2023-27 POWERLINK QUEENSLAND REVENUE PROPOSAL

Appendix 5.01 – PUBLIC

Operating and Capital Expenditure Criteria and Factors

1. Purpose

This document details the alignment of Powerlink's operating and capital expenditure forecasts for the 2023-27 regulatory period with the expenditure criteria and factors set out in the National Electricity Rules (the Rules).

Our expenditure forecasting methodologies are designed to satisfy the requirements of these criteria and factors for both operating and capital expenditure. We consider that the overall forecasts will allow us to maintain and operate the network safely and securely, meet the expected demand for prescribed transmission services and comply with all applicable regulatory obligations and requirements.

2. Operating Expenditure

2.1 Operating Expenditure Criteria

Our forecast of operating expenditure for the 2023-27 regulatory period reasonably reflects the operating expenditure criteria set out in clause 6A.6.6(c) of the Rules. As a result, we consider that it satisfies the Australian Energy Regulator's (AER's) requirements for acceptance.

Our compliance with each of the operating expenditure criteria is outlined in the following sections.

1. The efficient costs of achieving the operating expenditure objectives

Our operating expenditure forecast for the 2023-27 regulatory period has a strong focus on customer affordability. We have consulted extensively with customers and stakeholders to respond to concerns on affordability and develop an operating expenditure forecast which is prudent, efficient and capable of acceptance. Our target of no real growth in operating expenditure represents a stretch target for our business and is a floor below which we do not consider it would be prudent or efficient for us to operate in the circumstances. To achieve this target and, in combination with no proposed step changes in operating expenditure, we will aim to deliver productivity improvements at a level above the benchmark industry average. This will ensure that we continue to operate in a manner that is prudent and efficient.

As described in Chapter 6 Forecast Operating Expenditure, we have forecast operating expenditure using the AER's base-step-trend methodology. The base year used in our base-step-trend model is 2018/19. This base year is reflective of a typical year of operations, and was not subject to cost category inconsistencies and one-off cost movements observed in 2019/20 and 2020/21 due to the impacts of COVID-19.

We engaged HoustonKemp to perform an independent review of the efficiency of our base year expenditure. HoustonKemp (report included in Appendix 4.01) found that revealed expenditure was not materially inefficient, that we have been responding to the incentives in the regulatory framework and that we are operating relatively efficiently when compared to our peers.

We will drive the business hard to achieve an operating expenditure productivity factor of 0.5% per annum to offset growth in operating expenditure due to real price increases and growth in output. This productivity factor is higher than the benchmark industry average of 0.3% per annum. Real price growth associated with labour and materials has been the subject of independent expert opinion to ensure an efficient and realistic forecast of real price growth. Output growth forecasts are based on the Australian Energy Market Operator's (AEMO's) 2020 Electricity Statement of Opportunities (ESOO) and 2020 Integrated System Plan (ISP). Both of these sources account for the impact of COVID-19 on electricity demand.

We will not pursue any operating expenditure step changes for the 2023-27 regulatory period. This followed detailed investigation of potentially material changes in our regulatory obligations, as well as potential cost increases in insurances, cyber security and new outage management complexities to maintain system strength as new Inverter-Based Resources (IBR) are commissioned. These potential cost increases have an estimated value of $26.1m over the 2023-27 regulatory period, which we will seek to absorb. We will rely on cost pass through arrangements in the event of any material cost increases within period.

We consider that our proposal is prudent and efficient, and reflects the efficient costs of achieving the operating expenditure objectives while also addressing customer concerns regarding the current climate of economic and technical disruption.

2. The costs that a prudent operator would require to achieve the operating expenditure objectives

Our operating expenditure forecasts include provision for undertaking the activities of a prudent transmission network business. Beyond the efficient delivery and provision of prescribed transmission services, we act to ensure we are recognised as a prudent operator of our transmission network. This includes activities that support the primary delivery of transmission services such as:

- **Meaningful engagement with customers and stakeholders, with a particular focus on communities who host our transmission infrastructure.** We have a dedicated Customer Panel that represents a broad variety of customers and views. We also have a dedicated landholder relations team, who regularly engages with landholders as part of day-to-day operations, and a Business Development team who provides support to directly-connected customers.
- **Ensuring the physical and cyber security of the transmission network and its protection and control systems.** Over the next regulatory period, an increase in operating expenditure may be required to maintain our cyber maturity. In December 2020, the Federal Government introduced the *Security Legislation Amendment (Critical Infrastructure) Bill 2020* to Parliament. If passed, this legislation would establish a new security and resilience regulatory regime on operators of critical infrastructure and we anticipate there would be elevated security obligations and standards on critical infrastructure owners and operators such as Powerlink. We discuss these potential new operating expenditure costs and obligations in Section 6.6.3 Step changes of our Revenue Proposal.
- **Careful planning of network outages to minimise impacts to the wholesale energy market and our customers.** Outage management is becoming increasingly complex due to commissioning of new IBR across our network and the large number of diverse customers connected to our network. We continue to co-ordinate outages across this growing number of network users to ensure market impacts are minimised.
- **Pursuing business improvement initiatives to improve the overall efficiency of our products, people, and processes.** We seek to improve our overall efficiency as part of our business as usual operations. This will be a particular focus for the 2023-27 regulatory period in order to reach our productivity factor target of 0.5% per annum and absorb other potential step changes to achieve our no real growth outcome. We discuss our productivity and potential initiatives further in Section 6.6.2 Rate of change of our Revenue Proposal.

3. *A realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives*

For the development of operating expenditure forecasts, we have used the demand and energy forecasts in AEMO's most recent ESOO published in August 2020 as well as its 2020 ISP. Both the ESOO and the ISP take into account the estimated impact of COVID-19 on short-term demand growth and peak demand forecasts.

