Services and pricing policy, Appendix B

Tariff setting methodology for the second pricing period (2024-25 to 2026-27)

for access to Horizon Power's covered Pilbara network

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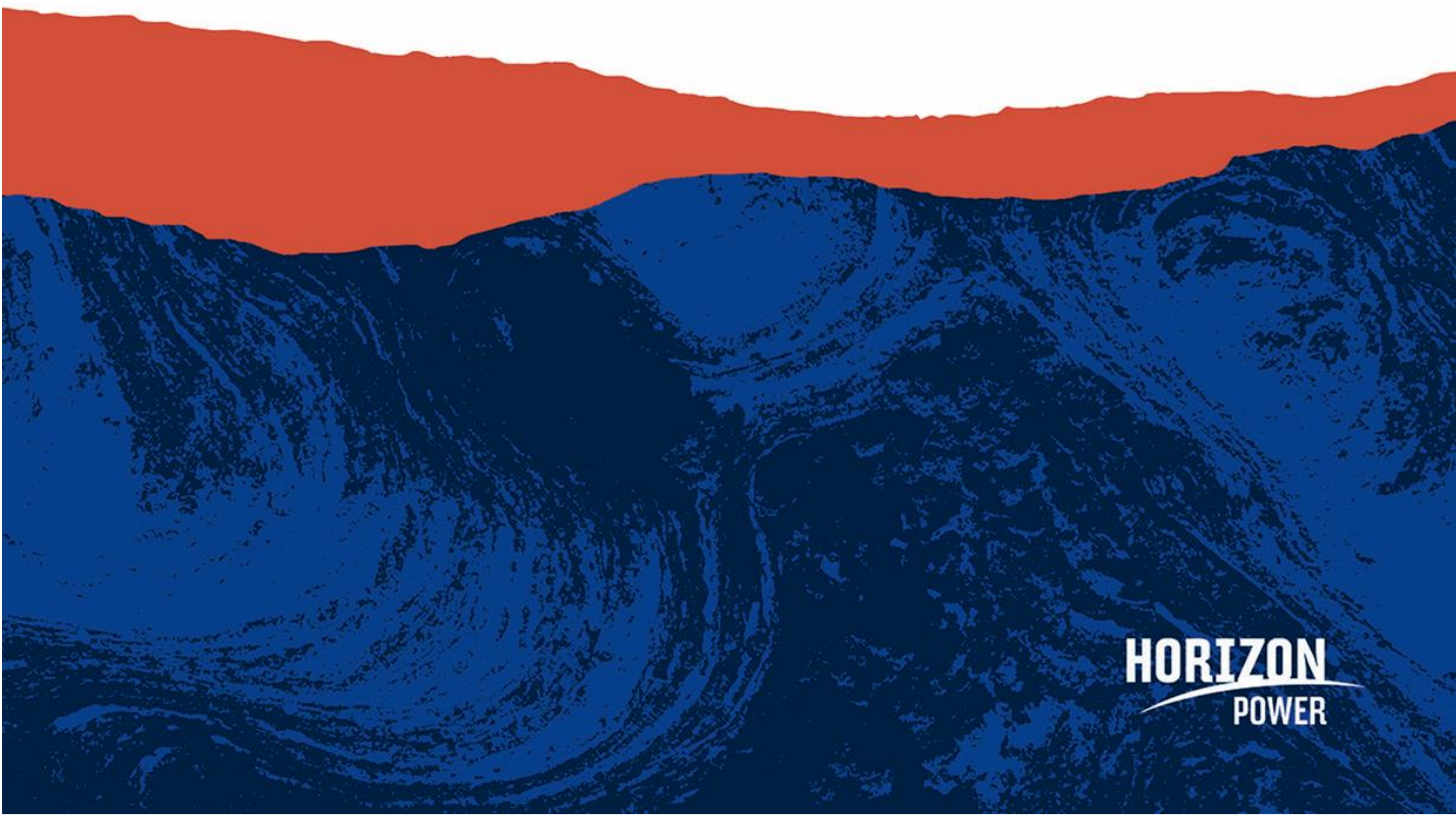

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This policy remains in effect, until replaced or updated, notwithstanding expiration of the review date.

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1. ABBREVIATIONS AND DEFINED TERMS

The following abbreviations are used in this document and have the meaning provided in the table below.

Table 1.1: Document Abbreviations

Abbreviation	Meaning
ALARP	As Low As Reasonably Practicable
AMP	Asset Management Plan
capex	capital expenditure
CMD	contracted maximum demand
CPI	Consumer Price Index
ENAC	Electricity Networks Access Code 2004
ENSMS	Electricity Network Safety Management System
ERA	Economic Regulation Authority
HV	high voltage
ICT	Information and Communication Technology
ISO	Independent System Operator
kV	kiloVolt (equals 1,000 Volts)
kVA	kiloVolt Amp (equals 1,000 Volt Amps)
LV	low voltage
MVA	Mega Volt-Amp (equals 1 million Volt Amps)
NSP	Network Service Provider
opex	operating expenditure
OT	Operational Technology
PV	photovoltaic
RBA	Reserve Bank of Australia
SCADA	Supervisory Control and Data Acquisition
TAC	Temporary Access Contribution
WACC	Weighted Average Cost of Capital

The following defined terms are used in this document and have the meaning provided in the table below.

Table 1.2: Document Defined Terms

Defined term	Meaning
Act	the *Electricity Industry Act 2004 (WA).*
bidirectional service	a *covered service* provided at a *connection point* on a *light regulation network* that is a bidirectional point. {As at 25 June 2021, the *Code* defines bidirectional point as a point on a *light regulation network* which is, or is to be, identified as such (explicitly or by inference) in a contract for *services* at which, subject to the contract for *services*, electricity is expected to be, on a regular basis, both transferred into the *light regulation network* and transferred out of the *light regulation network*.}
capital base	has the same meaning given to it in the *Code*. {As at 25 June 2021, the *Code* defines *capital base* for a *light regulation network* as the value of the *network assets* that are used to provide *covered services* on the *light regulation network* prescribed or determined under section 52, 53, 54 or Chapter 7 as applicable.}
capital expenditure (capex)	an expense to be shown on a company's balance sheet as an investment, rather than on its income statement as an expenditure.
capital-related costs	has the same meaning given to it in the *Code*. {As at 25 June 2021, the *Code* defines *capital-related costs* in relation to *covered services* provided by an *NSP* by means of a *light regulation network* for a period of time, as— (a) a return on the *capital base* of the *light regulation network*; and (b) depreciation of the *capital base* of the *light regulation network*.}
charge	has the same meaning given to it in the *Code*. {As at 25 June 2021, the *Code* defines *charge* for a *user* for a *covered service* as the amount that is payable by the *user* to the *NSP* for the *covered service*, calculated by applying the tariff for the *covered service*.}
Code	Pilbara Networks Access Code 2021 (WA).
connection point	has the same meaning given to it in the *Code*. {As at 25 June 2021, the *Code* defines *connection point* as a point on a *light regulation network* which is, or is to be, identified (explicitly or by inference) in, a contract for *services* as being an entry point, exit point, interconnection point or bidirectional point.}
Cost Allocation Methodology	the document developed by Horizon Power, in accordance with section 134(1)(b) of the *Code*, as part of the ringfencing rules, to ensure the ringfencing objective related to cost allocation is met, and published in accordance with section 133 of the *Code*.

Defined term	Meaning
covered Pilbara network	has the same meaning given to it in section 3 of the *Act* and for the purposes of this policy includes both a network and a right of the *NSP* to use a network (to the extent of that right of use). {As at 25 June 2021, the *Act* defines *covered Pilbara network* as a covered network that is located wholly or partly in the *Pilbara region*.}
covered service	has the same meaning given to it in the *Code*. {As at 25 June 2021, the *Code* defines *covered service* as a *service* provided by means of a *light regulation network*, but does not include an excluded service.}
customer	has the same meaning given to it in the *Code*. {As at 25 June 2021, the *Code* defines *customer* as a— (a) *user*; or (b) end-use customer in the end-use customer's capacity as indirect customer for *covered services*.}
distribution system	has the meaning given to it in the *Code.* {As at 25 June 2021, the *Code* defines *distribution system* as any apparatus, equipment, plant or buildings used, or to be used, for, or in connection with the transportation of electricity at nominal voltages of less than 66 kV.}
entry service	a *covered service* provided at a *connection point* on a *light regulation network* that is an entry point. {As at 25 June 2021, the *Code* defines entry point as a point on a *light regulation network* which is, or is to be, identified as such (explicitly or by inference) in a contract for *services* at which, subject to the contract for *services*, electricity is more likely to be transferred into the *light regulation network* than transferred out of the *light regulation network*.}
exit service	a *covered service* provided at a *connection point* on a *light regulation network* that is an exit point. {As at 25 June 2021, the *Code* defines exit point as a point on a *light regulation network* which is, or is to be, identified as such (explicitly or by inference) in a contract for *services* at which, subject to the contract for *services*, electricity is more likely to be transferred out of the *light regulation network* than transferred into the *light regulation network*.}
force majeure	has the same meaning given to it in the *Code*. {As at 25 June 2021, the *Code* defines *force majeure* in relation to operating on a person, as a fact or circumstance beyond the person's control and which a reasonable and prudent person would not be able to prevent or overcome.}
good electricity industry practice	has the same meaning given to it in the *Code*. {As at 25 June 2021, the *Code* defines *good electricity industry practice* as the exercise of that degree of skill, diligence, prudence and foresight that a skilled and experienced person would reasonably exercise under comparable conditions and circumstances consistent with applicable written laws and statutory instruments and applicable recognised codes, standards (including relevant Australian Standards) and guidelines.}

Defined term	Meaning
Horizon Power coastal network	has the same meaning given to it in the *Code*. {As at 25 June 2021, the *Code* defines *Horizon Power coastal network* as— (a) the network which became a covered network as a result of the Minister's "final coverage decision" of 2 February 2018 under the ENAC; and (b) any other network owned by Regional Power Corporation and interconnected as at the *code* commencement date with the network in paragraph (a); and (c) any augmentation as at the *code* commencement date of a network in paragraph (a) or (b); and (d) any augmentation of the network which forms part of the network under section 4(1).}
Horizon Power Pilbara Network Business	A ringfenced business unit within Horizon Power responsible for the *Horizon Power coastal network*, including those functions carried out by Horizon Power for the purposes of providing network *services* in the *Horizon Power coastal network*. Note: *Horizon Power Pilbara Network Business* is not a separate legal entity and all contractual commitments will be executed in the name of Horizon Power. Where the term *Horizon Power Pilbara Network Business* is used, it means Horizon Power, acting in its capacity as the owner and operator of the *covered Pilbara network*, as distinct from Horizon Power acting in its capacity as a provider of *services* to other regions or as a provider of non-regulated *services* such as generation and retail within the North West Interconnected System.
interconnection service	a *covered service* provided at a *connection point* on a *light regulation network* that is an interconnection point. {As at 25 June 2021, the *Code* defines interconnection point as a point on a *network* at which an interconnector connects to the network.}
light regulation network	has the same meaning given to it in the *Code.* {As at 25 June 2021, the *Code* defines *light regulation network* as a *covered Pilbara network* which is regulated by Part 8A of the *Act*.}
network assets	has the same meaning given to it in the *Code*. {As at 25 June 2021, the *Code* defines *network assets* in relation to a Pilbara network as the apparatus, equipment, plant and buildings used to provide or in connection with providing *covered services* on the Pilbara network.}
network service provider (NSP)	has the same meaning given to *'Pilbara network service provider'* in the *Act*. {As at 25 June 2021, the *Act* defines '*Pilbara network service provider*' as a person who— (a) owns, controls or operates a Pilbara network or any part of a Pilbara network; or (b) proposes to own, control or operate a Pilbara network or any part of a Pilbara network.}

Defined term	Meaning
new facility	has the same meaning given to it in the *Code*. {As at 25 June 2021, the *Code* defines *new facility* as any capital asset developed, constructed or acquired to enable the *NSP* to provide *covered services* and to avoid doubt, includes stand-alone power systems or other assets required for the purpose of facilitating competition in retail markets for electricity.}
new facilities investment	has the same meaning given to it in the *Code*. {As at 25 June 2021, the *Code* defines *new facilities investment* for a *new facility* as the capital costs incurred in developing, constructing and acquiring the *new facility*.}
new facilities investment test	has the same meaning given to it in the *Code*. {As at 25 June 2021, the *Code* defines *new facilities investment test* for a *light regulation network* as the test established under section 55.}
non-capital costs	has the same meaning given to it in the *Code*. {As at 25 June 2021, the *Code* defines *non-capital costs* in relation to *covered services* provided by a *NSP* by means of a *light regulation network* for a period of time, as all costs incurred in providing the *covered services* for the period of time which are not *new facilities investment* or *capital-related costs*, including those operating, maintenance and administrative costs which are not *new facilities investment* or *capital-related costs*.}
operating expenditure (opex)	an expense to be shown on a company's income statement as an expenditure, rather than on its balance sheet as an investment.
Pilbara region	has the same meaning given to it in the *Act*. {As at 25 June 2021, the *Act* defines *Pilbara region* as the *Pilbara region* defined in the *Regional Development Commissions Act 1993* Schedule 1.}
price list	has the same meaning given to it in the *Code*. {As at 25 June 2021, the *Code* defines *price list* as the schedule of *tariffs* for a *light regulation network*.}
pricing period	has the same meaning given to it in the *Code.* {As at 25 June 2021, the *Code* defines *pricing period* as the defined future period, which must not be more than 5 years, for which a *services and pricing policy* is applicable.}
rate of return	has the same meaning given to it in the *Code*. {As at 25 June 2021, the *Code* defines *rate of return* for a *light regulation network* as the value determined under section 57, 58 or, where applicable, Chapter 7.}
reference service	has the same meaning given to it in the *Code*. {As at 25 June 2021, the *Code* defines *reference service* as a *covered service* designated by a *services and pricing policy* to be a *reference service*, and which is provided on the corresponding reference terms and conditions.}

Defined term	Meaning
reference tariff	has the same meaning given to it in the *Code*. {As at 25 June 2021, the *Code* defines *reference tariff* as the *tariff* specified in a *price list* for a *reference service*.}
services	has the same meaning given to it in the *Act* and service has a corresponding meaning. {As at 25 June 2021, the *Act* defines *services* as— (a) the transport of electricity, and other services, provided by means of network infrastructure facilities; and (b) services ancillary to those services.}
services and pricing policy	has the same meaning given to it in the *Code*. {As at 25 June 2021, the *Code* defines *services and pricing policy* as the policy of an *NSP* which contains the details referred to in section 40.}
small use customer	has the meaning given to '*customer*' in section 78 of the *Act* (for the purposes of Part 6 of the *Act*). {As at 25 June 2021, the *Act* defines '*customer*' as a customer who consumes not more than 160 MWh of electricity per annum.}
stand-alone cost of service provision	has the same meaning given to it in the *Code*. {As at 25 June 2021, the *Code* defines *stand-alone cost of service provision* in relation to a *customer* or group of *customer*s, a *covered service* and a specified period of time, as that part of total costs that the *NSP* would incur in providing the *covered service* to the *customer* or group of *customer*s for the period of time, if the *covered service* was the sole *covered service* provided by the *NSP* and the *customer* or group of *customer*s was the sole *customer* or group of *customer*s supplied by the *NSP* during the specified period of time.}
sub-transmission system	has the same meaning given to it in the *Code*. {As at 25 June 2021, the *Code* defines *sub-transmission system* as any apparatus, equipment, plant or buildings used, or to be used, for, or in connection with, the transportation of electricity at nominal voltages of 22 kV or higher but less than 66 kV dedicated to a single *connection point* above 15 MVA.}
TAC eligible customer exit point	has the same meaning given to it in the *Code*. {As at 25 June 2021, the *Code* defines *TAC eligible customer exit point* as a *customer*'s exit point on the *Horizon Power coastal network* at which electricity is consumed by a *customer* who is not a prescribed *customer*.}
target revenue	has the same meaning given to it in the *Code.* {As at 25 June 2021, the *Code* defines *target revenue,* for a *light regulation network* for a *pricing period*, as determined in accordance with sections 47 to 60.}
tariff	has the same meaning given to it in the *Code.* {As at 25 June 2021, the *Code* defines *tariff* for a *covered service*, as the criteria that determine the *charge* that is payable by a *user* to the *NSP*.}

Defined term	Meaning
tariff setting methodology	has the same meaning given to it in section 62 of the *Code.* {As at 25 June 2021, section 62 of the *Code* defines *tariff setting methodology* as— (a) the structure of *tariffs* for all or part of the relevant *pricing period*, which determines how *target revenue* is allocated across and within *covered services*; and (b) includes all methodologies, processes, assumptions, inputs and criteria used in developing that structure and applying it to determine *tariffs*.}
transmission system	has the same meaning given to it in the *Act.* {As at 25 June 2021, the *Act* defines *transmission system* as any apparatus, equipment, plant or buildings used, or to be used, for, or in connection with, the transportation of electricity at nominal voltages of 66 kV or higher.}
user	has the same meaning given to it in the *Code.* {As at 25 June 2021, the *Code* defines *user* as a person, who is a party to a contract for *services* with an *NSP*, and in connection with a deemed associate arrangement, includes the *NSP's* other business.}

2. POLICY STATEMENT

This *tariff setting methodology* provides assurance to the community served by Horizon Power that the prices in Horizon Power's *price list* for *covered Pilbara network services* comply with the requirements as set out in the Pilbara Networks Access *Code* 2021 (the *Code*).

3. WHO THIS METHODOLOGY APPLIES TO

This methodology applies to the setting of *reference tariffs* for all *user*s accessing, or seeking to access, Horizon Power's *covered Pilbara network*.

Unless otherwise specified, all costs and revenue in this *tariff setting methodology* are in nominal dollars.

4. PURPOSE OF THIS TARIFF SETTING METHODOLOGY

The purpose of this *tariff setting methodology* is to describe how the prices for providing *covered Pilbara network services* for the second *pricing period* (from 1 July 2024 to 30 June 2027) have been calculated and to demonstrate that they are consistent with the Pilbara electricity objective, revenue and pricing principles, and the requirements in the *Code* for a *tariff setting methodology*.

This *tariff setting methodology* is part of Horizon Power's *services and pricing policy*, which is required to be published under section 40(4)(a) of the *Code*. The prices for providing *covered Pilbara network services* that are derived using this *tariff setting methodology* are set in Horizon Power's *price list* for the first year of the second *pricing period* (2024-25).

4.1 Pilbara electricity objective

The Pilbara electricity objective is:

> *To promote efficient investment in, and efficient operation and use of, services of Pilbara networks for the long-term interests of consumers of electricity in the Pilbara region in relation to—*
>
> *(a) price, quality, safety, reliability and security of supply of electricity, and*
>
> *(b) the reliability, safety and security of any interconnected Pilbara system.*[1]

For the purposes of applying this objective, regard may be had in relation to the following matters:

- the contribution of the Pilbara resources industry to the State's economy
- the nature and scale of investment in the Pilbara resources industry
- the importance to the Pilbara resources industry of a secure and reliable electricity supply
- the nature of electricity supply in the *Pilbara region*, including whether or not regulatory approaches used outside the *Pilbara region* are appropriate for that region, Pilbara network *users* and Pilbara networks
- any other matter the person or body considers relevant.[2]

4.2 Revenue and pricing principles

The revenue and pricing principles, as set out in section 8 of the *Code*, are as follows:

(a) An *NSP* of a *light regulation network* should be provided with a reasonable opportunity to recover at least the efficient costs it incurs in:

(i) providing *covered services*, and

(ii) complying with regulatory obligations, but excluding any costs it incurs in connection with access disputes.

(b) An *NSP* of a *light regulation network* should be provided with effective incentives in order to promote economic efficiency with respect to the *covered services* it provides. The economic efficiency that should be promoted includes:

(i) efficient investment in the *light regulation network*

(ii) the efficient provision of *covered services*

(iii) the efficient use of the *light regulation network*.

(c) The price for provision of a *covered service* should allow for a return commensurate with the regulatory and commercial risks involved in providing the *covered service* to which that price relates.

[1] *Electricity Industry Act 2004*, section 119(2)
[2] *Electricity Industry Act 2004*, section 119(3)-(4)

(d) Regard should be had to the economic costs and risks of the potential for:

  (i) under and over investment in a *light regulation network*, and

  (ii) under and over utilisation of the *light regulation network*.

4.3 Price list

Section 43 of the *Code* states that the *charges* to be paid for access to *services* of a *light regulation network* are to be determined by negotiation between the applicant and the *NSP* under the *Act* and the *Code*, and failing agreement, by arbitration under Chapter 7 of the *Code*. A *price list* is to be used as a reference point for those price negotiations and arbitration for *covered services*.

Section 44 of the *Code* states that the prices set out in a *price list* are to be calculated by:

(a) firstly, calculating the *target revenue* for the *light regulation network*, and then

(b) secondly, developing *tariff setting methodologies* and applying them to derive *tariffs* that are expected to deliver the *target revenue*, and then

(c) thirdly, applying the *tariff setting methodologies* to derive a *price list*.

4.4 Determining target revenue

An overview of the methodology for determining the *target revenue*, as set out in sections 47 to 60 of the *Code*, is as follows:

(a) The *target revenue* for each year (or other interval) in a *pricing period* is to be determined using the building block approach in which the building blocks are:

  (i) *capital-related costs* calculated by:

    a. (return on capital) calculating a return on the *capital base* for the *pricing period* by applying the *rate of return*, and adding

    b. (return of capital) depreciation for the *pricing period*, plus

  (ii) *non-capital costs* (also referred to as *operating expenditure*), plus

  (iii) *capital-related costs* associated with forecast *new facilities investment* (also referred to as *capital expenditure*) which at the time of inclusion are reasonably expected to satisfy the *new facilities investment test* when the *new facilities investment* is made.

(b) Costs are allocated between *covered service*s and any other activities undertaken by Horizon Power by applying the *Cost Allocation Methodology*.

(c) The value of the *capital base* for the first *pricing period* (the initial *capital base*) is specified in section 52(1) of the *Code*.

(d) The *capital base* is rolled forward during the *pricing period* by deducting depreciation and disposals, in accordance with Horizon Power's Capital Base Roll Forward Methodology.

(e) The *rate of return* for the second *pricing period* has been determined in accordance with the *Code*.

   a. Section 58(2)(a) of the *Code* states that the *rate of return* is to be commensurate with the regulatory and commercial risks involved in providing *covered services*.

   b. Section 57(2)(c) of the *Code* states that the *rate of return* is to be determined on a pre-tax basis.

(f) The *network assets* in the *capital base* are depreciated so that each *network asset* or group of *network assets* is depreciated over the economic life of that *network asset* or group of *network assets*, with adjustments as required to reflect changes in the expected economic life. [3]

(g) The *non-capital costs* are those *non-capital costs* that do not exceed the amount that would be incurred by a prudent *NSP*, acting efficiently, in accordance with *good electricity industry practice*, to achieve the lowest sustainable cost of delivering *covered services* having regard to the revenue and pricing principles and Pilbara electricity objective. [4]

Further details on the methodology for determining the *target revenue* are set out in subsequent sections of this *tariff setting methodology*.

4.5 Tariff setting methodology

The *tariff setting methodology* for a *light regulation network* must have regard to the Pilbara electricity objective and must apply the revenue and pricing principles.[5] It must include the following elements:

- the structures for each proposed *reference tariff*
- the charging parameters for each proposed *reference tariff*
- a description of the approach that the *NSP* will take in setting each *reference tariff* in each *price list* during the relevant *pricing period*.[6]

[3] Section 59(2)
[4] Section 60
[5] Section 62(4)
[6] Section 63(1)

The objectives of the *tariff setting methodology* are that:

(a) the *reference tariffs* that an *NSP* charges to provide *reference services* should reflect the *NSP's* efficient cost of providing those *reference services*

(b) for each *reference tariff*, the revenue expected to be recovered must lie on or between:

  (i) an upper bound representing the *stand-alone cost of service provision* for *customers* to whom or in respect of whom that *reference tariff* applies, and

  (ii) a lower bound representing the avoidable cost of not serving the *customers* to whom or in respect of whom that *reference tariff* applies

(c) the structure of *tariffs* must, to the extent practicable, be consistent with the Pilbara electricity objective, accommodate the reasonable requirements of *users* collectively and end-use *customers* collectively

(d) each *reference tariff* must be based on the forward-looking efficient costs of providing the *reference service* to which it relates with the method of calculating such cost and the manner in which that method is applied to be determined having regard to:

  (i) the additional costs likely to be associated with meeting demand from end-use *customers* that are currently on that *reference tariff* at times of greatest utilisation of the relevant part of the *light regulation network*, and

  (ii) the location of end-use *customers* that are currently on that *reference tariff* and the extent to which costs vary between different locations in the *light regulation network*

(e) the revenue expected to be recovered from each *reference tariff* must:

  (i) reflect the *NSP's* total efficient costs of serving the *customers* on that *reference tariff*

  (ii) when summed with the revenue expected to be received from all other *reference tariffs*, permit the *NSP* to recover the expected revenue for the *reference services* in accordance with the *services and pricing policy*

  (iii) comply in a way that minimises distortions to the price signals for efficient usage which would result from *reference tariffs* that comply with (d) above

(f) the structure of each *reference tariff* must be reasonably capable of being understood by *customers* that are currently on that *reference tariff*, including enabling a *customer* to predict the likely annual changes in *reference tariffs* during a *pricing period* having regard to:

(i) the type and nature of those *customers*

(ii) the information provided to, and the consultation undertaken with, those *customers*[7]

(g) the *reference tariff* to be paid by a *user* in connection with the *user's* supply of electricity to a *small use customer at a connection point*, does not differ from the *tariff* applying to that or any other *user* supplying electricity to *small use customers* at other *connection points* within the network, as a result of differences in the geographic locations of the *connection points.*[8]

4.6 Temporary access contribution

Horizon Power is required under section 129N(1) of the *Act* to pay a temporary access contribution (TAC) into the Temporary Access Contribution Account. Under section 48 of the *Code*, this may be added to the *target revenue* for the *pricing period*, and must be separately identified in the *services and pricing policy*.

