Assessment of Open Energy Networks Frameworks

CLIENT: Australian Energy Market Operator and Energy Networks Australia

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Executive summary

Context and Background

The Australian energy system is embarking on a period of significant change, as it moves towards greater decentralisation and decarbonisation of energy generation. The integration of Distributed Energy Resources (DER) such as solar PV, storage and electric vehicles (EV), into the electricity system is crucial to delivering decarbonisation at lowest cost, while maintaining security of supply. Providing market access to DER will enable consumers to realise the full value of these technologies, helping to reduce their own energy bills as well as those for all consumers. Consequently, the integration of DER into the electricity and wider energy system is a key step in enabling the business case for smaller scale, low carbon and flexible technologies to facilitate the transition of the electricity system. A number of work programmes are underway to help deliver the integration of DER into Australian electricity markets.[1]

AEMO is the independent market operator with responsibility for running the National Electricity Market (NEM) and Wholesale Electricity Market (Western Australia) and maintaining the security of the overall electricity system. The NEM design is a mandatory gross pool, whereby AEMO is responsible for the scheduling and dispatch of all physical volume through the NEM Dispatch Engine (NEMDE), ensuring that supply and demand is balanced in real-time. As DER starts to displace larger transmission-connected thermal generation, AEMO will need visibility of that DER and mechanisms to ensure DER can access wholesale markets, in order to keep the system secure.

Distribution Network Service Providers (DNSPs) are responsible to customers and regulators for operating and maintaining the local networks to which DER connect. This requires them to manage distribution network capacity to ensure that DER can have access to the network when required, while maintaining network reliability and quality of supply for all customers. To do to this, while minimising investment costs, DNSPs will also need to actively manage DER on their networks using a range of technical and commercial tools. These will include access to flexible DER to help operate their systems. The key question is therefore, how to maximise market and network access for DER, and ensuring that the use of the flexibility DER can provide is optimised across the whole system.

The Open Energy Networks programme has brought together AEMO, DNSPs and wider stakeholders to consider the changes required to market frameworks, alongside network and system operations to help deliver these goals and realise the new value streams for DER. The programme has developed four high level Frameworks to illustrate the different market design options which might be used to integrate DER more completely into the electricity system. The Frameworks were described as follows[2]:

- **The Single Integrated Platform (SIP):** The single platform model envisages a unitary point of entry to the entirety of the NEM and WEM. Under this option, the platform would be an extension of the wholesale market. AEMO would provide the platform as part of its

[1] These include the NEM 2025 project: http://coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/ESB%20-%20Post%202025%20Market%20Design%20-%20Scope%20and%20Forward%20Work%20Plan%20-%2020190322.docx.pdf and the Open Energy Networks programme: https://www.energynetworks.com.au/projects/open-energy-networks/

[2] https://www.energynetworks.com.au/sites/default/files/open_energy_networks_consultation_paper.pdf

market and system responsibilities and along with the individual distribution utilities will develop a single integrated platform that will use a set of agreed standard interfaces to support the participation in the integrated multi-directional market by retailers, aggregators, and VPP platform companies. The SIP will then simultaneously solve local security constraints and support wholesale market entry. Under this configuration, access to the platform will be a one-stop shop that provides market participants the opportunity to participate anywhere in the NEM or WEM without having to develop separate systems or tools to integrate with the various individual distribution platforms. DSOs would provide details of network constraints to AEMO, who would consider this information in determining the economically dispatch of resources.

- **The Two Step Tiered Platform (TST):** A layered distribution level platform interface operated by the local distribution network and an interface between the distribution network's platform and AEMO. Under this design, individual distribution networks can design interfaces that best meet their system requirements. Participants would then need to communicate directly with the distribution level platform for the local constraint issues and the distribution network would optimise these resources against local network constraints based on bids from the aggregators servicing the area. Distribution networks would provide an aggregated view per the transmission connection point. AEMO would take this information and consider the overall system security and economic dispatch
- **Independent DSO framework (IDSO):** This is a variant of the TST, whereby an independent party – a DSO that is separate from AEMO and the distribution utility. Under this model the independent DSO would work with the distribution utility to optimise the dispatch of the DER based upon local system constraints that are provided by the network business, provide the aggregated bids to AEMO for incorporation into the larger dispatch; and

Following consultation with stakeholders, which highlighted some concerns with all three Frameworks, a fourth, additional Framework was developed, as follows:

- **The Hybrid Framework:** Seeks to combine the SIP and TST Frameworks, whereby AEMO runs a single market platform but DSOs remain responsible for operating the distribution networks, accessing the market platform to help resolve distribution constraints and develop an aggregated (unconstrained) bid stack for its region for AEMO to consider in wholesale dispatch. This is designed to enable DSOs to help identify a dispatch schedule of DER to minimise network constraints while AEMO can use this information as part of a co-optimised dispatch, which looks at both network and markets benefits which DER can provide.

These conceptual Frameworks have been defined within Smart Grid Architecture Models (SGAMs) which map functionality to different parties in each Framework and the information flows required to support those functions.

In June 2019, Baringa Partners was appointed to undertake a cost benefit assessment (CBA) of the Frameworks. We have undertaken a high level quantitative assessment of the costs and benefits of the Frameworks, compared to a 'Do nothing' counterfactual. Our approach was broadly based on a similar assessment undertaken on the Future Worlds of distribution system operation, developed in

Great Britain (GB).[3] We have worked closely with AEMO, the DNSPs and TNSPs along with wider stakeholders to tailor this approach in recognition that the Australian wholesale market design is based on a 'gross mandatory pool' approach (as opposed to bi-lateral contracting in GB). We have also recognised that the primary drivers for change differ. In Australia the key issue is currently the integration of high levels of residential and industrial roof-top solar and emerging battery storage. By contrast, in GB the most pertinent issues are peak load management, and export constraints on distribution networks caused by concentrated pockets of grid connected generation.

Objectives

The aim of the CBA was not to pick a 'winning' Framework but to examine the 'case for change' to move to any of the Frameworks, and identify the strengths and weaknesses of the Frameworks to help understand the circumstances which might drive one Framework over others. Our quantitative assessment relied upon forecast data and assumptions which may change significantly over the coming years as we start to understand better the impact of DER on distribution system operation, and also how the Frameworks would operate in practice.

Approach

Our approach was based around an initial quantitative assessment of the potential benefits of integrating DER, which is Framework agnostic. Given the time available, we employed a top-down approach to quantifying the potential benefits of DER integration. This focused on four key areas:

- Avoided network investment (at both distribution and transmission);
- Avoided curtailment of DER,
- Reduced wholesale ancillary services costs; and
- Reduced wholesale energy costs.

We modelled the potential benefits available in these categories out to 2038/9 using two different DER uptake scenarios produced by AEMO[4] – a lower DER uptake scenario and a higher uptake scenario consistent with restricting global warming to two degrees Celsius. These DER uptake projections were only available over the required horizon for the NEM and consequently, the quantitative results are only applicable for the NEM. [5]

We adopted a bottom-up approach to the relative cost assessment. We used data received from DNSPs and AEMO to identify some baseline technology and resource costs and assessed how these would change for each actor in each Framework, based on the different roles being undertaken and scope of activities required. We assessed the maturity gap to develop the required functionality and allocated additional costs to bridge this gap. We also used the information within the SGAMs to assess the information exchange costs required in each Framework. We assumed two tranches of investment to build out the Frameworks, an initial tranche today and a second tranche in the late

[3] http://www.energynetworks.org/electricity/futures/open-networks-project/workstream-products/ws3-dso-transition/future-worlds/future-worlds-impact-assessment.html

[4] See the Electricity Statement of Opportunities dataset: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities

[5] The assessment should be replicable for the WEM, once the relevant data sources are available and the qualitative assessment is equally applicable for the WEM.

2020s to cater for system upgrades and more advanced functionality required to cater for a growing volume of DER.

To recognise the uncertainty which exists in assessing the performance of the Frameworks, we have developed some examples to illustrate the range of net benefits which might be delivered by the different Frameworks. One of these examples assumes that all Frameworks develop at equal pace and therefore deliver the same level of benefits. We have then shown three further examples based on different qualitative assessments of the speed at which different Frameworks may be able to deliver the available benefits.

We also undertook a broader qualitative assessment of the Frameworks against a range of criteria, including independence, accountability and adaptability, which should be seen alongside the quantitative assessment.

Results

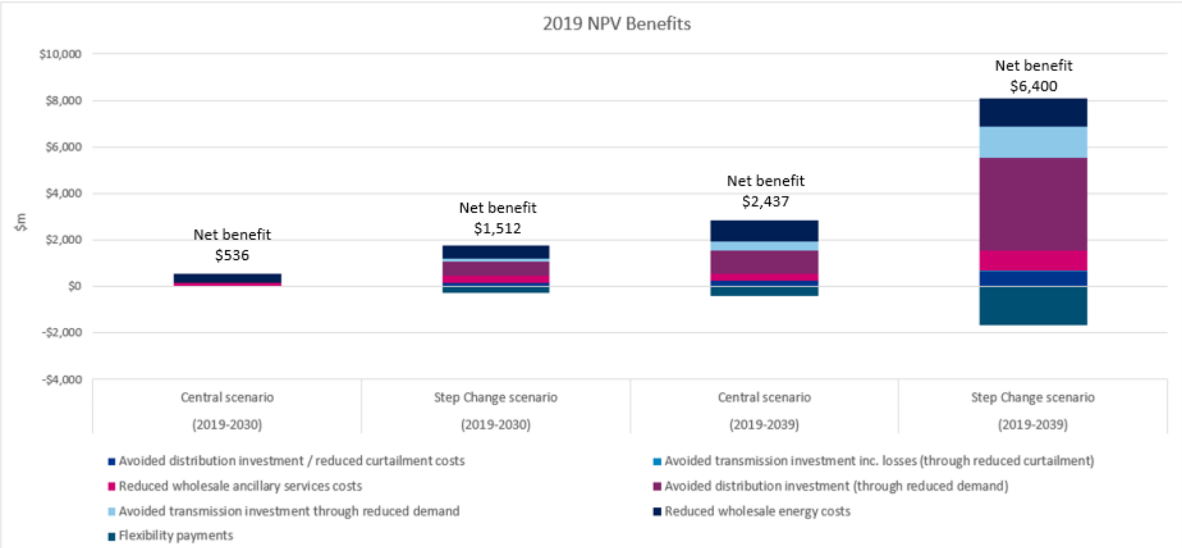
Potential benefits from better DER integration

Our assessment in Figure 1 illustrates that under the Step Change scenario, there are significant potential benefits from better DER integration of up to $6.5bn by the end of 2039. [6] However, if the uptake of DER follows a lower trajectory, the corresponding benefits are also lower ($2.5bn).[7] The results also indicate that the majority of these benefits materialise after 2030. This is because a key driver for benefits comes from avoiding network investment associated with the electrification of transport, while also using this new EV demand to resolve export constraints at residential level. These results are based on DER uptake across the NEM. It is important to stress that some regions are already experiencing high DER penetration now and that the profile of available benefits over time could look quite different in those regions.

[6] Please note that this chart includes the costs of paying DER to provide system and network services and in that sense is a net benefit. However, it does not include the costs of implementing and operating the Frameworks to deliver those benefits

[7] We note that DER uptake is already exceeding forecasts in the Central scenario which suggests that it represents a very low case.

Figure 1 Potential benefits available from greater DER integration ($m, NPV 2019/20 prices)

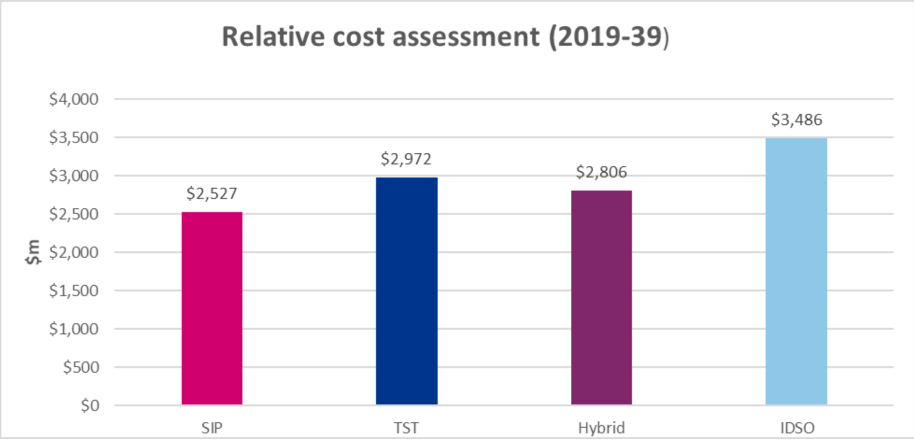


Cost of the Frameworks

Our cost assessment is based on forecasts from AEMO and DNSPs of the costs to build out the full functionality envisioned in the Frameworks. It is important to stress that some benefits can be delivered without requiring this level of functionality but the scope of our assessment was to consider the Frameworks in their 'end state' in order to provide high level learning to inform foundational steps which can be taken today. The conclusions around the costs of the Frameworks should be viewed in this light.

There is uncertainty around the nature and scale of systems needed and the subsequent cost but our methodology is able to highlight the key relative differences in the costs of the Frameworks, given a common baseline. Figure 2, shows the total cost of the Frameworks to range between $2.5bn-$3.5bn on a present value basis. Based on these costs, in the high DER uptake world of the Step Change scenario, this would mean net benefits in the region of $3bn out to 2039, if all benefits can be delivered. However, under the low DER uptake, the Central scenario, building out full functionality of the Frameworks would lead to negative benefits. This suggests that while there remains uncertainty around the scale of DER uptake, the new functionality required to integrate DER should be implemented in an incremental way.

Figure 2 Relative cost assessment results ($m, 2019/20 prices)



All the Frameworks envisage that DSOs develop the functionality to monitor network constraints and transfer that information to other parties. Therefore, the differences in cost are driven by how the functionality required to engage with market participants and optimise the dispatch of DER, sit across the range of industry parties. The analysis suggests that the IDSO Framework appears to be the highest cost Framework. This is due to the duplication of responsibilities and subsequent systems and functions across AEMO, IDSOs and DNSPs. The SIP and Hybrid Frameworks benefit from economies of scale associated with centralising many of the market facing functions and the functionality required to optimise dispatch of DER with a single party (AEMO The TST is relatively higher cost than the SIP and Hybrid since it requires each DNSP to each develop new systems and functionality.

The speed at which the potential benefits can be delivered

There are a number of assumptions or judgements which can be made over the ability of the Frameworks to deliver the available benefits. Rather than pick one assumption, we have shown results under a number of different assumptions, to illustrate a range of net benefits and the uncertainty which exists over the performance of the Frameworks.

Given effective design and implementation, it may be possible that any of the Frameworks would be able to deliver the available benefits in the long run. In this case, the differences between the net benefits delivered by the Frameworks would be solely driven by the costs

However, we consider it is more likely that the different features of the Frameworks might influence the speed at which benefits can be delivered. If, for example, DNSP's existing capabilities in distribution network planning, connections and operations, means that they can deliver network access sooner than a third party system operator, then the TST Framework will look more attractive. However, if a single route to market can deliver faster DER access into wholesale markets and AEMO and DSOs can coordinate planning and operations effectively under split responsibilities for market and system operations, then the Hybrid Framework looks most attractive. We note that the current gross pool market design of the NEM is based around single route to market and that utilising those existing structures could help reduce implementation costs for the Frameworks. While trials and pilots are currently exploring these issues, it is not possible at present to demonstrate which of these judgements is most accurate. Therefore, we have shown a range of results to illustrate the uncertainty which exists.

Conclusions and recommendations

There appears to be clear value in integrating DER into the Australian electricity system, which becomes very significant in a high DER uptake environment such as the Step Change scenario. All of the Frameworks may be capable of delivering this value, given sufficient time and resources, alongside effective design and implementation. The assessment does show that the case to move to the full functionality of any of the Frameworks is more challenging in a lower DER uptake environment such as the Central scenario. The results highlight the merits of AEMO and DSNPs exploring ways to roll out required functionality in an incremental manner, in line with need. This could include continuing to identify and implement least regret actions which can be taken to deliver near term benefits and enablers for changes in market design in the future.

While there is a range of uncertainty over the performance of the Frameworks in delivering the available benefits, the assessment suggests that the IDSO Framework is likely to be the least attractive, due to its high implementation and operating costs. While it can provide greater transparency from separate market and system operation, our qualitative assessment demonstrates that this could also be achieved under the Hybrid Framework. Consequently, at present, the case for the IDSO Frameworks appears to be the weakest.

The remaining three Frameworks could all be viable options to suit different circumstances and have significant long-term positive net benefits under high DER uptake scenarios. The differences in quantified net benefit are all within the margin of different qualitative assumptions on the relative speed that these Frameworks can deliver better market and network access.

As there becomes more certainty around the uptake of DER and it becomes increasingly difficult to integrate DER effectively within the current market framework, there may need to be a choice made over the different directions of travel captured within the Frameworks. In making this choice, we are conscious that the TST and SIP Frameworks represent contrasting end points of market design. Consequently, a natural conclusion is that the Hybrid is a pragmatic solution which can bring the best of both Frameworks and avoid the weaknesses. However, our assessment does illustrate that the Hybrid would benefit from more detailed definition to ensure that roles and responsibilities are clear, particularly in the dispatch process. There are a range of different choices for what a Hybrid Framework could look like. Some could take a form closer to the SIP and others closer to the TST. It would be helpful to trial these different Hybrids to help inform what the design of the Hybrid Framework(s) should be.

Our assessment has shown that there are already substantial variations in DER uptake and the subsequent level of network constraints, across different geographies. As a result, there are already differences emerging in the maturity of new DSO capabilities across DNSPs. This may mean that the Frameworks deployed in different geographies may need to differ, along with the timing and scale of implementation. This further indicates that trialling a range of Hybrid Frameworks, reflecting various flavours of the TST and SIP may be beneficial to understand which can suit specific circumstances.

We are conscious that there a number of areas of uncertainty associated with the inputs and assumptions which have been used in the assessment. We have listed some of the key areas below, to highlight where further work might help refine this initial assessment.

- The effectiveness of different parties in undertaking the range of new functions set out in all of the Frameworks;
- The scale and costs of systems and resources required to deliver some of functionality envisioned in the Frameworks e.g. understanding distribution constraints and the dispatch process and engine required to optimise DER across network and wholesale markets; and
- The definition of the Hybrid Framework and the respective roles of AEMO and DSOs in the dispatch process, including how disputes are resolved within operational timeframes

In addition, to help refine the conclusions, it may be helpful to build on this initial CBA, through undertaking the following:

- Undertake the Impact Assessment on a region by region basis to assess where there is merit in implementing new DSO capability. This should include the WEM, once data is available in a similar format to the NEM;
- Include broader forecast data on DER uptake to include smart household appliances, industrial demand side response and larger distributed generation, as well as including DER forecasts out to 2050, to understand the longer term benefits of investments; and
- Assess wider industry costs of the Frameworks including those for retailers and aggregators and DER.

1 Background

1.1 Context

The Australian energy system is embarking on a period of significant change, as it moves towards greater decentralisation and decarbonisation of energy generation. The integration of Distributed Energy Resources (DER) such as solar PV, storage and electric vehicles (EV), into the electricity system is crucial to delivering decarbonisation at lowest cost, while maintaining security of supply. Providing market access to DER will enable consumers to realise the full value of these technologies, helping to reduce their own energy bills as well as those for all consumers. Consequently, the integration of DER into the electricity and wider energy system is a key step in enabling the business case for smaller scale, low carbon and flexible technologies to facilitate the transition of the electricity system.

The Open Energy Networks programme has brought together AEMO and Network Service Providers, as well as broader stakeholders, to assess how best to integrate DER into the Australian electricity system.

AEMO is the independent market operator with responsibility for running the National Electricity Market (NEM) and Wholesale Electricity Market (Western Australia) and maintaining the security of the overall electricity system. As DER starts to displace larger scale thermal generation, AEMO will need visibility of that DER in order to integrate it into wholesale markets and keep the system secure. Visibility of DER can improve system modelling and forecasting and enable more informed decisions to be taken. This can help reduce the cost of keeping the system secure and the risk of system failure. The ability of DER to participate in wholesale markets can help ensure those markets have sufficient liquidity to keep the system secure and improve competition in those markets to reduce the costs to customers.

Distribution Network Service Providers (DNSPs) are responsible for operating and maintaining the local networks to which DER connect. This requires them to manage local network capacity to ensure that DER can connect and access the network when required, while maintaining network reliability and minimising investment costs. In the same way that DER can provide system services to AEMO, they can also provide local services to reduce the loading or generation flows on the distribution networks and avoid or defer the need to reinforce the network. This can reduce the network costs associated with increase in load and generation. Consequently, DNSPs will also be keen to access flexible resources to help operate their systems. The key question is therefore, how to maximise market and network access for DER, and ensuring that the use of flexibility is optimised across the whole system.

