Project EnergyConnect | Contingent Project Application

29 June 2020

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Executive Summary

The Project and this Application

This contingent project application (Application) relates to Project EnergyConnect (the Project or PEC)[1]. PEC involves the construction by mid-2023 of a new high voltage interconnector connecting the electricity networks of South Australia (SA) at Robertstown and New South Wales (NSW) at Wagga Wagga, together with an additional transmission line linking to north-west Victoria (at Red Cliffs).

PEC is a joint TransGrid and ElectraNet project that has many unique characteristics. It is a landmark project as it will be the first new interconnector built between Australian states in 15 years. PEC will be a predominantly greenfield project, built in areas where there has been no previous electricity infrastructure constructed (or where construction occurred many decades ago).

PEC is expected to reduce average annual residential electricity bills by up to $110 per year in NSW and by up to $23 per year in SA[2]. It is also expected to substantially improve electricity system stability[3], leading to longer term benefits for consumers.

This Application is the last step, subject to finalising our tender process, in the regulatory assessment process for the Project. The Australian Energy Regulator's (AER) approval of our prudent and efficient expenditure forecasts, and the resultant changes in our revenues and prices that are reflected in this Application, will enable the Project to proceed to a final investment decision subject to resolving matters related to the financeability of the Project. This will unlock the many benefits that the Project offers.

The timing for the submission of this Application is driven by our commitment to meet our contractual obligations to the SA Government in accordance with our early works agreement with them.

A Project of national significance

PEC was identified as an important element of the 'roadmap' for the NEM in the Australian Energy Market Operator's (AEMO) 2018 Integrated System Plan (ISP), and as one of AEMO's immediate priorities that would deliver positive net market benefits as soon as it is built. PEC's importance was confirmed in AEMO's Draft 2020 ISP[4]. It is included in AEMO's optimal development path as a Group 1 priority project. AEMO's final 2020 ISP will be published shortly and will include PEC.

PEC has been declared to be Critical State Significant Infrastructure for NSW[5]. The SA Government has declared it a 'Major Development'[6]. As a result, the SA Government has provided an expedited planning approval process and has supported our early works for delivery of the Project.

Benefits

PEC fulfils a vital role in the national energy supply system and offers extensive benefits, including:

> greater sharing of reserves, providing NSW with access to renewable generation as coal retires

> unlocking renewable generation development en-route and allowing greater market access

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1 The AER's 2018-23 Revenue Determination for TransGrid includes PEC as a contingent project (New South Wales to South Australia Interconnector)

2 FTI Consulting, Benefits of project EnergyConnect, June 2020

3 AEMO, Minimum Operation Demand Thresholds, 19 June 2020. Found at Link

4 Published in December 2019

5 Media Release, NSW Planning and Public Spaces Minister Rob Stokes, 29 August 2019.

6 Media Release, SA Premier Steven Marshall, 27 June 2019.

- decreasing price volatility through sharing of resources across regions
- reducing electricity prices through greater supply, diversity and competition
- supporting the energy transformation to low emission sources
- reducing reliance on increasingly costly gas plant in SA for dispatchable capacity
- deconcentrating the SA wholesale market and improving hedging liquidity
- allowing greater exports of embedded generation at times of minimum SA demand, and
- reducing vulnerability to extreme weather events and system disturbances, such as bushfires.

We commissioned FTI Consulting (FTI) to prepare an independent expert report on the benefits of PEC. FTI's assessment addresses the matters raised by the AER in its Regulatory Investment Test for Transmission (RIT-T) Determination for PEC[7], as well as the assumptions that will be reflected in AEMO's Final 2020 ISP[8].

FTI estimates gross benefits under the RIT-T framework of $1.6 billion in net present value (NPV) terms over the 2020 to 2040 period, which implies a 'break-even' cost[9] for the Project of $3.0 billion. In addition to the RIT-T benefits, FTI estimates:

- additional gross benefits of $0.8 billion to $1.0 billion by taking into account the benefits expected to accrue from the Project beyond the 2040 horizon of the current RIT-T assessment period[10]. The AER's draft cost benefit analysis guideline recognises that in the case of very long-lived and high-cost investments, it may be necessary to adopt a modelling period of 20 years or more.[11]
- an increase in gross benefits to $2.1 billion for the 2020-2040 period, where a lower societal discount rate of 3.5 per cent is adopted for the net present value (NPV) analysis. This results in an increase in the 'break even' point for the Project to $4.4 billion
- net consumer benefits of $7.1 billion to $11.9 billion, arising from the material reduction in wholesale prices in all national electricity market (NEM) regions driven by improved access to cheaper sources of generation from neighbouring regions and increased generator competition, and
- additional 'non-monetised' benefits reflecting the strategic importance of the Project to future NEM development.

These benefits are material and far exceed the interpretation allowed under the RIT-T framework. FTI's assessment reinforces that the Project will play a vital role in reducing electricity costs, improving system security and reliability and supporting the transition to a more renewables dominated electricity system:

Reducing electricity costs

We expect that PEC will significantly reduce customers' bills. FTI estimates[12] that PEC will reduce wholesale electricity prices in NSW by $10.50/MWh to $29.60/MWh on average up to 2040, and in SA by $1.20/MWh to $4.80/MWh on average up to 2040. This is equivalent to a reduction in average annual residential bills of $34.10 to $110.10 per year for NSW consumers and $5.10 to $22.50 per year for SA consumers[13].

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7 The AER's SA Energy Transformation (SAET) RIT-T Determination, published on 24 January 2020

8 FTI used AEMOs Draft 2020 ISP assumptions from December 2019. These are the most recent assumptions available to FTI at the time of preparing its report

9 The break-even cost is the maximum project cost to support positive net market benefits over the 20 year assessment period from 2020 to 2040

10 Up to the expected end of PEC's useful life in the 2070s

11 AER Draft Cost benefit analysis guidelines - Guidelines to make the Integrated System Plan actionable, May 2020 p. 63

12 FTI Consulting, Benefits of project EnergyConnect, June 2020

13 Assuming: (i) wholesale price changes; (ii) the cost of EnergyConnect; and (iii) the effect of the Project on existing interconnector residues, are fully passed on to consumer retail bills, and average annual household consumption figures remain constant over time.

Improving security and reliability of supply

PEC will improve system stability substantially, particularly for SA. AEMO's recent advice to the SA Government[14], found that delivering PEC is critical for the ongoing secure operation of the power system and will reduce the likelihood of SA 'islanding'. AEMO also found that if PEC does not proceed, extensive further measures will be required to address system security risks. AEMO considers that the current proposed commissioning date for PEC is crucial for the ongoing security of SA's power system. Given the timing of AEMO's assessment, its analysis was not included in the RIT-T assessment. AEMO will share the results of its analysis with the AER, to emphasise the importance of PEC for ongoing security of the SA power system.

FTI supports AEMO's assessment that PEC is likely to enhance the integration of SA with the rest of the NEM, thereby reducing the risk of 'islanding' during unexpected, low probability events (for example, unexpected outages of other transmission lines). FTI considers that PEC will drive down the cost of procuring essential system services that are needed by AEMO to balance the system on a second-by-second basis. The need for such services is increasing given the growth in variable intermittent renewable generation, which makes balancing the system more challenging.[15] PEC will provide greater scope for more services to be sourced, at lower cost, from neighbouring regions.

Transition to a renewables-based generation mix

PEC will facilitate the transition of the NEM to a generation mix with a higher share of renewable sources. Modelling undertaken by FTI shows that PEC is expected to facilitate greater integration of renewable generation in the NEM by enabling more renewables to be built within individual regions than would be the case without the interconnector. This increased volume of renewable generation will be transferred between NSW and SA in periods when output within one of these regions exceeds demand.

Our capex forecast and tender process

Our forecast capex in this Application is $2.3 billion (Real 2017-18). Our capex forecast reflects:

> greenfield project risks and associated construction costs. We will seek to transfer some of these risks and costs, but it will not be possible to fully transfer all of these, to the final contractor/s

> results of the market-testing of the forecast capex through our tender process.

At the time of submitting this Application, we are part-way through our tender process. We have short-listed three tenderers and their initial proposals are reflected in the capex forecast for the NSW component of the Project in this Application. The short-listed tenderers were selected by our tender Evaluation Panel, comprising members of our Executive Team, the project director and an independent member. The NSW Government, the SA Governments and ElectraNet joined the Panel as observers.

We will provide additional information to the AER as it becomes available from our tender process during the second half of 2020, including our revised capex forecast based on the final tender outcomes. We expect our capex forecast will be reduced through this process.

Customer consultation and support

We have consulted broadly with our customers and other stakeholders through public forums and individual meetings to keep them informed about the Project and to facilitate the exchange of views and feedback.

This has continued throughout our competitive and transparent tender process, where we have conducted fortnightly meetings and teleconferences to update stakeholders on key developments. This has been

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[14] AEMO, Minimum Operation Demand Thresholds, 19 June 2020. Found at Link

[15] Indeed AEMO has recently remarked that *"the requirement for interventions will increase across the NEM…as instantaneous penetrations of wind and solar generation grow"*. Source: AEMO, Renewable Integration Study: Stage 1 Report, April 2020. Found at Link

welcomed by stakeholders. Our engagement has revealed that stakeholders have a broad understanding of the need for the Project and of the benefits that will flow to customers and the energy system, if it proceeds.

Financeability of the project

This Application identifies a need to resolve with the AER the timing of revenue recovery and the ex post review of any significant capex overspend. These issues arise due to the unprecedented size and scale of this Project, and that its timing is driven by the ISP process and the expectations of SA Government and other key stakeholders. We want to continue to work collaboratively with AER staff and other stakeholders to identify the best way to address these issues that balances outcomes for investors and customers.