Under section 65 of the *Code*, the TAC must only be recovered from *users* of *reference services* in respect of *TAC eligible customer exit points*, excluding those located on a *transmission system* or a *sub-transmission system*.

[7] Section 63(2)-(7)
[8] Section 64

5. TARGET REVENUE – 1 JULY 2024 – 30 JUNE 2027

By applying the building block approach, the *target revenue* that is forecast to be required by Horizon Power to recover at least the efficient costs of providing *covered Pilbara network services* during the second *pricing period* (1 July 2024 to 30 June 2027) is set out in Table 5.1, and illustrated in Figure 5.1 (excluding the TAC).

The Temporary Access Contribution is the amount gazetted by the Government and represents 4.1% of the *target revenue* (including the TAC) in 2024-25. The TAC has been gazetted to be zero in 2025-26 and 2026-27.

In nominal terms, the *target revenue* (excluding the TAC) is forecast to increase by 2.4% from $97.9 million in 2024-25 to $100.2 million in 2025-26 and increase by 1.5% to $101.7 million in 2026-27.

Table 5.1: Target revenue – 2024-25 to 2026-27 ($ nominal)

Building block component	2024-25	2025-26	2026-27
Capital base (excl. corporate)			
Return of capital base	29,733,596	28,802,333	28,290,845
Return on capital base	29,701,337	28,924863	28,146,759
New facilities investment (excl. corporate)			
Return of new facilities investment	253,019	1,044,459	1,394,040
Return on new facilities investment	772,357	1,606,715	2,519,589
Non-capital costs	32,858,538	33,745,156	34,632,653
Share of corporate capital-related costs			
Capital base	3,499,879	3,443,753	2,566,350
New facilities investment	669,933	2,247,625	3,692,745
Revenue adjustment from last pricing period	391,709	423,687	457,963
Target revenue (excl TAC)	**97,880,369**	**100,238,591**	**101,700,945**
Temporary Access Contribution	4,087,626	0	0
Total target revenue	**101,967,995**	**100,238,591**	**101,700,945**

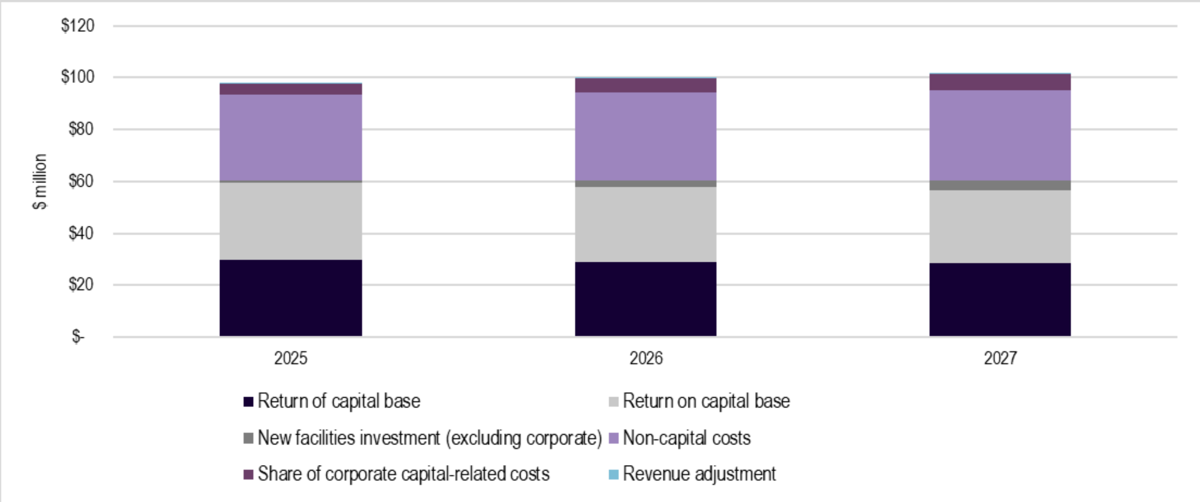

Figure 5.1: Target revenue (excluding the TAC), 2024-25 to 2026-27

The three most significant components of the *target revenue* are the return of the *capital base*, the return on the *capital base* and the *non-capital costs*. In 2024-25, these are forecast to comprise 30%, 30% and 34%, respectively, of the *target revenue* (excluding the TAC).

As illustrated in Figure 5.2, the *target revenue* in the second *pricing period* is higher than in the first *pricing period*. This is due to CPI, higher CPI in the first *pricing period* than forecast and an increase in the *rate of return* from 4.06% to 5.32% (refer section 11.2). After taking into account the actual increase in CPI and the increase in the *rate of return*, the revenue in the second *pricing period* is similar to the *target revenue* at the commencement of the first *pricing period*.

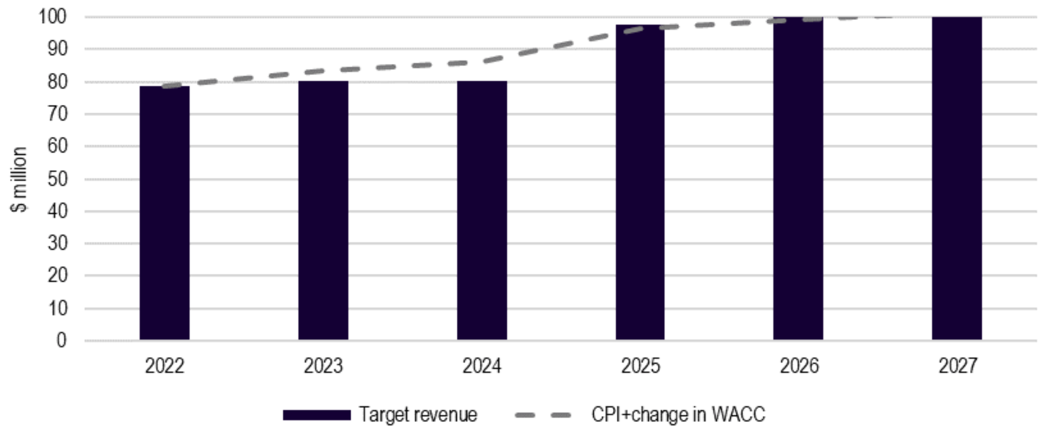

Figure 5.2: Target revenue (excluding the TAC), 2021-22 to 2026-27

The calculation of the *target revenue* is described in the following sections:

- forecast *new facilities investment* or *capital expenditure* (*capex*) in section 6
- forecast *non-capital costs* or *operating expenditure* (*opex*) in section 7
- opening *capital base* in section 8
- return of capital in section 9
- closing *capital base* in section 10
- return on capital in section 11
- temporary access contribution in section 12
- adjustments to *target revenue* in section 13.

The *reference tariffs* are derived by first allocating the *target revenue* to cost pools. The allocation of the *target revenue* to cost pools is described in section 15. These cost pools are then allocated to *reference tariffs*, which is described in section 17. The *reference tariffs* are then calculated and published in the *price list*. The *reference services* to which these *reference tariffs* relate, and the structure of the *reference tariffs*, are described in section 16.

6. FORECAST NEW FACILITIES INVESTMENT

Section 47(2) of the *Code* states that the *target revenue* for each year in a *pricing period* may include *capital-related costs* in relation to forecast *new facilities investment* which at the time of inclusion are reasonably expected to satisfy the *new facilities investment test* when the forecast *new facilities investment* is made.

The *new facilities investment test*, which is set out in section 55(1) of the *Code*, is as follows:

> *New facilities investment* satisfies the *new facilities investment test* if it is both *prudent* and *justified*, as follows—
>
> (a) the *new facilities investment* is **"prudent"** if it does not exceed the amount that would be invested by a prudent *NSP*, acting efficiently and in accordance with *good electricity industry practice*, having regard, without limitation, to—
>
> (i) whether the *new facility* exhibits economies of scale or scope; and
>
> (ii) whether incremental capacity can be added to the *new facility*; and
>
> (iii) whether the lowest sustainable cost of delivering *covered services* forecast to be provided over a reasonable period may require the installation of a *new facility* with capacity sufficient to meet the forecast supply, having regard to the revenue and pricing principles and the Pilbara electricity objective;
>
> and
>
> (b) the *new facilities investment* is **"justified"** if one or more of the following conditions are satisfied:
>
> (i) the anticipated incremental revenue for the *new facility* is expected to at least recover the *new facilities investment*; or
>
> (ii) the *new facility* provides a net benefit to those who generate, transport and consume electricity in the *light regulation network* or the *light regulation network* and any interconnected Pilbara system over a reasonable period of time that reasonably justifies higher *reference tariffs*; or
>
> (iii) the *new facility* is necessary to maintain the safety or reliability of the *light regulation network* or its ability to provide contracted *covered services*.

The purpose of this section is to describe the *new facilities investment* that is forecast for the second *pricing period* (1 July 2024 to 30 June 2027), which is reasonably expected to satisfy the *new facilities investment test*, and the processes applied by Horizon Power to forecast the *new facilities investment*.

6.1 Investment Governance Framework

Horizon Power's Investment Governance Framework describes the structure and approach that it applies to make investment decisions, which involves allocating and managing financial capital to deliver specific and measurable business outcomes to achieve corporate objectives.

The Investment Governance Framework is illustrated in Figure 6.1.

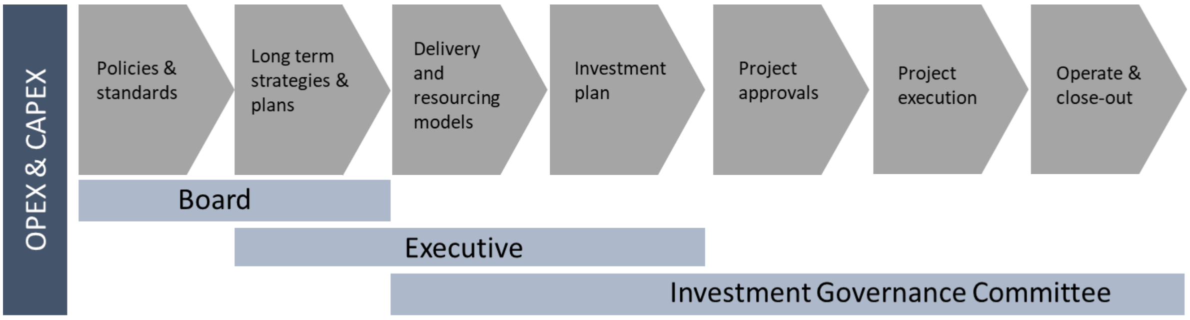

Figure 6.1: Investment Governance Framework

A key output of the Investment Governance Framework is the Investment Plan, which is discussed in section 6.2.

6.2 Investment Plan

The Investment Plan, which is a product of the Investment Governance Framework, is Horizon Power's approved *capex* and *opex* workplan.

In accordance with the asset management planning process, the Investment Plan is developed in response to the overarching policies, standards, long term strategies and plans to meet the corporate objectives.

Management of risks in each region is the responsibility of the Regional Asset Manager and, in accordance with the corporate risk management systems (Cintellate and CURA), assets and issues that require action are recorded. The Asset Class Strategies consider the risk from the assets and develop strategies to manage the risk to As Low As Reasonably Practicable (ALARP).

For other investments, Horizon Power applies an ALARP filter to the decision-making process, in accordance with the risk management framework, to ensure that only projects that reflect the Board's risk appetite are considered in the Investment Plan.

Following the bottom-up development of the Investment Plan, the proposed works are optimised to reflect the highest value to Horizon Power within the financial and resource constraints that may exist at the time.

The updated investment portfolio is approved by the Investment Governance Committee every 12 months to ensure that the portfolio aligns with the corporate objectives, and the Asset Management Strategy and objectives.

At the commencement of each *pricing period*, the approved Investment Plan is used as the basis for forecasting *opex* and *capex* for the *covered Pilbara network* as an input to the determination of the *target revenue* and *tariffs* for access to the network in that *pricing period*.

6.3 Expenditure forecasting methodology

Figure 6.2 provides an overview of Horizon Power's expenditure forecasting process. An Investment Plan is developed for the entire Horizon Power business by optimising the forecasts developed through a top down and a bottom-up approach. Horizon Power's *Cost Allocation Methodology* is applied to derive the *opex* and *capex* forecast that is relevant to the *covered Pilbara network*.

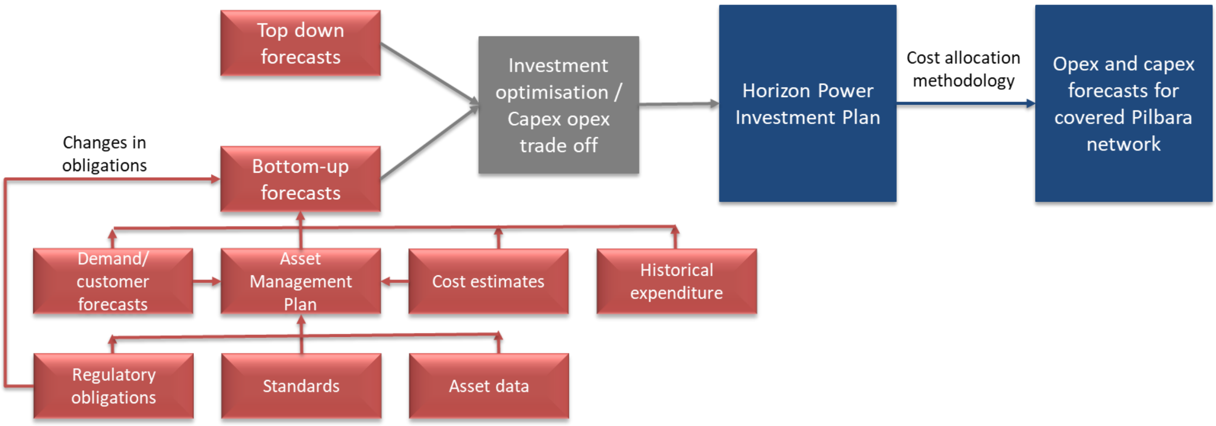

Figure 6.2: Overview of the expenditure forecasting process

The expenditure forecast also takes into consideration any submissions received through the public consultation process conducted in accordance with section 41(4) of the *Code*.

6.4 Top down forecast

Horizon Power operates under the *Electricity Corporations Act 2005*, led by a board of directors accountable to the Minister for Energy, representing all Western Australians. Section 50 of the *Electricity Corporations Act 2005* defines the principal functions of the Regional Power Corporation, trading as Horizon Power. Its primary objective is to reduce its cost base and improve the reliability of electricity supply.

6.4.1 Top down capex forecast

Performance objectives and targets are established for assets against the following key performance areas as shown in Table 6.1:

1. Safety (public and employee / contractor)
2. Asset Service
3. Economics
4. Reliability
5. Compliance
6. Customer
7. Capacity.

The asset-related key performance areas provide guidance on reviewing the cost-risk balance of progressing works on assets. Associated targets identify areas where expenditure may be justified on a risk reduction basis.

Horizon Power agrees its 10-year Asset Investment Program with the Government annually, subject to Expenditure Review Committee approval.

Table 6.1: Asset-related key performance areas

Objective	Key Performance Area	Policy Area
Presents a safety risk to Horizon Power's people and communities that is as low as reasonably practicable	Safety	Safety
Assets are managed to extract the maximum value, including replacement of assets at the end of their life	Asset Service	Safety, Supply Quality and Reliability
Assets, processes and systems maximise economic value including consideration of *customer* side solutions to maximise this value	Economics	Supply Quality and Reliability
Assets are proactively inspected and maintained to the value the community and stakeholders place on reliability of supply	Reliability	Reliability
Comply with regulations, codes and standards so far as is reasonably practicable	Compliance	Safety, Supply Quality and Reliability
Undertake works in response to customer request for connection or other services	Customer	Reliability
Assets are designed to meet the value that the community and stakeholders place on reliability of supply	Capacity	Reliability

6.5 Bottom-up capex forecast

The broad categories of *capex* incurred by Horizon Power are described in Table 6.2, together with the drivers for that expenditure.

Table 6.2: Description of capex categories

Capex category	Description	Driver
Safety	Typically incurred to ensure that Horizon Power's *network assets* present a safety risk to its people and communities that is as low as reasonably practicable	Safety risk
Asset Service	Typically incurred to manage risks to extract maximum value. This includes replacement of *network assets* at the end of their life, or where the costs exceed the benefits of the assets remaining in service considering elevated failure risks, technical obsolescence and inability to source spares or expertise	Asset data (asset condition, asset age, asset risk)
Reliability	Includes the proactive inspection and maintenance of *network assets* to ensure they meet the value that the community and stakeholders place on the reliability of supply	Load at risk
Compliance	Relates to meeting legislative and regulatory obligations in relation to, for example, the environment, so far is reasonably practicable	Legislative and regulatory obligations
Economics	Relates to maximising the value for *customers*	Benefits exceed costs
Customer	Typically relates to the cost of connecting *customers* to the network and other *customer*-related works	*Customer* number forecast Specific major projects
Capacity driven	Typically triggered by a need to build or upgrade assets to address changes in demand for *services* to meet the value that the community and stakeholders place on reliability of supply	Peak demand forecast Load at risk

Capex category	Description	Driver
Non-system	Primarily for activities not directly associated with the electricity system such as: • IT and communications • vehicles • plant and equipment • buildings and property	Asset data (asset condition, asset age, asset risk)

The approaches used to forecast *capex* varies by *capex* category. The following sections describe the approach in more detail.

6.5.1 Safety capex

Horizon Power continually scans its operating environment to identify investment needs emerging from safety risks – these are recorded and described, with any significant investments to address safety concerns supported with safety investigations.

The Asset Management Plan (AMP) will be updated to include the number of assets impacted. The unit costs of these works are estimated in accordance with the Cost Estimation Methodology.

6.5.2 Asset Service capex

Horizon Power forecasts asset service *capex* based on its AMPs. The AMPs are updated annually based on Horizon Power's Asset Management Policy, Asset Management Strategy and Asset Class Strategies, and rolling inspections of assets to evaluate the likelihood of failure based on observable defects or condition.

The Asset Management Policy outlines Horizon Power's commitment to systematically manage assets to meet the needs of its stakeholders while discharging legal, regulatory, statutory, and strategic obligations. The policy requires that Horizon Power establish an Asset Management System to do so.

In meeting the outlined asset management objectives, Horizon Power, among other things:

- scans the operating environment to identify changes in industry practice, which lead to changes in asset class strategies, and may drive upgrades, replacement or refurbishment of assets
- undertakes works based on the benefits to the business and community from the long-term risk reduction, including financial benefits

- manages safety risks to the more conservative of ALARP or *good electricity industry practice*. [9]

The Asset Management Strategy outlines Horizon Power's long-term strategy for developing its electricity system and managing its existing assets. It describes the asset management processes and explains how these assist Horizon Power to achieve its asset management objectives and meet stakeholder expectations, for a rolling 10-year period. This is captured in the AMP for each region.

The Asset Class Strategies are a suite of documents for each asset class that reviews the planning criteria for maintenance and asset service on the basis of the risk to Horizon Power. The strategies analyse each asset class across Horizon Power, identify significant issues and risks, and present recommended strategies and actions.

While the AMP identifies the volume of assets that are forecast to be replaced during the next *pricing period*, the costs of those assets to be replaced are estimated in accordance with Horizon Power's Cost Estimation Methodology.

6.5.3 Reliability capex

Horizon Power monitors the reliability of its network to identify those parts of the network where the reliability does not meet the value that the community and stakeholders place on the reliability of supply. Where economic to do so, *capex* is forecast to improve the reliability for the worst performing areas of the network.

The AMP will be updated to include the number of assets impacted. The unit costs of these works are estimated in accordance with the Cost Estimation Methodology.

6.5.4 Compliance capex

Horizon Power continually scans its operating environment to identify investment needs emerging from changing regulatory obligations – internal and external audits periodically identify compliance issues, which may drive upgrades, replacement or refurbishment of assets.

The AMP will be updated to include the number of assets impacted. The unit costs of these works are estimated in accordance with the Cost Estimation Methodology.

6.5.5 Economics capex

Horizon Power monitors its assets, processes and systems, and scans its operating environment, to identify opportunities to maximise the value for *customers*. Where these opportunities are identified, the AMP will be updated to include the number of assets impacted. The unit costs of these works are estimated in accordance with the Cost Estimation Methodology.

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[9] Safety-related residual risks are required to be "As Low As Reasonably Practicable" (ALARP), that is, Horizon Power must be able to demonstrate that the cost involved in reducing the safety risk further would be disproportionate to the benefit gained. Where ALARP indicates a lower/worse standard than *good electricity industry practice*, then *good electricity industry practice* is applied.

6.5.6 Customer capex

The forecast *customer capex* is driven by the number of new *customer*s choosing to connect to the network.

Connections may be simple or complex. The *capex* associated with simple connections is forecast based on the number of new connections (single phase or three phase) and the estimated cost of those connections.

The *capex* associated with complex connections is specific to each of those complex connections. Horizon Power forecasts each of the complex connections that are likely to occur and then estimates the costs associated with the connection and the costs that will be recovered from the *customer* in accordance with its Contributions Policy.

Each of the complex connections is assigned a probability. The forecast net *capex* for the complex connections is the probability weighted sum of the forecast gross *capex* less the capital contribution for each of the identified complex connections.

6.5.7 Capacity-driven capex

The forecast capacity-driven *capex* is largely driven by the forecast growth in peak demand.

The peak demand is forecast in accordance with Horizon Power’s Demand and Connections Forecasting Policy. Horizon Power applies this forecast to its network model to identify where capacity constraints may emerge, and then identifies efficient solutions to relieve or avoid those constraints.

A list of discrete possible projects is identified. The accuracy with which each of these discrete projects is costed depends on the timing for the project. Those that are to be delivered earlier in the next *pricing period* will be further progressed through the project investment lifecycle and hence the costings will be more accurate – ±10% for those at Phase 3: Define & Approve. Conversely, the costings for those that are to be delivered later in the next *pricing period* (or the following *pricing period*), and which are in the early stages of the project investment lifecycle will have less accurate costings – ±50% for those at Phase 1: Concept.

The projects are costed in accordance with Horizon Power’s Cost Estimation Methodology.

Depending on the timing of a specific project, a *new facilities investment test* may have been undertaken for the project.

6.5.8 Non-system capex

The approach to forecasting the non-system *capex* is the same as for forecasting replacement *capex*, with that approach applied to non-system assets.

6.6 Forecast new facilities investment

The *new facilities investment* that is forecast for the last year of the first *pricing period* and each year of the second *pricing period* (1 July 2024 to 30 June 2027) by category is set out in Table 6.3 and by cost pool is set out in Table 6.4.

Table 6.3: Forecast new facilities investment, by capex category, 2023-24 to 2026-27 ($ million, nominal)

Capex category	2023-24	2024-25	2025-26	2026-27
Safety	0.7	5.6	0.7	0.5
Asset Services	1.9	8.0	5.9	14.6
Reliability	0.0	1.0	4.0	6.1
Compliance	0.0	0.2	0.4	0.6
Economics	0.0	0.5	0.4	0.4
Sub-total – system capex	***2.6***	***18.3***	***11.4***	***22.2***
Non-system capex	2.0	6.9	4.5	4.2
Overhead costs recovered	0.5	4.4	2.1	5.3
Gross capex	**5.1**	**29.5**	**18.1**	**31.6**
Less contributions	0.0	0.0	0.0	0.0
Net capex	**5.1**	**29.5**	**18.1**	**31.6**

Table 6.4: Forecast new facilities investment, by cost pool, 2023-24 to 2026-27 ($ million, nominal)

Cost pool	2023-24	2024-25	2025-26	2026-27
Transmission	0.7	12.5	1.9	14.6
Sub-transmission	0.0	0.0	0.0	0.0
Distribution HV	0.8	4.2	4.7	8.5
Distribution LV	0.4	0.7	0.7	0.2
Streetlighting	0.4	2.0	0.7	0.7
Metering	0.2	0.2	0.2	0.2
Non-system assets	1.1	2.5	1.0	1.5
Sub-total	**3.5**	**22.0**	**9.2**	**25.7**
Corporate (share)	1.6	7.5	8.8	5.9
Total	**5.1**	**29.5**	**18.1**	**31.6**

The forecast *new facilities investment* is compared with the historical *new facilities investment* in Figure 6.3. The investment in non-system assets and a share of corporate assets is estimated in 2020 and 2021 (prior to coverage of the *Horizon Power coastal network*) as the information is not available in a consistent format in those years.

