SIMEC

MEMBER OF GFG ALLIANCE

SOUTH MIDDLEBACK RANGES PUMPED HYDRO ENERGY STORAGE PROJECT

Pre-feasibility Study – Knowledge Sharing Report

10 July 2019

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Contents

1 Introduction

1.1 Project purpose, concept and location

1.1.1 Purpose

The project's purpose is to deliver additional firming capability in the supply of electricity to the operations of SIMEC Mining and Liberty Primary Steel in the Whyalla region, and to provide surplus electricity to the grid via SIMEC ZEN Energy (an energy supplier).

1.1.2 Concept

The project concept is to utilise SIMEC Mining's Iron Duchess North mine in the South Middleback Ranges as the site for a pumped hydro facility (**the SMRPHES facility**) once mining has finished at that location. Key features of the project concept are:

- the existing mine pit will be used as the lower reservoir;
- an upper reservoir will be constructed on the mine waste dumps above the mine pit using waste rock from current mining operations;
- the project would be constructed while mining is progressing to take advantage of the synergies and cost-savings that could be delivered from that activity; and
- the pumped hydro project would commence operations in early-mid 2023 after the conclusion of mining at the site.

1.1.3 Location

The location of the project can be seen in the map below:

1.2 The base case for the project

1.2.1 Sizing and grid connection

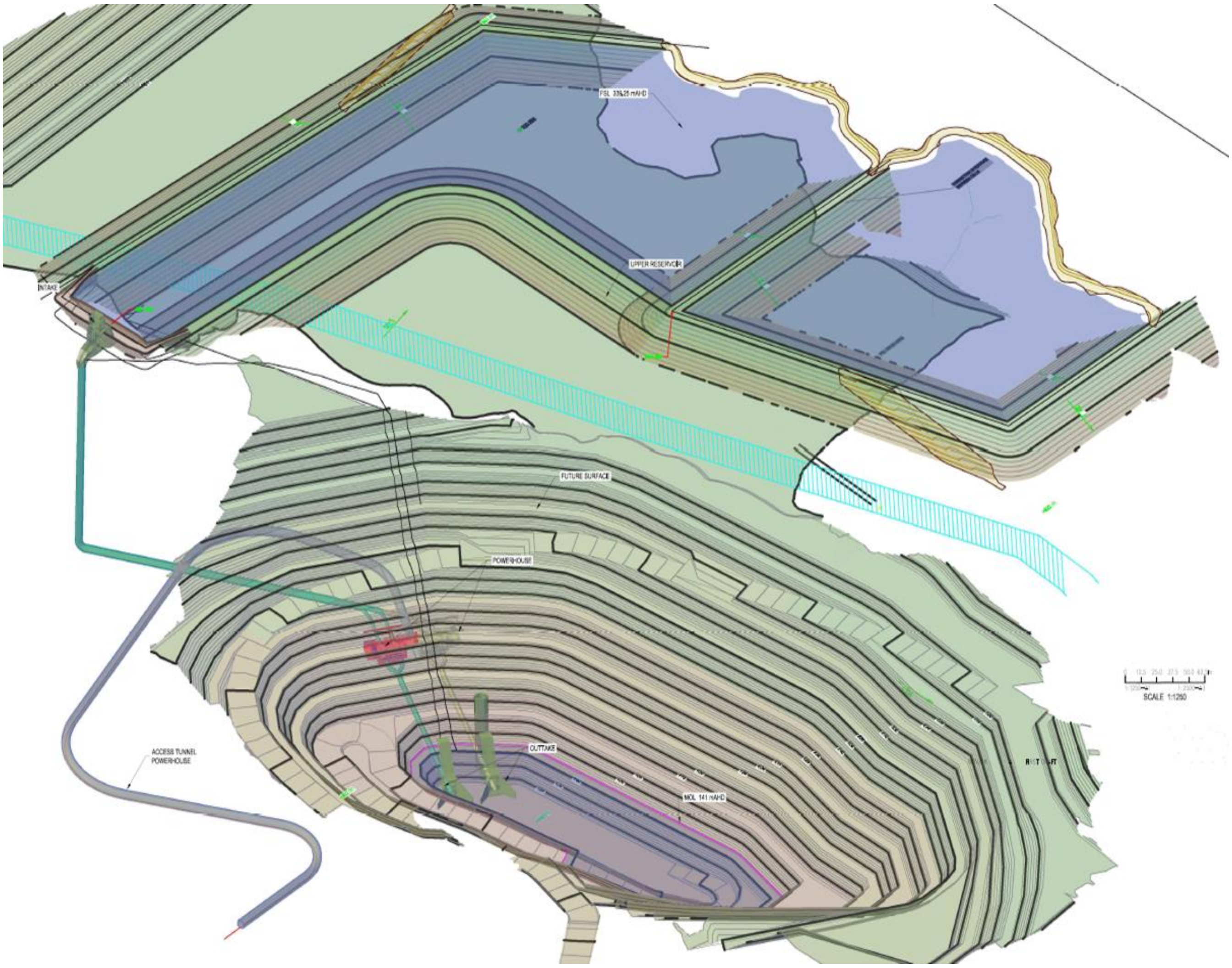
The base case for the purposes of this study was the following:

- Connection to the National Electricity Market via the existing ElectraNet transmission network;
- 1,500 MWh of storage; and
- 110 MW of generation (the possibility of sizing being expanded is currently under active consideration).

The Iron Duchess North mine pit is a versatile asset for a pumped hydro project and there are many other options for it, but the above base case was settled upon as a realistic configuration for the study.

1.2.2 Design and layout

A preferred, single, go forward technical design and layout was not selected at this stage because it was considered premature to do so despite the substantial amount of engineering design and other analysis undertaken thus far. In the course of the study many permutations for the best design and layout were considered and tested. At a high level the conceptual differences between the 11 design options was not great and what is basically the base conceptual design and layout can be seen in the drawing below:



Although there are cost differences between the various design options considered, there are no material operational differences between them.

