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Renew Stage II:
Modelling Methodology Report
DRAFT

Prepared for RENEW

12 November 2020

ENERGEIA

Executive Summary

Australia's Network Transformation Roadmap (NTR) found that up to 45%[1] of all electricity generation would be made by consumers or their agents behind the meter by 2050. While this is now occurring at the generation level, with an estimated 15%[2] of all generation capacity being attributed to behind-the-meter consumer generation, it is not yet the case at the network level, where less than 10%[3] of RIT-D projects in the last 5 years have identified a feasible non-network alternative, and none of them have been implemented to date.

While consumer investment in rooftop solar PV has been tracking the NTR view of a substantially more decentralised future, it will increasingly[4] be curtailed or blocked by distribution networks, and the Australian Energy Market Operator (AEMO) is calling[5] for it to be limited in the name of energy system security and reliability. AEMO's own modelling of the optimal future least cost system, even under its 'step change' in DER scenario, shows consumer side investment in DER providing up to 22%[6] of total underlying annual NEM energy consumption by 2040.

The electricity industry, including key governing, regulatory and market bodies, has been focused on addressing key barriers to optimal DER investment across a range of initiatives[7]. However, recently completed stakeholder engagement completed for this project has found that these industry initiatives are dominated by the status quo in terms of participation and therefore perspective, and that they do not have a clear vision of what an optimal future least cost system looks like for consumers, beyond that of the perspectives of the ENA and AEMO.

Renew is the industry association focused on enabling consumer-focused energy markets[8]. It is therefore interested in developing the evidence base and industry capability to identify the role of DER in the optimal future scenario for consumers, the key actions that will need to be taken to achieve it and their sequencing and timing, the roles of each industry group in their implementation, and perhaps most importantly, the net benefits of doing so and how they will be distributed across industry stakeholders, especially vulnerable consumers and those without DER.

Renew, supported financially by Energy Consumers Australia (ECA), undertook a project in 2019[9] to identify the key barriers to the efficient investment in DER and the least cost solutions for addressing them. A key finding[10] of that project was that a whole-of-system approach was needed to determine the optimal level of DER investment, and the optimal solutions for enabling it. Stage II of the project, which includes this report, seeks to address the analytical gaps identified in Stage I, as well as those identified via stakeholder consultation.

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[1] Energy Networks Australia (2017), 'National Transformation Roadmap', https://www.energynetworks.com.au/resources/reports/electricity-network-transformation-roadmap-final-report/, pg. i

[2] AER (2020), 'State of the Energy Market', https://www.aer.gov.au/system/files/State%20of%20the%20energy%20market%202020%20-%20Chapter%201%20A3%20spread.pdf

[3] Energeia research of pre-2019 DAPRs and RIT-Ds across the NEM

[4] As alluded to in SA Power Networks (2019), 'LV Management Business Case: 2020-2025 Regulatory Proposal': https://www.aer.gov.au/system/files/Attachment%205%20Part%207%20-%20Future%20Network.zip, pg. 6, and supported by modelling results from L. Ochoa, A. Procopiou, University of Melbourne (2019), 'Increasing PV Hosting Capacity: Smart Inverters and Storage': https://resourcecenter.ieee-pes.org/education/webinars/PESVIDWEBGPS0010.html

[5] AEMO has called for DNSPs to provide real time visibility requirements for distributed solar PV to better enable curtailment , see AEMO (2020), 'Renewable Integration Study: Stage 1 Report', https://www.aemo.com.au/-/media/files/major-publications/ris/2020/renewable-integration-study-stage-1.pdf

[6] AEMO (2020), '2020 Integrated System Plan', https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en

[7] As highlighted in Section 1.3 of Energeia (2019), 'Distributed Energy Resources Enablement Project – Discussion and Options Paper', https://renew.org.au/wp-content/uploads/2020/06/Energeia.pdf

[8] See Renew's mission statement, available at: https://renew.org.au/what-we-do/advocacy/consumer-focused-energy-markets/

[9] Renew (2020), 'Enabling Distributed Energy in Electricity Networks', https://renew.org.au/wp-content/uploads/2020/06/RenewDER.pdf

[10] See Section 5.2 of Renew (2020), 'Enabling Distributed Energy in Electricity Networks', https://renew.org.au/wp-content/uploads/2020/06/RenewDER.pdf

Scope and Approach

Energeia was engaged by Renew to develop and implement a whole-of-system modelling methodology that would support the achievement of Renew's DER enablement project Stage II objectives, namely, identifying the optimal future state for consumers that best meets the National Electricity Objectives (NEO), the role of DER, and level of DER enablement needed to realise it. Importantly, the ECA Board required Energeia's modelling methodology and results to be reviewed by an independent expert selected by Renew.

Energeia's approach to developing and implementing a whole-of-system modelling methodology involves:

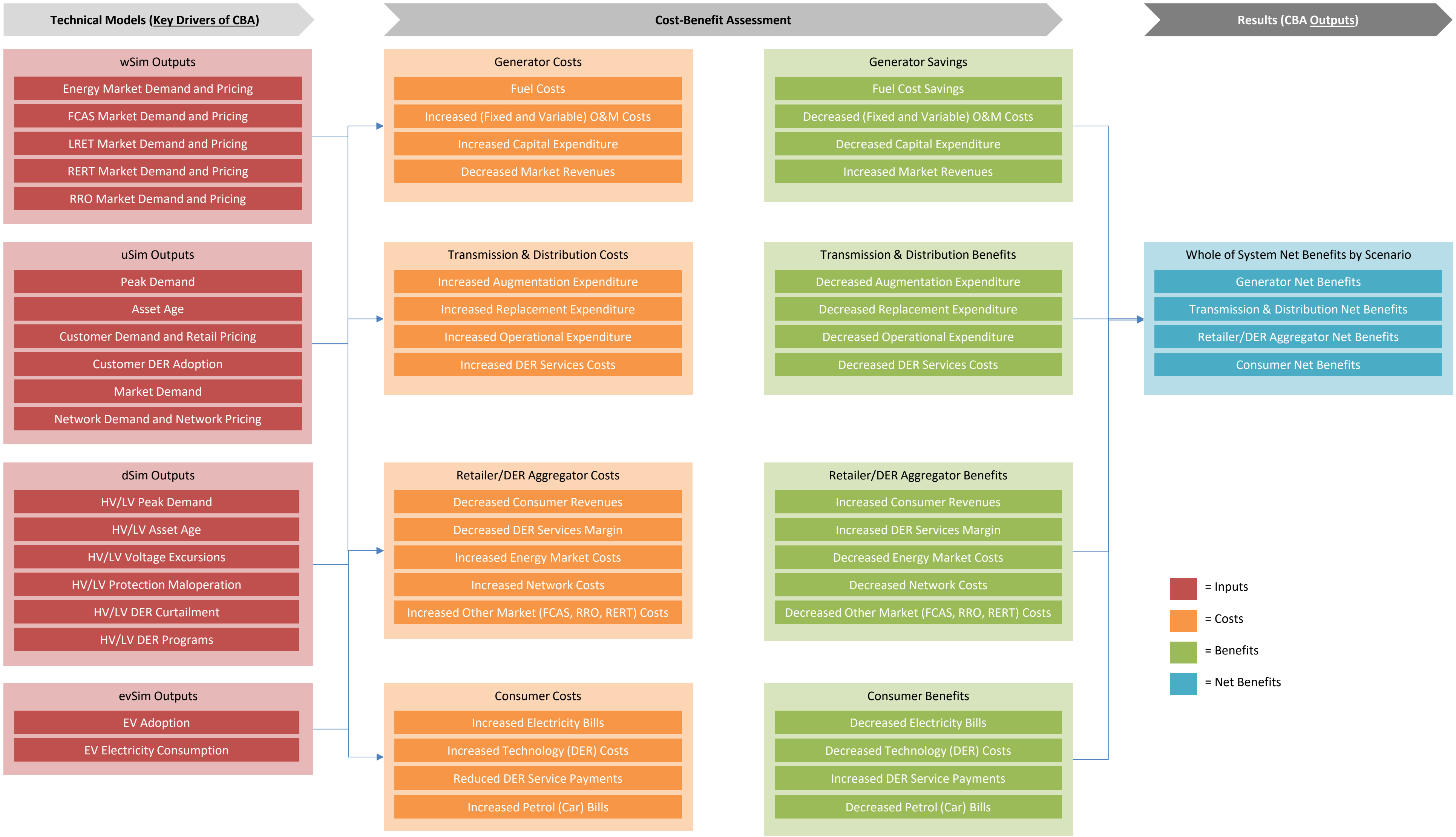
- Developing consumer-focused scenarios of the future to model the key future states of most interest to consumers, their agents and advocates
- Updating our whole-of-system modelling platforms including uSim, wSim, dSim and evSim with the latest inputs and assumptions
- Developing a fit-for-purpose Cost-Benefit-Assessment (CBA) model that brings together key outputs from the modelling platforms to identify the net benefits by stakeholder and overall, across scenarios
- Validating the modelling methodology and results including the scenarios and CBA with Renew's independent, third party expert reviewer, and making any revisions as agreed

The following sections summarises our whole-of-system and CBA modelling methodologies, including our scenario development methodology and designs.

Cost-Benefit-Assessment Modelling Methodology

Energeia has developed a fit-for-purpose whole-of-system cost-benefit-assessment (CBA) modelling methodology, which is summarised in the figure below. This methodology is designed to deliver a whole-of-system CBA that addresses the NEO and that identifies key stakeholder impacts including for vulnerable consumers and those without DER.

Cost Benefit Assessment Model Overview



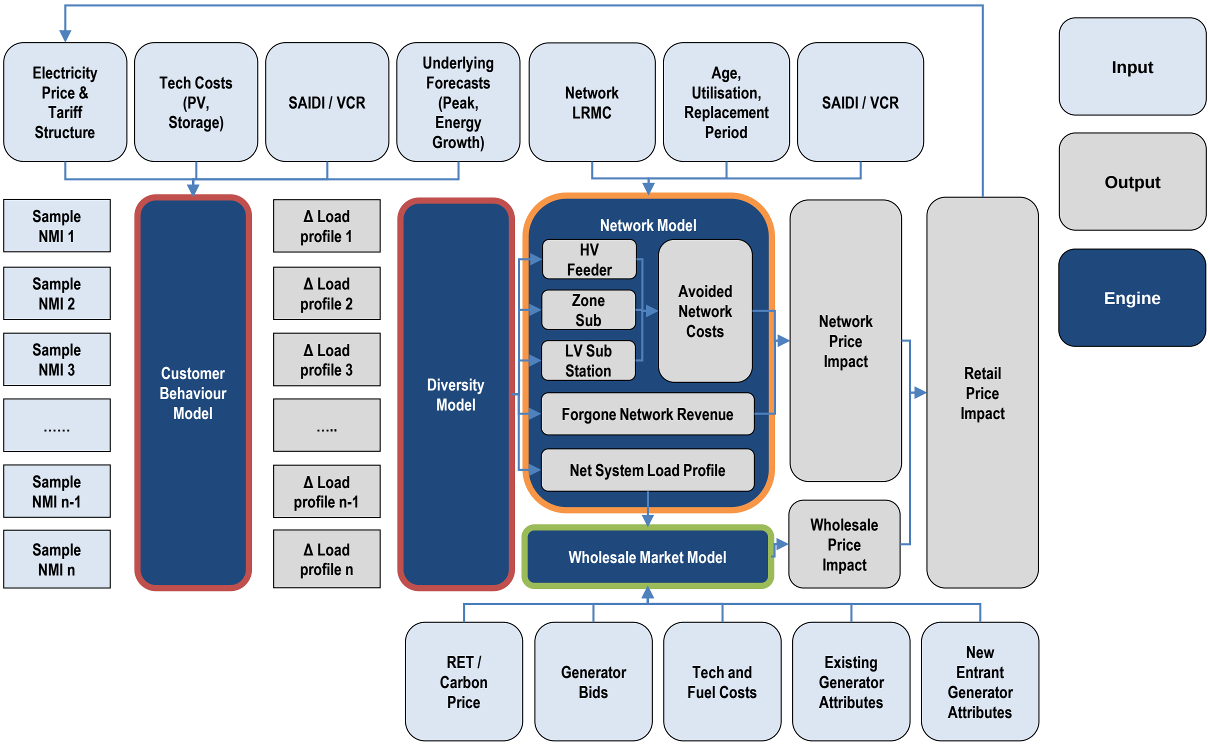
Source: Energeia

The costs and benefits in the CBA are taken from the outputs of our whole-of-system modelling platform, which is itself comprised of modelling sub-platforms, which are summarised in the following section and detailed in the appendices. The key cost and/benefit drivers modelled in each of the modelling sub-platforms are listed in the left most column above.

Whole-of-System Modelling Methodology

Energeia's bottom-up, whole-of-system modelling methodology is depicted in the figure below. It shows how we model customer behaviour including DER adoption, which is then turned into 17,520 interval load profiles, which are mapped to distribution and transmission assets, costs and revenues, the National Electricity Market (NEM) and ultimately network and retail tariffs, which feed back into the consumer model.

Energeia's Whole-of-System Modelling Methodology



Source: Energeia; Note: Red = uSim, Orange = dSim and uSim, Green = wSim

Implementation of our modelling methodology occurs in one of our key modelling platforms:

- **Wholesale Market Simulator (wSim)** – Models NEM Regional Reference Prices (RRPs), resource dispatch and new entry by state, year, and scenario.
- **Utility Simulator (uSim)** – Models customer behaviour, including DER adoption, 17,520 load profiles, distribution network substation assets, and network and retail tariffs by DNSP, year and scenario.
- **Distribution Network Simulator (dSim)** – Models HV/LV network asset management capital and operating costs, and demand and costs associated with DER VPP provided grid services.
- **Electric Vehicle Simulator (evSim)** – Models EV adoption, public infrastructure needs, load profile impacts and load management potential, for input into uSim.

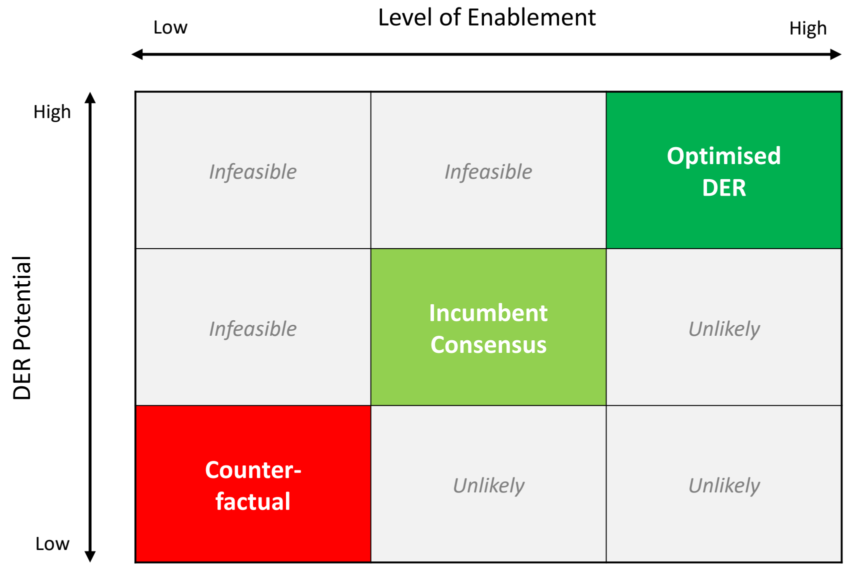
The detailed modelling methodologies for each of the above modelling platforms is provided in Appendices B-D.

Scenario Development Methodology

The above modelling platforms are configured on a scenario basis.

Energeia's scenario development methodology first sought to identify the key drivers of the future, and to then determine the most important potential combinations of these drivers. Using this process, Energeia identified that the level of DER enablement and level of DER potential were the two most important factors to consider, however, not every combination of their expression needed to be modelled[11], as explained in the above section.

Scenario Drivers and Key Scenarios



Source: Energeia

Based on the above scenario drivers and key parameters below, Energeia designed the following scenarios to be included in our modelling:

- **Scenario 1: Counterfactual** – Energeia's Counterfactual scenario focuses on a future where DER potential and enablement will be slower and more limited than conventional wisdom. As such, DER costs and benefits are expected to be relatively limited and lower than expected overall.
- **Scenario 2: Incumbent Consensus** – The Incumbent Consensus scenario is consistent with AEMO's Step Change scenario[12], and representative of incumbent consensus regarding DER's maximum potential impacts and associated costs and benefits.
- **Scenario 3: Optimised DER** – The Optimised DER scenario goes beyond Australia's incumbent industry consensus in terms of DER potential and enablement assumptions. DER costs are lower, due to pricing and cost assumptions, and DER is enabled across the full range of potential value streams.

The scenario settings for each of the scenarios modelled reported in Section 3.3.

Assessment Against Key Project Requirements

The Stage II project objective is to develop a more robust modelling approach and evidence base than was possible in Stage I. The Stage II project therefore focuses on identifying and quantifying the impact of DER enablement on the long-term interests of consumers including prosumers, including the ability to access and use the energy solution of their choice, and to potentially sell it to others or the industry, on a level playing field with transmission and distribution networks, and utility scale generation resources.

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[11] Other potential scenarios were found to be infeasible or unlikely, see Section 3.3 for more details

[12] AEMO's Step Change scenario is defined as a scenario with both consumer-led and technology-led transitions occur in the midst of aggressive global decarbonisation and strong infrastructure commitments. More information is available here: https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en

Based on our review of the Project objectives, industry best practice, gaps in whole-of-system modelling and DER valuation exercises to date and feedback from stakeholder consultation[13], Energeia believes our modelling methodology to be fit-for-purpose for the following reasons:

- **The needs identified in the stakeholder consultation process are considered** – Our modelling methodology will identify the least cost DER enablement solution over the long-term, taking all significant costs and benefits into account across key DER enablement scenarios, including a higher level of DER enablement envisioned by AEMO's ISP.
- **All costs and benefits are being considered per the project objectives** – Our modelling methodology models the impacts and associated significant costs or benefits across consumers, prosumers, retailers/VPP providers, networks, and generators. Importantly, it undertakes detailed modelling of key DER enablement net benefit drivers.
- **Costs and benefits are being modelled correctly –** Our cost benefit assessment model correctly identifies economic impacts as well as wealth transfers, to enable overall community as well as individual stakeholder net impacts to be quantified. This is particularly important to model the impact to passive consumers.
- **Modelling considers all key DER enablement scenarios and solutions –** Our scenarios have been developed to provide a counter factual, base case and stretch case, and includes all key forms of DER, and key centralized system solutions, including solar PV, energy storage, and demand response of water heaters and electric vehicles.
- **DER enablement scenarios and solutions modelled are correctly –** Our wholesale market, network, customer and tariff modelling methodologies are all based on industry best practice approaches, and have been reviewed by other consultancies and stakeholders over multiple engagements, excl. elements of dSim 2.0

[13] Stakeholder feedback is summarised in Appendix A – Stakeholder Consultation

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Disclaimer

While all due care has been taken in the preparation of this report, in reaching its conclusions Energeia has relied upon information and guidance from Renew, and other publicly available information. To the extent these reliances have been made, Energeia does not guarantee nor warrant the accuracy of this report. Furthermore, neither Energeia nor its Directors or employees will accept liability for any losses related to this report arising from these reliances. While this report may be made available to the public, no third party should use or rely on the report for any purpose.

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Structure of this Report

This report is structured as follows:

- **Section 1** – Project Background and Drivers reviews work to date on DER adoption scenarios and DER value and impacts, and summarises the project's goals and objectives, and their implications for the modelling methodology, including input from key stakeholders.
- **Section 2** – Project Scope and Approach describes Energeia's modelling scope, and our approach to developing a fit-for-purpose modelling methodology, including the development of an integrated cost-benefit-assessment framework using our whole-of-system modelling platform, the development of this report, and its validation via peer review.
- **Section 3** – Modelling Methodology outlines Energeia's proposed methodology in assessing the key net benefits associated with DER enablement, including an overview of the key value streams and opportunities for each key stakeholder, the key technical models used to develop the cost benefit assessment model and how their integrate, the scenarios to be modelled, and an assessment of the methodology against the key project and stakeholder requirements.

Supporting information is provided in the Appendices:

- **Appendix A** – Consultation details Energeia's stakeholder consultation process and key findings
- **Appendix B** – wSim details Energeia's wholesale market modelling platform, wSim
- **Appendix C** – uSim details Energeia's customer and network modelling platform, uSim
- **Appendix D** – dSim details Energeia's low voltage distribution network modelling platform, dSim
- **Appendix E** – evSim details Energeia's electric vehicle uptake and charging modelling platform, evSim
- **Appendix F** – Glossary provides the key acronyms used in this report
- **Appendix G** – About Energeia provides an overview of Energeia

1. Project Background and Drivers

Australia's Network Transformation Roadmap (NTR) found that up to 45%[14] of all electricity generation would be made by consumers or their agents behind the meter by 2050. While this is now occurring at the generation level, with an estimated 15%[15] of all generation capacity being attributed to behind-the-meter consumer generation, it is not yet the case at the network level, where less than 10%[16] of RIT-D projects in the last 5 years have identified a feasible non-network alternative, and none of them have been implemented to date.

While consumer investment in rooftop solar PV has been tracking the NTR view of a substantially more decentralised future, it will increasingly[17] be curtailed or blocked by distribution networks, and the Australian Energy Market Operator (AEMO) is calling[18] for it to be limited in the name of energy system security and reliability. AEMO's own modelling of the optimal future least cost system, even under its 'step change' in DER scenario, shows consumer side investment in DER providing up to 22%[19] of total underlying annual NEM energy consumption by 2040.

The electricity industry, including key governing, regulatory and market bodies, has been focused on addressing key barriers to optimal DER investment across a range of initiatives[20]. However, recently completed stakeholder engagement completed for this project has found that these industry initiatives are dominated by the status quo in terms of participation and therefore perspective, and that they do not have a clear vision of what an optimal future least cost system looks like for consumers, beyond that of the perspectives of the ENA and AEMO.

Renew is the industry association focused on enabling consumer-focused energy markets[21]. It is therefore interested in developing the evidence base and industry capability to identify the role of DER in the optimal future scenario for consumers, the key actions that will need to be taken to achieve it and their sequencing and timing, the roles of each industry group in their implementation, and perhaps most importantly, the net benefits of doing so and how they will be distributed across industry stakeholders, especially vulnerable consumers and those without DER.

Renew, supported financially by Energy Consumers Australia (ECA), undertook a project in 2019[22] to identify the key barriers to the efficient investment in DER and the least cost solutions for addressing them. A key finding[23] of that project was that a whole-of-system approach was needed to determine the optimal level of DER investment, and the optimal solutions for enabling it. Stage II of the project, which includes this report, seeks to address the analytical gaps identified in Stage I, as well as those identified via stakeholder consultation.

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[14] Energy Networks Australia (2017), 'National Transformation Roadmap', https://www.energynetworks.com.au/resources/reports/electricity-network-transformation-roadmap-final-report/, pg i

[15] AER (2020), 'State of the Energy Market', https://www.aer.gov.au/system/files/State%20of%20the%20energy%20market%202020%20-%20Chapter%201%20A3%20spread.pdf

[16] Energeia Research of pre-2019 DAPRs and RIT-Ds across the NEM

17 As alluded to in SA Power Networks (2019), 'LV Management Business Case: 2020-2025 Regulatory Proposal': https://www.aer.gov.au/system/files/Attachment%205%20Part%207%20-%20Future%20Network.zip, pg. 6, and supported by modelling results from L. Ochoa, A. Procopiou, University of Melbourne (2019), 'Increasing PV Hosting Capacity: Smart Inverters and Storage': https://resourcecenter.ieee-pes.org/education/webinars/PESVIDWEBGPS0010.html

18 AEMO has called for DNSPs to provide real time visibility requirements for distributed solar PV to better enable curtailment , see AEMO (2020), 'Renewable Integration Study: Stage 1 Report', https://www.aemo.com.au/-/media/files/major-publications/ris/2020/renewable-integration-study-stage-1.pdf

19 AEMO (2020), '2020 Integrated System Plan', https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en

20 As highlighted in Section 1.3 of Energeia (2019), 'Distributed Energy Resources Enablement Project – Discussion and Options Paper', https://renew.org.au/wp-content/uploads/2020/06/Energeia.pdf

21 See Renew's mission statement in this space, available at: https://renew.org.au/what-we-do/advocacy/consumer-focused-energy-markets/

22 Renew (2020), 'Enabling Distributed Energy in Electricity Networks', https://renew.org.au/wp-content/uploads/2020/06/RenewDER.pdf

23 See Section 5.2 of Renew (2020), 'Enabling Distributed Energy in Electricity Networks', https://renew.org.au/wp-content/uploads/2020/06/RenewDER.pdf

The following sections summarise key related work that has given rise to the need for this project, namely Australia's key DER scenarios of the future, value-of-DER studies, a summary of the project goals and objectives and key modelling methodology requirements.

1.1. Key Distributed Energy Resource Uptake Scenarios

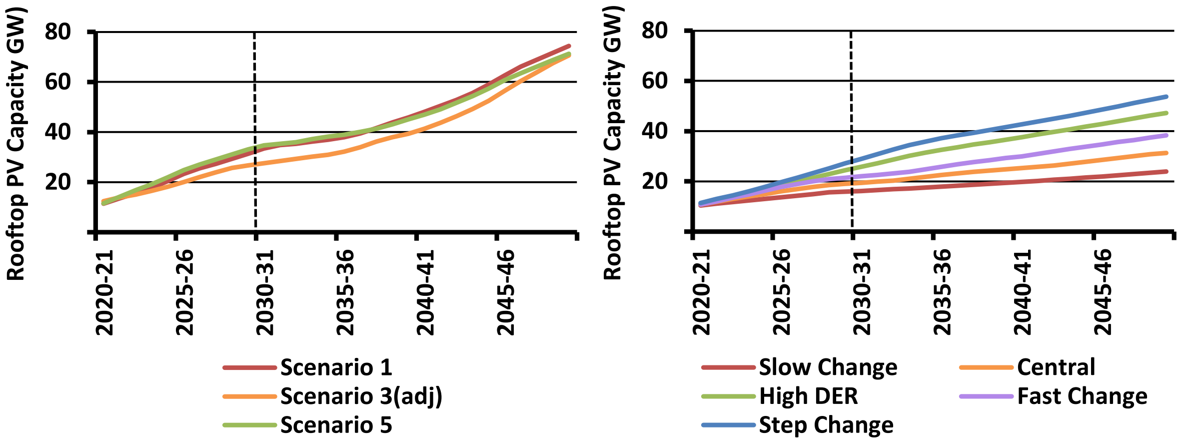
ENA's NTR issued in 2016 remains the most comprehensive, whole-of-system assessment of the role and impact of DER on the long-term interests of consumers and the wider industry. AEMO's bi-annual Integrated System Plan and the associated planning process is another key source of DER uptake scenarios, however, the modelling is not as comprehensive as the NTR due to the lack of distribution network modelling, for example.

The NTR scenarios were developed by a multidisciplinary team[24] led by CSIRO and the ENA, while AEMO's scenarios are developed by AEMO. It is fair to say that the NTR scenarios were developed to help inform network investment decision making, while AEMO's scenarios have been developed to help inform utility scale generation, storage, and interconnector investments to 2050.

Energeia reviewed both sources of industry scenarios regarding DER uptake potential to inform our own consumer-focused scenario development process. The results of our review are reported in Figure 1, which compares the NTR Scenarios on the left to the latest AEMO scenarios on the right. The comparison shows AEMO's comparable forecasts to be significantly lower than the NTR's for rooftop PV and storage.

Figure 1 show AEMO's latest forecasts for solar PV and storage uptake in the NEM respectively, based on forecasts provided by CSIRO and GEM. Whilst solar maintains a steady increase, adoption of storage in the NEM will sharply increase in the next few years in the High DER and Step Change scenarios.

Figure 1 – CSIRO/ENA's (Left) vs. AEMO's (Right) Rooftop Solar PV Capacity Forecasts in the NEM



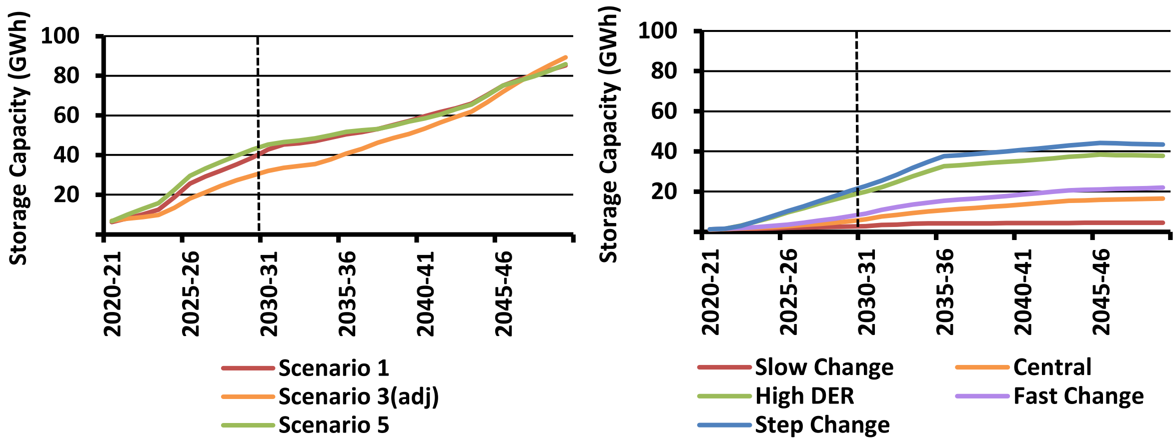
Source: ENA NTR (2016), AEMO Inputs and Assumptions to 2020 ESOO (2020)

However, it should be noted that only the Step Change scenario in the current AEMO ISP forecasts exceeds the rooftop solar PV forecast for 2030 in the NTR for Scenario 3(adj).

AEMO's 2020 ISP forecasts of storage under the High DER and Step Change scenarios assumes less than 10-20 GWh of storage capacity by 2030 compared to the 32-45 GWh of behind the meter storage forecast in the NTR forecasts.

[24] Energeia was a member of the modelling team and supported the translation of the scenarios into modelling parameters.

Figure 2 – CSIRO/ENA's (left) vs. AEMO's (right) Embedded Storage Capacity Forecasts in the NEM



Source: ENA NTR (2016), AEMO Inputs and Assumptions to 2020 ESOO (2020)

In summary, the key DER uptake forecasts in Australia have been developed to inform distribution network and wholesale market investment decision making, rather than to identify a future consumer-optimised electricity system. Also, the AEMO scenarios and resulting analysis limited by its modelling scope, which includes the costs and benefits of DER within the distribution networks, which account for 40-50%[25] of consumer bills in the NEM.

1.2. Key Distributed Energy Resources Studies and Analyses

Given the high level of expected DER adoption in the period to from 2020 to 2030, and the related regulatory, technical and consumer behaviour factors that need to be considered to integrate that level of DER into the grid, market bodies have commenced a number of DER integration studies and programs. These initiatives are summarised in Table 1, which shows recently completed DER projects uncovered from Energeia's research.

Table 1 – Recently Completed DER Studies

Project	Year	Sponsor	Author	Purpose and Objective
Pricing for the Integration of DER	2020		Oakley Greenwood	How can cost reflective prices assist in the economically efficient integration of DER into the grid
Distributor's incentives to efficiently incur DER export expenditure	2020		Houston Kemp	Assessment of regulatory reform options to unlock net benefits of DER enablement
Grid vs. Garage	2020		AECOM	Comparison of different battery storage deployment models
Assessment of Open Energy Network Frameworks	2020		Baringa	Cost and benefit assessment of four different DSO frameworks
Value of DER	2020		Cutler Merz / CSIRO	Development of a methodology for DNSPs to assess the value of DER from investments in hosting capacity
Feasibility of Export Capacity Obligations and Incentives	2020		CEPA	Assess the various options for DNSPs to optimise DER export capacity to maximise long-term consumer net benefits
Value of Optimised Flexible DER	2020		Baringa	Quantify the value of optimising flexible DER and other loads (e.g. HVAC and pool pumps) for households

Source: Energeia

Energeia has reviewed each of these studies for which areas of the DER enablement value stack they addressed, the barriers that they addressed and the solutions that they investigated. As shown in Table 2, the

[25] AER (2020) 'State of the Energy Market 2020', https://www.aer.gov.au/system/files/State%20of%20the%20energy%20market%202020%20-%20Full%20report%20A4.pdf, pg. 17

various studies address different barriers or investigate different solutions, and cover different components of the DER value stack.

Table 2 – Analysis of Recently Completed DER Studies

		DER Integration Pricing	DNSP Incentives	Grid vs. Garage	Open Energy Networks CBA	Value of DER	Export Capacity Incentives	Value of Optimised and Flexible DER
Value Stack Modelling								
Consumer Bill Minimisation	Consumer Self Consumption		✓	✓	✓	✓		✓
	Consumer Exports		✓	✓	✓	✓	✓	✓
Network Expenditure	Network Augmentation Expenditure	✓		✓	✓	✓		
	Network Replacement Expenditure	✓		✓		✓		
Network Operation	Network Sub-transmission							
	Network High Voltage							
	Network Low Voltage	✓			✓	✓	✓	
Wholesale Market Operation	RERT/Retailer Obligation Revenues	✓						
	Wholesale Market Revenues	✓		✓	✓	✓		✓
	Ancillary Services Revenues			✓	✓	✓		✓
Barriers and Solutions								
Policy and Regulatory Factors	Technical Regulation[26]	✓	✓	✓	✓	✓	✓	
	Economic Regulation	✓	✓	✓	✓	✓	✓	
	Pricing / Tariffs	✓	✓	✓				
	Market Design				✓			
Technical Factors	Technical Constraints	✓	✓	✓	✓	✓		
	Technical Solutions	✓	✓	✓	✓			✓
	Cost Recovery			✓				
Consumer Factors	Consumer Behaviour / Engagement		✓	✓			✓	
	Consumer Experience							
	Consumer Protection							
	Consumer Equity		✓	✓		✓	✓	

Source: Energeia

Energeia's review of studies to date has identified that none of them appear to attempt to determine the electricity system configuration that maximises the long term benefits for consumers, given price, reliability, security, safety of the electricity supply and the national electricity market, i.e. the National Electricity Objective (NEO).

[26] Technical Regulation includes Connection, Metering, B2B and Inverter Standards

1.3. Key Project Goals and Objective

Energeia completed the Stage I DER Enablement project in Q2 2020. The Stage I project sought to review the range of consumer and energy system issues related to DER adoption and potential solutions for resolving them:

- Energeia's Stage I Final Report[27] identified a net position of just $0.7-1.1B in in DER integration costs under a range of DER uptake scenarios, and demonstrated that curtailment was often highest cost than alternatives
- The study documented for the first time the match, and mismatch, of available network and consumer side impacts, costs, and solutions
- From the high level of stakeholder engagement, it was clear that there remained a number of key consumer and prosumer issues requiring further investigation and substantiation[2]

Renew identified that a follow-up, more in-depth study was needed to develop the technical understanding and evidence base through a consumer-focused, stakeholder-engaged process designed to influence industry practice and thinking

1.4. Stage II Modelling Requirements

Renew designed the Stage II project to address the key issues identified by the Stage I project, including enhanced stakeholder engagement, inclusion of generation and transmission costs and benefits, consideration of DER resource development and more advanced modelling of LV networks, resources and load.

1.4.1. Project Requirements

A key part of the Stage II project is therefore the development of a more robust modelling approach and evidence base than was possible in Stage I, one that will:

- **Maximise Demand Side Potential** – The existing supply-side dominated paradigm means that consumer side costs, solutions and benefits may not be being adequately addressed or valued by policymakers, regulators, institutions or industry players. The project will therefore need to deliver the best possible evidence base for the costs and benefits of consumer side solutions to ensure they are correctly considered on par with other system resources.
- **Improve Understanding of Consumer Needs and Drivers –** The existing paradigm and the power of incumbency may mean that policymakers, regulators and market institutions are focusing on status quo perspectives at the expense of understanding consumer needs and drivers. The project will therefore need to focus on and envision consumers and prosumers' current and future needs, so that this perspective may be given equal weight and consideration in future market design.
- **Develop Optimal Solutions on Net Benefits Basis –** Lack of timely engagement and evidence leads to missing the window of opportunity to influence the current wave of major near-term policy, regulatory and industry decision making. The project will need to focus on understanding the potential for DER enabled solutions, and not limit itself to 'good-enough' approaches that address near term needs without preparing for fundamental change if justified.

The Stage II project modelling methodology must therefore focus on identifying and quantifying the impact of DER enablement on the long-term interests of consumers and prosumers, including the ability to access and use the energy solution of their choice, and to potentially sell it to others or the industry, on a level playing field with transmission and distribution networks, and utility scale generation resources.

[27] Energeia (2020) 'Distributed Energy Resources Enablement Project – Discussion and Options Paper', available here: https://renew.org.au/wp-content/uploads/2020/06/Energeia.pdf

1.4.2. Stakeholder Requirements

Comprehensive stakeholder engagement[28] was undertaken at the request of the ECA Board to ensure that the work would have maximum impact on the industry by addressing the key issues and engaging key stakeholders.[29] Energeia's stakeholder engagement process identified a gap in the community's understanding of an optimal future power system for consumers, such a vision should:

- Consider all material costs and benefits and not just a sub-set
- Consider DER/VPPs and centralized system expenditure on a level playing field
- Consider fully enabled VPPs, including existing and potential new capacity, both retrofits and greenfield
- Consider the impact of fully cost reflective price signals and incentives across the value chain[30]
- Consider the impact of consumer barriers, especially to participation
- Consider the impacts on all consumers including renters, apartment dwellers and those without DER
- Identify the highest net benefit solutions for all consumers by time and place
- Be balanced and unbiased
- Provide a roadmap for unlocking it[31]

In the absence of a shared community vision for the optimal future consumer state, policymakers, regulators, and industry incumbents may not be focused on the right issues, at the right time and in the right amount.

The project therefore needs to identify the most important contributions that DER could be making if fully enabled, the timing of these contributions, and their potential net benefits, so that stakeholders can become better organised to address them.

Based on the stakeholder engagement process and our Stage I work, Energeia believes the key implications for the Stage II modelling approach include:

- Modelling DER/VPP potential and cost, including new, enabled, and leveraged use cases, considering all potential value streams
- Modelling the full range of DER/VPP value streams, including thermal, voltage, etc. from the LV network to the wholesale market
- Modelling the impacts of fully enabled DER/VPPs on consumers, including on NEM prices, network, and retail tariffs, etc.
- Modelling the full range of consumer stakeholders, including renters, apartment dwellers, vulnerable customers and those without DER
- Modelling the impacts of cost reflective price signals and the removal of barriers to customer participation

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[28] Energeia and Renew completed a total of 21 interviews of 57 people from 18 organizations representing a cross-section of the current and emerging industry, including policymakers and regulators. More details of the Stakeholder Engagement Process are

[29] Further details can be found in Appendix A – Stakeholder Consultation

[30] Modelling of different degrees of cost reflectivity is beyond the scope of this project, but could be included in a Stage III.

[31] Although not in scope, stakeholder engagement identified the need for a DER Enablement Roadmap, which could form part of Stage III.

2. Scope and Approach

Energeia was engaged by Renew to develop and implement a whole-of-system modelling methodology that would support the achievement of Renew's DER enablement project Stage II objectives, namely, identifying the optimal future state for consumers that best meets the National Electricity Objectives (NEO), the role of DER, and level of DER enablement needed to realise it. Importantly, the ECA Board required Energeia's modelling methodology and results to be reviewed by an independent expert selected by Renew.

Energeia's approach to developing and implementing a whole-of-system modelling methodology involves:

- Developing consumer-focused scenarios of the future to model the key future states of most interest to consumers, their agents and advocates
- Updating our whole-of-system modelling platforms including uSim, wSim, dSim and evSim with the latest inputs and assumptions, where:
  - uSim simulates customer level decision making with respect to DER investment and operation under different policy, regulatory, tariff, technology, and macro-economic settings, and estimates the corresponding impact of customer decision making on electricity networks
  - wSim simulates the dispatch of generation and associated pricing of energy, ancillary services and key generator revenue streams including reliability obligations and renewable energy certificates, and forecasts capacity expansion over time, considering the impact of behind-the-meter DER on these outcomes
  - dSim models the impacts, costs and benefits of DER for Low Voltage (LV) and High Voltage (HV) network assets, and assesses a range of options available to networks to address issues
  - evSim forecasts the uptake of electric vehicles and the associated spatial load impact
- Developing a fit-for-purpose Cost-Benefit-Assessment (CBA) model that brings together key outputs from the modelling platforms to identify the net benefits by stakeholder and overall, across scenarios
- Validating the modelling methodology and results including the scenarios and CBA with Renew's independent, third party expert reviewer, and making any revisions as agreed

The following sections summarises our whole-of-system and CBA modelling methodologies, including our scenario development methodology and designs.

3. Modelling Methodology

Energeia has developed a whole-of-system modelling methodology that is designed to address the project objectives, specifically maximising the beneficial impact on long-term consumer net benefits by providing an evidence based for an optimised, DER-enabled, consumer focused vision of the future.