In June 2018, the Open Energy Networks programme set out three strawman Frameworks for future system and market operation to facilitate the integration of DER.[8] The Frameworks seek to meet the challenge around how to operate more complex distribution systems, provide timely network access, and facilitate participation of DER in wholesale markets, whilst keeping costs down for wider network users. This is sometimes referred to as the transition to a Distribution System Operator (DSO). All

[8] https://www.energynetworks.com.au/sites/default/files/open_energy_networks_consultation_paper.pdf

Frameworks envisage DNSPs transitioning to Distribution System Operators to more actively forecast and monitor increasingly complex flows on their networks, but differ as to the extent that operational decisions on the distribution networks are undertaken by AEMO, DSOs or a new independent Distribution System Operator (IDSOs). The Frameworks were described as follows[9]:

- **The Single Integrated Platform (SIP):** The single platform model envisages a unitary point of entry to the entirety of the NEM and WEM. Under this option, the platform would be an extension of the wholesale market. AEMO would provide the platform as part of its market and system responsibilities and along with the individual distribution utilities will develop a single integrated platform that will use a set of agreed standard interfaces to support the participation in the integrated multi-directional market by retailers, aggregators, and VPP platform companies. The SIP will then simultaneously solve local security constraints and support wholesale market entry. Under this configuration, access to the platform will be a one-stop shop that provides market participants the opportunity to participate anywhere in the NEM or WEM without having to develop separate systems or tools to integrate with the various individual distribution platforms. DSOs would provide details of network constraints to AEMO, who would consider this information in determining the economically dispatch of resources.
- **The Two Step Tiered Platform (TST):** A layered distribution level platform interface operated by the local distribution network and an interface between the distribution network's platform and AEMO. Under this design, individual distribution networks can design interfaces that best meet their system requirements. Participants would then need to communicate directly with the distribution level platform for the local constraint issues and the distribution network would optimise these resources against local network constraints based on bids from the aggregators servicing the area. Distribution networks would provide an aggregated view per the transmission connection point. AEMO would take this information and consider the overall system security and economic dispatch
- **Independent DSO framework (IDSO):** This is a variant of the TST, whereby an independent party – a DSO that is separate from AEMO and the distribution utility. Under this model the independent DSO would work with the distribution utility to optimise the dispatch of the DER based upon local system constraints that are provided by the network business, provide the aggregated bids to AEMO for incorporation into the larger dispatch; and

Following consultation with stakeholders, which highlighted some concerns with all three Frameworks, a fourth, additional Framework was developed, as follows:

- **The Hybrid Framework:** Seeks to combine the SIP and TST Frameworks, whereby AEMO runs a single market platform but DSOs remain responsible for operating the distribution networks, accessing the market platform to help resolve distribution constraints and develop an aggregated (unconstrained) bid stack for its region for AEMO to consider in wholesale dispatch. This is designed to enable DSOs to help identify a dispatch schedule of DER to minimise network constraints while AEMO can use this information as part of a co-optimised dispatch, which looks at both network and markets benefits which DER can provide.

[9]https://www.energynetworks.com.au/sites/default/files/open_energy_networks_consultation_paper.pdf

The Frameworks are defined at a conceptual level but were developed in more detail through a set Smart Grid Architecture Models (SGAMs), commissioned by the Open Energy Networks programme.[10] The SGAMs defined a series of functional requirements and identified which party undertook those function in each Framework, alongside the information flows needed between parties to fulfil those functions.

1.2 Scope of work

In June 2019, Baringa Partners was invited to undertake a Cost Benefit Analysis (CBA) of the four Frameworks based on:

- A relative assessment of the costs of implementing each Framework;
- A relative assessment of the benefits each Framework can deliver across the electricity system; and
- A qualitative assessment against a range of agreed criteria.

The objective of the CBA was to examine the case for change and to understand the relative strengths and weaknesses of the different Frameworks, with quantification where possible. The intention was not to 'pick a winner', but to further the evidence base for future decisions, inform the case for transition, and to expose any gaps in knowledge or understanding where further analysis and trialling is needed.

1.3 Defining the Frameworks

To undertake the CBA we had to build on the existing definitions of the Frameworks. The SGAMs provided a huge volume of detail on which parties undertook different functions and the supporting data exchange required. However, it proved difficult to assess exactly what functionality or actions were required to perform the different roles envisioned in each Framework, particularly the time horizon in which actions need to be undertaken and the subsequent data transferred.

We have engaged the Network Service Providers and AEMO in this area and made some high-level assumptions for the purposes of this CBA. These are set out in Table 1 below. Our interpretation has focused on who is providing the route to market for DER, who is assessing the system actions needed to resolve constraints on the distribution system, and who is operating markets at the distribution level.

[10] https://www.energynetworks.com.au/projects/open-energy-networks/

Table 1 Interpretation of the Frameworks

Framework	Baringa Interpretation
SIP	AEMO is the route to market for all DER, via a single platform. All market participants place market bids on the single platform. The DSOs provide technical network data (constraint information) to allow AEMO to run a co-optimised wholesale market dispatch, seeking to resolve network constraints and delivering value into wholesale markets.
TST	Each DSO is the route to market for DER in the region in which it operates. Each DSO will assess how to resolve constraints (using market and non-market solutions) and develop an aggregated bid-stack of (unconstrained) DER in its area. This bid-stack is submitted to AEMO to include in wholesale dispatch (alongside Transmission connected bids). DSOs then have responsibility for settling the DER bids which AEMO have dispatched. We have assumed that each DNSP evolves to become a DSO.
IDSO	A new independent party (IDSO) becomes the market operator, and hence route to market for DER in each region. The IDSO collects technical data (constraint information) from each DNSP. It receives market bids from DER, decides on what actions can be taken to alleviate network constraints and develops an (unconstrained) aggregated bid stack for its region. This is then submitted to AEMO to include in wholesale dispatch (alongside Transmission connected bids). We have assumed that an IDSO develops in each DNSP region
Hybrid	There is a single route to market via a market platform (operated by AEMO). DSOs access information on the platform to assess network constraints, and identify market options to help alleviate those constraints. The DSOs then highlight where they want to use market bids to help resolve network constraints and AEMO assesses the merits of these as part of the dispatch process.

We also understand that the Frameworks were deliberately agnostic to network pricing signals and access arrangements. Therefore, we have not included the costs or benefits of these in the assessment. We highlight in Section 4, how network pricing signals and access arrangements may support the Frameworks.

1.4 Structure of this document

This report is structured as follows:

- **Section 2:** Provides a high level summary of the approach we took
- **Section 3**: Details the results of the Impact Assessment
- **Section 4**: Provides the insights and conclusions we have drawn from the results
- **Appendix A**: Illustrates the range of net benefit results
- **Appendix B:** Outlines the detail of the qualitative assessment
- **Appendix C**: Describes the benefits assessment methodology in detail
- **Appendix D**: Describes the cost assessment methodology in details
- **Appendix E**: Outlines the summary operating models we used to depict the Frameworks

2 Approach

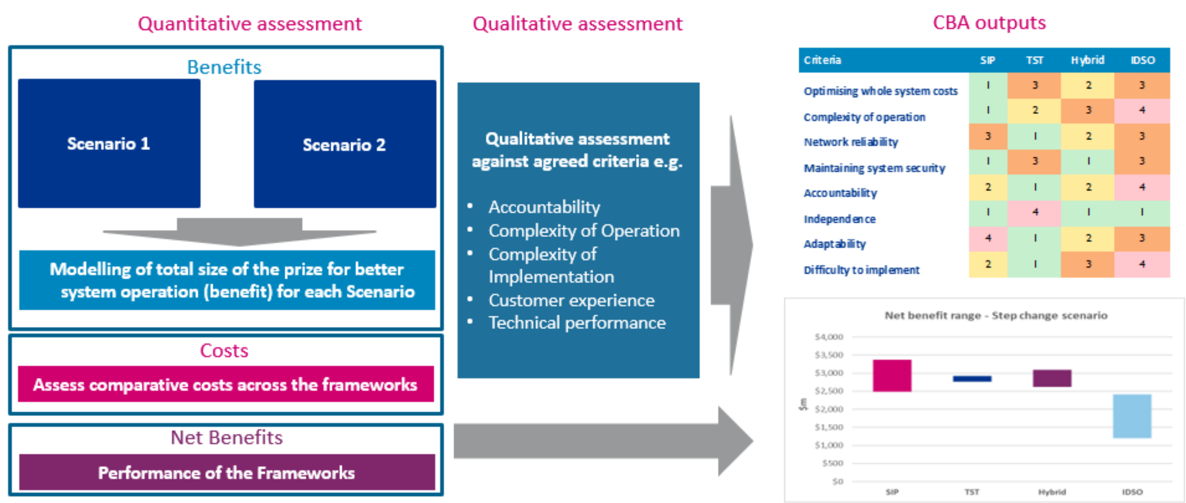
2.1 Summary of approach

In developing our approach, we were conscious that the Frameworks are still defined at a conceptual level and that undertaking any detailed modelling would require a significant number of assumptions to be made. Consequently, given the three to four months available for the study, we undertook a top down approach to the benefits assessment. Our aim was to develop an approach which was easy to understand and could be amended over time as more information became available.

Figure 3 below provides a high-level summary of our approach. This is broadly based on a similar study we undertook in Great Britain (GB) to assess the different frameworks of Distribution System Operation which had been developed.[11] We have worked closely with AEMO, the networks and other stakeholders to refine this approach for the specific context within the Australian market and to reflect the differences in the Frameworks developed for the Open Energy Networks programme. One key difference is that the NEM (and WEM) are based on a 'pool' approach as opposed to bi-lateral contracting in GB.

We also recognise that the primary drivers for change differ. In Australia the key issue is currently the integration of high levels of roof-top solar and emerging battery storage, whereas, in GB the most pertinent issues are peak load management, and export constraints on distribution networks caused by concentrated pockets of grid connected generation.

Figure 3 Overview of approach



The focus of the quantitative assessment has been on the relative costs and benefits under each Framework and the results should be viewed with this mind. We have assessed the benefits under two separate DER scenarios – a low DER uptake scenario (Central) and a high uptake scenario (Step

[11] http://www.energynetworks.org/electricity/futures/open-networks-project/workstream-products/ws3-dso-transition/future-worlds/future-worlds-impact-assessment.html

Change) as published by AEMO in its Electricity Statement of Opportunities (ESOO).[12] We used the forecast DER uptake in these scenarios to assess the potential quantum of benefits which might be possible through better optimisation of DER. Having established this 'overall size of the prize' we then evaluated the costs of each Framework to deliver the available benefits.

For the cost assessment, we collected baseline cost data from the DNSPs and AEMO on the technology and resource costs required to implement and operate the functions required in the Frameworks. We used information in the SGAMs to understand how these costs would vary in each of the Frameworks.

Assessing the net benefits required judgements to be made on the ability of different parties to effectively embed new capability to deliver the new functionality required. Since there is little evidence in this area we have run a range of examples to show the potential range of net benefits for each Framework.

Alongside the quantitative assessment, we undertook a broad qualitative assessment. This was based on analysing how the Frameworks performed against a range of criteria, agreed with AEMO and the DNSPs. The assessment took the form of a relative ranking of how the Frameworks performed against each of the criteria. This was designed to tease out strengths and weaknesses, particularly in areas which could not be quantified.

To support the assessment, the ENA established a specific working group consisting of AEMO, DNSPs and TNSPs to review and challenge the work. We used this group throughout the process, particularly to validate the benefits approach. Outside of the working group we also held bilateral calls with most DNSPs and AEMO to validate the cost data. Separately, we also spoke to some aggregators and retailers to understand how their role might change under each framework and met with the AER and AEMC to take feedback on our approach.

2.2 Assessing the potential benefits of DER integration

The first step in our approach was to understand the potential benefits which might be available through the successful integration of DER into the electricity system. This is agnostic to the performance of the Frameworks and was undertaken to get a sense of the 'size of the prize' available, which the Frameworks might deliver.

DER uptake scenarios

We assessed the potential benefits which might be possible under two of AEMO's future scenarios – the Central scenario (where DER uptake is low) and a Step Change scenario (where DER uptake is significantly higher and the only scenario consistent with keeping warming below 2 degrees Celsius). These scenarios include projections of solar PV, storage and Electric Vehicles out to 2038/9. We chose to look at these two different scenarios to understand how conclusions might differ depending on the level of DER uptake.

[12] https://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities

Benefit categories

We identified a number of benefits from integrating DER into the Australian power system which are outlined below:

- **Reduced curtailment cost:** Currently, in areas of the distribution network with low hosting capacity, DSNPs are ensuring that they have the capability to curtail solar output in order to maintain network reliability. This curtailment avoids the need to augment the distribution network[13] but to maintain the equivalent renewables mix, it needs to be replaced by transmission connected renewables. Reducing this curtailment drives a number of benefits across the electricity system:
    - **Saved marginal generation costs**: There is a cost to dispatching additional generation (typically fossil-fuelled and transmission connected), which could be avoided, if curtailment of local generation can be reduced.
    - **Reduced Losses**: Electricity generated on the transmission network has to be transported down the networks to sources of demand. On average around 7-11% of electricity is lost in transportation due to electrical losses.[14] This means that when curtailed residential solar is replaced by transmission connected generation, around 7-11% more electricity is required to be generated. If curtailment of local generation can be reduced, system losses also reduce with further savings in generation costs.
    - **Reduced Transmission investment:** If curtailed residential solar is replaced by transmission renewables, it will require new renewables to be connected onto the Transmission network.[15] This will drive the need for new connection assets on the transmission network. If curtailment of local generation can be reduced, then it can avoid some of the costs of connecting new transmission connected renewables.
- **Demand driven investment costs:** The uptake of Electric Vehicles has the potential to drive new reinforcement costs on both distribution and transmission networks. If distribution networks can be operated to enable EV charging to coincide with peak solar and to shift some EV charging to off-peak times, then it can reduce these investment costs on both networks. We note that this demand shifting can also provide consequential benefits such as deferring replacement of network assets.[16]
- **Reduced wholesale ancillary service costs:** DER can participate in wholesale ancillary service markets and compete with existing service providers. This additional competition can help drive down prices, as has already been seen in GB. If DER is curtailed due to network constraints, it is unable to access wholesale markets and deliver the benefits of

[13] Our understanding is that DNSPs currently have no remit to augment the network for generation, unless the generators pay the full cost. Consequently, curtailment is the only option available.
[14] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities
[15] Particularly given the planned number of coal plant closures set out in AEMO's Integrated System Plan: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan
[16] Note that we have not sought to quantify the benefits of replacement deferral.

additional competition in these markets. Equally, if small scale DER see the market rules as too complex and struggle to understand their route their market, then they will not participate and will be unable to deliver the benefits of additional competition.

- **Reduced wholesale energy costs:** Integrating DER into wholesale markets can expose them to new incentives to shift demand away from (or generation to) times of system peak, and thus reduce wholesale energy costs.

Table 2 below provides a summary of these benefits and aligns them across four categories, illustrating whether the benefit is demand or generation driven. Appendix C provides a detailed summary of how we calculated the value associated with each benefit category.

Table 2: Summary of benefit categories

Benefit Category	Generation driven	Demand driven
Avoided Distribution investment / reduced curtailment costs	Reduced curtailment of Distribution connected generation: • saved marginal generation costs • reduced losses	Reduced Distribution investment to meet higher local peaks • avoided local network augmentation to meet higher demand (e.g. from EVs)
Avoided Transmission investment	Reduced curtailment of Distribution connected generation avoids the need to build new Transmission network to connect large scale renewables • saved transmission connection costs	Reduced network augmentation to meet greater peak demand: • saved transmission augmentation costs
Reduced wholesale ancillary services costs	Greater competition provided by DER will drive lower prices	
Reduced wholesale energy costs	N/A – this is about shifting demand away from peak to off-peak	Demand response at peak (e.g. shifting demand and storage import to off – peak times)

Defining the counterfactual and optimal level of performance

In each benefit category we defined a counterfactual. This was based around a 'Do nothing' scenario where it was assumed that that DNSPs would need to curtail generation once a certain DER penetration was reached and that this restricted DER from participating in wholesale markets.[17] Having defined a counterfactual, we had to assess what the optimum level of performance could be from better system operation. We issued a data request to DNSPs to understand the volume of solar PV penetration that would drive constraints on different types of networks. Once solar penetration exceeded this volume we assumed that the generation would be curtailed. To assess the optimum performance, we looked at the volume of flexible demand and storage available at times of solar peak to make use of local generation and consequently reduce the constraint.[18] We looked at the value of this avoided curtailment based on the cost of producing the same amount of renewable generation, from larger scale transmission connected renewables.

On the demand side, we used the ESOO forecasts on the volume of flexible demand available and assumed that a proportion of this could be shifted to either avoid peak network demand or peak

[17] This level was based on an information request to the DNSPs.

[18] This included assumptions around the co-location of solar pv and storage and Electric Vehicles, as well as the efficiency of storage. These are all detailed in Appendix B

wholesale price. Where customers shift peak demand to help avoid network investment costs, we assumed that they are paid for this and have based the level of payments on evidence from emerging distribution flexibility markets in GB.[19]

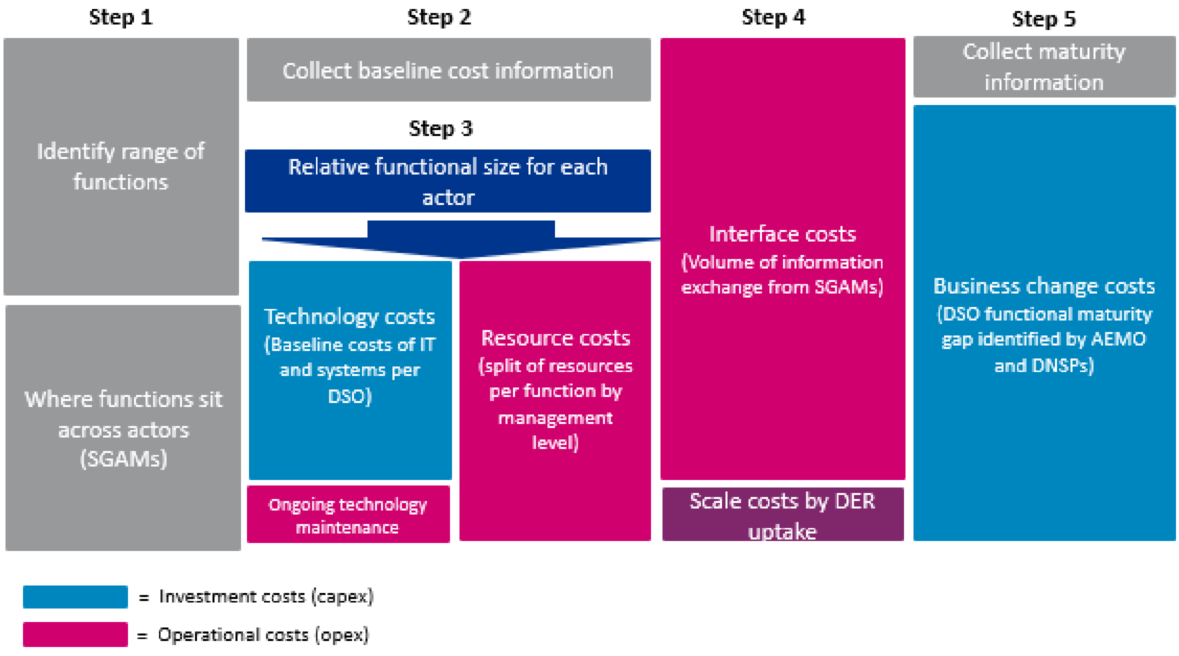
This analysis provided us with an 'overall size of the prize' from DER integration, compared to a 'Do nothing' counterfactual.

2.3 Assessing the costs of implementing and operating the Frameworks

The next step in our approach was to assess the costs of implementing and operating each of the Frameworks. To do this, we used a bottom up approach based around using the information within the SGAMs[20] and a maturity gap assessment produced by the DNSPs and AEMO.[21] This information focuses on the costs of implementing and operating the Frameworks on system and market operators (AEMO, DSOs and IDSOs). As part of the qualitative assessment, we have looked at the cost impact on other parties but those impacts have not been quantified.

The cost assessment was based around the five key steps which we illustrate in Figure 4 below.

Figure 4 Summary of cost assessment approach



1) **Identify the DSO functions and where those functions sit in each Framework:** We used the list of functions developed in the SGAM modelling to understand where functions sat across

[19] https://www.flexiblepower.co.uk/

[20] http://www.energynetworks.org/electricity/futures/open-networks-project/future-worlds/future-worlds-consultation.html

[21] http://www.energynetworks.org/assets/files/electricity/futures/Open_Networks/ON-WS3-P2%20DSO%20Functional%20Requirements-170925%20Published.pdf

different actors (AEMO/DSO/IDSO) in each Framework. In some cases, functions are partly duplicated across multiple actors. We developed operating models to depict this visually which are shown in Appendix D.

