Sydney Desalination Plant ("SDP") Expenditure Review

Consultant Report

Independent Pricing and Regulatory Tribunal ("IPART")

2 April 2023

Notice

This document and its contents have been prepared and are intended solely as information for Independent Pricing and Regulatory Tribunal ("IPART") and use in relation to Sydney Desalination Plant Expenditure Review.

WS Atkins International Limited assumes no responsibility to any other party in respect of or arising out of or in connection with this document and/or its contents.

This document has 134 pages including the covers.

Document history

Document title: Consultant Report

Revision	Purpose description	Originated	Checked	Reviewed	Authorised	Date
1.0	Initial Draft Report	TA	JC	GJ	GJ	9/12/2022
2.0	Draft Report	TA	JC	NJ	GJ	27/01/2023
3.0	Final Draft Report	TA	JC	NJ	GJ	2/03/2023
4.0	Updated Final Draft Report	TA	JC	NJ	GJ	2/04/2023

Client signoff

Client	Independent Pricing and Regulatory Tribunal ("IPART")
Project	Sydney Desalination Plant ("SDP") Expenditure Review
Job number	5218799
Client signature/date	

Contents

Tables

Figures

Glossary

Term	Definitions
AEMO	Australian Energy Market Operator
AIR	Annual Information Return
BOM	Bureau of Meteorology
Capex	Capital Expenditure
CEO	Chief Executive Officer
CMMS	Computerized Maintenance Management System
CPI	Consumer Price Index
DPE	NSW Department of Planning and Environment
DWPS	Drinking Water Pumping Station
EPA	Environmental Protection Authority
ERN	Emergency Response Notice
ESS	Energy Saving Scheme
FTE	Full Time Equivalent
FY	Financial Year
GSWS	Greater Sydney Water Strategy
HR	Human Resources
ICT	Information Communications Technology
IPART	Independent Pricing and Regulatory Tribunal
ISR	Industrial Special Risks
IT	Information Technology
LGCs	Large scale Generation Certificates
MFP	Multi-Factor Productivity
Mld	Megalitres per Day
NEM	National Electricity Market
NPV	Net Present Value
NSW	New South Wales
O&M	Operating and Maintenance
Ofwat	Water Services Regulatory Authority, England and Wales
Opex	Operational Expenditure
p.a.	Per annum
RAB	Regulated Asset Base

RET	Renewable Energy Target
RERT	Reliability and Reserve Emergency Trader
RFI	Request for Information
RRO	Retailer reliability obligation
SCADA	System Control and Data Acquisition
SDP	Sydney Desalination Plant Pty Ltd
SIR	Special Information Return
SLIs	Service Level Incentive Scheme
STCs	Small scale Generation Certificates
SWC	Sydney Water Corporation
VWA	Volume weighted average
WEC	Wholesale electricity purchase cost
WSA	Water Supply Agreement

Executive Summary

This report sets out the findings of the Sydney Desalination Plant Pty Ltd ("SDP") Expenditure Review. These are summarised below.

Operating environment

SDP's operating environment has changed significantly since the last review. At that time the plant had not been in operation for a number of years. That situation changed in early 2019 as a result of the 2017-2020 drought with desalinated water first supplied to Sydney Water in March 2019. Heavy rains ended the drought in early 2020. Rather than shutting down the plant has been operating under a series of Emergency Response Notices (ERNs) since that date.

The Greater Sydney Water Strategy published in August 2022 changed the approach to operation of SDP to "enable flexible and continuous operation". This was followed in September 2022 by a variation of SDP's Network operator's licence which formalised the role of the "Decision Framework for SDP Operation".

This period of operation has provided valuable operational experience and data including performance, energy use and expenditure. Since March 2020 the plant has been operated under a series of ad-hoc ERNs with limited notice of production requests, providing limited certainty for planning. The decision framework which formally comes into force in July 2023, will provide a more structured framework for planning. However, it also allows significant flexibility to vary production requests. It is important to note, however, that the plant has been operating in a flexible manner since the first ERN in March 2020.

Operating expenditure (excluding energy)

In the current period:

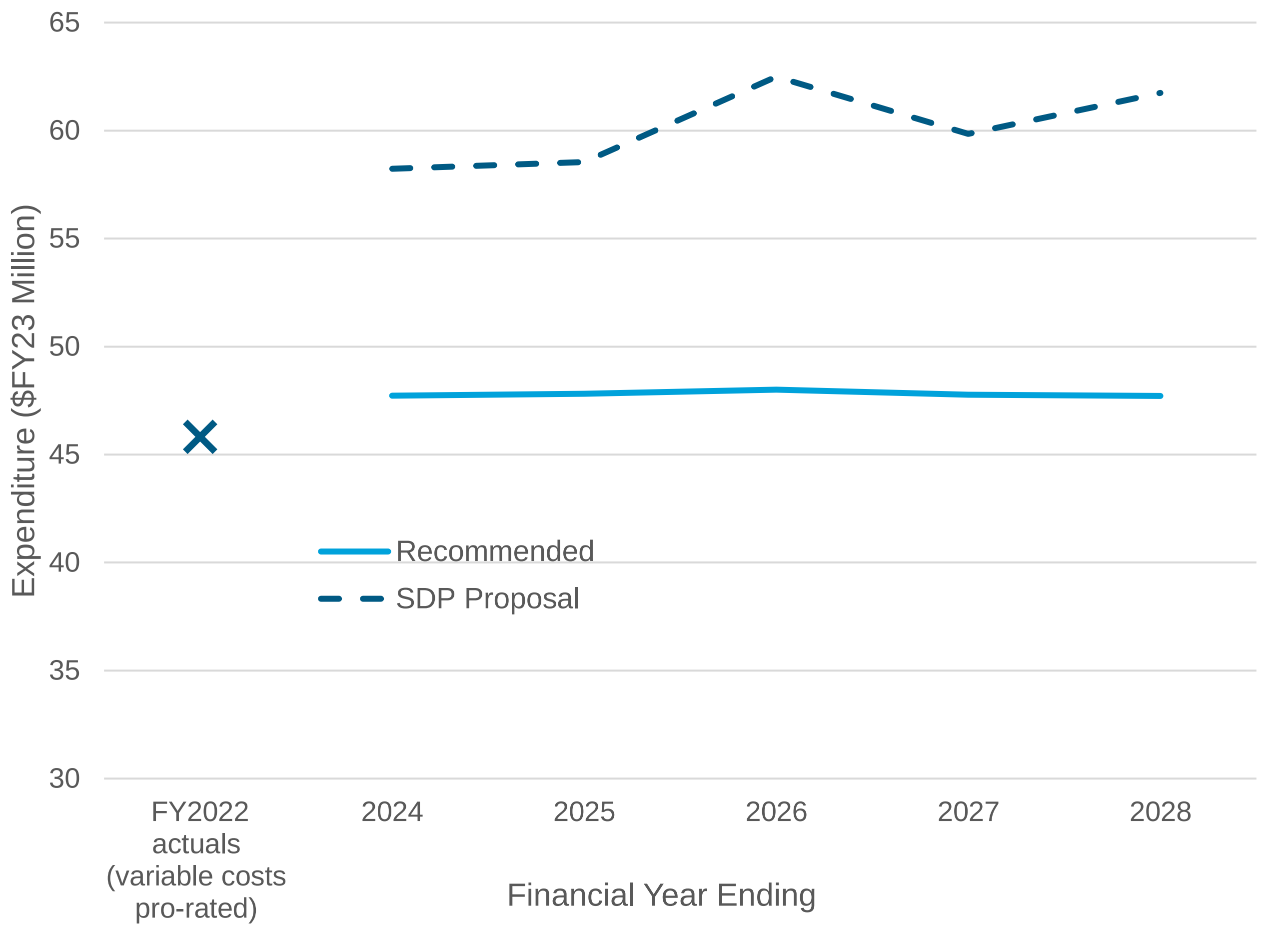
- SDP has overspent on 'fixed' opex- things like corporate costs and maintenance- compared to the Determination allowance. However, it has underspent on variable opex and energy costs.
- The net effect is an underspend on actual (FY18 to FY22) expenditure including energy of $2.1M. Due to the significant increase in costs (especially corporate and plant opex) assumed by SDP for FY23, SDP expects this underspend to become an overspend of $5.1M.
- There has been a generally increasing trend in corporate opex (Since FY15), but a reduction in fixed O&M costs since FY20.

In the next period:

- **In summary, SDP has proposed a 30% real terms average increase in opex at full production compared to the most recent financial year (FY22). This is made up of a 26% increase in fixed opex and 42% increase in variable opex.**
- **We have recommended an average 4% real terms increase in opex at full production. This is made up of a 5% increase in fixed costs and 2% increase in variable opex.**
- SDP is assuming significant increases across all opex areas with especially large increases in plant fixed and variable O&M costs and corporate costs. These increases are despite SDP having applied an efficiency challenge of 0.3% p.a. from FY25 onwards.
- We have reviewed the justifications provided by SDP and our own experience of other desalination plants and utilities and have recommended:
  - Allowing many of SDP's proposed increases including for example pipeline maintenance, many of the insurance cost increases, [redacted], travel costs, sustainability and some of the corporate remuneration costs to allow a focus on efficiency and sustainability.
  - Maintaining other expenditure at either base year (FY22) or historical averages where they may be cyclical. We recognise that SDP's operating role has changed. However, we consider that the new operating environment is not, in its own right, likely to lead to a material increase in fixed plant opex requirements. Reactive maintenance costs, one of the best indicators of the sustainability of maintenance practices, have been on a reducing trend across the recent

operating years, which is not suggestive of a plant being operated in an unsustainable way. We set out our view in further detail in Section 3.3.1.
   - For non-energy variable costs, we have not recommended accepting SDP's proposed increases. However, we have recommended a separate increase of $10/Ml due to membrane ageing phased in equal steps from FY24 to FY27.
- We consider there is reasonable additional efficiency to be gained through optimisation of the plant operations now that operational data are available and through rigorous focus on efficiency and cost management. Our view of catch-up efficiency is driven mainly by the scope for efficiencies in the following areas:
   - Having operated the plant across a range of volumes for a number of years, SDP and Veolia should now be in a better position to optimise operations and make efficiencies;
   - SDP has not yet carried out initiatives such as energy audits which would be expected to identify savings;
   - We have seen limited evidence of or detailed plans for efficiency improvements suggesting that there may be significant 'low hanging fruit' for efficiency with increased management focus; and
   - We have recommended additional expenditure for a new operations and sustainability coordinator and spend to save capex which should help to enable these efficiencies.
- We have proposed a catch-up efficiency of 0.5% per annum for fixed opex. We consider this should be achievable (i) now that the plant has been in operation for a number of years (ii) given the opportunities for efficiency identified and (iii) our view of SDP's maturity on the efficiency journey. This is in addition to the recommended continuing efficiency challenge of 0.7% p.a. which is consistent with that applied in other recent IPART water price Determinations.

Figure E-1 Summary of recommended fixed and variable opex at full production (excluding energy costs)



Energy

Consumption:

- The previous Determination was based on an allowance of 3.6 MWh/Ml. This was reasonable when considering energy consumption for a plant which was not envisaged to be in flexible operation.
- We have now recommended a more sophisticated approach suited to the flexible operation of the plant and taking advantage of the data now available. We have recommended a fixed allowance of 28.8MWh/d to allow for processes which need to be maintained even when no water is supplied on a given day, as well as a variable allowance of 3.4666 MWh/Ml representing the additional consumption associated with production. Compared to the previous approach, this increases the consumption allowance at lower production levels and reduces it at higher production levels. This is more representative of the realities of operating the plant at variable outputs.
- We have considered if this allowance should increase over time due to ageing of the membranes and pumps. We think that only a very minor increase is likely because the pumps generate more pressure than is required meaning that valves are used to throttle or 'burn' the excess pressure. We have, however, allowed for an average increase of 0.1 MWh/Ml for ageing of the pumps. This is included in the allowance set out above.

Costs:

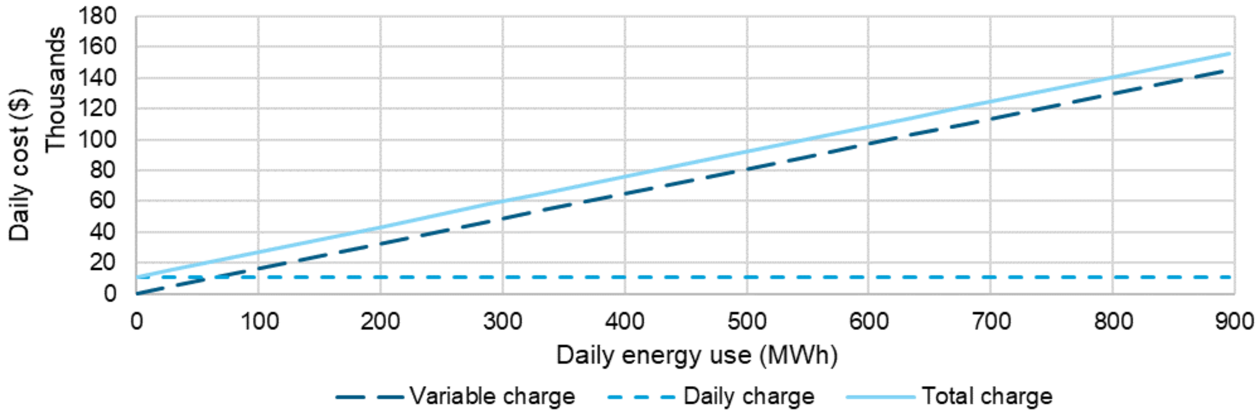
- Benchmark electricity price estimates have been developed for a two-part tariff consisting of a fixed daily charge and a variable charge per MWh of electricity consumed. Benchmark tariffs are summarised for each year in the table below. The values inclusive of assumed four (4) per cent non-production periods per annum give the costs for conversion to water production in ML across all water production modes.

Table E-1 Benchmark electricity prices ($FY23)

Price component	Unit	2024	2025	2026	2027
Fixed charge	$ per day	11,129	11,141	11,090	11,117
Variable charge	$/MWh	162	151	176	156
Fixed charge inc 28.8MWh fixed daily energy	$ per day	15,788	15,482	16,156	15,596
Variable charge inc 28.8MWh fixed daily energy	$/MWh	162	151	176	156

- Figure E-2 below shows the fixed daily cost (blue dotted line) and a variable cost (dark blue dotted line), relative to daily electricity demand for FY 2024. The daily total cost at different demand volumes is the light blue solid line. The pricing structure can be applied to the other years in the regulatory period.

Figure E-2 Daily $/MWh price by production volume (including 4% non-production) costs



Source: MJA modelling

- The fixed price reflects the cost incurred by the prudent, efficient, retailer to provide the optionality for the Plant to operate across a wide range of water production and associated electricity demand. The fixed daily cost is the purchase of electricity future electricity swap contracts for all periods from the Australian Stock Exchange.
- The purchase of swap purchases for maximum forecast demand is consistent with industry best practice and considered the most efficient compared with available alternatives for managing wholesale electricity price risk, given that future Plant demand at any trading interval is under the proposed Water Supply Agreement and SWC Decision Framework for SDP operation. While the Framework provides that SWC will forecast its supply requirements from SDP for the following year, operating rule objectives include that the volume of water produced by the plant can be varied as needed to support the resilience of SWC's system.
- The swap volume purchased is 41MWh, being the maximum recorded demand from the Plant over the period for which data is available when the Plant is running at or close to its maximum output. The swap cost reflects the estimated premium between forward swap prices and estimated forward spot prices.
- Table E-2 below shows the build-up of the benchmark electricity cost sack for each year of the period, differentiating between fixed and variable cost components. This includes the incremental cost of the Greenhouse Gas Reduction Plan (GGRP).

Table E-2 Estimated retailer cost stack for SDP benchmark price

Component	Group	Unit	FY2024	FY2025	FY2026	FY2027
Energy	Energy	$/MWh	110.57	103.43	133.40	117.72
Energy losses	Energy	$/MWh	0.19	0.18	0.23	0.20
Swap contract premium	Energy	$/day	10,957	10,969	10,919	10,945
LGCs	Green	$/MWh	8.50	7.92	6.57	5.41
GGRP	Green	$/MWh	24.68	21.12	17.09	13.72
STCs	Green	$/MWh	10.90	10.90	10.90	10.90
ESS (NSW Energy Saving Scheme)	Green	$/MWh	3.30	3.46	3.63	3.80
Ancillary Services	Other	$/MWh	0.36	0.36	0.36	0.36
Market fees (AEMO)	Other	$/MWh	1.17	1.17	1.17	1.17
Metering and Data Costs	Other	$/day	6.99	6.99	6.99	6.99
Fixed cost ex retail margin	*Total*	*$/day*	*10,964*	*10,976*	*10,926*	*10,952*
Variable cost ex retail margin	*Total*	*$/MWh*	*159.66*	*148.55*	*173.36*	*153.28*
Fixed cost inc retail margin	**Total**	**$/day**	**11,129**	**11,141**	**11,090**	**11,117**
Variable cost inc retail margin	**Total**	**$/MWh**	**162.06**	**150.77**	**175.96**	**155.58**

Source: MJA modelling

Capital expenditure

In the current period:

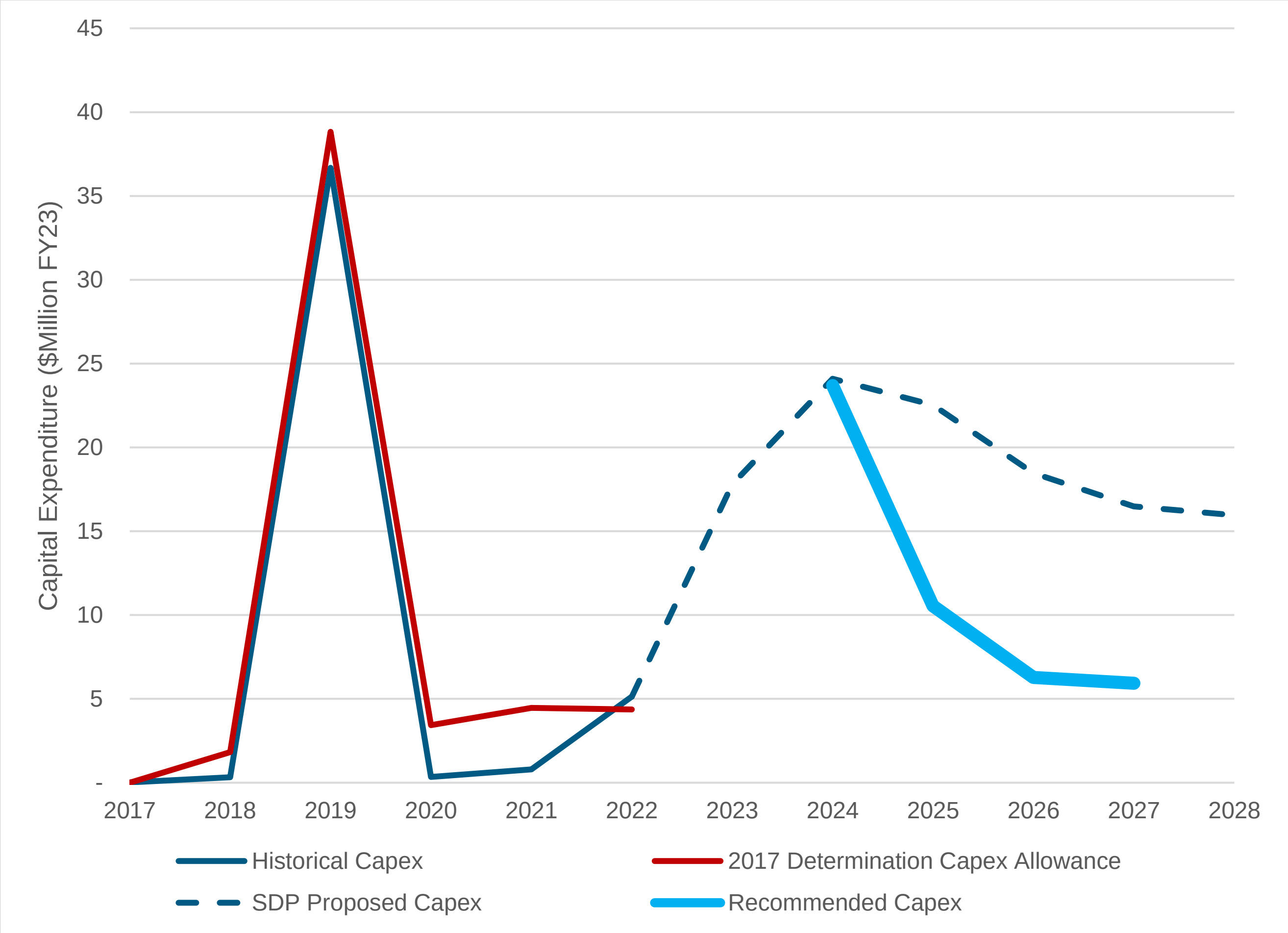
- SDP underspent $9.6M (18%) against its 2017 Determination capex allowance, of which $2.3M relates to membrane replacement. There was an even larger underspend in plant capex ($9.47M) which SDP attributes to prudent decision making to defer periodic maintenance and meet water delivery obligations. These underspends were partially counterbalanced by spend above the allowance on the pipeline and "specific projects" on the plant.
- We recommend that SDP's actual capex in the current determination period be adopted without any adjustments.

In the next period

- **In summary, excluding the membrane replacement program, SDP has requested an increase of $8.85M p.a. from the 2017 Determination period actual capex. We support the need for a step-up in periodic maintenance expenditure and have recommended an increase of $6.78M p.a. in capex.**
- SDP has proposed a total capex allowance of $81.00M (post-efficiency challenge). This includes
  - Membrane replacement of $35.7M.
  - Periodic maintenance of $23.24M. This is a 39% increase from the 2017 Determination allowance and a four-fold increase in periodic maintenance capex compared with actual expenditure in the 2017 Determination.
  - Plant capex projects which are estimated by SDP to cost $15.14M.

- Our findings and recommendations:
  - Periodic maintenance:
    - We support the need for a step up in periodic maintenance spend in order to ensure the efficiency, durability and safety of the plant now that it is operational. We have recommended a number of specific adjustments to some of the proposed expenditure items and applied a 10% reduction because of uncertainties in the underlying modelling, and delivery limitations in rolling out a planned maintenance program while maintaining production capability which was reflected in the significant underspend in the current period.
  - Membrane replacement:
    - We used an effective production age approach based on how much they have been used. Based on our analysis and information provided by SDP, we recommend that 25% of the first-pass membranes is to be replaced in FY2024. We have also set out an estimate of the costs of membrane replacement for low production and full production scenarios.
  - Opportunities for capex efficiencies
    - We have seen little evidence that there has been strong efficiency challenge in the way the scope and costs of the program have been assembled. It seems likely to us that the cost estimates used are conservative and that there is scope for efficiency through rigorous procurement and supply chain challenge e.g. through greater involvement and scrutiny in supplier engagement and/or market testing and strong efficiency challenge. We conclude that there is significant additional efficiency to be gained and have recommended a catch-up efficiency. The catchup efficiency challenge builds from FY24 reaching 7% efficiency by FY27.
  - The recommended capex for the next Determination period is $46.44M

Figure E-3 Summary of Recommended Capex



Asset Lives

- SDP has proposed changes to asset life for three asset types:
  - Membranes: which SDP proposed changing to 4.5 years, amended following interviews to 8 years
  - Pipeline: from 120 to 100 years
  - Periodic maintenance: from 30 to 7.6 years
- Our view and recommendation
  - We recommend an asset life of 11 years for the membranes based on modelling of the likely timings of replacement.
  - We recommend two options for pipeline asset life:
    - 116 years: Consistent with previous Determinations and assets life of SWC's assets at the time of construction. Accounts for 59% of the pipeline being undersea.
    - 100 years: Consistent with the basis of design for the pipeline and treats the pipeline as a singular asset.
  - We recommend an asset life for the periodic maintenance activities envisaged in this period to of 6.6 years. This is because a greater proportion of the higher cost items envisaged relate to overhaul rather than replacement of assets. We recommend reviewing this in future periods to ensure it reflects the nature of future periodic maintenance.

1. Introduction

1.1. Scope of the Report

In November 2022, the Independent Pricing and Regulatory Tribunal of New South Wales ("IPART") appointed the Atkins/Marsden Jacobs Associates (MJA) consortium to carry out a strategic management and expenditure review of Sydney Desalination Plant's ("SDP") operations. The purpose of this review is to inform the Tribunal's decision on prices for the new Determination period which applies from 1 July 2023 to 30 June 2027.

This Report has been prepared in accordance with the Scope of Works set out in the contract between Atkins and IPART dated 24 November 2022. A Summary of the Scope of Works is reproduced in Appendix A only for information purposes. Atkins has written Chapters 1-6 of this document except for Section 4.2. Marsden Jacobs has written Section 4.2 of this document.

The findings of this report form an important component of the overall price review process as set out in the IPART Issues Paper. The conclusions relating to prudence of expenditure in the current price path inform what IPART includes in SDP's opening Regulated Asset Base value. The conclusions relating to efficient operating and capital expenditure in the future price path assist the Tribunal's assessment of what are justified requirements to be included in the 'building block' model for determining future prices.

1.2. Review team

The team which has carried out this review is familiar with SDP's operating context having carried out the expenditure and energy price reviews for the 2017 Determination as well as the SDP expansion review in 2019. Of particular note, the Energy Director (Andrew Campbell), Desalination Technology Expert (Conor Kenny), and Team Leader (Graydon Jeal) have all played a central role in previous assignments and have been able to provide continuity of approach and understanding.

The team's understanding of and exposure to SDP's operation from the last review allows the team to appreciate and comprehend the change that the Plant's operation has gone under. The team also acknowledges the Minister's revised terms of reference to IPART as it is understood to impact the costs incurred by SDP in utilizing renewable energy and complying with the greenhouse gas reduction plan.

1.3. SDP Submission to IPART

IPART required SDP to provide a submission outlining and substantiating its proposed prices for the period 2023 to 2027 and historical costs for the current Determination period from 2017 to 2021 plus the 1-yearone year extension. The following versions of this information have been used in the preparation of this report:

- Submission to IPART;
- Annual Information Return ("AIR") and Special Information Return ("SIR") .

Whilst we have endeavoured to satisfy ourselves as to the provenance and robustness of the data provided, a detailed audit of the completeness and accuracy of the information lies outside the scope of this Project.

1.4. Methodology

Our methodology for undertaking this review is based on the combined experience of the team in undertaking similar expenditure reviews across Australia and internationally.

Our review work commenced in November 2022. Our initial task was to review the pricing proposal prepared by SDP. On this basis and in response to the objectives and scope set by IPART, we prepared an inception report to guide our review. In late November 2022 we made initial information requests and commenced meetings to interview SDP and Veolia staff. We completed this first round of interviews by 1 December 2022.

The decision framework for SDP operations provide three operating modes: sustain, flexible, and ready. We considered the impact of the framework on the plant regarding the different activities such as operational needs, membrane replacement, periodic maintenance, and others.

SDP outsources nearly all its services, either through its Operation and Maintenance (O&M) contract or procurement of professional services. We sought a detailed understanding of the O&M contract to identify the key cost drivers including labour, chemicals and energy use. We carried out a detailed review of the plant including the processes, the electrical and mechanical plant and historic performance and maintenance processes. We compared the plant performance and activities with other desalination plants across the world of similar size and process complexity.

While a contract is in place, we identified the scope for efficiencies in inputs - power usage and chemical storage - based on recorded works performance in the period 2017 to 2022 and our experience of similar plants. We were able to benchmark certain costs (e.g. corporate, energy, and others) and utilise our team's experience in the design and operation of similar plants across the world. We also tested the scope for efficiency in the timing and open procurement of membranes.

We reviewed the current price path expenditure and identified the reasons for variance. This analysis is a good basis to test future expenditure in understanding the reasons for cost variance against the 2017 Determination. We applied catch-up and continuing efficiencies to corporate costs to reflect the potential for efficiency savings through procurement and new technologies.

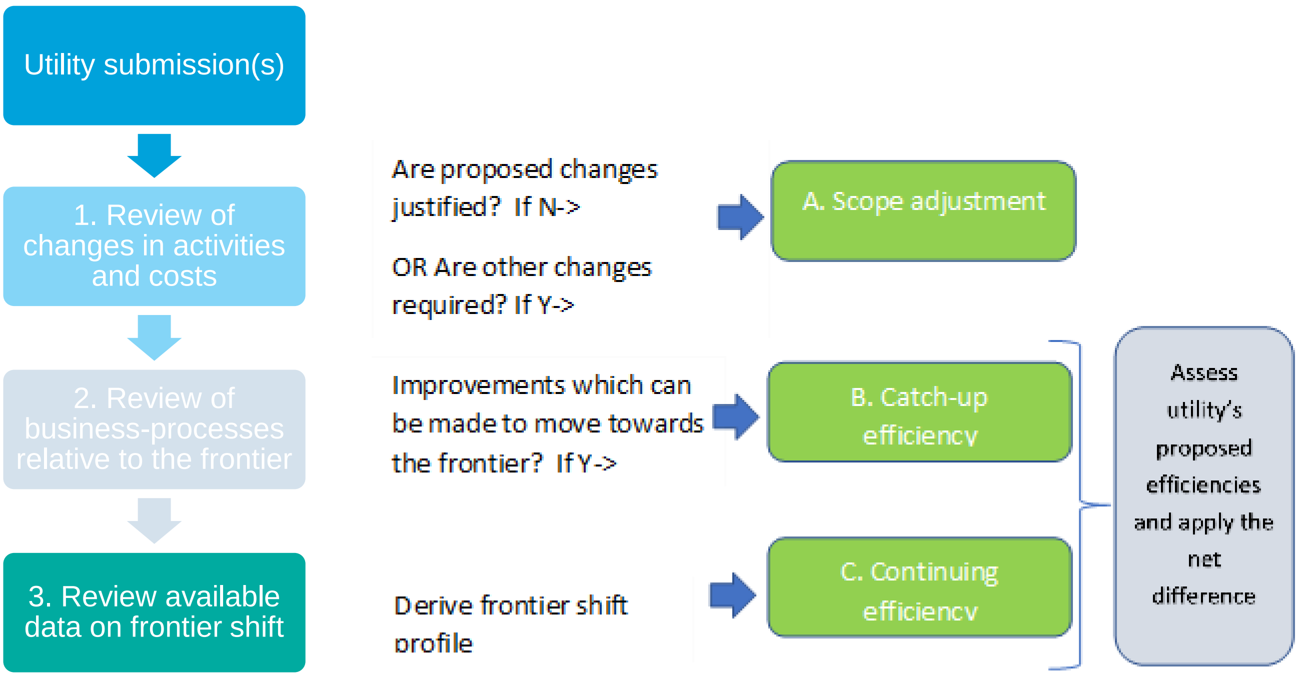
Throughout our review process, we were in communication with IPART and SDP to clarify specific items and enquire about new information. Our review included physical meetings at SDP offices and plant to discuss different aspect of SDP's 2023 pricing submission. We sought to gain an understanding of the operation of the plant and form a better grasp of the plant's operating philosophy by meeting with staff from the O&M Contractor. We also had an informal discussion with Sydney Water to understand the operating context. In addition, we met with IPART on various occasions to intermittently present findings and discuss SDP's options to become more efficient and prudent in its operation.

All expenditure in this report is in FY2023 price base unless otherwise stated.

1.4.1. Recommending efficient expenditure

In arriving at the recommendations in this Report, we have applied a three-stage approach to reviewing the efficiency and prudence of expenditure, as summarised below. This methodology is consistent with that applied for other regulatory reviews across Australia.

Figure 1-1 Approach to assessing efficiency



Source: Atkins

1. Review of changes in activities and costs

This step involves identifying inefficiencies within proposed changes to a utility's specific programs and does not apply to base expenditure to avoid double counting with Step 2. These adjustments are clearly distinct from the types of efficiencies identified in Step 2 in that they correct for an imprudent or inefficient proposed change to a utility's activities (and associated costs) rather than the business processes employed by the utility to deliver the utility's services. If the utility's proposed changes in activities (and associated costs) are not efficient, a **scope adjustment** is made.

2. Review of business-processes relative to the frontier

This step identifies the effectiveness of business processes (e.g. decision-making and procurement processes) relative to a benchmark frontier company. Where we identify improvements that can be made relative to the benchmark, a **catch-up adjustment** is made. This encourages the utility to move to the efficiency frontier.

We then recommend a profile or pathway of catch-up efficiency we consider the utility will realistically be able to achieve each year within the next Determination period. This is based on experience of how other utilities in a similar position have been able to achieve efficiencies with new business processes, management focus and appropriate incentives. It does not mean that the utility will have arrived at the frontier at the end of the Determination period.

3. Review available data on frontier shift

We consider a number of data points such as the efficiency gains of well-performing utilities and broader productivity trends (e.g., multi-factor or total factor productivity). This recognises that in competitive markets firms must innovate to achieve continuing efficiency gains over time.

We compare the total efficiency challenge we derive from steps (2) and (3) with the efficiencies applied by the utility in its own submission. We then apply the net difference as an adjustment to the utility's submission.

1.4.2. Continuing efficiency

The continuing improvement element of efficiency, termed 'Frontier Shift', relates to the increased productivity derived from process innovation and new systems and technology that all well-performing businesses should achieve. We have applied the results from the Australian Productivity Commission Multi-Factor Productivity (MFP) analysis and efficiencies applied to other water utilities in New South Wales. We have recommended applying a Frontier Shift of 0.7% per annum cumulating over the Determination period.

1.5. Information sources

The key documents relied upon for the review include:

- SDP's Pricing Submission, Appendices and Supporting Documents
- SDP's pricing model
- Annual Information Return ("AIR") and Special Information Return ("SIR")
- Responses to Requests for Information (RFI) provided by SDP.

While some of these documents are publicly available online, the majority were directly issued by SDP.

1.6. Response to SDP's Comments on Draft Report

In the process of developing this report, IPART shared with SDP an earlier version of the report for comments on 27 January 2023. In the correspondence, IPART provided SDP until 13 February 2023 to provide comments on the report.

SDP provided detailed comments on the Draft report which we respond to in detail in Appendix E. It also set out a number of key concerns:

- Whether it accurately reflected SDP's current efficient costs;
- Whether it recognised the implications of SDP's new operating regime for efficient expenditure;
- The basis for the catch-up efficiency adjustments;
- Whether key information provided by SDP has been considered and understood.

It makes a number of requested changes.

We summarise our response to these concerns below:

1.6.1. SDP's current efficient costs

SDP expressed concern that the report uses FY22 as the base year which "*does not recognise the extent to which SDP's operating environment has changed, and that a steady state of operation for SDP had not been reached in FY22*."

We have given due consideration to SDP's explanation and information provided for using FY23 rather than FY22 for O&M costs. However, it is best practice to use the most recent actuals (FY22) as the base year and to review justified changes from that year, as we have done in accepting many of SDP's proposed increases. It is not considered good practice to rely on budgets or projections as the base year.

1.6.2. Implications of SDP's new operating regime for efficient expenditure

SDP expressed concern that the report appears to have *"misunderstood the significance of changes to SDP's Network Operator's Licence and the draft recommendations have relied on the key assumptions that:*

1. the current level of service that SDP is providing under its restricted emergency response role is effectively identical to the level of service required under the new operating environment, and

2. the cost incurred in providing the current level of service under the emergency response role is reflective of the future cost of providing the level of service under the new operating environment."

We appreciate the significance of the changes to SDP's network licensee and operating environment and have added text to make this appreciation clearer. We have examined the justifications SDP has made for step changes in expenditure on a case-by-case basis and have recommended acceptance of a number of them as set out in detail in Section 3 below.

1.6.3. Basis for the catch-up efficiency adjustments

SDP was concerned about the lack of evidence and justification for the catch-up efficiency challenge. In particular it expressed concern that the report did not *"identify "the efficiency frontier" for SDP's circumstances"* and "*quantify SDP's distance from the frontier or comprehensively identify the range of measures SDP should be implementing to be at the frontier*".

It also states that an "*assessment of whether catch-up efficiencies are reasonable or not can only be made once the costs of operating under the new regime are incurred.*" and that it is not clear what has changed since the 2017 Determination.

We have carried out regulatory reviews of many companies and witnessed the extent to which they can improve their efficiency over time. The catch-up efficiencies are based on benchmarking of the efficiency challenges applied and achieved by utilities at different stages of the efficiency maturity journey. We have added further justification to explain this. We do not agree that it is only possible to assess whether catch-up efficiencies are reasonable once the costs of operating under the new regime are incurred. SDP's projected activities and costs are of the same type (e.g. maintenance, chemical dosing, corporate functions, etc) and scale to those which it has already been carrying out.

SDP also considered that the report seemed *"to conflate, and double-count, catch-up and continuing efficiency adjustments – by applying catch-up adjustments to reflect the scope for continuing efficiencies and then also applying separate continuing efficiency adjustments".*

We do not agree that there is any double counting of catch-up and continuing efficiency. We have set out the drivers for catch-up efficiency in Sections 3 and 5. This is a separate concept to continuing efficiency which is based on MFP analysis as set out in Section 1.4.2.

1.6.4. Consideration of key information

SDP expressed concern that *"the report did not "reference nor consider key information provided by SDP…appears to dismiss information provided by SDP without a clear explanation as to why, or has misunderstood information provided by SDP"*.

In an attempt to keep the report easy to read and not repeat the content of SDP's submission and documents, we did not reference all of the information provided by SDP. We have added further references in this version of the report where we consider it helps the reader.

SDP also expressed concern about the pipeline asset life, encouraging us to *"to consider other relevant material regarding SDP's proposal"* and that we *"mistakenly removed $1.25 million p.a. from SDP's fixed O&M allowance assuming these variable "other treatment costs" had been also included in SDP's proposed fixed O&M costs*".

We have considered the Basis of Design document provided to us on 23 February 2023 and updated our text ono the pipeline asset life in Section 6.

SDP expressed concern that we had *"mistakenly removed $1.25 million p.a. from SDP's fixed O&M allowance assuming these variable "other treatment costs" had been also included in SDP's proposed fixed O&M costs"*. This was because there was no cost against this line item for FY23 in Table 9.13 of the Appendix to SDP's submission. However, we now understand that these costs have always been reported as part of variable costs. We have therefore no longer recommended the increase in variable opex or matching reduction in fixed opex which were set out in the draft report.

1.6.5. Requested changes

In addition to the points outlined above SDP asked that we:

- Consider the impact of JLL's projected increases in SDP's land valuation.
- Incorporate office rental costs.
- Consider the information within the [redacted] analysis by Aon

We have refreshed the wording related to land tax to clarify the misunderstanding. We have also taken into account the 2023 land tax assessment notice provided to us with SDP's comments in February 2023.

We have revised the approach to office rental costs which SDP incorporated in its historical opex in its restated AIR issued on 13 February 2023 and recommended allowing these in opex.

We have considered all the information [redacted] provided to us and reflect this in our report and recommendations.

2. Business Environment

2.1. Background

The desalination project in Sydney was initially funded by the NSW Government and originally owned by Sydney Water Corporation ("SWC"). Construction took three years from 2007 to 2010 and a purpose-built wind farm was constructed by Infigen Energy (now Iberdrola Australia) to provide 100% renewable energy for the Plant. The first desalinated drinking water was delivered to Sydney in February 2010. The plant then ran continuously for two years, from 2010 to 2012, to prove plant capacity and reliability.

The NSW Government sold a 50-year lease on the plant in June 2012 backed by a 50-year Water Supply Agreement ("WSA") with SWC. Sydney Desalination Plant Pty Ltd ("SDP") is owned by Ontario Teachers' Pension Plan (60%) and Utilities Trust of Australia[1] (40%). The 50-year lease includes all assets associated with the Project including:

- Seawater Reverse Osmosis ("SWRO") Plant and associated land;
  - Seawater intake and tunnel, drum screens, Intake seawater pumping station;
  - Chemical coagulation and Rapid Gravity Filtration using 24 dual media filters;
  - Low pressure feed pumps to RO trains and energy recovery systems and Cartridge filters followed by RO high pressure feed pumps;
  - 13 first pass RO trains and seven second pass RO trains;
  - Isobaric energy recovery from the brine, (Dual Work Exchanger Energy Recovery ("DWEER") system);
  - Alkalinity addition using hydrated lime and carbon dioxide and treatment using sodium silicate, aqueous ammonia, sodium hypochlorite, and Fluorosilicic acid;
  - Pre-treatment waste solids thickening and solids centrifuge dewatering and brine outfall tunnel and multiport outfall diffusers.
- The Drinking Water Pumping Station ("DWPS"); and
- The potable water pipeline connecting the Plant to the water supply network.

