Network Management Systems

UE BUS 7.05 - Networks management - Jan2020 - Public

Regulatory proposal 2021–2026

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1 Overview

Business	United Energy
Title	Network management systems
Project ID	UE BUS 7.05 - Networks management - Jan2020 - Public
Category	IT capital expenditure - recurrent
Identified need	To maintain the currency of our network management systems in order to uphold network reliability, quality of supply, security and safety of the electrical distribution network in accordance with our regulatory commitments. To avoid the risk of unsupported or end-of-life systems that may compromise our ability to effectively monitor and manage our electricity network. Ensure public safety and provide timely and relevant information regarding interruptions of supply to our customers.
Recommended option	Option one, refreshing our current suite of network management systems is recommended. We assess this option to provide the most balanced approach. This option maintains our ability to monitor and manage the network, to deliver a safe and reliable electricity supply to our customers and to meet our regulatory reporting obligations. Ensuring public safety and making sure customers receive timely and relevant information regarding interruptions to supply is vital. Option one also supports continued investment in reliable, stable and tested solutions and avoids high remediation costs in the future.
Proposed start date	2021/22
Proposed end date	2025/26
Supporting documents	1. UE MOD 7.07 - Networks Management cost - Jan2020 - Public 2. UE MOD 7.08 - Networks Management risk - Jan2020 - Public 3. UE MOD 12.02 - Quoted services labour rate - Jan2020 - Public 4. UE ATT158 - ESC - Electricity distribution code - Jan2020 - Public

As an electricity distributor, our role is to ensure we deliver a safe and reliable supply of electricity. Every day we are working for our customers to bring energy into their homes and businesses through our distribution network.

The network management systems comprise core operational systems that play a critical role in ensuring that we effectively and efficiently manage our network. These systems have a real-time 24/7 requirement to provide control and monitoring of customers' supply reliability and network performance, as well as providing tools to ensure network, employee and public safety is maintained.

This business case outlines the need for us to invest in maintaining currency of mission critical system functionality that provides a key role in managing the electrical distribution network. The technological demands on the suite of network management systems are increasing due to external factors such as the expanding prevalence of distributed energy resources, and our customers' increased appetite for relevant and timely information regarding any planned or unplanned interruptions to supply.

An assessment of options was performed on the basis of alignment to the desired future state, cost-benefit analysis, and the reduction of risk to IT systems and Business operations. This analysis also assessed how each option could address our requirements over the 2021-2026 regulatory period.

Table 1 summarise the options considered and their associated capital expenditure.

Table 1 **Options analysis summary, total capital expenditure and incremental operating expenditure during 2021–2026 regulatory period, $m June 2021**

	Option	Cost	Risk
0	Do nothing - do not upgrade, maintain current software versions in relation to our Network Management Systems	0.0	50.3
1	Refresh current suite of network management systems Perform prudent technical upgrades to maintain core currency and regulatory compliance, whilst targeting alignment and simplicity.	24.9	13.4
2	Replace the network management systems with alternative solutions.	50.4	13.4

Source: United Energy

Based on our analysis of these options, we recommend option 1, to refresh our current suite of network management systems. This option stands out as the best option when all associated costs and risks have been considered for each option. The intent of this option is to maintain the currency of the network management systems so that we can continue to deliver a safe and reliable supply of electricity to our customers. The risks to supply reliability associated with option 0 were considered too high, as demonstrated by the risk monetisation results. The costs associated with option 2 were considered unjustified and avoidable.

Option 1 provides the optimal solution as it provides a pragmatic balance between mitigating the most probable risks and avoiding unnecessary costs. It ensures the health and currency of the existing systems and avoids the risk of incurring penalties or suspensions for regulatory non-compliance, as well as the direct risks to processes that support electricity supply reliability and safety.

2 Background

2.1 Electricity distribution

Every day we're working for our customers to bring energy into homes and businesses safely, reliably and seamlessly, delivering the electricity needed to power lives and livelihoods.

Our customers and stakeholders have high expectations about the level of service we provide, the focus we have on distributing safe and reliable energy, and the value we deliver for them and how we respond to their needs, individually and as a community.

We distribute electricity to more than 660,000 customers across east and south east Melbourne and the Mornington Peninsula. Ninety per cent of our customers are residential. We manage a network of 209,000 poles and over 13,000 kilometres of wires. Electricity is received via 78 sub transmission lines at 46 zone stations, where it is transformed from sub transmission voltages to distribution voltages.

2.2 Network management systems

Our network management systems comprise core operational systems that play a critical role in ensuring that we can effectively and efficiently manage our electrical distribution network. These systems have a real-time 24/7 requirement to provide control and monitoring of customers' supply reliability and network performance as well as providing tools to ensure network, employee and public safety is maintained.

The integrated nature of these systems, from managing network telemetered devices (e.g. remotely-controlled switches that affect customers' supply if operated) through to smart meters that derive real-time information for our business to more effectively monitor and manage our customers' supply, further substantiates their criticality.

The network management systems can be categorised into three groups:

- network management core
- network geospatial
- network reporting and data processing.

Table 2 provides a summary of each network management core system.

