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3-Party Covenant Financing of 'Semi-Regulated' Pumped Hydro Assets

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Abstract

All credible scenarios of a decarbonising Australian power system with high levels of renewables rely on a portfolio of flexible, dispatchable storage and firming assets. Given our current understanding of costs and prices, such portfolios are thought to include short-duration batteries, intermediate-duration pumped hydro and gas turbines providing the last line of defence. The stochastic intermittency of wind, the synchronicity of rooftop and utility-scale solar PV, and stubbornly inelastic aggregate final demand serve to underscore this point. Wind and solar output need to be moved through space (networks) and time (storage). The storage asset class with the highest energy density, pumped hydro, appears to be facing structurally high capital costs with recent Australian estimates given via high profile projects under development (viz. Snowy 2.0, Borumba) being ~$6000/kW in real terms. Under-development will result in rising renewable curtailment rates and greater reliance on gas-fired generation. In this article, we focus on material reductions in the carrying cost of capital-intensive, ultra-long-lived pumped hydro assets through a semi-regulated, 3-Party Covenant (3PC) financing structure between governments, the consumer base and plant investors. When government bonds are included in 3PC financings, the post-arbitrage carrying costs can be reduced by almost 50%.

Keywords: pumped hydro, energy storage, energy-only markets.

JEL Codes: D52, D53, G12, L94 and Q40.

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1. Introduction

Decarbonisation of Australia's National Electricity Market (NEM) commenced with the task of replacing 30GW of coal-fired plant. During 2016-2024, 22+GW of renewables across 160 projects reached financial close, representing $47 billion of investment. Over the same period, ~16GW of rooftop solar PV was also installed. This extraordinary run-up in Variable Renewable Energy (VRE) capacity, and the prevalence of utility-scale and rooftop solar in particular, will alter the traditional operating duties undertaken by power stations. Specifically, the historic mix of base, intermediate and peaking duties is progressively transitioning to a new set of asset classes comprising VRE (solar and wind), and dispatchable firming capacity, viz. short-duration batteries, intermediate-duration pumped hydro, and the last line of defence – gas turbines. This is more than a theoretical observation. From 2016-2024, more than 9GW of batteries, pumped hydros and gas turbines reached financial commitment across 35 separate projects, representing ~$34 billion of investment (Simshauser and Gilmore, 2022).

The inflexibility of coal plant (i.e. minimum stable loads) means they are incompatible with high levels of intermittent renewables, especially in solar rich regions (Simshauser and Wild, 2023). Sharply rising levels of low-cost utility-scale and rooftop solar PV tend to produce a rising frequency of negative spot price events, which are antithetical to the continued operation of coal-fired generation. Conversely, these same conditions provide ideal arbitrage opportunities for storage technologies.

But the exit of coal plant and displacement by comparatively low-capacity factor VRE involves a complex balancing task. Given the intermittent nature of renewables, limits to diurnal reliability and the fact that many periods will see vast surpluses of wind and solar compared to aggregate final demand, the need and benefit of storage capacity is axiomatic. Unsurprisingly, interest in flexible firming capacity, and storage in particular, has become a crucial topic globally (Javed et al., 2020; Stocks et al., 2021; Yang & Yang, 2019). To generalise a vast literature, it is broadly accepted no single generation technology can mitigate intermittency, maintain grid stability (viz. frequency, inertia, voltage, system strength) and ensure security of supply (Javed et al., 2020; Gilmore et al., 2023).

Given this backdrop, there has been a significant revival of interest in pumped hydro globally (Blakers *et al.*, 2021). For Australia this is not without tension. Pumped hydro schemes face significant development hurdles including environmental approvals, community reactions to inundation, access to shared transmission networks and the inevitable financing issues associated with very capital-intensive, ultra long-lived assets.

Dam costs – a central component of pumped hydro developments – have a long history of overruns in Australia. Petheram and McMahon's (2019) analysis of 98 Australian dam constructions since 1888 found systemic biases towards under-forecasting capital costs – the median cost blowout was 49% (average of 120%). Australian results are globally consistent. Ansar et al. (2014) found worldwide median cost overruns of 27% (average of 97%, see also Callegari et al., 2018).[1] Australia's 2000MW Snowy 2.0 project now has a $12 billion total budget, as does the 2000MW/48GWh Borumba project – having started at half this amount.

