# Business Case
# Intelligent Grid Enablement

Part of the Energy Queensland Group

# Executive Summary

The Intelligent Grid Enablement (IGE) program goes beyond the 'business as usual' expectations of our customers and aims to 'enable' our customers with new choices and capabilities. The proposed program is focused on using technology to cost-effectively unlock the value of constrained generation connected to our networks by maximising the utilisation of existing network assets. It will also aid in addressing challenges related to growing customer adoption of Distributed Energy Resources (DER).

This business case outlines a program of work in 'Intelligent Grid Enablement' which aims, among other things, to address the concerns raised by the AER[1] with conservative export limits imposed by DNSPs on their customers. The total market value of these export limits on the Ergon and Energex distribution networks is estimated to be in the order of $120 million in the medium growth forecast between 2019 and 2035.

The program includes work in the following areas:

- Low Voltage and Distributed Energy Resources Management
- Market sourced Demand Response
- Real-time Analytics supporting and validating the above programs
- Digital Control Room Visualisation and Digital Power Worker Network Awareness of the above programs

If no action is taken, Energy Queensland will face several risks relating to the safe and effective integration of DER with the network, will fail to meet customer expectations in developing capability required to integrate growing DERs and would lead to increasing loss of opportunity for the wider community.

In its revised proposal, and as noted in the recently released AER DER integration expenditure consultation[1], Energy Queensland has recognised the difficulty in calculating tangible benefits of all elements of the DER related programs and as such has conservatively only included quantitative benefits based the unlocking of currently constrained distributed solar photovoltaic (PV) generation. The additional non-quantified benefits are listed in Section 3.2 and are expected to represent direct or indirect value to our customers.

The quantitative benefit value is based on an increase in PV exports (zero fuel cost), which result in a corresponding decrease in the dispatch of grid-sourced generation (higher fuel cost). This approach is consistent with the RIT-D[2] market benefit categories of 'changes in fuel consumption arising from different patterns of generation dispatch', 'changes in electrical energy losses', 'changes in ancillary services costs' and represents a market benefit to the NEM as a whole.

Three options were evaluated in this business case:

**Option 1 –** The counterfactual (continue with existing static limit program).

**Option 2 –** IGE program to enable dynamic export for business customers.

**Option 3 –** Use traditional augmentation to accommodate higher export limits as required.

Energy Queensland aims to minimise expenditure in order to keep pressure off customer prices, however understands that this must be balanced against critical network performance objectives. These include network risk mitigation (e.g. safety, bushfire), regulatory obligations (e.g. safety), customer reliability and security and preparing the network for the ongoing adoption of new

[1] https://www.aer.gov.au/system/files/assessing-distributed-energy-resources-integration-expenditure-consultation-paper-19-november-2019.pdf

[2] https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018

technology by customers (e.g. solar PV). In this business case the need to support the adoption of new technology by customers is a strong driver, based on existing and forecast curtailment of customer-owned DER if no augmentation works are carried out on the Ergon Energy and Energex networks.

To this end, Option 2 is the prefer option. It provides a balanced approach to reducing the risks associated with the counterfactual case and delivers a positive Net Present Value (NPV) result of $3.8M. By contrast the traditional augmentation approach, as per Option 3, delivers a negative NPV result (-$65.5M).

The direct cost of the program for each submission made to the AER is summarised in the table below. Note that all figures are expressed in 2018/19 dollars and apply only to costs incurred within the 2020-25 regulatory period for the preferred option.

| Regulatory Proposal | Draft Determination Allowance | Revised Regulatory Proposal |
|---|---|---|
| $36.8M | $0 | $30.2M |

Note at this time there is no intention to extend the program to individual residential customers, however the program architecture will be designed to begin accepting residential customers beyond 2025 and the costings above assume this.

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# 1. Introduction

The ways our customers source and use energy are rapidly changing. Our customers are telling us that they want greater choice and control over their energy solutions.

There is a strong expectation that we will innovate and create a future focused network to support our commitments and customers' lifestyles. Our customers expect us to be able to facilitate and accommodate increasing integration of renewables, battery storage and electric vehicles into the network, without creating risks to network security, supply quality or performance.

***Key purpose***

*The Intelligent Grid Enablement program goes beyond the 'business as usual' expectations of our customers and aims to 'enable' our customers with new choices, capabilities and services. The proposed program is focused on using technology to cost effectively unlock the market value of constrained generation connected to our networks by maximising the utilisation of existing network*

Intelligent Grid Enablement sits in the wider context of changes to modernise energy networks throughout Australia. In 2017 the Commonwealth Scientific and Industrial Research Organisation (CSIRO) and Energy Networks Australia (ENA) released the Electricity Network Transformation Roadmap (ENTR) (ENA, 2017), which aims to guide all stakeholders in the electricity industry through the transformation necessary to enable the best outcomes for customers as Distributed Energy Resources (DER) become ubiquitous. The roadmap[3] focuses on 'no-regrets' tangible capabilities that are required in the 2017-2027 timeframe.

ENA followed on from the ENTR, collaborating with the Australian Energy Market Operator (AEMO), to develop a framework for integrating increasing penetrations of DER into Australia's electricity grid. The interim[4] report was released in July 2019 and is expected to be finalised before the end of 2019. It describes the benefits for all customers from a managed integration of DER and outlines the capabilities required to enable this (ENA & AEMO, 2019). This report notes the need for networks to improve network visibility and begin to develop capability to define network constraints and 'hosting capacity' in relation to DER operation. EQL is embarking on early steps to develop the capability required to address these identified 'no-regrets' capabilities and the elements outlined in this business case support these identified capabilities.

More recently, the Australian Energy Market Commission (AEMC) identified the integration of DER into energy markets as the key focus of their 2019 Economic regulatory framework review[5], which also highlighted that failure to provide a grid that enables customer choice and adoption of these technologies poses a strong risk of increasing costs to all customers in the future (AEMC, 2019). In a similar theme to the AEMO/ENA Open Energy Networks report, the AEMC acknowledges that networks need to explore capability to improve network visibility and to explore capability to identify network constraints. It also considers the development of dynamic connection agreements with customers to dynamically limit DER export as an alternative to expensive network augmentation.

Drawing from these reports, broader activities in globally progressive markets, and recognising the Queensland Government's renewable target of 50% by 2030, Energy Queensland's (EQL's) Future Grid Roadmap lays out the critical capabilities needed to transform Ergon Energy and Energex's

[3] https://www.energynetworks.com.au/projects/electricity-network-transformation-roadmap/
[4] https://www.energynetworks.com.au/projects/open-energy-networks/
[5] https://www.aemc.gov.au/market-reviews-advice/electricity-network-economic-regulatory-framework-review-2019

distribution businesses. This includes no-regret investments currently necessary to ensure efficient management and operation of the distribution networks, while facilitating a smooth transition to support likely emerging future network roles.

Three key capabilities are identified as being required to be realised in the 2020-2025 period:

- **Advanced Distribution Management System (ADMS)[6]** - the core platform for management of the High Voltage networks including substation protection and control across both the Ergon and Energex distribution networks.
- **Low Voltage (LV) network monitoring and visibility[7]** - a portfolio of data streams from network monitoring devices at the LV network level. This will include data from network devices, smart meters, customer devices with the capability of secure integration of 3rd party information sources (such as National Broadband Network (NBN) and 5G Telco assets) and IoT (Internet of Things) devices in future.
- **Intelligent Grid Enablement** - a collection of enabling technologies to leverage and manage LV data, interact with the ADMS, the market/aggregators, customers and within Ergon Energy and Energex to actively manage hosting capacity.

This strategic proposal is focussed on the third capability – Intelligent Grid Enablement – and the associated investment activities.

The Intelligent Grid Enablement program has been developed as a result of the learnings from a range of research projects such as the Evolve DER project, and the Solar Enablement Initiative (SEI) outlined below:

- **Evolve[8]:** Co-funded by the Australian Renewable Energy Agency (ARENA), this project is being delivered by a consortium involving the Australian National University (ANU), Zepben, EQL, NSW Distribution Network Service Providers (DNSPs), and aggregators, with the goal of developing a platform for calculating DER operating envelopes and publishing those envelopes to allow the market - or direct customer - responses, for the purposes of minimising traditional augmentation and increasing network utilisation and efficiency.
- **Solar Enablement Initiative (SEI)[9]:** Incorporating a consortium of DNSPs, universities, and technology vendors, this ARENA supported initiative is developing state estimation techniques. The goal is to utilise the state estimation algorithm for connection assessments and active signalling to customers to improve hosting capacity without requiring traditional augmentation, in lieu of complete saturation of monitoring of Medium Voltage (MV) and Low Voltage (LV) nodes and connection points. This program will provide the capability to improve visibility of LV and MV networks with only a sample of monitors and sensors.

Both above projects are trial and are expected to deliver outcomes by 2020 which will inform and refine EQL's technology solutions and scalability required for Intelligent Grid Enablement in the 2020-25 regulatory control period.

## 1.1 Purpose of document

This document recommends the optimal capital investment necessary for a program of initiatives to support Intelligent Grid Enablement. This is a preliminary business case document and has been developed for the purposes of seeking funding for the required investment in coordination with the

[6] ICT Business case ID02 (Network Operations Systems Consolidation & Replacement)
[7] EQL Business case 98 (Strategic Proposal LV Network Safety)
[8] https://arena.gov.au/projects/evolve-der-project/
[9] https://arena.gov.au/knowledge-bank/presentation-solar-enablement-initiative-distribution-state-estimation/

Energex and Ergon Energy's Revised Regulatory Proposal to the Australian Energy Regulator (AER) for the 2020-25 regulatory control period. Prior to investment, further detail will be assessed in accordance with the established EQL investment governance processes. The costs presented are in $2018/19 direct dollars.

## 1.2 Scope of document

This document seeks funding endorsement from the AER for a program of work to support Intelligent Grid capabilities*.* The components addressed include:

- Low Voltage Management Platform (LVMP)
- Demand Response System (DRS)
- Distributed Energy Resources Management System (DERMS)
- Real-time Analytics (RTA)
- Digital Control Room Visualisation (DCRV)
- Digital Power Worker Network Awareness (DPWNA)

## 1.3 Identified Need

Energy Queensland aims to minimise expenditure in order to keep pressure off customer prices, however understands that this must be balanced against critical network performance objectives. These include network risk mitigation (e.g. safety, bushfire), regulatory obligations (e.g. safety), customer reliability and security and preparing the network for the ongoing adoption of new technology by customers (e.g. solar PV). In this business case the need to support the adoption of new technology by customers is a strong driver, based on existing and forecast curtailment of customer-owned DER if no augmentation works are carried out on the Ergon Energy and Energex networks.

The introduction of affordable new energy technologies is a key driver for this program of work. Queensland has one of the highest penetrations of Solar Photovoltaics (PV) on detached houses in the world, at 30% (2018), and this trend is expected to continue for at least the next decade as shown in Figure 1 and Figure 2.

Forecast data for this business case has been updated since our draft submission and has been derived from the scenarios described in *"The Future of Energy in Queensland"* report, produced by CSIRO and Data61 in 2019 in partnership with Energy Queensland to examine the future of the energy sector in Queensland over the next decade, including implications for Energy Queensland's operating environment.