As these matters are in the process of being discussed by us with AER staff, we are not yet in a position to confirm the financeability of the Project under the current regulatory framework.

1. Introduction

Our 2018-23 Revenue Determination includes a contingent project for PEC.[16] The Project is defined in the NER as a priority project for early implementation[17].

Section 3.2 explains the relevant trigger events for the Project and demonstrates that they have occurred.

In accordance with the clause 6A.8.2 and clause 11.114.3 of the NER, this Application seeks the AER's approval to amend the revenue requirements and maximum allowed revenue (MAR) in its 2018-23 Revenue Determinations for TransGrid so that we can recover the efficient costs of our part of the Project.

Unless otherwise specified, all expenditure forecasts in this Application are expressed in real terms ($2017-18), and all revenue forecasts are expressed in nominal terms, consistent with our 2018-23 Revenue Determination.

1.1 Compliance with the NER

This Application and the supporting documents establish the matters in clause 6A.8.2(f) of the NER, being:

(1) the forecast of the total capital expenditure for the contingent project meets the threshold as referred to in clause 6A.8.1(b)(2)(iii)

(2) the amounts of forecast capital expenditure and incremental operating expenditure reasonably reflect the capital expenditure criteria and the operating expenditure criteria, taking into account the capital expenditure factors and the operating expenditure factors respectively, in the context of the contingent project

(3) the estimates of incremental revenue are reasonable, and

(4) the dates are reasonable.

1.2 Structure of this document

The remainder of this document is structured as follows:

> Chapter 2 describes the Project. It also overviews the updated costs and benefits expected to be delivered

> Chapter 3 sets out the regulatory requirements for this Application

> Chapter 4 sets out forecast incremental revenue for the Project

> Chapter 5 sets out forecast capex for the Project and incremental opex for the 2018-23 regulatory period

> Chapter 6 sets out how the NER requirements have been addressed

> Appendix A is our revenue application

> Appendix B is potential unintended consequences faced by Major ISP Projects

> Appendix C is the Board resolution, and

> Appendix B is a glossary of terms.

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[16] The NSW-SA Interconnector contingent project specified in TransGrid's 2018-23 Revenue Determination. See AER, *Final Decision – TransGrid transmission determination 2018 to 2023, Attachment 6 – Capital expenditure*, May 2018, pp. 137-8.

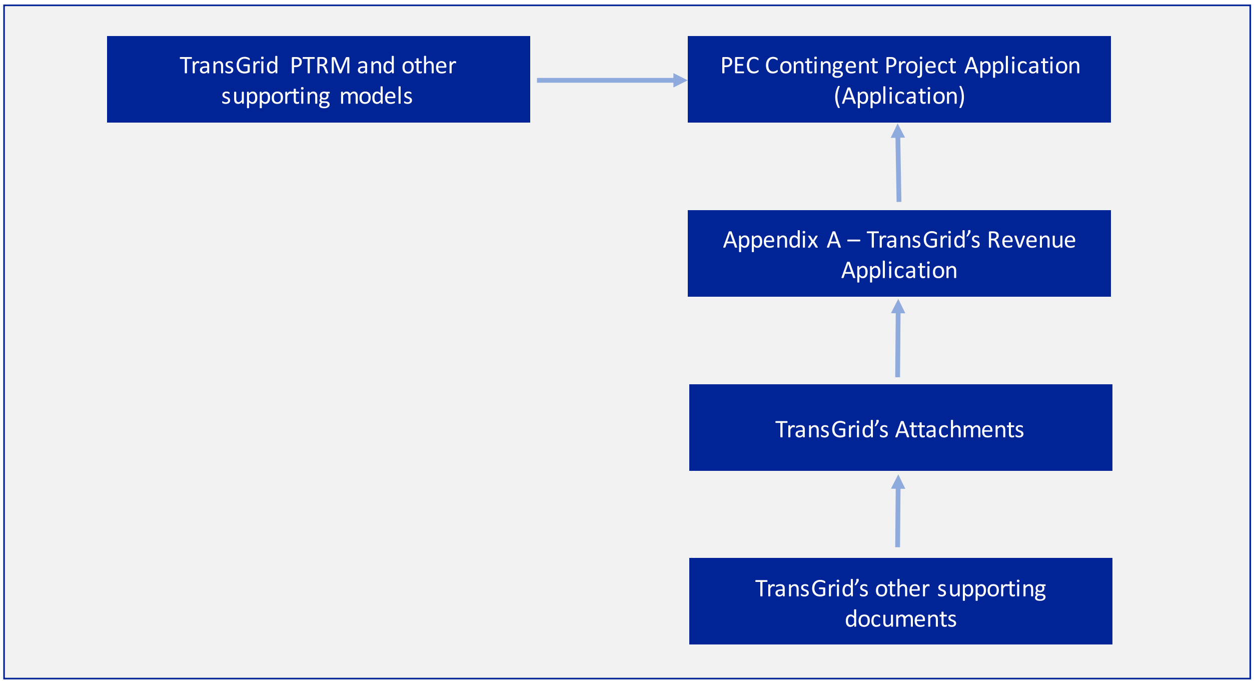
[17] See definitions of 'ISP Projects' and 'SA-NSW Interconnector Projects' in clause 11.114.1 of the NER, in Part ZZZP which deals with early implemnetation of ISP priority projects.

1.3 Structure of the Contingent Project Application Documents and Models for Project EnergyConnect

There are a number of other attachments and models that support, and form part of, our Application for the Project. This document references these attachments, models and other supporting documents for further detail and should be read in conjunction with them.

Our Application is structured as illustrated in Figure 1 to be as clear and accessible as possible to the AER, customers and other stakeholders.

Figure 1 – PEC Application document structure



The attachments and supporting models that, together with this document, comprise our Application are summarised in Table 1.

Table 1 – Documents and models comprising this Application (excluding our other supporting documents)

Document / model number	Name	Content/ purpose
A.1	Project EnergyConnect – Contingent Project Application	Seeks the AER's approval to amend the revenue requirements and MAR in the 2018-23 Revenue Determination
A.2	Stakeholder engagement overview	Describes pre-lodgement consultation undertaken by the businesses
A.3	PEC Post-Tax Revenue Model	Demonstrates the calculations to get to the incremental revenue requirements and MAR from the Project
A.4	Specification and scope for PEC	Explains development and refinement of project specification and scope since the PACR

Document / model number	Name	Content/ purpose
A.5	Capex forecasting methodology for Project EnergyConnect	Explains key steps to develop and validate our capex forecast and presents the basis on which the works have been efficiently scheduled.
A.6	Capex Model for Project EnergyConnect	Calculates our capex forecast
A.7	Corporate and network overhead forecast for Project EnergyConnect	Explains the bottom-up forecast of overheads, which are a component of our total capex forecast.
A.8	Corporate and network overhead spreadsheets for Project EnergyConnect	Calculates the corporate and network overhead forecast for the Project
A.9	GHD, Independent capex Assessment	GHD's independent assessment on the scope, procurement process and forecast capex for the Project.
A.10	FTI Consulting, Benefits of project EnergyConnect	FTI's provides an independent view on the gross benefits of PEC under the RIT-T approach, having regard for the AER's feedback, as well as other wider benefits of PEC currently not captured by the RIT-T framework.
A.11	Opex forecasting methodology for Project EnergyConnect	Explains key steps to develop and validate our opex forecast.
A.12	Opex model Project EnergyConnect	Calculates our opex forecast
A.13	[redacted]	Independent insurance report
A.14	Capex tender inputs and summary spreadsheet	Combines tender responses and summarises forecast capex
A.15	Demand forecast model	Calculates our incremental energy delivered forecast

In addition to the documents and models listed in Table 1, we have provided the AER with other supporting documents that are referenced in the documents in Table 1.

2. Project overview

2.1 Background to this Application

PEC was identified as an important element of the 'roadmap' for the NEM in AEMO's 2018 ISP, and as one of AEMO's immediate priorities that would deliver positive net market benefits as soon as it is built. PEC's importance was confirmed in AEMO's Draft 2020 ISP[18]. It is included in AEMO's optimal development path as a Group 1 priority project. AEMO's final 2020 ISP will be published shortly and will include PEC.

PEC has been declared to be Critical State Significant Infrastructure for NSW[19]. The SA Government has declared it a 'Major Development'[20]. As a result, the SA Government has provided an expedited planning approval process and has supported our early works for delivery of the Project.

This Application is the last step in the regulatory assessment process for the Project.

The AER's approval of our prudent and efficient expenditure forecasts, and the resultant changes in our revenues and prices that are reflected in this Application, will enable the Project to proceed to a final investment decision subject to resolving matters related to the financeability of the Project. This will unlock the many benefits that the Project offers.

The timing for the submission of this Application is driven by our commitment to meet our contractual obligations to the SA Government in accordance with our early works agreement with them.

2.2 Project description

The Project involves the construction of a 900 kilometre interconnector between Robertstown in mid-north SA and Wagga Wagga in NSW via Buronga, with an extension between Buronga and Red Cliffs in Victoria. The interconnector will provide 800 MW of nominal transfer capacity.

The scope of works involved includes:

> a new 330 kV double circuit line linking Robertstown to Buronga to Dinawan to Wagga Wagga

> a new 330 kV substation at Bundey near Robertstown including 275/330 kV transformers

> new 330 kV Phase Shifting Transformers at Buronga (in order to share power transfers between new and existing interconnectors) together with 330/220 kV transformers

> augmentation works at the existing Robertstown, Buronga, Wagga Wagga and Red Cliffs substations

> establishment of a new 330 kV switching station at Dinawan

> a new double circuit 220 kV line from Buronga to Red Cliffs in Victoria, including decommissioning and removal of the existing 220 kV line

> turning in the existing 275 kV line between Robertstown and Para to Tungkillo

> static and dynamic reactive plant at Robertstown, Buronga and Dinawan

> a Special Protection Scheme to detect and manage the loss of either interconnectors, and

> associated power system studies, commissioning works and testing.