At one level, the capital-intensive nature of pumped hydro, ultra-long useful lives, long payback periods, the complexity of navigating biodiversity and community challenges and the *iron law of mega-projects,* viz. over time, over budget, every time (Flyvbjerg, 2017) might suggest 'capital-lite' options such as short-duration batteries and open-cycle gas turbines (OCGTs) might dominate market-based firming investment commitments. And thus far in Australia's NEM, they have[2]. While prima facie

[1] The exception to the rule was North America with a median capital cost overrun of 11%.
[2] Gas turbines and associated PPAs are ideal for project finance given their small size, high variable but low capex costs and modest lifetimes. This contrasts with coal, nuclear and pumped hydro, all of which also have long and uncertain build times and costs.

appealing, this should not diminish our responsibility to apply rigour to investigating how to optimise energy storage *'at scale'*. The basis for doing so is as follows:

1. With ongoing VRE investments, coal plant exit is predictable and consistent with net zero policy outcomes. Yet looming episodes of 'intractable dispatch' (see Simshauser & Wild, 2023) suggest decisions on flexible firming and storage capacity additions to replace the coal fleet may need to be made now if they are to enter service on a timely basis given long-lead development times.

2. In the NEM, 3GW of batteries have reached financial close and 4+GW of new projects are seeking financial close during 2024. Battery investments are still dominated by two-hour storage configurations due to energy market prices and plant costs. There is no question two-hour (and in time, four-hour) storage assets help power system resilience. But short duration storage provides limited support for inter-day intermittency.

3. The last line of defence vis-à-vis power system security in NEM planning models typically comprises a large fleet gas turbine plant to manage inter-day and seasonal intermittency. Gas turbines will unquestionably play a vital role. But there are limits to Australia's natural gas pipeline network. Simshauser and Gilmore (2024) find 40+ days of structural gas supply shortfalls for the gas turbine fleet in the NEM's New South Wales and Victorian regions if no additional intermediate duration pumped storage is available following coal plant closures due to gas pipeline constraints[3].

4. Shifting VRE output through space (networks) and time (storage) *at scale* is therefore of utmost importance to ensure the defensive role of the gas turbine fleet is tractable. The energy density and cost of utility-scale batteries or the accumulation of household-level storage – as we currently understand existing costs and storage capacity of such assets – pales into insignificance compared to large-scale intermediate-duration pumped hydro schemes, even after accounting for elevated dam costs.

5. The practical reality is that commitment decisions on additional intermediate-duration storage need to be made now given the increasing task facing power system planners in a decarbonising power system. Battery cost projections frequently exhibit potential for very material reductions. Should these materialise they will reduce, but not eliminate, requirements for intermediate-duration storage and pumped hydro schemes (Gilmore, 2024).

6. Ongoing VRE entry results in increasing levels of 'renewable spill' given stubbornly inelastic power system aggregate final demand. Rising curtailment rates are a lead indicator of stalled VRE investment (Du and Rubin, 2018; Simshauser and Newbery, 2024). Deployment of storage assets *at scale* may alleviate the most acute effects of VRE curtailment (Chyong and Newbery, 2022; Simshauser and Newbery, 2024), thus ensuring new entrant renewables deployment occurs at lowest levelized cost by maintaining wind and solar Annual Capacity Factors at close to optimum levels.

By early-2024, the NEM had just over 800MW // 11.3GWh of pumped hydro in-service, with 2.4GW // 350GWh under construction, a further 2GW // 48GWh nearing financial close and a pipeline of 16.6GW // 250GWh in various stages of planning. The latest NEM-wide system plan presumes around 8GW to be optimal whereas Gilmore (2024) suggests 11GW // 485GWh is plausible under certain policy conditions. Worldwide, additions of pumped hydro plant during 2022 totalled 10GW, and the known global project pipeline exceeds 200GW (IHA, 2023).