Given the primary role of the National Electricity Objective (NEO) in industry reform, achieving the project objective will require a modelling methodology capable of identifying the electricity system configuration that best promotes efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to:

- Price, quality, safety and reliability and security of supply of electricity, and
- The reliability, safety and security of the national electricity system.[32]

AEMO's Integrated System Plan (ISP) and the Electricity Networks Association's (ENA's) National Transformation Roadmap (NTR) are both examples of major initiatives that have aimed to identify the most optimal system configuration, with very different outcomes, mainly due to different assumptions.

Key elements of our whole-of-system modelling approach that make it unique among of the DER valuation and system optimisation studies we have reviewed[33] include the following:

- Whole-of-system modelling approach includes detailed cost and benefit modelling of customer petrol, electricity bills, detailed network costs including LV and HV network costs
- Consumer-side resources are considered on a level playing field with centralised resources, including achievable, dependable DER capacity, 30-min availability and incremental pricing
- All potential consumer segments are included, such as renters and those in apartments, and not just those with existing DER or that live in owner-occupied single family dwellings
- All DER is considered, including storage and solar PV on an integrated basis rather than separately or partially integrated, e.g. solar with storage only
- Consumer-focused scenarios of the future are included in addition to existing industry developed views, including the impact of higher DER enablement on DER learning rates and customer participation

The following sections described our whole-of-system approach to modelling system costs, benefits and key system qualities mentioned in the NEO, i.e. price, security, reliability, quality, and safety.

3.1. Whole-of-System Cost-Benefit-Assessment Modelling Methodology

An overview of Energeia's end-to-end modelling methodology is depicted in Figure 3, which shows the outputs of the modelling platforms feeding into Energeia's whole-of-system CBA model, which in turn generates the CBA modelling results.

Energeia has configured its CBA model based on the project scope and objectives. The following sections detail the range of costs and benefits that Energeia is modelling by key stakeholder type, the key driver of the cost or benefit, and the technical model that is used to estimate them.

[32] As stated as the NEO in the National Electricity Rules, available here: https://www.aemc.gov.au/regulation/regulation

[33] As discussed in Section **Error! Reference source not found.**

Figure 3 – Cost Benefit Assessment Model Overview

Source: Energeia

3.1.1. Utility Scale Generators

Table 3 displays Energeia's approach to modelling utility scale generator costs and benefits across scenarios, which shows wSim as the primary source of cost and benefit driver modelling.

Table 3 – Utility Scale Generator CBA Modelling Detail

Technical Model	Cost and Benefit Driver	CBA Item	Units
wSim	Energy Market Demand and Pricing	Fuel Cost	$m p.a.
		Fixed O&M Cost	$m p.a.
		Variable O&M Cost	$m p.a.
		Capital Expenditure	$m p.a.
		Energy Revenue	$m p.a.
	FACS Market Demand and Pricing	DER Services	$m p.a.
		FCAS Revenue	$m p.a.
	LRET Market Demand and Pricing	DER Services	$m p.a.
		Capital Expenditure	$m p.a.
		LRET Revenue	$m p.a.
	RERT Market Demand and Pricing	DER Services	$m p.a.
		Capital Expenditure	$m p.a.
		RERT Revenue	$m p.a.
	Retailer Obligation Market Demand and Pricing	DER Services	$m p.a.
		Capital Expenditure	$m p.a.
		Retailer Obligation Revenue	$m p.a.

Source: Energeia

Energeia models the above generator costs and benefits by forecasting the 17,520 net load profile the NEM must satisfy, and forecasting the associated prices and resource dispatch to achieve it across the energy, RERT/retailer obligation and FCAS markets. Each generator's revenues and costs are then calculated.

Most of the generator impacts, costs and benefits are modelled in wSim[34], however, uSim[35] is used to model the DER-driven changes in each state's 17,520 load profile over time.

3.1.2. Transmission and Distribution Network Service Providers

Table 4 displays Energeia's approach to modelling TNSP/DNSP costs and benefits across scenarios, which shows uSim and dSim as the primary sources of cost and benefit driver modelling.
Energeia models the above costs and benefits by first forecasting the 17,520 net load profile at each zone substation, HV feeder and LV transformer, then estimating the resulting impacts on thermal, voltage, protection and safety/reliability constraints, and finally identifying the least cost solution for relieving the constraint.

Most of the TNSP/DNSP impacts, costs and benefits are modelled in uSim[36], however, dSim[37] is used to model the HV/LV assets. wSim is also used to model any additional DER developed by DER service providers to capture wholesale market opportunities.

[34] wSim modelling of P90 load, generator NEM energy, FCAS and retailer obligation related costs and benefits are detailed in Section B.2

[35] uSim modelling of the 17,520 load profiles loaded into wSim is detailed in Section C.2.1 and C.2.2 for consumers and assets

[36] uSim modelling of thermal and safety/reliability related costs and benefits are detailed in Section C.2.2

[37] dSim modelling of thermal, voltage, protection and safety/reliability related costs and benefits are detailed in Section D.2.2

Table 4 – TNSP/DNSP CBA Modelling Detail

Technical Model	Cost and Benefit Driver	CBA Item	Units
uSim / dSim	Peak Demand	Augmentation Expenditure	$m p.a.
		Replacement Expenditure	$m p.a.
		Operational Expenditure	$m p.a.
		DER Services Costs	$m p.a.
	Reliability / Safety (i.e. Asset Age)	Augmentation Expenditure	$m p.a.
		Replacement Expenditure	$m p.a.
		Operational Expenditure	$m p.a.
	Voltage Excursions	Augmentation Expenditure	$m p.a.
		Replacement Expenditure	$m p.a.
		Operational Expenditure	$m p.a.
		DER Services Costs	$m p.a.
	Protection Maloperation (Reverse Flow)	Augmentation Expenditure	$m p.a.
		Replacement Expenditure	$m p.a.
		Operational Expenditure	$m p.a.
		DER Services Costs	$m p.a.

Source: Energeia

3.1.3. Retailers and DER Service Providers

Table 5 displays Energeia's approach to modelling retailer and DER service provider costs and benefits across scenarios, which shows uSim and dSim as the primary sources of cost and benefit driver modelling.

Table 5 – Retailer *and DER Service Provider CBA Modelling Detail*

Technical Model	Cost and Benefit Driver	CBA Item	Units
uSim / dSim	Consumer Demand and Retail Pricing	Billable Revenue	$m p.a.
	Consumer DER Adoption	DER Services Payments	$m p.a.
		DER Costs	$m p.a.
	Energy Market Demand and Pricing	Energy Market Costs	$m p.a.
		FCAS Costs	$m p.a.
		RERT Costs	$m p.a.
		DER Services Costs	$m p.a.
	Retailer Obligation Market Demand and Pricing	Retail Obligation Costs	$m p.a.
		DER Services Payments	$m p.a.
		DER Services Costs	$m p.a.
	Network Demand and Network Pricing	NUOS Costs	$m p.a.
		DER Services Payments	$m p.a.
		DER Services Costs	$m p.a.

Source: Energeia

Energeia models the above costs and benefits by forecasting the adoption of DER by consumers, and the associated impact of DER on the consumer's load, bill and cost-of-service[38] for the retailer and DER service provider, including the effects of DER program development in response to wholesale or TNSP/DNSP opportunities. Each retailers and DER service providers' revenues and costs will then be calculated.

[38] Retailer cost-of-service include NEM settlement and market costs (including RERT/FCAS), retailer obligation costs and network costs

Most of the retailer and DER service provider impacts, costs and benefits are modelled in uSim[39], however, dSim[40] and wSim[41] is used to model any additional DER developed by DER service providers to capture HV/LV or wholesale market opportunities, respectively.

3.1.4. Consumer Costs

Table 6 displays Energeia's approach to modelling key consumer costs and benefits across scenarios, which shows each of Energeia's modelling platforms being used to model key cost and benefit drivers.

Table 6 – Consumer CBA Modelling Detail

Technical Model	Cost and Benefit Driver	CBA Item	Units
uSim / dSim / wSim / evSim	Consumer Demand and Retail Pricing	Electricity Costs	$m p.a.
	Consumer DER Adoption	DER Costs	$m p.a.
		DER Service Payments	$m p.a.
		Petrol Costs	$m p.a.

Source: Energeia

Energeia models the above costs and benefits by forecasting consumer adoption of DER, and its impact on consumer electricity costs, petrol costs, DER costs and DER service payments from DER service providers.

Most of the consumer impacts, costs and benefits is modelled in uSim[42], however, dSim[43] and wSim[44] is used to model any additional DER developed by DER service providers to capture HV/LV or wholesale market opportunities, respectively, and the associated DER service payments paid to participating consumers.

3.2. Whole-of-System Modelling Methodology

Energeia's bottom-up, whole-of-system modelling methodology is depicted in Figure 4. It shows how we model customer behaviour including DER adoption, which is then turned into 17,520 interval load profiles, which are mapped to distribution and transmission assets, costs and revenues, the National Electricity Market (NEM) and ultimately network and retail tariffs, which feed back into the consumer model.

[39] uSim modelling of consumer cost-of-service and DER adoption related costs and benefits are detailed in Section C.2

[40] dSim modelling of DER program opportunities and related costs and benefits are detailed in Section D.2.1

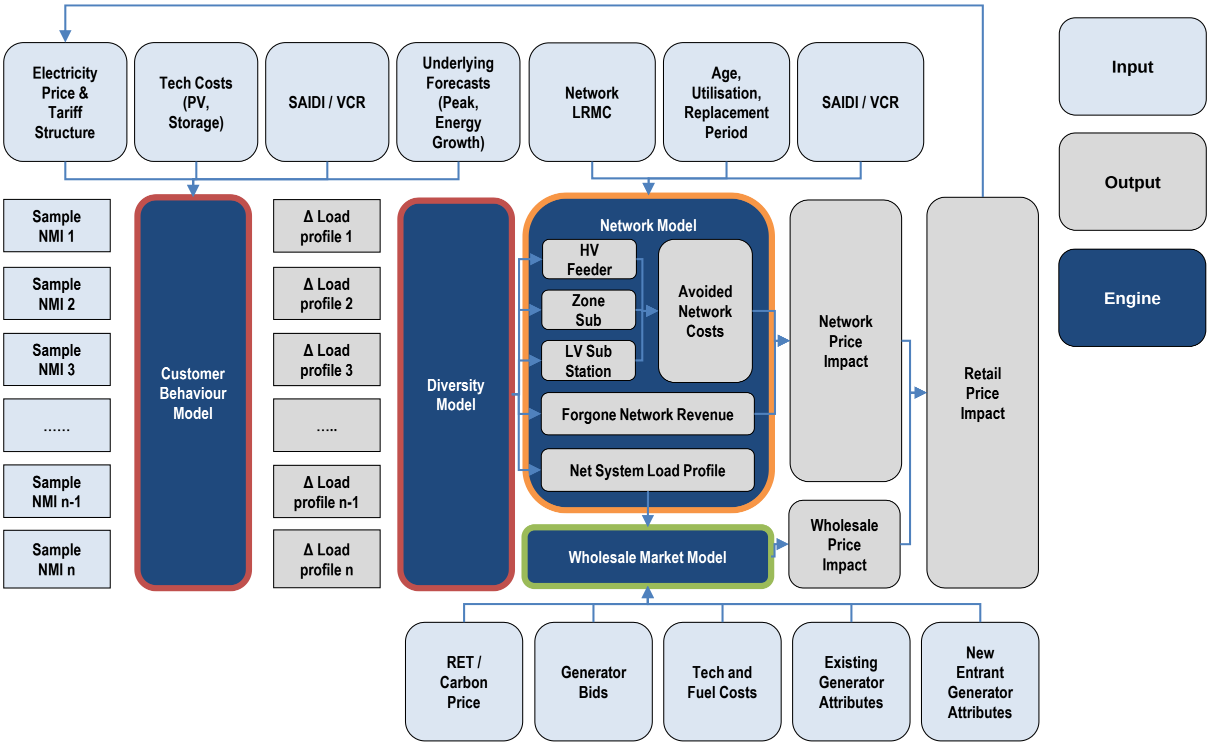
[41] wSim modelling of DER program opportunities and related costs and benefits through the wholesale market are detailed in Section B.2

[42] uSim modelling of consumer electricity and petrol consumption and DER adoption related costs and benefits are detailed in Section C.2 and C.3

[43] dSim modelling of DER program opportunities and related costs and benefits are detailed in Section D.2.1

[44] wSim modelling of DER program opportunities and related costs and benefits through the wholesale market are detailed in Section B.2

Figure 4 – Energeia's Whole-of-System Modelling Methodology



Source: Energeia; Note: Red = uSim, Orange = dSim and uSim, Green = wSim

Implementation of our modelling methodology occurs in one of our key modelling platforms:

- **Wholesale Market Simulator (wSim)** – Models NEM Regional Reference Prices (RRPs), resource dispatch and new entry by state, year, and scenario.
- **Utility Simulator (uSim)** – Models customer behaviour, including DER adoption, 17,520 load profiles, distribution network substation assets, and network and retail tariffs by DNSP, year and scenario.
- **Distribution Network Simulator (dSim)** – Models HV/LV network asset management capital and operating costs, and demand and costs associated with DER VPP provided grid services.
- **Electric Vehicle Simulator (evSim)** – Models EV adoption, public infrastructure needs, load profile impacts and load management potential.

The detailed modelling methodologies for each of the above modelling platforms is provided in Appendix B – wSim, Appendix C – uSim, Appendix D – dSim, and Appendix E – evSim.

3.3. Consumer Focused Modelling Scenarios

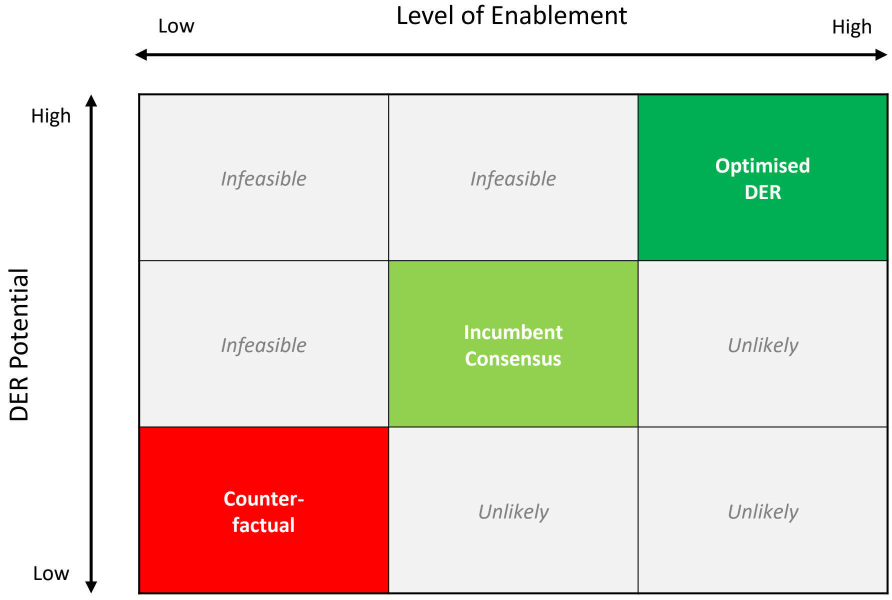
The above modelling platforms are configured on a scenario basis.

Based on the project objectives, discussion with Renew and engagement with key stakeholders and subject matter experts in the industry, Energeia developed three key scenarios based on the intersection of the two most important drivers of the future relevant for this project, which are shown in Figure 5.

Although additional scenarios could be modelled across the strategic space, Energeia believes the remaining potential scenarios to be infeasible or unlikely in reflecting the future state of the market:

- **Infeasible** – Potential scenarios which reflect higher levels of DER potential but are restricted by the level of enablement are infeasible as the level of DER aggregation services, and therefore level of enablement, are likely to increase over time with an increase in DER potential.
- **Unlikely** – Potential scenarios which involve investment from industry bodies to achieve a higher level of enablement but are restricted by lower levels of DER potential are unlikely as service providers are less likely to enter or operate in the market with restricted potential.

Figure 5 – Scenario Process and Framework



Source: Energeia

Further details on the scenario drivers and design, and the final scenario framework are discussed in the sections below.

3.3.1. Scenario Drivers

Energeia's scenario development methodology first sought to identify the key drivers of the future, and to then determine the most important potential combinations of these drivers. Using this process, Energeia identified that the level of DER enablement and level of DER potential were the two most important factors to consider, however, not every combination of their expression needed to be modelled, as explained in the above section.

The following sections describe DER potential and DER enablement scenario drivers.

DER Potential

DER uptake is a key driver in assessing the potential to unlock the full whole-of-system benefits of DER integration and enablement. Potential for DER enablement is increased by falling technology costs for solar PV, storage and EVs and increased propensities and rates of consumer adoption of these technologies.

Energeia configured each scenario with respect to potential DER and DER VPP adoption and associated services via the following key scenario assumptions:

- **Rate of Technology Cost Decline** – The rate of decline in technology costs is a key driver of return on investment for consumers and DER VPP economics for VPP program developers. Future technology cost assumptions are therefore the key scenario driver for technology cost declines.
- **Consumer Behaviour in Technology Adoption** – DER and DER VPP adoption is influenced by consumer adoption propensities. DER uptake coefficients[45] are the key scenario driver used to vary consumer-driven DER adoption propensities.

DER Enablement

DER enablement is defined for the purpose of this project as allowing DER to compete with centralised generation, transmission and distribution network services on a level playing field.

[45] Energeia's uSim model develops DER uptake forecasts driven by a customer's ROI. Additional details on Energeia's uptake functionality can be found in Appendix C – uSim.

In practical modelling terms, Energeia's scenario design will be configured as follows to reflect the level of DER enablement:

- **Value Stream Enablement** – This scenario driver focuses on the scope and quality of the ability for DER to access benefits from avoidable wholesale or network costs[46]. The range of addressable benefit streams and the share of potential benefits available to DER varies by scenario.
- **DER Service Provider Enablement** – This scenario driver focuses on the capability and capacity of DER program developers to deliver DER benefits to an identified grid constraint. It will drive the adoption rates of DER programs, which will be a function of the underlying customer propensity, DER economics, and technical potential.

3.3.2. Scenario Design

A hallmark of good scenario design is that each of the scenarios should be equally likely to occur. However, this does not mean that all stakeholders will weigh them equally.

Based on the above scenario drivers and parameters, Energeia has designed the following scenarios to be included in our modelling:

- **Scenario 1: Counterfactual** – Energeia's Counterfactual scenario focuses on a future where DER potential and enablement will be slower and more limited than conventional wisdom. As such, DER costs and benefits are expected to be relatively limited and lower than expected overall.
- **Scenario 2: Incumbent Consensus** – The Incumbent Consensus scenario is consistent with AEMO's Step Change scenario[47], and representative of incumbent consensus regarding DER's maximum potential impacts and associated costs and benefits.
- **Scenario 3: Optimised DER** – The Optimised DER scenario goes beyond Australia's incumbent industry consensus in terms of DER potential and enablement assumptions. DER costs are lower, due to pricing and cost assumptions, and DER is enabled across the full range of potential value streams.

The scenario settings for each of the scenarios modelled is shown in Table 7.

Table 7 – Scenario Settings

Scenario Driver	1. Counterfactual	2. Incumbent Consensus	3. Optimised DER
DER Potential			
Rate of Technology Cost Decline	Low	Moderate	High
Consumer Behaviour in Technology Adoption	Low	Moderate	High
Level of Enablement			
Value Stream Enablement	Low	Moderate	High
DER Service Provider Enablement	Low	Moderate	High

Source: Energeia

3.4. Assessment Against Key Project Requirements

The Stage II project objective is to develop a more robust modelling approach and evidence base than was possible in Stage I. The Stage II project therefore focuses on identifying and quantifying the impact of DER enablement on the long-term interests of consumers including prosumers, including the ability to access and use the energy solution of their choice, and to potentially sell it to others or the industry, on a level playing field with transmission and distribution networks, and utility scale generation resources.

[46] Costs include short-term and long-term costs

[47] AEMO's Step Change scenario is defined as a scenario with both consumer-led and technology-led transitions occur in the midst of aggressive global decarbonisation and strong infrastructure commitments. More information is available here: https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en

Based on our review of the Project objectives, industry best practice, gaps in whole-of-system modelling and DER valuation exercises to date and feedback from stakeholder consultation[48], Energeia believes our modelling methodology to be fit-for-purpose for following reasons:

- **The needs identified in the stakeholder consultation process are considered** – Our modelling methodology will identify the least cost DER enablement solution over the long-term, taking all significant costs and benefits into account across key DER enablement scenarios, including a higher level of DER enablement envisioned by AEMO's ISP.
- **All costs and benefits are being considered per the project objectives** – Our modelling methodology models the impacts and associated significant costs or benefits across consumers, prosumers, retailers/VPP providers, networks, and generators. Importantly, it undertakes detailed modelling of key DER enablement net benefit drivers.
- **Costs and benefits are being modelled correctly –** Our cost benefit assessment model correctly identifies economic impacts as well as wealth transfers, to enable overall community as well as individual stakeholder net impacts to be quantified. This is particularly important to model the impact to passive consumers.
- **Modelling considers all key DER enablement scenarios and solutions –** Our scenarios have been developed to provide a counter factual, base case and stretch case, and includes all key forms of DER, and key centralized system solutions, including solar PV, energy storage, and demand response of water heaters and electric vehicles.
- **DER enablement scenarios and solutions modelled are correctly –** Our wholesale market, network, customer and tariff modelling methodologies are all based on industry best practice approaches, and have been reviewed by other consultancies and stakeholders over multiple engagements, excl. elements of dSim 2.0

[48] Stakeholder feedback is summarised in Appendix A.

Appendix A – Stakeholder Consultation

Energeia completed the Stage I DER Enablement project in Q2 2020. The project sought to review the range of consumer and energy system issues related to DER adoption and potential solutions for resolving them. The study was ground-breaking in documenting for the first time the match, and mismatch, of available network and consumer side impacts, costs, and solutions. From the high level of feedback, it was clear that there remained several key consumer and prosumer issues requiring further investigation and substantiation[49].

Renew identified that a more in-depth study was needed to develop the technical understanding and evidence base through a consumer-focused, stakeholder-engaged process designed to influence industry practice and thinking. Renew, Energeia and ECA have designed Stage II with an increased focus on stakeholder engagement at the request of the ECA Board.

As part of the grant funding process, a third-party independent review was completed, which recommended amongst other things the inclusion of stakeholder perspectives in model design and a peer review process of the chosen modelling method. The ECA Board approved an extended budget to increase the project's focus on stakeholder engagement, investing in engagement to drive the project's impact on the industry.

The following sections details Energeia's stakeholder consultation, including the objectives, engagement process, key findings of the consultation, their implications on this project, conclusions and recommendations, and the detailed responses from the stakeholders interviewed.

A.1. Objectives

Energeia and Renew have committed to applying the key findings from the engagement process to shape the project design. The stakeholder process was designed to ensure that the project would address key sectors impacted by the work – regulators, networks, retailers, technology players, etc. It was intended to highlight the limitations of the industry's perspectives with respect to a consumer-focused future. The findings could play a key role in facilitating a more consumer-driven vision of the future and provide the evidence base to drive it through regulation.

Energeia and Renew had designed a stakeholder consultation process that engages with a representative number of key policy, regulatory and industry stakeholders, incumbents as well as new entrants, to discover and map their understanding and perspective on DER enablement, and their resulting DER enablement focus areas and activities. The project is seeking to impact the full range of stakeholders (networks, retailers, market bodies, etc.) by engaging with them to understand their existing views, concerns and issues, and then to use the data and evidence developed by the project to inform their perception of consumer's best interests and needs.

Active consultation with impacted stakeholders and subject matter experts helped ensure the project analysis is fit-for-purpose, and that the modelling inputs and methodologies are robust, and that the project outputs as useful as possible for impacted stakeholders. The stakeholder process was designed to help Energeia understand how stakeholders saw the potential of DER enablement (i.e. levelling the playing field for DER, with respect to competing for network and market revenues) and what associated information gaps existed that the project could address.

A.2. Engagement Process

Energeia's engagement process included developing a stakeholder list, contacting and interview stakeholders, and developing interview questionnaires. These are discussed in detail in the sections below.

A.2.1. Developing Stakeholder List

Renew developed a comprehensive list of suggested stakeholders, based on both Stage I participants, and targeted participants for Stage II. The list was developed to ensure a wide range of stakeholders in the energy industry were given an opportunity to have their voices heard in the process, including networks, retailers, market bodies, government departments and other organisations across all jurisdictions in Australia.

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[49] These issues include the value of DER to both consumers with and without DER and the clear value of consumer side solutions, including VPP, coordinated hot water and EV charging loads, and VPP coordinated BTM batteries, relative to network solutions

Energeia's finalised stakeholder list was developed through a filtering process that included:

- Consideration of the organisation's involvement in Stage I
- Potential participation of the organisation in either the Stage II project reference group or steering committee
- Representation of a range of different incumbents and new entrants, across the electricity value chain
- Availability and willingness of stakeholders to participate in the process

Renew's initial comprehensive list of stakeholders comprised of 61 organisations and is shown in Table 8 segmented into five key organisation types.

Table 8 – Initial List of Stakeholders

Networks	Market Bodies	Government	Retailer	Other
Ausgrid	AEC	ACT Govt	AGL	ACOSS
Ausnet	AEMC	VIC DELWP	Amber	ANU
Endeavour	AEMO	NSW DPIE	Diamond	BSL
EQL	AER	QLD Govt	Energy Locals	CVGA
Essential	ARENA	SA DEM	Lumo	ECA
Evo Energy	CEC	TAS Govt	Nectr	Farrier Swier
Jemena	CSIRO		Powershop	Freelance Advocate
Powercor	ENA		Simply Energy	Greensync
PWC - NT	ESC			Maroondah Council
SAPN	SEC			NAGA
Tas Networks				NE Solar
United Energy				PIAC
Western Power				Redback
				Rheem
				Solar Analytics
				Sonnen
				SVPD
				TEC
				Tesla
				Uni NSW
				Uni QLD
				UTS
				WA Govt
				Wattwatchers

Source: Energeia

Due to the limited time available, Energeia, together with Renew, developed a filtering process to maximise the value of the engagement process with respect to the project objectives, aiming to develop a stakeholder shortlist that was as representative of the electricity industry as possible, with a wide variation in the roles and level of influence of the organisations. Consideration to the personnel interviewed from each organisation was also paramount, with Energeia ensuring that the interviewee's experience and job roles were suitable for a discussion of the barriers and solutions to DER enablement. The final shortlist of organisations interviewed is displayed in Table 9.

Table 9 – Final Filtered and Contacted List of Stakeholders

Networks	Market Bodies	Government	Retailer	Other
Ausgrid	AEC	ACT Govt	AGL	ACOSS
Ausnet	AEMC	VIC DELWP	Amber	ANU
Endeavour	AEMO	NSW DPIE	Diamond	BSL
EQL	AER	QLD Govt	Energy Locals	CVGA
Essential	ARENA	SA DEM	Lumo	ECA
Evo Energy	CEC	Tas Govt	Nectr	Farrier Swier
Jemena	CSIRO		Powershop	Freelance Advocate
Powercor	ENA		Simply Energy	Greensync
PWC - NT	ESC			Maroondah Council
SAPN	SEC			NAGA
Tas Networks				NE Solar
United Energy				PIAC
Western Power				Redback
				Rheem
				Solar Analytics
				Sonnen
				SVPD
				TEC
				Tesla
				Uni NSW
				Uni QLD
				UTS
				WA Govt
				Wattwatchers

Source: Energeia; Note: Contacted stakeholders are in green, filtered stakeholders are in grey

Table 10 demonstrates the representativeness of the of the short-listed organisations, whom in total have a stake in all six NEM jurisdictions.

Table 10 – Final Stakeholder List

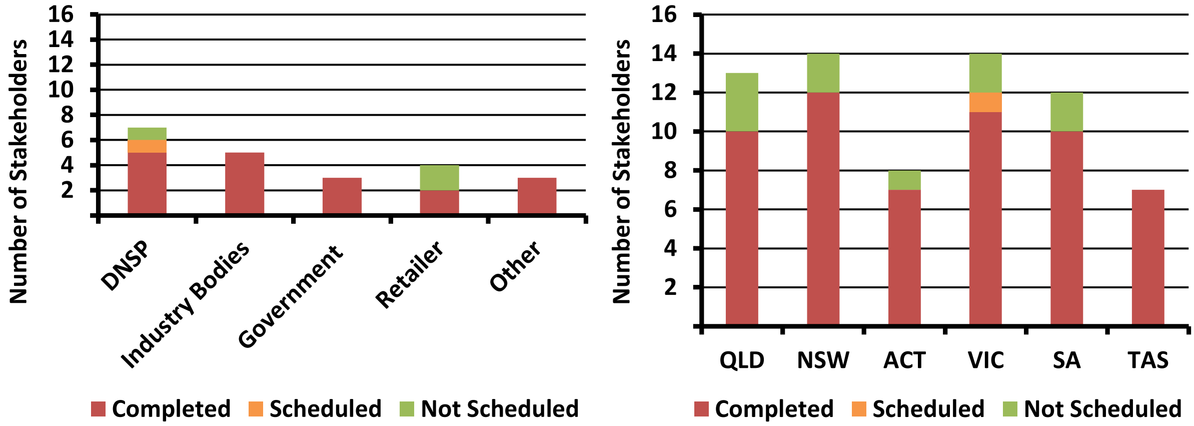
Organisation	Organisation Type	NEM Region						Stage I Participant	Industry Incumbent	Interview Completed
		QLD	NSW	ACT	VIC	SA	TAS			
SAPN	Distribution Network Services Providers					✓		✓	✓	✓
Ausnet					✓			✓	✓	✓
Ausgrid			✓						✓	✓
Essential			✓					✓	✓	✓
Energy Queensland		✓							✓	
Jemena					✓			✓	✓	✓
Powercor					✓				✓	✓
AEMO	Market Bodies	✓	✓	✓	✓	✓	✓		✓	✓
AER		✓	✓	✓	✓	✓	✓		✓	✓
AEMC		✓	✓	✓	✓	✓	✓		✓	✓
CEC		✓	✓	✓	✓	✓	✓		✓	✓
ARENA		✓	✓	✓	✓	✓	✓	✓	✓	✓
SA DEM	Government					✓			✓	✓
NSW DPIE			✓						✓	✓
VIC DELWP					✓				✓	✓
NECTR	Retailer	✓	✓							✓
AGL		✓	✓		✓	✓		✓	✓	✓
Energy Locals		✓	✓	✓	✓	✓				
Powershop		✓	✓		✓	✓				
Solar Analytics	Other	✓	✓	✓	✓	✓	✓	✓		✓
Energetic Communities		✓								✓
Tesla		✓	✓	✓	✓	✓	✓			✓

Source: Energeia Analysis; Note: Energeia was unable to secure interviews with Energy Queensland, Energy Locals and Powershop

A.2.2. Contacting and Interviewing Stakeholders

In total, Energeia secured interviews with 18 of the 21 short-listed organisations as shown in Figure 6.. Organisations covered all regions of the NEM, with at least three stakeholders from each category. The main gap in organisation type was new entrant retailers (e.g. Powershop and Energy Locals).

Figure 6 – Interview Status by Organisation Type (Left) and Region Right)

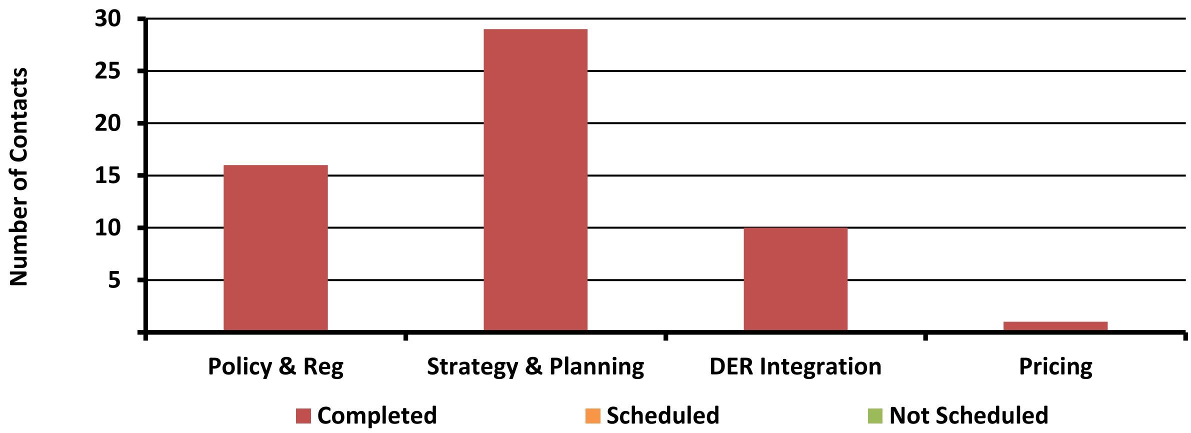


Source: Energeia; Note: Organisation can cover more than one region

The majority of interviewees had strategy and planning backgrounds, with policy and regulation and DER integration also well-represented, as shown in Figure 7.

While Energeia was mostly unable to secure more interviews with pricing experts, we believe that our final field of experts is evidently and sufficiently well-rounded and has provided us with ability to develop an industry consensus on the barriers and solutions of DER enablement.

Figure 7 – Interview Status by Role Type



Source: Energeia

A.2.3. Developing Interview Questionnaire

Energeia developed the interview questionnaire to discover and map stakeholder views regarding DER enablement, and their current related activities. The aim was to identify which particular barriers were of most concern to the industry, what solutions are presently being considered, and to what extent has the industry sough to implement solutions.

Energeia begin each interview by uncovering stakeholder's views on DER Enablement, to understand what it meant and why it was important. The first set of questions then focused on the barriers to DER enablement, which can be summarised to:

- What are the key challenges they *identified*?

- Which of these are most important or highest *priority*?

The second set of questions aimed to describe the enablers of future DER enablement success:

- How do they *identify* what success looks like?
- What are you doing to *address* these issues?
- What are the *priority* actions that could/should be done?

The full questionnaire design is displayed in Table 11.

Table 11 – Questionnaire Design

Understanding the Problem		
Barriers	Identified	What does you and your organisation see are the main barriers, drivers, uncertainties, risks, or issues facing DER enablement with respect to the NEO?
	Prioritised	What are the key DER enablement barriers, drivers, uncertainties, risks, or issues that you think we should prioritise for this project to best achieve the NEO?
Solutions		
Solutions	Identified	What does successful (NEO maximising) DER enablement look like to you and your organisation for policymakers, incumbents, new entrants, and consumers?
	Addressed	What is your organisation currently doing to address DER enablement, i.e. what DER enablement strategies are being pursued and what challenges are you facing?
	Prioritised	What are the key strategies to the key barriers, drivers, risks, uncertainties, risks, and issues that you think this project should consider?

Source: Energeia

A.3. Key Findings

Energeia's feedback assessment process, and the key findings of the stakeholder engagement on the stakeholders' views on DER enablement and the key barriers and issues to focus on are discussed in detail in the sections below.

A.3.1. Feedback Assessment Process

Energeia summarised the stakeholder consultations by noting the key points made by each stakeholder related to barriers and solutions around DER enablement, then categorising each response into categories and sub-categories:

- **Policy and Regulation** – Findings relating to any key frameworks with which stakeholders manage DER within, including technical and economic regulations, pricing, and market design, in which stakeholders saw the existing regulation as a barrier or amendments to policy as a solution.
- **Technical and Economic Factors** – Findings regarding DER technology constraints such as voltage, thermal, frequency, reverse flow, fault limits, protection maloperation, ride through all limiting DER capacity and operation, or solutions to these constraints, especially monitoring and control, better voltage management, VPP visibility and control, flexible exports and the inability to fund DER enablement solution investments.
- **Consumer Factors** – Findings regarding the behaviour, experience, protection, and equity of consumers with and without DER that are considered either a barrier to DER enablement, or that could be part of the solution.

The resultant data set was then analysed for patterns by category type, by organisation type and by activity. The summary findings are shown in Table 12.

Table 12 – Summary of Responses by Stakeholder Type

Question Category	Question	Feedback Category	Market Body	Network	Government	Retailer	Other	Total Responses
Understanding the Problem	What are the main barriers, drivers, uncertainties, risks, or issues facing DER enablement with respect to the NEO?	Policy and Regulation	13	12	8	3	7	43
		Technical Factors	5	14	5	2	4	30
		Consumer Factors	5	5	1	4	2	17
	What are the key DER enablement barriers, drivers, uncertainties, risks, or issues that you think we should prioritise for this project to best achieve the NEO?	Policy and Regulation	0	1	0	0	3	4
		Technical Factors	1	0	1	0	0	2
		Consumer Factors	2	1	0	0	2	5
Understanding the Solution	What does successful (NEO maximising) DER enablement look like to you and your organisation?	Policy and Regulation	5	10	3	0	3	21
		Technical Factors	4	10	4	1	2	21
		Consumer Factors	0	3	1	0	0	4
	What is your organisation currently doing to address DER enablement, i.e. what DER enablement strategies are being pursued and what challenges are you facing?	Policy and Regulation	6	5	3	0	0	14
		Technical Factors	1	7	2	1	2	13
		Consumer Factors	0	0	2	2	0	4
	What are the key strategies to the key barriers, drivers, risks, uncertainties, risks, and issues that you think this project should consider?	Policy and Regulation	2	3	0	0	2	7
		Technical Factors	2	4	1	0	0	7
		Consumer Factors	0	0	1	0	1	2

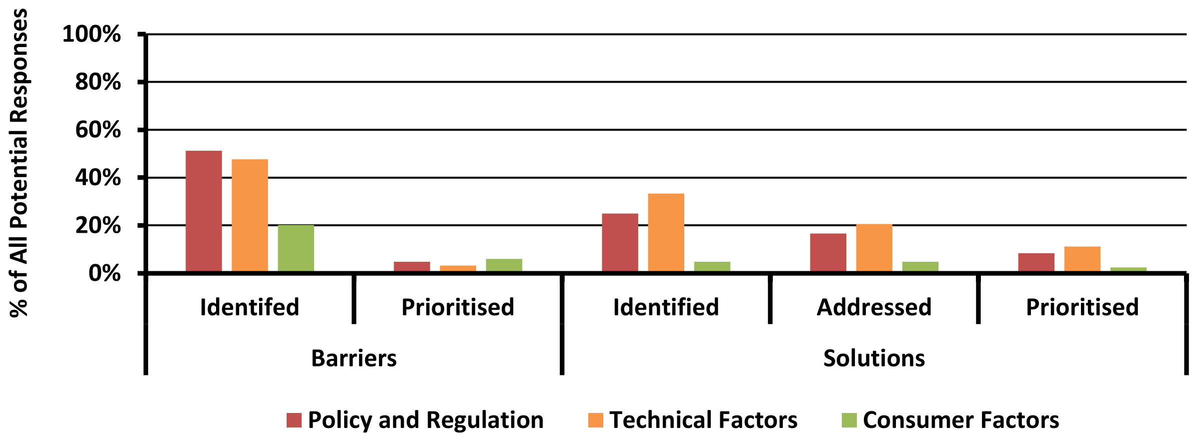
Source: Energeia

Detailed response matrices are provided in Section A.6.

A.3.2. Stakeholder Views on DER Enablement

Overall, stakeholders tended to be focused on the barriers to DER enablement. The majority of interviewees engaged more strongly around potential barriers than solutions. Most were able to identify a range of issues – either problems or solutions – but were less able to either describe the priority order that these issues should be addressed. The strength of the overall responses is summarised in Figure 8.

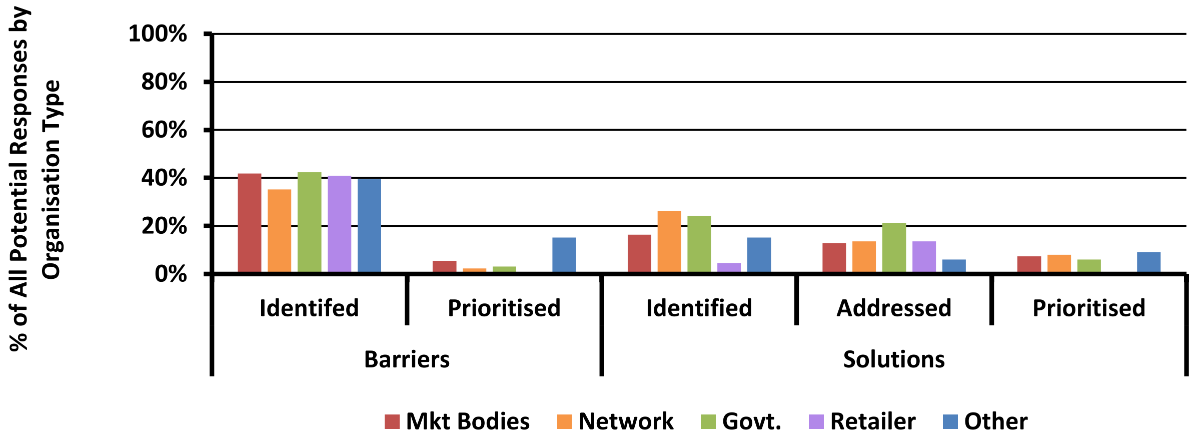
Figure 8 – Responses by Question Type



Source: Energeia

Energeia identified patterns in responses by organisation type, which is displayed in Figure 9. Government organisations identified relatively more problems and had the greatest number of in-progress initiatives. Other stakeholders identified relatively more priority barriers to be addressed and priority solutions to be delivered by this study than any other organisation type.