Sydney Desalination Plant is regulated by the Independent Pricing and Regulatory Tribunal ("IPART").

The site is located at Kurnell with the 18km long potable water pipeline from the DWPS on the site following a route along land and under Botany Bay to discharge into the SWC distribution system at Erskineville.

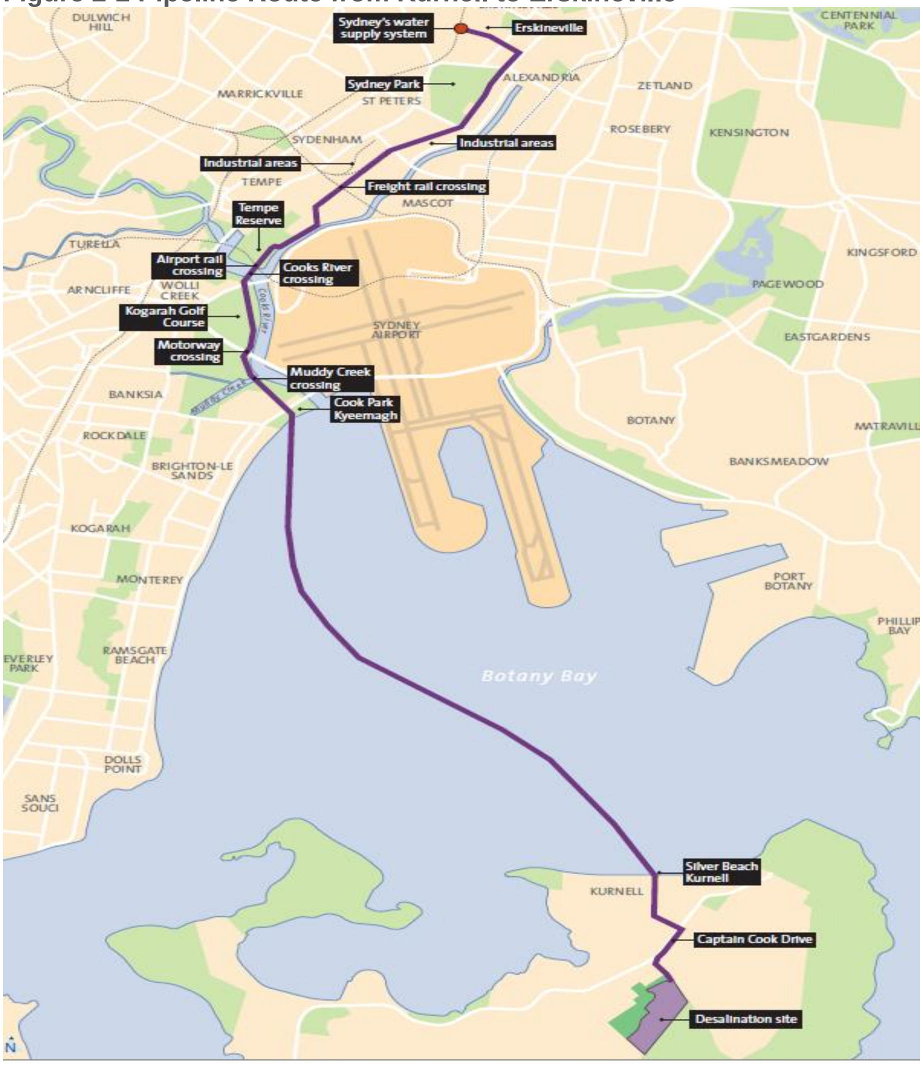
A photo of the Plant and a diagram of route of the potable water pipeline are shown in the following figures:

[1] Utilities Trust of Australia is managed by Morrison & Co.

Figure 2-1 SDP Site

Source: SDP

Figure 2-2 Pipeline Route from Kurnell to Erskineville

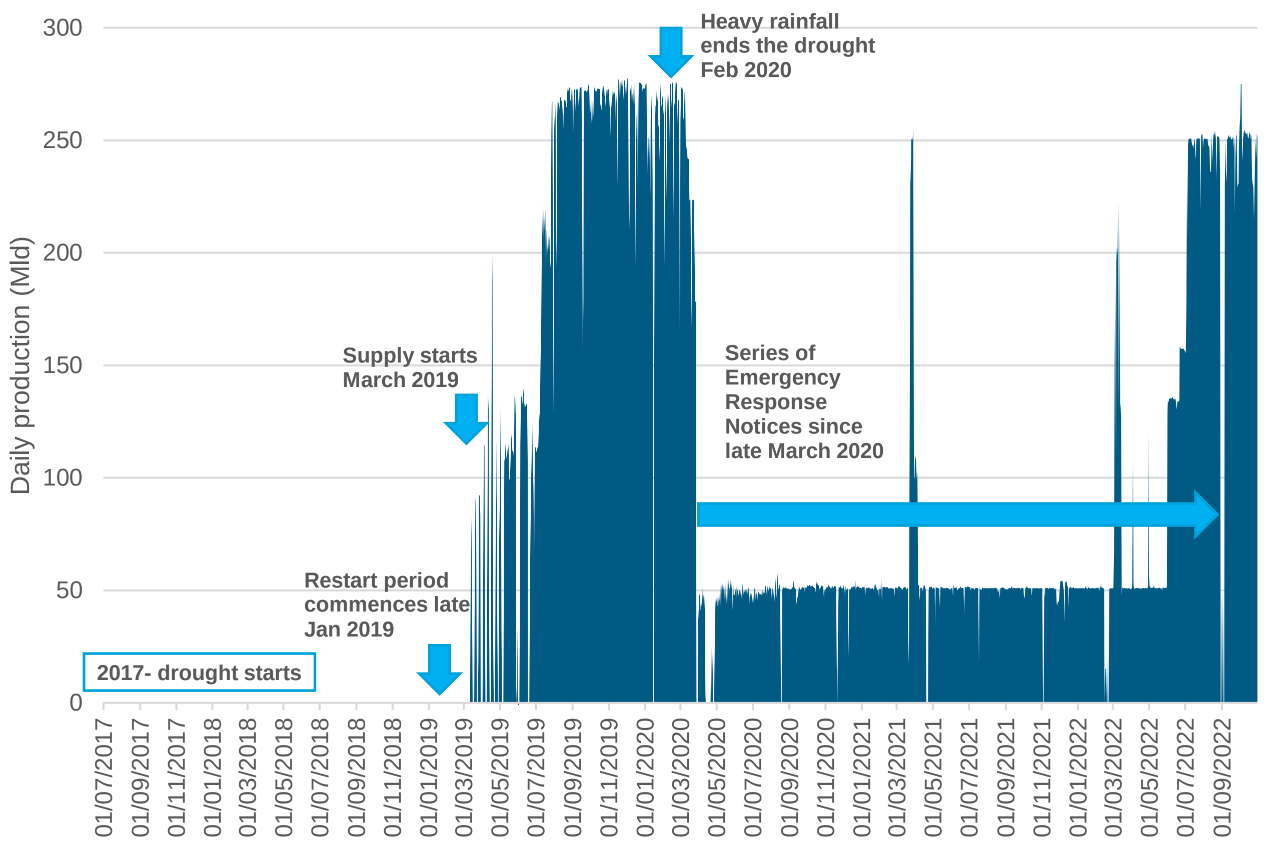


Source: SDP

2.1.1. Operating environment

SDP's operating environment has changed significantly since the last review. At that time the plant had not been in operation for a number of years. That changed in early 2019 as a result of the 2017-2020 drought with desalinated water first supplied to Sydney Water in March 2019. Rather than shutting down after heavy rains in early 2020, the plant has been operating under a series of Emergency Response Notices since that date.

Figure 2-3 – Water supplied by SDP



Source: SDP document "ATK-001_1 Jul 2017 to 31 Oct 2022 Energy and Production Data Rev 2"

In August 2022, the NSW Department of Planning and Environment ("DPE") published the Greater Sydney Water Strategy ("GSWS"), setting out the long-term vision and direction for the provision of sustainable and resilient water services.

The GSWS set out a number of responses to enhance resilience and support growth including:

- Water conservation and efficiency.
- Changing the approach to operation of SDP to **"enable flexible and continuous operation"**, aiming to have higher reservoir levels at the start of a drought and to slow dam depletion rates; and
- Planning for rainfall-independent supplies such as recycled water and desalination.

The GSWS anticipated that the change in SDP operation would lead to an increase in water supply approximately 20 Gl p.a. under average conditions, with more available for changes in circumstances such as an increase in demand or a return to drought conditions.

This is a significant change to the modes of operation set out in the 2017 Metropolitan Water Plan ("MWP"), which set out a trigger for SDP start-of 60% dam storage.

This was followed in September 2022 by a variation of SDP's Network operator's licence. Notable terms of the licence for this review include requirements on SDP:

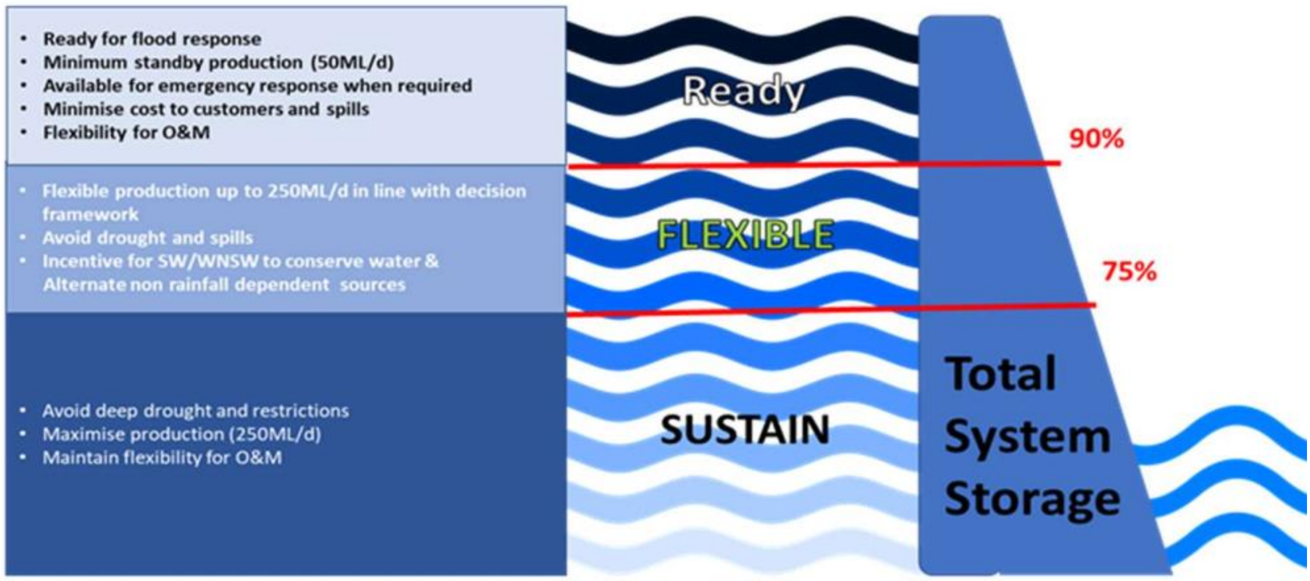
- to comply with any Annual Production Requests made by Sydney Water provided that the request is consistent with the Decision Framework. This obligation comes with some flexibility notably a 90% to 110% range for compliance and exceptions due to endeavouring to comply with other requests; and

- to use its best endeavours to comply with other requests made by Sydney Water under the Decision Framework.

The licence also provides flexibility by providing for events outside SDP's reasonable control.

The Decision Framework referenced under the licence is the "Decision Framework for SDP Operation" published in June 2022. It sets out the basis for production requests against three operating phases linked to reservoir storage levels, summarised graphically as follows:

Figure 2-4 - New operating phases under the Decision Framework



Source: Figure 1, Decision Framework for SDP Operation, June 2022

Key drivers for decision making for the three operating phases include:

1. READY to respond:
    a. Kept at minimum annual baseline production to maintain readiness to respond to emergencies and planned maintenance.
    b. Maintenance works are prioritised.
2. FLEXIBILITY:
    a. Target minimum production of 125 Mld during "risk neutral" conditions.
    b. Maximise production when there is an indication of drought and minimise it where there is high or imminent spill risk.
3. SUSTAIN dam storage:
    a. Maximise production (250 Mld).

It also sets out the basis for monthly and 7-day production requests. The latter is based on consideration of spills, water quality or maintenance work.

2.1.2. Contractual arrangements

The contractual arrangement between Sydney Water Company ("SWC") and Sydney Desalination Plant ("SDP") is regulated by the Water Supply Agreement ("WSA").

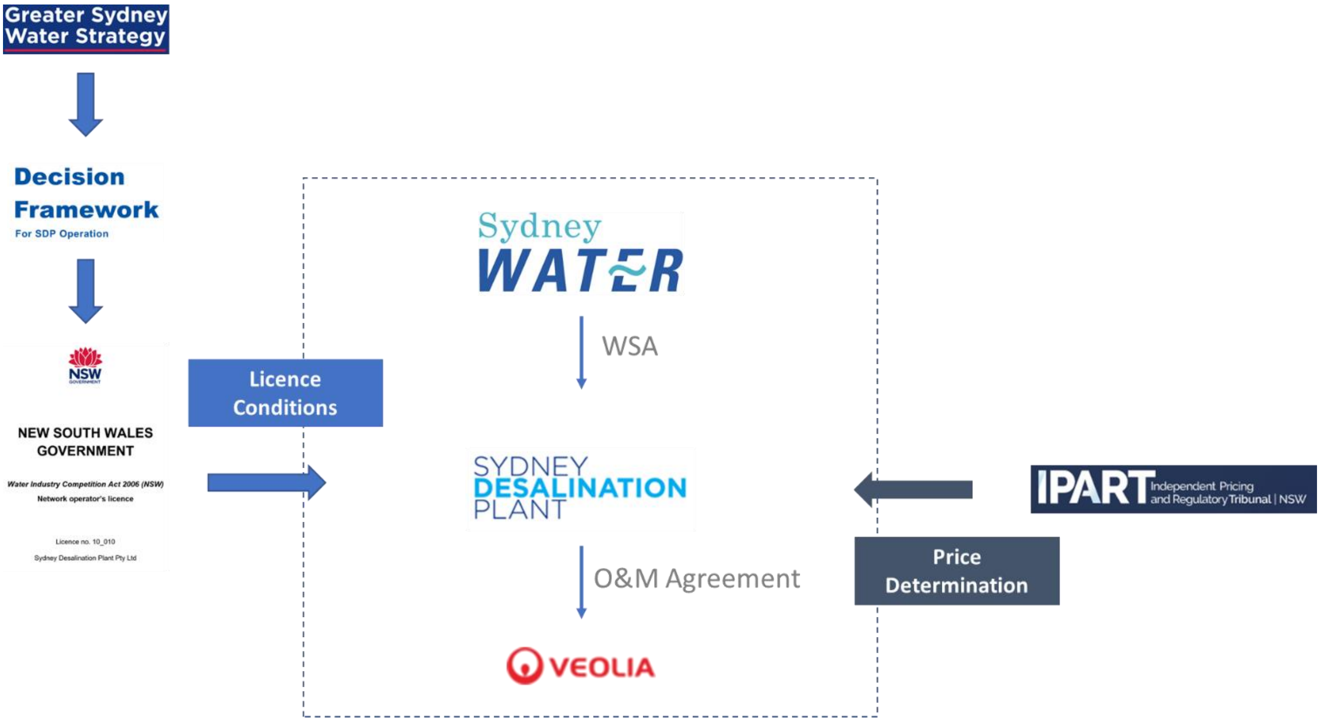
The current WSA was signed in June 2012 and it includes, amongst others, provisions for drinking water specifications, water quality tests, metering requirements and payment mechanism. The WSA has not been updated, however; the Operating Protocol was revised prior to the Restart of the Plant in 2019.

The contractual arrangement between SDP and Veolia Water Australia (the Operator) is regulated by the O&M Agreement. The O&M Agreement was originally signed in July 2007. Since then, there have been several amending deeds: (i) Amending Deed No.1 in May 2008; (ii) Amending Deed No.2 in April 2010; (iii) Amending Deed No.3 in June 2012; and (iv) Amending Deed No.4 in September 2019.

Furthermore, two amending deeds were signed between the parties in way of extending Amending Deed No. 4. The extension deeds were signed on May 2021 (expired 30 June 2022) and August 2022. The last extension deed commenced on 1 July 2022 is due to expire on 30 June 2023. Each extension deed included adjustment schedule for fixed costs and routine asset maintenance costs.

The following figure depicts the contractual arrangement and the governing processes:

Figure 2-5 - Contractual arrangement and governing processes



Source: Atkins

We understand that both WSA and O&M Agreement are currently being reviewed and are expected to be amended over the coming months.

2.2. Levels of Production

It is clear that, with SDP in flexible and continuous operation, there remains a significant range of potential production levels. For long term planning purposes, it is useful to have in mind a representative 'average' production level as it is not possible to know in advance how much production will be required each year.

In the absence of a detailed probabilistic modelling of the probabilities of (1) being in each operating phase and (2) drought or spill indications whilst in the flexible operating phase or maintenance activities, we have made a number of high-level estimates for the probability of being in each operating phase or events as summarised below:

Table 2-1 – High-level estimate of representative average production

	Scenario	Assumed probability	Production (Mld)
1	"Ready to respond" phase	30%	50
2	Flexibility phase	20% *of which:*	*see below*
	"Risk neutral"	*60%*	*125*
	Drought risk	*30%*	*250*
	Spill risk	*10%*	*50*
3	Sustaining dam storage phase or indication of drought in Flexibility phase	45%	250
4	Supply emergency	5%	250
	"Representative average" production		171 (68.4%)

IPART and consultant's analysis[2]. The last line is based on analysis of SDP's document 'ATK-001_1 Jul 2017 to 31 Oct 2022 Energy and Production Data'

NB: we have not provided a probability for zero production as it is assumed that annual production requests will not be set below 50Mld

The last line of the table represents a basic representation of what the average production would have been if a 50Mld minimum flow had been in place since 2022.

[2] Analysis of approximate periods spend in the new operating phase storage zones based on Greater Sydney storage levels since 2000 summarised in Figure 5 of the Greater Sydney Water Strategy

3. Operating Expenditure

3.1. Overview of historical and projected opex

SDP reports opex in the following areas:

- Corporate operating costs
- Pipeline operating costs
- Plant operating costs:
    - Fixed
    - Variable
- Energy costs (dealt with separately in Section 4 below)

The actual and SDP projected expenditure by these areas (excluding energy) are summarised below.

Figure 3-1 - [redacted]

[redacted]

From these it is clear that:

- "Fixed" plant opex has increased with the restart of the plant in 2019. This is expected as these costs include restart charges as well as the ramp up of costs such as labour for the operation of the plant.
- As expected, variable opex shows a strong link to production, with variable opex highest in FY20 when production was highest. We note that there may be a misalignment between variable opex and production

for FY23: the expenditure was submitted in September 2022, whereas the production data is based on the average from July to November 2022.

- Corporate opex has been on an increasing trend since 2018.
- SDP is projecting significant increases in corporate and fixed plant opex for the next Determination period.

We examine below the variance in expenditure in the current Determination period.

3.1.1. Variance in the current Determination period

Changes since the previous Determination period

As can be seen in Table 3-1, all opex components have increased since the end of the last Determination period with the exception of 'other' corporate opex, which was significantly affected by severe weather event repair costs in FY16 and FY17.

We summarise below the most significant changes by opex sub-components and the explanations for these changes.

Table 3-1 - Significant (non-energy) changes from FY17 to FY22

Cost category	Change ($FY23 Million p.a.)	As %	Comment
Labour and other fixed costs (plant)	+7.7	+129%	Plant entered operational mode
Variable costs (plant)	+3.5	n/a	Plant entered operational mode
Insurance (corporate)	+1.8	+74%	SDP explanation: due to rising premiums, driven by market pressures[3] and also the shift to operational mode
Remuneration (corporate)	+0.6	+17%	SDP has explained that the main driver was an increase in staffing in the operations and finance space (4 FTEs contributing 16% of the increase), as well as training and other staff costs [4]
'Other' (corporate)	-5.6	-100%	SDP has explained[5] that the apparent reduction is due to severe weather event repair and clean-up costs incurred in FY17 ($4.7M nominal, $5.6M in $FY23).

Source: AIRSIR . Note: only changes greater than $0.5M have been included in this Table

Adjusting for the severe weather event repair costs in FY16 and FY17 it is clear that corporate opex has also seen an increasing trend since 2015 as shown below.

[3] Page 126, SDP Pricing Submission
[4] Response to RFI 70
[5] Response to RFI 69

Figure 3-2 - [redacted]

[redacted]

Comparison to IPART allowance

SDP has provided a breakdown of variance against IPART's allowances. This suggests that all of the "fixed opex" elements (plant, pipeline, corporate and insurance) have exceeded the allowance whilst the variable elements (treatment and energy) have been outperformed.

Based on the breakdown of variance supplied by SDP we note that:

- Fixed plant and pipeline costs were approximately in line with the Determination allowance in FY22
- Corporate costs have generally been higher than the allowance except for FY20 when they were reduced by the reimbursement of some Preliminary Expansion Plan project costs actually incurred in FY19
- Fixed insurance costs have been on an increasing trend, resulting in a consistent shift from under- to over-spend
- Variable treatment and energy costs have consistently outperformed the Determination allowance; and
- In its submission, SDP has assumed an increase in cost in FY23 for all categories except for a minor improvement in variable treatment cost performance.

Figure 3-3 – [redacted]

[redacted]

The net effect is an underspend on actual (FY18 to FY22) expenditure including energy of $2.1M. Due to the significant increase in costs (especially corporate and plant opex) assumed by SDP for FY23, SDP expects this underspend to become an overspend of $5.1M. We note SDP's view that the aggregate underspend in FY18 to FY22 includes a period in which the operating context changed including a restart period with associated cost allowances. We consider it is nonetheless still useful of comparing outturn expenditure to cost allowances.

Table 3-2 - [redacted]

[redacted]

This is also summarised graphically below.

Figure 3-4 – [redacted]

[redacted]

3.2. Base year

SDP have proposed a mixed base year: using FY23 as the base year for O&M costs and insurance and FY22 for energy and corporate expenditure.

Our view is that it is preferable to use FY22 and to adjust for justified changes from that year. At the time of its submission, only two months of FY23 had elapsed meaning that that SDP's assumptions for O&M costs in FY23 were early year estimates presumably subject to change. Similarly, the largest insurance policy (ISR) is generally on a calendar year basis.

[redacted]

Table 3-3 - [redacted]

In some cases, we have chosen to use other time periods to assess the appropriateness of the proposed expenditure (e.g., use of a longer data set for power use). This is set out by cost type in the following sections.

3.3. Overview of forecast opex

SDP has proposed increases in opex in all areas (corporate, pipeline, fixed plant and variable) compared to the base year as summarised below.

Figure 3-5 – [redacted]

[redacted]

SDP has set out the key drivers for its proposed increase in operating expenditure in the next Determination period. They are addressed in this report as follows.

Table 3-4 – SDP's drivers for the forecast increase in opex

SDP driver for increase	Addressed in our report
Increasing fixed O&M costs, including labour and routine asset maintenance, to operate the Plant in a flexible manner and to maintain an ageing Plant	Section 3.3.1
Additional corporate costs to oversee the operation and maintenance of the Plant in line with the new Network Operator's Licence, customers' needs	Section 3.3.2
[redacted]	Part of Corporate opex examined in Section 3.3.2
Increasing insurance costs	Section 3.3.3
Chemicals and energy used to maintain state of readiness (rather than production)	Section 3.3.4 (non-energy variable costs) and Section 4 (energy)
Older average membrane age driving increased chemical usage and significant upward pressure on chemical supply costs	Section 3.3.4
Higher energy costs, also reflecting an older average membrane age which increases electricity consumption	Section 4

Source: drivers summarised from Page 128, SDP Pricing Submission, September 2022

We also summarise our own analysis of the largest (in $ terms) movements by cost category below.

Table 3-5 - Significant (non-energy) changes from FY22 to the next Determination period

Cost category	Change ($M p.a.)	As %	Comment
[redacted]	[redacted]		
[redacted]	[redacted]		
[redacted]	[redacted]		
[redacted]	[redacted]		
[redacted]	[redacted]		
[redacted]	[redacted]		
[redacted]	[redacted]		
[redacted]	[redacted]		

Source: AIRSIR . Note: only changes greater than $0.5M have been included in this Table. Next Determination period is based on the average of FY24 to FY27 inclusive

[6] See RFI 72

3.3.1. Fixed plant opex

This section addresses fixed plant opex including routine asset maintenance and labour costs.

In its submission and through the interview process, SDP has explained its view that fixed plant opex needs to increase to be able to operate the plant in a flexible manner and to maintain an ageing plant.

We consider that, taking account of the restart of the plant, the range of volumes produced since 2019 and the scale of investment in periodic maintenance foreseen, it is not clear that a further increase in fixed plant opex is justified. We recognise that SDP's operating role has changed significantly. However, we consider that the new operating environment is not, in its own right, likely to lead to a material increase in fixed opex requirements than the variable Emergency Response Notice conditions the Plant has been operating in for the last few years as summarised graphically below.

Figure 3-6 – [redacted]

[redacted]

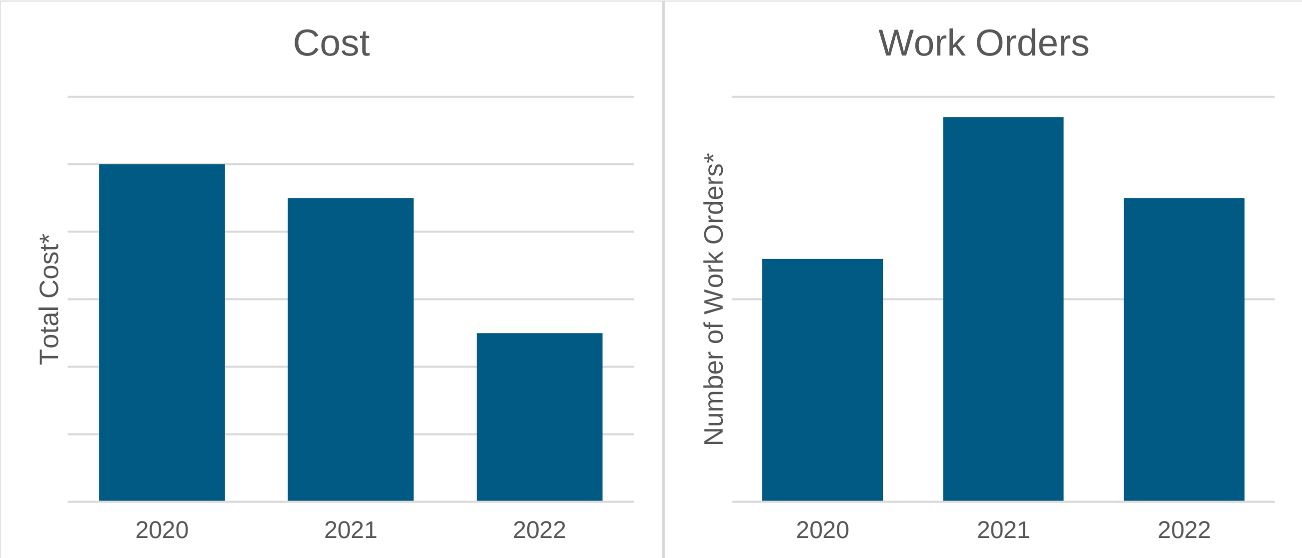
The coming into force of a structured process of annual, monthly and (by exception) 7-day production requests is likely to provide greater structure (and possibly certainty) than the ERNs the plant has been operating under since March 2020. We also do not see any indication that the plant will be more challenging to operate due to wear and ageing. The plant has not been used at full production for significant periods of time and a number of assets were replaced following the insurance-funded severe weather event reconstruction works. It may also be reasonable to assume that, having now operated the plant across a range of volumes for a number of years, SDP and Veolia have much more data and know the plant better and should be in a better position to optimise operations and make efficiencies rather than cost increases.

SDP has made the case that a number of costs were absorbed by the Operator in FY21 and FY22 with cost allowances for additional FTEs in place but not funded in these years and that future costs will therefore be higher than FY22[7]. However, it has not made a persuasive argument that commercial negotiations in the future would and should achieve a less efficient, higher cost, outcome than those in place for FY21 and FY22.

We consider that the explanations given for the proposed increase in routine asset maintenance (RAM) are not based on good industry practice such as analysis of assets' performance.

Indeed, analysis of work orders provided by SDP[8] suggests that repair maintenance costs, one of the best indicators of the sustainability of maintenance practices, have been on a reducing trend across the recent operating years from FY20 to FY22. The number of repair work orders and hours spent on them also reduced from FY21 to FY22, despite preventative work orders numbers being broadly the same and hours spend on preventative work orders reducing. These figures are not supportive of SDP's assertion that the plant has been run in an unsustainable manner[9]. A visual representation of the number of work orders and cost is shown below.

Figure 3-7 – Reactive (repair) work order trends in recent operating years



Source: SDP document "ATK-032 and ATK_033_IPART RFI 32 & 33 - Maintenance spend- RAM and PM"
*Cost and Number of work orders were extracted from a chart where no individual values for each year were provided

SDP's analysis indicates that reactive work orders are generally higher in number, hours and cost in FY20 to FY22 than in the preceding period from FY11. However, the preceding years were in a very different (largely non-operational) environment and, as noted by SDP, the change in computerized maintenance management system (CMMS) in 2018 may also affect the consistency of work order reporting.

Rather than looking at RAM in isolation, it is worth considering the combined expenditure on RAM and "labour and other fixed costs" given the possibility for interchangeability between the two categories. Whilst SDP spent more than the previous Determination assumption in FY20 and FY21 on RAM, it spent less than assumed on "labour and other fixed costs". Similarly, reductions in RAM from FY20 to FY22 were partially offset by increases in "labour and other fixed costs". This led to combined expenditure slightly above the Determination assumption in FY20 and FY21 but below it in FY22. It also highlights the scale of increase which SDP is proposing compared to recent actuals.

[7] SDP comments 13 February 2023
[8] SDP document "ATK-032 and ATK_033_IPART RFI 32 & 33 - Maintenance spend- RAM and PM"
[9] SDP comments 13 February 2023

Figure 3-8 – [redacted]

[redacted]

We acknowledge that assets will continue to age over the next period as indicated by recent trends in asset condition[10]. This is one of the reasons we have recommended a significant increase in periodic maintenance as set out in Section 5.2. Given this increase in periodic maintenance expenditure, we do not consider it likely that asset deterioration will significantly increase the level of routine asset maintenance required over the next Determination period.

[10] SDP document "ATK-032 SDP Asset Condition Trend 2014-2022 "

We set out below two potential approaches to setting recommended fixed plant opex.

Table 3-6 – Options for fixed plant expenditure including RAM

Approach	Average expenditure for FY24 to FY27 ($23)	Case for this approach
(1) Maintain base year level of expenditure + the increase in O&M insurance costs	[redacted]	SDP has not provided a robust empirical justification for the additional RAM and other fixed plant opex except for insurance. Trends in reactive repair activities and costs are not indicative of a plant operated in an unsustainable manner. We have recommended a significant increase in periodic maintenance (see Section 5) to combat the risks of asset failure and ageing.
(2) SDP proposal	[redacted]	There are not many years of operational data and some issues may take time to emerge. It provides SDP and the operator the benefit of the doubt in case their pricing submission accurately projects future expenditure.

Our view is that SDP has not made a robust justification for the proposed additional fixed plant opex relative to FY22. In our recommended opex figures we have therefore recommended maintaining pre-efficiency[11] fixed plant opex at the level of the most recent actuals i.e. FY22, except for SDP's proposed increase in O&M insurance which we have recommended accepting.

In order for us to recommend the second approach, with the increase in expenditure it entails, we would generally expect SDP to provide

- a clear empirically-based justification of the unsustainability of its current practices and
- a clear and evidence-based explanation of how the proposed higher level of activity and cost address the risks created by this unsustainability in an efficient and effective manner.

We would expect this evidence to be based on a hierarchy of (1) performance data specific to this plant wherever possible (2) data from other desalination plants where necessary and (3) data from non-desalination facilities used only where it is clearly relevant/not available at the SDP plant.

[11]'Pre-efficiency' means before the application of any catch-up or continuing efficiency

We summarise below the recommended fixed plant opex on the basis of approach (1) outlined above.

Figure 3-9 – [redacted]

[redacted]

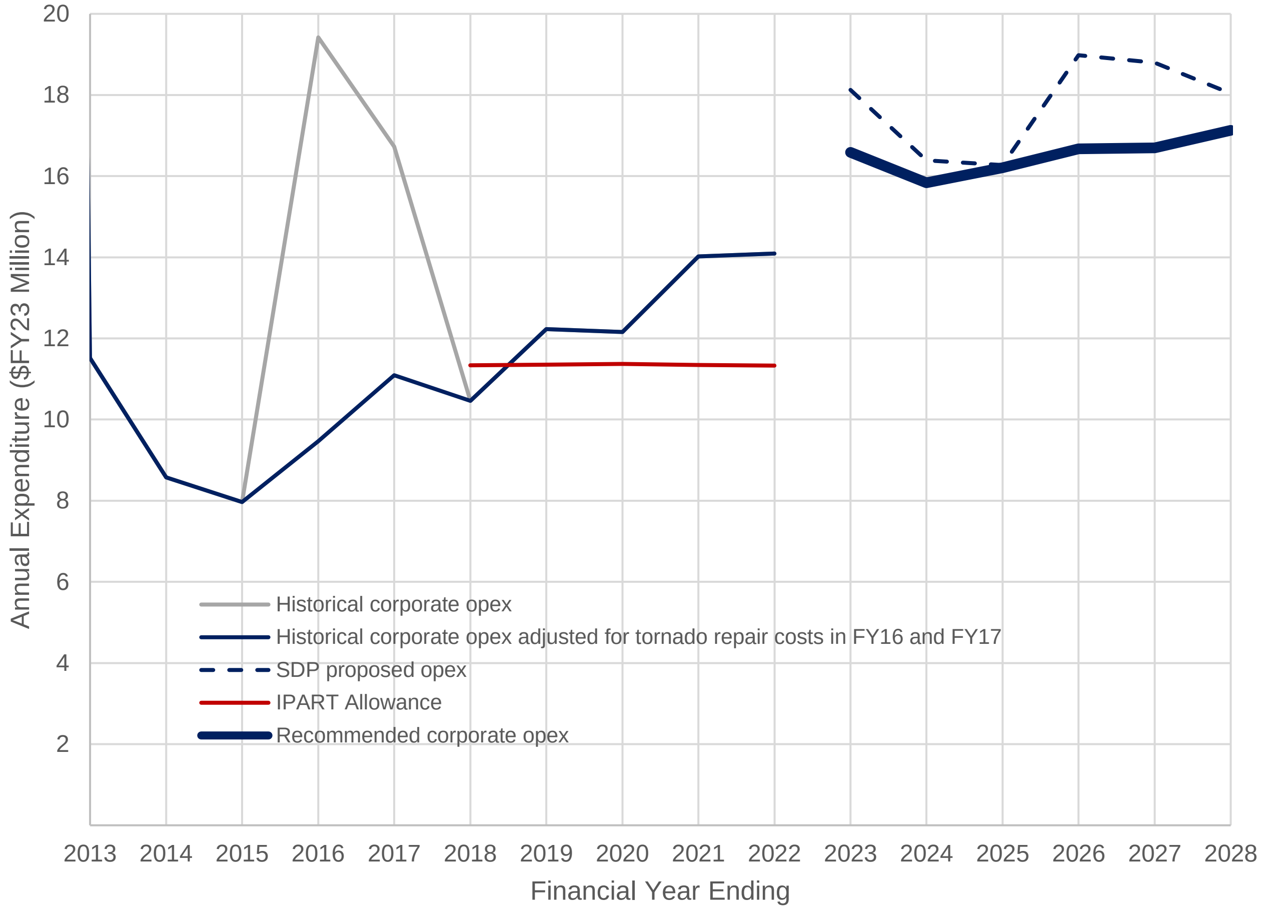
3.3.2. Corporate opex

This section addresses corporate opex including insurance, professional fees, land tax and council rates, and remuneration. After adjusting for the severe weather event repair costs in FY16 and FY17, it is clear that corporate opex has been on an increasing trend since FY15 as shown in Figure 3-10. SDP has assumed a significant step up from recent actuals in FY23 and for this new higher level of expenditure to be broadly maintained over the coming years.

In its submission SDP set out the reasons for the proposed increase:

> *Increasing corporate costs, including additional costs to oversee the prudent operation and maintenance of the Plant in line with our Network Operator's Licence, customers' needs and additional investment in* [redacted] *These costs are forecast to be incurred irrespective of the level of production given the need for the Plant to be able to respond in a timely and flexible way.*

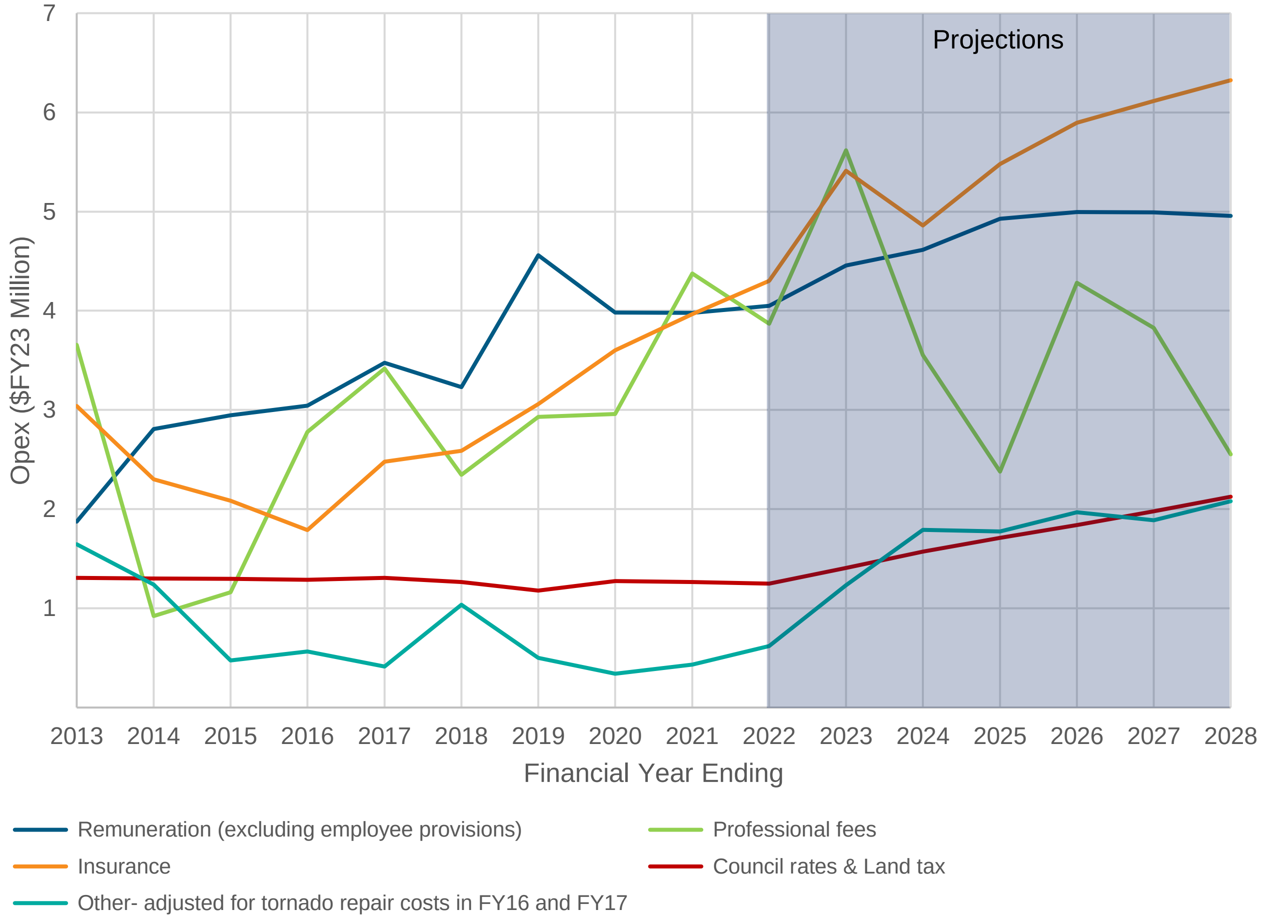
Figure 3-10 - Corporate opex ($FY23 Million)



Source: AIRSIR , IPART Determination and Atkins Final Report 2017

The trends in the make-up of corporate opex are summarised below.

