Aurora Energy's Application for Reconsideration of its Customised Price-quality Path

22 December 2023

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1. Executive Summary

1. This document sets out Aurora Energy's application for reconsideration of its customised price-quality path (CPP).
2. At the time our CPP proposal was submitted, on 12 June 2020, New Zealand was less than four months into its COVID-19 pandemic response. This had a material impact on our proposal, as there was considerable uncertainty as to how enduring the effects of the pandemic would be – our national border remained closed and tourism had all but ceased, with a significant impact on our Central Otago/Wānaka and Queenstown sub-networks, in particular. In response, our proposal was based on a subdued forecast for electricity growth, resulting in scaled-back capital expenditure forecasts for growth and security projects, and for consumer connections.
3. On 31 March 2021, when the Commerce Commission (the Commission) made its final decision on our CPP proposal, the future was no more certain. The border remained closed, except for limited entry for New Zealand citizens via managed isolation; however, some domestic tourism was becoming possible. Consequently, the Commission's final decision carried through our suppressed expectations, in terms of the final allowances for system growth and consumer connection capex.
4. Recognising the ongoing uncertainty, and the risk that the approved expenditure allowances may not be adequate, the Commission's final decision incorporated a modified CPP reconsideration mechanism. This mechanism allowed Aurora Energy's CPP to be 'reopened' if the demand for:

- consumer connection capex;
- system growth capex;
- asset relocation capex; or
- a combination of consumer connection capex and system growth capex;

required Aurora Energy to undertake greater than $2 million of additional investment (together, a Capacity Event).

5. The first two years of our CPP has demonstrated that demand for electricity has continued unabated, as has the demand for new connections. As a result, emerging constraints on some of our assets, forecast back in 2020, have crystalised and become more acute, putting significant load at risk during contingent events. As a result, we are applying to have our CPP reconsidered for increased consumer connection expenditure and to have the expenditure for the following five growth and security projects approved:

- R01: Riverbank Rd switching station conversion. This project is designed to relieve a security-of-supply constraint on the Wānaka zone substation that places approximately 1 MVA of load at risk (and increasing annually) during a winter contingent event.

- R02: Upper Clutha new auto-transformer. This project will increase the firm capacity of supply to the Upper Clutha region by approximately 20 percent and relieve a chronic security-of-supply constraint that places approximately 4MVA of load at risk (and increasing annually) during a winter contingent event.
- R03: Cardrona zone substation transformer upgrade. This project will increase the supply capacity in the Cardrona Valley area to accommodate increasing electricity demand driven by commercial and residential demand.
- R04: Bendigo distribution reinforcement. This project will increase supply capacity to the Bendigo region to enable connection of industrial load.
- R05: Frankton zone substation transformer upgrade. This project is designed to increase the firm capacity of the Frankton zone substation, which is currently determined by the lower of the two mixed-rated power transformers, thereby relieving a security-of-supply constraint within the critical Frankton zone that places approximately 1 MVA of load at risk (and increasing annually) during a winter contingent event.

6. In this CPP reconsideration application, Aurora Energy is requesting recognition of the following capital expenditure which, taken as a whole, comprises the Capacity Event as set out in the Aurora Energy CPP Determination (the Determination).[1] The capital expenditure included in this application has been prepared on a basis consistent with the Commission's prudent and efficient expenditure objective.

Table 1: Summary of Capacity Event actual and forecast expenditure, $ nominal.

Item	Value $(000)
System growth – Riverbank Road new transformer (R01)	6,522
System growth – Upper Clutha auto-transformers (R02)	5,351
System growth – Cardrona transformer replacement (R03)	3,615
System growth – Bendigo distribution reinforcement (R04)	3,223
System growth – Frankton transformer replacement (R05)	1,645
Consumer connection - net above allowance (R07)	25,967
Total Capacity Event expenditure	**46,323**

7. Reconsideration of our CPP is not expected to have any impact on consumer prices before 31 March 2026. When our CPP was determined, it was clear that recovery of approximately $69 million would be deferred until after the completion of the CPP period. Approval of this expenditure will simply increase the deferred revenue balance and likely extend the period over which that revenue is recovered.

[1] Commerce Commission. (2021). *Aurora Energy Limited Electricity Distribution Customised Price-Quality Determination 2021*. Schedule 12, p72.

8. Importantly, however, approval of this application will allow Aurora Energy to make these necessary investments without incurring 'expenditure inefficiency' penalties under the incremental rolling incentive scheme.

9. Similarly, we do not anticipate any material impact on our quality standards. These Capacity Event projects are growth and capacity-related investments, and while some of the projects restore appropriate levels of security of supply, the overall reliability improvement is not considered material/measurable in the context of the quality path in the CPP Determination. Furthermore, the unexpected erosion of security of supply over time and consequential loss of reliability at these sites was not modelled into our CPP reliability forecast.

2. CONTEXT FOR RECONSIDERATION

10. Aurora Energy submitted its application for a Customised Price-Quality Path (CPP) on 12 June 2020. The application was subsequently determined by the Commerce Commission (the Commission) on 31 March 2021, with effect from 1 April 2021.

11. Aurora Energy's CPP was finalised during a period of significant social and economic uncertainty, owing to the emerging COVID-19 pandemic. While Aurora Energy was well prepared for operational pandemic response, aspects of asset management planning faced significant uncertainty caused by an inability to forecast the course the pandemic would take, along with its subsequent impacts.

12. It seemed clear that there would be some enduring impact. With national borders closed and the prospect of further lockdowns, it seemed logical to consider that some suppression of growth might occur, especially in regions with a heavy reliance on hospitality and tourism. Having regard for the uncertainty created by the COVID-19 pandemic, we:

- applied for a reduced, 3-year CPP term in accordance with section 53W(2) of the Commerce Act 1986, to manage, in part, the uncertainty arising from COVID -19 impacts;[2]
- removed or deferred major growth projects to better match the need of reduced demand;[3]
- delayed some of the scheduled distribution and LV reinforcement, and applied a 20% decrease to the forecast expenditure in RY23 and RY24;[4] and
- reduced forecast consumer connection expenditure by 20% in RY2021 and by 25% in RY2022 and RY2023.[5]

13. In our CPP application, we forecast a decline in demand due to the economic impact of COVID-19, with a relatively subdued recovery. Demand growth has, however, outstripped our projections and has necessitated us making additional investments for growth and security, as well as elevated levels of consumer connection investments, relative to approved expenditure.

14. Figure 1, below, shows the difference between our forecast of maximum coincident system demand (which underpinned our CPP growth and security expenditure) and the out-turn for RY2020 to RY2022 which, in turn, informs our forecasts for subsequent years. This view demonstrates that demand growth has recovered more quickly, and has been more sustained, than was predicted at the time our CPP proposal was submitted.

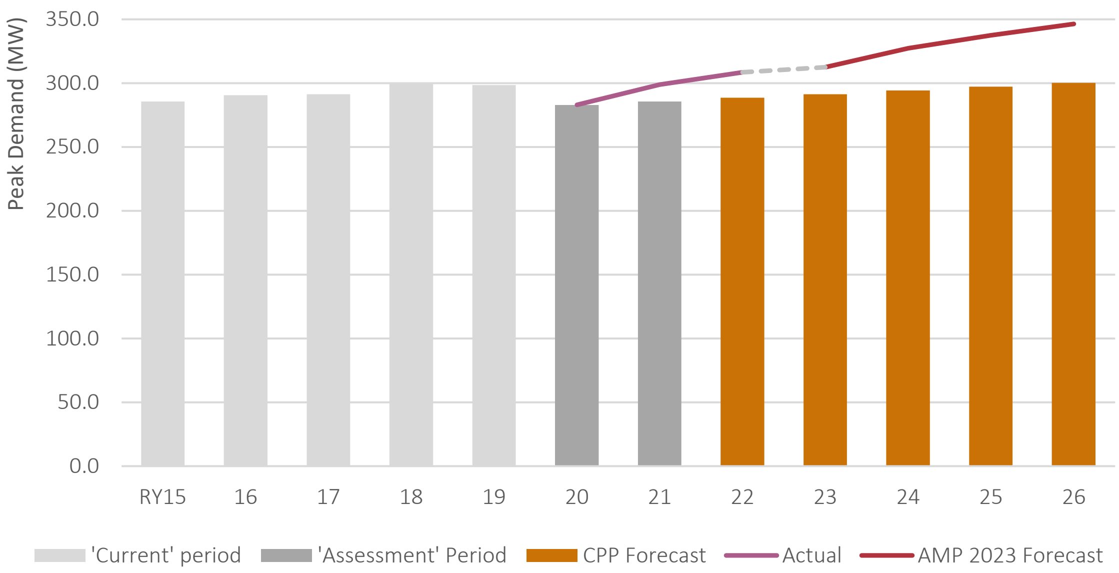
2 Aurora Energy Limited. (2020). *Customised price-quality path: Application.* Paragraph 64, p14.