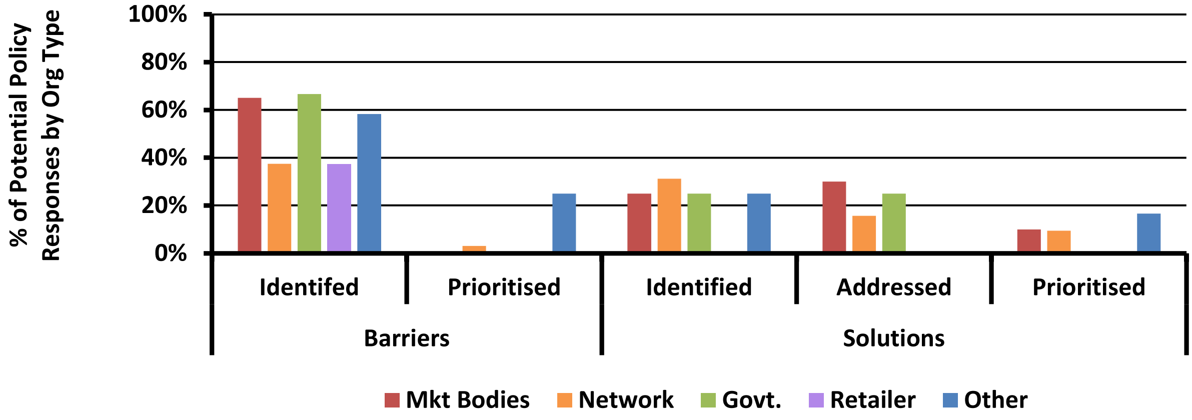
Figure 9 – Responses by Organisation Type



Source: Energeia

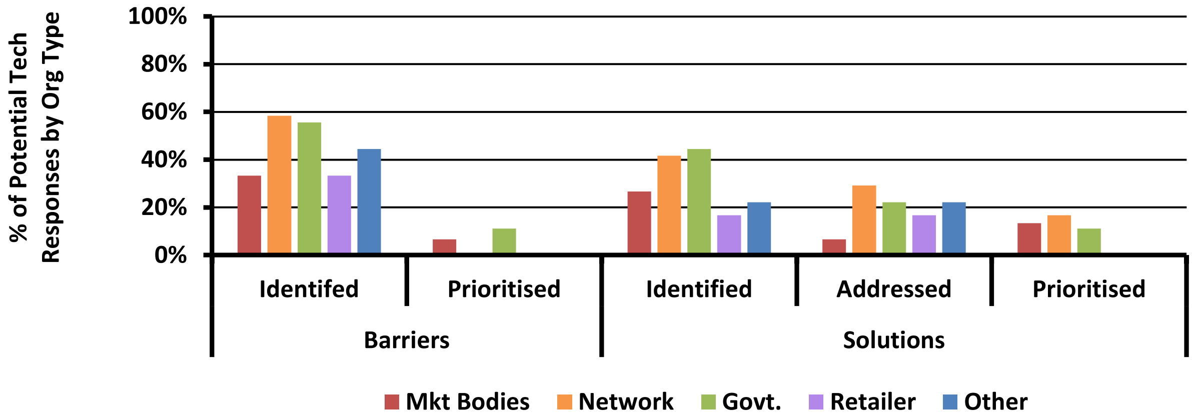
Generally speaking, organisations were the strongest in identifying barriers and solutions in the fields which the organisation was directly concerned with. Government organisations and market bodies had a relatively greater focus on policy and regulatory barriers, whereas networks identified and addressed more technology solutions than any type of issue. Other stakeholders were more likely to see consumer barriers as a priority for addressing, and retailers were more likely to identify barriers and provide solutions to consumer issues. A summary of the key findings by category is provided in Figure 10, Figure 11, and Figure 12.

Figure 10 – Policy and Regulatory Barriers and Solutions by Organisation Type



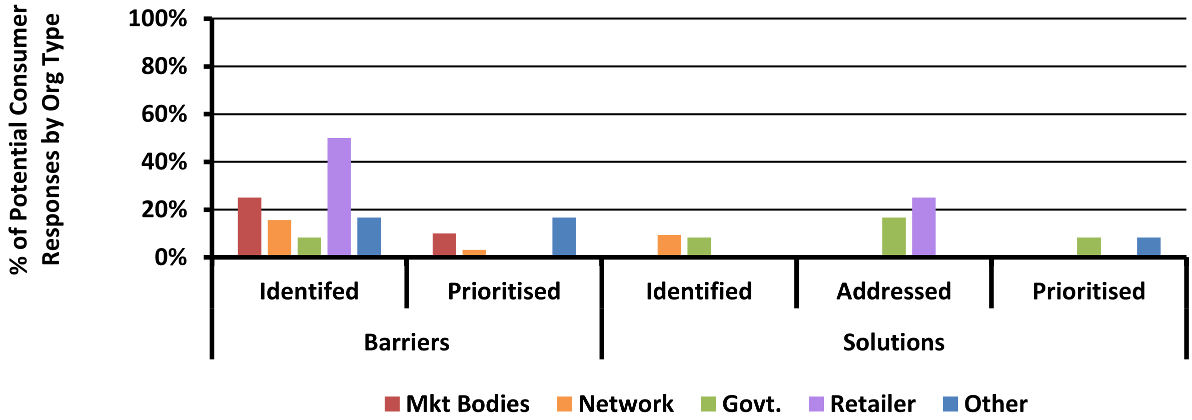
Source: Energeia

Figure 11 – Technology Barriers and Solutions by Organisation Type



Source: Energeia

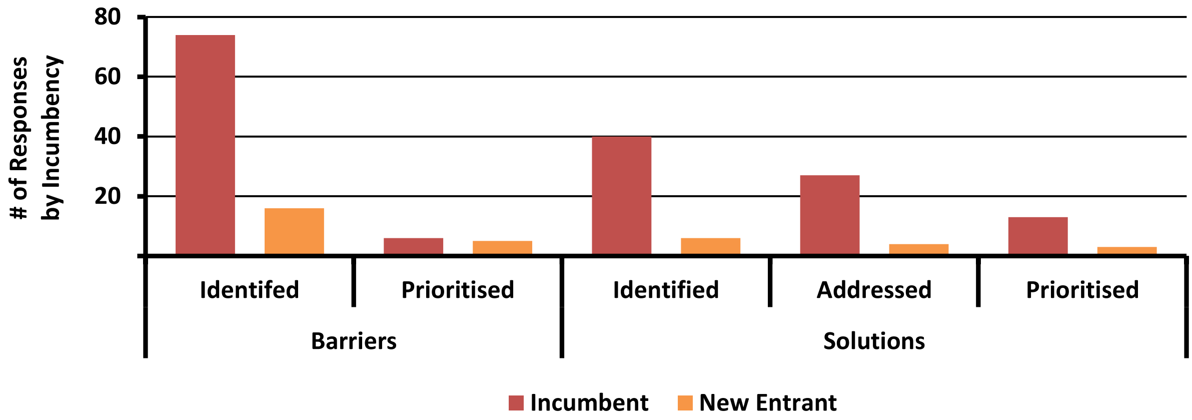
Figure 12 – Consumer Barriers and Solutions by Organisation Type



Source: Energeia

A limitation of the stakeholder consultation design was that, in an effort to ensure representativeness, significantly more incumbent organisations were consulted, including five market bodies, six DNSPs, three government organisations, and one retailer. Compared to only three non-incumbents (Other), our stakeholder findings are dominated by the responses of the incumbent organisations, as illustrated in Figure 13, whom have been operating in a centralised, supply-focused electricity market.

Figure 13 – Number of Responses by Incumbency



Source: Energeia

A.3.3. Key Barriers and Issues to Focus On

Considering the overweighting of incumbent organisations to the overall findings, Energeia believed it to be important to identify which barriers and solutions new entrant organisations were prioritising, and how this compared to the incumbent responses.

As Table 13 summarises the key barriers are highlighted by the interviewed stakeholders, including the following key points:

- New entrants highlighted regulation misalignment and ineffective market design as key barriers that need to be addressed, whereas incumbent organisations did not see these as a significant barrier.
- Cost reflective prices, a lack of technical solutions, and consumer participation and protections were the highest ranked issues overall.
- Technical solution availability was the highest ranked issue by incumbents.

In terms of priority solutions, as illustrated in Table 14, new entrants identified revising technical regulations and enhancing the consumer experience as an important solution to DER enablement issues, a solution that no incumbent organisation spoken to highlighted. However, incumbent organisations also highlighted improving competition in the market and technical solutions as the key ways in which DER enablement issues can be addressed.

Table 13 – Most Often Mentioned Priority Barriers by Stakeholder Group

Question	Category	Feedback Sub-Category	Explanation	All	Incumbents	New Entrants
What are the key DER enablement barriers, drivers, uncertainties, risks, or issues that you think we should prioritise for this project to best achieve the NEO?	Policy and Regulation	Technical Regulation incl. Connection, Metering, B2B and Inverter Standards	National standards are needed for DER aggregation and inverters, including interoperability. Metering and connection standards are based on obsolete, static paradigm and restricted access to data. Pace of reform is too long (2 yrs.+)	0%	0%	0%
		Economic Regulation	Regulatory barriers exist for new services and business models (e.g. community storage), economic regulation needs reform, inconsistent between Fed and state, the pace of reform is slow	5%	0%	25%
		Pricing / Tariffs	There is a lack of truly cost reflective price signals, including locational signals, to drive innovation	10%	6%	25%
		Market Design	Existing market design fractures and monopolises access to value streams and does not foster cooperation	5%	0%	25%
	Technical Factors	Technical Constraints	Technical constraints including voltage, thermal, frequency, reverse flow, fault limits, protection maloperation, ride through all limiting DER capacity and operation	0%	0%	0%
		Technical Solutions	A lack of solutions to technical constraints are limiting DER capacity and operation (especially monitoring and control, better voltage management, VPP visibility and control, flexible exports, etc.)	10%	12%	0%
		Cost Recovery	Investors, DNSP and ARENA are the only source of R&D funds, limiting scope and focus of DER enablement R&D, resulting in an uncoordinated focus, and limited DNSP and AER acceptance of potential DER enablement investments	0%	0%	0%
	Consumer Factors	Consumer Behaviour / Engagement	Consumers may not be willing to engage DER/VPPs, or may require significant engagement and education to engage in their own best interests	10%	6%	25%
		Consumer Experience	Consumers increasingly told they cannot install DER, or that it will be costly, or that their DER will be curtailed, and they will not enjoy the full benefits of it	0%	0%	0%
		Consumer Protection	Concerns regarding consumer protection needs (e.g. cyber security, lock-in, etc.) a key issue that may derail and/or unduly delay the pace of reform in their best interests	10%	6%	25%
		Consumer Equity	The industry cannot charge forward without ensuring that benefits of DER/VPPs is equitably available to all consumers, including those that do not choose to participate	5%	6%	0%

Source: Energeia

Table 14 – Most Often Mentioned Priority Solutions by Stakeholder Group

Question	Feedback Category	Feedback Sub-Category	Explanation	All	Incumbents	New Entrants
What are the key strategies to the key barriers, drivers, risks, uncertainties, risks, and issues that you think this project should consider?	Policy and Regulation	Technical Regulation incl. Connection, Metering, B2B and Inverter Standards	Smart metering is made a national baseline and allows for the implementation of smart tariffs	5%	0%	25%
		Economic Regulation	Regulation accommodates all types of DER, providing a platform that allows the value of DER to be realised and provides transparency between industry players	0%	0%	0%
		Pricing / Tariffs	Cost reflective (locational and user pay) pricing and tariffs are in place to allow for innovation in the market and incentivise efficient investment in the market	5%	6%	0%
		Market Design	Traditional distribution models change to equally incentivise network and non-network solutions, a proper evaluation of the costs and benefits of DER and provide all customers equal access the DER	24%	24%	25%
	Technical Factors	Technical Constraints	Networks provide required hosting capacity, accurately determined DOEs, flexible exports and connection agreements, whilst maximising asset utilisation and ensuring a stable grid	5%	6%	0%
		Technical Solutions	Networks provide access to VPPs, real time, locational visibility and control of capacity and constraints whilst remotely and dynamically manage voltage issues	29%	35%	0%
		Cost Recovery	Co-ordinated investment into DER enablement R&D between networks, regulators, and industry bodies	0%	0%	0%
	Consumer Factors	Consumer Behaviour / Engagement	Consumers are properly informed and incentivised to engage in DER/VPPs	0%	0%	0%
		Consumer Experience	Consumers have an issue free experience with networks and retailers are free to install and engage their DER assets to participate in available energy opportunities	10%	6%	25%
		Consumer Protection	Consumer protection (e.g. cyber security, lock-in, etc) is well-managed and maintained throughout the process of reform	0%	0%	0%
		Consumer Equity	Customers see the maximum value from their DER and industry investments help both consumer and prosumers	0%	0%	0%

Source: Energeia

A.4. Project Implications

The project needs to identify and quantify the optimal future state for consumers, with a focus on the potential role DER can play in that future, and the key policy, regulatory, market, industry, technical and consumer barriers that must be addressed to realise it. In the absence of a shared community vision for the optimal future consumer state, policymakers, regulators, and industry incumbents may not be focused on the right issues, at the right time and in the right amount. The project should therefore identify the most important contributions that DER could be making if fully enabled, the timing of these contributions, and their potential net benefits, so that stakeholders can become better organised to address them.

Based on the stakeholder engagement process and our Stage I work, Energeia believes this will include, at a minimum:

- Modelling DER/VPP potential and cost, including new, enabled, and leveraged use cases, considering all potential value streams
- Modelling the full range of DER/VPP value streams, including thermal, voltage, etc. from the LV network to the wholesale market
- Modelling the impacts of fully enabled DER/VPPs on consumers, including on NEM prices, network, and retail tariffs, etc.
- Modelling the full range of consumer stakeholders, including renters, apartment dwellers, vulnerable customers and those without DER
- Modelling the impacts of cost reflective price signals and the removal of barriers to customer participation

It is also critical that the project engage, mobilise, and empower more DER stakeholders, to better balance out the project voices, and to bring more attention to the current gap in representation in power system related deliberations. These issues are explored further in the sections below.

A.4.1. Industry Consensus Dominated by the Status Quo

Through the stakeholder consultation process, Energeia found that industry consensus is typically dominated by the status quo. It is relatively difficult to access voices for a more distributed energy system in the market development and integration dialogue due to there being relatively few of them with regulatory and market development functions. The dialogue is therefore largely determined by centralised energy system incumbents and stakeholders, leading to a potentially one-sided consideration of the issues, priorities, and actions. There is therefore a key role to be played by organisations like Renew, the Smart Energy Alliance and ECA to advocate for such a future if best for consumers.

Despite 40-50% of consumer bills going to distribution networks and almost zero network expenditure flowing to DER, no one raised this as an issue at all, or was focused on levelling the network investment playing field. While many stakeholders focused on enabling solar PV generation to access flat feed-in tariffs, only one stakeholder prioritised unlocking wholesale market price spikes, ancillary services, or reserve markets – another 20-30% of bills.

Differences in views on the key issues, actions and remaining priorities could be discerned between the two groups, with the centralised system group tending to focus on supply side issues, especially regulatory and technology-focused ones, for example, enabling flexible access to hosting capacity, connection agreements, etc. Few organisations appeared to understand the optimal future state for consumers and used it to orient their prioritisation of the key issues and solutions.

A.4.2. A Shared View of Optimal Consumer Future is Needed

Energeia's stakeholder engagement process identified a gap in the community's understanding of an optimal future power system for consumers, such a vision should:

- Consider all material costs and benefits and not just a sub-set
- Consider DER/VPPs and centralized system expenditure on a level playing field

- Consider fully enabled VPPs, including existing and potential new capacity, both retrofits and greenfield
- Consider the impact of fully cost reflective price signals and incentives across the value chain[50]
- Consider the impact of consumer barriers, especially to participation
- Consider the impacts on all consumers including renters, apartment dwellers and those without DER
- Identify the highest net benefit solutions for all consumers by time and place
- Be balanced and unbiased
- Provide a roadmap for unlocking it[51]

Although the above list provides a strong message regarding the need for and value of a consumer-focused view of the future power system, it may be incomplete and biased, due to limitations in current industry consultation approaches. Additional efforts should therefore be made to identify, engage, and enable potential new DER-related entrants and DER-savvy consumer advocates.

A.5. Conclusions and Recommendations

Our stakeholder consultation objective was to understand the range of industry perspectives regarding enabling DER to provide network and market services on a level playing field. We interviewed a wide range of electricity industry and consumer stakeholders and discovered that the focus of the majority of incumbents was on overcoming short-term barriers with little understanding or focus on long-term system optimisation for the benefit of consumers.

Based on our stakeholder consultation, as well as the results of the Stage I project, Energeia recommended that the project ensured the following critical success factors are addressed:

- **Consumer Objectives** – Identification and quantification of the optimal long-term consumer outcome, i.e. that best supports the National Electricity Objective (NEO) In terms of centralised vs. decentralized resources / services
- **Key Barriers and Enablers** – Identification and quantification of the key drivers and barriers to that outcome, across technical, industry, market and policy and regulatory domains
- **Risk and Uncertainty** – Identification and quantification of how different scenarios (esp. tech price and consumer behaviour) could impact on the above
- **Distributary Impacts** – Identification of the expected costs and benefits involved in moving to and being at, the optimal consumer future, which includes prosumers and consumers, not either or

Energeia therefore concluded that project stakeholders, and in particular consumers, will be best served by the development of an optimised future vision for consumers, defined as maximizing the long-term interests of consumers, consistent with the NEO. It was deemed essential that distributed energy system stakeholders were identified, engaged, and supported by the project.

[50] Modelling of different degrees of cost reflectivity is beyond the scope of this project, but could be included in a Phase 3.

[51] Although not in scope, the stakeholder engagement identified the need for a DER Enablement Roadmap, which could also be part of Phase 3.

A.6. Detailed Responses

Table 15 – Summary of Main Barriers Identified by Organisation Type

Question	Feedback Category	Feedback Sub-Category	Explanation	Market Body	Network	Gov	Retailer	Other	Total
What are the main barriers, drivers, uncertainties, risks, or issues facing DER enablement with respect to the NEO?	Policy and Regulation	Technical Regulation incl. Connection, Metering, B2B and Inverter Standards	National standards are needed for DER aggregation and inverters, including interoperability. Metering and connection standards are based on obsolete, static paradigm and restricted access to data. Pace of reform is too long (2 yrs.+)	4	3	2	1	2	**12**
		Economic Regulation	Regulatory barriers exist for new services and business models (e.g. community storage), economic regulation needs reform, inconsistent between Fed and state, the pace of reform is slow	4	3	3	0	2	**12**
		Pricing / Tariffs	There is a lack of truly cost reflective price signals, including locational signals, to drive innovation	3	3	1	0	1	**8**
		Market Design	Existing market design fractures and monopolises access to value streams and does not foster cooperation	2	3	2	2	2	**11**
	Technical Factors	Technical Constraints	Technical constraints including voltage, thermal, frequency, reverse flow, fault limits, protection maloperation, ride through all limiting DER capacity and operation	3	6	2	1	2	**14**
		Technical Solutions	A lack of solutions to technical constraints are limiting DER capacity and operation (especially monitoring and control, better voltage management, VPP visibility and control, flexible exports, etc.)	2	7	2	1	0	**12**
		Cost Recovery	Investors, DNSP and ARENA are the only source of R&D funds, limiting scope and focus of DER enablement R&D, resulting in an uncoordinated focus, and limited DNSP and AER acceptance of potential DER enablement investments	0	1	1	0	2	**4**
	Consumer Factors	Consumer Behaviour / Engagement	Consumers may not be willing to engage DER/VPPs, or may require significant engagement and education to engage in their own best interests	1	0	0	1	1	**3**
		Consumer Experience	Consumers increasingly told they cannot install DER, or that it will be costly, or that their DER will be curtailed, and they will not enjoy the full benefits of it	2	1	0	1	1	**5**
		Consumer Protection	Concerns regarding consumer protection needs (e.g. cyber security, lock-in, etc.) a key issue that may derail and/or unduly delay the pace of reform in their best interests	1	1	1	1	0	**4**
		Consumer Equity	The industry cannot charge forward without ensuring that benefits of DER/VPPs is equitably available to all consumers, including those that do not choose to participate	1	3	0	1	0	**5**

Source: Energeia

Table 16 – Summary Key Issues and Barriers Prioritised for Further Analysis

Question	Feedback Category	Feedback Sub-Category	Explanation	Market Body	Network	Gov	Retailer	Other	Total
What are the key DER enablement barriers, drivers, uncertainties, risks, or issues that you think we should prioritise for this project to best achieve the NEO?	Policy and Regulation	Technical Regulation incl. Connection, Metering, B2B and Inverter Standards	National standards are needed for DER aggregation and inverters, including interoperability. Metering and connection standards are based on obsolete, static paradigm and restricted access to data. Pace of reform is too long (2 yrs.+)	0	0	0	0	0	**0**
		Economic Regulation	Regulatory barriers exist for new services and business models (e.g. community storage), economic regulation needs reform, inconsistent between Fed and state, the pace of reform is slow	0	0	0	0	1	**1**
		Pricing / Tariffs	There is a lack of truly cost reflective price signals, including locational signals, to drive innovation	0	1	0	0	1	**2**
		Market Design	Existing market design fractures and monopolises access to value streams and does not foster cooperation	0	0	0	0	1	**1**
	Technical Factors	Technical Constraints	Technical constraints including voltage, thermal, frequency, reverse flow, fault limits, protection maloperation, ride through all limiting DER capacity and operation	0	0	0	0	0	**0**
		Technical Solutions	A lack of solutions to technical constraints are limiting DER capacity and operation (especially monitoring and control, better voltage management, VPP visibility and control, flexible exports, etc.)	1	0	1	0	0	**2**
		Cost Recovery	Investors, DNSP and ARENA are the only source of R&D funds, limiting scope and focus of DER enablement R&D, resulting in an uncoordinated focus, and limited DNSP and AER acceptance of potential DER enablement investments	0	0	0	0	0	**0**
	Consumer Factors	Consumer Behaviour / Engagement	Consumers may not be willing to engage DER/VPPs, or may require significant engagement and education to engage in their own best interests	1	0	0	0	1	**2**
		Consumer Experience	Consumers increasingly told they cannot install DER, or that it will be costly, or that their DER will be curtailed, and they will not enjoy the full benefits of it	0	0	0	0	0	**0**
		Consumer Protection	Concerns regarding consumer protection needs (e.g. cyber security, lock-in, etc.) a key issue that may derail and/or unduly delay the pace of reform in their best interests	0	1	0	0	1	**2**
		Consumer Equity	The industry cannot charge forward without ensuring that benefits of DER/VPPs is equitably available to all consumers, including those that do not choose to participate	1	0	0	0	0	**1**

Source: Energeia

Table 17 – Summary of Key Factors of Successful DER Enablement Identified

Question	Feedback Category	Feedback Sub-Category	Explanation	Market Body	Network	Gov	Retailer	Other	Total
What does successful (NEO maximising) DER enablement look like to you and your organisation?	Policy and Regulation	Technical Regulation incl. Connection, Metering, B2B and Inverter Standards	Smart metering is made a national baseline and allows for the implementation of smart tariffs	0	1	0	0	0	**1**
		Economic Regulation	Regulation accommodates all types of DER, providing a platform that allows the value of DER to be realised and provides transparency between industry players	0	1	1	0	2	**4**
		Pricing / Tariffs	Cost reflective (locational and user pay) pricing and tariffs are in place to allow for innovation in the market and incentivise efficient investment in the market	2	4	1	0	0	**7**
		Market Design	Traditional distribution models change to equally incentivise network and non-network solutions, a proper evaluation of the costs and benefits of DER and provide all customers equal access the DER	3	4	1	0	1	**9**
	Technical Factors	Technical Constraints	Networks provide required hosting capacity, accurately determined DOEs, flexible exports and connection agreements, whilst maximising asset utilisation and ensuring a stable grid	3	4	2	0	0	**9**
		Technical Solutions	Networks provide access to VPPs, real time, locational visibility and control of capacity and constraints whilst remotely and dynamically manage voltage issues	1	6	2	1	2	**12**
		Cost Recovery	Co-ordinated investment into DER enablement R&D between networks, regulators, and industry bodies	0	0	0	0	0	**0**
	Consumer Factors	Consumer Behaviour / Engagement	Consumers are properly informed and incentivised to engage in DER/VPPs	0	0	0	0	0	**0**
		Consumer Experience	Consumers have an issue free experience with networks and retailers are free to install and engage their DER assets to participate in available energy opportunities	0	1	1	0	0	**2**
		Consumer Protection	Consumer protection (e.g. cyber security, lock-in, etc) is well-managed and maintained throughout the process of reform	0	0	0	0	0	**0**
		Consumer Equity	Customers see the maximum value from their DER and industry investments help both consumer and prosumers	0	2	0	0	0	**2**

Source: Energeia

Table 18 – Summary of Current Initiatives Amongst Consulted Organisations

Question	Feedback Category	Feedback Sub-Category	Explanation	Market Body	Network	Gov	Retailer	Other	Total
What is your organisation currently doing to address DER enablement, i.e. what DER enablement strategies are being pursued and what challenges are you facing?	Policy and Regulation	Technical Regulation incl. Connection, Metering, B2B and Inverter Standards	Smart metering is made a national baseline and allows for the implementation of smart tariffs	1	0	0	0	0	1
		Economic Regulation	Regulation accommodates all types of DER, providing a platform that allows the value of DER to be realised and provides transparency between industry players	3	0	1	0	0	4
		Pricing / Tariffs	Cost reflective (locational and user pay) pricing and tariffs are in place to allow for innovation in the market and incentivise efficient investment in the market	0	4	1	0	0	5
		Market Design	Traditional distribution models change to equally incentivise network and non-network solutions, a proper evaluation of the costs and benefits of DER and provide all customers equal access the DER	2	1	1	0	0	4
	Technical Factors	Technical Constraints	Networks provide required hosting capacity, accurately determined DOEs, flexible exports and connection agreements, whilst maximising asset utilisation and ensuring a stable grid	0	2	0	0	0	2
		Technical Solutions	Networks provide access to VPPs, real time, locational visibility and control of capacity and constraints whilst remotely and dynamically manage voltage issues	1	5	2	1	2	11
		Cost Recovery	Co-ordinated investment into DER enablement R&D between networks, regulators, and industry bodies	0	0	0	0	0	0
	Consumer Factors	Consumer Behaviour / Engagement	Consumers are properly informed and incentivised to engage in DER/VPPs	0	0	0	0	0	0
		Consumer Experience	Consumers have an issue free experience with networks and retailers are free to install and engage their DER assets to participate in available energy opportunities	0	0	1	1	0	2
		Consumer Protection	Consumer protection (e.g. cyber security, lock-in, etc) is well-managed and maintained throughout the process of reform	0	0	0	0	0	0
		Consumer Equity	Customers see the maximum value from their DER and industry investments help both consumer and prosumers	0	0	1	1	0	2

Source: Energeia

Table 19 – Summary of Prioritised Enabling Strategies

Question	Feedback Category	Feedback Sub-Category	Explanation	Market Body	Network	Gov	Retailer	Other	Total
What are the key strategies to the key barriers, drivers, risks, uncertainties, risks, and issues that you think this project should consider?	Policy and Regulation	Technical Regulation incl. Connection, Metering, B2B and Inverter Standards	Smart metering is made a national baseline and allows for the implementation of smart tariffs	0	0	0	0	1	**1**
		Economic Regulation	Regulation accommodates all types of DER, providing a platform that allows the value of DER to be realised and provides transparency between industry players	0	0	0	0	0	**0**
		Pricing / Tariffs	Cost reflective (locational and user pay) pricing and tariffs are in place to allow for innovation in the market and incentivise efficient investment in the market	0	1	0	0	0	**1**
		Market Design	Traditional distribution models change to equally incentivise network and non-network solutions, a proper evaluation of the costs and benefits of DER and provide all customers equal access the DER	2	2	0	0	1	**5**
	Technical Factors	Technical Constraints	Networks provide required hosting capacity, accurately determined DOEs, flexible exports and connection agreements, whilst maximising asset utilisation and ensuring a stable grid	1	0	0	0	0	**1**
		Technical Solutions	Networks provide access to VPPs, real time, locational visibility and control of capacity and constraints whilst remotely and dynamically manage voltage issues	1	4	1	0	0	**6**
		Cost Recovery	Co-ordinated investment into DER enablement R&D between networks, regulators, and industry bodies	0	0	0	0	0	**0**
	Consumer Factors	Consumer Behaviour / Engagement	Consumers are properly informed and incentivised to engage in DER/VPPs	0	0	0	0	0	**0**
		Consumer Experience	Consumers have an issue free experience with networks and retailers are free to install and engage their DER assets to participate in available energy opportunities	0	0	1	0	1	**2**
		Consumer Protection	Consumer protection (e.g. cyber security, lock-in, etc) is well-managed and maintained throughout the process of reform	0	0	0	0	0	**0**
		Consumer Equity	Customers see the maximum value from their DER and industry investments help both consumer and prosumers	0	0	0	0	0	**0**

Source: Energeia

Appendix B – wSim

Energeia's network[52] and generator impact analysis are based on two models, Energeia's Utility Simulation Software (uSim) and Energeia's Wholesale Market Software (wSim). This section outlines the structure and approach of Energeia's wSim and details the modelling process, modules, and key assumptions.

B.1. Overview

The following sections describe Energeia's approach to determining the model's key inputs, simulating the NEM security-constrained economic dispatch (SCED) and associated pricing of energy, ancillary services and key generator revenue streams including reliability obligations and renewable energy certificates, and forecasting capacity expansion over time.

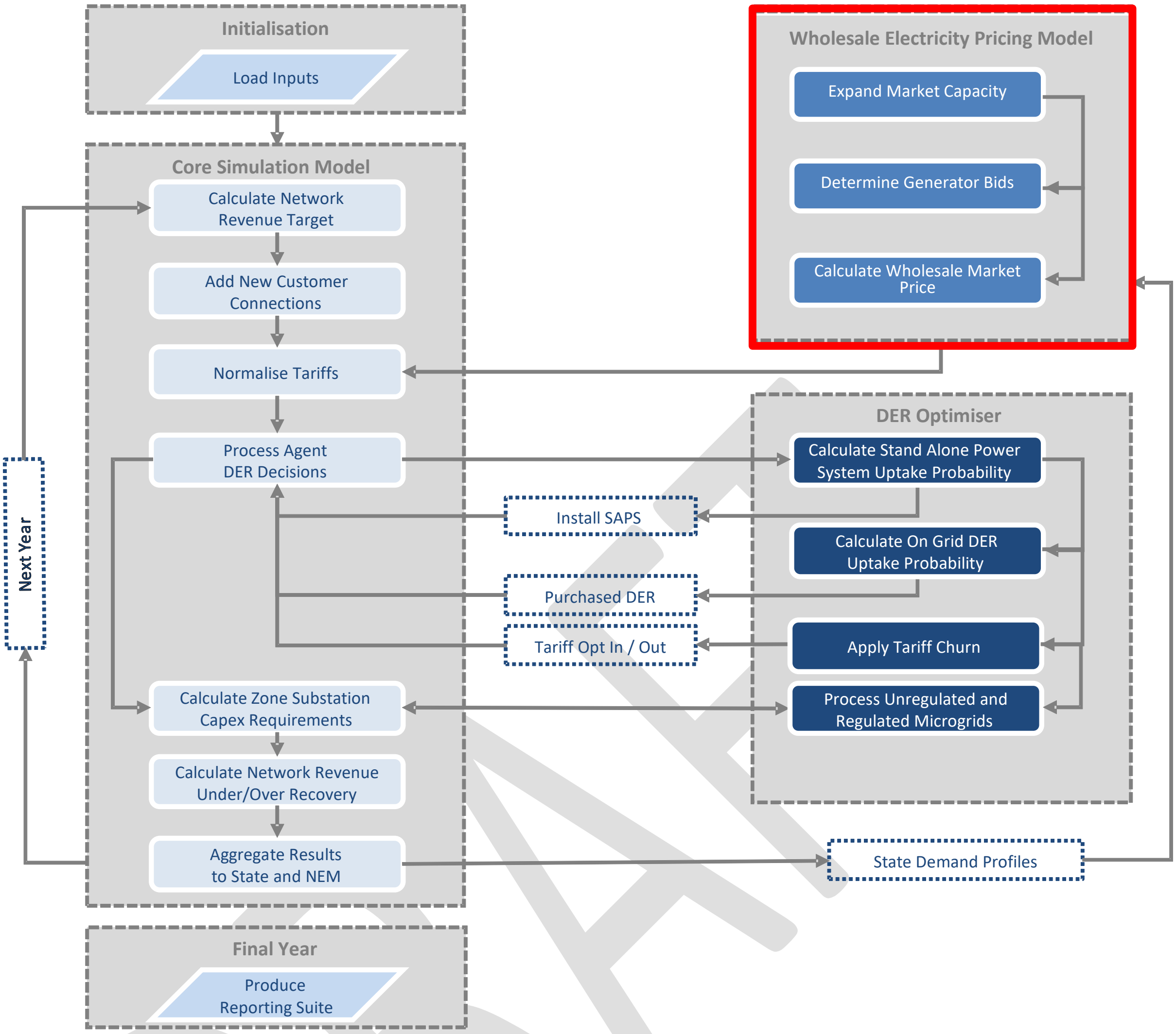
B.1.1. Structure of the Model

Energeia's wholesale market model (wSim) forms an essential part of Energeia's integrated energy system model, depicted in Figure 14.

[52] More details of the distribution network model's structure, process and key inputs are outlined in

Appendix C – uSim.

Figure 14 – Overview of Energeia's Integrated Energy System Simulation Platform (wSim)



Source: Energeia

Although the wSim model can be operated separately from the DER simulation platform, the two systems can also be optionally integrated.

B.1.2. Methodology Selection

The modular nature of Energeia's simulation platform determines the nature and structure of the modelling of the wholesale market in wSim. The wSim module is designed to estimate the retail component of customer prices – both usage and export tariffs – that underpin uSim's analysis of distributed energy resources, and determine if, when and where new generation enters or exits the market. To be effective at these tasks, wSim therefore needs to generate wholesale market prices, and the revenues for generators participating in this market. To accurately model future wholesale market prices, and estimate the financial viability of current and new entrant generators, any wholesale market model needs to:

- Replicate the system operator's economic dispatch of generators
- Apply security constraints to the economic dispatch to ensure that reliability requirements are met
- Reflect real world generator behaviours
- Estimate the financial viability of incumbent and new entry generators

Energeia assessed international best practice as well as consensus approaches to modelling in Australia's National Electricity Market (NEM) before selecting our wholesale market modelling methodology.

International Best Practice

Energeia researched the international best practice in wholesale market modelling to understand the trade-off between model complexity and computational effort. Our research identified that that are three broad types of modelling methodologies:

- **Simulation –** building a bottom-up model of the energy system based on specific equations and characteristics
- **Optimisation –** solving an equation subject to a set of constraints, e.g. minimising total system cost subject to a set of constraints
- **Equilibrium** – Modelling the energy sector as part of the whole economy, balancing supply and demand

The most commonly implemented solutions combine a simulation approach for dispatch (normally a SCED approach) with an optimisation approach for entry and exist of new generation. The most common gaps that were observed across the modelling approaches considered included:

- **Time-Interval Granularity** – modelling at the day/week/month level rather than at the interval level (currently 30 minutes in the NEM, or 17,520 intervals in a single year) reduces modelling complexity, but it poorly represents the real world operation of the market
- **Consumer Behaviour** – consumer loads, both in their shape and in their size, are often modelled statically, with no allowance for dynamic changes in customer behaviour over time.
- **Transparency** – most modelling platforms are proprietary rather than open source, and the ability to peer review models is limited to review model outcomes rather than model processes or logic

Consensus NEM Approaches

A review of the major commercial firms conducting wholesale market modelling, as well as the models used by the system operator (AEMO) found that almost all of the modelling solutions in place relied on SCED for annual market settlement, with different approaches to determining changes in generation capacity each year.

AEMO uses a linear optimisation program to forecast capacity expansion on a least cost basis for both generation and transmission. In any given year, AEMO first forecasts the availability of generators on a probabilistic basis to determine security constraints and the applies different bidding models (either a short-run marginal cost or a Nash-Cournot equilibrium model) to forecast economic dispatch in each interval.

Energeia's Chosen Solution

A review of international best practice and Australian consensus approach has shown that economic dispatch models and security constraints are effectively commoditised – these approaches are industry standard, and any solution that Energeia develops need to reflect this standard. However, as shown in Table 20, Energeia's assessment of different solutions has shown that there is considerable room to add value to a wholesale market forecast by more accurately reflecting real world generator bidding behaviour and generator financial viability.

Table 20 – Methodology Selection Factors

	Replicating AEMO Economic Dispatch	Applying Security Constraints	Reflecting Generator Bidding Behaviour	Estimating Generator Entry/Exit
Commoditised	✓	✓		
Value Added			✓	✓

Source: Energeia

Energeia's chosen solution is based on a SCED engine, with an optimisation approach to assessing the entry and exit of new generation capacity, with additional capacity to configure:

- **Bidding Behaviour** – Bidding strategies, be they portfolio approaches, multi-mode, annual or daily optimisation, are configurable on a jurisdictional and annual basis throughout the modelling period

- **Capacity Entry/Exit** – Investment decisions are based on real world financial hurdles for the owner of each asset, rather than a least-cost system optimisation approach, tailored for each potential technology across the suite of potential solutions (new interconnection, aggregated DER bidding into the wholesale market, or curtailment of renewables).

B.1.3. Recent Model Development

Energeia initially developed its wholesale market module as part of Energy Networks Australia's National Transformation Roadmap[53], based on a simulation-based approach using short-run marginal cost (SRMC) based bidding assumptions. Energeia's results using wSim in 2017 and 2018 showed that the market was clearing at a price in excess of the theoretical market clearing price assuming SRMC based bidding behaviour[54]. Additionally, further investigations showed that bidding approaches appeared to vary by load, with different bidding behaviours seen during peak and minimum load conditions compared to other times.

This led to the refinement of our bidding model [55] to reflect real world behaviours as evidenced in their historic bidding strategies, resulting in a more realistic price and generator utilisation outcome compared to a simpler linear model that the dispatches generation capacity from cheapest to most expensive.

Energeia uses its simulation engine as core part of its capacity expansion modelling. As well as accounting for scheduled generator exit and entry, wSim uses generator profitability to determine what type of generators exit and enter the market in any given year and region. Our focus on profit maximisation rather than cost minimisation sets our approach apart from other common capacity expansion approaches.

Key developments have included the functionality to assess large scale storage in the wholesale market, including:

- large pumped hydroelectric energy storage projects, such as Snowy 2.0
- large grid-scale batteries, and
- concentrated solar power

For this project, Energeia has made the following additions/improvements to its wSim platform:

- **Dispatch Engine Enhancement** – accounting for more security constraints in dispatch, including ramping, minimum uptime/downtime periods, minimum bid capacity, maintenance scheduling and forced outages and accounting for more market constraints including ancillary services including Frequency Control Ancillary Services
- **Capacity Expansion Enhancement** – further improvement of this engine by endogenously calculated interconnector upgrades, improving grid battery optimisation, including renewable energy curtailment and enabling aggregated DER as a generator / resource

B.1.4. Recent Application

Energeia has worked with a wide range of clients to provide insight into their key business challenges and opportunities by applying our integrated wholesale market model, including:

- The effect of energy efficiency measures on wholesale market outcomes
- The effect of natural gas substitution measures on wholesale market outcomes
- The effect of DER on wholesale energy demand and pricing

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[53] Energy Networks Australia (2017) *Electricity Network Transformation Roadmap: Final Report:* https://www.energynetworks.com.au/resources/reports/electricity-network-transformation-roadmap-final-report/

[54] Energeia (2018), *Concentrated Solar Thermal Market Modelling*: https://arena.gov.au/assets/2019/01/cst-roadmap-appendix-2-energia-modelling-report.pdf

[55] Our refined bottom-up approach to generator dispatch allows us to consider these real-world market behaviours, whilst reflecting the constraints faced by the generators in the NEM at different times of the year.

- The effect of various reliability and environmental policies on wholesale energy prices
- The impact of various government interventions on wholesale energy prices
- The potential market for new technology such as concentrated solar power at various price points
- The demand for storage, by hours of storage, over time under various policy assumptions
- The impact of renewable energy zones on wholesale energy prices

In each case, the wholesale energy market impact was fed through uSim to determine the impact on DER adoption, configuration and operation, distribution network investment and consumer bills.

B.2. Model Process and Modules

B.2.1. Process

Energeia's wSim platform involves two main processes and modules:

- **Capacity Expansion Processing –** For each modelled year, this module forecasts the entry and exit of generation into the NEM, subject to constraints
- **SCED Processing –** For each interval in each modelled year, this module forecasts the dispatch of electricity by each generating unit or resource in the NEM, subject to constraints

The modules of each process are explained in detail below.

B.2.2. Capacity Expansion Processing

Generators enter and exit the market based on their profits or their operation lifetime and subject to the satisfaction of wider market constraints, including economic, safety, security, reliability, emissions and renewable energy constraints. These are further detailed in the sections below.

Entry and Exit Process Overview

For each modelled year, wSim identifies the generators exiting the market, which is either due to sustained revenue losses or having reached the end of their operating life (the safety constraint). However, Energeia ensures that the total capacity of generators exiting the market does not exceed a given threshold inputted by the user. In these instances, generators operating with the greatest loss are removed from the market first.