Table 2 Network management core systems

System	Description
DMS	The Distribution Management System (**DMS**) monitors and controls the electricity distribution network and is tightly integrated with the Supervisory Control and Data Acquisition systems (**SCADA**) system by retrieving real-time data from network field devices through the SCADA system to enable more informed operational decision-making and control.
OMS	The Outage Management System (**OMS**) manages planned and unplanned network outages, and is the key system source for any outage information provided to customers. Integration with the DMS enables automated order creation and updates of outages from which real-time information is published to multiple customer communication channels for effective and timely outage information.
Protection Systems	Our protection systems application suite is used to manage power quality and field relay settings that assist in ensuring the distribution network is optimised and operated within network safety limits.
SCADA	SCADA are used to manage the real-time interface with field devices in the high voltage (**HV**) distribution network via the telemetry communications network. This is the core system that underpins the monitoring and control of the electrical distribution network.
SIQ	Sensor IQ (**SIQ**) is used to time effective analysis of the low voltage network. The Itron SIQ solution integrates with our Advanced Metering Infrastructure (**AMI**). SIQ enables us to perform real-time voltage assessment and can proactively identify quality of supply issues. Granular power quality data is available via voltage, current and power factor sampling of all meters. SIQ is also an integral part of United Energy's Summer Saver program since its inception 4 years ago. If currency of our SIQ system is not maintained, the risk of network supply quality and reliability issues increases as well as increased Guaranteed Service Levels (**GSL**) and the Service Target Performance Incentive Scheme (**STPIS**) payments when targets are not achieved.
Switching – controlled access for planned work	This provides support for planned network access requests and associated switching operations. This platform is necessary to manage planned works on the network including those that require supply interruptions to those customers who will be off-supply in order for the works to safely proceed. It includes workflow management, the initiation of the customer notification process, audit trail, attachments and internal notification processes. It ensures that only those authorised to work on the network can generate an access request.

Source: United Energy

Table 3 provides summary descriptions of each geospatial system.

Table 3 Network geospatial systems

System	Description
Geographic information	Geographical Information System (**GIS**) provides a spatial view and capture of electricity asset information relating to the network. It also provides connectivity modelling across the electrical network for purposes of identifying customers that are affected by planned and unplanned outages
Network visualisation	The network visualisation tool geographically displays data derived from multiple source systems including GIS, OMS, SAP and our customer billing system. This provides crucial data to allow us to manage the electricity network for planning, augmentation and operation/fault response purposes resulting in an improved fault response capability to restore supply to customers.

Source: United Energy

Table 4 provides a summary of each system within this group.

Table 4 Network reporting and data processing systems

System	Description
Network data processing & reporting	This enable network data analysis to assist in maintaining electricity assets by reviewing key data sourced from multiple systems to identify assets that require maintenance and initiating actions to address.
Outage reporting	Outage reporting is used to provide operational and management reporting of outage information derived from the network management core systems for customers and to the regulator to report on reliability performance. This also informs any supply reliability or restoration compensation awarded to customers who have incurred outages above set regulatory thresholds for outage frequencies and durations over a 12 month period.

Source: United Energy

2.3 Customer safety

Our network management systems have a significant impact on our ability to manage safety events as well as proactively identifying potential safety issues before they occur, so that rectification work can be undertaken.

Safety event management

Our OMS supports the management of safety events. When a customer calls our Contact Centre, to report a safety event (e.g. wire down, leaning pole) a ticket will be raised in the OMS. Public safety faults are considered a priority, and through the OMS our field crew engineers will be promptly dispatched to attend. Generally the issue will be addressed on site. As safety is always our paramount concern, in some cases it may be necessary for the premise to be taken off supply until rectification can occur.

Proactive customer safety

Our network management systems are used to proactively identify safety risks before they become a customer-impacting safety issue. As an example, in recent years there have been injuries and fatalities in Australia caused by broken neutral conductors. We have acted on this risk and improved customer safety in our network.

Through our network management systems the incidence of electric shocks reported by customers has steadily reduced in recent years. Our customers have an electricity service line (overhead or underground) that runs from the street to their property, and this is what we protect. Traditionally, based on regulations[1], these lines have been inspected every ten years. Through the SIQ system, together with network reporting and analytics, we can remotely monitor their condition by collecting five minute reads of power quality data from the smart meter and run algorithms to proactively identify potential failures before a customer is aware of a problem. The power quality data obtained by SIQ can be used to show voltage variations and impedance in the supply to the customer's premises outside acceptable safety tolerance limits (standard 240 volts at the customer's point of supply).

Based on the voltage and current data received, we can detect symptoms consistent with faulty neutrals and take action to respond and reduce the risk of a customer being impacted. Most customers will not be aware that there was a problem before their safety issue has been rectified. Some customers may see lights dim for a period of time but may not think anything is wrong. Now we are able to detect this as a problem which, if not addressed, could lead to a customer safety issue. Based on the data derived from SIQ, we can determine the

[1] Electricity Safety (Network Asset) Regulations, administered by Energy Safe Victoria

severity of the problem, and for serious safety hazards automatically and immediately disconnect the electricity supply to the customer's house using the smart meter. This can be performed in real time, detecting unsafe installations within minutes of the issue occurring. The call centre is notified simultaneously, who then contact the customer to explain the situation.