3 Ibid. Paragraph 278, p69.

4 Ibid. Box 23, p148.

5 Ibid. Paragraph 563, p152.

Figure 1: Maximum coincident system demand - CPP projections vs actual and 2023 forecast[6]



2.1. CPP Uncertainty Mechanism

15. To deal with the uncertainty presented by the COVID-19 pandemic, the Commission and Aurora Energy agreed (by Deed) to vary the input methodologies (IMs) relating to, *inter alia*, reconsideration of CPPs (subpart 6). The subpart 6 variation added capacity events and risk events to the circumstances under which Aurora Energy's CPP could be reconsidered.

16. This reconsideration application is being made on the basis that a capacity event has occurred, which is defined by new IM clause 5.6.6.A as:

5.6.6A Capacity event

'Capacity event' means an event for which an EDB demonstrates that—

(a) the EDB's network needs additional capacity to provide electricity distribution services;

(b) the additional capacity has the primary driver of meeting established or reasonably anticipated demand for-

(i) connection capex;

(ii) system growth capex;

(iii) asset relocation capex; or

(iv) a combination of connection capex and system growth capex;

(c) when the CPP was determined, the need for the additional capacity—

(i) was not sufficiently certain; or

6 'Actual' demand is sourced from Aurora Energy's information disclosure performance schedules for the relevant years (Schedule 9e), and the AMP 2023 Forecast is taken from the 2023 information disclosure forecast shcedules Schedule 12c)/

(ii) *could not reasonably have been foreseen by a prudent EDB; and*

(d) *providing the additional capacity—*

(i) *would require the EDB to incur costs of at least two million dollars of capex during the CPP regulatory period above any allowance provided for that additional capacity in the DPP or CPP; and*

(ii) *meets the expenditure objective.*

17. This reconsideration application demonstrates that:

17.1. additional capacity is required by Aurora Energy to continue to effectively provide distribution services;

17.2. the additional capacity is required to meet an established demand for a combination of connection capex and system growth capex;

17.3. owing to the uncertainty that the COVID-19 pandemic would have on electricity demand and the demand for new or upgraded consumer connections, the need for the additional capacity was either not sufficiently certain at the time Aurora Energy submitted (and the Commission determined) its CPP, or could not reasonably be foreseen by Aurora Energy;

17.4. providing the additional capacity requires Aurora Energy to spend $46.323 million above its CPP allowances; and

17.5. providing the additional capacity is both prudent and efficient.

2.2. Approach to this Capacity Event Reconsideration Application

18. The capacity event reconsideration mechanism represents a 're-opening' of Aurora Energy's CPP capital expenditure allowances.

19. This reconsideration application covers five new system growth projects, and an update to the consumer connection programme of work. The status of the system growth projects varies, as set out in Table 2.

Table 2: Status of reconsideration application projects

Project	Status
R01 – Riverbank switching station conversion	Initiating
R02 – Upper Clutha auto-transformer	Initiating
R03 – Cardrona capacity upgrade	Delivering
R04 – Bendigo distribution reinforcement	Delivering
R05 – Frankton transformer upgrade	Initiating

2.2.1. Cost Estimation

20. Cost certainty increases as projects move toward completion, when the otherwise unknown (unknowable) factors impacting the project cost reveal themselves. As a logical corollary, the

earlier a project estimate is prepared relative to its execution, the lower the cost certainty will be owing to the myriad of factors that may affect final costs.

21. When a project is in planning, we develop a forecast to help inform our business case decisions. By necessity, the forecast contains a number of high-level assumptions that are generally reflected by an average unit cost for a particular activity.

22. Aurora developed its first unit rate estimating tool for its CPP application. We have been working on improvements to our cost estimation approach, as outlined in our Development Plan[7], and recently completed an update of the estimating tool and associated unit rates, incorporating feedback from completed projects to enhance its accuracy.

23. Our refined estimating tool builds on the version used to develop forecasts for our CPP, which was reviewed at that time by Jacobs. We consider that the refined estimating tool derives project cost estimates that are efficient.

24. We have prepared all the capital project estimates on a basis consistent with the Commission's prudent and efficient expenditure objective. As outlined above we have taken reasonable steps to accurately estimate the project costs. We have opted not to engage an independent verifier to further validate the project cost estimates. We consider that the engagement of an independent verifier would add additional costs to the application that would ultimately be borne by consumers.

2.2.2. Reconsideration Application Expenditure

25. The different status of each project, as outlined in the preceding section, has necessitated different approaches:

- Initiating. The capital expenditure for these projects has been forecast using the latest version of our forecasting tool, and combined with recently updated escalators to derive nominal expenditure requirements. That nominal forecast is a component of the reconsideration application.
- Delivering. The capital expenditure for these projects was forecast some time ago using the 2020 version of our estimating tool. However, our reconsideration application for these projects uses the actual costs incurred, plus committed costs to complete (where applicable), since this is the most accurate view of the costs of each project. Each of these projects has been competitively tendered and reflect efficient costs within the local market.

26. The expenditure covered by this reconsideration application is summarised in Appendix A (Table 15).

2.3. Consumer Consultation

27. All the projects in this reconsideration application are ultimately driven by consumer demand, either directly in the form of consumer connection capex, or indirectly in the form of upstream

[7] Aurora Energy Limited. (2022). *Development Plan*. Section 8, p36. Published 31 March 2022 at https://www.auroraenergy.co.nz/disclosures/delivering-our-cpp/

system growth investments necessary to facilitate growing consumer demand. Unlike investments in resilience or reliability projects which may involve trade-offs between price and quality, investments to support consumer growth are a simple case of supplying the electricity demand of consumers. We consider that when consumers choose to connect and consume electricity supplied by our network, they are inherently signalling that they expect our network to be able to supply their needs. Accordingly, we have not undertaken any direct consumer consultation specific to these projects.

3. Growth and Security Projects

28. The driver for our growth and security investments is the need to ensure the capacity of our network is adequate to meet the peak demand of our customers, with appropriate supply security and quality of supply, now and into the future.

29. These three drivers – demand growth, security of supply and power quality – were discussed in our CPP application, along with our forecasting approach.[8] We have not repeated that discussion in this document.

30. Our reconsiderations comprised, in part, five growth and security projects:

- R01: Riverbank Rd switching station conversion. This project is designed to relieve a security-of-supply constraint on the Wānaka zone substation that places approximately 1 MVA of load at risk (and increasing annually) during a winter contingent event.
- R02: Upper Clutha new auto-transformer. This project will increase the firm capacity of supply to the Upper Clutha region by approximately 20 percent and relieve a chronic security-of-supply constraint that places approximately 4MVA of load at risk (and increasing annually) during a winter contingent event.
- R03: Cardrona zone substation transformer upgrade. This project will increase the supply capacity in the Cardrona Valley area to accommodate increasing electricity demand driven by commercial and residential demand.
- R04: Bendigo distribution reinforcement. This project will increase supply capacity to the Bendigo region to enable connection of industrial load.
- R05: Frankton zone substation transformer upgrade. This project is designed to increase the firm capacity of the Frankton zone substation, which is currently determined by the lower of the mixed-rated power transformers, thereby relieving a security-of-supply constraint within the critical Frankton zone that places approximately 1 MVA of load at risk (and increasing annually) during a winter contingent event.

31. Four of these five projects occur within Queenstown Lakes District, an area where significant economic value is derived from tourism and hospitality services. Our engagement with the Queenstown Lakes District Council (QLDC) throughout the CPP process made it clear that QLDC has a very low tolerance for poor supply reliability, and would not countenance any inability to meet demand growth. These themes were reflected in QLDC's submission on the Commission's draft decision on our CPP.[9]

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[8] Ibid. Appendix F, section F2, p132-136.