Potential generators can enter and exit the market based on the following conditions:

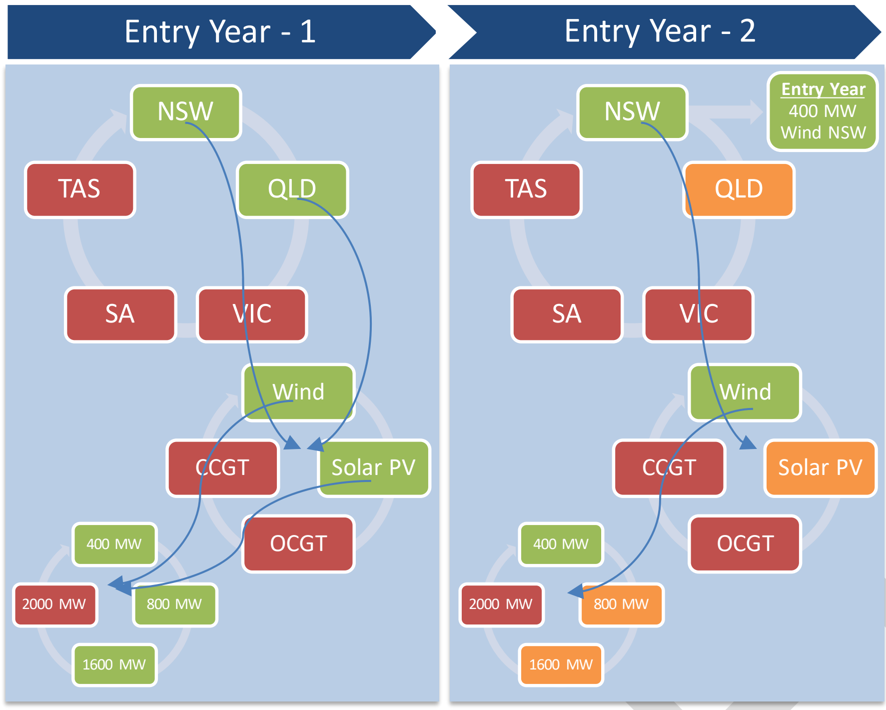
- Their calculated NPV
- User inputs to force the entry of generators, such as those currently in construction and are likely to begin operating in first few modelled years
- If a security or reliability constraint[56] is not satisfied by the end of the economically-determined capacity expansion process for the year
- To satisfy emission or renewable energy constraints[56] based on policy settings set by the user, or a subsidy for low-emission technologies can be applied to "soften" the constraint.

The model's wholesale market new entry procedure is illustrated in Figure 15, which shows that the model will iterate through a potential generator based on their location by state, their technology type and their capacity sizing[57] to assess configuration which would deliver the highest net present value (NPV).

[56] This is further detailed in the following sections

[57] All available states, technology types and capacity sizing available to be assessed is subject to the user

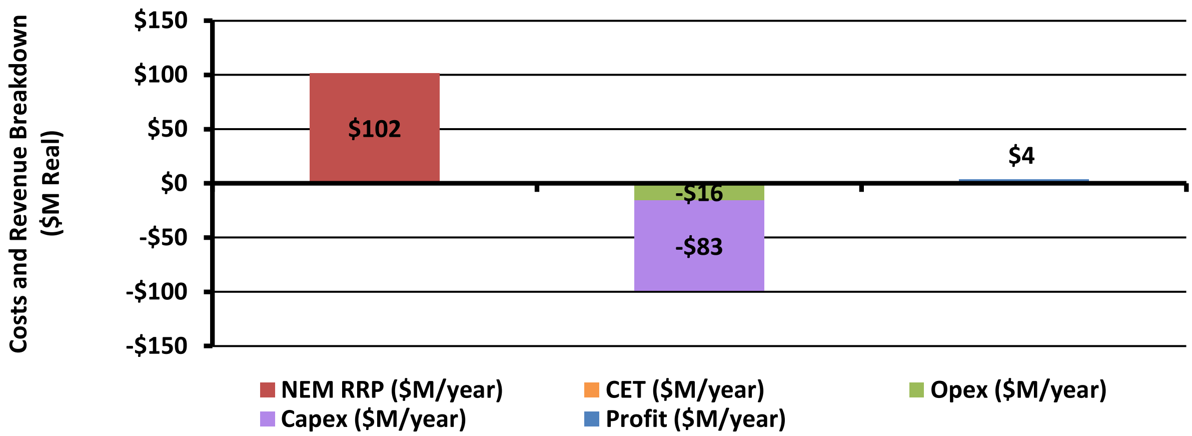
Figure 15 – Illustration of Wholesale Market Model Operating Procedure (Indicative)



Source: Energeia; Note: Colours represent the level of net present value for the generator configuration, where green is the highest and red is the lowest.

Generators enter the market based on their calculated NPV and an optimised fuel and capacity size. These calculations are determined through estimating forward-looking dispatch and profits in the simulated year, including spot price revenues, renewable energy certificates and carbon mechanism scheme payments (if any), fuel and variable operational and maintenance costs and capital charges as shown in Figure 16.

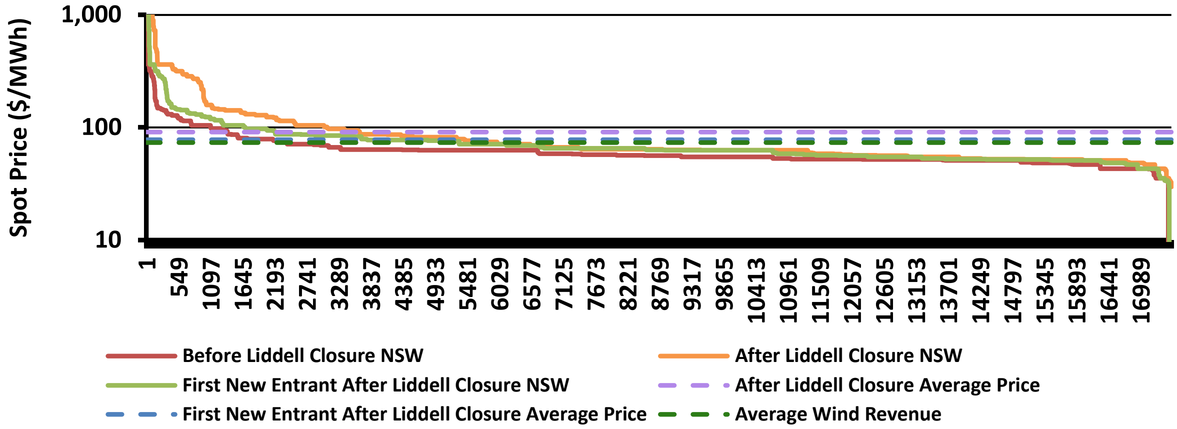
Figure 16 – Illustration of Key Costs and Benefits in a Project's NPV Calculation (Indicative)



Source: Energeia

The NPV calculation also considers the effect of the new project on market prices using the model's generator bidding and dispatch algorithms which estimates the merit order. Where the project displaces the marginal unit, it reduces the market clearing price. This typically tempers project sizing, as larger projects are more likely to displace the marginal generator. For example, Figure 17 illustrates how the merit order impact calculations affect the merit order and market pricing before and after Liddell closes, and before and after the first new entrant project.

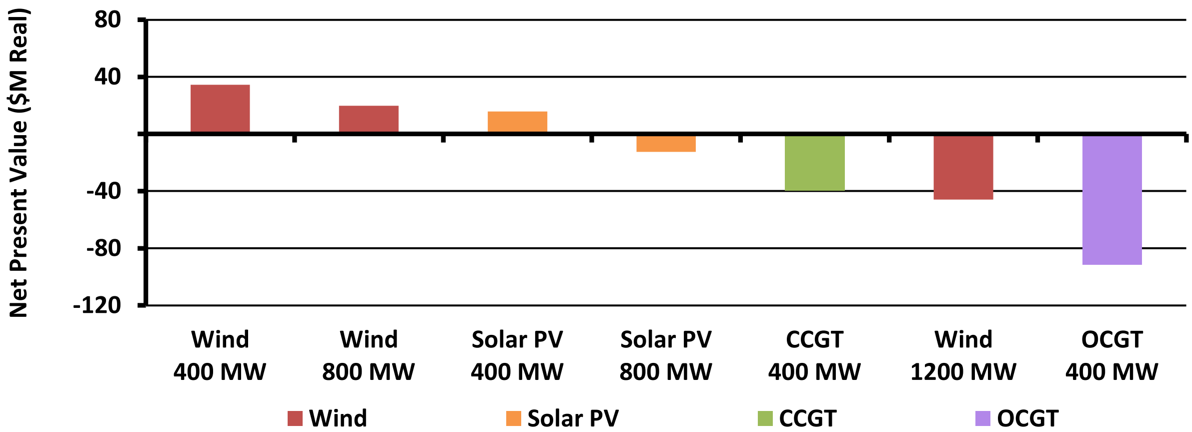
Figure 17 – Illustration of Merit Order Impact Calculations



Source: Energeia

Generators potentially entering the market are ranked, where generators with the highest calculated NPV enter into the market first until a threshold capacity of generation entry is reached, or all new entrants calculate a negative NPV from entry. This ranking system is illustrated in Figure 18 showing a 400 MW wind project as the project delivering the best financial outcome out of an array of potential open cycle gas turbines (OCGT), close cycle gas turbines (CCGT), wind, large-scale solar PV, concentred solar thermal (CST), large-scale lithium storage systems, pumped hydroelectric energy storage (PHES) and demand side DER aggregation projects.

Figure 18 – Illustration of NPV Ranking between Projects (Indicative)



Source: Energeia

Summary of Constraints

Energeia has applied the following constraints which impact the generator exit and entry process:

- **Economic Constraint** – This refers to determining generator entry or exit by profitability. Generators must show a positive NPV for two years in a row before deciding to enter and must record operating losses for two consecutive years before exiting the market. This is a configurable setting that acts as a ballast against gyrating wholesale prices due to generator entry and exit activity.
- **Safety Constraint** – This refers to generators exiting the market when they have reached their "end of life". Their capacity in the market is lost and may be replaced if it results in one of the other constraints not being satisfied.
- **Security Constraint** – This refers to the ability of market supply to meet demand in a single credible contingency event, such as an outage to the largest generator in each region (largest n-1 test) during peak demand. If this constraint is not satisfied, the model will force the entry of the lowest-cost generation in that region until it is no longer an issue.

- **Reliability Constraint** – This refers to the ability of firm capacity to meet peak demand. Firm capacity refers to generation that can be plausibly relied upon to deliver during the peak demand of each region. This includes only scheduled and semi-scheduled generation (> 30 MW), and discounts variable renewable energy capacity. If this constraint is not satisfied, the model will force the entry of the lowest cost firm generation in that region until it is no longer an issue.
- **Emissions Constraint** – This refers to the maximum carbon emissions the energy market is allowed to produce in a calendar year. It is a configurable setting intended to simulate environmental policy outcomes. If this constraint is not satisfied, wSim will force the exit of carbon-emitting technologies in favour of the lowest cost low/zero emissions technologies until carbon emissions levels are below the permissible level.
- **Renewable Energy Constraint –** This refers to the minimum requirements for demand met by renewable energy in the market. Similar to the emissions constraint, it is a configurable setting intended to simulate environmental policy outcomes. If this constraint is not satisfied, wSim will force the exit of non-renewable technologies in favour of the lowest cost renewable generation until the minimum % of electricity demand is met by renewable energy.

B.2.3. SCED Processing

wSim takes aggregated demand profiles and determines the bid stack of generation required to satisfy demand at each interval, subject to generation and transmission constraints, as well as any additional generation required for ancillary services where applicable. The following sections detail the following processes and constraints:

- Demand process
- Generator bidding and merit ordering process
- Generator constraints
- Transmission constraints
- Ancillary services process

Demand Process

Aggregate annual demand profiles for each state, with 30-minute frequency, are provided to the wSim model from uSim. These demand profiles include the impact of DER as customer demand prioritises behind-the-meter generation, which is an accurate reflection of reality.

Generator Bidding and Merit Ordering Process

Generator bidding is primarily based on the short-run marginal cost (SRMC) of the generator including the cost of carbon emissions by the generator.

As is the case in the actual NEM wholesale market, each generator has up to ten bids[58] they can submit for each eligible interconnector that it can access[59], representing "bands"[60] of each generator's determined bidding behaviour. For those generators without historical bidding data, there are generic inputs available for each fuel and state combination.

The value of a bid is a function of the generator's SRMC, a step-up dollar factor that is unique to each fuel type, and a step-up percentage factor that is unique to each fuel type. The step-up factors increase for each bid the generator has, with the tenth bid, or the last bid, being the highest.

[58] These bids are characterised by an amount of energy (expressed as a % of capacity per interval) and a price. These are set as inputs to the model

[59] Intra-state energy sales are modelled with a virtual interconnector having infinite capacity

[60] 10^{th}, 20^{th}, 30^{th}, etc. percentile

$$Bid_{gen,i=1\ldots10} = \left(SRMC_{gen} + DollarFactor_{i,fuel}\right) * (1 + PercentFactor_{i,fuel})$$

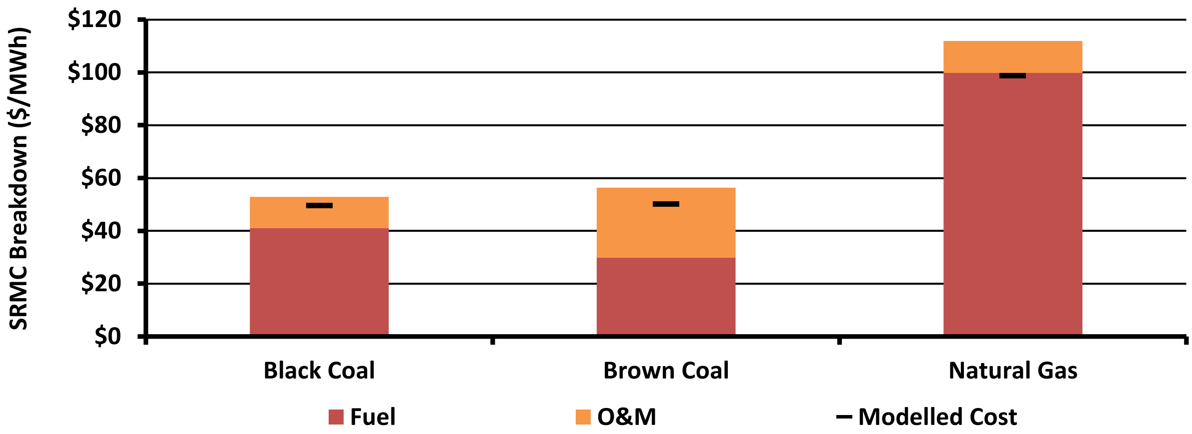
There are two exceptions to this bidding formula. Coal generators will always bid their minimum operating capacity at the market floor. This is their first bid and the remaining nine bids are for the remaining capacity. Non-dispatchable renewables will bid their entire capacity at zero dollars as they do not have the ability to control dispatch and have no SRMC. Note that this is configurable by the user.

For each interval, wSim determines which bid set applies, then dispatches each bid in order until state demand is met or all bids are exhausted, calculating effects of losses in real-time and skipping bids that cannot be dispatched due to generator unit capacity or transmission constraints. Energeia's bidding approaches is benchmarked against actual generator bidding behaviour by fuel and technology type as shown in Figure 19.

Storage technologies operate differently to generators. Grid batteries optimally charge and discharge once the bidding process has been completed. Grid batteries take the calculated wholesale price at each interval and aim to maximise their profits on a defined periodic basis by importing and exporting to the NEM based on a charging algorithm. After storage technology profiles have been generated, the bidding process is re-run to deliver the final generation outcomes for the modelled year.

Energeia notes that a key limitation of the generation bidding process is that bids are static not dynamic, in opposition to the real-life situation.

Figure 19 – Comparing Bidding Model to Actual Bidding Outcomes by Fuel and Technology



Source: Energeia

Generator Constraints

In addition to bidding strategies, wSim also considers some additional constraints on generation which reflect reality and will affect the profitability of generators. They are defined by each type of generation and include:

- **Ramping** – The maximum rate at which a generator can increase and decrease capacity exported per interval
- **Minimum Uptime and Downtime Periods** – If a generator start or stops dispatching in an interval, it must continue generating or not generating for a specified number of intervals following, even if that generation does not dispatch to the grid
- **Minimum Capacity** – The lowest amount of generation capacity that can be produced, as a % of maximum usable capacity, even if it does not all get dispatched to the grid
- **Fixed Generation** – Generators with variable generation profiles will be able to bid according to a fixed profile. For example, a solar PV generator will not be able to bid during intervals with no solar irradiance
- **Maintenance** – Some downtime is allocated to each generator in the year to undergo scheduled maintenance

- **Forced Outages** – The outage rates of each generator are accounted for in their potential maximum usable capacity.

The generator constraints generally favour generation that is more reliable and flexible when determining profitability.

Transmission Constraints

Interconnectors connect the transmission networks in each NEM state with each other. The wSim model utilises interconnectors to lower prices across the interconnected network by allowing energy to flow from high price states to low price states. In the model, interconnectors have two capacity ratings (one for each direction) and a loss factor.

Interconnector capacity is able to evolve each modelled year exogenously through AEMO's ISP schedule for transmission upgrades. This has a significant impact on the dispatchability of generation and the potential to satisfy security constraints. Energeia has flagged the calculation of interconnector upgrades as a future improvement for the model.

Ancillary Services Process

In addition to dispatching electricity in the wholesale market, generators are also able to participate in ancillary service markets that contribute to market reliability, including for ramping, regulation, and contingency services. For each interval modelled, wSim calculates ancillary demand, and generator bidding to determine the price received per MWh for the service. Note that bidding into the wholesale market is always prioritised over the provision of ancillary services.

Effectively, by accounting for ancillary services, wSim favours new generation technologies with a high level dispatchability (i.e. the ability to ramp up/down quickly), which is likely to reflect the future energy needs of the NEM.

B.3. Inputs and Assumptions

Energeia builds a database of all existing generators in the NEM as listed in AEMO's latest NEM Generation Information publication[61]. Energeia then uses a variety of sources to determine the key characteristics of existing generators that are necessary for wSim.

Energeia takes forward those characteristics to determine the key information for new potential generation and transmission in the NEM, for consideration in the capacity expansion process.

B.3.1. Generation

Energeia's key assumptions for generation assets includes the following:

- **Operation and Maintenance Costs** – Energeia researches the fixed operational costs by generator type, which count towards the NPV calculations each year. For simplicity, Energeia assumes there are no variable operation and maintenance costs of generation.
- **Heat Rates** – Heat rates affect the maximum output capacity of a generator. Energeia uses research to determine heat rates, which are assumed to vary by generator type and do not change over time.
- **Fuel Prices** – Energeia researches the latest relevant fuel price forecasts from a variety of sources which vary by generation technology. Fuel prices are assumed not to vary by region, and renewable generation is assumed to have no fuel cost.

[61] Available at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information

- **Summer and Winter Rating** – As weather factors affects the efficiency of energy production, Energeia assumes differing summer and winter capacities for thermal and storage and wind technologies, as determined through research.
- **Age and Lifetime** – The age of each existing generator is provided by AEMO in their NEM Generation Information, which also provides the expected year of exit. If the exit year is not provided, Energeia assumes that a generator unit has a useful life of 50 years, after which it will be decommissioned.
- **Minimum Loading** – Energeia uses research and analysis to determine the minimum capacity that a resource can generate at. This is assumed to vary by technology.
- **Ramp Rates** – Energeia uses research and analysis to determine the maximum ramp rates at which generation can increase or decrease over a single interval. This is assumed to vary by technology.
- **Outages and Maintenance** – Energeia researches the % of time a generator is likely to spend down in a year, either through unplanned or planned outages, which is assumed to vary by technology.
- **Generation Profiles** – For solar PV, wind and hydro generation, Energeia researches and processes the calendar year output profiles as a % of maximum usable capacity at any given interval. The profiles are assumed to vary by region and technology type, but do not change by year.
- **Capital Costs** – For new technology types only, the $/kW or $/kWh capital cost for designing, installing, and commissioning is forecasted on an annual basis based on research and analysis of current costs and learning rates, and varies by technology type. The capital cost affects the NPV calculation that determines if, when and where a new generator enters the market.
- **Minimum Build-Out** – Energeia assumes that all technologies must be built at a minimum capacity with additional incremental capacity available, both of which are user-defined inputs.

B.3.2. Transmission

Energeia's key assumptions for transmission assets includes the following:

- **Losses** – As ambient temperature affects the efficiency at which transmission lines can transport energy, Energeia assumes a different marginal loss factor for summer and winter for each interconnector. Energeia also makes the simplifying assumption that intrastate transmission has no losses in energy.
- **Age and Lifetime** – Energeia makes the simplifying assumption that interconnectors have an infinite asset life, and hence do not need replacing. They can only be upgraded.
- **Capital Cost** – For interconnector upgrades considered, Energeia analyses DNSP RIT-Ts and the AEMO ISP to estimate the current $/kVA capital cost of transmission in the NEM. Forecasts of capital costs are developed based on the current capital cost with a learning rate applied.
- **Minimum Build-Out** – Energeia assumes that all interconnector upgrades must be built at a minimum capacity with additional incremental capacity available, both of which are user-defined inputs.

Appendix C – uSim

Appendix C – uSim

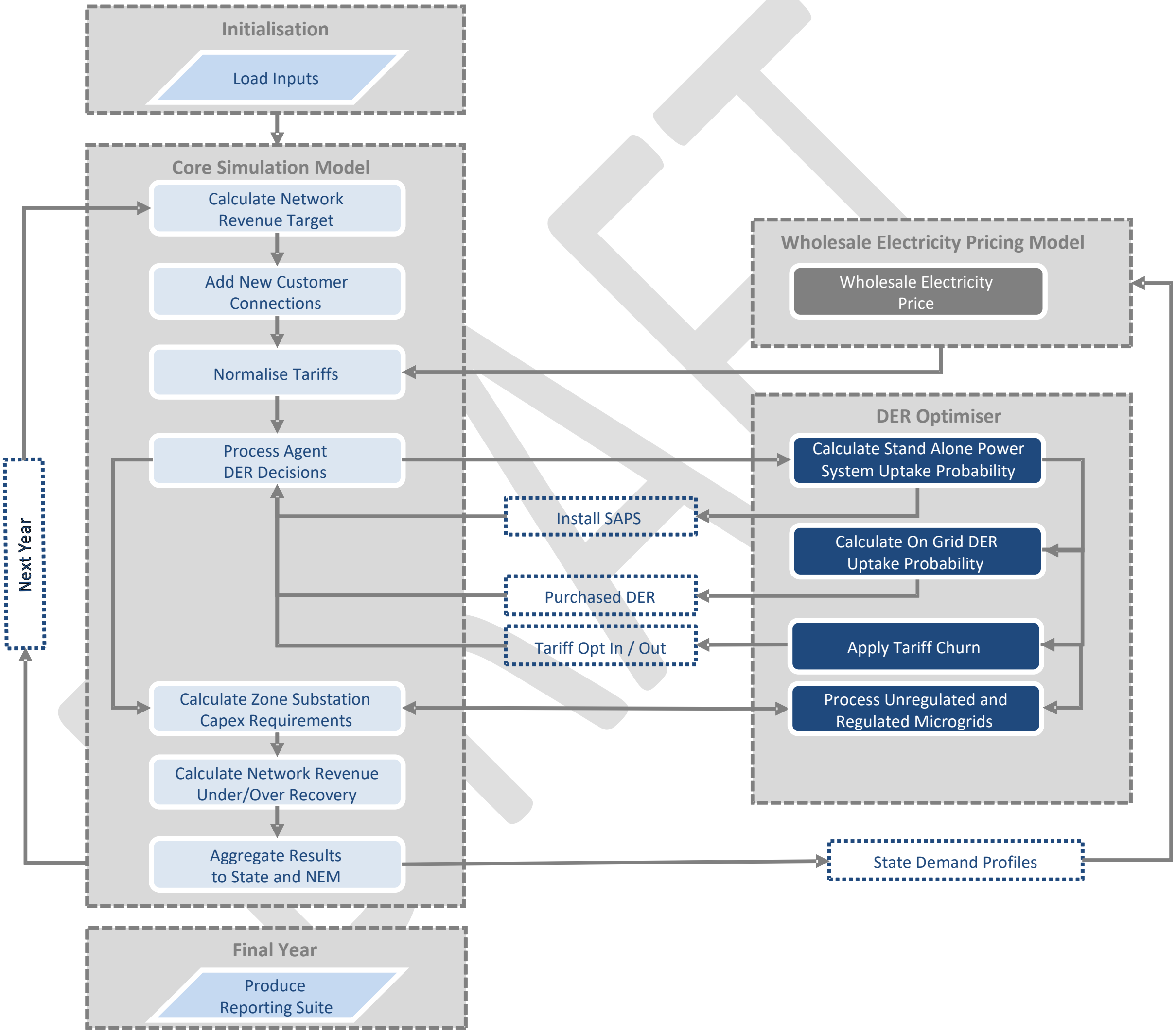
C.1. Overview

uSim is an agent[62] based model which simulates customer level decision making with respect to DER investment and operation under different policy, regulatory, tariff, technology, and macro-economic settings, and estimates the corresponding impact of customer decision making on electricity networks and wholesale markets.

C.1.1. Structure of the Model

uSim operates across a range of different functions and modules, through an iterative process year-on-year, for each year of the simulation period, working through the process loops shown in Figure 20.

Figure 20 – Overview of Energeia's Energy System Simulation Platform (uSim)



Source: Energeia

[62] Agents are the principal decision makers within the simulation. It is the decisions that agents (and the customers they represent) make that drive network decisions, energy prices and the outcomes of the grid.

Energeia's uSim model is built around two key modules:

- **Core Simulation Platform** – contains the main consumer and network functions of the models and is linked to the DER Optimiser module.
- **Solar PV and Storage Optimiser** – calculates the optimal solar PV and storage configuration for a consumer given the provided constraints, forming a subset of the Core platform.

Decisions to purchase DER systems, switch tariffs/incentives or disconnect from the grid are made by agents. The results then feed back into load, and network operating and capital costs, which determine network revenue allocations in the following year.

C.1.2. Methodology Selection

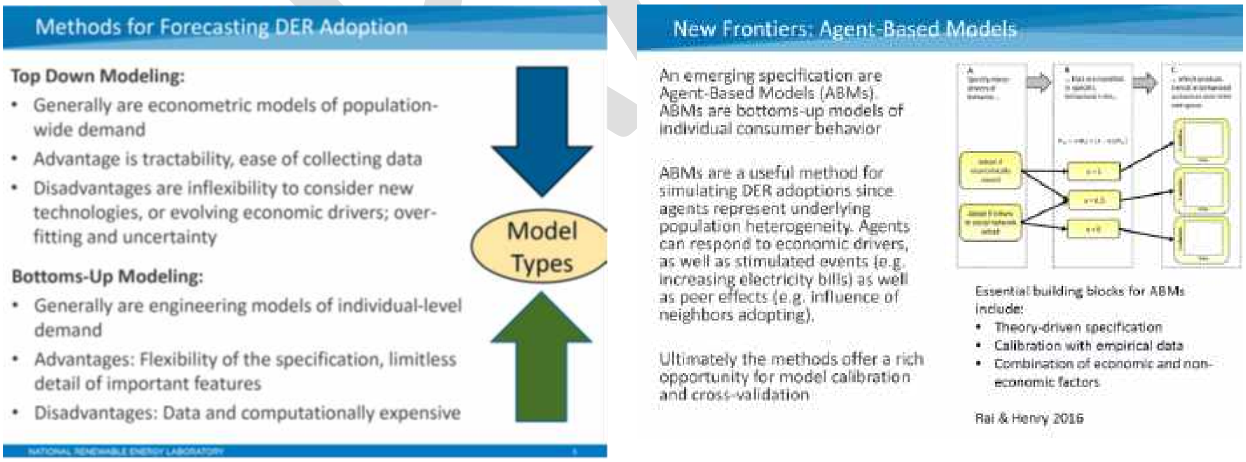
The emergence of new, interdependent DERs, e.g. electric vehicles and batteries, which impact on consumer demand behaviour and each other, combine to make forecasting even more difficult into the future. The impact of new tariffs like maximum demand and Virtual Power Plant services on consumer adoption and operation are also very material.

There is a growing consensus that bottom-up, agent-based approaches are best suited to the unique challenges involved in forecasting DER, with their strong path dependency and interdependencies:

- An agent-based simulation approach was recently selected by the California Energy Commission as the winner of a state-wide tender for new DER forecasting tools.[63]
- National Renewable Energy Laboratory (NREL), the pre-eminent US National Energy Laboratory for forecasting DER, has highlighted agent based, bottom-up forecasting approaches as well suited to the specific challenges of DER forecasting.

The slides below in Figure 21 are taken from a presentation to the California Energy Commission in 2017 on best practice forecasting methodologies,[64] highlighting the advantages of bottom up agent based modelling for DER forecasting, and therefore for load forecasting.

Figure 21 – Excerpts from NREL Presentation on Best Practice DER Forecasting



Source: NREL (2017)

C.1.3. Recent Model Development

Energeia's uSim bottom-up modelling system has been used since 2013 for some of Australia's highest profile, national modelling exercises, including the 2013 Smart Grid, Smart City initiative, the 2017 National

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[63] https://www.energy.ca.gov/sites/default/files/2019-05/GFO-17-305_NOPA.pdf

[64] Energeia can provide the full presentation upon request.

Transformation Roadmap[65], and most recently to the development of Distributed Energy Resources Forecasts for AEMO's Integrated System Plan[66], with significant updates to inputs including:

- Updated solar PV installation starting point
- Updated network and retail tariff structures for all distribution networks
- Recalibration of the return-on-investment uptake function
- Current network zone substation capacity
- Updated network asset age distributions

During this time, it has been continually developed to consider new DER technologies, consumer behaviour, policy settings and increased network asset granularity.

C.1.4. Recent Application

Energeia's uSim tool is foundational to our work with Australian clients, and recent applications include:

- The development of estimates of the impact of electrification of residential gas heating, cooking and hot water loads for a jurisdiction introducing gas connection moratorium for new residential construction
- Whole-of-system modelling of industrial, commercial and residential customers to determine the distribution network and wholesale market impacts of different energy efficiency measures

C.2. Methods

Energeia's uSim platform is comprised of two core processes and modules that are a subset of the larger modules as depicted in in Figure 20:

- **Customer Processing Module** – For each distribution network, uSim simulates the customer base represented by a sample set of agents. Each year these customers make economic decisions to optimise their electricity bill.
- **Asset Processing Module** – Following the decisions of customers the resulting load profiles are then aggregated to each network asset where investment decisions are made to augment, replace or move off-grid.

The functions and sub-functions of each of the above modules of the simulation platform are summarised below, including a high level of overview of interactions between different parts of the model, limitations of assumptions and their impact on modelling.

C.2.1. Customer Processing

The following sections detail Energeia's customer processing module and the associated sub-functions, including implementing new connections, load growth, tariff normalisation, DER optimisation, DER uptake and updating customer bills and load profiles.

New Connections

New connections are a key driver of demand and consumption growth for electricity networks, and the energy sector as a whole. In the model, new connections are modelled by creating additional agents. One residential and one commercial agent is spawned each year for each network and is assigned randomly selected load profile and the default tariff within each class for the respective distribution network.

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[65] Energy Networks Australia (2017) Electricity Network Transformation Roadmap: Final Report: https://www.energynetworks.com.au/resources/reports/electricity-network-transformation-roadmap-final-report/

[66] AEMO (2020) 2020 Integrated System Plan for the National Electricity Market: https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en

Agents representing new connections are assigned scaling factors that represent the population of new customer connections on each zone substation. The population growth factors are exogenous model inputs and are unique to each zone substation.

The limitations of this approach are:

- The premise type of the new agent is selected at random from the two options (house or unit for residential customers and warehouse or suite for commercial customers) with equal probability.
- Probability weightings are not applied to demand profile selection, so a very large profile has the same probability of being selected as a standard customer profile. This is most noticeable for commercial connections, where the range of customer consumption is wider than for residential.

Load Growth

Each agent begins the model with a single year demand profile. As the model progresses, this demand profile is adjusted to represent underlying trends in customer electricity demand patterns. This is achieved through the application of two growth factors:

- **Peak Growth –** The growth rate applied to the largest 5% of all half hourly interval loads for a customer.
- **Consumption Growth –** The growth rate of total annual consumption for the agent, used for determining the growth rate applied to the lowest 95% of half hourly interval loads.

Tariff Normalisation

Tariffs are calculated each year to reflect changing rates customers will pay associated with network's recovering their revenue allowance, and changing wholesale generation costs. The following sections outlines the tariff components normalised each year, including the peak revenue, residual revenue and the retail overhead and profit.

Peak Revenue Allocation

Networks will recover revenue from the peak component of the tariff to cover the cost of the contribution to peak demand by each customer class. Peak components are tariff mechanisms that specifically allocate cost to customers during peak demand periods (these include the peak period of a time of use or maximum demand tariff, critical peak events, and similar components in other tariffs).

The amount of revenue recovered by peak mechanisms across all tariff classes by a network at the zone substation level is:

$$Coincident\ Peak\ Revenue\ (\$) = Coincident\ Peak\ (kW) * \ LRMC(\$/kWh)$$

where the Coincident Peak (kW) is the peak half hour of the load of all residential and commercial customers during the year[67]. This is then divided between commercial and residential based on the percentage of the peak event that was due to each class.

Each tariff must be able to recover this amount from its peak mechanism such that the rate on the peak mechanism will be:

$$Peak\ Charge\ (\$\ per\ kWh) = \frac{Coincident\ Peak\ Revenue\ (\$)}{Chargeable\ Demand\ (kWh)}$$

For tariffs that do not have a peak mechanism, the non-peak mechanisms, or the residual, collect all revenue.

Residual Allocation

Network revenue that is not recovered through a peak mechanism is allocated to the residual components of a tariff. While some tariffs do not have a peak component, all tariffs have at least one residual component. The

[67] The time of the coincident peak event does not have to be within the peak times defined by the tariff's peak mechanism.

most common types of residual tariff components are a daily fixed charge or an energy charge that is billed on all consumption regardless of time of day.

Residual revenue is allocated between customer classes based on the allocation ratio implied by the current tariff settings by each network. As the model progresses, and the value of residual revenue allocated to the network rises, this ratio is retained.

Retail Overhead and Profit

Retail tariffs are the tariffs that customers see and pay. It is assumed that retail tariffs are structurally the same as their corresponding network tariff but with an additional wholesale, fixed and FiT component.

Retail tariffs are determined using an overhead plus profit margin calculation for each component of the tariff using the following formula:

$$\begin{aligned} Retail\ Price\ (\$) = {} & Wholesale\ Price\ (\$) + \\ & Network\ Price\ (\$) * \left(1 + RetailOverheadPct\ (\%)\right) + \\ & Retail\ Profit\ Margin\ (\$) \end{aligned}$$

where:

- The wholesale price is based on energy consumed and is only applied to energy based tariff components
- The retail overhead factor is an additional charge retailers levy on network components. This charge means that as network prices change, retailer margins move in the same direction. This premium is the same for all applicable components of a tariff
- The retail profit margin is an additional charge that is set in the initial year of the simulation and held constant thereafter. Where a tariff is available today, the retail profit value is set so the charges equal those currently available to eligible customers. For new tariffs developed for the project, the retail profit value is an adjustable input.

DER Optimisation

In the uSim Platform, the behaviour of each individual agent is simulated to reflect customer behaviours in the real world. Agents will have the option to purchase DER technology and/or change their current tariff to minimise their bill or go defect off the grid. The following sections detail the pathways available to agents and the processes of the model which simulate these pathways, including the option to remain on-grid, assess DER technology and tariff combinations, tariff churn and defect off-grid.

Remaining On-Grid

Agents remaining connected to the grid are able to purchase DER technology and/or change tariffs. This decision is based on the combination of DER technologies sizes and tariffs which will provide the highest NPV based on the inputs provided. An uptake function (see Section C.3.3. Distributed Energy Resources) is then applied to the best option to determine the uptake probability and whether the agent made a purchase. Agents that do not purchase any DER or change tariffs are eligible for the third and final decision-making step, tariff churn.

DER Technology and Tariffs Combinations

The Optimisation function takes a brute force approach, testing every valid combination of technologies, sizes and tariffs that are available for each customer or zone substation.

For each combination of DER and tariff, the first step taken by the optimiser is to apply the behaviour change effect of the tariff in the combination. The optimiser then loops through all of the allowable sizes of solar PV, battery, inverter and diesel technologies, in that order, that are valid against a restrictive criterion. For example, an invalid combination would include a solar panel without an inverter or a battery with a DER restricted tariff.

The allowable sizes are subject to the following constraints:

- Minimum and maximum DER technology size for a single purchase and technology step size,
- Customer roof or storage space constraint, and
- Existing DER technology capacity.

Unlike inverters and diesel generators, solar PV and storage systems can both be augmented, with new purchases adding to the existing capacity installed. However, agents can only augment solar and storage systems up to the size that will fill their remaining space constraint. If the minimum purchase size cannot fit in the customers remaining roof or storage space, no purchase can be made, and the current combination will be ruled invalid.

An agent will only consider taking up the DER and tariff configuration with the highest NPV, which includes the customer's retail bill, the cost of the DER technologies and the value of unserved energy (if any). The NPV formula uses the discount rate of the buyer and ongoing payments determined by the DER lifetime and system characteristics, including any bill savings from DER technology and associated costs. An example can be shown in Table 21. The payback of this "winning" combination is then used by the uptake function to determine if the agent purchases the combination.

If an agent purchases a DER system or changes tariff the simulation moves on to the next agent. If the agent did not make a change, they are sent to the tariff churn function.

Table 21 – Comparison of NPV for DER Technology Sizing (Indicative)

Solar Size (kW)	Storage Size (kWh)				
	2	4	6	8	10
2	-$4	$26	$55	-$34	-$141
4	$69	$95	$178	$42	-$51
6	$133	$156	$133	$99	-$9
8	$33	$64	$33	-$12	-$153
10	-$18	$17	-$18	-$69	-$230

Source: Energeia

Tariff Churn

Tariff churn is a function that is applied to agents that are connected to the grid and have not purchased a DER system or voluntarily changed tariff in the current year. Tariff churn represents the effect of changes in occupancy at a premise and new and replacement meters. When a customer moves in or out of a house or business premise or the meter on the premise is replaced, the connection is changed to the default network tariff.

Tariff churn is represented in the simulation by switching agents from their current tariff to the default tariff. All other characteristics of the agent are retained, including their load profile and DER systems they have previously purchased. The rate of tariff churn is an input, with values specified for every year, customer class and network. Because of the approach, agents that are already on the default tariff will not change.

For the agents that are potentially subject to this function, a random number is generated from a uniform distribution between 0 and 1. If the number generated for a particular agent is lower than the applicable rate of tariff churn for that agent, the agent's tariff is changed to the default tariff.

Defect Off-Grid

Customers are able to defect off-grid and become completely independent of the grid through Stand-Alone Power Systems (SAPS). This decision is determined by calculating the mix of DER that optimises the cost of the system while minimising unserved energy, capital expenditure of the system and operation costs. Unlike customers remaining on-grid, diesel generators and larger DER technologies system sizes are available for customers who are looking to defect.

Once an agent has defected off the grid, they cannot revert back to a grid connection. This constraint also extends to customers that switched to a SAPS tariff.

The value of unserved energy, or value of customer reliability (VCR) is crucial in this process. Agents value unserved energy and treat the cost of unserved energy in the same way they treat an electricity bill, minimising the bill to the extent it makes financial sense. The VCR is unique to different customer classes and networks and remains constant in real terms.

DER Uptake

An agent's decision to uptake their best configuration of DER and tariffs are dependent on the ROI uptake functionality based on the inputs provided (see Section C.3.3. Distributed Energy Resources).

Update Customer Bill and Load Profile

Based on the customer's tariff and DER decisions, the model will calculate the customer new consumption load profile adjusted by DER, which is then used to calculate the customer's retail electricity bill.

Each DER technology is applied to the customer's load profile in the following order:

- **Solar PV –** The solar generation profile is added to the customer's load profile
- **Battery –** The customer's solar adjusted profile will be used to calculate the battery charging and discharging profile. The battery algorithm differs depending on the customer's tariff. The battery is calculated after the solar PV because batteries will often utilise solar PV exports to obtain bill savings.

The customer's retail bill will be calculated based on the DER adjusted load profile and their respective tariff.

C.2.2. Asset Processing

The following sections detail Energeia's asset processing module and the associated sub-functions, including aggregation, processing and optimising load profiles, optimising assets and updating revenue requirements.

Aggregation

After the customer processing procedures, the results, including new load profiles, DER sizing capacities, and bills, are aggregated upwards in the asset hierarchy. All assets are then processed and in turn undergo aggregation upwards in the asset hierarchy, from customers to feeders, feeders to zone substations, zone substations to networks and networks to states and systems.

Process and Optimise Load Profile

Assets are able to optimise their load profile through either adopting network control of available batteries or leasing a battery to be used to reduce capacity constraints.

Network Control

If the scenario permits, assets can act as an aggregator and has the ability to control all agent's, or a restricted set of battery devices to limit network peak demand and prevent capacity breaches by discharging batteries during peak events. Note that this is applied after the customer has used their battery functionalities to minimise their bill.