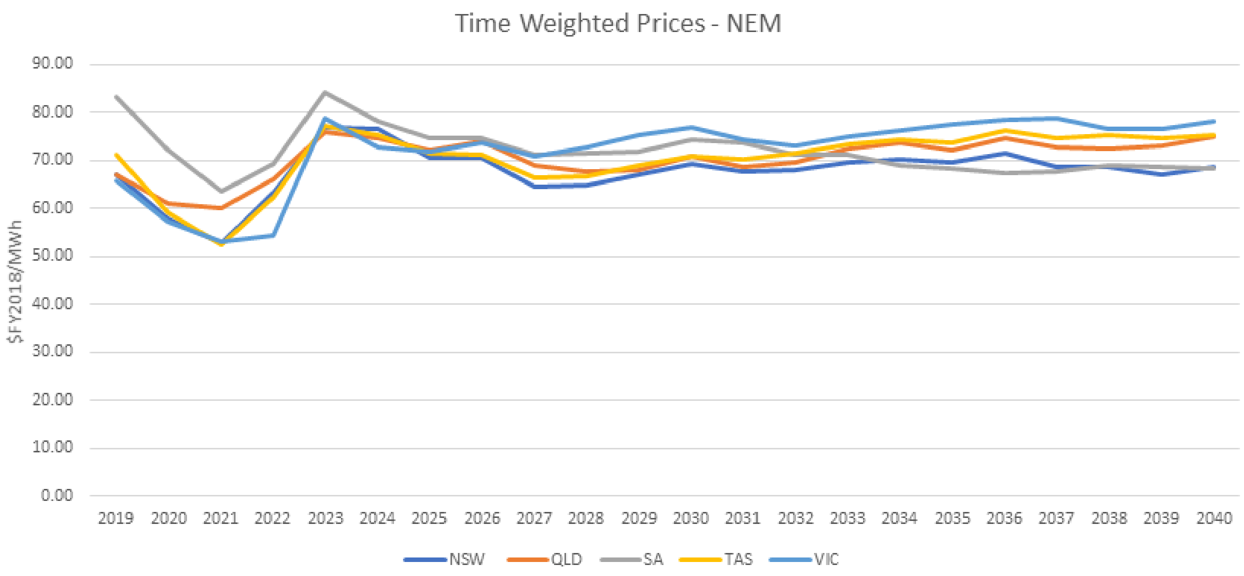
The final preferred design and layout is yet to be developed, and the final configuration will be influenced by many factors including further electricity market analysis, government policy and whether there is a firm decision from the Australian Energy Regulator for ElectraNet to proceed with the proposed transmission line expansion on Eyre Peninsula. The versatility of this project site, and the mining fleet and other resources currently available to it, means that the selection of the final design and layout can be delayed for a period in order to ensure the best design and layout is selected.

The hydro design and layout considerations are considered in greater detail in Section 4 of this report.

2 The strategic context

2.1.1 Electricity prices

As part of their work for this study, Jacobs provided the following projections for electricity prices in the National Electricity Market (NEM) were obtained:



Key assumptions of the market modelling are set out below:

Parameter	Assumption
Demand growth	AEMO 2018 Electricity Forecasting Insights (EFI) update - neutral demand scenario (Released March 2018).
Gas prices	Around $10/GJ
Coal price	Coal prices are based on the Wood Mackenzie outputs published and used by AEMO as part of the 2017 ESOO
Emissions policy	Emissions Policy of the National Energy Guarantee
Renewable energy policies	LRET continues operation in current form. 1st stage of VRET included – 674MW Wind and 255MW Solar Queensland ‘Renewables 400’ plan included, consisting reverse auction for 400 MW renewables including 100 MW of energy storage. 2nd stage of VRET not included (40% renewables by 2025) as final decision is contingent on being legislated. Subsequent stages of the ‘Powering Queensland Plan’ not included i.e. 50% renewable energy target by 2030, sometimes referred to as ‘QRET’.
Retirements of coal fired power stations	Liddell within the financial year of 2023. Yallourn is assumed to retire progressively from 2031 to 2034. Gladstone is to retire in 2030.
Interconnector upgrades	QNI upgraded by 300 MW in both directions by 2023 and Snowy Hydro 2.0 associated upgrades.

Snowy Hydro 2.0	Starts operations in FY 2026-2027
Distributed battery storage	Forecast as proposed in the ESOO 2018 (published in August 2018)

Table 1 - Overview of Jacobs' base case energy market modelling scenario (Source: Jacobs, 20180918 SIMEC Mining Scenarios Table clean rev 5.1.pdf)

Also, Jacobs' electricity price projections were that the cost to fill the upper reservoir would be ~$40/MWh upon its commissioning and that this cost would fall to ~$25/MWh after about 2034.

It is to be noted that prices in South Australia are forecast to drop to mid-$80/MWh in 2019 (compared to current prices of $128/MWh) with prices stabilising by 2027 in the range of $65/MWh to $75/MWh. However, it is worth noting that "AEMO forecasts risks to supply in the next five years in South Australia, due to the region's interconnectedness with Victoria"[1].

[1] AEMO's "South Australian Electricity Report", November 2018, at p.5.

3 Scope of the pre-feasibility study

3.1 Study scope

The scope of the study was to look at all matters relevant to a pumped hydro facility at the Iron Duchess North mine other than those matters excluded in Section 3.2 below. The study was done on a pre-feasibility basis and based on the likely configuration of the mine pit and surrounding areas after mining concludes in 2023. The study was also based on the existing grid transmission capability in the region. The key assumptions behind the study are set out in Section 3.3 below.

The pre-feasibility study primarily looked at the issues of constructability and financial viability, however tenure, regulatory arrangements and other matters have also been considered to a degree suitable for this stage of the project.

3.2 Work excluded from scope

The following elements were excluded from the scope of work conducted:

- Other possible pumped hydro sites on SIMEC Mining's operations in the Middleback Ranges;
- Generation of new sources of water; and
- Detailed consideration of the implications of a new expanded ElectraNet transmission line for the Eyre Peninsula, which has been proposed by ElectraNet to the Australian Energy Regulator.

