5. Forecast Capital Expenditure

5.1 Introduction

This chapter presents Powerlink's forecast capital expenditure for each year of the 2023-27 regulatory period.

Key highlights:

- We have responded to the feedback received from our customers, the Australian Energy Regulator (AER), and the AER's Consumer Challenge Panel (CCP23) to our draft Revenue Proposal. In focusing on how we can more prudently and efficiently manage our network, our forecast capital expenditure has reduced by more than 12% since our draft Revenue Proposal in September 2020.
- Our forecast capital expenditure for the 2023-27 regulatory period is $863.9m.
  - This is $27.4m (3.1%) lower than actual/forecast capital expenditure for the 2018-22 regulatory period.
  - The majority of this forecast ($726.1m or 84%) is non load-driven network expenditure.
- The key drivers that underpin our forecast for the 2023-27 regulatory period are:
  - forecast continued decline in minimum demand and energy delivered to Queensland customers;
  - our response to the changing energy market environment including the growth in deployment of Inverter-Based Resources (IBR); and
  - targeted reinvestment in the transmission network to maintain security, reliability and quality of supply as our assets continue to age.
- Our Hybrid+ forecasting approach integrates top-down and bottom-up methods, with project-specific justification provided for approximately 70% of our forecast capital expenditure.
- We have proposed one contingent project and decided not to continue to pursue contingent reinvestments in our Revenue Proposal, which is a change from the position in our draft Revenue Proposal in response to customer and AER feedback.

5.2 Regulatory requirements

The National Electricity Rules (the Rules)[1] require that our Revenue Proposal provides information on our capital expenditure for each year of the previous and current regulatory periods. The Rules[2] also require that the AER has regard to this expenditure when it considers our forecast capital expenditure.

Prior to the submission of our Revenue Proposal we are required to propose a methodology for the development of our capital and operating expenditure forecasts[3] (our Expenditure Forecasting Methodology). This methodology, and our forecasts, must also have regard to the AER's 2013 Expenditure Forecast Assessment Guideline for Electricity Transmission.

We must submit our forecast capital expenditure for the 2023-27 regulatory period based on the requirements set out in the Rules[4].

5.2.1 Capital expenditure objectives

We consider that our forecast capital expenditure achieves the capital expenditure objectives set out in clause 6A.6.7(a) of the Rules. This is summarised in Table 5.1 and discussed in detail in Appendix 5.01 Operating and Capital Expenditure Criteria and Factors.

1 National Electricity Rules, schedule 6A.1, clause S6A.1.1(6).
2 National Electricity Rules, clause 6A.6.7(e)(5).
3 National Electricity Rules, clause 6A.10.1B.
4 National Electricity Rules, clause 6A.6.7 and schedule 6A.1.

Table 5.1: How we meet the capital expenditure objectives

Capital expenditure objective	How our proposal meets this objective
Meet or manage the expected demand for prescribed transmission services over the period	Demand is forecast to be relatively constant across our network over the 2023-27 regulatory period, in line with minimal growth seen over the 2018-22 regulatory period. Our reinvestment forecast excludes any assets we have identified that can be retired at their end of life without replacement.
Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services	We are subject to regulatory obligations as the holder of a Transmission Authority under the *Electricity Act 1994* and as a registered Transmission Network Service Provider (TNSP) in the National Electricity Market (NEM). As a company we are also subject to various other environmental, cultural heritage, planning approval, Workplace Health & Safety, financial and other regulations. Our compliance with these regulatory obligations and requirements is encompassed in our Asset Management Framework and associated policies and procedures, which provide the foundation for our capital expenditure activities. These are provided as supporting documents to our Revenue Proposal.
Maintain the quality, reliability and security of supply of prescribed transmission services and maintain the safety, reliability and security of the transmission system through the supply of prescribed transmission services	Our capital expenditure forecasts include prudent provision for maintaining the safety of the transmission system while maintaining and meeting the mandated level of quality, reliability and security of supply to customers. Where there are no mandated service levels we will maintain the existing levels of service.

5.3 Capital expenditure categories

We have largely retained the same categories of capital expenditure drivers as applied in both our 2013-17 and 2018-22 regulatory periods. As noted in our Expenditure Forecasting Methodology, we have included a new category of expenditure driver, System Services. This new category of capital expenditure is forward-looking and does not require the reclassification of any historical capital expenditure.

Our capital expenditure categories, and the prescribed transmission services they relate to, are shown in Table 5.2.

Table 5.2: Powerlink's capital expenditure categories

Capital expenditure category	Definition	Prescribed transmission service
Network – Load-driven		
Augmentations	Relates to augmentations defined under the Rules. Typically these include projects such as the construction of new lines, substation establishments and reinforcements or extensions of the existing network.	Transmission Use of System (TUOS) services and exit services
Connections	Works to facilitate additional connection point capability between Powerlink and Distribution Network Service Providers (DNSP's) or other TNSPs. Associated works are identified through joint planning with the relevant Network Service Provider (NSP).	Exit services
Easements	The acquisition of transmission line easements to facilitate the projected expansion and reinforcement of the transmission network. This includes land acquisitions associated with the construction of substations or communication sites.	Common services, TUOS services and exit services
Network – Non load-driven		
Reinvestments	Relates to reinvestment to meet the expected demand for prescribed transmission services. Expenditure is primarily undertaken due to end of asset life, asset obsolescence, and asset reliability or safety requirements. A range of options are considered for asset reinvestments including, removal without replacement, non-network alternatives, life extension to extend technical life or replacement with assets of the same or different type, configuration or capacity. Each option is considered in the context of future capacity needs accounting for forecast demand and the changing mix and location of generation.	Common services, TUOS services and entry/exit services
System Services	Investments to meet overall power system performance standards and support the secure operation of the power system. This includes the provision of system strength services and inertia services.	Common services
Security / Compliance	Expenditure undertaken to ensure compliance with amendments to various technical, safety or environmental legislation. In addition, expenditure is required to ensure the physical security (as opposed to network security) of Powerlink's assets, which are regarded as critical infrastructure.	Common services, TUOS services and entry/exit services
Other	All other expenditure associated with the network which provides prescribed transmission services, such as communications system enhancements, improvements to network switching functionality and insurance spares.	Common services
Non-network		
Business Information Technology (IT)	Expenditure to maintain IT capability and replace or improve business system functionality where appropriate.	Common services
Support the Business	Expenditure to replace or improve business requirements including, commercial buildings, motor vehicles and other tools and equipment.	Common services

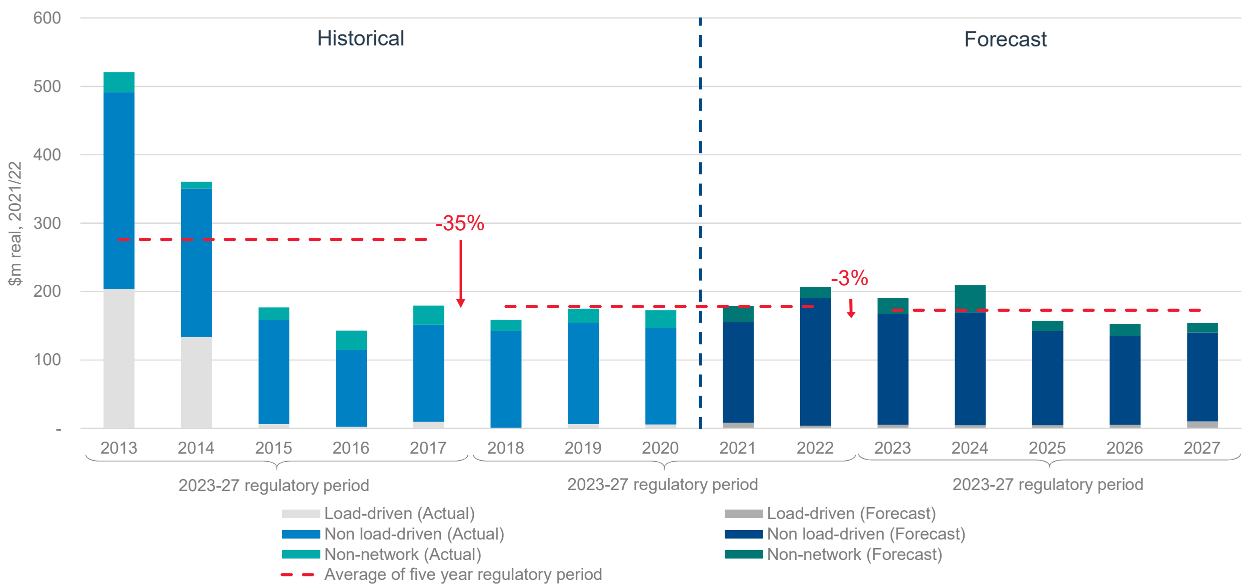
5.4 Forecast capital expenditure overview

This section presents our forecast capital expenditure for the 2023-27 regulatory period.