Details on the inputs we have used to determine the rate of change elements of the base-step-trend model are included in Section 6.6.2 Rate of change of our Revenue Proposal. Further details on the calculation of input costs including labour and materials price growth, is contained in Chapter 7 Escalation Rates and Project Cost Estimation of our Revenue Proposal.

2.2 Assessment against operating expenditure factors

In deciding whether or not the AER is satisfied that our operating expenditure forecast reasonably reflects the operating expenditure criteria, the AER also has regard to the operating expenditure factors set out in clause 6A.6.6(e) of the Rules. The operating expenditure factors are detailed in the following sections:

1. *AER benchmarking report*

The most recent annual benchmarking report for electricity Transmission Network Service Providers (TNSPs) was published by the AER in November 2020.The report presents information on a range of benchmarks, namely:

- Multilateral Total Factor Productivity (MTFP);
- Multilateral Partial Factor Productivity (MPFP); and
- Partial Performance Indicators (PPIs).

We have had regard to the AER's benchmarking report in the preparation of our forecast capital and operating expenditure for the 2023-27 regulatory period.

We engaged HoustonKemp to provide an independent review of our performance based on the information in the AER's benchmarking report and to advise on the efficiency of our proposed base year (2018/19) to forecast operating expenditure in the 2023 27 regulatory period.

We discuss how we have had regard to benchmarking in Section 4.6 Benchmarking performance of our Revenue Proposal and have provided HoustonKemp's report in Appendix 4.01 Efficiency of Powerlink's Base Year Operating Expenditure.

2. *Expenditure during preceding regulatory periods*

An overview of our operating expenditure performance in the 2018-22 regulatory period is provided in Chapter 4 Historical Capital and Operating Expenditure.

Total operating expenditure in the 2018-22 regulatory period is forecast to be $1,035.6m (real 2021/22) excluding debt raising, which represents a 7% decrease in operating expenditure compared to the 2013-17 regulatory period.

Significant measures were taken in the 2018-22 regulatory period to reduce operating expenditure, including a reduction in layers within the organisational structure and adjustment of resource levels within the business in response to more prudent levels.

Our total forecast expenditure of $1,035.6m is $9.5m (0.9%) higher than the AER's total allowance for the 2018-22 regulatory period. This is driven mainly by non-controllable increases to the AEMC Levy, which has exceeded the AER's allowance for the 2018-22 regulatory period in nominal terms by $5.6m (25.8%) to date.

Several emerging drivers of expenditure have been identified in the current regulatory period, including outage management complexities associated with the growth in IBR, and an increased focus on cyber security. These have had a limited impact on expenditure within the current regulatory period, but may drive increases in operating expenditure during the 2023-27 regulatory period. Increased decommissioning activities are also emerging as potential cost drivers as our network assets age.

We provide an analysis of our operating expenditure spend by category in Section 6.6.1 Efficient base year of our Revenue Proposal and discuss our historical and forecast operating expenditure drivers in Chapter 4 Historical Capital and Operating Expenditure and Chapter 6 Forecast Operating Expenditure.

3. Feedback from consumers

Customer engagement has been critical to the development of forecast operating expenditure for the 2023-27 regulatory period. Details of our approach to engaging with customers are described in Chapter 3 Customer Engagement and Chapter 6 Forecast Operating Expenditure.

In the development of our Revenue Proposal, we undertook engagement activities with customers and stakeholders including our Customer Panel and a sub-set of our Customer Panel called the Revenue Proposal Reference Group (RPRG).

Customer feedback directly influenced several key aspects of our operating expenditure forecast:

- **No real growth target:** customer concerns about affordability were central to our decision to target no real growth in underlying operating expenditure. Customers welcomed our commitment to this approach. This is discussed further in Section 6.4.1 No real growth target of our Revenue Proposal.
- **Productivity:** customers encouraged Powerlink to drive a higher productivity factor than the industry average. We have proposed a productivity factor of 0.5% per annum, which is higher than the benchmark industry average of 0.3%[1]. Our productivity factor is a key component of our no real growth target. Customers were also interested in understanding how we would meet a higher productivity target. We have provided details about this in Section 6.6.2 Rate of change of our Revenue Proposal.
- **Step changes:** customers sought further information on the process of identifying and pursuing step changes, with a particular focus on cyber security requirements for the 2023-27 regulatory period. From an original list of 27 potential step changes, six were progressed for consideration by the RPRG, and we ultimately decided to not propose any step changes, including for cyber security. This was another key component to our no real growth target. We discuss step changes further in Section 6.6.3 Step changes of our Revenue Proposal.
- **Insurance:** customers recognise and are concerned by increases in insurance premiums across the energy sector. To provide our customers and other stakeholders with the opportunity to hear from and speak directly to experts in the global insurance field, we arranged for our insurance broker, Marsh, to discuss the insurance market with our RPRG. We also held a deep dive workshop in November 2020 which was open to broader customers and stakeholders to discuss the trade-offs between cost and risk and to help inform our considerations and decision making on insurance cover over the 2023-27 regulatory period and beyond. We discuss insurance in Section 6.7.1 of our Revenue Proposal.

[1] Economic Benchmarking Results for the Australian Energy Regulator's 2020 TNSP Annual Benchmarking Report, Economic Insights, October 2020, page 62.

4. Relative prices of capital and operating inputs and substitution possibilities between capital and operating expenditure

We consider the interaction of capital and operating expenditure and practices as part of our Revenue Proposal development, and asset management practices in the normal course of business. This includes consideration of the opportunities for substitution between capital and operating expenditure to deliver prudent and efficient outcomes.