[9] Queenstown Lakes District Council. (2020). *AuroraEnergy Investment Plan – Draft Commerce Commission Decision Feedback.* Availabe from Commerce Commission website: https://comcom.govt.nz/regulated-industries/electricity-lines/projects/our-assessment-of-aurora-energys-investment-plan

3.1. Riverbank Rd Switching Station Conversion

3.1.1. Summary

Project status: Initiating.

Primary driver: System growth (capacity, security-of-supply).

Project cost: $6.522 million.

Commissioning: RY2026.

CPP status Foreseen, but timing not sufficiently certain.

Project Scope: Install new 24 MVA 66/11 kV transformer, associated 66kV switchgear, and an 11kV switchboard at the Riverbank Road switching station to reduce demand on the Wānaka zone substation and resolve an existing, persistent security-of-supply constraint.

3.1.2. Problem Statement

32. The Wānaka zone substation has a firm 11 kV capacity of 24 MVA, which is constrained by both the 11 kV winding of the transformer and by the 1,250 Amp rating of the 11 kV switchboard. The peak demand on the Wānaka zone substation during RY2022 was 27.2 MVA, exceeding the substation's firm capacity. The Wānaka zone substation has a transfer capacity of just 2 MW, meaning that at-risk load is 1.2 MVA and growing with each subsequent year.

33. The load at Wānaka is category Z1 (for security-of-supply), so consumers should not experience any interruption for a single cable, line or transformer fault. Once the substation is operating above the firm capacity, transformer and line faults will likely cause a total loss of supply at the substation as the remaining supply will trip on overload (note that switchgear has a small thermal time lag and cannot be overloaded for any significant length of time). The load will then need to be restored slowly up to the capacity of a single transformer, which would result in significant outages for consumers.

34. Demand at Wānaka is expected to grow at approximately 2% per annum (refer Table 3, below). Hence, to meet demand growth, it is planned to install a 24 MVA 66/11 kV transformer, associated 66kV switchgear, and an 11 kV switchboard at the Riverbank Road switching station.

35. The Wānaka and Riverbank Road zone substations demand forecasts are shown in Table 3.

Table 3: Wānaka & Riverbank Road zone substations - demand forecasts

				--- Historic ---						--- Forecast ---							
Zone Substation	Security Class	Security Level	Firm Capacity (MVA)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Peak Period
Wānaka	Z1	N-1	24	24.9	25.0	27.2	27.5	28.2	28.7	21.0	20.9	20.9	19.9	20.5	20.9	21.3	Winter
Riverbank	Z3	N	24							8.2	8.5	8.9	9.8	10.1	10.3	10.5	(New)

36. There is a pressing need to resolve this constraint, which will deliver the following benefits:

- Improved security for the Wānaka region.
- Increased firm capacity of 48 MVA from the combined Wānaka and Riverbank substations.
- Provision of additional 11 kV feeders into the Wānaka area, reducing load on existing feeders and enabling better back-feed ability in planned and unplanned events.
- Significantly reduced risk of a HILP event, involving the total loss of the Wānaka and Camp Hill substation, which would see significant outages in the Wānaka and Hāwea area.

3.1.3. Scope

37. This project involves the installation of a new 24 MVA, 66/11 kV transformer, associated 66kV switchgear, and an 11kV switchboard at the Riverbank Road switching station to reduce demand on the Wānaka zone substation and resolve an existing, persistent security-of-supply constraint.

38. Following commissioning of the new transformer, parts of existing Wānaka substation feeders will be transferred to the new Riverbank feeders.

39. This project is a three-year development with expected commissioning of the new transformer in RY2025, and reconfiguration of Wānaka zone substation feeders in RY2026.

40. Once completed, this project will enable the provision of firm capacity of 48 MVA across the two sites (Wānaka and Riverbank Road), doubling the existing 24 MVA firm capacity.

3.1.4. Short-listed Options

41. To address the capacity constraint on the Wānaka zone substation, the following options were shortlisted:

- Status Quo: This option is to do nothing other than react when a failure occurs.
- Riverbank Road switching station upgrade: This option involves upgrading the Riverbank Road switching station to a zone substation by installing a 66/11 kV, 24 MVA transformer and associated 66 kV switchgear, 11kV switch-room and 11 kV switchboard. When the Riverbank Road switching station was constructed in 2017, provision was made to install this equipment in the future. Additionally, a number of Wānaka 11 kV feeders are located near the Riverbank site, which makes it relatively easy to quickly connect the substation into the 11 kV network.
- New Wānaka / Upper Clutha zone substation: This option involves establishing a new substation at another location in the Wānaka / Upper Clutha area. This would involve the selection and purchase of a suitable section of land, and installing an earth mat, buildings, transformers, and switchgear. Additionally, 66 kV sub-transmission cables would need to be run from the Riverbank Road switching station to the new site, and 66kV circuit breakers installed.
- Spare transformer: This option involves purchasing a new, spare 66/11kV transformer that would be suitable for installation at the Wānaka substation. This would resolve the main issue with running the Wānaka substation above its firm capacity that, in the case of a major transformer failure, supply

would be constrained for a significant period as there is no suitable spare 66/11kV transformer available.

3.1.5. Project solution

42. The preferred solution is to upgrade the Riverbank Road switching station to a zone substation.

43. The demand for electricity on the Wānaka zone substation has increased, to the extent that its firm capacity was exceeded in RY2020. The Wānaka zone substation has a transfer capacity of just 2 MW, meaning that at-risk load is 1.2 MVA and growing with each subsequent year. In the event of a transformer fault during winter, we would expect that consumer interruptions would be required at peak periods for a matter of weeks, if not months, while the faulted transformer is repaired or replaced.

44. In the event that consumers are subjected to a prolonged winter outage, we expect it will attract significant stakeholder attention, including the media and escalation to Central Government.[10] A prolonged winter outage of the Wānaka zone substation would have a significant negative effect on Aurora Energy's reputation and the confidence of its stakeholders. Additionally, Wānaka's reputation as a ski resort town is likely to be severely damaged and, therefore, we do not believe that the 'do nothing' approach is sensible.

45. The alternative options of establishing a new Wānaka/Upper Clutha zone substation or purchasing a spare transformer have significant disadvantages that warrant their exclusion:

- Establishing a new zone substation is the most capital intensive of all options, and will require considerable time to implement, given the need to acquire land, design, consent, construct and commission.
- Purchase of a spare transformer for Wānaka zone substation incurs the lowest capital cost; however, putting the transformer into service following a fault on one of the existing Wānaka transformers could not be done quickly, and would result in prolonged outages. Additionally, an appropriate storage location would need to be identified and constructed.

46. The preferred solution has the following advantages:

- It is the most economic option;
- It returns Wānaka zone substation to compliance with Aurora Energy's security of supply guidelines; and
- Offloading sections of existing Wānaka feeders to new Riverbank Rd feeders will allow feeder sizes to be optimised across the two substations, reducing the consumer impact of feeder faults.

3.1.6. Forecast Expenditure

47. The expenditure forecast that underpinned our business case decision for this project was compiled using the recently updated estimating tool and price book. This yielded a project

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[10] An example of the stakeholder attention that a prolonged, mid-winter outage attracts is given by the transformer fault that occurred at Clyde/Earnscleugh zone substation on 13 June 2020, impacting 1,150 consumers for over 8 hours. This fault occurred before distribution upgrades were completed that now allows the substation to be off-loaded.

estimate of $6.273 million in constant RY2024 dollars. Applying current forecast escalation indices yields a nominal forecast of $6.522 million.

48. The forecast expenditure for this project is shown in Table 4. This project will be competitively tendered.

Table 4: Riverbank Road switching station conversion project: Forecast expenditure

Forecast $(000)	RY2022	RY2023	RY2024	RY2025	RY2026	CPP
Capex ($RY2024 constant)				690	5,583	6,273
Capex (nominal)				708	5,814	6,522
Commissioned assets (nominal)					6,522	6,522

49. Aurora Energy therefore requests that its expenditure allowances be adjusted to reflect commissioning of the Riverbank switching station conversion project in RY2026 at a value of $6.522 million.

3.2. Upper Clutha – Auto Transformer Upgrade

3.2.1. Summary

Project status: Initiating.

Primary driver: System growth (capacity, security-of-supply).

Project cost: $5.351 million.

Commissioning: RY2025.

CPP status Foreseen, but timing not sufficiently certain.