Network Leasing

If permitted in the scenario, assets have the option to lease a grid scale or aggregated battery on a one-year basis and place it at the asset (or to contract to customers within that asset). The battery is used to remediate shortfalls of the asset (due to demand exceeding capacity) by discharging when demand is above the asset's rated capacity.

The battery in general has no preference in terms of when it charges itself. The exception is when the asset has net negative demand caused by large volumes of rooftop solar PV exports by agents. When negative demand is available the battery will attempt to charge from this to increase minimum demand.

The utilisation rates of contracted batteries are generally very low, only discharging when demand is greater than the rated capacity of the zone substation, occurring a handful of times a year. Due to this low level of utilisation, battery degradation due to cycling is negligible in most cases and so is not included in the pricing function for the battery lease.

Note that the contracted battery will only operate to reduce demand to the rated capacity. It will not reduce demand further, solar shift or wholesale price arbitrage. Adding these capabilities to reduce the cost of the network is a future development direction.

Optimise Asset

The modelled cost of a network is built around the zone substation. The value of remaining network assets is largely held constant. The exception is the zone substation asset class, which has a set capacity and requires replacement and augmentation as the simulation progresses. Zone substations which have breached their capacity limits will require undergoing augmentation, replacement or other means to reduce their capacity breach, including the following:

- Leasing a battery to temporarily reduce peak demand;
- Taking the traditional option and augmenting the substation, or;
- Installing new equipment with higher rated capacities, to meet reliability targets, depending on the options allowed by each scenario.

Zone substations have finite lifetimes due to deterioration in their condition, and when the end of life is reached the substation must be replaced.

Capacity Limits

The simulation assumes all zone substations are rated on an N-1 basis[68]. This assumes individual zone substations have capacity more than their rated capacity but are required to have 100% asset redundancy at all times. The simulation allows for a reasonable amount of exceedance of the N-1 rating. This allowed exceedance is expressed as the number of half hour intervals per year when the demand on a zone substation is greater than its rated capacity. The number of intervals is an input into the simulation.

In reality, actual installation of N-1 redundancy differs by state, network and within networks. Some areas, such as CBDs, have greater than N-1 redundancy whereas others have no redundancy.

Demand Forecast

The construction of a new zone substation or a microgrid firstly requires knowledge about the future demand profile of the asset to be replaced. The chosen construction option must be built large enough to service demand decades into the future, and such limiting additional augmentation or replacement in the lifetime of the asset.

A linear extrapolation is used to produce a 20-year forecast of future demand, based on previous years' peak demand growth. For forecasts in the initial year of the simulation, when no historical demand is available to create a forecast from, a simulation wide default growth rate is used.

The growth rate derived from peak demand growth is applied uniformly over the asset's interval demand profile to generate a full year profile of half hourly demand for each forecast year.

The method used to forecast demand for determining asset build sizes has the following limitations:

- The forecast is dependent on two data points, current demand and demand growth of (up to) five years previously. If demand is volatile, the forecast may vary widely one year to the next. Therefore, the year when a constraint is breached may have a large influence on the augmented capacity of an asset
- Forecasts in the first few years of the model are unlikely to be representative of the long run given less historical data is available

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[68] N-1 refers to having the ability to supply all demand on the zone substation when one set of equipment (transformer, switchgear, sub transmission feeder line etc.) is down.

- DER investment by customers may reduce demand over a period, resulting in a forecast decline, but if penetration of DER is near the maximum the declining demand may not be sustainable. This can lead to zone substation reaching the end of its life being replaced smaller than necessary for the target lifetime and require rebuilding a few years later when demand growth resumes
- All intervals are grown at the same rate. However, it is more likely the growth rate of the maximum value will be more extreme than the average growth rate of the individual intervals. The peak demand could also be declining while total consumption is rising. This issue applies only to microgrids as they use the full demand profile, whereas augmentation of the zone substation only requires sizing based on peak demand.

Asset Augmentation

Network augmentation occurs when the demand incurred by a network asset (zone substation or feeder) exceeds the rated capacity of the asset requiring the asset to be upgraded to accommodate the increased demand. Augmentation here is triggered when the rating of the asset is breached *n* times within a model year (where n is adjustable according to network settings). The upgrade min size and step sizes are adjustable for accuracy in the model.

Upon network augmentation, all associated costs are allocated to the networks' regulated asset base and passed through to customers via network tariff charges. uSim utilises this functionality to optimise community costs by minimising customer bills.

Asset Replacement

The response to an ageing asset that has reached their end of life is to replace it with a new, correctly sized substation.

To determine the optimal sizing for the new asset, the peak demand forecast for the asset is used to determine an appropriate build size. The build size must be large enough that in the final forecast year the asset will not breach its rated capacity. Then an additional margin is applied to this size and the result is rounded up to the nearest available size.

$$MW_{New} = max\left(PeakMW_t, PeakMW_{t+y}\right) * (1 + margin\ \%)$$

The number of years the forecast is for is an input to the model. Zone substations have a lifetime of up to 50 years, and in some cases longer than this. However, they are typically built to accommodate 20 to 25 years of growth, with an upgrade mid-lifetime to reach the final configuration capacity.

Upon network replace, all associated costs are allocated to the networks' regulated asset base and passed through to customers via network tariff charges.

Update Revenue Requirement

All changes in asset optimisation are reflected in the changes in network revenue requirements. The target network revenue represents the revenue that the network aims to recover across all customer classes. It is made up of operating expenses, capital costs, depreciation, a balancing item and adjustment for under or over recovery of revenue in previous years.

The revenue target is calculated at the start of each year modelled using a simplified version of the methodology used by the AER when setting network revenue allowances:

$$\begin{aligned} Target\ (\$) = {} & Opex\ (\$) + Return\ on\ RAB\ (\$) + Depreciation\ (\$) + Balancing\ Item\ (\$) \\ & + Unders\&Overs\ (\$) \end{aligned}$$

This revenue requirement is then used to update network tariff pricing for all customer classes and network tariffs, as discussed in the tariff normalisation section of Section C.2.1. Customer Processing.

Under and Over Recovered Revenue from Previous Year

When customers make decisions to change tariffs, purchase DER and move to a stand-alone power solution, the amount of revenue collected by the network may fall short of the revenue target for the year. To protect networks from lost revenue, and consistent with the revenue cap regulatory framework, an allowance is provided to recover the missed revenue during the following year.

$$Under\ and\ Over\ Recovered\ Revenue_t\ (\$) = \big((\$) - Revenue_{t-1}(\$)\big) * (1 + WACC(\%))$$

Where:

- The compensation for missed revenue is increased by the WACC to reflect the missed opportunity to reinvest the revenue that was not recovered in the previous year
- If the network over-recovered revenue during the previous year, this item will reduce the network's revenue in the current year.

C.3. Inputs and Assumptions

This section details the key inputs and assumptions used by Energeia's uSim platform for customers, assets and DER.

C.3.1. Customers

Energeia created a customer base and agent base to represent the more than nine million customers connected to the NEM and the WEM. The following sections detail the process Energeia conducted to produce the customer and agent base used in the uSim model.

Segmentation

Each customer was created based on the following segmentations:

- **Customer Class** – The customer base was first segmented into residential and commercial customers. The number of residential and commercial customers was collected from network regulatory reporting statements (benchmarking RIN response) for all networks in Australia.
- **Dwelling Type** – Each customer was sub-segmented into two dwelling types:
  - *Detached Dwellings* – Including houses for residential customers and warehouses for commercial customers.
  - *Attached Dwellings* – Including units (or apartments) for residential customers and suites for commercial customers.

  Through acquiring ABS data on the number and share of attached and detached dwellings, Energeia proportioned the total customer base split by customer class into their corresponding dwelling type.
- **Annual Consumption** – A customer's annual consumption is critical in understanding the customer's future DER purchasing decisions. Customer consumption data was not available in the public domain. Instead, Energeia approximated each customer's annual consumption through a log-normal distribution of the average customer's annual consumption in each zone substation in a network. This was done using the total consumption of customers by customer class, and the number of customers by customer class taken from the RINs.

  Solar PV Usage – The next level of segmentation was whether customer have solar PV. Solar uptake was limited in our platform to houses and warehouses due to roof space constraints. Historic solar installation data in Australia, including the number of installs and the size of existing solar PV systems, were collected from APVI and segmented into residential and commercial customers that are eligible to purchase solar PV. Additionally, Energeia determined the customer's historic purchase year through a random distribution of historic solar PV uptake. Energeia also ensured that the existing solar PV system for a customer is appropriate for their annual consumption (i.e. a "small" customers will not have a large solar PV system).

Using the segmentations listed, the resulting customer base was mapped to their corresponding lowest-level asset in the asset hierarchy, by feeders or zone substations[69].

Connection Mapping

Energeia's customer base requires a connection to the lowest-level network asset available. Using zone substation annual consumption and customer connections by customer class from the RINs, Energeia mapped each customer to their corresponding zone substation based on their segmentation characteristics.

Agents

Modelling each of the more than nine million customers connected to the NEM and the SWIS is not computationally feasible, so the customer base is represented by a smaller number of agents in the model. Each agent can represent hundreds of thousands of individual customers.

Allocation Method

Each agent has a unique set of characteristics (Agent Type) and represents a distinct group of customers or population segment. Agents are characterised and segmented by the properties shown in Table 22, similar to the customer creation process.

Table 22 – Agent Types by Customer Class, Premise Size and Solar PV Usage

		Business Customer Class		Residential Customer Class	
		Warehouse	**Suite**	**House**	**Unit**
Solar PV Usage	Yes	Agent Type 1	Agent Type 3	Agent Type 4	Agent Type 6
	No	Agent Type 2		Agent Type 5	

Source: Energeia

The full customer base for each DNSP is segmented according to the above variables and allocated to the sample agents according to their annual consumption. Table 23 shows the number of agents per customer segment in the model by state.

The limitations of the agent creation process are:

- The range of actual customers' annual consumption is wider than the range of annual consumptions in the load profiles of the agents. This meant that the largest and smallest agents represented all the customers in the tail of the distribution, which in some cases resulted in the agent having a much larger weight within the model than would be preferred.
- This also applies to the uneven distribution of agent's annual consumption within the range of extremes. Where three agents have a very similar annual consumption, very few customers will have an annual consumption closer to the middle agent than the other two agents.
- Customers are allocated to agents in each sub segment according to their respective annual consumption. If the sample agent consumption used to represent reality do not match the existing distribution of sample customers, it may result in some agents with a much larger weight in the model. i.e. some consumption bands have a relatively large number of customers and may be represented by the same number of agents as a less popular consumption band.

[69] Please refer to Section C.3.2. Assets for further details on the asset hierarchy.

Table 23 – Agent Allocation by State

	Residential				Commercial			
	Unit		House		Suite		Warehouse	
	No PV	Has PV	No PV	Has PV	No PV	Has PV	No PV	Has PV
NSW	293	×	267	27	276	×	262	13
VIC	301	×	268	35	373	×	347	24
QLD	121	×	90	31	120	×	86	34
SA	68	×	46	22	58	×	55	3
WA	57	×	48	9	63	×	52	8
NT	62	×	43	20	40	×	34	6
TAS	60	×	53	7	73	×	69	5

Source: Energeia

Selection Method

As agents represent various customers within a segment, each agent was mapped to their corresponding zone substation. As a result, a zone substation would be mapped to multiple agents, each representing a different number of customers in their customer base.

C.3.2. Assets

The asset hierarchy in uSim modelling is as follows:

1. System
2. State
3. Distribution Networks
4. Zone Substations
5. Feeders (Excluded)[70]
6. Distribution Transformer (Excluded)

The following sections details Energeia's inputs and assumptions for each of the assets modelled in uSim.

Systems

Energeia's uSim model can be configured for three energy systems in Australia.

- National Electricity Market (NEM): Includes NSW, QLD, VIC, SA and TAS
- South West Interconnected System (SWIS): Includes the South-West region of WA
- Northern Territory Electricity Market: Includes NT

Distribution Networks

The simulation platform works primarily on the distribution network level, with each network operating independently to other networks with agent and network decisions being contained within a single network. The exception to this is the setting of wholesale electricity prices, which are set at the state level and were provided by AEMO.

Zone Substations

Zone substations are individually modelled. This is because of the importance of zone substations in determining network costs and costs incurred by peak demand growth. Peak demand management and reducing the cost of

[70] Note that Energeia's modelling on the feeder level is performed in dSim, as detailed in .

distributing energy is a key focus of the simulation and the zone substation is an important cost component. Their need for replacement and augmentation are what drive network expenditure, which in turn drives tariff rates for a network.

In the simulation platform, the term zone substation primarily refers to the substation itself, but also includes related network assets and their associated operating, maintenance, and replacement costs. Related assets are modelled on a zero-growth basis and operating and maintenance costs are fixed over time. Related assets include:

- Upstream sub-transmission feeder lines (defined as the length of line that cannot serve any other zone substation),
- Downstream HV feeder lines, and
- LV distribution assets.

The value of all network assets split into each asset type was obtained from each network's most recent Regulatory Information Notice and annual reports for Western Power. The value of each asset and operating and maintenance costs was normalised by a dividing factor (lines as $/km, vegetation management as $/km, substation value as $/kVA etc.).

The limitations of zone substations in the simulation include the following:

- No investment is required for augmentation of HV feeder lines and LV distribution assets over time despite growth in the number of connections
- Large scale industrial customers are those connected to a zone substation that does not serve any residential or commercial customers or are connected directly to a sub-transmission line or bulk supply point. These customers are not modelled in the simulation and are only relevant for determining prices in the spot market.
- The load profiles of large industrial customers do not change over the course of the simulation, and their load impacts on zone substations are accounted for in the asset balancing loads.

Technical Characteristics

Assets in Energeia's database are defined by a series of technical characteristics as shown in the example in Table 24 for zone substations.

Table 24 – Asset Data Example

Classification	Asset Name	Asset Type	Capacity (kVA)	Network	State	Age (Years)	Parent ID
Short	ES232	ZS	25300	Essential	NSW	2	976609
Urban	EN287	ZS	4280	Ergon	QLD	13	976607
Long	PC026	ZS	33400	Powercor	VIC	6	976612

Source: Energeia

The main technical characteristics include the following:

- **Classification** – Each asset is assigned a type from the AER classification system taken from each DNSP regulatory information response for CBD, Urban and Long or Short Rural feeders and zone substations.
- **Connections** – Energeia maps each zone substation to its parent asset, the network. The zone substations are real and based on information in network annual reports. The characteristics of the agents on each zone substation are derived by mapping the zone substation to its nearest postcode.
- **Capacity** – Each zone substation in the network starts with its an N-1 capacity rating that determines how much energy demand it can comfortably handle. The ratings are based on network annual reports. These ratings are aggregated at the network level and determine the modelled network capacity in year 0 of the model (the year before forecasting begins).

- **Age and Lifetime –** Each zone substation is assigned a starting age. The age determines when (or if) in the modelled period the zone substation needs to be replaced, thereby requiring additional network replacement expenditure for that year. The amount of expenditure required is dependent on the zone substation's capacity rating and whether there is a need to increasing in the rating.

  The zone substation age distribution for each network is estimated based on RIN information NEM and NT networks, and network annual reports for WA. Energeia assumes that a zone substation asset has a lifetime of 50 years, i.e. if a zone substation reaches 50 years of age, it needs to be replaced.

Financial Classification

This section defines the financial classification of the assets in the model, including the capital expenses, operating expenses and the LRMC.

Capital Expenses

Capital costs are made up of two components, return on the RAB and a depreciation allowance as shown in the following formulas:

$$Return\ on\ RAB\ (\$) = RAB\ (\$) * WACC\ (\%)$$

$$Depreciation\ (\$) = \sum^{a} RAB_a\ (\$) * Rate_a\ (\%)$$

Where:

- The RAB is the RIN estimate for each asset.
- The WACC is unique and fixed for each network and was taken from the most recent AER determination for each network. This assumes interest rates and the required rate of return on equity in Australia and the risk profile of electricity distribution businesses do not change over time.
- The depreciation rate is unique to each asset and was calculated using data from each network's RIN by dividing reported depreciation by reported asset value for each category of asset. This results in the depreciation allowance in the initial model year matching the year the RIN data was collected.

The RAB value for each asset is updated annually by the following formula:

$$RAB_{a,t}(\$) = RAB_{a,t-1}(\$) - Depreciation_{a,t-1}(\$) + Repex_{a,t-1}(\$) + Augex_{a,t-1}(\$)$$

Where:

- For all asset categories, excluding zone substation assets, repex is set equal to depreciation and augex is set to zero so the RAB value does not change. The only exception is when the asset is removed from the network, such as when it is made redundant by a conversion of a zone substation to a microgrid.
- For zone substation assets, a depreciation calculation is only required when replacement or augmentation expenditure is made. For subsequent years, the value of the asset depreciates to zero using straight line depreciation over the course of the assets' life.

Operating Expenses

Operating expenses for networks include all operating and maintenance costs. Where these costs can be assigned to individual network assets or categories of assets from RIN data they have been. All remaining operating expenses are assigned to an operating expense balancing item.

Long Run Marginal Cost (LRMC)

The LRMC, the cost-to-serve the network faces, is defined in the model as:

$$LRMC\ \left(\frac{\$}{kVA}\right) = \frac{Peak\ Revenue\ in\ year_0(\$)}{Peak\ Demand\ in\ year_0\ (kVA)}$$

Where:

- Peak revenue refers to the revenue collected by the network cost-reflective tariff's peak component in year 0
- Peak demand refers to the weighted average peak demand for the year across all classes of customer on the network

The LRMC is held constant throughout the duration of model and is what determines the peak revenue target in year t, and therefore the network price component of agent bills:

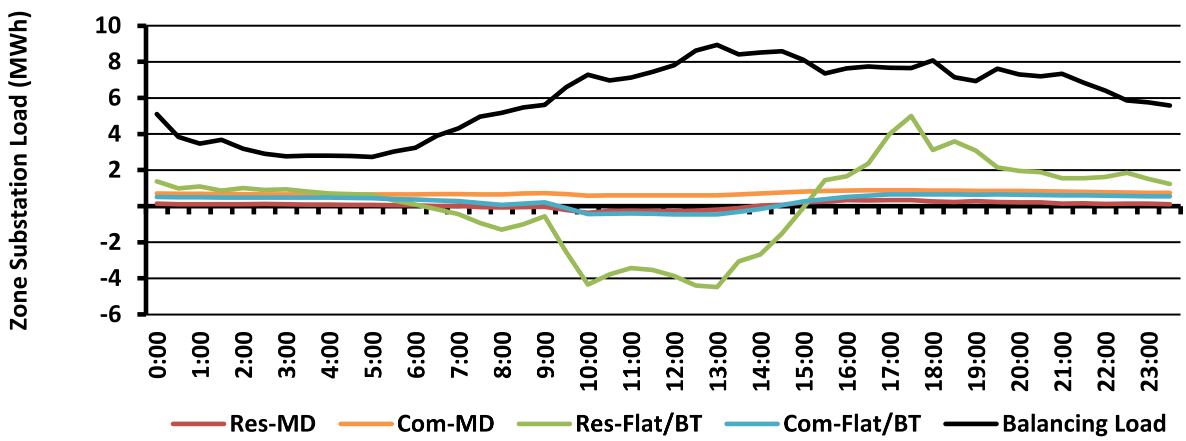
$$Peak\ Revenue\ Target_t(\$) = Peak\ Demand\ in\ year_t(kVA) \times LRMC\ (\frac{\$}{kVA})$$

Load Profiles

Industrial customers are not currently modelled in uSim. To account for their impact on the load on a zone substation (and therefore peak demand), each zone substation starts with a balancing load. This is the real energy demand profile on that zone substation in the starting year. It is taken from network websites, with the exception of Western Power and NT Power and Water, who do not publish this information.

In the modelled years, the aggregated demand profiles grow and adjust with the agent's growth and energy decisions. An indicative load profile of a zone substation on a peak day is shown in Figure 22. The area under the balancing load can be considered the load of large commercial customers.

Figure 22 – Zone Substation Load on Peak Day by Tariff Type (Indicative)



Source: Energeia

C.3.3. Distributed Energy Resources

In uSim, agents face a decision each year on whether to either purchase DER, or if they already have DER, augment their system. DER refers to any of solar PV, storage, and diesel generators[71].

Uptake

While the agents in uSim have information regarding the true value of their DER decisions, this significantly differs from reality, where consumers are often unaware of the true costs and benefits of adopting a DER system. Energeia's solution to this problem is for agents to take up DER through the real-world relationship between market uptake of DER and the payback period of DER. In the technical sense, there exists an observed relationship between the probability of a consumer choosing to purchase DER in a given year and the ROI of that decision at the time of purchase.

[71] In the rare case that an agent's optimal decision is to move off-grid. Diesel generators are not available to on-grid agents

To quantify this relationship, Energeia constructed an Excel modelling tool that calculates the historic first-year ROI of the average[72] solar PV purchase in a particular month. The benefit of constructing the relationship at monthly intervals is that often the FiT rates can change in the middle of a year. Energeia uses the following inputs in the ROI calculation:

- **% of solar PV output that is exported to the grid** – Calculated using NREL annual solar profiles and Smart Grid Smart City annual load profiles for customers, scaled to reflect consumption in each state
- **Historic Feed-in-Tariff (FiT) rates at monthly and state-level granularity** – Gathered from a variety of state government and industry sources
- **Historic electricity retail price at monthly and state-level granularity** – Taken from the annual AEMC Retail Trends reports
- **Historic annual solar PV system price, net of STCs zoned by each state's capital city** – Derived from Solar Choice
- **Historic monthly average PV system size** – Estimated at the state-level using APVI data

The first-year ROI of the average solar PV system purchase is then calculated as:

$$ROI = \frac{First\ Year\ FiT\ Revenue + Electricity\ Saved\ in\ the\ First\ Year}{Capital\ Cost\ of\ Average\ PV\ System}$$

Energeia has also researched the following inputs in the market uptake calculation:

- Consumer solar PV uptake per month by state and size as the market uptake
- Number of eligible dwellings as the market size as the total number of dwellings in each state, excluding rented and attached dwellings

The % of uptake in a given month is then calculated as:

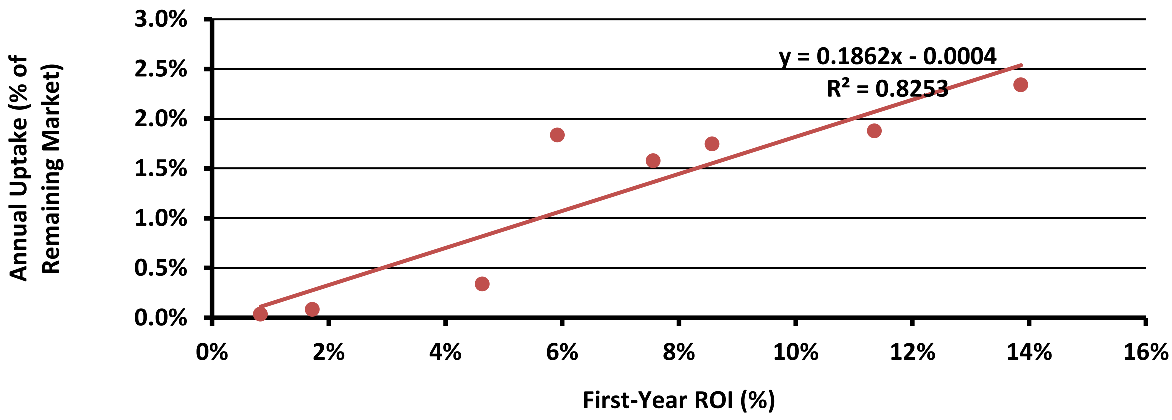
$$\%\ Uptake = \frac{PV\ Systems\ Purchased}{Eligible\ Dwellings\ without\ PV\ Systems}$$

The ROI and % Uptake are then annualised, and the linear relationship is then determined. The intercept and slope coefficients of the curve are then used in uSim to calculate the probability of an agent taking up their optimal DER combination. An example of the relationship is shown in Figure 23.

Note that for each state, the premium-FiT months are removed from the relationship. The customers who purchased solar PV in these periods have a level of certainty with their payback that pre and post premium-FiT customers are not privileged to.

72 The average capacity of each solar PV system purchased in a given month and state

Figure 23 – ROI vs Uptake Curve Example



Source: Energeia Modelling

Energeia applies the same uptake rate for batteries as solar PV. This is mainly due to the lack of reliable and detailed battery uptake data available in the public domain. Energeia believes that the historic uptake of solar PV and their corresponding ROI is applicable to batteries.

Solar PV

Technical

Residential and commercial agents face a separate minimum and maximum system size. The options are presented in Table 25, where:

- Min (kW) is the smallest size solar PV system an agent can install
- Max (kW) is the largest size solar PV system an agent can install
- Step (kW) is the difference between each option an agent can consider

For example, a residential agent can choose between 2, 4, 6, 8 or 10 kW of solar PV.

Table 25 – Min/Max/Step Sizes – Solar PV

Class	Connection Type	Solar PV Size Min (kW)	Max (kW)	Step (kW)
Residential	On Grid	2	10	2
Residential	Off Grid	2	10	2
Commercial	On Grid	10	100	10
Commercial	Off Grid	10	100	10

Source: Energeia

The inverter is assumed to be between the solar PV and battery storage units and the house circuit. The solar PV unit can therefore charge the battery at the same time as it is exporting to the house circuit, which allows solar usage to be greater than inverter capacity. Therefore, the inverter capacity can be smaller than the output of the solar PV unit, and it is assumed the inverter limits power flowing above its capacity, rather than fully disconnecting the solar PV and battery storage system when overloaded.

For this reason, the inverter constraint is applied after the battery algorithm has run to calculate solar generation. The inverter also applies as a constraint within the battery algorithm.

Solar PV is available to agents in all modelled years, however there are two separate restrictions on agents taking up solar PV:

- Agents of attached premises (i.e. units and suites) are not allowed to take up solar PV in the model.

- Of the agents who are permitted to take up solar PV (houses and warehouses), the maximum amount of solar PV they can take up is limited by the roof-area of their premise. For example, even though the maximum available system size to a residential agent is 10kW, an agent with an 80m^2 roof can only take up a maximum of 8 kW.

The method used to model solar PV has the following limitations:

- All customers within one state have the same solar profile, which excludes the beneficial effects of geographic diversity on solar PV output. Clouds, which greatly reduce solar PV output, affect all panels within a state simultaneously
- The solar output profile source does not necessarily align to the original dates of the demand profiles that agents in the model have. In many cases, customer and network peak demand occurs on very hot, sunny days. Since the source data does not align, the network peak event may for example coincide with high cloud cover, rendering solar PV ineffective at reducing peak demand.

Financial

The associated cost to install a solar PV system comprises of multiple components. These include the capital cost of the solar PV system itself and the installation costs. Additionally, the costs of the inverter are included in these costs.

Operational costs are not applied to solar PV systems.

Energeia's solar PV costs are generated from several solar PV cost curves from reliable sources in the public domain and tested against our subject matter expertise.

Impacts

Solar PV is not controllable by its owner and is therefore unaffected by most variables once the size is determined. Due to this, solar PV is the first DER technology that is applied to the demand profile:

- A solar profile trace[73], multiplied by the size of the solar PV system, is subtracted from the demand profile. The simulation platform contains an annual solar PV output profile for each state. The same profile is applied to all residential and commercial customers and microgrids in the same state and is obtained from the actual output of a representative 1kW solar PV system. Since the profile is from an actual solar system's output, it includes the effects of seasons and weather effects such as cloud cover. Solar profiles do not change between years.
- Solar PV systems do not degrade over time but have a finite life and fail immediately when the end of life is reached. However, if a solar PV system is augmented, the new system, including the capacity retained from the old system, will have the lifetime of a new system.

Battery Storage

Technical

Residential and commercial agents face a separate minimum and maximum system size, to align with the treatment of solar PV in the model. The options are presented in Table 26 where:

- Min (kWh) is the smallest size storage system an agent can install
- Max (kWh) is the largest size storage system an agent can install
- Step (kWh) is the difference between each option an agent can consider

[73] Energeia uses a 2013 state-based solar PV trace from north-facing per unit sized solar PV panels sourced from PVWatts (available here https://pvwatts.nrel.gov/).

Table 26 – Min/Max/Step Sizes – Battery Storage

		Battery Storage Size		
Class	**Connection Type**	**Min (kWh)**	**Max (kWh)**	**Step (kWh)**
Residential	On Grid	8	32	8
Residential	Off Grid	8	32	8
Commercial	On Grid	16	80	16
Commercial	Off Grid	16	80	16

Source: Energeia

Unlike Solar PV, battery storage is available to all agents in all modelled year, regardless of premise type. This is because there is no consistent physical constraint to installing a battery storage system like there is with rooftop solar PV, which requires the premise to have a rooftop.

This then implies that it is possible for agents in our model to install a storage system without solar PV and arbitrage with cost reflective pricing, charging from the grid during times when the retail price is low, and discharging to avoid high retail costs.

Financial

Similar to solar PV costs, the overall installed capital cost of a battery includes the cost of balance of systems and installation costs. Inverter costs are applied separately only if the customer does not already possess an inverter.

Energeia does not apply any maintenance costs to operating the battery.

Energeia's battery cost curves are again produced based on publicly available and reliable battery costs together with Energeia's subject matter expertise.

Impacts

Batteries are used to increase the value of solar PV generation and to arbitrage tariffs by shifting the battery owner's grid demand to times when retail electricity prices are lower.

Batteries have a set of characteristics that limit their ability to complete their objectives:

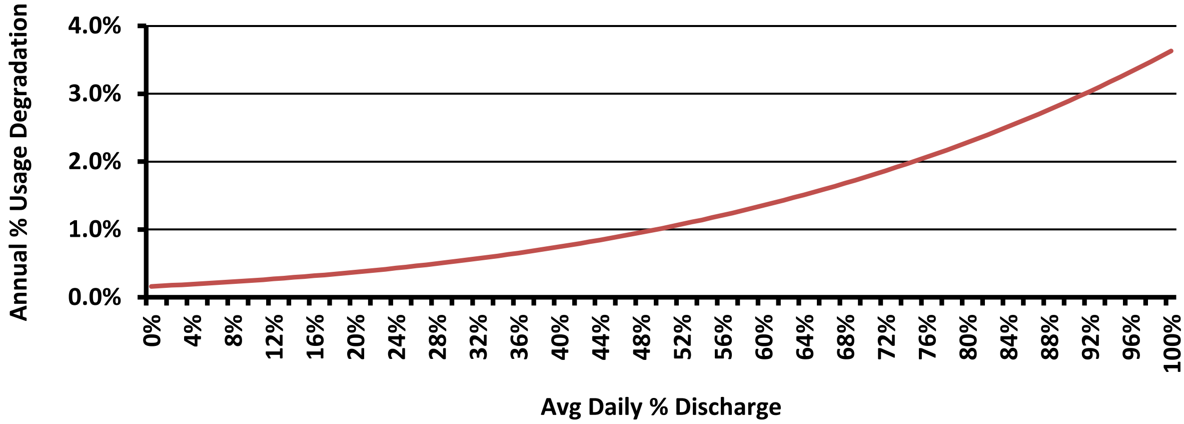
- **Depth of Discharge** – The depth of discharge (DoD) of a battery is the maximum percentage of the battery's rated capacity that can be used. A battery with a rating of 1kWh and a 90% DoD can be discharged to a minimum level of 0.1kWh. At this point the battery must be recharged. This is a built-in feature by the manufacturer of the battery that improves the lifetime of the battery. Discharging to very low levels has a greater effect on the battery's degradation. However, the manufacturing cost of a battery is driven by the total capacity, which is a function of the volume of materials that go into the final product
- **Output Limits** – Batteries are constrained by how quickly they can be charged or discharged. Higher rates of charging or discharging generate additional heat and degrade the battery faster. The charging and discharging limit are measured by c, which is the number of times a battery can be discharged in one hour. For example, a battery with c=0.5 can be discharged fully in two hours. In the simulation, the same constraint is applied to both charging and discharging for a battery
- **Losses** – In the simulation, batteries incur losses during charging and discharging. The rate of losses can differ for charging and discharging, but does not vary based on the rate of charging of discharging. These factors are an input into the simulation and can be set uniquely for each battery variant
- **Battery Degradation** – Battery degradation is an important factor in determining the NPV of purchasing a battery. Unlike other DER technologies in the simulation platform, batteries degrade each year. Other DER technologies have a constant maximum capacity/output over their lifetimes and then fail immediately when they reach the end of their lives. Batteries do not have an end of life failure, they continue to operate indefinitely, albeit with a lower level of capacity

  Battery degradation is a factor of two effects, calendar degradation and cycle degradation.

- *Calendar Degradation* – A decrease in capacity because of age, which is applied as a percentage reduction in remaining capacity at the end of each year.
- *Cycle Degradation* – Cycle degradation is caused by battery use and is dependent on the total amount of use the battery gets and how much of its capacity is discharged in a single cycle, as shown in Figure 24. Cycle degradation is calculated for each charge, discharge cycle and summed across each year to calculate total degradation as a percentage of initial capacity. A battery that is discharged fully each time it is used will degrade faster than a battery that cycles constantly between 90% and 100% of capacity.

  Since batteries degrade over time and do not have a finite lifetime, they are assigned a lifetime for the purposes of calculating the net present value (NPV) and payback of a battery purchase. This brings them into line with other DER technologies. The battery lifetime is the number of years until the battery is expected to degrade to 70% of its initial capacity. This is calculated by assuming the battery will degrade at the same rate every year as it did in the first year it was purchased.

Figure 24 – Rate of Cycle Degradation



Source: Energeia

The method used to model batteries has the following limitations:

- Each battery variant has the same *c* for all sizes, which means the model will prefer purchasing a larger capacity battery when the customer needs a battery with a faster rate of discharge
- Only one battery variant is available to each customer class in the simulation so customers are not able to select between different battery characteristics that may be more optimal for a given situation
- There are additional technical factors that affect battery degradation, such as heat and the rate of charging and discharging, that are not incorporated into the degradation calculation
- The degradation calculation always assumes the battery is discharging beginning at 100% but actual degradation depends on how much the battery discharges and the levels the battery is discharging between. For example, a battery cycling between 20% and 30% will degrade more than a battery cycling between 45% and 55%
- Battery lifetime is calculated using a simplified assumption of constant degradation over time. However, degradation will vary over time as the discharge profile of the battery changes. The cause of this variation is due to customer demand changes, other technology purchases and previous degradation of the battery affecting how the remaining capacity can be used

The battery algorithm determines when the battery charges and discharges. The inputs to the algorithm are:

- The characteristics of the battery
- The size of the inverter
- A demand profile

- A tariff

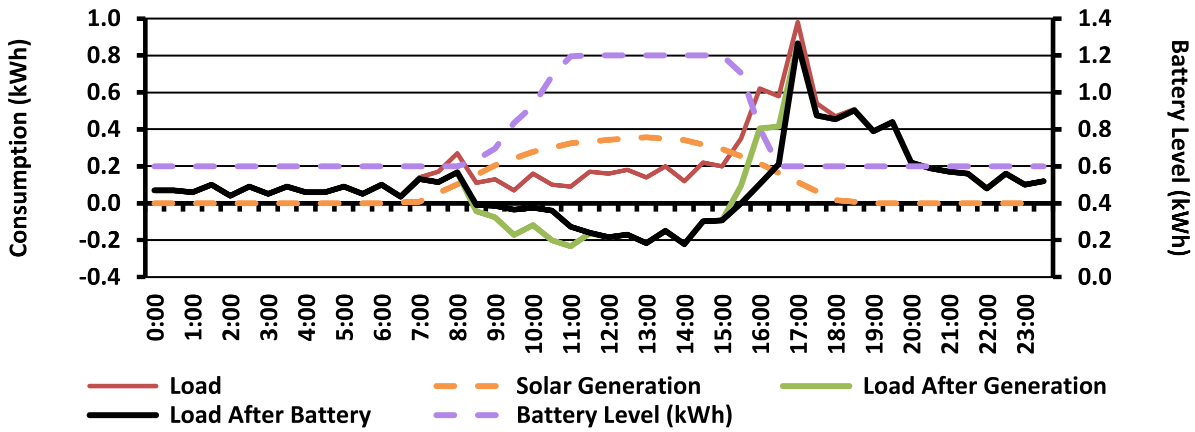
The battery algorithm aims to lower the battery owner's bill as much as possible by taking advantage of arbitrage opportunities present in the tariff. The battery algorithm works within the physical constraints of the battery and the inverter. The battery is not allowed to charge or discharge at a rate greater than the inverter size, unless it is charging from solar PV, when it is constrained only by the physical charge limit of the battery. This is because both systems are assumed to be 'behind' the inverter and can operate in DC to DC.

The algorithm will reduce a customer's retail electricity bill, starting with the most valuable action and progressing to lower value actions. A high value action is usually discharging in response to a peak mechanism in a tariff, such as clipping demand spikes in response to a maximum demand charge. Lower value actions include arbitraging price differentials for a time of use energy charge, charging during the off peak and discharging during the peak period and then possibly during the shoulder period.

The battery algorithm will charge the battery during the lowest cost period without triggering an increase in the peak demand charge (if any). This is often when there are solar PV exports which have a minimal cost to the customer of the foregone FiT revenue which would otherwise be received for exports.

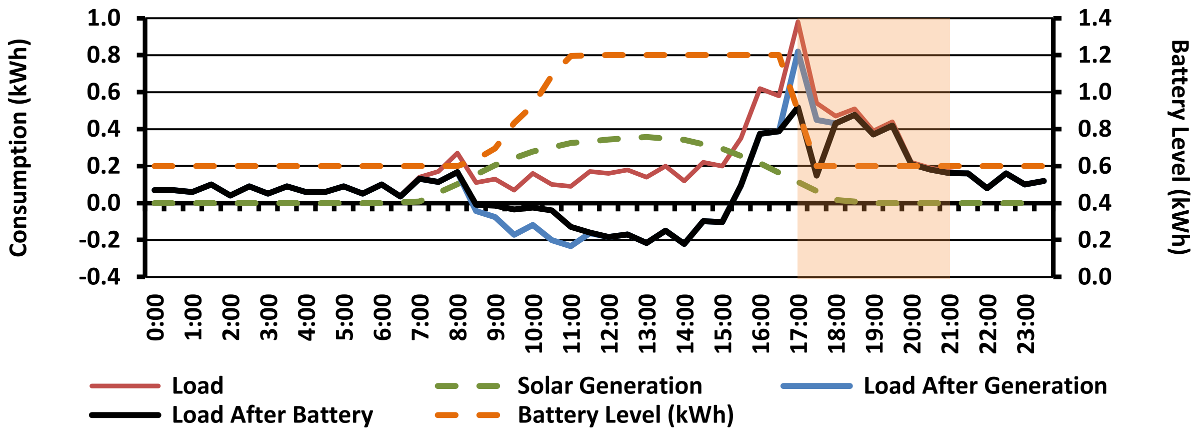
Figure 25, Figure 26 and Figure 27 show how the battery algorithms change depending on the tariff and technology choice.

Figure 25 – DER Impact on a Customer Load Profile on a Flat Tariff (Indicative)



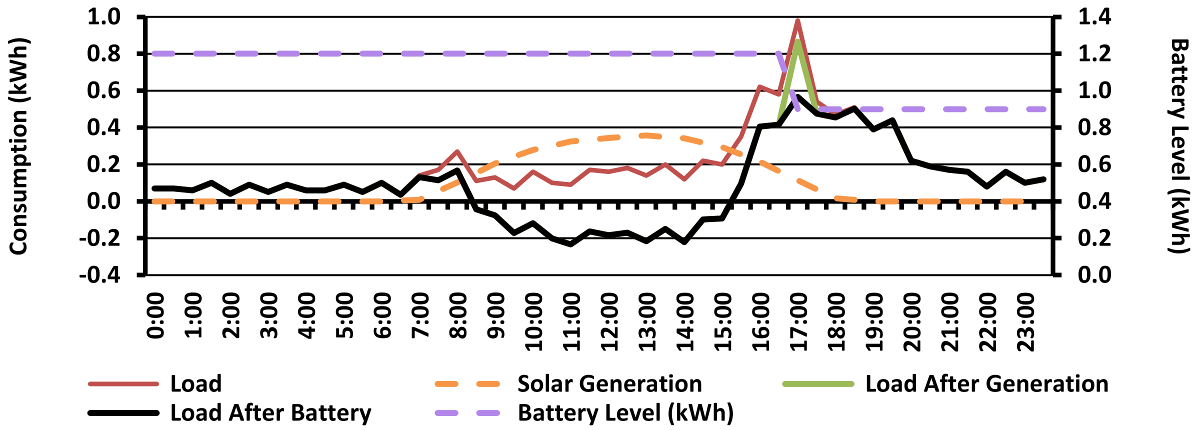
Source: Energeia

Figure 26 – DER Impact on a Customer Load Profile on a Time-of-Use Tariff (Indicative)



Source: Energeia. Note: The orange shaded area represents the peak period within the Time-of-Use tariff.

Figure 27 – DER Impact on a Customer Load Profile on a Max Demand Tariff (Indicative)



Source: Energeia

Although the battery algorithm achieves a near perfect optimisation, there is a trade-off between a perfect optimisation and processing time, which has meant a perfect optimisation has not been used in certain situations.

The battery algorithm has the following limitations:

- All customers have the same algorithm effectively eliminating diversity. Large numbers of customers will charge at the same time, potentially causing new peak demand events
- The algorithm is built based on the battery having perfect foresight of the owner's demand. This means the results of the battery algorithm set an upper limit for the savings achievable by a battery in a real-world situation.