Utilising network management reporting, an average of approximately 500 neutral faults are detected each month and issued to the OMS to enable rectification.

We are constantly developing new ways to utilise our network management systems to better manage the network. By developing new algorithms which utilise power quality from AMI data we can identify potential safety hazards and imminent asset failures, enabling us to improved safety outcomes for our customers.

2.4 Network reliability

In addition to our commitment to safety, our focus is on ensuring we provide a reliable supply of electricity. Our customers have told us they want a safe and reliable supply of electricity. This is the essence of why we have network management systems.

Our network management systems allow us to efficiently manage a network of over 13,000 kilometres of power lines. We provide a reliable electricity supply to our customers. Our regulatory performance is measured by the System Average Interruption Duration Index (**SAIDI**). SAIDI measures the average duration of interruption in the power supply indicated in minutes per customer. In 2018 we achieved regulatory performance of 46.2 SAIDI minutes. We are proud of this result and will continue to invest in our network management systems both to maintain and improve our service delivery.

Supporting network reliability, our IT disaster recovery strategy has identified that in the event of system failure, the following applications have very high priority for restoration across the business:

- the OMS which manages planned and unplanned network outages and is the key source of outage information provided to customers
- the GIS which provides a spatial view of electricity asset information, relating to the network and connectivity modelling that is used for the purpose of identifying customers affected by an outage.

As an indication of the significance these applications have in supporting continued business operations, the maximum period of tolerable disruption before severe business, network, or customer impact occurs is 24 hours, and the recovery time objective is 12 hours.

2.4.1 Regulatory obligations

As an electricity distributor in the National Electricity Market (**NEM**), we are required to ensure compliance with the Distribution Code. Our customers expect us to continue to provide a safe, dependable, flexible and affordable electricity supply while meeting our regulatory obligations. Our network management tools support the control and monitoring of customers' supply reliability and network performance, as well as providing tools to ensure network, employee and public safety is maintained.

The reliability of our network management systems is critical to support our business so that we can continue to meet these obligations. This reliability depends on us maintaining currency of the systems through the application of upgrades, refreshes, patches or maintenance releases as necessary. Failure to maintain the currency of our network management systems could result in:

- lost management of the electrical distribution network impacting supply reliability
- significant increases to supply restoration times
- extremely high safety risk to our workforce

- an inability to effectively and safely perform planned maintenance work
- missed guaranteed service levels with our customers
- the Essential Services Commission (**ESC**) issuing energy industry penalty notices (**EIPNs**) due to non-compliance with the Distribution Code, EIPNs ranging from $10,000 to $20,000 per instance.[2]

Maintaining currency of our network management systems will continue to underpin our ability to satisfy key regulatory obligations including:

- providing performance data in regard to the STPIS so this can be reported to the AER
- management of GSL associated with supply reliability and supply restoration
- notification of planned outages to customers within a prescribed period of 4 business days in accordance with the Distribution Code.

Ensuring currency of our network management systems will ensure we can continue to meet our regulatory obligations in relation to network safety and reliability outcomes and information reporting.

[2] See Appendix A for details of EIPN penalties

3 Identified need

3.1 Problem statement

As an electricity distributor, we are required to ensure a reliable electricity supply in accordance with the Distribution Code. Further, our customers expect us to continue to provide safe, dependable, flexible and affordable electricity supply. In the past we have invested significantly in the development and maintenance of our network management systems to ensure we can continue to provide a high level of service. During the 2021–2026 regulatory period, the existing versions of our network management systems will require upgrades, refreshes, maintenance releases and patching to ensure currency.

3.2 Need

Maintaining currency through software upgrades ensures that we receive the latest version of the software as provided by the vendor. The latest version of the system is effectively under warranty by the vendor, which means they have responsibility for fixing issues in a timely manner. As a result there is less disruption to the reliability of our systems, and hence the reliability and safety of our customers' electricity supply is maintained. If our network management systems were to fall out of vendor support, they would no longer be covered by vendor warranty support. Should a failure occur in one of our network management systems, we would not be able to guarantee a safe and reliable supply of electricity to our customers or the safety of our electrical workers.

3.3 Desired future state

Through upgrades and patching, we can continue to maintain efficient and effective management of the electrical network so that the current high levels of supply reliability and public safety can be upheld. Vendors are constantly updating their software to ensure software faults and bugs are rectified and improved security is in place. By safeguarding our software currency we will ensure we receive vendor supported fixes to known software defects and new functionality which comes standard with the upgraded version.

Ensuring currency of our network management systems will also:

- maintain the quality, reliability and security of the distribution system to achieve operational requirements and power quality standards
- ensure we can continue to provide a centralised and automated supply isolation and restoration approach in response to high voltage faults detected, which in turn limits the number of customers impacted by an outage and the duration of the outage
- provide customers with relevant and timely information regarding interruptions to supply
- maintain the safety of the distribution system through the real-time monitoring of network status and field activities on the network
- be proactive in the identification and resolution of issues to keep our customers safe, including enabling us to develop algorithms using AMI data which better detect safety risks on our network
- avoid unsupported or end-of-life systems that cannot be modified to meet operational and/or regulatory requirements such as the Distribution Code. Refer to appendix A for further details.