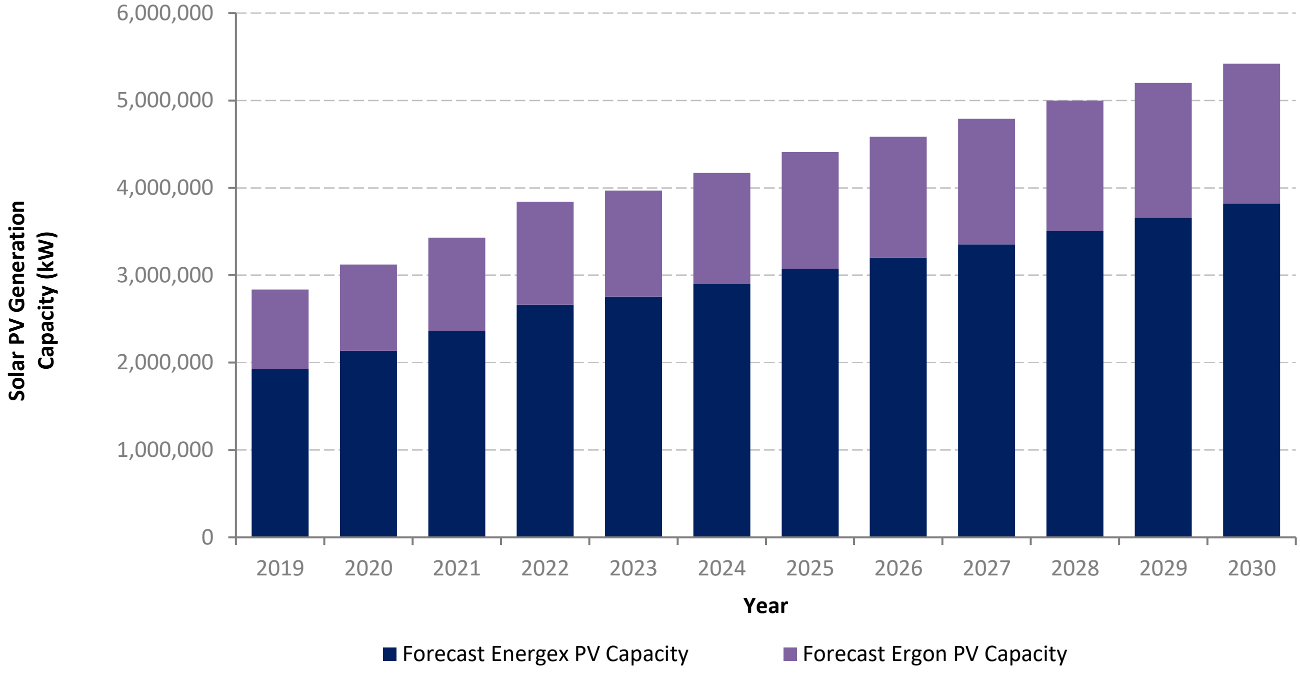


**Figure 1: Solar PV DER uptake in the Energy Queensland area (medium growth scenario)**

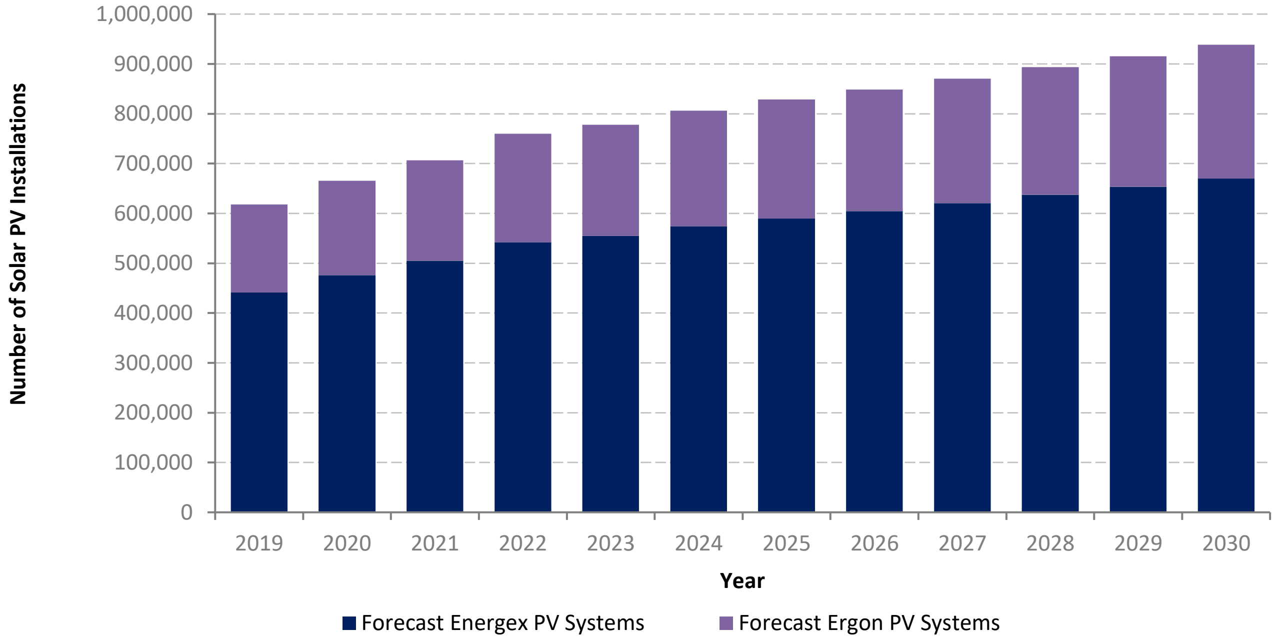


**Figure 2: Number of solar PV installations in the Energy Queensland area (medium growth scenario)**

It can be seen that the capacity per PV system is increasing beyond residential limits over the forecast period, indicating strong growth in commercially driven PV connections. Both Ergon Energy and Energex have a significant funnel of utility-scale (1MW-plus) renewable energy generating plants with committed projects of 1.2GW and a pipeline of 1.7GW as of October 2018. Furthermore, the emergence and impact of greater market participation through Virtual Power Plants (VPPs) and other aggregator/retail services with commercial objectives are expected to increase during this period.

In addition to this growth in PV, there is significant ongoing activity around the development and deployment of complementary battery storage technology, with over 32 MWh of energy storage installed in Queensland over the last 12 months, more than double the volume installed in the previous 12 months. This will be a growing challenge as DER achieves a more active capability to enable energy to be stored and aggregated in response to broader market opportunities.

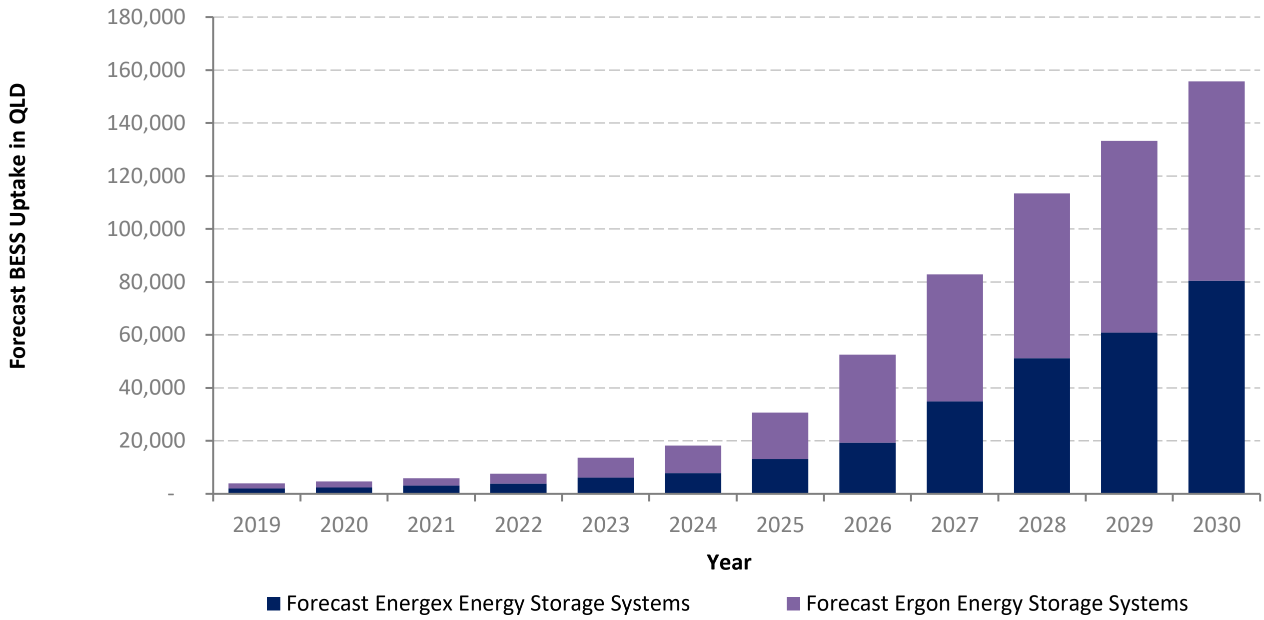


**Figure 3: Forecast Battery Energy Storage Systems in Queensland (medium growth scenario)**

### *Limitation*

As distribution and sub-transmission networks are becoming more congested, Energex and Ergon Energy are increasingly required to put significant static operating limitations on customers to maintain stability and ensure voltage and capacity constraints are not breached during 'worst case' periods. As well as causing the unnecessary consumption of market-based resources, this significantly reduces the customer's present and future value of their installed generation.

### *Augmentation*

The traditional method for increasing the hosting capacity of the power network is to provide augmentation options – such as conductor and transformer upgrades. Based upon the growth in customer PV deployment indicated in Figure 1 and Figure 2, Energex and Ergon Energy would need to significantly increase its associated traditional network augmentation AUGEX for DER related activity to meet hosting capacity required to allow full DER export as is expected by many customers. Energy Queensland estimates the cost to augment to this level as higher than the export generation value unlocked in the timeframes examined. This analysis is detailed in *Option 3: Traditional Augmentation*.

### *Technology Alternatives*

The preferred alternative is to progressively build up and utilise the proposed Intelligent Grid Enablement technologies, where Ergon Energy and Energex can more effectively utilise the existing capacity of the network dynamically, and more efficiently increase hosting capacity, while minimising the need to do additional costly network augmentation. This proposal aligns with the CAPEX objectives and criteria from the National Electricity Rules as detailed in Appendix C.

## 1.4 Energy Queensland Strategic Alignment

Table 1 details how Intelligent Grid Enablement contributes to Energy Queensland's corporate and asset management objectives. The linkages between these Asset Management Objectives and EQL's Corporate Objectives are shown in Appendix D.

**Table 1: Asset Function and Strategic Alignment**

| Objectives | Relationship of Initiative to Objectives |
|---|---|
| **Ensure network safety for staff contractors and the community** | The Digital Control Room Visualisation and Digital Power Worker Network Awareness components will provide near –real-time information about the network at all times. This will significantly improve information in decision making at all levels of the field organisation. |
| **Meet customer and stakeholder expectations** | This program's goal is to enable maximum hosting capacity for customers at the least viable cost. Further discussion of the impact on customers can be found in Section 1.7. |
| **Manage risk, performance standards and asset investments to deliver balanced commercial outcomes** | This program will deliver customer requirements more cost-effectively than traditional augmentation. It will also allow the existing field resources to be focused on faults and other critical network activities. |
| **Develop Asset Management capability & align practices to the global standard (ISO55000)** | This program will deliver significantly more information about the operation and performance of the distribution networks in EQL than is currently available. |
| **Modernise the network and facilitate access to innovative energy technologies** | This program unlocks the potential for hosting capacity using a range of modern and innovative technologies to facilitate and maximise customers' participation in the energy market. |

## 1.5 Applicable service levels

Corporate performance outcomes for this asset are rolled up into Asset Safety & Performance group objectives, principally the following Key Result Areas (KRA):

- Customer Index, relating to Customer satisfaction with respect to delivery of expected services
- Optimise investments to deliver affordable & sustainable asset solutions for our customers and communities

Under the Distribution Authorities, Energex and Ergon Energy are expected to operate with an 'economic' customer value-based approach to reliability, with "Safety Net measures" for extreme circumstances. Safety Net measures are intended to mitigate against the risk of low probability vs high consequence network outages. Safety Net targets are described in terms of the number of times a benchmark volume of energy is undelivered for more than a specific time. EQL is expected to employ all reasonable measures to ensure it does not exceed minimum service standards (MSS) for reliability, assessed by feeder types as

- System Average Interruption Duration Index (SAIDI), and;
- System Average Interruption Frequency Index (SAIFI).

Both Safety Net and MSS performance information are publicly reported annually in the Distribution Annual Planning Reports (DAPR). MSS performance is monitored and reported within EQL daily.

## 1.6 Compliance obligations

Table 2 shows the relevant compliance obligations for this proposal.

**Table 2: Compliance obligations related to this proposal**

| Legislation, Regulation, Code or Licence Condition | Obligations | Relevance to this investment |
|---|---|---|
| **QLD Electrical Safety Act 2002**<br><br>**QLD Electrical Safety Regulation 2013** | We have a duty of care, ensuring so far as is reasonably practicable, the health and safety of our staff and other parties as follows:<br>• Pursuant to the Electrical Safety Act 2002, as a person in control of a business or undertaking (PCBU), EQL has an obligation to ensure that its works are electrically safe and are operated in a way that is electrically safe.[10] This duty also extends to ensuring the electrical safety of all persons and property likely to be affected by the electrical work.[11] | The proposed works will play a significant role in ensuring the safety of EQL staff and the community by enabling EQL to detect potential issues in the LV network that could lead to injuries or fatalities and providing this information to field workers in real time. |
| **Distribution Authority for Ergon Energy or Energex issued under section 195 of *Electricity Act 1994* (Queensland)** | Under its Distribution Authority:<br>• The distribution entity must plan and develop its supply network in accordance with good electricity industry practice, having regard to the value that end users of electricity place on the quality and reliability of electricity services.<br>• The distribution entity will ensure, to the extent reasonably practicable, that it achieves its safety net targets as specified.<br>• The distribution entity must use all reasonable endeavours to ensure that it does not exceed in a financial year the Minimum Service Standards (MSS) | This proposal is in alignment with recommendations made by the AEMC given in Appendix F, as well as general good electricity industry practice. The works aim to mitigate a number of risks that would result in excessive outages and additional negative impacts for customers. |

[10] Section 29, *Electrical Safety Act 2002*
[11] Section 30 *Electrical Safety Act 2002*

| Legislation, Regulation, Code or Licence Condition | Obligations | Relevance to this investment |
|---|---|---|
| **Electrical Regulation 2006 (Queensland)** | Under the Electricity Regulation 2006 we have an obligation to supply low voltage electricity in accordance with AS60038 and AS61000.3.100 which specifies a nominal voltage of 230V, an acceptable range of 216V – 253V and a preferred median voltage of 225V – 244V. | This proposal is intended to contribute to maintaining compliance with increasing penetrations of DER while minimising traditional network augmentation. |

## 1.7 Limitation of existing assets

If no action is taken, a variety of negative impacts would be experienced by EQL and the communities it serves. Customers would experience the following:

- **Economic cost to customers** - due to export limitations, customer investments would be underutilised, representing not only a direct opportunity cost to customers but an opportunity cost to the wider community and the electricity market in terms of unnecessary resource consumption, electrical losses and fees. Many of these challenges can be addressed by a more responsive grid.
- **Failure to realise the value of existing investments** – because customers and EQL would not be utilising the full value of the network that has already been funded by customers. Orchestrated customer DER has the potential to assist in stabilising the grid and providing network support services (e.g. voltage regulation) which benefit our customers through improved network efficiencies and outcomes.
- **Limited customer options** – due to a reduced ability for customers to choose to benefit from demand or export control.
- **Breaching network constraints** – due to lost opportunity of making use of active DER to support power quality objectives may lead to increased non-compliant voltages or network asset overloads which may cause outages or asset failures and breach our obligations.

This is in alignment with commentary from the AEMC shown in Appendix F, and feedback Ergon Energy and Energex received as part of customer and industry consultation in 2018 as part of their Regulatory Proposal development. This indicated that most customers surveyed expected EQL to invest in modern technologies that enable improved DER hosting capabilities – allowing the expected 'choice' in how they use their DER.

If no solution is proposed (augmentation or technology) then Energex and Ergon networks will see a significant increase in issues at the LV network level, even with the proposed $23M in power quality related augmentation. This is further explored in the Energex and Ergon Energy Power Quality business cases, where funding has been sought for monitoring capability to enable more proactive management of LV issues. These issues include:

- Regular tripping of inverters due to high voltage (resulting in step change impacts on the network and loss of load support for individual customers and across the network);
- Blown fuses at the Distribution Transformers and increased outages;
- Significantly increased customer complaints and dissatisfaction due to a lack of amenity

- Increased operational costs due to the high number of complaints – as each one will need to be investigated and resolved

### *Low Voltage and Distributed Energy Resources Management*

Currently there is no solution for the active management of LV networks in either the Energex or Ergon networks. With the growth in PV, Batteries, and Electric Vehicles (EVs), the LV networks will require active management of both power quality (statutory requirements) and thermal capacity to maximise generation export capabilities. Customers will expect that they can invest in technology (such as DER) and be able to trade their resources whilst connected to the network.