Project Scope:

50. Install a new 50 MVA, 66/33 kV auto-transformer at Cromwell, and parallel the two existing 30/36 MVA units, to increase the firm capacity of the Upper Clutha sub-transmission circuits to 40/43 MVA (summer/winter).

3.2.2. Problem Statement

51. The Upper Clutha region is supplied by two 54 km, 66 kV sub-transmission circuits, via two 66/33 kV, 30 MVA auto-transformers located at Cromwell. The auto-transformers have a summer rating of 30 MVA and a winter rating of 36 MVA (the transformer is rated for 37 MVA in winter but is limited to 36 MVA by the 630 A rating of its 33 kV bushings). Further, during a contingent event, the in-service circuit will also absorb the line losses of the out-of-service line, increasing the load on the in-service circuit by at least 2-3 MW and affecting voltage. The winter firm capacity is 32 MVA, which is the maximum load where voltage remains within regulatory limits when one circuit is out-of-service.

52. The total electricity demand on the Upper Clutha sub-transmission circuits was 36.2 MVA during the winter of RY2023, exceeding the firm capacity of the circuits by 4.2 MVA. Growth in the Upper Clutha region is strong and persistent and, without intervention, the Upper Clutha sub-transmission circuits will remain constrained.

53. The load in the Upper Clutha region is category Z1 (for security of supply), so consumers should not experience any interruption for a single cable, line or transformer fault. During peak periods, a tripping of either circuit will cause the other to trip also, leaving the whole of the Upper Clutha region without supply. Load would need to be restored slowly, up to the capacity of a single circuit, which would result in significant outages for consumers.

54. Aurora Energy has commissioned a special protection scheme (SPS) in the Upper Clutha, which allows the load to exceed the N-1 capacity of the Upper Clutha sub-transmission circuits by quickly reducing load during a contingent event, preventing the remaining circuit from tripping. With growing demand, the SPS is a short-term solution only. Additional capacity is required on the Upper Clutha sub-transmission circuits to securely meet existing and forecast demand.

55. The demand forecast for the Upper Clutha sub-transmission circuits is shown in Table 5.

Table 5: Upper Clutha sub-transmission circuits demand forecast

Circuit	Security Class	Security Level	Firm Capacity (MVA)	--- Historic --- 2021	2022	2023	2024	2025	2026	--- Forecast --- 2027	2028	2029	2030	2031	2032	Peak Period
56. Upper Clutha	57. Z1	N-1	32	30.5	34.5	36.2	38.1	39.1	40.1	41.7	42.6	42.7	43.9	44.7	44.8	Winter
			30	25.0	27.8	28.4	29.1	29.0	29.1	29.1	29.1	29.5	29.3	30.1	30.5	Summer

58. There is a pressing need to resolve this constraint, which will deliver the following benefits:

- Increased supply capacity to the Upper Clutha region
- Avoided long-duration load loss and associated customer impact during a forced outage on either sub-transmission circuit or auto-transformer.

3.2.3. Project Scope

59. This project involves the installation of a new 50 MVA, 66/33 kV auto-transformer at Cromwell, and paralleling of the two existing 30/36 MVA units, to increase the firm capacity of the Upper Clutha sub-transmission circuits to 40/43 MVA (summer/winter).

3.2.4. Short-listed Options

60. To address the capacity constraint on the Upper Clutha sub-transmission, the following options were shortlisted:

- Status Quo: This option is to do nothing other than react when a failure occurs.
- New auto-transformer: This option involves establishing a new 66/33 kV, 50 MVA auto-transformer at Transpower's Cromwell grid exit point, under an amended access and occupation schedule, and paralleling the two existing 66/33 kV, 30 MVA auto-transformers.
- Replace auto-transformers: This option involves replacing both existing 66/33 kV, 30/36 MVA auto-transformers at Transpower's Cromwell grid exit point with new 66/33 kV, 50 MVA units.

3.2.5. Project solution

61. The preferred solution is to commission a new 66/33 kV, 50 MVA auto-transformer and parallel the existing 66/33 kV, 30/36 MVA units.

62. The Upper Clutha region includes the popular ski and summer resort town of Wānaka, within the Queenstown Lakes District of Central Otago. Peak demand for electricity in the Upper Clutha region has increased, such that the sub-transmission circuits that supply the area have exceeded their firm capacity (winter) and are in constraint. Without intervention, an unplanned outage on one circuit is likely to result in the remaining circuit tripping on overload. We do not consider that the 'do nothing' approach is reasonable.

63. In the short-term, Aurora Energy has implemented an SPS that seeks to avoid cascade failure of both circuits by immediately activating hot water control and then sequentially tripping nine designated feeders across the Wānaka, Camp Hill and Lindis Crossing zone substations.

64. The Upper Clutha SPS is a viable project in its own right and will assist while other solutions are implemented. However, the SPS relies on deliberate service interruptions, most likely during winter, to maintain the integrity of the Upper Clutha sub-transmission network (with those interruptions not allowed for in Aurora Energy's quality standards). As a singular solution to the Upper Clutha constraint, the SPS would have an untenable impact on consumers if nothing else is done.

65. We do not consider that the option of upgrading the 30 MVA auto-transformers is warranted or economic at this time. While detailed options for increasing capacity to the Upper Clutha are currently being considered, it seems certain that a third 66 kV sub-transmission line will need to be constructed toward the end of the planning period (circa 2031 or potentially earlier).[11] At that time, the paralleled 30 MVA auto-transformers will be split, with each dedicated to a 66 kV circuit. Eventually, it may be necessary to upgrade the 30 MVA units in order to provide additional sub-transmission capacity; however, the timing is uncertain and is expected to be well beyond the current planning period (RY2025 to RY2034). The 30 MVA auto-transformers are at less than half of their nominal life and, if needed in the future, upgrading is likely to occur closer to their expected replacement.

66. The preferred solution has the following advantages:

- It is the most economic option;
- It is easiest to construct;
- It requires fewer outages than the replacement option; and
- It returns the Upper Clutha sub-transmission circuits to compliance with Aurora Energy's security of supply guidelines.

3.2.6. Forecast Expenditure

67. The expenditure forecast that underpins our business case decision for this project was compiled using the recently updated estimating tool and price book. This yielded a project estimate of $5.323 million in constant RY2024 dollars. Applying current forecast escalation indices yields a nominal forecast of $5.351 million.

68. The forecast expenditure for this project is shown in Table 6. This project will be competitively tendered.

Table 6: Upper Clutha sub-transmission – new auto-transformer project: Forecast expenditure

Forecast $(000)	RY2022	RY2023	RY2024	RY2025	RY2026	CPP
Capex ($RY2024 constant)			4,099	1,224		5,323
Capex (nominal)			4,099	1,253		5,351
Commissioned assets (nominal)				5,351		5,351

[11] Aurora Energy Limited. (2023). Asset management plan. Table 6.21, p137.

69. Aurora Energy therefore requests that its expenditure allowances be adjusted to reflect commissioning of the Upper Clutha new auto-transformer project in RY2025 at a value of **$5.351 million.**

3.3. Cardrona Zone Substation Transformer Upgrade

3.3.1. Summary

Project status: Delivering.

Primary driver: System growth (capacity).

Project cost: $3.615 million.

Commissioning: RY2024.

CPP status Foreseen, but timing not sufficiently certain.

Project Scope: Replacement of the 66/33/11kV, 5/6.7 MVA transformer at Cardrona zone substation with a 24 MVA unit, to increase supply capacity to the Cardrona Valley.

3.3.2. Problem Statement

70. Aurora Energy supplies the Cardrona Valley from the Cardrona zone substation which is equipped with a single 66/33/11kV, 5/6.7 MVA rated transformer[12]. The principal loads in the Cardrona Valley are the Cardrona and Soho Basin ski areas, the Southern Hemisphere Proving Ground and associated residential and commercial developments in and around the Cardrona Village. The Cardrona zone substation is winter peaking and the pre-COVID peak demand in July 2019 was 4.8 MVA, just below the nominal rating of the transformer.

71. The total electricity demand on the Cardrona zone substation was 3.9 MVA during winter 2022. Significant load growth is expected in the Cardrona Valley over the AMP planning period. Cardrona Alpine Resort Limited (CARL) operates the Cardrona ski area and owns a secondary network with two network supply points at the Valley floor. CARL's secondary network provides an interconnection to the adjacent Soho Basin ski area. Both the Cardrona and Soho Basin ski areas have significant development plans that will see over 6.5 MVA of demand added to the CARL secondary network in the period to RY2031.