The PEC route is shown in Figure 2.

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18 Published in December 2019

19 Media Release, NSW Planning and Public Spaces Minister Rob Stokes, 29 August 2019.

20 Media Release, SA Premier Steven Marshall, 27 June 2019.

Figure 2 – PEC line route

2.3 Project benefits

PEC fulfils a vital role in the national energy supply system and contributes to all three corners of the energy trilemma: affordability; security; and climate change, though its extensive benefits including:

> greater sharing of reserves, providing NSW with access to renewable generation as coal retires
> unlocking renewable generation development en-route and allowing greater market access
> decreasing price volatility through sharing of resources across regions
> reducing electricity prices through greater supply, diversity and competition
> supporting the energy transformation to a more intermittent based resource mix
> reducing reliance on increasingly costly gas plant in SA for dispatchable capacity and for system stability
> allowing greater exports of embedded generation at times of minimum SA demand, and
> reducing vulnerability to extreme weather events and system disturbances, such as bushfires.

RIT-T benefits and 'break-even' point for the Project

We commissioned FTI to prepare an independent expert report on the benefits of PEC. FTI's assessment addresses the matters raised by the AER in its RIT-T Determination for PEC[21], as well as the assumptions that will be reflected in AEMO's Final 2020 ISP[22].

FTI estimates gross benefits under the RIT-T framework of $1.6 billion in NPV terms over the 2020 to 2040 period and calculates the associated maximum project cost to support positive net market benefits to be $3.0 billion. This is referred to as the 'break-even' cost for the Project.[23]

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21 The AER's SA Energy Transformation (SAET) RIT-T Determination, published on 24 January 2020

22 FTI used AEMOs Draft 2020 ISP assumptions from December 2019. These are the most recent assumptions available to FTI at the time of preparing its report

23 This is calculated using the commercial discount rate of 5.9 per cent. We note that a contemporary commercial discount rate would be substantially lower than 5.9 per cent given current market returns and discount rates. Using a contemporary commercial discount rate would

Other benefits not assessed under the RIT-T framework

In addition to the RIT-T benefits, FTI estimates:

- additional gross benefits of $0.8 billion to $1.0 billion by taking into account the benefits expected to accrue from the Project beyond the 2040 horizon of the current RIT-T assessment period. The AER's draft cost benefit analysis guideline recognises that in the case of very long-lived and high-cost investments, it may be necessary to adopt a modelling period of 20 years or more.[24]
- an increase in gross benefits to $2.1 billion for the 2020-2040 period, where a lower societal discount rate of 3.5 per cent is adopted for the NPV analysis. This might better reflect a societal discount rate rather than the higher discount rate of 5.9 per cent currently used in the RIT-T. This results in an increase in the 'break even' point for the Project to $4.4 billion
- additional 'non-monetised' benefits reflecting the strategic importance of the Project to future NEM development. This is discussed further below, and
- net consumer benefits of $7.1 billion to $11.9 billion, arising from the material reduction in wholesale prices in all NEM regions driven by improved access to cheaper sources of generation from neighbouring regions and increased generator competition.

FTI notes that the primary focus of Great Britain's energy regulator, the Office of Gas and Electricity Markets (Ofgem), involves assessing the impact of new interconnector investments from the perspective of consumers. Accordingly, the RIT-T may significantly undervalue total project benefits as there are benefits, such as consumer benefits stemming from changes in wholesale prices, that do not fall into the allowed benefit categories.

These additional benefits are material and far exceed the interpretation allowed under the RIT-T framework and support the project proceeding at an even higher 'break-even' cost. FTI's assessment reinforces that the Project will play a vital role in reducing electricity costs, improving system security and reliability and supporting the transition to a more renewables dominated electricity system:

Reducing electricity costs

We expect that PEC will significantly reduce customers' bills. FTI estimates[25] that PEC will reduce wholesale electricity prices in NSW by $10.50/MWh to $29.60/MWh on average up to 2040, and in SA by $1.20/MWh to $4.80/MWh on average up to 2040. This is equivalent to a reduction in average annual residential bills of $34.10 to $110.10 per year for NSW consumers and $5.10 to $22.50 per year for SA consumers[26].

Improving security and reliability of supply

PEC will improve system stability substantially, particularly for SA. AEMO advised the SA Government[27] that delivering PEC as soon as possible is critical for the ongoing secure operation of the power system and to reduce the likelihood of SA 'islanding'. AEMO also advised the SA Government that if PEC does not proceed, extreme measures will be required to maintain power system security, such as an immediate moratorium on new solar installations and costly retrofits of existing installations. AEMO therefore considers that the current proposed commissioning date for PEC is crucial for the ongoing security of SA's power system. Given the timing

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substantially increase the benefits and break-even cost of the Project. Using the regulatory WACC from the AER's most recent revenue determination, which is the lower boundary for the discount rate under the AER's Draft Cost benefit analysis guidelines, would also result in significantly higher benefits and therefore a higher break-even cost. The AER's most recent Decision at the time of making this Application is its 2020 to 2025 Final Decision for SA Power Networks. This determined a nominal WACC of 4.75 per cent.

24 AER Draft Cost benefit analysis guidelines - Guidelines to make the Integrated System Plan actionable, May 2020 p. 63

25 FTI Consulting, Benefits of project EnergyConnect, June 2020

26 Assuming: (i) wholesale price changes; (ii) the cost of EnergyConnect; and (iii) the effect of the Project on existing interconnector residues, are fully passed on to consumer retail bills, and average annual household consumption figures remain constant over time.

27 AEMO, Minimum Operation Demand Thresholds, 19 June 2020. Found at Link

of its advice, AEMO's analysis was not included in the RIT-T assessment to date. AEMO will share the results of its analysis with the AER, to emphasise the importance of PEC for ongoing security of the SA power system.

FTI supports AEMO's assessment that PEC is likely to enhance the integration of SA with the rest of the NEM, thereby reducing the risk of 'islanding' during unexpected, low probability events (for example, unexpected outages of other transmission lines). FTI found that PEC will drive down the cost of procuring essential system services that are needed by AEMO to balance the system on a second-by-second basis. The need for such services is increasing given the growth in variable intermittent renewable generation, which makes balancing the system more challenging.[28] PEC will provide greater scope for more services to be sourced, at lower cost, from neighbouring regions.

Transition to a renewables-based generation mix

PEC will facilitate the transition of the NEM to a generation mix with a higher share of renewable sources. Modelling undertaken by FTI shows that PEC is expected to facilitate greater integration of renewable generation in the NEM by enabling more renewables to be built within individual regions than would be the case without the interconnector. This increased volume of renewable generation will be transferred between NSW and SA in periods when output within one of these regions exceeds demand.

Broader strategic benefits

PEC has been identified by AEMO as a key component of the NEM Roadmap enabling the transition of the Australian energy sector. As discussed earlier, it has been identified in AEMO's 2018 ISP and the draft 2020 ISP as a priority project for implementation.

The Project is expected to bring a range of strategic benefits to the NEM as the energy sector transitions, including enabling greater diversification across generation sources and improving the ability of the system to withstand High Impact Low Probability (HILP) events.

FTI highlights that in overseas jurisdictions transmission planners take into account strategic and 'hard-to-monetise' benefits associated with major investments, such as the impact in mitigating key risks and facilitating greater diversity and resilience. These benefits form part of the formal regulatory evaluation and are considered within the relevant decision-making frameworks.

FTI has identified strategic 'non-monetary' benefits associated with PEC additional to those that were considered as part of the RIT-T. These include benefits:

> supporting the integration of renewable generation
> connecting complementary generation mixes in SA and NSW
> contributing to security of supply in SA (including in relation to High Impact, Low Probability events)
> providing optionality for potential future policy changes, and
> supporting the National Electricity Objective (particularly in relation to reliability and security of supply).

The flexibility given to AEMO under the new 'actionable ISP' Rules framework now enables greater consideration of these type of benefits as part of the NEM planning framework.

If the RIT-T for PEC was being commenced now, following publication of the final 2020 ISP, we believe that the direction provided by AEMO in relation to the 'identified need' and the scenarios to be adopted would result in a materially different focus for the RIT-T analysis. In particular, it would be likely to give greater weight to the additional strategic benefits underlying AEMO's inclusion of PEC as part of the optimal development path.

Given the extent of the analysis conducted to date, and the high profile and desired near-term timing of PEC as an ISP priority project, it would be impractical to now restart the RIT-T assessment under the new ISP

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28 Indeed AEMO has recently remarked that *"the requirement for interventions will increase across the NEM…as instantaneous penetrations of wind and solar generation grow"*. Source: AEMO, Renewable Integration Study: Stage 1 Report, April 2020. Found at Link

framework. However, we expect that these broader strategic benefits will continue to be a key driver for AEMO in its decision to include PEC as part of the ISP's optimal development path. AEMO's final 2020 ISP is expected to be published shortly.

3. Regulatory requirements

The regulatory requirements for contingent projects are contained in:

> clause 6A.8.2 of the NER, as modified by Part ZZZP for this Project, and

> the AER's Process Guideline for Contingent Project Applications.[29]

The key requirements are outlined below. Chapter 5 of this Application shows how we have satisfied the regulatory requirements.

3.1 Regulatory requirements

Clause 6A.8.2 of the NER, as modified for the Project by clause 11.114.3 of the NER, sets out the requirements for making an application to amend a revenue determination to include a contingent project.