In addition, neither Energex nor Ergon has an automated method of managing large scale DER (>1.5MW) across the network. This means that where 'worst case' network constraints are identified, systems must be designed with fixed or scheduled limits when they connect to the network. There is no flexibility in the way these resources are managed going forward and the business is unable to dynamically manage these DERs for customer or network benefit. This becomes increasingly problematic as the density of DER connections increase and the impact on and of existing DER needs to continually be re-evaluated.

### *Market sourced Demand Response*

The AEMC has indicated that customers should be rewarded for integrating their behind-the-meter appliances to the network, and an expansion of demand response initiatives is a key method to facilitate this. With the growth in DER, opportunities emerge to make greater use of demand response (DR) to address issues on the network.

The current AER submission for broad base DM included procurement of DR at an increasing volume over the five-year period. The conservative estimates of DR procurement for the 2020-25 regulatory control period for the South-East Queensland (SEQ) region alone is shown below in Table 3. It has been assumed that DR will be procured from the market in this region from 2020-21, at a decreasing rate ($). This would enable EQL to deliver more MVA from the broad-based program for the same cost. To achieve this, there is a need for EQL to introduce a solution to enable procurement of DR from the market.

**Table 3: Planned demand response procurement for SEQ for 2020-25**

| Planned Demand Response Procurement | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total 2020-2025 |
|---|---|---|---|---|---|---|
| **Operational Expenditure (OPEX) ($,000)** | 7,327 | 7,327 | 7,327 | 7,327 | 7,327 | 36,633 |
| **Capital Expenditure (CAPEX) ($,000)** | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Expenditure ($,000)** | **7,327** | **7,327** | **7,327** | **7,327** | **7,327** | **36,633** |
| **MVA** | 27.10 | 27.30 | 27.80 | 28.80 | 30.80 | |
| **MVA (Audio Frequency Load Control)** | 26.80 | 26.80 | 26.80 | 26.80 | 26.80 | |
| **MVA (From market)** | 0.25 | 0.50 | 1.00 | 2.00 | 4.00 | |
| **$/kVA (From market)** | $250 | $240 | $230 | $215 | $200 | |
| **$/kVA** | $270 | $268 | $264 | $254 | $238 | |

Neither Energex nor Ergon currently has an automated method of managing demand response programs outside of the existing Audio Frequency Load Control (AFLC)/Peak Smart system, and hence are unable to deliver an efficient outcome at a competitive cost. Any contracts for demand response at the commercial/industrial level are managed manually at great resource cost by the Control Room.

There is a need for Energex and Ergon to contract DR support efficiently from the market in a manner that can be better integrated with the existing network load control capability. To do this, a more sophisticated Demand Response System (DRS) is required and will allow the Control Room to manage this in an automated and well-integrated fashion at a localised level.

#### *Real-Time Analytics*

Currently data is generally collected from the network and then reviewed off-line for any analysis. Any insights are then manually transferred into action in the business. This is acceptable for longer term work like network planning but does not meet the needs of improving day to day operations, detecting unsafe conditions or maximising real time utilisation of the network, which is especially important with a growing range of DERs. It is expected that real time analytics and machine learning will form a key part of automated auditing of dynamic export connection agreements, ensuring that market participants are fulfilling their contractual obligations.

The installation and maintenance cost of sensing is also reduced as modern analytical techniques are used to fill gaps and prioritise operational work.

#### *Digital Control Room Visualisation and Digital Power Worker Network Awareness*

The addition of new DER information streams and complexities are already having an impact on the way our control rooms operate and how they consume and visualise data in an increasingly active and bi-directional network. Improved visualisations in conjunction with the DER management capability referred to above would ensure consistency of communication and declutter the operator interface to ensure that only matters related to system security and stability are flagged to an operator, as low risk or low value actions are handled on an automated and real-time operational basis by the system. The automation and responsiveness of such capability leads to more effective integration and operation of DER.

Likewise, field-based power workers and other customer facing field staff presently have very limited information on the current operation and performance of the network. This increases the complexity in addressing customer DER issues and complaints or offering new solutions to network connection and expansion requests such as residential solar.

# 2 Counterfactual Analysis

## 2.1 Purpose of proposed work

The counterfactual analysis in this case is a ‘Do nothing different’ scenario, where no action is taken and there would be no additional expenditure for the Intelligent Grid Enablement program or additional augmentation works. The business would continue with its existing approach of using static limits as the only instrument of control of DER for business customers.

## 2.2 Business-as-usual service costs

Under this scenario, with the forecast increase in penetrations of Solar PV and other DERs such as household batteries and electric vehicles, the network will require at a minimum to be augmented as per the Power Quality business cases just to remain compliant.

Lost market value is estimated by examining the actual PV generation capacity connected to both Energex and Ergon Energy networks under zero and partial export agreements (73.21 MW, 2019) for business customers. A conservative generation estimate and market value per kWh is then applied to annual weekend and public holiday days at the forecasted business PV growth rate over the period.

Energy Queensland will likely be forced to increase the application of static limits to customers over this period and the total value of curtailed generation to the wider market will continue to rise to nearly $120 million by 2035 as per the below base case forecast.

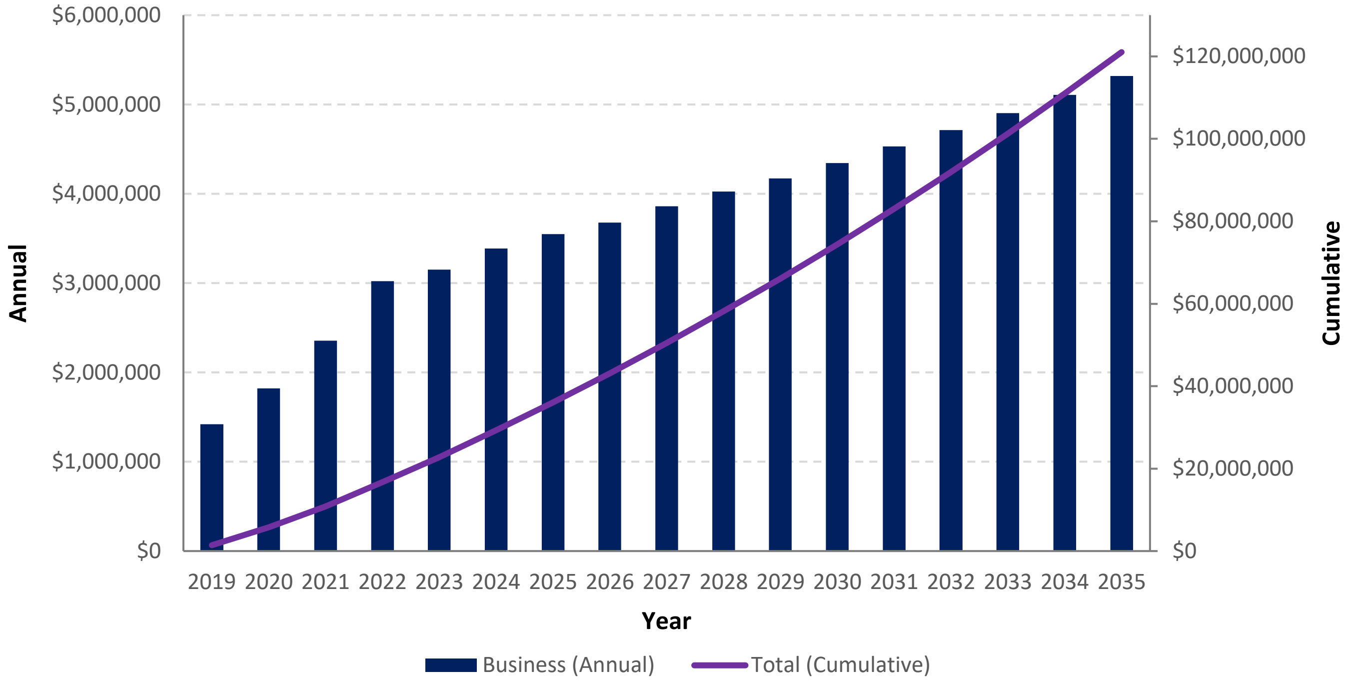


**Figure 4: Estimated total curtailed energy value associated with static export limits**

## 2.3 Key assumptions[12]

- Business customers defined as systems between 30kVA and 1500kVA.
- Business PV generation is export limited on weekends and public holidays.
- The majority of business systems are sized to match load site load during business hours.
- Base case PV forecast at $50/MWh market value decreasing by 2% by 2035. This follows the methodology applied by the QCA[13] in calculating the Queensland region Feed in Tariff (FiT) but additionally removes estimated non fuel-related costs from the wholesale energy cost.

## 2.4 Risk assessment

This risk assessment is in accordance with the EQL Network Risk Framework and the Risk Tolerability table from the framework is shown in Appendix E.

**Table 4: Counterfactual risk assessment**

| Risk Scenario | Risk Type | Consequence (C) | Likelihood (L) | Risk Score | Risk Year |
|---|---|---|---|---|---|
| **Without the Intelligent Grid Enablement (IGE) program** EQL risks being unable to cost effectively unlock the existing and future value of constrained generation, resulting in loss of customer trust. | Customer | 3 *(Loss of customer trust / action groups formed)* | 6 *(Almost certain)* | **18** ***(High Risk)*** | 2020-2025 |
| **Without the IGE program** EQL risks being unable to adequately influence load and generation at the customer ends of the network, leading to **network performance issues** and **interruptions to >15,000 customers[14/15].** | Customer | 4 *(Interruption to >15,000 customers)* | 3 *(Unlikely)* | **12** ***(Moderate Risk)*** | 2020-2025 |

12 Refer to NPV sheet, 'PVForecasts' tab for more detail and assumptions

13 https://www.qca.org.au/wp-content/uploads/2019/07/solar-feed-in-tariff-201920-determination-final1374799_3.pdf

14 https://www.abc.net.au/news/2019-01-25/sa-blackouts-related-to-heat-not-network-sapn-says/10748884

15 https://www.abc.net.au/news/2018-01-29/melbourne-heat-brings-hottest-night-of-summer-blackouts/9369228

| Risk Scenario | Risk Type | Consequence (C) | Likelihood (L) | Risk Score | Risk Year |
|---|---|---|---|---|---|
| **Without the IGE program** EQL risks being unable to meet customer expectations with flexibility of choice (e.g. PV, Batteries) when they connect to the network resulting in **adverse national media attention and loss of public trust.** | Customer | 4<br>*(Adverse national media attention)* | 3<br>*(Unlikely)* | **12**<br>***(Moderate Risk)*** | 2020-2025 |
| **Without the IGE program** EQL risks being unable to detect an asset issue within the network or latent safety issue due to the lack of real-time LV network data **resulting in a single fatality.** | Safety | 5<br>*(Single fatality / incurable fatal illness)* | 3<br>*(Unlikely)* | **15**<br>***(Moderate Risk)*** | 2020-2025 |
| **Without the IGE program, unmonitored growth** in DER related energy flows may result in increasing complexities in field and control room operations, resulting in significant impact on any restoration or planned works >$1 million. | Business | 4<br>*(Business cost of >$1million)* | 4<br>*(Likely)* | **16**<br>***(Moderate Risk)*** | 2020-2025 |
| **Failure to implement the IGE program** leads to EQL being unable to meet its strategic commitments to enable customer choice and flexibility around energy usage and price. This results in EQL being **unable to meet its strategic objectives** which could lead to **additional costs to the business.** | Business | 4<br>*(Unable to deliver an agreed strategic initiative)* | 5<br>*(Very Likely)* | **20**<br>***(High Risk)*** | 2020-2025 |

Further Details of the risk ratings and descriptions can be found in Energy Queensland's Network Risk Framework.

The network (business) risk the organisation would be exposed to if the project was not undertaken is not deemed to be as low as reasonably practicable (ALARP). Addressing the risks detailed above through implementation of the preferred option will reduce EQL's risk exposure.

## 2.5 Retirement decision

This proposal relates to new components and systems and thus discussion of retirement of existing assets is not needed in this case.

# 3 Options Analysis

## 3.1 Options considered but rejected

The most viable option excluded was an expansion of Option 2 to also include residential customers in the program beyond 2025. While this option would improve the overall case, Energy Queensland believes it would be prudent to prove the concept at a lower volume of endpoints via business customers and aggregators before committing to extending the program to a broader base.

## 3.2 Identified options

### *Option 1: The counterfactual (continue with existing static limit approach)*

This option is detailed in full in the previous section and involves no capital expenditure. It is considered a viable option in the 2020-25 regulatory period; however, the untreated risks of starting the program late are significant.

### *Option 2: Intelligent Grid Enablement program for business customers*

This option consists of delivering six primary components to address the limitations:

- Low Voltage Management Platform (LVMP)
- Demand Response System (DRS)
- Distributed Energy Resources Management System (DERMS)
- Real-time Analytics (RTA)
- Digital Control Room Visualisation (DCRV)
- Digital Power Worker Network Awareness (DPWNA)

The proposed relationship between each of these components is shown in the diagram below. Note this is only indicative and part of the program will be to establish the overlap, interaction and architecture of each of the major elements.