C.4. Outputs

Energeia's uSim platform is able to forecast various key outputs regarding customer behaviour, asset performance and DER adoption and impact, as described in the following sections.

C.4.1. Customer

Regarding customer behaviour, Energeia's uSim includes the following key outputs:

- **Customer Tariff Switch** – A unique customer bill is calculated for a customer using all tariffs type (e.g. Flat/BT, ToU, Demand) available to the customer. If a tariff provides a lower bill to the customer, then they have the option to switch onto the preferred tariff. Our model outputs the percentage of customers on each tariff for each year in the simulation. This allows us to see the change in uptake of each tariff over time.
- **Market Penetration of Prosumers**[74] **and Consumers**[75] – Our model forecasts the number of prosumers and consumers in the network. When forecasting prosumers, the forecast splits out those with existing DER vs those purchasing DER in the forecast year. Energeia notes that market penetration is capped by the percentage of market that can take up DER. For example, the renter segment limits DER penetration in the residential sector and the suite segment limits DER penetration in the commercial sector.
- **Customer Bills** – Customer bills are a key component in our simulator. Customer bills are reported for all customer segments and are broken down into network and retail components. If customers own

[74] This refers to customers with DER, such as solar, storage or a combination of solar and storage

[75] This refers to traditional electricity customers without DER and solely rely on the grid for their electricity consumption needs

DER, the cost of DER is annualised over the life of the asset and the annualised cost is included into the customer bill as a technology cost component.

C.4.2. Assets

The asset processing module of uSim calculates and outputs key characteristics of the modelled network, including the following:

- **Levelised Cost of Electricity (LCOE) –** The model calculates the LCOE ($/kWh) of electricity from the system, providing the network and the retail LCOE over the forecast period. Furthermore, the model calculates the solar and storage LCOEs from customer DER.
- **Network Load Profiles –** By modelling individual customer impacts on load profiles from activity such as DER uptake and tariff switching, our model then aggregates customer load profiles and report on the net load profiles seen on the network.
- **Network Peak Demand –** The model is able to identify the period with the highest demand during the year and breaks it down into the underlying demand, the change in demand from solar and storage and the change in demand due to customers reacting to changes in tariff. Peak demand can be reported on a network level or if required, the peak demand load shaped for multiple networks in a state can be aggregated to identify a new state level co-incident peak demand.
- **Network Capacity Upgrades –** Network assets need to be built/upgraded if they reached the end of their asset lifetime (replacement) or if the demand on the asset grows beyond the rated capacity (augmentation). When the asset is replaced, the model looks at the existing demand to optimally size the upgrade of the asset. If the peak demand has reduced from when the asset was first built, the model will replace the existing asset with a smaller capacity to minimise network expenditure. All changes in capacity are recorded and outputted in uSim.
- **Network Expenditure** – In uSim, network expenditure is broadly segmented into three categories:
    - *Capital Expenditure* – The capex segment represents the cost of network upgrades and is broken down into repex and augex. Capex follows the shape of network capacity upgrades.
    - *Operating Expenditure* – Opex covers annual operating expenditure of the network and is based off research from network annual reports.
    - *Battery Leasing* – This represents the cost to networks for leasing customer batteries for network services.
- **Network Revenue Requirement** – uSim models the annual network revenue requirement for each network. This is broken down into network opex, depreciation, STS allowance and the return (WACC) on their regulated asset base.

C.4.3. Distributed Energy Resources

Energeia's ability to forecast DER uptake also provides the following key outputs:

- **DER ROI** – Each time DER is taken up by a customer in the model, the configuration of DER provides a unique ROI to customers which changes according to the cost of electricity, the cost of DER, the type of tariff they are on and the FiT available to customers. For each year in the model, the average ROI of DER is calculated and reported as an output. This ROI output is separated into two segments, the first is the ROI for customers that do not have DER and are buying a new system. The second is for customers that already have an existing system and are looking to augment their system with new DER. Note, customers are limited by network export limits which depends on whether the customer is on three phase or single phase electricity.
- **DER Capacity on the Network –** DER is segmented into three main categories, solar, storage and leased battery, the latter being the customer battery leased out to networks for network services. As customers take up DER, the model aggregates these values and reports on the total available capacity from DER on an annual basis. This allows us to see the trends in DER growth over the forecast, providing insight into periods of strong growth and plateaus.

- **DER Generation and Consumption Profiles –** The model operates using 17520 customer load profiles which allows it to analyse the impact DER has on customer load shapes. In the model, the battery and PV load is aggregated to the network level and the average load shape is reported on an annual basis.

Appendix D – dSim

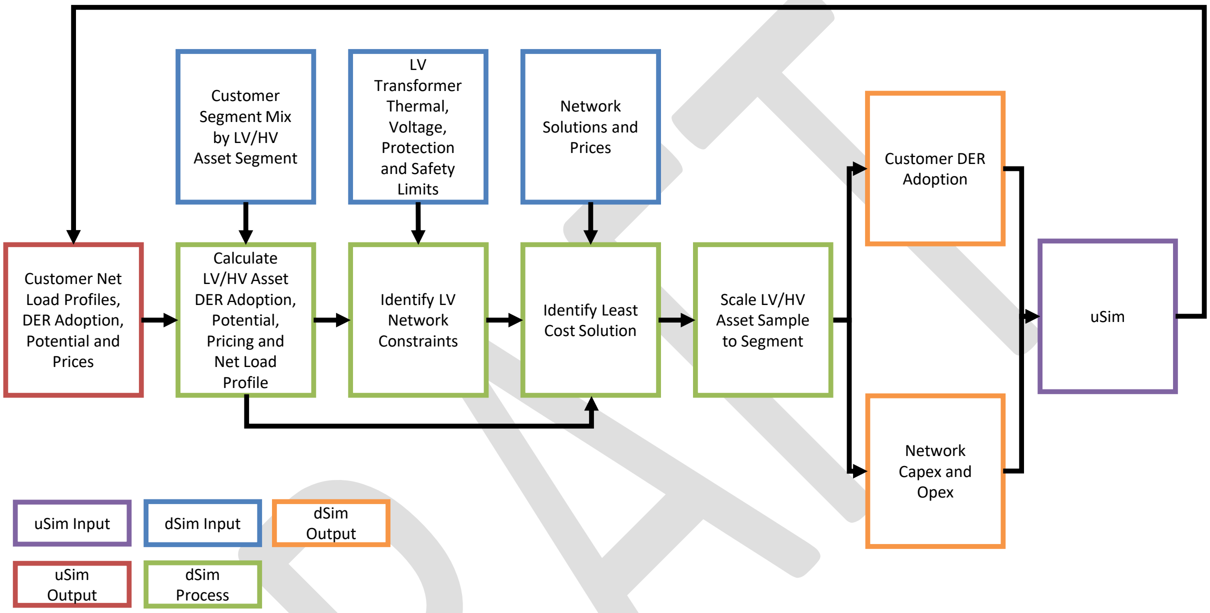
D.1. Overview

Energeia's dSim module models the impacts, costs, and benefits of DER for Low Voltage (LV) and High Voltage (HV) network assets. It functions similarly to wSim in that it models a particular aspect of the electricity system independent of uSim, but on an integrated basis when appropriate.

D.1.1. Structure of the Model

Figure 28 displays the structure of the dSim model, covering its key processing steps in green, key inputs in blue and red.

Figure 28 – Structure of dSim, Energeia's Techno-Economic Modell of LV/HV Networks



Source: Energeia

D.1.2. Methodology Selection

Modelling forecast network capital and operational expenditure, including due to rising DER penetration, is typically only done by DNSPs due to the lack of published data, and the lack of significant consulting activity in this space until recently. LV networks are typically operated on a run to failure basis, so very little planning occurs, and most constraints, e.g. thermal, protection or voltage are managed on a reactive basis only. HV planning does occur and is typically focused on forecasting thermal and voltage constraints and their remediation.

HV/LV planning typically involves forecasting changes to customers and load, including DER adoption, and then running a load flow model to identify any voltage or thermal overloads. This is typically only done at the feeder level, due to the sheer number of LV transformers that would need to be modelled, hence the reliance on reactive responses rather than planned ones.

Load and DER Forecasting

HV feeder forecasting is typically undertaken using a regression of some type, ranging from simple trending to more sophisticated Auto-Regressive Integrated Moving Average (ARIMA) based approaches. Energeia has worked with a number of DNSPs in Australia and the US to assess HV and LV forecasting approaches in light of the impact of DER uptake on their accuracy. A summary of our findings is shown in the table below, which highlights that simple trending is often the best approach in the near-term, but becomes inaccurate over time.

Table 27 – Comparison of HV Feeder Short-term Load Forecasting Methodologies

		Bass Diffusion	**ARIMA**	**Machine Learning**	**Multi-Variate Regression**	**Trending**	**Simple Regression**	**Simple Log Regression**	**Simple Log-Log Regression**
Accuracy (e.g. R^2 > 0.9)	Solar PV	×	×	×	✓	✓	✓	✓	✓
	Storage	×	×	×	×	✓	×	×	×
Methodological Simplicity		✓	×	×	✓	✓	✓	✓	✓
Industry Alignment		×	×	×	✓	✓	✓	✓	✓
Simple Sore		1	0.0	0	3	4	3	2.5	2.5

Source: Energeia

Based on the results of our comparative analysis of the various options, Energeia developed a hybrid load and DER forecasting approach that applied straight line projections for three years, before transitioning to bottom-up, agent based forecasting similarly to our uSim model after that, with a phase in of results in the 3-5 year period. This addresses our findings that trends are difficult to beat in the short term, but bottom-up approaches are likely to be more accurate in the medium to longer-term.

Constraint Forecasting

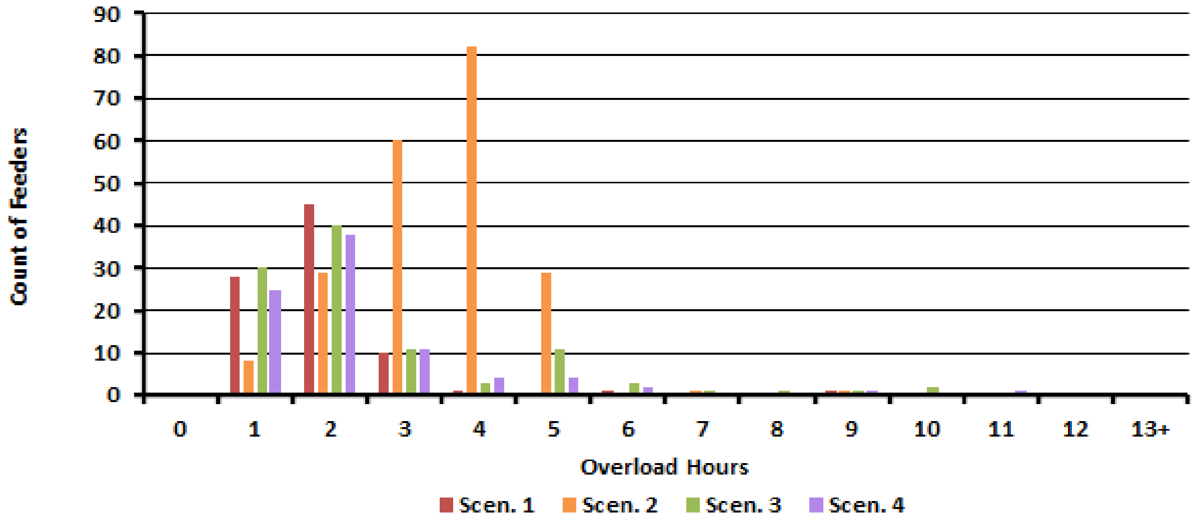
Energeia typically partners with an engineering consultancy to develop forecasts of HV/LV asset constraints, where we provide 17,520 interval load shape for each asset, and the engineering consultancy runs a load flow to identify thermal, voltage and other electrical constraints.[76] Based on the results of this modelling, we identify key triggers of over-voltage in particular, and use that in dSim to trigger network solutioning.

Importantly, Energeia's use of 17,520 interval load forecasts enables us to better characterise the constraint, especially in the case of thermal overloads, so that solutions requirements can be better described. For example, there is a significant difference between a constraint that only lasts one hour per day and one that last 8 hours per day, in terms of the types and costs of potential DER solutions.

The figure below displays the results of our distribution feeder constraint forecasting by scenario, and how the duration and depth of the constraint changed by scenario. Getting this right is important for getting the potential for DER to provide a cost effective solution right. The timing and duration of the peak period are both key drivers of DER availability and cost effectiveness. Solar PV can reduce a 7pm peak but not an 11pm peak.

[76] Energeia is not using load flow for this project.

Figure 29 – Illustrative Forecast Counts of Distribution Feeder Thermal Overload Durations by Scenario



Source: Energeia

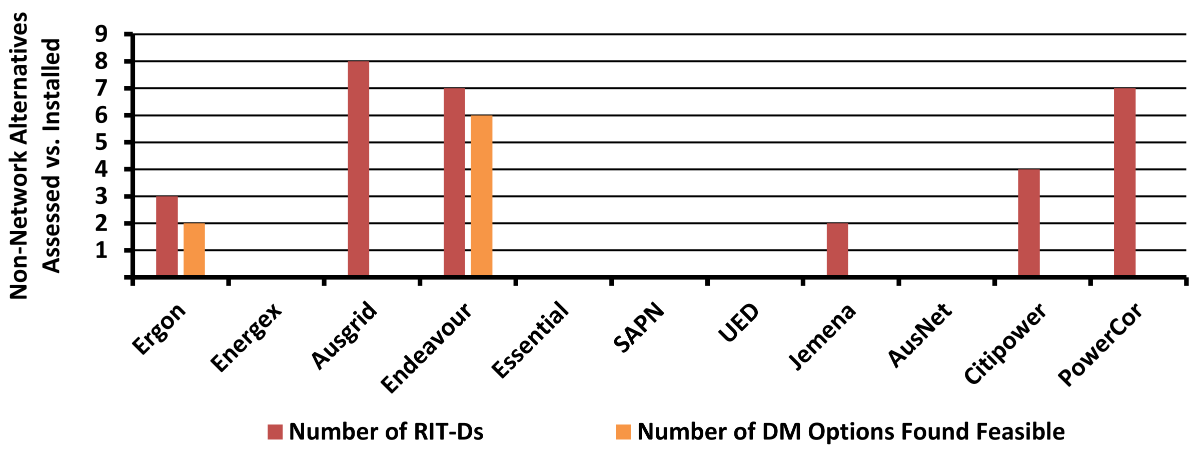
In Australia, there is very little in the public domain regarding the relationship between solar PV adoption and over-voltage conditions on the HV or LV network. For dSim, Energeia has adopted published results from the University of Melbourne, which are discussed under the key input section below, to drive our over-voltage constraint function, which links the level of solar PV penetration to solar PV curtailment.

Solution Optimisation

HV and LV solutions to relieve thermal, voltage, protection and other asset constraints are generally limited to key options including phase balancing, changing transformer tap settings, installing new capacitors or voltage regulators, reconfiguring the conductor, reconductoring or installing a larger transformer. Increasingly, DNSPs are also considering more active solutions including statcoms and storage devices.

Determining the least cost approach is traditionally done on a manual basis for the HV network, and a reactive rules basis for LV networks. Under the Rules, Australian DNSPs are required to assess whether non-network alternatives could relieve the constraint. However, Energeia is only aware of a handful of DNSPs in Australia or the US that have actually included customer DER in their HV solutioning as per recent Australian results reported in Figure 30.

Figure 30 – Comparison of Non-Network Alternatives Assessed vs. Installed in 2017-2018



Source: Energeia, DNSPs

The key reasons that DER is not being used to relieve constraints in Australia include the lack of sufficient amounts of dependable DER, the lack of an industry capability and sufficient time to develop DER solutions.

Energeia's dSim solution optimisation approach helps address many of the limitations in the industry's current approach by developing estimates of achievable DER adoption, including how much could be enrolled in a VPP if additional communications and control technology were installed at customer's premises, and how much additional capacity could be developed via targeted VPP development programs.[77]

In summary, by using 17,520 forecasts of load and DER operations to more accurately characterise future constraints, and by considering most distribution network solution options alongside and on a level playing field with DER solution options, Energeia believes dSim is best able to accurately identify the truly least cost solution for relieving LV/HV network constraints.

D.1.3. History of Recent Model Development

Energeia's dSim model aims to models the costs and benefits of various solutions, for a given category of HV/LV network, to identify the set of solutions that are expected to deliver the highest net benefits. This modelling approach builds on from our Stage I optimisation framework which ultimately focused on optimising the costs for addressing over-voltage issues due to excess generation, mainly by rooftop solar PV systems.

Table *28* details the key changes or dSim delivered in Stage I and proposed in Stage II respectively. The Stage I optimisation solution was limited due to the constraints of budget and timelines. As such, Energeia is proposing to further develop the solution, based on stakeholder feedback in Stage II.

Table 28 *– Comparison of dSim Modelling Scope and Approaches*

Modelling Element	Stage 1 – Actual	Stage 2 – Proposed
Network	A three-fold segmentation of low-voltage assets was developed based on DNSP RINs: namely 50 kVA, 250 kVA, 1,000 kVA, representing rural, suburban and urban/CBD LV network asset segments	Existing asset segmentation will be expanded to cover off on different customer mixes
Constraint	Although 11 network constraints were identified overall, the solution optimisation approach focused on voltage management in the low-voltage network, and was restricted to the impacts of solar PV on voltage	Reverse power flow (impacts on DNSP protection schemes), load (impacts on thermal overload and DNSP need for reconductoring) and safety impacts (age driven replacement) will also be considered
DER Solutions	Battery storage, water heating and EV load control were considered, including DER services but with full costing	Expanded consideration of DER services including DER program development based on achievable potential and net costing approaches
Network Solutions	The optimization approach included both network opex (off-load tap reconfiguration), capex (PV export limits, new on-line tap changing transformers)	Largely as per Stage 1, with more accurate modelling of tariff based solutions
CBA	Solution optimisation was undertaken on a cost optimization basis, to uncover the lowest possible combination of network and consumer solutions to estimate least cost DER integration	Solution optimisation will include a net benefits assessment, inclusive of both the DER integrations costs for networks and consumers, as well as the benefit stack that can be unlocked for consumers, retailers, networks and generators

Source: Energeia

D.1.4. Current Application

dSim has been used in the following key applications:

- **DER Enablement Stage 1 (Renew)** – dSim used to model solar PV driven voltage constraints, solution pricing and optimization and total expenditure over ten years in three archetypical low voltage network configurations. The outputs were used to estimate the least cost solutions, and the relative benefits for implementing them over three scenarios.
- **Integrated Distribution Resource Plan (SMUD)** – dSim was used to identify which network constraints could be met at lower cost using DER over three scenarios as part of the utility's Integrated Distribution Resource Plan (IDRP). The results were used to estimate the potential network expenditure savings.

[77] Figure 34 illustrates how achievable potential can be estimated by asset and constraint type, e.g. thermal overload.

- **DER Enablement Stage 2 (Renew) –** An expanded dSim is being used to update the Stage 1 analysis using additional network asset types, network solutions and DER solutions. The modelling will also use a more accurate 17,520 interval based constraint modelling approach rather than the rules based approach adopted in Stage 1.

D.2. Model Process and Modules

The following sections describe each of the key modelling steps in terms of the key inputs to the process, each process step, and the key outputs.

D.2.1. Load and DER

In this step, dSim takes each customer segment load profiles and DER adoption, VPP adoption and DER technical potential forecasts for the given year and scenario from uSim outputs and generates a load profile, DER price and capacity for each HV/LV asset considered.

Key Inputs

The key inputs of this step are 17,520 interval load and DER profiles for each customer segment being modelled, the number and type of customers by segment and asset, their associated VPP DER, Non-VPP DER and achievable VPP DER, and the associated costs for network services.

DER and Customer Load Profile Development

Table *29* shows the customer segmentation developed for the Smart Grid, Smart City (SGSC) project, which is used in dSim when more granular or accurate customer and load data for a given network is unavailable. Currently, detailed customer and load data is not published in Australia[78].

Table 29 – *Smart Grid, Smart City Customer Segmentation*

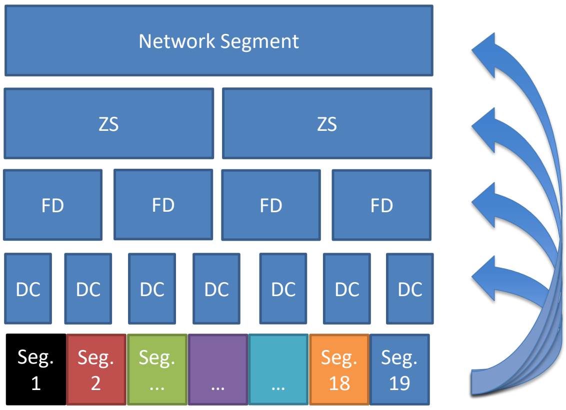
Segment	Income	Building Type	Climate Zone	Electricity Consumption	Gas
1	High	House	Z5	S1	G1
2	High	House	Z5	S2	G1
3	High	House	Z5	S3	G1
4	High	House	Z5	S3	G1
5	High	Unit	Z5	S1	G1
6	High	Unit	Z5	S1	G1
7	High	Unit	Z5	S2	G1
8	Low	House	Z5	S1	G1
9	Low	House	Z5	S2	G1
10	Low	House	Z5	S3	G1
11	Low	House	Z6	S1	G1
12	Low	House	Z6	S2	G1
13	Low	House	Z6	S3	G1
14	Low	Unit	Z5	S1	G1
15	Low	Unit	Z5	S2	G1
16	Low	Unit	Z6	S1	G1
17	Commercial	-	-	0 - 15MWh	-
18	Commercial	-	-	15 - 40MWh	-
19	Commercial	-	-	40 - 160MWh	-

[78] In the US, best practice is for distribution utilities to publish detailed HV feeder data, including rating, load profiles, and customers.

Source: Ausgrid

Figure 31 shows how each customer segment, based on the customer segmentation from the SGSC project, is mapped to each network asset, based on the weighting of customers on each asset, which was also developed as part of the SGSC project.

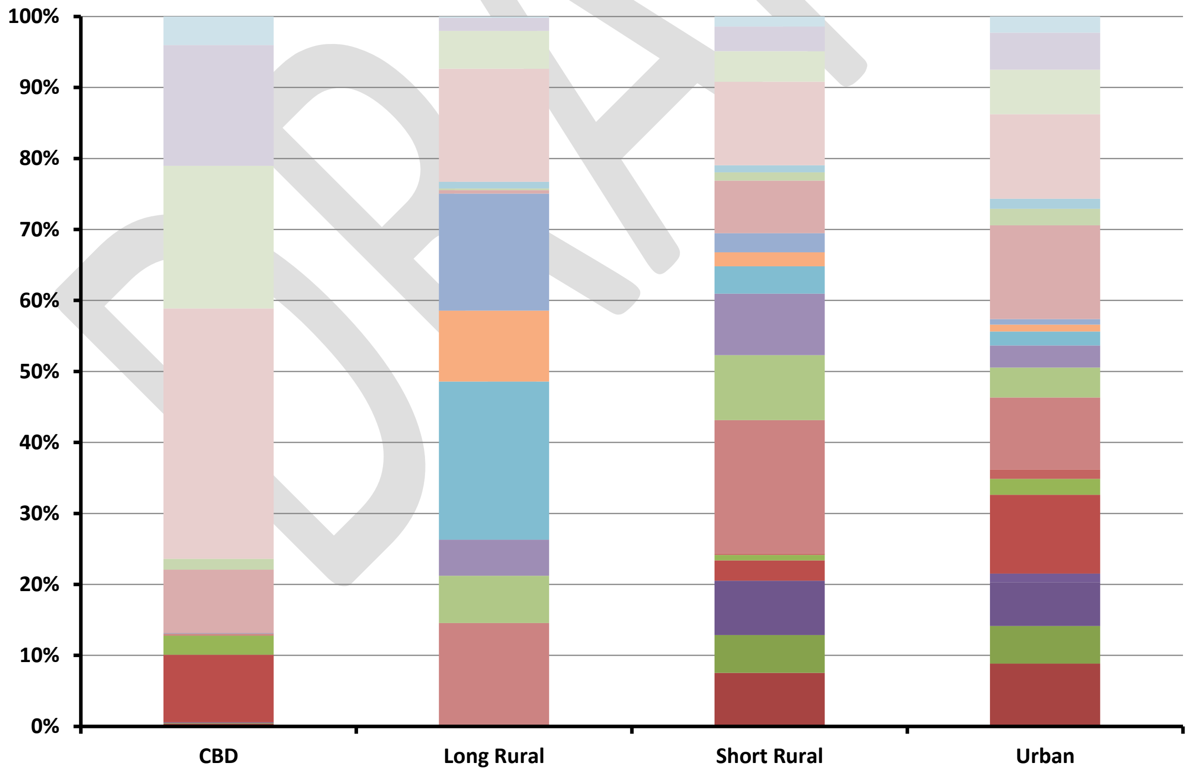
Figure 31 – Smart Grid, Smart City Customer Segmentation Mapping



Source: Energeia; Note: ZS = Zone Substation, FD = HV Feeder, DC = Distribution Centre (i.e. LV Transformer)

Figure 32 shows the weighting of each customer segment for each archetypical HV/LV asset using the SGSC weightings. Again, dSim uses actual customer to LV/HV asset mapping for this step, when available.

Figure 32 – SGSC Customer Segment to Prototypical Feeder Mapping



Source: Energeia

The output of the above customer and load sample expansion process are 17,520 interval load and DER operating profiles for each HV/LV asset being modelled. Also generated is an estimate of the available DER during each 17,520 interval, grouped by VPP DER, DER not yet in a VPP and achievable potential DER, based on the technical potential, less already installed DER, and an assumed annual VPP development rate limit.

The processes involved in each of the above DER availability and costing steps are described in the following sections.

Cost and Availability of VPP DER

VPP DER is estimated for each asset based on the level of VPP DER adopted by each customer segment, and the number of customers on a given asset from that segment. This results in a total potential available VPP DER, estimates for each 17,520 based on the uSim outputs.

The cost of accessing this DER is estimated using opportunity cost. The main drivers of opportunity cost are available NEM prices, customer tariff price signals and any available network demand response pricing signals. The modelling ensures that the cost of dispatching VPP DER is set equal to the highest opportunity.

Cost and Availability of non-VPP DER

Non-VPP DER availability is estimated for each asset using the same methodology described for VPP DER. It is also priced the same way, i.e. based on opportunity cost, with an additional premium levied to account for the cost of installing a control box, which is shared among the estimated value stack value stream for the given scenario[79].

Cost and Availability of Achievable Potential VPP DER

The cost and availability of potential VPP DER is also estimated for each asset using the same methodology described for VPP DER, in that customer segment values are scaled based on the numbers of customers mapped to each asset for each given segment. The key variables mapped in this case is the achievable VPP DER development potential, which is based on the assumed rate of adoption possible for a VPP development program (including additional incentives compared to tariffs), which can vary over time, as the industry matures[80].

The pricing of achievable potential VPP DER is based on the DER installation costs, any additional DER program development costs, less the value of the benefit stack for the given type of DER and scenario.

DER Capacity and Availability by DER Resource Type

DER capacity refers to the maximum capacity that DER could deliver. DER availability is the fraction of this that may be available for a VPP application, e.g. network voltage support or peak demand reduction. Both inputs are needed to determine the potential supply of DER for a given constraint.

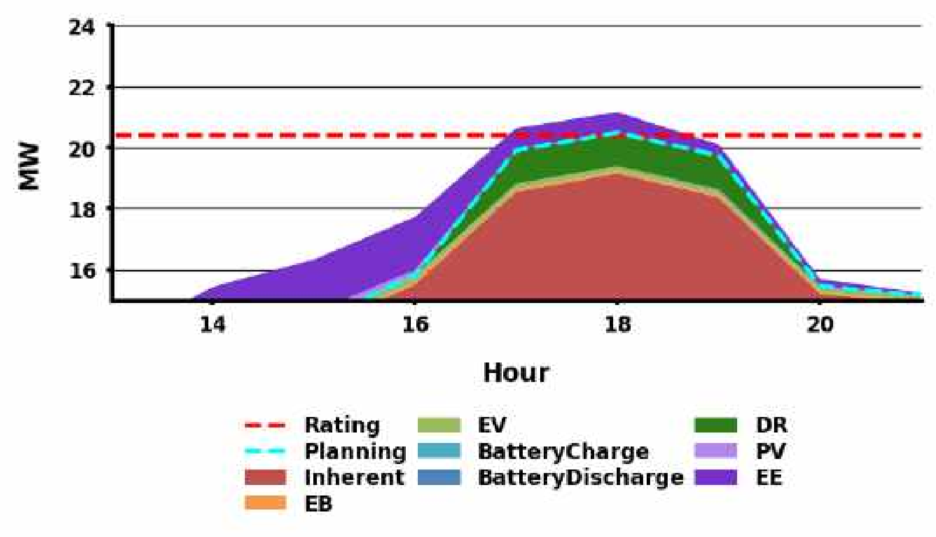
Figure 33 illustrates the different DER availability by hour during a typical weekday. Some types of DER, e.g. energy efficiency and demand response, are a function of when load is being used, and vary over time. Other types of DER like solar PV and smart inverter functionality, are driven by solar insolation[81]. Flexible DER, like batteries, can be available any hour of the day with sufficient warning to ensure that their batteries are charged.

[79] Value stack estimation is covered later in this section.

[80] Achievable potential assumptions are discussed further below in the Key Inputs and Assumptions section.

[81] Intermittency impacts on solar PV availability significantly reduce its dependable capacity rating.

Figure 33 – Illustration of Weekday DER Availability by Hour



Source: Energeia

DER availability is relative to installed capacity. Installed capacity for planning purposes includes:

- **Forecast installed DER VPP capacity**, which includes all non-dispatchable DER (e.g. PV), and all VPP enabled DER (i.e. battery storage VPPs, electric vehicle VPPs, HVAC VPPs, etc.)
- **Forecast installed non-VPP DER capacity**, which includes all DER that could be part of a VPP if a control box were installed or if consumers enrolled an existing VPP capable device.
- **Forecast achievable DER VPP capacity**, which includes all potential DER that could be actively developed by a VPP aggregator given available time, incentives and customer behaviour.

Although there are currently very low levels of VPP enabled DER, it is expected to increase significantly over time as the industry develops. Until this occurs, it is important to track and include potential sources of DER capacity that could be available for constraint relief.

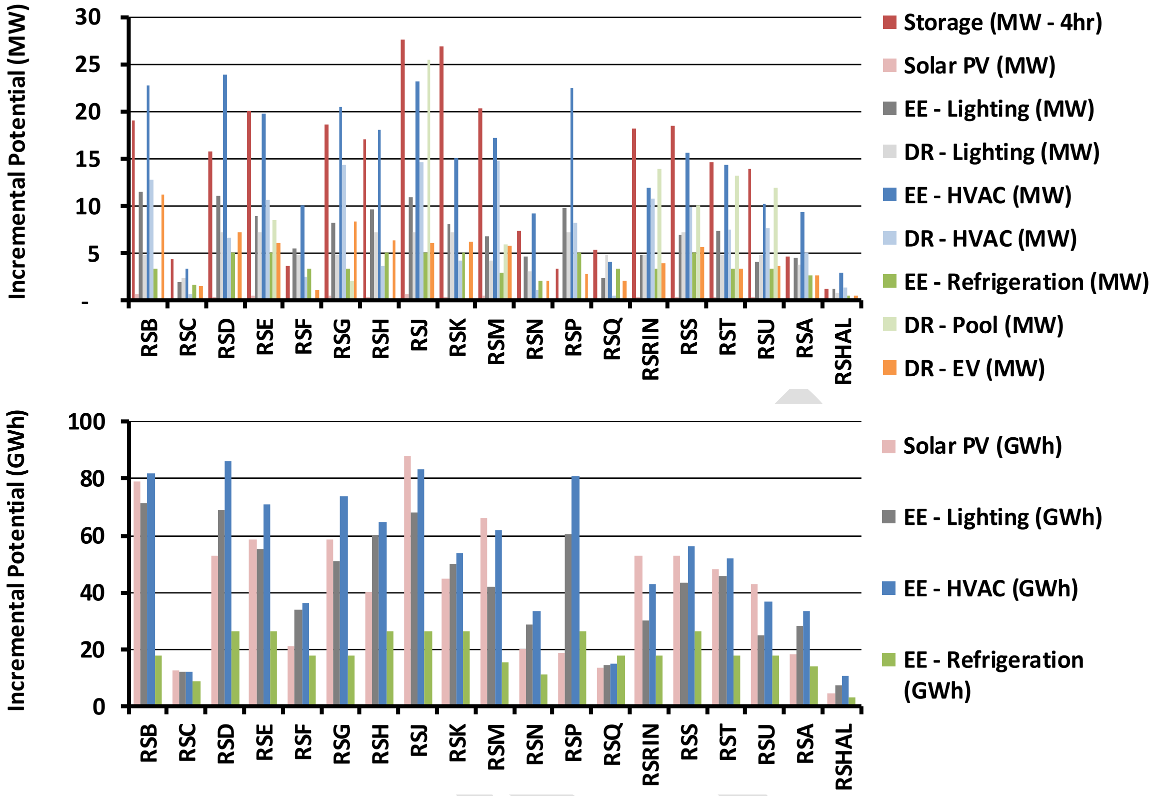
Achievable DER Development Potential

Calculating achievable DER development potential can be used to determine how much DER capacity could be developed to meet a given NEM or network opportunity, e.g. a thermal LV transformer constraint given time, incentive levels industry maturity and the customer's attached to the asset.

Energeia models achievable DER potential based on a combination of technical potential, DER economics, customer behaviour and DER service industry maturity. Based on our analysis, which is done primarily in uSim, we can develop estimates of achievable kWh and peak demand kWs by specific asset for a given year.

Figure 34 illustrate the level of achievable kWh and peak kW potential across bulk-supply points by DER by 2030. The estimates may look different for 2025 and for 2035, due to changes in the timing of the peak period, DER economics, and assumptions regarding customer behaviour or industry maturity.

Figure 34 – Illustration of Estimated Achievable Potential by Bulk Supply Point and DER in 2030



Source: Energeia

When supporting DER program developers, dSim and uSim can be used to design DER development programs, identifying annual program targets to achieve targeted capacity levels including total DER capacity by year and by customer, and the associated program costs including incentives.

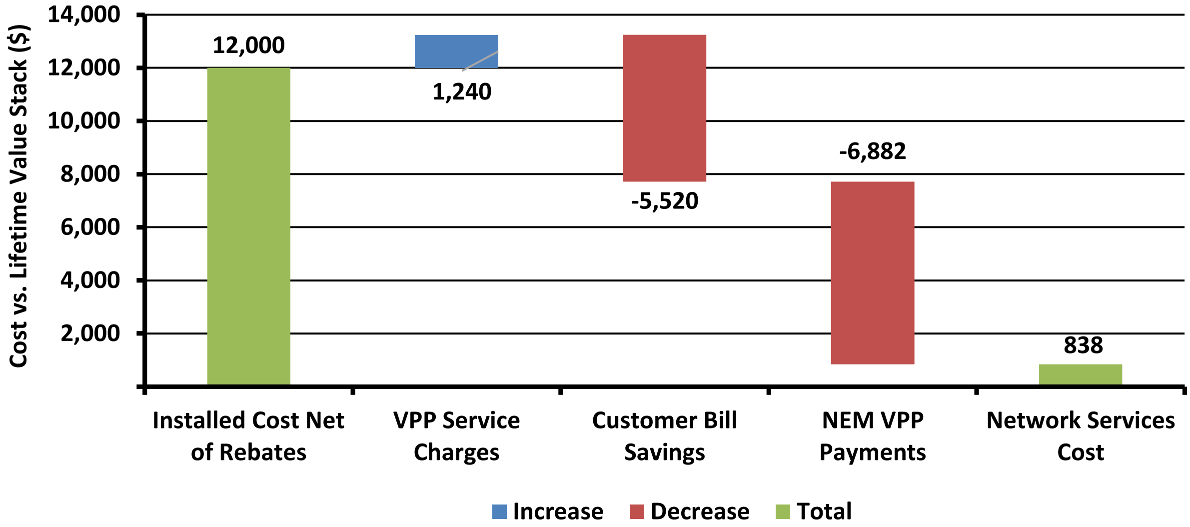
DER Net Costing Based on Value Stacking

The ability to provide multiple types of services and receive associated revenues means that DER costs can be shared across all services, rather than assuming that a single service, even if it may be triggering the DER investment, e.g. due to a targeted VPP DER development program. This is a key concept for accurate costing.

Figure 35 illustrates the above net costing approach by showing estimated potential revenue streams a BTM battery could be expected to be able to achieve over its lifetime. dSim develops the estimated cost charged for each LV/HV grid service based on that service's share of the overall revenues, a simple pro-rata approach[82].

[82] A more sophisticated approach would be to allocate DER costs based on available producer surplus

Figure 35 – Illustrative Cost vs. Lifetime Value Stack for a 10 kWh BTM Battery



Source: Energeia

Importantly, the value stack is developed by calculating the forecast best use for the battery each over its lifetime. The model takes recent wholesale, network and consumer benefits into account when performing this calculation.[83] There is no double counting of benefits, but where there is a conflict between two potential services and revenue streams, the more valuable one is assumed.

dSim uses the above estimate of the expected lifetime value of DER to other services to determine the incremental cost that would need to be paid by LV/HV to cover the cost gap. Key assumptions include VPP service charges and the discount rate applied to each revenue stream to account for the investment risk given the uncertainty of the cashflows[84].

A key limitation of the above approach is the assumed lifetime value of the DER asset's value stack, but DER investors have to make similar estimates when deciding on whether to invest in DER or not.

Key Outputs

The key outputs of this step are 17,520 interval load and DER profiles for each HV/LV asset being modelled, and the associated incremental cost of VPP DER, non-VPP DER and achievable potential VPP DER.

D.2.2. Constraints

The next step of the process is to identify and character key HV/LV asset constraints, which include:

- Thermal
- Voltage
- Protection
- Safety/reliability

The following sections described dSim's constraint modelling processes.

[83] This is a key limitation of the approach, but one that is consistent with investor decision making.

[84] VPP service costs and discount factors applied to DER lifetime value stacks are discussed in Section D.3.3

Thermal Constraints

dSim identifies thermal constraints by comparing the thermal rating[85] of each asset against the forecast 17,520 load profile for the asset developed from the previous step, net of any network VPP-contracted services. Thermal ratings may be emergency or nominal, depending on the application. The load profile enables identification as to the number of hours, and even the ambient temperature, of the overload.

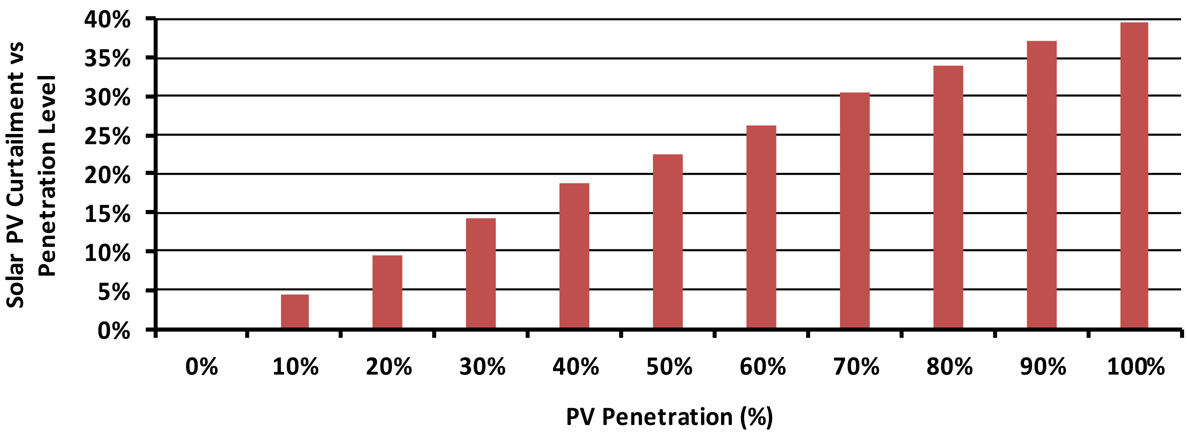
Using 17,520 interval data allows dSim to properly identify the key characteristics of the constraint, including its month, day type, time-of-day and duration. Each of these parameters impacts on the capacity, availability and therefore, the relative cost of a DER solution for meeting it. Network solutions are less sensitive to these factors, as a transformer or conductor upgrade delivers a fixed capacity that is almost always available.

Earlier, Figure 29**Error! Reference source not found.** showed the results of a recent project forecasting thermal o verloads in terms of the duration of asset overloads. It can be seen in that figure that the duration can vary significantly across assets and by scenario. Trend-based peak demand forecasts are generally not able to determine anything about the timing or duration of the constraints, undermining analysis of potential DER solutions.

Voltage Constraints

dSim identifies voltage constraints via a load flow module, which takes 17,520 load and DER profile data, and asset technical data, and identifies voltage constraints. dSim can also be configured to run without the load flow module by using overvoltage rules, typically developed using low flow modelling. When a rules-based simulation is run, dSim compares the installed solar PV inverter capacity[85] of each asset against the curtailment function detailed below for to identify the level of curtailment[86].