Figure 3-11 – Breakdown of corporate opex ($FY23 Million)



Source: Analysis of SDP's AIRSIR , IPART Determination and Atkins Final Report 2017

SDP has provided an explanation for the increases in expenditure as summarised below. Insurance costs are discussed separately in Section 3.3.3 and not included in the table below.

Table 3-7 – SDP drivers for increase in corporate opex (excluding insurance)

Cost area and SDP explanation	Average impact on FY24 to FY27 ($M)	Our view
Remuneration costs —additional roles to efficiently manage oversight of the Plant. Increase average staffing levels from 10.5 FTEs in FY22 to 13 FTEs over the 2023-27 period to allow SDP to improve its risk management, sustainability objectives and operational processes. Also, real terms increase in remuneration rates related to a tight labour market and increases in statutory superannuation costs.	0.75 (of which approximately half relates to FTE increases)	SDP has explained that most of the FTE increase relates to two roles: • an operations and sustainability coordinator who will be responsible for the net zero strategy, corporate energy efficiency, chemical use and similar activities. The role is also expected to help with SDP's refinancing (sustainable finance options, maintaining the GRESB Score[12]) • a risk manager for business continuity planning and similar activities SDP has explained that the new role brings the work in house and has an offsetting saving in professional services. Our view is as follows: • the appointment of an operations and sustainability coordinator appears to be reasonable and will help to drive efficiency. We recommend accepting this increase. • The risk manager role should lead to an approximately equivalent reduction in professional services (see below) so should not lead to a net increase in corporate opex. We do not recommend accepting a net increase in corporate opex as a result of this. • We recommend accepting statutory increases in costs but have not been persuaded of the other 'real' cost increases in the absence of attrition data for example[13]. We recommend accepting half of the non-FTE growth element. This results in 50% of the increase proposed by SDP. High level benchmarking of SDP staffing levels is set out in the box below.

[12] GRESB, previously known as the Global Real Estate Sustainability Benchmark, is an organisation which provides ESG performance standards

[13] SDP has explained that an independent remuneration benchmarking review has been carried out which supports a real terms increase in salary levels. However, benchmarking reviews are challenging to carry out in a robust manner. The purpose of attrition data would be to (1) quantify the retention issues which we would expect to see in a company with pay significantly below market value and (2) where possible, to help to understand the reasons for retention issues (e.g. salary v other)

Cost area and SDP explanation	Average impact on FY24 to FY27 ($M)	Our view
Professional fees — *"during the 2017-23 regulatory period we obtained greater understanding of the efficient use of professional fees to manage the operation of the Plant. For example, we incurred additional pipeline-related professional fees that were not included in IPART's Allowance"* There are also several costs that are not incurred every year. We have included step changes for these costs in the year in which they will be incurred.	0.70	The emergence of professional fee costs during the current period is not in itself a justification for a further future increase. Many of the professional fees identified in SDP's Submission are ongoing rather than new requirements. We recognise that some costs are cyclical (e.g., preparation of the regulatory submission) so have recommended the average costs for FY18 to FY22 over the next period.
[redacted]	0.71	We recommend allowing an increase in expenditure as a genuine external and statutory change in operating context.
Other corporate costs — SDP is forecasting travel costs return to levels observed prior to the COVID-19 pandemic.	Not known but assumed <0.15	We note that total 'other' corporate opex was nearly twice the level in FY22 than in largely pre-pandemic FY20. This means that there is not a strong case that that step changes are required above FY22 spending because of Covid-driven low expenditure in FY22. However, recognising the shift in operational status we have recommended allowing for the increase in travel expenditure[14] due to the Covid conditions affecting travel expenditure in the base year.
Sustainability — SDP is proposing additional costs to implement new sustainability initiatives. It is pursuing a range of initiatives including feasibility assessments for carbon neutrality and net zero greenhouse gas emissions certification.	0.33	We consider that it is appropriate for SDP to move towards carbon neutrality and that offsetting of the remaining residual emissions (after implementation of all reasonable reduction measures) is reasonable. We have recommended allowing this increase which is based on a mid-range water production assumption and covers things like offsite chemical use.
Land tax and council rates — SDP proposes a step change based on the expected increase in underlying land valuation. It states that there is substantial uncertainty over the land valuation.	0.52	Land tax and council rates have not increased in real terms over the current period, with FY22 costs of $1.25M which is slightly below the FY14 to FY22 average. It is not clear to us that SDP has justified that costs will increase above historical rates in real terms. We have recommended maintaining the FY22 expenditure level plus the increase in land tax seen in FY23 as shared with us by SDP.

[14] A $66k increase from $33k to $100k based on SDP comments on Draft Report received 13 February 2023

Source: Section 9.7 and Appendix of SDP's Pricing Submission and interviews with SDP in November 2022. $ impact taken from Figure 9.6 of SDP's Pricing Submission, with the left most column understood to be FY22 not FY23 as per Table 9.2 and conversation with SDP on 30 November 2022

Benchmarking of corporate staffing levels

We have benchmarked SDP's staffing levels against a series of worldwide desalination plants currently in operation.

Staff levels benchmark

Project	Plants Capacity Mld	Staffing of Project Company
Sydney Desalination Plant	250	Increasing from 10.5 to 13 FTEs
Project 1	600 – 700	10-15
Project 2	550 - 650	10-15
Project 3	200 – 300	10-15
Project 4	400 – 500	10-15
Project 5	550 - 650	10-15

Source: Atkins own benchmark. Note: FTE for pipeline not shown

In addition to the staff directly employed by SDP, professional support services such legal, tax and IT are outsourced on as-need basis. This falls within our expectations for these types of organisations.

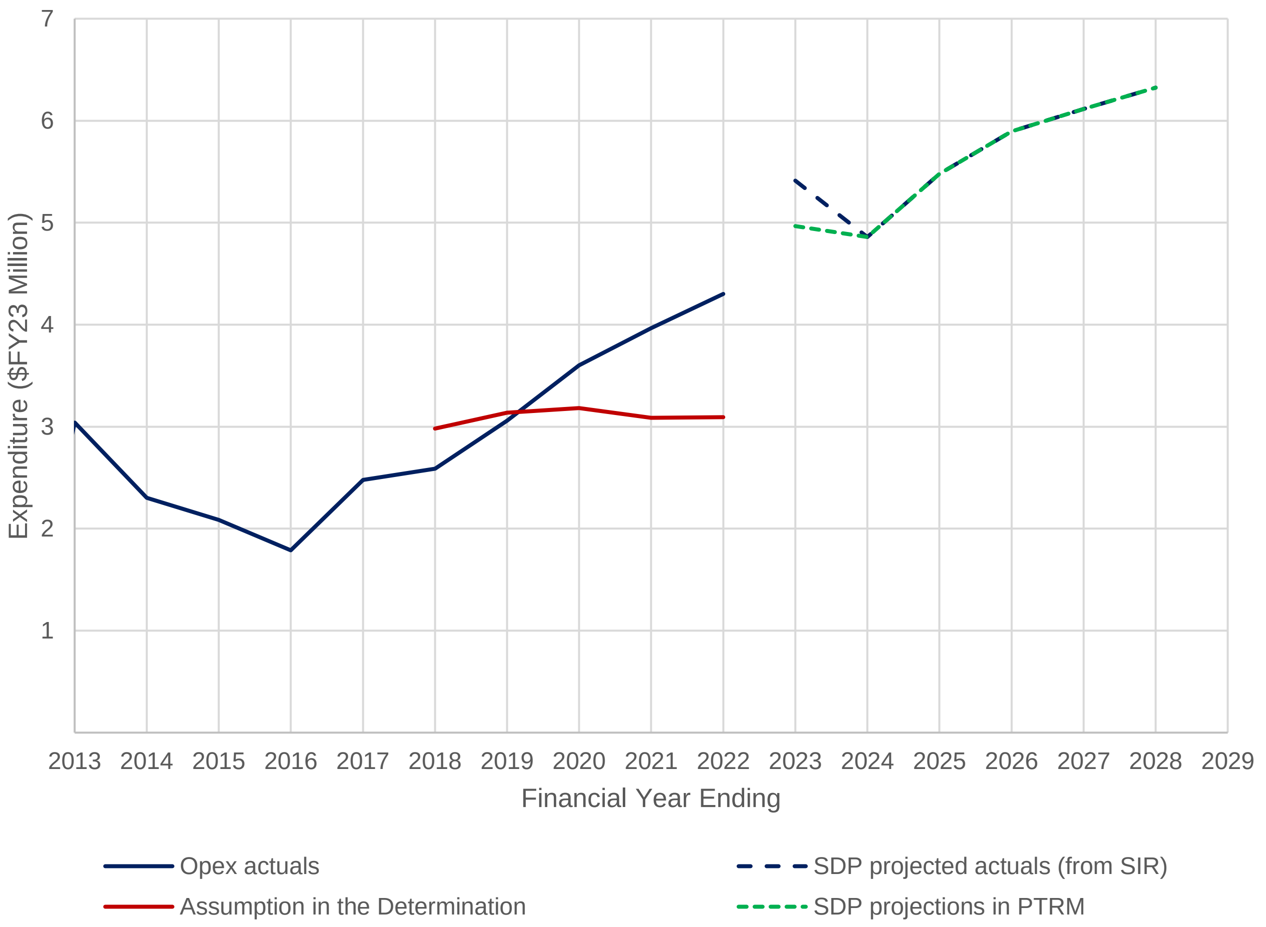
We consider the staffing levels of SDP to be within the expected range.

The net effect of these adjustments is summarised following the review of insurance costs.

3.3.3. Insurance

SDP has seen significant increases in corporate insurance expenditure since FY16. It projects these costs to continue increasing.

Figure 3-12 – Total insurance expenditure



Source: AIRSIR , IPART Determination and Atkins Final Report 2017
Note: the figure shown for FY23 is lower than shown in the PTRM and Aon's documents[15]

SDP has based its projections on work carried out by Aon[16]. Aon's forecast is based on expert views on likely market conditions and SDP's circumstances. It has prepared forecasts with and without SDP's proposed service level incentive scheme ("SLIS") limits applied. Aon separates the drivers for change into market driven increases and SDP exposure growth, with exposure growth being responsible for 92% of the increase[17]. Exposure growth relates to increases in asset values and Business Interruption risks with the plant being in operational model [redacted]

The trends in actual and proposed insurance expenditure are summarised graphically below. This highlights the predominance of ISR [redacted] driving the increases in assumed insurance costs.

[15] Table 1 of Aon's Sydney Desalination Plant – Premium Forecast (August 2022) quotes a figure of $4.97M consistent with the PTRM model
[16] Premium Cost Forecast- Sydney Desalination Plant Limited, Aon, August 2022
[17] Based on analysis of the figure on page 3 of Aon's forecast report

The trends in actual and proposed insurance expenditure are summarised graphically below. This highlights the predominance of ISR [redacted] in driving the increases in assumed insurance costs.

Figure 3-13 – [redacted]

[redacted]

We understand that the high ISR expenditure figure in FY23 is because of a top up of cover paid in October 2022 to correct an earlier error in only taking out three years of cover in June 2022[19]. We also note that expenditure projections from FY24 onwards are based on SDP's proposed SLIS rather than the current period abatement mechanism.

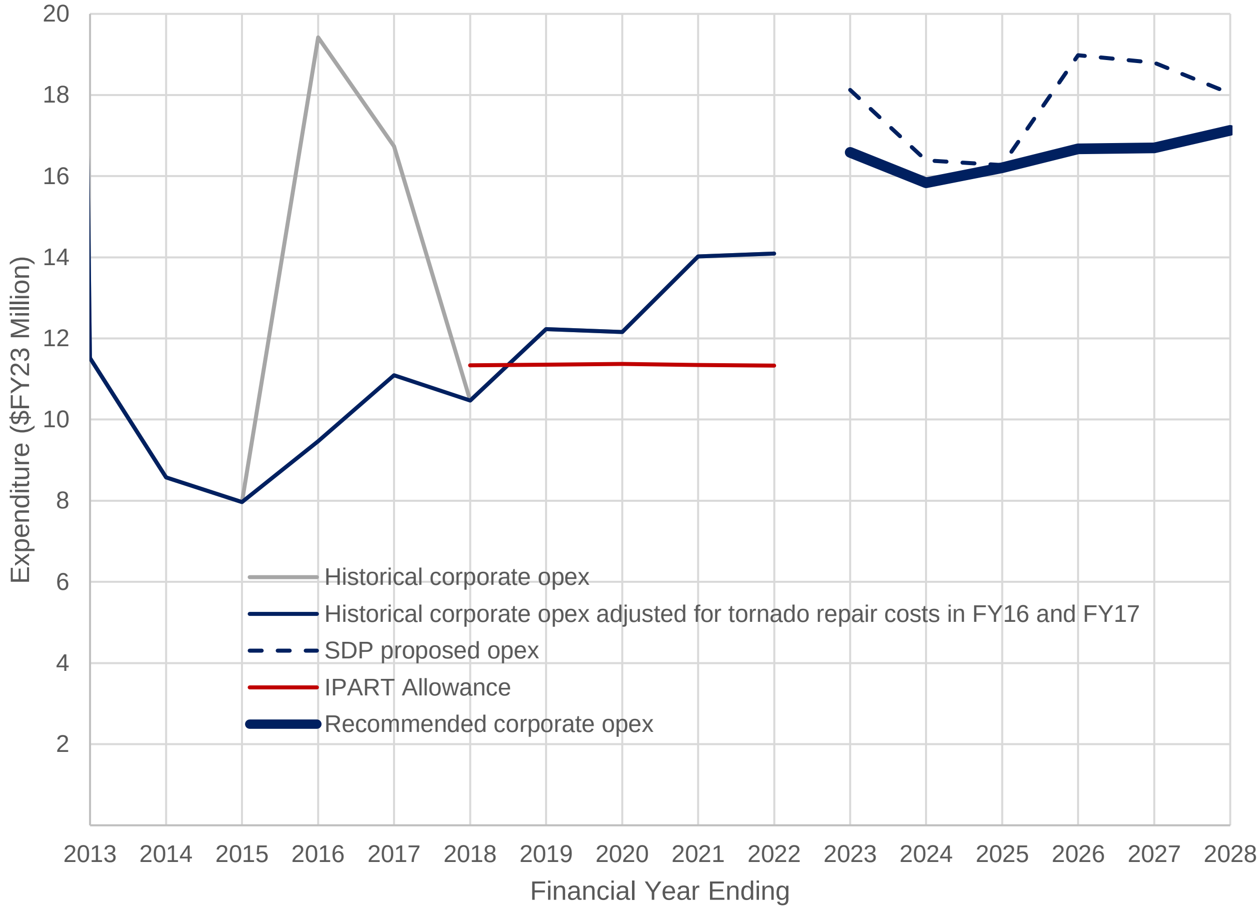
We summarise our view of SDP's proposed insurance expenditure by policy below. Figure 3-14 below presents our recommended insurance and non-insurance corporate expenditure.

[18] NB: projections matches the totals in the SIR, actuals are close to the AIR figures. The FY23 figure shown is consistent with Table 9-13 of the submission and the PTRM

[19] SDP response to RFI778

We summarise our view of SDP's proposed insurance expenditure by policy below. Figure 3-14 below presents our recommended corporate expenditure taking account of the recommended insurance adjustments.

Figure 3-14 – Recommended corporate opex including insurance



Source: Analysis of AIRSIR
Note 1: the recommended expenditure in this graph incorporates scope adjustments, not any catch-up or continuing efficiency discussed below.
Note 2: these projections are based on SDP's proposed SLIS

Table 3-8 Our view of SDP's proposed insurance policy expenditure

Policy	Change within current period (FY18 to FY22)		FY22 expenditure $FY23 M p.a.	Change from FY22 to next period (FY24 to FY27)		SDP/Aon explanation	Our view
	$FY23 M p.a.	%		$FY23 M p.a.	%		
Industrial Special Risks ("ISR")	+1.4	63%	3.5	+ 0.3	9%	Growth in SDP declared asset values and higher Business Interruption values with the plant being in operational mode Change in limit from $300M to $600M because of sustaining Operational mode throughout the forecasted period will require premiums costed for $600M The new limit change has been in place since 2019. However, all years in the forecast period are assumed to have premiums based on $600M limit, representing an increase over the current period	We consider it is reasonable and efficient for SDP to have ISR coverage and for this to have increased as result of the shift to operational status. We also think it is reasonable to assume real price increases due to market conditions based on publicly available data as well as Aon's forecasts. The level of ISR coverage and therefore cost will depend on the design of any abatement or incentive mechanism. We have recommended accepting SDP's proposed expenditure as the best estimate for future premiums.
[redacted]	[redacted]	[redacted]	[redacted]	+0.7	n/a	[redacted]	[redacted]

							[redacted] [redacted]
Liability	+0.3	215%	0.5	+0.1	24%	Increased because of the shift to operational mode and market factors (capacity reductions and impacts of Covid)	We recommend accepting this as it is primarily due to the shift to operational status and market factors
[redacted]	[redacted]	[redacted]	[redacted]	+0.1	n/a	One of the two new policies [redacted] recommended as part of Aon's risk profile and gap analysis.	We recommend accepting this increase as it is a minor cost and covers one of the identified insurance gaps.
Miscellaneous (All Other) Including broker fee	0.0	7%	0.3	+0.1	41%		We understand this is governed largely by the total insurance costs and recommend accepting it.
Environmental Liability	0.0	69%	0.0	0.0	-2%		Negligible change.
Total	+1.7	66%	4.3	+1.3	30%		

Source: Aon documents provided by SDP

[redacted]

3.3.4. Variable costs

SDP's variable costs are made up of two categories:

- Chemical variable costs (CVC)- dosed as part of the functioning of the plant
- Other variable costs (OVC)- for the disposal of ferric and lime sludge, and the cost of cartridge filters

SDP has proposed a significant increase in variable expenditure, with an especially large (37%) step up from FY23 to FY24 followed by a gradual decline due to SDP's proposed 0.3% p.a. continuing efficiency challenge starting from FY25.

Table 3-9 Historical and projected variable costs ($FY23)

	Actuals				Projections					
FY ending	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Variable costs ($FY23 '000s)	[redacted]									
Production (Ml p.a.)										
Average variable cost ($FY23/Ml)										
Year-on-year change										

Source: Analysis of AIRSIR and volumes in SDP document "ATK-001_1 Jul 2017 to 31 Oct 2022 Energy and Production Data Rev 2"

Figure 3-15 - [redacted]

[redacted]

SDP has provided a breakdown of its proposed variable opex, which is made up of [redacted] of CVC and [redacted] of OVC in FY24. However, SDP does not track OVC costs separately from total variable costs. As such it was not possible to provide a like for like timeseries of OVC and CVC expenditure.

SDP has based its CVC on an assessment of dosing rates (incorporating weighted min., max., and average scenarios), chemical price and process flow assumptions including factors such as backwash frequency. SDP has made the case that chemical prices have increased beyond CPI and that is has limited ability to influence these prices.

SDP has derived its OVC projections based on a bottom-up assessment of each sub-component, which it has benchmarked against a bottom-up assessment it commissioned from Emerald Process Engineering.

We present below our view against SDP's summarised drivers for the increases in variable costs.

Table 3-10 – SDP drivers for increase in variable costs

SDP explanation	Our view
Material upward movement (above CPI) of the efficient costs of chemicals (CVC impact),	We recognise that the chemical price index has increased above CPI and this is likely to have affected expenditure. However, a cost having increased above CPI in the past is not in itself an indication that it will do so in the future. It is particularly unclear why this would lead to a very significant step change between FY23 and FY24 specifically. The higher costs are already included in actual expenditure. Indeed, SDP states that its chemical costs increased by over 30% since FY20. As such we have not recommended a step change for this reason.
Projected and proposed increases in chemical usage above actuals due to membrane age effects e.g. sodium hydroxide dosing for part of the year when seawater temperature is highest, and increased frequency of membrane chemical cleaning (CVC impact)	We consider that there is a case for an allowance for the impacts of membrane ageing (noting however, that we have recommended a program of membrane replacement). We have recommended accepting an increase of $10/Ml due to membrane ageing phased in equal steps from FY24 to FY27.
Addition of costs for lime sludge disposal, noting that no allowance was made for lime disposal in the 2017 Determination as lime was beneficially reused in 2010-2012. Lime is still disposed of in a beneficial manner reducing disposal cost, but costs are still incurred (OVC impact)	SDP states that the lime is already being disposed of and costs incurred, meaning that these costs are already incorporated in actual expenditure. This appears to be an explanation for variance from the 2017 Determination *allowance* rather that a justification for a step change in *expenditure*. As such we have not recommended a step change for this reason.
Miscellaneous adjustments to OVC based on sludge dryness, disposal costs, cartridge filter usage etc (OVC impact)	It is not clear why this would lead to a step change from FY22 and FY23 to FY24.

Source: SDP summary provided by email correspondence 1 March 2023

On a more general note, we consider that bottom-up assessments are not a strong basis for a significant increase from outturn costs unless supported by rigorous top-down assessment and variance analysis. It is also not clear why the major step-up would come into effect with such striking effect in FY24 specifically.

Our review of SDP's chemical dosing assumptions has identified a number of areas where efficiencies may be possible. We have not incorporated these here as we consider they are not scope changes as such and will be captured through the catch-up efficiency challenge.

We have therefore recommended maintaining pre-efficiency variable costs at the FY22 level with an allowance for membrane ageing at a phased increase of $10/Ml by FY27.

Figure 3-16 – [redacted]

[redacted]

3.3.4.1. Variable costs in Non-Production Mode

In a non-production mode (i.e., no water supplied to Sydney Water but the Plant being available to supply water within a day or two's notice) the Plant will require "variable" costs to keep things like the dual media filtration pre-treatment in operation and to produce first pass permeate for flushing of the RO membranes every two days.

Rather than attempt a bottom-up analysis of the mainly variable activities which need to be maintained in periods of non-production, we have estimated the total costs in non-production mode based on the variable costs incurred in FY19 when SDP produced only 7.8Gl p.a, suggesting a variable treatment cost of [redacted] p.a. We recognise that the costs of chemical purchase have increased during the intervening period. However, this is counterbalanced by the fact that water was actually produced during the period. We consider it would be unlikely to be possible to reduce the variable costs significantly below this level whilst keeping the plant available to supply water with a day or two's notice.

3.3.5. Efficient FY2023 Opex

The aim of this section is to provide an indicative estimate of the likely efficient level of opex in FY23.

To derive this estimate we have applied the same reasoning as set out in the rest of Section 3.3. We have not applied efficiency challenges as we recommend applying these from FY24 as discussed in Section 3.4 below.

Table 3-11 and Table 3-12 below summarise indicative fixed and variable opex for FY2023. The variable opex is based on a continuation of the average production in the period for which production data are available (1 July 2022 to 31 October 2022) i.e. 232Mld or 85 Gl p.a.

We recommend limited reliance on these figures as they do not take account of any year specific atypical expenditure and are based on estimated production only.

Table 3-11 – Indicative efficient FY2023 fixed opex ($FY23 000's)

	FY2022 (latest actuals)	Indicative efficient FY2023	Note
Corporate			
Remuneration (excluding employee provisions)	4,051	4,319	Includes half SDP's proposed increase from FY22, see Table 3-7
Professional fees	3,868	3,296	FY18 to FY22 average (smoothing of price submission preparation costs)
Insurance	4,302	4,968	Table 2, Aon Forecast Report
Council rates & Land tax	1,250	1,446	FY22 actuals plus the increase in land tax seen in FY23
Other	620	2,560	FY22 actuals plus SDP proposed [redacted] opex (pre-efficiency) from PTRM model
Corporate total	14,091	16,589	Sum of the above
Adjustment to SDP proposal		(1,537)	
Pipeline			
Routine asset maintenance	[redacted]	[redacted]	Recommended accepting SDP's proposed increase[20]
Labour and other fixed costs	[redacted]	[redacted]	Moved to RAM above to align with SDP projections
Professional fees	[redacted]	[redacted]	
Other	[redacted]	[redacted]	
Pipeline total	[redacted]	[redacted]	Sum of the above
Adjustment to SDP proposal	[redacted]	[redacted]	
Plant fixed	[redacted]	[redacted]	
Routine asset maintenance	[redacted]	[redacted]	FY22 actuals including DWPS charges (reported in this line by SDP in its projections)
DWPS charges (excluding insurance)	[redacted]	[redacted]	Included in line above
Standby charges	[redacted]	[redacted]	
Labour and other fixed costs	[redacted]	[redacted]	FY22 actuals
Insurance - O&M	[redacted]	[redacted]	SDP proposed
Restart charges- O&M	[redacted]	[redacted]	FY22 actuals
Other	[redacted]	[redacted]	FY22 actuals
Veolia efficiency saving	[redacted]	[redacted]	Set to zero
Plant fixed total	[redacted]	[redacted]	Sum of the above
Adjustment to SDP proposal	[redacted]	[redacted]	
TOTAL	**31,695**	**34,456**	

Analysis of SDP's AIRSIR

[20] SDP has explained that the key driver for the proposed increase in O&M for the Pipeline is an increase in Routine Asset Maintenance and that this is based on a revised preventative maintenance program identified, following a detailed condition assessment of the Pipeline which culminated in the 2020 Pipeline Asset Management Plan (PAMP). We challenged why the increase was only projected from FY23 onwards given that the PAMP has been in place since June 2020. In RFIs 124 and 125 SDP was able to explain that it is only being increased once certain key renewals have been completed. This appears reasonable to us and we have recommending SDP's proposed increase due to the criticality of the pipeline.

Table 3-12 - Indicative efficient FY23 variable opex ($FY23 000's)

	Indicative efficient FY23	Note
Variable costs	[redacted]	[redacted]

Analysis of SDP's AIRSIR
Assumes continuation of the average production in the period for which production data are available (1 July 2022 to 31 October 2022) i.e. 232Mld or 85 Gl p.a.

Estimated cost for shutdown

IPART requested that we provide an overview of a best estimate for efficient costs in case of an agreed shutdown between SDP and SWC.

If there is a shutdown, two factors are likely to have a significant effect on potential fixed opex savings: i) length of the shutdown and ii) certainty of timing. We consider that opex savings from shutdown are only likely to be material if the shutdown is both certain (pre-arranged start and end dates) and long enough. We do not envisage that significant savings will be achieved if the shutdown lasts only a few months as SDP and the operator will need to retain their workforce and equipment in good operational state. As a rough indication, it seems likely that SDP would only see meaningful fixed opex savings if the shutdown is pre-agreed and lasts for more than approximately six months.

3.4. Opportunities for operating efficiency

The adjustments set out above are 'scope adjustments' reflecting our view of SDP's proposed changes in activities and costs. The recommended expenditure in Section 3.3 is all on a 'pre-efficiency' basis i.e. excluding the effect of efficiency challenges by either SDP or ourselves. The way in which we have ensured no efficiency challenge has been incorporated is summarised by different cost area in Table 3-13 below.

We consider there is scope for SDP to achieve catch-up and continuing efficiency. In its submission, SDP has incorporated a "continuing efficiency factor" of 0.3% p.a. from FY24 for controllable corporate costs and FY25 for O&M costs. SDP has explained that the O&M efficiency starts in FY25 to allow a year to adjust to the new operating rules. It has excluded costs such as insurance, council rates and land tax from its efficiency challenge.

Catch-up and continuing efficiencies have been applied to our recommended pre-efficiency expenditures after the scope adjustments set out above. The approach taken to ensure that the efficiency challenge has been applied correctly without double-counting SDP's proposed efficiency is summarised as follows:

Table 3-13 - Approach taken to ensure there is no double-counting of SDP's proposed efficiency challenge

Cost area	Approach taken to SDP's proposed efficiency	Basis of our recommendations in Section 3.3
Corporate opex- professional fees and others not listed below Plant fixed opex (excluding O&M insurance addressed below) Variable opex	No adjustment required as we have based our recommendation on historical expenditure and a number of pre-efficiency adjustments which don't incorporate SDP's proposed 0.3% efficiency challenge.	Pre-efficiency
Pipeline opex	We have used SDP's proposed pre-efficiency expenditure from the PTRM model	Pre-efficiency
Corporate- remuneration and 'other'	No adjustment required as we have based our recommendation on historical expenditure plus a part of the pre-efficiency increment set out in SDP's PTRM model	Pre-efficiency
Corporate opex- insurance	No adjustment required as our recommendation is based on Aon's	Pre-efficiency

	projections and SDP has not applied efficiency challenge to these costs	
Corporate opex- council rates & land tax	No adjustment required as SDP has not applied efficiency to this component	Pre-efficiency
O&M insurance	No adjustment required as SDP has not applied efficiency to this component	Pre-efficiency

Source: Consultant's analysis

Our view on the scale of efficiency opportunities is set out below.

3.4.1. Catch-up efficiency

We consider there is reasonable additional efficiency to be gained through optimisation of the plant operations now that data are available and through rigorous focus on efficiency and cost management.

Catch-up efficiency is what we consider is required to achieve the performance of a Frontier Company. We have sought to benchmark SDP performance against other desalination SPVs and utilities, but the specific nature of SDP's business does not allow us to benchmark with confidence.

Our view of catch-up efficiency is driven mainly by the scope for efficiencies in the following areas:

- Operating efficiency: having operated the plant across a range of volumes for a number of years, SDP and Veolia should now be in a better position to optimise operations and make efficiencies;
- Energy audits: SDP has not yet carried out initiatives such as energy audits which would be expected to identify savings;
- Efficiency plans: we have seen limited evidence of or detailed plans for efficiency improvements suggesting that there may be significant 'low hanging fruit' for efficiency with increased management focus; and
- Enabling efficiency: we have recommended additional expenditure for a new operations and sustainability coordinator and spend-to-save capex which should help to enable significant efficiencies.

We have proposed a catch-up efficiency challenge of 0.5% p.a. cumulating annually. We consider this to be achievable (i) now that SDP and Veolia have the benefit of the plant having been in operation for a number of years (ii) given the opportunities for efficiency set out above and (iii) our view of SDP's efficiency maturity compared to other sector organisations, noting that this degree of efficiency challenge is at the lower to mid-range of challenges set, as can be seen in the table below.

Table 3-14 - Operating expenditure: Catch-up efficiency in previous Determinations (annual NOT cumulative)

Utility % in year (not cumulative)	Start year	Year 1	Year 2	Year 3	Year 4	Comments
Sydney Water	2012	1.50	2.00	2.00	2.00	
Hunter Water	2016	0.25	0.25	0.25	0.25	
Sydney Water	2016	0.50	0.75	2.00	2.00	
Sydney Water	2020	0.00	0.00	0.00	0.00	Efficiencies included in submission
WaterNSW-Greater Sydney	2020	0.9	0.9	0.9	0.9	

Source: Previous Determinations

We have applied this challenge from FY24 onwards as the plant has been operating in a flexible way since early 2020, giving more than sufficient time to identify and prepare for implementation of improvements.

The efficiencies above are generally organisation or Determination level. The scope for efficiencies should be considered in all activities within the business; hence the catch-up efficiency should be applied across all expenditure. However, we have not recommended applying any catch-up efficiency to variable costs as we consider that our recommendations would take SDP to the efficient frontier for these costs.

3.4.2. Continuing efficiency

We have applied continuing efficiency as set out in Section 1.4.2. As with catch-up efficiency, we have applied this challenge in a cumulative way from FY24 onwards.

3.5. Recommended future opex

3.5.1. Fixed opex

Table 3-15 summarises the recommended fixed 'pre-efficiency' operating expenditure taking account of the scope adjustments set out above. Catch-up and continuing efficiency are then applied as summarised in Table 3-16 to derive the efficient operating expenditure for the next Determination period.

Table 3-15 - Recommended 'pre-efficiency' fixed opex expenditure taking account of the recommended scope adjustments ($FY23 000's)

	2022 (latest actuals)	2024	2025	2026	2027	2028
Corporate						
Remuneration (excluding employee provisions)	4,051	4,440	4,662	4,662	4,662	4,662
Professional fees	3,868	3,296	3,296	3,296	3,296	3,296
Insurance	4,302	4,860	5,155	5,416	5,656	5,885
Council rates & Land tax	1,250	1,446	1,446	1,446	1,446	1,446
Other	620	1,794	1,648	1,849	1,638	1,840
Corporate total	**14,091**	**15,836**	**16,208**	**16,669**	**16,699**	**17,129**
Adjustment to SDP proposal		*(555)*	*(65)*	*(2,311)*	*(2,099)*	*(911)*
Pipeline	-	-	-	-	-	-
Routine asset maintenance	[redacted]					
Labour and other fixed costs	[redacted]					
Professional fees	[redacted]					
Other	[redacted]					
Pipeline total	**174**	**516**	**487**	**487**	**487**	**487**
Adjustment to SDP proposal	-	-	*1*	*3*	*4*	*6*
Plant fixed	[redacted]					
Routine asset maintenance	[redacted]					
DWPS charges (excluding insurance)	[redacted]					
Standby charges	[redacted]					
Labour and other fixed costs	[redacted]					
Insurance - O&M	[redacted]					
Restart charges- O&M	[redacted]					
Other	[redacted]					
Veolia efficiency saving	[redacted]					
Plant fixed total	**17,430**	**17,491**	**17,548**	**17,577**	**17,592**	**17,594**
Adjustment to SDP proposal		*(3,734)*	*(4,249)*	*(5,518)*	*(3,100)*	*(5,767)*
TOTAL	**31,695**	**33,843**	**34,243**	**34,734**	**34,778**	**35,210**

Analysis of SDP's AIRSIR
Note: these figures do not take account of the catch-up and continuing efficiency, set out below.

Note 2: "adjustment to SDP proposal" includes the adjustment from post-efficiency to pre-efficiency where appropriate i.e. where we have recommended accepting SDP's proposed expenditure and SDP have incorporated efficiency to that cost line as set out in Table 3-13 above. This is why there is a positive adjustment to pipeline opex.

Table 3-16 - Recommended efficient fixed opex (after catch-up and continuing efficiencies) ($FY23 000's)

	2024	2025	2026	2027	2028
SDP Proposal					
Corporate	16,392	16,273	18,980	18,798	18,039
Pipeline	516	485	484	482	481
Plant fixed	21,224	21,798	23,096	20,693	23,361
Adjustment					
Corporate	(555)	(65)	(2,311)	(2,099)	(911)
Pipeline	-	1	3	4	6
Plant fixed	(3,734)	(4,249)	(5,518)	(3,100)	(5,767)
Pre-efficiency recommendations					
Corporate	15,836	16,208	16,669	16,699	17,129
Pipeline	516	487	487	487	487
Plant fixed	17,491	17,548	17,577	17,592	17,594
Efficiency adjustment					
Catch-up efficiency (%)	0.50%	1.00%	1.49%	1.99%	2.48%
Catch-up efficiency ($)	(169)	(342)	(518)	(690)	(871)
Continuing efficiency (%)-	0.70%	1.40%	2.09%	2.77%	3.45%
Continuing efficiency ($)-	(236)	(473)	(714)	(944)	(1,185)
Recommended opex (post-efficiency)					
Corporate	**15,647**	**15,822**	**16,078**	**15,914**	**16,128**
Pipeline	**509**	**475**	**470**	**464**	**458**
Plant fixed	**17,281**	**17,131**	**16,954**	**16,765**	**16,566**

Source: Analysis of SDP's AIRSIR

Note 2: "adjustment" includes the adjustment from post-efficiency to pre-efficiency where appropriate i.e. where we have recommended accepting SDP's proposed expenditure and SDP have incorporated efficiency to that cost line as set out in Table 3-13 above. This is why there is a positive adjustment to pipeline opex.

Figure 3-17 - [redacted]

[redacted]

3.5.2. Variable opex (excluding energy)

Recommended efficient variable opex is summarised in Table 3-17 and Table 3-18 below. It is important to note that the recommended zero production figures are based on the costs of keeping the plant in a state of readiness to produce and do not represent the costs of a sustained shutdown.

Table 3-17 - Recommended efficient variable opex (after catch-up and continuing efficiency)

FY$23 $/Ml	2024	2025	2026	2027	2028
SDP Proposal					
Total variable cost $/Ml	219.75	219.09	218.43	217.78	217.12
Adjustment					
Total variable cost $/Ml	(62.41)	(59.25)	(56.10)	(52.94)	(52.29)
Pre-efficiency recommendations					
Total variable cost $/Ml	157.34	159.84	162.34	164.84	164.84
Efficiency adjustment					
Catch-up efficiency (%)	0.00%	0.00%	0.00%	0.00%	0.00%
Catch-up efficiency ($/Ml)	-	-	-	-	-
Continuing efficiency (%)-	0.70%	1.40%	2.09%	2.77%	3.45%
Continuing efficiency ($/Ml)-	(1.10)	(2.23)	(3.39)	(4.57)	(5.69)
Recommended (post-efficiency) opex					
Total variable cost $/Ml	**156.24**	**157.61**	**158.95**	**160.27**	**159.15**

Source: Analysis of SDP's AIRSIR

Table 3-18 - Recommended efficient variable opex by production level (after catch-up and continuing efficiency) ($FY23 '000s)

	2024	2025	2026	2027	2028
SDP Proposal					
Average production (Mld)					
0	-	-	-	-	-
50	4,021	3,998	3,986	3,974	3,973
125	10,054	9,996	9,966	9,936	9,933
250	20,107	19,992	19,932	19,872	19,867
Adjustment					
Average production (Mld)					
0	709	709	709	709	709
50	(1,162)	(1,122)	(1,086)	(1,050)	(1,061)
125	(2,906)	(2,805)	(2,714)	(2,624)	(2,652)
250	(5,812)	(5,610)	(5,428)	(5,248)	(5,305)
Recommended (post-efficiency) opex					
Average production (Mld)					
0	**709**	**709**	**709**	**709**	**709**
50	**2,859**	**2,876**	**2,901**	**2,925**	**2,912**
125	**7,148**	**7,191**	**7,252**	**7,312**	**7,281**
250	**14,296**	**14,382**	**14,504**	**14,625**	**14,562**

Analysis of SDP's AIRSIR
Note: the SDP proposal figures are inferred from SDP's proposed unit cost applied as they are not available in this form.
Note 2: there are 366 days in FY24 and FY28

3.5.3. Total opex (excluding energy)

Bringing together the variable and fixed opex, SDP has proposed a 30% real terms average increase in opex at full production. This is made up of a 26% increase in fixed opex and 41% increase in variable opex.

We have recommended an average 4% real terms increase in opex at full production. This is made up of a 5% increase in fixed costs and 2% increase in variable opex.

The proposed and recommended combined fixed and variable opex are summarised below.