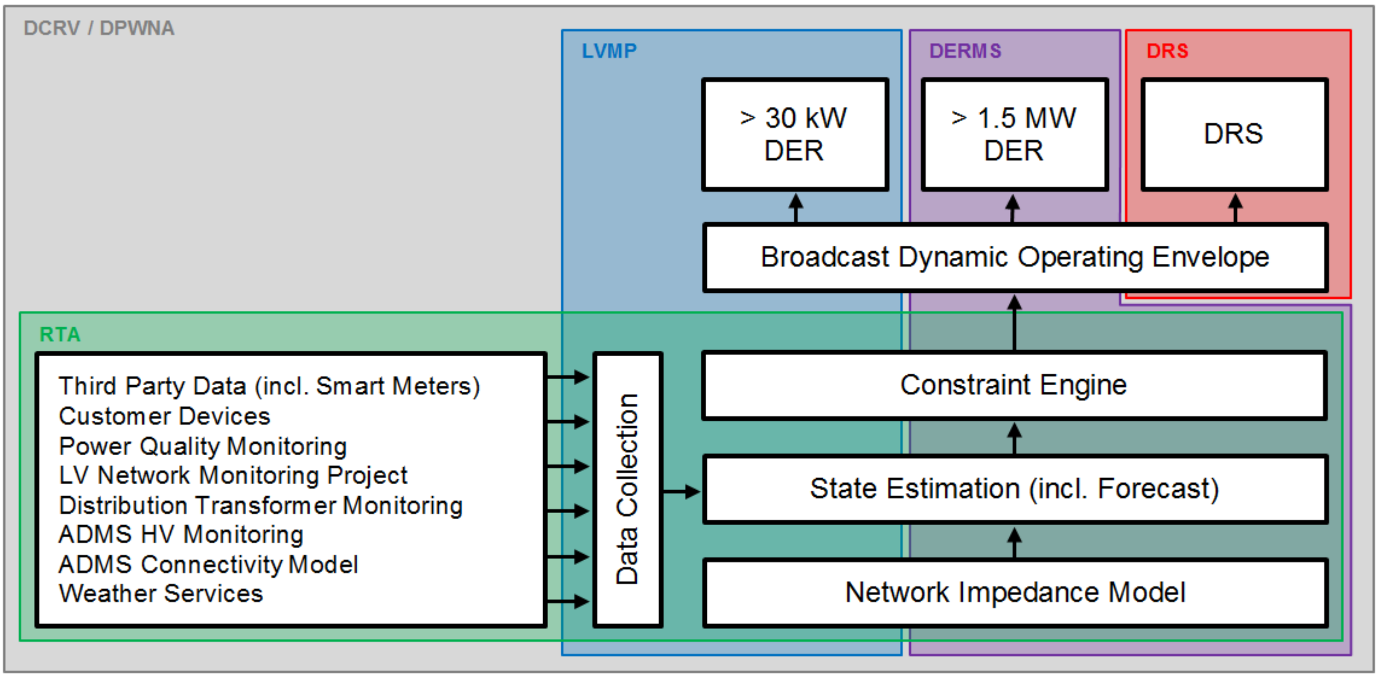


**Figure 5: Proposed relationship between each program element**

A more detailed explanation of each programs scope follows in the section below.

### *Low Voltage Management Platform (LVMP)*

The LVMP intends to cater for a large quantity of low criticality, low complexity connections to customers on <1.5MW connection agreements. It incorporates:

1. The high-speed **collection** of necessary network data from a variety of internal and external sources to dynamically inform the present and forecasted state of the network. This includes third party smart meter data, distribution transformer monitoring[16] and other new and existing network monitoring assets[17].
2. The **hosting** of a real time state estimation service to 'fill in the gaps' of unmonitored assets and a corresponding constraint engine to identify safe operating envelopes for customer load and generation assets.
3. The **communication** of widespread, real time dynamic operating envelopes.

The purpose is to build a tool that assists EQL to automatically ensure new and existing LV customers can safely maximise their export potential without breaching of (increasingly dynamic) network limits. The intention is to roll out the capability on an 'as needed basis' and progressively grow the user base, with the option to merge or integrate with the HV DERMS in the future.

This platform will also underpin the Real Time Analytics program by managing the various streams of data from the LV network such as network monitoring devices deployed for safety management, smart meters, customer and IoT devices in future.

### *Case Study*

*In 2019, Energy Queensland deployed a successful 'Dynamic Operating Envelope' trial by making use of existing infrastructure and distribution transformer monitors. The trial broadcasts a real time capacity limit to all customers on the LV segment via the public internet, who curtail load or generation output accordingly via simple mechanisms. The next phase will incorporate the real time State Estimation Algorithm (SEA) to consider both thermal and voltage constraints.*

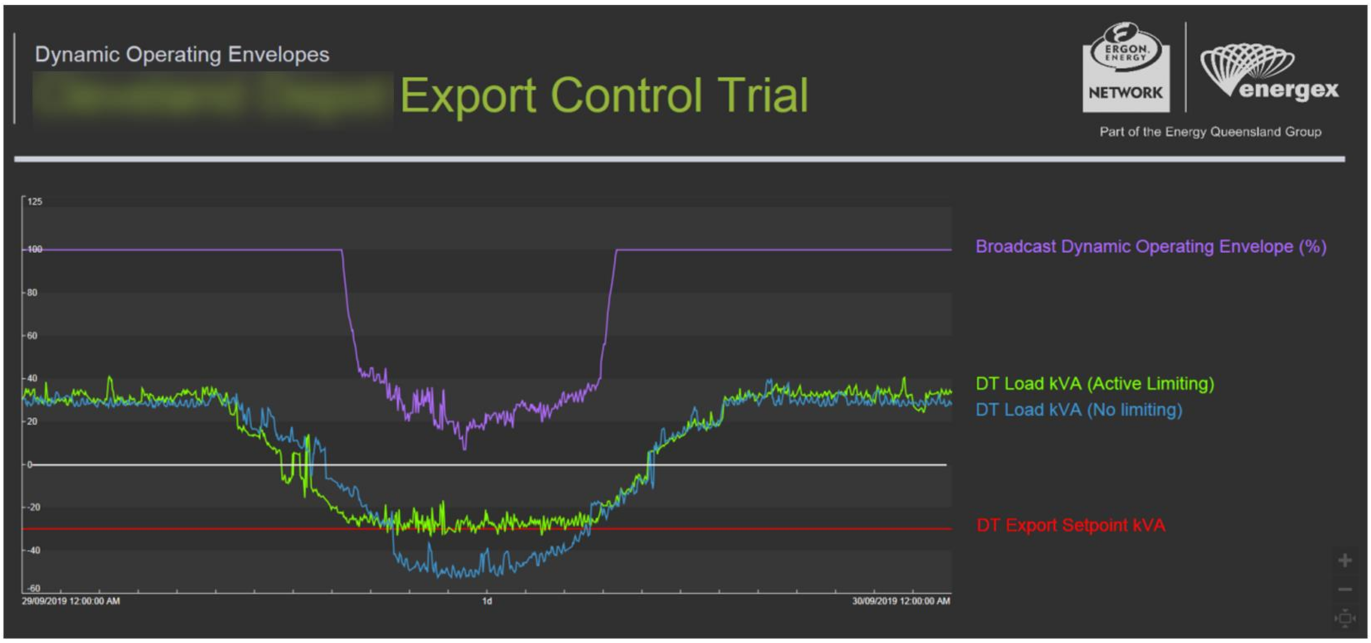


**Figure 6: Dynamic Operating Envelope Weekend Curtailment Trial**

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16 EE and EX Business cases 108 and 109 (Strategic Proposal Power Quality)

17 EQL Business case 98 (Strategic Proposal LV Network Safety)

### *Distributed Energy Resources Management System (DERMS)*

The DERMS system intends to initially cater for a (relatively) low quantity of high criticality, high complexity connections to medium and large scale (>1.5MW) DER assets. As the penetration and diversity of DER in the network increase, the DERMS will allow EQL to dynamically manage network constraints and maximise export opportunities for our customers at an MV & HV level. The program would enable direct interaction with large scale DERs and relevant market participants and intends to incorporate:

1. A dedicated, commercial DERMS software platform, either standalone or fully integrated within the ADMS.
2. Interfaces to the LVMP for reach beyond the distribution transformer.
3. Standardised operational rule sets that can be easily applied to new DER assets and updated on mass.
4. Standardised two-way communication methodology, making use of the dedicated large customer communication digital security zone[18].

With standardisation that the DERMS intends to provide, it is expected to facilitate an important step in the development of dynamic connection agreements and potentially associated network tariffs.

*"…connection agreements should allow for the dynamic engagement of DER in the power system, and energy customers should have a right to initiate a review of their connection agreement and the opportunity to receive a better deal." (CEC, 2019)*

An important example use case for this system would be to facilitate the application of dynamic limits to DER connected to constrained overhead lines, based on prevailing weather conditions.

#### *Case Study*

*Energy Queensland recognises the need to maximise the utilisation of its existing assets and invested in its dynamic conductor capacity monitoring capabilities in 2018. The technology was applied to 29 constrained overhead feeders in the Ergon distribution and sub-transmission network.*

*The chart below shows the indicative average annual performance improvement of the selection of feeders beyond their static limit, with a median improvement across all feeders of* ***11.65%.***

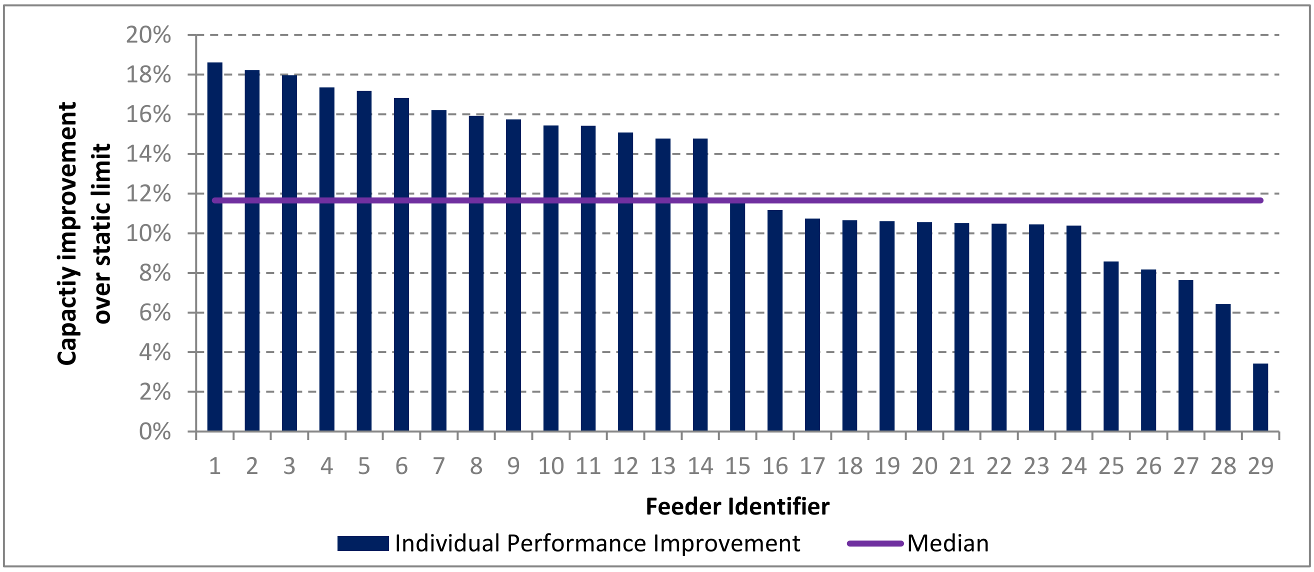


**Figure 7: Real time Capacity Monitoring Indicative Annual Performance results**

[18] EQL Business case 131 (Strategic Scope Enabling a Secure Data Zone)

### *Demand Response System (DRS)*

This capability would expand the existing Audio Frequency Load Control (AFLC) direct load control capability responsible for 700+MW across EQL to utilise individually addressable, market sourced loads for network support. The intent is to invest in Energy Queensland's technical systems and capabilities to interact with third party aggregators and virtual power plants (VPPs) to allow for the purchase and control of load in specific areas as required. This would occur in a manner that is effectively integrated with existing load control operational capability and systems with minimal impact on required resources.

*"The advent of connectable and controllable appliances and the 'Internet of things' presents an opportunity for load shifting so that customers can optimise energy supply arrangements and make a return on their DER investment." (CEC, 2019)*

### *Case Study*

*In October 2019, Energex initiated a "market-delivered demand response" pilot by engaging with a diverse group of service providers. Whilst the objectives of a pilot are many, one of the major outputs is to inform EQL network businesses how IPDRS (Internet Protocol Demand Response System) technology will integrate with customers, aggregators and electricity networks.*

*The key objective is to understand the functional requirements for the network's DRS (as a Remote Agent) which in turn will allow delivery of the technical build specifications. The goal will be the ability to deliver automated control signalling to IPDRS service providers via a standardised communication path (either directly or through a DSO model as considered to be likely in the future by the AER's DER investment guideline consultation).*

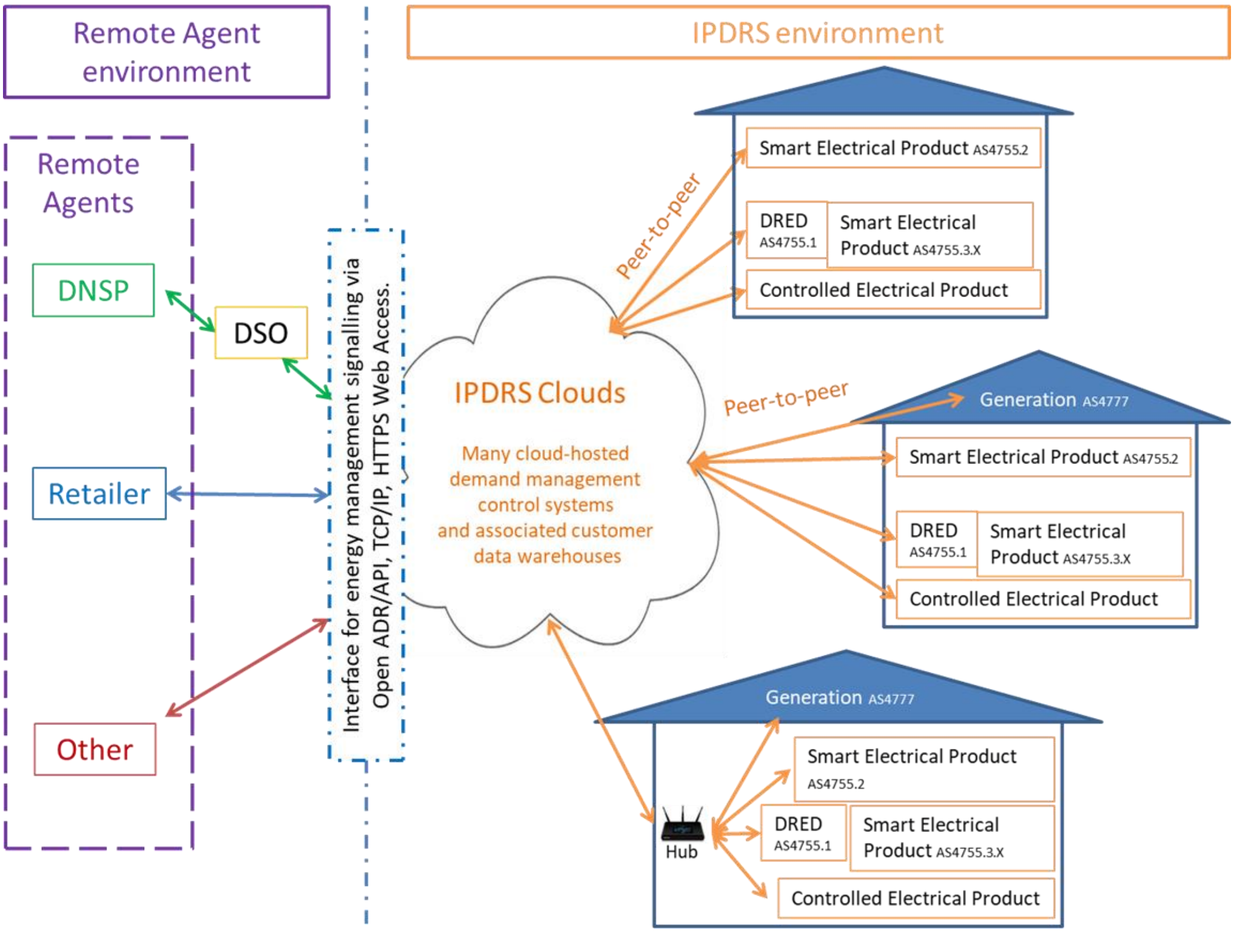


**Figure 8: The Internet Protocol Demand Response System (IPDRS)**

### *Real-Time Analytics (RTA)*

Energy Queensland recognises that we are living in an increasingly data driven and fast paced digital world. For an organisation with millions of customers, endpoints and assets there is high potential, with the right set of tools and expertise, for significant value to be realised through the effective use of data.