5.4.1 Forecast capital expenditure

Our total forecast capital expenditure for the 2023-27 regulatory period, along with our actual/forecast expenditure for the previous and current regulatory periods, is shown in Figure 5.1.

Figure 5.1: Capital expenditure by driver ($m real, 2021/22)



Our total forecast capital expenditure is $863.9m, which is $27.4m (3.1%) lower, than the actual/forecast expenditure for the 2018-22 regulatory period. The majority of this ($726.1m or 84%) is non load-driven network expenditure.

Our forecast expenditure by category is shown in Table 5.3. Further details about the forecast by category is provided in Section 5.6.

Table 5.3: Forecast capital expenditure by category ($m real, 2021/22)(1)

Category	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Network capital expenditure						
Load-driven capital expenditure						
Augmentations	3.4	2.1	1.1	0.1	-	6.7
Connections	-	-	-	-	2.4	2.4
Easements	2.0	2.5	3.4	5.1	8.2	21.1
Total: load-driven	**5.4**	**4.6**	**4.5**	**5.2**	**10.5**	**30.2**
Non load-driven capital expenditure						
Reinvestments	143.2	150.1	132.6	124.7	124.2	674.8
System Services	13.2	9.3	-	-	-	22.5
Security/compliance	2.9	2.9	2.9	2.9	2.9	14.5
Other	2.9	2.9	2.9	2.9	2.9	14.3
Total: non load-driven	**162.2**	**165.1**	**138.3**	**130.5**	**130.0**	**726.1**
Non-network capital expenditure						
Business IT	15.8	13.7	9.5	11.5	8.8	59.3
Support the Business	7.5	26.1	4.9	5.2	4.7	48.4
Total: non-network	**23.3**	**39.8**	**14.4**	**16.7**	**13.5**	**107.7**
Total	**190.9**	**209.4**	**157.2**	**152.4**	**154.0**	**863.9**

(1) This table is net of disposals.

Our forecast capital expenditure reflects the key drivers for investment described in our Business Narrative (refer to Appendix 2.01) and in Chapter 2 Business and Operating Environment. In particular:

- our forecast load-driven capital expenditure reflects the outlook of minimal growth in peak demand. More than two thirds of the forecast expenditure in these categories is for easement acquisition, primarily for the Queensland/New South Wales Interconnector (QNI) Medium upgrade project;
- reinvestment in existing network assets accounts for nearly 80% of the total forecast capital expenditure. The most significant drivers for this reinvestment are to address increasing levels of corrosion across our fleet of over 23,500 steel transmission towers[5], and the cyclical replacement of digital technologies that protect and control our high voltage assets due to obsolescence/lack of support and spares; and
- investment in network assets to ensure we continue to meet the prescribed standards of power system technical performance as minimum demand decreases and there is greater variability in power flows across the network.

To meet these challenges we also need to continue to invest in the facilities and tools that support our people. Our forecast non-network capital expenditure includes provision for a major refit of our office facilities which will enable more efficient use of the available space as well as replacement and renewal of our legacy IT systems.

5.4.2 Changes from the draft Revenue Proposal

Our draft Revenue Proposal included total forecast capital expenditure of $988.9m, which is $97.6m (11%) higher than the actual/forecast capital expenditure for the 2018-22 regulatory period.

Since we published our draft Revenue Proposal we have continued to focus on how we can more prudently and efficiently manage the network while continuing to deliver safe and reliable electricity transmission services for customers. We continue to challenge ourselves on the needs for proposed investments. These activities have occurred in parallel with the development of our 2020 Transmission Annual Planning Report (TAPR) included in Appendix 5.02, and our annual asset management planning cycle, which concluded in December.

Key items which have contributed to the substantial reduction in forecast capital expenditure are:

- removal of some proposed projects where the need for capital expenditure in the 2023-27 regulatory period could not be robustly demonstrated at this stage;
- critical review of the scope of some of the major transmission line life extension projects. For example, for the Ross to Chalumbin 275kV transmission line we have been able to identify specific sections of the line where the condition has deteriorated more significantly and have been able to better target the scope of life extension works;
- critical review of the unit costs for reinvestment projects, particularly for secondary systems replacement projects. We are investigating the potential for more cost-effective ways to deliver these projects through replacing selected equipment within existing panels. For secondary systems projects we have set ourselves the stretch target of reducing the per unit costs for these projects by 10% compared to our current approach; and
- recalibration of the asset mean replacement lives used in the Repex Model based on the most recent five years of actual condition-based replacement quantities. As a result the mean replacement lives are now slightly longer than the lives determined in our previous AER determination.

We have also updated our forecasts to reflect the latest inflation forecast, as published by the Reserve Bank of Australia (RBA) in November 2020.

As a result of these reviews and consistent with our commitment to affordability, we have been able to reduce our total forecast capital expenditure for the 2023-27 regulatory period by $125.0m (12.6%) compared to our draft Revenue Proposal. Our view is that this forecast responds to feedback we received on the draft Revenue Proposal which highlighted that a 12% increase in capital expenditure (compared to the current regulatory period) was a serious concern for our customers. Importantly, it also reflects our commitment to delivering electricity transmission services prudently and at an efficient cost.

Table 5.4 summarises the difference in total forecast capital expenditure between our draft Revenue Proposal and our Revenue Proposal.

[5] This increasing corrosion is a normal feature of the lifecycle of steel transmission towers and the rate varies depending on local climatic conditions.

Table 5.4: Capital expenditure – draft Revenue Proposal vs Revenue Proposal ($m real, 2021/22)(1)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Draft Revenue Proposal	200.7	191.5	180.4	208.2	208.1	**988.9**
Revenue Proposal	190.9	209.4	157.2	152.4	154.0	**863.9**
Difference ($m)	(9.8)	17.9	(23.2)	(55.8)	(54.1)	**(125.0)**
Difference (%)	(4.9)	9.3	(12.9)	(26.8)	(26.0)	**(12.6)**

(1) This table is net of disposals.

5.5 Capital expenditure forecasting methodology

We have developed our capital expenditure forecast consistent with the requirements of the Rules[6] and our Expenditure Forecasting Methodology, which was provided to the AER in June 2020. In the course of developing our capital expenditure forecast we made several small refinements to our forecasting methodology (refer to Appendix 5.03 Expenditure Forecasting Methodology). The most significant change is that the detailed methodology for integration of top-down and bottom-up forecasts is no longer required. The top-down forecasts are now complementary to, and do not overlap with, the bottom-up forecasts so the total capital expenditure forecast is simply the addition of the top-down elements with the bottom-up elements. We have also had regard to the AER's 2019 Industry Practice Application Note for Asset Replacement Planning[7].

While we have specific project estimates for significant investments we also use the AER's Replacement Expenditure (Repex) Model to support an additional element of the capital expenditure forecasts. The Repex Model takes a top-down approach to forecast part of our network reinvestment expenditure under our Hybrid+ approach (explained further in Section 5.5.2). We have adapted the AER's Repex Model to better reflect our asset management planning practices. In particular, where our planning has identified opportunities to retire assets without replacement at their end of life these have been excluded from the forecast.

We have also had regard to information on proposed transmission investments within a 10 year outlook, as published in our TAPR and related material[8], our 30 year Network Vision[9] and Australian Energy Market Operator's (AEMO's) 2020 Integrated System Plan (ISP).

As we developed our methodology and forecasts for the 2023-27 regulatory period, we regularly engaged with our customers and stakeholders (refer Chapter 3 Customer Engagement). We also engage with our customers and stakeholders on planning and other business related matters in the normal course of business, including at our annual Transmission Network Forum[10].

Our capital expenditure forecasts are limited to investment or reinvestment in assets that provide prescribed transmission services, consistent with our Cost Allocation Methodology (CAM) approved by the AER in 2008. Where a single project cost estimate includes expenditure on both prescribed and non-prescribed assets, the proportion of expenditure attributable to assets that provide prescribed transmission services is included in our capital expenditure forecasts. Our Repex Model includes only those assets that are allocated to the provision of prescribed transmission services.