We have proposed no material capital and operating expenditure substitutions in our 2023-27 Revenue Proposal. However, several operating environment factors and non-network initiatives may have a minor impact on our capital and operating expenditure over the 2023-27 regulatory period.

A significant contributor to forecast network non-load driven capital expenditure in the 2023-27 regulatory period is our ageing population of steel lattice transmission towers and is discussed in Chapter 5 Forecast Capital Expenditure. As these steel lattice towers age, the level of corrosion and deterioration reaches a point where actions beyond normal maintenance will be required, which trigger the need for reinvestment works. Reinvestment can involve retiring the asset without replacement if it is no longer required to maintain the prescribed levels of transmission services, life extension of the existing asset, like-for-like replacement of the asset, or replacement with a different asset. If reinvestment is delayed, this may result in increased operating expenditure to manage deterioration of asset condition.

Our secondary systems assets, which provide the protection and control function for network elements such as transmission lines, are another significant element of our forecast capital expenditure. The unit of plant for these assets is defined as being at the switching bay level, which means that replacement of an individual device which might fail in service is operating expenditure. These assets are now almost universally comprised of digital technologies such that the driver for reinvestment is based on the obsolescence and unsupportability of devices, rather than the condition of asset infrastructure such as wiring. Reinvestment in those assets that have an enduring need is directed to replacing all of the obsolete and unsupported digital technologies so that the life of entire asset is efficiently extended to match the life of other physical components such as buildings and wiring. If reinvestment is delayed then in-service failures of individual devices within the asset may result in an inefficient increase in operating expenditure as failed devices get replaced in an ad-hoc manner.

We also consider substitution possibilities between capital and operating expenditure in our use of network support as an alternative to network investment. We continue to investigate opportunities to extend the capability of transmission network assets through non-network solutions such as network support. Contracts with generators and large loads may mitigate the power system impact from contingency events and improve power system security, and allow us to deliver additional market benefits without network augmentation.

We have outlined several additional non-network initiatives within Chapter 6 Forecast Operating Expenditure, which may have a minor impact on the interaction of capital and operating expenditure over the 2023-27 regulatory period. These initiatives, including our proposed office refit and business IT upgrades, represent capital projects which may contribute to operating expenditure efficiencies.

With regards to the relative prices of inputs to operating and capital expenditures we have adopted the same cost escalation factors to both our operating and capital expenditure forecasts.

5. Consistency with incentive schemes or other schemes

The Efficiency Benefit Sharing Scheme (EBSS), Service Target Performance Incentive Scheme (STPIS) and Demand Management Innovation Allowance Mechanism (DMIAM) are relevant to our operating expenditure forecasts.

Efficiency Benefits Sharing Scheme (EBSS)

Our operating expenditure forecast is consistent with the Version 2 of the EBSS that will apply to Powerlink in the 2023-27 regulatory period (as noted in the final Framework and Approach Paper for Powerlink[2]). The EBSS offers a continuous incentive for improvements in operating expenditure efficiency. Our EBSS approach is explained in detail in Section 14.3 Efficiency Benefit Sharing Scheme of our Revenue Proposal.

Service Target Performance Incentive Scheme (STPIS)

Our forecast operating expenditure does not include any expenditure specifically to improve network performance under the STPIS. Any improvement in STPIS outcomes as a result of undertaking maintenance or other operating expenditure activities is ancillary to the primary purpose of the expenditure. We have removed operating expenditure costs associated with a Network Capability Incentive Parameter Action Plan (NCIPAP) in our base year. This is discussed further in Chapter 6 Forecast Operating Expenditure.

Demand Management Innovation Allowance Mechanism (DMIAM)

On 5 December 2019, the Australian Energy Market Commission (AEMC) published its Final Determination for a rule change to apply the DMIAM to TNSPs. The AER must develop and publish the first transmission DMIAM by 31 March 2021, though this has been delayed to June 2021, with a Draft Decision released in December 2020. Based on the criteria discussed in the Draft Decision on DMIAM we consider that our forecast operating expenditure does not include any expenditure that should be included as part of the DMIAM.

6. Expenditure reflects arm's length terms

Any part of our forecast operating expenditure that is referable to arrangements with other parties reflects arm's length terms.

7. Contingent projects

Our forecast operating expenditure does not include any expenditure relating to our proposed contingent project. The rate of change parameter in our base-trend-step model does not include any growth attributable to contingent projects.

8. Most recent Integrated System Plan

We have had regard to the 2020 ISP in the development of our Revenue Proposal. While the 2020 ISP does not present any factors that have directly impacted our operating expenditure forecast, we have considered the potential implications of preparatory works related to ISP projects should those projects not proceed.

AEMO's 2020 ISP included no actionable projects for the Queensland transmission network but did identify the requirement for Powerlink to undertake preparatory works for the following future ISP projects:

- QNI Medium and Large;
- Central to Southern Queensland Transmission Link; and
- Gladstone Grid Reinforcement.

These preparatory works, which include desktop corridor identification and early project cost estimation, are required to be completed by 30 June 2021. Any operating expenditure

[2] Final Framework and Approach for Powerlink, Australian Energy Regulator, July 2020.

associated with these works will occur during the current regulatory period. We have not included any specific amounts in our operating expenditure forecast for these activities.

9. Non-network options

Our approach to considering non-network alternatives such as network support is outlined in Section 6.7.3 Network support of our Revenue Proposal. We anticipate that there may be a need to contract with generators and large load operators to provide a contingency tripping service as part of an upgraded scheme to extend Central and Southern Queensland (CQ-SQ) transfer limits.

