L	PV_M:B_L	PV_L:B_L	PV_M:B_M	PV_M:B_S
2031	PV_L:B_{XL}	PV_L:B_{XL}	PV_L:B_L	PV_L:B_M	PV_M:B_S
2032	PV_L:B_{XL}	PV_L:B_{XL}	PV_L:B_{XL}	PV_L:B_L	PV_M:B_S
2033	PV_{XL}:B_{XL}	PV_L:B_{XL}	PV_L:B_{XL}	PV_L:B_L	PV_M:B_S
2034	PV_{XL}:B_{XL}	PV_L:B_{XL}	PV_L:B_{XL}	PV_L:B_L	PV_L:B_M
2035	PV_{XL}:B_{XL}	PV_L:B_{XL}	PV_{XL}:B_{XL}	PV_{XL}:B_{XL}	PV_L:B_M
2036	PV_{XL}:B_{XL}	PV_{XL}:B_{XL}	PV_{XL}:B_{XL}	PV_{XL}:B_{XL}	PV_L:B_M
2037	PV_{XL}:B_{XL}	PV_{XL}:B_{XL}	PV_{XL}:B_{XL}	PV_{XL}:B_{XL}	PV_L:B_L

Appendix C. Techno-economic model

C.1. Key modelling assumptions

Electroscape is an open-source model written in R and developed as part of earlier research by the authors (Say et al., 2018, 2019). The aim of the model is to assess PV battery investment outcomes that are specific to a household's demand and insolation profile, expected retail and feed-in tariffs, and installed PV battery system costs. Electroscape consists of three components, a *technical model* that evaluates the operation of a specific PV and/or battery capacity on a household's load profile, a *financial model* that calculates the financial viability of that choice, and an *investment decision model* that evaluates across a range of PV battery combinations to determine if the household should make an investment, and the most suitable PV and/or battery capacity to invest in. If an investment is made, the household demand profile is updated, and the process repeats for the following year. The grid-utilisation changes are generated by applying Electroscape to each of the 261 households and aggregating the results. The key modelling assumptions in this paper are summarised as follows:

- Underlying household demand profiles, insolation profiles, expected retail and feed-in tariffs, and expected PV battery system costs are exogenous parameters.
- Feed-in tariff payments are only eligible for households with a combined PV capacity of 5 kW_P and under.
- Household demand and insolation profiles from Sydney, Australia are used as representative examples for Perth, Australia.
- The meter data from Sydney, Australia consists of half-hourly resolution underlying demand and PV generation data between July 1, 2012 and June 30, 2013 collected from gross utility energy meters (Ausgrid, 2018).
- Insolation profiles are calculated by normalising the PV generation utility meter data with the declared PV capacity.
- The annual underlying demand and insolation profiles for each household are repeated for each year of the simulation.
- The PV battery investment transition results for each household are independently evaluated.
- PV generation performance degrades linearly.
- Battery energy storage capacity degrades linearly.
- Battery charge/discharge efficiencies and operational performance remain constant over its operational lifespan.
- The operational lifespan of battery systems matches their warranty period of 10 years.
- Batteries operate to maximise PV self-consumption and with flat tariffs, grid-charging and grid-discharging operation is not evaluated.

C.2. Technical model

For a single household, the *investment decision model* requires the discounted cash flows over a 10-year financial horizon from potentially installing a range of PV battery combinations. The *technical model* provides the 10-year grid-utilisation profile used to define these discounted cash flows. Given a specific PV capacity (p) and battery capacity (b) the *technical model* will simulate their operation using a household's load and insolation profiles (at 30-min resolution). The PV generation profile is calculated by scaling the insolation profile by the PV capacity with a linear degradation in generation (80% capacity after 25-years). An 'intermediate net-load' profile is calculated by subtracting the PV generation profile from the household's load profile. A battery simulation model (based on the Tesla Powerwall 2) maximises PV self-consumption by using excess generation from the 'intermediate net-load' to charge the battery (while under a 5-kW limit) until it is full, and during times where PV generation is below that of 'intermediate net-load', the battery will discharge (while under the 5 kW limit) until it is empty. Reflecting technical specifications, the battery simulation model assumes a 100% depth-of-discharge, round-trip efficiency of 89%, and a linear degradation in battery capacity (70% remaining after 10-years). After the battery simulation model, the resulting residual load profile reflects the grid-utilisation after having installed the specific PV and battery system.