Figure 36 – Comparison of LV Transformer Load Forecasting Methodologies



Source: IEEE / University of Melbourne

Real power-driven, static over-voltage conditions are the key voltage constraints typically modelled in dSim based on rules. Other drivers of voltage constraints are typically not modelled, nor are under-voltage conditions, without a load flow assessment. Dynamic voltage issues, e.g. flicker, are also not modelled.

Another key limitation of the model when running in a rule-based mode is that the accuracy of constraint identification is lower than if load flow modelling was completed on each asset. However, this can take much more time and effort, with a commensurately higher budget requirement.

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[85] Thermal ratings for each asset discussed below.

[86] Curtailment is assumed for ASS 4777 compliant inverters, non-compliant inverters are assumed to trigger an over-voltage situation.

Protection Constraints

dSim identifies reverse flow constraints, which can affect HV asset protection settings, as well as some voltage regulators including offload tap changers. Reverse flow conditions are identified where the 17,520 net load, after taking any network controlled VPP capabilities into account, is negative.

Safety/Reliability Constraints

The final constraint that dSim models is safety/reliability, which is either based on asset condition analysis, or where that is not available, is based on the age of the asset. Assets that are older than the assumed age limitation are flagged as having a safety/reliability constraint.

Key Outputs

The key outputs of this step are the identified constraint profiles for thermal overloads, over-voltages, reverse flows and safety/reliability constraints.

D.2.3. Solution Optimisation

dSim identifies the optimal solution for each identified constraint profile by modelling the marginal cost of each available network or DER option that relieves the constraint.

Key Inputs

The key inputs to this step are the identified constraint profiles for thermal overloads, over-voltages, reverse flows and safety/reliability constraints from the preceding step, and unitised network solution costs by constraint.

Solution Options

The key first step in the solution optimisation process is determining the network and DER options available to address a given constraint. Table 30 reports on the range of potential solutions by constraint type. However, they may not always be available, e.g. VPP DER where there is not sufficient achievable potential. Which of these are able to be modelled in dSim is indicated by column D.

Table 30 – Key Options for Managing Modelled HV/LV Network Asset Constraints

Category	Solution	Description	T	V	P	S/R	D
Consumers	Load Management	Shifting of water heating, pool pumping & under floor heating to soak up excess generation	✓	✓	✓	✓	✓
	Energy Management	Use of storage or smart inverters to control real-energy output or Volt-VAR or to soak up excess generation	✓	✓	✓	✓	✓
Pricing Signals	Coarse	Use of more cost-reflective pricing signals (e.g. tariff or rebates) that better reflect the value of marginal generation/consumption of real/reactive power, e.g. Time-of-Use	✓	✓	✓	✓	✓
	Granular	Use of highly granular price signals that reflect the value of marginal generation/consumption of real/reactive power in real-time, e.g. Locational Marginal Price	✓	✓	✓	✓	✓
Technical Standards	Inverter Standards	Changes to require DER inverter capabilities and settings at time of installation, including smart inverter capabilities, e.g. Volt-Var, Volt-Watt and Frequency-Watt		✓	✓		✓
	Remote Inverter Configuration	Remotely configurable inverter capabilities, for managing voltage, frequency and other limitations by the network or service provider		✓	✓		✓
	Static Limitations	Use of rating, rate-of-change or output limitations to ration available hosting capacity based on the worst-case scenario	✓	✓	✓		✓
	Dynamic Limitations	Dynamic setting of rating, rate-of-change or output limitations to make additional hosting capacity available as conditions warrant	✓	✓	✓		✓
Reconfiguration	Change Taps	Manual changes in transformer tap voltages to keep voltage profiles within limits		✓			✓
	Change Topology	Changes to MV and LV network topology to manage voltage and under-frequency load shedding issues	✓	✓	✓	✓	
	Change UFLS	Changes to relay settings to maintain required load shedding and to avoid dropping circuits with reverse flow					
	Change Protection	Changes to protection settings and schemes to resolve issues related to reverse flow			✓		✓
	Balance Phases	Manual changes in the allocation of single-phase connections to the three-phase system to maintain balance within standard	✓	✓			✓
New Methods	Third Party Data	Customer side automation technologies that respond to market and network signal to improve efficiency and reliability of customer energy usage	✓	✓			✓
	Better Forecasts	Improved analytical models to reduce or eliminate inverter related forecasting risk	✓	✓			✓
New Assets	LV Metering	Installation of monitoring and control systems to monitor the LV network	✓	✓			✓
	Voltage Regulators	Installation of transformer or line-drop voltage regulators to manage over or under-voltage conditions or to increase hosting capacity		✓			✓
	Larger Transformer and / or Conductor	Installation of larger transformers and/or conductors	✓	✓	✓		✓
	On Load Tap Changer	Installation of on load tap changers to enable real-time response to changing network conditions		✓			✓
	Harmonic Filters	Installation of harmonic filters					
	STATCOMs	Installation of STATCOMs		✓			✓
	Network Storage	Installation of battery storage as a network asset	✓	✓	✓	✓	✓

Source: Energeia; Note: P = Thermal, V = Voltage, P = Protection and S/R = Safety/Reliability, D = dSim

The set of solutions available as well as the associated costs are changing rapidly, with the presentation of new solution sets. Energeia has provided a range of currently available solutions that address remediation of the key issues identified.

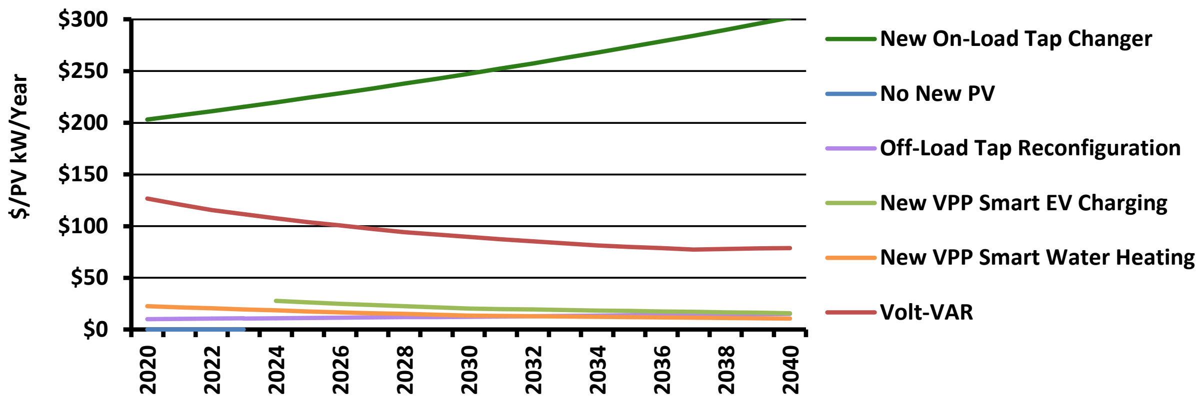
Marginal Pricing

dSim develops marginal costing for each option for each asset and year, based on assumed solution costs[87] and constraint impacts.

Solution costs, regardless of whether they are capital or operational expenditure, are annuitized to enable a fair comparison. This also enables assets with different lifetimes to be compared on relatively equal terms[88].

Figure 37 illustrates marginal costing for a selection of the above voltage constraint solution options over time. New on-load tap changer costs are the highest and rising over time, while off-load tap reconfiguration is the lowest, but rising over time.

Figure 37 – Illustration of Solution Marginal Cost Over Time



Source: Energeia modelling

dSim then selects the least cost option for addressing the constraint and records the resulting network capex and opex for a network solution, or for a DER program, if a DER solution is found to be the least-cost solution.

dSim calculates the least cost solution for each constraint where data for each asset is available, and processing times are acceptable. Where processing times are unacceptable, e.g. where there are more than a couple thousand HV assets, i.e. LV transformers, a sampling based approach is adopted for the asset class, and the resulting least cost solution outcomes are scaled based on the size of the asset segment.

Key Outputs

The key outputs of this step are the adopted solution, its impact on either the asset's limit or the constraint profile, and its costs, at the asset and customer segment level.

D.3. Inputs and Assumptions

This section details the key inputs and assumptions used by Energeia's dSim platform for assets, load and solutions, which have not already been described above.

[87] Solution pricing and solution impact assumptions are reported later in this section.

[88] A more accurate approach would be to include real-option value, which would increase the value of shorter lifetime solutions.

D.3.1. HV/LV Assets

dSim configuration depends on the application. It is either configured with data from all assets being considered, or if that is not computationally-feasible, a segmented sample data approach is developed based on a provided asset population.

Population Statistics

Table 31 displays the key asset population assumptions used for Australian utilities unless more accurate data is available on a project by project basis. As this data is not published in the public domain in Australia, more accurate data is typically limited to projects with utilities.

Table 31 – Default Population Statistics

		NSW			QLD		VIC					SA	WA		TAS	ACT	NT
		Ausgrid	Essential	Endeavour	Energex	Ergon Energy	Citipower	Jemena	Powercor	SP AusNet	United Energy	ETSA Utilities	Horizon Power	Western Power	Aurora Energy	Actew/AGL	Power and Water
HV Network																	
CBD	Total kms	139	-	-	161	-	173	-	-	-	-	297	-	136	57	-	50
Urban	Total kms	10,610	1,884	6,742	7,747	2,401	1,629	2,028	2,279	1,987	4,211	2,713	-	3,891	928	1,408	612
Short Rural	Total kms	16,863	50,077	13,005	16,009	38,803	-	542	9,559	10,379	1,394	24,600	-	7,461	5,305	576	2,299
Long Rural	Total kms	1,632	81,995	-	-	80,026	-	-	47,333	22,275	-	-	-	2,494	9,402	-	784
CBD	% OH	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Urban	% OH	45%	49%	46%	54%	66%	50%	73%	79%	82%	67%	49%	0%	33%	52%	45%	49%
Short Rural	% OH	96%	96%	96%	92%	97%	0%	94%	94%	94%	94%	94%	0%	71%	79%	96%	76%
Long Rural	% OH	99%	99%	0%	0%	100%	0%	0%	99%	99%	0%	0%	0%	78%	99%	0%	99%
CBD	Total Feeders	56	-	-	67	-	75	-	-	-	-	120	-	48	23	-	20
Urban	Total Feeders	1,733	306	1,088	1,314	399	259	167	167	138	393	450	-	472	126	230	97
Short Rural	Total Feeders	293	907	226	316	712	-	7	124	134	18	450	-	171	95	10	41
Long Rural	Total Feeders	4	238	-	-	151	-	-	102	48	-	-	-	79	24	-	2
CBD	Avg kW rating (firm)	6,534	-	-	6,710	-	6,098	-	-	-	-	6,534	-	5,650	6,534	-	6,534
Urban	Avg kW rating (firm)	2,965	3,256	3,036	3,176	4,432	3,141	5,164	5,684	5,944	4,670	3,051	-	5,100	3,658	2,965	3,177
Short Rural	Avg kW rating (firm)	4,898	5,215	4,907	4,981	3,599	-	9,891	9,811	9,891	9,891	4,933	-	20,674	9,003	4,898	9,787
Long Rural	Avg kW rating (firm)	4,382	4,787	-	-	4,292	-	-	12,002	12,002	-	-	-	3,446	8,841	-	8,841
CBD	Avg Utilisation	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%
Urban	Avg Utilisation	58%	58%	58%	58%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
Short Rural	Avg Utilisation	51%	51%	51%	51%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
Long Rural	Avg Utilisation	40%	40%	40%	40%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%
CBD	Avg Customers per Feeder	148	-	-	150	-	138	-	-	-	-	148	-	139	148	-	148
Urban	Avg Customers per Feeder	970	639	995	869	702	969	1,866	2,097	2,212	1,647	929	-	925	1,090	970	962
Short Rural	Avg Customers per Feeder	772	563	772	1,047	640	-	2,685	2,656	2,685	2,685	887	-	3,218	1,882	772	2,073
Long Rural	Avg Customers per Feeder	1,082	559	-	-	565	-	-	2,406	2,406	-	-	-	45	1,374	-	1,374
Feeder Losses	Avg %	1.8%	2.8%	1.2%	0.8%	2.9%	0.3%	1.4%	2.6%	2.3%	0.7%	2.0%	1.7%	1.7%	1.1%	2.0%	1.7%
LV Network																	
Total DCs	Total	30,551	135,757	30,398	46,792	92,300	4,581	5,260	81,553	57,000	11,500	51,280	-	53,046	31,287	4,670	3,965
CBD	Avg DC kW	3,568	-	-	3,568	-	3,568	-	-	-	-	3,568	-	3,568	3,568	-	3,568
Urban	Avg DC kW	830	300	830	830	364	830	830	830	830	830	830	-	830	830	830	830
Short Rural	Avg DC kW	190	50	190	190	86	-	190	190	190	190	190	-	190	190	190	190
Long Rural	Avg DC kW	127	25	-	-	35	-	-	127	127	-	-	-	127	127	-	127
CBD	DC Utilisation	44%	44%	44%	44%	44%	44%	44%	44%	44%	44%	44%	44%	44%	44%	44%	44%
Urban	DC Utilisation	39%	39%	39%	39%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
Short Rural	DC Utilisation	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%
Long Rural	DC Utilisation	43%	43%	43%	43%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
CBD	Avg Customers per DC	12	-	-	12	-	12	-	-	-	-	12	-	17	12	-	12
Urban	Avg Customers per DC	60	61	60	49	37	56	56	56	56	56	56	-	44	54	60	55
Short Rural	Avg Customers per DC	8	9	8	12	7	-	15	15	15	15	10	-	41	18	8	19
Long Rural	Avg Customers per DC	3	2	-	-	2	-	-	4	4	-	-	-	1	3	-	3
LV Losses	Avg %	2.0%	0.5%	3.6%	1.5%	3.4%	2.2%	1.7%	2.5%	2.6%	2.1%	2.6%	2.3%	2.3%	3.3%	2.3%	2.3%

Empirical
Estimated from Ausgrid data
State Feeder Sample
Average Feeder Sample
Energeia/SME Estimate
State/AUS average
Changed after Industry Validation
Issues with Data raised by DNSP

Source: DNSPs, Energeia

The above population statistics are used to scale the sampled estimated average asset load profiles.

D.3.2. Customers and Load

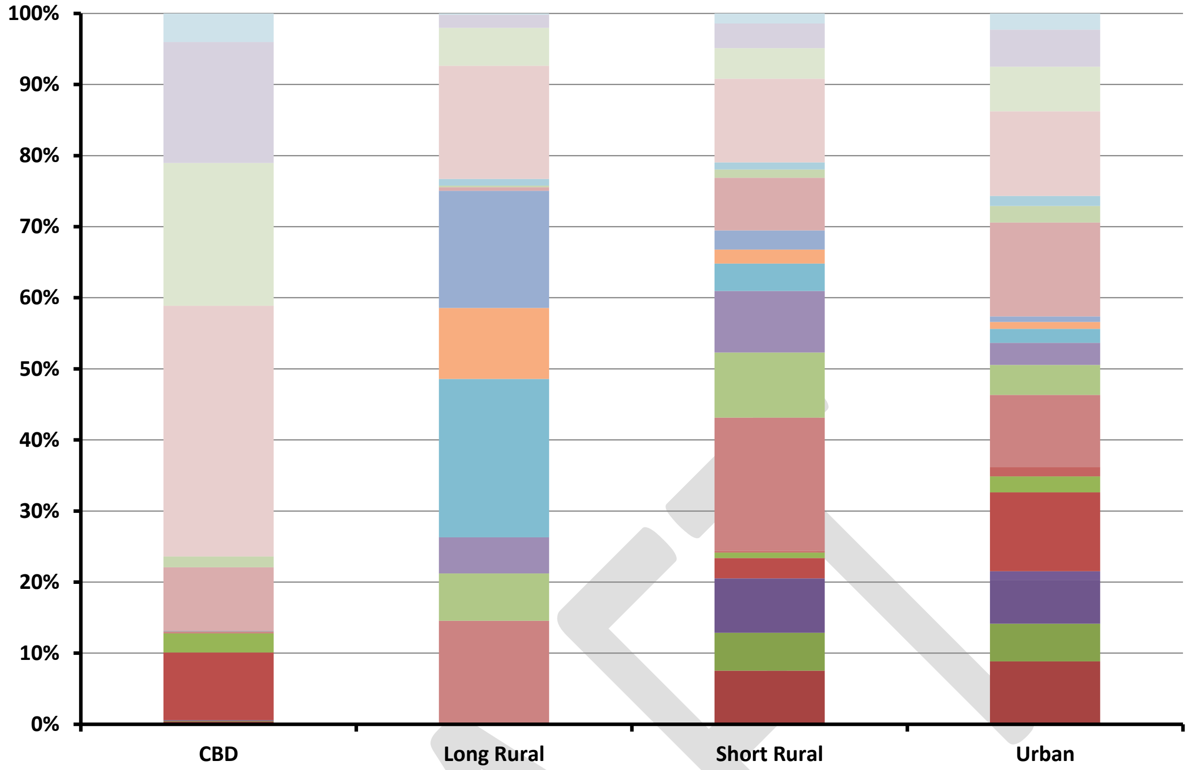
Customer Segments

dSim and uSim exchange information regarding customer and DER profiles, DER adoption and network solution cost accumulation. dSim therefore uses the same customer segments as uSim, please see section X for more information regarding customer segmentation.

Load Mix

dSim is designed to map customer segments directly to HV/LV assets. Where actual data is not available, Energeia uses public domain data such as that provided by SGSC project, which is reported in Figure 38 by HV feeder type.

Figure 38 – SGSC Customer Segment to Prototypical Feeder Mapping



Source: Energeia

Where more accurate information is not available, Energeia assumes each LV asset has the same load mix as the HV asset it is connected to, scaled based on the asset population statistics reported above.

D.3.3. Solutions

Network Solution Costs

The table below reports on the assumed network solution costs, which were gathered and validated as part of the Stage 1 project.

Table 32 – Key Solution Cost Estimates by Category

Category	Solution		Capex	Opex	Units
Consumer	Water Heater Management – Retrofit Control		$150	$15	kW
	EV Management – Retrofit Control		$150	$15	kW
	Storage Management – Install New Controllable		$1k	$15	kW
Pricing	Coarse (e.g. ToU pricing), excl. smart meter		Negligible	$0	Customer
Signals	Granular (e.g. real-time pricing), excl. smart meter		$12m	$250k	DNSP
Technical Standards	Inverter Standards		Negligible	$0	DNSP
	Remote Inverter Configuration		Negligible	$0	Country
	Static Limitations		Negligible	$0	DSNP
	Dynamic Limitations		$6m	$250k	DNSP
Reconfiguration	Change Taps		Negligible	$1-2k	Trip
	Change Topology		$200k-$660k	$0	Feeder
	Change UFLS		$100k-$150k	$0	Feeder
	Change Protection		$1k	$0	Feeder
	Balance Phases		Negligible	$1.5-$2k	Trip
New Methods	Third Party Data	New Install	$500	$5	Customer
		Previous Install	Negligible	$5	Customer
	Better Long – Term Forecasts		$8m	$250k	DSNP
New Assets	LV Metering		$3.5k	$30	Transformer
	Voltage Regulators		$k	2.5% of capex	Regulator
	Larger Assets		$100k-$400k	2.5% of capex	Asset
	On Load Tap Changer	Vault	$120k	$7k	Transformer
		Pole-Mounted	$60k	$7k	Transformer
	Harmonic Filters		$500k	$0	Substation
	Statcom (Single-Phase)		$5-8k	2.5% of capex	LV Phase
	Network Storage		$1.2k	2.5% of capex	kWh

Source: Energeia; Notes: 1. Changes deemed to be part of existing operations excluded, e.g. introduction of new price structures. 2. In-depth consultation with DNSPs would be required on to better understand costs on a jurisdictional basis. 3. Solutions are not mutually exclusive; the application of certain solutions may be limited by the absence of others i.e. electric water heaters must be in place to control their load.

DER Solution Costs

dSim and uSim exchange information regarding DER costs. dSim therefore uses the same DER costs uSim, please see Section C.3.1 for more information regarding customer segmentation.

VPP Margin

dSim assumes VPP operating costs are a percentage (margin) of the value of the revenues they are serving, e.g. if the margin is 10%, and bill savings, NEM payments and network payments for a battery are $1,000/year, then the VPP provider earns a revenue of $1,000 / 90% or $1,111. This approach consistent with electricity retailing, which offers a similar service. This price is added on to the consumer cost of capital and the cost of DER.

The VPP margin can vary by scenario but is assumed to be a flat 10% by default.

DER Value Stream Discount Factors

dSim discounts the customer and NEM value streams used to estimate the net cost for new DER VPP solutions to reflect the investment risks involved and the maturity of the industry over time.

The DER value stream discount factor can vary by year, scenario and DER type, but makes the following assumptions by default:

- Expected customer value streams are discounted by 7.5% per annum
- Expected NEM value streams are discounted by 15% per annum

VPP Achievable Potential

dSim develops estimates of DER program achievable potential based on uSim uptake probability estimates, which are a function of DER economics and observed customer uptake behaviour.

The achievable potential function calculates:

- the technical potential for all customers connected to the asset that do not already have DER,
- the economics for a given DER including the full value stack, and
- the capacity of all technical potential with a positive net present value result, up to the assumed behavioural and supply side capacity constraint.

The customer behavioural and supply side constraint can vary by asset type, DNSP, year, scenario and DER, but the following assumptions are assumed by default:

- Achievable potential starts at 10% of economic potential, rising to 80% over 10 years

Appendix E – evSim

Energeia's Electric Vehicle (EV) uptake and charging impact forecasting methodology is outlined below, together with the key model inputs and drivers.

E.1. Overview

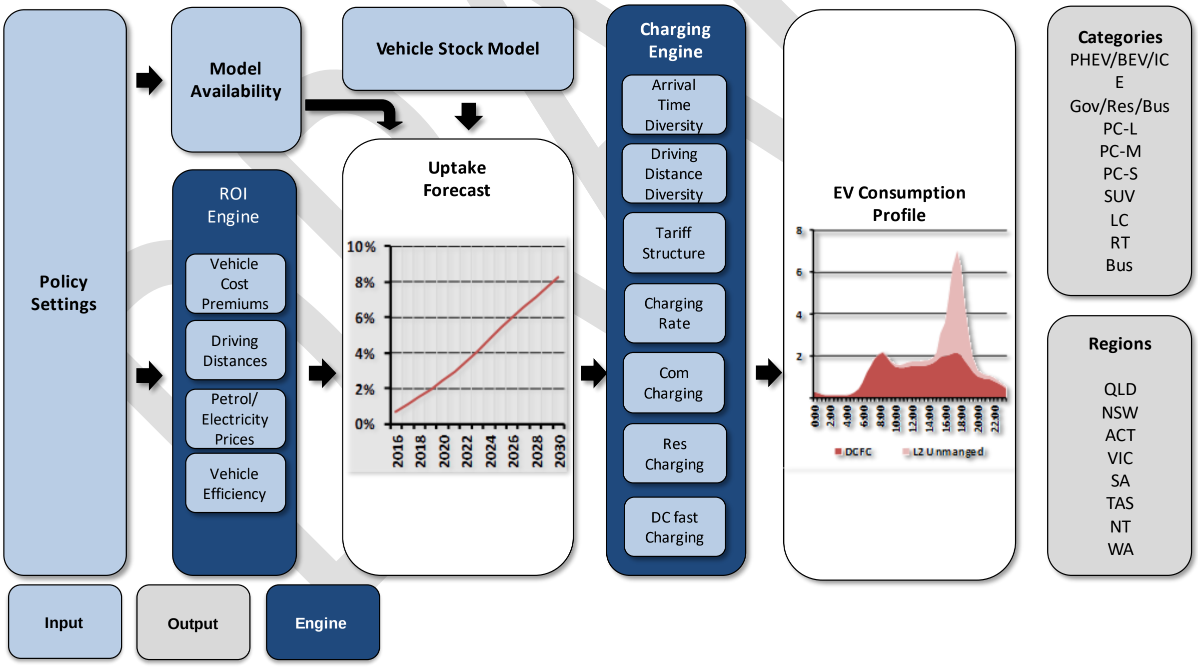
Energeia has developed, configured, and operated its EV simulation platform, evSim, to model the influence of various market and policy settings to influence electric vehicle uptake in Australia on a scenario basis. The developed modelling platform:

- is based on two-stage structure, with vehicle uptake forecast first, driven by the first year return-on-investment of the vehicle buying decision, and with charging impacts second, driven by driving patterns, tariff structures and load control methods.
- was developed progressively over the course of our forecasting work with AEMO, various Australian government bodies, and various DNSPs and retailers
- reflects enhancements (vehicle lifetimes, residential uptake segmentation, additional plug-in hybrid vehicle classes and technology uptake allocation) delivered in this round of modelling

E.1.1. Structure of the Model

evSim is a regression-based model that forecasts the technology composition of the vehicle sales market over the modelling period and determines electric vehicle charging impacts on the broader electricity system. A summary of the model process and structure is supplied Figure 39.

Figure 39 – Overview of EV Simulation Platform



Source: Energeia

evSim operates across a range of different functions, through a two-stage process first forecasting electric vehicle uptake then the charging impacts. The key modules include:

- **Uptake Module** – Comprised of the Return on Investment Engine (Calculates return on investment for purchasing a battery electric vehicle (BEV) or plug in hybrid (PHEV) for each of the vehicle categories considered) and a vehicle stock engine that models fleet growth and replacement.

- **Vehicle Charging Engine –** The charging behaviour and annual consumption of the forecast electric vehicle is calculated using both a managed and unmanaged case to determine the effect on peak demand

The functions and sub-functions of each of the above modules of the simulation platform are summarised below, including a high level of overview of interactions between different parts of the model, limitations of assumptions and their impact on modelling.

E.1.2. Methodology Selection

Over the course of more than 10 EV-related projects for major utilities, governments, and EV market players, Energeia has developed a suite of sophisticated tools and methodologies for answering the key questions facing our clients.

- **EV Uptake Modelling Tools –** Energeia's third-generation EV uptake model reflects more than $500K in investment. It is two generations more advanced than the typical Bass Diffusion models used by our competitors. Its advanced functionality is designed to deliver a much more accurate forecast with more driver and vehicle type granularity and scenario flexibility.
- **EV Charging Impact Modelling Tools –** Based on 7 years of specialised research and analysis of the PEV and charging market and technology evolution, Energeia has developed its own proprietary model of public and private charging. It reflects our view that PEV batteries are likely to reach 100 kWh or more over the next 3-5 years to achieve parity with gasoline-powered vehicles, and that public charges will be 350kW or more so that recharging will also reach parity with gas stations. It also reflects our view that most PEV drivers will charge at home, and the market for public charging will follow the gas station model but be smaller due to the impact of home charging.

E.1.3. History of Recent Model Development

Energeia's evSim has been progressively developed over the past 4 years, in that time three public forecasts have been released.

- **AEMO 2016 –** This model was primarily focussed on assessing simple policy impacts such as fuel efficiency standards, introduction of priority lanes and a carbon price[89]. The charging of electric vehicles was only segmented by tariff structures (flat and controlled load) for residential customers with DC fast charging (DCFC) not being directly modelled.
- **AEMO 2017 –** The next iteration of the model introduced the DCFC segment and further developed the vehicle charging behaviour engine[90]. Level 2 charging was controlled by an algorithm optimising the fleet of EV's to charge outside of system peak periods.
- **CEFC and ARENA 2018 –** Additional policy inputs and drivers were implemented to the uptake model in 2018[91] which allowed for greater flexibility in determining technology outcomes given the high level of influence policy has on emerging technologies. These improvements included financial incentives, the possibility of additional negotiated models for sale in Australia, consideration of overseas importation policy and the segmentation impacts of charging infrastructure rollout.

E.1.4. Current Application

This iteration of the model had the following enhancements developed and integrated:

[89] AEMO (2016), 'Electric Vehicle Insights'

[90] AEMO (2017), 'Electric Vehicle Insights'

[91] CEFC (2018), 'Australian Electric Vehicle Market Study'

- **Changing Vehicle Lifetimes –** Electric vehicle total effective lifetimes are highly uncertain currently and were modified to increase to reach parity with ICE vehicles as technology improvements are developed as previous iterations of the model had tied BEV lifetime the vehicles battery warranty (10 years).
- **Residential Uptake Segmentation** – In the early years of the modelling period the potential annual sales market for uptake of BEV's is limited by residential customer access to level 2 charging at home, those without access can uptake as public charging networks are rolled out nationwide.
- **Plug in hybrid additional vehicle classes** – As more plug in hybrid models have become available, they have been added to each vehicle class for uptake consideration.
- **Alternative Vehicle Technology Uptake Allocation** – Vehicle classes with multiple technology options for uptake (BEV and PHEV) are weighted by the magnitude of their uptake function result. This caps the number of alternative vehicle purchases in each year to ensure technology types are not overrepresented.

E.2. Model Process and Modules

The EV modelling process is a two stage process, where EV uptake is forecast first, and then charging impacts are developed.

E.2.1. Process

Energeia's EV forecasting model is comprised of two parts, namely EV uptake and EV charging:

- **Uptake Module** – The EV uptake component drives the forecasts of EV uptake as a percentage of annual vehicle sales for each category of vehicle type. This is based on vehicle model availability and the vehicle owner's return on investment.
- **Vehicle Charging Engine** – The EV charging component then applies a charging regime to each vehicle adopted based on the arrival and departure time of the vehicle at the point of charge, the number of kilometres travelled and any incentives or restrictions of the prevailing tariff.

E.2.2. Modules

Each of the two modules, the uptake forecasting and system size segmentation modules, are detailed in the following sections together with the applied post-model adjustments.

Uptake Module

The uptake module considers eight categories of vehicle types with their own specific characteristics which drive both uptake and charging, including purchase premium, energy consumption per km[92], and battery size. EV uptake is determined by a two-parameter function that describes vehicle uptake over time based on:

- **Return on Investment –** the first-year return to the vehicle owner investing in an EV in terms of reduced operational costs (fuel savings) on the premium paid compared to a conventional ICE vehicle.
- **Model Availability** – the percentage of models within a given vehicle class available in EV form.

This functional form accordingly considers the supply side constraints (lack of model availability) as well as demand-side drivers (reduced operational costs) in the vehicles owner's decision to adopt. The function is derived from analysis of the diesel vehicle and hybrid electric vehicle markets in Australia whereby uptake can be explained by a combination of both these parameters.

The forecast uptake of EVs (both BEV and PHEV) is then fed into your vehicle stock model, which accounts for the turnover of the existing fleet and new vehicle purchases due to population growth

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[92] Fuel costs and average daily driving are based on state level factors.

Uptake Function

EV uptake is determined by a two-parameter function that describes vehicle uptake over time based on:

1. EV premium payback more than two years:

$$EV\ Uptake_t = Total\ New\ Vehicle\ Sales_t * (a_t \times ROI_t + b_t \times Model\ Availability_t)$$

2. EV premium payback less than two years (tipping point):

$$EV\ Uptake_t = Total\ New\ Vehicle\ Sales_t * \ MIN(Upper\ EV\ Limit, Model\ Availability_t)$$

Where:

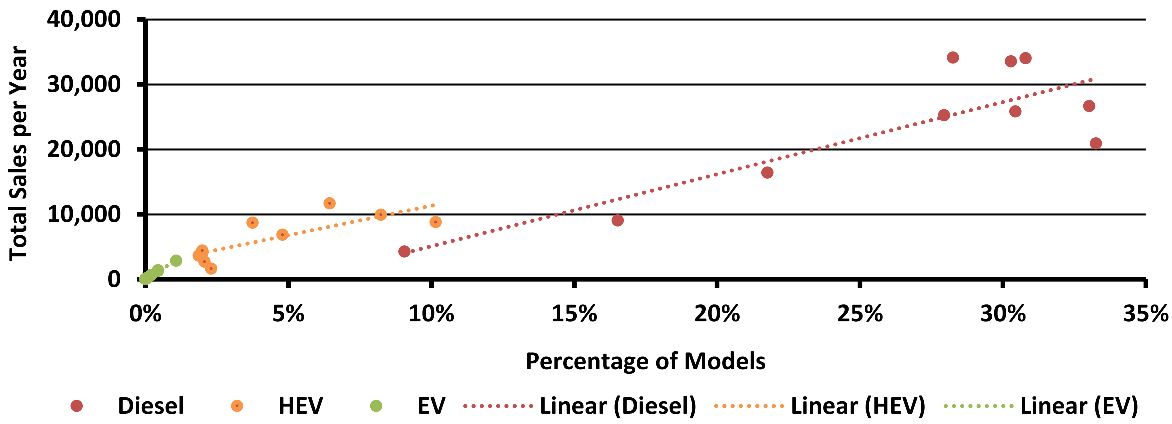
- $Total\ New\ Vehicle\ Sales_t$ = Total new vehicle sales within a given vehicle class in year t
- $Model\ Availability_t$ = Percentage of models within a given vehicle class available in EV form in year t. This inclusion of this factor reflects that, for the mass market, a primary driver of vehicle purchase is the availability of that model in EV form. This factor effectively places an upper bound on EV adoption, which is determined by a scenario based parameter.
- $Upper\ EV\ Limit$ = Upper model availability limit for all vehicles within a given vehicles class
- ROI_t = The first-year return on investment for the vehicle owner investing in an EV in year t in terms of reduced operational costs (fuel) and premium paid compared to the equivalent ICE vehicle
- a_t = Model coefficient derived from historical data of diesel and hybrid electric vehicle uptake for observed ROIs
- b_t = Model coefficient derived from historical data of diesel and hybrid electric vehicle uptake for observed model availability

EV uptake depends on the functional form assumed for model availability and change in ROI over time. It should be noted that Energeia's ROI calculation does not consider step changes in depreciation or salvage value due to increasing EV penetration.

Return on Investment (ROI)

The historical relationship between vehicle uptake and model availability in the Australia market for alternative technologies is shown in Figure 40.

Figure 40 – Relationship between EV Uptake and Model Availability



Source: Energeia

Each year for each vehicle category the return on investment of purchasing an alternative fuel vehicle is calculated (BEV or PHEV):

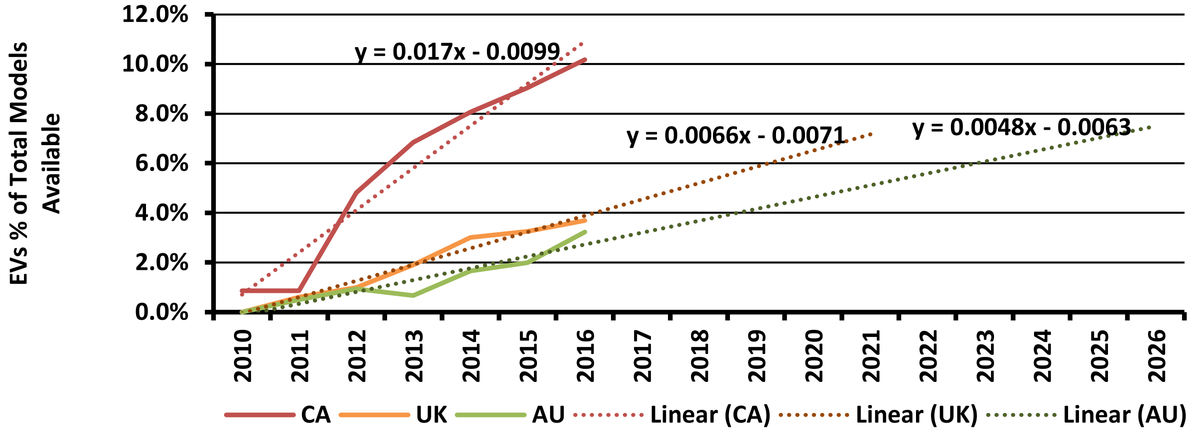
- This considers the annual average distance travelled by each vehicle category and calculates the total fuel consumption (electric or petrol) of the vehicle.
- The annual cost of the vehicle is then calculated and the return on investment for each vehicle type is reported.

Model Availability

Model availability determines the capability for a decision to purchase a vehicle to be a BEV. For BEV and PHEV uptake to be considered in a purchasing decision there must exist an equivalent model to an ICE in that vehicle category. The model availability forecast in the model captures the rate in which new vehicles are developed by OEMs and introduced to the market as competitors to existing ICE models.

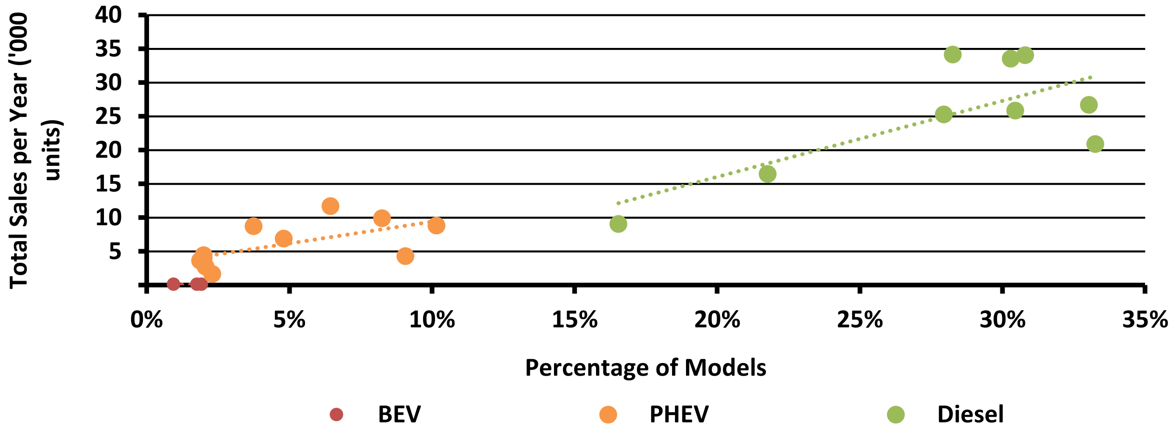
Energeia has developed its assumed rate of EV model availability based on an empirical analysis of model availability relative to the level of jurisdictional incentives. Figure B3 displays the results of our analysis of the UK, California and Australian markets. It shows that California, the market with the highest EV incentive at around $10,000 USD including Federal incentives, sees the fastest rate of new EV model introductions. The UK market, which offers around $5,000 USD in incentives, is higher than virtually incentive-free Australia.

Figure 41 – EV Model Availability by Year by Key Market



Source: Energeia

Figure 42 – Relationship between EV Uptake and Model Availability



Source: VFACTS, Energeia

Vehicle Stock Engine

Each year the annual vehicle sales are determined through the model's vehicle stock engine, which accounts for the turnover of the existing fleet and new vehicle purchases due to population growth. The mechanics of the engine is detailed is the equations below:

$$ICE_t = \sum^{i,j} \Big[ICE_{i,j(t-1)} + (Vehicle\ Sales_{i,j(t)} - EV\ Uptake_{i,j(t)}) - \text{if}\Big(t \le AvgLifetime\ , \frac{ICE_{i,j(0)}}{AvgLifetime}, 0\Big)\Big]$$

$$EV_t = \sum^{i,j} \Big[EV_{i,j(t-1)} + EV\ Uptake_{i,j(t)} - \text{if}\Big(t \le AvgLifetime\ , \frac{EV_{i,j(0)}}{AvgLifetime}, 0\Big)\Big]$$

Where:

- ICE_t = Total stock of ICE vehicles in year t
- EV_t = Total stock of EV vehicles in year t
- ICE_0 = Opening stock of ICE vehicles
- $EV0$ = Opening stock of EV vehicles
- $ICE_{i,j(t-1)}$ = Stock of ICE vehicles in market i in class j in year t-1
- $EV_{i,j(t-1)}$ = Stock of EV vehicles in market i in class j in year t-1
- $EV\ Uptake_{i,j(t)}$ = % EV sales in market i in class j in year t
- $Vehicle\ Sales_{i,j(t)}$ = Vehicle sales in market i in class j in year t
- $Average\ Lifetime$ = Average vehicle lifetime

Vehicle Charging Engine

Energeia has developed a detailed, data-driven approach to forecasting the likely impact of EV charging on electricity demand, energy resources, and network assets. This approach is driven by the assumed rate structure and level, historical EV adoption patterns, driving patterns, charging infrastructure availability, and the availability of charging management systems.

Energeia's EV demand model is grounded in actual travel statistics, which drive when EVs are likely to be plugged in (arrival times), and the total energy they need to replenish (distance), and when any smart charging will need to have been completed by (departure time).

The EV charging module then applies a charging regime to each vehicle adopted based on its:

- charging type,
- arrival and departure time for home and workplace charging or transportation profile for DCFC,
- the number of kilometres travelled and
- grid load to optimise workplace and home charging.