Table 3-19 - Recommended efficient combined fixed and variable opex by production level (after catch-up and continuing efficiency) ($FY23 '000s)

	2022 actuals	2024	2025	2026	2027	2028
SDP Proposal						
Average production (Mld)						
0	31,695	38,132	38,555	42,560	39,973	41,881
50	34,521	42,153	42,554	46,547	43,948	45,855
125	38,760	48,185	48,551	52,526	49,909	51,815
250	45,824	58,239	58,547	62,492	59,846	61,748
Adjustment						
Average production (Mld)						
0		(3,985)	(4,418)	(8,349)	(6,121)	(8,019)
50		(5,856)	(6,249)	(10,144)	(7,879)	(9,789)
125		(7,600)	(7,932)	(11,772)	(9,454)	(11,381)
250		(10,506)	(10,737)	(14,486)	(12,077)	(14,033)
Recommended (post-efficiency) opex						
Average production (Mld)						
0		**34,147**	**34,137**	**34,211**	**33,853**	**33,862**
50		**36,297**	**36,305**	**36,403**	**36,068**	**36,065**
125		**40,586**	**40,619**	**40,754**	**40,456**	**40,434**
250		**47,733**	**47,810**	**48,006**	**47,768**	**47,715**

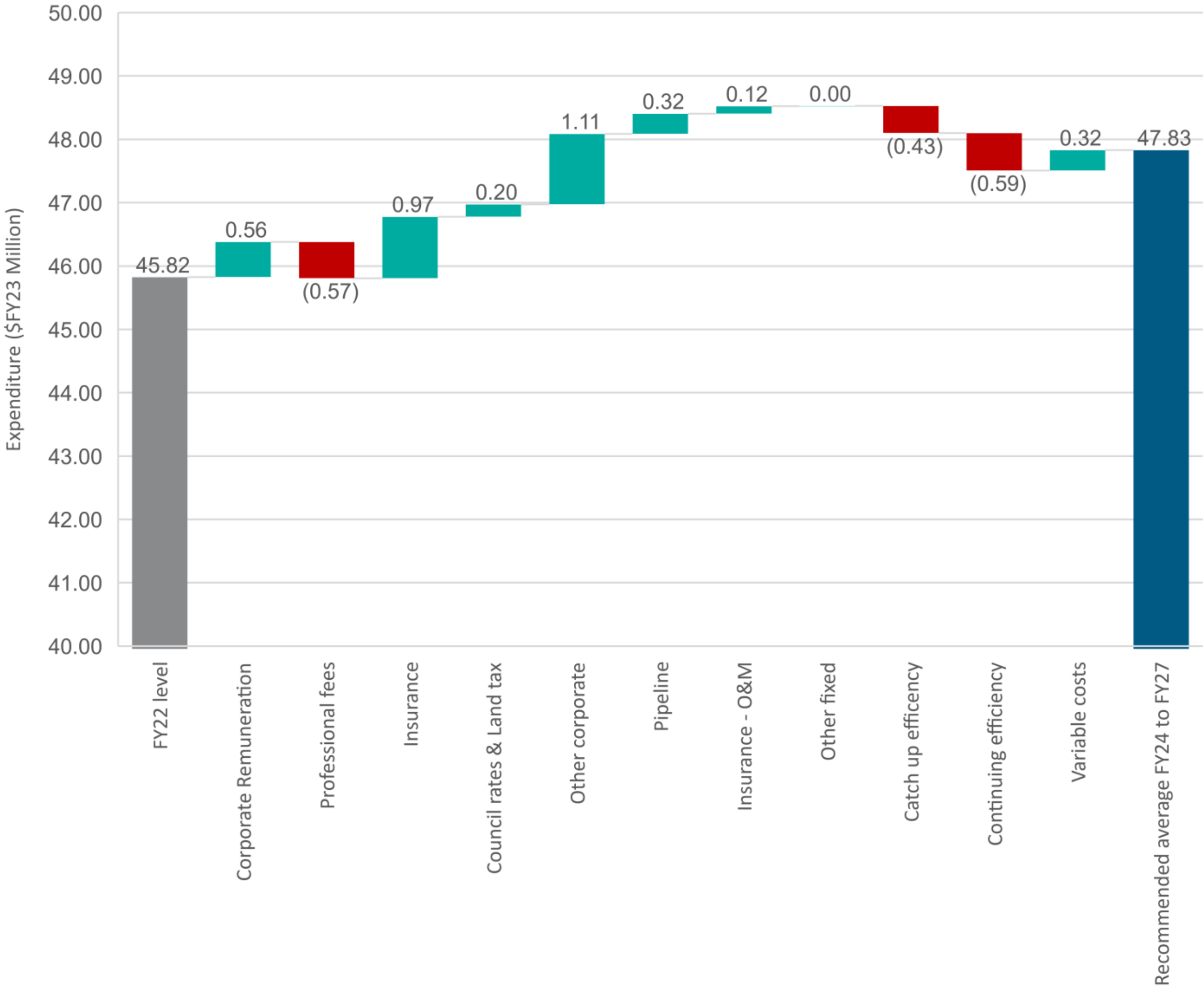
Analysis of SDP's AIRSIR
Note: variable costs have been pro-rated for FY22

Figure 3-18 - [redacted]

[redacted]

We also present a summary of our recommended opex compared to the FY22 base year in a 'waterfall' format below.

Figure 3-19 – Drivers for the variance between the FY22 actuals and average recommended opex ($FY23 Million)



Analysis of SDP's AIRSIR

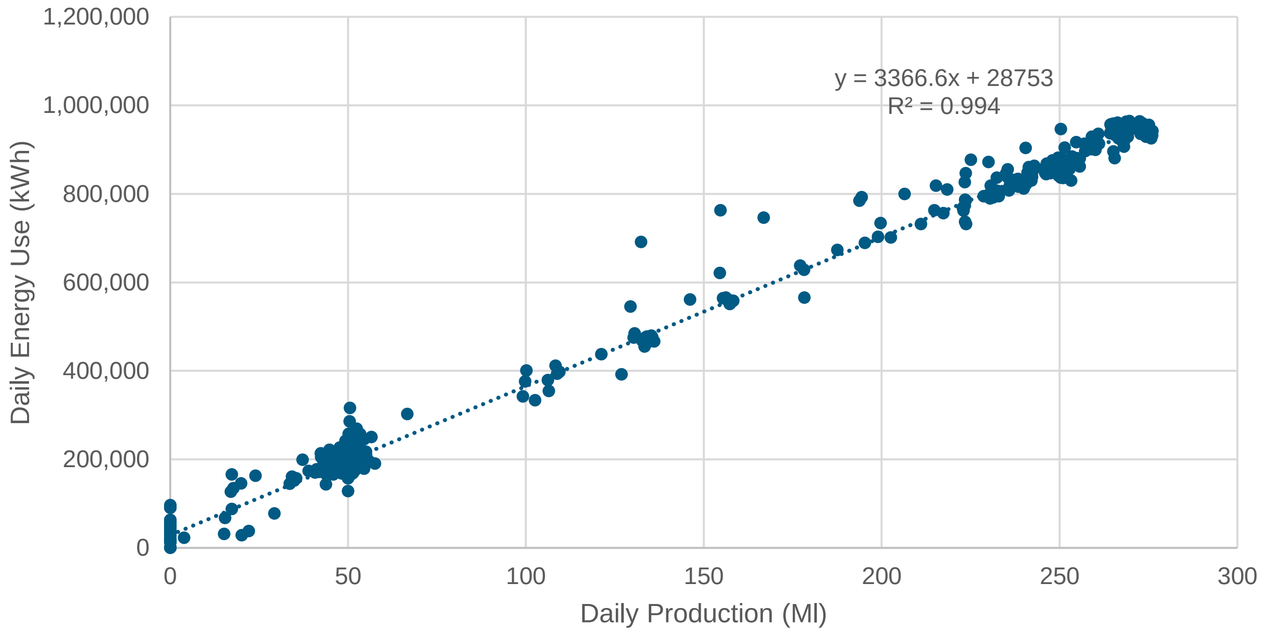
4. Energy

4.1. Energy consumption

4.1.1. Historical consumption

Figure 4-1 presents the daily power consumption of the SDP facility against the product water volume delivered for the period between 01 January 2020 and 31 October 2022. This period is representative of recent performance since the replacement of the membranes in 2019.

Figure 4-1 – Relationship between power use and water production



Source: ATK-001_1 Jul 2017 to 31 Oct 2022 Energy and Production Data

The best fit curve for this the data indicates:

- A fixed energy of the 28.8 MWh/d
- A variable energy of 3.366 MWh per Ml of product water supplied.

We have also confirmed that the recent performance has not deteriorated using just 2022 data, which suggests a slightly lower gradient (3.333 MWh per Ml). We based our recommendation on the 2020 to 2022 period rather than just 2022 as it utilises a greater number of data points and therefore increases confidence in the analysis.

4.1.2. Membrane age and pump throttling

The SDP facility has been designed to have sufficient pumping pressure to treat seawater water with a design maximum salinity of 41g/l and lowest temperature of 15 degrees Celsius. The Plant is capable of delivering 70 bar pressure at the RO membranes. We estimate the minimum turndown pressure at the RO membranes without using pump discharge valve energy throttling is 60.4 bar. This is given the sum of the following:

- High Pressure Pump ("HPP") developed pressure: 58.3 bar[21]
- Net Positive Suction Head with margin ("NPSH")[22]: 2.5 bar
- Pressure loss from the HP pump discharge to the membranes: -0.4 bar

[21] From High Pressure Pump Curve

[22] Minimum suction positive head with safety of feed pressure of pump.

Minimum Pressure at Membrane = 58.3 + 2.5 - 0.4 = 60.4 bar.

The actual salinity of the seawater at the Kurnell intake can be established by the seawater conductivity data. The conductivity data for period 2011-2012[23] indicates that the actual intake seawater salinity is approximately 36.3 g/l.

Dupont membrane projection software[24] ("WAVE") can be used to estimate the feed pressures required at the RO membranes for new and fully aged membranes with different seawater temperatures. A summary of the pressures required at the membranes is presented Table 4-1 derived from the WAVE software.

Table 4-1 Dupont software predicted feed pressures at first Pass Membranes

Temperature	15ºC	20ºC	26ºC
first Pass New Membrane Feed Pressure (bar)	55.8	54.1	53.1
first Pass Aged Membranes Feed Pressure (bar	61.2	57.9	56
Minimum Pressure Turndown No Throttling (bar)	60.4	60.4	60.4

Source: Atkins (using Dupont software)

It can be observed from the table above that the first pass RO membranes feed pumps cannot reduce their feed pressure sufficiently to take advantage of the lower than 60.4 bar feed pressure required by the RO membranes which will exist for most of the seawater temperature range for aged membranes. The high-pressure pump discharge valves after the HPP (high pressure pumps) are used to throttle the pressure (waste the excessive energy) when the feed pressure required at the RO membranes is less than the 60.4 bar minimum for the first pass feed pumps.

4.1.3. SDP proposed consumption and logic

Since the last IPART Determination period, the Plant has operated at a fixed energy allowance of the 21 MWh/d, and a variable allowance of the 3.516 MWh/Ml.

For the next Determination, SDP's submission proposes to increase the fixed energy allowance to 34 MWh/d, and the variable energy allowance of the first year to 3.666 MWh/Ml with a continuous increase to 3.732 MWh/Ml in the last year.

The following table summarises the energy allowance regime proposed by SDP:

Table 4-2 SDP Proposed energy regime for Determination

Energy Regime	2023 - 2024	2024 - 2025	2025 - 2026	2027 - 2028
Fixed (MWh/d)	34.56	34.65	34.84	34.84
Variable (MWh/Ml)	3.666	3.679	3.732	3.732
SEC (MWh/Ml)	4.36	4.373	4.426	4.426

Source: SDP Price Submission Proposal

SDP explains the increase in the fixed energy allowance as a result of the:

- Need to generate extra RO permeate to flush RO membranes every 2 days with RO permeate water when the trains are not in use (for periods of low water demand);
- Need to operate the intake pumps above pre-treatment process demand to ensure that a sufficient velocity in the outfall diffusers is achieved to achieve the required brine dispersion.

SDP explains that the increase in in variable energy is due to ageing of the RO membranes increasing the feed pressure requirement. We do not consider that this increase in variable energy is technically justified because the Plant cannot turn down the feed pressure to the RO membranes sufficiently to match the true pressure needed for the membrane age and seawater temperature.

[23] We have not received the data for the period between 2019 and 2022
[24] Dupont software is Wave

4.1.4. Our recommendation

Fixed energy: we agree with SDP that during low product water demand periods, there will be higher requirement for the RO membranes to flush water and for the intake pumping water to be in operation. However, during full production demand the additional flushing and intake water requirements should be very small. Hence, we consider that the appropriate way to establish the fixed energy demand is using the best fit curve shown above in Figure 4-1. which is based on actual historical data of the Plant during the period between 01 January 2020 and 31 October 2022. This implies a fixed allowance of 28.8 MWh/d. The used period covers a wide range of production, during most of which the plant has had to operate in a flexible manner in response to ERNs. It is therefore considered reasonably representative of the conditions the plant is expected to operate in in future.

The best fit energy curve (Figure 4-1) against production for the 2020-2022 period indicates the variable energy requirement can be estimated by using 3.366 MWh/Ml. We propose an additional allowance of 0.1 MWh/Ml to give a variable allowance of 3.466 MWh/Ml, the additional allowance is to account for pump degradation, and some small pressure increase above when the pump throttling valve is fully open as membrane age at lowest sea water temperatures. We consider this is reasonable based on an assessment of the potential scale of pressure increase.

We have not incorporated any energy savings resulting from trimming of impellers (discussed in Section 5) as this may not happen early enough in the Determination period to have a significant impact on energy demand.

Table 4-4 and Table 4-5 summarise the energy allowance for fixed and variable energy (i) during the current Determination, and (ii) SDP's submission and (iii) Our recommendation for the next Determination period including the difference between SDP's submission and our recommendation for the next Determination period for four difference scenarios:

- Flow: 0 Mld (non-production mode);
- Flow: 50 Mld;
- Flow: 125 Mld;
- Flow: 250 Mld (full production mode).

As the proposed and recommended figures do not vary by year these figures can be summarised as follows. It is clear that the current Determination allowance and our recommendations are similar. Our recommended energy consumption allowance is slightly higher at lower production levels and slightly lower at higher production levels.

Table 4-3 Summary of energy use (MWh/d) by production level

Production level (Mld)	0	50	125	250
Current Determination Allowance	21	197	461	900
SDP proposal	35	218	493	951
Our recommendation	29	202	462	895

Source: SDP Price Submission Proposal

Figure 4-2 – Comparison of proposed and recommended energy use

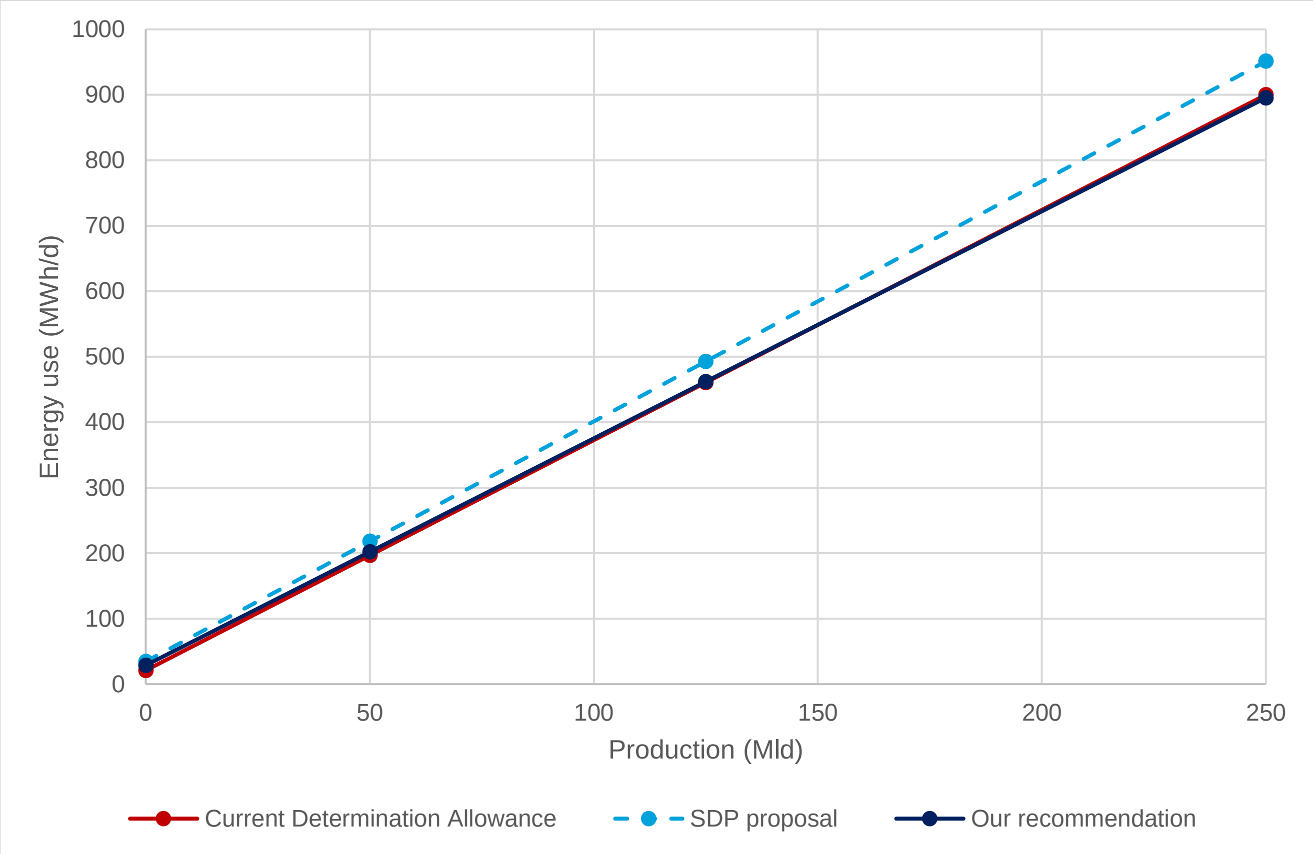


Table 4-4 Energy for each Determination year - with flow scenarios: 0 - 50 Mld

Year	**2023 - 2024**	**2024 - 2025**	**2025 - 2026**	**2027 - 2028**	**2023 - 2024**	**2024 - 2025**	**2025 - 2026**	**2027 - 2028**
Production (Mld)	**0**	**0**	**0**	**0**	**50**	**50**	**50**	**50**
Current Determination Allowance								
Fixed Energy (MWh/d)	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Variable (MWh/Ml)	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52
Total Energy Use (MWh/d)	21.0	21.0	21.0	21.0	196.8	196.8	196.8	196.8
Aggregate SEC (MWh/Ml)	n/a	n/a	n/a	n/a	3.94	3.94	3.94	3.94
SDP Submission								
Fixed Energy (MWh/d)	34.6	34.7	34.8	34.8	34.7	34.7	34.7	34.7
Variable (MWh/Ml)	3.67	3.68	3.73	3.73	3.67	3.68	3.73	3.73
Total Energy Use (MWh/d)	34.6	34.7	34.8	34.8	218.0	218.6	221.3	221.3
Aggregate SEC (MWh/Ml)	n/a	n/a	n/a	n/a	4.36	4.37	4.43	4.43
Recommended								
Fixed Energy (MWh/d)	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8
Variable (MWh/Ml)	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47
Total Energy Use (MWh/d)	28.8	28.8	28.8	28.8	202.1	202.1	202.1	202.1
Aggregate SEC (MWh/Ml)	n/a	n/a	n/a	n/a	4.04	4.04	4.04	4.04
Year	**2023 - 2024**	**2024 - 2025**	**2025 - 2026**	**2027 - 2028**	**2023 - 2024**	**2024 - 2025**	**2025 - 2026**	**2027 - 2028**
Production (MLD)	**0**	**0**	**0**	**0**	**50**	**50**	**50**	**50**
Difference between SDP Proposal and Our Recommendation								
Fixed Energy (MWh/d)	-5.8	-5.9	-6.1	-6.1	-5.9	-5.9	-5.9	-5.9
Variable (MWh/Ml)	-0.20	-0.21	-0.27	-0.27	-0.20	-0.21	-0.27	-0.27
Total Energy Use (MWh/d)	-5.8	-5.9	-6.1	-6.1	-15.9	-16.6	-19.2	-19.2
Aggregate SEC (MWh/Ml)	n/a	n/a	n/a	n/a	-0.32	-0.33	-0.38	-0.38

Source: Analysis of SDP document “ATK-001_1 Jul 2017 to 31 Oct 2022 Energy and Production Data” and SDP Price Submission Proposal

Table 4-5 Energy for each Determination year with flow scenarios: 125 - 250 Mld

Year	2023 - 2024	2024 - 2025	2025 - 2026	2027 - 2028	2023 - 2024	2024 - 2025	2025 - 2026	2027 - 2028
Production (Mld)	125	125	125	125	250	250	250	250
Current Determination Allowance								
Fixed Energy (MWh/d)	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Variable (MWh/Ml)	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52
Total Energy Use (MWh/d)	460.5	460.5	460.5	460.5	900.0	900.0	900.0	900.0
Aggregate SEC (MWh/Ml)	3.68	3.68	3.68	3.68	3.60	3.60	3.60	3.60
SDP Submission								
Fixed Energy (MWh/d)	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Variable (MWh/Ml)	3.67	3.68	3.73	3.73	3.67	3.68	3.73	3.73
Total Energy Use (MWh/d)	492.9	494.6	501.2	501.2	951.2	954.4	967.7	967.7
Aggregate SEC (MWh/Ml)	3.94	3.96	4.01	4.01	3.80	3.82	3.87	3.87
Recommended								
Fixed Energy (MWh/d)	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8
Variable (MWh/Ml)	3.47	3.47	3.47	3.47	3.47	3.47	3.47	3.47
Total Energy Use (MWh/d)	462.1	462.1	462.1	462.1	895.4	895.4	895.4	895.4
Aggregate SEC (MWh/Ml)	3.70	3.70	3.70	3.70	3.58	3.58	3.58	3.58
Year	**2023 - 2024**	**2024 - 2025**	**2025 - 2026**	**2027 - 2028**	**2023 - 2024**	**2024 - 2025**	**2025 - 2026**	**2027 - 2028**
Production (MLD)	**125**	**125**	**125**	**125**	**250**	**250**	**250**	**250**
Difference between SDP Pr	**Difference between SDP Proposal and Our Recommendation**							
Fixed Energy (MWh/d)	-5.9	-5.9	-5.9	-5.9	-5.9	-5.9	-5.9	-5.9
Variable (MWh/Ml)	-0.20	-0.21	-0.27	-0.27	-0.20	-0.21	-0.27	-0.27
Total Energy Use (MWh/d)	-30.9	-32.5	-39.1	-39.1	-55.8	-59.0	-72.3	-72.3
Aggregate SEC (MWh/Ml)	-0.25	-0.26	-0.31	-0.31	-0.22	-0.24	-0.29	-0.29

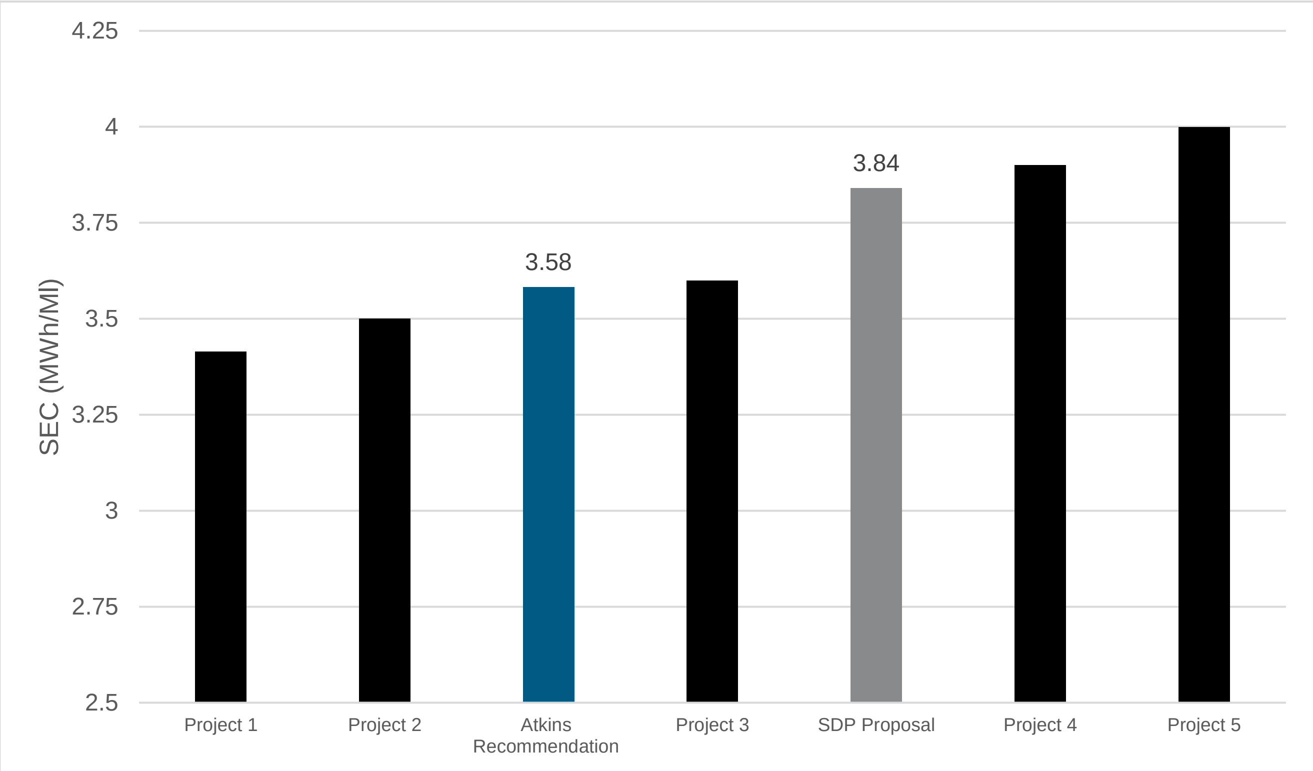
Source: Analysis of SDP document "ATK-001_1 Jul 2017 to 31 Oct 2022 Energy and Production Data" and SDP Price Submission Proposal

4.1.5. Benchmarking

The following figure benchmarks (i) the Specific Energy Consumption ("SEC") proposed by SDP for the Plant for next Determination Period and; (ii) Our recommended SEC for the Plant at 250 Mld production against guaranteed SECs for some SWRO plants that are contemporary for the design of the Sydney SWRO Plant:

The benchmark includes projects of sizes between 60 Mld and 540 Mld designed and entering operations between 2006 and 2015.

Figure 4-3 – SEC benchmarking against desalination plants built at a similar date

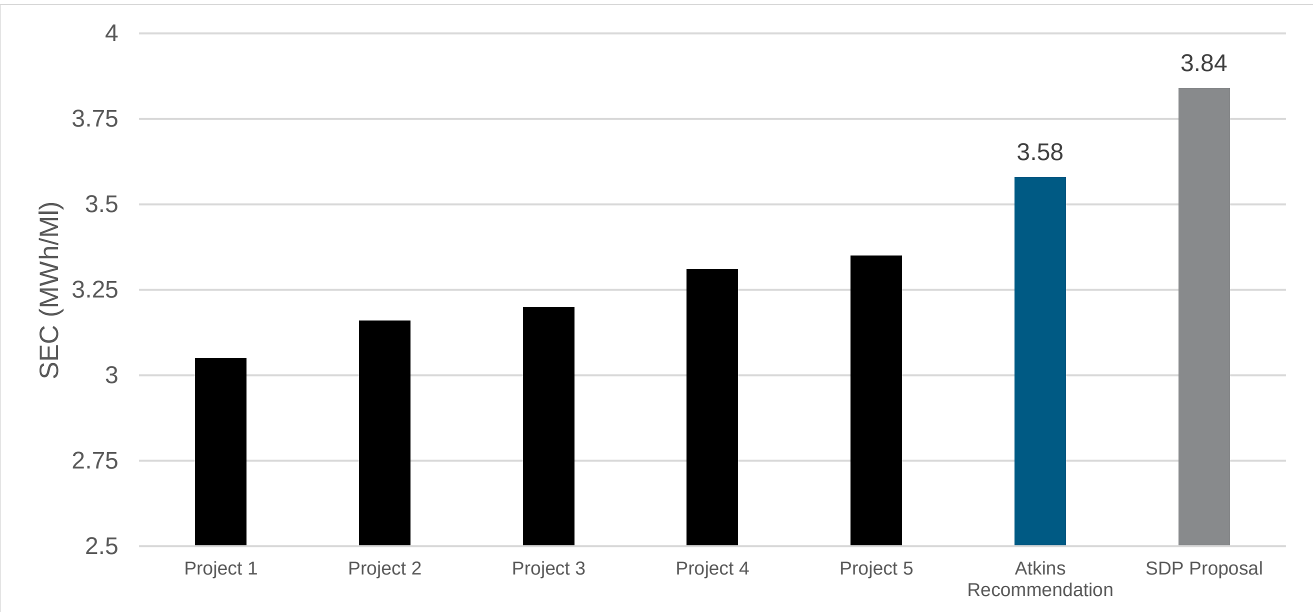


Source: Atkins own database

Since year 2018, large scale SWRO projects in the middle east of size >= 450,000 m^3/d have SEC requirements in range of approx. 3.0 - 3.3 MWh/Ml. These recent plants are generally base load production facilities replacing thermal desalination which will operate at full capacity most of the time. The recent large plants are all design using pressure centre concepts to increase pump hydraulic efficiencies and lower SEC requirements.

The benchmark includes projects of sizes between 250 Mld and 900 Mld designed and entering operations after 2018.

Figure 4-4 –SEC benchmarking against more recent desalination plants



Source: Atkins own database

The SDP Plant was designed approx. between 2007-2008 and does not use a pressure centre design concept. In addition, it uses a first recovery (permeate volume vs feed volume) of 45% compared to the 40-42% used for recent SWRO plants with lowest SEC. The SEC of 3.582 MWh/Ml (at 250 Mld production) for the SDP SWRO facility will be higher than the most recent large SWRO facilities with SECs in the range of 3-3.3 MWh/Ml, but it is efficient in comparison with other facilities designed before 2010.

4.2. Benchmark energy price

4.2.1. Introduction

This section sets out the approach, estimation methodology, data and other considerations used to develop estimates of prudent and efficient benchmark future wholesale electricity purchase prices ("benchmark price"), applicable to the upcoming Determination period, to meet the plant's forecast efficient electricity consumption. The benchmark price provides a point of comparison relative to SDP's actual long term wholesale electricity purchasing arrangements.

The methodology used to estimate future benchmark prices is consistent with the methodology used to set benchmark prices for the current Determination period. However, this has been modified and developed to reflect significant modifications to SDP's energy consumption, and other factors influencing efficient benchmark prices, for the upcoming Determination period. This reflects the following changes since 2017.

- The Greater Sydney Water Strategy.
- The updated terms of reference for the IPART referral under the WIC Act.[25]
- Substantially changed wholesale electricity market conditions.
- Sydney Water's June 2022 'Decision Framework for SDP operation'.
- Interval metering data revealing SDP's historical annual and intra-day electricity demand profile and actual maximum demand.

4.2.2. Background

4.2.2.1. Terms of reference for Referral to IPART

In June 2022, terms of reference for the Referral to IPART were updated by the Minister. The terms of reference include pricing principles.

Under clause 7 of the pricing principles, the charges for water supply services should reflect all efficient costs that vary with output, including variable energy costs. In addition, the price determination should consider the SDP's ability to recover all costs it incurs in complying with the GGRP, other than the costs related to surplus energy in relation to which the energy adjustment mechanism applies.

4.2.2.2. The purpose of the benchmark efficient electricity price

In setting the electricity component of regulated SDP tariffs under the Referral, it appears IPART can choose whether to apply an estimated efficient forward-looking benchmark price, or to apply the actual costs of future SDP electricity purchases under SDP's existing power purchase arrangements with Iberdrola (previously Infigen). The estimation of the efficient benchmark price makes no reference to prices payable under Iberdrola's PPA.

SDP has proposed that IPART apply forecast actual power purchase costs, with pass through adjustments for identified currently unknown costs.[26] It is understood SDP's legacy power contracts will continue to operate for the entire duration of the upcoming Determination period.

[25] See updated referral to IPART from the Minister, dated 16th June 2022, made under section 52 of the Water Industry Competition Act 2006 (NSW), especially clauses 7 and 7A.

[26] See for example page 10 of SDP's Pricing Submission to IPART, 16 September 2022.

In the current regulatory period, the electricity component of regulated SDP tariffs is set with reference to the efficient benchmark electricity price.[27] The benchmark price is forward looking and does not consider sunk costs or any gains or losses from technology, market and other change, relative to an efficient forward-looking price.

When setting regulated prices, economic regulators often use efficient benchmarks rather than actual costs for estimating key inputs[28]. This is to avoid adverse outcomes under cost-based approaches where regulated entities do not have incentives to reduce input costs. Use of a benchmark electricity price avoids the potential for consumers to bear the burden of any inefficient historical contracted energy costs. Use of benchmarks gives regulated entities opportunities and incentives to outperform efficient benchmarks.

In the event benchmark electricity prices vary from actual legacy contract prices, for example due to movements in international energy prices, there is an opportunity for the regulated entity to enjoy windfall gains or bear windfall losses. Under the updated terms of reference for the Minister's referral for the current IPART SDP price review, any gains or losses between wholesale electricity purchase costs determined under clause 7 for this part of SDP's overall regulated revenue requirement, on the one hand, and the actual net costs of electricity purchases and sales of surplus contracted electricity, on the other, are dealt with in accordance with clause 8 of the reference. Clause 8 includes reference to an energy adjustment mechanism and associated methodology. It is understood the energy adjustment mechanism and methodology would continue to operate throughout the forthcoming regulatory period.

4.2.2.3. Electricity retail agreements

Unless registering as "market customer" with AEMO, SDP must enter into a retail agreement with a licenced electricity retailer for the supply of electricity from the NEM to meet the plant's demand. The benchmark retailer is required to purchase all electricity suppled to SDP via the gross NEM wholesale market settling with AEMO at prevailing spot prices against half hourly metered demand for every trading interval, inclusive of average losses calculated by AEMO at the Kurnell transmission network identifier.

The benchmark retailer is obliged to comply with all AEMO market customer participant requirements including payment of AEMO fees and charges for ancillary and security services. It is also required to comply with AEMO prudential requirements, including by purchasing bank guarantees. The benchmark retailer is subject to all NSW and Commonwealth obligations and liabilities applicable to registered NEM retailers licenced in NSW.

SDP's electricity purchase agreement with a registered retailer can apply a range of possible retail products, as follows.

a) Fixed electricity contract: the price (in $/MWh) is fixed but will reflect the "risk" of the demand profile. Relevant variables include the load factor (the ration of maximum to average demand), the shape (daily to seasonal) and the flex (e.g., how high demand can increase to in any given interval).
b) Flexible Purchase Product: the customer can instruct the retailer when to purchase hedges and how much (as a % of total load). The retail price is the trade weighted average of the hedges times a factor reflecting the shape, load factor and flex of the customer load.
c) Pool Price Pass Through Products: the retail price is the load weighted spot price marked-up by a factor or a premium to cover the retailer market costs and margin. This structure can be complemented by cap contract to protect the customer against extreme spot prices (e.g., above $300/MWh)
d) Sleeved PPA: where a customer has entered into a PPA (LGC + Contract for Difference (CfD on spot electricity price) with a third-party provider, a retailer may "firm-up" the energy produced under the PPA and the energy consumed by the retailer. The retailer charges a firming (or sleeving fee) reflecting the shape, flex load factor of the PPA against the shape, flex and load factor of the customer demand.

[27] See page 102 of IPART's final report for its review of SDP prices from 1 July 2017 to 30 June 2022, dated June 2017.
[28] Ibid.

4.2.3. Definition of the benchmark price

4.2.3.1. The benchmark price is the total benchmark retailer supply cost

The benchmark price is the price that would be offered, by a prudent and efficient electricity retailer (the benchmark retailer), to supply SDP's specific forecast annual demand profile and annual volume for each year of the upcoming Determination period. That is, the assumed retail contract period is identical to the Determination period.

The total price offered by the benchmark retailer would reflect the outcome under a competitive wholesale electricity procurement process with multiple potential retailers. The benchmark retailer would seek to minimise its actual wholesale electricity and renewable energy offset supply costs. Its price would nevertheless include an adequate mark up for uncertainty and risk in relation to future wholesale market conditions and outcomes. The benchmark retailer would seek to recover all of its costs, including its mark up, for supplying the forecast SDP demand profile.

The benchmark price for the forthcoming period reflects conditions at the time the notional forward electricity contract is entered between SDP and the benchmark retailer. This reflects the fact that forward electricity contract prices for a given trading period move over time in the lead up to that period.

As a result, depending on when forward contracts for a given trading period are entered, unit prices for that period will vary. This also means that use of a base year plus cost index adjustment approach may not be applicable to the estimation of the benchmark electricity price in each year of the forthcoming period.

The benchmark retailer is assumed to be a substantial financial entity. It is assumed to have a strong balance sheet and low counterparty risk (with a good credit rating).

4.2.3.2. Components of the benchmark price

The benchmark price includes all prudent and efficient wholesale electricity purchase costs, other than regulated network charges, including losses and wholesale cost components other than energy. Consistent with the updated terms of reference, the benchmark price includes all efficient electricity purchase related costs from complying with the SDP project approval greenhouse gas reduction plan (GGRP).

The components of the benchmark electricity price are described and listed in Table 4.6 below. The sections that follow describe the components in more detail, including the risks involved in purchasing wholesale electricity, and how these risks can be managed via forward contracting.

Table 4-6 Components of the benchmark electricity price (Retailer cost stack)

Component	Description
Energy costs	Volume weighted average (VWA) of electricity spot price reflecting the demand profile supplied. Units are $/MWh.
Network losses	Average annual network losses at the nearest transmission network identifier, as calculated by the AEMO. These are added to energy costs.
Forward contracting cost	The difference payment ("premium") between the fixed cost of hedges, versus settlement against physical ("spot") electricity prices in the relevant trading periods.
LGCs	Federal Renewable Energy Target (RET) scheme: large scale generation certificates needing to be procured and/or surrendered to meet calendar year scheme liabilities.
STCs	Federal Renewable Energy Target (RET) scheme: small scale generation certificates needing to be procured and/or surrendered to meet calendar year scheme liabilities.
GGRP	Purchase of greenhouse gas certificates above the mandated minima to meet GGRP requirements (1- LGC RPP (mandatory RET)- STC RPP)
ESS (Energy Saving Scheme)	NSW scheme applicable to all NSW demand. Retailers must surrender an appropriate number of Energy Saving Certificates (ESCs) to meet their annual energy savings targets.
Market fees (AEMO)	Charges imposed by AEMO on a per MWh basis to cover the costs of operating the NEM.
Ancillary Services	Cost of non-energy services purchased by AEMO to manage the power system safely, securely and reliably. This includes frequency control, network control and system restart.
Metering and Data Costs	Charges imposed by a meter service provider for supplying and operating metering installations and associated data acquisition and forwarding services. This is a contestable service and therefore is not part of regulated network charges.
Retailer mark-up on the cost of goods sold	The reasonable estimated cost converted to $/MWh of running a wholesale electricity purchase and retail service operation for a large customer. This is expressed as a mark-up on the total cost of goods sold (COGS).

Source: MJA

The regulated network component of SDP's electricity purchase cost is payable to SDP's local distribution network supplier, Ausgrid. These charges include both regulated distribution and transmission costs, and any non-regulated dedicated network connection infrastructure between SDP and the common network. Accordingly, all these regulated and dedicated connection costs are excluded from the benchmark price. This means that the cost of jurisdictional schemes recovered from network use of service charges are excluded from the retailer's cost stack.

4.2.3.3. The benchmark cost includes a retailer mark-up

The costs of wholesale electricity procurement are incurred by the benchmark retailer supplying SDP's total demand. The benchmark price therefore has no effect on SDP's efficient non-electricity operating costs.

The benchmark price includes a retailer mark-up to recover the following costs and activities.

- Setting customer prices and "acquiring" a new customer.

- Owning and operating a customer service platform and customer information system, including a call centre.
- The costs of wholesale trading operations, including a middle office between wholesale trading operations and the customer facing retail operation.
- The costs of acquiring credit support to meet AEMO prudential requirements – bank guarantee fees.
- The cost of preparing customer bills and receiving payments.
- Working capital costs between incurring wholesale purchase expenditure and receiving revenues from SDP.
- Counter-party settlement credit risks reflecting the credit rating of SDP.

Retailers may also seek to include in prices or via cost pass through arrangements, the total cost of meeting other regulatory obligations, including the following.