2) **Baseline Technology and Resource costs:** We collected a set of baseline technology and resource costs from DNSPs and AEMO. DNSPs reported costs against the requirements of the TST framework. AEMO reported costs against the SIP Framework. These two Frameworks were chosen as a baseline as they represented the largest scale of activity for both DNSPs and AEMO and so allowed us to scale back from that footprint in other Frameworks.
3) **Assess the relative size of functions for each actor in each Framework:** We looked at how both the DNSP and AEMO baseline costs would vary in the other Frameworks - we termed this the functional thickness.
4) **Assess the interface costs in each Framework:** We wanted to understand the different costs associated with information exchange and co-ordinating with other actors in each Framework. We used data in the SGAMs on the volume of information exchanges as the basis for our analysis. We scaled up these interface costs over time based on the increasing take-up of DER.
5) **Understand the business change costs associated with each Framework:** We wanted to recognise that the investment costs were not simply the technology costs but the costs of integrating that technology into the business. We issued a survey to DNSPs and AEMO to understand the maturity of functions today compared to the maturity required under each Framework. We took the average of this assessment and used the relative scores across the Frameworks to inform the proportion of technology costs to allocate to business change for each function in each Framework (up a maximum of a 100% for areas where there was a high maturity gap).

Table 3 below provides a high-level summary of how we assessed the functional thickness illustrating each of these as either no cost, low (L), medium (M), high (H) or very high (VH)[22]. Any costs classed as High (H) represent the baseline costs as reported by AEMO or the DNSPs. For AEMO, these baseline costs were based on the SIP Framework (as it represents the largest scale of activity for AEMO under any of the Frameworks). For DNSPs these baseline costs were based on the TST Framework (as this represented the largest scale of activity for DSOs). For the other Frameworks, we then applied separate scaling factors to each function to represent how the scale of that function (for that actor) changed compared to the baseline.

[22] While for the majority of costs, we scaled back from the baseline costs, in one instance we felt a function required scaling up (hence the Very High category).

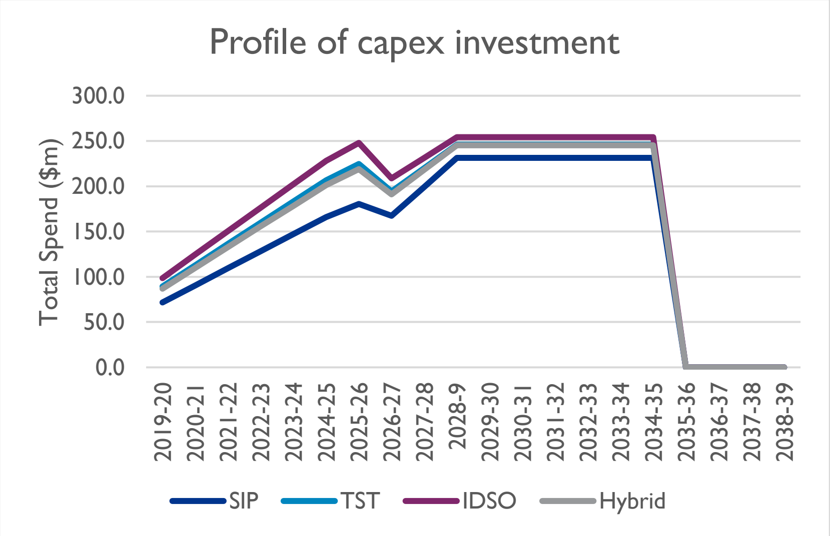
Table 3 Summary of functional thickness

			SIP	TST	Hybrid	IDSO	TST	SIP	Hybrid	IDSO	
	SGAM function	**SGAM activity**	AEMO	AEMO	AEMO	AEMO	DSO	DSO	DSO	DSO	IDSO
1	**Distribution system monitoring and planning**	Gather network data	No cost	No cost	No cost	No cost	H	H	H	H	No cost
		Network planning and investment	No cost	No cost	No cost	No cost	H	H	H	H	No cost
2	**Distribution constraints development**	DER engagement	H	No cost	L	No cost	H	H	H	H	No cost
3	**Forecasting systems**	Forecast short-term network state	H	No cost	L	No cost	H	H	H	H	No cost
6	**DER optimisation at the distribution network level**	Optimise operating envelopes of distribution network end-customers	H	No cost	L	No cost	H	No cost	M	M	H
		Aggregation of wholesale and FCAS bids	No cost	No cost	No cost	No cost	H	No cost	M	No cost	H
7	**Wholesale - distributed optimisation**	Update market dispatch engine	H	M	M	M	No cost	No cost	No cost	No cost	No cost
		Determine dispatch schedules for bilateral RERT contracts	H	H	H	H	No cost	No cost	No cost	No cost	No cost
8	**Distribution network services**	Bilateral contracts for D-network support and control ancillary services	No cost	No cost	No cost	No cost	H	H	H	L	H
		D-network market engagement for network support and control ancillary services	H	No cost	VH	No cost	H	No cost	No cost	No cost	H
9	**Data and settlement (network services)**	Settlement of bilateral contracts for network services	No cost	No cost	No cost	No cost	H	H	H	No cost	H
		Settlement of NCAS market	H	No cost	H	No cost	H	No cost	No cost	No cost	H
10	**Data and settlement (wholesale, RERT, FCAS and SRAS)**	Settlement of bilateral contracts for RERT	H	H	H	H	No cost	No cost	No cost	No cost	No cost
		Settlement of wholesale, FCAS and SRAS markets	H	No cost	H	No cost	H	No cost	No cost	No cost	H
		Dispute resolution (wholesale, RERT, FCAS and SRAS)	H	No cost	H	No cost	H	No cost	No cost	No cost	H
11	**DER register**	Establish, maintain and publish or share DER register data	H	H	H	H	H	H	H	H	No cost

The number of functions with costs allocated to them varies in each Framework. This is because in some Frameworks, a function might be duplicated among multiple parties whereas in other Frameworks, the function might only be performed by a single party.

We used the functional thickness to assess the overall costs to implement each Framework. We then had to make some assumptions around the profile of this investment. We assumed that there are two stages of investment, an initial investment which starts today and gradually increases in line with average DER uptake across the NEM. We then assumed a second stage of investment in the late 2020s which has a flatter profile. Figure 5 below illustrates the assumed investment profile and shows that we assume all investment costs have been made by 2035/6.

Figure 5 Cost investment profile



We also assumed that operating costs ramp up in line with average DER uptake across the NEM. We assume that resource costs increase as the framework fully mature.

Appendix D outlines our cost assessment approach in more detail, including the key assumptions used.

2.4 Assessing the net benefits of the Frameworks

The final step in our approach was to assess the performance of the Frameworks in delivering the available benefits of DER integration. We used this alongside the results of the cost assessment to illustrate the net benefits which the Frameworks can deliver.

Assessing the ability of the Frameworks to deliver the available benefit requires some judgements on how different parties will perform in undertaking new capabilities and functionality. There is a series of different judgements which could be made, reflecting the uncertainty which exists around the performance of the Frameworks. To illustrate this as accurately as possible, we have run a series of examples to show the net benefits which each Framework might deliver based on different judgements.

One example is based on the premise that given effective design and implementation and sufficient time and resources, it is possible that all the Frameworks could equally deliver the available benefits. The other examples are based on the premise that the different features of the Frameworks may influence the speed at which the available benefits are realised. The key areas where we identified the performance of the Frameworks might impact the delivering of the available benefits were:

- **The speed at which network access could be maximised**: This is the ability for DER to access the network for either import or export when they require. This will require an understanding of the network constraints, considerations of the most effective option to resolve that constraint (technical running of the network or a commercial solution, through providing incentives or payments to DER to shift demand or generation); and
- **The speed at which wholesale market access can be maximised:** The volume of available DER which can be encouraged to participate in wholesale markets. This is likely to be driven by the ease in which DER can participate in wholesale markets, particularly how a large number of small scale DER can be aggregated to participate in national markets, and ensuring that those DER receive the full value for that participation.

We considered that some of the benefits categories in Table 2 (avoided Distribution and Transmission investment) would be driven primarily by the increased level of network access each Framework could deliver through optimising flexibility at the distribution level. While the broader wholesale benefits would be a function of firstly the level of wholesale market access which can be delivered and secondly, the level of network access (to ensure that the network could support the provision of services into wider markets).

2.5 Limitations of the approach

We have tailored our approach to fit both the level of detail available in the SGAMs on how each Framework would operate and to the time available for the study. It is predominantly a top down assessment designed to understand at a high level the case for change to support DER integration, and tease out initial differences (and similarities) across the Frameworks and inform what conditions might suit different Frameworks. It is not, on its own, designed to 'pick a winner'.

The following are limitations of our approach:

- **NEM focussed**: The benefits assessment relies on granular forecasts of DER uptake out to 2038/9. We have not been able to source similar data for the WEM, and therefore our quantitative analysis has not been able to take account of the WEM, although the qualitative assessment is still applicable.
- **Not all benefits have been quantified**: The benefits assessment has been largely driven by available data on DER uptake. We have used AEMO's latest ESOO forecasts for this, but note that they exclude smart household appliances and industrial demand side response – both of which can deliver benefits to networks and wholesale markets. We have also focused the network benefits around avoided or deferred augmentation costs but note that there could also be benefits around avoided or deferred replacement costs. Consequently, the benefits quoted in our assessment are likely to be conservative.
- **Average costs and benefits**: To produce results which are valid across the NEM, we have had to take a number of average inputs across the costs and benefits, for instance, the volume of curtailment on distribution networks and enabling costs for monitoring equipment. This means that our results represent an average, and different regions could have deviations on this, particularly in terms of the time taken for significant benefits to materialise.

- **Relatively short assessment period**: The DER uptake data in the ESOO only goes out to 2038/9. This means that we are only able to model benefits out to this point. The majority of investment would have been made by this date and if we were able to access DER projections out to 2050, the quantum of net benefits would be far greater.
- **Focus on network and AEMO costs:** The quantitative assessment has focused on the cost of implementing and operating the frameworks for AEMO and the DNSPs. While we have included costs for other parties as part of our qualitative assessment and in our assessment of wholesale market access, further studies may want to look at these in more detail.
- **Treating DER as an exogenous variable:** We have assumed a specific level of DER uptake as per the ESOO forecasts and looked at the available benefits in a 'Do nothing' and 'Optimal' scenario to reveal differences between the Frameworks. In reality, there will be a cause and effect, with the DER uptake itself a function of how well each Framework will perform.

3 Results of the Impact Assessment

3.1 Introduction to results

The CBA has produced a large volume of results and insights which we have summarised in the main body of this report, with further details in the appendices. We have structured this section to first illustrate the potential benefits of DER integration before showing the relative costs of the Frameworks to deliver these benefits. We then provide a summary of the net benefit results based on a range of assumptions around the speed at which the Frameworks can deliver the potential benefits. Finally, we include the summary results of the qualitative assessment.

3.2 The potential benefits of DER integration

The first step in the assessment was to undertake a top down assessment of the overall value of DER integration. Figure 6 below outlines the quantum of benefits we assessed under the Central and Step Change scenarios. These are Framework agnostic but take account of the payments needed to pay DER for services (flexibility payments).[23] The benefit categories align with those outlined in Table 2.

Figure 6 Potential benefits available from greater DER integration ($m, NPV in 2019/20 prices)

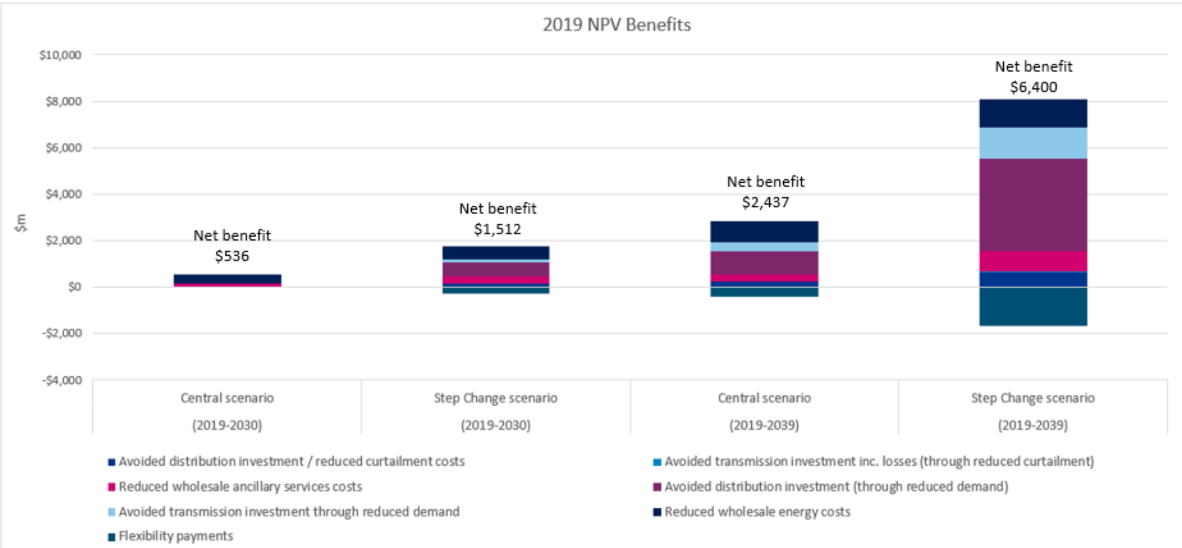


Figure 6 indicates that in a high DER uptake scenario (Step Change), there are substantial benefits from DER integration of up to $6.5bn by the end of 2039. The results also indicate that the majority of these benefits materialise after 2030 (under both scenarios). This is because a key driver for benefits comes from avoiding network investment associated with the electrification of transport, while also using this new EV demand to resolve export constraints at residential level. For the same reason, the available benefits are far lower in the low DER uptake scenario (Central) since EV uptake

[23] As outlined in Appendix C, these payments are based on what UK Distribution networks are paying for similar flexibility services

is lower. The analysis shows a key difference in the composition of the available benefits under the two DER scenarios – this is illustrated in Table 4 below.

Table 4 Proportion of benefit from wholesale markets

	NPV values($m)			
	(2019-2030) Central scenario	(2019-2030) Step Change scenario	(2019-2039) Central scenario	(2019-2039) Step Change scenario
Avoided distribution investment / reduced curtailment costs	$39	$147	$244	$652
Avoided transmission investment inc. losses (through reduced curtailment)	$4	$14	$17	$47
Reduced wholesale ancillary services costs	$95	$301	$274	$856
Avoided distribution investment (through reduced demand)	$0	$620	$999	$3,958
Avoided transmission investment through reduced demand	$0	$124	$393	$1,358
Reduced wholesale energy costs	$399	$570	$933	$1,207
Flexibility payments	$0	-$263	-$423	-$1,677
Total benefits	$536	$1,512	$2,437	$6,400
Proportion of benefits from wholesale markets	92%	58%	50%	32%

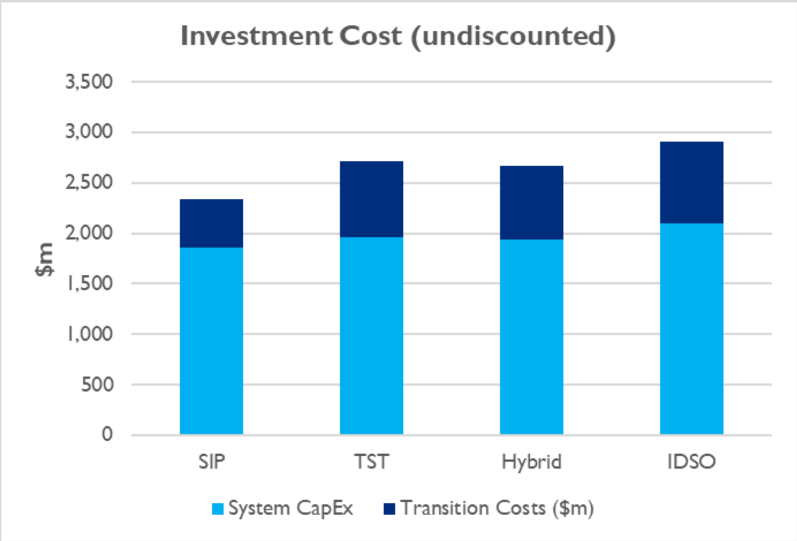
In a lower DER uptake under the Central scenario, a much higher proportion of the benefits accrue from integrating DER into wholesale markets, as opposed to avoided network investment. This is particularly the case in 2019-30 period where 92% of the benefits come from integrating DER into the wholesale market. This scenario suggests that on average, across the NEM, there would be few network constraints to resolve, meaning that subsequent network related benefits are low. This is important, since where there are limited network constraints, the wholesale benefits could be delivered without the need to invest in the full DSO functionality envisaged under the Frameworks. However, in the Step Change scenario a much higher proportion of benefits come from avoided network investment (particularly when looking out to 2039). This suggests a higher level of network constraints across the NEM, which would require more advanced DSO capabilities to manage.

It is worth highlighting that these results are based on average DER uptake across the NEM. Our assessment illustrates that some regions are already experiencing high DER penetration now, and that the profile of available benefits over time could look quite different in those regions.

3.3 Cost assessment results

We assessed the investment (capex) and resource and operational costs (opex) required in each Framework to deliver the benefits outlined in Figures 6 above. Figure 7 below shows the relative total investment costs required for each Framework. As well as technology costs, we have included business transition costs which relate to the spend needed to embed new functions and systems into the business.

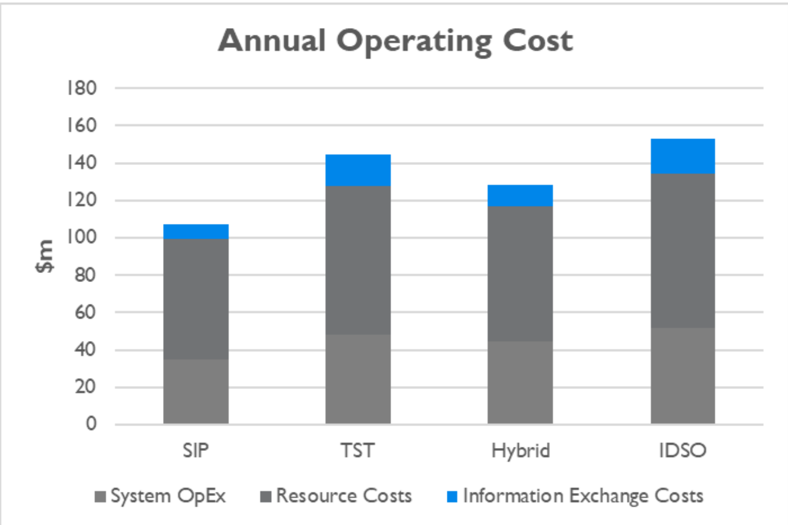
Figure 7 Investment cost results out to 2039



All the Frameworks envisage that DSOs develop the functionality to monitor network constraints and transfer that information to other parties. Therefore, the differences in cost are driven by how the functionality required to engage with market participants and optimise the dispatch of DER, sit across the range of industry parties. The IDSO Framework has the largest investment required, as it splits roles and responsibilities across three actors (DSOs, AEMO and IDSOs). The TST is slightly higher cost than the Hybrid Framework as each DSNP is required to build out DSO functionality. The SIP has the lowest investment costs, as much of the new market based functionality is centralised within a single party (AEMO),

Figure 8 highlights the average annual resource costs across the assessment period. The trends are similar to the investment costs in Figure 8 with the IDSO Framework having the highest operating costs. The SIP has the lowest operating costs of all the Frameworks.

Figure 8 Average operating costs



3.4 Overall net benefits

We have run a series of net benefits examples based on different judgements around the relative performance of the Frameworks in delivering the potential benefits. Figure 9 below provides a summary view of these results, under the higher DER uptake scenario (Step Change). It is presented in a way to show the range of results across the examples we have run. The top of the coloured blocks indicates the highest potential net benefits and the bottom of the coloured blocks indicates the lowest potential net benefits, based on the examples we have run.

Figure 9 Summary net benefit results – Step Change scenario ($m NPV, 2019/20 prices)

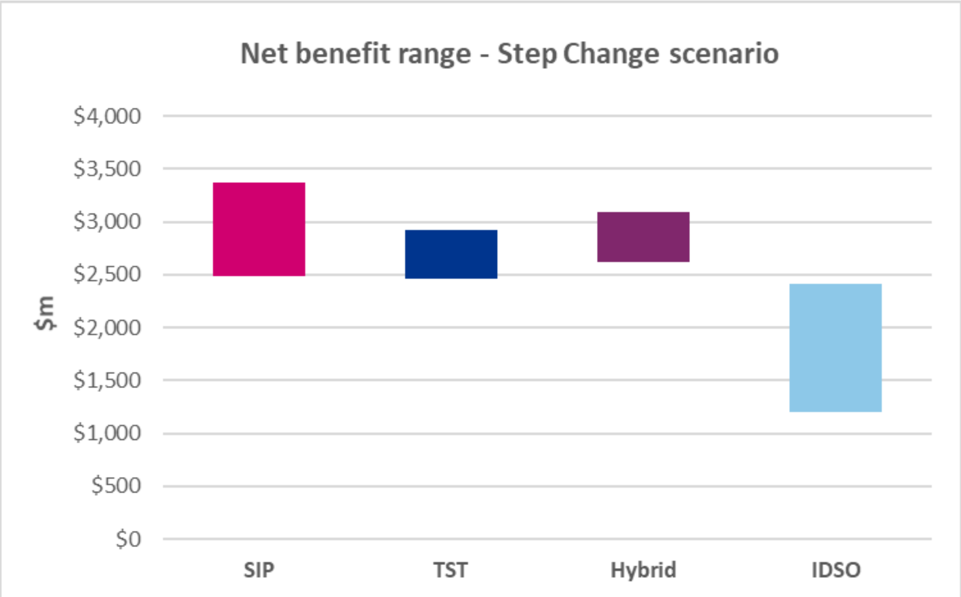


Figure 9 illustrates that the SIP Framework has the potential to deliver the highest net benefits ($3.4bn), since it is the lowest cost framework to implement. However, it may not be able to deliver the benefits as fast as the other frameworks. For example, network access for DER in this Framework may be slower since AEMO would need to build new capabilities for DSO, that DNSPs may be able to do more quickly, given more intimate existing knowledge of their networks. Hence, the lower end of the net benefits range for the SIP Framework is lower than for the TST or Hybrid Frameworks.