At this stage, we have no committed non-network alternatives beyond the current regulatory period. For the 2023-27 regulatory period we have proposed $0 allowance per annum for network support costs as part of our total forecast operating expenditure. To the extent that a network support event occurs during the 2023-27 regulatory period, we will make a cost pass through application under clause 6A.7.2 of the Rules.

10. Regulatory Investment Test for Transmission (RIT-T)

Since September 2017 TNSPs have been required to apply the RIT-T to the replacement of transmission network assets with project value over $6m, in addition to projects to augment the network[3]. In that time we have published 23 Project Assessment Conclusion Reports (PACRs) related to network reinvestment projects. We have also published, jointly with TransGrid, one PACR for expanding the capacity of the Queensland/New South Wales Interconnector (QNI) – the QNI Minor project.

None of these 23 PACRs have resulted in any material increase in the scale of the transmission network that would trigger any increase in our operating expenditure forecast. One of the PACRs recommended the removal of approximately 70km of 132kV transmission line in North Queensland. The reduction in the scale of the transmission network attributable to this recommendation has been factored into the growth rate in our operating expenditure forecast.

11. Other factors

At the time of submission of our Revenue Proposal in January 2021, the AER had not advised Powerlink of any additional operating expenditure factors.

[3] Final Determination Cost Thresholds Review, Australian Energy Regulator, November 2018.

3. Capital Expenditure

3.1 Capital expenditure criteria

Our forecast of capital expenditure for the 2023-27 regulatory period reasonably reflects the capital expenditure criteria set out in clause 6A.6.7(c) of the Rules, and in so doing satisfies the Australian Energy Regulator's (AER's) requirements for acceptance.

Our compliance with each of the capital expenditure criteria is outlined in the following sections.

1. The efficient costs of achieving the capital expenditure objectives

Our forecast capital expenditure for the 2023-27 regulatory period represents an efficient forecast of works required to balance the requirements of our customers, the AER, and our network in the face of increasing uncertainty. The efficient costs of achieving the capital expenditure objectives is demonstrated through both an efficient quantity of investment, and an efficient unit rate for delivering that quantity of investment.

The quantity of asset investment, particularly reinvestment in network assets, represents a continuation of the benchmarks established by the AER in its Final Decision for our current regulatory period. The proposed increase in reinvestment quantities for overhead transmission lines and secondary systems are consistent with the original investment quantities in those assets over time (refer Section 5.6.2 of the Revenue Proposal). Similarly, the decrease in reinvestment quantities for substation switchgear also reflects the original investment profile and the reinvestment quantities that have already been undertaken during the current and previous regulatory period for those types of assets.

Our forecast costs for delivering the forecast investment quantities are based on a continuation of our practices that were accepted by the AER for our current regulatory period and are consistent with industry benchmarks for efficient project delivery.

We engaged GHD to independently provide benchmark costs for the typical project works that make up the majority of our capital expenditure forecasts. This is discussed further in Chapter 7 Escalation Rates and Project Cost Estimation. Based on tGHD's analysis, we consider the costs that comprise our capital expenditure forecasts represent efficient costs.

2. The costs that a prudent operator would require to achieve the capital expenditure objectives

Our capital expenditure forecasts include provision for undertaking the activities of a prudent transmission network business. Beyond the efficient delivery and provision of prescribed transmission services, we ensure we are recognised as a prudent operator of our transmission network. This includes activities that support the primary delivery of transmission services such as:

- **Meaningful engagement with customers and stakeholders, with a particular focus on landholders who host our transmission infrastructure.** We have a dedicated Customer Panel that represents a broad variety of customers and views. We also have a dedicated landholder relations team, who regularly engages with landholders as part of day-to-day operations, and a Business Development team who provides support to directly-connected customers.
- **Ensuring the physical and cyber security of the transmission network and its protection and control systems.** Cyber and physical security are an increasing priority for investment for TNSPs as critical infrastructure providers and we take reasonable steps to ensure the security of our network. This is discussed further in Chapter 6 Forecast Operating Expenditure and in Preliminary Investment Case - IT07 - Cybersecurity Maturity, which is provided as a supporting document to our Revenue Proposal.

- **Careful planning of network outages to minimise impacts to the wholesale energy market and our customers.** One example of works to support outage planning capability is the procurement of a mobile switching bay to facilitate outages in constrained parts of the network. With the rapid changes being experienced on the power system, there are diminished opportunities for extended outages of switching bays to facilitate equipment refurbishment or replacement. The deployment of a mobile switching bay will provide a temporary bypass within a switching bay to allow the network element to remain in service while the main switching bay equipment is replaced.
- **Pursuing business improvement initiatives to improve the overall efficiency of our products, people, and processes**. Key initiatives that are currently under trial or development as part of our structured Innovation Framework include new helicopter work practices to improve productivity in insulator replacement works, the use of drones and artificial intelligence to improve assessment of corrosion levels on steel transmission towers, and application of Phasor Monitoring Units (PMUs) to improve our ability to monitor and respond to the changing characteristics of the power system.

3. A realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives

For the development of capital expenditure forecasts, we have sourced demand forecasts from publicly available sources including AEMO's ESOO as well as its 2020 ISP. Their use is common within TNSP regulatory determinations. Both the ESOO and the ISP take into account the estimated impact of COVID-19 on short-term demand growth and peak demand forecasts.

Details on the approach we have adopted to the escalation of input costs, including our cost estimating approach, unit rates, labour and materials price growth, is contained in Chapter 7 Escalation Rates and Project Cost Estimation.