- Retailer reliability obligation (RRO). The Retailer Reliability Obligation (RRO) started on 1 July 2019 to help manage the risk of declining reliability of supply in response to the large amounts of development in intermittent renewable projects coupled with the closures of thermal power stations. If the RRO is triggered for a given quarter and region of the NEM, then retailers need to secure sufficient qualifying contracts to cover their share of a one-in-two-year peak demand. RRO has never been triggered in NSW. The retailer may include an allowance for this cost in its retail mark up or make it a pass-through item in the retail contract.

- Reliability and Reserve Emergency Trader (RERT). This refers to additional charges incurred by AEMO to access emergency reserves to maintain or restore the power system to a reliable operating state. RERT is calculated based on purchased load by energy retailers, then passed through to consumers based on their MWh consumption. Charges are received by the retailers in line with AEMO's calendar which operates in arrears. The retailer may include an allowance for this cost in its retail mark up or make it a pass-through item in the retail contract.

- NSW peak demand reduction scheme (PDRS). The benchmark retailer is required to comply with the NSW peak demand reduction scheme and may associated direct and overhead costs. The retailer may include an allowance for this cost in its retail mark up or make it a pass-through item in the retail contract.

4.2.4. The impact of uncertainty over SDP's future electricity demand profile

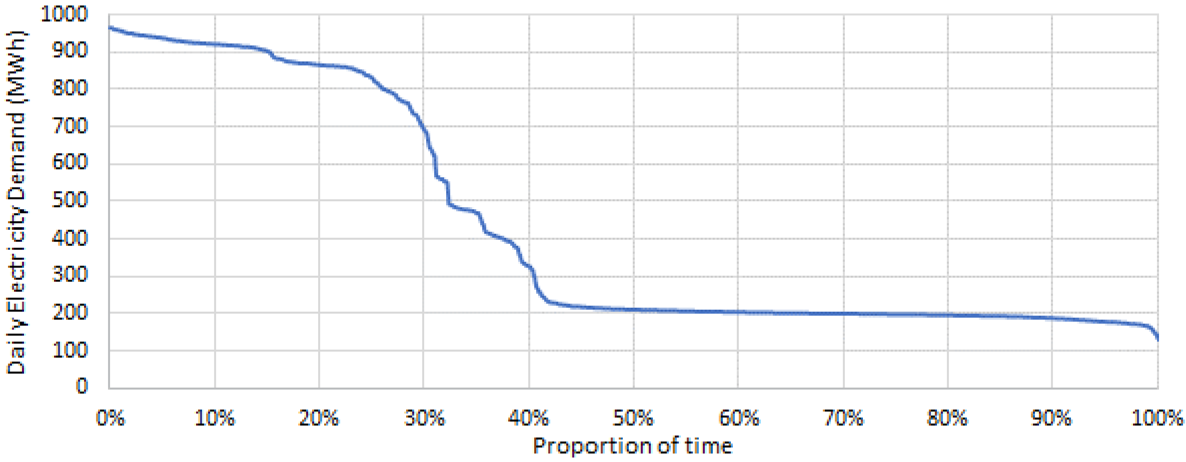
4.2.4.1. Historical annual electricity demand profile

The benchmark electricity price is strongly influenced by SDP's *future* electricity demand profile, and the extent this can be reliably forecast. The benchmark retailer would expect to receive information from SDP regarding its forecast volume of demand and associated demand profile.

Box 1 What is an annual electricity demand profile?

An annual demand profile is a summary of a customer's electricity demand at a half hourly resolution over a year, which by convention can be presented graphically from highest to lowest demand. A representation of SDP's historical demand profile over the period from 1 January 2019 is provided below, at a daily resolution.[29]

Figure 4-5 – SDP load duration curve from July 2017 to Oct 2022



Traditionally, "flatter" load profiles (with little or no variation in demand over a year) are the lowest cost to supply, while "peaky" load profiles, where the customer peak coincides with total system demand peaks and wholesale prices are also likely to be extremely high, are the highest cost to supply. Other things being equal, flat demand profiles are lower cost to supply because fixed supply costs (generation capacity) can be applied to larger volumes.

Demand profiles where peak annual demand is outside peak system demand are lower cost than demand profiles coincide with peak system demand, and contribute to scarcity in available capacity, potentially contributing to a need to expand capacity. An ideal profile from a retailer perspective is flat but with the opportunity to reduce substantially during a small number of peak price periods – demand response.

Many demand types have significant intra-day variation in demand, most notably residential customer demand peaks during evenings and is lowest pre-dawn. SDP demand does not appear to have significant intra-day variation.

As discussed in section 4.1, SDP's electricity demand profile is driven by its water production. Its level of water production for any given part of the forthcoming regulatory period will in turn depend on decisions made by SWC under its 'Decision Framework for SDP Operation, of June 2022. Noting that the Decision Framework is subsidiary to the Water Supply Agreement (WSA) to the extent there is any inconsistency.

As noted in Section 2.1.2. the current WSA is expected to be revised, among other things to reflect the outcome of IPART's SDP pricing Determination for 2023-2027.

SWC's Decision Framework for SDP operation provides that:

1. SWC will forecast its supply requirements from SDP in April each year for the following financial year.
2. SWC will provide SDP with an annual production request by 1 May each year for 12 months in the following financial year.
3. The production request assumes that SDP will operate at or above a minimum baseline production to maintain the ability to respond production requests.
4. The production request will be reviewed every six months. SWC's Supply Forecast will be reviewed in October each year before summer to manage risks of high demand and the potential rapid dam depletion, 'if drought conditions persist'.
5. The production request will be averaged over the longest period possible to give greatest operational flexibility to both SWC and SDP.

[29] Periods of low electricity demand reflecting SDP's ramp up were removed as these do not reflect the future operating environment.

6. The Decision Framework states that 'The flexibility in operation allows SDP and SWC to perform planned and reactive maintenance without financial penalties that are ultimately passed on to consumers.'
7. The Annual Production Request is then adjusted for days of planned SWC and/or SDP maintenance, from a Joint Annual Maintenance plan process or as otherwise communicated and agreed.
8. These specific production requests (Fixed Production Day) will be added and scheduled into the annual production forecast 'as much as possible'.
9. SWC states that 'The Annual Production Request is based on best information available at the time of forecasting. Sydney Water will maintain the ability to adjust production requests to ensure we minimise costs to consumers while remaining responsive to changes…'
10. The Annual Production Request will be reviewed and updated prior to the start of each month during the year, taking into account BOM forecast and total storage level. Production requests may be adjusted via a Monthly production request.
11. Any change to a monthly production request that has a material variance (plus or minus 10%) could trigger the Annual Production request to be reviewed and updated.
12. Any unplanned events from SDP or SWC (cancellation, deferment or extension of maintenance work) or indication of wet weather and spill event that prompts SWC to change is production request from the relevant Monthly production request will be communicated to SDP through a 7-day production request.

The Decision Framework establishes operating rule objectives, which include:[30]

- That the volume of water produced by the plant can be varied as needed to support the resilience of SWC's system
- Increase production to slow down dam depletion during droughts and keep dam levels higher when needed
- Reduce production when dam levels are high in order to minimise the risk of spills
- Maintain minimum baseline production of water, for the Plant to maintain a state of readiness
- Be ready to manage system shocks and emergencies
- Introduce flexibility to maintain cost effectiveness
    - Coordinate major outage work to consider timing and minimise cost
    - Reduce production during times when the probability of spill is higher and hence reduce cost to customer where possible
    - Consider alternative future sources where available.

4.2.4.2. SDP's forward electricity demand profile

SDP's forward electricity demand profile is highly uncertain and unlikely to mirror the previous three years. Key features of the forward electricity demand profile applied for the purpose of estimating the benchmark price are as follows.

SWC and SDP will agree an annual water output volume no less than two months before the start of each financial year over the forecast period. The associated schedule of SDP water deliveries may incorporate some inter-seasonal and intra-month variability reflected in varying monthly and daily water output volumes. For example, water demand may be lower in winter months. In addition, the schedule will incorporate allowances for scheduled outages driven either by SDP or SWC requirements.

The annual schedule will reflect SWC's assessment of its requirements relative to three defined operating modes in the SWC Decision Framework, as set out in the table below.

[30] Decision Framework, page 14.

Table 4-7 – Electricity demand relative to output and operating modes

Operating modes[31]		Daily water production	Average daily energy demand (MWh/d)
1	Non-production	Zero	28.8
2	Sustaining water security when storage <75%	250Mld	895.4
3	Sustaining water security when storage 75% to 90%	125Mld	462.1
4	Minimise spills when storage >90%	50Mld	202.1

The corresponding annualised electricity demand under the defined operating modes is as shown in the table below.

Table 4-8 – Electricity demand – broad variances between operating mode

Operating mode	Daily demand (MWh/d)	Annual demand (MWh p.a.)	Difference from 'low' (MWh p.a.)	Multiple of 'low'
Non-production	28.8	10,092	NA	NA
250Ml/d (High)	895	313,608	151,723	4.4
125Ml/d (Med)	462	161,885	91,104	2.3
50Ml/d (Low)	202	70,781		

Depending on operating modes throughout a year, annual demand could be as low as ~70,800MWh and up to ~314,000MWh p.a. Demand in the high mode over a year is 4.4 times demand in the low mode. Note that for each of the production modes, it is assumed that total annual demand during non-production periods is ~10,092MWh or 4 per cent of the time.[32]

Within each 24-hour period, there is no "shape" or regular variation in electricity demand under normal operating conditions. This is not to say that demand is constant every day. From reviewing consumption data, there are periods where demand reduces for scheduled maintenance, as requested by SWC, or sometimes due to plant outages. There are also periods where demand is briefly higher than average demand over a day.

Under the SWC Decision Framework, scheduled demand over each financial year of the forthcoming determination period is to be agreed by no later than 1 May. From the scheduled daily water output volumes, the associated electricity demand at a daily resolution can be estimated. This means the retailer could estimate the benchmark price for scheduled demand over each 12 month period within the forthcoming determination period.

It is possible for the plant to reduce output and electricity demand in response to wholesale market conditions. For benchmark pricing purposes, it is assumed that, with around four hours' notice, electricity demand can be ramped down by up to 50 per cent for several hours. This results in a small but still significant reduction in the base benchmark price.

SDP has confirmed that both the SWC Decision Framework and draft amended WSA will provide substantial flexibility for SWC to vary its water supply orders within the 12-month period, relative to the scheduled daily demand. SDP has stated that[33], based on recent examples, variations can be:

- Substantial in volume terms – e.g. moving from the equivalent of ~200MWh consumption per day to over 895MWh per day and vice versa.
- Extensive in duration – e.g. a 693MWh change in daily demand can extend for months resulting in a substantial variation in annual demand.

[31] See page 14 and 15 of the Decision Framework.
[32] Since early 2020, non-production days have been around 3.7 per cent of the time and this has been rounded up to 4 per cent.
[33] SDP response to Atkins information request, January 2022.

- Subject to varying advance notification periods, with notifications often far shorter than 7 days and sometimes even less than 24 hours
- The plant will be required to reduce production to zero and require only ~29MWh per day when not producing water, due to planned and unplanned outages by either SDP or SWC.

As the highest cost supplier of potable water in SWC's supply system SDP is the marginal supplier and there is therefore a high degree of variability over its future demand profile. To the extent the amended WSA fully reflects the Decision Framework and recent practice in terms of notification of changes to demand, it appears that SDP would be able to give the benchmark retailer a scheduled annual demand profile, for the first year of the upcoming regulatory period.

To meet its obligations under the Decision Framework and WSA, SDP would seek a high level of optionality to vary its demand from the scheduled annual demand profile, reflecting recent practice. The benchmark retailer would therefore be expected to respond by applying a tailored ex-ante approach to pricing demand variations. This approach would seek to balance cost reflectivity and sound risk management, on the one hand, with simplicity and comprehensibility, on the other hand, to avoid imposing onerous requirements on either itself or SDP.

Uncertainty regarding SDP's actual demand profile, and annual consumption in each year over the upcoming regulatory period, is likely to be a key factor influencing the benchmark retailer's ex-ante pricing of SDP's demand profile. Alternatively, the retailer could provide SDP with a contracted retail price only up to a minimum annual volume, for example equivalent to the 'low' operating mode. It could then offer SDP a PPPT for additional demand. This would leave SDP exposed to wholesale price risk which it may not be able to recover from SWC. Accordingly, this option is not considered further.

4.2.5. Retailer prudent forward contracting

4.2.5.1. Why the retailer needs to hedge or forward contract for its physical energy purchases

Under the design of the wholesale National Electricity Market, physical ("spot") wholesale price outcomes for each trading interval can vary between minus $1,000/MWh to $15,500/MWh (to 30 June 2023).[34] Retailers purchase electricity at "spot" price to service their customer load. Retailer are exposed to both:

- The volatility of the spot price
- The volatility of customer demand (volume).

This means that, if SDP were operating at full daily capacity, with an assumed daily consumption of 895MWh, then the benchmark retailer is potentially exposed to spot prices of up to $13.9m per day up to the point where the cumulative administered price cap could be triggered. If the benchmark price had been $200/MWh, then the retailer would incur a daily loss of $13.7m.

Even a one-day trading loss is likely to be significant compared with the annual retailer mark up on COGS. Depending on the annual value of electricity being sold at the benchmark price, the benchmark retailer's trading loss could easily exceed the revenue from its annual mark up.

The benchmark retailer therefore prudently manages its exposure to spot wholesale electricity price risk. Accordingly, before committing to a price, the benchmark retailer would make contingent arrangements to acquire the required volume of electricity for each trading interval, using a combination of forward hedging instruments. If vertically integrated with generation, the retailer may secure its whole or part of its hedge requirement internally; best practice accounting requires the internal transfer price to reflect the prevalent forward market curve.

The benchmark retailer could also manage the volume risk of its customer load via a combination of:

- Progressive hedging: acquiring hedge contracts up to three years prior to consumption and adjusting the hedge position as market conditions change, and as the future demand profile becomes more certain.
- Cap contracts: these protect buyers against spot prices above $300/MWh; if, in a given period, customer demand is higher than forecast, the retailer is only exposed to low/medium prices.

[34] See https://www.aemc.gov.au/news-centre/media-releases/2022-23-market-price-cap-now-available

The benchmark retailer would include in its pricing methodology additional cost components for:

- financing the purchase of forward contracts against future demand;
- trading losses and gains, depending on future movements in forward contract prices for a given trading interval;[35]
- liquidity risk reflecting the ability to secure or close hedge position prior delivery; and
- credit risk: the cost of posting credit support to guarantee the hedges.

4.2.5.2. Outlook for wholesale electricity markets over 2023-27

Compared with the outlook at the start of the current regulatory period, the outlook for the forthcoming regulatory period is highly uncertain. Key features of the new outlook include:

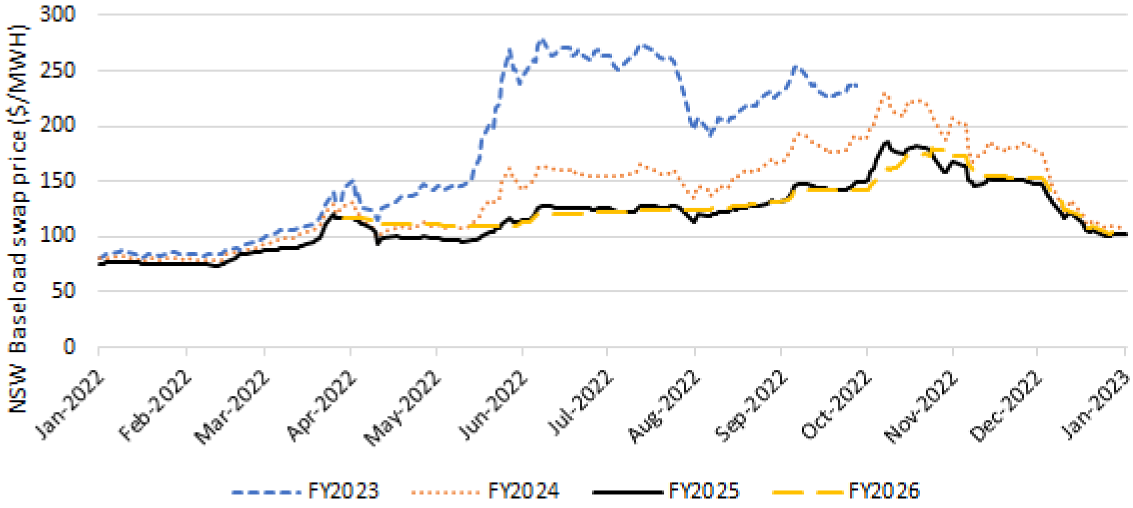
- Extreme gas and coal prices, and an uncertain outlook of market response, international influences, and the policy response in the form of price caps.
- Tightening of firm capacity as coal closes, replaced by renewable (non-firm) generation, transmission, pumped "deep" storage and short-term storage (batteries).
- Significant changes in the National Electricity Market (NEM) / NSW energy markets over the period to 2027 driven by factors that include NSW government "energy roadmap" initiatives and ongoing work on the redesign of NEM wholesale markets.
- High levels of transmission congestion due to differences between lead times for new renewable generation, on the one hand, and completion of new transmission, on the other.
- Change and uncertainty regarding the adoption and impact of consumer energy resources, including rooftop solar capacity, battery electric vehicle adoption, and the impact of building and appliance energy efficiency standards.
- High capital costs and increased commercial financing costs, with an outlook for capital cost increases to reduce, but in an uncertain timeframe.
- As a result of all the factors above, much greater volatility in the outlook for future spot and contract prices.

Recent increases in economy-wide inflation are also affecting key cost components including future capital, labour, and financing costs. This suggests that, even if international energy prices moderate in coming years, and dependence on fossil fuels is reduced, key electricity cost inputs could remain elevated compared with LRMC inputs used in the current regulatory period.

The extended suspension of NEM gas and electricity spot markets in June this year, preceded by very high spot prices, contributed to significant increases in forward wholesale contract prices, and higher levels of volatility in these prices. As a point of reference, current NSW forward wholesale contract prices, for energy alone, are substantially higher than for the entire benchmark prices used for the current Determination period. The movement in forward wholesale electricity contract prices over the 12 months to 29 December 2022 is shown in the Figure below.

Figure 4-6 – Forward NSW baseload swap price variation between January 2022 and January 2023

[35] Under international financial reporting standards (IFRS), specifically IFRS 9, reporting entities are required to disclose gains and losses on derivatives and hedging instruments in their financial statements and these gains and losses therefore increase variability in reported profit outcomes.



Source: MJA analysis of ASX energy contract market data[36]

This highlights that settled nominal forward contract prices for calendar year 2023 varied between ~$78//MWh and ~$266/MWh since the contracts began trading, a range of more than 230 percent. Forward contract prices are expected to moderate for 2024 and 2025, compared with Calendar 2023.

Forward contract prices moderate toward the end of 2022, due in part to Australian government intervention in the form of a domestic gas price cap. However, for calendar 2023, the average price is more than double observed prices at the end of 2021.

Other things being equal, the increases in forward contract prices alone could be expected to result in a substantial increase in benchmark prices for the upcoming Determination period. Similarly, traded prices for renewable energy certificates ("green" energy) are reflecting high levels of voluntary demand above the minimum mandatory targets.

Recent and possible future changes in government policy settings create further sources of uncertainty and volatility regarding key future components of benchmark prices. Other factors are increasing forward price uncertainty. These include potential increased constraints on the development of future coal and gas resources, and measures to support new infrastructure including large scale new electricity transmission, alongside large-scale electricity storage. Other factors include proposals for far reaching changes to: the wholesale market design; support for greater participation by consumer energy resources; changes to ancillary services markets; the management of transmission congestion; and changes to the carbon safeguard mechanism.

While forward contract volumes are at historically high levels, traded future volumes fall off rapidly. The low level of liquidity in forward contract prices beyond the second year of the forthcoming Determination period increases uncertainty regarding forward contract prices in years three to four of the forecast period.

4.2.6. Forward trading in renewable energy certificates and NSW energy savings certificates.

Under the national mandatory renewable energy target (MRET) scheme and the NSW energy efficiency scheme (ESS), electricity retailers, including the benchmark retailer, are obliged to purchase and surrender minimum volumes of relevant renewable and energy efficiency certificates related to the volume of electricity they supply in a given compliance period.

To meet its obligations, and avoid price risk, the benchmark retailer would purchase renewable and energy efficiency certificates from the relevant markets and surrender them at the end of the compliance period (calendar year). There are forward markets for buying and selling:

- Large scale greenhouse certificates (LGCs)

[36] https://www.asxenergy.com.au/about

- Small scale technology certificates (STCs) and
- Energy efficiency certificates (ESCs).

Under the GGRP, SDP is also required to comply with specific requirements for the purchase of additional renewable energy. The GGRP requires that all SDP electricity demand is offset by renewable energy purchases. As a result, the "green" energy liability for SDP will be around five times that for a customer seeking only minimum compliance with green energy requirements.

The benchmark retailer can manage the procurement of renewable energy and energy efficiency certificates and incorporate this into its pricing to supply SDP. Alternatively, in the absence of a reliable annual demand forecast, the benchmark retailer would need to procure certificates as data on actual SDP consumption becomes available. This means, however, that the retailer could be exposed to the price volatility of those markets. This will translate into a price premium, or a full pass-through of the higher cost, up to post-tax "penalty" rate (as a cap on certificate prices). The penalty applies where there is a volume shortfall between the liability (actual demand) and surrendered certificates. The penalty is unlikely to apply to the benchmark retailer supplying SDP, because even if the liability doubles, the large volume of voluntary certificate purchases would provide a buffer.

There is also forward trading in Australian Carbon Credit Units (ACCUs). It is assumed that the benchmark retailer does not trade in ACCUs to supply SDP demand. Accordingly, no consideration is given to future ACCU prices for the purpose of estimating the benchmark price.

4.2.6.1. Large Green Certificate price forecasts

The demand for LGC's is based on the following:

The requirement to achieve 20% renewable energy generation in Australia in 2020 – this amounts to 33,000 LGCs per annum until scheme closure (December 2030);

- Voluntary cancellations that relate to the following:
- Voluntary demand for LGCs to meet state or territory renewable energy targets;
- Electricity retailers offering renewable energy products to customers ("Greenpower");
- Industrial customers commitment to reduce emissions (can buy Australian Carbon Credit Offsets or LGCs) by 2030.

Requirement by obligated parties to redeem their LGC shortfall charges (LGC penalty price is effectively $93 per LGC after tax (i.e., $65 per LGC cap / (1 – corporate tax rate), corporate tax rate is 30%). While the current price is below the penalty price, parties will buy LGCs to make up previous shortfalls. This adds to demand today (and contributes to higher prices today).

The demand and supply situation for CAL 2022 is shown in Table 4.9 below.

Table 4-9 LGC Demand and Supply (2022 Assessment Year)[37]

	Supply	Demand
LGCs available from previous years	7.8	
2022 LGC supply (available for surrender)	44	
Total Supply	51.8	
Legislated demand for 2022		32.6
Estimated shortfall charge refunds for 2022		5.4
Voluntary cancellations		8
Total Demand		46.0
	Balance for 2022 assessment year	5.8

Source: https://www.cleanenergyregulator.gov.au/Infohub/Markets/Pages/qcmr/march-quarter-2022/Large-scale-generation-certificates-(LGCs).aspx

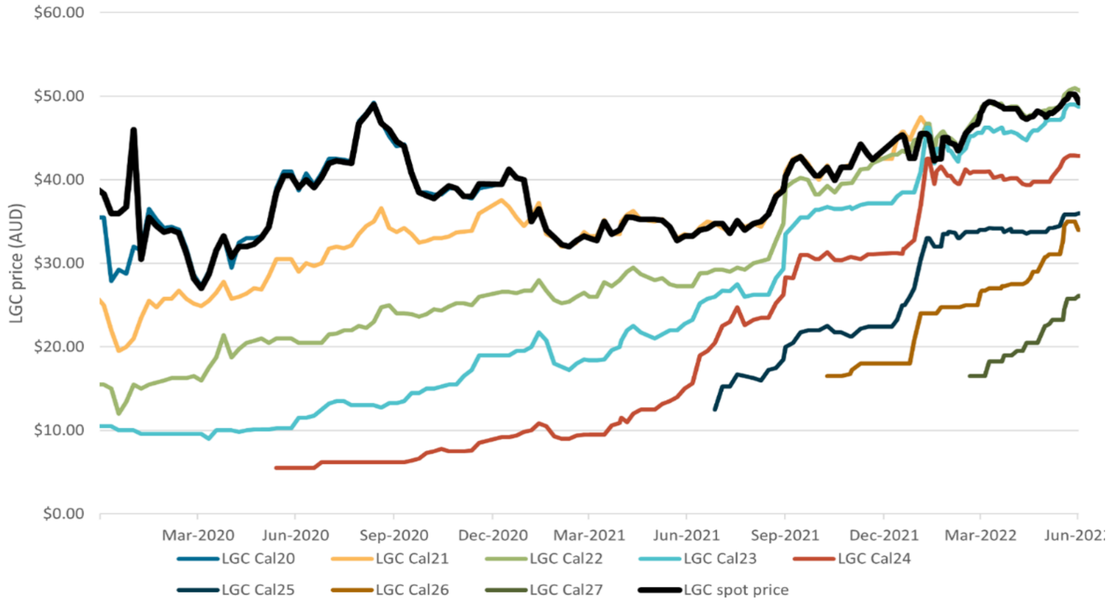
As liable parties meet their shortfall charges in current and near future years, this source of future LGC demand may reduce over time. However, LGC demand for voluntary surrenders of LGCs may increase over time, given state and territory government and corporate commitments to reduce emissions by 2030. Voluntary demand increased to 8 million LGCs in 2022, compared with 5.8 million LGCs in 2021.

The forward curve in indicates that future demand for LGCs would remain strong for most of this decade. For example, LGC prices in Cal26 and Cal27 increased by 28% and 58% respectively off a low-price expectation to $34 and $26 per LGC respectively). The strong increase in LGC prices is due to rapidly increasing voluntary demand and ongoing taking and redeeming of shortfall charges to provide liquidity. On the latter, there was an effective deficit of 14.7 million LGCs needed to redeem $950 million in shortfall charges in consolidated revenue.

The most recent forward curve for LGCs from mid-2022 is shown in Figure 4-7 below.[38] This indicates that prices were $70 per MWh. This is likely to fall in the future due to new supply from renewable projects and the fact that LGC shortfall obligations will reduce overtime. As of the end of January 2023, LGC prices for CAL 2026 are forecast to be $33.

[37] LGCs are “surrendered” to acquit a LGC liability electricity acquired between 1 January and 31 December of the “assessment year.”
[38] This is the latest data on the CER website.

Figure 4-7 LGC Forward Curves



Source: https://www.cleanenergyregulator.gov.au/Infohub/Markets/Pages/qcmr/june-quarter-2022/Large-scale-generation-certificates-(LGCs).aspx

LGC prices beyond 2026 are highly uncertain (driven by many demand and supply factors) but are still likely to remain above zero. This has been reflected in REC forward curves (see Appendix B for details). These prices are likely to have increased upward in line with recent developments.

4.2.7. The impact of uncertainty over future electricity prices

Retailers are now required to purchase spot price electricity in five-minute trading intervals.[39] The interval for customer sales is half-hourly or quarter hourly, corresponding to the available customer meter data. Accordingly, the "raw" wholesale energy component of the annual benchmark price represents:

- SDP demand (volume) for each half (or quarter) hourly trading interval over the year multiplied by
- The corresponding spot price for each half hourly trading interval (converted from six five-minute trading intervals)

Immediately following the execution of a supply contract with SDP, the benchmark retailer would seek to enter forward wholesale hedges well in advance of the relevant trading periods. Forward hedging would be undertaken in accordance with energy risk management policies.

Forward trading takes many forms including:

- Purchase of standardised baseload (flat) and cap forward contracts for difference traded on a specific ASX operated forward market.
- Purchase of over-the-counter contracts for difference and other trading instruments and derivatives with specific counterparties, such as one or more generators.
- Trading in forward options to sell or buy future swap contracts (known as "swaptions").
- Entering long term bilateral agreements with owners of generation assets, per SDP's current electricity contract.

These different types of forward contracts all enable the benchmark retailer to "lock in" the purchase cost of electricity for a given set of trading intervals, regardless of spot price outcomes for those intervals. In doing so, the retailer would incur a fixed to floating premium above the expected forward spot price for the relevant intervals, at the time the forward trading instrument is transacted.

[39] See https://aemo.com.au/initiatives/major-programs/nem-five-minute-settlement--program-and-global-settlement/five-minute-settlements

Energy risk management policies governing wholesale energy trading are likely to require high levels of forward contracting in the first year of a five-year supply contract, falling away in the latter part of the supply contract period. In the lead up to the first year, the benchmark retailer would seek to adjust its forward contract portfolio as new information becomes available, adjusting the mix of flat and cap products, and exercising swaptions.

The objective would be to minimise exposure to spot prices, especially during periods where there is potentially a tight demand-supply balance and a high likelihood of spot price spikes. In forward contract markets, traders would similarly seek to avoid periods where forward traded liquidity is low and there is an imbalance between buyers and sellers of forward contracts. In other words, in the lead up to a given trading period, such as a quarter, a retailer will seek to buy during periods when there are more sellers of that forward contract and avoid periods when there are fewer sellers. As the quarter approaches, a retailer will be under pressure to 'close out' its open position, and this may result in prices favouring sellers, other things being equal.

On the other hand, there is a financing cost associated with forward trading, to the extent that there are timing differences between incurring forward contract purchase costs and recovering these purchase costs from SDP. Accordingly, the extent retailers forward contract seeks to balance the benefits from price risk reduction with the costs of financing the forward trading portfolio.

This also highlights that retailers will seek to minimise the extent they are "long" on forward contract purchases. First, this is because they will have incurred financing costs which they may not be able to recover fully. Second, this is because retailers could face losses from selling excess forward contracts at prices below their purchase prices, and such losses may not be fully recoverable.

Table 4-10 Stylised example of retailer forward hedging strategy

Period	1st quarter	2nd quarter	3rd quarter	4th quarter	Year 2	Year 3
Hedged percentage of forecast demand for each trading interval	100	95	85	75	50	25

Source: MJA

The more uncertainty the retailer faces regarding forecast SDP demand profiles and hence specific volumes for each interval within a given set of trading periods (for example a quarter), the smaller its ability to minimise its exposure to future forward-contract and spot price uncertainty regarding that set of trading intervals.

Accordingly, the benchmark retailer would seek commitments regarding the minimum and maximum demand for each trading interval that it would be required to supply to SDP. The retailer could then forward contract on that basis. To minimise its risk exposure, the retailer would "over contract" for each trading interval compared with its best estimate of expected demand.

4.2.7.1. Retailer hedging and price structure decisions

Retailer hedging and retail pricing structure decisions are closely related. Multi-part retail pricing structures are widely used across the electricity supply sector. The objective is to signal the extent average wholesale costs vary depending on the volume, and timing, of demand and associated hedging costs.

A typical pricing structure may allocate demand volumes between peak, shoulder and off-peak demand periods. This means that average prices over say a year will be higher for customers whose demand volume is high during peak periods and low during off-peak periods and lower for customers whose demand volume is low during peak periods and high during off-peak periods.

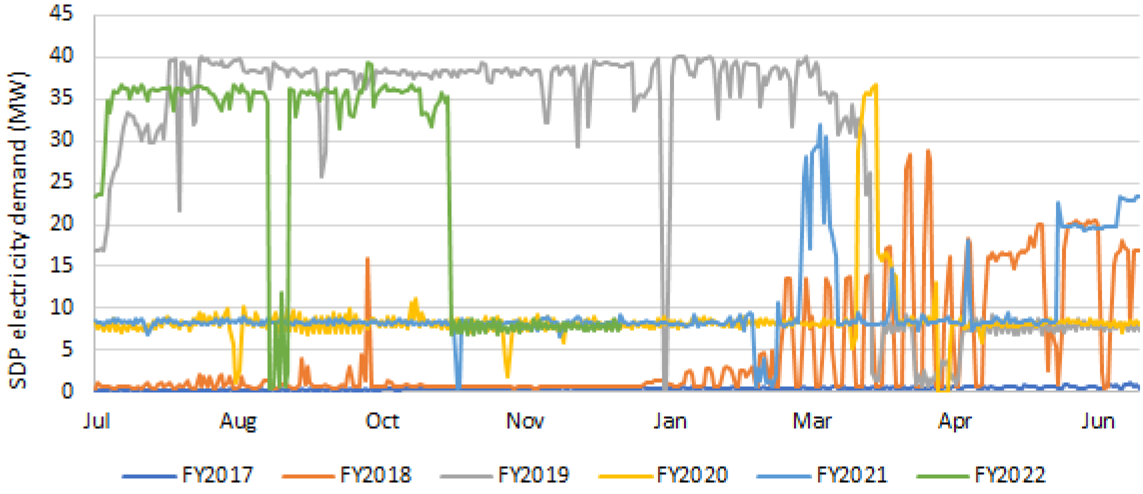
This typical pricing structure is not considered relevant or useful for SDP demand, because it would not reflect variability in supply costs for the benchmark retailer. This reflects our understanding there is no consistent intra-day variability of demand shape and that the plant will be able to reduce its demand during very limited duration extreme high wholesale price events, as discussed in below. Demand reduction reduces the retailer's obligation to purchase forward price caps.

The key driver of actual supply costs for SDP relates to optionality to vary demand over a quarter or year to reflect changes in daily and annual water deliveries. Figure 4-8 below plots SDP's daily demand for the past 5 years.

While on the one hand, like Figure 4-5, there are clearly three main operational modes, on the other hand clearly there is significant inter-day variability SDP's demand profile.

The implication of Figure 4-8 is that a prudent benchmark retailer would forward contract 100 per cent of potential SDP demand to hedge the possibility of short notice requirement to ramp to 100 per cent water production.

Figure 4-8 – SDP daily demand 2017 to Oct 2022



As noted earlier, electricity is traded in 5 minute intervals and therefore the benchmark wholesale price reflects intra-day demand variations, especially where maximum demand within a day exceeds average demand over even the highest daily demand day of the year. While average daily demand during mode 2 is 37.3MWh, a review of interval data provided by SDP reveals that maximum demand is 41MWh at some periods.[40] Maximum demand therefore needs to be reflected in the benchmark retailer's prudent forward trading.

Of the possible hedging options identified earlier, for benchmark price setting purposes, it is assumed that the retailer will exclusively hedge by trading in ASX electricity future swap contracts, at a quarterly resolution. This is because:

- ASX forward contracts are the most liquid and transparent available. Over the counter and other types of bilateral contracts are relatively illiquid and non-transparent.
- Cap contracts are not appropriate given SDP's demand profile discussed above. A retailer could make large trading losses from over-reliance on caps.
- Swap contracts are the best means of managing variability in SDP's actual demand.
- Quarterly rather than annual swap contracts are better suited to the potential seasonality in SDP's actual demand.

Details on the operation of swap contracts are provided in Appendix C. The remainder of this section describes the impact of hedging requirements on the benchmark price and structure.

Because the benchmark retailer would need to ensure it is always 100 per cent forward contracted (hedged), it will recover its full hedging cost regardless of the plant's operating mode and actual demand. The unit cost in this case has two components:

[40] MJA analysis of SDP interval meter data converted to 1 MWh units.

1. Volume. This refers to any volume mismatch between hedges and demand over the minimum period to which standardised hedges apply – a quarter.
    a. The unit for swaps is 1MWh. SDP's maximum historical demand is 41MWh. To avoid spot price risk, the retailer would need to procure swaps at maximum demand or to the nearest 1MWh above maximum demand.
    b. Demand above 40MWh only occurs for short periods and historically is a relatively small volume over a year and only during some years. Consideration was given to hedging to 40MWh and pricing spot exposure above 40MWh. Given that the incremental annual cost of hedging at 41MWh instead of 40MWh is slightly less than $100,000, it is clear a prudent retailer would hedge to 41MWh.
2. Risk premium. Even if there is zero volume mismatch, and contracted and physical volumes are perfectly aligned, there would be an expected risk premium – or a fixed to floating premium. This reflects the allocation of future price and volume risk under a swap between the supplier and buyer of these instruments. There is, for example, an asymmetric risk between $15,500 market cap prices and -$1000 market floor. In addition, the swap buyer's risk can be limited by contracting for a higher volume (see previous point). However, a swap seller's risk may be affected by low probability, high impact events, including transmission and plant outages.

The $/MWh swap and spot prices and estimated premia between swap and spot prices are shown in Table 4-11 below. The benchmark retailer would purchase swap contracts for the full daily electricity energy requirement. The benchmark retailer's energy costs comprise a variable cost for consumption volumes settled at the node spot price in the NEM and a fixed hedging cost for the potential consumption volume at the hedging premium (swap contract over the average spot price premium).

Table 4-11 Swap to spot price premium (ex-ante)

Component	Unit	2024	2025	2026	2027
Spot (not capped) [adjusted]	$/MWh	110.57	103.43	133.40	117.72
Swap [adjusted]	$/MWh	121.89	114.75	144.72	129.05
Ratio	%	110%	111%	108%	110%
Swap to spot premium	$/MWh	11.32	11.32	11.32	11.32

Source: MJA analysis from ASX data and internal spot price and contract price modelling. See Appendix B for further details. All values in Calendar Q1 $2023.

As discussed in Appendix B, the modelling assumes the 5-year average swap contract premium in each of the years to smooth out significant inter-annual and forecasting variations during a period of significant change in the NEM. From this the average NSW spot price was determined as the swap contract price less the assessed swap contract premium.

Ex-post swap to spot price premia (for an identical set of NEM trading intervals) may of course vary from ex-ante expectations at the time swaps are traded (via the ASX). Swap to spot price discounts may occur from time to time, for example where spot price spikes exceed expectations driving swap price premia at the time swap prices are settled via the ASX. This can result in contract for difference payments in favour of swap purchasers over a month or quarter. This does not change the fact that the benchmark retailer would expect to incur a swap premium at the time it settles swap purchases via the ASX.

Where physical and hedging demand volumes are more or less equal, the hedging cost per unit of energy used is typically in the range of 10 to 15 per cent. This means that, where SDP is operating at or close to its full capacity, the incremental hedging cost of premium per unit of electricity consumed reflects the risk premium plus the model mismatch discussed above.

Where the gap between SDP's actual and potential demand is large, then the hedging premium as a percentage of actual electricity demand becomes substantial. This is shown in the table below giving the over contracted volume for each of the three long term operating modes.

Table 4-12 Over-contracted volume variation by operating mode

Component	Unit	Mode 2	Mode 3	Mode 4	Non-production
Production	ML/d	250	125	50	0
Average energy Use per day	MWh	895.4	462.1	202.1	28.8
Average energy Use per hour	MWh	37.3	19.3	8.4	1.2
Swap contract reflecting maximum demand	MWh	41.0	41.0	41.0	41.0
Over contracted MWh	MWh	3.7	21.7	32.6	39.8
Over-contracted rate (swap/average)	%	110%	213%	487%	3417%

Source: MJA analysis. See Appendix B for further details.

The percentage of demand that is over-contracted varies from a low of 10 per cent under high production mode 2 through to 487 per cent under minimum production or mode 4.