The EV charging profile is determined by aggregating the unique charging profile of each individual electric vehicle adopted. The individual profiles are assigned based on:

- Whether the vehicle is assigned as L2 (9.6kW) home charging, L2 commercial charging (charges at work or depot location), or DCFC which is defined as the EV equivalent of a gas station (Charger rating up to 1MW station with 5 min charge time at the end of the modelling period)
- DCFC chargers enable drivers without a garage to own an EV, encourage EV charging during daytime hours of excess supply from solar PV, and extend EV range to enable EV use for any trip type

- The daily travel distance for both weekday and weekend travel (drawn from a database of regionally specific diversified travel distances[93]), which determines the amount of charge to be supplied by day type
- An arrival time for both weekday and weekend travel (drawn from a database of diversified times specific to either home charging or commercial charging[94]) which dictates when charging starts, in the absence of any other tariff restrictions
- A departure time for both weekday and weekend travel (drawn from a database of diversified times specific to either home charging or commercial charging) which dictates when charging must cease in the absence of any other tariff restrictions
- For home and workplace charging, the optimal EV weekday and weekend demand profile for a given state to minimise whole-of-system cost
- For DFCF charging, the weekday and weekend DCFC demand profile is based on the weekday and weekend transportation demand profile, no demand management of DCFC load is assumed
- No vehicle-to-grid exporting of electricity from the vehicle to the grid is assumed

E.3. Inputs and Drivers

The inputs of evSim can be split into two categories:

- **Scenario Drivers –** These inputs are configurable by scenario and used to test macroeconomic outlooks, technology assumptions and policy settings.
- **Common Assumptions –** These inputs are typically static between scenarios and underpin the operation of the model and sub-models

E.3.1. Scenario Drivers and Inputs

evSim can be configured with a number of scenario drivers to test different policy and industry settings on electric vehicle uptake. These drivers impact on the vehicle fleet size, the economic, technical and operational characteristics of the available vehicles by technology type, the financial incentives available to non-ICE vehicles, the availability of non-ICE models and the relative operating costs by technology type.

The majority of the scenario inputs are focused on the uptake module, as the only scenario available the vehicle charging engine is between managed and unmanaged charging.

Uptake Module

Energeia's uptake module is driven by a range of different scenario inputs that:

- Vehicle Fleet (population growth)
- Vehicle Characteristics (convergence of ICE and BEV/PHEV lifetimes over time; BEV/PHEV distance and price parity; battery cost declines)
- Financial Incentives (policy and industry incentive levels and starting years)
- Model Availability (additional models, importation policy)
- Operation Costs (refuelling and charging costs

Vehicle Fleet

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[93] ABS Survey of Motor Vehicle Use (2016)

[94] Queensland Household Travel Survey (2017)

Each year, each vehicle class in their respective market is assumed to grow at a constant rate per capita based on input population growth forecasts. Scenarios can be configured to test multiple population growth sensitivities which drive vehicle sales growth over the modelling period. This will determine the max market for vehicle sales in each year and the final vehicle fleet numbers for Australia.

Average Lifetime

Average vehicle lifetime of all ICE vehicles is assumed to be 18 years based on ABS data[95], while the average vehicle lifetime of all EVs are assumed to be 10 years in 2019, extending to ICE equivalence at different trajectories based on the scenario configuration.

The EV uptake module forecasts EV uptake for each category of vehicle using vehicle model availability and the vehicle owner's return on investment as inputs. The forecast is allocated on a pro-rata basis to each state

Vehicle Capital Cost Curves

The vehicle purchase price is broken down into two components in the model as shown in Table 33. These costs determine the overall purchase premium of the vehicle which is used to calculate the annual return on investment of ownership.

Table 33 – Capital Cost

Cost Component	ICE	BEV	PHEV
Balance of System	✓	✓	✓
Battery		✓	✓

Source: Energeia Modelling

Electric vehicle premiums for each vehicle class are calculated based on currently available vehicles and their ICE equivalent. The premium is calculated from the balance of system of a vehicle, which encompasses all the components of the vehicle other than the EV batteries.

Table 34 – Estimated Current EV Premiums

Vehicle Class	Vehicle Technology	EV Premium	EV Premium (% of Total EV Cost)
Passenger Car Small	BEV	$ 21,237	31%
Passenger Car Medium	BEV	$ 22,886	57%
Passenger Car Large	BEV	$ 28,415	21%
Passenger Car Medium	PHEV	$ 6,100	8%
Passenger Car Large	PHEV	$ 9,371	3%
Sport Utility Vehicle Medium	BEV	$ 21,996	37%
Sport Utility Vehicle Large	BEV	$ 21,250	14%
Sport Utility Vehicle Medium	PHEV	$ 14,282	37%
Sport Utility Vehicle Large	PHEV	$ 30,374	20%
Light Commercial	BEV	$ 3,619	8%
Rigid Truck	BEV	$ 19,353	18%
Bus	BEV	$ 339,622	40%

Source: Energeia Research, OEM Websites

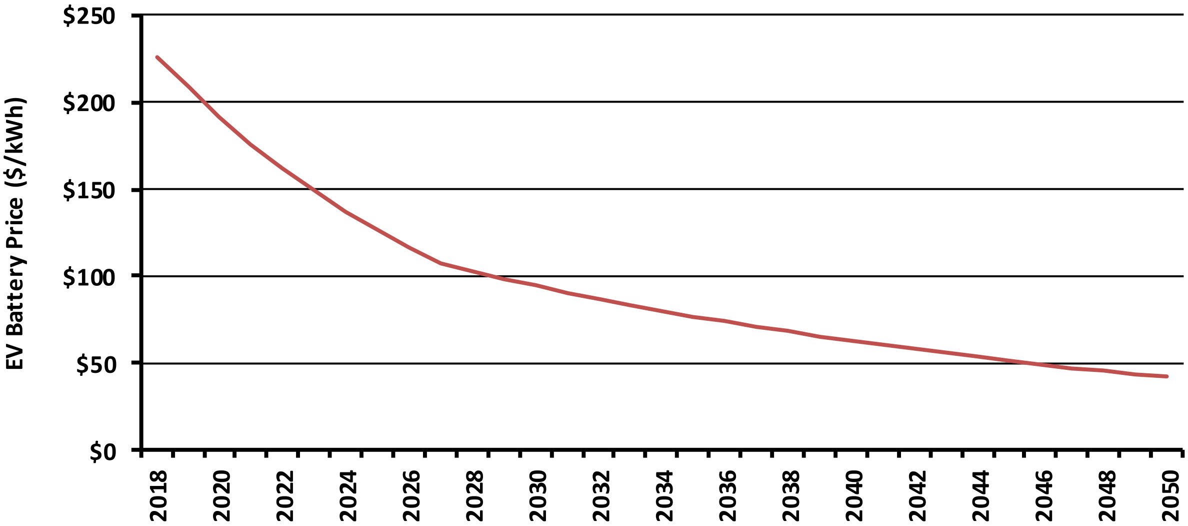
Battery Price

[95] ABS 9208.0 - Survey of Motor Vehicle Use, Australia, 12 months ended 30 June 2016

Energeia's short and medium-term battery price outlook is a function of expected improvements in lithium-based battery manufacturing and economies of scale, while the long-term battery price outlook is based on next generation storage technologies that will achieve higher energy densities with significantly less raw material.

The model assumes a decline in lithium battery prices over the modelling period leading to the battery cost projection shown in Figure 43. This forecast is based on a consensus average among leading international lithium battery price forecasters. This setting is configurable by scenario and the cost is applied to all vehicle sizes.

Figure 43 – EV Battery Cost Forecast



Source: Energeia Analysis, Mckinsey (2017) Electrifying Insights, Bloomberg New Energy Finance (2016), US DOE (2017), Tesla (2017)[96]

Incentives

Proposed government and industry incentives can be applied to the model to influence the economics of purchasing an electric vehicle through both direct financial incentives and indirect incentives.

Model Availability

The model enables the procurement of additional models to be available for sale in selected years, this allows for government or industry intervention to increase model availability which will increase the resultant annual uptake of electric vehicles in early years of the model. An assumed trajectory of model availability in Australia is a key input for each scenario.

Operating Costs

Maintenance costs are not implemented in Energeia's EV model due to their minimal impact on a customer's purchase decision in part as a result of the warranty of new vehicle purchases.

Petrol and electricity costs can be input to the model for each scenario and region being modelled. Three fuel price scenarios can be configured at a time allowing for testing of a range of sensitivities.

- **Petrol Costs** – Energeia used petrol price forecasts from CEFC's 2018 Australian EV Market Study as shown in Table 35. These were developed using historical relationships between the price of petrol and the oil price, which are then projected using the scenario assumption for oil prices. These do not change by scenario.

[96] Reported Tesla EV battery pack prices on kWh basis

- **Electricity Costs**– Retail electricity prices are an essential input to the model and scenario design. Three different price trajectory scenarios can be configured into the model to influence the annual fuel costs for electric vehicles.

Table 35 – Fuel Price by State

Year	WA	QLD	SA	TAS	ACT/ NSW	VIC
2017	$1.15	$1.15	$1.14	$1.21	$1.15	$1.14
2018	$1.17	$1.17	$1.16	$1.22	$1.17	$1.16
2019	$1.19	$1.18	$1.17	$1.24	$1.18	$1.17
2020	$1.20	$1.20	$1.19	$1.26	$1.20	$1.19
2021	$1.22	$1.21	$1.20	$1.28	$1.22	$1.20
2022	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2023	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2024	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2025	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2026	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2027	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2028	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2029	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2030	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2031	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2032	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2033	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2034	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2035	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2036	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2037	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2038	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2039	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22
2040	$1.24	$1.23	$1.22	$1.29	$1.23	$1.22

Source: CEFC (2018) 'Australian EV Market Study Report'

E.3.2. Common Assumptions

Uptake Model

Vehicle Classes

A selection of the vehicle class described in the ABS survey of Motor Vehicle Use (2016) are modelled separately in with independent sales, stock and uptake forecasts. Passenger vehicles are further segmented into sub-categories to capture the diverse range of vehicle efficiency and price points.

- Passenger Car (PC)
  - Passenger Car Large (PC-L)
  - Passenger Car Medium (PC-M)
  - Passenger Car Small (PC-S)
  - Sport Utility Vehicle Medium (SUV-M)
  - Sport Utility Vehicle Large (SUV-L)
- Light Commercial (LC)
- Rigid Truck (RT)
- Bus (B)

Opening Stock

The opening stock of vehicles by vehicle class is sourced from VFACTS data for the calendar year 2016[97] for EV and ICE vehicles by state. The opening stock feeds into the vehicle stock model at t=0 in the above equations.

Charging Segmentation

The total eligible market for EV uptake in a given year is determined by the availability of charging in the region.

Modelled Technology Types

The model considers three vehicle technology types:

- **Battery Electric Vehicle –** Single electric drive train vehicles using a battery as its fuel store.
- **Plug-in Hybrid Electric Vehicle** – Vehicles containing both an electric and internal combustion drive train, while also having the ability to charge from an electrical outlet (Conventional hybrids or HEVs are excluded from this category).
- **Internal Combustion Vehicles** – Conventional vehicles containing an internal combustion drive train.

Travel Distances

The travel distance dictates energy requirements and therefore has a direct impact on both ICE vehicles and EV annual fuel expenditure. The model adopts an average driving distance in this application to determine annual vehicle costs that vary by state and by vehicle class as summarised in Table 36.

Table 36 – Travel Distance

State	Annual Average Distance Travelled (km/year)	
	Light Passenger	Light Commercial
NSW	12,300	17,100
ACT	12,800	18,200
VIC	13,800	17,700
QLD	13,300	17,100
SA	11,600	16,700
WA	12,400	17,200
TAS	11,600	12,100

Source: ABS Survey of Motor Vehicle Use

EV Range

EV ranges are based on what is currently reported for each vehicle type by OEMs as shown in Table 37. Each year, the vehicle's battery size increases linearly until it reaches the size required for distance parity with an equivalent ICE. The number of years this takes varies by scenario.

[97] Federal Chamber of Automotive Industries (2016), VFACTS

Table 37 – EV Range

Vehicle Class	Vehicle Technology	EV Range Parity Battery Size (kWh)
Passenger Car Small	BEV	82
Passenger Car Medium	BEV	94
Passenger Car Large	BEV	147
Sport Utility Vehicle Medium	BEV	121
Sport Utility Vehicle Large	BEV	137
Light Commercial	BEV	60
Rigid Truck	BEV	160
Bus	BEV	1,136

Source: Energeia Modelling, Vehicle OEM websites

Fuel Efficiency

Fuel efficiency in the model is a key factor in determining energy requirements and fuel costs. The underlying fuel efficiency of ICE vehicles and EVs stay constant in the model as combustion and electric engines are well understood and established technologies.

The assumptions for fuel consumption are summarised in Table 38. These estimates have been developed based on OEM reported efficiency data. These remain constant throughout the modelling period. Future considerations include sensitivities of efficiency improvements in both drive trains.

Table 38 – Fuel Consumption

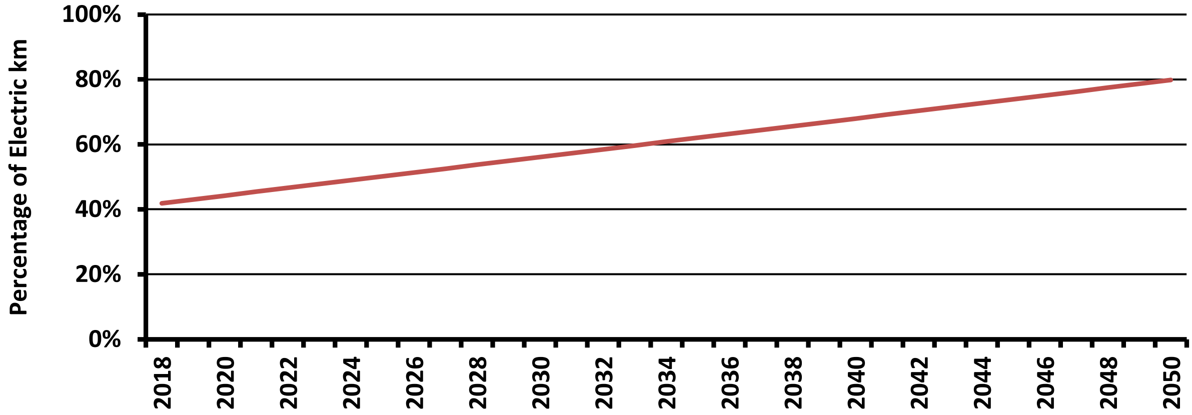
Vehicle Class	2017 Efficiency	
	EV kWh/km	ICE L/km
Passenger Car Small	0.137	0.052
Passenger Car Medium	0.178	0.063
Passenger Car Large	0.181	0.102
Sport Utility Vehicle Medium	0.181	0.064
Sport Utility Vehicle Large	0.181	0.104
Light Commercial	0.155	0.065
Rigid Truck	0.400	0.488
Bus	0.364	0.445

Source: Energeia, OEM websites

PHEV Drive Train Utilisation

Plug in hybrids are assumed to currently utilise their electric drive train a certain proportion of the time, this utilisation is assumed to increase overtime as battery storage capacity of the vehicles increases the forecast period.

Figure 44 – PHEV Percentage of Annual Kilometres Travelled Using Electricity



Source: Energeia analysis, Idaho National Laboratory (2015)

Charging Impacts Module

Charging Segmentation

Charging availability is determined by access to private parking for residential. Customers with direct access to level 2 charging can take up electric vehicles at the start of the modelling period, with those that require DCFC progressively become available to uptake as charging infrastructure is rolled out. Infrastructure roll-out is configurable by scenario setting.

A vehicle can be assigned to either a L2 home charger, a L2 commercial charger or DCFC.

Passenger cars allocated to DCFC reflect the percentage of households in each state with more than one vehicle. Energeia expects these vehicles will use DCFC rather than try and share private parking space. Commercial vehicles are assumed to be charged at their respective depots. Detailed charge type assumptions are shown in Table 39.

Table 39 – Charger Access Segmentation

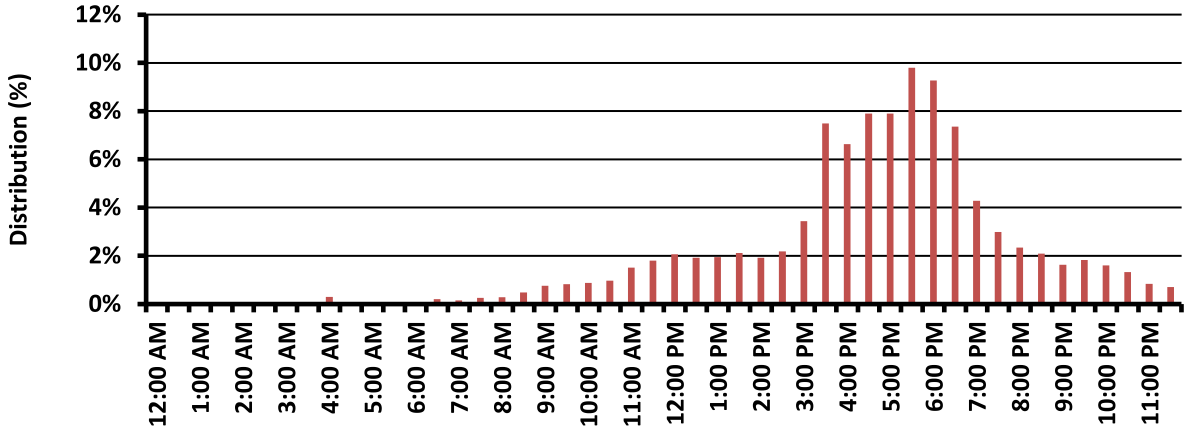
Vehicle Type	Charger Type	NSW	QLD	SA	VIC	WA	TAS	NT
Residential	Destination (Home) Charging	38.7%	38.2%	43.2%	40.0%	37.1%	42.7%	32.8%
	DCFC Public Charging	61.3%	61.8%	56.8%	60.0%	62.9%	57.3%	67.2%
Commercial	Destination (Home and Depot) Charging	100%	100%	100%	100%	100%	100%	100%

Source: Energeia analysis, ABS Household Survey (2016)

Driving Diversity

The charging engine uses the arrival time distribution shown in Figure 45.

Figure 45 – Vehicle Arrival Distribution

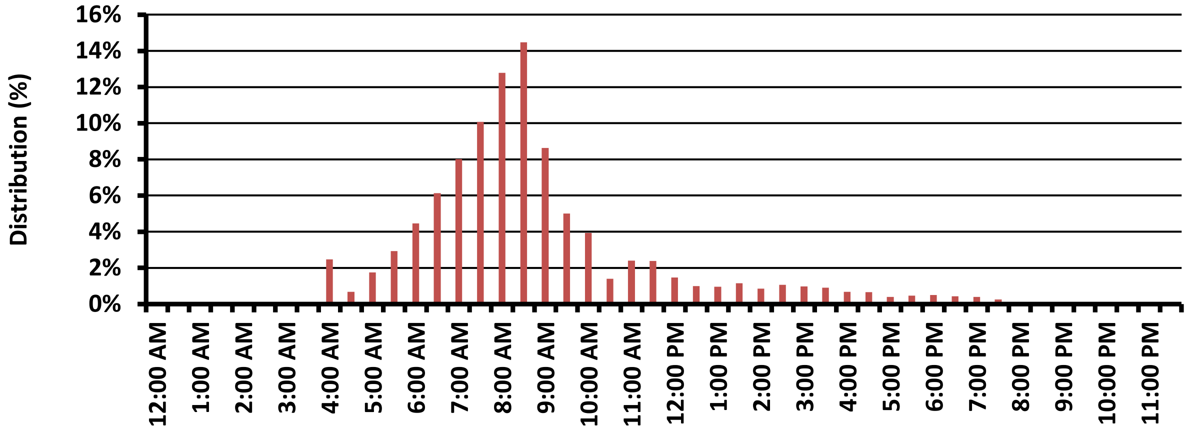


Source: Queensland Household Travel Survey

The charging completion time depends upon the start time, the assumed departure time, and the amount of charge required, which is in turn dependent on the daily driving distance. Generally speaking, the charging management function attempts to recharge the vehicle as quickly as possible while maximising the impact on minimum demand and minimising the impact on maximum demand.

The model uses the departure time distribution shown in Figure 46.

Figure 46 – Vehicle Departure Distribution

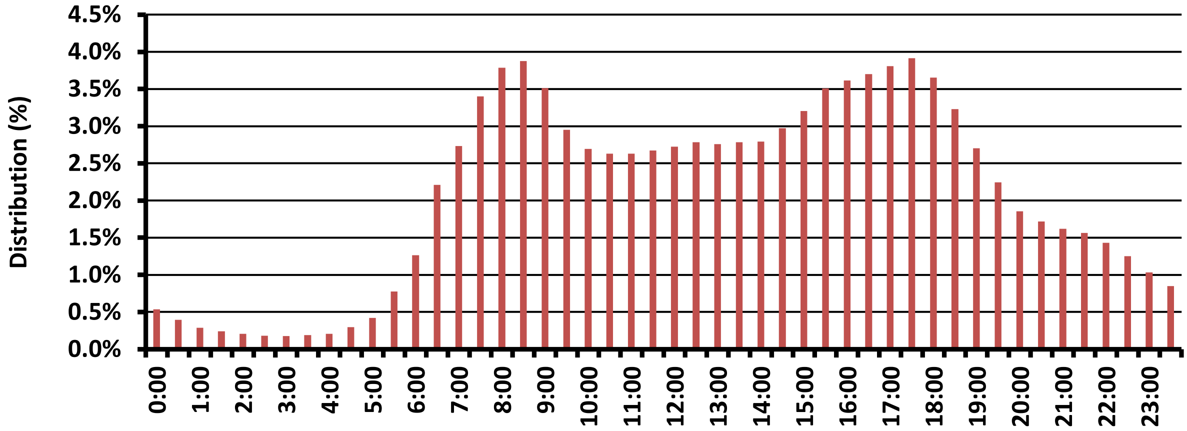


Source: Queensland Household Travel Survey

EV fast charging starts as soon as the vehicle arrives at the charging station and is completed within 5 minutes using 1MW chargers by 2036.

The charging start time is based on the Victorian Managing Traffic Congestion report and uses the traffic volume by time of day to determine the distribution of DCFC use, this is shown in Figure 47.

Figure 47 – Arrival Time Distribution



Source: VAGO (2013), Managing Traffic Congestion.

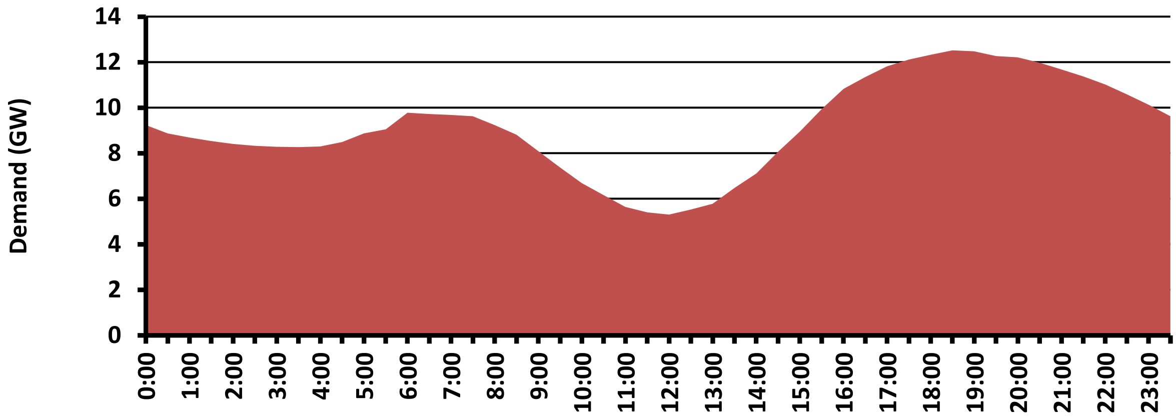
Managed Charging

Level 2 EV charge management can be enabled in the scenario settings of the model, this allows the charging profile of level 2 segment vehicles to be altered to reduce peak demand impact. This is modelled for each year using half-hourly interval data. Managed charging is optimised over two parameters:

- Vehicle availability to charge
- Current half-hourly demand

This allows for a minimisation of peak demand while increasing network asset utilisation by increasing average demand across the year.

Figure 48 – Indicative uSim NSW Average Day Profile (2035)



Source: Energeia Modelling

E.4. Outputs and Reporting

The standard reporting of both the uptake and charging engine are shown in the following sections.

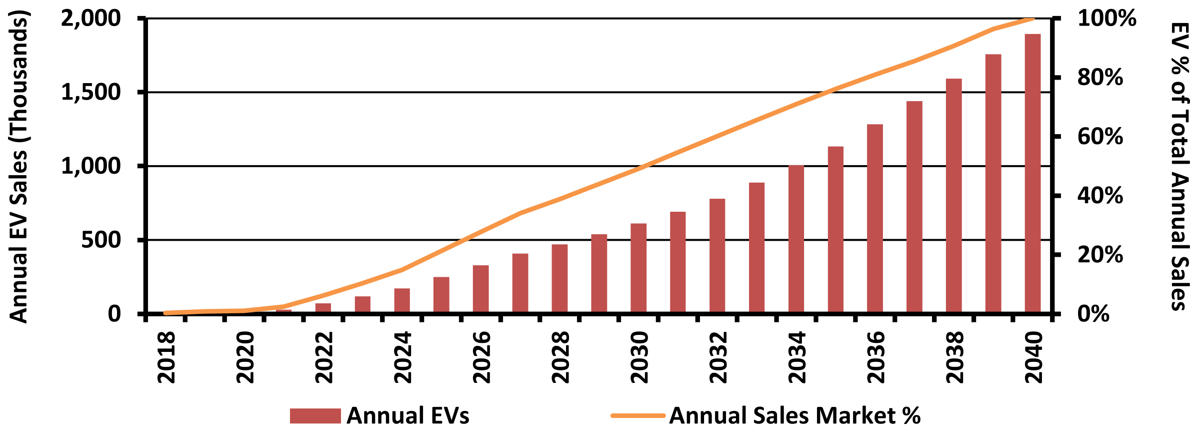
E.4.1. Uptake Module

The uptake module forecasts both annual and cumulative sales and fleet share.

Annual Vehicle Sales

Annual electric vehicle sales and market share can be reported on aggregate and by vehicle class, segment and region over the modelling period.

Figure 49 – Annual Vehicle Sales and Market Share (Indicative)

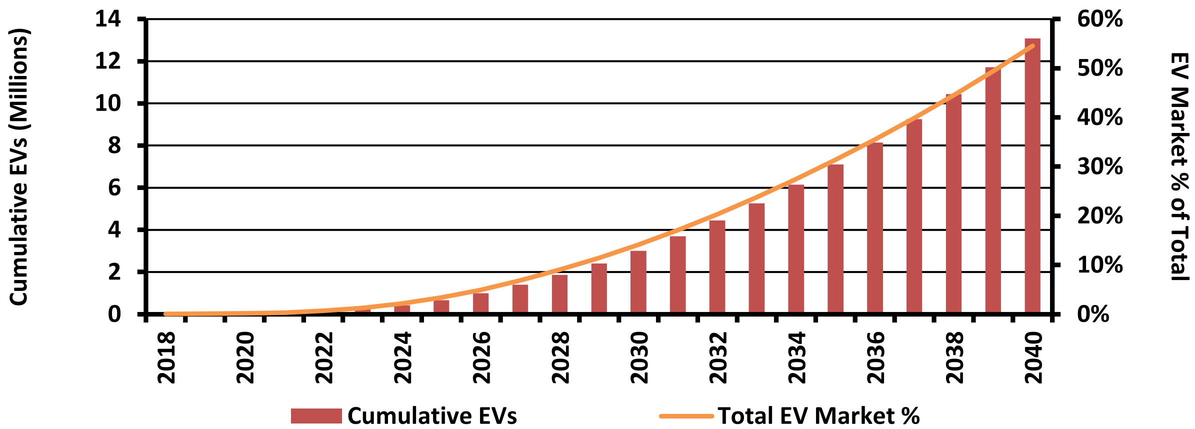


Source: Energeia Modelling

Fleet Share

Cumulative electric vehicle sales and fleet share can be reported on aggregate and by vehicle class, segment and region over the modelling period.

Figure 50 – Cumulative Vehicle Sales and Fleet Share (Indicative)



Source: Energeia Modelling

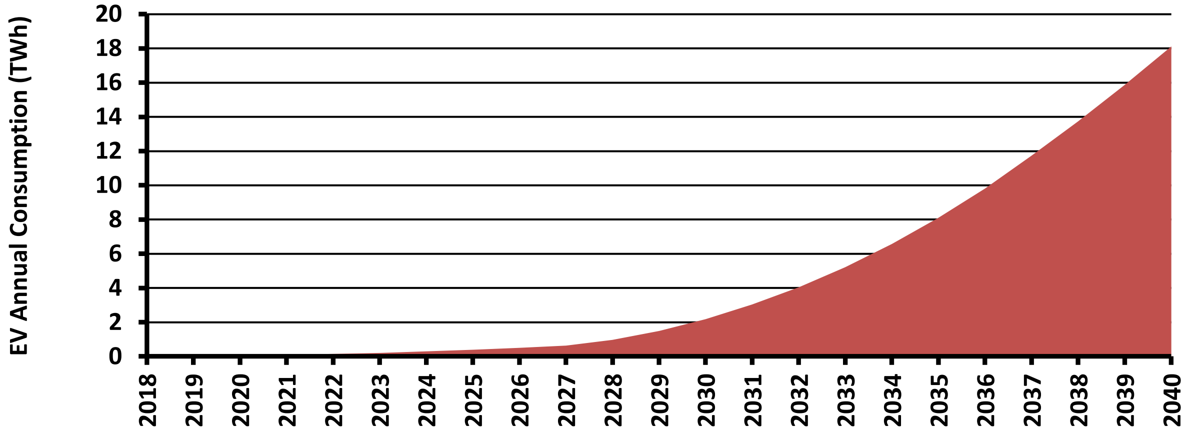
E.4.2. Vehicle Charging Engine

The Vehicle charging engine reports electric vehicle consumption and fleet charging profiles on a charger type and control basis.

Electric Vehicle Consumption

The vehicle charging engine reports the total electric vehicle consumption on aggregate and by vehicle class, segment and region over the modelling period.

Figure 51 – Annual Energy Consumption (Indicative)



Source: Energeia Modelling

Charging Profiles

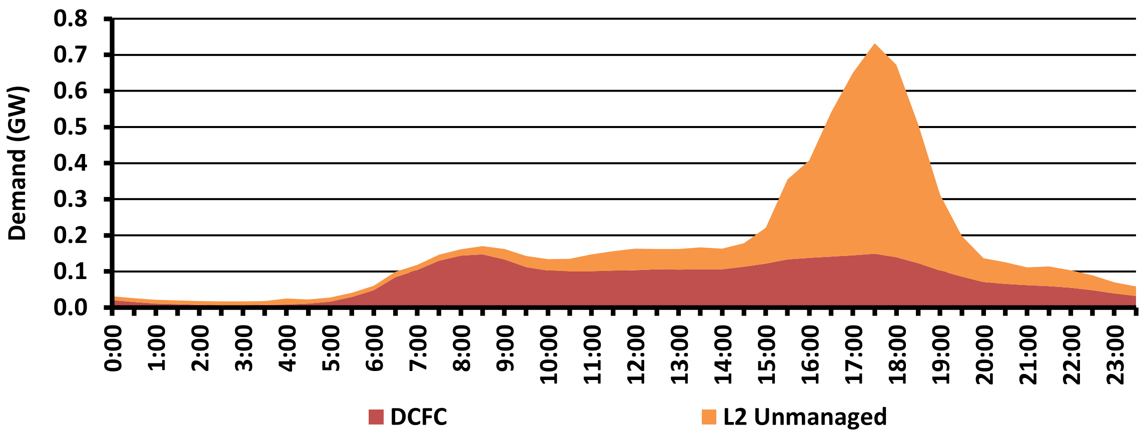
Charging profiles are reported on a managed or unmanaged basis for each year modelled, the profiles are segmented by charger type:

- DCFC
- Level 2 Unmanaged (for both residential and business customers)
- Level 2 Managed (for both residential and business customers)

Unmanaged

Unmanaged charging can be reported for weekdays or weekends segmented by charger type and vehicle class.

Figure 52 – Average Day Unmanaged Charging Profile

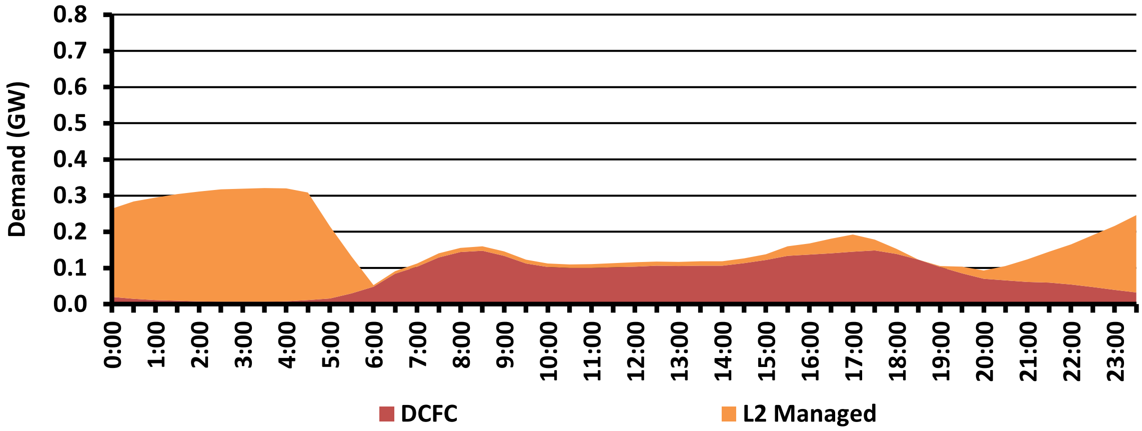


Source: Energeia Modelling

Managed

Managed charging can be reported for peak, average and minimum demand days segmented by charger type and vehicle class.

Figure 53 – Average Day Managed Charging Profile



Source: Energeia Modelling

E.5. Model Enhancements and Potential Improvements

E.5.1. Current Enhancements

This iteration of the model had the following enhancements developed and integrated:

- **Changing Vehicle Lifetimes** – Electric vehicle lifetimes were modified to increase to reach parity with ICE vehicles as technology improvements are developed as previous iterations of the model had tied BEV lifetime the vehicles battery warranty (10 years).
- **Residential Uptake Segmentation** – In the early years of the modelling period the potential annual sales market for uptake of BEV's is limited by residential customer access to level 2 charging at home, those without access are able to uptake as public charging networks are rolled out nationwide.
- **Plug-In Hybrid Additional Vehicle Classes** – As more plug in hybrid models have become available, they have been added to each vehicle class for uptake consideration. The total uptake of alternative fuel vehicles is the weighted sum of the uptake calculated for each technology type.

E.5.2. Future Improvements

Energeia's EV forecasts are independent of the base electricity price forecasts. That is, there is no feedback loop between the forecasted EV uptake and the corresponding response from networks, retailers or the wholesale market.

Further, there are a range of future possibilities as to how EV loads will be priced and how the EV market will integrate with the electricity market and it is foreseeable that tariff products could evolve to encourage increased charging of EVs during solar generation times. This analysis assumes initial EV tariffs for home and workplace charging reflect controlled load tariffs, which will be orchestrated to ensure they minimise peak demand impacts.

The household transport model upon which the EV forecast model relies are derived from the Queensland Household Travel Survey and the Victorian Auditor-General's Managing Traffic Congestion Report. That is, while the model reflects different average driving distances between states, it assumes that travel patterns (origins, destinations, arrival times and departure times) in all regions of Australia are consistent with those of Queensland drivers for passenger vehicles with access to private parking, while travel patterns for commercial EVs and vehicles without access to private parking are consistent with drivers in Victoria.

The EV uptake model is driven in part by the financial return on investment to vehicles owners based on the EV vehicle premium and reduced operational costs. The model does not consider costs associated with any required upgrade to the household switch board and/or service, which could add considerable cost. However, this is not expected to be a material number of households based on anecdotal evidence from pilots, etc.

Appendix F – Glossary of Key Terms

Table 40 – List of Acronyms

Key Term	Definition
ABS	Australian Bureau of Statistics
AC	Alternating Current
ACOSS	Australian Council of Social Service
AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ANU	Australian National University
APVI	Australian Photovoltaic Institute
ARENA	Australian Renewable Energy Agency
ARIMA	Auto-Regressive Integrated Moving Average
B	Bus
BEV	Battery Electric Vehicle
BSL	Brotherhood of St. Laurence
BT	Block Tariff
BTM	Behind the Meter
CBA	Cost-Benefit Assessment
CBD	Central Business District
CCGT	Closed Cycle Gas Turbines
CEC	Clean Energy Council
CEFC	Clean Energy Finance Corporation
CET	Clean Energy Target
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CST	Concentrated Solar Thermal
CVGA	Central Victorian Greenhouse Alliance
DC	Direct Current
DCFC	Direct Current Fast Charging
DER	Distributed Energy Resource
DM	Demand Management
DNSP	Distributed Network Service Provider
DoD	Depth of Discharge
DR	Demand Response
ECA	Energy Consumers Australia
ECA	Energy Consumers Australia
EE	Energy Efficiency
ENA	Energy Networks Australia
ENA	Energy Networks Australia
EQL	Energy Queensland
ESC	Essential Services Commission
EV	Electric Vehicle
FCAS	Frequency Control Ancillary Services
FD	Feeder
FiT	Feed-in Tariff
HEV	Hybrid Electric Vehicle'
HV	High Voltage
HVAC	Heating, Ventilating, and Air Conditioning
ICE	Internal Combustion Engine
IEEE	Institute of Electrical and Electronics Engineers
ISP	Integrated System Plan
kVA	Kilo-Volt-Amperes
kW	Kilowatt
kWh	Kilowatt hour
L2	Level 2 Charging

LC	Light Commercial
LCOE	Levelised Cost of Energy
LRET	Large-scale Renewable Energy Target
LRMC	Long-Run Marginal Cost
LV	Low Voltage
MW	Megawatts
NAGA	Northern Alliance for Greenhouse Action
NE Solar	New England Solar Power
NEM	National Electricity Market
NEO	National Electricity Objectives
NMI	National Meter Identifier
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
NSW DPIE	New South Wales Government Department of Planning, Industry and Environment
NTR	Network Transformation Roadmap
NUOS	Network Use of System
O&M	Operation and Maintenance
OCGT	Open Cycle Gas Turbines
OEM	Original Equipment Manufacturer
OLTC	On-Load Tap Changer
PC	Passenger Car
PEV	Plug-In Electric Vehicle
PHES	Pumped Hydroelectric Energy Storage
PHEV	Plug-In Hybrid Electric Vehicle
PIAC	Public Interest Advocacy Centre
PV	Photovoltaic
PWC NT	Northern Territory Power and Water Company
R&D	Research and Development
RAB	Regulatory Asset Base
RERT	Reliability and Emergency Reserve Trader
RET	Renewable Energy Target
RIN	Regulatory Information Notice
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
ROI	Return on Investment
RRO	Retailer Reliability Obligation
RRP	Regional Reference Price
RT	Rigid Truck
SA DEM	South Australian Government Department of Energy and Mining
SAIDI	System Average Interruption Duration Index
SAPN	South Australia Power Networks
SAPS	Stand-Alone Power Systems
SCED	Security-Constrained Economic Dispatch
SEC	State Electricity Commission of Victoria
SGSC	Smart Grid Smart City
SRMC	Short-Run Marginal Cost
STATCOM	Static Synchronous Compensator
STC	Small-Scale Technology Certificate
STS	Standard Trading Service
SUV	Sport Utility Vehicle
SVPD	St Vincent de Paul Society
SWIS	South West Interconnected System
TEC	Total Environment Centre
TNSP	Transmission Network Service Provider
ToU	Time of Use
UFLS	Under Frequency Load Shedding
Uni NSW	University of New South Wales
Uni QLD	University of Queensland
US	United States

UTS	University of Technology Sydney
VAGO	Victorian Auditor-General's Office
VCR	Value of Customer Reliability
VIC DELWP	Victorian Government Department of Environment, Land, Water and Planning
VPP	Virtual Power Plant
WACC	Weighted-Average Cost of Capital
WEM	Wholesale Electricity Market
ZS	Zone Substation

Appendix G – About Energeia

Energeia was founded in 2009 and has grown to become one of the largest specialist energy consultancy in Australia. Energeia specialises in providing advisory and technical services in the following areas:

- Energy policy and regulation
- Smart networks and smart metering
- Energy storage
- Electric vehicles and charging infrastructure
- Distributed generation and storage technologies
- Network planning and design
- Demand management and energy efficiency
- Energy product development and pricing
- Wholesale and retail electricity markets

Energeia delivers its services across three lines of business:

- **Proprietary Research** – We provide in-depth reports on Distributed Energy Resources related markets and technologies of strategic interest, including PEVs, solar PV and storage, smart grids, microgrids, energy efficiency and home energy management.
- **uSim and wSim Utility and Market Simulators** – We have developed industry leading utility simulation software that models customer behaviour, bills, DER adoption, 17520 load profiles, utility sales, capex, opex, rates and financial performance, on an integrated basis.
- **Professional Services** – We offer tailored services in the areas of rate and incentive design, cost of service analysis, DER and load forecasting, system planning, and DER technology related strategy and plan development.

We are organised into research, consulting and software development functional units, but there is significant cross-over between the working groups due to the significant quantitative analysis that we perform on behalf of our clients, much of which requires custom tooling.

- The software development working group is responsible for the development of our utility simulation tool, uSim.
- The consulting and research team are responsible for delivering Energeia's proprietary research reports and professional services.

Energeia's mission is to empower our clients by providing the evidence-based advice using the best analytical tools and information available



Heritage

Energeia was founded in 2009 to pursue a gap foreseen in the professional services market for specialist information, skills and expertise that would be required for the industry's transformation over the coming years.

Since then the market has responded strongly to our unique philosophy and value proposition, geared towards those at the forefront and cutting edge of the energy sector.

Energeia has been working on landmark projects focused on emerging opportunities and solving complex issues transforming the industry to manage the overall impact.

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