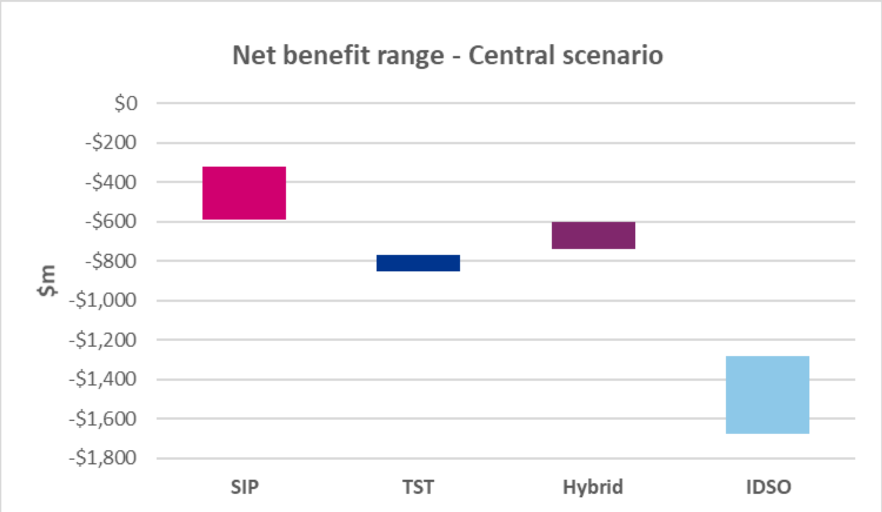
The net benefit range for the TST framework is relatively tight. This is because in all our examples it performs well in terms of delivering network access. While in some examples it is slower at maximising wholesale market access, this has less impact, since if DER does not have network access, it cannot deliver any wider market benefits.

As you might expect the Hybrid Framework results reflect a mixture of the SIP and TST Frameworks. It is lower cost than the TST Framework, so has a higher upper bound of net benefits (if you assume each Framework can deliver all the potential benefits), but would have lower net benefits than the TST is it was not able to maximise network access as quickly, as represented by the lower bound of the range.

The IDSO Framework appears to be more of an outlier. Due to its higher implementation and operating costs, even if you assume it can deliver all the available benefits, its upper bound of net benefits is still significantly lower than the worst case for all other Frameworks.

Figure 10 below illustrates the net benefit results under the Central scenario which has a low DER uptake.

Figure 10 Summary net benefit results – Central scenario ($m NPV, 2019/20 prices)



As highlighted in Figure 6, the available benefits are three fold higher in the Step Change scenario compared to the Central scenario. However, our cost assessment is based on building and operating the full functionality envisioned in the Frameworks, in all regions by the mid-2020s. Consequently, it is unsurprising that Figure 10 shows negative net benefits in a low DER uptake scenario. While we consider the Central scenario represents an low scenario , it does highlight the need to adjust the levels of investment in DSO capabilities according to the expected levels of DER uptake. It also highlights the merits of least regret steps which can deliver benefits today and lay the foundations for a potential more radical re-design of the market in the future, as there becomes greater certainty around DER uptake.

The relative results in Figure 10 are similar to those under the Step Change scenario. It also indicates that in lower DER uptake scenarios, there is a potentially a stronger case for the SIP Framework, as where there are lower benefits available, the lower cost nature of the SIP becomes more attractive. This is also driven by the fact that under a low DER scenario, a higher proportion of the available benefits come from integrating DER into wholesale markets (where the SIP Framework performs well), rather than avoided network investment (where the SIP Framework performs less well compared to the Hybrid and TST Frameworks).

In Appendix A we provide the separate results for each example of net benefits which we have used to construct these ranges of results.

3.4.1 Sensitivity over baseline costs

The range of net benefit results illustrated in Figures 9 and 10, highlights some of the uncertainty which exists around the ability of the Frameworks to deliver the available benefits. There was also a range of uncertainty around the baseline information provided by AEMO and DNSPs on the costs of implementing and operating the new functionality required across all the Frameworks. The scale of new systems needed is still difficult to assess in many areas and even where scale is understood, the costs of procuring systems, currently not available as 'off the shelf' products, is unknown.

One of the key areas of uncertainty in the cost assessment was around the costs of monitoring equipment required by DNSPs under all Frameworks to understand the constraints on the distribution networks. There are a number of factors that will drive the level of monitoring equipment required:

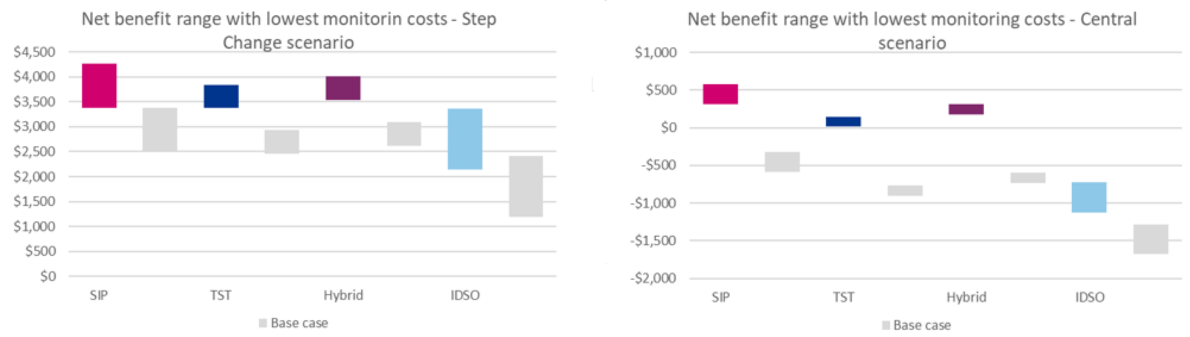
- **Existence of smart metering data**: States like Victoria have committed to a roll out of smart meters and DSOs should be able to use smart metering data to understand the load and generation on its low voltage networks but in other States, this data will not be available.[24]
- **Ability to use representative network modelling**: Some DSOs are looking at strategic roll out of monitoring equipment on representative areas of their network which they can then use to inform decisions on other areas of the network.
- **Available hosting capacity:** The level of monitoring will depend on the network headroom different DSOs have. Where there is existing network capacity, there may be less of a case to install monitoring equipment. Each network has different hosting capacity headroom which drives different requirements for monitoring equipment.
- **Ability to purchase data:** In some areas DSOs may be able to purchase customer data and use this to understand loading on the network, as an alternate or supplement to monitoring equipment.

These uncertainties were reflected in the cost data we received from DNSPs around monitoring equipment. The cost assessment results in Figures 7 and 8 and subsequent net benefits results in Figures 9 and 10 are based on a high degree of network monitoring in areas where there are currently no plans for a smart meter roll out. However, there was a range of views among DNSPs as to the level of monitoring equipment which needed to be deployed.

To illustrate the impact this has on the results, we have run a sensitivity based on the lowest cost approach to monitoring equipment being rolled out across all other DNSPs, compared to the average costs used in the summary of net benefits in Figures 9 and 10 (shown in grey).

[24] We excluded monitoring equipment costs in States which had committed to rolling out smart meters.

Figure 11 Summary net benefits using lowest cost monitoring equipment ($m, NPV 2019/20 prices)



These results show that once the lowest cost approach to monitoring equipment is adopted, across all DNSPs where there is no smart metering data, then the net benefits increase under both scenarios. In the Step Change scenario, this is of the order of 40% (noting that the relative performance of the Frameworks remains the same). In the Central Scenario, the net benefits improve from being negative to be broadly neutral under the SIP, TST and Hybrid Frameworks.

This highlights some of the uncertainty within the assessment but also illustrates the value in an efficient roll out of monitoring equipment, in line with network needs.

3.5 Qualitative results

While much of the focus of the CBA has been on the quantitative assessment, the qualitative assessment can provide broader insights into the strengths and weaknesses of the Frameworks. To identify these, we undertook a relative ranking of the Frameworks in terms of how they performed against a range of criteria, which was agreed with the DNSPs and AEMO.

This qualitative assessment is based on our judgement of how the Frameworks might perform. It is by its nature subjective and in Appendix B we have provided a full write up and justification for the assessment. It is also worth stressing the relative nature of the assessment. To take an example, all Frameworks will be complex to operate compared to today. What we have sought to do is to look at the SGAMs and assess the operational transfer of data and assess which might be most complex. In areas where there were little obvious differences between the Frameworks, we have ranked the Frameworks the same, so as not to force differences which may be marginal.

Table 5 below provides a summary of the outcome of the qualitative assessment as a RAG assessment to visually highlight the differences between Frameworks. We have deliberately avoided weighting the criteria as different stakeholders will each have a different view on which is the most important.

Table 5 Summary of qualitative assessment results

Criteria	SIP	TST	Hybrid	IDSO
Optimising whole system costs	1	3	2	3
Complexity of operation	1	2	3	4
Network reliability	3	1	2	3
Maintaining system security	1	3	1	3
Accountability	1	2	3	4
Independence[25]	1	4	1	1
Adaptability	4	1	2	3
Difficulty to implement	2	1	3	4

The assessment in Table 5 illustrates varied performance across the Frameworks and there is no stand out 'winner' with green across the board. There appear to be three different categories of performance:

- **The SIP and TST Frameworks demonstrate strong performance in a number of areas but weaker in a couple of areas**: The SIP Framework performs well in terms of being simpler to operate than the other Frameworks, providing good access to wholesale market and also level of independence of system operation. However, it may take longer to be as effective in maintaining network reliability. This is because it requires a new party (AEMO) to develop new capabilities in assessing network constraint information and making DER dispatch decisions on the basis of that information. It may take time for AEMO to fully understand the intricacies of distribution network, particularly in reacting to fault situations and assessing how to change the planned dispatch of DER to restore supplies as quickly as possible. The SIP Framework may also be less adaptable, since once new functionality is centralised within AEMO, the case for devolving that functionality to DSOs becomes far weaker, given the duplication of costs it would entail. The TST Framework performs strongly in terms of network access and reliability but less well in terms of providing wholesale market access and optimising decisions across the electricity system. This is because the TST is based on firstly optimising the distribution network and then the wholesale market. Consequently, it may utilise DER flexibility to resolve distribution level constraints, where there may have been greater value in the wholesale markets, leading to inefficiencies.
- T**he Hybrid performs moderately well across most criteria:** The Hybrid Framework performs fairly well across all criteria - occasionally ranked joint first and where not, ranked second or third. This suggests that it can bring a better balance of performance

[25] We have assessed 'Independence' based on the current context and regulatory framework. We note that regulation could evolve in the future which may impact this assessment.

across the range of qualitative criteria. It also brings the same benefits of independent market operation as the SIP or IDSO Frameworks.

- **The IDSO Framework performs relatively worse against most criteria but stronger in others:** The performance of the IDSO Framework illustrates that it is an outlier in terms of its performance against most criteria. However, like the Hybrid Framework, it performs strongly in terms of demonstrating independence (avoiding conflicts of interest).

Table 6 below provides a summary of the relative strengths and weaknesses which we have identified in both the qualitative and quantitative assessments. It also outlines what you would need to be true in order to implement any one of the Frameworks.

Table 6 Summary of strengths and weaknesses of the Frameworks

Framework	Potential strengths	Potential weaknesses	What would need to be true in order to implement
SIP	• Lower cost • Ease of participation for market participants • Utilises AEMO's capabilities in operating markets	• May take longer to maximise network access	• That a single route to market can help maximise DER participation in those markets; • That AEMO can be effective at running location distribution markets to resolve constraints; and/or • That the majority of benefits come from integrating DER into wholesale markets and DSO functionality can be developed over time in an incremental fashion
TST	• Enables DSOs to use knowledge of local networks to help manage constraints • Can potentially be implemented in some regions ahead of others	• Relatively higher cost • The perception of conflict of interest remains	• That DSOs can be more effective at running local markets to facilitate network access; • That any perceived conflicts of interest in DSO running local markets can be mitigated through transparent decision making processes; and • That DSOs can be effective in developing the market capabilities required to develop regional dispatch schedules
IDSO	• Can demonstrate transparency of decision making at local level	• Higher cost • May takes time to implement • Splits accountabilities across different parties	• That local network operators are more effective at running local markets to facilitate network access; • That local network operators need to be independent to foster trust in those new markets; and • That the additional costs and complexity of the IDSO Frameworks is offset by the benefits that greater trust and transparency can deliver.
Hybrid	• Ease of participation for market participants • Utilises AEMO's capabilities in operating markets • Enables DSOs to use knowledge of local networks to help manage constraints	• Requires further definition to understand how it might operate in practice • Potential for some duplication of responsibilities and consequently cost across AEMO and DSOs	• That a single route to market can help maximise DER participation in those markets; • That AEMO can be most effective at developing a co-optimised dispatch schedule across networks and wholesale markets; • That DSOs can be most effective at resolving network constraints; and • That the Hybrid can be further defined to provide clarity on roles and responsibilities and avoid blurring accountabilities

4 Conclusions and Insights from the Impact Assessment

4.1 The case for change

An objective of the impact assessment was to further examine the case for change to move to any of the Frameworks in order to better integrate DER into the Australian electricity system. The results illustrate that under a high DER uptake scenario that there are significant benefits available if DER can be fully integrated and optimised. Based on the current view of costs of building out the required functionality, there are net benefits available of up to $2.5 to 3.5bn out to 2039, depending on Framework.

The results also illustrate that the business case for investing in the full functionality envisioned in all of the Frameworks is much more challenging in a low DER uptake scenario. While this low DER uptake scenario represents the lower bound of outcomes (and current uptake is closely following the higher DER Central Scenario), it underlines the merits of an incremental approach to implementing new functionality and ensuring that it is undertaken in line with need. This could include least regret steps which can be taken to deliver near term benefits and enablers for changes in market design in the future.

Our assessment highlighted that some regions in the NEM are not likely to experience high DER uptake and resultant network constraints until the 2030s. In the more immediate term the available benefits can be delivered through enabling greater DER to access and participation in wholesale markets and through technical solutions to resolve pockets of network constraints to allow DER to access those wider markets.

4.2 Performance of the Frameworks

Another objective of the CBA was to understand the strengths and weaknesses of the Frameworks and start to identify the circumstances which might drive a move to one Framework over another. The assessment shows that across the board, the case for the IDSO Framework seems to be the weakest. Its strengths are that it devolves system operation of DER to a more local level, while providing transparency of decision making and greater independence. However, the qualitative assessment indicates that these are strengths which are shared by the Hybrid Framework. Given the high implementation and operating costs which have been identified with the IDSO Framework, along with the split nature of accountabilities, it is currently difficult to see why it would be implemented over and above the other Frameworks. The remaining three Frameworks all appear to be viable options with the differences between then all within the margin of our quantitative assessment.

Our qualitative assessment highlighted that the SIP and TST Frameworks tended to perform best or worse against the various criteria, while the Hybrid Framework performed reasonably well more consistently across the criteria. We are conscious that both the SIP and TST Frameworks represent contrasting end points of market design which could both be viewed as quite radical options. The Hybrid was developed with this in mind and a natural conclusion is that it can provide a pragmatic option which can bring the strengths of both the TST and SIP Frameworks, and less of the weaknesses. We are cautious of reaching this conclusion because the assessment has shown that the definition of the Hybrid Framework is open to various interpretations. In reality there are a range of options spanning between the SIP and the TST Framework that the Hybrid could take. As noted in Section 4.4 below, it would be helpful if further work could be undertaken to explore these range of options and further define what different forms of a Hybrid Framework could look like.

4.3 Wider insights

The CBA has illustrated that both DER scenarios result in substantial variations in DER penetration and subsequent network constraints across regions in the NEM. These variations are already emerging and as a result DNSPs are starting to develop DSO type functionality at different paces, leading to different levels of maturity across DNSPs. This is a good indicator that functionality is developing in line with need, which our analysis illustrates is a sensible approach while DER uptake is uncertain. However, it also means that it is unlikely that any single Framework, implemented in a uniform manner across the NEM, will completely suit the range of different geographical circumstances.

This suggests that there may need to be flexibility in the implementation of new market design and that the timing of implementation may vary across different regions. For instance, it may make sense to implement central systems to enable better access for DER into wholesale markets. However, the analysis suggests that centralised systems to assess and resolve distribution network constraints may not be the optimal solution in the near term, since many regions are not forecast to experience widespread network constraints for a number of years. With this in mind, it is worth understanding how current market rules and governance arrangements might lend themselves to different paces of transition in across different regions.

We are also conscious that as defined, the Frameworks deliberately omitted network-pricing signals, but targeted price signals and defined network access products could help to resolve network constraints and release some capacity for new DER without a complex new dispatch processes. The approach in GB is moving towards more tailored network pricing and access arrangements on the basis that they can influence customer behaviour and therefore reduce the volume of system operation actions which are needed and therefore, the complexity of managing dispatch of DER .[26] This could be beneficial in supporting the Frameworks and potentially reducing costs of systems needed to determine and manage complex dispatch schedules.

4.4 Where further work would be useful

There are a number of areas of uncertainty across the inputs and assumptions used in the analysis. We have looked to illustrate this through the range of net benefit examples and also the sensitivity analysis. However, further work may be useful to provide additional evidence and understanding around the following areas:

- The effectiveness of different parties in undertaking the range of new functions set out in all of the Frameworks

[26] https://www.ofgem.gov.uk/system/files/docs/2018/12/scr_launch_statement.pdf

- The scale and costs of systems and resources required to deliver some of functionality envisioned in the Frameworks e.g. understanding distribution constraints and the dispatch process and engine required to optimise DER across network and wholesale markets
- The definition of the Hybrid Framework and the respective roles of AEMO and DSOs in the dispatch process, including how disputes are resolved within operational timeframes.

In addition, to help refine the conclusions, it may be helpful to build on this initial CBA, through undertaking the following :

- Undertake the Impact Assessment on a region by region basis to assess where there is merit in implementing new DSO capability. This should include the WEM, once data is available in a similar format to the NEM;
- Including broader forecast data on DER uptake to include smart household appliances, industrial demand side response and larger distributed generation, as well as including DER forecasts out to 2050, to understand the longer term benefits of investments; and
- Assess wider industry costs of the Frameworks including those for retailers and aggregators and DER.

Appendix A Net benefit example results

A.1 Introduction to net benefit examples

As highlighted in Section 3, we ran a series of net benefits results based on different assumptions around the speed at which the Frameworks could maximise wholesale market access and network access. Figures 9 and 10 in the main report, illustrate the combined results of these examples. For completeness we have set out the individual results of each example in this appendix, including the assumptions and judgements which sit behind each.

As explained in Section 2 and in the more detail in Appendix C, the net benefit results are driven by how quickly each Framework can maximise wholesale market access and network access. To capture this, in each net benefit we allocated a year to when each Framework might maximise wholesale market access and maximise network access based on different assumptions or judgements on the performance of the Frameworks. These dates are used to capture the relative differences between the Frameworks in each example, as opposed to reflecting a precise prediction. For each example below we show the different dates used in the model to drive the results. In all examples we assume that the dates to maximise wholesale market access will be earlier than those for network access. This is because we consider that the processes and systems required to provide a route to market for DER are likely to be in place sooner than the systems required to deliver network access (in areas of constraints). The assessment of available benefits also illustrates that widespread network constraints may not be common across the NEM until later in the 2020s, which also suggests that it is more appropriate to have a later assumed date for maximising network access.

These examples are not intended to illustrate the full range of examples but to highlight some of the uncertainties around the performance, particularly around the Hybrid and TST Frameworks.