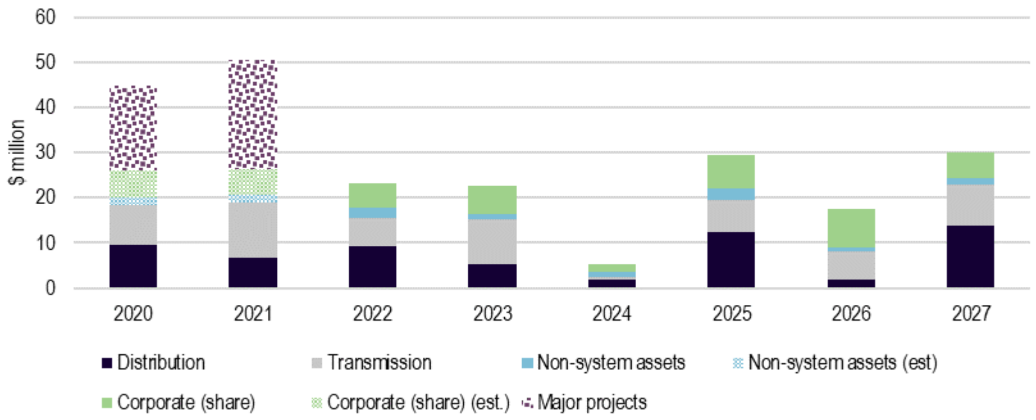

Figure 6.3: Comparison of forecast capital expenditure to historical expenditure, [real, $2025[10]]

The *new facilities investment* varies substantially from year to year. The historical *capital expenditure* in the *Horizon Power coastal network* in 2020 and 2021 was dominated by a number of high profile major projects, including:

- Pilbara Underground Power Program (PUPP)
- replacement of the Karratha to Dampier 132kV transmission line
- replacement of the Wedgefield transformers.

These projects have been separately identified in Figure 6.3 to provide a more comparable basis on which to compare the forecast *new facilities investment*.

In real terms, the average *new facilities investment* that is forecast for the second *pricing period* is similar to that in 2020 and 2021, with the exclusion of major projects, and is higher than that for the first *pricing period*. The increase in *new facilities investment* compared to the first *pricing period* is due to increased costs as a result of supply chain disruptions caused by the COVID-19 pandemic and higher expenditure in:

- 2024-25 on:
  - safety-related capex, including the replacement of high-risk HV disconnectors in the Karratha and South Hedland Terminal Stations
  - non-system capex, including refreshing the vehicle fleet to align with industry standards and a major upgrade to specialist meter data management software

[10] Conversion to real June 2020 is based on ABS data using CPI for Australia

- 2026-27 on:
    - asset services capex, including replacement of power transformers at high risk of failure
    - reliability capex, including addressing deteriorating performance of two feeders.

This profile has been provided to the State Government and is consistent with the funding (and borrowing) arrangements in place for Horizon Power over this period, and which extend beyond the *Pilbara region*.

6.6.1 Composition of the forecast new facilities investment

The composition of the forecast *new facilities investment* during the 2024-25 to 2026-27 *pricing period* is shown in Figure 6.4. The *new facilities investment* (*capex*) is driven largely by Asset Services, Reliability, and Non-system assets.

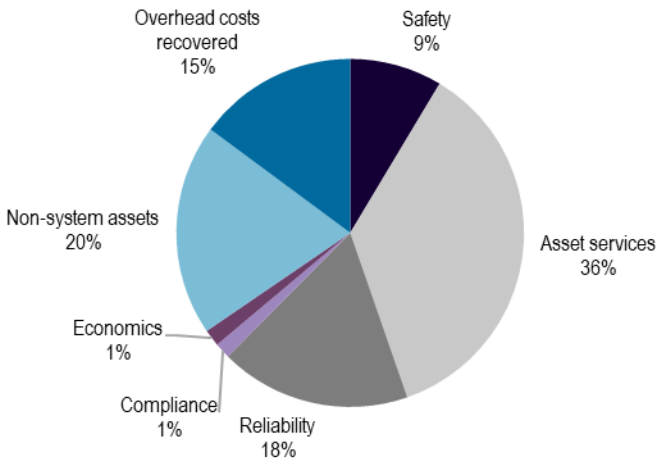

Figure 6.4: Composition of the total capex, 2024-25 to 2026-27

Asset Services is the largest category of *capex*, at 36% of the total *capex* in the Investment Plan and 55% of the system-related *capex*. Consistent with the long-term management of key *network assets* in the region, the planned replacement of assets identified in the latest condition assessment of transmission assets will be continued.

The reliability-driven *capex* comprises 18% of the total *capex*. The projects target improvements to areas of the network where critical *customer*s continue to experience extended outages from the impact of extreme weather events, including cyclones.

Safety-driven *capex* comprises a further 9% of the total *capex*. The safety-driven projects target areas of the network where the safety risk exceeds or is expected to exceed an acceptable level of risk over the *pricing period,* consistent with meeting Horizon Power's safety obligations.

A very small component of the *capex* is driven by compliance obligations and economics, each comprising less than 2% of the total *capex*.

Of the non-system *capex*, the key driver is the planned replacement of key fleet and the progressive refurbishment of operational depots, to address immediate safety issues consistent with a long-term improvement plan. Collectively this comprises 11% of the total *capex*. Supporting essential ICT infrastructure contributes a further 9%.

The forecast *new facilities investment* for the second *pricing period* is described further in the following sections. The forecast *new facilities investment* for the last year of the first *pricing period* is as previously forecast, adjusted for actual CPI.

6.6.2 Safety

The forecast safety *capex* for the second *pricing period* is $6.8 million or $2.3 million per year, on average.

Overview

Safety-driven *capex* includes projects where the performance of the asset, and more specifically the risk of failure, presents a level of safety risk that is no longer tolerable.

This decision is made consistent with Horizon Power's Electricity Safety Network Management System (ENSMS) and assessment to maintain the safety risk ALARP.

These risks may be current or emerging, whereby if action is not taken, the consequence of failure may be serious injury or fatality.

Expenditure summary

Horizon Power is forecasting a number of projects to target specific asset classes where the safety risks are no longer at an acceptable level. Projects forecast in the second *pricing period* include:

- Replacement of high-risk HV disconnectors in the Karratha and South Hedland Terminal Stations which are at end of life. Operators are using live line sticks to ensure these are making good contact which is a safety and reliability issue. These will be replaced with standard substation rated equipment to ensure the equipment can be operated in a safe manner, reducing risk to employees and supply interruption from operation of this equipment.
- Replacement of 16 LV distribution boards that have been identified in the Port Hedland area as a safety risk to switching operators as they contain exposed live connections. Horizon Power standard LV cubicles will be installed to replace the existing LV panels.
- Implementation of an early air-aspirated fire warning system as recommended by an insurance audit. The objective is to provide immediate notification to Horizon Power in the event of a fire starting within a relay room to enable prompt response to extinguish the fire before severe damage occurs to the relay room and its contents thus preventing extensive outages and long restoration times.

6.6.3 Asset Services

The Asset *Services capex* forecast for the second *pricing period* is $28.6 million or $9.5 million per year, on average.

Overview

Some *network assets* are approaching 50 years of service and other assets are approaching the end of their technical life. This is reflected in the declining condition of in-service assets, which will no longer be capable of maintaining the service performance. The replacement of these assets drives our Asset Services *capex*.

Deteriorating condition and/or health of *network* assets typically results in a high risk of failure that presents an elevated risk to the safety of people (including members of the public) and extended outages to supply. In many cases, rapid deterioration and increasing risk are evident at the end of the asset's technical (or design) life that can be validated with modelling of operational behavior to predict failure before it occurs.

The consequences associated with failure can be catastrophic, including where an oil-filled device fails explosively resulting in potentially fatal injuries to a worker or member of the public. It is important that sufficient information is gathered to understand the operating characteristics and failure modes to treat the risk of failure before it occurs.

The Investment Plan includes the priority projects that have been identified following a review of the condition of key transmission transformers in the *covered Pilbara network*. The observations and recommendations associated with assets in poor condition and which require replacement have been included into the investment forecast.

Expenditure summary

Horizon Power has included several projects to target specific asset classes where the condition of the assets threatens the ability to maintain the current level of service. Network *capex* projects forecast in the second *pricing period* include:

- Replacement of Power Transformers that are at high risk of failure, consistent with industry practice. The transformers are experiencing high levels of dissolved gas and increased leaks increasing risk of catastrophic failure.
- Feeder upgrade and reinforcement to reduce outages on the Roebourne and Point Sampson feeders. The Roebourne feeder is consistently failing to meet the reliability performance objective of 160 minutes off supply by a significant margin. This project is to reduce outages so far as reasonably practicable to meet regulatory reliability targets for the Roebourne feeder and to realise net benefits for *customers* by upgrading the Point Sampson feeder.
- Replacement of high-risk substation assets that are at end of life with excessive leaks and poor test results with standard substation rated equipment to ensure the equipment can be operated in a safe manner, reduce risk to employees and supply interruption from operation of this equipment.

6.6.4 Reliability

The forecast reliability *capex* for the second *pricing period* is $14.1 million or $4.7 million per year, on average.

Overview

The *network* reliability performance of the *Horizon Power coastal network* has in general been good. However, the performance experienced by some *customers* following a major weather event has been deteriorating. The *Pilbara region* is subject to regular tropical cyclones and is one of the most affected regions in Australia for cyclones.

As the frequency and magnitude of extreme weather events, including tropical cyclones, increases, the length of time that *customers* may be without supply is also likely to increase.

Performance of the network is analysed regularly to identify the feeders or feeder areas with reliability below regulatory performance targets or areas where the net benefit to *customers* may justify additional reinforcements.

Consideration is given to *customers* in outer residential areas that may experience long interruption times. These *customers* can experience extended outages during major weather events. Horizon Power reviews the reliability impact on *customers* with the objective of meeting regulatory performance targets and to improve reliability of underperforming areas of the network where justified.

A range of solutions are employed to improve performance including:

- sectionalising feeders using automatic protection devices to reduce *customers* affected by outages
- automating field switching devices to improve fault finding and restoration times
- replacing open wire lines with insulated or covered conductors
- upgrading of pole top hardware at end of life to improve insulation levels
- improving the resilience of infrastructure to major weather events.

Expenditure summary

Horizon Power has included targeted projects in the *capex* forecast for the second *pricing period* that are aimed at improving the resilience of infrastructure supplying the major airports in the region, located at Karratha and Port Hedland.

6.6.5 Compliance

The forecast compliance *capex* for the second *pricing period* is $1.2 million or $0.4 million per year, on average.

Overview

Horizon Power regularly reviews compliance with the Technical Rules, Planning standards and guidelines and design criteria, as part of the annual planning process. As the network information and asset data has been improving, the annual planning review may identify areas of non-compliance with Horizon Power’s technical requirements and obligations.

Detailed investigations are undertaken of any areas of non-compliance. Targeted projects and programs are developed to mitigate the highest areas of risk on a prioritised basis, whilst ensuring that Horizon Power adheres to strict safety requirements and maintain the current service level performance. These include low ground clearances, fault level upgrades, and network security analysis.

Expenditure summary

Horizon Power has forecast a small number of compliance-related projects in the second *pricing period* to resolve issues identified with compliance to the Technical Rules and Planning standards for the *pricing period* including:

- upgrading transformer bunding that is at end of life and has been determined to be non-compliant with the technical requirements.

6.6.6 Economics

There is an ongoing programme to upgrade streetlights with LED lamps that would provide increased efficiency and asst life.

6.6.7 Customer

There is no net *customer capex* forecast for the second *pricing period*. It is assumed that all *customer capex* is recovered through *customer* contributions.

6.6.8 Capacity-driven

There is no capacity-driven *capex* forecast for the second *pricing period*.

Overview

When required, Horizon Power augment the existing network to manage capacity constraints arising from the growth in maximum demand, as well as to ensure compliance with power quality and performance requirements. These activities typically include upgrades in low voltage *network*s, distribution substations, high voltage feeders, zone substations and *transmission system*s.

The key factors reviewed in determining the capacity-driven *capex* requirements include:

- Demand growth – A key driver of growth in the electricity *network* is the growth in maximum demand caused primarily by population growth or specific development within localised parts of the distribution *network* where there are forecast to be capacity constraints.
- Asset utilisation – Horizon Power undertakes regular planning studies to maintain asset utilisation rates at appropriate levels, and to ensure that safety, reliability, security of supply and other compliance obligations are achieved.
- Increasing connection of solar PV systems – Horizon Power is experiencing a steady increase in the uptake of solar PV panels connecting to the *network*, by both residential and commercial *customers*. Horizon Power continues to monitor the increasing uptake of solar panels to understand where they may cause voltage issues in the low voltage distribution *network*.

The long-term demand forecast prepared for 2023-24 was used to determine the level of demand-driven investment required in the *Horizon Power coastal network*. As illustrated in Figure 6.5, Horizon Power is forecasting steady demand over the short to medium term in

Horizon Power's *interconnected Pilbara network*. Accordingly, no capacity-driven *capex* is forecast for the second *pricing period.*

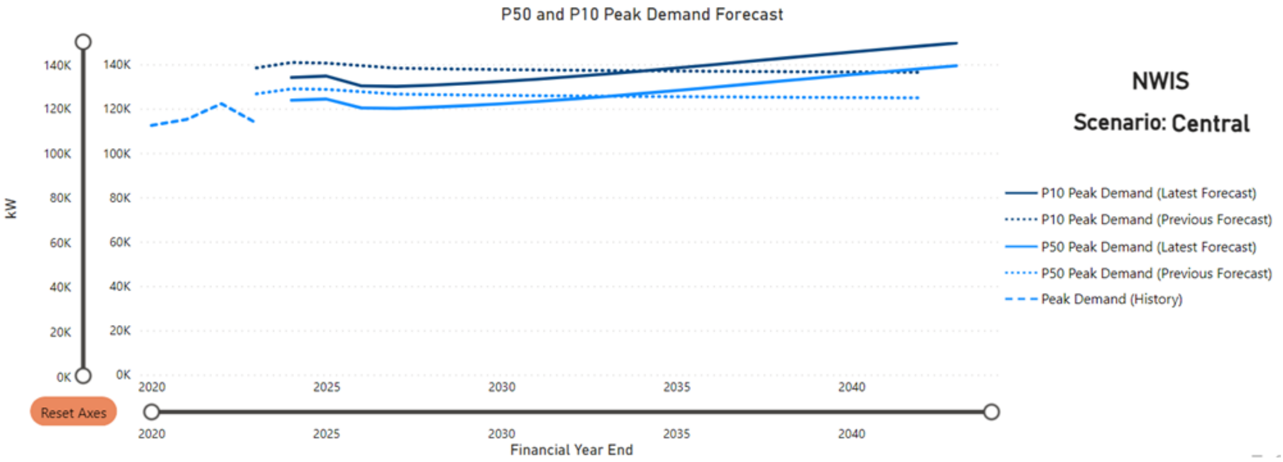

Figure 6.5: Demand forecast, including historical and forecast demand

6.6.9 Non-system capex

The total forecast non-system *capex* for the second *pricing period* is $15.6 million, or $5.2 million per year, on average.

Operational Technology (OT)

To meet the needs of network operations, Horizon Power has forecast operational technology (OT) *capex* in the second *pricing period* for the SCADA and telecommunications infrastructure for remote operations of its power system in the *Pilbara region*.

The continued operation of the SCADA system ensures that Horizon Power can manage the electricity *network* from a centralised control room and provide efficient response and recovery from system outages and events.

The OT *capex* includes:

- OT attributed directly to the *Horizon Power coastal network*
- the share of corporate OT attributed, or allocated, using Horizon Power's *Cost Allocation Methodology* to the *Horizon Power coastal network* that relate to the delivery of *covered services*.

The OT *capex* for the *pricing period* includes:

- maintenance of existing critical operational systems for the Horizon Power Control Centre, including updates to the Advanced Distribution Management System (PowerOn)
- replacement of existing software and hardware to minimise operational risk, including architecture updates and hardware replacement on the core OT network, core OT server hardware refresh, and replacement of an end-of-life virtualisation system
- maintenance of cyber protection systems to mitigate the risk of successful cyber-attacks on the OT network.

Fleet and property

Horizon Power operates regional offices at Karratha, and depots at both Karratha and Port Hedland. To meet the business needs of staff located at these locations, Horizon Power maintains a fleet of vehicles and plant.

The Fleet and Property *capex* includes:

- fleet and property *capex* attributed directly to the *Horizon Power coastal network*
- the share of corporate fleet and property *capex* attributed, or allocated, using Horizon Power's *Cost Allocation Methodology* to the *Horizon Power coastal network* that relate to the delivery of *covered service*s.

Horizon Power has undertaken a strategic review of its fleet and property needs and identified an asset improvement plan, which it has commenced implementing. The *capex* included for the second *pricing period* forms part of the delivery of this asset improvement plan and is generally consistent with historical *capex* levels.

The fleet and property *capex* for the *pricing period* includes:

- **Fleet** – Horizon Power purchases fleet for use in the transmission and distribution network. The size of the vehicle fleet is commensurate with the *services* that Horizon Power provides. The *Pilbara region* is exposed to extreme weather including cyclones and local flooding, often restricting access to parts of the *network*. It is essential to have a reliable, well-maintained fleet for the safety, reliability, quality and security of the supply of *services* to *customers*.

  In many cases, Horizon Power has extended the useful life of its vehicle fleet beyond that of industry standards. In light of the strategic review, Horizon Power has taken a risk-based replacement approach to refresh the vehicle fleet based on individual condition, and to more closely align with industry standards for vehicle replacement in the coming years. It will replace fleet based on policy life of assets rather than condition based.

- **Buildings and property** – Horizon Power leases and acquires buildings and property to provide *services* to *customers*. This includes fitting-out offices to accommodate Horizon Power employees and contractors. Key determinants in the development of the investment plan are the capacity of current buildings and property to support the efficient delivery of *services*, including whether they are best owned or leased, and are at a safe and acceptable standard to accommodate staff and contractors satisfactorily.

  Key improvements will also be made to Horizon Power depots to improve hardstand, storage and access to improve safety of the workforce and improve efficiency of the crews.

Information and Communications Technology (ICT)

To meet the business needs of staff located at its regional locations, Horizon Power maintains an engineering and administration office based in Bentley, including the ICT infrastructure necessary to support the regional offices.

ICT for the electricity industry is undergoing rapid changes. To continue to align ICT with business needs, Horizon Power has identified several projects to deliver its business strategy over the coming period.

The ICT *capex* includes:

- ICT *capex* attributed directly to the *Horizon Power coastal network*
- the share of corporate ICT attributed, or allocated, using Horizon Power's *Cost Allocation Methodology* to the *Horizon Power coastal network* that relate to the delivery of *covered service*s.

The ICT *capex* for the *pricing period* includes:

- upgrading existing enterprise-wide systems, including critical systems used for collaboration across the Horizon Power business involving multiple geographic locations, and licencing changes and increases for existing systems
- migration of systems hosted on 'on-premises' server hardware to virtual servers hosted in the AWS Cloud, to meet the needs for increased flexibility and reliability of hosted systems
- maintenance of existing software and hardware to minimise operational risk, including annual software licencing requirements and associated upgrades
- replacement of existing software and hardware to minimise operational risk, including end of life device replacement.

6.6.10 Capitalised business overheads

The corporate and network overheads that are forecast to be capitalised as part of the *new facilities investment* for the *covered Pilbara network* in the second *pricing period* are $11.8 million or $3.8 million per year, on average.

Horizon Power uses the same approach to capitalising corporate and network overheads for statutory purposes and for determining the *target revenue*, in accordance with Horizon Power's Capitalisation Policy.

Corporate and network overheads are capitalised in proportion to the direct *capex*, with the proportion based on the nature of the *capex*.

Horizon Power understands that there is a wide range of capitalisation approaches and outcomes adopted by electricity network businesses, with the amount of overheads capitalised ranging from 20% to 50% of overheads. Horizon Power's capitalisation approach results in a forecast that falls within this range.

The Pilbara network share of corporate overheads, and overheads related to the Pilbara network, that are not capitalised are recovered through the forecast *opex* component of total costs. Horizon Power’s capitalisation approach, and *opex* forecasts, will ensure that only efficient overhead costs are recovered through either capitalised overheads or the efficient level of *opex* so that there are no gaps or over-recoveries.

7. FORECAST OPERATING EXPENDITURE

Section 60(1) of the *Code* states that:

> The *non-capital costs* component of total costs for a *light regulation network* to be applied under section 47(1)(b) must only include those *non-capital costs* (including any *non-capital costs* associated with pursuing alternative options)—
>
> (a) that do not exceed the amount that would be incurred by a prudent *NSP*, acting efficiently, in accordance with *good electricity industry practice*, to achieve the lowest sustainable cost of delivering *covered service*s having regard to the revenue and pricing principles and Pilbara electricity objective; and
>
> (b) in respect of an alternative option if at least one of the following conditions is satisfied—
>
> (i) the additional revenue for the alternative option is expected to at least recover the alternative option *non-capital costs*; or
>
> (ii) the alternative option provides a net benefit to those who generate, transport and consume electricity in the *light regulation network* or the *light regulation network* and any interconnected Pilbara system over a reasonable period of time that reasonably justifies higher *reference tariff*s; or
>
> (iii) the alternative option is necessary to maintain the safety or reliability of the *light regulation network* or its ability to provide contracted *covered service*s.

Section 60(2) of the *Code* states that the *non-capital costs* component of total costs must not include any costs of the *NSP* incurred or forecast to be incurred in respect of access disputes.

7.1 Forecasting opex

Horizon Power forecasts the *opex* for its entire business, excluding the generation-related cost of goods sold, using the base-step-trend approach, which is a well-accepted methodology in the electricity industry for forecasting the *opex* for *NSP*s.

An overview of the base-step-trend approach is illustrated in Figure 7.1.

Figure 7.1: Overview of the base-step-trend forecasting approach

7.1.1 Base year opex

The funding that is provided by the Government to Horizon Power for *opex* in the final year of the previous *pricing period*, excluding generation-related costs, is taken as the base expenditure for each year of the subsequent *pricing period*, indexed by forecast CPI to the first year of the subsequent *pricing period*.

Horizon Power operates under the *Electricity Corporations Act 2005*, led by a board of directors accountable to the Minister for Energy, representing all Western Australians. Section 50 of the *Electricity Corporations Act 2005* defines the principal functions of the Regional Power Corporation, trading as Horizon Power. Its primary objective is to reduce its cost base and improve the reliability of electricity supply.

Horizon Power's *opex* has been constrained over a long period of time by the funding that is provided by the Government.

For these reasons, it is assumed that the base *opex* is efficient.

7.1.2 Adjustment for one-off costs

The base year *opex* is adjusted for any one-off or non-recurrent funding in that base year, excluding funding related to any one-off or non-recurrent generation-related expenditure. An example of one-off or non-recurrent funding is the additional funding that was provided to Horizon Power to stimulate the economy following the onset of the COVID-19 pandemic.

7.1.3 Step changes

The forecast costs associated with any changes to legislative or regulatory obligations that are expected prior to, or during, the *pricing period*, other than those that relate to generation-related costs, are added to the base year *opex*. The costs are forecast based on the volume of additional activity and the unit costs associated with that additional activity.

The volume of activity may be informed by any analysis published to accompany the change in the legislative or regulatory obligation. In the absence of any published analysis, Horizon Power will use its best endeavours to estimate the volume of activity.

The unit costs of the activity are estimated in accordance with Horizon Power's Cost Estimation Methodology.

7.1.4 Trend

The trend component of the forecast *opex* includes:

- escalation for CPI
- real changes in input prices
- output growth
- changes in productivity.

Due to financial constraints imposed by the Government, Horizon Power has been reviewing the scope for efficiency gains on an annual basis. It has been offsetting real changes in input prices and output growth with changes in productivity. Horizon Power assumes that it will continue to be subject to financial constraints and the scope for efficiency gains will continue to be reviewed annually. Horizon Power will continue to offset real changes in input prices and output growth with changes in productivity.