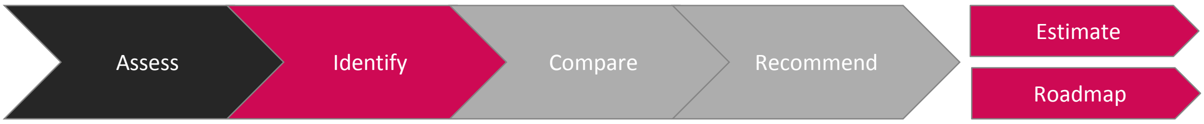
4 Options analysis

This section outlines the approach taken and the different options considered.

4.1 Approach

We followed a structured approach when analysing how various options could address our requirements over the 2021–2026 regulatory period.

Figure 1 High level approach diagram



Assess

In defining the scope of this business case, we undertook the following sequence of activities:

- performed a comprehensive assessment of our portfolio of network management systems, i.e. an assessment of the current applications
- reviewed industry trends affecting the energy sector
- understood vendor future plans in regard to these changes
- reviewed the history of past upgrade frequency.

Identify

Considering the set of applications within the network management systems portfolio, we assessed potential options in order to define an approach that would result in the best value for our customers, and ensure our ability to maintain a stable technology environment while aligning to our compliance requirements.

Compare

A comparison of options was performed on the basis of alignment to desired future state, cost-benefit analysis, reduction of risk to IT systems and business operations.

We also assessed the proposed options against our three themes:

- **Safe and dependable** – ensure the overall safety and stability of electricity supply is not compromised.
- **Flexible** – maintain a flexible IT network management systems ecosystem that can be easily adapted to changing requirements and customer expectations.
- **Affordable** – balance costs and benefits, while ensuring that the work performed delivers value to customers.

Recommend

Based on the outcome of the comparison, we recommended the option which delivers the best value for our customers, maintains the health and currency of our network management systems, and enables continued regulatory compliance, network reliability and safety.

In line with our IT deliverability plan, our recommendation also considered a number of general factors (e.g. project concurrency, resource availability, etc.) to ensure that the option selected and upgrade timing was pragmatic, actionable, and would have the highest probability of delivering a successful outcome.

Estimate and roadmap

The costs for the recommended option were estimated using a bottom-up approach that leveraged information from historical projects relating to the target applications, and information on projects of similar nature and scope. Estimates were produced in terms of labour, contracts and material costs, with labour rates being based on a blended external IT labour rate provided by PwC.[3] While determining costs, we also developed an indicative high-level roadmap. See Appendix C for a high-level view of this roadmap.

4.2 Options summary

The results of our analysis against three options is summarised in the table 5. To understand the potential impact of leaving the target applications in their current state over the 2021–2026 regulatory period, we defined and assessed a number of potential risks using our IT risk monetisation framework. The result of this analysis is provided in appendix B.

Table 5 Options outline, $m 2021-2026

	Option	Cost	Risk
0	Do nothing - do not upgrade, maintain current software versions in relation to our Network Management Systems	0.0	50.3
1	Refresh current suite of network management systems Perform prudent technical upgrades to maintain core currency and regulatory compliance, whilst targeting alignment and simplicity.	24.9	13.4
2	Replace the network management systems with alternative solutions.	50.4	13.4

Source: United Energy

4.3 Option 0 - do nothing - do not upgrade, maintain current software versions

In addition to our meeting our customers' expectations of dependable, flexible and affordable electricity, as an electricity distributor we are required to ensure reliable electricity supply in accordance with:

- the Essential Services Commission's Distribution Code[4]
- the Australian Energy Market Commission's (**AEMC**) National Electricity Rules (**Rules**)[5]
- the AEMC's national electricity objective.[6]

In not actively maintaining the health of our network systems, this option prioritises the avoidance of capital expenditure over risks to electricity supply reliability and the safety of customers and electrical workers.

In addition, the risk of not maintaining currency may result in a broader enterprise impact as underlying third party operating system components required to run software may be prevented from being upgraded.

[3] See UE MOD 12.02 - Quoted services labour rate - Jan2020 - Public

[4] Essential Services Commission, Electricity Distribution Code (Version 9A), 20 August 2018

[5] Australian Energy Market Commission, National Electricity Rules, version 123

[6] Australian Energy Market Commission, The National Electricity Objective (NEO)

Software vendors recommend that we refresh and upgrade software to the latest version, rarely investing in previous software versions, and generally withdrawing support beyond the published end of life support date. When we do not maintain currency and perform the recommended refreshes, then we are not able to take advantage of defect fixes and new functionality. Recent examples of where a vendor recommended upgrade enabled both a defect fix and use of new functionality are provided in appendix **Error! Reference source not found.**. This can restrict our ability to perform necessary upgrades to the other systems, and inhibit our ability to meet changing industry requirements such as those around Distributed Energy Resources (**DER**).