[3] Remediation is complex as the pipeline network spans 1000s of kms and the marginal gas load occurs on ~40 days (i.e. extremely poor load factor).

However, there is a commercial complexity for pumped hydro plant – at least in Australia's NEM – due to inherent market design features. In Australia, the NEM's organised spot electricity market coordinates plant scheduling and unit dispatch while the forward derivatives market ties the economics of the physical power system to Resource Adequacy and new capacity investments. Rising forward 'swap' prices (i.e. two-way Contract-for-Differences or 'CfD') signal looming energy shortages vis-à-vis baseload (now VRE) plant, while rising $300 Cap prices (i.e. one-way CfD) signal looming capacity shortages, viz. peaking plant.

While the NEM adequately telegraphs for short duration storage (i.e. negative prices, frequency control markets, $300 Caps), there is no market signal for 'intermediate duration storage' because such duties are not currently required – at least not within the functioning timeframes of the forward market (i.e. ~3 years). In consequence, the NEM's organised spot and forward markets currently guide investments to 'capacity over storage'[4]. That is, all else equal, investors would *currently* favour a 1000MW, 8 hour pumped hydro over a 500MW, 16-hour configuration even though the former involves higher underlying capital outlays (i.e. same storage costs, higher plant costs through additional installed capacity). Yet as Gilmore (2024) finds, the optimal median-term storage requirement for marginal pumped hydro plant in the NEM is 16-23 hours.

To summarise, the NEM's organised spot and forward markets still exhibit the characteristics and market fundamentals of 'soon to be, but not yet retired' baseload coal-fired generation. Spot and forward price formation currently provides only a dim reflection of the firming-storage task ahead. The true value of storage has not been revealed because remnant coal plant continues to undertake firming duties and the storage task is currently being provided by their *vast* coal stockpiles. To be sure, all competitive electricity markets – with their design and implementation dating back to the 1980-1990s (Schweppe et al., 1988; Pollitt, 2004) are characterised by 'missing and incomplete' markets (Newbery, 2016).

In this article, we analyse a 2,000 MW // 48GWh (24-hour) pumped hydro scheme in Australia's NEM. We assume the plant has a useful life of ~100 years with an all-in capital cost of ~$12 billion. Our focus is on corporate financing with an objective of radically reducing the carrying cost of storage capacity additions by observing, then modifying, existing market conventions. Our emphasis is on intermediate (i.e. inter-day) duration storage and while we focus on pumped hydro, our constructs apply readily to any storage technology, including intermediate duration batteries. Our aim is to help bridge intermediate storage economics with what are likely to be transitioning forward markets and relative forward market prices.

Our results can be summarised as follows. Conventional on-balance sheet financing is uneconomic for intermediate duration storage given the NEM's current market setup, even for the most successful vertically integrated merchant utility. Missing and incomplete markets warrant policy inquiry. Drawing on our PF Model, we examine on- and off-balance sheet debt facilities across merchant and semi-regulated industrial organisation and markets for storage reserves. Our modelling culminates in a '3-Party Covenant' financing involving the credit-wrapped issuance of zero-spread Commonwealth Government Securities set in an ultra-long duration, semi-permanent structure. Such financing appears capable of *radically reducing* the equilibrium 'price gap' that exists between existing market benchmarks for plant capacity, and intermediate duration storage.

This article is structured as follows. Section 2 reviews relevant literature. Sections 3-4 introduces our data, model and results. Policy implications and concluding remarks follow.

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[4] In discussions with pumped hydro proponents, often it is the case that potential storage of the upper dam is fixed (e.g. 10,000MWh of storage equivalence) but plant capacity can be varied (e.g. 2 x 250MW with 20 hours runtime, or 4 x 250MW with 10 hours runtime). Existing market mechanisms bias investment decision making to the higher capacity, shorter storage options (i.e. 4 x 250MW with 10 hours storage) – a product of incomplete and missing markets.

2. Review of Literature

Our review of literature examines the history and revival of pumped hydro, and financing challenges in energy-only electricity markets.