Accordingly, the trend component applied by Horizon Power is escalation for CPI only. By using the base-step-trend approach, any efficiency gains identified during a *pricing period* will be reflected in the base year *opex* for the following *pricing period*.

7.1.5 Capitalisation of operating expenditure

As discussed in section 6.6.10, a portion of Horizon Power's *opex* is recovered by applying an overhead recovery rate to capital and *operating expenditure* (projects) in accordance with Horizon Power's Capitalisation Policy.

The *opex* that is forecast using the base-step-trend approach (gross *opex*) includes the *opex* that is recovered through the application of the overhead recovery rate. The portion of *opex* that is forecast to be recovered through the application of the overhead recovery rate is then deducted from the forecast gross *opex*.

7.1.6 Reconciliation of the bottom-up forecast to the base-step-trend approach

The *opex* that is forecast using a bottom-up approach is reconciled against the *opex* forecast using the base-step-trend approach. The bottom-up forecasts are adjusted downwards so that, in aggregate, they are equal to the *opex* forecast using the base-step-trend approach.

7.1.7 Allocation of costs to the covered Pilbara network

The *operating expenditure* is either directly attributed to the *covered Pilbara network* or allocated in accordance with the *Cost Allocation Methodology*.

7.2 Forecast operating expenditure

This section describes how the *operating expenditure* for the *covered Pilbara network* has been forecast for each year of the second *pricing period* (1 July 2024 to 30 June 2027).

7.2.1 Base year opex

The funding that was provided by the Government to Horizon Power for *operating expenditure* in 2022-23, was $188.7 million as set out in Table 7.1. This is the base year *opex* for the purposes of forecasting *operating expenditure* for 2024-25 to 2026-27.

Table 7.1: Base operating expenditure, 2020-21

	Base opex ($ million)
Operating expenditure – expensed	178.5
Operating expenditure – capitalised	10.2
Total base opex	**188.7**

The base *opex* does not include any costs in connection with access disputes. Accordingly, the forecast *operating expenditure* does not include any costs in connection with access disputes.

7.2.2 Adjustment for one-off costs

The *operating expenditure* in 2022-23 was significantly higher than in previous years due to additional projects and resourcing in the corporate area. Accordingly, a one-off adjustment of $36.4 million has been made to the base *opex* to reflect costs that were incurred in 2022-23 but are unlikely to be incurred in future years.

7.2.3 Step changes

Horizon Power has not forecast any material step changes in *opex* relating to the *covered Pilbara network*. Any increases in *opex* will be offset by efficiency improvements.

7.2.4 Trend

As discussed in section 7.1.4, Horizon Power escalates the 2022-23 base year *opex* by CPI. Horizon Power has forecast the CPI to index the *opex* from 2022-23. The forecast CPI in 2023-24 and 2024-25 is from the Reserve Bank of Australia's (RBA's) Statement of Monetary Policy.[11] The forecast CPI in 2025-26 is estimated to be 2.7% based on the reduction in CPI over the last couple of years. The CPI is then assumed to decrease linearly to the midpoint of the target range (2.5%) over the next three years.

The forecast CPI and the resultant increase in the base year *opex* from 2022-23 to 2026-27 is set out in Table 7.2.

Table 7.2: Forecast indexation of base operating expenditure, 2023-24 to 2026-27

	2023-24	2024-25	2025-26	2026-27
Forecast CPI	3.6%	3.0%	2.7%	2.63%
Indexation ($ million, nominal)	5.5	10.3	14.7	19.1

7.2.5 Capitalisation of operating expenditure

Horizon Power capitalises some *opex* in accordance with its Capitalisation Policy. The amount capitalised in any year will be a function of the size and nature of the investment program.

The overheads that are forecast to be capitalised in each year of the second *pricing period* (1 July 2024 to 30 June 2027) are set out in Table 7.3. The overheads that are forecast to be capitalised increase from $9.3 million in 2024-25 to $9.8 million in 2026-27.

Table 7.3: Forecast capitalisation of overheads, 2024-25 to 2026-27 ($ million, nominal)

	2024-25	2025-26	2026-27
Overheads capitalised	9.3	9.6	9.8

[11] Reserve Bank of Australia, Statement of Monetary Policy, February 2024, Forecast Table

7.2.6 Total forecast operating expenditure

The total forecast *operating expenditure* for Horizon Power for each year of the second *pricing period* (1 July 2024 to 30 June 2027) is set out in Table 7.4 and illustrated in Figure 7.2.

Table 7.4: Total forecast operating expenditure, Horizon Power, 2024-25 to 2026-27 ($ million, nominal)

	2024-25	2025-26	2026-27
Base year *opex*	188.7	188.7	188.7
One-off adjustment	-35.5	-35.5	-35.5
Step changes	0.0	0.0	0.0
Indexation	10.3	14.7	19.1
Subtotal	**163.5**	**167.9**	**172.3**
Capitalisation of overheads	9.3	9.6	9.8
Total forecast *opex*	**154.1**	**158.3**	**162.4**

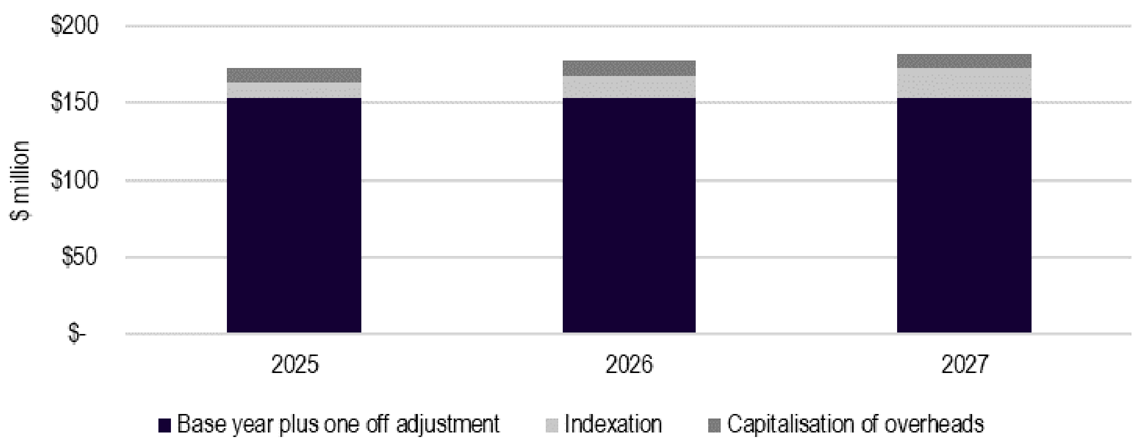

Figure 7.2: Total forecast operating expenditure, Horizon Power, 2024-25 to 2026-27

7.2.7 Allocation of costs to the covered Pilbara network

The total forecast *operating expenditure* for 2024-25 to 2026-27 is allocated in accordance with Horizon Power's *Cost Allocation Methodology* by:

- location – there are six locations:
  - East Pilbara
  - West Pilbara
  - East Kimberley
  - West Kimberley
  - Midwest

- Esperance
- function – there are four functions:
  - generation
  - transmission
  - distribution
  - retail.

A large proportion of the costs that are allocated to the East Pilbara and West *Pilbara region*s and to the transmission and distribution functions are then allocated to the following cost pools that are used for the purposes of pricing *covered Pilbara network services*:

- transmission
- sub-transmission
- distribution HV
- distribution LV
- streetlighting
- metering.

The costs allocated to these cost pools are categorised as:

- direct operating costs
- shared operating costs
- system control and dispatch shared costs
- shared corporate costs.

Some of the costs that are allocated to the East Pilbara and West *Pilbara region*s and to the transmission and distribution functions relate to the provision of services to the ISO. These costs are **not** recovered through the pricing for *covered Pilbara network services*.

More details on Horizon Power's cost allocation methodology are provided in section 8 of the Ringfencing Rules.[12] Key aspects of the cost allocation methodology are provided in Appendix A.

Direct operating costs

There are offices and depots located in the *Pilbara region* that only operate and maintain the assets in the *Pilbara region*. The direct operating costs include costs associated with operations, asset management, works delivery, property and facilities, fleet, and network regulation and open access.

[12] Available at https://nwis.com.au/media/lkal0ui2/ringfencing-rules.pdf

The forecast direct operating costs for the *covered Pilbara network* for each year of the second *pricing period* (1 July 2024 to 30 June 2027) are set out in Table 7.5.

Table 7.5: Forecast direct operating costs, 2024-25 to 2026-27 ($ million, nominal)

	2024-25	2025-26	2026-27
Transmission	4.79	4.92	5.05
Sub-transmission	0.32	0.33	0.34
Distribution HV	1.40	1.44	1.47
Distribution LV	0.83	0.86	0.88
Street lighting	0.17	0.17	0.18
Metering	0.10	0.10	0.10
Total direct operating costs	**7.61**	**7.81**	**8.02**

Shared operating costs

Shared operating costs generally relate to:

- network *services* and generation *services*
- *services* provided in the *Pilbara region* and *services* provided in other parts of regional WA
- regulated and unregulated distribution and transmission network *services*.

The shared operating costs that are forecast to be allocated to the *covered Pilbara network* for each year of the second *pricing period* (1 July 2024 to 30 June 2027) are set out in Table 7.6.

Table 7.6: Forecast allocation of shared operating costs, 2024-25 to 2026-27 ($ million, nominal)

	2024-25	2025-26	2026-27
Transmission	2.91	2.99	3.07
Sub-transmission	0.25	0.26	0.26
Distribution HV	2.42	2.49	2.56
Distribution LV	1.61	1.65	1.70
Street lighting	0.12	0.12	0.13
Metering	0.13	0.13	0.13
Total shared operating costs	**7.44**	**7.64**	**7.84**

Shared system control and dispatch costs

System control and dispatch shared costs include costs for:

- network operations in the *Pilbara region*
- system and network operations in regional WA, excluding the *Pilbara region*
- the provision of services to the ISO
- generation dispatch functions for Horizon Power's retail business in the *Pilbara region*.

The only system control and dispatch shared costs that are allocated to the *covered Pilbara network* are those in the first category – for network operations in the *Pilbara region.* The shared system control and dispatch costs that are forecast to be allocated to the *covered Pilbara network* for each year of the second *pricing period* (1 July 2024 to 30 June 2027) are set out in Table 7.7.

Table 7.7: Forecast allocation of shared system control and dispatch costs, 2024-25 to 2026-27 ($ million, nominal)

	2024-25	2025-26	2026-27
Transmission	1.62	1.66	1.71
Sub-transmission	0.17	0.17	0.18
Distribution HV	1.16	1.19	1.22
Distribution LV	0.00	0.00	0.00
Street lighting	0.00	0.00	0.00
Metering	0.00	0.00	0.00
Total system control and dispatch costs	**2.95**	**3.03**	**3.11**

Shared corporate costs

There are a range of corporate functions that are shared across Horizon Power. These include the costs associated with the CEO, Board, Company Secretary, Finance, Human Resources and Technology.

The shared corporate costs that are forecast to be allocated to the *covered Pilbara network* for each year of the second *pricing period* (1 July 2024 to 30 June 2027) are set out in Table 7.8.

Table 7.8: Forecast allocation of shared corporate costs, 2024-25 to 2026-27 ($ million, nominal)

	2024-25	2025-26	2026-27
Transmission	6.20	6.37	6.53
Sub-transmission	0.53	0.55	0.56
Distribution HV	5.09	5.22	5.36
Distribution LV	3.04	3.12	3.21
Street lighting	0.00	0.00	0.00
Metering	0.00	0.00	0.00
Total shared corporate costs	**14.86**	**15.26**	**15.66**

Total forecast operating costs for the *covered Pilbara network*

The total forecast operating costs for the *covered Pilbara network* for each year of the second *pricing period* (1 July 2024 to 30 June 2027) are set out in Table 7.9 and illustrated in Figure 7.3. In 2024-25, 21.3% of Horizon Power's forecast *opex* (excluding capitalised overheads) was attributed or allocated to the provision of *covered Pilbara network services*.

Table 7.9: Forecast total operating costs, 2024-25 to 2026-27 ($ million, nominal)

	2024-25	2025-26	2026-27
Direct	7.61	7.81	8.02
Shared operating	7.44	7.64	7.84
Shared system control and dispatch	2.95	3.03	3.11
Shared corporate	14.86	15.26	15.66
Total	**32.86**	**33.75**	**34.63**

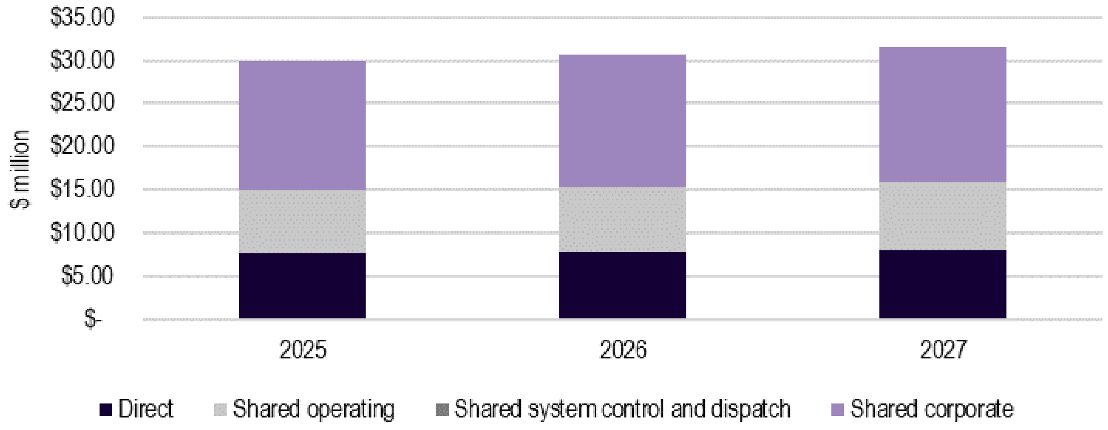

Figure 7.3: Forecast total operating expenditure, 2024-25 to 2026-27

The forecast *opex* is comprised of shared corporate *opex* (45%), direct operating costs (23%), shared operating costs (23%) and shared system control and dispatch costs (9%).

The forecast *opex* increases by 2.7% from $32.9 million in 2024-25 to $33.7 million in 2025-26 and by 2.6% to $34.6 million in 2026-27 due to indexation.

8. OPENING VALUE OF THE CAPITAL BASE

Section 54 of the *Code* states that:

> The *NSP* must determine the *capital base* for a *light regulation network* to be used from the start of each *pricing period* after the first *pricing period*, as follows—
>
> (a) start with the *capital base* used from the start of the previous *pricing period*; then
>
> (b) add *new facilities investment* from the previous *pricing period* which satisfy the *new facilities investment test*; and
>
> subtract the following:
>
> (c) depreciation over the previous *pricing period* (to be calculated in accordance with the relevant provisions of the *services and pricing policy* governing the calculation of depreciation over the previous *pricing period*); and
>
> (d) an amount for redundant assets to the extent necessary to ensure that *network assets* which have ceased to contribute in any material way to the provision of *covered services* are not included in the *capital base*; and
>
> (e) the disposal value of *network assets* disposed of during the previous *pricing period*.

The *capital base* for the *covered Pilbara network* has been rolled forward from 30 June 2021 to 30 June 2024 using the:

- value of the initial *capital base*, as discussed in section 8.1
- *new facilities investment* from the first two years of the *first pricing period*, as discussed in section 8.2, noting that the *new facilities investment* for the third year of the first *pricing period* will be added to the *capital base* in the third *pricing period*
- depreciation of the *capital base*, as discussed in section 8.3
- indexing the capital base to maintain its value in real terms by using the forecast CPI as set out in Table 7.2.

There were no disposals and no assets considered to be redundant during the first *pricing period*.

8.1 Value of initial capital base

The initial *capital base* for Horizon Power's *covered Pilbara network* as at 30 June 2021 was prescribed in section 52(1) of the *Code* as $535 million. The composition of the initial capital base, by revenue cost pool and for the share of the corporate assets, is set out in Table 8.1.

Table 8.1: Initial capital base by cost pool as at 30 June 2021 (nominal dollars)

	Initial capital base ($ million)
Transmission	252.4
Sub-transmission	17.1
Distribution HV	120.3
Distribution LV	73.5
Street lighting	17.0
Metering	10.3
Non-system assets	32.5
Sub-total	**523.0**
Corporate (share)	12.2
Total	**535.2**

8.2 New facilities investment

During the first two years of the first *pricing period*, Horizon Power invested $42.0 million in *new facilities investment* compared to a forecast of $25.1 million. Figure 8.1 provides a comparison of actual and forecast *capex* over these two years.

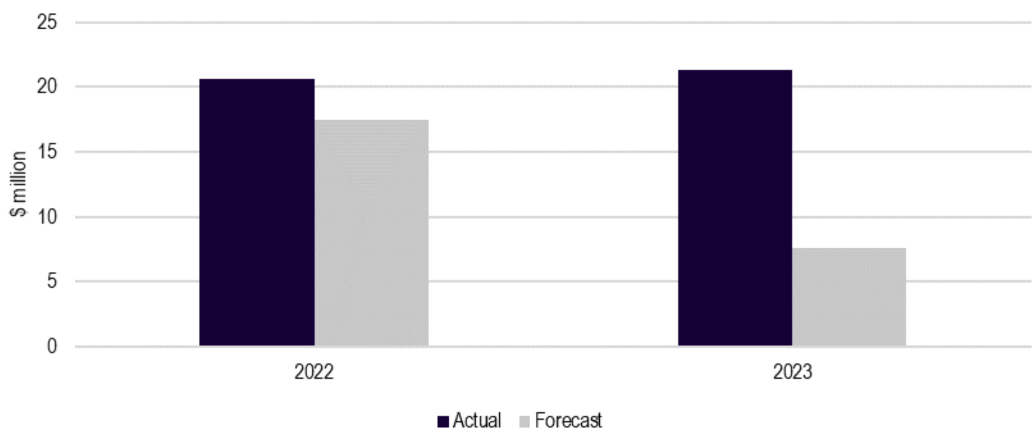

Figure 8.1: Comparison of forecast and actual capital expenditure, 2021-22 to 2022-23

The variance by cost pool is illustrated in Table 8.2. The increase in *capital expenditure* relative to forecast was predominantly due to:

- 123% more investment in the shared transmission network to service existing transmission infrastructure
- 431% more investment in corporate assets to support corporate initiatives
- 65% more investment in streetlighting assets and 32% more investment in distribution LV assets, offset by a 73% decrease in investment in metering assets.

In addition, indexation over the period was higher than forecast and supply chains were disrupted due to the COVID-19 pandemic resulting in higher than forecast input costs.

Table 8.2: Comparison of forecast and actual capital expenditure, by cost pool, 2021-22 to 2022-23 (nominal dollars)

	Forecast capex ($ million)	Actual capex ($ million)	Variance ($ million)	Variance (%)
Transmission	6.8	15.0	8.3	123%
Sub-transmission	0.0	0.0	0.0	-
Distribution HV	9.7	9.6	-0.1	-1%
Distribution LV	1.5	1.9	0.5	32%
Street lighting	0.8	1.3	0.5	65%
Metering	1.0	0.3	-0.8	-73%
Non-system assets	3.3	3.0	-0.3	-8%
Corporate (share)	2.0	10.8	8.8	431%
Total	**25.1**	**42.0**	**16.9**	**67%**

8.3 Depreciation of the capital base

The *NSP* of a *light regulation network* must determine and include in its *services and pricing policy*, its criteria and methodology for the depreciation, including a depreciation schedule, for each *pricing period* to be applied under section 47(1)(a)(ii), of the *network assets* comprising the *capital base*.

Section 59(2) of the *Code* states that:

> The depreciation criteria and methodology should be designed—
>
> (a) so that *reference tariffs* will vary, over time, in a way that promotes economic growth in the market for *reference services*; and
>
> (b) so that each *network asset* or group of assets is depreciated over the economic life of that *network asset* or group of *network assets*; and

(c) so as to allow, as far as reasonably practicable, for adjustment reflecting changes in the expected economic life of a particular *network asset*, or particular group of *network assets*; and

(d) so that (subject to the rules about capital redundancy in section 54), a *network asset* is depreciated only once (that is, the amount by which the *network asset* is depreciated over its economic life does not exceed the value of the *network asset* at the time of its inclusion in the *capital base* (adjusted, if the accounting method used by the *NSP* (as referred to in section 46 permits, for inflation)); and

(e) so as to allow for the *NSP*'s reasonable needs for cash flow to meet financing, *non-capital costs* and other costs.

Horizon Power's Capital Base Roll Forward Methodology sets out Horizon Power's methodology for rolling forward the *capital base*, including the approach to depreciating the *network assets* and the circumstances in which the depreciation of a *network asset* may be accelerated.

In summary, the return of capital (depreciation) is calculated on a straight-line basis using the asset lives for each asset class. The asset lives for the initial *capital base* are calculated based on the weighted average remaining life for each asset at the commencement of coverage, and are set out by asset class and cost pool in Table 8.3.

The depreciation is being accelerated for assets in two asset classes to reflect the expected economic life of these assets:

- motor vehicles – where the weighted average remaining life for motor vehicles in a cost pool is longer than 10 years, the asset life is reduced to 10 years, in line with the life of new assets
- meters – where the weighted average remaining life for meters in a cost pool is longer than 15 years, the asset life is reduced to 15 years, in line with the life of new assets.

Table 8.3: Asset lives by asset class and cost pool, initial capital base

Asset class	Transmission – East Pilbara	Transmission – West Pilbara	Sub-transmission
Buildings	27.34	30.07	N/A
Control/Monitoring/Communications and Protection	4.40	7.56	N/A
Land	0	0	N/A
Lines	20.89	24.64	45.00
Low Value Pool	1.54	1.00	N/A
Plant & Equipment	12.26	11.68	15.00
Sub Stations	25.82	25.33	40.00 / 37.00

Asset class	Transmission – East Pilbara	Transmission – West Pilbara	Sub-transmission
Switch Yards	N/A	N/A	45.00
Transformers	32.24	23.30	N/A
Asset class	**Distribution HV – East Pilbara**	**Distribution HV – West Pilbara**	**Distribution LV**
Buildings	27.50	29.40	29.00
Control/Monitoring/Comms & Prot.	7.19	N/A	6.25
Furniture & Fittings	N/A	N/A	3.36
Land	0	0	N/A
Lines	33.68	34.27	37.40
Low Value Pool	1.00	N/A	2.12
Motor Vehicles	N/A	10.00	N/A
Office Equipment	N/A	3.00	N/A
Plant & Equipment	11.42	13.42	16.02
Sub Stations	20.73	28.96	N/A
Transformers	23.10	29.23	N/A
Connection assets	N/A	N/A	35.78
Metering	N/A	N/A	15.00
Public lighting	N/A	N/A	14.24
Asset class	**Non-system**	**Corporate**	
Buildings	23.24	32.43	
Communication equipment	N/A	7.00	
Computer equipment	N/A	2.40	
Computer software	N/A	2.35	
Control/Monitoring/Comms & Prot.	6.01	5.59	
Furniture & Fittings	3.15	2.40	
Land	0	0	
Lines	39.13	44.67	
Motor Vehicles	9.37	7.33	
Office Equipment	1.84	1.14	
Plant & Equipment	10.07	12.15	

Asset class	Non-system	Corporate
Sub Stations	30.78	29.00
Connection assets	N/A	38.00
Metering	N/A	15.00

The asset lives for *new facilities investment* that is added to the *capital base* following commencement of coverage are set out in Table 8.4.

Table 8.4: Asset classes and asset lives, new facilities investment

Asset class	Transmission/ Sub-transmission	Distribution / Non-system / Corporate
Buildings	40	40
Communication equipment	9	9
Computer equipment	4	4
Computer software	4	4
Control/Monitoring/ Comms & Protection	11	11
Furniture & Fittings	11	11
Land	0	0
Lines	48	48
Low Value Pool	4	4
Motor Vehicles	10	10
Office Equipment	7	7
Plant & Equipment	18	18
Sub Stations	40	40
Switch Yards	50	N/A
Transformers	40	40
Street lighting	N/A	20
Connections	N/A	40
Metering	N/A	15

8.4 Value of the opening capital base as at 30 June 2024

The value of the opening *capital base* by cost pool as at 30 June 2024 is as set out in Table 8.5. The value of the *capital base* increased from $535.2 million at 1 July 2021 to $573.0 million at 30 June 2024.