This Application is made in accordance with the requirements of clause 6A.8.2(a), (a1) and (b) of the NER, being made:

> during the 2018 to 2023 regulatory period

> to amend the revenue determination that applies to us in respect of a contingent project included in the revenue determination, and[30]

> within the specified time limits.[31]

This Application includes the information specified in clause 6A.8.2(b) of the NER:

(3) except in the case of a clause 5.16.6 trigger,[32] *an explanation that substantiates the occurrence of the trigger event*

(4) a forecast of the total capital expenditure for the contingent project

(5) a forecast of the capital and incremental operating expenditure, for each remaining regulatory year which the Transmission Network Service Provider considers is reasonably required for the purpose of undertaking the contingent project

(6) how the forecast of the total capital expenditure for the contingent project meets the threshold as referred to in clause 6A.8.1(b)(2)(iii)

(7) the intended date for commencing the contingent project (which must be during the regulatory control period)

(8) the anticipated date for completing the contingent project (which may be after the end of the regulatory control period), and

(9) an estimate of the incremental revenue which the Transmission Network Service Provider considers is likely to be required to be earned in each remaining regulatory year of the regulatory control period as a result of the contingent project being undertaken as described in subparagraph (3), which must be calculated:

(i) in accordance with the requirements of the post-tax revenue model referred to in clause 6A.5.2

(ii) in accordance with the requirements of the roll forward model referred to in clause 6A.6.1(b)

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29 AER, Process Guideline for Contingent Project Applications under the NER, September 2007

30 NER clause 6A.8.2(a)

31 NER clause 6A.8.2(a)

32 That is, a determination that a preferred option satisfies the regulatory investment test for transmission

(iii) using the allowed rate of return for that Transmission Network Service Provider for the regulatory control period as determined in accordance with clause 6A.6.2

(iv) in accordance with the requirements for depreciation referred to in clause 6A.6.3, and

(v) on the basis of the capital expenditure and incremental operating expenditure referred to in subparagraph (b)(3).

Clause 6A.8.2(f)(2) of the NER requires the AER to accept the relevant amounts in this Application if it is satisfied that:

> *the amounts of forecast capital expenditure and incremental operating expenditure reasonably reflect the capital expenditure criteria and operating expenditure criteria, taking into account the capital expenditure factors and operating expenditure factors, in the context of the contingent project.*

In addressing these requirements, we have had regard for the AER's Process Guideline for Contingent Project Applications[33]. We have met regularly with the AER in preparing this Application and the AER's feedback has informed the content and structure of this Application and supporting documentation.

3.2 Trigger events

Table 2 shows that the trigger events approved by the AER in its 2018-23 Revenue Determination for the Project have been, or are in the process of being, met.

Table 2 – Occurrence of the Trigger Events

Trigger event	Status
1. Successful completion of a RIT-T demonstrating an overall network investment by all parties involved in the interconnector construction that maximises the positive net economic benefits from establishing a new high voltage interconnection from South Australia, and/or that addresses a reliability corrective action.	**Complete** On 13 February 2019, ElectraNet published a PACR for the SAET Project in which the preferred option demonstrated positive net economic benefits.
2. Determination by the AER that the proposed investment satisfies the RIT-T.	**Complete** On 24 January the AER published its RIT-T Decision that Project EnergyConnect satisfies the RIT-T as the preferred option.
3. TransGrid Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	On 26 June 2020, the TransGrid Board committed to proceed with the Project subject to: > The AER awarding incremental revenue commensurate with the capital and operating costs of the Project proposed by TransGrid; > TransGrid obtaining debt and equity funding on terms satisfactory to it; and > the Board of ElectraNet making a corresponding commitment.

[33] AER, *Process Guideline for Contingent Project Applications under the National Electricity Rules*, September 2007 available at: https://www.aer.gov.au/system/files/ac06907-Final%20guideline.pdf.

Trigger event	Status
4. Clauses 1 and 2 do not apply if a change in the law occurs that allows the inclusion of the proposed investment in TransGrid's maximum allowed revenue under this revenue determination even if a RIT-T is not carried out.	Not Applicable – no such change in law has occurred.

3.3 Project timing

For the purposes of this Application, the applicable dates for the commencement and completion of the contingent project are:

> Date for commencement of the contingent project – 1 July 2018

> Anticipated date for completion of our component of the contingent project – June 2023.

This timing reflects a realistic assessment of the earliest dates that the investments can be delivered.

The capex for the Project will occur during the 2018-23 regulatory period. Opex will continue into subsequent regulatory periods once the assets are operational. The completion date is consistent with indicative date set out in the PACR.

3.4 Stakeholder input and pre-lodgement consultation

We remain committed to continuing to engage effectively with customer representatives and wider stakeholders on the Project.

Full details of the extensive RIT-T consultation undertaken to date are set out in ElectraNet's request for determination.[34] In summary, since commencing its RIT-T consultation in 2016, in addition to the three required RIT-T documents (the PSCR, PADR and PACR), ElectraNet also released extensive supplementary reports, models, results and analysis, including reports from independent consultants that corroborated and further investigated aspects of the analysis and points raised in stakeholder submissions. Separate public forums and 'deep dive' sessions were held in Adelaide and Sydney, to help explain the assessment to stakeholders and to hear stakeholders' views. Detailed information was also released responding to the questions and issues raised by stakeholders.

All consultation materials, submissions received, and actions taken to address feedback from stakeholders in relation to the RIT-T process are available on ElectraNet's website.[35]

Following the conclusion of the RIT-T process in early 2019, we have continued to engage with stakeholders about this Application.

The purpose of the engagement is to inform customers and other stakeholders about the SA-NSW interconnector and to allow them to provide their views and perspectives on the Project. In July 2019, we jointly published with ElectraNet a draft engagement plan, which set out high-level plans and approaches and invited input. We incorporated feedback received into the final engagement plan, which is provided in the "Stakeholder engagement overview" attached to this Application.

Engagement on the Project has occurred both through individual briefings and meetings and stakeholder forums, including:

> Project EnergyConnect stakeholder forum on 25 July 2019, held in Sydney, and

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34 ElectraNet, *Letter to Paula Conboy, AER, Re: SA Energy Transformation RIT-T – Request for determination*, 11 April 2019, esp. pages 4 to 6, and Attachments 1, 2 and 3.

35 See https://www.electranet.com.au/projects/south-australian-energy-transformation/

- Project EnergyConnect stakeholder forum on 21 October 2019, held in Adelaide.

This process provided valuable feedback to inform the development of this Application. For example, stakeholders expressed a preference for certainty about estimated costs for the Project and asked us to nominate a specific cost estimate in our Application, rather than nominating a cost range. This Application provides a specific expenditure forecast for our component of the project, rather than ranges, for both capex and opex.

We have also held fortnightly updates for our stakeholders, which covered a broad range of topics including the impact of COVID-19, the refinement of the Project's line route, the status of the procurement process and the interaction between PEC and other ISP projects.

The "Stakeholder engagement overview" provided as an attachment to this Application summarises the outcomes of this engagement and how it has been reflected into this Application.

We will continue to engage with customers and other stakeholders through the remaining stages of the regulatory approval process.

3.4.1 Consultation on our procurement process

We have adopted a robust, transparent and inclusive procurement process to ensure our capex forecast reflects prudent and efficient capex and that customers are paying no more than they should be for the services that they will receive.

This involved establishing an Evaluation Panel (Panel) comprising members of our Executive Team, the project director and an independent member. The NSW Government, the SA Governments and ElectraNet joined the Panel as observers.

On 28 November 2019, the Panel assessed the initial tender responses, received on 11 November 2019, based on an agreed criteria and weighting methodology. The Panel short-listed three tenderers for the next stage of the procurement process. We have reflected the costs from short-listed tenderers in this Application.

In February 2020, we presented an overview of the tender process to stakeholders including AER, AEMO and consumer groups before releasing the tender documents to the short-listed tenderers on 11 February 2020. This provided an opportunity for key stakeholders to raise any issues with the procurement documents, process and structure. Stakeholders inquired about our approach to prioritising the use of Australian service providers. We responded to this feedback by developing an Australian Industry Participation Plan for the Project. The successful contractor will implement this Plan.

Our approach has provided full transparency with respect to our tender documents and process.

4. Forecast revenue

This section sets out total forecast revenue for the Project.

This Application identifies a need to resolve with the AER the timing of revenue recovery (refer Appendix B). Accordingly, the following section is presented in accordance with the current regulatory framework, as the matter is unresolved. We have forecast revenue using the same assumptions and approaches recently adopted by the AER in its determination on the QNI Minor Upgrade contingent project application. Table 3 summarises the incremental revenue forecast of $118.7 million ($Nominal), broken down by building block component, and briefly explains how we have calculated these. Further detail is provided in Appendix A.

As mentioned above, Appendix B of our Application explains that applying the current regulatory framework defers recovery of revenue for PEC (and other Major ISP Projects) into the future. This issue arises due to the unprecedented size and scale of PEC. We have been discussing with AER staff alternative approaches so that PEC can be financeable. At the time of this Application, this matter remains unresolved with the AER. We look forward to continuing to engage with AER staff about this matter in the lead up to its Determination.