C.3. Financial and investment decision model

The residual load profile coupled with the projected retail tariffs and FiT is used to determine the expected electricity bills over the next 10 years. By comparing this electricity bill with a scenario without additional PV or battery systems installed, the expected cash flow over 10-years are calculated (C.2). By factoring in the installation cost of the PV (p) and battery (b) system (C.8) and the discount rate (R_d), the value of the PV battery investment can be expressed as NPV (C.1). Each PV battery combination is then evaluated and treated as competing investment opportunities and valued according to their NPV (C.9). The PV battery configuration with the largest NPV becomes a prime candidate for installation.

To represent a minimum level of awareness and investment confidence before households commit their limited financial capital, an additional test is performed. Reflecting the use of discounted payback periods by the AEC (2019) to report on the attractiveness of PV investments across Australia, this model requires at least one of the evaluated PV battery configurations to have a discounted payback of under 5 years before deciding to install the PV and/or battery system with the highest NPV. Once the system is installed, the household load profile is updated, and all subsequent PV battery investments must consider this installed system. This allows the model to simulate how households transition to different types of PV battery investments as the retail cost factors change over time. The PV battery investment results for each household are provided in the research data.

As previously described in Say et al. (2019) the financial equations are as follows, the profitability of each PV and battery investment in each year (t) of the simulation can be expressed as an NPV that depends on discounted annual cash flows over the 10-year investment horizon (N) and upfront system costs.

$$NPV(p,b,t)=\sum_{n=1}^{10}\frac{Cash\ Flow(p,b,n,t)}{(1+R_d)^n}-Cost(p,b,t) \tag{C.1}$$

where, p = Rated PV capacity (kW_P); and
b = Battery energy storage capacity (kWh)

$$Cash\ Flow(p,b,n,t)=Bills_{Base}(n,t)-Bills_{System}(p,b,n,t) \tag{C.2}$$

where, *Base* is the cost of electricity without the proposed PV or battery system; and
System is the cost of electricity with a particular PV battery system.
The *Base* and *System* electricity costs for each n-th year from the t-th forecast year are given by:

$$Bills_{Base}(n,t)=E_{Import}(0,0,n)\cdot T_{Import}(n,t)-E_{Export}(0,0,n)\cdot T_{Export}(0,n,t)+365\cdot T_{Daily}(n,t) \tag{C.3}$$

$$Bills_{System}(p,b,n,t)=E_{Import}(p,b,n)\cdot T_{Import}(n,t)-E_{Export}(p,b,n)\cdot T_{Export}(p,n,t)+365\cdot T_{Daily}(n,t) \tag{C.4}$$

where,

$$T_{Export}(p,n,t)=\begin{cases}T_{Export\_Start}\cdot\left(1+R_{Tariffs}\right)^{n+t-2}, & p\le P_{Export\_Limit}\\ 0 & ,\ otherwise\end{cases} \tag{C.5}$$

$$T_{Daily}(n,t)=T_{Daily\_Start}\cdot\left(1+R_{Tariffs}\right)^{n+t-2} \tag{C.7}$$

The system cost is given by:

$$Cost(p,b,t)=p\cdot C_{PV\_Start}\cdot(1+R_{PV})^{t-1}+b\cdot C_{Battery\_Start}\cdot\left(1+R_{Battery}\right)^{t-1} \tag{C.8}$$

The PV and battery configuration with the highest NPV in the t-th year is chosen according to the equation following, with the PV and battery capacities defined as p_c and b_c respectively:

$$Investment\ Choice(t)=Max\ [NPV(p,b,t)] \tag{C.9}$$

where,

$$0\le p\le P^{*}\ and\ P^{''}=\begin{cases}10\ kW_P & ,\ initial\\ P^{'}\cdot(1+40\%), & if\ Investment\ Choice(t)=(P^{'},b_c)\\ P^{'} & ,\ otherwise\end{cases} \tag{C.10}$$

$$0\le b\le B^{*}\ and\ B^{''}=\begin{cases}20\ kWh & ,\ initial\\ B^{'}\cdot(1+40\%), & if\ Investment\ Choice(t)=(p_c,B^{'})\\ B^{'} & ,\ otherwise\end{cases} \tag{C.11}$$

The decision to invest in a given year (t) depends on the Discounted Payback Period (DPP) for one of the assessed PV (p) and battery (b) combinations to be less than or equal to 5 years.

$$DPP[-Cost(p,b,t),\ Cashflow(p,b,n,t)]\le 5 \tag{C.12}$$

with $n = \{1, 2, \ldots, 10\}$

Appendix D. Research data

The R open-source code, demand profile data, insolation data, household investment analysis, sensitivity and computational results are publicly accessible from https://doi.org/10.25917/5ea7d261ae32a.

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