4.2.7.2. Impact of non-production mode

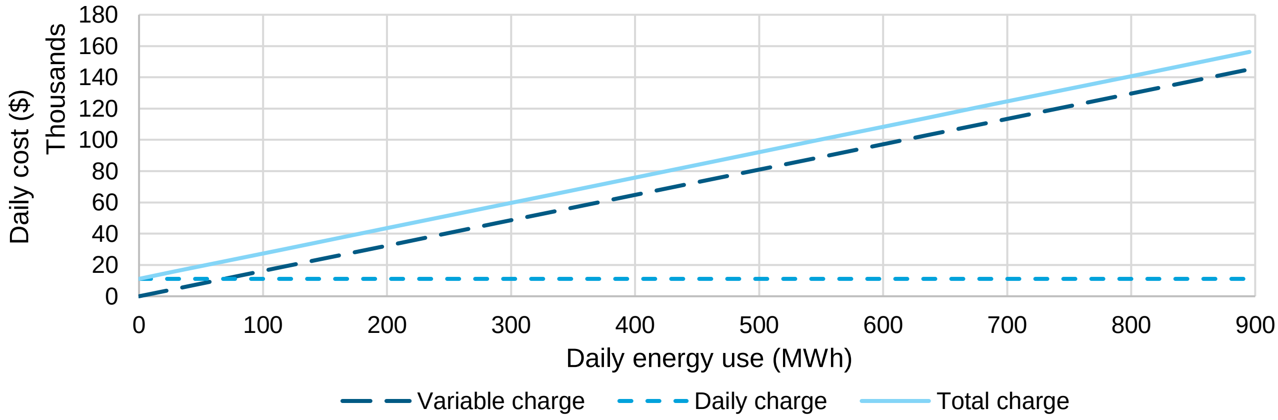
In the non-production mode, there are fixed costs arising from both over-contracting and the minimum energy requirement. It is assumed that, under the new operating environment, non-production mode will only occur for limited periods over a year. To estimate the effect of non-production mode on electricity demand, we used the percentage of days below 10Mld10Ml/d since the start of 2020. This was 3.7 per cent. For electricity benchmark price modelling purposes, this was rounded up to four (4) per cent.

4.2.7.3. Retailer retail pricing decisions

Given the fixed daily cost associated with over-contracting, a tariff structure with a single unit price across production levels will not be cost reflective. A two-part pricing structure is proposed as this will be cost reflective.

The figure below shows the fixed daily cost (horizontal blue dotted line) and a variable cost (dark blue upward sloping dotted line), relative to daily electricity demand for FY 2024. The daily total cost at different demand volumes is the light blue solid upward sloping line. The pricing structure can be applied to the other years.

Figure 4-9 – Daily $/MWh price by production volume (including 4% non-production)



4.2.8. Benchmark electricity prices

The two components of the estimated benchmark electricity prices are given in the top two rows of Table 4-13 below for each year of the period. They are all expressed in constant 2023 dollars, using RBA inflators and deflators. The cost build-up of the benchmark electricity prices is shown in the following Table 4-14.

Table 4-13 - Benchmark electricity prices ($FY23)

Price component	Unit	2024	2025	2026	2027
Fixed charge	$ per day	11,129	11,141	11,090	11,117
Variable charge	$/MWh	162	151	176	156
Fixed charge inc 28.8MWh fixed daily energy	$ per day	15,788	15,482	16,156	15,596
Variable charge inc 28.8MWh fixed daily energy	$/MWh	162	151	176	156

For converting the benchmark electricity price to an electricity price per ML (fixed and variable), the fixed charge should be inclusive of the energy consumption when the plant is in non-production mode. The bottom two rows in Table 4-13 give the estimated electricity benchmark rates, with the assumed 28.8MWh minimum daily volume. The fixed charge is increased, now accounting for both the over-contracting premium (e.g. $11,129/day in FY2024) and the minimum electricity consumption ($4,659/day in FY2024). The variable electricity rate for energy consumed above this minimum amount remains unchanged.

In developing the forward price estimates underpinning benchmark prices, consistent with industry practice, we referred to NSW forward swap contract market data. Price data for NSW base quarter futures products to Q2 2026 were obtained on 15 February 2023.

At this time, futures products will not be available for three of the four regulatory years, so we were required to use our market model to estimate the swap and spot prices for the final two years of the period. Our method included ensuring the historical future model outcomes and market data align for the available data from July 2022, with a good alignment.

For 2026 our modelled prices increase from 2025, reflecting higher uncertainties and risk for 2026. At the time the report was finalised at the end of March 2023, some initial lightly traded forward prices have become available for calendar 2026. The lightly traded ASX futures for 2026 were, however, more or less at the same prices as for 2025.

A decision was therefore required whether to use modelled future prices for the third as well as fourth year of the regulatory period. In our view, early traded price data three years out does not reflect a prudent retailer's assessment of future market risks, particularly the uncertainty around the timing of exits and entries of major generation and storage facilities. Accordingly, the proposed benchmark prices are based on two years of ASX futures and two years of MJA modelling.

The prudent retailer would provide SDP with contract prices linked to a defined offer period, with provisions to vary the offer in the event of material changes in market conditions. The prudent retailer would therefore monitor and review NSW forward curve data for variations.

Our approach to considering any variation reflects the dynamics of an arms' length transaction between a sophisticated buyer and seller. A material reduction in forward prices would likely be passed through by the retailer, to avoid the risk that SDP could switch to an alternative supplier. Similarly, a material increase in forward prices would also be likely to be passed through, to protect the retailer's margin.

If MJA considers that a material and permanent shift in forward wholesale prices has occurred, then MJA would propose that the Benchmark Price be recalculated based on an updated forward price curve. The assessment of whether an observed change represents a shift would be based on factors that include any observed trend, the basis for an observed shift (such as a major announcement on entry or exit), and consistency with Marsden Jacob modelling.

The table below gives the cost build-up of unitised benchmark prices for the rates in Table 4-13 above, in per MWh (variable) and per day (fixed) units. Most components are variable with consumption except swap contract premium and metering costs which are converted to daily fixed costs.

Table 4-14 Estimated retailer cost stack for SDP benchmark price

Component	Group	Unit	FY2024	FY2025	FY2026	FY2027
Energy	Energy	$/MWh	110.57	103.43	133.40	117.72
Energy losses	Energy	$/MWh	0.19	0.18	0.23	0.20
Swap contract premium	Energy	$/day	10,957	10,969	10,919	10,945
LGCs (18.64%)	Green	$/MWh	8.50	7.92	6.57	5.41
GGRP (54.10%)	Green	$/MWh	24.68	21.12	17.09	13.72
STCs (27.26%	Green	$/MWh	10.90	10.90	10.90	10.90
ESS (NSW Energy Saving Scheme)	Green	$/MWh	3.30	3.46	3.63	3.80
Ancillary Services	Other	$/MWh	0.36	0.36	0.36	0.36
Market fees (AEMO)	Other	$/MWh	1.17	1.17	1.17	1.17
Metering and Data Costs	Other	$/day	6.99	6.99	6.99	6.99
Fixed cost ex retail margin	*Total*	*$/day*	*10,964*	*10,976*	*10,926*	*10,952*
Variable cost ex retail margin	*Total*	*$/MWh*	*159.66*	*148.55*	*173.36*	*153.28*
Fixed cost inc retail margin	**Total**	**$/day**	**11,129**	**11,141**	**11,090**	**11,117**
Variable cost inc retail margin	**Total**	**$/MWh**	**162.06**	**150.77**	**175.96**	**155.58**

Source: MJA modelling

As discussed above, a prudent retailer will purchase annual/quarterly swap contracts and incur the swap contract premium costs irrespective of volume of consumption in that period. Metering and data costs are charged on an annual basis. Both these fixed costs have been unitised to daily costs. The cost components are summed before applying a 1.5% retail margin to all costs.

Depending on annual demand, the retail margin component of the benchmark price is between $2.3m and $10,1m annually (at 2024 benchmark price values) and allows the retailer to recover its internal costs other than those itemised in the above cost stack. The 1.5% margin is consistent with industry pricing where commercial and industrial segment margins are modest compared with marks ups for mass market customer segments. In this case, customer acquisition costs would be amortised over four years. Other costs recovered from this margin include billing and the retailer platform (including responding to queries) and provision for working capital. Competition for commercial and industrial customers is strong and this limits opportunities to charge higher margins.

In addition to forward contracting, a prudent retailer would also manage its risk and protect its margin via the terms and conditions of its contract with SDP. Consistent with standard industry practice, the retail contract would include pass-through clauses in relation to material changes in parts of the cost stack the retailer is unable to forecast, hedge or otherwise manage. This typically includes provision to pass-through any material changes in Commonwealth, State and Local government taxes, or the impact of any other material changes in regulatory requirements. Pass-through items typically include changes in network cost and AEMO market fees. The estimated SDP benchmark price assumes that standard industry pass through clauses apply and therefore provisions for any material changes in the defined costs are not required in the retail margin.

As shown in the table above, it is assumed that the balance of the GGRP obligation, above the mandatory renewable energy requirement, is met by the purchase of LGCs. This reflects the higher level of liquidity in LGC market compared with STC markets. Similarly, the change in the ESS (NSW Energy Saving Scheme) unit cost over the period reflects decisions already made regarding ESS.

4.3. Estimated energy cost per annum

The table below shows estimated annual cost of electricity at the benchmark prices where annual demand exactly matches the defined production modes. This total annual cost is derived for the electricity rates in the two top rows of Table 4-13 above, including:

- The fixed cost being 365 days at the benchmark fixed charge, and
- The variable cost being the benchmark variable charge and the annualised daily volume reduced by a factor of 4% accounting for the average annual period of non-production days per year when the desalination plant is not operating for maintenance or other purposes.

Table 4-15 illustrates the fixed cost of electricity contracting and fixed energy use of around $5.8 million p.a., and the linear increase in costs with volume of water production/energy consumption.

Table 4-15 Estimated annual cost of energy per year by production mode ($FY23 Million)

Operating mode	Production (ML/d)	Energy Use (GWh/annum)	2024	2025	2026	2027
High	250	313.7	54.9	51.4	59.3	52.9
Medium	125	161.9	30.3	28.5	32.5	29.2
Low	50	70.8	15.5	14.7	16.5	15.1
Non-production	0	10.5	5.8	5.7	5.9	5.7

Source: MJA modelling

5. Capital expenditure

5.1. Efficiency of capex in FY2017 and the 2017 Determination period

FY2017

In FY2017, SDP's capital expenditure was $0.02 million and is attributed to corporate capital expenditure. In the 2012 determination period, SDP's capex allowance was $1.97 million. We consider that $0.02 million corporate capex is not material. Therefore, we do not view that any adjustments or efficiency questions are required.

2017 Determination Period

SDP's capex for the last Determination period was dominated by the Membrane Replacement program which took place in FY2019. Overall, SDP's expenditure allowance for 2017-2022 was $52.87M ($FY23), while actual spending by SDP for the same period was $43.26M ($FY23). This equals a variance of $9.61M of underspend by SDP. A summary of capex for the 2017 Determination period is shown in Table 5-1.

Table 5-1 - Summary of capex for FY2017 and the 2017 Determination period ($FY23 Million)

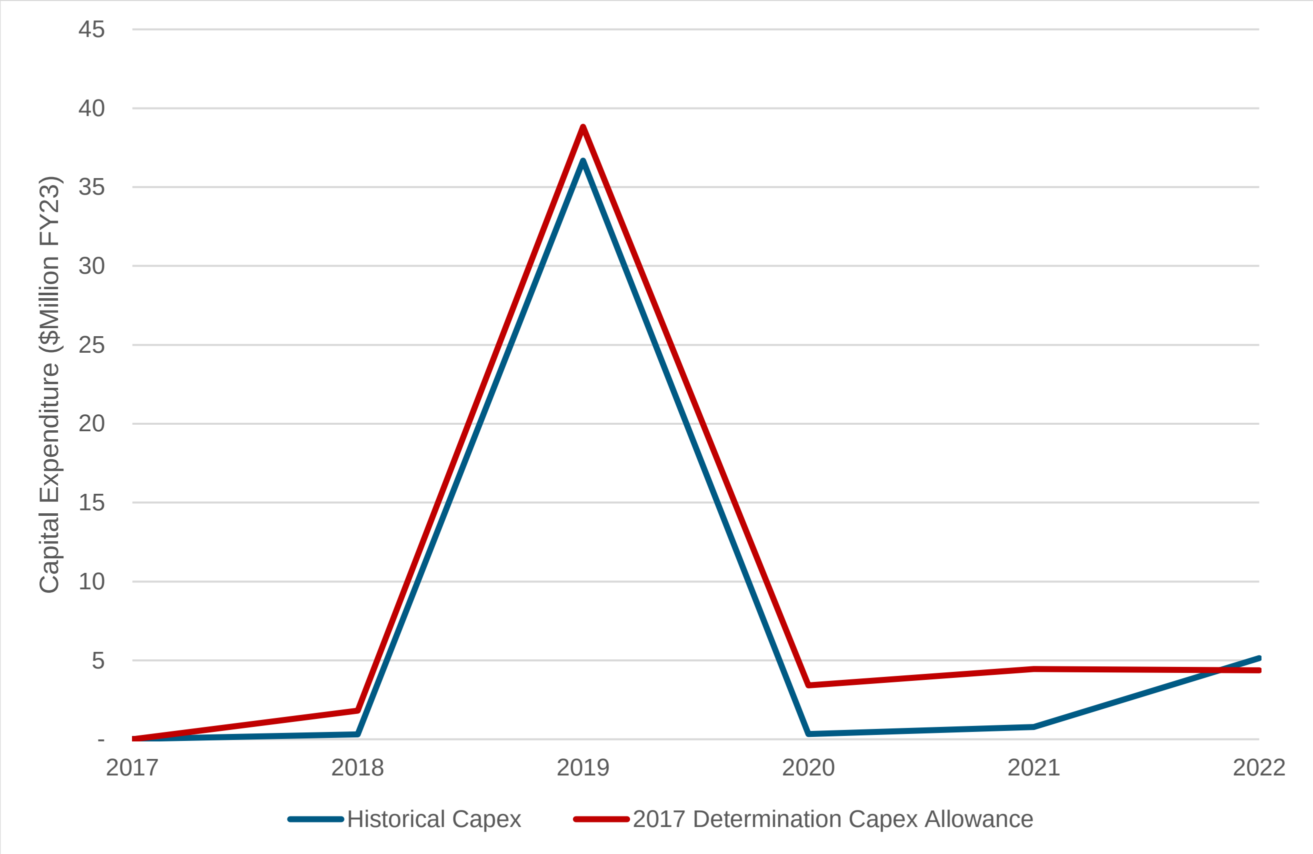
Description	2017	2018	2019	2020	2021	2022	Total 2018-22
Plant – Other Plant Projects	-	0.01	0.46	0.07	0.44	1.68	**2.67**
Plant – Periodic Maintenance	-	-	1.62	-	0.03	2.66	**4.31**
Plant – Pumping Station	-	-	0.43	0.14	-	0.17	**0.75**
Total Plant (Excluding Membrane)	-	0.01	2.52	0.21	0.47	4.52	**7.73**
Plant – Membranes	-	-	33.36	-	-	-	**33.36**
Pipeline	-	0.04	0.76	0.12	0.30	0.61	**1.83**
Corporate	0.02	0.27	0.04	0.01	0.02	0.01	**0.34**
Total	**0.02**	**0.32**	**36.68**	**0.34**	**0.79**	**5.13**	**43.26**
Capex Allowance	**-**	**1.82**	**38.81**	**3.41**	**4.46**	**4.36**	**52.87**
Variance	**0.02**	**(1.50)**	**(2.14)**	**(3.07)**	**(3.67)**	**0.77**	**(9.61)**

Sources:

- ATK-014_Projects by Year – provided by SDP
- SDP 2023-27 PTRM – FINAL
- 2017 SDP review Final Report, IPART

Figure 5-1 provides a demonstration of SDP's historical capex in comparison to the expenditure allowance as well as future total capex proposed by SDP. In its price submission, SDP provided that the capex underspend is attributed to the renewals and refurbishment that occurred after the storm event, rigorous assessments of asset conditions and rectifying deficiencies, and SDP's decision to delay certain capex items after assessments.

Figure 5-1 – Historical Total Capital Expenditure Summary



5.1.1. Plant capex

Based on information provided by SDP[41], Plant capex for the 2017 Determination is spread across categories with the following understanding:

- Plant:
  a. Other plant capex: This category is allocated to expenditure items on specific projects in the Plant, excluding specific drinking water pumping station (DWPS).
  b. Periodic Maintenance: All expenditure items regarding to periodic maintenance, including DWPS, fall under this category.
  c. DWPS: Expenditure items relating to DWPS specific projects.
- Membrane Replacement: Expenditure specific to the membrane replacement program that took place over the 2017 determination period.

SDP's Plant capex during the Determination period was around $41M with the majority being for the membrane replacement program ($33.36M) and a relatively small capex for the remaining categories ($7.73M). In this section, we will discuss the efficiency and prudency of plant capex for each category.

In the process of developing the report, SDP raised concerns regarding the separation of non-membrane plant capex as the IPART 2017 Determination capex allowance did not include regulatory sub-categories for plant capex. We indicate that even though the regulatory allocation aggregated plant capex allowance, documents[42][43] leading up to the 2017 Determination discussed sub-categories of plant capex such as periodic maintenance and DWPS separately. For example, the 2017 Determination plant capex allowance recommended comprises of capitalization of periodic maintenance minus SDP proposed DWPS investment and permeate hose cost.

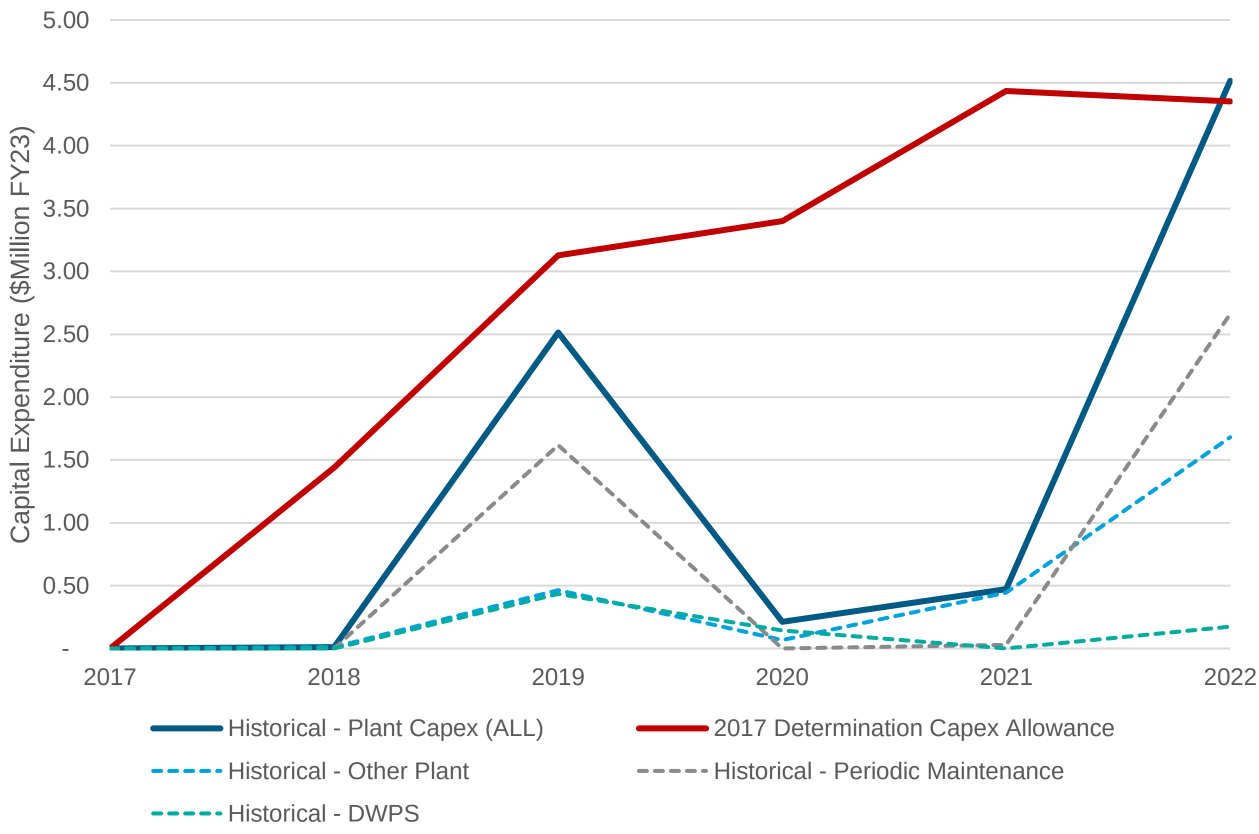
[41] *ATK-014_Projects by Year.xlsx* which provides actual expenditure for the 2017 Determination period per project, category, and accounting class.
[42] SDP Price Review Final Report, IPART, 27 Jun. 2017
[43] SDP Expenditure Review, Atkins Cardno, 21 Mar 2017

Therefore, we view that reviewing plant capex sub-categories against the allowance provides a comprehensive review of efficient capex and inform, with limitation, future plant capex.

5.1.1.1. Plant

Because the 2017 determination period plant capex in IPART's final report included periodic maintenance, we have prepared Figure 5-2 to represent SDP's actual plant capex compared with the 2017 determination allowance excluding the membrane replacement program. Although Plant capex was summed in the 2017 Determination Final Report, it is useful to review capex for each of the three subcategories independently as designated in SDP's documents shared with the Consultants.

Figure 5-2 - Historical Capex Compared with 2017 Determination Allowance



<u>Other Plant Capex</u>

SDP has reported $2.67M in other plant capital expenditure (excluding membrane replacement). The other plant capex is associated with specific capital projects that SDP undertook over the last Determination period. The largest capex year in this category is FY22 where SDP commenced its control system upgrade, which has a total of $1.16M , which includes the early works for the whole program capex project. Our view on the control system upgrade project is discussed further in section 5.2. Although we recommended a slight adjustment to the overall project, we view the spending on early works of the control system upgrade as prudent and efficient. All other plant capex items are also considered to have been carried out efficiently and prudently.

<u>Periodic maintenance</u>

During the 2017 Determination period, SDP undertook 11 periodic maintenance projects, of which nine took place in FY22. The total periodic maintenance capex for the last Determination period was $4.31M (including only $28K in 2021). In its reporting of the periodic maintenance capex, SDP included both plant and DWPS periodic maintenance activities.

In the last Determination period, the Consultants' Report[44] provided that $16.75M ($FY23) should be allowed for SDP to spend on periodic maintenance. This cost was a capitalization of opex items that were considered by the consultants (including Atkins), and accepted by IPART, and that should be reviewed every year.

We accept that during operation, SDP had to make capex decisions where amounts from periodic maintenance allowance was spent on other non-periodic maintenance plant activities. Although in the 2017 Determination, IPART did not provide a standalone allowance for periodic maintenance, the build-up of the Plant Capex was majorly composed of the capitalization of periodic maintenance. Overall, we consider that the periodic maintenance allowance was significantly underspent compared to the allowance provided by IPART in the 2017 determination period as demonstrated in Table 5-1 and Figure 5-2. SDP relay that this is due to prudent decision making which directed them to defer the periodic maintenance investment as well as operational requirements to deliver contracted water. In our view, we add that SDP in its periodic maintenance proposal might have overestimated and took a conservative approach. This is understood given that SDP was not operating prior to its re-start. In this report, we have considered this underspend to reflect a more prudent and accurate estimate of periodic maintenance in the next determination period (section 5.2).

We consider a capitalization policy as a best-practice to clearly define and provide guidance to users, enable consistency in approach and inform regulators on what amounts can be considered a capital cost opposed to operating cost. We have enquired about SDP's capitalization policy and SDP clarified that it does not have a specific document stating its capitalization policy. However, it has stated that its capitalization complies with the Australian Accounting Standard Board 116 (AASB 116).

The O&M Contract defines periodic maintenance as works exceeding $30,000 for plant asset. For DWPS assets, periodic maintenance is works involving replacement or addition of spare parts or the planned overhaul or renewal of specific items of plant and equipment forming part of DWPS, which is the same for pipeline assets.

We recommend that SDP establishes a clear written capitalisation policy.

Pumping station (DWPS)

The drinking water pumping station (DWPS) capex in the last Determination period was $0.75M. Six activities under this category were undertaken during the last Determination period, which include improvement to various elements of the drinking water pump station (DWPS). It is worth noting that DWPS investments were recommended to be deferred to the current Determination period. We have assumed that SDP have carried out necessary evaluation of the investment since the restart of the plant.

In our view, SDP's DWPS capex in the last Determination is considered to be efficient and prudent.

5.1.1.2. Membrane replacement

SDP's report on the prudency of membrane replacement[45] provides the actual cost incurred by SDP as well as the approach taken to achieve an efficient and prudent replacement. In the report, SDP states that the total cost of the membrane replacement was $33.36M including purchase, procurement, installation, and membrane disposal (Table 5-2).

Table 5-2 – Summary Costs of Membrane Replacement during the 2017 Determination period

	Unit Cost	Avg. Exchange Rate	Number	Total ($FY19 Million)	Total ($FY23 Million)
Membrane first Pass	[redacted]				
Membrane second Pass					
Procurement/shipping					
Installation/disposal					
Membrane Disposal					
Total				**29.10**	**33.36**

Sources:

- SDP Report - Prudency of membrane replacement in 2019

[44] Consultant Report by Atkins Cardno – Expenditure Review, 21 Mar 2017
[45] SDP Report: Prudency of membrane replacement in 2019, SDP, 18 June 2020

During the procurement phase, SDP has reached out to three different RO membrane manufacturers, including the manufacturer of the old RO membrane, Dow. Their decision to go with Dow was heavily influenced by delivery time as other suppliers could not commit to SDP's timeline (final batch arrival in June 2019). It also was stated that Dow had shown willingness to meet delivery time given the relationship as current supplier. We consider that the selection of the RO membrane manufacturer to be prudent and efficient.

SDP's membrane purchase, procurement and shipping comes to $27.16M. [redacted] SDP ensured that since membrane replacement was considered a capex in the 2017 Determination period, the fixed O&M cost does not cover margin, overhead, or project management. The remaining $0.16M is attributed to port charges, bank guarantee, and spares, which we view as acceptable and reasonable.

Additionally, SDP went out for competitive bid for the installation of the RO membrane. Three contractors, including Veolia, submitted their bid with Veolia providing the lowest price. [redacted] Similar to the mark-up for procurement, we recommend that SDP reviews the O&M contract for future membrane replacement projects to identify inclusion of project management, supervision, and margins for activities like membrane replacement.

Compared to the allowance provided to SDP for the membrane replacement project ($35.67M), SDP has delivered the project with an underspend of $2.31M.

Our view is s that SDP has acted prudently and efficiently in carrying out the membrane replacement project. However, we note that SDP should explore the opportunity to remove the cost associated with project management, supervision, and margins as it may be included in the fixed operating cost through the O&M Contractor

5.1.2. Pipeline

Pipeline capex in the 2017 Determination period was $1.83M, which represents the expenditure for four projects. Some of the main items include pipeline repairs that took place every year during the last Determination period. Additionally, SDP carried out inspection of the Botany Bay section of the pipeline and implemented a project to resolve the flooding of the pipeline air valve.

We consider that the pipeline capex for the 2017 Determination period to align within our expectation of prudent and efficient expenditure.

5.1.3. Corporate

Corporate capex was $0.34M in the last Determination period. The largest spending under this category is attributed to the office interior renovation which took place in 2018. All other corporate capex includes the purchasing of office equipment such as PC's, work phones, and other IT equipment.

After reviewing the corporate capex in the 2017 Determination period, we consider it to be efficient and prudent.

5.1.4. Total capex summary

For the 2017 Determination period, SDP significantly underspent against its total capex allowance. We recommend that SDP's actual capex in the current determination period be adopted without any adjustments.

We recommend that, in the next Determination period, SDP establishes a clear written capitalisation policy.

5.1.5. Asset Disposals – 2017 Determination Period

In the last determination period, SDP declared a total of $133.14M ($FY23) in asset disposal. The disposal amount is attributed to two categories of the desalination plant asset class.

- $88.03M is the de-recognition of storm-damaged assets as the reinstatement of these assets were fully funded from insurance claims.
- The remaining $45.11M relates to the disposal of the original membranes which were replaced over the 2017 Determination period.

Through an enquiry regarding assets disposal, SDP stated that the relevant asset disposal line items were applied following discussion with IPART.

Given that the insurance-funded capex associated with storm-damage has not been added to RAB, it is consistent that the associated assets should not be removed from RAB.

We also note that membranes were assigned an asset life of eight years in the last Determination. As such, we understand that they will have been fully depreciated by the time they were replaced in 2019. As such, it appears reasonable that no adjustment to RAB would be required for disposal of the membranes.

5.2. Efficiency of capex in the 2023 Determination period

In our review of SDP's capex, we have considered the on-going efficiency that SDP applied from FY24. When reviewing capex projects, we evaluated the SDP's proposal prior to the application of the efficiency factor. Therefore, recommended capex are values that represent an evaluation of SDP's pre-efficiency proposal. The pre-efficiency proposed capex items were obtained through various documents that SDP shared with the expenditure review team. Table 5-3 below summarizes our approach regarding the on-going efficiency factor.

Table 5-3 – Summary of approach regarding the application of efficiency challenge

Capex item	Explanation
Plant – Specific Projects	The evaluation of each reviewed project was done using documents that SDP provided which includes pre-efficiency proposed capex. The adjustments shown for reviewed projects are in relation to pre-efficiency proposed values. However, the overall Plant capex adjustment in Section 5.5 shows the difference between post-efficiency SDP's proposal for Plant capex and recommended Plant capex. i.e. adjustment for overall capex includes SDP's efficiency challenge.
All other Capex	Recommended capex for all other capex items were in relation to pre-efficiency proposed capex using documents provided by SDP separately. However, the adjustments are the difference between the post-efficiency proposed SDP values and pre-efficiency recommended values. i.e. adjustments include efficiency challenge presented by SDP
Post-efficiency recommended capex	Efficiency challenge presented by Atkins-MJA have been applied in relation to pre-efficiency recommended values which do not use SDP's post efficiency values. Therefore, post-efficiency recommendations do not double-count efficiency challenge presented by SDP.

5.2.1. Plant – specific projects

SDP has proposed a $15.24 million cost for plant capex over the next determination period The Plant capex includes specific plant projects which SDP has identified in its proposal. The purpose and justification vary for each project. In this review, we focused on certain projects that have higher value and are considered more complex. The review aims to identify and evaluate the efficiency and prudency of these projects.

5.2.1.1. RO Vessel Sampling Panels

The current design of the plant includes a sampling of the RO train vessels as a whole. The current sampling panels provide measurement for the train (28 vessels or 224 membranes). To narrow down the search for faults in the permeates quality (e.g. high conductivity), a manual sampling for each vessel takes place, where an O&M employee is lifted using a scissor lift to sample the effluent from the RO trains. This procedure exposes the plant's workforce to high pressure elements in the process of collecting the sample. To reduce the hazard, SDP proposes to install RO sampling panels for each vessel. This is generally viewed as best-practice and other equivalent desalination plants include this feature from initial design of the plant.

SDP's business case for this Capex project provides that it takes place over three years, where the first year (FY23) includes a pilot; installing a sampling panel for one (1) train. The pilot allows SDP to evaluate the performance of the panel and add adjustment as required. For the initial 1-year pilot, SDP provided the following breakdown.

Table 5-4 – SDP RO Sampling Panels Cost Estimate (1 year pilot) ($FY23)

Description	%	Cost
Supply and Installation		[redacted]
Project Management	5	
Overhead and Margin	15	
Total Supply and Installation Cost		
SDP Contingency	15	
Total Proposed		

Sources:
- ATK-005_2. CAP042A - RO Sampling Panels - BC Recommendation (Approved)

The supply and installation cost requested by the operator to complete the RO sampling 1-year pilot is considered reasonable. The operator includes project management, overhead, and margin in the total costs, which is viewed as acceptable given that the RO sampling panels, once installed, are added new assets. SDP also includes a 15% contingency to allow for variation to the scope. The contingency is reasonable given the level of risk in implementing this project.

The operator provided in the Capital Request Business Case for the RO sampling panels an estimate for installing the remaining [redacted] panels. The breakdown of the cost is shown below.

Table 5-5 – SDP Proposed RO Sampling Panels Cost (remaining [redacted] panels) ($FY23)

Description	%	Cost
Supply and Installation		[redacted]
Project Management	5%	
Overhead and Margin	15%	
Total Supply and Installation Cost		
SDP Contingency	15%	
Total Proposed		

Sources: Sources:
- ATK-005_2. CAP042A - RO Sampling Panels - BC Recommendation (Approved)

The estimate assumes a supply and installation cost of [redacted] for each panel. Given that the first panel will be installed as a one-off cost and the remaining [redacted] will be installed in bulk, it is expected that there will be an economy of scale. For example, a single supplier might provide a discount for the purchase of [redacted] panels. Additionally, it is expected that the labour cost will be reduced when installation is done in bulk. This is also aligned with SDP's statement in the price submission regarding using the first panel to

> "*evaluate the design and collect sufficient information to enable competitive submissions (quotes or tender) for delivery of the remaining 19 panels over the following two years.*"

Therefore, it is recommended that the cost of supplying and installing the remaining [redacted] panels would have a 15% reduction from what is proposed by SDP as shown in Table 5-6.

Table 5-6 – Recommended RO Sampling Panels Cost (remaining 19 panels) ($FY23)

Description	%	Cost
Supply and Installation		[redacted]
Project Management	5%	
Overhead and Margin	15%	
Total Supply and Installation Cost		
Contingency	15%	
Total Recommended		

Sources:
- ATK-005_2. CAP042A - RO Sampling Panels - BC Recommendation (Approved)

The capex cost for the RO sampling panels project is summarised in Table 5-7 below. It is recommended that, on total, a reduction cost adjustment of $255,883 be applied on the SDP proposed cost for the RO Sampling Panel. We note that for FY23, SDP requested a cost lower than that is quoted, our recommendation includes the quoted cost instead of the proposed, which is higher by around $3,000.

Table 5-7 - RO Sampling Panels Cost Summary ($FY23 Million)*

Description	2023	2024	2025	2026	2027	2028	Future Determination (FY24-27)
SDP Proposal*	0.08	1.04	0.61	-	-	-	1.65
Adjustments	0.003	(0.16)	(0.09)	-	-	-	(0.26)
Recommended	0.09	0.88	0.51	-	-	-	1.39

Sources:
- ATK-014_Projects by Year
- SDP Pricing Submission
- ATK-005_2. CAP042A - RO Sampling Panels - BC Recommendation (Approved)

***reviewed plant capex are evaluated and presented in pre-efficiency values**

5.2.1.2. Control Systems Upgrade

SDP proposes to upgrade multiple aspects of the control systems for the plant. This project involves upgrading the PLC's, fieldbus hardware, [redacted] and SCADA systems. SDP proposes that this project takes place in three stages. Stage 1 includes providing early works to lay grounds for the upgrade. The first stage had already taken place with a scheduled completion of July 2022. The remaining two stages are expected to be completed at the beginning of the FY24 (August 2023). [redacted] This is due to multiple factors including hardware replacement and repair difficulties due to the age of the asset. [redacted]

The proposed project to upgrade the control systems is viewed to be reasonable and recommended. We acknowledge that a desalination plant of this size requires a system that allows for an efficient operation. In addition, the control system upgrade project [redacted]

SDP's proposed cost is applied for the years FY23 and FY24. The costs provided by SDP do not match the cumulative amounts from the business cases for the control system upgrades (Business Cases are dated as FY23). Per information received from SDP, this is due to two factors:

- The business cases include costs that were incurred prior to FY23 and are represented in the 2017 Determination period.
- The proposed cost includes the upgrading of the data logging and reporting system (Historian) which does not have a business case developed yet.

The non-development of a business case for the Historian system upgrade capex is not in accordance with best practice process. Understanding that certain limitations might have impacted this, we want to emphasize the importance of developing business cases for requested capex. However, we acknowledge that the Control System update is a holistic program with many potential benefits, [redacted]. Therefore, we do not recommend adjustments to the proposed capex for this project as shown in Table 5-8.

Table 5-8 – Control System Upgrade Cost Summary ($Million FY23)*

Description	2023	2024	2025	2026	2027	2028	Future Determination (FY24-27)
SDP Proposal*	3.56	1.26	-	-	-	-	1.26
Adjustments	-	-	-	-	-	-	-
Recommended	3.56	1.26	-	-	-	-	1.26

Sources:
- ATK-014_Projects by Year
- ATK-006_1 to ATK-006_11
- SDP's Pricing Submission

***reviewed plant capex are evaluated and presented in pre-efficiency values**

5.2.1.3. Additional HV Feeder

The SDP plant is connected to an Ausgrid substation through a high voltage (HV) cable. The plant receives a supply of 132kV and a backup supply of 11kV from the Ausgrid Kurnell South ZS. The current connection is a single point to the substation and in the case of maintenance or failure of the cable, the plant shuts down or is unable to deliver 250 Mld. SDP proposes to avoid this single point of failure by adding another cable to the same substation but using a different breaker. SDP provided that generally when maintenance is required for the substation, only one breaker is impacted, hence SDP expects that connecting to the same substation using another breaker will significantly reduce the risk of a single point failure. It is also understood that SDP maintains regular weekly meetings with Ausgrid for operational discussions, including scheduling maintenance and planning future projects.

We agree that reducing the risk of a single point failure is reasonable and recommended, specifically for plants of similar size. However, we emphasise that before progressing the project, SDP should clarify with Ausgrid that a connection to another breaker will prevent shutdowns, at least, during regular substation maintenance impact. It is also understood that the power supplied from the substation from each cable, current and future one, should have the capacity to power the plant even after an expansion (up to 500 Mld).

In SDP's pricing submission Appendix 10.8 HV Feeder Project Summary, a high-level estimate was provided. The estimate includes a cost for the supply, design, and construction of the project as well as project management and contingency allowance as shown in Table 5-9.

Table 5-9 – HV Feeder Cost Estimate – Proposed by SDP ($FY23)

Description	%	Cost	
Supply			[redacted]
Ausgrid Design and Construction Works			[redacted]
Supply, Design, and Construction Total			[redacted]
Project Management and Supervision	22%		[redacted]
Contingency	10%		[redacted]
Total Project Estimate			[redacted]

Source:
- SDP's Pricing Submission Appendix - 10.8 SDP project summary: Dual 132kV Feeder

We acknowledge that the supply and construction work estimates are high-level, which is generally acceptable during this stage of the project progression. We expect that this will be further developed but the cost allocated is reasonable including the proposed allowance for contingency. As for the project management and supervision-allowance, SDP has requested 22% of the supply, design, and construction total. From an initial point of view, this is regarded as high. We propose that this value is reduced to represent 15% of the supply, design, and construction total. The value is reflected in the recommended line in the below Table 5-10.

Table 5-10 – Dual HV Feeder Cost Estimate – Recommended ($FY23)

Description	%	Cost	
Supply			[redacted]
Ausgrid Design and Construction Works			
Supply, Design, and Construction Total			
Project Management and Supervision	15%		
Contingency	10%		
Total Project Estimate			

Source:

- SDP's Pricing Submission Appendix - 10.8 SDP project summary: Dual 132kV Feeder

Therefore, for this project, a total adjustment of $0.55 million is recommended as shown in Table 5-11.

Table 5-11 – Dual HV Feeder Cost Summary ($FY23 Million)*

Description	2023	2024	2025	2026	2027	2028	Future Determination (FY24-27)
SDP Proposal*	-	-	-	1.61	1.61	-	3.22
Adjustments	-	-	-	(0.08)	(0.08)	-	(0.16)
Recommended	-	-	-	1.53	1.53	-	3.06

Sources:

- SDP's Pricing Submission Appendix - 10.8 SDP project summary: Dual 132kV Feeder
- SDP's Pricing Submission

***reviewed plant capex project are evaluated and presented in pre-efficiency values**

5.2.1.4. Ongoing Efficiency

SDP proposes $2.19 million in ongoing efficiency projects as part of the plant specific projects capex. The purpose of the requested allowance is to increase the efficiency, reliability, availability, or safety of the plant. SDP does not specifically identify the projects that will be included in this category. However, it gives the Lime System Improvements as an example.

In various meetings with SDP, specifically on 11 Jan 2023, we discussed the issue of trimming the impellers to reduce the pump power requirements as it is currently being throttled to reduce pressure and achieve required flows in the system. This process represents energy loss that SDP can overcome by exploring trimming the impellers. We believe that trimming the impellers will offer reasonable savings in its operating energy expenditure and recommend that some of the amount in the ongoing efficiency allowance requested be allocated to the trimmings of the impeller. In the case that SDP is concerned about losing capacity of the plant due to trimming of the impeller and that the additional capacity might be needed if an expansion (phase 2) occurs, we recommend that SDP explores the option of buying a spare full-size impeller and trimming the current one, or vice versa as it sees fit. We view this project as an opportunity for SDP to become more efficient while retaining its capacity.