2.1 Brief history and the revival of pumped hydro

Pumped hydro schemes date back to the 1890s in the Alpine regions of Switzerland, Austria and Italy (Javed et al., 2020). To summarise the technology, pumped hydro schemes comprise upper and lower reservoirs connected by a series of tunnels/pipes with reversible pumps/generators[5] (Stocks *et al.*, 2021). In the classic case, pumped hydros utilise generation overcapacity conditions in off-peak periods to pump water from the lower to the upper reservoir and in doing so create a store of potential mechanical energy (Deane et al., 2010). When aggregate demand reaches daily maximums, water is released from the upper reservoir to drive the generators which in turn undertake peaking duties (Ali et al., 2021).

Pumped hydros are characterised by high upfront capital costs (Javed *et al.*, 2020) with storage spanning from a few hours to 24+ hours (Nikolaos et al., 2023). Expected round-trip efficiency is typically ~75-82% with a reported range of 70-87% (Rehman et al., 2015). Schemes have low maintenance costs (Ali et al., 2021) and ultra-long asset lives of up to 100 years (Guittet *et al.*, 2016).

Pumped hydros were developed extensively during the 1970-80s, typically paired with inflexible baseload nuclear (Nikolaos et al., 2023) or coal plant (Guittet *et al.*, 2016). The intuition of pairing is the pumping cycle raises minimum loads in lower demand (off-peak) periods while the generating cycle matches peaking duties (Rehman et al., 2015; Stocks et al., 2021).[6]

Pumped hydro capacity additions came to a virtual halt during the 1990s (Yang and Jackson, 2011; Steffen, 2012). It was frequently assumed this halt was due to a lack of feasible sites. But as Ali et al. (2021) explain, an abundance of projects existed. Environmental permitting constraints and the rise of the low capital cost OCGT are more probable causes (Rehman et al., 2015; Guittet et al., 2016). When combined with the uncertainty of organised spot electricity markets and rising involvement of the private sector, the entry of capital-intensive, long-lived assets became problematic (see Von der Fehr and Harbord, 1995). As Offer (2018) explains, the private sector requires considerable assurances to invest in assets with payback periods beyond 15 years, the key issue being the *credit time horizon* of banks and capital markets (see also Newbery et al., 2019).

Sharply rising levels of VRE has led to a revival of interest in pumped hydro (Tuohy and O'Malley, 2011; Yang and Jackson, 2011; Steffen, 2012; Pérez-Díaz and Jiménez, 2016; Stocks et al., 2021; Nikolaos et al., 2023). The known pumped hydro project pipeline world-wide exceeds ~200 GW (IHA, 2023). Short duration batteries are becoming increasingly prominent, but at the time of writing electrical energy storage was dominated by pumped hydro (Rehman., 2015) for plant capacity of 1000+ MW and storage of 10-600 GWh (Guittet *et al.*, 2016).[7] There are currently over 400 pumped hydro plants worldwide totalling ~190GW, including 105GW under construction (Nikolaos et al., 2023).

[5] Early schemes were characterised by their separate pump impellers and turbine generators. However from the 1950s the reversible pump/generator became the dominant design. See Rehman et al., (2015).
[6] Queensland's 500MW Wivenhoe pumped hydro is a case in point, developed in the 1970s, it was commissioned in 1984 along with a fleet very low-cost, baseload coal-fired generators. Tarong, Callide B and Stanwell Power Stations, which were at the time amongst the lowest cost coal-fired generators in the world.
[7] Specifically, pumped hydro represents 97% of electrical energy storage by both MW capacity (Ali et al., 2021), and MWh storage (Blakers et al., 2021; Stocks et al., 2021; Nikolaos et al., 2023).