A.2 Example 1: All Frameworks deliver benefits at the same pace

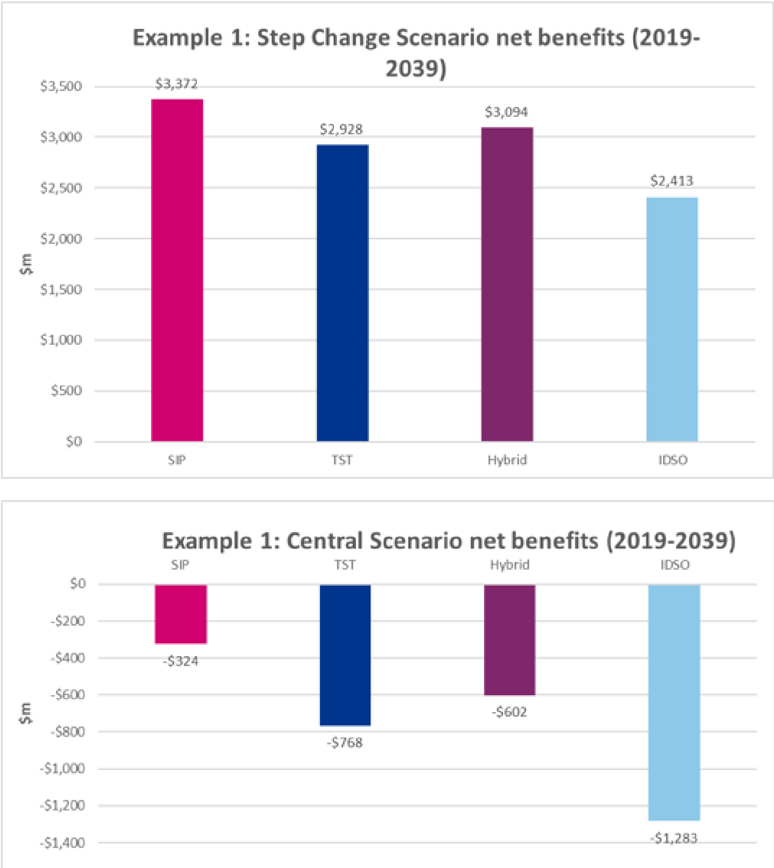
Our first example was based on the assumption that all Frameworks perform equally in delivering the available benefit. This means that they all have the same date for maximising network and wholesale market access (as shown in Table A1).

Table A1 Speed of maximising network and wholesale market access in Example 1

Factor assessment	SIP	TST	IDSO	Hybrid
Date when network access maximized	2028	2028	2028	2028
Date when wholesale market access maximized	2025	2025	2025	2025

This produces the following results, shown in Figure A1.

Figure A1 Net benefits results based on all Frameworks delivering the same benefit ($m NPV, 2019/20 prices)



A.3 Example 2: TST and Hybrid perform strongest

This example is based on the following judgements and assumptions:

- That DSOs will be able to use their existing knowledge of the distribution system to deliver network access sooner than AEMO or IDSOs.
- That the TST Framework enables DSOs to use this knowledge most effectively, and as a result, the TST Framework maximises network access earlier than the other Frameworks.
- That the Hybrid Framework is almost as effective as the TST Framework in the speed at which it maximises network access but takes marginally longer (1 year longer)
- That a single route to all markets will maximise access to wholesale markets sooner than multiple routes and that AEMO will be able to develop new markets faster than DSOs or IDSOs. As a result, the SIP and Hybrid deliver network access earlier than the other Frameworks.
- That it will take time to set up IDSOs and develop the market and network rules required to integrate them into the electricity system. Consequently, the IDSO Framework takes longer to maximise both network and wholesale market access.

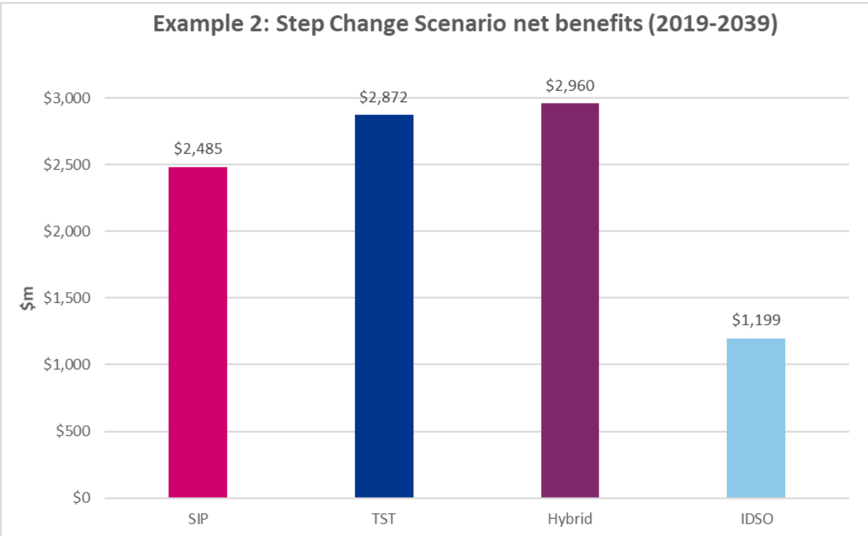
We have reflected these judgements in Table A2 below which shows the indicative dates used for maximising wholesale market and network access in each Framework.

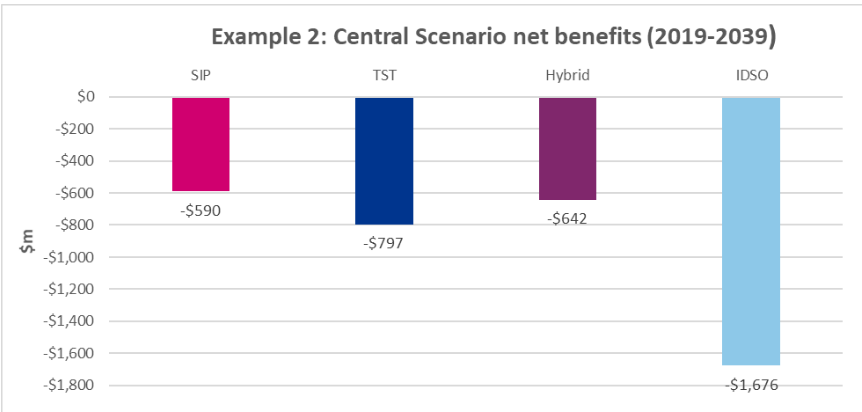
Table A2 Speed of maximising network and wholesale market access in Example 2

Factor assessment	SIP	TST	IDSO	Hybrid
Date when network access maximized	2033	2028	2034	2029
Date when wholesale market access maximized	2025	2025	2031	2025

This produced the net benefit results shown in Figure A2 below.

Figure A2 Overall net benefits under the Step Change Scenario ($m, NPV 2019/20 prices) – Example 2





A.4 Example 3: The Hybrid Framework performs strongest

This example is based on the following judgements and assumptions:

- That DSOs will be able to use their existing knowledge of the distribution system to deliver network access sooner than AEMO or IDSOs.
- That the Hybrid Framework enables DSOs to use this knowledge to determine dispatch of DER as effectively as the TST Framework.
- That a single route to all markets will maximise access to wholesale markets sooner than multiple routes and that AEMO will be able to develop new markets faster than DSOs or IDSOs. As a result, the SIP and Hybrid deliver network access earlier than the other Frameworks.
- That it will take time to set up IDSOs and develop the market and network rules required to integrate them into the electricity system. Consequently, the IDSO Framework takes longer to maximise both network and wholesale market access.

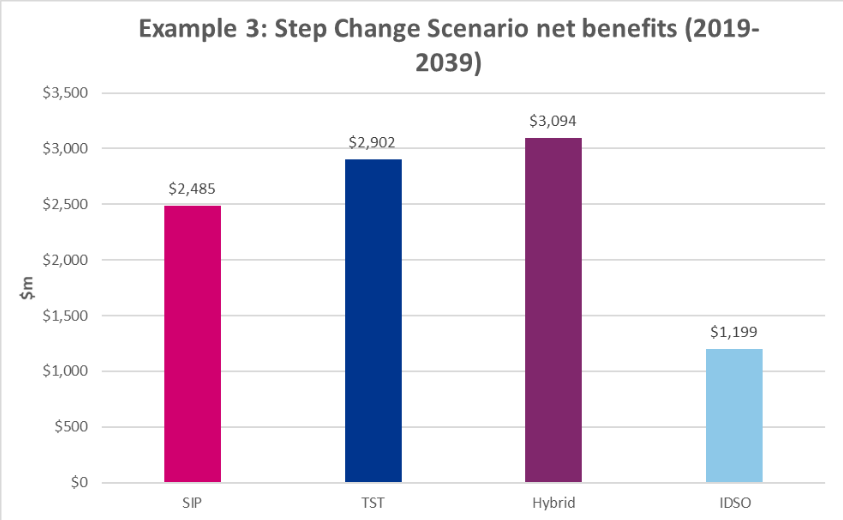
This has driven the following dates of maximising network and wholesale market access (as shown in Table A3).

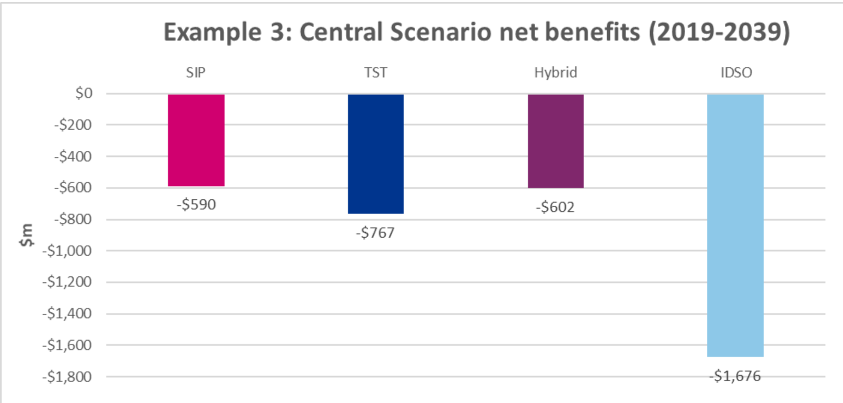
Table A3 Speed of maximising network and wholesale market access in Example 3

Factor assessment	SIP	TST	IDSO	Hybrid
Date when network access maximized	2033	2028	2034	2031
Date when wholesale market access maximized	2025	2028	2031	2025

This produces the net benefit results shown in Figure A3, below.

Figure A3 Overall net benefits under the Step Change and Central Scenario ($m, NPV 2019/20 prices) – Example 3





A.5 Example 4: The TST performs strongest

This example is based on the following judgements and assumptions:

- That DSOs will be able to use their existing knowledge of the distribution system to deliver network access sooner than AEMO or IDSOs. As a result, the TST Framework maximises network access earlier than the other Frameworks.
- That the Hybrid Framework proves complex to run once network constraints are widespread and takes some time to maximise network access (compared to the TST)
- That DSOs can maximise wholesale market access (through multiple routes to market) just as quickly as AEMO can under a single route to market.
- That it will take time to set up IDSOs and develop the market and network rules required to integrate them into the electricity system. Consequently, the IDSO Framework takes longer to maximise both network and wholesale market access.

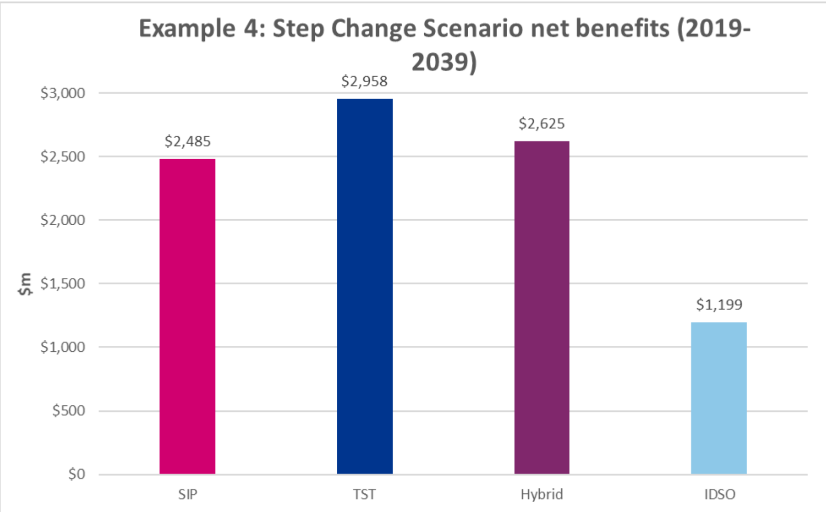
This has driven the following dates of maximising network and wholesale market access (as shown in Table A4)

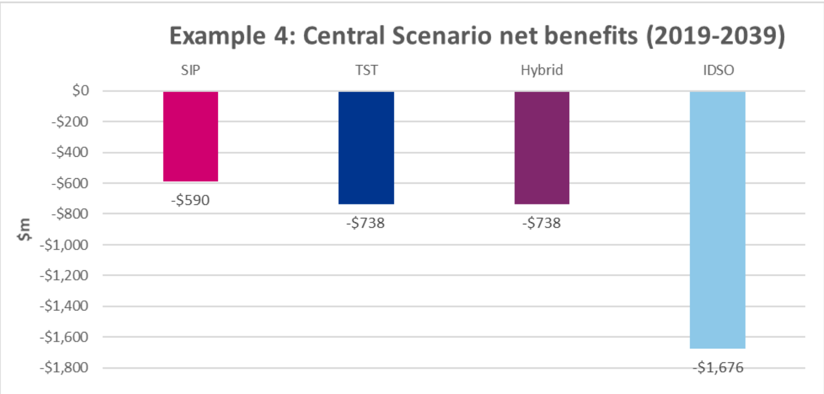
Table A4 Speed of maximising network and wholesale market access in Example 4

Factor assessment	SIP	TST	IDSO	Hybrid
Date when network access maximized	2033	2028	2034	2031
Date when wholesale market access maximized	2025	2025	2031	2025

This produces the net benefit results shown in Figure A4 below.

Figure A4 Overall net benefits under the Step Change and Central Scenario ($m, NPV 2019/20 prices) – Example 4





Appendix B Qualitative assessment

In this appendix, we have included the detailed write up of the qualitative assessment and subsequent ranking. The purpose of the ranking was not to pick a winner but to more fully understand the trade-offs between the Frameworks. The assessment is a high level one designed to highlight the strengths and weaknesses of the Frameworks against different criteria. We have deployed a relative ranking of the Frameworks. This means that the best performing framework is ranked 1 and the next best 2. If the remaining Frameworks were ranked equally, then they would both be ranked 3. We have sought to base this ranking on the more obvious differences between the Frameworks. This means that in some cases there are equal rankings as the Frameworks are either likely to perform the same, or there is not the information available to distinguish between them.

Table B1 Justification for qualitative assessment

Qualitative Criteria	SIP	TST	IDSO	Hybrid	Justification
Optimising whole system costs: How well does the framework optimise across different parts of the electricity system.	1	3	3	2	This criterion looks at the ability of the Frameworks to co-optimise the dispatch of DER to deliver wholesale and network benefits. The SIP and Hybrid Frameworks are specifically designed to co-optimise DER across networks and wholesale markets, with dispatch decisions taken by a single party on the basis of the information available on the value of actions to networks and wholesale markets. However, the current design of Hybrid Framework seems to achieve this through an iterative process which could lead to some delays in decision making, potentially causing it to perform slightly less well than the SIP. The TST and IDSO frameworks are more layered optimisation models where a dispatch schedule designed to optimise distribution benefits is developed first and then AEMO validates whether that schedule is economical from a wholesale perspective. This process is less likely to maximise benefits across both networks and wholesale markets and is more geared to resolving network constraints, rather than checking that the action to resolve those constraints are economical from a wholesale value perspective.

Qualitative Criteria	SIP	TST	IDSO	Hybrid	Justification
Complexity of Operation: Level of complexity in operating the overall system i.e. layers of decision making between actors, including complexity of ICT operation	1	2	4	3	All of the Frameworks will be complex to operate, compared to today. To assess this criterion we have looked at the volume of near time information exchange required in each Framework and the complexity in processing that information to take operational decisions. The SIP is the simplest model as a single party makes all decisions. The TST is slightly more complex as a result of each DSO having to validate decisions with AEMO. The Hybrid Framework requires a number of information exchanges between each DSO and AEMO (albeit potentially through a platform) which would need to occur in close to real time. The IDSO model performs less well as dispatch schedules appear to be needed to be validated by both AEMO and the DSO in close to real time.
Network Reliability : Ability to ensure safe, reliable networks	3	1	3	2	We have assessed the Frameworks against this criterion, on the basis on the level of control over dispatch available to respond to unforeseen events and maintain local network reliability. The TST Framework would appear to perform best as DSOs retain control of dispatch of DER on local networks and can amend dispatch schedules to respond to events and maintain reliability. Similarly, in the Hybrid Framework, DSOs will retain a level of control in that they can propose a dispatch schedule to AEMO which fully accounts for distribution reliability. However, since there is a chance that AEMO can amend this schedule when they look to co-optimise with wholesale market, it performs relatively less well than the TST. Both the SIP and IDSO requires parties other than the DSO to take operational decisions on the dispatch of DER to maintain distribution reliability and in the near term, they may not be as effective as this as the DSOs themselves, particularly in responding to unforeseen events and having to interpret data submitted by the DSO before taking actions.

Qualitative Criteria	SIP	TST	IDSO	Hybrid	Justification
Maintaining system security: Ability to keep the overall system secure	1	3	3	1	This criterion assesses the ability of the Frameworks to access the flexible resources needed to maintain overall system security across the NEM. The SIP and Hybrid Frameworks look to perform best, as the co-optimised dispatch will allow AEMO to use DER to maintain overall system security, even where that might pose some local network issues (on the basis that maintaining overall system security is more valuable). Under the TST and IDSO Frameworks, it may be more difficult for AEMO to over-rule dispatch decisions geared towards maintaining local reliability rather than whole system security.
Accountability: Ability to provide clear separate roles and responsibilities with specific accountabilities	1	2	4	3	To assess the Frameworks against this criterion, we have examined the clarity of responsibilities for parties in based on the current design of each Framework. All the Frameworks result in a blurring of responsibilities compared to today's roles, as the integration of DER requires greater co-ordination across all parties. The SIP would appear to provide clearer accountability as AEMO undertake dispatch of all parties (based on information provided by the DSOs). The TST Framework devolves dispatch of DER to DSOs which can potentially blur the lines with AEMO's role in dispatching Transmission connected parties and responsibilities for system security. The Hybrid Framework outlines an iterative dispatch process which requires information exchange between DSOs and AEMO which makes it difficult to understand where accountability sits (based on the current design). The IDSO Framework appears to perform least well, since as in the TST Framework, it splits responsibility for dispatch but across 3 different parties, creating further potential for blurred lines of responsibilities.
Independence Ability to provide independent decision making	1	4	1	1	We have based our assessment of the Frameworks against this criterion, based on how neutral a party can be in taking operational decisions, based on the current market structure and regulatory framework. Both IDSOs and AEMO are independent system operators, with no other interests. Therefore, we have scored the Frameworks where the initial development of DER dispatch, is developed by AEMO or the IDSO as performing equally well. Under the TST Framework, DSOs would be responsible for both system operation of DER (defining dispatch schedules) and network investment. This can lead to the perception that decisions on dispatch are unduly influenced by the financial impact on not investing in

Qualitative Criteria	SIP	TST	IDSO	Hybrid	Justification
					asset solutions. This means that the TST Framework performs relatively worse than the others. However, these issues can be overcome through implementing clear and transparent processes.
Adaptability: How adaptable is the framework to the different pace of change in different regions.	4	1	3	2	We have assessed the Frameworks against this criterion on the basis of how well each Framework can respond to changing circumstances i.e. sudden increase in DER uptake, as well as facilitate a different pace of transition in different regions. The TST would appear to be the Framework which can facilitate the most regional variation, as it allows each DSO to develop at the pace needed (driven by the level of constraints on the network). The Hybrid Framework would appear to perform next best as there is a still a fair amount of responsibility devolved to DSOs to progress at their own pace and for the level of DSO functionality to evolve in line with need. Since the Hybrid Framework builds up greater system operational functions in both the DSO and AEMO, it provides some degree of optionality for the future (albeit at a potentially high price). The IDSO Framework could allow for some future changes and could enable a degree of regional variation. However, this is likely to be difficult/costly to implement once time and resources have been invested in setting up regional IDSOs. The SIP Framework would seem to require a single, national implementation, leaving less room for adaptation over time. It would also require a significant upfront investment to implement DSO functionality on a national scale which would remove any opportunity to reduce investment costs by ensuring functionality was aligned with regional needs.
Difficulty to Implement: How difficult is it to implement each framework i.e. level of rule changes required (n.b. we have ordered the ranking in terms of the easiest to implement)	2	1	4	3	We have assessed the Frameworks against this criterion based on the time and work required to implement each Framework. All Frameworks require quite radical change. The TST Framework seems to require the least change as it retains current responsibilities for network operation (DSOs) and wholesale optimisation (AEMO). The SIP Framework requires an expansion of AEMOs current role to process operational data from DSOs and be able to interpret that data to understand the implications of DER dispatch decisions on low voltage distribution networks. This is likely to be more difficult to implement than the TST Framework. The Hybrid Framework would seem to require substantial work to establish the market platform and information

Qualitative Criteria	SIP	TST	IDSO	Hybrid	Justification
					exchange required between AEMO and the DSOs, as well as how the more iterative dispatch process would work in practice. The IDSO Framework would require a series of new organisations to be established and for the IDSOs to process and understand the data being submitted by DNSPs, so performs least well.

Appendix C Approach to assessing benefits

C.1 Overview

C.1.1 Tailoring the Methodology for Australia

The high-level approach for this benefits assessment was informed by our 2018 work on the UK Future Worlds Impact Assessment.[27] This methodology was tailored for Australia to take into account the different DER forecasts including higher PV adoption and slower uptake of electric vehicles. We also took into account relevant existing Australian studies such as:

- Arena projects (e.g. Oakley Greenwood);
- Victoria feed in tariff review;
- SAPN's work with Houston Kemp on valuing DER;
- CSIRO's high level review of the benefits assessment and;
- The Electricity Network Transformation Roadmap from 2017.