72. Additionally, the Mt Cardrona Station is a residential development, adjacent to the Cardrona ski area access road, that will comprise 437 residential and commercial lots. Construction of the

[12] The transformer was purchased in 2010 as a 5MVA KNAN unit and has had fans fitted subsequently. The 6.7 MVA rating is constrained by the 11 kV tap changer.

wastewater treatment plant, access road and main power supply began in 2020, with the first sales taking place in 2021.

73. The Cardrona zone substation demand forecast is shown in Table 7.

Table 7: Cardona zone substation demand forecast

Zone Substation	Security Class	Security Level	Firm Capacity (MVA)	--- Historic --- 2020	2021	2022	2023	2024	2025	--- Forecast --- 2026	2027	2028	2029	2030	2031	2032	Peak Period
Cardrona	Z3	N	6.7	3.7	3.7	3.9	5.2	6.2	6.7	7.3	8.7	9.3	9.6	9.8	9.8	9.8	Winter

74. There is a need to increase the capacity of the Cardrona zone substation to meet this forecast increase in demand.

3.3.3. Project Scope

75. This project involves the replacement of the 66/33/11 kV, 5/6.7 MVA transformer at Cardrona zone substation with a 24 MVA unit, to increase supply capacity to the Cardrona Valley.

3.3.4. Short-listed Options

76. To increase the supply capacity of the Cardrona zone substation, the following options were shortlisted:

- Status Quo: This option is to do nothing other than react when substation capacity is exceeded.
- Transformer upgrade: This option involves constructing a new transformer pad and bunding and installing a new 66/11 kV, 24 MVA transformer. The existing 66/33/11 kV, 5 MVA unit must remain in service during construction, and is likely to be retained on-site (hot stand-by) until a redeployment decision has been made. The existing transformer location will be available for future development when a second 24MVA unit is required.
- Additional transformer: This option involves constructing a new transformer pad and bunding and installing a new 66/11 kV, 7.5 MVA transformer with its own 11 kV incoming circuit breaker.

3.3.5. Project solution

77. The preferred solution is to replace the existing 66/33/11 kV, 5/6.7 MVA transformer with a 66/11 kV, 24 MVA unit.

78. The Cardrona zone substation is winter peaking, and demand is influenced by two customers that own and operate high voltage secondary networks – CARL and Southern Hemisphere Proving Grounds Limited (SHPG). CARL owns and operates the Cardrona ski area and provides supply to the adjacent Soho Basin ski area via an interconnection from its secondary network. SHPG owns and operates a world-class winter vehicle testing facility, which makes a significant contribution to global automotive development. It is critical to the economic wellbeing of the Upper Clutha region, and to the reputation of the Southern Lakes District as a winter sports destination, that these two critical customers are able to access sufficient electrical capacity for their needs.

79. N-security substations pose a specific challenge in a growth environment. Experience has shown that the demand of a secondary network can increase very quickly, often faster than the network can react. For this reason, it is prudent and common practice to commence planning for N-security capacity upgrades when a 70 percent capacity threshold has been reached, owing to the time required to design, procure, and commission the necessary upgrades.

80. On this basis, the 'do nothing' option cannot be seriously considered.

81. The transformer upgrade and additional transformer options have similar primary benefits, in that they both cater for the forecast growth in peak demand over the short term.

81.1. The additional transformer option has a lower capital cost, and has the benefit of providing some redundancy in the event of a transformer fault (summer maintenance could also be programmed without having to deploy the mobile substation).

81.2. The higher capacity of the transformer upgrade option caters for demand growth beyond the short term. While carrying a higher capital cost than the alternative additional transformer option, this option provides the flexibility to redeploy the existing transformer to another site (Lindis Crossing is currently being considered as a candidate site, for commissioning in 2028), thereby lowering the economic cost of this option.[13]

82. The preferred solution has the following benefits:

- It provides a firm capacity of 24MVA from the Cardrona zone substation;
- It facilitates the connection of a known new development, and accommodates the increasing demand of existing connections.

3.3.6. Forecast Expenditure

83. As noted in Table 2, above, this project is in the delivery phase. Separate tenders were called for design and construction, with two respondents to each tender. The project is sufficiently advanced that we have a clear understanding of the final costs of the project. This is shown in Table 8.

Table 8: Cardrona zone substation transformer upgrade project: Forecast expenditure

Forecast $(000)	RY2022	RY2023	RY2024	RY2025	RY2026	CPP
Capex (nominal)	137	1,283	2,182			3,602
Commitments (nominal)			13			13
Completed cost	137	1,283	2,195			3,615
Commissioned assets (nominal)			3,615			3,615

13 There is also potential to redeploy the 66kV circuit breaker associated with the existing transformer. It could be transferred to Lindis Crossing with the existing transformer, or used when the planned 3rd Upper Clutha sub-transmission line is constructed, which, subject to planning confirmation, is expected to interconnect at Cardrona.

84. Aurora Energy therefore requests that its expenditure allowances be adjusted to reflect commissioning of the Cardrona zone substation transformer upgrade project in RY2024 at a value of $3.615 million.

3.4. Bendigo – Distribution Upgrade

3.4.1. Summary

Project status: Delivering.

Primary driver: System growth (capacity).

Project cost: $3.223 million.

Commissioning: RY2024.

CPP status Not reasonably foreseen. Connection inquiry received after CPP submission.

Project Scope: Reinforce Cromwell distribution feeder CM833 to increase supply capacity in the Bendigo region.

3.4.2. Problem Statement

85. Aurora Energy has received a request to connect 2.3 MVA of new industrial load in the Bendigo area (above the eastern shore of Lake Dunstan, north of Cromwell and adjacent to the Bendigo Downs lifestyle subdivision). The new load is located near the extreme end of the Lindis Crossing LC2086 feeder and, geographically, is around midway between the Cromwell and Lindis Crossing zone substations.

86. The land above the eastern shore of Lake Dunstan, north of Cromwell, has seen a range of developments in recent years. While the land is less amenable to development than the opposite shore, it has nevertheless seen a number of vineyards established, along with large-area, high-end residential allotments.

87. Aurora has a firm contract to supply a new industrial load (Scapegrace distillery, bottling house, warehouse and barrel room) at a nominal capacity of 2.3 MVA.

88. Without distribution circuit reinforcement, Aurora Energy would need to decline supply.

3.4.3. Project Scope

89. This project involves reinforcement of Cromwell distribution feeder CM833 to increase supply capacity in the Bendigo region.

90. Enabling supply to the new distillery has two distinct components:

- Constructing the connection assets and commissioning the new connection; and
- Reinforcing Aurora Energy's distribution network to enable the contracted connection capacity to be supplied.

91. The construction of the connection assets is categorised as consumer connection capex and is subject to Aurora Energy's capital contributions policy. The feeder reinforcement is categorised as system growth capex.

3.4.4. Short-listed Options

92. To increase the capacity to the Bendigo area, the following options were shortlisted:

- Status Quo: This option is to do nothing and decline to supply the new connection.
- Reinforce Lindis Crossing feeder LC2086: This option involves rebuilding sections of the Lindis Crossing feeder LC2086:
  - replacing 5.2 km of Squirrel conductor line with Krypton conductor;
  - installing a new 2.3 km cable in parallel with the existing cable and overhead line from Lindis Crossing zone substation to where the feeder LC2086 bifurcates at Pole 86927; and
  - installing a 200 A, 2-unit, open delta voltage regulator approximately 6.1 km out from the zone substation.
- Reinforce and extend Cromwell feeder CM833: This option involves rebuilding (and extending) sections of the Cromwell feeder CM833:
  - replacing 0.31 km of Mink line with Krypton conductor;
  - replacing 5.91 km of Squirrel conductor line with Krypton conductor;
  - replacing 1.86 km of 2 phase Squirrel line with a 3 phase Krypton line;
  - extending the feeder with a new 2.7 km Krypton section of line; and
  - installing a 200 A, 2-unit, open delta voltage regulator approximately 8 km out from the Cromwell zone substation.

3.4.5. Project solution

93. The preferred option is to reinforce sections of Cromwell feeder 833 (CM833), install a new voltage regulator, and extend CM833 to create a parallel option with Lindis Crossing feeder 2086 (LC2086).