The intent of the Real Time Analytics program is to bring together all the operational and asset data sources described in the previous sections into a single, best practice platform. The platform would be used for both ad-hoc analysis and ongoing, in operation tuning of operating envelope algorithms.

It is expected that real time analytics and machine learning will form a key part of automated auditing of dynamic export connection agreements, ensuring that market participants are fulfilling their contractual obligations.

> ***Case Study***
>
> *Energy Queensland recognises that as well as the right tools, we need the right people and skills to maximise value from 'big data'. In 2019, Energy Queensland set the foundations for the new $I^2$Gradute program, targeted at students in data science, computing science, computational maths and information technology.*
>
> *With key opportunity areas in cloud computing, artificial intelligence, data visualisation and data analytics the program is expected to provide the skills required to drive the best outcomes and value from initiatives such as the Real Time Analytics program.*

### *Digital Control Room Visualisation (DCRV)*

This pilot initiative would allow the information associated with customers and the LV network state to be combined with ADMS and distilled into situational awareness for the Control Rooms, allowing faster outage management and improved network restoration.

The aim is to move Control Rooms to a more holistic approach to situational awareness by implementing the concept of a 'single pane of glass' to provide contextualised information to the users when and where they need it. This will also enable EQL to increase the number of users making use of the system, particularly for major weather events.

Benefits will include faster response to events, as well as the ability to prepare better and predict issues and develop responses before the issue becomes an outage.

### *Digital Power Worker Network Awareness (DPWNA)*

As more real-time information about lower levels in the network becomes available, it provides significant potential productivity, safety and performance improvements as well as enhanced customer service benefits. This initiative aligns with customer feedback and front-line customer service staff that readily accessible data will improve outcomes and increase efficiencies in operations.

This extended pilot initiative would provide relevant 'live' network status and performance information directly to a selection of EQL's field-based workers to improve customer response, efficiency in decision making, fault management, and overall safety outcomes. Providing live network information overlaid across a modern digital interface will give greater visibility and customer service. This will provide a better result for customers when there are faults and complaints regarding voltage on the network.

The pilot will be validated in an iterative fashion via regular feedback from field workers with a view to expand the capability to the wider organisation in the next regulatory period should the identified benefits justify further expenditure.

***Case Study***

*As part of the Solar Enablement Initiative (SEI) in 2018, a real time LV Adaptive State Estimation algorithm was put into practice in an inner-city suburb of Brisbane. As well as acting as a proof of concept for a number of the programs referenced above, it highlighted the large quantity of useful data that these programs might be able to provide to Control Rooms and field workers.*

*To demonstrate this, a series of displays and a real time map showing live voltages and power flows were built using standard, off the shelf tools and made available in various formats for users.*


**Figure 9: Adaptive State Estimation visualisation options for control room or field workers.**

*A further trial was conducted in 2018 a remote area near ROMA, where more live SCADA (recloser, circuit breaker, transformer data) was incorporated in map layers of data with communications equipment and power quality monitors and made available on a touchscreen tablet.*

*The initial results of the contextualised information displays were promising, particularly in the 'on the ground' diagnosis of voltage complaints where significant travel or complex phone calls to the control room may have been ordinarily required.*

### *Option 2: Benefits*

The monetary benefits below are based entirely on the unlocked market value of constrained generation, starting in 2022. It is expected that by the end of the 2020/25 regulatory period, approximately $7.1 million of curtailment could be avoided, with this benefit growing to $44.9 million by 2035.

The benefits are calculated by applying a realistic rate of connecting new and existing business customers to the Intelligent Grid Enablement program and allowing full export during the periods described in *Section 2.2 Business-as-usual service costs*.

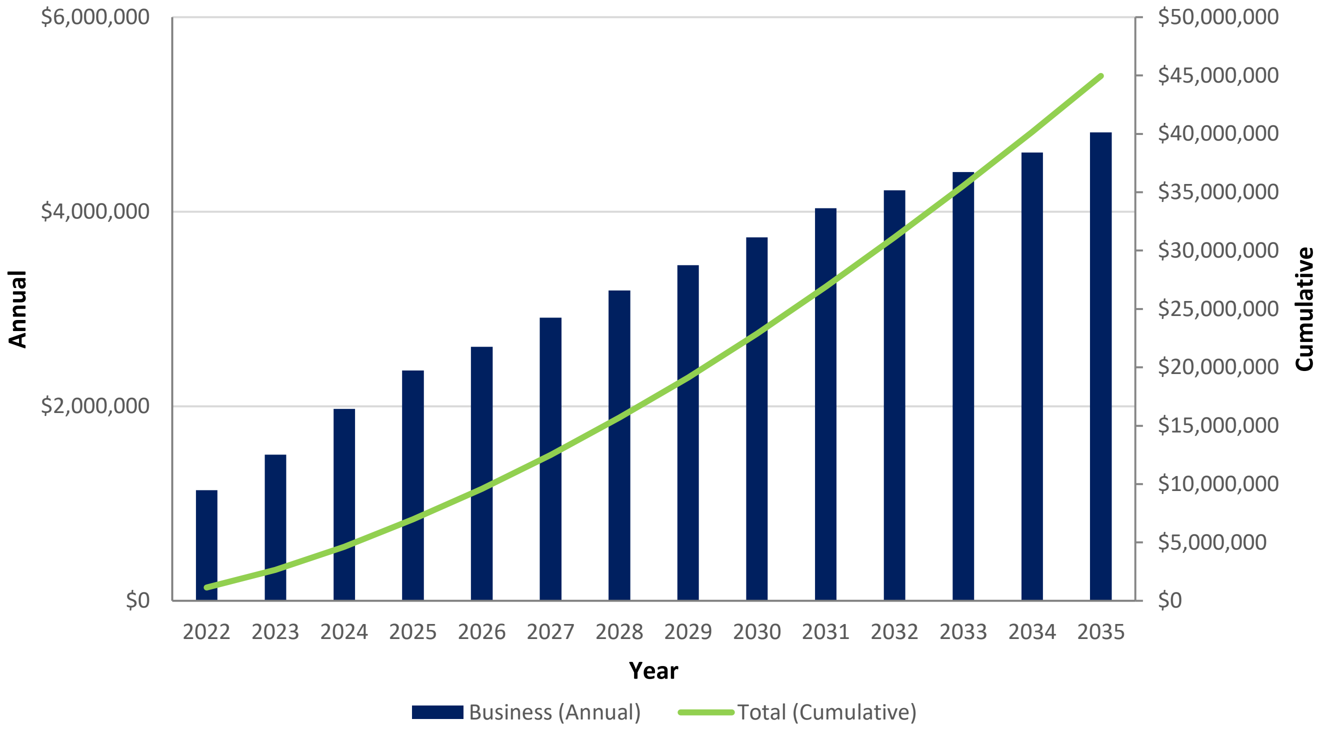


**Figure 10: Market value of unlocked energy from business PV export via IGE**

### *Option 2: Key assumptions*

The monetary benefits above are subject to the following assumptions[19]:

- 3 kWh[20] generated per 1 kW of installed PV capacity per day on non-business days. This is considered conservative to allow for some onsite consumption and possible curtailment on the worst case non-business days.
- All new export limited business customers are included in the program, starting 2022.
- 50% of existing export limited business customers are converted onto the program by 2025 and 80% of existing export limited business customers are converted onto the program by 2032. This rapid uptake is assumed to be realistic given the expected short payback of the low cost retrofit necessary to enable broadcast dynamic operating envelopes (export limits).

[19] Refer to NPV sheet, 'PVForecasts' tab for more detail and assumptions
[20] CEC - Consumer guide to buying household solar panels indicates an average of 4.2 kWh per 1 kW for Qld.

### *Option 2: Additional Benefits*

There are a number of benefits to the program that have not been included due to difficulty in accurately estimating value. Energy Queensland has prudently assigned no monetary value to these but does expect some to be realised and improve the overall NPV of these options within the 2020/25 period.

- Energy Queensland has a number of situations with large mines and solar farms on the same HV feeders. The solar farm generation constraints are sized based on an average mine load whereas in reality the load is highly volatile. A high speed DERMS could potentially accurately match the load with the solar generation for increased network stability, power quality and market benefit.
- The establishment of network state estimation and sustainable dynamic connection agreements may lay the groundwork for more accurate Distribution use of System (DUOS) charges in the future. These tariffs could have large potential benefits to battery customers and the market, as well as incentivise investment in areas of network need.
- Wider environmental benefits due to overall increased clean energy supply.
- Active control of DER will compliment power quality strategies and give a ‘first tier’ option to resolve issues before augmentation is required.

In addition, an overall increase in the volume of real time and recorded data across the network enables:

- Increased network visibility to enable faster response for unexpected failures and complaints, as well as greater clarity of potential failure points.
- Increased visibility of downstream DER and LV network activity could add efficiency to customer connection studies, potentially improving the speed, accuracy and costs of those studies.
- Identification of higher loss areas of the network for increasing the potential value of localised generation.
- Higher quality data inputs into network simulation software, which in turn reduces network risks for new technologies and configurations, both on the customer side and the network side.
- Improved datasets to remotely monitor assets without the need for on-site inspections, which is especially valuable for Ergon Energy where site visits are a costly component of any on location work.
- Power worker situational awareness as the front line of customer response – being able to have current and correct information.

### *Option 2: Capital Costs*

It is expected that the Intelligent Grid Enablement program will be provided by a number of different technologies and vendors as the requirements mature over the investment period.

The Intelligent Grid Enablement program financials comprises the spend profile below and is broken down by the Energex and Ergon Energy networks. The numbers below are based on direct, 2018/19 dollars.

**Table 5: Intelligent Grid Enablement annual expenditure forecast ($'000s); period 2020-2025**

| Intelligent Grid Enablement | DNSP | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|---|
| **Low Voltage Management Platform** | **Energex** | $0 | $4,760 | $0 | $2,100 | $350 | **$7,210** |
| | **Ergon** | $0 | $2,040 | $0 | $900 | $150 | **$3,090** |
| **Demand Response System** | **Energex** | $1,085 | $420 | $0 | $350 | $0 | **$1,855** |
| | **Ergon** | $465 | $180 | $0 | $150 | $0 | **$795** |
| **Distributed Energy Resources Management System** | **Energex** | $0 | $3,600 | $240 | $300 | $0 | **$4,140** |
| | **Ergon** | $0 | $2,400 | $160 | $200 | $0 | **$2,760** |
| **Real Time Analytics** | **Energex** | $1,200 | $900 | $1,560 | $720 | $870 | **$5,250** |
| | **Ergon** | $800 | $600 | $1,040 | $480 | $580 | **$3,500** |
| **Digital Control Room Visualisation** | **Energex** | $0 | $0 | $200 | $100 | $100 | **$400** |
| | **Ergon** | $0 | $0 | $200 | $100 | $100 | **$400** |
| **Digital Power Worker Network Awareness** | **Energex** | $0 | $0 | $200 | $100 | $100 | **$400** |
| | **Ergon** | $0 | $0 | $200 | $100 | $100 | **$400** |
| **Total** | | **$3,550** | **$14,900** | **$3,800** | **$5,600** | **$2,350** | **$30,200** |

### *Option 3: Traditional Augmentation*

The alternative to a technology-based method to increase hosting capacity is by augmenting the network beyond which may be required for traditional power quality purposes.

The power quality regulatory proposals[21] are requesting approximately $23M for augmentation due to forecasted PV related power quality issues in the 2020-25 period. This work assumes no change to the export limiting connection standards and only allows Energex and Ergon Energy to address forecasted customer complaints.

Option 3 addresses the significant additional augmentation that would be required to enable maximised export in feeders with new and existing business customers.

- For existing and future business customers wishing to export energy, a network study will be required, and an investment plan put in place to modify network as needed.
- For areas where hosting capacity was constraining customers in some way despite completion of re-balancing and tap changing, more expensive augmentation solutions would be proposed such as re-conductoring and additional or upgraded distribution transformers. This would provide passive management by sizing the network capacity to meet the current and best estimate of future customer choice expectations.

The Electricity Network Transformation Roadmap (ENTR) modelled ~$1.6B in augmentation would be required across the NEM between 2021-26 to deal with PV and battery hosting capacity unless other means were deployed.

### *Option 3: Benefits*

The monetary benefits below are based entirely on the market value of previously constrained generation. The benefits are calculated by upgrading all existing (~766) and new business LV networks with zero and partial export agreements associated with them to allow for full export agreements. With the extensive initial augmentation program, the expected benefits would be in the order of $10.1 million in the 2020/25 period, growing to $53.9 million by 2035.