Acknowledging the state of the plant and the need to increase its efficiency, we view that the ongoing efficiency capex to be prudent and efficient. We recommend that the associated cost of $2.19 million be included in the next Determination period.

5.2.1.5. Second Drinking Water Tank

In its pricing submission, SDP presented a project to build a second drinking water tank with an initial estimated cost of $22.90M. The current plant site includes an area that is set aside for an additional storage tank to accommodate an expansion in production from 250 Mld to 500 Mld. The project presented in the submission was developed as a result of consultation with Sydney Water regarding the benefits of a second tank for the costumers. The proposal states that the cost of building the second drinking water tank is not included in the proposed capex as SDP is unable to clearly demonstrate prudency without further information. Additionally, SDP did not present a business case for the project.

Our view is that SDP has not demonstrated that the project is prudent as it has stated in its submission. Sydney Water, in its response to the 2023 Determination Issues Paper, expressed its support for the second drinking water tank project as it provides additional storage capacity and increase its reliability. However, Sydney Water did not present any material case for how this project will provide benefits to the costumer. Therefore, like SDP, we are unable to recommend this project to be included as an efficient and prudent capex.

5.2.2. Plant – periodic maintenance

SDP's proposal includes a cost of $23.41M for periodic maintenance. It is stated in the submission that the cost includes regular inspection and significant periodic maintenance overhauls of major assets. The proposed cost is influenced by the expectation that equipment replaced or renewed after the 2015 Storm Event are reaching their age for an overhaul or replacement. In addition, the cost proposed is derived from suggested maintenance intervals in equipment manufacturers manuals adjusted using risk-based predictive modelling.

Per documents provided by SDP[46], the periodic maintenance program includes 41 different scopes with 67 periodic maintenance activities over the next Determination period. Some of these projects only take place over one year while others over several years. The cost for each year is based on O&M manual and OEM recommendations.

Table 5-12 – SDP Proposed Periodic Maintenance Breakdown ($FY23 million)

Main Activity		2023	2024	2025	2026	2027	2028	Future Determination (FY24-FY27)
Periodic Maintenance	Count	10	18	21	16	12	15	67*
	Value	5.01	6.93	5.55	5.85	5.08	5.95	23.41

Sources:
- ATK-014_Projects by Year

* Because some projects take place over multiple periods the total number of projects in this table is greater than 41, which is the unique number of projects that are expected to take place over the next Determination period

We view SDP's proposal to perform periodic maintenance as reasonable and provides a safeguard for the plant against major failure of equipment. It is a standard that a desalination plant of this size requires periodic maintenance work. It is our understanding that SDP's periodic maintenance program is derived by a predictive model and annual assessment toto determine the status of equipment/asset. It is acknowledged that because continuous operation of the plant only started in 2019, SDP will have to predict the cost for periodic maintenance through other means, like the operator's predictive model. Although activities for the first year of the determination are based on the annual assessment, the remaining years' activities are understood to have been influenced by Veolia's predictive model. We view that an efficient periodic maintenance program is built upon information received from periodic inspection, especially when operation is continuous. It is standard for a desalination plant to build their periodic maintenance budget based on the plant's design and understanding of its asset.

In its proposed periodic maintenance capex, SDP included $1.25M to replace the filter media in the gravity Dual Media Filters (DMF). SDP provides that overtime the filter media can breakdown, potentially constraining the overall desalination operation and compromising the downstream water quality. Additionally, SDP states that there is no immediate need to replace the media and this item is a placeholder. Based on our understanding of the state of the filter media, knowledge of plants of similar size and age, and SDP's comments, we do not view that the replacing of the filter media as required in this Determination period. Therefore, we recommend that this cost is removed from the overall periodic maintenance capex for the next Determination period.

Additionally, SDP included the inspection and repair of concrete tanks and bunds at a cost of $0.28M over the next Determination period. Another $0.74M is proposed by SDP to be spent on the same item in FY28. We do not view that the repair of concrete tanks and bunds will be required in the 2024 Determination period. Repairs to concrete tanks and bunds are typically done when there is known to be a damage as these assets are designed for the life of the plant. SDP has not provided evidence that there is a known potential damage and inspections are expected to be covered under the O&M Contract. Therefore, we propose that $0.28M is removed and adjusted for in the periodic maintenance for the next Determination period.

Based on the evidence provided by SDP, the shift to continual flexible operation, and the historical underspend in periodic maintenance spending, we envisage it will be challenging to carry out the amount of overhaul and replacement proposed by SDP. We believe that there will be prudent and efficient decisions as well as operational requirements for delivery that will constrain SDP's ability to undertake all planned periodic maintenance. Additionally, in building the periodic maintenance capex, SDP relied on Veolia's predicative model, which is not necessarily reflective of the state of the assets. The periodic maintenance capex includes assumptions regarding the need to have routine renewals, repairs, or overhauls over the next Determination period. The cost basis for these future repeated capex items have not been demonstrated to be put together efficiently. Without evidence for how these repeated costs were built in, we believe that there is no room for more efficient pricing and carrying

[46] ATK-014_Projects by Year.xlsx

out of the work each year. We recommend that an additional 10% scope reduction is applied to periodic maintenance capex starting in FY2024. This reduction is applied after removing the two periodic maintenance items suggested above. Table 5-13 below shows how the recommended adjustments were applied to pre-efficiency proposed periodic maintenance capex

Table 5-13 – Periodic Maintenance Adjustment Approach ($FY23 Million)

Description	2023	2024	2025	2026	2027	2028	Future Determination (FY24-FY27)
SDP Proposal (pre-efficiency)	5.01	6.93	5.55	5.85	5.08	5.95	23.41
Adjustment – Removal of items	-	-	-	(1.47)	(1.32)	(0.74)	(2.79)
Adjustment – 10%	-	(0.69)	(0.56)	(0.44)	(0.38)	(0.52)	(2.06)
Total Adjustment	-	(0.69)	(0.56)	(1.91)	(1.70)	(1.27)	(4.85)
Recommended	5.01	6.23	5.00	3.94	3.38	4.69	18.56

Sources:
- ATK-014_Projects by Year
- SDP Pricing Submission

Therefore, we recommend a periodic maintenance capex of $18.56M over the next Determination period. It is worth noting that the recommended periodic maintenance capex is 331% higher than SDP's actual periodic maintenance capex over the 2017 Determination period ($4.31M). A summary of the adjustments is shown in Table 5-14.

Table 5-14 – Plant – Periodic Maintenance Capex Summary ($FY23 Million)

Description	2023	2024	2025	2026	2027	2028	Future Determination (FY24-FY27)
SDP Proposal (post-efficiency challenge)	5.01	6.91	5.52	5.80	5.02	5.86	23.24
Adjustments	-	(0.67)	(0.52)	(1.85)	(1.63)	(1.18)	(4.68)
Recommended (pre-efficiency)	5.01	6.23	5.00	3.94	3.38	4.69	18.56

Sources:
- ATK-014_Projects by Year
- ATK-008_1 to ATK-008_6
- SDP Pricing Submission

Note: "adjustments" includes the adjustment from post-efficiency to pre-efficiency where appropriate i.e. where we have recommended accepting SDP's proposed expenditure and SDP have incorporated efficiency to that cost line as set out in Table 5-3 above.

5.2.3. Pumping station

For the 2023 determination period, SDP has proposed a $5.01M capex for pumping station projects. The pumping station capex program includes 5 five projects that take place over FY23 to FY25. The greater proportion of the cost is attributed to the additional DWPS that is estimated at $3.32M which is reviewed in detail below. Overall, we view that the pumping station capex program proposed to be efficient and prudent.

5.2.3.1. Additional DWPS

Currently, the plant includes two Drinking Water Pump Stations (DWPS's) that transfer water from the Plant's drinking water tank into the Sydney Water's distribution network. The capacity of one pump can provide up to 185 Mld, where the maximum amount that can be requested by Sydney Water is up to 250 Mld. Hence, in the event of a failure of one pump, SDP will be at risk in breaching its contract with Sydney Water and ability to deliver the maximum daily production rate. The lack of redundancy for a desalination plant of this size is unusual. It is viewed that the construction of a new DWPS is a good practice to create redundancy in the system and reduce the risk of failure to deliver the required daily production.

SDP proposes a cost [redacted] for the delivery of a new DWPS over two years. The cost provided by SDP is based on budget quotations from suppliers and estimated values. It is understood that the concept design has been developed for SDP and it is ready for tender. To ensure that the most efficient pricing is considered, the operator will go out to procure three quotes.

The request for the cost of the additional DWPS is considered reasonable and acceptable. Therefore, no adjustments are recommended for this project as shown in Table 5-15.

Table 5-15 – Additional DWPS Cost Summary ($FY23 Million)

Description	2023	2024	2025	2026	2027	2028	Future Determination (FY24-FY27)
SDP Proposal (post-efficiency challenge)	-	[redacted]					
Adjustments	-	[redacted]					
Recommended (pre-efficiency)	-	[redacted]					

Sources:
- ATK-014_Projects by Year
- ATK-008_1 to ATK-008_6
- SDP Pricing Submission

Note: "adjustments" includes the adjustment from post-efficiency to pre-efficiency where appropriate i.e. where we have recommended accepting SDP's proposed expenditure and SDP have incorporated efficiency to that cost line as set out in Table 5-3 above. This is why there is a positive adjustment to DWPS capex.

5.2.4. Pipeline capex

SDP pumps water to the Sydney Water's water supply system through an 18 km pipeline that includes 454 individual assets. SDP carried out multiple asset inspection programs since 2017. SDP's submission states that the inspections have identified 16 out of 19 air valves which are exposed to water and are at risk of becoming continuously submerged. In the case of a failure of the air valves, there is a risk of contamination of the water supplied to Sydney Water. Therefore, SDP proposes a pipeline program that allows for further investigation and implementation of permanent drainage system.

Our view is that the risk of air valves failure under the submerged conditions could compromises the quality of the water delivered. We agree that a mitigation will need to be explored to minimize the risk of contamination through the air valves. Per conversations with SDP on 29 November 2022, SDP stated that the source of the water is not clear. Therefore, in our view, the solution proposed by SDP come with uncertainty regarding the effectiveness. For example, SDP proposes to install drainage pipes connected from the air valve champers to the stormwater drainage system to avoid submergences of the valves. While this can be effective in theory, we challenge how effective the solution will be in the field, especially that the source of water is undefined. Consequently, we recommend that only a pilot program be implemented for the future Determination, including a periodic monitoring. The pilot is expected to provide enough information on the effectiveness of the drainage pipes and allow for design modification.

SDP's proposed pipeline capex includes two main items. The first is for the air valve drainage program (pit dewatering) with a cost of $0.33M every year from FY24 onward as shown in Table 5-16. The second proposed pipeline capex is allocated for the inspection of the pipeline crossing Botany Bay (From Kurnell to Rockdale). SDP proposed a cost of $469,800 over FY25 to implement the inspection.

Table 5-16 – SDP Proposed Pipeline Capex ($FY23 Million)

Description	2023	2024	2025	2026	2027	2028	Future Determination (FY24-FY28)
Pit Dewatering Program	0.11	0.33	0.33	0.33	0.33	0.33	1.34
Botany Bay Inspection		-	0.47	-	-	-	0.47
Total	**0.11**	**0.33**	**0.80**	**0.33**	**0.33**	**0.33**	**1.81**

Sources:
- ATK-014_Projects by Year
- SDP's Pricing Submission

We note that the concept study report for the air valve drainage by Kellogg Brown & Root Pty Ltd (KBR) dated 7 October 2022 evaluated all 16 air valves in question and recommended a drainage pipe solution to 14 out 16 air valves. According to the report, the remaining two (2) valves already have drain pipes installed in the pits from the original construction. KBR's report provided a capital cost estimate for the installation of a drain pipe for each air valve, where the cost for each air valve vary based on distance from stormwater pipe and complexity. The total estimated cost given in the report is $0.59M. It is understood that SDP's proposed cost include a 10% of the estimated cost as contractor margin/overhead as well as allowance for development of final design. Additionally, SDP's pit dewatering program build up included a management cost (20% of construction and design cost) and contingency cost equal to 42% of construction and design cost.

Given the uncertainty around the source of the water intrusion and the effectiveness of the solution, we recommend a pilot program to explore options to remedy the air valve water submergence issue. We have estimated that the pilot program would implement a pipe drain solution for six (6) air valves as shown below. The allowance recommended includes estimate for scope increase, contingency, project management, and program monitoring cost derived from the KBR drainage pit program estimate. The recommended allowance is assumed to take place over FY24 and FY25. The recommended value is set out based on the implementation of pipe drainage solution for six (6) air valves. However, SDP might elect to implement a project within the allowance for providing a drainage pipe solution for either more or less air valves as seen appropriate. It is also envisaged that SDP might explore different solutions to remedy the water intrusion problems using different methods within the allowance provided.

Table 5-17 – Recommended drainage pit pilot program ($FY23 Million)

Pipeline Section	Asset Number	%	Estimated Cost
Kurnell	KUAV4		0.02
Rockdale	ROAV4		0.05
Rockdale	ROAV7		0.03
Marrickville	MAAV1		0.03
Marrickville	MAAV2		0.03
Marrickville	MAAV4		0.02
	Total Cost of installation		0.19
	Allowance for increase due to scope reduction	5%	0.01
	SDP Contingency	10%	0.02
	Project Management	5%	0.01
	Monitoring Cost	15%	0.03
	Total Cost of Pilot Program		0.25

Sources:
- ATK-014_Projects by Year
- SDP's Pricing Submission

For the Botany Bay pipeline section inspection, SDP provided costs from KBR [redacted] This recommendation reflects a $185,122 adjustment from SDP's proposal for Botany Bay. After our review of SDP's document[47] that provided estimates for the Botany Bay pipeline, it appears that SDP aggregated the total sum and the individual items that add up to the total sum. This double-counting is assumed to be an error as the costs provided by KBR were not clearly labelled, resulting an adjustment of about $0.19M.

Based on the costs provided by SDP through suppliers as well as our understanding of the problem, proposed solutions, and prospect outcome, we recommend an adjustment to SDP's proposed outcome as shown in Table 5-16. The recommended cost incorporates the monitoring cost over the next determination period.

Table 5-18 – Pipeline Capex Cost Summary ($M FY23)

Description	2023	2024	2025	2026	2027	2028	Future Determination (FY24-FY28)
SDP Proposal (post-efficiency challenge)	0.11	0.33	0.80	0.33	0.33	0.33	1.80
Adjustments	-	(0.22)	(0.39)	(0.32)	(0.32)	(0.33)	(1.26)
Recommended (pre-efficiency)	0.11	0.11	0.41	0.01	0.01	-	0.54

Sources:
- ATK-014_Projects by Year
- SDP Pricing Submission
- ATK-007.1, ATK-007.2, and ATK-007.3 (evidence or business case submitted by SDP for pipeline capex)

Note: "adjustments" includes the adjustment from post-efficiency to pre-efficiency where appropriate i.e. where we have recommended accepting SDP's proposed expenditure and SDP have incorporated efficiency to that cost line as set out in Table 5-3 above.

[47] ATK-029 Budget estimates for the specific capital projects listed

5.3. Membrane replacement programme

Current Determination period (2017 – 2023)

After an initial two-year (2011 - 2012) proving period when the Plant was constructed, the Plant was placed into 'water security mode' to minimise ongoing operating costs. During the water security mode, the RO membranes were stored in preservation fluid.

The warranty period[48] provided by the manufacturer for the membranes was activated in June 2010 in accordance with the membrane contract commencement date following the site acceptance testing.

Once the warranty period elapses (it would have been in June 2019), the manufacturer no longer guarantees operational performance parameters such as volume, energy consumption, and water. The Plant was in the 'water security mode' (with none or very low production) for the majority of the time covered under the guarantees. Due to these circumstances, there was no operational and condition data available on membrane deterioration over the 'water security mode' period, and actual membrane condition could only be known once the Plant was restarted, and the membranes operationally tested.

SDP considered a range of options for replacing the membranes to achieve the regulatory requirements to restart within eight months of the restart trigger being reached and returning to full reliable production. These options included:

- A full replacement of the membranes on restart triggered by low dam levels
- A temporary restart with existing membranes to assess the condition of the membranes before low dam level triggered restart

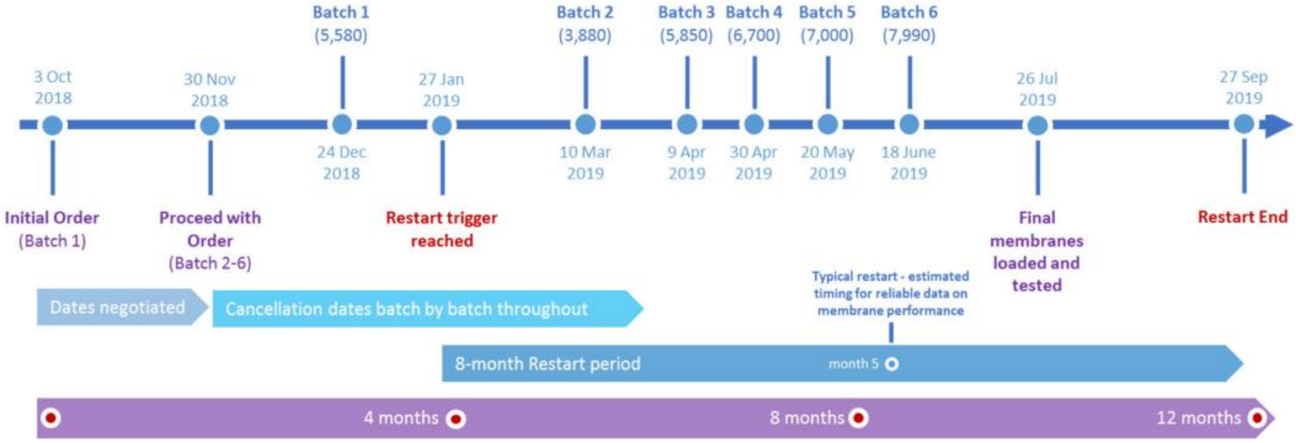
The costs of a temporary restart to test the membrane performance would have been a significant amount of the membrane replacement. If RO membranes are then found not to meet water quality or quantity specifications, long lead-times would have rendered it difficult to meet regulated restart timeframes.

Consequently, SDP proceeded with the option to replace a full set of membranes when storage low levels were reached to ensure the Plant could restart and return to full production within eight months from the restart trigger. While replacing the full set of membranes was in line with our recommendations, we note that SDP started the replacement of the membranes before the trigger level (defined by storage levels). While the trigger for the membrane replacement originally deviated from the previous recommendations and could have resulted in being inefficient (i.e., the membranes being replaced and the storage levels not going below the trigger levels); we understand that SDP considered likely rainfall and actual and potential dam levels and engaged closely with the NSW Government prior to taking this decision.

[48] Eight years with an additional twelve-month extension due to long term preservation irrespective of the time actually in preservation.

The following figure provides a summary of the procurement and installation timelines of the membrane replacement.

Figure 5-3 – Membrane replacement (full replacement option)



Source: *"ATK-010_10-1 CONFIDENTIAL SDP Report - Prudency of membrane replacement in 2019 (00099308-3xCE34F)"*

The instalation of the final batch of membranes was at the end of July 2019, with final commissioning and optimisation of the Plant in September 2019.

Next Determination Period (2024 – 2027)

When RO membranes are used over time, there is a gradual increase in the feed pressure required to achieve the same permeate flow rate. When in use, membranes require periodic chemical cleaning to remove particulate and biological fouling that has built up. The chemical cleaning events and the use of the membranes gradually increases the feed pressure required and the amount of salt that passes through them reducing the permeate quality.

For this facility the need to replace the membranes is likely to be driven by the increase in feed pressure over time. To ensure that feed pressure and hence the electricity use for water production is efficient the membranes in the RO pressure vessels will have to be replaced. The main question is when.

For the Next Determination Period (2024 – 2027), SDP has proposed a progressive membrane replacement programme. This programme is intended for desalination plants that are operating on full production as an ongoing basis targeting a rolling annual replacement of membranes in order to achieve a targeted average membrane age to achieve the desired water quality and plant efficiency. This approach is considered in line with standard practice.

By doing this, an average membrane age[49] can be established in the design process and a membrane replacement strategy devised, feeding into the design of the Plant to ensure optimal cost of water over the life of the plant.

The membrane supplier's proprietary software is used to predict RO membrane feed pressures and permeate quality under all conditions (namely min/max temperature, salinity, new/old membranes).

Following the installation of new membranes and the Plant restart in 2019, SDP, and its Operator intended to operate the plant with the following average membrane age strategy:

- 4 years for the first pass membranes.
- 6 years for the second pass membranes.

[49] Average Membrane Age is different from Membrane Asset Life. For information on the Membrane Asset Life, please refer to Section 6.1.2 of this Report.

We understand the above is proposed for budgetary purposes and the decision, in line with good market practice, will be based on the actual performance of the membranes.

Current Membrane Age

The calendar age of the membrane is expected to reach its 4th calendar anniversary towards the end of the current Determination period in June 2023. However, when RO trains are not producing permeate, we do not consider that calendar age is the best indicator of asset ageing provided the membranes are correctly preserved with regular permeate flushing.

We consider that membrane age is better understood on the basis of how much it has been utilised relative to the design assumption. For example, if the plant has produced 50% of its capacity production over four years, then the "effective" production age of the membranes is two years.

This approach has been used in our analysis to determine the effective production age of the membranes following the membrane replacement in 2019 and to forecast the ageing of the membranes in the next Determination Period.

To determine the current production age of the membranes, we have summarised the potable water produced by the Plant since the full replacement of the membranes. This is summarised in the following table:

Table 5-19 – Membrane age

Description	Potable Water Produced (Ml)	Potable Water if Full Capacity	Average Production	Membrane Age (Production equivalent)
FY20	71,146	97,090	73.3%	0.73 years
FY21	19,628	97,090	20.2%	0.20 years
FY22	22,309	97,090	23.0%	0.23 years
FY23	89,759*	97,090*	92.4%*	0.92 years
Total	202,842	388,360	52.2%	2.09 years

* FY23 Potable Water Produced accounts for (i) 4 months of actual production at ~87% of the Plant's capacity; (ii) 5 months at 100% of the Plant's full capacity (in line with the Emergency Response Notice period SDP is currently in; and (iii) 3 months at ~87% of production as a reasonable assumption

Source: *"ATK-001_1 Jul 2017 to 31 Oct 2022 Energy and Production Data"*

Based on the above analysis, the current effective production age of the membranes at the end of the current Determination Period will be equivalent to 2.09 years.

Considering that SDP's average membrane age strategy for the first pass membranes and second pass membranes is four and six years respectively, the Plant's membranes would be expected to have ~2 years (1.91) and ~4 years (3.91) of production use remaining for first and second pass respectively (counting from July 2023) prior to commencing their replacement. This would bring the requirement to commence replacement of first pass membranes not earlier than the end of FY 2025 (June 2025) and the end of FY 2027 for second pass membranes (i.e., second pass membranes would not be required to be replaced within the next (FY24 – FY27) Determination Period).

The above is under the assumption of a 100% potable water production rate from the commencement of the next Determination Period. However, this does not necessarily reflect the most likely scenario of potable water requirements over the next Determination Period. To assess the impacts of a different level of operation on the average membrane age, please refer to the next section of this Report.

5.3.1. Impact of different levels of operation on membrane life

For this section, the starting points are (i) 2.09 years of membrane age at the end of FY 23 and (ii) an assumed average production estimate for the next Determination period of 68.4%[50] of the Plant's Capacity.

We have also continued with the concept that calendar average membrane age needs to be corrected for the effective production age. In other words, determining the membranes' age based on the flow of water treated (Flow based age) as opposed to calendar years. For avoidance of doubt, in the below analysis we will differentiate between calendar average membrane age and the production average membrane age.

The following table summarises the ageing of the membranes during the next Determination Period both considering the calendar average membrane age and production average membrane age at an assumed production of 68.8% of the Plant's capacity (i.e., 171Mld).

Table 5-20 – Membranes' calendar average age vs production average age (at 68.4% of production)

	FY23	FY24	FY25	FY26	FY27	FY28	Age at End of Current Det. Period	Age at End of Next Det. Period
Calendar Average Membrane Age	2.09y	3.09y	4.09y	5.09y	6.09y	7.09y	2.09y	6.09y
Production Average Membrane Age	2.09y	2.77y	3.46y	4.14y	4.83y	5.51y	2.09y	4.83y
Note: 2.09y of age is considered at the end of the respective financial year (e.g., 2023). This age is based on the production average membrane age calculate based on the actual production flows of the plant since the membrane replacement. Years shadowed in blue correspond to the next Determination Period (FY24 – FY27)								

Source: *Atkins projections"*

The membranes of the Plant are projected to have an average production age of 4.83 years at the end of the next Determination Period assuming 68.4% of potable water production. As the average age is forecasted to remain below the six-year target, we do not recommend replacement of the second pass membranes will need to be replaced in the next Determination period.

For the first pass membranes, we recommend allowing replacement of a certain number of membranes during the first year (FY24) of the next Determination Period to allow SDP certain operational flexibility. The assumptions do not change the fact that SDP will need to base its actual replacement decisions on the actual performance of the membranes during the Determination Period.

[50] Please refer to Section 2.2. of this Report for the support of this level of production.

The table below summarises SDP's progressive membrane replacement programme and our recommendation:

Table 5-21 – Progressive Membrane Replacement Programme (number of membranes)

Description	FY23	FY24	FY25	FY26	FY27	FY28	Next Determination
SDP Proposal							
First Pass	2,027	4,662	5,388	4,580	3,772	3,772	20,474
Second Pass	0	0	0	1,666	1,372	1,372	3,038
Our Recommendation							
First Pass	0	6,734	0	0	0	*	6,734
Second Pass	0	0	0	0	0	*	0
Adjustment							
First Pass	(2,027)	2,072	(5,388)	(4,580)	(3,722)	*	(13,740)
Second Pass	-	-	-	(1,666)	(1,372)	*	(3,308)

*** The above analysis does not include a replacement of membranes for FY28. This is just a working assumption for the next Determination Period.**

Source: ATK-009_10-6 CONFIDENTIAL Ongoing RO membrane replacement business case (00099312-4xCE34F)

SDPs proposal consists of replacing 76% of first pass membranes and 31% of second pass membranes for the next Determination Period. Our recommended replacement programme consists of the replacement of 25% (2 out of 8 elements) of first pass membranes in the first year (FY24) of the next Determination Period and not changing the second pass membranes. The following table shows further detail of our proposed replacement model (Assuming 68.4% average annual production) for the first pass membranes:

Table 5-22 – First Pass Membranes Proposed Replacement Model – In FY24

Element	FY23	FY24	FY25	FY26	FY27	FY28[1]
1	2.09y	2.77y	3.46y	4.14y	4.83y	5.51y
2	2.09y	2.77y	3.46y	4.14y	4.83y	5.51y
3	2.09y	2.77y	3.46y	4.14y	4.83y	5.51y
4	2.09y	2.77y	3.46y	4.14y	4.83y	5.51y
5	2.09y	2.77y	3.46y	4.14y	4.83y	5.51y
6	2.09y	2.77y	3.46y	4.14y	4.83y	5.51y
7	2.09y	0.68y	1.37y	2.05y	2.74y	3.42y
8	2.09y	0.68y	1.37y	2.05y	2.74y	3.42y
AMPL	**2.09y**	**2.25y**	**2.93y**	**3.62y**	**4.30y**	**4.99y**

Note: the age is considered at the end of the respective financial year (e.g., 2023). Years shadowed in blue correspond to the next Determination Period (FY24 – FY27)
(1) The above analysis does not include a replacement of membranes for FY28. This is just a working assumption for the next Determination Period.
(2) For avoidance of doubt, going above the 4 years threshold for first pass membranes, does not mean a failure of the membranes.

Source: *Atkins projections*

SDP's financial budget summary for the progressive membrane replacement programme is presented in Table 5-23. Our recommended allowance includes proposed cost of procurement, shipping, spare parts, consumables, and waste disposal for FY24. For installation cost we included a fixed cost (at 20% of purchase + Shipping Cost of Membranes). Lastly, the capex cost for membrane replacement includes project management, operator fee overhead and risk, not included in the fixed cost as assure by SDP. Figure 5-4 demonstrates the membrane replacement capex compared with historical and recommended values.

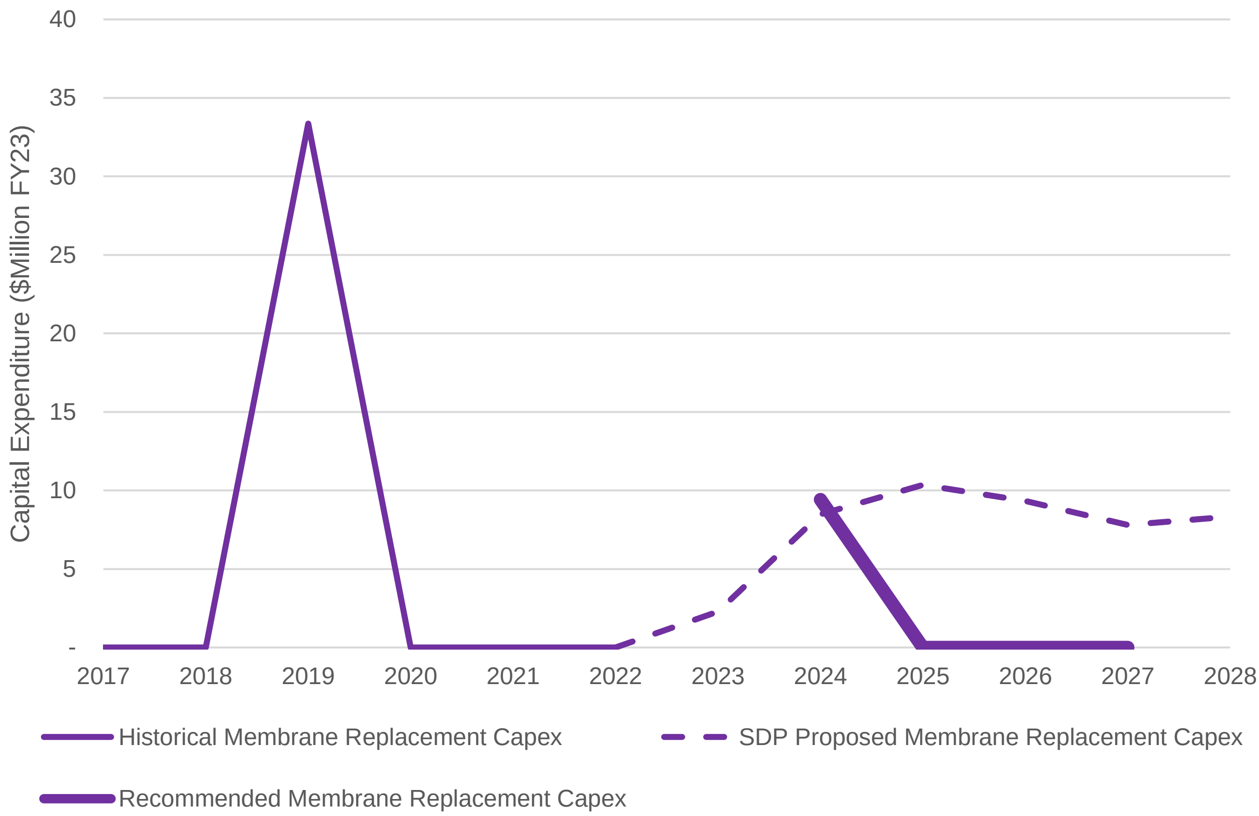
Table 5-23 – Membrane Replacement Capex Cost Summary ($FY23 Million)

Description	2023	2024	2025	2026	2027	2028	Future Determination (FY24-FY27)
SDP Proposal (post-efficiency challenge)	2.28	8.44	10.29	9.26	7.71	8.21	35.70
Adjustments	(2.28)	1.19	(10.29)	(9.26)	(7.71)	(8.21)	(26.07)
Recommended (pre-efficiency)	-	9.63	-	-	-	-	9.63

Sources:
- ATK-009_10-6 CONFIDENTIAL Ongoing RO membrane replacement business case (00099312-4xCE34F)
- ATK-014_Projects by Year
- SDP Pricing Submission

Note: "adjustments" includes the adjustment from post-efficiency to pre-efficiency where appropriate i.e. where we have recommended accepting SDP's proposed expenditure and SDP have incorporated efficiency to that cost line as set out in Table 5-3 above.

Figure 5-4 – Membrane Replacement Capex Summary



5.3.1.1. Sensitivity analysis

Our recommendation for the membrane replacement programme is based on an assumed average production level of 68.4%[51] (eq. to 171 Mld), although we acknowledge there is uncertainty in the level of production and therefore performance of the membranes.

We have undertaken a sensitivity analysis on membrane replacement based on the production average membrane age running several scenarios for different production levels. Table 5-22 below captures the estimated efficient levels of membrane replacement capex for three scenarios: low production (assumed to be 50Mld), our representative average assumption (171Mld), used as the basis of our recommendation and full production. This suggests that an additional $7.8M capex may be required if the plant is operated at full production through the future determination period.

[51] Please refer to Section 2.2. of this Report for the support of this level of production.

Table 5-24 – Sensitivity Analysis for Efficient Levels of Membrane Replacement Capex

Assumed Level of Production (Mld)	%	Estimated Efficient Membrane Replacement Capex during the next Determination period ($ million)
50	20%	0.0
171	68.4%	9.6
250	100%	19.3
Note: percentages of production over 250Mld		

Source: *Atkins sensitivity analysis"*

It is worth highlighting that membrane replacement should be based on performance of the membranes which is in turn determined by a series of factor amongst which the flow levels play a key part.

5.3.2. Purchase of 'spare' membranes for risk management

During a meeting with SDP held on 11 January 2023, SDP explained the intention to purchase replacement membranes for one train to provide for emergencies or incidents which might take a train out of service. This is to mitigate the risk of membrane supplier lead times affecting ability to meet production requirements.

Our understanding is that the plant can produce the required 250Mld using 11 trains, meaning that two of the 13 trains can be out of use and the plant still meet the 250Mld maximum production required. Assuming that CIP takes a train out for a single day and each train is subject to CIP twice a year, CIP should only reduce production equivalent to approximately 26 production days from a single train per year.

We also note that there are challenges around storing membranes beyond one year. We therefore consider that purchasing replacement membranes for one train to provide for emergencies would not be prudent and efficient given SDP's ability to more than meet production requirements whilst also carrying out CIP even if one train is out of service.

5.3.3. Reselling of membranes

In Current Determination Period (FY17 – FY23)

SDP and the Operator (Veolia) explored options for resale of used membranes as part of the membrane replacement in 2018/19. Amongst the options, they considered: (i) reuse; (ii) recycle; and (iii) disposal.

No options were identified for the reuse and recycle options. During the membrane replacement and installation process, the successful tenderer for the works offered to take ownership of a proportion of used membranes in lieu of disposal costs to landfill providing a saving of ~$250k. These membranes had only 2 years production life used.

The final use by the tenderer of the used membranes is unknown, and SDP understands it will be very challenging to resell any future used membranes with longer production history because other desalination projects do not want membranes without warranties for permeate production quantity, feed pressures (energy) and permeate quality. SDP consider landfill being more than likely the method of disposal and are investigating options for alternative green solutions for disposal. We are in agreement.

Forecasted in Next Determination Period (FY24 – FY27)

SDP and the Operator (Veolia) have confirmed that they will investigate any opportunities as part of any membrane replacements proposed in the next Determination Period. However, they envisage no other savings other than disposal costs to landfill savings.

5.4. Opportunities for efficiency

All of the adjustments set out above are 'scope adjustments' reflecting our view of SDP's proposed changes in activities and costs. As detailed below, we also consider there is also scope for catch-up and continuing efficiency.

In its submission, SDP has incorporated a "continuing efficiency factor" of 0.3% pa from FY24. Unlike for opex, SDP has applied this efficiency from FY24 onwards rather than assuming a year is required to adjust to the new operating rules.

Our view on the scale of efficiency opportunities is set out below.

5.4.1. Catch-up efficiency

We consider there is reasonable additional efficiency to be gained in SDP's capital program.

We have seen little evidence that there has been strong efficiency challenge in the way the scope and costs of the program have been assembled. It seems likely to us that the cost estimates used are conservative and that there is scope for efficiency through rigorous value engineering and procurement e.g. through greater involvement and scrutiny in supplier engagement and/or market testing and strong efficiency challenge.

Our view of the conservativeness of the program cost is reinforced, by, for example, the significant periodic underspend in the 2017 Determination period, with SDP spending $4M of the $17M allowed. We also found that the models underlying the periodic maintenance program were not specific to desalination plants.

Catch-up efficiency is what we consider is required to achieve the performance of a Frontier Company. We have sought to benchmark SDP's performance against other desalination SPVs and utilities. Precedent catch-up efficiencies from previous Determination in New South Wales for capex are listed in Table 5-25.

Table 5-25 – Capital expenditure: catch-up efficiency in previous Determinations

Utility % in year (cumulative)	Start year	Year 1	Year 2	Year 3	Year 4
Sydney Water	2013	1.30	4.40	9.60	12.00
Hunter Water	2016	0.00	0.00	0.00	0.00
Sydney Water	2017	2.90	5.80	7.20	8.60
Central Coast Council	2020	3.25	7.50	10.75	13
WaterNSW- Greater Sydney	2020	2.07	5.13	7.70	9.26

Source: Previous Determinations

In our approach to build-up a catch-up efficiency, we consider four areas to impro ve efficiency:

Capital Program Development, Optimisation and Prioritisation

Effective capital program development helps to identify synergies, to challenge expenditure and to optimise capital programs by improved targeting of expenditure to areas where it is most required and prioritised according to needs. It usually involves a mixture of culture, incentives, systems and processes.

In the case of SDP, we have considered this area of efficiency in our review of its capital program. Therefore, we do not think it is necessary to apply an efficiency adjustment factor for this area.

Value engineering

Moving from the program level to the scheme-specific level, value engineering looks to reduce the cost of delivering a given scheme by challenging scope and methods and looking for alternative ways to achieve the outcome required.

Similar to the capital program development efficiency, we have evaluated value engineering for specific projects within SDP's capex proposal. In our review of the membrane replacement program, periodic maintenance, and specific projects, where applicable, we have incorporated our opinion on value engineering and the efficiency adjustment associated. Consequently, we recommend no value engineering efficiency to be applied to SDP's capex proposal.

Cost estimation

From our review, we consider SDP's approach to cost estimation as in its early stage of maturity. We view that SDP had utilized a conservative approach in estimating the cost of various capital projects. Business cases for various periodic maintenance and Plant specific projects demonstrated that SDP might be able to save as it gains better visibility of the market.

We have applied a catch-up efficiency to reflect the potential for recent cost estimates to fail to capture efficiency improvements and for estimates to routinely include conservative assumptions. Considering the opportunity for SDP to save on various capital projects by acquiring a more accurate estimations, we recommend a cumulative efficiency factor building up to 4% by the end of the Determination period, 2027 as shown in Table 5-26

Procurement

Procurement efficiency involves finding better ways to purchase capitalised goods and services. It can involve packaging of works, incentivisation and contractual arrangements, such as alliancing and partnering.

It is evident that SDP has gained improvement in its procurement approach and supporting tools and systems as it evolves its operation to a more continuous production. We view that the improved procurement function should provide greater insight into the overall program and identification of opportunities for efficiencies.

We have therefore applied an additional procurement efficiency adjustment equal to 3% from 2026 onwards. The efficiency is phased from 2024 reflecting the fact that a significant proportion of capital expenditure in the first year of the next price path may already be procured.

Table 5-26 - Capex Catch-up Efficiency Factor

	2024	2025	2026	2027	2028
Catch-up: capital program development, optimisation and prioritisation	0.00%	0.00%	0.00%	0.00%	0.00%
Catch-up: value engineering	0.00%	0.00%	0.00%	0.00%	0.00%
Catch-up: cost-estimating	0.50%	2.00%	3.00%	4.00%	4.00%
Catch-up: procurement and supply chain	1.00%	2.00%	3.00%	3.00%	3.00%
Total Catch-up efficiency	**1.50%**	**4.00%**	**6.00%**	**7.00%**	**7.00%**

Our view is that all costs are controllable in some way. The scope for efficiencies should therefore be considered in all activities within the business; hence the catch-up efficiency should be applied across all expenditure. We consider that the 7% cumulative catch-up efficiency by 2027 for SDP as reasonable and achievable, acknowledging that most water utilities reviewed in previous determinations have been recommended and some achieved higher cumulative catch-up efficiencies as shown in Table 5-.