3.3 Key assumptions

The following assumptions were made in the conducting the study:

- Regulatory approvals – it has been assumed that all necessary regulatory approvals will ultimately be obtained;
- Tenure - it has been assumed that secure, long term tenure will ultimately be secured;
- Electricity pricing, modelling, CAPEX, OPEX and investment evaluation – numerous assumptions have been made and are broadly set out in this report;
- Unless otherwise specifically stated, all the CAPEX amounts referenced in this report are the (unescalated) P50 amounts using the AACE Standard for the Hydropower Industry as calculated by Turner & Townsend; and
- The potential economic value of the SMRPHES facility has been calculated on the basis that it is a stand-alone electricity project.

4 The pumped hydro facility

4.1 Overview

The technical proposal for the pumped hydro facility is based on well understood, established hydropower technology. At a high level, the proposed technical solution is the following:

- An upper reservoir will be constructed on the waste rock dump areas above, and to the east of, the Iron Duchess North mine;
- Once mining has finished, the mine pit of the Iron Duchess North mine will act as the lower reservoir;
- The two reservoirs will be connected by a waterway comprising a combination of penstock shafts and tunnels;
- A powerhouse housing two 55 MW reversible Francis pump-turbines will be constructed in an underground cavern behind the eastern wall of the Iron Duchess North mine;
- The pump-turbines will transfer water from the lower reservoir into the upper reservoir at times of low National Electricity Market electricity prices (**pumping mode**); and
- Water will be released from the upper reservoir and hydro electricity generated through the pump-turbines (**generation mode**).

4.2 Operating strategy

The pumped hydro system will be a versatile and agile facility and so it will switch between pumping and generating operations frequently throughout the day and in response to changes in the grid electricity price.

If the project proceeds, the next stages of project development will include detailed modelling of the plant operating regime and dispatch strategy in order to confirm the business case and to maximise the value of the SMRPHES facility.

4.3 Hydropower system design

All hydropower engineering work for the study was carried out by Stantec.

During the prefeasibility study several project alternatives including scheme layouts and approaches for staged construction of each of the key project components were considered.

A summary of the key aspects of the proposed pumped hydro system follows.

4.3.1 Pumping, generation and storage capacity

Optimisation of the project to maximise the benefits derived from the pumping, generation and storage capacities will be undertaken in the next stages of the project development. However, for the purposes of the study the following physical characteristics were assessed:

- Conventional, fixed speed, vertical shaft, single stage reversible Francis pump-turbines (currently sized at 55 MW – see section 4.3.8 for further information) with spherical inlet valves; and
- The limit on the stored energy reserve (MWh) is a function of the live storage capacity of the lower reservoir and the practical range of water levels and net heads resulting, which the pump-turbine units can exploit efficiently. The current 'base case' is based on a maximum live storage of 3.8 GL representing a stored energy reserve of approximately 1,500 MWh.

4.3.2 Location

The identification of a suitable location can often be one of the most problematic aspects for new-build hydropower schemes. However, as a working site, the Iron Duchess North location presents the opportunity to make use of existing mine infrastructure and adapt the new mine working operations to facilitate both the pit's future use as a lower storage reservoir and for the associated waste rock dumping operations to provide a suitable topography for the construction of the new upper storage reservoir required.

Although currently no significant issues are identified with the site from an engineering perspective (issues that could represent a fatal flaw), further engineering work is still required.

4.3.3 Lower reservoir

Re-mining of the Iron Duchess North site has now commenced – this will increase the current size of the mine pit substantially once mining finishes in 2022.

There are several factors which affect the optimal operation of pump-turbine units, including head, submergence and the range of fluctuation in the reservoir levels during operations. These will ultimately contribute to determining the final design of the lower reservoir and scheme itself.

4.3.4 Upper reservoir

There is no practical constraint that restricts the size of the upper reservoir to match the live storage of the lower reservoir and provide adequate submergence at the intake. The current layout has been designed to site the intake structure on original ground with rock near to the surface and minimise the length of the penstock, which should significantly reduce capital costs. If it is ultimately decided to increase the stored energy reserve, then this will largely be reflected in a deeper upper reservoir (with proportionately less evaporation) than one having a larger surface area.