Table 8.5: Opening value of the capital base, by cost pool as at 30 June 2024 ($ million, nominal)

	2021-22	2022-23	2023-24
Transmission			
Opening capital base	252.4	259.1	268.9
Net capex	5.5	9.5	0.0
Depreciation	-14.3	-15.3	-16.1
Indexation	15.5	15.5	9.7
Closing capital base	259.1	268.9	262.4
Sub-transmission			
Opening capital base	17.1	17.7	18.2
Net capex	0.0	0.0	0.0
Depreciation	-0.5	-0.5	-0.5
Indexation	1.0	1.1	0.7
Closing capital base	17.7	18.2	18.4
Distribution HV			
Opening capital base	120.3	129.6	135.5
Net capex	6.5	3.0	0.0
Depreciation	-4.5	-5.0	-5.2
Indexation	7.4	7.8	4.9
Closing capital base	129.6	135.5	135.2
Distribution LV			
Opening capital base	73.5	76.5	79.4
Net capex	1.0	1.0	0.0
Depreciation	-2.5	-2.7	-2.6
Indexation	4.5	4.6	2.9
Closing capital base	76.5	79.4	79.6

	2021-22	2022-23	2023-24
Street lighting			
Opening capital base	17.0	17.4	17.8
Net capex	0.6	0.7	0.0
Depreciation	-1.3	-1.4	-1.5
Indexation	1.0	1.0	0.6
Closing capital base	17.4	17.8	16.9
Metering			
Opening capital base	10.3	10.3	10.3
Net capex	0.1	0.1	0.0
Depreciation	-0.7	-0.8	-0.8
Indexation	0.6	0.6	0.4
Closing capital base	10.3	10.3	9.9
Non-system assets			
Opening capital base	32.5	34.3	35.2
Net capex	1.9	1.1	0.0
Depreciation	-2.0	-2.3	-2.4
Indexation	2.0	2.1	1.3
Closing capital base	34.3	35.2	34.1
Sub-total			
Opening capital base	523.0	545.1	565.3
Net capex	15.7	15.4	0.0
Depreciation	-25.8	-27.9	-29.1
Indexation	32.1	32.7	20.3
Closing capital base	545.1	565.3	556.5
Corporate (share)			
Opening capital base	12.2	14.4	17.7
Net capex	4.9	5.9	0.0
Depreciation	-3.5	-3.5	-3.4
Indexation	0.8	0.9	0.6
Closing capital base	14.4	17.7	14.9

	2021-22	2022-23	2023-24
Total			
Opening capital base	535.2	559.4	582.9
Net capex	20.6	21.3	0.0
Depreciation	-29.3	-31.4	-32.5
Indexation	32.9	33.6	21.0
Closing capital base	559.4	582.9	571.4

9. RETURN OF CAPITAL

A return of capital (depreciation) is calculated on the *capital base* and *new facilities investment*.

9.1 Return of capital – capital base

Section 47(1)(a) of the *Code* states that one of the building blocks of the *target revenue* is depreciation, which is calculated on the *capital base* at the start of the *pricing period* in accordance with section 59.

Horizon Power's Capital Base Roll Forward Methodology sets out Horizon Power's methodology for rolling forward the *capital base*, including the approach to depreciating the *network assets* and the circumstances in which the depreciation of a *network asset* may be accelerated. In summary, the return of capital (depreciation) is calculated on a straight-line basis using the asset lives for each asset class.

The lives of the assets in the initial *capital base* are calculated based on the weighted average remaining life for each asset at the commencement of coverage. They are set out by asset class and cost pool in Table 8.3. The lives of the assets that have been added to the *capital base* following the commencement of coverage are set out by asset class and cost pool in Table 8.4.

By applying this method of depreciation to those assets in the opening *capital base* as set out in Table 8.5, the forecast depreciation of the *capital base* for each year of the second *pricing period* (1 July 2024 to 30 June 2027) is as set out in Table 9.1 and illustrated in Figure 9.1.

The depreciation of the *capital base* is forecast to decrease over the second *pricing period* from $32.5 million in 2024-25 to $30.4 million in 2026-27, largely due to a reduction in the depreciation of transmission assets as the control/monitoring/communications and protection equipment in the *initial capital base* reaches the end of its life.

The depreciation of the transmission assets represents just under 50% of the return of the *capital base*.

Table 9.1: Forecast return of capital (depreciation) of capital base, by cost pool, 2024-25 to 2026-27 ($ million, nominal)

	2024-25	2025-26	2026-27
Transmission	16.62	15.38	14.59
Sub-transmission	0.52	0.54	0.55
Distribution HV	5.33	5.48	5.62
Distribution LV	2.69	2.76	2.75
Street lighting	1.51	1.55	1.59
Metering	0.84	0.87	0.89
Non-system assets	2.22	2.24	2.30

	2024-25	2025-26	2026-27
Sub-total	**29.73**	**28.80**	**28.29**
Corporate (share)	2.76	2.83	2.07
Total	**32.49**	**31.63**	**30.36**

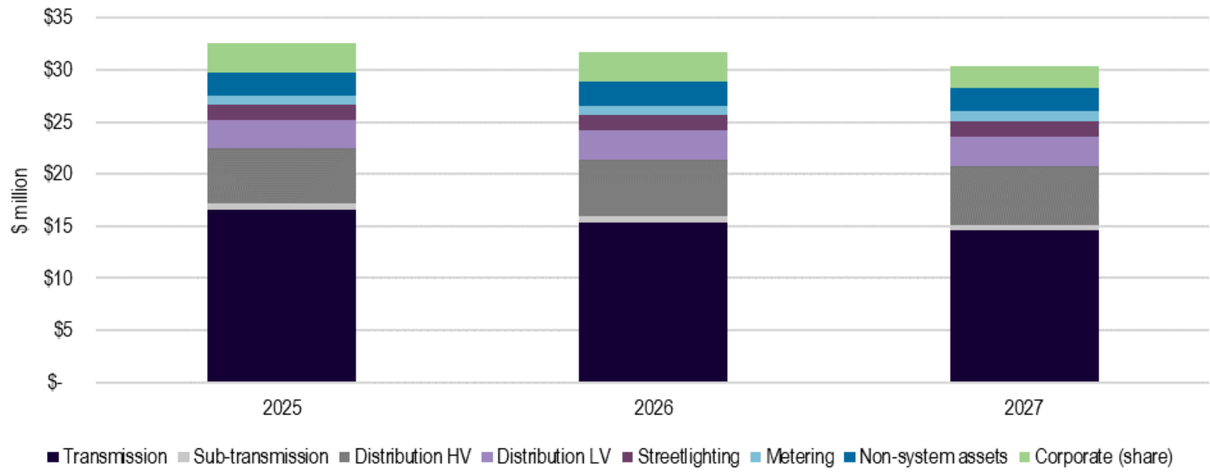

Figure 9.1: Forecast return of capital (depreciation) of capital base, by cost pool, 2024-25 to 2026-27

9.2 Return of capital – new facilities investment

Section 47(2) of the *Code* states that the *target revenue* for each year (or other interval) in a *pricing period* may include *capital-related costs* (including return of capital) in relation to forecast *new facilities investment* which at the time of inclusion are reasonably expected to satisfy the *new facilities investment test* when the forecast *new facilities investment* is made.

Horizon Power's Capital Base Roll Forward Methodology sets out Horizon Power's methodology for rolling forward the *capital base*. A similar approach is adopted to forecast the depreciation on forecast *new facilities investment*.

In summary, the return of capital (depreciation) on *new facilities investment* is calculated on a straight-line basis using the asset lives for each asset class, commencing the year following the year in which the investment occurs. The asset lives for *new facilities investment* are set out in Table 8.4.

By applying this method of depreciation to the forecast *new facilities investment* as set out in Table 6.3, the forecast depreciation of the forecast *new facilities investment* for each year of the second *pricing period* (1 July 2024 to 30 June 2027) is as set out in Table 9.2 and illustrated in Figure 9.2.

The depreciation of the forecast *new facilities investment* is forecast to increase over the second *pricing period* from $0.6 million in 2024-25 to $4.1 million in 2026-27, in line with the forecast *new facilities investment* during the *pricing period*.

The depreciation of the corporate assets represents 64% of the return of the *new facilities investment* due to the short lives of corporate assets.

Table 9.2: Forecast return of capital (depreciation) of the forecast new facilities investment, by cost pool, 2024-25 to 2026-27 ($ million, nominal)

	2024-25	2025-26	2026-27
Transmission	0.06	0.38	0.44
Sub-transmission	0.00	0.00	0.00
Distribution HV	0.02	0.21	0.32
Distribution LV	0.06	0.13	0.20
Street lighting	0.02	0.12	0.16
Metering	0.01	0.03	0.04
Non-system assets	0.08	0.18	0.24
Sub-total	**0.25**	**1.04**	**1.39**
Corporate (share)	0.39	1.58	2.73
Total	**0.65**	**2.62**	**4.12**

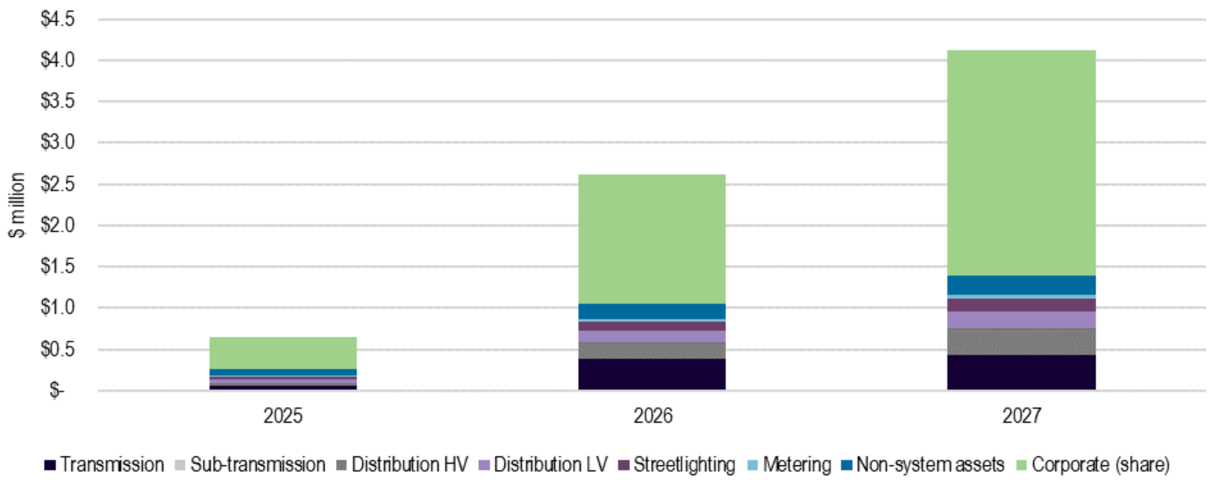

Figure 9.2: Forecast return of capital (depreciation) of the forecast new facilities investment, by cost pool, 2024-25 to 2026-27

10. CLOSING CAPITAL BASE

Section 54 of the *Code* states that:

> The *NSP* must determine the *capital base* for a *light regulation network* to be used from the start of each *pricing period* after the first *pricing period*, as follows—
>
> (a) start with the *capital base* used from the start of the previous *pricing period*; then
>
> (b) add *new facilities investment* from the previous *pricing period* which satisfy the *new facilities investment test*; and
>
> subtract the following:
>
> (c) depreciation over the previous *pricing period* (to be calculated in accordance with the relevant provisions of the *services and pricing policy* governing the calculation of depreciation over the previous *pricing period*); and
>
> (d) an amount for redundant assets to the extent necessary to ensure that *network assets* which have ceased to contribute in any material way to the provision of *covered service*s are not included in the *capital base*; and
>
> (e) the disposal value of *network assets* disposed of during the previous *pricing period*.

The *capital base* for the *covered Pilbara network* has been rolled forward from 30 June 2021 to 30 June 2024 using the:

- value of the opening *capital base* as set out in Table 8.5
- depreciation of the *capital base*, as set out in Table 9.1
- indexing the capital base to maintain its value in real terms by using the forecast CPI as set out in Table 7.2.

No disposals are forecast for the period from 1 July 2024 to 30 June 2027, and no assets are forecast to be redundant.

The forecast value of the closing *capital base* by cost pool as at 30 June 2025, 2026 and 2027 is as set out in Table 10.1. With the depreciation of the *capital base*, the value of the *capital base* decreases from the opening *capital base* of \$571.4 million at 1 July 2024 to \$523.2 million at 30 June 2027.

Table 10.1: Forecast closing value of the capital base, by cost pool, 2024-25 to 2026-27 ($ million, nominal)

	2024-25	2025-26	2026-27
Transmission			
Opening *capital base*	262.4	253.7	245.1
Depreciation	-16.6	-15.4	-14.6
Indexation	7.9	6.8	6.4
Closing *capital base*	253.7	245.1	237.0
Sub-transmission			
Opening *capital base*	18.4	18.4	18.4
Depreciation	-0.5	-0.5	-0.6
Indexation	0.6	0.5	0.5
Closing *capital base*	18.4	18.4	18.3
Distribution HV			
Opening *capital base*	135.2	133.9	132.0
Depreciation	-5.3	-5.5	-5.6
Indexation	4.1	3.6	3.5
Closing *capital base*	133.9	132.0	129.9
Distribution LV			
Opening *capital base*	79.6	79.3	78.7
Depreciation	-2.7	-2.8	-2.8
Indexation	2.4	2.	2.1
Closing *capital base*	79.3	78.7	78.0
Street lighting			
Opening *capital base*	16.9	15.9	14.8
Depreciation	-1.5	-1.5	-1.6
Indexation	0.5	0.4	0.4
Closing *capital base*	15.9	14.8	13.6

	2024-25	2025-26	2026-27
Metering			
Opening *capital base*	9.9	9.3	8.7
Depreciation	-0.8	-0.9	-0.9
Indexation	0.3	0.3	0.2
Closing *capital base*	9.3	8.7	8.0
Non-system assets			
Opening *capital base*	34.1	32.9	31.5
Depreciation	-2.2	-2.2	-2.3
Indexation	1.0	0.9	0.8
Closing *capital base*	32.9	31.5	30.1
Sub-total			
Opening *capital base*	556.5	543.4	529.3
Depreciation	-29.7	-28.8	-28.3
Indexation	16.7	14.7	13.9
Closing *capital base*	543.4	529.3	514.9
Corporate (share)			
Opening *capital base*	14.9	12.6	10.1
Depreciation	-2.8	-2.8	-2.1
Indexation	0.4	0.3	0.3
Closing *capital base*	12.6	10.1	8.3
Total			
Opening *capital base*	571.4	556.0	539.4
Depreciation	-32.5	-31.6	-30.4
Indexation	17.1	15.0	14.2
Closing *capital base*	556.0	539.4	523.2

11. RETURN ON CAPITAL

A return on capital is calculated on the *capital base* and forecast *new facilities investment*.

11.1 Code requirements

Section 47(1)(a)(i) of the *Code* states that a return on the *capital base* for the *pricing period* is calculated by applying the *rate of return*.

In addition, section 47(2) of the *Code* states that the *target revenue* for each year in a *pricing period* may include *capital-related costs* (including a return on capital) in relation to forecast *new facilities investment* which at the time of inclusion are reasonably expected to satisfy the *new facilities investment test* when the forecast *new facilities investment* is made.

Section 58(1) of the *Code* states that:

> Except to the extent that section 57 applies, the *NSP* for a *light regulation network* must determine for a *pricing period*, and include in its *services and pricing policy*, the *rate of return* to be applied to the *capital base* under section 47(1)(a)(i) together with the methodology used to determine the *rate of return*.

Sections 57(2) and 58(2) of the *Code* state that the *rate of return*:

(a) must be commensurate with the regulatory and commercial risks involved in providing *covered services*; and

(b) have regard to regulatory precedent on rates of return in the electricity and other industries, but—

   (i) undertake a specific assessment for the particular *light regulation network* based on its unique circumstances and any matters prescribed under regulation 4 of the regulations; and

   (ii) not assume that the circumstances of each *light regulation network* are the same; and

(c) use a pre-tax version of the costs of capital.

The return on the *capital base* in each year of the *pricing period* is a function of:

(a) the *rate of return* for that year, which is discussed in section 11.2

(b) the average written down value of the capital base in that year, which is discussed in section 11.3.

The return on the forecast *new facilities investment* in each year of the *pricing period* is a function of:

(a) the *rate of return* for that year, which is discussed in section 11.2

(b) the average written down value of the forecast *new facilities investment* in that year, which is discussed in section 11.4.

11.2 Calculating the rate of return

In accordance with section 57 of the *Code*, the ERA determined Horizon Power's *rate of return* for the first *pricing period*.

The *rate of return* for the second *pricing period* (1 July 2024 to 30 June 2027) has been guided by ERA's determination of the *rate of return* for the first *pricing period*. Key points made by the ERA in its determination were:

- The ERA set a long-term *rate of return* recognising the *Code's* light-handed regulatory framework.[13] This is consistent with the ERA's other light-handed approach for rail.[14]
- The Pilbara networks have a higher risk profile compared to other regulated energy networks. This higher risk profile is attributable to the higher cash flow risk and uncertainty present in the Pilbara networks compared to other regulated energy networks.
    - The Pilbara networks are significantly exposed to particular customers, geography and industry.
    - As the light-handed regulatory framework does not set prices, but provides a starting point for negotiation, there may be a greater range of, and more variable, cashflow outcomes.[15]
- Recognising the light-handed regulatory framework, the ERA determined estimates for the Pilbara networks' Weighted Average Cost of Capital (WACC) risk parameters around the top of the sample range for energy networks.[16]
- The risk profile of the Pilbara networks had a particular bearing on the gearing ratio, equity beta and credit rating.[17]
- The ERA adopted its standard approach to determining the market risk premium, debt issuing costs, inflation and gamma. These parameters align with the ERA's rail *rate of return*. These metrics are annually updated and publicly available, and could be used by the Pilbara networks in future *pricing periods*.[18]

To minimise the costs associated with estimating the *rate of return*, and consistent with the objective of light regulation, Horizon Power has:

1. adopted the same approach as the ERA to estimate the *rate of return* for the second *pricing period*
2. used the same static parameters as determined by the ERA, other than the equity beta
3. updated the dynamic parameters based on the ERA's determinations on the *rate of return* for the regulated railways.

[13] Economic Regulation Authority, *Determination of Pilbara networks rate of return, Final decision*, 24 November 2021, para 55
[14] Ibid, para 56
[15] Ibid, para 58
[16] Ibid, para 65
[17] Ibid, para 67
[18] Ibid, paras 68 and 69

Consistent with the ERA's determination on the *rate of return* for the first *pricing period*, Horizon Power has estimated the *rate of return* using a WACC, which aggregates the different returns expected by lenders and equity investors using the following formula[19]:

$$WACC = \frac{D}{D+E}R_d + \frac{E}{D+E}R_e$$

where:

D is the total market value of debt

E is the total market value of equity

R_e is the nominal post-tax return on equity

R_d is the nominal pre-tax cost of debt

Gearing ratio

The gearing ratio is the proportion of debt to equity.

The ERA determined a gearing ratio of 45% debt and 55% equity for the *Horizon Power coastal network* for the first *pricing period*. This was determined by the ERA based on the gearing estimate for benchmark entities from observable data for Australian energy networks over the 5 year period from 2016 to 2020. The ERA determined a gearing ratio at the low end of the range for the sample because it considered that the risks faced by Horizon Power are towards the high side of those faced by other Australian energy networks. [20]

In its most recent decision on Western Power's access arrangement for 2022/23 – 2026/27, the ERA considered an additional year's data to determine the gearing ratio. Based on the data in Table 11.1, the ERA maintained a gearing ratio of 55% debt and 45% equity for Western Power.

Table 11.1: ERA market value gearing ratios (%)

Year	APA Group	AusNet Services	DUET Group	Spark Infrastructure Group	Average
2012	47	59	72	59	59
2013	46	57	71	62	59
2014	45	58	64	55	55
2015	50	59	62	56	57
2016	49	57	51	54	52
2017	49	52	N/A	52	51
2018	46	56	N/A	57	53

[19] Ibid, para 74
[20] Ibid, para 104

Year	APA Group	AusNet Services	DUET Group	Spark Infrastructure Group	Average
2019	45	55	N/A	60	53
2020	45	59	N/A	60	55
2021	49	57	N/A	60	55
5 year average (2016-20)	**47**	**56**	**51**	**57**	**52**
5 year average (2017-21)	**47**	**56**	**N/A**	**58**	**53**
10 year average (2012-21)	**47**	**57**	**64**	**57**	**55**

Source: Economic Regulation Authority, Determination of Pilbara networks rate of return, Final decision, 24 November 2021, para 100; Economic Regulation Authority, Final decision on proposed revisions to the access arrangement for the Western Power Network 2022/23 – 2026/27, Attachment 5: Return on regulated asset base, 31 March 2023, Table 3

The low end of the range for the gearing ratio was the same at the time of ERA's final decision on Western Power's access arrangement as it was when the ERA made its decision on the gearing ratio for Horizon Power for the first *pricing period*.

Accordingly, the gearing ratio applied for the second *pricing period* continues to be 45% debt and 55% equity.

11.2.1 Cost of debt

The estimate of the cost of debt is based on a risk premium over and above the risk-free rate, combined with an additional margin for administrative and hedging costs, where these costs are not included in the cash flows. The nominal pre-tax cost of debt (Rd) is estimated in accordance with the following equation, consistent with the approach adopted by the ERA for the first *pricing period*.[21]

$$R_d = R_f + DRP + DRC$$

where:

R_f is the nominal risk-free rate

DRP is the debt risk premium

DRC is the debt raising costs

[21] Ibid, para 169

The cost of debt has been estimated using a trailing average approach over a 10 year period, consistent with the approach adopted by the ERA for the first *pricing period*.[22] The cost of debt is updated annually so that each year a new year's cost of debt is estimated and the oldest estimate in the 10-year series is removed.

Nominal risk-free rate

The risk-free rate is the return an investor would expect when investing in an asset with no risk.

The ERA is required to make an annual determination on the *rate of return* appropriate for regulated rail networks, which includes a determination of the nominal risk-free rate. As the estimates of the risk-free rate are economy-wide (i.e. not industry specific), the nominal risk-free rate published annually by the ERA for the regulated rail networks has been used to estimate the *rate of return* for Horizon Power.

The nominal risk-free rates, as published annually by the ERA, are set out in Table 11.2.

Table 11.2: Nominal risk-free rates as determined by the ERA for the regulated rail networks

Date of determination	Nominal risk free rate
11 September 2023	3.77%
3 August 2022	3.62%
21 July 2021	1.60%
11 August 2020	0.92%
22 August 2019 (for 2019)	1.53%
22 August 2019 (for 2018)	2.76%
6 October 2017	2.49%
28 October 2016	2.22%
18 September 2015	2.97%
24 October 2014	3.75%
Average	**2.56%**
Source: ERA's annual determinations on the rate of return for the regulated rail networks, available at https://www.erawa.com.au/rail/rail-access/weighted-average-cost-of-capital	

The average nominal risk-free rate determined for the regulated railways over the last ten years is 2.56%. This has been used to estimate the cost of debt.

[22] Ibid, para 201

Debt risk premium

The benchmark credit rating is an input required to estimate the debt risk premium.

The ERA uses different credit ratings for each of the regulated rail networks:

- the Public Transport Authority (PTA) has a credit rating of A as the risks are considered to be lower than those of the companies in the benchmark sample, which is based on European toll road operators[23]
- Arc Infrastructure has a credit rating of BBB+ as it is considered to be comparable to a median credit rating[24]
- the Pilbara Railways has a credit rating of BBB- as it is considered to face a higher level of risk relative to the comparators in the benchmark sample.[25]

In making its decision on the *rate of return* for the first *pricing period*, the ERA found that credit ratings of the Australian energy network sample varied between BBB and A-. It determined a credit rating for the *Horizon Power coastal network* at the low end of the range – BBB.

The credit ratings of the Australian energy network sample considered by the ERA in making subsequent decisions on the *rate of return* for Western Power and the Gas Rate of Return instrument are set out in Table 11.3. The credit ratings are now in the range between BBB and BBB+.

Table 11.3: Australian energy network sample credit rating

Firm	2018	2019	2020	2021	2022
APA Group	BBB	BBB	BBB	BBB	BBB
AusNet	A-	A-	A-	A-	BBB+
Spark Infrastructure	BBB+	BBB+	BBB+	BBB	BBB

Source: Economic Regulation Authority, Explanatory statement for the 2022 final gas rate of return instrument, 16 December 2022, Table 7; Economic Regulation Authority, Final decision on proposed revisions to the access arrangement for the Western Power Network 2022/23 – 2026/27, Attachment 5: Return on regulated asset base, 31 March 2023, page 27

When determining the cost of debt, a credit rating of BBB has been applied.

The ERA's annual determination of the *rate of return* for regulated rail networks includes the determination of a debt risk premium for the three rail networks with credit ratings of A, BBB+ and BBB-. The debt risk premium for Horizon Power has been estimated by taking the average of the debt risk premia for Arc Infrastructure (with a credit rating of BBB+) and Pilbara Railways (having a credit rating of BBB-).