5.5.1 Key drivers of our capital expenditure forecast

There are a number of significant external drivers that have influenced our capital expenditure program in the current regulatory period and are also expected to continue to have an impact in the 2023-27 regulatory period. These are summarised in Table 5.5.

6 National Electricity Rules, clause 6A.6.7.
7 Industry practice application note - Asset replacement planning, Australian Energy Regulator, January 2019.
8 2020 Transmission Annual Planning Report, Powerlink, https://www.powerlink.com.au/reports/transmission-annual-planning-report-2020.
9 Network Vision, Powerlink, https://www.powerlink.com.au/network-vision.
10 Engagement Forums, Powerlink, https://www.powerlink.com.au/engagement-forums.

Table 5.5: Key capital expenditure drivers

Key driver	Description
Continued decline in consumption	AEMO's Central scenario in its Electricity Statement of Opportunities (ESOO) forecasts a continued decline in energy consumption over our 2023-27 regulatory period[1]. This includes a rapid decline in minimum operational demand as a result of continued growth in solar PV generation to meet daytime demand. AEMO also highlighted the considerable uncertainty surrounding its forecasts, primarily due to the COVID-19 pandemic.
COVID-19	As explained in Chapter 4 Historical Capital and Operating Expenditure, COVID-19 has impacted the timing of the delivery of some of our projects. This is a result of delays in sourcing specialist equipment and resources from overseas, as well as necessary changes to work practices. We expect to be able to catch-up some of this delay in 2021/22.
Inverter-Based Resources	We have also discussed the impact of the rapid growth in IBR on our network, which includes grid-connected and rooftop solar PV, wind farms and battery technologies. This has resulted in the creation of a new category of expenditure for System Services. It also impacts how we plan and deliver projects as we seek to efficiently minimise network outages in an environment of reduced synchronous generation capacity.
An ageing network	The average age of our network has continued to increase during the 2018-22 regulatory period. While age alone is not a trigger for individual asset reinvestments, the trend in the average age of the fleet of assets can indicate the likely need for more or less expenditure on asset renewal.
Cyber security	TNSPs are considered amongst the highest criticality segment under the Australian Energy Sector Cyber Security Framework (AESCSF). Cyber security has therefore received increased focus in the current regulatory period and this will continue to be the case into the 2023-27 regulatory period. We have critically reviewed the need for any material additional expenditure driven by cyber security requirements. While we currently consider that it will be sufficient to maintain our current level of capability, in December 2020 the Commonwealth Government proposed changes to legislation[2] which result in elevated security obligations and standards on Australian critical infrastructure owners and operators. Given the uncertainty around the scope and timing of these future formal obligations, we have not included additional capital expenditure in our forecasts at this time.

(1) 2020 Electricity Statement of Opportunities, Australian Energy Market Operator, August 2020.

(2) *Security Legislation Amendment (Critical Infrastructure) Bill 2020.*

5.5.2 Our Hybrid+ approach

We continue to apply a hybrid approach to develop our capital expenditure forecasts, which integrates top-down and bottom-up methods. We applied this hybrid approach to forecast our capital expenditure in our 2018-22 Revenue Proposal.

We have built on the experience, input and feedback gained during our previous revenue determination process and have further refined and improved this approach for the 2023-27 regulatory period. A key improvement includes the provision of project-specific supporting justification for over 70% of our total forecast capital expenditure. Dependent on the type of proposed investment this justification may include condition assessment reports, specific asset strategies, project scopes and estimates, network planning assessments and risk/cost quantification[11]. This bottom-up information provides justification for the primary expenditure forecast for these significant investments. This is complemented by the top-down forecast for the remaining assets.

We refer to this further development as the Hybrid+ approach. This approach provides a number of advantages in that it:

- reduces the cost to Powerlink (and ultimately customers) of preparing our Revenue Proposal compared to a fully bottom-up approach;
- assists the AER and stakeholders in terms of the time, effort and cost to review and assess our Revenue Proposal; and
- balances the desire of stakeholders to understand the technical and economic justification for significant investments with the uncertainty of forecasting capital expenditure needs many years in advance, all while the technical demands on the transmission network are rapidly changing through the energy transition.

Details of the Hybrid+ approach can be found in Appendix 5.03 Expenditure Forecasting Methodology and a summary is presented in Table 5.6.

11 As part of the material submitted in support of our Revenue Proposal we have included a guide to assist stakeholders understanding of this supporting documentation.

Table 5.6: Application of the Hybrid+ approach

Approach	Application	Method
Bottom-up	Approved projects. Load-driven capital expenditure. Power transformer and Static Var Compensator (SVC) reinvestment. Any major one-off expenditure needs. System services such as system strength and inertia. Significant network projects (indicative threshold of >$12.0m project cost). Contingent projects (these do not form part of the ex-ante capital expenditure forecast).	Analysis of need, preparation of project scope, estimate, planning statement and risk/cost assessment.
Top-down	Network assets including transmission lines, substations (excluding transformers which are bottom-up) and secondary systems.	Use of the AER's Repex Model.
Trend analysis	Security/compliance. Other network capital expenditure, including reinvestment in substation auxiliary systems and buildings.	Trend of recent expenditure with outliers removed.

In adopting our Hybrid+ approach we set a target of at least 60% of our forecast capital expenditure in the 2023-27 regulatory period being based on bottom-up methods. We received feedback on our draft Revenue Proposal from customers and the AER's CCP23 seeking more detail around what proportion of the capital expenditure forecasts are derived from bottom-up versus top-down techniques. Table 5.7 summarises the proportion of bottom-up and top-down forecasts for each of the major categories of capital expenditure.

Table 5.7: Proportion of bottom-up and top-down forecasts ($m real, 2021/22)

Capital expenditure category	Forecast $	Bottom-up	Top-down
Augmentation	6.7	100%	0%
Connections	2.4	100%	0%
Easements	21.1	100%	0%
Reinvestment	674.8	79%	21%
- Transmission lines	243.6	89%	11%
- Substation primary plant	145.5	73%	27%
- Substation secondary systems	219.0	65%	35%
- Telecommunications	60.2	100%	0%
- Network switching centre	6.4	80%	20%
System services	22.5	100%	0%
Security / Compliance	14.5	0%	100%
Other	14.3	0%	100%
Business IT	59.3	51%	49%
Support the Business	48.4	85%	15%
Total	**863.9**	**76%**	**24%**

While full bottom-up analysis is not currently available, nor expected to be available, for all future capital investments, detailed bottom-up analysis continues to be required and prepared to support final investment approval in our normal course of business. Much of our network capital expenditure is also subject to public consultation through the Regulatory Investment Test for Transmission (RIT-T) process.

5.5.3 Key inputs and assumptions

The key inputs and assumptions we applied to develop our forecast capital expenditure for the 2023-27 regulatory period are summarised in Table 5.8. Powerlink's Directors have certified the reasonableness of the key assumptions (refer to Appendix 1.01 Board Certification of Key Inputs and Assumptions).

We have also included a brief guide to our key inputs and assumptions for capital expenditure in Attachment 1.

Table 5.8: Inputs and assumptions for our capital expenditure forecast

Input/assumption	Sources and approach
Forecast demand and generation	• For our electricity demand forecast, we use the Central Scenario in AEMO's 2020 ESOO. • The location and capacity of existing and committed generation in Queensland is sourced from AEMO, unless modified following specific advice from relevant participants. • Information about existing and committed embedded generation and demand management within distribution networks is provided by DNSP's.
Integrated System Plan	• AEMO's 2020 ISP sets out a whole-of-system, least-cost development path for the NEM over a 20 year outlook. • Where the ISP identifies future augmentation of a part of Powerlink's transmission network in the optimal development path we will consider reinvestment in existing assets, and future easement requirements in that context.
Transmission reliability of supply standard	• Clause 6.2 of our Transmission Authority obligates us to plan and develop the transmission network such that mandated power quality and reliability of supply standards will be met. • This includes a requirement to plan and develop the transmission network to be able to supply the forecast maximum demand, with no more than 50MW or 600MWh of customer supply curtailed, even with the most critical network element out of service.
Asset information	• Our Hybrid+ forecasting methodology requires substantial information on the current fleet of assets and equipment installed on our network. We source this information from our Enterprise Resource Planning database, SAP.
Cost escalators and risk	• The main input cost components of our capital expenditure forecasts are labour costs (internal and external), various metals commodities (aluminium, copper and steel) and general plant and equipment. • The cost escalators we have applied are outlined in Chapter 7 Escalation Rates and Project Cost Estimation.
Repex Model unit rates	• An explanation of our approach to develop the unit rates for our Repex Model is included in Chapter 7 Escalation Rates and Project Cost Estimation.