94. Aurora Energy's fundamental purpose is to provide electricity distribution services to new and existing customers. By delivering electricity to our communities when and where it is needed, safely, reliably and efficiently we support social and economic wellbeing of our communities and their economic growth. In this case, the 'do nothing' option, which would deny an electricity supply to a new customer, cannot be seriously considered as it is in direct conflict with our purpose.

95. The option of reinforcing the Lindis Crossing feeder LC 2086 is advantageous from the perspective of capital cost – it is lower than the alternative Cromwell feeder CM833 reinforcement by circa $1.1 million. However, this option has some significant drawbacks, relative to the Cromwell feeder CM833 option:

- It has a higher reliability cost;

- It adds a significant demand 'step' to the heavily constrained Upper Clutha sub-transmission network; and
- The new voltage regulator would be heavily loaded during summer months (~95%), limiting the available downstream capacity for new loads.

96. The advantages of reinforcing and extending the Cromwell feeder CM833, relative to the Lindis Crossing feeder LC2086 option, include:

- Lower overall economic cost;
- New load is supplied from the unconstrained and relatively lightly loaded Cromwell zone substation;
- Enables load growth in the Bendigo area and has the capacity to accept more load onto this feeder after the connection of the distillery (the highest loaded section of line will only be ~70% loaded).
- The new voltage regulator will only be moderately loaded (~68%) after connection of the distillery; and
- Creation of a tie between CM833 and LC2086 provides some (limited) off-load capability, benefitting mainly customers connected to the LC2086 feeder, but also providing the distillery with basic (non-process) supply back-up.

97. The heavily constrained Upper Clutha sub-transmission network, and the limited spare capacity of the Lindis Crossing zone substation, are over-riding considerations that makes the Cromwell feeder CM833 option more feasible.

3.4.6. Forecast Expenditure

98. As noted in Table 2, above, this project is in the delivery phase. The project was executed in two stages, with each stage being competitively tendered:

- Stage 1 – new line to create CM833 to LC2086 intertie – four tender respondents.
- Stage 2 – feeder CM866 rebuild – two tender respondents.

Additionally, two proposals were received for the project design.

99. The project is sufficiently advanced that we have a clear understanding of the final costs of the project. This is shown in Table 9.

Table 9: Bendigo - distribution upgrade expenditure: Costs at completion

Forecast $(000)	RY2022	RY2023	RY2024	RY2025	RY2026	CPP
Capex (nominal)		491	1,963			2,454
Commitments (nominal)			769			769
Completed cost		491	2,732			3,223
Commissioned assets (nominal)			3,223			3,223

100. Aurora Energy therefore requests that its expenditure allowances be adjusted to reflect commissioning of the Bendigo distribution upgrade project in RY2024 at a value of **$3.223 million.**

3.5. Frankton Zone Substation - Transformer Upgrade

3.5.1. Summary

Project status: Initiating.

Primary driver: System growth (capacity, security-of-supply).

Project cost: $1.645 million.

Commissioning: RY2025.

CPP status Foreseen, but timing not sufficiently certain.

Project Scope: Upgrade transformer T1 at the Frankton zone substation to alleviate an existing, persistent security-of-supply constraint.

3.5.2. Problem Statement

101. The Frankton zone supplies a mix of commercial, industrial and residential consumers on the Frankton Flats, and concentrated suburbs of residential consumers to the north and south. The wider Queenstown Lakes District economy is largely based on the many tourist activities that the region offers, and the Frankton zone includes the critical Queenstown international airport and (excluding the Queenstown CBD) the Wakatipu region's two main commercial and retail hubs (Five Mile and Queenstown Central).

102. In the past few years, the Frankton zone has seen steady increases in the demand for electricity and there are clear indications that electricity demand will continue to grow. Peak electricity demand on the Frankton zone substation was 19.0 MW during RY2023 (winter 2022), exceeding its firm capacity by 4.0 MW. The Frankton zone substation has a transfer capacity of 3 MW, meaning that at-risk load is 1.0 MVA and growing with each subsequent year.

103. The load at Frankton is category Z1 (for security of supply), so consumers should not experience any interruption for a single cable, line or transformer fault. These faults may actually cause a total loss of supply at the substation as the smaller transformer will likely trip on overload for loss of the larger transformer. The load will then need to be restored slowly up to the capacity of the 15 MVA transformer.

Table 10: Frankton zone substation demand forecast

				--- Historic ---				--- Forecast ---									
Zone Substation	Security Class	Security Level	Firm Capacity (MVA)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Peak Period
Cardrona	Z1	N-1	15	16.6	17.1	18.0	19.0	19.8	20.7	21.6	22.5	23.4	24.2	25.0	25.7	26.4	Winter

104. There is a pressing need to resolve this security-of-supply constraint, which will deliver the following benefits:

- Improved security-of-supply for the Frankton zone (brings Frankton back into compliance with Aurora Energy's security-of-supply guidelines).
- Firm capacity of 24 MVA at the Frankton zone substation.

3.5.3. Project Scope

105. This project involves replacing the existing Frankton T1 transformer (33/11 kV, 15 MVA) with a new 33/11 kV, 24 MVA unit. The existing transformer will be relocated to Port Chalmers zone substation as part of a renewals project.

3.5.4. Short-listed Options

106. To address the constraint on the Frankton zone substation, the following options were shortlisted:

- Status Quo: This option is to do nothing other than react when a failure occurs.
- Upgrade the T1 transformer: This option involves procuring, installing and commissioning a new 33/11 kV, 24 MVA transformer. The transformer foundations and bunding were established in anticipation of a future upgrade when the Frankton zone substation was rebuilt in 2011, and so negligible civil construction costs are required. However, some control and protection upgrading is required, including new differential and AVR relays.
- Increase off-load capability: This option involves increasing the capability to off-load to the Commonage zone substation by constructing a distribution feeder extension across lake Wakatipu at the Franktown Arm narrows, and extending the distribution feeder around the Kelvin Heights golf course to a new tie point at Peninsula Road.

3.5.5. Project solution

107. The preferred solution is to replace the existing 33/11 kV, 15 MVA transformer with a 24 MVA unit.

108. A sub-transmission fault on the FK33-2 circuit or fault on the T2 transformer may cause a total loss of supply at the substation, as the smaller transformer will likely trip on overload for loss of the larger transformer. The load will then need to be progressively restored up to the capacity of the 15 MVA transformer which, given the incomplete load transfer capability at Frankton, may result in some customers being without supply until the 24 MVA transformer can be returned to service. On this basis, we consider that the 'do nothing' option is untenable.

109. Currently, there is no ability to off-load feeder FK7784, to the south of the Frankton zone substation, to another zone substation. This feeder supplies predominantly residential customers at Kelvin Heights and Jacks Point, and further south to the network boundary at Wye Creek. The inability to off-load this feeder is driven by geography. However, an option has been identified that would create a tie point between FK7784 and Commonage zone substation feeder CG5730 by traversing the Frankton Arm of Lake Wakatipu at its narrowest point. This would allow further load to be transferred to the Commonage zone substation, to maintain the

demand on the Frankton zone substation at or below its firm rating. This would delay the upgrade of the Frankton T1 transformer by around two years.

110. There are some disadvantages with the off-load option, however:

- The 24 MVA transformer at Frankton remains under-utilised as the 15 MVA transformer still constrains the firm capacity of the substation;
- Some Commonage feeders will be very heavily loaded, with significant reliability risk in the event of feeder faults.
- Feasibility is likely to be an issue, as there is an emerging voltage constraint on the 33kV supply to Commonage zone substation;
- The option incurs a higher capital cost than the transformer upgrade option, and with traversing the Frankton Arm being a challenging work package, there is some uncertainty over the ultimate capital cost and deliverability; and
- The off-load option only defers upgrading the transformer at Frankton by around two years.

3.5.6. Forecast Expenditure

111. The expenditure forecast that underpinned our business case decision for this project was compiled using the recently updated estimating tool and price book. This yielded a project estimate of $1.625 million in constant RY2024 dollars. Applying current forecast escalation indices yields a nominal forecast of $1.645 million.

