Notice on Screening for Non-Network Options Report

Extending Distribution Network Operational Capability

November 2018

1. Executive Summary

National electricity network operations have become increasingly complex in recent years. A move to incorporate more intermittent renewable generation, increasing penetration of Distributed Energy Resources (**DER**), and customers transitioning from being consumers to 'prosumers' of energy, have fundamentally altered when and how electricity networks are being used. As a result, issues with two way power flows, network constraints and the ability to support peak network demands have become increasingly important.

In order to meet these challenges, ensure power system security and continue to meet customer expectations around the quality and reliability of supply, TasNetworks has identified the need to enhance its Distribution Control System (**DCS**) capability. TasNetworks proposes to do so via the implementation of a Distribution Management System (**DMS**). A DMS is a purpose built software solution offering an integrated suite of tools that can remotely monitor and control networks, improve planned outage and emergency event management, optimises power-flow management and provide fault location, isolation and restoration capabilities amongst other functionality.

Although TasNetworks already operates a Transmission and Distribution Control System (**TADCS**), this is most effectively used to manage the complexity of the Tasmanian transmission system and its interconnection to Victoria. It has limited distribution management functionality and lacks features that are becoming the common standard for distribution companies internationally and within Australia, e.g. automated fault level restoration. In this regard, implementation of a DMS will:

- improve the quality and reliability of Tasmanian electricity supply,
- enhance Tasmanian power system security and emergency management,
- increase customer and worker safety,
- reduce outage durations,
- better support the management and integration of DER,
- improve service response times,
- keep downward pressure on customer costs,
- reduce the number of outages caused by switching errors,
- improve customer notification and communication,
- enhance regulatory compliance and reporting activities, and
- help meet Tasmanian distribution licencing requirements.

TasNetworks has evaluated 3 options for capturing these benefits against a 'Do Nothing' base case. These alternative options include replacing the entire TADCS, implementing a new vendor product for the DMS and extending the existing TADCS functionality via the installation of selected DMS software modules. As illustrated in the table below, Option 4 has the highest Net Present Value (**NPV**), lowest cost, shortest implementation timeframe and lowest implementation risk. It is therefore TasNetworks' preferred option.

Option	Description	Cost ($M)	Benefit per annum ($M)	NPV ($M)	Implementation Time (Years)	Implementation Risk
1	Do Nothing	-	-	-	-	Neutral
2	Replace the Existing Transmission and Distribution Control Systems	24	1.1	- 18.5	5	Very High
3	Replace Only the Distribution Control System and Maintain Transmission	12	1.1	- 6.4	3	Medium
4	Extend the Existing Transmission and Distribution System (preferred)	6.5	1.1	+ 0.27	2	Low

Changes to the National Electricity Rules (**NER**) in July 2017 now require replacement planning for existing operational technology systems to be subject to a Regulatory Investment Test for Distribution (**RIT-D**). As such, this document has been prepared under 5.17.4(d) of the NER and summarises TasNetworks' determination that no non-network option is, or forms a significant part of, any credible option for the RIT-D relating to the extension of TasNetworks' existing DCS. Further details on the identified need and options considered for this RIT-D can be found below including the reasons for TasNetworks' determination, the methodology employed and assumptions used. In accordance with rule 5.17.4, TasNetworks will proceed to publish the Final Project Assessment Report (**FPAR**) as soon as practicable following the publication of this Notice on Screening for Non Network Options Report.

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2. Background

TasNetworks maintains and operates the Tasmanian Transmission and Distribution systems. This involves responsibility for 'critical infrastructure' comprising physical transmission and distribution assets, information technologies, communication networks and advanced control schemes. If these were destroyed, degraded or rendered unavailable for an extended period, significant impacts to the security, social and economic wellbeing of Tasmania, and other states and territories which are from time to time electrically interconnected, would result.

TasNetworks was formed in 2014 via the merger of the Transend transmission and Aurora distribution businesses. As part of the merger, and in order to keep costs for customers down, the Transend Transmission Control System (**TCS**) was co-opted for distribution network monitoring and control. Although the system has performed reliably and to expectations, distribution network operations have become increasingly complex in recent years due to the growing penetration of solar photovoltaic (**PV**) systems, electric vehicles (**EVs**) and battery storage technologies. This has fundamentally altered when and how the grid is being used, particularly in terms of two way power flows, network utilisation and peak network demands.