The following sections detail how each key input has been integrated into our capital expenditure forecast.

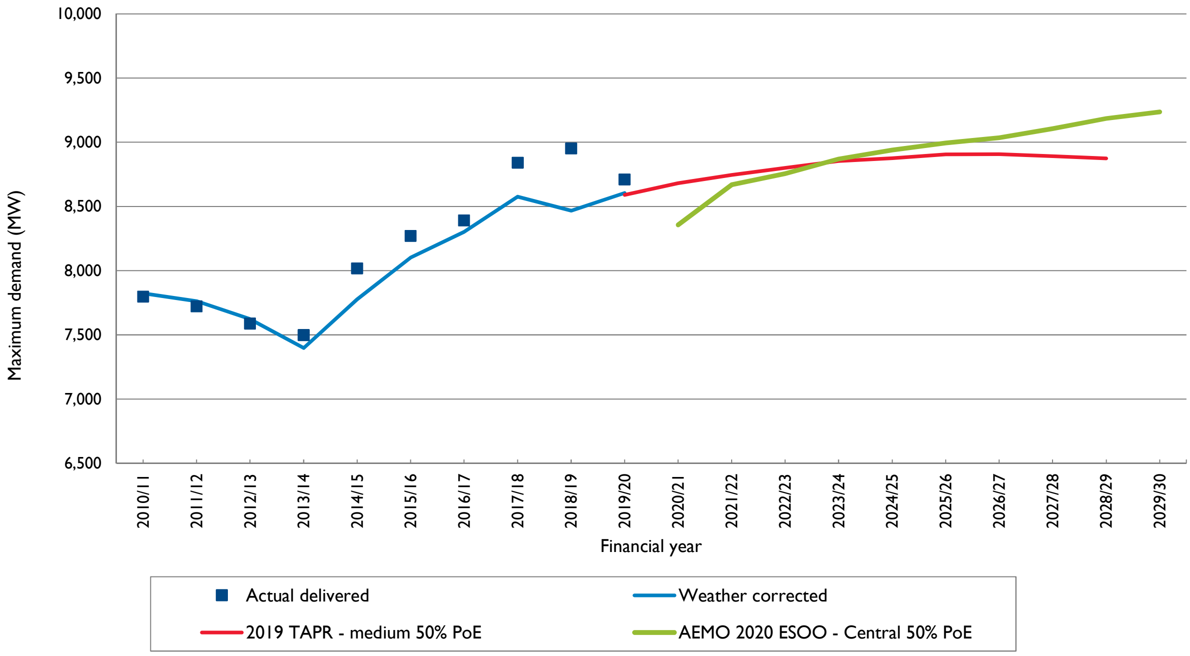
Demand and energy forecast

We have adopted AEMO's 2020 ESOO forecasts as the basis for our network planning analysis. These forecasts have been informed by a review of actual demand outcomes observed over the 2019/20 summer peak conditions. The forecasts have also included an estimate of the impact the COVID-19 pandemic could have on both peak demand and energy consumption for 2020/21. We have converted these forecasts from 'operational sent-out' to 'transmission delivered', which we consider is a better measure of the demand for transmission services as it aligns with the level of service specified in our Transmission Authority. A description of the different measures of demand and energy is provided in our TAPR[12].

As shown in Figure 5.2, the peak demand forecast under the ESOO central scenario starts below Powerlink's previous demand forecast from the 2019 TAPR. This reflects the assumed impact of COVID-19 on peak demand for the 2020/21 summer. It can be seen that the forecast quickly recovers in 2021/22 and continues to grow steadily at around 0.7% per annum over the next 10 years.

[12] 2020 Transmission Annual Planning Report, Powerlink Queensland, October 2020.

Figure 5.2: Comparison of the 2019 TAPR demand forecast with AEMO's 2020 ESOO (MW)



Notes:

(1) AEMO's 2020 ESOO forecast has been converted from 'operational sent-out' to 'transmission delivered' for the purposes of comparison.

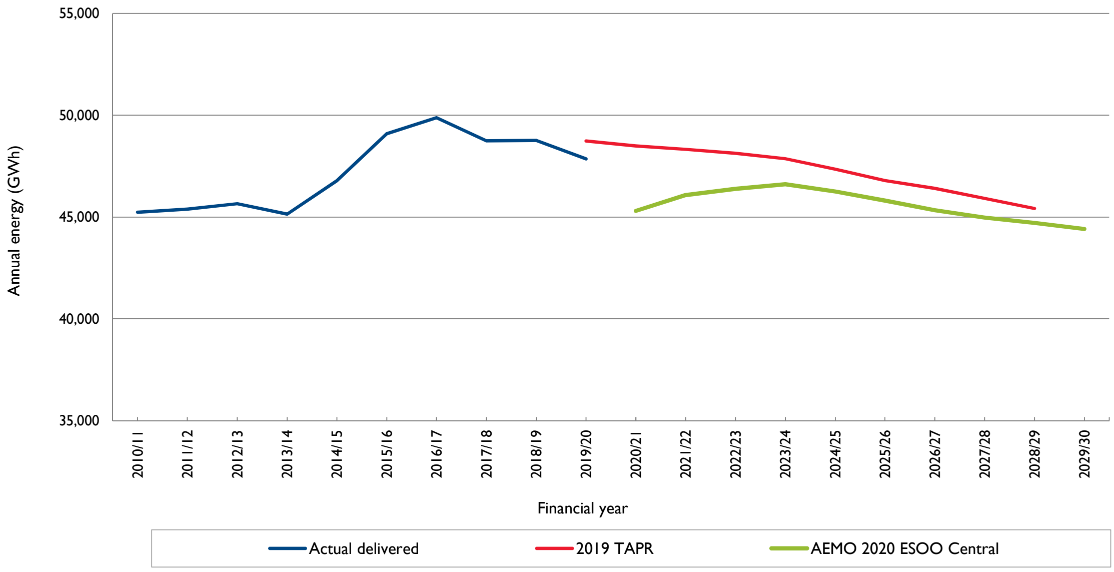
(2) AEMO's 2020 ESOO forecast has been adjusted for future uncommitted distribution connected renewables by Powerlink to incorporate the Queensland Government's target of 50% renewable energy by 2030.

Similarly, forecast annual energy consumption (refer Figure 5.3) shows a significant reduction in 2020/21 compared to the 2019 TAPR forecast, due to the assumed impact of COVID-19, before recovering over the next few years. However, in contrast to forecast peak demand, energy consumption is then expected to resume its recent declines as a result of the continued uptake of rooftop photovoltaic (PV) and other embedded energy resources. Overall energy consumption is forecast to decline at an average rate of 0.7% per annum over the next 10 years.

Noting that the 2019 ESOO and 2019 TAPR forecasts were similar to each other, there are several reasons why the demand and energy forecasts from the 2020 ESOO and 2019 TAPR are different. These mainly relate to changes and updates to the 2020 ESOO forecast from 2019, which include:

- energy efficiency measures have been recalibrated to reflect their diminishing contribution to peak demand events (i.e. saturation);
- lower retail electricity prices which tends to encourage consumption;
- higher growth in new connections; and
- electric vehicle (EV) penetration is slightly higher in the long-term.

Figure 5.3: Comparison of the 2019 TAPR energy forecast with AEMO's 2020 ESOO (GWh)



Notes:

(1) AEMO's 2020 ESOO forecast has been converted from 'operational sent-out' to 'transmission delivered' for the purposes of comparison.

(2) AEMO's 2020 ESOO forecast has been adjusted for future uncommitted distribution connected renewables by Powerlink to incorporate the Queensland Government's target of 50% renewable energy by 2030.