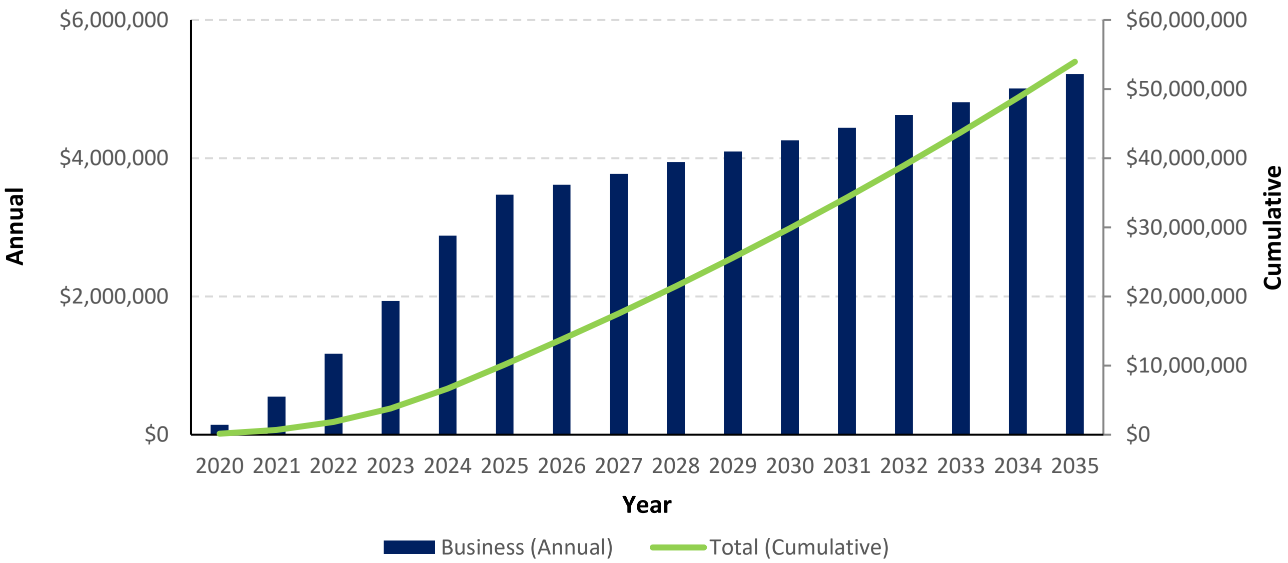


**Figure 11: Market value of unlocked energy from business PV via augmentation**

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[21] EE and EX Business cases 108 and 109 (Strategic Proposal Power Quality)

### *Option 3: Key assumptions*

- All existing and forecasted networks with constrained generation (~1229) are upgraded by 2025, starting at a rate of 10% per annum in 2020/21 and accelerating to 30% per annum by 2024/25.
- Beyond 2025, networks are upgraded as new constrained generation customers are connected (average of ~110 per annum), with a 6 month in delay following connection.
- Base case PV forecast at $50/MWh market value decreasing by 2% by 2035 as per Option 2.

### *Option 3: Capital Costs*

Costs to allow full export to business customers via network augmentation are estimated using historical spend and are in addition to any augmentation work proposed in the Power Quality business cases, which assume no changes to existing zero/partial export policies. The historical LV augmentation cost due to PV related problems is approximately $50,000 per transformer segment, based on Ergon Energy median spend on PV related issues between 2012 and 2018. This costing is conservative as augmentation to allow full export is likely to be more expensive than simple power quality corrective measures.

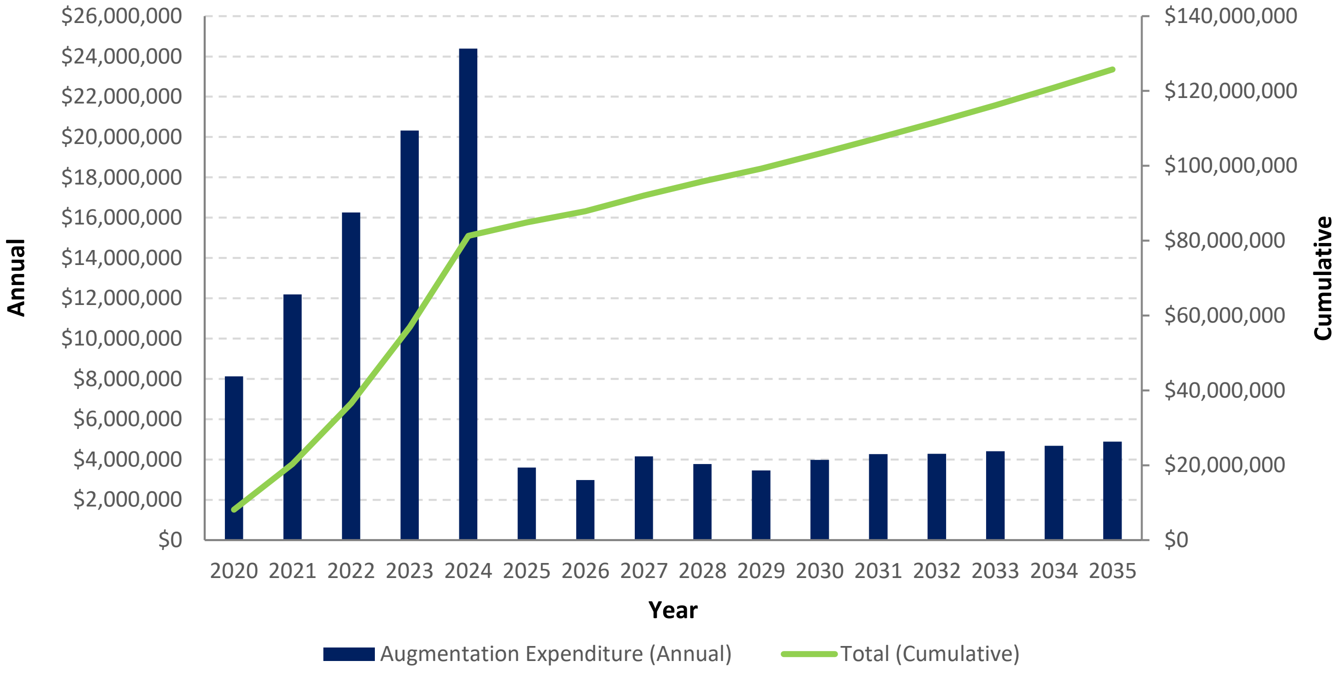



**Figure 12: Augmentation expenditure profile to unlock export limited business PV**

The above assumes the base forecast case. The table below considers the sensitivities of the high and low forecast cases (within the next regulatory period only).

**Table 6: Traditional augmentation additional annual expenditure forecast; period 2020-2025**

| Traditional Augmentation | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | Total |
|---|---|---|---|---|---|---|
| **Low Case** | $6,320,927 | $9,481,390 | $12,641,854 | $15,802,317 | $18,962,780 | **$63,209,268** |
| **Base Case** | $8,130,840 | $12,196,261 | $16,261,681 | $20,327,101 | $24,392,521 | **$81,308,404** |
| **High Case** | $9,861,421 | $14,792,131 | $19,722,841 | $24,653,552 | $29,584,262 | **$98, 614,207** |

## 3.3 Economic analysis of identified options

### 3.3.1 Cost versus benefit assessment of each option

Based on the costs and benefits described in the previous section, the Net Present Value (NPV) to FY2035/36 for each option has been determined using the EQL standard NPV analysis tool. The Regulated Real Pre-Tax Weighted Average Cost of Capital (WACC) rate of 2.62% has been applied as the discount rate for this analysis (as per EQL's Standard NPV Tool).

Variation in costs +/-10% and sensitivity to benefits based on current PV forecasts were considered. The final results are shown in Table 7 below, which reveal that Option 2 provides a better NPV than the other options. Option 1 has been taken as the base case for this analysis and represents an estimated market loss of $120 million in generation in the medium growth forecast between 2019 and 2035.The benefits for Options 2 and 3 are therefore derived from the relative reduction in curtailment that would otherwise have been incurred under Option 1.

**Table 7: NPV for options considered**

| Option | Total Expenditure 2020-2025 (PV $M) | NPV 2035 ($M) |
|---|---|---|
| **Option 1: Continue with existing static limit approach** | 0 | 0 |
| **Option 2: IGE program for business customers** | (28.5) | 3.8 |
| **Option 3: Traditional augmentation** | (104.4) | (65.5) |

Note at this time there is no intention to extend the program to individual residential customers within the 2020-25 regulatory period, however the program architecture will be designed to begin accepting residential customers beyond 2025 and the costings above assume this.

Option 2 provides a balanced approach to reducing the risks associated with the counterfactual case and as such is the preferred option.

## 3.4 Scenario Analysis

### 3.4.1 Sensitivities

There are potentially three different DER growth scenarios in terms of the need for technology for hosting capacity:

- Low Growth
- Medium Growth (Current trajectory)
- High Growth

The impact of each of these scenarios on PV and Storage uptake in the Ergon Energy and Energex areas is shown in Appendix G. Each scenario was analysed for their impact on the NPV calculated for each option. It's key to note that the Intelligent Grid Enablement program is about unlocking hosting capacity, but the capability is not linear. The spend profile is developed using a model of initial capability and then step change in incremental capability. This is generally represented by an additional acquisition of capability through additional software licenses and the associated engineering and configuration services. The necessary expenditure under each scenario is shown in **Error! Reference source not found.**.

The options analysis shows that *Option 2: IGE program for business customers* is more cost-effective than traditional augmentation and that the greater the DER penetration, the more cost-effective the solution becomes.  The medium growth scenario has been chosen as it is the most likely scenario for

PV growth and thereby represents a responsible approach to the development of a sustainable enablement program.

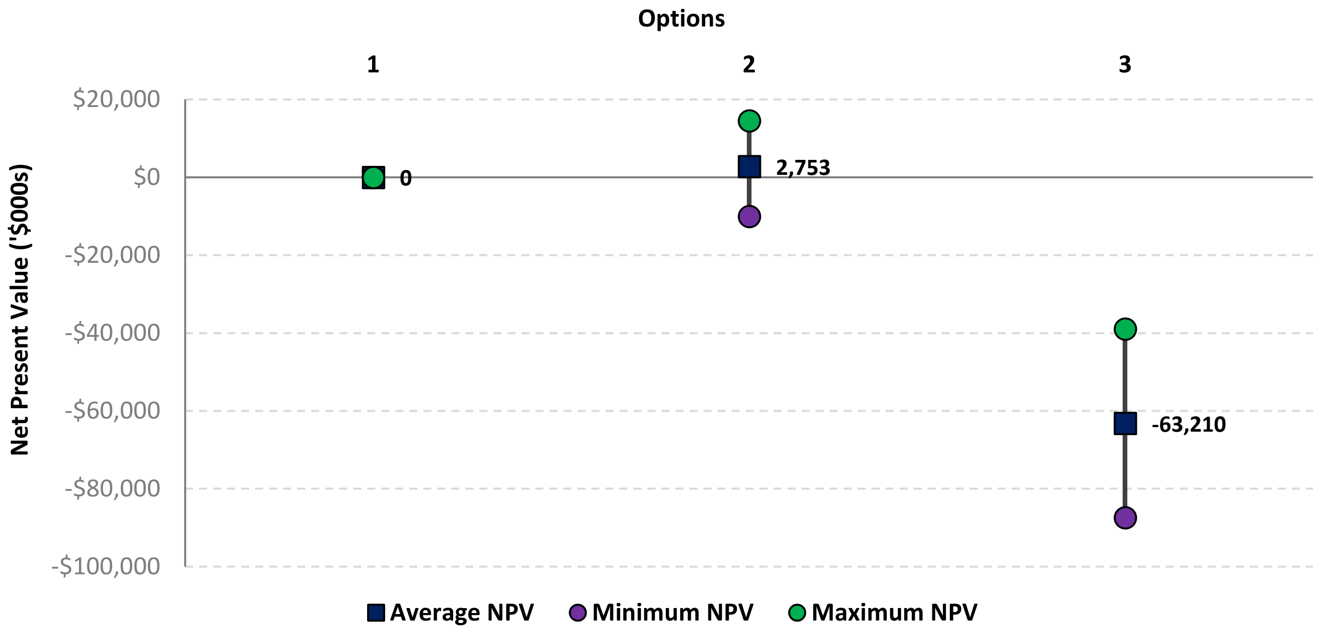



**Figure 13: Monte Carlo NPV Outcomes**

This compares the four scenarios over 3000 Monte Carlo iterations with moderate, high and low levels of PV uptake. While augmentation costs are roughly double that of IGE out to 2025 these assets are designed to have a much longer life.

### 3.4.2 Value of regret analysis

The analysis reveals a significantly better NPV for Option 2 than Option 3 regardless of cost variations and which growth scenario is selected, with some potential for Option 2 to perform worse that Option 1. Considering Option 1 represents an estimated market loss of $120 million in generation, Energy Queensland believes *Option 2: IGE program for business customers* represents a better longer-term sustainable development to support customer requirements in the future and is the least-regret option of choice.

## 3.5 Qualitative comparison of identified options

### 3.5.1 Advantages and disadvantages of each option

Table 8 below details the advantages and disadvantages of each option considered.

**Table 8: Assessment of options**

| Options | Advantages | Disadvantages |
|---|---|---|
| Counterfactual | | • **Risk:** This option introduces the highest risks as detailed in Section 2.4, which are not considered to be ALARP.<br>• **Cost:** Taking no action to address these risks would lead to higher costs to address them in the future and greater cost for customers.<br>• **Customer Choice:** Failure to address these issues would reduce customer choice, limiting their ability to engage with the grid and take advantage of the opportunities presented by new technologies.<br>• **Business:** Ongoing limited network capacity operation – not getting to reach true value of overall network capacity. |
| Option 2: IGE program for business customers | • **Risk:** This option provides a balanced approach to reducing the risks associated with the counterfactual case.<br>• **Cost:** This option provides the best return on investment.<br>• **Customer choice:** This option enables the greatest range of customer choice for the lowest spend. | • **Risk:** As per the other options, the coverage of the program would be limited relative to the size of the overall network. |
| Option 3: Traditional Augmentation | | • **Risk:** This option would not mitigate the risks described in Section 2.4 to the same degree that Option 2 would, leaving a variety of risks unaddressed.<br>• **Cost:** This option would result in significantly higher costs than the other options, at around double the cost. |

### 3.5.2 Alignment with network development plan

Several elements of the Electricity Network Transformation Roadmap relate to this initiative. The first is Intelligent Networks and Markets. The expectation is that in the 2020-2025 period, Energex and Ergon have a suite of grid intelligence and control architectures to automate distributed energy resources markets as well as providing system security. The second is Customer Orientated Electricity where it is expected that collaboration with customers and market actors will create new value with streamlined connections. The third is Power System Security where distribution networks provide visibility of DER and potentially enable Frequency Control Ancillary Services (FCAS) and other delegated balancing services through real-time communications and controls.