However, in many ways this type of assessment is a first in Australia and consequently we brought some of our approach from the UK study (for example the approach to modelling Electric Vehicle impact) and worked with stakeholders to adapt it for the Australian context. The methodology section describes the approach and assumptions in more detail.

C.1.2 Stakeholder Engagement

A sub-group of DNSPs (Essential Energy, SAPN, AusNet Services and Energy Queensland) and representatives from AEMO were involved in a series of working sessions to refine and iterate the methodology. Data requests (as detailed below) were shared with all DNSPs, AEMO and some TNSPs. The AER and AEMC were engaged upfront to feedback on the methodology.

C.1.3 Data Requests

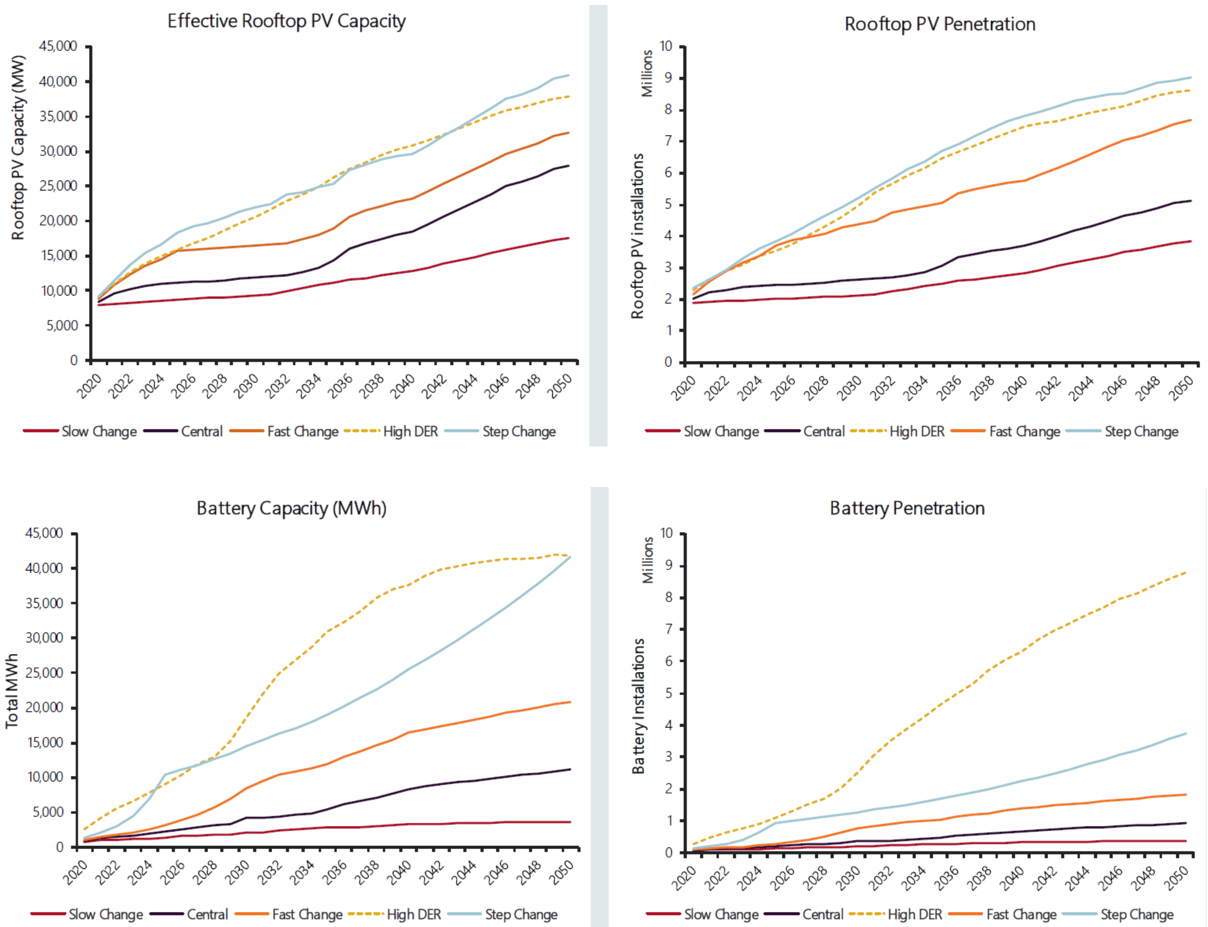
This modelling was informed by data inputs from both AEMO and the DNSPs. The majority of the DER forecasting and demand data was taken from AEMO's 2019 ESOO. The DNSPs provided data on the level of forecast constraints as a result of both PV and demand increases from EVs. Data from both the DNSPs and TNSPs was used to inform network augmentation costs. The benefits methodology states these inputs and assumptions in more detail and the model itself contains source information.

[27] http://www.energynetworks.org/electricity/futures/open-networks-project/workstream-products/ws3-dso-transition/future-worlds/future-worlds-impact-assessment.html

C.1.4 Methodology

We assessed the potential benefits which might be possible under two of AEMO's future scenarios – the central scenario (where DER uptake is low) and a step change scenario (where DER uptake is significantly higher), and the only scenario where warming is kept below 2 degrees Celcius, see Figure C1. We chose these two scenarios out of the five available to cover a range in DER uptake to tease out key differences in the frameworks and to understand how their suitability might change under different DER uptake scenarios. However, it should be noted that DER uptake was kept as an exogenous variable, and in reality barriers such as difficulty to access both networks and wider markets would impact DER uptake.

Figure C1: AEMO's DER uptake scenarios



We identified four high-level benefit categories of DER integration into the Australian power system (further detailed in Table C1):

- **Avoided distribution investment / reduced curtailment costs**
- **Avoided transmission investment**
- **Reduced wholesale ancillary services costs**
- **Reduced wholesale energy costs**

This initial step was designed to understand the quantum of benefits which might be possible through integration of DER in each of the four categories we identified. This was important since different Frameworks might be better or worse at delivering certain categories of benefit. We took a top down approach to modelling, rather than develop a bottom up, complex, whole system energy model. We considered that this level of detail was appropriate for an initial Impact Assessment and the detail of the Framework definitions.

Table C1: Key Benefits Categories

Benefit Category	Generation driven	Demand driven
Avoided Distribution investment / reduced curtailment costs	Reduced curtailment of Distribution connected generation: • saved marginal generation costs • reduced losses	Reduced Distribution investment to meet higher local peaks • avoided local network augmentation to meet higher demand (e.g. from EVs)
Avoided Transmission investment	Reduced curtailment of Distribution connected generation avoids the need to build new Transmission network to connect large scale renewables • saved transmission connection costs	Reduced network augmentation to meet greater peak demand: • saved transmission augmentation costs
Reduced wholesale ancillary services costs	Greater competition provided by DER will drive lower prices	
Reduced wholesale energy costs	N/A – this is about shifting demand away from peak to off-peak	Demand response at peak (e.g. shifting demand and storage import to off – peak times)

C.2 Defining the counterfactual

In order to assess the potential benefits of better DER integration we needed to define a counterfactual. The counterfactual assumed that there would be limited distribution network access for a fixed DER uptake. As a result, a proportion of generation would be curtailed, DER would be managed in an uncoordinated way with limited access to wholesale markets and there would be unmanaged EV charging, driving network augmentation. We also assume there would be not access to flexible demand to reduce network or wholesale peaks.

C.2.1 Curtailment of distribution connected generation

In the counterfactual we assumed that a proportion of distribution connected generation will be curtailed as a result of network constraints. We used forecast data on network constraints from the DNSPs to inform the level of curtailment forecasted in the counterfactual. We assumed that rooftop solar and PV non-scheduled generation (PVNSG) were curtailed, we did not account for other non-scheduled generation (ONSG) as part of the curtailment analysis[28]. We assumed that in the counterfactual all curtailed solar energy is replaced with transmission connected solar generation.

[28] It was assumed that this type of generation would not be dispatched at solar peak, it is more likely to be dispatched to meet the demand peak

We assume that the curtailed energy is required to meet demand as a result of planned coal plant closures, hence why new generation build is required in the counterfactual.

To assess the volume of energy curtailed in the counterfactual:

- We calculated a customer adoption (%) of PV for each NEM region and each scenario (based on AEMO's PV uptake forecast and customer numbers per NEM region), as PV adoption most aligned with the data provided on DER uptake and corresponding network export constraints from the DNSPs.
- The DNSPs provided forecast data on the constraints which emerge for different types of networks as PV adoption increased
- In general PV was unconstrained to a threshold level of adoption, above which new generation capacity would be curtailed
- We have made assumptions based on DNSP data inputs that in the median case above 15% PV penetration, new generation capacity was curtailed by 80% (at all times of day). Above 37% PV adoption, all new capacity was fully curtailed. We acknowledge that these are averages and that individual regions will vary.

The volume of curtailed energy in the counterfactual was also increased to account for actual transmission and distribution losses, as we have assumed in the counterfactual that the curtailed energy is replaced with transmission connected generation.

We have assumed the following transmission and distribution losses:

Table C2: Actual Transmission and Distribution Loss Factors[29]

NEM Region	T Loss factors	D Loss factors (LV)	T + D loss factors
NSW	98.317%	94.091%	92.408%
QLD	97.079%	94.110%	91.189%
SA	99.001%	90.909%	89.910%
TAS	97.403%	95.238%	92.641%
VIC	98.238%	94.787%	93.025%

To calculated the value of this curtailed energy, we use the solar levelised cost of energy (LCOE) $/MWh to value the curtailed generation. It was assumed that curtailed distribution connected PV would be replaced with transmission connected solar, maintaining the equivalent renewables penetration and export profile. The LCOE was used as generation would not be curtailed at the same time as peak demand. This is taken to be **$66/MWh[30]**, It should be noted that there could be alternative approaches to assessing the value of this curtailed generation, for example, the methodology used to calculate the revised feed in tariff for Victoria included a broader range of DER benefits including a carbon price.

[29] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Loss_Factors_and_Regional_Boundaries/2019/Distribution-Loss-Factors-for-the-2019-20-Financial-Year.pdf

[30] Based on Baringa's reference case modelling

C.2.2 Transmission Infrastructure Investment: Generation driven

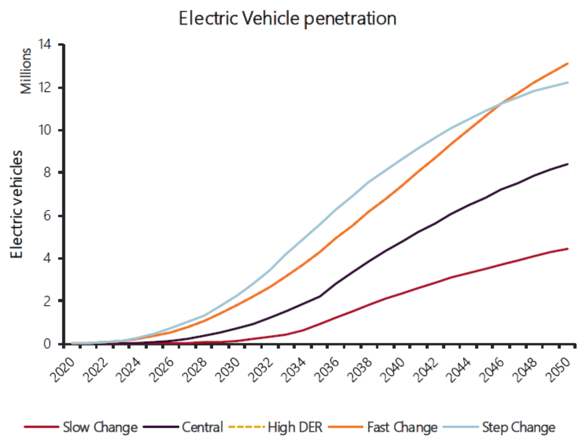
We assume that transmission network capacity needs to be built out to accommodate the equivalent volume of curtailed generation on the distribution networks. While demand is only expected to increase slightly in AEMO's forecast to 2038/9 (primarily driven by EVs in the 2030s), AEMO's Integrated System Plan (ISP) sets out a number of coal plant closures in the near future. As a result, this means that additional generation capacity (equivalent to the curtailed generation) will be required in the counterfactual to meet demand. It is assumed that this capacity will be connected within Renewable Energy Zones which will require additional transmission infrastructure. As part of the modelling we also assume there is limited existing export capacity within the current transmission infrastructure.

The additional capacity of transmission infrastructure capacity required to meet the energy curtailed was calculated on an annual incremental basis using the load factor for renewable generation **(29%).** The cost of this incremental transmission capacity was calculated using a value of **$87,000/MW** based on AEMO's ESOO data[31]. It should be noted that this augmentation value relates to building out transmission infrastructure for newly connected generation, if wider transmission infrastructure needed to be augmented the $/MW would likely be higher.

C.2.3 Distribution Network Investment: Demand driven

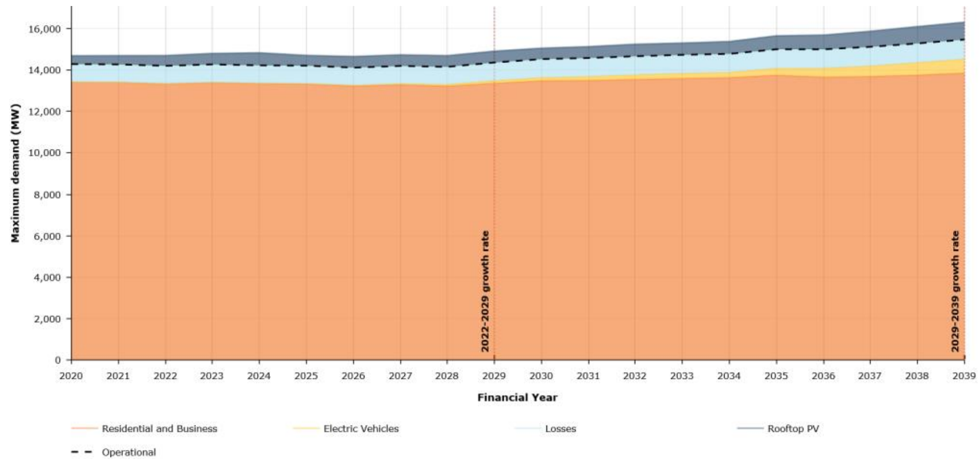
We assume that the main driver of peak demand growth is residential EV charging, as informed by AEMO's DER uptake scenarios and AEMO's maximum demand forecasting (in Figures C2 and C3 below).

Figure C2: AEMO's 2019 ESOO scenarios, showing EV uptake



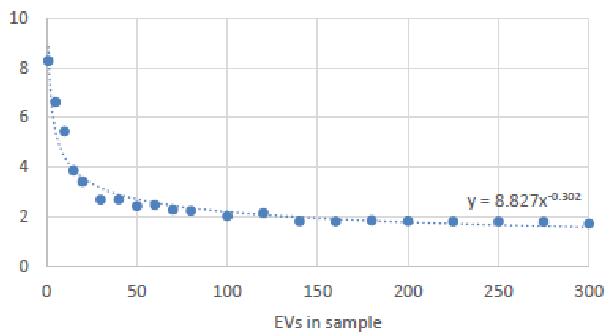
[31] AEMO's 2019 ESOO data inputs

Figure C3: AEMO maximum demand forecasting, showing demand increase from 2030 due to EVs[32]



We assume that EV peak load will have the largest impact on the low voltage network, as diversity of EV charging is lowest with lower numbers of EVs (e.g. on a single feeder). This assumption has been validated in a number of large-scale EV trials in the UK, such as My Electric Avenue and Electric Nation[33] which appear equally applicable to Australian distribution networks. We calculate the average number of EVs per feeder over time based on AEMO's EV forecast, household numbers per NEM region and data on number of feeders per DNSP. We then assess the peak load at LV feeder level as a result of EVs, using unmanaged charging diversity assumptions based on peak load per EV data from the UK Electric Nation trail (trail of nearly 400 vehicles) – as per Figure C4 below.

Figure C4: Electric Nation diversity curve, kW/EV vs. number of EVs



We assess the incremental annual LV and HV distribution network augmentation required (per region) as a result of EV peak load (incremental capacity required), based on the average load increase required to trigger LV reinforcement (based on augmentation volumes around EV scenarios provided by the DNSPs). This scalar value included DNSP data on the number of EVs at a point in time and the associated network augmentation.

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32 http://forecasting.aemo.com.au/Electricity/MaximumDemand/Operational - Forecast for New South Wales

33 http://myelectricavenue.info/sites/default/files/documents/Close%20down%20report.pdf

We assess the distribution investment associated with this level of network augmentation, based on a $/MW input of augmentation. This is assumed to be **$85,000/MW** at LV and **$100,000/MW** at HV as part of our median model inputs, based on data provided by the DNSPs (based on the average equivalent capex cost of augmenting the network). We assumed that as a result of EV diversity EV peak demand would have only a third of the impact at HV when compared to LV (as informed by our UK Future Worlds Impact Assessment).

It should be noted that there will be significant locational variation in terms of EV uptake which has not been represented as part of this modelling. In reality, EV uptake tends to cluster in urban areas of higher income with charging infrastructure provision. Therefore, distribution network augmentation could be significantly earlier in some local areas of high EV uptake than shown as part of this modelling.

C.2.4 Transmission Network Investment – Demand driven

We have assessed how the EV peak load at transmission level differs from at LV to understand the volume of transmission capacity required in the counterfactual. UK EV trials assume diversity at transmission to be approximately 1.5kW/EV (Electric Nation diversity assumptions). As a result, we have assessed the demand impact of unmanaged EV charging on the transmission network, based on an estimated network headroom (as informed by TNSP data). We have used a value of **$150,000/MW** provided by a TNSP to calculate the augmentation cost in the counterfactual.

C.3 Optimal System Operation

C.3.1 Reduced Curtailment

We assessed the volume of curtailment reduction that might be possible through optimal distribution system operation. This involved assessing the volume of excess generation (the curtailment calculated in the counterfactual) which could be absorbed by local coordination of demand (e.g. storage and EVs). The premise is that through running local market mechanisms, local flexible demand can be better matched to local peak solar, helping to reduce the volume of constraints of that solar. The following assumptions are applied to the volume of flexible storage available:

- We use the storage uptake assumptions for each scenario from the ESSO data set
- Battery round-trip efficiency of **85%**
- Proportion of storage which is used to reduce curtailment assumed to be **100%**
- Co-location of storage and PV assumed to be **100%**

We then made assumptions about the volume of curtailed energy which can be reduced through aligning peak solar with EV charging demand:

- Based on the proportion of drivers who could incentivised to charge during the day time solar peak e.g. **20%**[34]
- Proportion of drivers taking part in flexibility propositions e.g. **80%** (modelled as part of UK smart charging studies, Project Shift[35])

[34] Informed by the UK's Electric Nation trial, http://www.electricnation.org.uk/
[35] https://innovation.ukpowernetworks.co.uk/projects/shift/

- PV and EV co-location factor e.g.**75%**
- EVs which charge from storage during the evening peak were not included, as they were captured through the curtailed energy absorbed by storage

Combining these assumptions, we assess how much curtailment (MWh) is reduced by the above flexible demand and calculate the associated benefits through the marginal generation costs shown previously.

C.3.2 Reduced Distribution Network Augmentation

We assessed the volume of demand that is flexible through EVs and storage (peak shifting), as a result of better integration of DER:

We assumed the volume of flexible peak demand associated with EVs (for each DER uptake scenario)

- Based on the proportion of EVs charging at peak times on a daily basis e.g. **20% -** this is based on 40% of drivers charging at peak times, and charging their vehicles 3.5 times per week, as informed by the UK's Electric Nation trial.[36]
- Peak charging demand reduction through smart charging e.g. **90%,** this assumption has been used in UK trials and assumes a significantly increased diversity factor[37]
- Proportion of customers taking part in flexibility propositions e.g. **80%**, modelled as part of UK smart charging studies

We then assessed the volume of demand flexibility through storage:

- We took account of the total volume of storage forecast for each DER uptake scenario
- We assumed the proportion of storage ready to discharge at peak times, **90%**

We assessed whether the augmented distribution network capacity calculated in the counterfactual can be reduced or avoided as a result of this reduced demand. We then assessed the value of delaying or avoiding this distribution network augmentation based on previous costs. We have also sense checked these benefits to ensure that we are not avoiding or deferring all distribution augmentation through demand flexibility as this would not be reflective of reality. Over the 2038/9 time horizon the model assumes a maximum of 80% avoided/deferred augmentation, which is similar to the assumptions applied in our UK Future Worlds Impact Assessment and validated by UK distribution businesses.

C.3.3 Reduced Transmission Infrastructure Investment

Reduced curtailment

The reduced curtailed energy through better integration of DER will also have an effect on the capacity of transmission augmentation required. In our optimal scenario, there is less generation build required at transmission, therefore the corresponding transmission infrastructure build can also be reduced, using the augmentation costs presented previously.

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[36] We note that commuting distances and therefore the charging frequency may be marginally higher in Australia but no concrete data was available.

[37] UKPN Shift trial - https://www.ukpowernetworks.co.uk/internet/en/news-and-press/press-releases/Launch-of-UKs-first-electric-vehicle-smart-charging-marketplace-trial.html

Reduced demand

Similarly, to the calculation for avoided distribution network augmentation, at transmission we assessed the volume of flexible demand through storage and EVs which could be used to reduce peak demand and therefore avoid the corresponding transmission network augmentation.

The storage capacity is equivalent to that at distribution level (as the use of storage is not influenced by a secondary use, such as driving), however, EV peak demand is less significant at transmission demand as a result of higher charging diversity.

We apply the same methodology as for distribution to understand the proportion of transmission augmentation which can be deferred or avoided, using the same transmission network augmentation value used in the counterfactual - **$150,000/MW**.