3.2 Assessment against capital expenditure factors

In deciding whether or not the AER is satisfied that the total capital expenditure forecast reasonably reflect the capital expenditure criteria, the AER also has regard to the capital expenditure factors set out in clause 6A.6.7(e) of the Rules. We have undertaken our own assessment of the capital expenditure forecasts against these factors, as set out below:

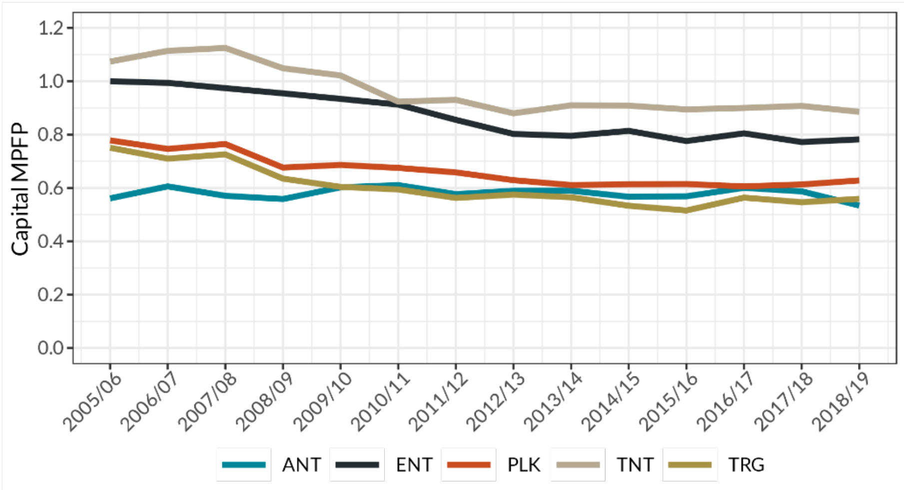
1. AER benchmarking report

As discussed in Chapter 4 Historical Capital and Operating Expenditure, we engaged HoustonKemp to undertake an independent review of our benchmarking performance against other TNSPs and key productivity trends as presented in the AER's 2020 benchmarking report.

Figure 3.1 presents the trend in capital expenditure multilateral partial factor productivity (MPFP) index for TNSPs over the period 2006-19.

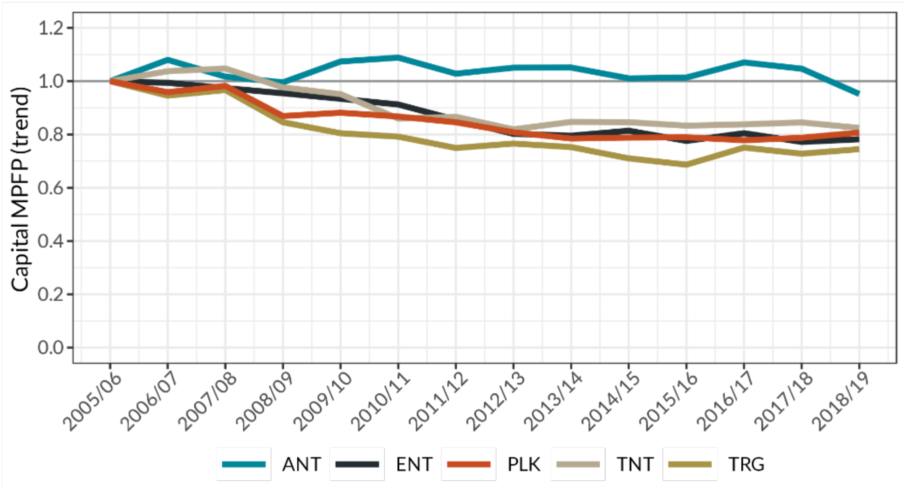
Our capital MPFP performance relative to other TNSPs improved marginally due to the correction to benchmarking methodology in the AER's 2020 Economic Benchmarking report discussed in Section 2.2(1) above. Our ranking over the period 2006-19 improved from fourth place to third place on average due to relative reductions in the MPFP performance of TransGrid and AusNet Services.

Figure 3.1: Capital Expenditure MPFP Index, 2006-19



Source: HoustonKemp, Efficiency of Powerlink's base year operating expenditure, November 2020

Figure 3.2: Capital multilateral partial factor productive (trend)



Source: HoustonKemp, Efficiency of Powerlink's base year operating expenditure, November 2020

Our capital MPFP measure has improved marginally since 2017/18. However, our overall performance has been relatively flat over the last five years. This is primarily due to minor increases in the output measure, driven by increases in maximum demand and customer numbers and a reduction in energy not supplied, while the capital input measure has remained fairly constant.

In trend terms, HoustonKemp noted that the TNSPs are grouped closely with respect to capital MPFP with the exception of AusNet Services, which does not undertake material augmentation expenditure in Victoria.