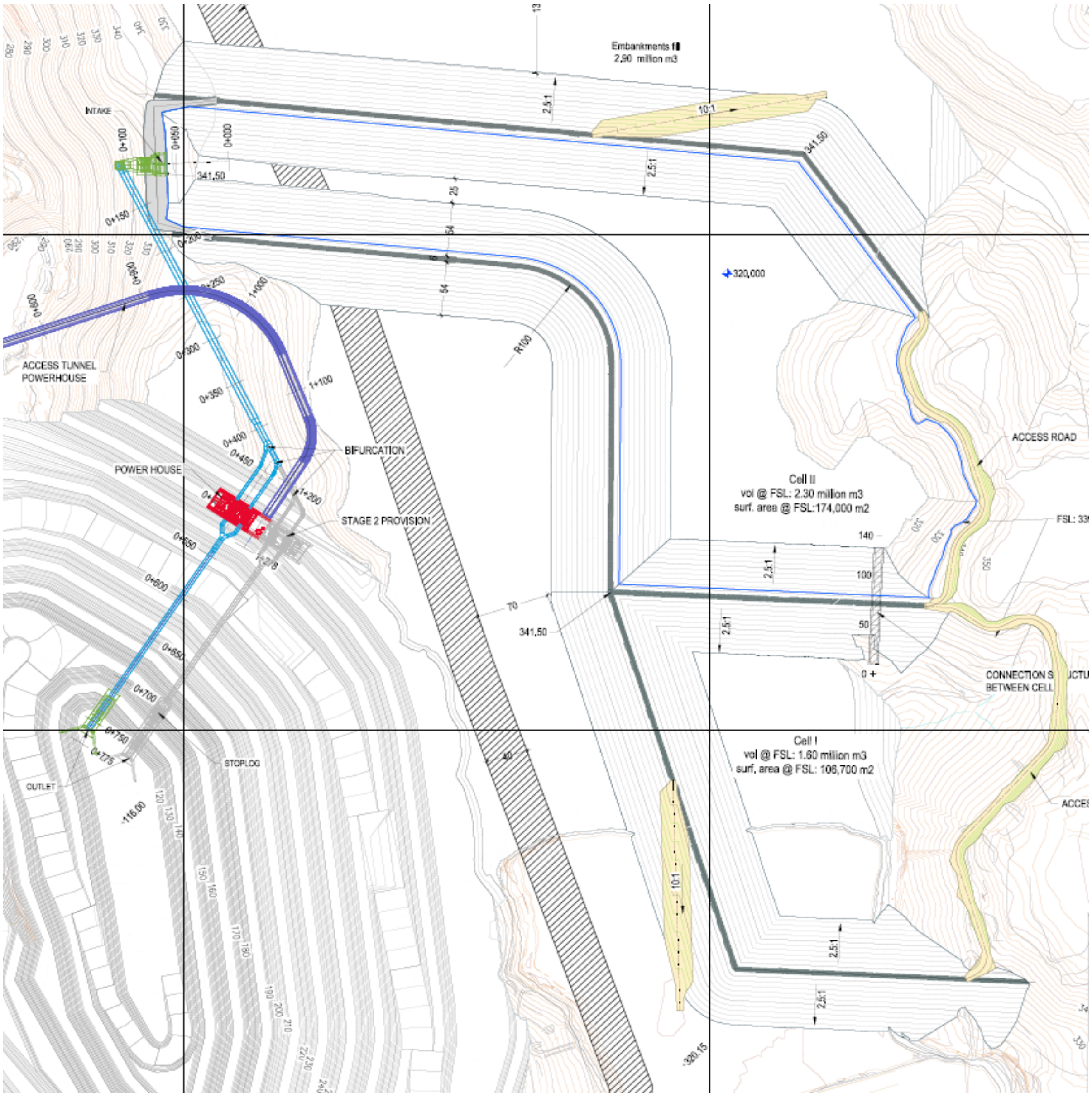


Figure 4.1 Upper Reservoir – General Layout

A subsequent design layout to that identified in Figure 4.1 above, has been developed by Stantec (which provides for a larger storage capacity of 2,4000 MWh). Further optimisation work is necessary to assess effective physical asset scaling to deliver the benefits of any additional storage capacity.

4.3.5 Waterways

The waterway conveys flows from the upper reservoir to lower reservoir (and vice-versa) via the pump-turbines in the powerhouse. Figure 4.2, below, shows the waterway profile in cross-section.

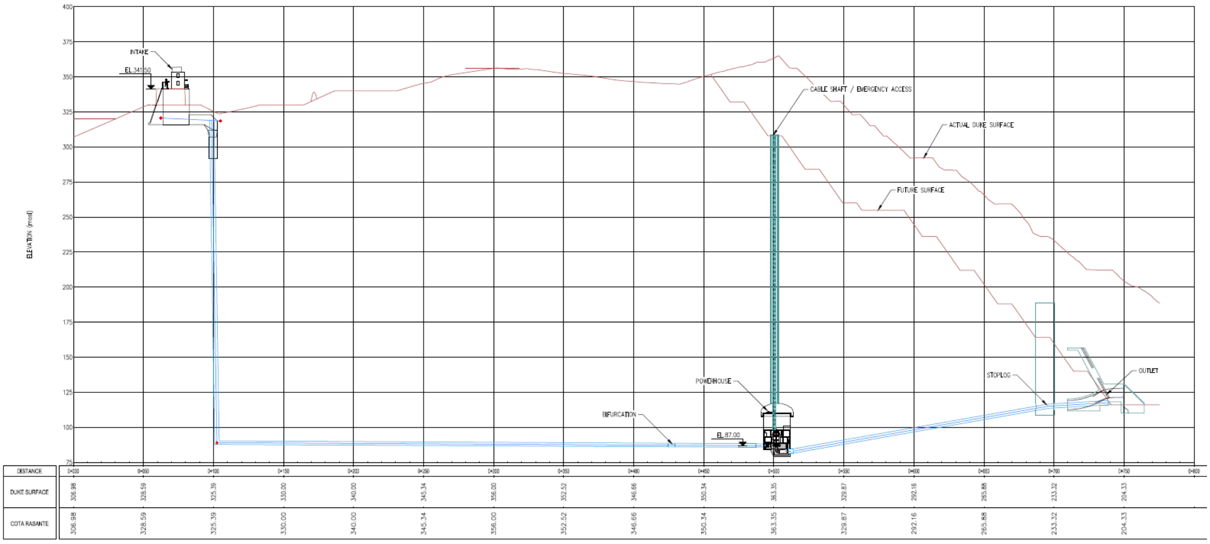


Figure 4.2 Waterway – Longitudinal Profile

4.3.6 Powerhouse

The powerhouse containing the 2 x 55 MW pump-turbine units is proposed to be constructed in an underground cavern.

Access to the powerhouse will be provided by a 6 m finished diameter tunnel – the Main Access Tunnel (MAT) – which will connect the powerhouse with a portal adjacent to the existing main mine haulage road on the west of Iron Duchess North pit.