C.3.4 Reduced wholesale costs as a result of reduced peak demand

This benefit category is the value of flexible DER in the wholesale market, in terms of the ability to reduce system peak and avoid running more expensive generating plant. Therefore, we assessed the volume of flexible demand which could be used to reduce the peak. This flexible demand is made up of both EV peak demand and the peak demand which can be offset by storage.

We had to make some assumptions around the duration of the peak shift, based on the capacity of the flexible assets (EV chargers and storage). We calculated that, based on the profile of these assets, the duration of the daily flexible demand reduction is **2 hours** (e.g. 11kWh battery exporting at around 5kW). We note that there may also be further flexible demand available through increasing the proportion of customers partaking in Demand Side Participation (DSP), such as customers giving away more control of air conditioning. However, there was not sufficient data on these volumes of flexibility to include in our analysis.

The value of shifting this peak demand is equivalent to difference between wholesale peak and off-peak pricing (taken to be **$90/MWh**[38]). However, there we note the uncertainty as to how this price differential will change over time (e.g. the effect of higher intermittent renewable penetration, cost of storage, cost of new peaking assets).

C.3.5 Reduced wholesale ancillary service costs

We assessed how integration of DER might reduce wholesale ancillary service costs as a result of increased competition. We have focussed FCAS and NSCAS ancillary services, as services which are likely to be influenced through DER uptake. We have used the following methodology to assess how the value of these services might change out to 2038/9, as a result of increased penetration of renewables and more utility scale storage:

- We assessed the percentage of renewables in 2012 compared to 2018 to evaluate how the volume of FCAS and NCAS services required changes due to increased renewable penetration[39]

[38] https://www.aemo.com.au/-/media/Files/Media_Centre/2019/QED-Q2-2019.pdf

[39] https://www.energy.gov.au/publications/australian-energy-statistics-table-o-electricity-generation-fuel-type-2017-18-and-2018

- We used the increased spend of ancillary services to date as a way to project the value of ancillary services out to 2038/9, based on forecast renewables under both DER uptake scenarios
- We have also included assumptions on how large scale transmission connected storage will reduce ancillary service costs over the next 3 years in the counterfactual, based on the performance of the Hornsdale battery and Baringa's ancillary services forecasting.
- We then use a **10%** (central scenario) and **30%** (step change scenario) assumption, as to how competition through DER will reduce prices. These assumptions are based on evidence of the impact which access to distribution level storage has had on UK wholesale ancillary services costs, where there is evidence of a 10-30% reduction. We consider that this evidence is equally applicable to the Australian market.

C.3.6 Flexibility payments

We assume that DSOs will need to pay DER (or DER via aggregators) to shift their demand away from peak (this is in addition to customer benefits through off-peak wholesale pricing). We assume a $/MW/year flexibility payment for flexible demand which can delay or avoid distribution network augmentation. We assume that DSOs would only pay for flexibility when it results in a benefit of avoided network augmentation, therefore from a modelling perspective these payments only apply to flexible EV demand which can reduce distribution network augmentation.

The price that will need to be paid through distribution service markets for flexibility is a key unknown. Such markets are only just being established in Australia and no country has a fully mature market. Consequently, we have used data from the emerging distribution services markets in the UK to assess the type of payments which would have to be made. This corresponds to around **be $50,000/MW/year**.

C.4 Assessing the performance of the Frameworks in delivering the potential benefits

In order to assess the performance of the Frameworks, you need to make judgements about how different parties will perform in taking on new functionality. For instance, how effective can AEMO be at interpreting distribution constrain information and designing a dispatch process to mitigate those constraints. Equally how effective will DNSPs be at establish and running markets to help resolve local constraints. Since there is little data and evidence available in this area, we used a range of different assumptions to produce a series of different results and presented these as a range (see Figures 9 and 10 in Section 3).

We broke down the assessment of how each Framework performed in delivering each category of benefits in the following way:

- The avoided distribution investment / reduced curtailment costs and avoided transmission investment benefits categories are driven by how quickly the frameworks can maximise distribution network access

- The reduced wholesale ancillary services costs and reduced wholesale energy costs benefit categories are driven by both speed of maximising network access and speed of maximising wholesale market access

For each example we used different dates for when each Framework would maximise network and wholesale market access. They are used to apportion the benefits to each Framework over time. The specific dates chosen for each example are set out in Appendix A. It was assumed that 80% of each benefit category was delivered by the specified date (noting which benefit categories are driven by network access and or market access) ramped up linearly from 2019/20. We then assumed a five-year "maturing phase" following the network access date where the benefits linearly ramped up from 80% to 100%, thereby allowing systems and processes to scale. It should also be noted that the volume of DER is a significant driver of benefits, which is not affected by the factor assessment.

An illustrative worked example of how the dates are applied to each benefit category is shown in Table C4. Note the dates and the potential benefits available are illustrative figures to demonstrate how the drivers align to each benefit category. The potential benefits available in this example also represents only 80% of the benefit available, as we then assume a 5 year maturing phase to reach the full 100%.

Table C4: Illustrative worked example of applying the factor assessment

SIP	2020	2021	2022	2023	2024	2025	2026
Proportion of network access benefits allocated	25%	50%	75%	100%	100%	100%	100%
Proportion of wholesale access benefits allocated	50%	100%	100%	100%	100%	100%	100%

Benefit Category	Potential benefits available in 2022	Benefit driver	How we would calculate proportion of benefit allocated to SIP in 2022
Avoided Distribution investment / reduced curtailment costs	$100m	Level of network access for DER	75% x $100m = $75m
Avoided Transmission investment	$50m	Level of network access for DER	75% x $50m = $37.5m
Reduced wholesale ancillary services costs	$75m	Level of wholesale access for DER **and** level of network access for DER	(100%*$75m)*75% = $56.25m
Reduced wholesale energy costs	$100m	Level of wholesale access for DER **and** level of network access for DER	(100%*$100m)*75% =£75m

C.5 Suggested future data capture to inform further modelling

There were a number of aspects of the modelling which could have been improved with better data. There were certain inputs which were based on UK studies when no equivalent Australian data was available. There are also a number of input assumptions which are based on customer behaviour which could be validated through trials. The input assumptions which could be further refined in future are as follows:

- Unmanaged EV diversity in Australia and corresponding demand at different network levels

- Customer uptake of flexibility propositions (e.g. smart charging, using storage to reduce local curtailment of PV, Demand Side Participation (DSP))
- Further work could be undertaken to understand how the volume of flexible demand might increase in future, as this modelling focused on purely storage and EVs, for example we did not assess how the DSP volume could increase through future customer propositions
- Customer sensitivity to flexibility payments
- TNSP network headroom (the data in the model was informed by a single TNSP)
- The level of generation export capacity on the transmission network (this was assumed to be limited)
- Co-location of PV, storage and EVs
- The modelling was focussed at NEM region level, however, there would be benefits in carrying out the equivalent methodology at more granular locations to drive out differences in network augmentation costs, DER uptake and network constraints.
- Whilst the modelling looked at the benefits of peak vs. off-peak wholesale pricing, distribution network reflective pricing was out of scope for this work (and was not captured as a Future Framework or function within the SGAMs). Further work and trials should be carried out to understand customer response to network reflective pricing,
- This work did not look to apportion benefits to what could be delivered through “least regrets” network solutions vs. market solutions, or to breakdown market solutions into wholesale vs. local. Further work on this will help to inform appropriate timelines for investment in specific technology and capabilities to deliver the Future Frameworks.
- There are wider benefits to DER that have not been captured through this work, such as carbon benefits or benefits driven by retailers or aggregators.

Appendix D Cost assessment approach

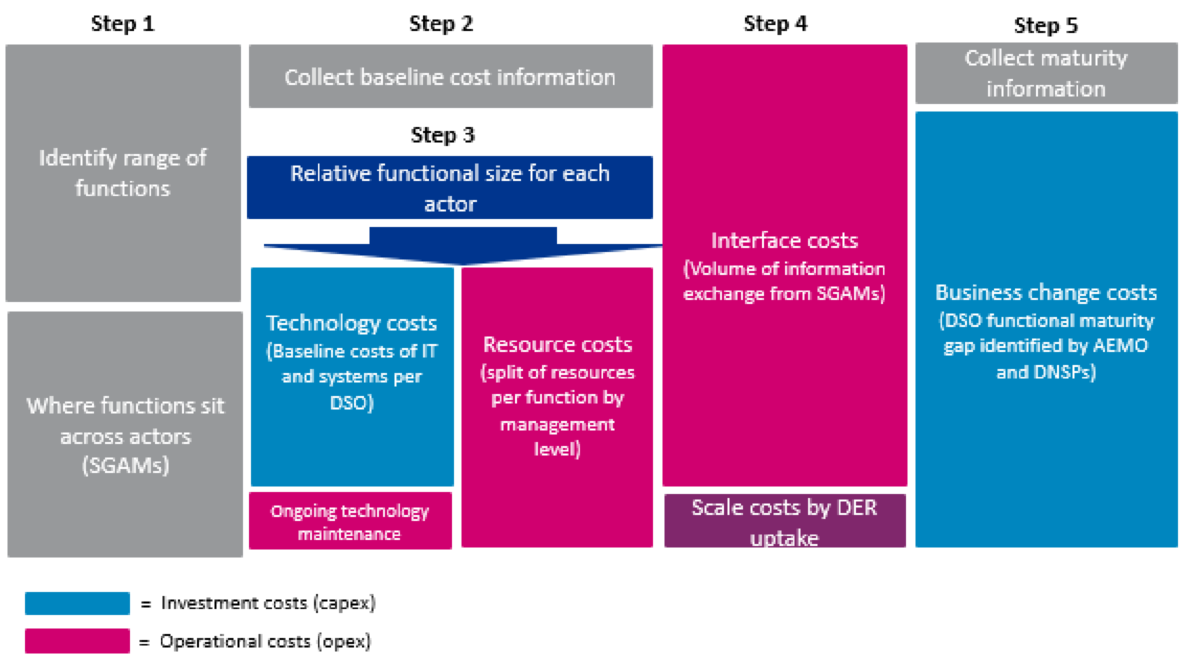
D.1 Summary of approach

The cost methodology utilises the existing work undertaken in the SGAM modelling and publications within the Open Networks programme to understand the relative differences in costs between the Frameworks. To do this we have focused on the following elements:

- The degree to which DSO functions (and subsequent resources) are duplicated across actors within each Framework
- The volume of information exchanges required between actors in each Framework
- Where economies of scale can reduce the costs within a Framework.

To tease out how these areas impact the relative costs of the Frameworks, we have used the high level methodology outlined in Figure D1 below.

Figure D1 Summary of costs assessment methodology

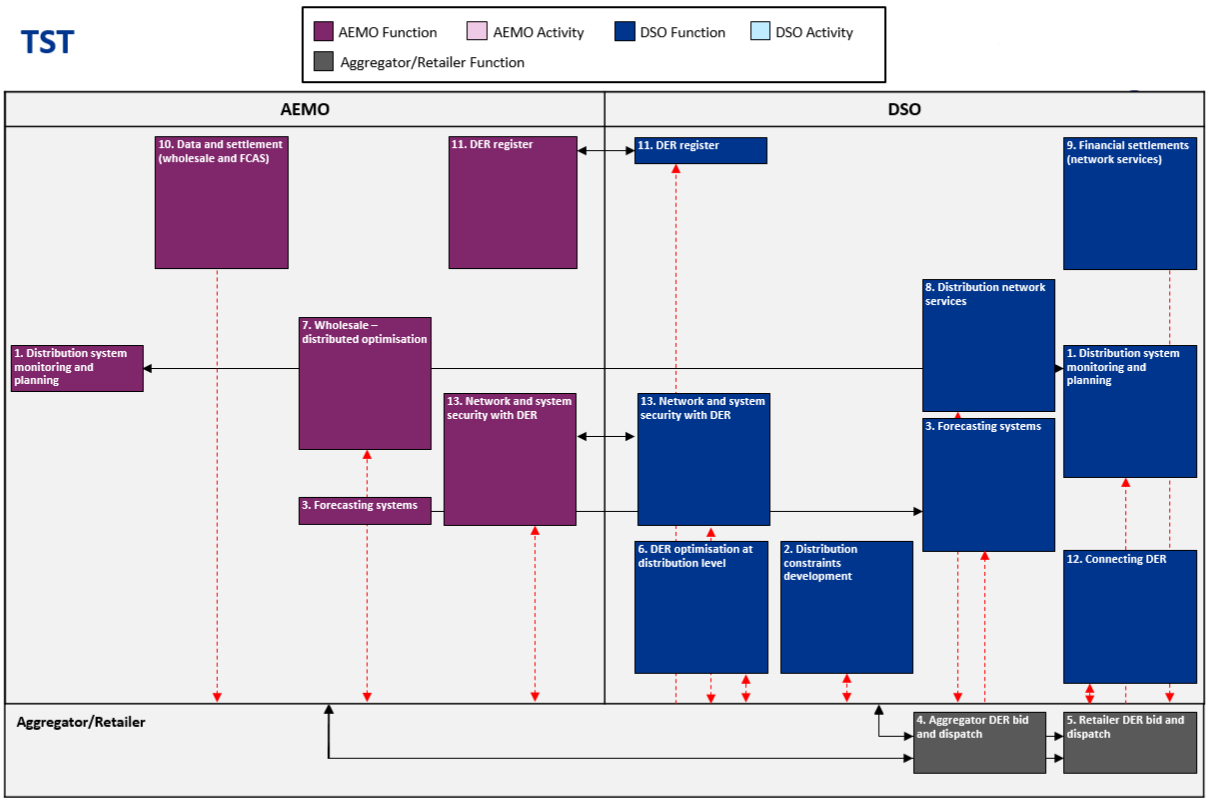


We describe each of the five key steps in turn below and provide a summary of the key assumptions at the end of each section.

D.2 Identifying DSO functions and where they sit in each Framework

We wanted to understand the drivers for cost within the Frameworks. As a starting point, we were able to use the work produced for the Open Energy Networks interim report which identified the key functions required for DSOs.[40] This identified the key DSO functions required. The SGAM modelling used these same DSO functions as its basis. This allowed us to take the outputs of the SGAM modelling to understand where different DSO functions sat across different actors in each Framework. We captured these in high level operating models. As an example we have shown in Figure D2 below, the operating model for the TST Framework to highlight where functions sit across the different actors and how these functions interact with each other. The size of the boxes in the operating model relates to the size of the function for each actor – we expand on this in Section D.4 below. Appendix E includes the operating models for all of the Frameworks.

Figure D2 Example of TST Framework operating model



D.3 Collecting baseline cost information

Through data requests to AEMO and the DNSPs, we identified a set of baseline technology costs that are required for operation of DSO functions. We asked DNSPs to provide costs based on the TST Framework and AEMO to provide costs based on the SIP Framework. These were chosen as they represented the largest footprint of activity for each actor, which we could then scale back in other Frameworks. We asked for costs to be broken out into two stages, an initial stage whereby the Framework is less mature and integrating fewer DER (Stage 1) and more mature, enduring end state (Stage 2).

[40] https://www.energynetworks.com.au/assets/uploads/open_energy_networks_-_required_capabilities_and_recommended_actions_report_22_july_2019.pdf

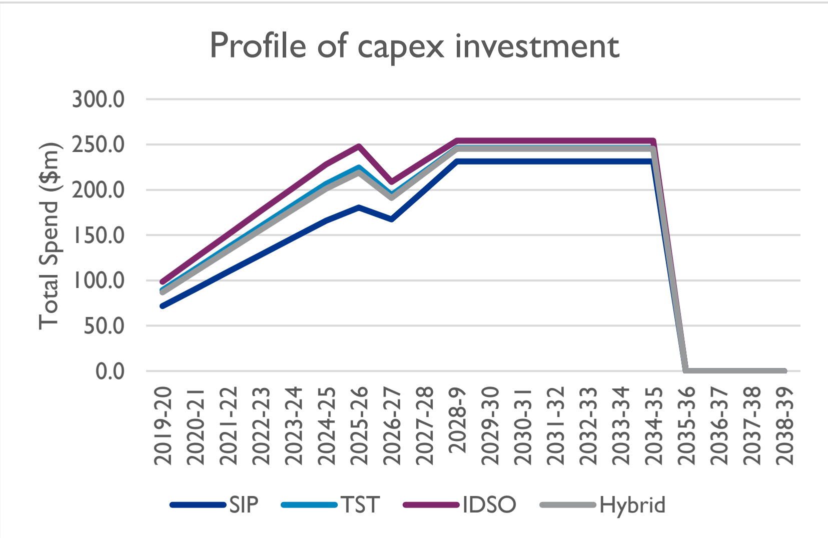
We received a wide range of costs from DNSPs, particularly around the costs of Distribution System monitoring and DER optimisation. We used the cost information provided to deduce a standardised "typical" set of technology and resource costs for each DNSP Function. This effectively represented what we deemed as the costs required for a 'typical' DNSP in the NEM to implement and operate the TST Framework in both stages of development.[41] We took AEMO's data at face value.

We recognise that the cost data provided by DNSPs and AEMO reflects current best view and that there are a number of uncertainties, particularly when trying to assess the resource costs to run the electricity network 20 years from now. However, the baseline information provided was sufficient to enable comparative assessments across the frameworks. We have also chosen to apply some sensitivities across the cost areas which had the most variation across DNSPs.

D.3.1 Technology costs

We assumed that capex costs are incurred aligned with the uptake of DER. We assume an initial tranche of investment starting in 2019 that ramps up in line with DER uptake. We then assume a second tranche of investment starting in the late 2020s, designed to cater for greater DER uptake and refresh the systems put in place in the early 2020s.[42] This is illustrated in Figure D3 below:

Figure D3 Profile of investment costs



In addition, since the baseline costs have been assumed as being on a per DSO basis, we applied economies of scale to each function for each actor. This takes account of where that function is performed by AEMO (as a single actor) or the IDSO (one for each DNSP region). We broadly scale each function directly to the number of parties, with the exception of some DSO functions which we scale by the number of DNSP ownership groups.

[41] We did not include costs from Western Power in establishing our typical cost. This was due to the fact that we were unable to include the benefits from the WEM in the assessment and it therefore felt unbalanced to include the costs.
[42] Assuming a 10 year asset life for many of these systems

We assumed that 10% of these technology costs would be required to cover ongoing system refreshes and maintenance. This takes account of the fact that many of these costs will be IT and communications system which have annual and biennial upgrades. For Stage 2 of each Framework, these costs are based on 10% of the combined technology costs for Stage 1 and Stage 2.

The baseline technology costs are set out in Table D1 below. For the DSO costs, we have provided an indication of the range of cost data submitted across all DNSPs. High denotes a range of +/- 200%; medium +/- 50%-199% and Low a range lower than +/-50%.

Table D1 Baseline technology costs (DSO & AEMO)

		DSO		DSO Range	AEMO	
Activity	**Relevant Function**	*Stage 1*	*Stage 2*		*Stage 1*	*Stage 2*
Gather network data	1. Distribution system monitoring and planning	$40,000,000	$100,000,000	High	$0	$0
Network planning and investment	1. Distribution system monitoring and planning	$2,500,000	$2,000,000	Low	$0	$0
Forecast short-term network state	3. Forecasting systems	$2,000,000	$5,000,000	Med	$11,010,000	$7,000,000
Optimise operating envelopes of distribution network end-customers	6. DER optimisation at the distribution network level	$10,000,000	$5,000,000		$75,000,000	$30,000,000
Aggregation of wholesale and FCAS bids	6. DER optimisation at the distribution network level	$5,000,000	$2,000,000	Med	$0	$0
Update market dispatch engine	7. Wholesale - distributed optimisation	$1,000,000	$500,000	Med	$29,360,000	$10,500,000
Determine dispatch schedules for bilateral RERT contracts	7. Wholesale - distributed optimisation	$0	$0	n/a	$3,670,000	$875,000
Bilateral contracts for D-network support and control ancillary services	8. Distribution network services	$525,000	$175,000	Low	$0	$0
D-network market engagement for network support and control ancillary services	8. Distribution network services	$2,000,000	$1,000,000	Low	$30,000,000	$20,000,000
Settlement of bilateral contracts for network services	9. Data and settlement (network services)	$875,000	$350,000	High	$0	$0
Settlement of NCAS market	9. Data and settlement (network services)	$1,625,000	$650,000	Low	$7,340,000	$3,500,000
Settlement of bilateral contracts for RERT	10. Data and settlement (wholesale, RERT, FCAS and SRAS)	$0	$0	n/a	$18,350,000	$1,950,000
Settlement of wholesale, FCAS and SRAS markets	10. Data and settlement (wholesale, RERT, FCAS and SRAS)	$4,050,000	$650,000	Low	$44,040,000	$4,650,000
Dispute resolution (wholesale, RERT, FCAS and SRAS)	10. Data and settlement (wholesale, RERT, FCAS and SRAS)	$350,000	$50,000	Low	$3,670,000	$390,000
Establish, maintain and publish or share DER register data	11. DER register	$2,000,000	$750,000	Low	$5,505,000	$3,500,000

D.3.2 Resource costs

For resource costs, we allocated a management structure to each of the functions. This was based on three levels of skill types with different salary levels – skill level 1 being the most junior and skill level 3 being senior management level. We looked at the split of skill levels which might be required for each function. We collected data form DNSPs and AEMO on the resources required in both Stage 1 and Stage 2 of either the TST or SIP Framework . Table D2 illustrates the 'Typical' DNSP resource costs in the TST Frameworks and AEMO's resource estimates under the SIP Framework.