Table 3 – 2018-23 forecast incremental revenue from the Project ($M, Nominal)

Building block	$ Million, Nominal	Approach
Return on capital	184.8	Calculated by multiplying the forecast opening capital base (updated to include expenditure on the Project) for a given year by the allowed rate of return adopted by the AER.
Return of capital	(70.6)	Calculated as forecast straight line depreciation for each asset class less indexation of the capital base. The value is negative because indexation is higher than depreciation over the 2018–23 regulatory period. As discussed in Appendix B, we have concerns with how indexation undermines financeability of large projects like PEC. We are working collaboratively with AER staff to identify the best way to address this issue that balances outcomes for investors and customers.
Opex	3.6	Calculated as a bottom-up build of expected operating and maintenance costs once the Project assets are commissioned. Debt raising costs, calculated using the AER's standard approach, are added on top.
Corporate income tax	0.3	Calculated as forecast pre-tax income multiplied by the corporate tax rate, less the assumed value of imputation credits.
Annual revenue requirement (i.e. unsmoothed)	**118.0**	
Impact of smoothing	0.7	Revenue is smoothed by shifting some revenue from 2019–22 to 2022-23 to reduce volatility, without affecting net present value of revenue. This slightly increases total revenue over the 2018–23 regulatory period.

Building block	$ Million, Nominal	Approach
Maximum allowed revenue (i.e. smoothed)	**118.7**	

5. Forecast capex and opex

This section sets out total forecast capex and opex for the Project.

5.1 Forecast capex

This section presents the capex forecast for our component of the Project to address clause 6A.8.2(b) of the NER. All of this capex will be incurred in the 2018-23 regulatory period.

The capex forecast is prudent and efficient having regard for the capex objectives, criteria and factors in clause 6A.5.7 of the NER.[36] The total forecast capex also satisfies the contingent project expenditure threshold.

5.1.1 Capex forecast

The Project is large with unique characteristics. It will be:

- the first new interconnector to be built between Australian states in 15 years, and
- a greenfield project where there has been no previous electricity infrastructure constructed (or construction occurred many decades ago), which gives rise to significant environmental, bio-diversity, geotechnical, land access and indigenous heritage risks.

The delivery of the Project is made more complicated because Government and other stakeholders have tight timing expectations. The timing coincides with significant demand for infrastructure delivery in the Australian market, particularly in NSW, leading to a shortage in available labour and construction resources. This is compounded by the remoteness of much of the construction, which poses significant challenges to the availability of required resources.

These characteristics and delivery considerations present risks and uncertainties that need to be reflected in our capex forecasts for the Project at this time, but which we anticipate will reduce following completion of the tender process. Many of the costs reflect factors outside of our control and we are seeking to efficiently transfer these risks to the final contractor/s. However, we will not be able to transfer all of these costs to the final contractor/s and we will only know this once our tender process is complete.

We are using our best endeavours to provide accurate forecasts of the prudent and efficient capex of the Project. We therefore want as much of our forecast capex as possible to be market-tested. This will help to ensure that customers are paying no more than they should be for the services that they will receive.

At the time of submitting this Application, we are part-way through our tender process for the NSW component of the Project. As part of this process we:

- sent initial tender documents to the market on 3 October 2019
- received initial tender responses from five tenderers on 11 November 2019
- short-listed three tenderers for the next stage in December 2019
- issued final tender documents to the short-listed tenderers on 11 February 2020
- will receive final tender submissions and therefore binding offers on 29 June 2020
- will select a preferred tenderer by September 2020, and
- will execute a Commitment Deed in September 2020 and an engineering, procurement and construction (EPC) deed in December 2020, subject to receiving a satisfactory AER Determination on this Application.

36 As required by clause 6A.8.1(b)(2)(ii) of the NER.

We have already mobilised our team to support the tender process and begin preparations to deliver the Project. By the end of March 2020 we had incurred $17.1 million (Real 2017-18) in indirect (or support) costs.

Table 4 details our current total capex forecast of $2,290.9 million (Real 2017-18) for our component of the Project over the 2018-23 period.

Table 4 – 2018-23 forecast capex ($M, Real 2017-18, including overheads)

	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Actual[1]	3.4	13.7	-	-	-	**17.1**
Forecast	20.1	50.8	776.3	843.1	583.6	**2,273.8**
Total forecast capex[2]	**23.5**	**64.5**	**776.3**	**843.1**	**583.6**	**2,290.9**

Notes: These are actual indirect costs that we have already incurred up to March 2020.[37] Capex for 2018-19 includes equity raising costs of $19.9 million for TransGrid.

Our capex forecast comprises:

> $1,826.8 million (Real 2017-18) for tendered works. This capex reflects:
  – the average tender prices of the three short-listed tenders that we received in November 2019 for substations and transmission lines
  – quotations from suppliers for the large specialist equipment, which we consider provides a more reasonable and realistic cost estimate than the tender prices, and
  – other construction costs not included in the current tender pricing. We are seeking to transfer these costs to the final contractor/s efficiently by including them in the final contract price or as a variation to the final contract price.

> $122.1 million (Real 2017-18) for project risks. These costs have been determined in accordance with the AER’s risk cost methodology. The AER defines project risk costs as including both the cost of mitigating risks (mitigation costs) and the costs associated with bearing residual risks after mitigation (contingency costs), and

> $342.0 million (Real 2017-18) for other costs, including property and easements, corporate and network overheads (i.e. indirect costs), biodiversity offsets, real input escalators and equity raising.

We expect our capex forecast will be reduced through the tender process. In particular, we expect that the risk and other construction costs arising from the greenfield nature of the Project will be significantly reduced, however we will only know this once our tender process is complete.

The AER has publicly indicated that its review process for this Application will take at least six months.

We propose to provide additional information to the AER as it becomes available from our tender process during the second half of 2020. This will ensure that the capex forecast for the Project, and therefore our adjusted revenues and prices, reflect the best view of the market-tested costs that we will incur.

5.1.2 Basis for estimates

We developed the capex forecasts based on a detailed scope of works using methods that reflect the specific nature of the costs, as shown in Table 5.

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37 These costs are discussed further in section 8.2 of Appendix A.5 (Capex Forecasting Methodology) and in Appendix A.7 (Corporate and network overhead forecast for Project EnergyConnect).

Table 5 – Basis of Capex Forecast ($M, Real 2017-18)

Category of PEC capex	Description	Basis of capex forecast	Forecast capex	% of total capex
Tendered works	Substations and transmission lines, including access tracks	Forecast capex based on market pricing, including responses provided by tenderers and quotes from suppliers of large specialist equipment as well as top-down estimates of other construction costs	1,315.2	57.4%
	Large specialist equipment		216.3	9.4%
	Other construction costs		295.3	12.9%
Property and easements	Property and easement acquisition and costs	Forecast capex based on project land prices and other costs associated with acquiring easements, including the cost of offsetting biodiversity and species loss	109.5	4.8%
	Environmental 'offset' costs		74.7	3.3%
Indirect costs	Actual costs	Actual indirect costs incurred up to March 2020	17.1	0.7%
	Corporate and Network overheads	Forecast capex based on a bottom up-build of our indirect costs, which have been determined using current available market rates and recent historical data.	105.3	4.6%
Risks	Biodiversity risk cost	Forecast capex calculated using the AER's risk cost methodology (detailed probabilistic risk assessment)	122.1	5.3%
Real input escalators	Real labour cost escalation	Forecast capex calculated by multiplying the projected labour components of forecast capex for tendered works, property and easements and indirect costs, by the real labour cost escalators approved in the AER's 2018-23 Revenue Determination for TransGrid.	15.5	0.7%
Equity raising costs	Equity raising costs	Forecast capex calculated using the AER's Post Tax Revenue Model	19.9	0.9%
Total capex			**2,290.9**	**100%**

Our capex forecast for PEC is prudent and efficient in accordance with the capex criteria and meets the required capex objectives set out in the NER. This is demonstrated by:

> a rigorous, well-defined and transparent capex forecasting methodology

> the application of our governance framework and process

- the reliance on market testing and expert reports, and
- external validation of both the capex forecast and deliverability.

Our capex forecast is explained and justified in the following supporting documents:

- Capex Forecasting Methodology for PEC
- Corporate and network overhead forecast for PEC, and
- Independent engineering capex verification and assessment - this independent expert report prepared by GHD confirms that the scope of the Project is reasonable and realistic to meet the investment need and that our forecast capex is consistent with that which would be incurred by a prudent and efficient business.

Our capex forecast model is also provided as an attachment to this Application.

5.1.3 Capex threshold

The proposed capex of a contingent project is required to exceed either $30 million, or 5 per cent of the MAR for the first year of the regulatory control period, whichever is the greater.

Table 6 shows that the forecast capex satisfies the relevant threshold. This means that the capex is covered by the contingent project requirements of the NER.

Table 6 – Contingent project thresholds ($M, Nominal)

AER Decision First year MAR	5% of MAR	Contingent Project Threshold	Pass / Fail
716.7[38]	36	36	Pass (as capex > $36 million)

Note: NER clause 6A.8.1(b)(2)(iii) requires that expected capex is higher than the greater of $30 million or 5% of MAR. The threshold is $36 million (being 5% of MAR).

5.1.4 Application of the CESS

The AER's capital expenditure sharing scheme (CESS) applies to our 2018-23 regulatory period. As previously discussed with the AER, we consider the application of the CESS to PEC should be considered in the context of the overall risk associated with Major ISP Projects under the current regulatory framework.

We continue to use our best endeavours to accurately forecast the prudent and efficient costs of the Major ISP Projects to comply with the regulatory timeframes, recognising project-level uncertainties. While we support an incentive based regulatory regime we have identified two significant potential unintended consequences arising from the application of the current regulatory framework to the Major ISP Projects, given their:

- unprecedented size and scale, and
- that the timing of delivery is being driven by the ISP process and the expectations of government and other stakeholders.

These risks are discussed in Appendix B. We propose further engagement with the AER, and our other stakeholders, to identify how best to manage, and fairly allocate, these risks for the Major ISP Projects. We consider the application of the CESS to Major ISP Projects should be considered as part of this discussion.

[38] AER, Final Decision – TransGrid – Post-tax Revenue Model – May 2018, Revenue Summary.