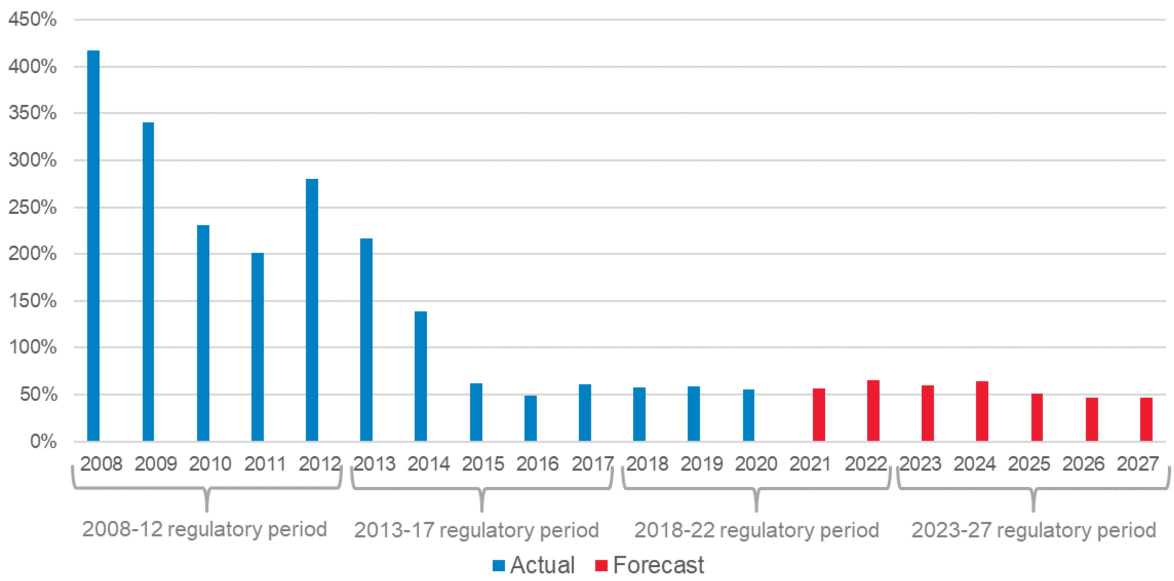
Under the multilateral productivity measures published by the AER, the measure of capital inputs relates to the physical capacity of the network, not the cost to customers of providing that physical capacity. The reduction in the real value of our Regulatory Asset Base (RAB) that has occurred since 2014/15 is not recognised in the multilateral productivity measures. Costs to customers for the capital assets deployed is captured in the AER's Partial Performance Indicators (PPI) which include return on capital and depreciation, as well as operating expenditures. Under PPI measures such as total cost per MWh of energy transported, we have recorded the largest percentage improvement of any TNSP since 2014/15.

As outlined in Chapter 2 Business and Operating Environment, our RAB has decreased in both nominal and real terms in the current regulatory period, in line with flat or declining forecasts of delivered energy. This is forecast to continue in the 2023-27 regulatory period, as noted in Chapter 8 Regulatory Asset Base.

We have developed an alternative measure to benchmark our capital expenditure performance. Figure 3.3 shows the ratio of capital expenditure (as incurred) to straight line depreciation over time. This clearly demonstrates that since 2014/15 our capital expenditure performance reflects a gradual consolidation of the network in the face of much reduced growth in demand for transmission services.

We consider that this provides a reasonable indicator of our prudent asset management and reinvestment approach. This will also contribute to improvements in our PPI measures over the coming regulatory period. Improvements to our capital MPFP measure will only occur when physical capacity inputs, such as transmission lines and transformers, can be retired without replacement or be replaced with lower capacity assets.

Figure 3.3: Capital expenditure (as incurred)/straight line depreciation (%)



2. *Expenditure in preceding regulatory periods*

An overview of our capital expenditure performance in the 2013-17 and 2018-22 regulatory periods is provided in Chapter 4 Historical Capital and Operating Expenditure.

Table 3.1 shows the expected total capital expenditure in the 2013-17 and 2018-22 regulatory periods compared to the forecast capital expenditure in the 2023-27 regulatory period by expenditure category.

Table 3.1: Comparison of total expenditure by category ($m, 2021/22)

Expenditure category	2013-17 Total	2018-22 Total	2023-27 Total	Change (%) 2013-17 to 2023-27	Change (%) 2018-22 to 2023-27
Augmentation	294.4	21.3	6.7	-98%	-68%
Connection	15.1	0.1	2.4	-84%	+3,908%
Easement	46.5	5.4	21.1	-54%	+13%
Network load-driven	**355.9**	**26.8**	**30.2**	**-92%**	**+13%**
Reinvestment (replacement)	833.1	713.1	674.8	-19%	-5%
System Services	0.0	18.0	22.5	N/A	+25%

Expenditure category	2013-17 Total	2018-22 Total	2023-27 Total	Change (%) 2013-17 to 2023-27	Change (%) 2018-22 to 2023-27
Security/compliance	50.4	25.0	14.5	-71%	-42%
Other	28.5	7.4	14.3	-50%	+95%
Network non load-driven	**912.0**	**763.6**	**726.1**	**-20%**	**-5%**
IT	71.4	72.1	59.3	-17%	-18%
Buildings	29.2	7.1	28.3	-3%	+299%
Motor vehicles	6.3	16.3	12.9	+104%	-24%
Moveable plant/tools and equipment	6.7	5.5	7.2	+8%	+32%
Non-network	**113.6**	**101.0**	**107.7**	**-5%**	**+7%**
Total	**1,381.5**	**891.3**	**863.9**	**-37%**	**-3%**

Total capital expenditure in the 2018-22 regulatory period is forecast to be $891.3m (real 2021/22), which is $1.8m (0.2%) lower than the AER's total capital expenditure allowance for the 2018-22 regulatory period. This is also 35% lower than total capital expenditure in the 2013-17 period, driven mainly by a substantial reduction in load-driven expenditure forecasts. There has also been a significant reduction in reinvestment capital expenditure as there is less need for reinvestment options to also include provision for forecast demand growth.

The COVID-19 pandemic has caused some delays in the delivery of network capital expenditure in 2019/20 and this is expected to result in further delays into 2020/21. There have been disruptions or delays to specialist equipment and resources brought in from overseas, as well as necessary changes to some of our field work practices. At this time we anticipate that we will be able to catch-up some of this delay during 2021/22, which we have reflected in our current forecast expenditure for that year, although this is not certain. The reintroduction of restrictions in response to localised outbreaks in Sydney and Brisbane in December 2020 and January 2021 highlight the difficulty in confidently planning project delivery across the whole of Queensland at this time.