2020 Integrated System Plan (ISP)

The 2020 ISP was released in June 2020 and sets out an optimal development path for the NEM transmission grid over the next 20 years. This optimal development path includes several future ISP projects on the Powerlink transmission network, currently expected to be required during the 2030's. These future ISP projects and their currently forecast timing are:

- QNI Medium Upgrade – early 2030's;
- Central to Southern Queensland Augmentation – early 2030's;
- Gladstone Grid Reinforcement – 2030's; and
- Far North Queensland Renewable Energy Zone – 2030's.

The 2020 ISP does not include any projects declared as actionable for Powerlink that would trigger us to undertake a RIT-T assessment.

The capital expenditure forecasts in our Revenue Proposal are consistent with the 2020 ISP. Specific elements of the capital expenditure forecasts which support the 2020 ISP are:

- $14.3m for acquisition of new easements required for the QNI Medium upgrade; and
- $18.2m[13] for targeted life extension of existing transmission line assets to maintain the existing network capacity along those major transmission flow paths identified in the ISP as requiring future augmentation. This has been included in the ex-ante capital expenditure forecast instead of proposing contingent reinvestment projects, and is pending further refinement of the timing and scope of the required augmentations in future iterations of the ISP.

Asset planning criteria

Powerlink has been issued a Transmission Authority by the Queensland Government. The Transmission Authority requires Powerlink to plan and develop the network so that only a limited amount of customer demand and energy is at risk of not being supplied during the most critical single contingency event. These demand and energy limits are set in our Transmission Authority at 50MW and 600MWh.

13 This has reduced from an initial estimate of approximately $21.0m that we advised to the RPRG in late November 2020.

Our Transmission Authority also includes a requirement to apply good electricity industry practice which, in turn, necessitates the use of a range of supporting technical standards. In the Proserpine area, for example, we forecast voltage stability limitations to occur which will result in interruptions to supply should a critical contingency event occur at peak demand times. These voltage stability limitations are an example of a supporting technical standard and can be mitigated by interrupting some supply to customers to remain within the standard. However, the magnitude of the potential supply interruption is less than the standards set in our Transmission Authority. In this example, the application of our Asset Planning Criteria Framework has deferred investment in network augmentation and delivered cost savings to electricity customers.

The reliability of supply standard, along with the supporting technical standards, comprises our Asset Planning Criteria Framework. Our Asset Planning Criteria Framework is provided as a supporting document to our Revenue Proposal.

Asset reinvestment criteria

Powerlink's Asset Management System ensures assets are managed in a manner consistent with the Asset Management Policy and overall corporate objectives to deliver cost-effective services. We demonstrate this by adopting a proactive approach to asset management that optimises whole of life-cycle costs, benefits and risks, while ensuring compliance with applicable legislation, regulations, standards, statutory requirements, and other relevant instruments.

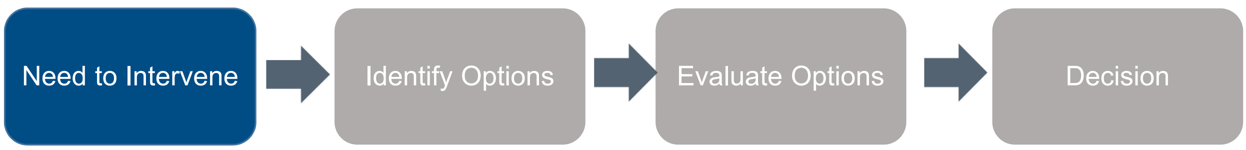
Our Asset Reinvestment Criteria Framework defines the methodology that we use to assess the need and timing for intervention on network assets to ensure that industry compliance obligations are met. The methodology aims to improve transparency and consistency within the asset reinvestment process, enabling our customers and stakeholders to better understand the criteria to determine the need and timing for asset intervention.

This framework is relevant where the asset condition changes so it no longer meets its level of service or complies with a regulatory requirement. This category of reinvestment is triggered when the existing asset has degraded over time and no longer provides the required standard of service as prescribed within applicable legislation, regulations and standards.

The trigger to intervene needs to be identified early enough to provide an appropriate lead time for the asset reinvestment planning and assessment process. The need and timing for intervention is defined when business-as-usual activities (including routine inspections, minor condition-based and corrective maintenance and operational refurbishment) no longer enable the network asset to meet prescribed standards of service due to deteriorated asset condition.

Our Asset Reinvestment Process (refer Figure 5.4) enables timely, informed and prudent investment decisions to be made that consider all economic and technically feasible options, including non-network alternatives or opportunities to remove assets where they are no longer required. An assessment of the need and timing for intervention is the first stage of this process.

Figure 5.4: Asset Reinvestment Process



Our Asset Reinvestment Criteria Framework has been developed progressively and we have engaged with our Customer Panel during the course of its development. The principles set out in this framework underpin the timing of specific reinvestment projects in our Revenue Proposal. The Asset Reinvestment Criteria Framework is provided as a supporting document to our Revenue Proposal.

5.6 Forecasts by category

5.6.1 Network load-driven expenditure

Our total forecast load-driven expenditure of $30.2m is $3.4m (13%) more than the actual/forecast expenditure in the current regulatory period.

Augmentation

As noted in Section 5.5.3 peak demand is forecast to grow modestly over the next 10 years, averaging 0.7% per annum. Based on this demand forecast we do not anticipate the need for any capital expenditure on new shared network assets to meet increases in peak demand.

Our augmentation expenditure mainly relates to our ongoing program of ground clearance rectification to remove identified encroachments to our transmission lines. This will increase our network capacity and enhance the performance of an existing asset. For this reason the expenditure is categorised as augmentation.

Connections

Based on the demand forecast we have identified the need to augment connection point transformer capacity at one bulk supply substation at Goodna Substation which supplies the Springfield area south-west of Brisbane. This area continues to experience significant residential and commercial development.

Easements

Forecast expenditure on easements is focused on the acquisition of new easements required for the QNI Medium project. While the 2020 ISP's timing for the completion of QNI Medium is around 2032 the scale of the project is such that construction would need to commence by the late 2020s. This requires that line easements be acquired during the 2023-27 regulatory period.

A key driver of this timing is to ensure we can undertake meaningful engagement with landholders who may be impacted by this major transmission line investment. We consider it is important that this work be commenced early in the 2023-27 regulatory period to enable this to occur. These activities are beyond the preparatory works identified by AEMO in its 2020 ISP, which we are required to report on by 30 June 2021.

5.6.2 Network non load-driven expenditure

Network non load-driven expenditure is the most significant contributor to our forecast capital expenditure for the 2023-27 regulatory period. Our forecast expenditure of $726.1m is $37.5m (4.9%) lower than the actual/forecast expenditure in the current regulatory period. The majority of this is in the reinvestment category.

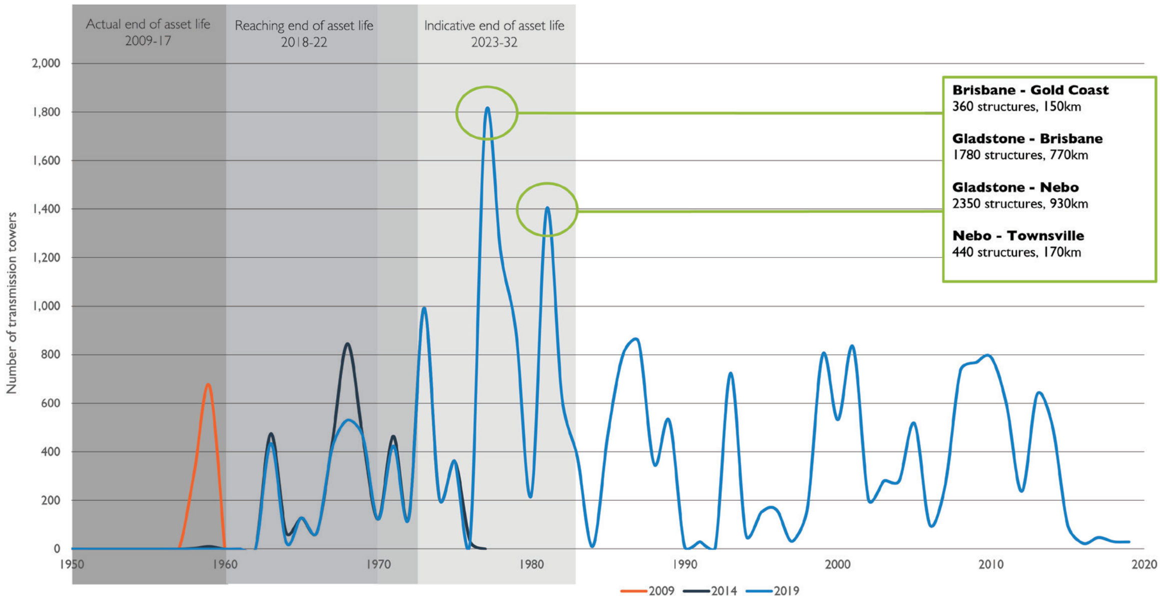
Forecast reinvestment expenditure for the 2023-27 regulatory period is slightly lower than actual/forecast reinvestment in the current regulatory period. While reinvestment expenditure is not as lumpy as augmentation expenditure, which is required to meet increases in demand, the reinvestment expenditure profile will tend to reflect the earlier, initial investment profile. That is, it is not recurrent in the same way that operating expenditure is largely recurrent. Given the transmission network in Queensland developed rapidly from the late 1960's to early 1980's we expect to see a growing trend in reinvestment expenditure needs into future regulatory periods.