5.2 Forecast opex

This section presents the incremental opex forecast for PEC in accordance with the requirements of clause 6A.8.2(b)(iii) of the NER.

The incremental opex forecast detailed is that reasonably required to undertake the Project, in accordance with the opex objectives, factors and criteria set out in the NER.

5.2.1 Opex forecast

Table 7 shows that forecast opex for PEC is $3.2 million over the 2018-23 regulatory period.

Incremental opex is minimal given that the interconnector will be under construction, and will enter service, at the end of the current regulatory period. Future maintenance and other opex associated with the new assets will be recovered in future regulatory periods.

Table 7 – 2018-23 forecast opex ($M, Real 2017-18)

2018-19	2019-20	2020-21	2021-22	2022-23	Total
-	0.0	0.1	0.8	2.2	**3.2**

Note: Note: Forecast opex is incremental to the allowance in our 2018-23 Revenue Determination and includes debt raising costs. The opex shown here is presented in real terms (in $2017-18) and differs from the opex building block values shown in section A8 of Appendix A, which is presented in nominal terms.

5.2.2 Basis of opex forecast

Our opex forecasting methodology for the Project, provided as an attachment to this Application, explains and justifies the incremental opex forecast. Our opex forecast model is also provided as an attachment to this Application.

We have applied a bottom-up build approach to forecast incremental opex for the Project for the 2018-23 regulatory period. We have adopted the inflation and real cost escalation assumptions approved by the AER in its current 2018-23 Revenue Determination. The bottom-up build approach reflects the AER's preferred approach for how it would like us to prepare our opex forecast.[39] It is also consistent with the approach accepted by the AER for all contingent projects to-date.

We consider that the forecast opex is efficient and prudent in accordance with the opex criteria and meets the required opex objectives set out in the NER.

5.2.3 Opex Forecast for the Purposes of the EBSS

The efficiency benefit sharing scheme (EBSS) provides a constant incentive for TNSPs to pursue efficiency improvements in opex. Our 2018-23 Revenue Determination specifies that version two of the EBSS will apply to the 2018–23 regulatory period. The EBSS requires that the incremental opex approved through this Application is added to the opex allowance for the purposes of applying the EBSS.

Incremental opex to be included in the EBSS opex allowance is set out in Table 8 (in accordance with the requirements of the scheme).

Table 8 – 2018-23 forecast opex ($M, Real 2017-18)

2018-19	2019-20	2020-21	2021-22	2022-23	Total
-	0.0	0.1	0.4	1.3	**1.8**

Note: Opex shown in is table is the same as that in Table 7 with debt raising costs removed (which are excluded from the EBSS).

[39] The AER advised us on 18 October 2019 that it preferred a bottom-up build approach to forecast incremental opex.

6. Guide to compliance

Table 9 details how this Application complies with the NER requirements.

Table 9 – Compliance with NER requirements

NER, clause 6A.8.2(b) requirements	Reference in Application
(1) an explanation that substantiates the occurrence of the trigger event	Section 3
(2) a forecast of the total capex for the contingent project	Section 5
(3) a forecast of the capital and incremental opex, for each remaining regulatory year which the Transmission Network Service Provider considers is reasonably required for the purpose of undertaking the contingent project	Section 5
(4) how the forecast of the total capex for the *contingent project* meets the threshold as referred to in clause 6A.8.1(b)(2)(iii)	Section 5
(5) the intended date for commencing the *contingent project* (which must be during the *regulatory control period*)	Section 3
(6) the anticipated date for completing the *contingent project* (which may be after the end of the *regulatory control period*) and	Section 3
(7) an estimate of the incremental revenue which the *Transmission Network Service Provider* considers is likely to be required to be earned in each remaining *regulatory year* of the *regulatory control period* as a result of the *contingent project* being undertaken as described in subparagraph (3), which must be calculated: (i) in accordance with the requirements of the post-tax revenue model referred to in clause 6A.5.2 (ii) in accordance with the requirements of the roll forward model referred to in clause 6A.6.1(b) (iii) using the allowed rate of return for that Transmission Network Service Provider for the regulatory control period as determined in accordance with clause 6A.6.2 (iv) in accordance with the requirements for depreciation referred to in clause 6A.6.3, and (v) on the basis of the capex and incremental opex referred to in subparagraph (b)(3).	Section 4 and Appendix A

Appendices

Appendix A – Our revenue application

This Appendix A sets out our estimate of the incremental revenue for the Project over the 2018-23 regulatory period, having regard for clause 6A.8.2(b)(9) of the NER.

Our incremental revenue is relatively small given that incremental opex for the Project is low and incremental capex is not expected to be commissioned until 2022-23. As shown in Table 19 below, this means that the customer bill impact in the current regulatory period is also expected to be low (relative to a typical retail bill).

Appendix B of our Application explains that applying the current regulatory framework to estimate incremental revenue defers revenue recovery for PEC into the future. We have been discussing with AER staff ways to resolve this issue so that PEC remains financially viable. At the time of this submission, we have not resolved this matter with the AER. We look forward to continuing to engage with AER staff about this matter in the lead up to its Determination.

Table 10 sets out the incremental MAR for the Project for the 2018-23 regulatory period. This has been calculated using the AER's 2018-23 PTRM, updated for:

- the 2019-20 and 2020-21 return on debt estimates, and
- the AER's recent determination on the Queensland NSW Interconnector upgrade contingent project application (QNI CPA), and
- incremental forecast capex, opex and energy delivered for the Project. [40]

Table 10 – Incremental MAR ($M, Nominal)

	2018-19	2019-20	2020-21	2021-22	2022-23	Total
AER 2018-23 determination	734.3	759.5	779.5	828.2	865.2	**3,966.7**
Impact of Project EnergyConnect	-	-	-	36.3	82.4	**118.7**
Updated MAR	**734.3**	**759.5**	**779.5**	**864.4**	**947.6**	**4,085.4**

The rest of this Appendix A:

- identifies the weighted average cost of capital (WACC) and standard asset life assumptions
- sets out projected regulatory depreciation, tax allowance, debt and equity raising costs, unsmoothed revenue requirements and MAR, and
- details the potential customer bill impact from the incremental revenue requirements resulting from the Project.

A1 WACC

We have calculated the incremental revenue for the Project using the same WACC assumptions as those adopted by the AER in its 2018-23 Revenue Determination, updated for the 2019-20 return on debt averaging period. This is consistent with clause 6A.8.2(b)(4)(ii) of the NER.

[40] Throughout this Appendix A we refer to the AER 2018–23 determination updated for the 2019-20 and 2020-21 return on debt estimates and the AER's recent determination on the QNI CPA as the 'AER 2018-2023 determination'.

The WACC parameters are set out in Table 11.

Table 11 – WACC parameters

Parameter	AER Approved Value[41]
Forecast inflation	2.45%
Value of imputation credits	40%
Gearing	60%
Nominal pre-tax return on debt	5.97% for 2018-19 5.77% for 2019-20 5.41% for 2020-21 onwards
Nominal post-tax return on equity	7.40%
Nominal vanilla WACC	6.54% for 2018-19 6.42% for 2019-20 6.21% for 2020-21 onwards

A2 Asset lives

We have allocated our forecast capex for the Project across regulatory asset classes, as detailed in the Capex Forecasting Methodology. Capex is depreciated in the PTRM using the standard asset lives used in the AER's 2018-23 Revenue Determination, with two exceptions:

> a new asset class has been added for synchronous condensers with a standard life of 40 years. This is because these assets are new and have not been included in the RAB previously, and

> the standard life for equity raising costs was updated from 'n/a' to 37.9 years using the approach adopted by the AER in its recent determinations.

The applicable standard asset lives are set out in Table 12.

Table 12 – Asset lives

Asset Category	Standard Life (years)	Explanation
Transmission lines	50	As per the AER's 2018-23 Revenue Determination
Substations	40	
Synchronous condensers	40	As per the AER's August 2019 decision on ElectraNet's South Australian Main Grid System Strength Contingent Project Application[42]
Secondary systems	15	As per the AER's 2018-23 Revenue Determination
Communications (short life)	10	

41 As last annually updated by the AER for the trailing average cost of debt in January 2019.

42 AER, August 2019, *Final Decision, ElectraNet Contingent Project, Main Grid System Strength*, pp. 24-28.

Asset Category	Standard Life (years)	Explanation
Land and easements	n/a	
Equity raising costs	38.6	As per recent AER decisions, this is calculated as the weighted average standard life for forecast net commission capex[43]

Note: Only asset classes that attract the Project capex are shown.

A3 Depreciation

Table 13 sets out our forecast incremental regulatory depreciation for the 2018-23 regulatory period for the Project, consistent with clause 6A.8.2(b)(7)(iv) of the NER. This forecast has been calculated using the PTRM, projected incremental capex, and the asset lives in section A2.

Incremental regulatory depreciation is negative over the 2018-23 regulatory period. This is because the long-lived nature of the assets leads to indexation being higher than real straight-line depreciation earlier in the lives of those assets. This relationship will reverse later in the assets' lives, leading to positive regulatory depreciation.

Table 13 – Incremental regulatory depreciation ($M, Nominal)

	2018-19	2019-20	2020-21	2021-22	2022-23	Total
AER 2018-23 determination	101.2	118.8	129.9	129.3	144.7	**623.9**
Impact of Project EnergyConnect	-	(0.1)	(1.7)	(22.6)	(46.3)	(70.6)
Updated regulatory depreciation	**101.2**	**118.8**	**128.1**	**106.7**	**98.4**	**553.2**

A4 Tax allowance

Table 14 sets out the forecast incremental net tax allowance for the 2018-23 regulatory period attributed to the Project. This has been calculated using the PTRM and projected incremental capex.