2.2 Pumped hydro and VRE integration

In a high renewables power system, large-scale intermediate storage will become *indispensable* for protecting VRE investor interests (Javed *et al.*, 2020). As Newbery (2023) explains, peak-to-average output ratios for wind and solar are ~3:1 and ~4:1, respectively. There will be periods when aggregate VRE plant produces at peak levels, and in such circumstances fleet output may vastly exceed largely inelastic aggregate final electricity demand (and vice versa). In the absence of storage in all formats, average VRE curtailment rates will steadily rise across a power system with marginal curtailment increasing at 3-4x the average rate (Newbery, 2023; Simshauser and Newbery, 2024). Rising curtailment means the unit cost of new renewable plant would rise for consumers, even after holding wind speeds and solar irradiation constant.

Pumped hydro plant are ultimately 'net users' of energy due to hydraulic and electrical losses during the round-trip cycle of power generation (Guittet *et al.*, 2016). But despite this, they can move otherwise 'spilled' solar and wind output en-masse through time (Rehman et al., Newbery, 2018), simultaneously maintaining reliability of supply and reducing adverse effects of marginal curtailment rates for incumbent and pending VRE investors (Steffen, 2012; Nikolaos et al., 2023).

When deployed at scale, pumped hydro can also be expected to reduce OCGT run-times (Tuohy and O'Malley, 2011) and help manage gas market loading (Simshauser and Gilmore, 2024). Material reductions in remnant thermal plant scheduling costs (ramping and unit commitment) are also predictable (Pérez-Díaz and Jiménez, 2016) given the array of generation plant non-convexities not co-optimised in organised spot electricity markets such as Australia's NEM (Sioshansi et al., 2008). Operationally, pumped hydro response times span 'minutes to seconds' (Javed *et al.*, 2020). Given the synchronous nature of pumped hydro pumps/generators and their ability to continue to spin 'dewatered', they may assist with system inertia, dynamic stability, system strength and security of supply (Rehman et al., 2015).

2.3 Incomplete and missing markets, financing and uncertainty

Kear & Chapman (2013) surveyed industry experts in New Zealand and the consistent theme regarding pumped hydro plant was 'technically optimal, but prohibitively costly'. Zafirakis et al. (2016), using price data from five deregulated EU markets, found arbitrage revenues were inadequate to cover annualised costs. In Latin America, Delgado and Franco (2023) find a similar result with sharply rising levels of renewables. In Great Britain, Newbery (2018) observed ancillary services revenues dominated with arbitrage revenues inadequate. Chyong & Newbery (2020) found sharply rising VRE increased production duties and profits of existing pumped hydro plant when inflexible baseload plant still formed part of the plant stock. However, they also found inflexible plant exit may have the opposite effect, albeit noting operating reserves become increasingly volatile and therefore valuable. Delgado and Franco (2023) found similar patterns with and without *el nino* weather patterns in Latin America. Gilmore (2024) finds pumped hydro plant capacity factors rise in the Australian context even with the exit of coal plant, but this hinges critically on commensurate rooftop and utility-scale solar PV entry at-scale.

Pumped hydros are complex, capital-intensive developments that face unusually high investment hurdles. Physical constraints[8] aside, the most significant challenge is their onerous upfront capital costs. Total planned construction contingencies usually comprise 10-15% whereas outturn costs historically span +0-25% of capex plans (Nikolaos., 2023). To generalise the literature, the financial uncertainty associated with these ultra-long-lived assets present the greatest challenge (Deane et al., 2010; Yang and Jackson, 2011; Steffen, 2012). This is compounded by the fact that deregulated

[8] Those typically associated with pumped hydro schemes include land acquisition, environmental concerns (i.e. biodiversity loss), water issues and connection to the shared transmission network.

energy markets are characterised by missing and incomplete markets (Newbery, 2016; Simshauser, 2019; Javed et al., 2020; Nikolaos et al., 2023).

Central to the notion of *missing and incomplete markets* is missing money – the seeming inability of energy-only markets to deliver the optimal mix of derivative instruments required to facilitate efficient plant entry, specifically, long-dated contracts sought by risk averse project banks (Newbery, 2016, 2017; Grubb and Newbery, 2018; Bublitz et al., 2019; Simshauser, 2020). Consequently, few firms appear capable of financing long-lived capital-intensive assets in deregulated electricity markets (Ali et al., 2021).