This is provided in more detail in the Future Grid Roadmap document.

### 3.5.3 Alignment with future technology strategy

This program is based on the strategies defined in the Future Grid Roadmap and the Intelligent Grid Technology Plan. From these strategies, a suite of technology solutions and their associated costing and benefits have been described to deliver on these strategic aims. This program of works is therefore essential to allowing Energy Queensland to deliver on its vision for the Future Grid Roadmap, and will form the foundation for the transition process.

### 3.5.4 Risk Assessment Following Implementation of preferred option

**Table 9: Risk assessment showing risks mitigated following Implementation**

| Risk Scenario | Risk Type | Consequence (C) | Likelihood (L) | Risk Score | Risk Year |
|---|---|---|---|---|---|
| **Without the Intelligent Grid Enablement (IGE) program** EQL risks being unable to cost effectively unlock the existing and future value of constrained generation, resulting in loss of customer trust and action groups formed. | Customer | Original | | | 2020-2025 |
| | | 3 *(Loss of customer trust / action groups formed)* | 6 *(Almost certain)* | **18 *(High Risk)*** | |
| | | Mitigated | | | |
| | | 3 *(Loss of customer trust / action groups formed)* | 3 *(Unlikely)* | **9 *(Low Risk)*** | |
| **Without the IGE program** EQL risks being unable to adequately influence load and generation at the customer ends of the network, leading to **network performance issues** and **interruptions to >15,000 customers**[22/23]. | Customer | Original | | | 2020-2025 |
| | | 4 *(Interruption to >15,000 customers)* | 3 *(Unlikely)* | **12 *(Moderate Risk)*** | |
| | | Mitigated | | | |
| | | 4 *(Interruption to >15,000 customers)* | 2 *(Very unlikely)* | **8 *(Low Risk)*** | |
| **Without the IGE program** EQL risks being unable to meet customer expectations with flexibility of choice (e.g. PV, Batteries) when they connect to the network resulting in **adverse national media attention and loss** | Customer | Original | | | 2020-2025 |
| | | 4 *(Adverse national media attention)* | 3 *(Unlikely)* | **12 *(Moderate Risk)*** | |
| | | Mitigated | | | |
| | | 4 *(Adverse national media attention)* | 2 *(Very unlikely)* | **8 *(Low Risk)*** | |

22 https://www.abc.net.au/news/2019-01-25/sa-blackouts-related-to-heat-not-network-sapn-says/10748884

23 https://www.abc.net.au/news/2018-01-29/melbourne-heat-brings-hottest-night-of-summer-blackouts/9369228

| Risk Scenario | Risk Type | Consequence (C) | Likelihood (L) | Risk Score | Risk Year |
|---|---|---|---|---|---|
| **of public trust.** | | | | | |
| **Without the IGE program** EQL risks being unable to detect an asset issue within the network or latent safety issue due to the lack of LV network data **resulting in a single fatality.** | Safety | Original | | | 2020-2025 |
| | | 5 *(Single fatality / incurable fatal illness)* | 3 *(Unlikely)* | **15** ***(Moderate Risk)*** | |
| | | Mitigated | | | |
| | | 5 *(Single fatality / incurable fatal illness)* | 2 *(Very Unlikely)* | **10** ***(Low Risk)*** | |
| **Without the IGE program, unmonitored growth** in DER related energy flows may result in increasing complexities in field and control room operations and significant impact on any restoration or planned works >$1million. | Business | Original | | | 2020-2025 |
| | | 4 *(Business cost of >$1million)* | 4 *(Likely)* | **16** ***(Moderate Risk)*** | |
| | | Mitigated | | | |
| | | 4 *(Business cost of >$1million)* | 3 *(Unlikely)* | **12** ***(Moderate Risk)*** | |
| **Failure to implement the IGE program** leads to EQL being unable to meet its strategic commitments to enable customer choice and flexibility around energy usage and price. This results in EQL being **unable to meet its strategic objectives** which could lead to **additional costs to the business.** | Business | Original | | | 2020-2025 |
| | | 4 *(Unable to deliver an agreed strategic initiative)* | 5 *(Very Likely)* | **20** ***(High Risk)*** | |
| | | Mitigated | | | |
| | | 4 *(Unable to deliver an agreed strategic initiative)* | 2 *(Very Unlikely)* | **8** ***(Low Risk)*** | |

# 4 Recommendation

## 4.1 Preferred option

The preferred option is *Option 2: IGE program for business customers* occurring in stages based upon the growth in PV and battery energy storage systems. The initial period (20/21) will focus on planning and pilot areas. It is expected that in 21/22 and 22/23 most of the infrastructure will be installed and then capacity expanded over the remainder of the period. The funding required to support a program of work in Intelligent Grid Enablement for Energy Queensland is $30.2 million (real 2018/19 dollars).

The initial period includes development of technology pilot and trials utilising DMIA funding and other sources (e.g. ARENA) to test concepts. The insights will assist in defining product specifications before procuring the service from the market.

## 4.2 Scope of preferred option

Pilots will be conducted for Digital Control Room Visualisation and Digital Power Worker Network Awareness to better understand and quantify the benefits of such a program as well as the complexity of a widescale rollout.

For each of the remaining 4 component areas, the scope will comprise Operational Technology (OT) software systems, customisations and integration, and interfaces with real-time data sources e.g. smart meters. The scope for each of the components is as follows:

- Develop requirements, use cases, and technology architecture.
- Determine which components will be developed in-house versus procured from the market.
- TOTEX analysis for software-as-a-service (SaaS) in lieu of a traditional CAPEX approach to project delivery and ownership.
- Procurement and delivery of technology services and capabilities where appropriate.
- Training of internal resources and development of technology champions within the “field organisation”
- Operationalisation of the component within the business.

# Appendix A. References

**Note:** Documents which were included in Energy Queensland's original regulatory submission to the AER in January 2019 have their submission reference number shown in square brackets, e.g. Energy Queensland, *Corporate Strategy [1.001], (31 January 2019).*


AER, *Assessing DER integration expenditure (November 2019)*

AEMC, *Integrating Distributed Energy Resources for the Grid of the Future, Economic Regulatory Framework Review,* (26 September 2019).

CSIRO/Data61, *The Future of Energy in Queensland (2019)*

QCA, 2019–20 Solar feed-in tariff determination

CEC, *THE DISTRIBUTED ENERGY RESOURCES REVOLUTION,* (August 2019)

Electricity Networks Australia, *Electricity Network Transformation Roadmap: Final Report, 2017-27*, (April 2017).

Energex, *Distribution Annual Planning Report (2018-19 to 2022-23) [7.050]*, (21 December 2018).

Energy Queensland, *Asset Management Overview, Risk and Optimisation Strategy [7.025]*, (31 January 2019).

Energy Queensland, *Corporate Strategy [1.001],* (31 January 2019).

Energy Queensland, *Future Grid Roadmap [7.054],* (31 January 2019).

Energy Queensland, *Intelligent Grid Technology Plan [7.056],* (31 January 2019).

Energy Queensland, *Network Risk Framework*, (October 2018).

Ergon Energy, *Distribution Annual Planning Report (2018-19 to 2022-23) [7.049]*, (21 December 2018).

Energex & Ergon Energy, *Connection Standard, Micro Embedded Generating Units (0-≤30kVa),* (2017)

Queensland Government, Department of Energy and Water Supply, *Powering Queensland: Our Renewable Energy Achievements,* (July 2017)

# Appendix B. Acronyms and Abbreviations

The following abbreviations and acronyms appear in this business case.

| Abbreviation or acronym | Definition |
|---|---|
| $M | Millions of dollars |
| $ nominal | These are nominal dollars of the day |
| $ real 2019-20 | These are dollar terms as at 30 June 2020 |
| 2020-25 regulatory control period | The regulatory control period commencing 1 July 2020 and ending 30 Jun 2025 |
| ADMS | Advanced Distribution Management System |
| AEMC | Australian Energy Market Commission |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| AFLC | Audio Frequency Load Control |
| ALARP | As Low as Reasonably Practicable |
| AMP | Asset Management Plan |
| ANU | Australian National University |
| ARENA | Australian Renewable Energy Agency |
| Augex | Augmentation Capital Expenditure |
| BAU | Business as Usual |
| CAPEX | Capital expenditure |
| CSIRO | Commonwealth Scientific and Industrial Research Organisation |
| Current regulatory control period or current period | Regulatory control period 1 July 2015 to 30 June 2020 |
| DAPR | Distribution Annual Planning Report |
| DCRV | Digital Control Room Visualisation |
| DER | Distributed Energy Resource |
| DERMS | Distributed Energy Resources Management System |
| DNSP | Distribution Network Service Provider |
| DPWNA | Digital Power Worker Network Awareness |
| DR | Demand Response |
| DRS | Demand Response System |
| ENA | Energy Networks Australia |
| ENTR | Electricity Network Transformation Roadmap |
| EQL | Energy Queensland Ltd |
| EV | Electric Vehicles |

| Abbreviation or acronym | Definition |
| --- | --- |
| FCAS | Frequency Control Ancillary Services |
| GW | Gigawatt |
| HV | High Voltage (35 kV – 230kV) |
| IoT | Internet of Things |
| IT | Information Technology |
| KRA | Key Result Areas |
| kV | Kilovolt |
| kVA | Kilovolt Amperes |
| kW | Kilowatt |
| LV | Low Voltage (100 V - 1000 V) |
| LVMP | Low Voltage Management Platform |
| MSS | Minimum Service Standard |
| MV | Medium Voltage (1 kV - 35 kV) |
| MVA | Megavolt Ampere |
| MW | Megawatt |
| NBN | National Broadband Network |
| NEL | National Electricity Law |
| NEM | National Electricity Market |
| NEO | National Electricity Objective |
| NER | National Electricity Rules (or Rules) |
| Next regulatory control period or forecast period | The regulatory control period commencing 1 July 2020 and ending 30 Jun 2025 |
| NPV | Net Present Value |
| OPEX | Operational Expenditure |
| OT | Operational Technology |
| PCBU | Person in Control of a Business or Undertaking |
| Previous regulatory control period or previous period | Regulatory control period 1 July 2010 to 30 June 2015 |
| PV | Solar Photovoltaic |
| Repex | Replacement Capital Expenditure |
| RIN | Regulatory Information Notice |
| RIT-D | Regulatory Investment Test – Distribution |
| RTA | Real-time Analytics |
| RTS | Return to Service |
| SaaS | Software as A Service |

| Abbreviation or acronym | Definition |
|---|---|
| SAIDI | System Average Interruption Duration Index |
| SAIFI | System Average Interruption Frequency Index |
| SAMP | Strategic Asset Management Plan |
| SCADA | Supervisory Control and Data Acquisition |
| SEQ | South-East Queensland |
| SFAIRP | So Far as Is Reasonably Practicable |
| VPP | Virtual Power Plant |
| WACC | Weighted average cost of capital |
| ZS | Zone Substation |

# Appendix C. Alignment with the National Electricity Rules (NER)

The table below details the alignment of this proposal with the NER capital expenditure requirements as set out in Clause 6.5.7 of the NER.

**Table 10: Alignment with NER**

| Capital Expenditure Requirements | Rationale |
| --- | --- |
| **6.5.7 (a) (1)**<br>**The forecast capital expenditure is required in order to meet or manage the expected demand for standard control services.** | This project is required to meet the forecast growth in DER and the need to introduce solutions to address that growth. |
| **6.5.7 (a) (3)**<br>**The forecast capital expenditure is required in order to:**<br>**(iii) maintain the quality, reliability and security of supply of supply of standard control services**<br>**(iv) maintain the reliability and security of the distribution system through the supply of standard control services** | A key component of this proposal is the enablement of tools to deliver power quality and reliability in an environment of rapidly growing DER |
| **6.5.7 (c) (1) (i)**<br>**The forecast capital expenditure reasonably reflects the efficient costs of achieving the capital expenditure objectives** | The Unit Cost Methodology and Estimation Approach sets out how the estimation system is used to develop project and program estimates based on specific material, labour and contract resources required to deliver a scope of work. The consistent use of the estimation system is essential in producing an efficient CAPEX forecast by enabling:<br>• Option analysis to determine preferred solutions to network constraints<br>• Strategic forecasting of material, labour and contract resources to ensure deliverability<br>• Effective management of project costs throughout the program and project lifecycle, and<br>• Effective performance monitoring to ensure the program of work is being delivered effectively.<br>The unit costs that underpin our forecast have also been independently reviewed to ensure that they are efficient (Attachments 7.004 and 7.005 of our initial Regulatory Proposal). |
| **6.5.7 (c) (1) (ii)**<br>**The forecast capital expenditure reasonably reflects the costs that a prudent operator would require to achieve the capital expenditure objectives** | The prudency of this proposal is demonstrated through the options analysis conducted and the quantification of risk and benefits of each option.<br>The prudency of our CAPEX forecast is demonstrated through the application of our common frameworks put in place to effectively manage investment, risk, optimisation and governance of the Network Program of Work. An overview of these frameworks is set out in our Asset Management Overview, Risk and Optimisation Strategy (Attachment 7.026 of our initial Regulatory Proposal). |
| **6.5.7 (c) (1) (iii)**<br>**The forecast capital expenditure reasonably reflects a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objective** | Our peak demand forecasting methodology employs a bottom-up approach reconciled to a top-down evaluation, to develop the ten-year zone substation peak demand forecasts. Our forecasts use validated historical peak demands and expected load growth based on demographic and appliance information in small area grids. Demand reductions, delivered via load control tariffs, are included in these forecasts. This provides us with accurate forecasts on which to plan. |

# Appendix D. Mapping of Asset Management Objectives to Corporate Plan

This proposal has been developed in accordance with our Strategic Asset Management Plan. Our Strategic Asset Management Plan (SAMP) sets out how we apply the principles of Asset Management stated in our Asset Management Policy to achieve our Strategic Objectives.