Table D2 Typical resource costs

		Stage 1						Stage 2					
		DSO			AEMO			DSO			AEMO		
SGAM activity	Function	Resource numbers by skill level / Activity						Resource numbers by skill level / Activity					
		Skill Level	Skill Level	Skill Level	Skill	Skill Level	Skill Level	Skill	Skill Level	Skill Level	Skill Level	Skill	Skill Level
Gather network data	1. Distribution system monitoring and planning	0	2	0	0	0	0	0	2	1	0	0	0
Network planning and investment	1. Distribution system monitoring and planning	2	4	1	0	0	0	3	2	1	0	0	0
Forecast short-term network state	3. Forecasting systems	2	5	2	5	3	1	2	8	2	10	4	2
Optimise operating envelopes of distribution network end-customers	6. DER optimisation at the distribution network level	1	2	1	10	4	2	1	2	1	16	6	2
Aggregation of wholesale and FCAS bids	6. DER optimisation at the distribution network level	1	2	0	0	0	0	1	2	0	0	0	0
Update market dispatch engine	7. Wholesale - distributed optimisation	0	0	0	8	3	2	0	0	0	20	6	3
Determine dispatch schedules for bilateral RERT contracts	7. Wholesale - distributed optimisation	0	0	0	2	1	1	0	0	0	8	3	1
Bilateral contracts for D-network support and control ancillary services	8. Distribution network services	0	0	0	0	0	0	0	0	0	0	0	0
D-network market engagement for network support and control ancillary services	8. Distribution network services	1	2	0	5	3	2	2	2	0	11	5	2
Settlement of bilateral contracts for network services	9. Data and settlement (network services)	2	1	0	0	0	0	2	1	0	0	0	0
Settlement of NCAS market	9. Data and settlement (network services)	1	2	0	4	2	0	2	2	0	8	4	2
Settlement of bilateral contracts for RERT	10. Data and settlement (wholesale, RERT, FCAS and SRAS)	0	0	0	4	2	1	0	0	0	10	4	2
Settlement of wholesale, FCAS and SRAS markets	10. Data and settlement (wholesale, RERT, FCAS and SRAS)	0	0	0	0	0	0	0	0	0	0	0	0
Dispute resolution (wholesale, RERT, FCAS and SRAS)	10. Data and settlement (wholesale, RERT, FCAS and SRAS)	0	0	0	0	0	0	0	0	0	6	4	1
Establish, maintain and publish or share DER register data	11. DER register	2	3	2	4	2	1	2	3	2	8	3	1

D.4 Functional thickness

To assess the resource and technology costs per Framework, we needed to scale the baseline costs which DNSPs and AEMO had reported under the TST and SIP to reflect how they might change in each Framework. Table D3 below highlights the functional thickness we applied to the baseline costs. We have used High/Medium/Low to denote the size of the function for each actor in each Framework, where they mean the following:

- **High** : Any costs categorised as 'High' means that the costs are the same as the baseline costs reported. This means that in the TST Framework, all functions where DNSP's report costs are deemed as high. Similarly in the SIP framework, all areas where AEMO report costs are High;

- **Medium and Low**: Where we have highlighted that a specific function for a specific actor is Medium or Low we are illustrating that the function is smaller (and therefore less cost involved) than envisaged in the baseline costs. A good example is the Hybrid Framework which requires both DSOs and AEMO to have a role in optimising DER. So AEMO still incurs retains some functionality in this area but not to the extent envisaged in the SIP. Therefore, we apply a scaling factor to reduce the baseline costs down**;**
- **'No cost'**: In each of the Frameworks there is a spit of functions between actors. For example, even in the SIP where AEMO are running the majority of functions, there are still some (particularly around Distribution monitoring and planning) which the DSOs are undertaking. Therefore, AEMO incur no costs against those functions but the DSOs do.

Where we have assessed a function for a specific actor as Very High, Medium or Low, we apply a different scaling factor for each function. This is because the change in size of the function will vary depending on which function it is and what Framework is being applied. The specific scaling factors used are detailed in the 'Technology Costs' and 'Resource Costs' tabs of the Cost Assessment Master Model, provided alongside this report.

Table D3 Summary of Functional thickness

			SIP	TST	Hybrid	IDSO	TST	SIP	Hybrid	IDSO	
SGAM function		SGAM activity	AEMO	AEMO	AEMO	AEMO	DSO	DSO	DSO	DSO	IDSO
1	Distribution system monitoring and planning	Gather network data	No cost	No cost	No cost	No cost	H	H	H	H	No cost
		Network planning and investment	No cost	No cost	No cost	No cost	H	H	H	H	No cost
2	Distribution constraints development	DER engagement	H	No cost	L	No cost	H	H	H	H	No cost
3	Forecasting systems	Forecast short-term network state	H	No cost	L	No cost	H	H	H	H	No cost
6	DER optimisation at the distribution network level	Optimise operating envelopes of distribution network end-customers	H	No cost	L	No cost	H	No cost	M	M	H
		Aggregation of wholesale and FCAS bids	No cost	No cost	No cost	No cost	H	No cost	M	No cost	H
7	Wholesale - distributed optimisation	Update market dispatch engine	H	M	M	M	No cost	No cost	No cost	No cost	No cost
		Determine dispatch schedules for bilateral RERT contracts	H	H	H	H	No cost	No cost	No cost	No cost	No cost
8	Distribution network services	Bilateral contracts for D-network support and control ancillary services	No cost	No cost	No cost	No cost	H	H	H	L	H
		D-network market engagement for network support and control ancillary services	H	No cost	VH	No cost	H	No cost	No cost	No cost	H
9	Data and settlement (network services)	Settlement of bilateral contracts for network services	No cost	No cost	No cost	No cost	H	H	H	No cost	H
		Settlement of NCAS market	H	No cost	H	No cost	H	No cost	No cost	No cost	H
10	Data and settlement (wholesale, RERT, FCAS and SRAS)	Settlement of bilateral contracts for RERT	H	H	H	H	No cost	No cost	No cost	No cost	No cost
		Settlement of wholesale, FCAS and SRAS markets	H	No cost	H	No cost	H	No cost	No cost	No cost	H
		Dispute resolution (wholesale, RERT, FCAS and SRAS)	H	No cost	H	No cost	H	No cost	No cost	No cost	H
11	DER register	Establish, maintain and publish or share DER register data	H	H	H	H	H	H	H	H	No cost

We used the assessment of the scale of function size for each actor to understand the capex and resource costs for actor in each Framework.

D.5 Resource costs

Similar to the technology costs, we scale the baseline resource costs in line with our functional thickness. This is applied to each function, for each actor in each Framework.

We scale up resource costs scale up over time in line with DER uptake until the mid 2020s at which point full stage 1 resource costs are incurred. We move to stage 2 resource costs in the late 2020s, to reflect that managing more DER on the system is likely to require more resources.

We then use the following to build up the resource costs:

- We assume that there is annual system OpEx is assumed to be 10% of system capex
- System OpEx is also introduced in line with DER uptake in stage 1, this aligns it with the CapEx investment profile
- Incremental system capex has been included at the start of Stage 2 to represent the step change in functionality
- System depreciation has not been included, as the annual system OpEx is assumed to be sufficient to maintain systems and allow for incremental change
- IT capex and business transition cost has been profiled over the stage 1 period, to represent buildout and transition taking place in line with the penetration of DER
- The profiling in line with DER still assures that the whole cost of the system is recovered by the end of stage 1
- Some systems have no cost when they are not relevant to a Framework to a specific actor

As with technology costs, we also apply economies of scale depending on which actor the function sits with. These are the same as applied to the technology costs.

D.6 Interface costs

We wanted to understand how the costs of data exchange and co-ordination vary in each Framework. To do this, we looked at the information in the SGAMs on the types and volumes of information exchange. We considered that these acted as a useful reference for the interface and co-ordination costs. The SGAMs included four different types of information exchange:

- SCADA
- Gateway
- Publish
- Contract

We made some assumptions on the costs of each type of information exchange based on data provided by the ENA UK Strategic Telecoms Group in the UK on SCADA costs.[43] This provided us with

[43] The STG provided the SCADA costs and we used this to make proportionate assumptions for the other information exchange types.

a basis to understand the proportionate costs of each type of data exchange as shown in Table D4 below.

Table D4 Data exchange unit costs

Data exchange type	Cost ($k)
SCADA	40
Gateway	20
Publish	4
Contract	8

This provided a baseline cost per unit of the different data exchanges. We then applied these costs to volumes of the different types of information exchange outlined in the SGAMs.[44] We also scaled up the interface costs in line with DER uptake. We have applied a different weighting of DER scaling factor in each functional area, based on the average % uptake of DER for stage 1 and 2. This DER scaling drives differences between the assessment in Stage 1 and Stage 2 of each Framework in respect to information exchange costs. We have also applied economies of scale to the interface costs.

D.6.1 Key assumptions on interface costs

- The volume of interface exchanges per Framework was taken from SGAMs
- Interface types split into SCADA, Gateway, Publish, Contract as set out in SGAMs
- Interface set-up costs are included within the technology capex costs, therefore interface costs purely refer to interface OpEx
- Individual unit cost assigned to each exchange type, scaled off cost of SCADA system from data given by the ENA's Strategic Telecoms Group.
- Individual unit costs then multiplied by the volumes to produce costs of interface change.
- Interface volumes are then scaled in proportion to DER.

D.7 Business transition costs

We wanted to recognise that the costs of the DSO transition were not simply just the investment costs in new technology but also in integrating that technology into the business and aligning with existing system and operational functions.

We issued a survey to DNSPs and AEMO asking them to rate the maturity of the functions envisaged in the SGAMs on the basis of the following scale:

1. **New activity**: No current functionality exists;
2. **Some basic capability exists:** Functionality is partial and largely project or trial based;

[44] *https://www.energynetworks.com.au/projects/open-energy-networks/#open-models*

3. **Defined capability:** Initial trials are compete and partial functionality is moving into the business;
4. **Low to medium scale capability:** Functionality exists in the business but is at low to medium scale; and
5. **Scaled and optimised capability:** Functionality is already rolled out and operating at scale across the network.

The survey results were very similar across DNSPs, allowing us to produce overall scores for the maturity gap which existed for each function in each Framework. We used these relative scores to allocate a High, Medium or Low ranking for each function, for each actor in each Framework. We used these rankings to allocate different percentages of the technology CapEx cost to represent the business change costs. These are shown in Table D5 below.

Table D5 Ratio of capex costs applied as business change costs

Maturity Gap	Ratio of Capex to Business Transition Cost:
H	1
M	0.5
L	0.25

Table D5 illustrates that where a specific function in a Framework was assessed as having a High maturity gap, we allocated 100% of the CapEx costs for that function as business transition costs. Where a function was assessed as having a Low maturity gap, we allocated 25% of the CapEx costs for that function to business transition costs.

Appendix E Operating Models

The operating models outline in us a sense of where functions would sit between actors but we needed to understand how much to scale back sizes (or costs) of these functions were for each actor in each framework. For instance in the Hybrid framework, function 6 “DER optimisation ad the distribution network level” both AEMO and the DNSPs have some role in optimising operating envelopes for distribution network end-customers. However, they are likely to be thinner than in a framework where this is completely done by one actor. Consequently, we used the definitions of the Frameworks to judge where functions would be a Very high, High, Medium, Low, or Very low scale. This assessment feeds directly into the technology and resource costs as described below.

Figure E1: SIP Operating model

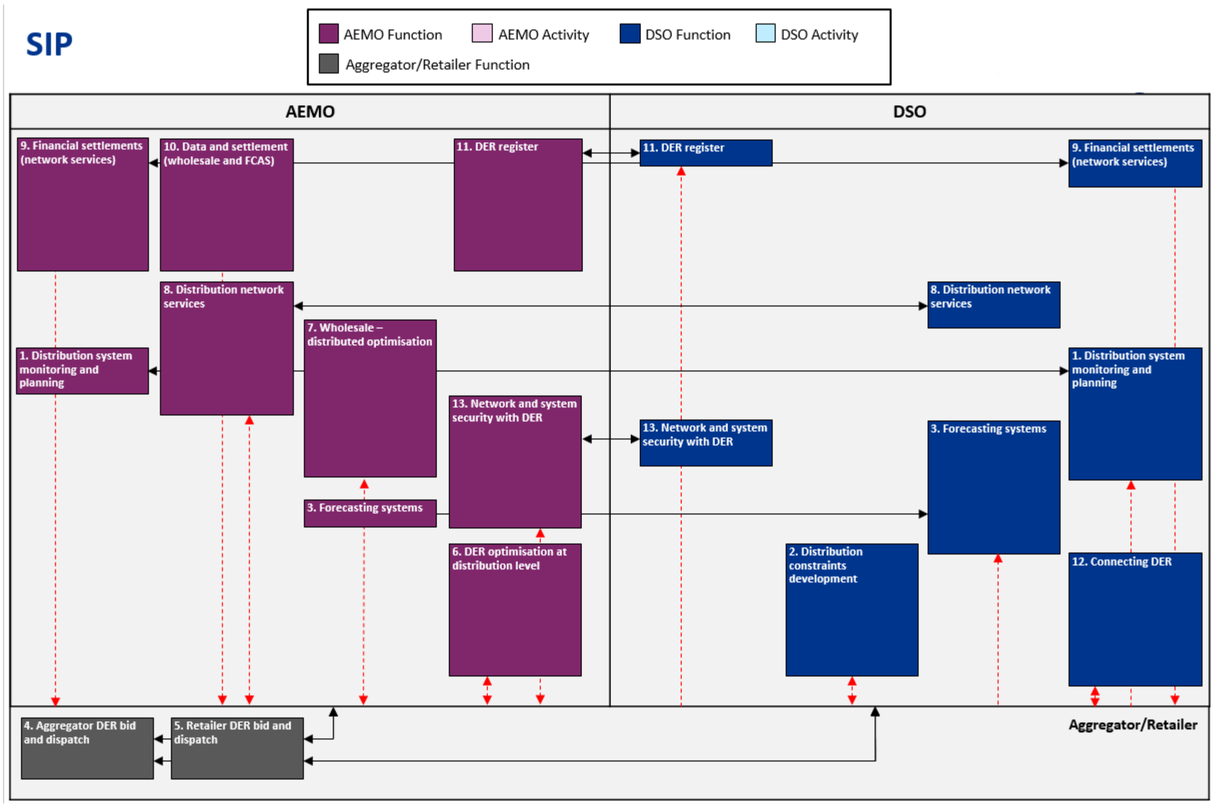


Figure E2: TST Operating model

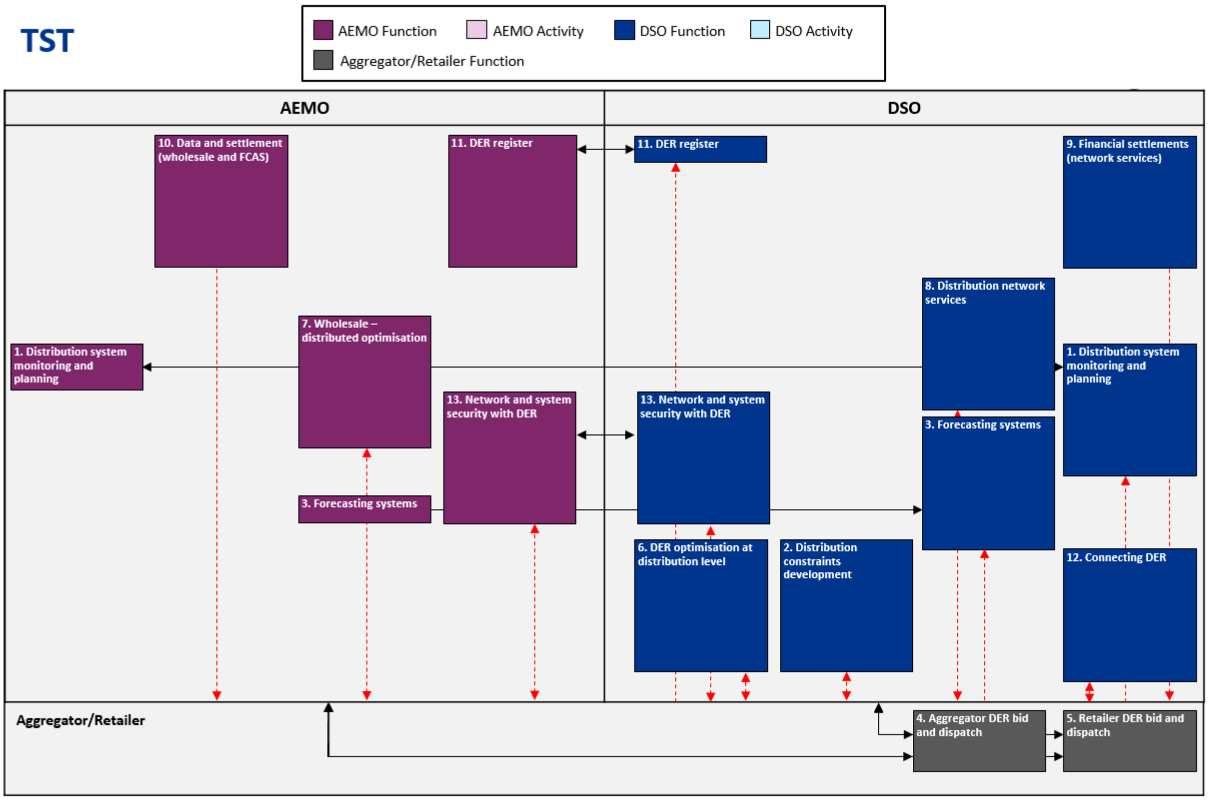


Figure E3: IDSO Operating model

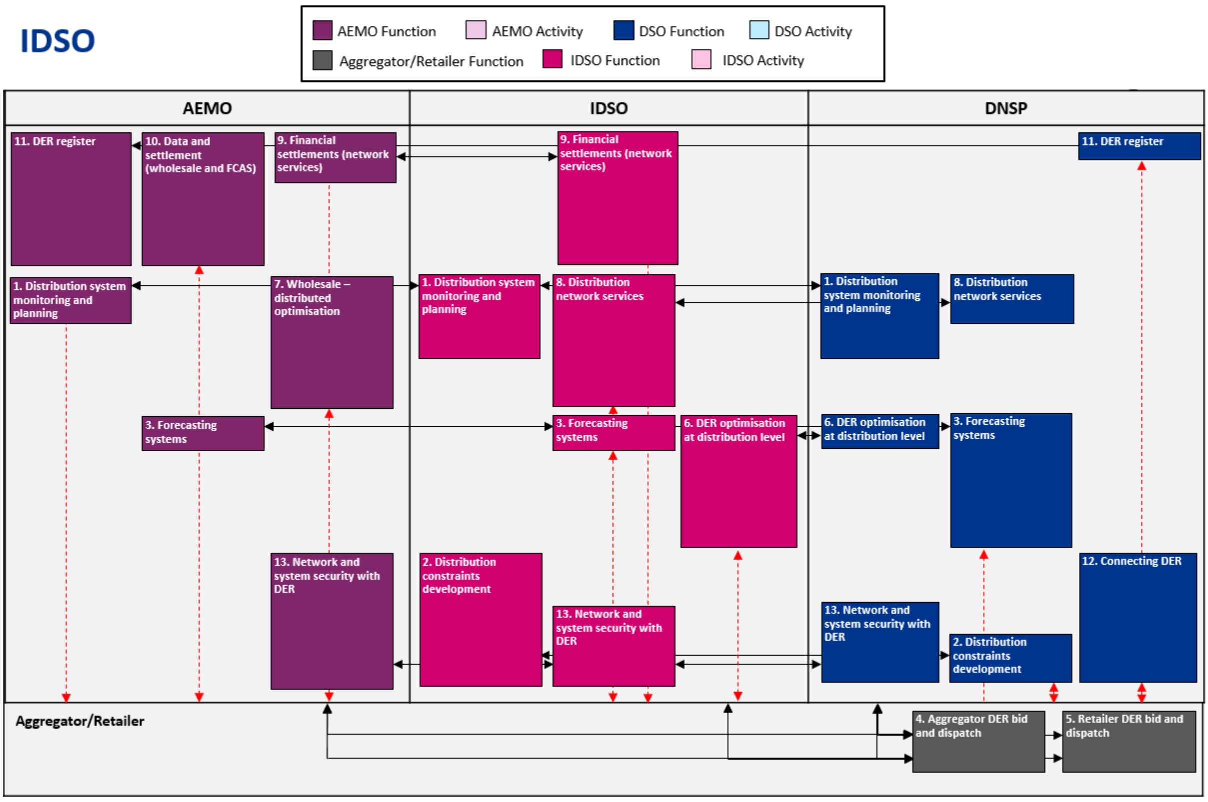


Figure E4: Hybrid Operating model