[23] Economic Regulation Authority, *2023 Draft Determination For the Freight and Urban Networks, and the Pilbara Railways*, 30 May 2023, para 157
[24] ibid, para 159
[25] Ibid, para 162

The debt risk premia, as published annually by the ERA, are set out in Table 11.4.

Table 11.4: Debt risk premium as determined by the ERA for the regulated rail networks

Date of determination	Debt risk premium Arc infrastructure (BBB+)	Debt risk premium Pilbara Railways (BBB-)
11 September 2023	2.464%	3.525%
3 August 2022	2.468%	3.297%
21 July 2021	1.616%	2.190%
11 August 2020	2.576%	3.580%
22 August 2019 (for 2019)	2.081%	3.167%
22 August 2019 (for 2018)	1.687%	2.244%
6 October 2017	1.992%	2.512%
28 October 2016	2.450%	3.578%
18 September 2015	2.223%	3.234%
24 October 2014	1.388%	2.084%
Average	**2.518%**	
Source: ERA's annual determinations on the rate of return for the regulated rail networks, available at https://www.erawa.com.au/rail/rail-access/weighted-average-cost-of-capital		

The average debt risk premium determined for Arc Infrastructure and Pilbara Railways over the last ten years is 2.518%. This has been used to estimate the cost of debt.

Debt raising costs

The debt raising costs are the administrative costs incurred by businesses when obtaining finance. They can be included in the *rate of return* or in the cash flows. Consistent with ERA's determination of the *rate of return* for the first *pricing period*, the debt raising costs are included in the *rate of return*.[26]

[26] Economic Regulation Authority, *Determination of Pilbara networks rate of return, Final decision*, 24 November 2021, para 211

The ERA reviewed debt raising costs as part of its 2022 review of the Gas Rate of Return Instrument. In the 2022 Gas Rate of Return Instrument, the ERA:

- maintained that debt raising costs should be based on direct costs associated with established regulatory practices
- considered that debt raising costs should be updated based on advice from Chairmont of 0.155% per annum and adjusted for a higher allowance for arranger fees
- considered that debt raising costs of 0.165% per annum are appropriate.[27]

In its 2023 determination, the ERA included debt raising costs of 0.165% per annum in the *rate of return* for the regulated railways and indicated that this would remain fixed until the next rail WACC method review.[28] This has been used to estimate the cost of debt.

Real pre-tax cost of debt

The nominal pre-tax cost of debt is converted to a real pre-tax cost of debt using the Fisher market transformation as per the following formula:

$$R_{d,real,pretax} = \frac{\left(1 + R_{d,nom,pretax}\right)}{(1 - f)} - 1$$

where:

$R_{d,real,pretax}$ is the real pre-tax cost of debt

$R_{d,nom,pretax}$ is the nominal pre-tax cost of debt

f is the expected rate of inflation

This is consistent with the approach adopted by the ERA in its determination of the *rate of return* for the first *pricing period*.[29]

Expected rate of inflation

The expected rate of inflation is required to calculate a real *rate of return*.

The expected rate of inflation has been estimated by adopting a similar approach to that used by the Australian Energy Regulator. The approach is to calculate the geometric average of the expected inflation rates over the 3-year *pricing period* using:

- the RBA's forecasts of inflation for year 1
- an estimate of the RBA's forecast of inflation for year 2 based in its forecast for the first 6 months
- a glide path from year 2 to the mid-point of the inflation target band (2.5%) in year 5.[30]

[27] Economic Regulation Authority, *Explanatory statement for the 2022 final gas rate of return instrument, 16 December 2022,* pages 197-208

[28] Economic Regulation Authority, *2023 Draft Determination For the Freight and Urban Networks, and the Pilbara Railways*, 30 May 2023, paras 200-201

[29] Economic Regulation Authority, *Determination of Pilbara networks rate of return, Final decision*, 24 November 2021, para 230

[30] Australian Energy Regulator, *Final Position, Regulatory treatment of inflation,* December 2020

Table 11.5: Expected inflation

Year	Source	Expected inflation
2024-25	RBA Statement of Monetary Policy, February 2023	3.0%
2025-26	Based on RBA Statement of Monetary Policy, November 2023	2.7%
2026-27	Glide path	2.63%
Average		**2.77%**

The expected inflation rate that has been applied to determine the *rate of return* for the second *pricing period* is 2.77%.

11.2.2 Return on equity

The return on equity has been estimated using the Sharpe-Lintner Capital Asset Pricing Model, consistent with the ERA's determination on the *rate of return* for the first *pricing period*.[31] The nominal post-tax return on equity is estimated using the following formula:

$$R_e = R_f + \beta_e(R_m - R_f)$$

where:

β_e is correlation between the equity asset's risk and market risk (equity beta)

$R_m - R_f$ is the market risk premium

Risk-free rate

The risk-free rate for estimating the return on equity is the nominal risk-free rate in Table 11.2 for 2023 (3.63%).

Equity beta

The equity beta of a firm has two key determinants:

- systematic risk arising from the sensitivity of the firm's cash flow to the overall market
- financial risk arising from capital structure, with a higher level of debt implying a higher beta.

The ERA determined an equity beta of 0.80 in its determination of the *rate of return* for the first *pricing period*.[32] This was a 0.1 increase on the equity beta of 0.7 for a benchmark energy network, based on Horizon Power's debt capacity and systematic risk. It considered

[31] Economic Regulation Authority, *Determination of Pilbara networks rate of return, Final decision*, 24 November 2021, para 108
[32] Ibid, para 165

this to be commensurate with the level of commercial and regulatory risk for the *Horizon Power coastal network* and consistent with a target gearing of 45%.[33]

Horizon Power sought a third party economic expert's advice (Expert's Advice) on the equity beta for the second pricing period. The Expert's Advice is that the available evidence supports an equity beta higher than the ERA's current allowance. In particular, the ERA's own set of evidence supports an equity beta for the benchmark energy network of 0.8 rather than 0.7. There are two primary reasons for its conclusions on this point:

1. The evidence supports an estimate materially above 0.7. For example:
   (a) the ERA has published a total of 232 comparator beta estimates.[34] The mean of these estimates is 0.87. Only 27% are below the 0.7 figure adopted by the ERA and 73% are above
   (b) the mean beta estimates over the ERA's 5 comparator markets are all materially above 0.7
   (c) the mean beta estimates over the ERA's 49 comparator firms are all materially above 0.7
   (d) the estimates that the ERA has reported for various markets are almost exclusively above 0.7. It is only the single comparator in New Zealand that has a beta estimate below 0.7.
2. Also, the ERA appears to rely equally on Ordinary Least Squares (OLS) and Least Absolute Deviations (LAD) estimates of equity beta. It can be argued that the OLS estimate is consistent with the definition of equity beta in the Capital Asset Pricing Model (CAPM), but the LAD estimate is not. In its view, there is a reasonable argument that OLS produces estimates of the CAPM beta whereas LAD does not. This would seem to suggest that a higher beta estimate is warranted.[35]

Based on the Expert's Advice, Horizon Power has adopted an equity beta of 0.8 rather than 0.7 for the benchmark energy network. Accordingly, Horizon Power has assumed an equity beta of 0.90 (a 0.1 increase above the equity beta for a benchmark energy network) to estimate the return on equity.

Market risk premium

The market risk premium represents the reward that investors require if they are to accept the risk associated with a diversified portfolio of equity investments. Thus, it is measured as the difference between the returns achieved by a well-diversified portfolio of stocks and the risk-free rate.

The ERA determined a market risk premium of 5.9% in its determination of the *rate of return* for the *Horizon Power coastal network* for the first *pricing period*, consistent with the regulated railways.[36] It also determined a market risk premium of 5.9% in its most recent

[33] Ibid, para 163 and 165
[34] 58 comparator businesses, OLS and LAD beta estimates, data periods of 5 years and 10 years.
[35] Frontier Economics, *Updated gearing and beta parameter estimates*, January 2024.
[36] Ibid, para 142

determination for the regulated railways.[37] Accordingly, Horizon Power has assumed a market risk premium of 5.9% to estimate the return on equity.

Real pre-tax return on equity

The nominal post tax rate of equity is converted to a real pre-tax return on equity using the Officer definition of WACC and a Fisher market transformation as per the following formula:

$$R_{e,real,pretax} = \frac{1 + {R_{e,nom,post\ tax}}/{(1 + T(1-\gamma))}}{(1-f)} - 1$$

where:

$R_{e,real,pretax}$ is the real pre-tax return on equity

$R_{e,nom,post\ tax}$ is the nominal post tax return on equity

T is the rate of taxation

ɣ is gamma (franking credits)

f is the expected rate of inflation

Rate of taxation

Horizon Power pays tax at the statutory corporate taxation rate of 30%.

Gamma (franking credits)

The imputation system allows shareholders to receive a credit for the amount of corporate tax already paid by the company. Gamma (γ) is defined as the proportion of actual company tax paid on behalf of shareholders as a pre-collection of personal tax and is used to adjust the taxation rate used in the calculation of a pre-tax WACC.

Gamma is often assessed using the Monkhouse approach, whereby gamma is defined as the product of the credit payout ratio (or distribution rate) and the utilisation rate (termed theta) where:

- the credit payout ratio is defined as the face value of imputation credits distributed by the firm as a proportion of the face value of imputation credits generated
- theta is defined as the value of distributed imputation credits to investors as a proportion of their face value.

The ERA determined a distribution rate of 0.9 and a utilisation rate of 0.6, providing a gamma of 0.5 for the *rate of return* for the *Horizon Power coastal network* for the first *pricing period*[38] and for the recent determination on the *rate of return* for the regulated railways.[39] Horizon Power has used the same value in estimating the *rate of return* for the second *pricing period*.

[37] Economic Regulation Authority, *2023 Draft Determination For the Freight and Urban Networks, and the Pilbara Railways*, 30 May 2023, para 288

[38] Economic Regulation Authority, *Determination of Pilbara networks rate of return, Final decision*, 24 November 2021, para 108

[39] Economic Regulation Authority, *2023 Draft Determination For the Freight and Urban Networks, and the Pilbara Railways*, 30 May 2023, para 397

11.2.3 Real pre-tax rate of return

Table 11.6 summarises each of the *rate of return* parameters and the resultant real pre-tax *rate of return* that has been applied for the 1 July 2024 to 30 June 2027 period.

Table 11.6: Rate of return parameters

Parameter	Value
Gearing ratio (debt : equity)	45% : 55%
Equity beta	0.90
Market risk premium	5.9%
Franking credits (gamma)	50%
Nominal risk-free rate – equity	3.77%
Nominal risk-free rate – debt	2.56%
Debt risk premium	2.518%
Debt raising costs	0.165%
Expected rate of inflation	2.77%
Tax rate	30%
Pre-tax real WACC	**5.32%**

11.3 Return on the capital base

The return on the *capital base* has been forecast based on:

(a) the *rate of return*, as set out in Table 11.6

(b) the average value of the opening and closing *capital base* in each year as set out in Table 10.1.

The forecast return on the *capital base* for the second *pricing period* (1 July 2024 to 30 June 2027) is as set out in Table 11.7 and illustrated in Figure 11.1.

The return on the *capital base* is forecast to decrease over the second *pricing period* from $30.4 million in 2024-25 to $28.6 million in 2026-27, largely due to a reduction in the return on transmission assets as the control/monitoring/communications and protection equipment in the *initial capital base* reaches the end of its life.

The return on the transmission assets represents 46% of the return on the *capital base*.

Table 11.7: Forecast return on the capital base, by cost pool, 2024-25 to 2026-27 ($ million, nominal)

	2024-25	2025-26	2026-27
Transmission	13.94	13.45	13.00
Sub-transmission	0.99	0.99	0.99
Distribution HV	7.27	7.17	7.06
Distribution LV	4.29	4.26	4.22
Street lighting	0.89	0.83	0.77
Metering	0.52	0.49	0.45
Non-system assets	1.81	1.74	1.66
Sub-total	**29.70**	**28.92**	**28.15**
Corporate (share)	0.74	0.61	0.50
Total	**30.44**	**29.54**	**28.64**

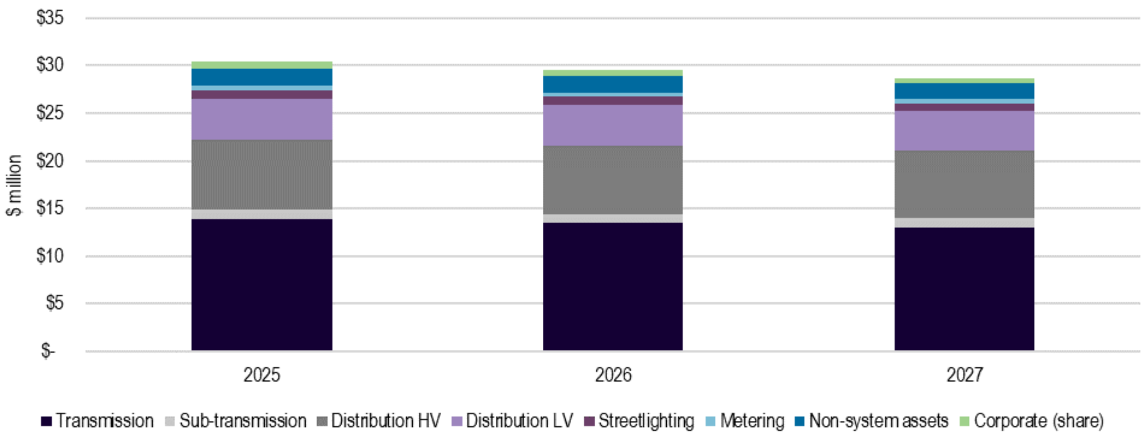

Figure 11.1: Forecast return on the capital base, by cost pool, 2024-25 to 2026-27

11.4 Return on the forecast new facilities investment

The return on the forecast *new facilities investment* has been forecast based on:

(a) the *rate of return*, as set out in Table 11.6

(b) the average written down value of the forecast *new facilities investment*.

The written down value of the forecast *new facilities investment* from 30 June 2024 to 30 June 2027 has been calculated using the:

- forecast *new facilities investment* as set out in Table 6.3
- depreciation of the forecast *new facilities investment*, as set out in Table 9.2

- indexing the forecast *new facilities investment* to maintain its value in real terms by using the forecast CPI as set out in Table 7.2.

The forecast written down value of the *new facilities investment* as at 30 June 2025, 2026 and 2027 is as set out in Table 11.8.

Table 11.8: Forecast written down value of the new facilities investment, by cost pool, 2024-25 to 2026-27 ($ million, nominal)

	2024-25	2025-26	2026-27
Transmission			
Opening value	0.65	13.10	14.95
New facilities investment	12.48	1.87	14.63
Depreciation	-0.06	-0.38	-0.44
Indexation	0.02	0.35	0.39
Closing value	13.10	14.95	29.53
Sub-transmission			
Opening value	0.00	0.00	0.00
New facilities investment	0.00	0.00	0.00
Depreciation	0.00	0.00	0.00
Indexation	0.00	0.00	0.00
Closing value	0.00	0.00	0.00
Distribution HV			
Opening value	0.77	4.94	9.61
New facilities investment	4.17	4.75	8.50
Depreciation	-0.02	-0.21	-0.32
Indexation	0.02	0.13	0.25
Closing value	4.94	9.61	18.05
Distribution LV			
Opening value	0.38	1.00	1.63
New facilities investment	0.68	0.73	0.21
Depreciation	-0.06	-0.13	-0.20
Indexation	0.01	0.03	0.04
Closing value	1.00	1.63	1.69
Street lighting			

	2024-25	2025-26	2026-27
Opening value	0.40	2.38	3.00
New facilities investment	1.98	0.68	0.68
Depreciation	-0.02	-0.12	-0.16
Indexation	0.01	0.06	0.08
Closing value	2.38	3.00	3.60
Metering			
Opening value	0.20	0.38	0.54
New facilities investment	0.18	0.18	0.18
Depreciation	-0.01	-0.03	-0.04
Indexation	0.01	0.01	0.01
Closing value	0.38	0.54	0.70
Non-system assets			
Opening value	1.11	3.61	4.57
New facilities investment	2.54	1.04	1.50
Depreciation	-0.08	-0.18	-0.24
Indexation	0.03	0.10	0.12
Closing value	3.61	4.57	5.94
Sub-total			
Opening value	3.52	25.41	34.30
New facilities investment	22.04	9.25	25.70
Depreciation	-0.25	-1.04	-1.39
Indexation	0.11	0.69	0.90
Closing value	25.41	34.30	59.52
Corporate (share)			
Opening value	1.59	8.71	16.18
New facilities investment	7.47	8.81	5.90
Depreciation	-0.39	-1.58	-2.73
Indexation	0.05	0.24	0.43
Closing value	8.71	16.18	19.78

	2024-25	2025-26	2026-27
Total			
Opening value	5.10	34.12	50.48
New facilities investment	29.51	18.06	31.60
Depreciation	-0.65	-2.62	-4.12
Indexation	0.15	0.92	1.33
Closing value	34.12	50.48	79.29

The forecast return on the forecast *new facilities investment* for each year of the second *pricing period* (1 July 2024 to 30 June 2027) is as set out in Table 11.9. The return on the forecast *new facilities investment* is forecast to increase over the first *pricing period* from $1.0 million in 2024-25 to $3.5 million in 2026-27, in line with the forecast *new facilities investment* during the *pricing period*.

Table 11.9: Forecast return on the forecast new facilities investment, by cost pool, 2024-25 to 2026-27 ($ million, nominal)

	2024-25	2025-26	2026-27
Transmission	0.37	0.76	1.19
Sub-transmission	0.00	0.00	0.00
Distribution HV	0.15	0.39	0.74
Distribution LV	0.04	0.07	0.09
Street lighting	0.07	0.14	0.18
Metering	0.02	0.02	0.03
Non-system assets	0.13	0.22	0.28
Sub-total	**0.77**	**1.61**	**2.52**
Corporate (share)	0.28	0.67	0.97
Total	**1.05**	**2.28**	**3.49**

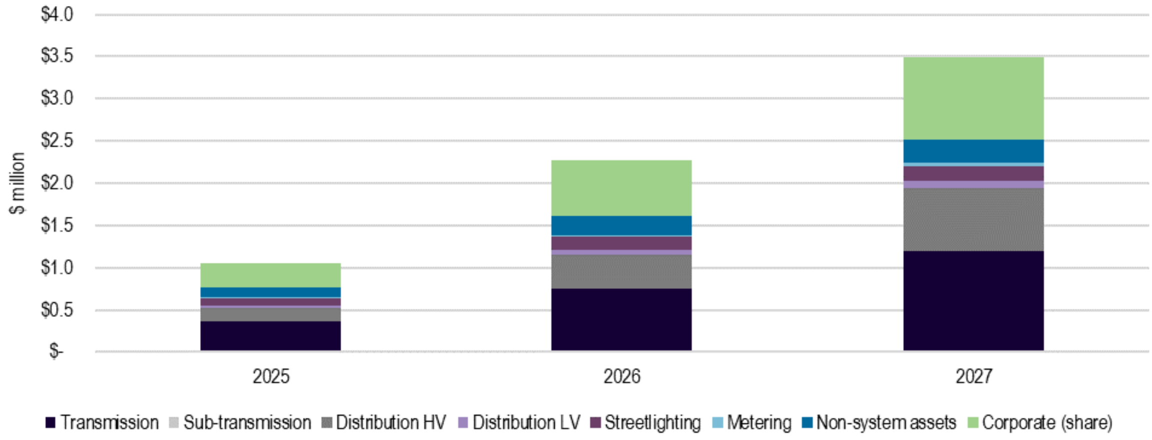

Figure 11.2: Forecast return on the forecast new facilities investment, by cost pool, 2024-25 to 2026-27

12. TEMPORARY ACCESS CONTRIBUTION

Under section 129M of the *Act*, a Temporary Access Contribution Account has been established under section 16 of the *Financial Management Act 2006*. Under section 129N of the *Act*, the Treasurer determines the temporary access contribution (TAC) that is payable on a financial year basis.

Under section 129P of the *Act*, *Horizon Power Pilbara Network Business* must pay the TAC at the times and in the manner determined by the Treasurer. *User*s accessing *services* of the *Horizon Power coastal network* must make payments to *Horizon Power Pilbara Network Business* in accordance with the *Code* in respect of the TAC payable by it.

Under section 48 of the *Code*, if the Treasurer determines that *Horizon Power Pilbara Network Business* must pay a TAC into the TAC Account, then:

an amount may be added to *target revenue* for the *Horizon Power coastal network* for the *pricing period* which—

1. must not exceed the total of the temporary access contributions which are or will be required to be paid under the notice, including any amount that was payable or paid before the commencement of the *pricing period* and not already included in the *target revenue*; and
2. must be separately identified in the *services and pricing policy* as being under this section 48.

In accordance with section 129N of the *Act*, the Treasurer has determined that *Horizon Power Pilbara Network Business* must contribute to the TAC Account an amount of $4,087,626 in 2024-25 and nil in 2025-26 and 2026-27. In accordance with section 48 of the *Code*, the *target revenue* includes these amounts as the contribution by *user*s to the TAC.

13. ADJUSTMENTS TO TARGET REVENUE

13.1 Adjustments to *target revenue* at the start of the pricing period

Section 50 of the *Code* states that:

1. If during a *pricing period*, the *NSP*—

   (a) incurred costs in respect of any matters in section 49(2); and

   (b) was unable to recover some or all of those costs during that *pricing period*,

   then the *NSP* may adjust the *target revenue* for a year (or other interval) at the start of a new *pricing period* to recover those costs.

2. Nothing in section 50(1)—

   (a) requires the amount added to be equal to; or

   (b) permits the amount to be greater than,

   the amount of the unrecovered costs.

3. An amount can only be added to the *target revenue* under section 50(1) in respect of costs, to the extent the amount is efficient, prudent and justifiable.

4. The *NSP* for a *light regulation network* must adjust the *target revenue* for the next successive *pricing period* for any difference between:

   (a) *capital-related costs* actually incurred during the immediately preceding *pricing period* in respect of *new facilities investment* which meet the *new facilities investment test*; and

   (b) *capital-related costs* which were included in the *target revenue* during the immediately preceding *pricing period* in respect of forecast *new facilities investment* as permitted by section 47(2).

5. The adjustment in section 50(4) must also remove any surplus or shortfall associated with any difference between the *capital-related costs* in respect of *new facilities investment* and *capital-related costs* actually incurred.

An adjustment has been made to the *target revenue* in accordance with section 50(4) of the *Code* for the difference between the *capital-related costs* actually incurred during the first *pricing period* and the *capital-related costs* that were included in the *target revenue* in respect of forecast *new facilities investment*.

Table 13.1 compares, by cost pool, the *capital-related costs* that were included in the *target revenue* for the first *pricing period* in respect of forecast *new facilities investment* and the *capital-related costs* actually incurred during the first *pricing period*.

Table 13.1: Capital-related costs on the forecast new facilities investment and the actual capital-related costs, by cost pool, 2021-22 to 2023-24 ($ million, nominal)

	Capital-related costs on forecast new facilities investment			Actual capital-related costs		
	2021-22	2022-23	2023-24	2021-22	2022-23	2023-24
Transmission	0.12	0.47	0.56	0.11	0.60	1.14
Sub-transmission	0.00	0.00	0.00	0.00	0.00	0.00
Distribution HV	0.13	0.51	0.66	0.13	0.50	0.65
Distribution LV	0.02	0.14	0.22	0.02	0.15	0.25
Street lighting	0.01	0.04	0.08	0.01	0.07	0.13
Metering	0.01	0.08	0.12	0.00	0.02	0.04
Non-system assets	0.04	0.24	0.40	0.04	0.27	0.38
Sub-total	**0.33**	**1.48**	**2.03**	**0.32**	**1.61**	**2.58**
Corporate (share)	0.02	0.34	0.51	0.03	0.34	0.71
Total	**0.35**	**1.82**	**2.54**	**0.35**	**1.95**	**3.30**

The revenue adjustment that has been made in the second *pricing period* is the present value of the variance between the forecast *capital-related costs* and the actual *capital-related costs.* The revenue adjustment has been smoothed over the three years of the second *pricing period*, adjusted for the time value of money, as set out in Table 13.2.