Table 1: "Asset Function and Strategic Alignment" in Section 1.4 details how this proposal contributes to the Asset Management Objectives.

The Table below provides the linkage of the Asset Management Objectives to the Strategic Objectives as set out in our Corporate Plan (Supporting document 1.001 to our Regulatory Proposal as submitted in January 2019).

**Table 11: Alignment of Corporate and Asset Management objectives**

| Asset Management Objectives | Mapping to Corporate Plan Strategic Objectives |
|---|---|
| **Ensure network safety for staff contractors and the community** | **EFFICIENCY**<br>***Operate safely as an efficient and effective organisation***<br>Continue to build a strong safety culture across the business and empower and develop our people while delivering safe, reliable and efficient operations. |
| **Meet customer and stakeholder expectations** | **COMMUNITY AND CUSTOMERS**<br>***Be Community and customer focused***<br>Maintain and deepen our communities' trust by delivering on our promises, keeping the lights on and delivering an exceptional customer experience every time |
| **Manage risk, performance standards and asset investments to deliver balanced commercial outcomes** | **GROWTH**<br>***Strengthen and grow from our core***<br>Leverage our portfolio business, strive for continuous improvement and work together to shape energy use and improve the utilisation of our assets. |
| **Develop Asset Management capability & align practices to the global standard (ISO55000)** | **EFFICIENCY**<br>***Operate safely as an efficient and effective organisation***<br>Continue to build a strong safety culture across the business and empower and develop our people while delivering safe, reliable and efficient operations. |
| **Modernise the network and facilitate access to innovative energy technologies** | **INNOVATION**<br>***Create value through innovation***<br>Be bold and creative, willing to try new ways of working and deliver new energy services that fulfil the unique needs of our communities and customers. |

# Appendix E. Risk Tolerability Table

The Energy Queensland Network Risk Framework assesses individual risks in dimensions of Likelihood and Consequence according to a six by six risk matrix (Figure 16).

| Risk Analysis 6x6 multiplication R=C x L | | Consequence → | | | | | |
|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 |
| Likelihood ↑ | 6 | 6 | 12 | 18 | 24 | 30 | 36 |
| | 5 | 5 | 10 | 15 | 20 | 25 | 30 |
| | 4 | 4 | 8 | 12 | 16 | 20 | 24 |
| | 3 | 3 | 6 | 9 | 12 | 15 | 18 |
| | 2 | 2 | 4 | 6 | 8 | 10 | 12 |
| | 1 | 1 | 2 | 3 | 4 | 5 | 6 |

**Network Risks -** ***Risk Tolerability Criteria and Action Requirements***

| Risk Score | Risk Descriptor | Risk Tolerability Criteria and Action Requirements | | |
|---|---|---|---|---|
| 30 – 36 | ***Intolerable*** *( stop exposure immediately)* | | | |
| 24 – 29 | ***Very High Risk*** | ***ALARP** Risk in this range managed to As Low As Reasonably Practicable | **Executive Approval** ( required for continued risk exposure at this level ) | May require a full Quantitative Risk Assessment (QRA)<br>Introduce new or changed risk treatments to reduce level of risk<br>Periodic review of the risk and effectiveness of the existing risk treatments |
| 18 – 23 | ***High Risk*** | | **Divisional Manager Approval** (required for continued risk exposure at this level ) | Introduce new or changed risk treatments to reduce level of risk<br>Periodic review of the risk and effectiveness of the existing risk treatments |
| 11 – 17 | ***Moderate Risk*** | | **Group Manager / Process Owner Approval** (required for continued risk exposure at this level) | Introduce new or changed risk controls or risk treatments as justified to further reduce risk<br>Periodic review of the risk and effectiveness of the existing risk treatments |
| 6 – 10 | **Low Risk** | | | |
| 1 to 5 | ***Very Low Risk*** | | No direct approval required but evidence of ongoing monitoring and management is required | *Periodic review of the risk and effectiveness of the existing risk treatments* |

**Note: SOFAIRP to be used for Safety Risks and ALARP for Network Risks*

**Figure 14: A Risk Tolerability Scale for evaluating Semi-Quantitative risk score**

# Appendix F. AEMC Economic Regulatory Framework Review Commentary

The following is commentary from the AEMC Economic Regulatory Framework Review – "Promoting Efficient Investment in the Grid of the Future", in July 2018. This supports the need for programs to enable Intelligent Grid capabilities.

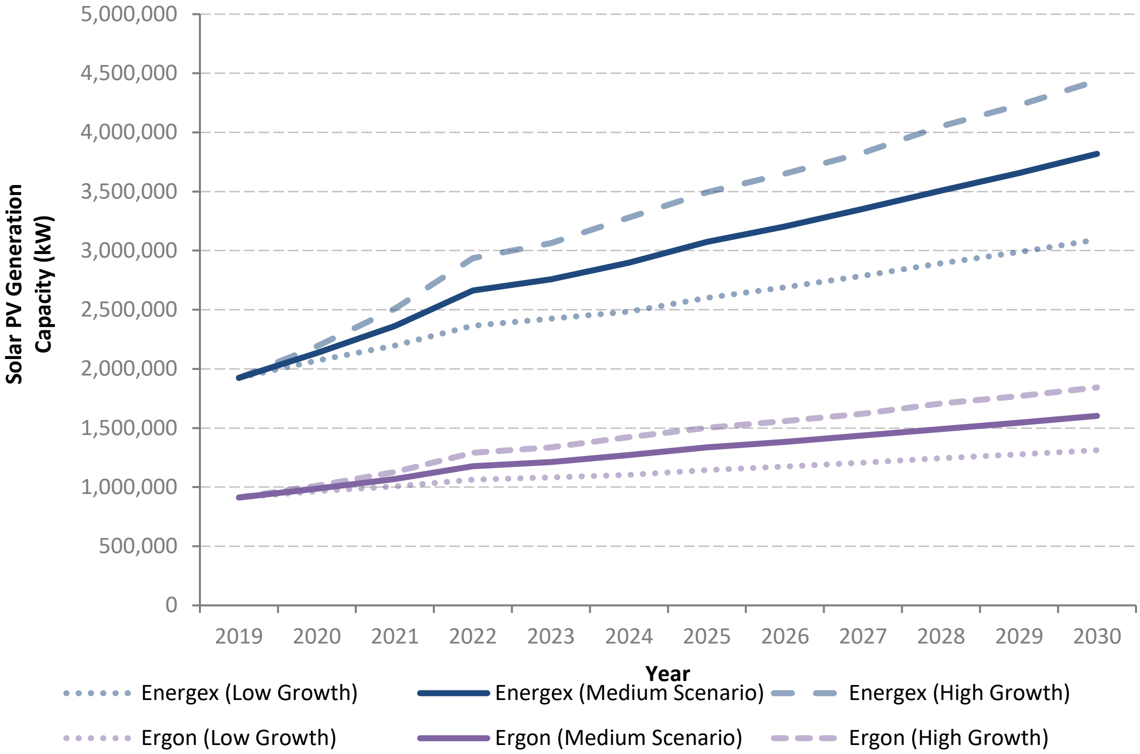
*In its first major review of the future role of distribution networks since its distribution market model project in 2017, the Australian Energy Market Commission drew the following recommendations and conclusions:*

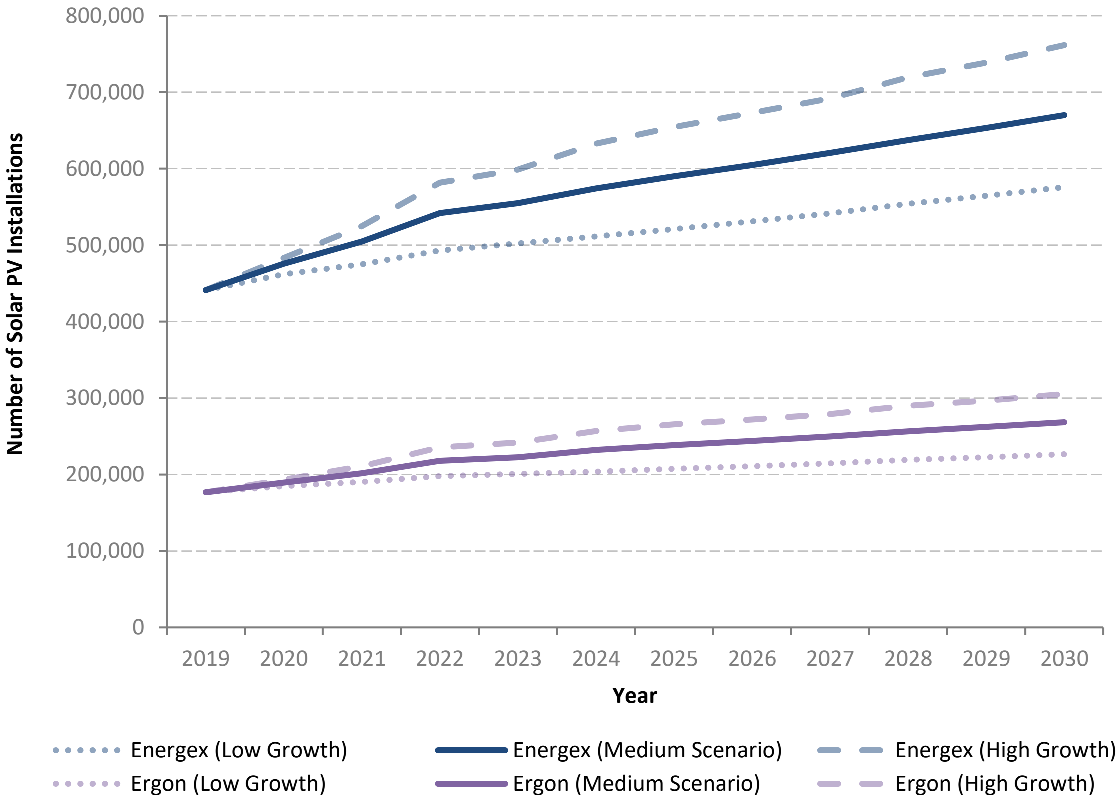
- *Static strategies such as network tariffs can minimise overall electricity network costs […] however, price signals and incentives alone will not prevent some technical issues arising at the network and system level*
- *Static export limits on export are a blunt approach to addressing the impact of distributed energy resources on the network*
- *Prohibiting new DER systems from exporting where local hosting capacity has been reached or imposing broad restrictions is unlikely to be efficient or to meet customer expectations*

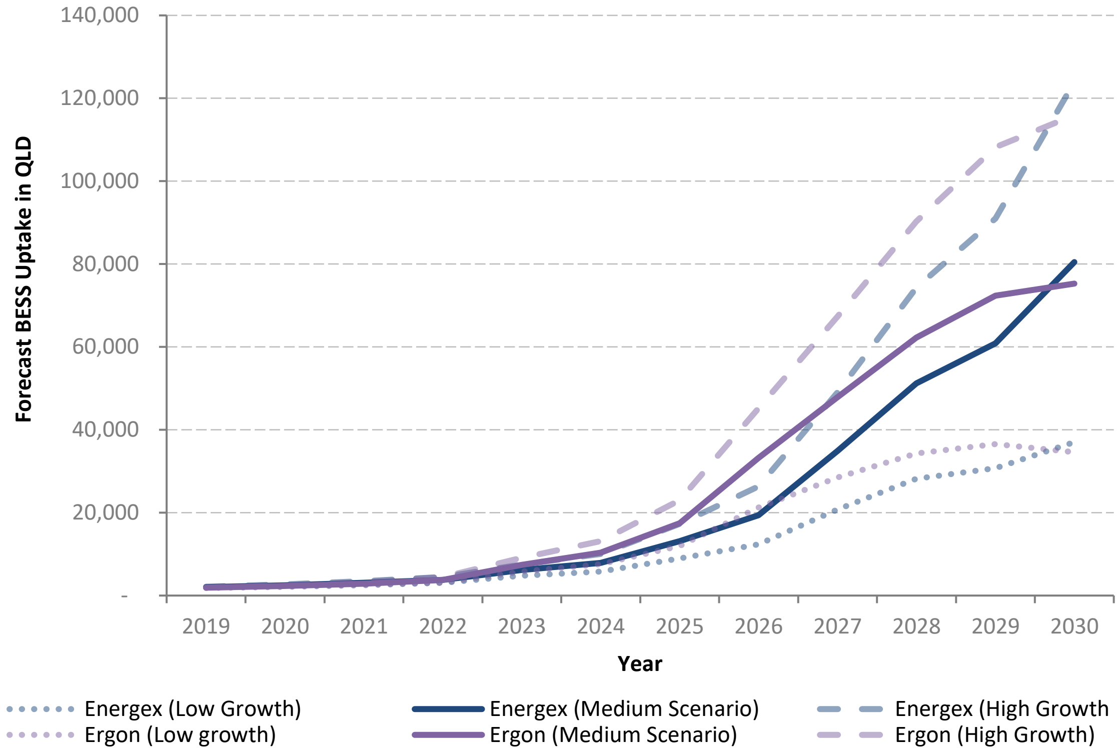
*AEMC considers a more sophisticated and dynamic approach such as managing output to meet security, reliability and safety needs of the network would be better suited to managing the increasing penetration of DER.*

# Appendix G. DER Growth Scenarios

The variation in DER uptake in the Ergon Energy and Energex regions under the low, medium, and high growth scenarios is shown in the figures below.

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Forecast BESS Uptake in QLD
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Year
Energex (Low Growth)
Ergon (Low growth)
Energex (Medium Scenario)
Ergon (Medium Scenario)
Energex (High Growth
Ergon (High Growth)

# Appendix H. Reconciliation Table

| Reconciliation Table<br>Conversion from $18/19 to $2020 | |
|---|---|
| **Business Case Value** | |
| **(M$18/19)** | $30.20 |
| | |
| **Business Case Value** | |
| **(M$2020)** | $31.32 |