We have applied this catch-up efficiency challenge to our recommended pre-efficiency expenditures. This means there is no need to disentangle from SDP's own efficiency challenge.

We have applied this challenge from FY24 onwards as the plant has been operating in a flexible way since early 2020, giving more than sufficient time to plan an efficient capital program.

5.4.2. Continuing efficiency

We have applied continuing efficiency as set out in Section 1.4.2. As with catch-up efficiency, we have applied this challenge in a cumulative way from FY24 onwards.

5.5. Recommended efficient capex

The below table and graphs demonstrate our recommended efficient capex for SDP over the next Determination period.

Table 5-27 –Capex Cost Summary ($FY23 Million)

	2023	2024	2025	2026	2027	2028	Future Determination (FY24-FY27)
SDP Proposal (post-efficiency challenge)							
Plant – Specific Projects	5.19	5.81	3.24	2.89	3.20	1.29	15.14
Plant – Membrane Replacement	2.28	8.44	10.29	9.26	7.71	8.21	35.70
Plant – Periodic Maintenance	5.01	6.91	5.52	5.80	5.02	5.86	23.24
Pumping Station	0.04	2.51	2.48	-	-	-	4.99
Pipeline	0.11	0.33	0.80	0.33	0.33	0.33	1.80
Corporate	0.14	0.02	0.07	0.03	0.02	0.02	0.13
Adjustments							
Plant – Specific Projects	0.007	(0.11)	(0.05)	(0.05)	(0.04)	0.02	(0.25)
Plant – Membrane Replacement	(2.28)	1.19	(10.29)	(9.26)	(7.71)	(8.21)	(26.07)
Plant – Periodic Maintenance	-	(0.67)	(0.52)	(1.85)	(1.63)	(1.18)	(4.68)
Pumping Station	-	0.01	0.01	-	-	-	0.02
Pipeline	-	(0.22)	(0.39)	(0.32)	(0.32)	(0.33)	(1.26)
Corporate	-	0.00	0.00	0.00	0.00	0.00	0.00
Pre-efficiency recommendations							
Plant – Specific Projects	5.20	5.71	3.18	2.84	3.16	1.31	14.89
Plant – Membrane Replacement	-	9.63	-	-	-	-	9.63
Plant – Periodic Maintenance	5.01	6.23	5.00	3.94	3.38	4.69	18.56
Pumping Station	0.04	2.51	2.50	-	-	-	5.01
Pipeline	0.11	0.11	0.41	0.01	0.01	-	0.54
Corporate	0.14	0.02	0.07	0.03	0.02	0.02	0.14
Efficiency adjustment							
Catch-up efficiency (%)	0.00%	1.5%	4.0%	6.0%	7.0%	7.0%	
Catch-up efficiency ($)	-	(0.36)	(0.45)	(0.41)	(0.46)	(0.42)	(1.68)
Continuing efficiency (%)-	0.00%	0.70%	1.40%	2.09%	2.77%	3.45%	
Continuing efficiency ($)-	-	(0.17)	(0.16)	(0.14)	(0.18)	(0.21)	(0.65)

Recommended capex (post-efficiency)							
Plant – Specific Projects	5.20	5.58	3.01	2.61	2.85	1.17	14.06
Plant – Membrane Replacement	-	9.42	-	-	-	-	9.42
Plant – Periodic Maintenance	5.01	6.10	4.73	3.63	3.05	4.20	17.50
Pumping Station	0.04	2.46	2.36	-	-	-	4.82
Pipeline	0.11	0.11	0.39	0.01	0.01	-	0.51
Corporate	0.14	0.02	0.06	0.02	0.02	0.02	0.13
TOTAL	**10.50**	**23.69**	**10.55**	**6.27**	**5.93**	**5.39**	**46.44**

Source: Atkins Summary
Note: "adjustments" includes the adjustment from post-efficiency to pre-efficiency where appropriate i.e. where we have recommended accepting SDP's proposed expenditure and SDP have incorporated efficiency to that cost line as set out in Table 5-3 above. This is why there is a positive adjustment to pumping station capex.

Figure 5-5 - Total Capex Summary

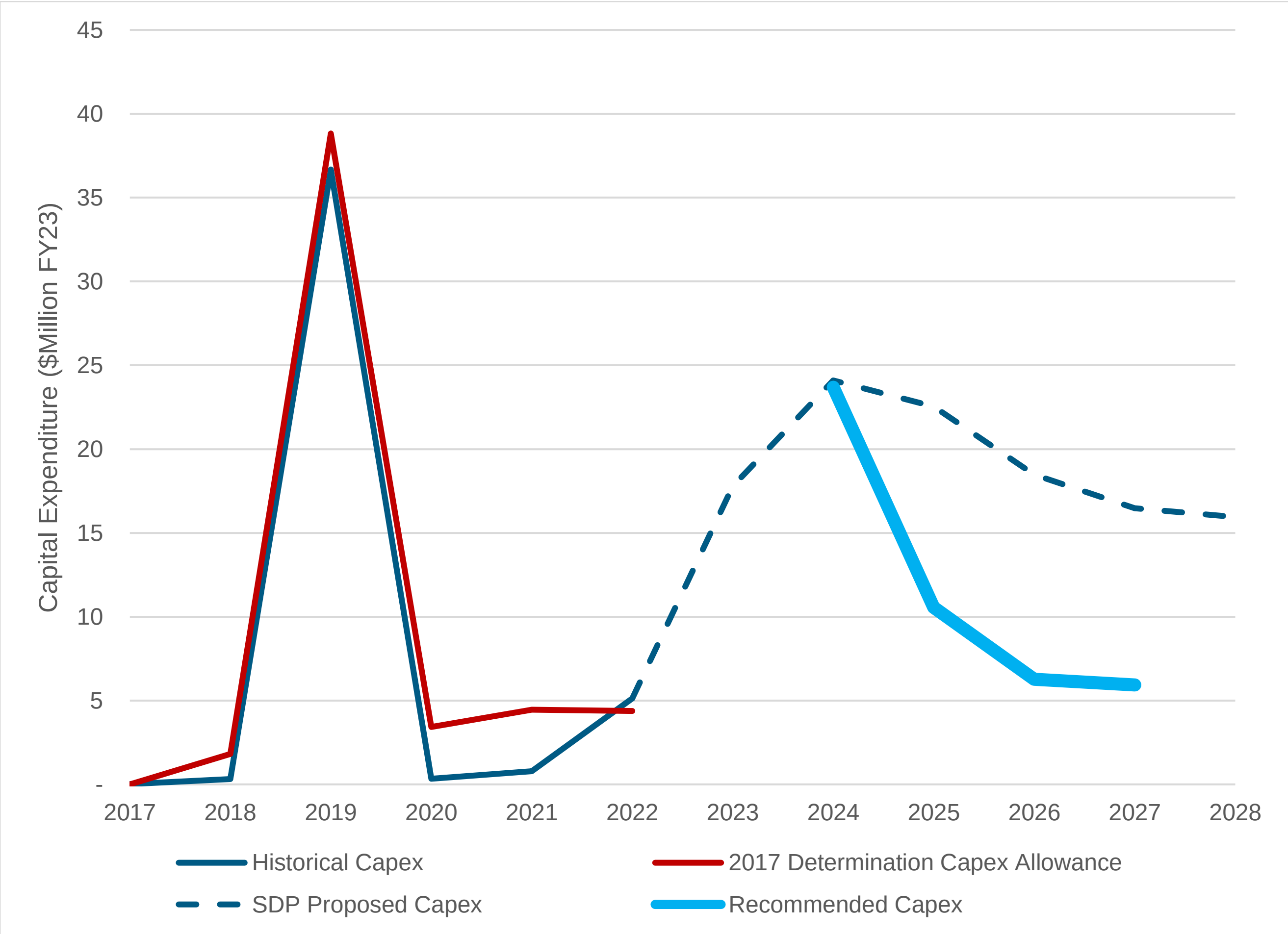
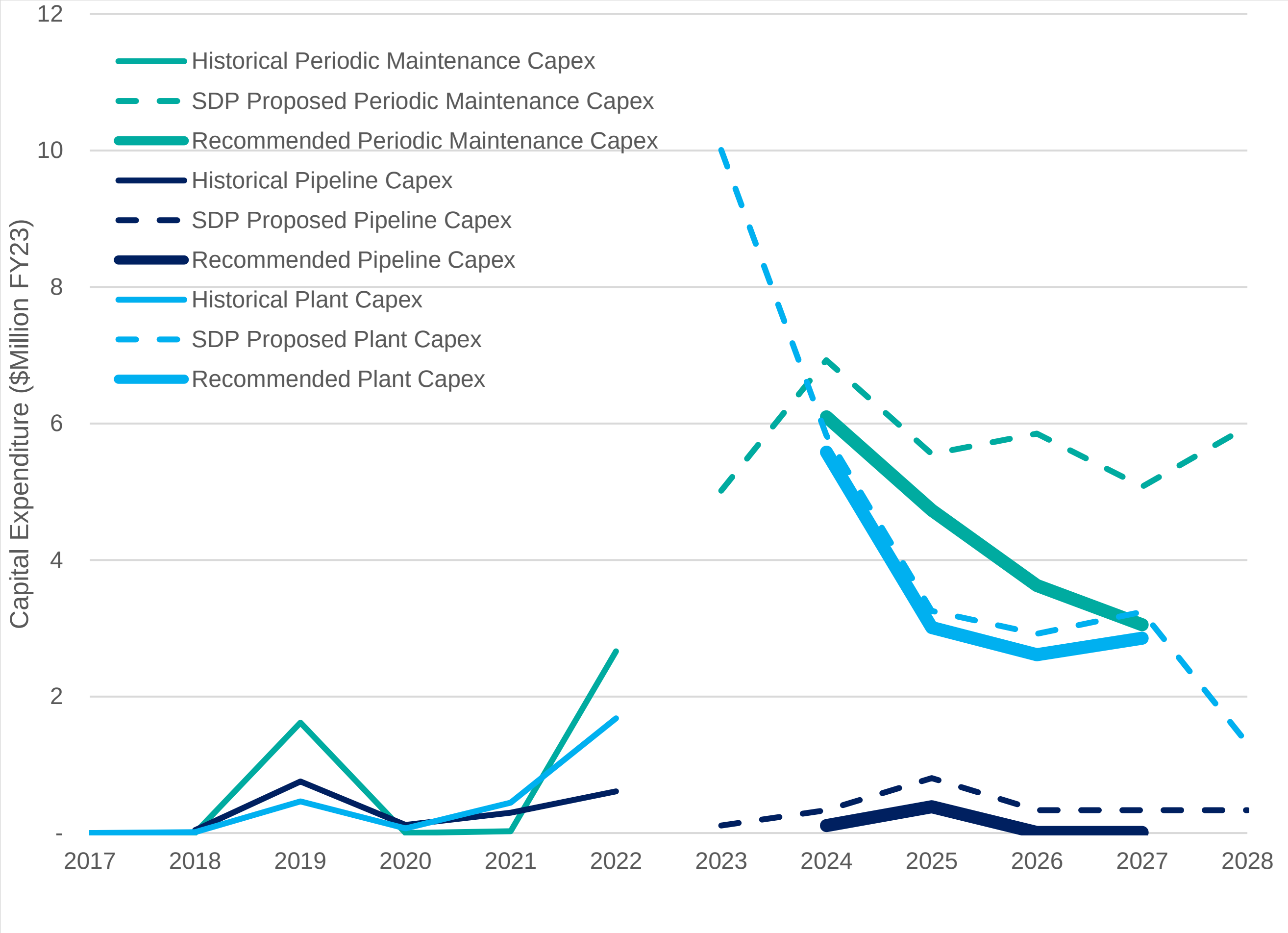


Figure 5-6 – Breakdown of Plant, Pipeline, and Periodic Maintenance Capex



6. Asset Lives

SDP has proposed changes to asset life for three asset types:

- Pipeline- which SDP proposes changing from 120 to 100 years.
- Membranes: which SDP proposed changing to 4.5 years, amended following interviews to 8 years.
- Periodic asset maintenance- - which SDP proposes changing to 7.6 years.

We examine each asset type below.

6.1. Pipeline

The asset life assumed for the pipeline in the 2017 Determination period was 120 years, which was based on a weighted average of pipeline assuming that 50% is undersea and the remaining is on land.

For this upcoming Determination period, SDP has engaged KBR to undertake a study and provide a technical opinion on the asset life of the pipeline. KBR provides in its technical memo, Appendix 11.4 SDP Pipeline Design Life, that the asset life of the pipeline should be 100 years for the following main reasons:

- The initial design basis provided 100 years as the pipeline asset life and because it is the intention of the design, all elements of the pipeline were designed to sustain it for 100 years.
- Because a section of the pipeline is undersea, it presents an aggressive marine environment for the pipeline. SDP argues that its pipeline is different from Sydney Water's network.
- The pipeline should not be averaged using the land-based section as it should be treated as a singular asset.

We reviewed the asset life of the pipeline in detail as part of the 2017 review[52]. The main challenges to reducing the asset life of the pipeline in that review were:

- Assigning 140 years is consistent with SWC's asset life for water mains with similar diameter and similar condition (i.e. 140 years for land-based pipes).
- The pipeline was designed for a full capacity of 500 Mld where SDP currently operates at half of that capacity, 250 Mld.
- The Basis of Design document for SDP presented the pipeline design criteria which indicates a design life of 100 years. The design criteria reference the WSAA Code which indicates a minimum design life of 100 years.

Based on the challenges above, the 2017 determination expenditure review Consultants, including Atkins, recommended a weighted average method to account for the undersea section of the pipeline being in a more aggressive condition. That recommendation used a 50% each for on land and undersea sections resulting a weighted average pipeline asset life of 120 years.

SDP has clarified[53] that the percentage of the pipeline that is undersea is 59% and not 50% as was assumed in the 2017 Determination review. Using the recommended method from the 2017 expenditure review but adjusting for an undersea pipeline portion of 59%,results in a pipeline asset life of 116 years instead of 120, as set out in the table below.

Table 6-1 - Pipeline Asset Life Adjustment

Section	Percentage of total pipe length	Asset Life
Land-based	41%	140
Undersea	59%	100
Weighted Averaged Asset Life (rounded)		116

[52] Consultant Report – 2017 Expenditure Review, Atkins Cardno, 21 Mar. 2017
[53] Sydney Desalination Plant Pipeline Design Life – Technical Memorandum, KBR, 16 Aug. 2022

We acknowledge that the challenge made by SDP focuses on that the original design of the pipeline assigned a design life of 100 years. Additionally, SDP states that other reviews[54][55] by IPART and its consultant has accepted the design life assigned in the basis of design as asset life. We note that review of different assets or services should be treated separately as conditions, purpose, and design of infrastructure assets present varying conclusions. However, we consider SDP's proposal to maintain the design life for the pipeline as the asset life as valid.

In this review, we considered all challenges presented relating to assigning asset life for the pipeline. Consequently, we present IPART with two options for setting the asset life for the pipeline summarized in the table below.

Table 6-2 – Options for Assigning Asset Life for the Pipeline

Option	Asset Life	Comments
1. Keep the 2017 asset life methodology with 59% undersea section	116 years	Consistent with previous Determinations and assets life of SWC's assets at the time of construction. Considers the different conditions of the two portions of the pipeline and operational capacity.
2. Reduce the current pipeline asset life to the design life	100 years	Consistent with the basis of design for the pipeline and treats the pipeline as a singular asset.

6.2. Membranes

The asset life of the membranes has been calculated by running two potential membrane replacement scenarios for both the first and second pass membranes and the representative average production. These suggested that half of the first pass membranes would be replaced by either year 9 or 10 after installation and half of the second pass membranes by year 13 or 14.

Weighting these results by the number of first and second pass membranes suggests an average asset life of 11 years (rounded to the nearest year).

Table 6-3 – Membranes Asset Life Adjustment

Membrane	Number of membranes	Asset Life
First pass	26,936	9.5
Second pass	9,800	13.5
Weighted Averaged Asset Life (rounded)		11

[54] Review of WaterNSW's Broken Hill Pipeline, IPART, 30 May 2019
[55] Consultant Report – Expenditure Review of WaterNSW Broken Hill Pipeline, AECOM, 7 Jun 2022

6.3. Periodic asset maintenance

Periodic asset maintenance life represents the asset life covers several asset categories across SDP's RAB. In the last Determination period, the plant has not experienced continuous operation and little to no periodic maintenance took place prior to the 2017 review. However, since the restart of the plant in 2019, SDP has accumulated a better understanding of the periodic maintenance of its assets. Therefore, SDP proposes that a weighted average approach for periodic maintenance where the asset life is calculated using the economic useful life of the asset weighted using the estimated periodic maintenance cost during the Determination period. SDP obtained the economic useful life of each asset using different sources but mostly from the O&M manual.

Using this approach, SDP proposes that a 7.6 years of asset life to be assigned to periodic maintenance. In its calculation of the periodic maintenance, SDP included periodic maintenance cost from FY24 to FY28.

We agree with SDP's approach in calculating the asset life for periodic maintenance using the economic useful life of assets weighted by the cost. However, to provide a representative sample of the future Determination period, we recommend that SDP uses the periodic maintenance cost up to FY27 to weigh the average. Furthermore, our adjustment to the periodic maintenance impacts the asset life using the weighted average approach adjusting the periodic maintenance asset life from 7.6 to 6.6 years as shown below.

Table 6-4 – Periodic Maintenance Asset Life Adjustment

Category	Cost Estimate ($FY23 Million)	Cost x Useful Economic Life ($FY23 Million)	Weighted Average Useful Economic Life (years)
SDP Proposed	29.36	222.25	7.6
Adjustment	(3.53)	(52.99)	(1.02)
Recommended	25.83	169.26	6.6

We note that this is specific to the periodic maintenance activities proposed for this next period as a lot of the higher cost items envisaged relate to overhaul rather than replacement of assets. It is expected that as the plant's periodic maintenance program evolves, using the same calculation method, will result a less varying value for periodic maintenance asset life. We recommend reviewing this in future periods to ensure it reflects the nature of future periodic maintenance.

Appendices

Appendix A. Scope of Works

The Independent Pricing and Regulatory Tribunal (IPART) is conducting a review of Sydney Desalination Plant Pty Limited's (SDP's) maximum prices for its declared monopoly services, to apply from 1 July 2023 for a period up to five years ('the 2023 Determination'). The review forms IPART's third price Determination for SDP, with prior reviews completed in 2012 and 2017.

Objectives

The objective Atkins review is to review SDP's proposed operating and capital expenditure over the upcoming Determination period, as well as SDP's historical capital expenditure over the current Determination period. For ease of reference:

- Current Determination period corresponds to the period from 1 July 2017 to 30 June 2022, plus the period between 1 July 2022 and 30 June 2023 (the 2017 Determination period);
- Upcoming Determination period corresponds to the period from 1 July 2023 up to 30 June 2028 (the 2023 Determination period)

Description of Services

The following table provides (for information only) a summary of the tasks required under this scope of works.

Task	Review	Description
Task 1	SDP's forecast operating expenditure (excluding energy) for the 2023 Determination period	Comment on how SDP's proposed operating expenditure compares to other similar Australian and/or international desalination facilities, and what conclusions can be drawn from that comparison (if any). Comment on the reasonableness of SDP's total costs, including the division of fixed versus variable costs, and identify any double counting that may be present. Assess the potential for any efficiency savings in the 2023 Determination period and provide annual efficient operating expenditure estimates with reasoning to support any recommended savings. Assessment of the membrane costs on total O&M costs resulting from SDP's proposed membrane replacement program, and average membrane age assumption Minimum level of production: consideration of total operating costs in relation to minimum level of production specified by SDP, vs. the minimum level of production specified in the GSWS. Assessment of cost pass-throughs relating to SDP's insurance for underproduction or Network Operators License breaches/penalties.
Task 2	SDP's forecast energy cost over the 2023 Determination period	Forecast energy consumption assessing SDP's efficient energy consumption over the upcoming regulatory period. Forecast energy prices (i.e. price benchmarking): to determine efficient benchmark unit prices of energy prices over the upcoming regulatory period considering all relevant components of SDP's energy costs, including electricity and large-scale generation certificates (LGCs).
Task 3	SDP's historical and forecast capital expenditure	Review of efficient capital expenditure over the 2017 Determination period: asses and provide recommendations on the efficient level of capital expenditure over the 2017 Determination period, including the final year of the 2012 Determination period. • Review of efficient capital expenditure for the 2023 Determination period: Assess the prudency and efficiency of proposed capital expenditure projects included within SDP's pricing submission. Relevant items for examination under the capital expenditure review include: Membrane replacement program; New periodic maintenance asset class; Periodic maintenance RAB; Asset lives etc.

Appendix B. Benchmark price modelling

Price forecasting methodology and data sources

This appendix sets out data sources and methodology used to estimate the per unit costs for each of the identified components of the cost of goods sold (COGS) plus the retailer mark-up, all expressed in $/MWh. COGS include:

- **Energy purchase costs,** comprising spot market costs, marginal loss factors (MLF) and hedging risk premia reflecting a prudent retailer's
- **Green energy costs,** including mandatory large (LGCs) and small renewable energy certificates (STCs), voluntary LGCs to make up 100% green energy commitment, and mandatory NSW energy savings certificates (ESCs).
- **Other purchase costs,** being other supply costs including ancillary service charges, metering services and market fees for AEMO participants.

A Retail mark up ("margin") of 1.5 per cent is applied to estimated COGS.

NEM Modelling Approach and Assumptions

Energy spot market and swap contract prices beyond the forward curve are built up from modelling future wholesale market conditions and spot price outcomes.

The modelling is focused on prices at the NSW regional reference node, as SDP is located in NSW. Accordingly, modelling outputs are estimating future average annual NSW spot prices and expected price of swap contracts in NSW.

The modelling of NEM spot and contract prices was undertaken using the PROPHET market simulation model and the MJA contract pricing model respectively.

The use of these market models (instead of Long Run Marginal Cost modelling and historical contract premiums) reflected the following issues:

- Key requirements of the modelling were the provision of both contract prices and spot prices (or equivalently contract premiums[56]);
- The market simulation and contract pricing models benchmark more readily to forward contract prices and spot price outcomes. This included the basis of contract premiums in the modelling and comparison to historical;
- The changing nature has changed the level of expected contract premiums;
- Industry structure is known and is not a key issue to the modelling.

The NEM market modelling involved 30-minute simulation modelling of the NEM to determine the 30-minute Spot prices at the NSW Reference Node. The contract prices modelling involved establishing assumptions and benchmarking the NEM market modelling such that contract prices (from the contract pricing model) aligned with the forward curve, and extending the contract prices for the year no forward curve data was available.

NEM Assumptions

The NEM modelling assumptions were based on the most recent information relevant to the modelling period 1 July 2023 to 30 June 2027. The was obtained from AEMO publications, government and market announcements. The information sources included the following:

- ASX swap contract data as of 2 February 2023;
- AEMO 2022 ESSO Central scenario;
- AEMO 2021-22 Modelling Assumptions (updated 30 June 2022);
- Draft 2023 Inputs and Assumptions Workbook (December 2022);
- AEMO, 2022 Integrated System Plan, 2022;
- CSIRO, GenCost 2022-23, Consultation draft, December 2022;

[56] For a given period (such as a year) the swap contract premium is defined as the swap contract price less the average spot price.

- Federal government announcements on capped gas and coal costs for 2023;
- Queensland Energy and Job Plan, September 2022.

The key assumptions of the modelling are presented in the table (under the headings presented in the first column.

Table B1 – Summary of NEM Assumptions

Review	Description
Issue	Assumption Description
Summary / Narrative	In line with AEMO Step Change scenario
Policy Setting	Current policy with consumer led transformation and coordinated economy wide action. Achieve 43% reduction in emissions below 2005 levels by 2030. No carbon price was assumed.
States schemes	• NSW Infrastructure roadmap: met by 2030 • Queensland Energy and Jobs Plan: coal generato9r closure dates consistent with the Queensland Energy and Jobs Plan • Victoria: VRET met. No offshore wind prior to July 2027
Demand forecast	AEMO 2022 ESOO Central scenario. Thile has very little growth in energy but an increasing reduction in middle of the day demand (due to rooftop PV).
Gas Prices	Capped prices for 2023, increasing after that in line of LNG prices, and moving to AEMO 2022 gas price outlook.
Coal Prices	Cap price of $125/tonne 2023, and then reding to prices in the range $4 to $6/GJ after that.
LGCs	Based on the LGC forward curve as of 31 January 2023.
Coal Plant Closures	Based on AEMO Step Change scenario and announcements. key dates are: • Liddell closes in April 2023 • Eraring closes August 2025.
New Entrant Capex	CSIRO Outlook dated December 2022.
New plant entry (prior to 1 July 2027)	• Kurri Kurri gas plant (NSW) December 2024 • Tallawarra B gas plant (NSW): December 2024
Transmission Links and Build Out plan	Based on Optimal Development Plan as per ISP 2022, with exceptions based on new announcements. The key date (prior to July 2027) is Project Energy Connect: 1 July 2026.

Source: Marsden Jacob

Loss factors

Spot energy prices at the node are adjusted to incorporate estimated (transmission) marginal loss factors at SBP for the Kurnell transmission national identifier (TNI) using AEMO data. AEMO average MLF for a given year are carried forward from the previous year. No data on the average loss factor for 2022/23, which would be applicable in 2023/24 and the following three years, is currently available from AEMO. Accordingly, further consideration needs to be given to the possibility of future changes in the relevant loss factor over the forecast period.

Hedging risk premium

Prices for swap contracts were obtained from ASX (https://www.asxenergy.com.au/) for financial years 2024 to 2025 (sourced 31 Jan 2023). Prices for spot prices and swap contract prices for 2026 and 2027 were calculated from NEM modelling.

The relationship between the spot and contract market was expressed through the relationship:

Swap contract price ($/MWh) spot energy prices (capped at $300/MWh) + cap contract prices ($/MWh)

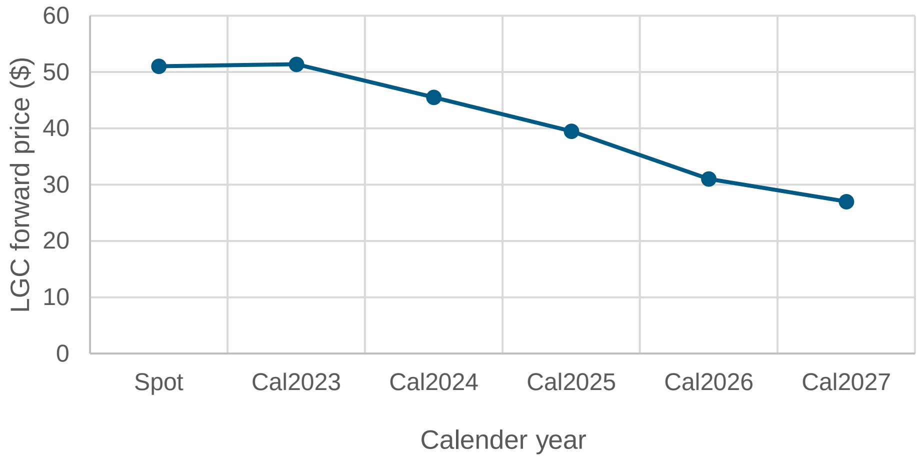
The modelling made the assumption that over the study period the expected swap contract premium would be the same in all years. To address the limited market modelling simulations undertaken in each year, the modelling determined the average swap contract premium over the years 2023/24 to 2026/27 and assigned this as the swap contract premium for each year. From this the average NSW spot price was determined as the swap contract price less the assessed swap contract premium.

Modelling Green Energy Prices

Green energy. There are two components to green energy costs: large (LGCs) and small renewable energy certificates (STCs). The total estimate is developed from the most recently available forward LGC prices. An initial placeholder is used for STC unit costs. Compared with a typical large customer, SDP will require around five times the volume of green energy relative to its actual energy demand.

The LGC outlook was developed through a consideration of the current forward price, and the demand and supply outlook of LGCs to 2030, and the potential green certificate policy position post 2030. From this assessment it was concluded that the LGC prices are being driven by many factors, of which a key factor is voluntary demand which is not known (in total). For this reason, LGC prices were based on the current forward curve to 2026 and extrapolated to 2027 on the current trend.

Figure B1 LGC forward price curve based on mid-point index



Source: https://www.mercari.com.au/lgc-closing-rates/ accessed 17 January 2023

Small renewable energy certificates and NSW energy savings certificates trade at relatively stable prices, so projections extrapolate the latest trading prices.[57]

Other procurement costs

Ancillary services charges. For the initial estimates, the most recent ancillary service charge outcome is applied for each year of the forecast period.[58] No data on ancillary service charges for 2023/24 and the following four years, is currently available. Accordingly, further consideration needs to be given to the possibility of future changes in this cost component over the forecast period.

AEMO market fees. AEMO recovers its operational costs by charging market participants market fees in accordance with approved fee schedules. Along with annual fixed fees, these are converted to $/MWh payable by retailers ('market customers') on all wholesale market purchases.[59] For the initial estimates, the most recent AEMO charge outcome is applied for each year of the forecast period.[60] No data on AEMO fees for 2023/24 and the following four years, is currently available from AEMO.

Metering charges. The benchmark retailer would be responsible for procuring metering services and incurring associated charges. An estimate has been derived from data on SDP's actual metering costs.

[57] Trading date for LGCs, STCs and ESCs derived from https://www.mercari.com.au/lgc-closing-rates/ and https://www.demandmanager.com.au/certificate-prices/, accessed 17 January 2023
[58] Australian Energy Regulator, Default market offer prices 2022–23 Final determination, 2022
[59] https://aemo.com.au/-/media/files/about_aemo/energy_market_budget_and_fees/2021/fy22-aemo-electricity-revenue-requirement-and-fees-schedule.pdf?la=en
[60] Australian Energy Regulator, Default market offer prices 2022–23 Final determination, 2022

Inflation

All nominal dollar values used as inputs have been converted to constant FY2023 dollars using the RBA's historical and most recent forecast values.[61]

[61] See https://www.rba.gov.au/publications/smp/2022/nov/forecasts.html

Appendix C. ASX contract trading

Hedging Contracts - Swaps and Caps

Hedging contracts are fundamental to the operation the NEM. Without hedging contracts parties would not be able to manage their respective risks, particularly around cash flows. A prudent retailer develops a hedging strategy to manage the volatility of the spot price and the volatility of their customer loads. This means the NEM (and other similar markets) requires a functioning and liquid derivatives contract market.

Wholesale electricity contracts are traded on the Australian Security Exchange (ASX) and through brokers in the over-the-counter bilateral contract market. The two most common hedging contracts used in the NEM are swap and cap contracts.

A “swap contract” exchanges the cash flows associated with the spot price for a defined quantity (MW) for the cash flows associated with a fixed price for the same defined quantity.

A cap contract is an agreement that provides the buyer an upper limit (known as the strike price) on the spot price that they would need to pay.

These contracts operate as an “option” that is automatically “exercised” when the spot price exceeds the strike price. Hence the buyer needs to pay the seller a fixed amount for this contract. De-risking costs means that contracts are purchased at a premium to spot price costs.

Swap contracts

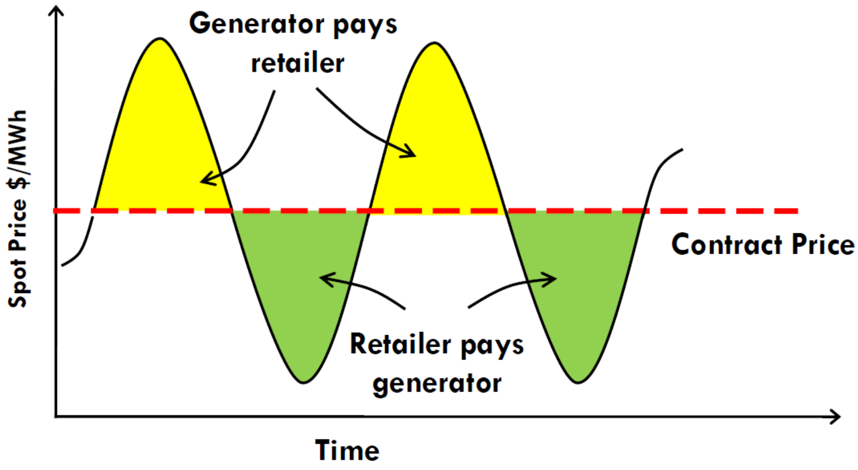
(These are also called Fixed for Floating Swaps or 2-Way Contract for Differences (CFDs))

A “swap contract” exchanges the cash flows associated with the spot price for a defined quantity (MW) for the cash flows associated with a fixed price for the same defined quantity.

The terms that describe a swap contract are as follows:

- The fixed price of the swap contract is referred to as the contract price;
- The quantity of swap contracts is often a fixed amount for the duration of the contract (often referred to as a flat contract);
- The term of the contract (usually 3 months or a year).
- The price of swap contracts is influenced by the outlook of spot prices and the risk of high spot prices.
- An example of the payments of a swap contract (or contract for differences) sold by a generator and purchased by a retailer is illustrated in Figure 3 below. This is represented as a contract for differences which shows that:
- The party that sold the contract (Generator) pays the party that bought the contract (Retailer) the difference between the spot price and the contract price whenever the spot price is above the contract price; and
- The party that sold the contract (Generator) gets paid by the party that bought the contract (Retailer) the difference between the contract price and the spot price and the whenever the spot price is below the contract price.

Figure C1 Illustration of a Swap Contract



The contract price of a swap contract has typically been in the range $50/MWh to $90/MWh (depending in season, year and region).

Source: Marsden Jacob

Cap Contracts

A cap contract is an agreement that provides the buyer (say a retailer) an upper limit on the spot price that they would need to pay. The upper limit is known as the strike price. For example, a cap contract with a strike price of $300/MWh ensures that a buyer will pay no more than $300 per MWh for an agreed quantity (MW) energy.

These contracts operate as an “option” hence the buyer needs to pay the seller a fixed amount (referred to as a “premium”) for this contract.

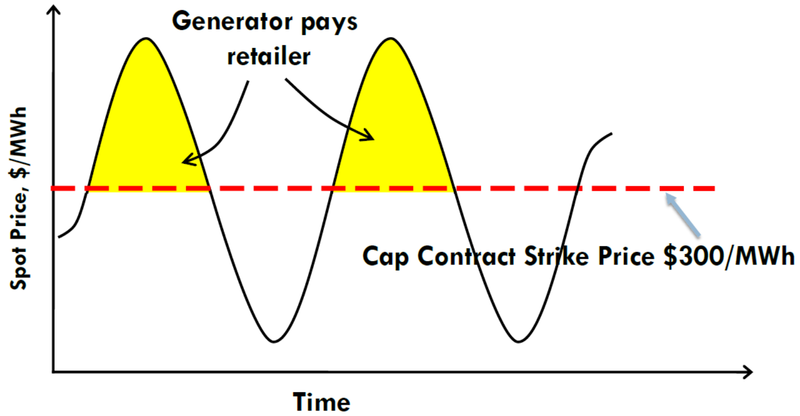
The contract is automatically “exercised” when the spot price exceeds the strike price. For those periods the seller of the contract is required to make a settlement payment to the buyer. Otherwise (when spot price is below $300), there is not CfD. As a result, those contracts are of also called 1-way CfDs.

In the same manner as Figure 3, Figure 4 presents the operation of a cap contract. Only the seller of the cap contract makes payments (and this is when the spot price is above the contract strike price).

These contracts are used by retailers to hedge very high demands (not hedged by swap contrast) that occur infrequently. They limit the cost of purchasing this high demand component that can be associated with very high spot prices of up to $15,500/MWh.

The cost of providing a cap contract reflects the type of generation that can start and stop quickly and only operate when spot prices exceed the strike price. Open Cycle Gas Turbines (OCGTs) fulfil this role and are often used to price cap contracts

Figure C2 Illustration of a $300 Cap Contract



This is a $300 cap Contract.

These are the most common cap contracts in the NEM

Source: Marsden Jacob

Expressing the Cost of a Cap Contract

A price of a cap contract is often expressed a $/MWh. This price is understood as follows:

- The cost is the cost of supplying a defined amount of capacity (MW) for a year;
- MWh is the capacity (MW) multiplied 8760 (hours in a year) – to give the MWh of demand that can be “covered” by this contract.

Expressed in this manner, the cost of a new entrant OCGT supplying a cap contract is typically assessed to be in the order of $12.5/MWh.

Contract prices and contract premium

The suppliers (i.e. sellers) of contracts have increased risk, as opposed to the buyers of contracts that have a reduced risk.

When a generator sells a contract, it accepts outage risk. This is the risk that the generator may not be available to generator when spot prices are very high (and the generator is required to pay high payments to the contract buyer). Unavailability to generate can result from the generator breaking down or transmission congestion that limits the amount the generator can be dispatched.

The asymmetric risk profile between contract sellers and buyers has resulted in contract prices historically being higher than the corresponding spot prices. This is referred to as contracts having a premium over the spot prices.

Modelling Cap premium

By design the $300 cap contract provides the buyer with an insurance against prices exceeding $300/MWh.

Prophet models the spot prices outcome once the system has reached equilibrium and the cap premium modelling return the risk of price volatility above $300/MWh (frequency and range). The cap reflects the cost of capacity needed to reach supply-demand balance and meet the reliability standard in each region.

Instead, the market (traders) uses caps as the prevalent instrument to prices all "market" risks, such as:

- Capacity: frequency and range of prices above $300 (as per modelling)
- Unplanned outage: transmission and generation
- System constraints and break downs
- Weather events: impacting demand (such as the third 40-degree day lag in demand)
- Liquidity:
  - because of the premium paid upfront (OTC) or high Initial Margin (ASX), caps rarely trade earlier than 12-18 months forward (contrary to swaps which trade up to 3 years forward).
  - some regions are structurally short of caps: e.g. South Australia.
- Regulatory risk: e.g. the Australian East Coast $12/GJ price cap on gas resulted in cap prices halving within a fortnight (NSW & QLD)
- Traders risk appetite

Those underlying drivers combined lead to the cap forward prices being excessively sensitive to current and forward spot prices (Gamma & Vega).

Accordingly, the Cap premium resulting from the MJA modelling may not fully reflect the market pricing.

-

Appendix D. Review of chemical use

The production of potable water from seawater requires the use of chemicals. SDP's submission includes a table of the proposed chemical usage allowances per Gigalitre ("GL", "Gl", or "gl" used indistinctively in this Report) of water.

We have reviewed SDP's stated dosing rates and provide a brief summary of a few areas for consideration in the search for potential future efficiency below.

- Optimisation in the use of PolyDadmac during normal good seawater conditions. We have observed that on many SWRO facilities the use of the PolyDadmac dosing has been eliminated in recent years for normal seawater conditions.
- Optimisation of first Pass and second Pass Antiscalant based on the dosing levels initially used in 2011-12 and experience on other plants.
- Whilst we recognise some potential need for sodium hydroxide dosing during the summer months when the RO membranes have aged, there is scope for SDP and the Operator to optimise the dose and the number of months when Cleaning in Place ("CIP") is used as the membranes become fully aged;
- Optimisation in the use of Citric Acid (which represents the highest cost per gigalitre of all the chemicals used in the plant) based on our allowance (from historical data of the plant) of two number Citric Acid CIPs per first pass train per year and 1 citric CIP per second pass RO trains per year.
- Optimisation in the use of Carbon Dioxide, Hydrated Lime, and Fluorosilicic Acid based on the average use of the plant of these chemicals during the period 2019 – 2020.

Appendix E. Responses to SDP comments on the draft report

Attached as a separate document

Member of the SNC-Lavalin Group

Trad Alroweilly
WS Atkins International Limited
Level 10
45 Clarence Street
Sydney
NSW 2000
Australia

Tel: +61 02 8239 8700

© WS Atkins International Limited except where stated otherwise