As Offer (2018) explains, the credit time horizon of project banks has limits and as it turns out, equity and debt capital markets require more certainty for long-lived generation assets than deregulated markets appear capable of delivering – in which case its management defaults to public administration. Newbery (2018) and Nikolaos et al. (2023) note grant funding or low interest loans may be required, along with a *full set* of well-designed markets to ensure pumped hydro is fairly compensated at the marginal value of services provided (Newbery, 2016, 2018).

This collision between the energy-only market design and applied corporate finance has led various jurisdictions to introduce strategic reserves (e.g. Belgium, Finland, Germany, Sweden and Texas) where *capacity payments* are paid to a limited number of generation units within a designated *strategic reserve*, (Holmberg and Tangeras, 2023), or introduce broad-based capacity mechanisms, such as Great Britain.[9] Bublitz et al. (2019) note that globally, organised capacity markets appear to have a growing role to overcome episodes of missing money.

It would seem the NEM's energy-only design may also require adjustment and inclusion of new markets for inertia and system strength (see Newbery, 2017; Qays et al., 2023), expanded voltage support, frequency management and operating reserves (Newbery, 2017; Simshauser and Gilmore, 2022) and potentially as our subsequent analysis tends to suggest, some form of market for intermediate storage reserves (see also Mountain et al., 2022). It is to be noted that few existing capacity mechanisms send the correct signal for optimal operation of short and intermediate duration storages during critical event days (see Holmberg and Tangers, 2023).

3. Model and data

Our analysis focuses on financing intermediate duration storage (nominally 15+ hours). The modelling sequence commences by accepting the NEM has missing markets, which requires that we observe existing market conventions to begin with. We therefore start by deriving the equilibrium value for '$300 Cap' contracts.

In Australia, $300 Caps (or 'one-way' CfDs) are the NEM-equivalent of a capacity market in a large thermal power system. The NEM's spot price ceiling is currently A$16,600/MWh and therefore demand for $300 Caps comes from risk-neutral and risk-averse retail suppliers and traders. The premium paid for a $300 Cap, in equilibrium, has historically been taken to be the annual 'carrying cost[10]' of a gas turbine (Simshauser, 2020). Our modelling sequence is therefore set up to derive this value initially. Once determined, we then focus on optimising a '*post-arbitrage carrying cost'* of pumped hydro plant under various financing structures, expressed as either a $300 Cap shortfall amount ($/MWh) or intermediate storage reserve ($/kWh/a).

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[9] Most restructured electricity markets in the U.S. commenced with organised capacity markets.
[10] The carrying cost of plant capacity can be defined as the annualised fixed and sunk cost of any generation technology, including taxation expenses and a normal return to equity.

Due to incomplete and missing markets, a gap will certainly exist. This gap or *missing money* is due to missing markets vis-à-vis the requirement for intermediate duration storage reserves. Our objective is to minimise the gap between 'capital-lite' OCGT plant and a capital-intensive, intermediate-duration pumped hydro plant intending to shift scarce renewable resources through time. How we approach this problem is through unconventional financing structures. Given our focus is on structured financing, we rely on our 'PF Model'.

The PF Model logic is set out in detail in the pages of this Journal (Simshauser, 2024) so we do not propose to reproduce it here. Suffice to say it is an integrated, multi-year corporate and project finance model which produces levelized cost of electricity results for an array of plant technologies. Results comprise a level of detail well beyond typical LCoE calculations because corporate (or project) finance, associated credit covenants and taxation variables are internalised and co-optimised within the model.

Our base scenario assumes a 2000MW // 48GWh pumped hydro plant relevant to either the NEM's Queensland or New South Wales regions in an energy-only market setting with ever rising levels of intermittent renewables. Critical plant engineering parameters are listed in Table 1.