A more detailed description of how the Hybrid+ forecasting methodology has been applied to these categories of capital expenditure is provided in Appendix 5.04 Non Load-Driven Network Capex Forecasting Methodology.

Transmission towers reinvestment

A main driver of our reinvestment program is our steel lattice transmission towers. This reflects the age profile of the towers. Significant investment occurred to interconnect the Queensland network from the early 1970s to 1980s, with nearly 20% of our current fleet of transmission towers constructed between 1977 and 1981. This is shown in Figure 5.5 (where the different coloured lines show the asset age profile as it was at those earlier times). A large number of these towers are now approaching their end of life.

Figure 5.5: Transmission towers age profile



As these steel lattice towers age, the level of corrosion and deterioration reaches a point where actions beyond normal maintenance will be required.

Given the number of towers approaching their end of life, we expect there will be a need to undertake an extended investment program over several regulatory periods. As the rate of corrosion and deterioration is not uniform, replacement decisions will be based on an assessment of asset condition. This is more prudent and efficient than simply basing these decisions on individual asset age.

While individual asset age is not a driver of reinvestment decisions, the trend in the age across the fleet of assets can indicate whether the level of reinvestment is likely to be higher or lower going forward. Between 2015/16 and 2018/19 the average age of our fleet of transmission towers increased by 2.7 years. Based on the level of reinvestment being proposed we expect the average age at the end of the 2023-27 regulatory period to have increased by a further five years. This reflects our approach to transmission line life extension works which targets those sections of a transmission line where local environmental conditions cause faster rates of corrosion while leaving the slower deteriorating sections for later reinvestment. In this way we aim to exhaust as much life as possible across the entire asset before committing to a full replacement.

Secondary systems and telecommunications reinvestment

Another significant driver of reinvestment expenditure is our fleet of digital secondary systems and telecommunications assets. The adoption of digital technologies in protection and control systems has brought a number of benefits to both Powerlink and electricity customers, including:

- multiple functions within a single device which reduces the total cost to provide the full range of functions required to safely and securely operate the power system;
- self-monitoring which signals when a device has failed in service and minimises the risk of mal-operation of a previously failed device that went undetected; and
- remote interrogation which allows power system faults to be rapidly analysed and diagnosed. This can pre-empt or even avoid the cost of calling out crews to attend remote substations and speed the restoration of supply to customers.

The nature of these digital technologies is such that obsolescence and lack of vendor support for discontinued devices diminishes these benefits over time. Once a like-for-like replacement is no longer available, then unplanned or reactive replacement is operationally and technically more complex due to issues such as:

- interoperability and protocol difference between other devices on site, and with remote ends (if applicable);
- development and testing of new configurations and settings;
- physical differences with the mounting and installation, including cabling and connectivity; and
- legislative requirements for professional engineering certification[14].

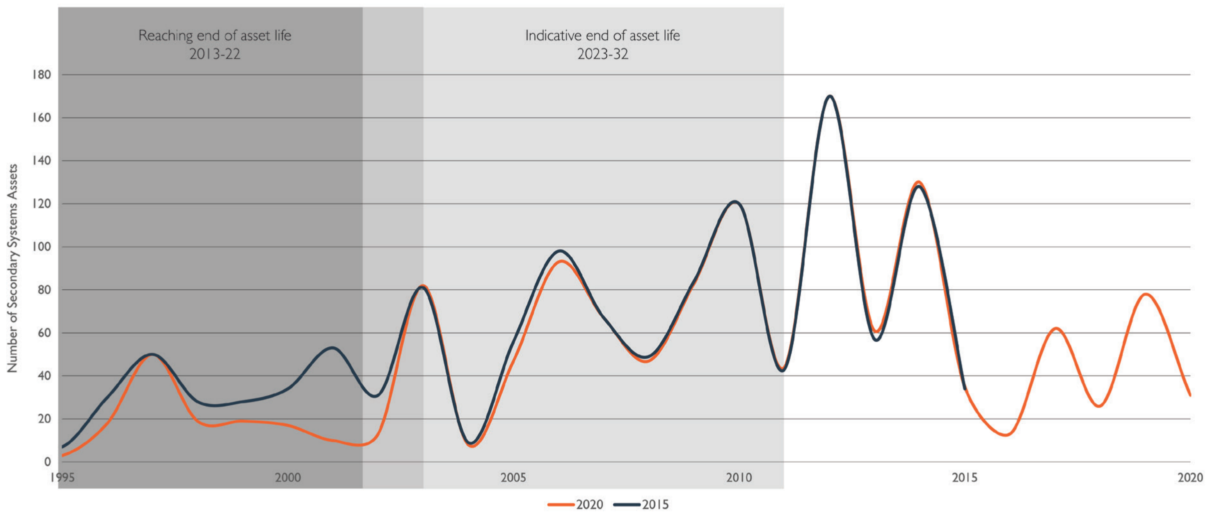
[14] *Professional Engineers Act 2002* (Queensland), s115.

The implication of this is that return to service times will extend considerably for these unsupported devices.

In addition to the impacts of obsolescence at any one site, it is also important to note the compounding impact of equipment obsolescence that may occur across the fleet of secondary systems assets installed in the network. When a particular equipment type or model is no longer supported by the manufacturer, and limited spares are available to service the fleet of assets, an attempt to run multiple secondary systems to failure across the network would increase the likelihood of concurrent systemic faults. This could overwhelm our capacity to undertake corrective maintenance or replacement projects and potentially leave us in breach of the Rules[15], the AEMO standards[16] and its jurisdictional obligations[17].

For these reasons, we consider it is important to not allow a significant volume of obsolete and unsupported devices to remain in service on the network. The typical product lifespan for our secondary systems assets is around 20 years. With significant expansion of our network during the 2000s in response to growth in customer demand there will be an increasing volume of secondary systems assets requiring reinvestment in the 2023-27 and 2028-32 regulatory periods. This is shown in Figure 5.6.

Figure 5.6: Secondary systems age profile



Meeting power system performance standards

We have also included a new System Services category in our capital expenditure forecast. This category is driven by the need to meet power system performance standards, including voltage control, inertia and system strength. Our forecast capital expenditure for this category is similar to forecast capital expenditure in the current regulatory period.