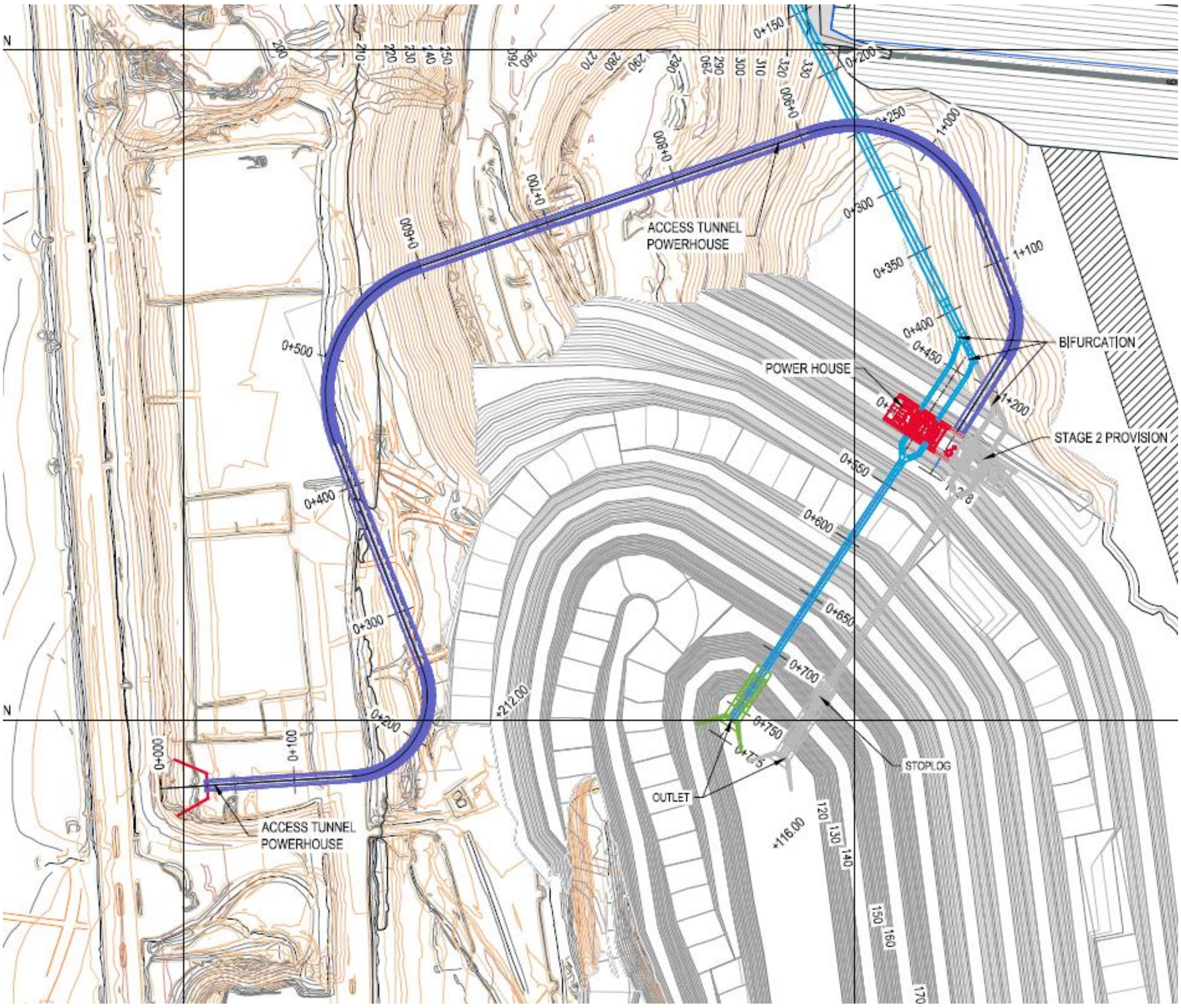


Figure 4.3 Main Access Tunnel (MAT) to Underground Powerhouse

4.3.7 Tailrace

Generation flows are discharged to the lower reservoir through the tailrace tunnel and an outlet structure constructed at the base of the Iron Duchess North pit.

The outlet structure enables the tailrace tunnel to be isolated for major maintenance purposes and comprises a bulkhead isolation gate and transition section to promote smooth flow conditions to, and from, the lower reservoir.

4.3.8 Power System Equipment Selection & Basis

In order to maximise the economic benefits of operation the asset must be flexible, rapid in response to system changes and capable of running smoothly over a wide range of loads. so Ideally the asset will also have the capability to provide merchant 'peak lopping' output.

The proposed base case design adopts two single stage reversible Francis pump-turbine units. Reversible generating sets consist of a motor-generator and a reversible pump-turbine that works either as a pump or as a turbine depending on the direction of rotation. A third mode of operation is also available, synchronous condenser mode. In this mode, the turbine runner spins in air (with the guide vanes closed and the tailwater level depressed with compressed air) and the asset is subsequently capable of supplying Market Ancillary Services including voltage and power factor correction. This operating mode clearly adds an additional source of economic value for the asset.

4.3.9 Powerhouse switchyard

With the step-down transformers located underground, the surface switchyard includes a landing gantry for the high voltage cables emerging from the shaft and the necessary switchgear to connect with the transmission line.

4.3.10 System Optimisation

There are multiple inter-related facets of pumped hydro schemes that are highly dependent on the site and project-specific conditions. Further improvement and optimisation of the layout arrangements and component design is possible and requires further examination.

5 Water demand, supply and evaporation management

5.1 Water requirements

5.1.1 First fill

The first fill of water must be enough to fill the dead volume in both the upper and lower reservoirs and provide the live volume for the minimum commissioning and operating time, which is assumed to be 3.0 hours. Enough water must also be delivered to replace water lost to evaporation during filling.

5.1.2 Ongoing operational demand

Existing water supply lines have sufficient excess capacity to top-up evaporation and leakage losses in the pumped hydro facility.

5.2 Supply Options

5.2.1 First fill water

There are several possible water supply sources for the first fill, but most if not all of that water is expected to be sourced from SA Water.

5.2.2 Top-up water

Existing water supply lines have sufficient excess capacity to top-up evaporation and any leakage losses.

5.3 Water management

5.3.1 Evaporation management

The impact of evaporation on asset operation will need to be managed and appropriate solutions explored.

5.3.2 Water quality and chemistry

The water chemistry will need to be managed. If most/all of the water used in the reservoir is water from SA Water (or similar) it should be possible to manage water chemistry effectively.