112. The forecast expenditure for this project is shown in Table 11. This project will be competitively tendered.

Table 11: Frankton zone substation - transformer upgrade project: Forecast expenditure

Forecast $(000)	RY2022	RY2023	RY2024	RY2025	RY2026	CPP
Capex ($RY2024 constant)			406	1,219		1,625
Capex (nominal)			406	1,239		1,645
Commissioned assets (nominal)				1,645		1,645

113. Aurora Energy therefore requests that its expenditure allowances be adjusted to reflect commissioning of the Frankton transformer upgrade project in RY2026 at a value of **$1.645 million.**

4. Consumer Connection Capex

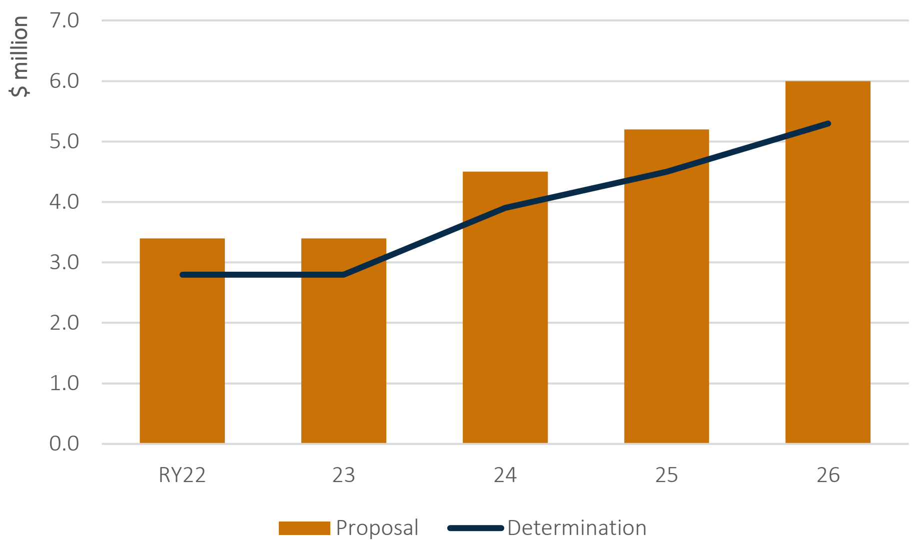
114. Consumer connection expenditure forms part of Aurora Energy's 'other network capex' portfolio. Consumer connection is expenditure on assets where the primary driver is the establishment of a new customer connection point or an alteration to an existing customer connection point. In general, the expenditure is recoverable in total, or in part, by a contribution from the requesting customer.

115. During our development of our CPP, we had forecast net consumer contribution expenditure[14] of $24.6 million (constant $2020) over the 5-year CPP period. During verification, in order to accommodate the uncertainty created by the emerging COVID-19 pandemic, we reduced our forecast expenditure to $22.5 million, by reducing our RY2022 and RY2023 forecasts by 25%.

116. The final determination approved 5-year expenditure that was reduced by a further $3.2 million to $19.3 million, including removal of a tourism-related connection upgrade that the independent verifier had recommended be considered contingent.

117. Figure 2 shows Aurora Energy's original proposal for consumer connection capex against the approved expenditure contained in the Commission's final CPP determination.

Figure 2: Net Consumer connection capex (constant $2020) - proposed versus approved



14 Gross expenditure less capital contributions.

4.1. Capital Contributions – Overview

118. Consumer connection expenditure is subject to deduction of capital contributions.

119. Aurora Energy's network continues to grow, driven by new connections and upgrades to existing connections. We believe it is important to maintain a funding policy for capital contributions that is fair to both existing customers and new customers.

120. The purpose of requiring a new customer to pay a capital contribution, where new investment is required, is generally to ensure that existing customers are not exposed to the full cost of funding that new investment in the event that they will receive little or no future benefit. That said, Aurora Energy currently faces aggressive competition from a neighbouring EDB in the Queenstown Lakes and Central Otago regions, which means there are some situations in which reducing the capital contribution payable by a new customer is prudent to ensure existing assets are not bypassed and existing customers benefit from volume growth and the socialisation of fixed costs across a growing number of customers. Given that capital contributions have been required for many decades, and many existing customers have paid, directly or indirectly, capital contributions when they first connected to the network, the key is to avoid an inequitable wealth transfer from existing customers to new customers in applying the capital contribution policy.

121. In 2021, Aurora Energy formalised changes to its approach to capital contributions and publicly disclosed a new policy. Aurora Energy's capital contributions policy applies to customer-initiated work where:

121.1. an extension of the network is required to supply a new connection, or a series of new connections (e.g., a subdivision);

121.2. existing assets are upgraded for the sole benefit of one consumer[15]; or

121.3. customers require Aurora Energy's assets to be relocated.

122. Aurora Energy's capital contributions policy does not apply to:

122.1. expenditure to provide additional capacity in the network;

122.2. expenditure to maintain existing security-of-supply;

122.3. asset replacements and renewals; or

122.4. customer-owned installation assets.

4.2. Expenditure

123. The demand for consumer connection capex has remained strong throughout the COVID-19 pandemic. Net consumer connection capex has exceeded both Aurora Energy's

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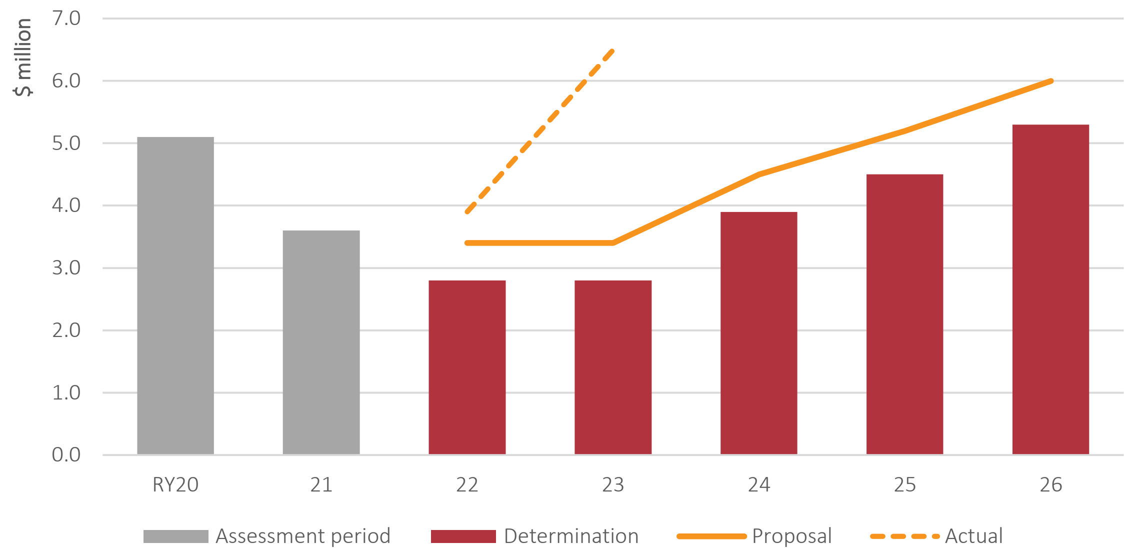
15 As Aurora Energy's capital contributions policy does not include a reapportionment mechanism, judgement is required to determine whether the upgrade will only benefit one consumer over the longer term. Where there is a liklihood of additional consumers utilising assets subject to a capital contribution, the capital contributions policy reserves Aurora Energy discretion to vary funding arrangements.

proposal and the Commission's determination in the first two years of the CPP period. This is demonstrated in Figure 3, below.

Figure 3: Net Consumer connection capex (constant $2020) - actual versus proposed and approved



124. Table 12, below, shows that actual consumer connection assets commissioned has exceeded the allowance provided by the Commission in its final CPP determination by $13.464 million over the two-year period RY2022-RY2023.

Table 12: Consumer connection commissioned assets - actual vs allowed

Consumer connection $(000) nominal		RY2022	RY2023	Total
Gross commissioned	Allowed	8,324	7,241	15,565
Capital contributions	Allowed	5,270	4,294	9,564
Net commissioned	Allowed	3,054	2,947	6,001
Gross commissioned	Actual	20,518	15,840	36,358
Capital contributions	Actual	9,378	7,515	16,893
Net commissioned	Actual	11,140	8,325	19,465
Net commissioned	Difference	8,086	5,378	13,464

125. We have updated our forecast of consumer connection expenditure for the remainder of the CPP period, using the same methodology as we used to develop our CPP forecasts. Reflecting the strong and persistent residential and commercial development on our network, and in the Queenstown Lakes and Central Otago Districts in particular, we are forecasting an additional $12.503 million over the remaining CPP period (RY2024 – RY2026). This is shown in Table 13.