We have not made any other changes to the net tax calculation from that used in the AER's 2018-23 Revenue Determination.

Table 14 – Incremental net tax allowance ($M, Nominal)

	2018-19	2019-20	2020-21	2021-22	2022-23	Total
AER 2018-23 determination	31.7	33.7	35.3	37.6	39.5	**177.8**
Impact of Project EnergyConnect	-	(0.7)	(0.7)	0.3	1.4	**0.3**
Updated net tax allowance	**31.7**	**33.0**	**34.7**	**37.8**	**40.8**	**178.0**

[43] See, for instance, AER, April 2019, *Final Decision, Power and Water Corporation, Post-tax Revenue Model,* PTRM input sheet, W327 cell. Net commissioned capex was used in the weighted average, rather than net as incurred capex, as the former is used to calculate regulatory depreciation in the 'Assets' sheet of our PTRM.

A5 Debt and equity raising costs

Our forecast incremental revenue includes allowances for debt and equity raising costs, consistent with the AER's 2018-23 Revenue Determination. Both costs are calculated automatically within the PTRM.

Debt raising costs are included within the opex building block and are calculated as follows:

> projected opening RAB at the start of each regulatory year is multiplied by assumed gearing (of 60%) and the debt raising cost benchmark (of 0.085%).

Equity raising costs are included within the capex forecast and recovered via the return on and of capital building blocks. These costs are calculated as follows:

> retained cash flows are projected by subtracting opex, interest payments, revenue adjustments, tax payable, and dividends from projected smoothed (i.e. MAR) revenue

> equity raising is projected by subtracting retained cash flows from the equity funding component of projected capex (assuming 60% gearing), and split between distribution reinvestment and external equity raising sources, and

> equity raising costs are calculated by multiplying the two sources by assumed benchmark equity raising cost rates.

No equity raising costs were projected in the AER's 2018-23 Revenue Determination, because retained cash flows were sufficient to cover projected equity funding. However, because of the size of the Project's capex, the PTRM projects that some equity raising will be required. This attracts equity raising costs.

Table 15 – Incremental debt raising costs ($M, Real 2017-18)

	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Debt raising costs						
AER 2018-23 determination	3.2	3.3	3.3	3.3	3.4	**16.5**
Impact of Project EnergyConnect	-	0.0	0.0	0.4	0.9	**1.4**
Updated debt raising costs	**3.2**	**3.3**	**3.3**	**3.8**	**4.2**	**17.9**
Equity raising costs						
AER 2018-23 determination	-	-	-	-	-	**-**
Impact of Project EnergyConnect	19.9	-	-	-	-	**19.9**
Updated equity raising costs	**19.9**	**-**	**-**	**-**	**-**	**19.9**

A6 Incremental revenue requirements for each year to end of period

Table 16 details the incremental annual building block revenue requirements for the Project, based on the forecasts provided above and using the PTRM.

Table 16 – Incremental revenue requirements ($M, Nominal)

	2018-19	2019-20	2020-21	2021-22	2022-23	Total
AER 2018-23 determination						
Return on capital	416.8	417.1	417.7	434.8	449.9	**2,136.3**
Regulatory depreciation	101.2	118.8	129.9	129.3	144.7	**623.9**
Opex	179.9	187.6	196.7	208.6	205.9	**978.7**
Revenue adjustments	4.7	18.5	5.4	12.7	5.1	**46.5**
Net tax allowance	31.7	33.7	35.3	37.6	39.5	**177.8**
Unsmoothed revenue requirement	**734.3**	**775.7**	**785.0**	**823.0**	**845.1**	**3,963.1**
Impact of Project EnergyConnect						
Return on capital	-	1.6	5.8	58.7	118.8	**184.8**
Regulatory depreciation	-	(0.1)	(1.7)	(22.6)	(46.3)	**(70.6)**
Opex allowance	-	0.0	0.1	0.9	2.5	**3.6**
Revenue adjustments	-	-	-	-	-	**-**
Net tax allowance	-	(0.7)	(0.7)	0.3	1.4	**0.3**
Unsmoothed revenue requirements	**-**	**0.8**	**3.5**	**37.3**	**76.3**	**118.0**
Updated						
Return on capital	416.8	418.7	423.5	493.5	568.7	**2,321.2**
Regulatory depreciation	101.2	118.8	128.1	106.7	98.4	**553.2**
Opex allowance	179.9	187.6	196.8	209.6	208.4	**982.2**
Revenue adjustments	4.7	18.5	5.4	12.7	5.1	**46.5**
Net tax allowance	31.7	33.0	34.7	37.8	40.8	**178.0**
Unsmoothed revenue requirements	**734.3**	**776.6**	**788.5**	**860.3**	**921.4**	**4,081.1**

A7 Amended MAR

The AER's final decision on the annual building block revenue requirements for the 2018-23 regulatory period is set out in Table 17, together with the calculation of the amended revenue required for the Project.

We will begin to recover incremental revenue approved by the AER in the 2021-22 regulatory year, in accordance with our approved Transmission Pricing Methodology, as shown in Table 17.

Table 17 – Amended annual building block revenue requirements ($M, Nominal)

	2018-19	2019-20	2020-21	2021-22	2022-23	Total
AER 2018-23 determination	734.3	775.7	785.0	823.0	845.1	**3,963.1**
Impact of Project EnergyConnect	-	0.8	3.5	37.3	76.3	**118.0**
Updated annual revenue requirements	**734.3**	**776.6**	**788.5**	**860.3**	**921.4**	**4,081.1**

Table 18 sets out the updated MAR and X-factors for the current regulatory period.

The incremental revenue requirements have been smoothed so that the only change to the MAR occurs in the 2021-22 regulatory year. This approach was adopted to ensure that the final year (2022-23) difference between MAR and the annual revenue requirements was less than 3 per cent and so that there is minimal change to the revenue profile from the 2018-23 Revenue Determination.

Table 18 – Amended MAR and X factors ($M, Nominal)

	2018-19	2019-20	2020-21	2021-22	2022-23	Total
MAR (i.e. smoothed revenue)						
AER 2018-23 determination	734.3	759.5	779.5	828.2	865.2	**3,966.7**
Impact of Project EnergyConnect	-	-	-	36.3	82.4	**118.7**
Updated MAR	**734.3**	**759.5**	**779.5**	**864.4**	**947.6**	**4,085.4**
X-factors						
AER 2018-23 determination	(0.51%)	(0.97%)	(0.17%)	(3.70%)	(1.98%)	**n/a**
Impact of Project EnergyConnect	-	-	-	(4.55%)	(5.02%)	**n/a**
Updated X-factors	**(0.51%)**	**(0.97%)**	**(0.17%)**	**(8.25%)**	**(7.00%)**	**n/a**

Note: Negative X factors represent a real revenue increase.

A8 Customer bill impact

PEC is expected to have only a marginal impact on customer bills over the 2018-23 period. This is largely because return of capital is pushed back into future regulatory periods and energy throughput is expected to increase (reducing per MWh costs).

Table 19 shows the indicative customer bill impact of the Project, assuming that a typical customer consumes 4.22 MWh per year.

Table 19 – Indicative customer bill impact ($ per household, Nominal)

	2018-19	2019-20	2020-21	2021-22	2022-23
AER 2018-23 determination	45.8	48.4	50.1	53.4	56.4
Impact of Project EnergyConnect	-	-	-	2.3	4.9
Updated typical customer bill impact	**45.8**	**48.4**	**50.1**	**55.8**	**61.3**

Note: Typical customer bills are calculated by multiplying the projected MAR per MWh by assumed consumption of 4.22 MWh per year per household. Project EnergyConnect is expected to increase energy delivered in 2022-23 by 494 GWh. The increase in energy delivered was estimated using market modelling that underpins the project design.

Appendix B – Potential unintended consequences faced by Major ISP Projects

We strongly support PEC and are committed to its successful implementation to meet the expectations of our customers and stakeholders, where it remains identified by AEMO as one of the priority elements of the ISP.

We also strongly support AEMO's ISP process and the Major ISP Projects that it has identified. These projects are necessary to underpin the energy market transition and ensure reliable and affordable electricity supply to consumers. They are expected to deliver net market benefits including lower prices for the NEM, and for NSW and other Australian consumers. AEMO describes these projects as "nationally significant and essential investments in the electricity system to ensure the system meets its security and reliability requirements with the least cost and lowest regret to consumers"[44].

As part of our assessment of PEC, we have identified two significant potential unintended consequences arising from the application of the current regulatory framework to the Major ISP Projects. These issues are discussed below and arise due to the unprecedented size and scale of these projects, and because their timing is being driven by the ISP process and the expectations of the SA Government and other key stakeholders such that they will be delivered concurrently. We are working collaboratively with the AER staff and other stakeholders to find acceptable solutions that balance outcomes for investors and customers.

B1. Cash-flow impact of indexation of the regulatory asset base (RAB)

The current regulatory framework is designed to return the cost of efficient investment over the life of the assets – a principle often referred to as Financial Capital Maintenance. This principle is applied within the regulatory framework using an approach that indexes the RAB for inflation.

The current approach to RAB indexation defers recovery of invested capital until later in the lives of those assets by increasing their value each year by inflation and removing that increase (i.e. indexation) from the revenue recovered via annual tariffs. This effectively capitalises the inflation portion of the debt and equity returns to the RAB, resulting in a reduction in cash inflows from revenue in the initial years of the project's operations and a theoretical compensatory increase in later years.

We acknowledge that the RAB indexation approach makes sense for business-as-usual (BAU) network investments, as it means that current and future consumers pay a similar amount each year, in real terms, promoting intergenerational equity. At the same time, the net cash flows are relatively flat because new BAU investments largely offset old BAU investments and so the returns to network owners are more consistent with other investment alternatives.