5.3.3 Forward work plan

As part of a next phase for the project, a forward work plan for water would need to be developed which would include:

- Design of the water transfer system from lower to upper reservoir;
- A detailed pumping plan;
- Longer term dust suppression water requirements for the wider mining operations;

- Alternative sources of water;
- Water chemistry investigation and management methods; and
- Alternative evaporation management methods and trials.

6 Electricity connection and transmission

6.1 Connection proposal

6.1.1 Background

The SMRPHES facility will require electrical connection to the Cultana substation (see Figure 6.1 below), approximately 75 km to the northeast via the Cultana-Yadnarie transmission line which is owned by ElectraNet and operates at 132 kV.

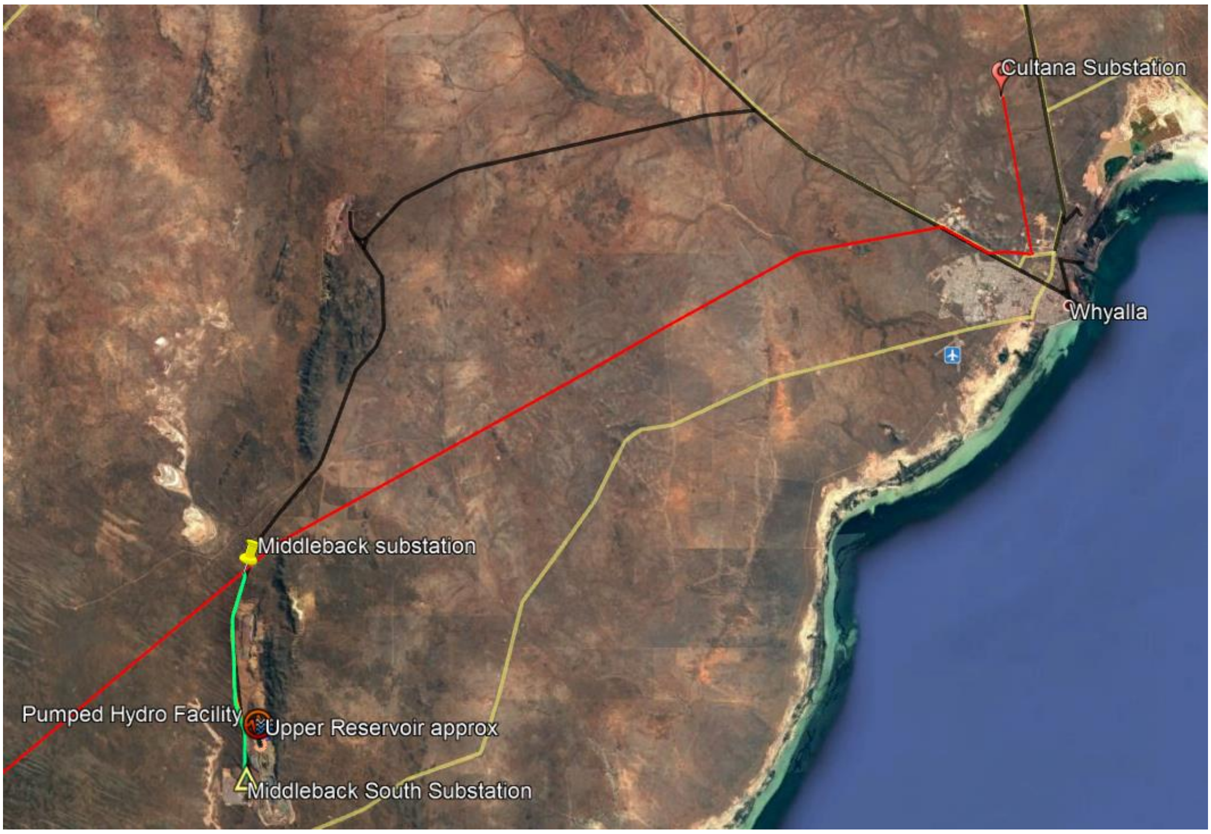


Figure 6.1 Map of region around proposed SMRPHES facility

The Cultana substation has capacity for 500 MW additional generation and 120 MW load. The Cultana-Yadnarie transmission line has a maximum available capacity on hot days of 90 MW, and up to ~130 MW in cooler weather. There is no scope for increasing the capacity of the transmission line without substantial pole and line replacement.

As at November 2018, the Australian Energy Regulator was considering a proposal by the South Australian Transmission network operator, ElectraNet, to upgrade the transmission infrastructure on the Eyre Peninsula. The proposed upgrade would allow for substantially higher transfer of electricity between Cultana and Yadnarie.

6.2 Base case connection proposal

The connection point at the pumped hydro power station would be a landing gantry operating at 132 kV. Mining operations would be connected to the pumped hydro project from the new 132 kV line at either a new switchyard (providing isolation of the SMRPHES facility) and/or the Middleback South substation. Connection of the new 132 kV line – and the old transmission line – is approximately 1 km west of the SMRPHES facility.

7 Environment, community, health and safety

7.1 Environment

The site is located in the South Middleback Ranges and is expected to be established on land covered by mining tenements connected with SIMEC Mining's mining operations.

The site is bordered to the south-east by a pastoral property, and to the west by the Ironstone Conservation Park, owned by the State of South Australia. The nearest regional communities are Whyalla and Cowell, approximately 60 and 55km by road from the site respectively.

7.1.1 Project environmental impacts

A screening environmental impact assessment was conducted on environmental elements that could possibly be impacted by construction and operation of the pumped hydro plant to establish if source, pathway and receptor linkages exist, with a description and classification of the likely impacts and studies required to be undertaken during the approvals phase of the project.

Environmental elements assessed included flora and fauna, weeds, pests and pathogens, soil, surface water, ground water, air quality, visual amenity, noise and light, traffic, public safety, adjacent land use, heritage and waste. All of these elements are able to be managed using appropriate control strategies.