Should a high severity IT system failure occur, this could prevent us from effectively operating the network for the duration of the IT system failure. For example, a SCADA system failure would cause a loss of visibility of the operational status of the electricity network. In this case we would not be able to perform remote switching to facilitate supply restoration and would need to locate an authorised field crew member to attend the fault site to patrol, detect and manually operate switches to safely isolate and restore supply. All of this would result in an impact on customers, i.e. an outage duration increasing from close to immediate resolution to perhaps 4 or 5 hours duration.

Any network interruptions during this period would only become apparent through customer reports into our Contact Centre. We would need to invoke manual procedures across the Contact Centre, Dispatch and Field Crews for customer reported faults and emergencies. The ability to respond and restore supply in a coordinated manner would be severely hindered. Planned work would also be significantly impacted as centralised visibility of the network activity would be unavailable.

Table 6 Option 0 - advantages/disadvantages

Category	Advantages	Disadvantages
Safe and Dependable		Out of support core systems introduce significant risk on the mission critical systems running the electricity network. A high severity failure of our mission critical systems would compromise our ability to monitor and manage the network to deliver a safe and reliable supply of electricity. If there was an event on the electricity network during this period, then there would be a significant risk of being unable to effectively respond and restore supply to customers in a safe and timely manner. Resulting defects occurring when the software is out of support could result in a critical process failure resulting in customers being unable to receive services including: • planned outage notifications • unplanned outage restoration and updates • remote energisation and de-energisation of customers premise. Software faults and bugs will not be rectified by the vendor resulting in increased disruption to our business operations. High risk of regulatory compliance breaches with associated financial penalties. • negative customer experience due to prolonged supply outages • lost visibility of life support customers in relation to the electricity supply assets.
Flexible		Software faults and bugs will not be rectified by the vendor resulting in increased disruption to our business operations. Unable to develop new algorithms which use AMI data to identify potential safety risks on the network. Lost product currency leads to compromised commercial vendor support arrangements and negotiating power. Lost product currency leads to complicated future product roadmap realignment.
Affordable	Lower cost in short term.	Increased future capex spend required to remediate existing systems or migrate to new systems that are out of support or end of life, resulting in higher costs to customers. Higher costs expected in next period for remediation works if a system issue arises in production that impacts our ability to manage the electricity network. It may only be resolved based on vendor instruction to upgrade to a current version. Financial penalties associated with EIPNs issued by the ESC due to non-compliance.

Source: United Energy

4.4 Option 1 - refresh current suite of network management systems

Perform prudent technical upgrades to maintain core currency whilst targeting alignment and simplicity. This option enables continued regulatory compliance, maintaining reliability and safety of the electricity network. The intent is to maintain currency on all core network management systems applications by performing vendor recommended upgrades. The current core network management systems were implemented to ensure we can effectively operate and manage the network to satisfy regulatory obligations and maintain a safe, reliable and secure supply of electricity to our customers.

As the demand for distributed energy resources continues to grow, we need to ensure systems are robust and current to manage the impact on the electricity network in order that supply reliability, safety and security are maintained.

Option 1 maintains our ability to effectively monitor and manage the network at lower cost than replacing the systems. This option entails a rolling program of refreshes of the identified network management systems spread over the five year regulatory reset period. The network management systems currency roadmap is provided in Appendix C.

The benefits of this approach include:

- software defects are resolved with the new release
- enables development of new algorithms to identify safety risks on the network
- hardware compatibility is maintained with newer software versions. Hardware refreshes can introduce incompatibility issues with older software versions.

The future vendor roadmap for the incumbent network management platform continues to reflect industry trends, including modelling, monitoring, forecasting and DER integration.

Our expenditure forecast for option 1 reflects the efficient cost of refreshing our IT systems:

- our timing profile is based on prudent and timely investments aligned with vendor product support schedules
- our forecast cost per refresh is based on previous refresh costs incurred in 2016-2020 as well as projected infrastructure hardware replacement cycles which have historically been every five years.

Table 7 Option 1 - advantages/disadvantages

Category	Advantages	Disadvantages
Safe & dependable	Ensures current, supportable robust technology platforms required to manage the electrical distribution network. Software warranty is protected. Ensures continued vendor support and maintenance. Continued support of critical business processes. Investment in reliable, stable and tested solutions. Software faults and bugs are rectified by the vendor resulting in reduced disruption to our business units. Regulatory compliance maintained. Network reliability and safety maintained.	
Flexible	Enables development of algorithms to improve network safety. Ensures system functionality supports changing business and/or regulatory requirements. Ensuring currency makes it easier than option zero to adapt to changes in the technology landscape and evolving customer expectations around service delivery.	
Affordable	By performing a refresh we avoid high remediation costs in the future. Reduce inherent technical debt that would otherwise increase the total cost of ownership and likely require a significantly larger future investment to upgrade or replace. Lower cost than system replacement (option 2).	Higher costs in the short term than not undertaking any system refresh (option 0).

Source: United Energy

4.5 Option 2 - replace network management systems with alternative solutions

This option involves replacing the network management systems, with alternative solutions which provide similar functionality. This option would involve significant organisational and technology change. Considerable changes to operational business processes would introduce an increased risk of interruptions to network operations/performance. This in turn would impact on supply reliability, safety and customer service.