However, as we explain below, the RAB indexation approach can significantly undermine the financeability of large projects that lead to a step increase in invested capital – as the PEC and other Major ISP Projects would do for us.[45]

The revenue impact of indexation for a large stand-alone $2 billion project is illustrated as an example in Figure 3, where the capital-related revenues are compared with and without indexation applying to the capital expenditure. As shown, indexation tilts revenue recovery to much later in the investment horizon. The figure also shows that using 'as-incurred' capex to calculate regulatory depreciation – rather than 'as-commissioned' capex – brings forward some of that revenue recovery earlier to occur during the construction period. Other adjustments, such as shortening asset lives or accelerating depreciation, could also be used to bring forward revenue recovery. We have been discussing with the AER staff the impact of each of these potential adjustments for Major ISP Projects over the past few months. Our discussions in this regard are still in progress.

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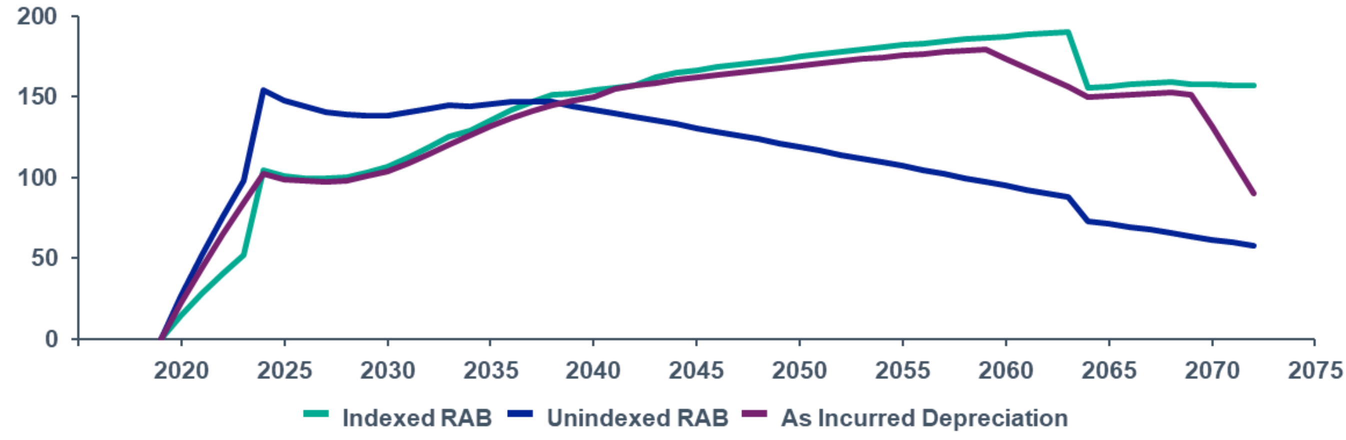
44 AEMO, draft 2020 ISP, p. 6. Found at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2019/Draft-2020-Integrated-System-Plan.pdf

45 Our financeability concerns are exacerbated by the tendency for the AER to over-forecast inflation when setting revenue allowances, which leads to under-recovery of revenues. We are actively engaging in the AER's current consultation on how it forecasts inflation.

Figure 3 – Illustrative impact on allowed revenues for a stand-alone $2 billion project



Source: TransGrid analysis. Capital-related allowed revenues are shown in nominal dollar terms, comprising the return on capital, return of capital and taxation building blocks. Projected revenues are illustrative only because they are based on simplifying assumptions.

In the case of a project or investment that is of a modest scale (such as a BAU investment), this (indexed RAB) revenue profile can be managed within the existing means of a network business. However, for projects of a significantly larger size, such as the Major ISP Projects, BAU revenues are insufficient to support financing requirements over the period within which (indexed RAB) revenue ramps up for the particular projects. This is exacerbated where multiple Major ISP Projects are undertaken simultaneously. We are facing this predicament, particularly over the next 5-10 years.

If revenue is too low, particularly during the construction period, then a business cannot achieve the credit metrics required to support a BBB+ credit rating (with model firm gearing). For us, this would mean that:

> equity investors would need to provide a significant amount of equity (well in excess of that assumed in the regulatory WACC building blocks) to fund the initial years of the Major ISP Projects to cover both the initial capital outlay, as well as the RAB indexation – materially reducing the risk-adjusted value of these projects to those investors, and

> debt financiers may require higher returns to provide debt funding than those allowed in regulated tariffs for these projects – thereby further increasing the risk and reducing the value of these projects.

Accordingly, RAB indexation appears likely to significantly impair our ability to finance large, non-BAU investments in a reasonable, value-accretive manner and we consider this to be a significant potential unintended consequence faced by those looking to build and own the Major ISP Projects.

Regulatory authorities and policy makers in other jurisdictions have considered this issue in different ways. For instance, faced with a similar step change in required transmission investment, the Commerce Commission (in New Zealand) allowed for the value of assets for Transpower – NZ's government-owned transmission business – to be rolled forward *without* indexation.[46] This effectively flattened the revenue profile faced by Transpower in an effort to help fund needed investment in its network, while doing so in a way that meant that consumers paid the same amount over the longer term (in net present value terms).

Other regulatory adjustments have also been used, such as shortening asset lives, accelerating depreciation or allowing for NPV-neutral RAB adjustments.

As mentioned above, we are working collaboratively with the AER staff and our other stakeholders to identify how best to address this issue for the Major ISP Projects so that they remain financially feasible while still

[46] Commerce Commission, *Input Methodologies (Transpower): Reasons Paper*, December 2010, pp. 30–31.

delivering significant benefits to customers. This involves assessing potential solutions, including as to how best to manage any impact to customer bills.[47]

B2. Regulatory risks from capex overspend

The Major ISP Projects are large in size and scale and have unique characteristics that make it difficult to forecast their costs accurately. In particular:

> the scale of the Major ISP Projects is unprecedented and is beyond the delivery capacity of many Australian construction companies

> many of the Major ISP Projects are proposed to be constructed in regions where there has been no previous electricity infrastructure constructed (or construction occurred many decades ago), which gives rise to significant environmental, bio-diversity, geotechnical, land access and indigenous heritage risks

> there is a significant demand for the delivery of other major Australian infrastructure, particularly in NSW, leading to a shortage in available labour and construction resources, and

> government and other stakeholders' interest in Major ISP Projects is creating expectations in relation to delivery times that do not adequately allow for the necessary timeframes for the regulatory approval processes, giving rise to risks that are usually mitigated during the regulatory process.

It appears that the current regulatory framework did not anticipate such a confluence of circumstances and does not provide an adequate means of identifying, quantifying and sharing risks associated with Major ISP Projects in a manner that is fair to all market participants, including customers and networks.

We continue to use our best endeavours to forecast accurately the prudent and efficient costs of the Major ISP Projects to comply with the regulatory timeframes, recognising project-level uncertainties. However, we do not consider it appropriate or reasonable that we should bear the regulatory risks of recovering costs of these projects, especially given that their delivery and timing are being driven by the broader ISP process.

There are scenarios where the application of the current regulatory arrangements may mean that we do not have a reasonable opportunity to recover efficient costs of delivering these projects. The risks and uncertainties of the Major ISP Projects may result in our actual capex of delivering the projects being higher than the capex that the AER approves through the regulatory contingent project application process. Overspend could potentially be very significant given the scale, number and timing of Major ISP Projects.

There is currently no provision in the contingent project application process for adjusting the capex allowance approved by the AER for a Major ISP Project. We bear the cost risk of a project and may therefore not have a reasonable opportunity to recover the efficient costs of the project.

Further, overspend on the Major ISP Projects could result in our total actual capex significantly exceeding our total capex allowance. This could result in us being penalised through the ex-post capex review process by having actual capex incurred excluded from the RAB.

We propose further engagement with AER staff, and our other key stakeholders, to identify how best to manage, and fairly allocate, these risks for the Major ISP Projects. Potential options to be explored include:

> excluding the Major ISP Projects from the coverage of the CESS

> pass-through provisions for actual capex incurred, and

> excluding the Major ISP Projects from the coverage of the capex ex post review (which applies to our total capex program, including the Major ISP Projects, for the review period).

[47] Potential solutions included changes to how the capital invested in the Major ISP Projects is returned such as: calculating depreciation on an as-incurred rather than as-commissioned basis; adopting a weighted trailing average cost of debt; shortening asset lives; removing indexation from the RAB, and accelerating depreciation.

Appendix C – Board resolution

Below is a certified extract of the relevant board resolution.

On 26 June 2020, the Board resolved to commit to proceed with Project EnergyConnect subject to:

> The AER awarding incremental revenue commensurate with the capital and operating costs of the project proposed by TransGrid;

> TransGrid obtaining debt and equity funding on terms satisfactory to it; and

> The Board of ElectraNet making a corresponding commitment.

Appendix D – Glossary

Abbreviations/acronyms	Definition
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Application	Contingent Project Application
Capex	Capital expenditure
CESS	Capital Expenditure Sharing Scheme
EBSS	Efficiency Benefit Sharing Scheme
GWh	Gigawatt Hour
ISP	Integrated System Plan
kV	kilovolt
M	Millions
MAR	Maximum Allowed Revenue
MWh	Megawatt Hour
NEL	National Electricity Law
NEM	National Energy Market
NEO	National Electricity Objective
NER (Rules)	National Electricity Rules
NSW	New South Wales
Opex	Operating expenditure
PADR	Project Assessment Draft Report
PACR	Project Assessment Conclusions Report
PTRM	Post-Tax Revenue Model
RAB	Regulatory Asset Base
RIT-T	Regulatory Investment Test for Transmission
ROE	Return on equity
SA	South Australia