7.1.2 Hydrology

Both upper and lower reservoirs are located entirely within modified mining environments, therefore construction of the plant will not have an effect on any surface water drainage channel or water body.

7.1.3 Hydrogeology

A full consideration of the hydrogeological issues associated with the pumped hydro scheme was undertaken. There is low likelihood of the proposed pumped hydro facility adversely impacting the receiving environment from a hydrogeological perspective.

7.2 Stakeholder engagement and external relations

Key stakeholders have been identified and consulted regarding this project. As a long term mining operator in the Middleback Ranges, SIMEC Mining has extensive and ongoing relationships with all stakeholders in the region.

The stakeholders that are currently identified as being relevant to this project are set out below:

Australian Government Departments/Agencies	South Australian Government Departments/Agencies	Local and Regional Stakeholders
ARENA - Australian Renewable Energy Agency	DPTI – Department of Planning, Transport and Infrastructure	WCC – Whyalla City Council
DEE – Department of the Environment and Energy	DEW – Department for Environment and Water	Landholders
AEMO	DEM – Department for Energy and Mining	Native Title Owners
	EPA – Environment Protection Authority	
	ESCOSA – Essential Services Commission of SA	

As the project develops further, local and regional stakeholders will be further consulted regarding the project’s development.

8 Capital cost estimate

8.1 High level summary

8.1.1 Preliminary comments

As this was a prefeasibility study, the estimation of capital costs was not considered to be conclusive because the Project is still evolving. This is especially the case because of the following factors:

(a) The final and optimum configuration of the facility (including layout) has not yet been determined and will not be finally determined until a full feasibility study has been completed;

(b) The detailed design has not yet been undertaken;

(c) The contracting strategy has not yet been defined;

(d) The value of engineering practices to reduce capital and enhance value creation have not yet been completed; and

(e) Engagement with contractors and equipment suppliers has not yet been undertaken.

8.2 Estimates

Parameter	Unit			
Capacity of the plant	MW	110	220	330
Capital cost estimate – at P50, unescalated (includes 33% contingency)	$M	$452	$617	$777
Projected average annual revenues 2024-2040 per Jacobs report (see Section 10 below)	$M/year	$24	$39	$43

9 Operating cost estimate

9.1 Basis of Estimate

9.1.1 General

The pumped storage plant is required to be capable of operating continuously with a peak-lopping duty, capable of reliable rapid response with a high plant capacity factor over its service life. Due to the fact that the pumped storage role is likely to be highly valued commercially with maximum availability a prerequisite, high levels of plant redundancy are assumed to be warranted.

A long term availability figure of 92 per cent was considered reasonable to cover both planned and unplanned outages.

9.2 Staff planning

A production shift operations team will typically be located close to the powerhouse, responsible for the safe operation and routine maintenance of the plant, the reservoirs and their environs and for the planning, organization and management of the planned maintenance work. This operations team would be able to provide assistance with mode change sequencing, back-up for remote control failure and with investigating alarms - as well as day-to-day condition and incident reporting and policing of risks such as fire, flooding, oil spill and the like.

The permanent team might be expected to comprise 10 staff or so, plus support if required locally, with the power station despatched remotely.

9.3 Estimates of OPEX and Sustaining CAPEX

9.3.1 General

Typical costs for the main routine planned maintenance outages depend on the complexity of work necessary and the extent of any assistance from the OEM. Expenditure would normally be categorised as follows:

- Routine Expenditure (OPEX): Typically, recurring operating and maintenance costs associated with operation and management of the power station and including dam safety inspections and deformation surveys of dams and day-to-day maintenance of the civil works assets, routine (annual) plant overhauls and restoration and the provision of consumables and some of the power station services; and
- Non-Routine Expenditure (Sustaining CAPEX): Non-routine expenditure typically covering most of the ‘one-off’ refurbishment costs for the civil works and appurtenant structures, hydro-mechanical and main generating plant and their essential auxiliary systems, including major life-extending overhauls and some mid-life performance enhancing improvements. CAPEX would also include updating of control and instrumentation systems, typically every 15 years.

9.3.2 OPEX

In view of their site-specific nature there is no standard practice for costing operation and maintenance of pumped storage facility, however assuming the scheme has no over-riding issues, a rule-of thumb OPEX cost characteristic for pumped storage projects of 2 to 2.5 per cent of the capital cost of construction would be typical.

9.3.3 Sustaining CAPEX

Allowances for the non-routine OEM outages might typically be $4.0M and $15.0M per Unit respectively.

9.4 Estimate

The operating cost estimate excluding major shutdown costs, developed by Turner & Townsend for the study, indicates an annual operating cost of approximately $7.5M, representing 1.4% of the P50 capital cost estimate.

10 Revenue

10.1 Types of revenue

Principal sources of revenue for a stand-alone pumped hydro project are through energy arbitrage and supplying Market Ancillary Services including Frequency Control Ancillary Services (FCAS) and other ancillary markets as operated by the Australian Energy Market Operator.

The FCAS markets considered include the six markets for contingency raise and lower and the market for regulation raise and lower. Revenues from non-market ancillary[2] services such as Network Support Ancillary Services (NSCAS) and System Restart Ancillary Services (SRAS) have not been considered as potential revenue streams for the plant.

The revenues from participation in the energy markets have been estimated on a merchant basis i.e. no assumption on a contracting strategy for the plant has been made.

Over the long term, we would expect that the value of the plant – on a merchant basis –will reflect the value that could be achieved by contracting the plant's output. For example, by selling electricity futures contracts traded through the Australian Stock Exchange (ASX). It is noted however, that having offtake agreements with creditworthy counterparties in place would be beneficial from a financing perspective.

10.1.1 Energy markets scenarios

Jacobs was commissioned to undertake several revenue projection scenarios, including a 110MW generating/70MW pumping scenario, 220MW scenario and 330MW scenario. The

[2] https://www.aemo.com.au/-/media/Files/Electricity/National Electricity Market/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3708---Non-market-Ancillary-Services.pdf

larger capacity options assumed that an Eyre Peninsula transmission network upgrade would occur.