Core system replacement can be a long and challenging endeavour. There is a high risk of cost overrun and schedule slippages due to the broad scope and complexity of the project. The impact of changing to a new network management suite of products would be all-encompassing. Transformation would necessitate changes to processes, procedures, policies, controls, roles, service levels and the way of doing business.

At a minimum, a replacement suite of systems must provide additional functionality and benefits beyond those provided by the incumbent systems, i.e. providing additional benefits to the customer or enabling further operational efficiencies. Also note that in addition to implementation costs, there will still be currency costs. These could be post implementation, towards the end of the regulatory period, and into the following one.

Table 8 lists examples of alternative solutions on the market, where an equivalent is available.

Table 8 Option 2 - advantages/disadvantages

System	Current Product	Potential Alternative Products
SCADA/DMS/OMS	CGI Mosaic Oracle Network Management System	GE ADMS, Schneider ADMS
Supply Quality	Sensor IQ	No equivalent on the market
Switching	Network Access Request System	ZepBen EDNAr
Protection System	Schneider Electric ION	DigiSILENT Stationware
GIS	GE Smallworld CORE	ESRI GIS
Network Visualisation	GE Network Viewer Plus	ESRI Equivalent, Map Insights
Outage Reporting	Oracle Utilities Analytics	SAP BI
Network Data Processing	PostgreSQL Future Grid integrated platform	GE Grid Analytics

Source: United Energy

The current suite of network management systems already meets our business needs. Therefore the cost of replacing our network management systems and the risk of business disruption cannot be justified. Note that this option has a higher expenditure profile than options 0 and 1.

A variation on this option was considered in which only selected network management systems would be replaced with alternative solutions. This was discounted early on due to the integrated and tightly coupled nature of the systems, i.e. replacing one system would likely require replacing all systems or involve extensive modification work to ensure full functional coverage and compatibility between systems.

Table 8 lists the advantages and disadvantages for the option to replace the existing network management systems with alternative solutions.

Table 9 Potential alternative solutions

Category	Advantages	Disadvantages
Safe & dependable	Maintains our ability to effectively monitor and manage the electricity distribution network to deliver and safe and reliable supply of electricity. Ensures we have supported technology to manage the electricity network.	The ability to provide support for the new systems is unlikely to be as strong in the interim period due to a learning curve. It will take time for support staff to become familiar with the new products. Long implementation timeframe to implement the new suite of systems and associated business disruption. Significant change management impact on business operations.
Flexible		The new systems may not provide functionality beyond the old systems even though significant investment has been made to conduct the replacement. Significant organisational and technology change that may introduce increased risk of interruptions to network operations/performance impacting on supply reliability, safety and customer service.
Affordable		Significantly higher capital outlay than refreshing our existing systems. Despite significant outlay to implement, the support costs for the new systems are likely to be similar to those of the current systems.

Source: United Energy

5 Recommendation

Option 1, refreshing our current suite of network management systems is recommended. We assess this option to provide the most balanced approach. Risks associated with option 0 were considered too high, whilst costs associated with option 2 were considered unjustified and avoidable.

Option 1 maintains our ability to monitor and manage the network, to deliver a safe and reliable electricity supply to our customers and to meet our regulatory reporting obligations. Ensuring public safety and making sure customers receive timely and relevant information regarding interruptions to supply is vital. This option also supports continued investment in reliable, stable and tested solutions and avoids high remediation costs in the future. Our proposed expenditure profile is shown in table 10.

Table 10 Recommended option: expenditure forecast, $m June 2021

IT capital expenditure	2021/22	2022/23	2023/24	2024/25	2025/26	Total
United Energy	5.0	5.2	4.0	4.2	6.4	24.9

Source: United Energy

A Network management regulatory requirements

Ensuring currency of the network management systems enables us to meet the regulatory requirements outlined in table 11.

Table 11 Compliance with regulatory obligations

Instrument	Obligation	Obligation description	Penalty
Distribution Code 5.5.1	Notice of planned interruptions	Planned interruptions In the case of a planned interruption, the distributor must provide each affected customer with at least 4 business days written notice of the interruption. The notice must: (a) specify the expected date, time and duration of the interruption; and (b) include a 24 hour telephone number for enquiries.	EIPN $10,000
Distribution Code 6.4	Service Levels - Time for payment	Time for payment Any payments required to be made by the distributor to a customer under this clause 6 must be paid by the distributor as soon as practicable after the obligation arises under clauses 6.1 or 6.2 and as soon as practicable following the end of the year in which the obligation arises under clause 6.3.	EIPN $10,000
Distribution Code 6.3.1	Service levels - supply restoration payments	6.3.1 A distributor must make a supply restoration payment to a customer of: (a) $120 where the customer experiences more than 20 hours of unplanned sustained interruptions per year; or (b) $180 where the customer experiences more than 30 hours of unplanned sustained interruptions per year; or (c) $360 where the customer experiences more than 60 hours of unplanned sustained interruptions per year; or (d) $80 where the customer is supplied by a CBD feeder or an urban feeder and experiences an unplanned sustained interruption of more than 12 hours, and 20 hours or less of unplanned sustained interruptions in that year; or (e) $80 where the customer is supplied by a short rural feeder or a long rural feeder and experiences an unplanned sustained interruption of more than 18 hours, and 20 hours or less of unplanned sustained interruptions in that year; not counting the period of an event to which clause 6.3.3 or 6.3.4 applies.	EIPN $10,000