Table 13.2: Revenue adjustment for the difference between the forecast and actual capital-related costs on the new facilities investment during the first pricing period, by cost pool, 2024-25 to 2026-27 ($ million, nominal)

	2024-25	2025-26	2026-27
Transmission	0.24	0.26	0.28
Sub-transmission	0.00	0.00	0.00
Distribution HV	-0.03	-0.03	-0.03
Distribution LV	0.01	0.01	0.01
Street lighting	0.03	0.03	0.03
Metering	-0.06	-0.07	-0.07
Non-system assets	0.00	-0.01	-0.01
Sub-total	**0.18**	**0.20**	**0.21**
Corporate (share)	0.21	0.23	0.24
Total	**0.39**	**0.42**	**0.46**

13.2 Adjustments to target revenue during the next pricing period

Section 49 of the *Code* states that:

1. The *NSP* for a *light regulation network* may include in its *services and pricing policy*, a methodology to determine adjustments to the *target revenue* during the relevant *pricing period* in respect of costs for which no allowance was made in the *target revenue*.
2. The methodology referred to in section 49(1), may only adjust the *target revenue* for a year (or other interval) during a *pricing period*, in respect of costs incurred by the *NSP* as a result of:
   - (a) a *force majeure* event, where:
     - (i) the *NSP* was unable to, or is unlikely to be able to recover some or all of the costs under its insurance policies; and
     - (ii) at the time of the force majeure event, the NSP had insurance to the standard of a reasonable and prudent person; or
   - (b) in the case of the Regional Power Corporation, a significant restructure of that corporation; or
   - (c) significant changes in loads on the *light regulation network*; or
   - (d) a regulatory change event.
3. Nothing in this section 49 requires the amount added to be equal to the amount of the unrecovered costs.

4. An amount can only be added to the *target revenue* under this section 49 in respect of costs, to the extent the amount is efficient, prudent and justifiable.

A *force majeure* event is defined in the *Code* as:

> … operating on a person, means a fact or circumstance beyond the person's control and which a reasonable and prudent person would not be able to prevent or overcome.

A regulatory change event is defined in the *Code* as:

> A change in a written law or statutory instrument that—
>
> (a) occurs during the course of a *pricing period*; and
>
> (b) substantially affects the manner in which the *NSP* provides *covered services*; and
>
> (c) materially increases or materially decreases the costs of providing those *covered services*.

If, during the *pricing period*, there is a *force majeure* event, a significant restructure of Horizon Power, a significant change in load on the *light regulation network* or a regulatory change event that has a material impact on Horizon Power's *target revenue*, this *tariff setting methodology* will be updated for the remaining years of the *pricing period* to reflect the change in circumstances. A material impact on Horizon Power's *target revenue* is an increase (or decrease) in *target revenue* of more than 1%.

The *tariff setting methodology* will specify:

- the details of the event that occurred, including the date(s) on which it occurred and the steps taken to mitigate the impact of the event
- the increase (or decrease) in costs incurred as a result of that event
- the resultant increase (or decrease) in *target revenue* to account for the increase (or decrease) in costs.

The increase (or decrease) in the *target revenue* will take into account the time value of money.

Horizon Power will consult on the changes in *target revenue* in accordance with the standard consultation procedure as set out in the *Code*.

14. TARGET REVENUE

The *target revenue* comprises the:

- return of the *capital base* (depreciation) as set out in Table 9.1
- return of the forecast *new facilities investment* as set out in Table 9.2
- return on the *capital base* as set out in Table 11.7
- return on the forecast *new facilities investment* as set out in Table 11.9
- non-capital (operating) costs as set out in Table 7.9
- TAC as discussed in section 12
- revenue adjustment for the difference between the forecast and actual *capital-related costs* on the *new facilities investment* during the first *pricing period* as set out in Table 13.2.

The *target revenue* for each year of the second *pricing period* (1 July 2024 to 30 June 2027) is summarised in Table 14.1 and is provided by revenue cost pool (excluding the TAC) in Table 14.2 and Figure 14.1.

Table 14.1: Target revenue for 2024-25 to 2026-27 ($ million, nominal)

Year ending 30 June	2024-25	2025-26	2026-27
Capital base (excluding network)			
Return of capital base	29.7	28.8	28.3
Return on capital base	29.7	28.9	28.1
New facilities investment (excluding corporate)			
Return of new facilities investment	0.3	1.0	1.4
Return on new facilities investment	0.8	1.6	2.5
Non-capital costs	32.9	33.7	34.6
Share of corporate capital-related costs			
Capital base	3.5	3.4	2.6
New facilities investment	0.7	2.2	3.7
Revenue adjustment	0.4	0.4	0.5
Target revenue (excluding TAC)	**97.9**	**100.2**	**101.7**
Temporary Access Contribution	4.1	0.0	0.0
Target revenue (including TAC)	**102.0**	**100.2**	**101.7**

Table 14.2: Target revenue (excluding TAC) by cost pool for 2024-25 to 2026-27 ($ million, nominal)

	Return of capital base	Return on capital base	New facilities investment – capital-related costs	Non-capital	Share of corporate capital-related costs	Revenue adjust-ment	Total
Year ending 30 June 2025							
Transmission	16.62	13.94	0.43	16.79	1.75	0.25	49.78
Sub-transmission	0.52	0.99	0.00			0.00	1.51
Distribution HV	5.33	7.27	0.17	10.07	1.52	0.00	24.35
Distribution LV	2.69	4.29	0.10	5.48	0.91	0.02	13.49
Street lighting	1.51	0.89	0.09	0.29		0.03	2.81
Metering	0.84	0.52	0.03	0.22		-0.06	1.56
Non-system	2.22	1.81	0.20			0.00	4.22
Target revenue (excl TAC)	**29.73**	**29.70**	**1.03**	**32.86**	**4.17**	**0.23**	**97.72**
Year ending 30 June 2026							
Transmission	15.38	13.45	1.14	17.25	2.38	0.28	49.86
Sub-transmission	0.54	0.99	0.00			0.00	1.53
Distribution HV	5.48	7.17	0.60	10.34	2.07	0.00	25.66
Distribution LV	2.76	4.26	0.20	5.63	1.24	0.02	14.11
Street lighting	1.55	0.83	0.27	0.30		0.03	2.97
Metering	0.87	0.49	0.05	0.23		-0.07	1.57
Non-system	2.24	1.74	0.40			-0.01	4.37
Target revenue (excl TAC)	**28.29**	**28.15**	**3.91**	**34.63**	**6.26**	**0.27**	**101.52**

	Return of capital base	Return on capital base	New facilities investment – capital-related costs	Non-capital	Share of corporate capital-related costs	Revenue adjust-ment	Total
Year ending 30 June 2027							
Transmission	14.59	13.00	1.63	17.70	2.62	0.30	49.83
Sub-transmission	0.55	0.99	0.00			0.00	1.54
Distribution HV	5.62	7.06	1.06	10.61	2.28	-0.01	26.62
Distribution LV	2.75	4.22	0.29	5.78	1.36	0.03	14.43
Street lighting	1.59	0.77	0.34	0.30		0.03	3.03
Metering	0.89	0.45	0.07	0.24		-0.07	1.58
Non-system	2.30	1.66	0.52			-0.01	4.48
Target revenue (excl TAC)	**28.29**	**28.15**	**3.91**	**34.63**	**6.26**	**0.27**	**101.52**

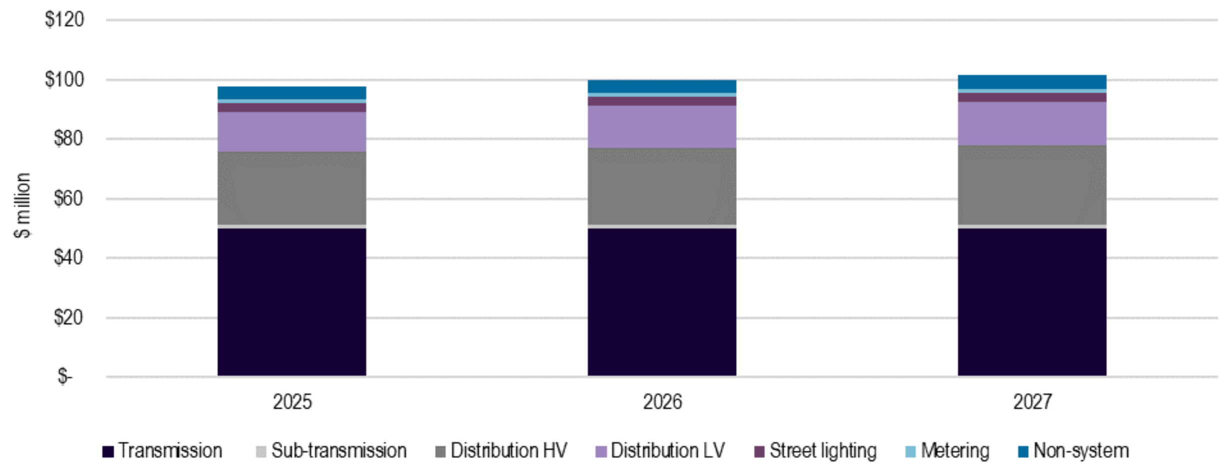

Figure 14.1: Target revenue (excluding the TAC) by cost pool, 2024-25 to 2026-27

The cost pools with the largest proportion of the *target revenue* (excluding the TAC) are transmission (51% in 2024-25), distribution HV (25% in 2024-25) and distribution LV (14% in 2024-25). In total, these three cost pools constitute 90% of the *target revenue* (excluding the TAC).

15. DERIVATION OF THE COST OF SUPPLY

The *target revenue* has been derived by reference to the cost pools that align with the *reference services* that are offered by Horizon Power for *users* accessing, or seeking to access, the *covered Pilbara network*.

Table 15.1 indicates how the cost pools align with each of the *reference services*. For example, the costs associated with low voltage distribution assets in the *Pilbara region* are recovered through *tariffs* for distribution LV *exit services* and *bidirectional services*, streetlighting *exit services* and auxiliary *services*. Distribution LV *exit services* and *bidirectional services* include costs associated with transmission, distribution HV, distribution LV assets and non-system assets.

Table 15.1: Alignment of cost pools with reference services

Type of service	Transmission	Sub transmission	Distribution (HV)	Distribution (LV)	Streetlighting	Metering	Non-system assets
Transmission exit, entry and interconnection services	X						X
Sub-transmission exit services	X	X					X
Distribution HV exit, entry and bidirectional services	X		X				X
Distribution LV exit, entry and bidirectional services	X		X	X			X
Streetlighting exit service	X		X	X	X		X
Supplementary metering services						X	
Auxiliary services			X	X	X	X	

The following sections describe how the cost pools are derived for the:

- *transmission system* cost of supply
- *sub-transmission system* cost of supply
- *distribution system* cost of supply
- streetlighting costs
- metering costs
- non-system costs.

The cost of supply is derived in this section for each year of the second *pricing period* (1 July 2024 to 30 June 2027). However, while the *target revenue* is set for each year of the second *pricing period*, subject to any adjustments that are made within the *pricing period* (in accordance with section 13), the *tariff*s will be updated on an annual basis using the same methodology as set out in this section, with the latest demand forecasts.

15.1 Transmission system cost of supply

The following cost pool is used in the derivation of the *transmission system* cost of supply:

- Transmission.

The *transmission system* cost of supply is allocated to *customer*s based on the forecast peak demand (contracted, metered or calculated) and the forecast after diversity maximum demand, evenly weighted and adjusted by the relevant loss factor(s).

Horizon Power does not currently charge *user*s for *entry services*. Accordingly, the *transmission system* cost of supply is recovered through *exit service*s, *interconnection services* and *bidirectional service*s.

The forecast peak demands and loss factor(s) are set out in Table 15.2, other than for transmission and sub-transmission *reference services*. Transmission and sub-transmission *reference service*s are currently provided to a small number of *customer*s on grandfathered or non-*reference service tariff*s. To maintain confidentiality for these *customers* and any new *customer* that may access these *services*, the demand for transmission and sub-transmission and sub-transmission *reference service*s are not included in Table 15.2.

Table 15.2: Forecast peak demand and loss factor(s), transmission system cost of supply, 2024-25 to 2026-27

	Forecast maximum demand (kVA)	Forecast after diversity maximum demand (kVA)	Loss factor
Year ending 30 June 2025			
Distribution HV exit, entry and bidirectional services	40,860	26,590	3.0%
Distribution LV exit, entry and bidirectional services (including streetlighting)	175,623	74,968	7.27%
Year ending 30 June 2026			
Distribution HV exit, entry and bidirectional services	40,860	26,590	3.0%
Distribution LV exit, entry and bidirectional services (including streetlighting)	175,623	74,968	7.27%

	Forecast maximum demand (kVA)	Forecast after diversity maximum demand (kVA)	Loss factor
Year ending 30 June 2027			
Distribution HV exit, entry and bidirectional services	40,860	26,590	3.0%
Distribution LV exit, entry and bidirectional services (including streetlighting)	175,623	74,968	7.27%

By applying this methodology, the cost pool revenues as set out in Table 15.3 were derived for each year of the second *pricing period*.

Table 15.3: Transmission pricing cost pools, 2024-25 to 2026-27 ($ nominal)

Year ending 30 June	2024-25	2025-26	2026-27
Transmission exit, entry and interconnection services and sub-transmission exit services	13,628,821	13,321,435	13,068,662
Distribution HV exit, entry and bidirectional services	7,106,787	7,142,392	7,154,963
Distribution LV exit, entry and bidirectional services (including streetlighting)	29,042,294	29,401,018	29,609,543
Total	**49,777,901**	**49,864,845**	**49,833,168**

15.2 Sub-transmission system cost of supply

The following cost pool is used in the derivation of the *sub-transmission system* cost of supply:

- Sub-transmission.

The *sub-transmission system* cost of supply relates to specific assets for a small number of *customer*s. Accordingly, the *sub-transmission system* cost of supply is recovered only from those *customer*s receiving a sub-transmission *exit service*.

By applying this methodology, the cost pool revenue as set out in Table 15.4 was derived for each year of the second *pricing period*.

Table 15.4: Sub-transmission pricing cost pool, 2024-25 to 2026-27 ($ nominal)

Year ending 30 June	2024-25	2025-26	2026-27
Sub-transmission exit services	1,514,816	1,527,199	1,538,097
Total	**1,514,816**	**1,527,199**	**1,538,097**

15.3 Distribution system cost of supply

The following cost pools are used in the derivation of the *distribution system* cost of supply:

- Distribution HV
- Distribution LV.

The distribution HV and distribution LV cost pools include *non-capital costs* associated with providing auxiliary *reference services*. These costs are first deducted before allocating the:

- distribution HV cost of supply to all distribution *customers* based on forecast peak demand (contracted or metered) and the forecast after diversity maximum demand, evenly weighted and adjusted by the relevant loss factor(s)
- distribution LV cost of supply to distribution LV and streetlighting *customers* based on forecast maximum demand (contracted, metered or calculated) and the forecast after diversity maximum demand, evenly weighted and adjusted by the relevant loss factor(s).

By applying this methodology, the cost pool revenues as set out in Table 15.5 were derived for each year of the second *pricing period*.

Table 15.5: Distribution pricing cost pools, 2024-25 to 2026-27 ($ nominal)

Year ending 30 June	2024-25	2025-26	2026-27
Distribution HV exit, entry and bidirectional services	5,261,347	5,549,384	5,741,212
Distribution LV exit, entry and bidirectional services (including streetlighting)	32,225,595	33,850,466	34,938,443
Auxiliary services	357,626	367,282	387,119
Total	**37,844,568**	**39,767,132**	**41,066,775**

15.4 Streetlighting costs

Allocation of costs to streetlighting is in two components – the use of network costs, as discussed in the section above, and the costs associated with the streetlighting assets. The following cost pool is used to derive the cost associated with the streetlighting assets:

- Streetlighting.

The streetlighting cost pool includes *non-capital costs* associated with providing auxiliary *reference services*. These costs are first deducted.

By applying this methodology, the cost pool revenues as set out in Table 15.6 were derived for each year of the second *pricing period*.

Table 15.6: Streetlighting pricing cost pools, 2024-25 to 2026-27 ($ nominal)

Year ending 30 June	2024-25	2025-26	2026-27
Streetlighting	2,779,039	2,943,752	3,002,705
Auxiliary services	26,735	27,457	28,940
Total	**2,805,774**	**2,971,209**	**3,031,645**

The revenue for streetlights is allocated on the basis of the number of streetlights (7,717) which have an average demand of 96.7 VA per streetlight.

15.5 Metering costs

The following cost pool is used to derive the cost associated with metering:

- Metering.

The metering cost pool includes *non-capital costs* associated with providing auxiliary *reference services*. These costs are first deducted before allocating the revenue for metering on the basis of the number of meters, as set out in Table 15.7.

Table 15.7: Metering pricing cost pools, 2024-25 to 2026-27 ($ nominal)

Year ending 30 June	2024-25	2025-26	2026-27
Metering	1,539,590	1,552,857	1,563,197
Auxiliary services	15,639	16,061	16,929
Total	**1,555,229**	**1,568,918**	**1,580,126**

The revenue for metering is allocated to *connection points* based on whether supply is taken at a high voltage or a low voltage. The allocation weights the revenue for meters for high voltage *services* five times higher than for meters for low voltage *services*, based on the differential in the purchase cost of the meters.

The forecast number of *connection points* is set out in Table 15.8.

Table 15.8: Forecast number of connection points, 2024-25 to 2026-27

Year ending 30 June	2024-25	2025-26	2026-27
Number of connection points with HV meters	38	38	38
Number of connection points with LV meters	16,105	16,105	16,105
Total	**16,143**	**16,143**	**16,143**

15.6 Non-system costs

The following cost pool is used in the derivation of the non-system costs:

- Non-system assets.

The non-system costs are first allocated to the transmission, sub-transmission and distribution cost pools based on asset value and then recovered from all *customer*s, based on forecast peak demand (either contracted, metered or calculated) and the forecast after diversity maximum demand, evenly weighted and adjusted by the relevant loss factor(s).

By applying this methodology, the cost pool revenues as set out in Table 15.9 were derived for each year of the second *pricing period*.

Table 15.9: Non-system pricing cost pools, 2024-25 to 2026-27 ($ nominal)

Year ending 30 June	2024-25	2025-26	2026-27
Transmission exit, entry and interconnection services and sub-transmission exit services	687,224	706,887	724,468
Distribution HV exit, entry and bidirectional services	565,740	583,683	596,533
Distribution LV exit, entry and bidirectional services (including streetlighting)	2,971,946	3,078,715	3,157,761
Total	**4,224,909**	**4,369,285**	**4,478,762**

16. REFERENCE SERVICES AND TARIFF STRUCTURE

Table 16.1 details the relationship between the *reference service*s and the *reference tariff*s. The following sections provide an overview of the *reference tariff*s that apply in the *Pilbara region*. Further details on the *reference service*s, including a description and the eligibility criteria, are provided in Horizon Power's Reference Services document.

Table 16.1: Reference services and reference tariffs

Reference service	Reference tariff
A1 – Metered demand (low voltage) exit service	DT1
A2 – Contract Maximum Demand (low voltage) exit service	DT2
A3 – Metered demand (high voltage) exit service	DT3
A4 – Contract Maximum Demand (high voltage) exit service	DT4
A5 – Sub-transmission exit service	TT1
A6 – Transmission exit service	TT2
A7 – Streetlighting exit service	DT5
B1 – Distribution (high voltage) entry service	DT7
B2 – Entry service facilitating distributed generation or other non-network solution	DT8
B3 – Transmission entry service	TT3
C1 – Metered demand (low voltage) bidirectional service	DT1
C2 – Contract Maximum Demand (low voltage) bidirectional service	DT2
C3 – Metered demand (high voltage) bidirectional service	DT3
C4 – Contract Maximum Demand (low voltage) bidirectional service	DT4
C5 – Bidirectional service facilitating distributed generation or other non-network solution	DT6
D1 – Transmission interconnection service	TT2
E1 – Disconnection of supply ahead of abolishment service	AT1
E2 – Disconnection of supply service	AT2
E3 – Reconnection of supply service	AT3
E4 – Remote disconnection service	AT4
E5 – Remote reconnection service	AT5

16.1 Exit service tariff overview

An overview of the structure of each of the *reference tariff*s applicable to *exit service*s is presented in the following sections.

16.1.1 DT1 – Distribution (low voltage) metered demand

The *tariff* structure includes:

- a *charge* per kVA of metered maximum demand.

The maximum demand used is a running 12-month peak. This provides a clear incentive to manage the peak demand because any excessive demand recorded in one month then impacts upon the demand *charge* for the next 12 months.

In addition, a *customer* on a DT1 *tariff* pays:

- a fixed *charge* for a supplementary metering service
- if the *connection point* is a *TAC eligible customer exit point*, a TAC *charge*.

16.1.2 DT2 – Distribution (low voltage) Contracted Maximum Demand

The *tariff* structure includes:

- a *charge* per kVA of contracted maximum demand
- a *charge* per kVA for demand in excess of the contracted maximum demand in a month.

The *tariff* requires the *user* to nominate a contracted maximum demand (CMD) that reasonably reflects their expected annual peak demand. There is a monthly penalty for any demand excursion above the CMD, which is twice the CMD *charge*.

The incentive is for the *user* to manage their peak demand through the initial nomination of the CMD and the monthly penalty for exceeding the CMD. The CMD nominations provide certainty to Horizon Power as to the peak demand on the network to ensure there is sufficient capacity. The monthly penalty needs to be high enough to incentivise *user*s to manage their peak demand within their nomination. By setting the penalty for any demand excursion above the CMD at twice the CMD *charge*, *user*s have an incentive to ensure that any CMD excursions only occur for a few months each year.

In addition, a *customer* on a DT2 *tariff* pays:

- a fixed *charge* for a supplementary metering service
- if the *connection point* is a *TAC eligible customer exit point*, a TAC *charge*.

16.1.3 DT3 – Distribution (high voltage) metered demand

The *tariff* structure includes:

- a *charge* per kVA of metered maximum demand.

The maximum demand used is a running 12-month peak. This provides a clear incentive to manage the peak demand because any excessive demand recorded in one month then impacts upon the demand *charge* for the next 12 months.

In addition, a *customer* on a DT3 *tariff* pays:

- a fixed *charge* for a supplementary metering service
- if the *connection point* is a *TAC eligible customer exit point*, a TAC *charge*.

16.1.4 DT4 – Distribution (high voltage) Contracted Maximum Demand

The *tariff* structure includes:

- a *charge* per kVA of contracted maximum demand
- a *charge* per kVA for demand in excess of the contracted maximum demand in a month.

The *tariff* requires the *user* to nominate a CMD that reasonably reflects their expected annual peak demand. There is a monthly penalty for any demand excursion above the CMD, which is twice the CMD *charge*.

The incentive is for the *user* to manage their peak demand through the initial nomination of the CMD and the monthly penalty for exceeding the CMD. The CMD nominations provide certainty to Horizon Power as to the peak demand on the network to ensure there is sufficient capacity. The monthly penalty needs to be high enough to incentivise *user*s to manage their peak demand within their nomination. By setting the penalty for any demand excursion above the CMD at twice the CMD *charge*, *user*s have an incentive to ensure that any CMD excursions only occur for a few months each year.

In addition, a *customer* on a DT4 *tariff* pays:

- a fixed *charge* for a supplementary metering service
- if the *connection point* is a *TAC eligible customer exit point*, a TAC *charge*.

16.1.5 DT5 – Streetlighting

Streetlights do not have metering data to support either the initial setting of the *tariff* or the billing of *user*s based on actual maximum demand. The maximum demand per lamp is calculated based on the typical globe wattage.

The *tariff* structure includes:

- a *charge* per lamp based on calculated maximum demand.

The *tariff* includes a *charge* to reflect the capital and operating costs of the streetlight asset itself. There is no *charge* for metering.

16.1.6 TT1 – Sub-transmission Contracted Maximum Demand

The *tariff* structure includes:

- a *charge* per kVA of contracted maximum demand
- a *charge* per kVA for demand in excess of the contracted maximum demand in a month.

The *tariff* requires the *user* to nominate a CMD that reasonably reflects their expected annual peak demand. There is a monthly penalty for any demand excursion above the CMD, which is twice the CMD *charge*.

The incentive is for the *user* to manage their peak demand through the initial nomination of the CMD and the monthly penalty for exceeding the CMD. The CMD nominations provide certainty to Horizon Power as to the peak demand on the network to ensure there is sufficient capacity. The monthly penalty needs to be high enough to incentivise *user*s to manage their peak demand within their nomination. By setting the penalty for any demand excursion above the CMD at twice the CMD *charge*, *user*s have an incentive to ensure that any CMD excursions only occur for a few months each year.

In addition, a *customer* on a TT1 *tariff* pays a fixed *charge* for a supplementary metering service.

16.1.7 TT2 – Transmission Contracted Maximum Demand

The *tariff* structure includes:

- a *charge* per kVA of contracted maximum demand
- a *charge* per kVA for demand in excess of the contracted maximum demand in a month.

The *tariff* requires the *user* to nominate a CMD that reasonably reflects their expected annual peak demand. There is a monthly penalty for any demand excursion above the CMD, which is twice the CMD *charge*.

The incentive is for the *user* to manage their peak demand through the initial nomination of the CMD and the monthly penalty for exceeding the CMD. The CMD nominations provide certainty to Horizon Power as to the peak demand on the network to ensure there is sufficient capacity. The monthly penalty needs to be high enough to incentivise *user*s to manage their peak demand within their nomination. By setting the penalty for any demand excursion above the CMD at twice the CMD *charge*, *user*s have an incentive to ensure that any CMD excursions only occur for a few months each year.