Recently there has also been a renewed focus on electricity pricing and service delivery. Customers have become active 'prosumers' of energy, demanding enhanced service capability to better manage and minimise their electricity bills. Peer to peer electricity trading, Home Energy Management Systems (**HEMS**) and the increasing use of smart appliances and Distributed Energy Resources (**DER**) are but three examples in this regard.

As identified in TasNetworks' Transformation Roadmap 2025[1], the ability to support and integrate new generation, storage and network technologies is a driving need for a modern and adaptive control system. This same recognition has spurred the majority of other Australian distribution companies to invest in DMS. These mature, purpose built software solutions offer an integrated suite of tools that can remotely monitor and control networks, improve planned outage and emergency event management, optimise power-flows as well as provide fault location, isolation and restoration capabilities.

In having been specifically designed to integrate multiple data sources, DMS can also provide a highly accurate model of the current network state. This enables better integration of business processes required to safely and efficiently operate the electricity grid. However, it can also facilitate better data utilisation and analysis thereby helping to comply with regulatory reporting obligations.

3. Identified Need

TasNetworks' existing Transmission and Distribution Control System (**TADCS**) is most effectively used to manage the complexity of the Tasmanian transmission system and its interconnection to Victoria. It has limited distribution management functionality and lacks features that are becoming the common standard for distribution companies internationally and in Australia, e.g. automated fault level restoration. Keeping the current distribution network management arrangements will be unlikely to support future customer services, lower service response times nor reduce customer costs. In contrast, there are likely to be increased security and safety risks as distribution system operations become increasing complex.

Clause 8.7(a) of the Tasmanian Electricity Code sets out Tasmanian Distribution Licencing requirements which mandate that TasNetworks observes '*good electricity practice*'. This encompasses the planning, design, construction, maintenance and operation of each Distribution

[1] AER Website: TasNetworks Transformation Roadmap 2025, January 2019

Network Service Provider's (**DNSP's**) DCS to ensure that the relevant standards for safety and reliability of the system are consistent with community, business and customer needs.

A DMS will provide the capability to integrate key business processes and safety cross checks into work practices, whilst allowing advanced applications to automate real time operations. For example, a DMS would improve customer reliability and quality of supply through automating fault identification, location and restoration services. These capabilities would also improve community safety through the rapid location of faulted feeder sections and the subsequent isolation of the faulted section.

The real time network status and communication functionality afforded by a DMS will reduce outages caused by errors in switching. It will also promote more up to date customer outage notifications and communications. This includes ensuring Life Support Customers are notified prior to outages due to the improved systems interfaces.

Beyond this, a DMS will allow TasNetworks to better integrate and manage customer DER to maintain quality of supply, manage voltage levels and control two way power flows. These are fundamental to customer service delivery expectations in a rapidly changing industry, characterised by increasing levels of distributed generation, more customer engagement and greater customer empowerment.

A dedicated DMS is therefore a key tool for TasNetworks to:

- overcome and avoid the future risks associated with continued operation of the current distribution monitoring and control system,
- meet customer service expectations,
- reduce costs,
- improve service response times,
- reduce outages,
- enhance compliance and reporting,
- increase customer and worker safety, and
- thereby meet Tasmanian distribution licencing requirements.

4. Credible Options

TasNetworks estimates that the benefits stemming from implementation of a DMS listed above would be in the order of $1.1m per annum. Although TasNetworks has identified several options for extracting these benefits, TasNetworks considers that there is only one credible implementation option. Rather than implementing an entirely new system, TasNetworks is proposing to extend the current TADCS capabilities by leveraging existing hardware, architecture and support resources. This conservative approach will minimise implementation risks and keep costs down by installing only a limited number of advanced DMS modules that will:

- automatically restore customers to service following faults (FLISR module),
- improve the rigour and efficiency of the planned work process (Switch Order Management module),
- improve the visibility of our power flows (Distribution Power Flow),
- improve the ability to train distribution network operators (Distribution Operator Training Simulator), along with
- maintaining and enhancing existing cyber security protections.

The following options to implement a DMS were considered in coming to the preferred option.

Option 1: Do Nothing

In the do nothing option all of the identified benefits of a DMS would be foregone. There would be increased security and safety risks, degradation in the quality of supply and customer experience as distribution network complexity increased over time. In failing to meet the identified need, this option was discounted. However, it has been retained for modelling purposes as the option against which other options can be compared to determine their relative value. That is, all options have been assessed against the opportunity cost of the do nothing option. As such, the cost and benefits of this option are shown as zero in the summary table below, and the project implementation risk has been set to neutral.