Distribution Code 6.3.2	Service levels - low reliability payments	6.3.2 A distributor must make a low reliability payment to a customer of: (a) $120 where the customer experiences more than 8 unplanned sustained interruptions per year; or (b) $180 where the customer experiences more than 12 unplanned sustained interruptions per year; or (c) $360 where the customer experiences more than 24 unplanned sustained interruptions per year; and (d) $30 where the customer experiences more than 24 momentary interruptions per year; or (e) $40 where the customer experiences more than 36 momentary interruptions per year, not counting an event to which clause 6.3.3 or 6.3.4 applies.	EIPN $10,000
Distribution Code 5.6.1 & 5.6.3	Life Support Equipment supply address	5.6.1 Where a customer or a retailer provides a distributor with confirmation from a registered medical practitioner or a hospital that a person residing at the customer's supply address requires Life Support Equipment, the distributor must: (a) register the supply address as a Life Support Equipment supply address; (b) not disconnect supply to the customer's supply address while the supply address remains registered as a Life Support Equipment supply address; and (c) give the customer: • at least 4 business days written notice of any planned interruption to supply at the supply address (the 4 business days to be counted from the date of receipt of the notice), unless a longer period of notice is requested by the customer and provided that the longer period of notice: – is reasonably necessary – can be accommodated by the distributor • advice to assist the customer to prepare a plan of action in case an unplanned interruption should occur • an emergency telephone contact number. 5.6.3 At least once in each year a distributor must take all reasonable steps to ensure the accuracy and completeness of its register kept under clause 5.6.1(a).	EIPN $20,000

Source: United Energy

B Risk monetisation summary

Table 12 IT risk monetisation summary for recommended option

Risk Category	Risk Type	Description of Risk
IT Risks	Outage	Ensuring currency maintains the current low risk and duration of an outage, minimising delay of responding to customer outages Continuing with support under our preferred option means we can expect low risk levels similar to that experienced. High severity incidents may result in partial or total loss of system functionality, impacting on our ability to manage the electricity network. Without investing in currency as under option 0, an outage lasting from 1 hour to 15 hours is likely to occur, and progressively increase each year.
	Suitability	Suitability issues occur as a result of external changes eg regulatory compliance or industry drivers, meaning that while a system continues to work, it is no longer suitable to perform required functions. New functionality through major upgrades can occur as per present-day, facilitated through vendors as required each year.
	System Sustainability	System sustainability issues (defects) can occur from time to time in our network management system. Without correcting them, they grow over time resulting in lost staff productivity. Under vendor support, system sustainability issues are rectified by the vendor issuing patches for us to implement about 2-3 times each year.
Business Risks	Reliability Impact	We rely on our network management system to both help diagnose/rectify faults, and to remotely switch customers to different feeders when an outage occurs so that we minimise customer minutes off supply. We can do this on parts of our network automatically. If our network management system failed, this would conservatively double the amount of time it would take to rectify the fault as a result of crews needing to locate, diagnose, repair and conduct final restoration. In addition, through FDIR we are able to automatically switch about 12% of our customers to other feeders (so they essentially have no time off supply). Switching customers manually would increase customer time off supply as additional time would be spent sending crews out into the field. However, we are not resourced to conduct manual switching activities so there is a risk we would not be able to switch customers onto new supply. However, we cannot recall a time when a network management system has gone offline at the same time as a network outage and therefore consider this a low risk.

Compliance Risk	As an electricity distributor in the National Electricity Market (**NEM**), we are required to ensure compliance with the Distribution Code. We are obliged to provide control and monitoring of customers' supply reliability and network performance, as well as providing tools to ensure network, employee and public safety is maintained. Any system impact will likely affect compliance through delayed response to rectify customer outages or through delays to inform customers of planned outages within the required notice period. However, given the low duration of outages currently and expected in future under our proposed investment option, this is considered a low risk.
Safety Risk	A system impact may delay our ability to respond to electricity faults that have a public safety risk. For example, in the case of an unplanned outage this would impact our ability to proactively identify and prioritise any Life Support Customers that have been affected. Further, we also use network management for planned works which, if not available would mean resorting to paper-based planning activities. This would also have safety implications for the crews working on the network through greater risk of human error in communicating planned works. Given low current and expected outage times, the risk of the network management system contributing to any arising safety issue is very low although the consequences are high.
	Any system impact will have a negative customer experience through impacting our able to provide timely and accurate outage information. Network management provides up to date information about the status of outages for the call centres. If the system were to go down, contact centre staff would be able to implement manual workarounds to determine generic information from control centres about the general locations of outages, although they would have difficulty providing information to customers about their specific circumstances and may result in higher call volumes through being unable to resolve customer queries as quickly. However, given low current and expected outage times, the risk of the network management system contributing to any arising compliance issue is considered low.
Bushfire Risk	We receive information about equipment sparking and catching fire through customer calls. Failure of the network management system may result in an increase in call centre volumes, causing delays to customers reporting electricity faults with public safety risks that may lead to a bushfire impact. However, given the low duration of a network management system failure, the probable volume of people contacting the call centre to enquire is low.