Table 1: Engineering model inputs

Generation Technology		OCGT	Pumped Hydro	Battery*
Project Capacity	(MW)	250	2,000	200
- Storage Capacity	(Hrs)	-	24	4
Overnight Capital Cost	($/kW)	1,588	2,626	547
- Storage	($/kWh)	-	83	450
- Contingency		-	30%	-
Plant Capital Cost	($ M)	397	12,007	469
Operating Life	(Yrs)	35	100	20
Annual Capacity Factor	(%)	5.0	17.2-18.2**	14.7
Transmission Loss Factor	(MLF)	1.000	1.000	1.000
Fixed O&M	($/MW/a)	1,000	20,000	10,000
Variable O&M	($/MWh)	8.0	1.0	0.0
FCAS	(% Rev)	1.0%	1.5%	5.2-7.4%

* Degradation assumed 1.5% pa.

** See also Table 3

Source: Simshauser (2020), Gohdes (2023), AEMO 2024 Integrated System Plan.

In Table 1, pumped hydro capital costs comprise elements in $/kW for power (i.e. water conveyance, turbine hall, reversible pumps/turbines, generators and the substation) and in $/kWh for storage reservoirs (see Stocks et al., 2021). A similar setup is used for battery storage. Most importantly, we commence with a high inherent capital cost for pumped hydro, effectively equating to $6000/kW in line with the most recent cost estimates for plant of this size and scale. Sensitivities appear in Appendix A1.

Financing parameters are outlined in Table 2 and are consistent with Gohdes et al. (2022, 2023) for merchant and project financed plant, while regulated metrics have been drawn from Simshauser and Akimov (2019). For scenarios comprising semi-regulated business configurations, the weighted average of 'merchant' and 'regulated' debt sizing covenants are used in a manner consistent with the approach adopted by project banks as set out in Gohdes (2023). Semi-regulated industrial organisation requires that we construct two distinct debt facilities, one serviced by regulated cashflows (regulated metrics), and one serviced by forecast merchant cashflows (merchant metrics). Total debt service obligations therefore comprise the sum of the two facilities.

Table 2: Financing model inputs

Corporate & Project Finance	2023 Avg	
- 10 Yr Commonwealth Govt Securities	3.92%	
- 7 Yr 'BBB' Corporate Bonds	6.00%	
- 7 Interest Rate Swap	4.21%	
- 7 Year Project Finance Spread	2.89%	
- 7 Yr Project Finance Term Loan A	7.10%	
Equity Returns (post tax)	Asset β*	Equity IRR
- Merchant 'Gentailer' Utility	0.60	8.5%
- Regulated Utility	0.30	7.6%
- Semi-Regulated Generator	0.48	7.9-8.2%
- PPA Project Financed Generator**	0.30	9.0%
- OCGT (Merchant Uility)	0.75	10.5%
Balance Sheet Debt Sizing	Merchant	Regulated
- BBB Rated (FFO+I)/I	4.2x	2.4x
- BBB Rated (FFO/Debt)	20-35%	>9%
- Gearing Limit	40%	66%
Project Finance Debt Sizing	Merchant	PPA
- Debt Service Cover Ratio	1.8x	1.25x
- Loan Life Cover Ratio	1.8x	1.25x
- Gearing Limit	40%	82%
- Lockup Ratio	1.35x	1.15x

* Asset β are subsequently levered to obtain Equity IRRs

** For any ultra-long-life Pumped Hydro PPA, +100 basis points is added (IRR=9%)

Sources: Simshauser and Akimov (2019), Gohdes et al. (2022, 2023)

It is acknowledged that certain input variables remain sensitive to the changing technology mix in the NEM. The progressive exit of coal plant is a material consideration in the decarbonising plant mix. To ensure robust results, outputs from Gilmore's (2024) J-Solve simulation model were used to define pumped hydro capacity factors, and pumping/dispatch prices. To summarise, Table 3 notes with 10GW of coal plant in-service, NEM-optimal pumped hydro plant will, on average, operate with Annual Capacity Factors (ACF) of ~17%. Associated pumping and generation costs/prices equate to ~$29.8/MWh (pumping) and ~$92/MWh after capping dispatch prices at $300/MWh (i.e. sold $300 Caps). Following coal plant exit and commensurate rise in solar PV resources, the optimal fleet of pumped hydro plant exhibit average ACFs of ~18%. Both the unit cost of pumping and capped unit dispatch prices rise marginally, as Table 3 illustrates.