5.6.3 Non-network expenditure

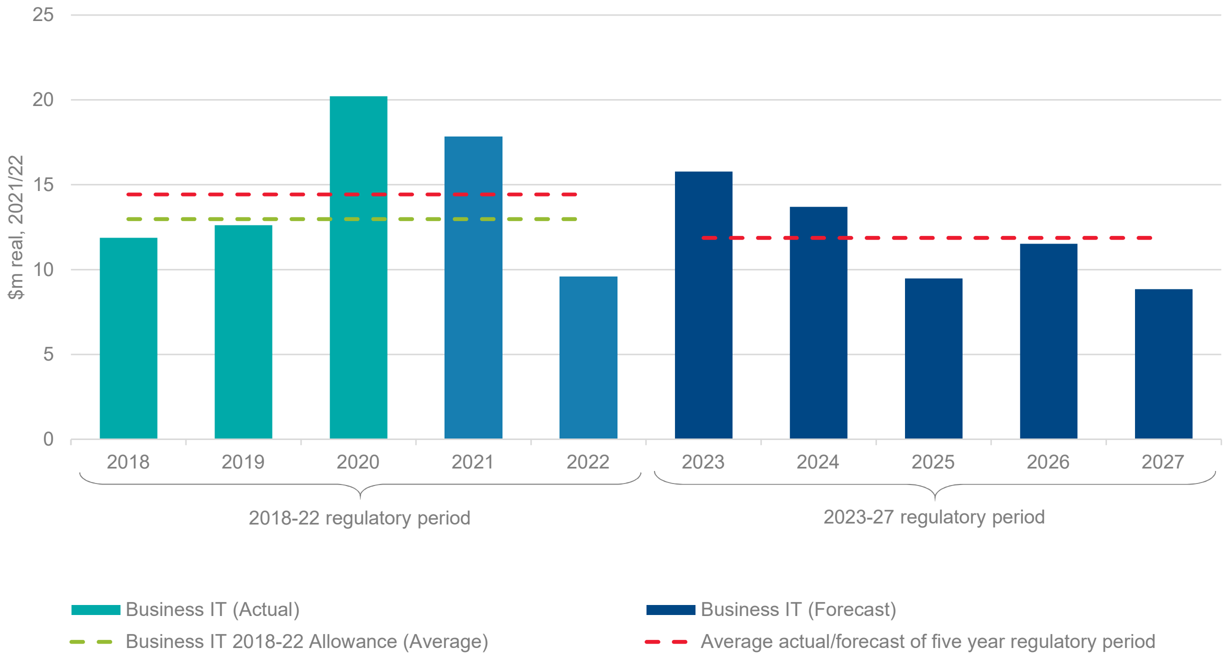
Our total forecast non-network capital expenditure of $107.7m is $6.7m (6.7%) more than the actual/forecast expenditure for the current regulatory period.

We forecast reduced expenditure in the Business IT category for the 2023-27 regulatory period compared to the current regulatory period. Approximately $7.0m of capital expenditure for renewal of our Enterprise Resource Planning (ERP) and Geographical Information System (GIS) platforms has been brought forward to provide more efficient integration with other initiatives within the current regulatory period. This has reduced the forecast capital expenditure for Business IT in the 2023-27 regulatory period. We have included a copy of our IT Plan, which explains our IT approach, in Appendix 5.05 IT Plan 2023-27.

Our forecast capital expenditure for Business IT for the 2023-27 regulatory period, along with our actual/forecast expenditure for current regulatory period is shown in Figure 5.7.

15 National Electricity Rules, schedule 5.1, clause S5.1.2.1(d), clause S5.1.9(c).
16 Power System Operating Procedure (SO_OP_3715), AEMO and Power System Security Guidelines, AEMO.
17 *Electricity Act 1994* (Queensland), s34(1)(a) and Powerlink's Transmission Authority T01/98.

Figure 5.7: Business IT capital expenditure ($m real, 2021/22)



The vast majority (> 95%) of our forecast capital expenditure for Business IT is either recurrent expenditure, being periodic replacement or cyclical upgrade with less than a five year cycle, or non-recurrent expenditure to maintain the capability of our systems, being periodic renewal with longer than a five year cycle. A summary of our forecast capital expenditure for Business IT is shown in Table 5.9.

Table 5.9: Business IT capital expenditure by investment driver ($m real, 2021/22)

Driver	Forecast capital expenditure	Brief definition
Non-recurrent		
Compliance and Risk	2.7	Expenditure to comply with new or changed regulatory obligations or to meet new or emerging risks, such as increasing cyber security threats.
Maintain capability	27.5	Periodic expenditure longer than a five year cycle such as upgrade or renewal of major corporate systems.
New capability	-	Expenditure to acquire new or expanded capability such as automating an existing manual task, where this is the primary justification for the expenditure.
Recurrent	29.2	Periodic expenditure less than a five year cycle such as end-user device replacement or upgrades to Windows and Office.
Total	**59.3**	

The IT Plan forecasts investment of $27.5m, around 46% of the total Business IT capital expenditure, on the replacement and renewal of legacy systems to maintain capability. This investment will contribute to improving our operating expenditure productivity in the following ways:

- support improvements in process efficiency when we replace legacy systems with contemporary ones that provide for more seamless data integration and management of process flows; and
- the total cost of IT system ownership will reduce through consolidation of applications, databases, platforms etc. and the use of standardised systems with fewer customisations.

Within the overall non-network capital expenditure forecast, our reduced IT spend is offset by the deferral of our proposed office refit project, which was included in our forecast for the current regulatory period[18]. We now plan to undertake these works during the 2023-27 regulatory period. Our analysis shows that a major refit of our office facilities will provide for more efficient use of the available space. This will allow us to consolidate staff accommodation and sell the premises that are no longer required, which would result in ongoing cost savings for customers. This may need to be further optimised as we incorporate the learnings from the COVID-19 pandemic into efficient work practices and office arrangements.

Our approach to forecasting non-network capital expenditure is provided in Appendix 5.06 Guide to Non-Network Capital Expenditure.

5.7 Contingent projects

Contingent projects are investments that may be required during the regulatory period should certain trigger events occur. As the need for investment during the regulatory period is not certain, or the costs associated with addressing the need for investment are not sufficiently certain, contingent projects do not form part of the ex-ante capital expenditure allowance[19]. If a contingent project trigger event occurs during the regulatory period, we can apply to the AER to amend the Revenue Determination to include the revenue required to undertake the contingent project. Before it amends the Revenue Determination the AER will assess the prudency and efficiency of the proposed additional expenditure[20].

Generally, contingent projects are significant network augmentation projects[21] that are reasonably required to achieve the capital expenditure objectives set out in the Rules. Such projects are often linked to unique investment drivers, such as commitment of new large loads or retirement of generation, rather than general investment drivers such as expectations of load growth in a region.

We have considered potential contingent projects under the following three categories of drivers.

Local demand increase and/or generation reduction

Our TAPR identifies potential load developments and generation retirements that could trigger significant expenditure to augment the network to continue to meet our mandated reliability of supply standard. For these projects we propose contingent project triggers that identify the level of additional demand or reduction in generating capacity that will lead to failure to meet our mandated reliability of supply standards.

Integrated System Plan

AEMO's 2020 ISP identifies significant network augmentations that could deliver net market benefits and are part of the optimal development path across the NEM. While the expected timing for these projects is currently beyond the 2023-27 regulatory period the ISP is reviewed and updated on a two-yearly cycle. Given the rapid changes occurring in the electricity sector with the retirement of ageing coal-fired generation and rapid uptake of IBR it is possible that one or more of these projects could be required during the 2023-27 regulatory period.

The Rules provide that where an ISP identified project is declared actionable it is automatically treated as a contingent project, even if it was not identified as such in the relevant TNSPs' Revenue Proposal[22]. To avoid the potential for conflicting trigger conditions between our proposed contingent projects and actionable ISP projects, we have not proposed any contingent projects that are already within the ambit of the 2020 ISP. This is a change from our draft Revenue Proposal where we considered it appropriate to include these ISP projects as contingent projects. This change is in direct response to feedback received on our draft Revenue Proposal from AER staff.

While we have not proposed any existing ISP identified projects as contingent projects we have included information regarding our current estimates of the costs of the ISP projects, based on our understanding of the scope of works at this time. This is to aid transparency around the process and ensure customers are fully informed. Future ISP projects and their indicative timing and estimated costs are summarised in Table 5.10.

[18] We intend to return the revenue attributable to the capital expenditure allowance for this project to customers in 2021/22
[19] National Electricity Rules, clause 6A.8.1.
[20] National Electricity Rules, clause 6A.8.2(a)-(f).
[21] For us, this will be approximately $34.5m in the 2023-27 regulatory period.
[22] National Electricity Rules, clause 6A.8.2(a)(2).

Table 5.10: Future ISP projects ($m real, 2021/22)

Project name	2020 ISP indicative timing	Indicative capital cost
QNI Medium Upgrade	2032/33	582 (Queensland component only)
Far North Queensland Renewable Energy Zone	2030's	261
Gladstone Grid Reinforcement	2030's	298
Central to Southern Queensland Reinforcement	Early-2030's	353

Contingent reinvestment

In our draft Revenue Proposal we proposed to apply the contingent projects framework to network reinvestment projects where the timing of the condition-based reinvestment trigger remains uncertain, or where the expected solution to the condition trigger is not sufficiently certain.