Option 2: Replace the Existing Transmission and Distribution Control Systems

The second option considered replacing the entire control system, including both transmission and distribution components. This 'big bang' approach would capture the DMS benefits listed above and would keep a common system architecture across both systems. This option has been costed at approximately $24 million including contingency of 20%.

Option 2 has a significantly higher implementation cost than Options 3 and 4 with few additional benefits over and above the $1.1 million of estimated distribution system benefits. This is because the TCS replacement would offer little in the way of additional value compared with the existing TCS.

This option would take the longest time to implement and has the highest business risk. Significant customised development and testing of the new system would be required in order to preserve system stability and cater for the bespoke arrangements relating to Tasmanian energy system protection schemes and management of the Basslink DC interconnector to the mainland. Residual operational risks would also remain high.

The NPV of this option was calculated as -$18.5 million over a 10 year investment horizon. As the highest cost, and highest risk, option with the lowest NPV, Option 2 was not selected for implementation.

Option 3: Replace Only the Distribution Control System

The third option considered involved implementing a new DCS from a new software vendor and leaving the current TCS untouched. The estimated cost of this option was $12m. Compared with Option 2, this is a lower cost and lower risk alternative. However, decoupling the existing Supervisory Control And Data Acquisition (**SCADA**) system from the transmission control system would add project complexity and risk. Moreover, this option would also entail greater longer term support costs associated with running two separate control systems from two different vendors.

The Option 3 NPV has been calculated at -$6.4 million over the 10 year investment analysis horizon. Based on this assessment, this option was not selected for implementation.

Option 4: Extend the Existing Transmission and Distribution System

Option 4 would retain the existing TCS functionality but enhance DCS capabilities with the implementation of selected software modules from the existing software provider. TasNetworks has assessed the range of advanced DMS applications available and selected the combination of modules that maximises the NPV. These modules are tables below.

Module	Capability
Fault Location Isolation and Supply Restoration	Automatically restores customers to service following a fault where automated transfer capability exists
Switch Order Management	Enables planned switching to be executed using DMS enabled switching programs with safety logic cross checks

Distribution Power Flow	Enables distribution network power flows to be calculated to accurately enable FLISR load transfers
Distribution Operator Training Simulator	Enables advanced training capability for distribution operators to improve real time decision making capability

Installation of these modules would crystallise the same benefits as other options but at a significantly reduced cost of $6.5m, including a 20% contingency. Option 4 would have the shortest implementation time and lowest risk owing to leveraging existing systems, hardware, in house expertise and mature vendor relationships. This puts the NPV of option 4 at $270k when calculated over the 10 year investment analysis horizon.

As the only option with a positive NPV and low business risks, TasNetworks considers Option 4 represents the only credible option to implement a DMS. The table below compares Option 4 with the other options considered.

Option	Description	Cost ($M)	Benefit per annum ($M)	NPV ($M)	Implementation Time (Years)	Implementation Risk
1	Do Nothing	-	-	-	-	Neutral
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Notes:

- The Do Nothing option is used as the base case option against which all other options were compared.
- A 10 year NPV period was used for the implementation timeframe of all options consistent with the estimated benefit stream over the lives of the assets.
- Implementation risk is the risk of achieving the outcomes of the project within the cost, schedule, scope and quality constraints.

5. Assessment of Non-Network Options

Typically, non-network options are used to identify opportunities for reducing network peak demand and/or reducing the risk associated with unserved energy to customers from a specific network asset. In this manner, non-network options can promote cost effective deferral and avoidance of unnecessary network investments.

The identified need for this RIT-D is not related to electricity demand characteristics. Instead, as discussed above, the identified need relates to improving customer service, safety and cost outcomes, as well as meeting Tasmanian Licensing requirements, via the extension of TasNetworks' current control system infrastructure. In this respect, is not reasonable to expect that non-network options can form part of a solution to address this need. TasNetworks does, however, note that the preferred option (Option 4) has the potential to enable non-network options to be used more efficiently to address specific network investments in the future, particularly, through the integration, optimisation and orchestration of distributed energy resources.

6. Conclusion

Given the foregoing considerations, TasNetworks has determined that no non-network option is, or forms a significant part of, any credible option for the purposes of this RIT-D. Consequently, a Non-Network Options Report has not been prepared in accordance with rule 5.17.4(c) of the National Electricity Rules. Further, and also in accordance with rule 5.17.4, as the total proposed network investment is under $10M, TasNetworks will proceed to publish the Final Project Assessment Report (**FPAR**) as soon as practicable following the publication of this Notice on Screening for Non Network Options Report.