Figure 10.1 below, shows the net revenues achieved in energy (left panel) and frequency control (right panel) markets projected for each design option.

Energy market net revenues | **Frequency control markets net revenues**

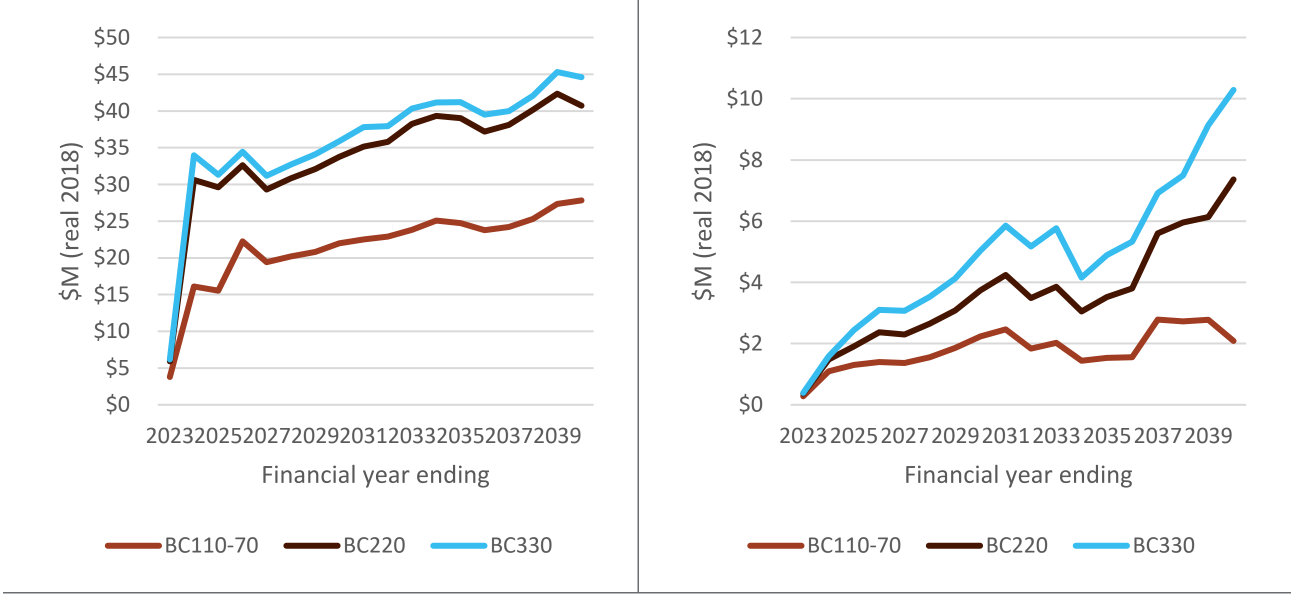


Figure 10.1 **Net revenues from participation in the National Electricity Market** (Source: Jacobs, Electricity Market Modelling Results, 12 November 2018)

10.2 Benefits to the State price of electricity from the pumped hydro facility

The operation of the SMRPHES facility is likely to put downward pressure on the wholesale electricity spot market in South Australia. Jacobs' modelling of the electricity market indicated that the facility will generate at times when the wholesale electricity market spot price is highly sensitive to the addition of supply to the market. While the facility also consumes energy for pumping, which puts upward pressure on (off-peak) demand and subsequently electricity prices, this is expected to occur at times when the wholesale market price is less sensitive to a change in demand. Overall the SMRPHES facility's presence in the National Electricity Market is expected to have a net lowering impact on spot market prices.

Modelling undertaken indicates that the presence of the SMRPHES facility reduces electricity prices in the South Australian region of the National Electricity Market by on average \$1.60/MWh (real 2018) over the period 2024 to 2030 for a 110 MW power station design and \$2.80/MWh and \$3.00/MWh for the 220 MW and 330 MW options respectively.

Where a reduction in wholesale electricity prices is passed on to consumers this may result in an increase of consumer surplus in South Australia in the region of \$21 million, \$34 million and \$37 million per year for the 110 MW, 220 MW and 330 MW options respectively.

It is noted that this analysis of consumer surplus is simplistic in nature. For example, the analysis assumes demand levels as per the 2017-18 financial year and does not include potential for increased consumption due to a positive response to by consumers to the price elasticity of demand i.e. lower prices may generate additional demand therefore shifting the supply demand balance.

The consumer surplus analysis is based on the change in time weighted average prices in the region and assumes that any reduction in wholesale market pricing is passed on to consumers.

10.3 Conclusions

Some important conclusions can be drawn from the work undertaken on revenue:

- Price arbitrage and FCAS revenues from a storage facility (such as a stand-alone pumped hydro facility) are relatively modest compared to the capital cost of such a facility even though such facilities perform a critical role in the transition to renewables and can operate for up to fifty years or, in some cases, longer.
- Revenue models are very sensitive to the assumptions on which they are based and are clearly incapable of predicting all market changes (i.e. plant withdrawal and policy changes). Further, the Jacobs modelling would produce greater price arbitrage and FCAS revenues if either or both of the following was to occur:
  - (a) Less market penetration of batteries; and
  - (b) Snowy 2.0 was not to proceed or was delayed.
- Increasing the size of the storage facility does not proportionally increase the revenues from price arbitrage and FCAS; and
- The direct public benefit from the 110 MW facility – in the form of consumer surplus - is $21M p.a. which is more than the direct benefit that a private investor would derive from such a facility ($24M p.a. less OPEX of say $8M).

11 Other matters

11.1 Key risks

Numerous risks were identified and were considered manageable using established technologies and techniques.

11.2 Execution strategy

In developing the capital cost estimate it was assumed that the project would be executed under an Engineering-Procurement-Construction (EPC) contract. Many alternative contracting strategies are available.

Substantial consideration of the best contracting framework will be required in the next stage of the project's development.