Source: United Energy

C Network management systems currency roadmap

Figure 2 UE Network Management Systems Roadmap 2021-2026

System	Product	2021/22	2022/23	2023/24	2024/25	2025/26
Network Management Core						
SCADA DMS/OMS	Mosaic NMS	NMS Upgrade	Mosaic Upgrade	Mosaic Upgrade	NMS Upgrade	Mosaic Upgrade
Supply Quality	Sensor IQ	Upgrade				Upgrade
Switching	NARS – Network Access Request System	Upgrade	Upgrade			Upgrade
Protection Systems	Schneider Electric ION			Upgrade		
Network Geospatial						
GIS	Smallworld CORE		Upgrade	S4HANA Integration	S4HANA Integration	Upgrade
GIS Network Viewer	Smallworld Network Viewer+	Maintenance Release	Upgrade	Maintenance Release	Maintenance Release	Upgrade
Network Reporting and Analytics						
Outage Reporting	Oracle Utilities Analytics	Upgrade			Upgrade	
Network Data Processing	Future Grid PostgreSQL	Maintenance Release	Maintenance Release	Maintenance Release	Maintenance Release	Maintenance Release

Source: United Energy

D Network management core initiatives

Table 13 Network management core initiatives summary

Network Management Core		
SCADA/DMS/OMS	Status as of January 2021	CGI Mosaic version 5.1; Oracle Utilities NMS version 2.3
	Initiatives	OUNMS Upgrade: Upgrade to v2.4 for functional improvements in particular switching and outage management, bug fixes as well as support for DER management Mosaic Upgrade: Upgrade to v6.x to keep application service components current and secure as well as functional support for DER management OUNMS Upgrade: Upgrade to v2.x to keep application service components current and enable functionality to support network automation and expanded DER Mosaic Upgrade: Upgrade to v6.x to keep application service components current and secure as well as functional support for DER management
Supply Quality	Status as of January 2021	Itron SensorIQ 3.1
	Initiatives	SensorIQ Upgrade: To upgrade SensorIQ in line with the compatible version of UIQ required for 5 Minute Settlement compliance requirements SensorIQ Upgrade 2025/26: To upgrade SensorIQ in line with the compatible version of UIQ
Switching	Status as of January 2021	NARS version 1.0
	Initiatives	NARS Upgrade: NARS functional uplift to better manage the switching process inclusive of planned outages notifications
Protection Systems	Status as of January 2021	Schneider Electric ION PME version 8.2
	Initiatives	ION PME Upgrade: Uplift to v9.x to support modernised ION meters for Zone Substations and improved application security authentication features ION PME Upgrade: Upgrade to v10.x for currency and functional capability to support modernised power quality meters

Source: United Energy

Table 14 **Geospatial initiatives summary**

Network Geospatial		
GIS	Status as of January 2021	GE Smallworld CORE version 4.3
	Initiatives	Smallworld CORE Upgrade: Upgrade to v5.x to keep application service components current as well as product functional improvements and bug fixes Smallworld CORE Upgrade: Upgrade to v5.x to keep application service components current as well as
GIS Network Viewer	Status as of January 2021	Smallworld Network Viewer+ version 5.1
	Initiatives	Smallworld Network Viewer+ Maintenance: Maintenance Release as a pre-requisite for GIS Smallworld Upgrade Smallworld Network Viewer+ Upgrade: Version uplift to keep application service components current and compatible with upgraded Smallworld Smallworld Network Viewer+ Maintenance Release: Maintenance Release as a pre-requisite for GIS Smallworld Upgrade Smallworld Network Viewer+ Maintenance Release: Maintenance Release as a pre-requisite for GIS Smallworld Upgrade Smallworld Network Viewer+ Upgrade: Version uplift to keep application service components current and compatible with upgraded Smallworld

Source: United Energy

Table 15 Reporting and analytics initiative summary

Network Reporting and Analytics		
Outage Reporting	Status as of January 2021	Oracle Utilities Analytics version 2.7
	Initiatives	Oracle Utilities Analytics Upgrade Version uplift to keep application service components current and compatible with upgraded OUNMS Oracle Utilities Analytics Upgrade Version uplift to keep application service components current and compatible with upgraded OUNMS
Network Data Processing	Status as of January 2021	Future Grid version x.y PostGreS version ver 11.0
	Initiatives	Future Grid Maintenance: To incorporate bug fixes and functional improvements PostGreS Maintenance Release To provide improved platform stability and integration compatibility Future Grid Maintenance: To provide platform stability and supportability for compatible services components PostGreS Maintenance Release: To provide for modernised technology service components Future Grid Maintenance Release: To provide product bug fixes and functional improvements Develop the new algorithms for identifying safety risks including to: • Prevent LV fires caused by Overhead Line Connection Boxes • Early detection of candling fuses to prevent fires • Broken live LV, HV conductor detection as well as location identifiers.

Source: United Energy