Table 13: Consumer connection commissioned assets – actual vs forecast

Consumer connection $(000) nominal		RY2024	RY2025	RY2026	Total
Gross commissioned	Allowed	9,459	11,717	14,006	35,182
Capital contributions	Allowed	5,492	6,785	8,060	20,338
Net commissioned	Allowed	3,967	4,932	5,946	14,845
Gross commissioned	Forecast	19,911	19,555	18,850	58,316
Capital contributions	Forecast	10,464	10,137	10,367	30,968
Net commissioned	Forecast	9,448	9,418	8,482	27,348
Net commissioned	Difference	5,481	4,485	2,537	12,503

126. In determining the difference between allowance and forecast, we have had to make an assumption about the timing of asset commissioning vs expenditure. Timing of capitalisation can vary from expenditure in the consumer capex portfolio; however, most consumer connection projects are recognised in the year in which they are constructed. For this reason, we have assumed that expenditure and capitalisation is contemporaneous.

5. Impact of Approving this Application

5.1. Revenue Recovery

127. Approval of this application will result in $7.033 million increase in aggregate Forecast Net Allowable Revenue across the remainder of the CPP period. Table 14, below, details the changes to forecast net allowable revenue, with the 'original' values being those specified in Schedule 1.3 of the Determination.

Table 14: Changes to Forecast Net Allowable Revenue resulting from reconsideration

CPP assessment period ending	Forecast net allowable revenue (original)	Forecast net allowable revenue (reconsideration)
31 March 2022	$103,663,000	$103,663,000
31 March 2023	$99,660,000	$99,660,000
31 March 2024	$96,596,000	$99,012,000
31 March 2025	$93,722,000	$96,066,000
31 March 2026	$90,867,000	$93,140,000

128. Our CPP was determined with a 10 percent provisional limit[16] on the annual increase in forecast revenue from prices, which resulted in Aurora Energy being unable to recover all of its allowable revenue within the CPP period. Instead, recovery of approximately $69 million of revenue would be deferred to future regulatory periods, after the term of the CPP expired.

129. The revenue associated with this reconsideration application will be added to the existing deferred revenue balance and likely recovered during the DPP4/5 periods, as Aurora Energy draws down its deferred revenue balance. We have not modelled the deferred revenue balance beyond the current CPP period as we consider there are too many unknown assumptions to reliably do so. These assumptions include, but are not limited to:

- DPP4 and DPP5 WACC.
- DPP4 and DPP5 expenditure allowances.
- CPI.
- Pass-through and recoverable costs.
- Durability of revenue cap settings[17].

16 The limit is provisional because it also allows for recovery of the difference between the Commission's forecast of transmission expenses and CPI (when the CPP was determined), and out-turn.

17 The continued application of a 10% cap on the annual change in forecast revenue from prices, as historically implemented in price-quality determinations, may not be in the long-term interest of consumers in the context of strong forecast growth from decarbonisation-driven electrification of the economy.

5.2. Consumer Prices

130. Approval of this reconsideration application will not have any immediate effect on consumer prices during this CPP period. The amount of revenue that Aurora can recover in any given year is set by:

- the forecast net allowable revenue specified in Schedule 1.3 of the Determination; and
- Provisional limit on annual percentage increase in forecast revenue from prices specified in Schedule 1.7 of the Determination;

With the latter being the key constraining factor.

131. We have not modelled the impact on consumer prices beyond the CPP period as we consider modelling contains too many assumptions to reliably do so. Consumer prices will be impacted by the pace of growth and the associated change in chargeable quantities as communities grow and electrify.

132. Further, as mentioned above, distribution pricing is changing and, by the time the impact of this reconsideration application flows through to prices, it is likely that the proportion of residential fixed prices will have increased to the extent that the difference between a high and low user's variable charges will have narrowed substantially.

133. Aurora Energy's pricing approach aims to allocate the cost of investments to the pricing region in which the investment is required. On this basis, with four of the five reconsideration projects occurring within the Central Otago/Wānaka pricing region, along with a substantial share of consumer connection investments, the incremental price impact is highest in that pricing region.

5.3. Incentives

134. Our expectation is that approval of this reconsideration application will result in adjustment of the specified amounts for the capex IRIS, listed in Schedule 2.2 of the Determination. We have stated the necessary adjustments to the IRIS amounts in Appendix B, on the expectation that this reconsideration application is approved in full.

5.4. Reliability

135. We do not anticipate any material impact on our quality standards. The Capacity Event projects are growth and capacity-related investments, and not designed to effect a reliability improvement. While some of these projects restore appropriate levels of security of supply, the overall reliability improvement is not considered material/measurable in the context of the quality path in the CPP Determination. Furthermore, the unexpected erosion of security of supply over time and consequential loss of reliability at these sites was not modelled in our CPP reliability forecast.

Appendix A. Reconsideration Project expenditure by Year

136. Table 15, below, summarises the expenditure associated with the reconsideration projects & programmes in this application and sets out an adjusted view of total capital expenditure should this application be approved in full. This table is based on Schedule E, Table 2b, as set out in workbook Aurora-CPP-Expenditure-Model-With-ComCom-Adjustments-Final-Decision-31-March-2021.xlsx, published alongside the Commission's final decision on Aurora Energy's CPP.

Table 15: Actual and forecast reconsideration project expenditure - summary

Expenditure $(000) nominal	RY2022	RY2023	RY2024	RY2025	RY2026
CPP Determination, Schedule 2.2, Table 2.2.2 - forecast capex	$69,227	$73,454	$75,239	$69,866	$62,490
R01: Riverbank Rd switching station conversion				$708	$5,814
R02: Upper Clutha sub-transmission auto-transformer upgrade			$4,099	$1,253	
R03: Cardrona zone substation transformer upgrade	$137	$1,283	$2,195		
R04: Bendigo distribution reinforcement		$491	$2,732		
R05: Frankton zone substation transformer upgrade			$406	$1,239	
R07: Consumer connection	$8,086	$5,378	$5,481	$4,485	$2,537
Schedule 2.2, Table 2.2.2 - forecast capex (adjusted)	$77,450	$80,606	$90,152	$77,552	$70,841

Appendix B. IRIS Adjustments

B.1. Proposed Changes to the Specified Amounts for the Incremental Rolling Incentive Scheme (IRIS)

137. Table 16, below, shows the adjustment that will be needed to the specified amounts for the capex IRIS, were this reconsideration application to be approved in full.

Table 16: Proposed adjustments to the capex IRIS amounts

Commissioned assets $(000) nominal	RY2022	RY2023	RY2024	RY2025	RY2026
CPP Determination, Schedule 2.2, Table 2.2.2 - Forecast commissioned assets	$76,398	$65,392	$77,959	$71,489	$65,748
R01: Riverbank Rd switching station conversion					$6,522
R02: Upper Clutha sub-transmission auto-transformer upgrade				$5,351	
R03: Cardrona zone substation transformer upgrade			$3,615		
R04: Bendigo distribution reinforcement			$3,223		
R05: Frankton zone substation transformer upgrade				$1,645	
R07: Consumer connection	$8,086	$5,378	$5,481	$4,485	$2,537
Schedule 2.2, Table 2.2.2 - Forecast commissioned assets (adjusted)	$84,484	$70,770	$90,278	$82,970	$74,807

Appendix C. Compliance Matrix

Input Methodologies (IM) Capacity Event Requirement	IM Reference	Application Reference
'Capacity event' means an event for which an EDB demonstrates that -		
the EDB's network needs additional capacity to provide electricity distribution services	5.6.6.A (a)	Section 2, paragraph 14
the additional capacity has the primary driver of meeting established or reasonably anticipated demand for-	5.6.6.A (b)	
(i) connection capex;		Section 4.2, paragraph 121
(ii) system growth capex;		Section 3.1.2 Section 3.2.2 Section 3.3.2 Section 3.4.2 Section 3.5.2
(iii) asset relocation capex; or		N/A
(iv) a combination of connection capex and system growth capex;		N/A
providing the additional capacity—	5.6.6.A (c)	
(i) would require the EDB to incur costs of at least two million dollars of capex during the CPP regulatory period above any allowance provided for that additional capacity in the DPP or CPP; and		Section 1, table 1
(ii) meets the expenditure objective.		Section 1, paragraph 6