Our proposal for contingent reinvestment projects related to those transmission line assets on major transmission flow paths aligned with ISP identified needs. The ISP has identified the potential future need for significant additional capacity along those major transmission flow paths and the optimal asset reinvestment strategy can depend on the timing and scale of those ISP identified needs. However, the scale and timing of those future needs is highly dependent on the rate of development and location of new renewable energy sources, and the timing of the retirement of existing thermal generators. While the eventual need for this capacity may be highly likely, the optimal timing can be expected to shift between successive iterations of the ISP, as updated information becomes available.

The objective of our contingent reinvestment proposal has been to ensure customers do not pay for the forecast cost of reinvestment projects within the capital expenditure and revenue allowances set by the AER upfront, where the quantum and timing of those costs is still uncertain. It also protects Powerlink against the need to undertake major reinvestment expenditure that also provides additional network capacity to meet needs identified in the ISP. This could occur where the condition-based trigger to reinvest arises before an ISP project becomes actionable, noting that it is only when an ISP project becomes actionable that it is deemed under the Rules to become a contingent project.

We undertook regular engagement with stakeholders on our contingent reinvestment proposal in advance of our draft Revenue Proposal, including with our Revenue Proposal Reference Group (RPRG), the AER, and the AER's CCP23. While the RPRG and the AER's CCP23 were supportive of the concept as a way to balance risks between consumers and Powerlink, their feedback on our draft Revenue Proposal was to not support using the existing contingent project framework for this purpose. Through our engagement the AER raised the following concerns with our proposal:

- it reduces the incentive properties of the ex-ante revenue determination framework;
- an asset condition trigger cannot be objectively verified, as required by the Rules; and
- an asset condition trigger is not an exogenous event, beyond the ability of a TNSP to influence.

Based on this feedback and in the interests of lodging a Revenue Proposal that is capable of acceptance by the AER, we are no longer proposing contingent reinvestment projects in our Revenue Proposal. Notwithstanding this decision, we consider there is still a need for the regulatory framework to accommodate some form of contingent reinvestment trigger and we may look to pursue this further outside of our Revenue Proposal.

5.7.1 Proposed contingent projects

Our proposed contingent projects and their indicative costs are summarised in Table 5.11. Appendix 5.07 Contingent Projects provides further detail on our single proposed contingent project and its triggers. Should any of these triggers occur, we will undertake the required regulatory processes, including engagement with the AER.

Table 5.11: Contingent projects ($m real, 2021/22)

Project name	Type of trigger	Indicative capital cost
Central to North Queensland Reinforcement	Additional customer demand[(1)]	52.3
Total indicative cost		**52.3**

(1) This could include additional customer demand from Mount Isa should the Copperstring project proceed.

Central to North Queensland Reinforcement

The Central West and North Queensland zones are areas where significant increases in the demand and energy are plausible during the 2023-27 regulatory period. The most significant sources for this increased load include, but may not be limited to:

- development of the Copperstring transmission project to connect Mt Isa and the North West Minerals province to the NEM; and
- development of large-scale coal mines in the Galilee Basin and associated rail and port infrastructure.

Power transfer capability into northern Queensland is limited by thermal ratings or voltage stability limitations, depending on prevailing weather conditions and scheduled generation. Thermal limitations may occur on the Bouldercombe to Broadsound 275kV line following a critical contingency of a Stanwell to Broadsound 275kV circuit. Voltage stability limitations may occur following the trip of the Townsville gas turbine or following a contingency of a Stanwell to Broadsound 275kV circuit.

As demand increases in northern Queensland transmission congestion may occur, requiring northern Queensland generators to be constrained on. As generation costs are higher in northern Queensland due to reliance on liquid fuels, it may be economic to advance the timing of augmentation to deliver positive net market benefits. The additional load in northern Queensland that would justify the network augmentation in preference to continued network support cost is between 250MW and 380MW. The lower bound assumes the out-of-merit-order generation is predominantly liquid fuelled at approximately $450/MWh, while the upper bound assumes up to 240MW of gas-fired generation is available at approximately $60/MWh.

This proposed contingent project comprises the stringing of the second circuit of an existing double circuit line between Stanwell and Broadsound that currently has only one side strung. The proposed contingent project is estimated to cost $52.3m.

We consider that the project should be accepted as a contingent project for the 2023-27 regulatory period due to the uncertainty about the trigger event occurring and the scope and cost of the project required to maintain reliability of supply.

5.8 Network support

We use network support as an alternative to network investment when it is economic to do so. We have well established processes for engaging with parties who are interested in the provision of non-network services. This includes our Non-Network Engagement Stakeholder Register where non-network solution providers can register to receive the details of potential non-network solution opportunities[23]. We have also published a Network Support Contracting Framework as a general guide to assist potential non-network solution providers understand the key contracting principles that underpin our network support agreements[24].

For any given network limitation, the viability and specification of non-network solutions are first introduced in the TAPR. Further opportunities are then explored during the consultation and stakeholder engagement undertaken as part of any subsequent RIT-T.

These established processes have been enhanced with the introduction of inertia services and system strength services to accommodate increasing levels of IBR and the reduced level of synchronous generation.

In its 2020 System Strength and Inertia Report, AEMO concluded that fault level and inertia shortfalls are not yet considered likely for Queensland in the next five years, but shortfall risks are increasing[25]. Changes to the operating patterns of large synchronous generators could result in either or both types of shortfall declared during the 2023-27 regulatory period. If any fault level or inertia shortfalls occur we will consider the use of network support arrangements as alternatives to investment in new network assets.

We have also identified the potential for future network support arrangements with generators and large loads to form part of an upgraded scheme to extend the power transfer limits between Central Queensland and Southern Queensland[26]. These costs, if they are able to provide a net market benefit, form an efficient use of operating expenditure in place of capital expenditure – a capex/opex trade-off.

[23] Non-Network Solutions, Powerlink, https://www.powerlink.com.au/non-network-solutions.
[24] *Ibid.*
[25] 2020 System Strength and Inertia Report, Australian Energy Market Operators, December 2020, page 24.
[26] National Electricity Rules, schedule 6A.1, clause S6A.1.1(8)

5.9 Deliverability of future expenditure

We have a proven ability to deliver capital projects to meet the needs of Queensland customers for a safe, secure, reliable and cost-effective supply of electricity. Our forecast capital expenditure for the 2023-27 regulatory period is approximately 3% lower than the actual/forecast expenditure for the current regulatory period. To ensure we have the capability to deliver this level of work, we will continue to use the proven business processes identified in our 2018-22 Revenue Proposal and take the following steps to enhance these:

- ***Portfolio risk management***: We have continued the development of our portfolio risk management approach with the deployment of a Portfolio Risk System (PRS). The PRS performs asset data analytics to support more structured asset reinvestment planning across various asset classes. This supports the optimisation in planning our portfolio of projects to manage overall risk across the network.
- ***Delivery Optimisation Framework***: We recognise that delivery of a significant program of capital expenditure projects to mitigate network asset risks is subject to multiple constraints. The Delivery Optimisation Framework (DOF) provides a structured mechanism to coordinate the delivery of our portfolio of projects throughout their delivery lifecycle. It allows for the early identification and resolution of resource constraints or conflicts to maximise the deliverability across the whole portfolio.
- ***Substation and line refit panel arrangements:*** During the current regulatory period we have worked collaboratively with our contractors to better structure work packages to accommodate the many site-specific constraints that exist with brownfield reinvestment works. While this can require additional effort in the early stages of project delivery it can significantly reduce the risks of delays and rework during the site delivery and commissioning phases.
- ***Relocatable switching bay:*** We have recently procured a mobile high voltage switching bay that will facilitate project delivery in circumstances where network outages are difficult to secure. It provides a temporary bypass to allow for equipment replacement within a switching bay without the need for an extended outage of the element connected to that switching bay.

5.10 Summary

We have developed our forecast capital expenditure for the 2023-27 regulatory period consistent with the requirements of the Rules and our Expenditure Forecasting Methodology (refer to Appendix 5.03 Expenditure Forecasting Methodology). Our Hybrid+ approach integrates top-down and bottom-up approaches, with project-specific justification provided for over 70% of our forecast capital expenditure.

Our total forecast capital expenditure for the 2023-27 regulatory period is $863.9m, which is $27.4m (3.1%) lower than the actual/forecast expenditure for the current regulatory period. The majority of this forecast ($726.1m or 84%) is non load-driven network expenditure. We have proposed one contingent project that is not in our ex-ante capital expenditure forecast.