In addition, a *customer* on a TT2 *tariff* pays a fixed *charge* for a supplementary metering service.

16.2 Entry service tariff overview

An overview of the structure of each of the *reference tariff*s applicable to *entry service*s is provided in the following sections.

16.2.1 DT7 – Distribution (low voltage) Contracted Maximum Demand

The *tariff* structure includes:

- a *charge* per kVA of contracted maximum demand
- a *charge* per kVA for demand in excess of the contracted maximum demand in a month.

The *tariff* requires the *user* to nominate a contracted maximum demand (CMD) that reasonably reflects their expected annual peak demand. There is a monthly penalty for any demand excursion above the CMD, which is twice the CMD *charge*.

The incentive is for the *user* to manage their peak demand through the initial nomination of the CMD and the monthly penalty for exceeding the CMD. The CMD nominations provide certainty to Horizon Power as to the peak demand on the network to ensure there is sufficient capacity. The monthly penalty needs to be high enough to incentivise *user*s to manage their peak demand within their nomination. By setting the penalty for any demand excursion above the CMD at twice the CMD *charge*, *user*s have an incentive to ensure that any CMD excursions only occur for a few months each year.

In addition, a *customer* on a DT7 *tariff* pays a fixed *charge* for a supplementary metering service.

16.2.2 DT8 – Entry service facilitating distribution generation or other non-network solution

The *tariff* structure includes:

- a *charge* per kVA of metered maximum demand.

The maximum demand used is a running 12-month peak. This provides a clear incentive to manage the peak demand because any excessive demand recorded in one month then impacts upon the demand *charge* for the next 12 months.

In addition, a *customer* on a DT8 *tariff* pays a fixed *charge* for a supplementary metering service.

16.2.3 TT3 – Transmission Contracted Maximum Demand

The *tariff* structure includes:

- a *charge* per kVA of contracted maximum demand
- a *charge* per kVA for demand in excess of the contracted maximum demand in a month.

The *tariff* requires the *user* to nominate a CMD that reasonably reflects their expected annual peak demand. There is a monthly penalty for any demand excursion above the CMD, which is twice the CMD *charge*.

The incentive is for the *user* to manage their peak demand through the initial nomination of the CMD and the monthly penalty for exceeding the CMD. The CMD nominations provide certainty to Horizon Power as to the peak demand on the network to ensure there is sufficient capacity. The monthly penalty needs to be high enough to incentivise *user*s to manage their peak demand within their nomination. By setting the penalty for any demand excursion above the CMD at twice the CMD *charge*, *user*s have an incentive to ensure that any CMD excursions only occur for a few months each year.

In addition, a *customer* on a TT3 *tariff* pays a fixed *charge* for a supplementary metering service.

16.3 Bidirectional service tariff overview

An overview of the structure of each of the *reference tariff*s applicable to *bidirectional service*s is provided in the following sections.

16.3.1 DT1 – Distribution (low voltage) metered demand

The *tariff* structure includes:

- a *charge* per kVA of metered maximum demand.

The maximum demand used is a running 12-month peak. This provides a clear incentive to manage the peak demand because any excessive demand recorded in one month then impacts upon the demand *charge* for the next 12 months.

In addition, a *customer* on a DT1 *tariff* pays:

- a fixed *charge* for a supplementary metering service
- if the *connection point* is a *TAC eligible customer exit point*, a TAC *charge*.

16.3.2 DT2 – Distribution (low voltage) Contracted Maximum Demand

The *tariff* structure includes:

- a *charge* per kVA of contracted maximum demand
- a *charge* per kVA for demand in excess of the contracted maximum demand in a month.

The *tariff* requires the *user* to nominate a CMD that reasonably reflects their expected annual peak demand. There is a monthly penalty for any demand excursion above the CMD, which is twice the CMD *charge*.

The incentive is for the *user* to manage their peak demand through the initial nomination of the CMD and the monthly penalty for exceeding the CMD. The CMD nominations provide certainty to Horizon Power as to the peak demand on the network to ensure there is sufficient capacity. The monthly penalty needs to be high enough to incentivise *user*s to manage their peak demand within their nomination. By setting the penalty for any demand excursion above the CMD at twice the CMD *charge*, *user*s have an incentive to ensure that any CMD excursions only occur for a few months each year.

In addition, a *customer* on a DT2 *tariff* pays:

- a fixed *charge* for a supplementary metering service
- if the *connection point* is a *TAC eligible customer exit point*, a TAC *charge*.

16.3.3 DT3 – Distribution (high voltage) metered demand

The *tariff* structure includes:

- a *charge* per kVA of metered maximum demand.

The maximum demand used is a running 12-month peak. This provides a clear incentive to manage the peak demand because any excessive demand recorded in one month then impacts upon the demand *charge* for the next 12 months.

In addition, a *customer* on a DT3 *tariff* pays:

- a fixed *charge* for a supplementary metering service
- if the *connection point* is a *TAC eligible customer exit point*, a TAC *charge*.

16.3.4 DT4 – Distribution (high voltage) Contracted Maximum Demand

The *tariff* structure includes:

- a *charge* per kVA of contracted maximum demand
- a *charge* per kVA for demand in excess of the contracted maximum demand in a month.

The *tariff* requires the *user* to nominate a CMD that reasonably reflects their expected annual peak demand. There is a monthly penalty for any demand excursion above the CMD, which is twice the CMD *charge*.

The incentive is for the *user* to manage their peak demand through the initial nomination of the CMD and the monthly penalty for exceeding the CMD. The CMD nominations provide certainty to Horizon Power as to the peak demand on the network to ensure there is sufficient capacity. The monthly penalty needs to be high enough to incentivise *user*s to manage their peak demand within their nomination. By setting the penalty for any demand excursion above the CMD at twice the CMD *charge*, *user*s have an incentive to ensure that any CMD excursions only occur for a few months each year.

In addition, a *customer* on a DT4 *tariff* pays:

- a fixed *charge* for a supplementary metering service
- if the *connection point* is a *TAC eligible customer exit point*, a TAC *charge*.

16.3.5 DT6 – Bidirectional service facilitating distributed generation or other non-network service

The *tariff* structure includes:

- a *charge* per kVA of metered maximum demand.

The maximum demand used is a running 12-month peak. This provides a clear incentive to manage the peak demand because any excessive demand recorded in one month then impacts upon the demand *charge* for the next 12 months.

In addition, a *customer* on a DT6 *tariff* pays:

- a fixed *charge* for a supplementary metering service
- if the *connection point* is a *TAC eligible customer exit point*, a TAC *charge*.

16.4 Interconnection service tariff overview

An overview of the structure of the *reference tariff* applicable to *interconnection services* is provided in the following section.

16.4.1 TT2 – Third party transmission network *interconnection service*

The *tariff* structure includes:

- a *charge* per kVA of contracted maximum demand
- a *charge* per kVA for demand in excess of the contracted maximum demand in a month.

The *tariff* requires the *user* to nominate a CMD that reasonably reflects their expected annual peak demand. There is a monthly penalty for any demand excursion above the CMD, which is twice the CMD *charge*.

The incentive is for the *user* to manage their peak demand through the initial nomination of the CMD and the monthly penalty for exceeding the CMD. The CMD nominations provide certainty to Horizon Power as to the peak demand on the network to ensure there is sufficient capacity. The monthly penalty needs to be high enough to incentivise *user*s to manage their peak demand within their nomination. By setting the penalty for any demand excursion above the CMD at twice the CMD *charge*, *user*s have an incentive to ensure that any CMD excursions only occur for a few months each year.

In addition, a *customer* on a TT3 *tariff* pays a fixed *charge* for a supplementary metering service.

16.5 TAC tariff overview

The *tariff* structure includes:

- for *user*s on a maximum demand-based *reference tariff* (DT1 or DT3), a *charge* per kW of metered maximum demand, or
- for *user*s on a CMD-based *reference tariff* (DT2 or DT4):
    - a *charge* per kW of contracted maximum demand
    - a *charge* per KW for demand in excess of the contracted maximum demand in a month.

The metered maximum demand expressed in kW is equivalent to the metered maximum demand expressed in kVA for the purposes of the *reference tariff*s DT1 and DT3. The CMD expressed in kW is equivalent to the CMD expressed in kVA for the purposes of *reference tariff*s DT2 and DT4.

For *users* on a CMD-based *reference tariff*, there is a monthly penalty for any demand excursion above the CMD, which is the TAC *tariff*.

16.6 Other tariffs overview

An overview of the structure of each of the other *reference tariffs* is provided in the following sections.

16.6.1 AT1

AT1 consists of a *charge* per request to abolish a *connection point* supply.

16.6.2 AT2

AT2 consists of a *charge* per request to disconnect supply (removal of fuse).

16.6.3 AT3

AT3 consists of a *charge* per request to reconnect supply (re-insertion of fuse).

16.6.4 AT4

AT4 consists of a *charge* per request to remotely disconnect supply.

16.6.5 AT5

AT5 consists of a *charge* per request to remotely reconnect supply.

17. DERIVATION OF REFERENCE TARIFFS

This section describes how the *reference tariff*s are derived from the cost pools. The *reference tariff*s for the first year of the *pricing period* are set out in the *price list*. The *price list* will be updated prior to the commencement of each year of the *pricing period* by applying the same methodology and incorporating any adjustments to the *target revenue* in accordance with section 13.2.

17.1 Derivation of transmission and sub-transmission system tariffs (TT1, TT2 and TT3)

The only *customer*s currently receiving a transmission or sub-transmission *exit service* are *customer*s that are on grandfathered *tariff*s or non-*reference tariffs*. There is currently no *charge* for *entry service*s.

Section 69 of the *Code* states that:

> In respect of any contracts for *services* entered into by an *NSP* before the date of the relevant Pilbara network becoming a *light regulation network*—
>
> (a) the *tariff* payable under those agreements must not be taken into account in the *tariff setting methodology* for *reference service*s, and instead the *user* must be treated for *tariff* setting purposes as though it were paying the *reference tariff*; and
>
> (b) if that agreement specifies a higher level of reliability than the *reference service*, no additional contributions can be sought by the *NSP* in respect of the cost incurred to provide that higher level of reliability.

Accordingly, this section derives the transmission and *sub-transmission system tariff*s assuming that those *customer*s receiving an *exit service* are paying a *reference tariff* rather than a grandfathered *tariff*. As there is only a small number of transmission and sub-transmission *customer*s, the derivation of the *reference tariff*s for these *customer*s has been aggregated so as to maintain confidentiality.

The *transmission system tariff* components are:

- *transmission system* cost of supply
- non-system costs.

The *sub-transmission system tariff* components are:

- *transmission system* cost of supply
- *sub-transmission system* cost of supply
- non-system costs.

*Transmission system tariff*s and *sub-transmission system tariff*s for *exit service*s and *interconnection service*s are fixed and expressed in the form of dollars per kVA per annum.

Annual *transmission system tariff*s and *sub-transmission system tariff*s are derived by dividing the relevant cost pools by the forecast loss adjusted contracted maximum demand applying to those assets. The annual price is invoiced monthly by dividing the annual price by twelve and, where *charges* are applicable for part of a month, the annual *charges* are prorated based on the number of days in that year.

Table 17.1 details the revenue that is forecast to be recovered through the *transmission system tariffs* and *sub-transmission system tariffs* in each year of the second *pricing period* if the transmission and sub-transmission *customers* were paying the *reference tariff*.

Table 17.1: Transmission and sub-transmission revenue forecast, 2024-25 to 2026-27

Year ending 30 June	2024-25	2025-26	2026-27
Forecast revenue recovered ($ million)	15.83	15.56	15.33

17.1.1 Compliance with pricing rules

Section 63(3) of the *Code* states that:

> Subject to section 65, for each *reference tariff*, the revenue expected to be recovered must lie on or between—
>
> (a) an upper bound representing the *stand-alone cost of service provision* for *customers* to whom or in respect of whom that *reference tariff* applies; and
>
> (b) a lower bound representing the avoidable cost of not serving the *customers* to whom or in respect of whom that *reference tariff* applies.

Horizon Power has determined values for each of these concepts for the transmission and sub-transmission *reference services*.

The total costs that are avoided are a portion of the costs that Horizon Power incurs in performing its network operations activities and the return on and of assets that are only required to provide transmission and sub-transmission *reference services*. All other activities, e.g. asset maintenance and replacement would still be performed. The network operations expenditure is based on the *operating expenditure* forecast for the *pricing period*.

Horizon Power has determined that, within a financial year, other than the network operations costs identified above, all other costs would still apply to transmission and sub-transmission connected loads.

Table 17.2 demonstrates that the forecast revenue that would be recovered from transmission and sub-transmission *customers* in 2024-25, if they were paying a *reference tariff*, is between the avoided cost and *stand-alone cost of service provision*.

Table 17.2: Demonstration that transmission and sub-transmission reference tariffs would be between avoided and stand-alone cost of service provision for 2024-25

Reference service	Reference tariff	Avoided cost of service ($ million)	Stand-alone cost of service ($ million)	Forecast revenue recovered from reference tariffs ($ million)
A5	TT1	1.90	49.76	15.83
A6	TT2			
B3	TT3			
D1	TT2			

17.2 Derivation of distribution system tariffs (DT1, DT2, DT3, DT4, DT5, DT6, DT7 and DT8)

The *distribution system tariff* components are:

- *transmission system* cost of supply
- *distribution system* cost of supply
- non-system costs.

*Distribution system tariff*s for *exit service*s and *bidirectional service*s are fixed and expressed in the form of dollars per kVA per annum. There is currently no *charge* for *entry service*s.

Annual *distribution system tariff*s are derived by dividing the relevant cost pools by the forecast loss adjusted maximum demand (either contracted, metered or calculated) applying to those assets. The annual price is invoiced monthly by dividing the annual price by twelve and, where *charge*s are applicable for part of a month, the annual *charge*s are prorated based on the number of days in that year.

17.2.1 Streetlighting

The streetlighting *tariff* components are:

- *distribution system tariff*
- streetlighting costs.

Streetlighting *tariff*s are fixed and expressed in the form of dollars per lamp per annum.

Streetlighting *tariff*s are derived by multiplying the calculated demand for streetlights by the *distribution system tariff*, adding the streetlighting costs, and then dividing by the number of lamps. The annual price is invoiced monthly by dividing the annual price by twelve and, where *charge*s are applicable for part of a month, the annual *charge*s are prorated based on the number of days in that year.

17.2.2 Forecast revenue

Table 17.3 details the revenue that is forecast to be recovered through the *distribution system tariffs* (including the streetlighting *tariffs*) in each year of the second *pricing period*.

Table 17.3: Distribution revenue forecast, 2024-25 to 2026-27

	Forecast maximum demand (kVA)	Forecast revenue recovered ($ million)
Year ending 30 June 2025		
DT1 – Metered demand (LV) DT2 – Contract maximum demand (LV)	175,623	63.97
DT3 – Metered demand (HV) DT4 – Contract maximum demand (HV)	40,860	12.93
DT5 – Streetlighting	746	3.05
DT6 – Non-network solutions (bidirectional)	0	0.00
DT7 – Contract maximum demand (HV) (entry)	0	0.00
DT8 – Non-network solutions (entry)	0	0.00
Total *target revenue* – distribution system *tariffs*		**79.95**
Year ending 30 June 2026		
DT1 – Metered demand (LV) DT2 – Contract maximum demand (LV)	175,623	66.05
DT3 – Metered demand (HV) DT4 – Contract maximum demand (HV)	40,860	13.28
DT5 – Streetlighting	746	3.22
DT6 – Non-network solutions (bidirectional)	0	0.00
DT7 – Contract maximum demand (HV) (entry)	0	0.00
DT8 – Non-network solutions (entry)	0	0.00
Total *target revenue* – distribution system *tariffs*		**82.55**

	Forecast maximum demand (kVA)	Forecast revenue recovered ($ million)
Year ending 30 June 2027		
DT1 – Metered demand (LV) DT2 – Contract maximum demand (LV)	175,623	67.42
DT3 – Metered demand (HV) DT4 – Contract maximum demand (HV)	40,860	13.49
DT5 – Streetlighting	746	3.29
DT6 – Non-network solutions (bidirectional)	0	0.00
DT7 – Contract maximum demand (HV) (entry)	0	0.00
DT8 – Non-network solutions (entry)	0	0.00
Total *target revenue* – distribution system *tariffs*		**84.20**

17.2.3 Compliance with pricing rules

Horizon Power has determined values for the avoided cost and *stand-alone cost of service provision* for each of the distribution *reference services*.

The total costs that are avoided are a portion of the costs that Horizon Power incurs in performing its network operations activities. All other activities, e.g. asset maintenance and replacement would still be performed. The network operations expenditure is based on the *operating expenditure* forecast for the *pricing period*.

Horizon Power has determined that, within a financial year, other than the network operations costs identified above, all other costs would still apply to distribution connected loads.

Table 17.4 demonstrates that the forecast revenue recovered from distribution *reference services* in 2024-25 is between the avoided cost and *stand-alone cost of service provision*.

Table 17.4: Demonstration that distribution reference tariffs are between avoided and stand-alone cost of service provision for 2024-25

Reference service	Reference tariff	Avoided cost of service ($ million)	Stand-alone cost of service ($ million)	Forecast revenue recovered from reference tariff ($ million)
A1, A2, B2, C1, C2, C5	DT1, DT2, DT6, DT8	9.61	75.13	64.24
A3, A4, B1, C3, C4	DT3, DT4, DT7	0.02	45.47	12.93
A7	DT5 (excl network *charge*)	2.67	31.18	2.78

17.3 Derivation of supplementary metering charges

The supplementary metering *charge* is derived by dividing the metering cost pool by the number of *customer*s, with the number of high voltage *customer*s weighted five times higher than the number of low voltage *customer*s.

Table 17.5 details the revenue that is forecast to be recovered through the supplementary metering *charge*s in each year of the second *pricing period*.

Table 17.5: Metering revenue forecast, 2024-25 to 2026-27

Supplementary metering charges	Forecast number of meters	Forecast revenue recovered ($ million)
Year ending 30 June 2025		
Metering for *customers* connected to the low voltage network (less than 6.6 kV)	16,105	1.54
Metering for *customers* connected to the high voltage network (between and including 6.6 kV and 33 kV)	38	
Year ending 30 June 2026		
Metering for *customers* connected to the low voltage network (less than 6.6 kV)	16,105	1.55
Metering for *customers* connected to the high voltage network (between and including 6.6 kV and 33 kV)	38	

Supplementary metering charges	Forecast number of meters	Forecast revenue recovered ($ million)
Year ending 30 June 2027		
Metering for *customers* connected to the low voltage network (less than 6.6 kV)	16,105	1.56
Metering for *customers* connected to the high voltage network (between and including 6.6 kV and 33 kV)	38	

17.4 Derivation of the TAC tariff

The TAC *tariff* is fixed and expressed in the form of dollars per kW per annum.

The TAC *tariff* is derived by dividing the TAC as gazetted by the Government by the forecast loss adjusted maximum demand (either contracted, metered or calculated) for *TAC eligible customer exit point*s. The annual price is invoiced monthly by dividing the annual price by twelve and, where *charge*s are applicable for part of a month, the annual *charge*s are prorated based on the number of days in that year.

The *Code* defines a *TAC eligible customer exit point* as:

> A *customer*'s exit point on the *Horizon Power coastal network* at which electricity is consumed by a *customer* who is not a prescribed *customer*.

In addition, section 65(2) of the *Code* states that:

> None of the amount added to the *target revenue* under section 48 is to be recovered from *user*s of *reference service*s in respect of *TAC eligible customer exit points* located on a *transmission system* or a *sub-transmission system*.

The Government has gazetted the TAC for each year of the second *pricing period*. Table 17.6 details the revenue that is forecast to be recovered through the TAC *tariff* in each of these years.

Table 17.6: TAC revenue forecast, 2024-25 and 2025-26

	2024-25	2025-26	2026-27
Forecast maximum demand (kW)	35,731	35,731	35,731
Forecast revenue recovered ($ million)	4.088	0.00	0.00

17.5 Derivation of other tariff components

The following *tariff*s are on a fee for *service* basis with the fees approved by the Government:

- AT1 – disconnection of supply ahead of abolishment
- AT2 – disconnection of supply
- AT3 – reconnection of supply
- AT4 – remote disconnection
- AT5 – remote reconnection.

18. REFERENCES

The following material is required and should be read in conjunction with this document:

LEGAL REFERENCES:	*Electricity Industry Act 2004* Pilbara Networks Access Code 2021
STANDARD & GUIDELINES:	
RELATED POLICIES AND OTHER DOCUMENTS:	Capital Base Roll Forward Methodology Capitalisation Policy Contributions Policy Cost Allocation Methodology Cost Estimation Methodology Demand and Connections Forecasting Methodology Expenditure Forecasting Methodology Investment Governance Framework Price List Reference Services

APPENDIX A – KEY ASPECTS OF HORIZON POWER'S COST ALLOCATION METHODOLOGY

Horizon Power's cost and revenue items are allocated or attributed in accordance with the following principles:

1. Any costs that are directly attributable to the network business or to an other business are allocated accordingly.
2. Any costs that are not directly attributable are allocated to the network business in accordance with an appropriate allocator, which:
   (a) unless unable to be delivered without undue cost or effort or the cost is immaterial, is causation based, and
   (b) otherwise reflects a reasonable and well-accepted allocation approach.
3. Revenue received by the Horizon Power Pilbara Network Business from the provision of goods and services to an Associate or deemed associate is separately identified in the Horizon Power Pilbara Network Business accounts.
4. Expenditure by the Horizon Power Pilbara Network Business on the provision of goods or services by an Associate or deemed associate is separately identified in the Horizon Power Pilbara Network Business accounts.

In support of the above, Horizon Power commits to the following principles:

1. A cost or revenue item will not be attributed and/or allocated more than once.
2. A direct cost or revenue item will only be attributed to one location, function and, as appropriate, category of service.
3. An indirect cost or revenue item will only be allocated once between locations, functions and, as required, categories of service.
4. The same cost or revenue item will not be treated as both a direct and an indirect cost or revenue item.
5. The same cost will only be recovered once through tariffs and fees.
6. Unregulated costs will be allocated to the unregulated business segments and will be ringfenced from the recovery of costs through regulated services.
7. The allocation of a cost or revenue item will be determined by the substance of the transaction or event rather than the legal form.
8. An avoided cost allocation method (or any other method of allocation not specifically referred to within these rules) is not currently applied to allocate cost or revenue items.

Shared costs are allocated using a three step allocation process. They are allocated by:

- location e.g. West Pilbara, then
- function e.g. distribution services, then
- where required, category of service e.g. unregulated distribution service or cost pool for revenue and pricing purposes e.g. distribution LV.

The most common causal correlation methods are as follows:

1. **Direct costs**: shared costs are allocated based on direct costs when the underlying transaction has a causal correlation to other costs incurred, e.g. costs related to a

management role. The direct cost is determined by the ratio of the direct costs in the business segment to the total value of the direct costs that are relevant to the allocation of costs.

2. **Asset value**: allocation on an asset value basis is applied when the underlying transaction has a causal correlation to Horizon Power's principal service of building, maintaining and operating assets, e.g. asset services management. Asset value is determined by the ratios of the asset value in the business segment to the total value of some or all of Horizon Power's assets, depending on which assets are relevant to the allocation of costs. For example, the value of retail assets is not relevant to the allocation of costs that relate to generation and network services.
3. **Energy consumption** is applied when the underlying transaction has a causal correlation to the consumption of energy e.g. energy trading. It is commonly used to allocate costs to a particular location. Energy consumption is determined by the ratio of the energy consumed in a town to the total value of energy consumed across the whole or part of Horizon Power's operating region, depending on which locations are relevant to the allocation of costs. For example, some services are not provided in the Pilbara region.
4. **Full time staff equivalents (FTE):** allocation on an FTE basis is applied when the underlying transaction has a causal correlation to the consumption of staff/labour, e.g. property and facilities, and fleet. FTE is determined by the ratio of FTE within a specific business segment to the total of some or all FTEs, depending on which FTEs are relevant to the allocation of costs.
5. **Customer numbers**: allocation on a customer number basis is applied when the underlying transaction has a causal correlation to the number of customers, e.g. metering. Customer numbers are determined by the ratio of the number of customers within a specific business segment to the total number of customers.
6. **Corporate three factor method**: allocation using the corporate three factor method is applied when there is no causal correlation between the underlying transaction and the consumption of staff/labour or the service of building, maintaining and operating assets, e.g. commercial support. The corporate three factor method for allocating costs and revenue to a location is an equal weighting of asset value, revenue and FTEs (locational corporate 3-factor), and then allocating costs and revenue to a function is an equal weighting of asset value, a fixed component and FTEs (functional corporate 3-factor). As appropriate, the corporate three factor method may allocate costs and revenues across some or all locations and across some or all functions.