We forecast our load-driven capital expenditure for the 2018-22 regulatory period will be $15.2m (131%) higher, than the AER's allowance. The main driver of the additional expenditure is ground clearance rectification works. These works are being undertaken progressively over the current and next regulatory periods. Work is underway to acquire easements to allow for replacement of a section of the Woree to Kamerunga 132kV transmission line in the Cairns area. Together with a planned second stage of easement acquisition in 2021/22, this accounts for much of the increase in expenditure in this category. In addition, some network augmentation works that were forecast to occur late in the 2013-17 regulatory period were delayed until early in the 2018-22 regulatory period to co-ordinate with planned generator outages.

We currently forecast that we will invest $7.4m (1.0%) less than the AER's allowance for network non-load driven capital expenditure. This forecast underspend in the current regulatory period is primarily due to increased complexity in the delivery of our extensive replacement and refit projects. This has been driven by two of the key changes in our operating environment: a low demand growth environment influencing the scope of reinvestment projects, and the emergence of low system strength impacting how we deliver reinvestment projects.

Our current forecast is that we will invest $9.6m (8.7%) less, than the AER's allowance for non-network capital expenditure in the 2018-22 regulatory period. Within Business Information Technology (IT), renewal of our Enterprise Resource Planning and Geographical Information System platforms has been brought forward to provide more efficient integration with other initiatives within the current regulatory period. This is offset by deferral of our proposed office building refit project, which was included in the Support the Business category.

As shown in Table 3.1, total capital expenditure for the 2023-27 regulatory period is expected to be approximately 35% less than in the 2013-17 regulatory period and 3% less than in the 2018-22 regulatory period.

It can be seen that forecast capital expenditure for the 2023-27 regulatory period for the non load-driven and non-network categories is less than the capital expenditure in the 2013-17 regulatory period for the same categories. Importantly, reinvestment expenditure is still forecast to be less than in the 2013-17 regulatory period, reflecting ongoing optimisation of the network in the face of subdued demand growth.

3. Feedback from consumers

Customer engagement has been critical to the development of our forecast capital expenditure for the 2023-27 regulatory period. It has also directly shaped many of the positions in our Revenue Proposal, including our proposed 3% reduction in capital expenditure forecast for the next regulatory period.

Details of our approach to engaging with customers (referred to as consumers in the Rules) and how customers have directly influenced our capital expenditure forecasts is outlined in Chapter 3 Customer Engagement and Chapter 5 Forecast Capital Expenditure.

Engagement with our customers and stakeholders has allowed us to produce forecasts of capital expenditure which appropriately balance the risks and concerns of consumers, the AER, and our network in an affordable manner.

4. Relative prices of capital and operating inputs and substitution possibilities between capital and operating expenditure

Our response to this item is included in Section 2.2 Assessment against Operating Expenditure Factors, Item 4 of this appendix.

5. Consistency with incentive schemes and other schemes

The Capital Expenditure Sharing Scheme (CESS), Service Target Performance Incentive Scheme (STPIS) and Demand Management Innovation Allowance Mechanism (DMIAM) are relevant to our capital expenditure forecasts.

Capital Expenditure Sharing Scheme (CESS)

The effectiveness of the CESS is dependent on the forecast capital expenditure being efficient, or that it reasonably reflects the capital expenditure criteria. As described in Section 2.1 above, we consider that the forecast capital expenditure reasonably reflects the capital expenditure criteria. As noted in the Final Framework and Approach Paper for Powerlink the AER proposes to apply the CESS to Powerlink in the 2023-27 regulatory period.

Service Target Performance Incentive Scheme (STPIS)

The forecast capital expenditure does not include any expenditure specifically to improve network performance under the STPIS.

Demand Management Innovation Allowance Mechanism (DMIAM)

On 5 December 2019, the Australian Energy Market Commission (AEMC) published its Final Determination for a rule change to apply the DMIAM to TNSPs. The AER must develop and publish the first transmission DMIAM by 31 March 2021, though this been delayed to June 2021, with a Draft Decision released in December 2020. Based on the information in the Draft Decision the DMIAM will be limited to operating expenditure only. We consider that our forecast capital expenditure does not include any expenditure that should be included as part of the DMIAM.

6. Expenditure reflects arm's length terms

Any part of our forecast capital expenditure that is referable to arrangements with other parties reflects arm's length terms.

7. Contingent projects

The forecast capital expenditure in our Revenue Proposal is based on a single, most likely, scenario of demand growth and energy market development, being the Central Scenario from AEMO's 2020 ESOO. Our proposed contingent project is an investment that may be needed during the regulatory period should certain trigger events occur beyond the predicted demand growth and energy market development scenario.

Our proposed contingent project is described in more detail in Section 5.7 of the Revenue Proposal and in Appendix 5.07. The forecast capital expenditure in our Revenue Proposal does not include any proposed contingent capital expenditure, either in whole or in part, as required by clause 6A.8.1(b)(2)(i) of the Rules.

8. Most recent Integrated System Plan

AEMO's biennial ISP presents an integrated approach to the development of Australia's eastern power system for the next 20 years. It aims to identify investments to minimise costs and the risks of events that can adversely impact future power system costs and consumer prices, while also maintaining the reliability and security of the power system. As discussed in Section 5.5.2 (Our Hybrid+ approach) of our Revenue Proposal, we have had regard to the 2020 ISP in the development of our Revenue Proposal.

AEMO's 2020 ISP included no actionable projects for Queensland transmission networks but did identify the requirement for Powerlink to undertake preparatory works for three future ISP projects[4]. While the scope of the preparatory works for these projects required by AEMO do not contribute to our forecast capital expenditure in the 2023-27 regulatory period we have included forecast expenditure to acquire new 500kV transmission lines easements and substation sites for the QNI Medium project.

9. Non-network alternatives

Our approach to considering non-network alternatives is described in Section 5.8 Network Support of our Revenue Proposal. In preparing the capital expenditure forecasts for our Revenue Proposal, we have identified where there may be opportunities for non-network alternatives.

10. Regulatory Investment Test for Transmission (RIT-T)

Since September 2017, TNSPs have been required to apply the RIT-T to the replacement of transmission network assets, in addition to projects to augment the network. In that time we have published 23 Project Assessment Conclusion Reports (PACRs) related to network reinvestment projects. We have also published, jointly with TransGrid, one PACR for expanding the capacity of the Queensland – New South Wales Interconnector (QNI) – the QNI Minor project.

Details of the PACRs which are relevant to forecast capital expenditure in the 2023-27 regulatory period are provided in Table 3.2 below.

[4] QNI Medium and Large, Central to Southern Queensland Transmission Link, and Gladstone Grid Reinforcement.

Table 3.2: Project Assessment Conclusion Reports related to network reinvestment projects ($m real, 2021/22)

Project Assessment Conclusions Report	PACR Date	Project	2023-27 capital expenditure
Addressing the secondary systems condition risks at Baralaba Substation	30 August 2018	CP.01457 - Baralaba Secondary Systems Replacement	3.3
Addressing the secondary systems condition risks at Dan Gleeson Substation	21 September 2018	CP.01640 - Dan Gleeson Secondary Systems Replacement	0.0
Maintaining reliability of supply to Ingham	2 October 2018	CP.02462 - Ingham South No.1 & 2 Transformers Replacement	0.1
Addressing the secondary systems condition risks at Palmwoods Substation	14 December 2018	CP.02303 - Palmwoods 275kV secondary system replacement	0.0
Addressing the secondary systems condition risks at Tarong Substation	14 December 2018	CP.01999 - Tarong Secondary Systems Replacement - Stage 2	1.3
Addressing the secondary systems condition risks at Belmont Substation	10 January 2019	CP.02319 - Belmont 275kV Secondary System Replacement	0.0
Addressing the secondary systems condition risks at Abermain Substation	10 January 2019	CP.01635 - Abermain Secondary Systems Replacement	0.3
Maintaining reliability of supply at Kamerunga Substation	18 July 2019	CP.02617 - Kamerunga Substation Rebuild	25.2
Maintaining reliability of supply to the Rockhampton area	16 April 2019	CP.01158 - Egans Hill - Rockhampton TL Refit	0.0
Maintaining power transfer capability and reliability of supply at Bouldercombe Substation	13 February 2019	CP.02350 - Bouldercombe Primary Plant Replacement	10.5
		CP.02371 - H010 Bouldercombe - Transformer 1 & 2 Replacement	0.0
Maintaining reliability of supply at Townsville South Substation	5 March 2019	CP.02353 - Townsville South Primary Plant Replacement	0.1
Maintaining power transfer capability and reliability of supply at Ross Substation	10 April 2019	CP.02723 - H013 Ross 275kV Primary Plant Replacement	8.7
		CP.02721 - H013 Ross 132kV Primary Plant Replacement	6.4
Addressing the secondary systems condition risks at Woree Substation	11 April 2019	CP.02717 - H039 Woree Secondary Systems Replacement Stage 1	2.1
		CP.02321 - Woree SVC Secondary Systems Replacement	3.2
	5 March 2019	CP.02533 - South Pine - Upper Kedron 110kV BS1000 Life Extn	0.6

Project Assessment Conclusions Report	PACR Date	Project	2023-27 capital expenditure
Maintaining reliability of supply to the Brisbane metropolitan area		CP.02508 - West Darra - Sumner 110kV BS1038 Life Extension	0.0
		CP.02509 - Rocklea - Sumner 110kV BS1039 Life Extension	0.0
Expanding NSW-Queensland transmission transfer capacity (Joint Consultation with TransGrid)	20 December 2019	CP.02718 – QNI – Upgrade Transfer Capacity	0.0
Maintaining reliability of supply between Clare South and Townsville South	30 November 2019	CP.02019 - Townsville South-Clare South T/L Refit	0.1
		CP.01561 - Strathmore 2nd 275/132kV Transformer	0.2
Maintaining power transfer capability and reliability of supply at Lilyvale	29 October 2019	CP.02356 - Lilyvale 132/66kV No.3&4 Transformers Replacement	2.0
		CP.02340 - H015 Lilyvale Selected Primary Plant Replacement	10.2
Maintaining reliability of supply in the Blackwater area	15 October 2019	CP.02369 - T032 Blackwater - Transformer 1 & 2 Replacement	5.5
Addressing the secondary systems condition risks at Kemmis	21 October 2019	CP.02712 - T067 Kemmis Secondary Systems Replacement	0.4
Addressing the secondary systems condition risks at Mudgeeraba	21 October 2019	CP.02272 - Mudgeeraba 275kV Secondary System Replacement	0.2
Addressing the secondary systems condition risks at Mt England	6 April 2020	CP.02726 – H012 Mt England Secondary Systems Replacement	0.0
Addressing the secondary systems conditions risks in the Gladstone South area	7 July 2020	CP.02727 - T152 Gladstone South Secondary Systems Replacement	7.3
		CP.02728 - T153 QAL West Secondary Systems Replacement	0.0
Addressing the secondary systems condition risks at Cairns	17 August 2020	CP.02714 – T051 Cairns Secondary Systems Replacement	0.0
TOTAL			**87.9**

11. Other factors

At the time of submission of our Revenue Proposal in January 2021, the AER has not advised Powerlink of any additional capital expenditure factors.