Table 3: ACF and Pumping/Dispatch Prices

Impacted by Coal Plant Exit	Ops Yr1	Ops Yr6
Total Coal Capacity in NEM	10GW	0GW
Pumped Hydro Capacity Factor	17.2%	18.2%
Avg. Pumping Cost ($/MWh)	29.8	31.3
Avg. Dispatch Price ($/MWh)	92.0	100.5
Net Arbitrage ($/MWh)	62.2	69.2

Source: Gilmore (2024)

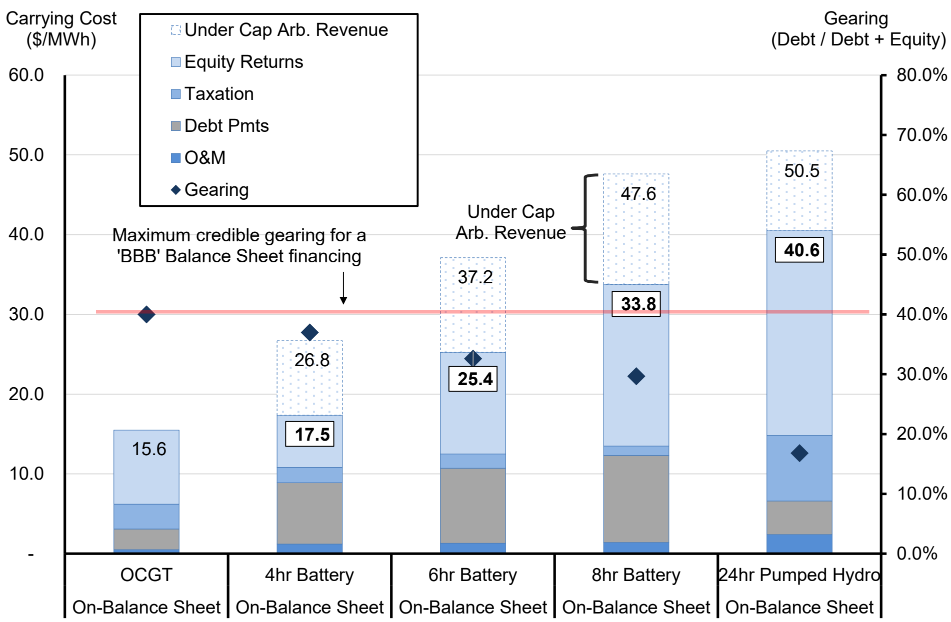
4. PF Model Results

Model results commence with base case 'on-balance sheet' financings for various flexible firming assets including gas turbines, batteries and pumped hydro while strictly observing existing market conventions. Each asset presumes investment origination by a 'BBB' rated merchant utility seeking to maintain investment-grade credit metrics (Table 2). Results in Sections 4.2 – 4.4 progressively vary the form of industrial organisation and form of forward markets.

4.1 Base case model results

Recall from Section 3 our starting point is to observe existing market conventions. Doing so enables us to identify missing and incomplete markets and their proximate value. Consequently, we start by determining the prevailing equilibrium price of $300 Caps, which has historically converged with the carrying cost of an OCGT over the business cycle (Simshauser, 2020). Using assumptions from Tables 1-2, Figure 1 contrasts PF Model results for the OCGT, 4hr, 6hr and 8hr Lith-Ion battery and 24hr pumped hydro.[11] The carrying cost of each technology is presented by the stacked bars (LHS y-axis) with the gearing ratio captured by diamond markers (RHS y-axis).

Figure 1: Carrying cost (on-balance sheet financings)



The first point to note in Figure 1 is the equilibrium price of $300 Caps, given by the carrying cost of OCGT, which equates to $15.6/MWh. In this calculation, the plant is assumed to be idle (i.e. 0% ACF) and thus the carrying cost is equal to the annualised fixed and sunk costs of the plant, (represented as a cost per MW per hour) including a 'normal' return to equity[12]. Of course in practice, the OGCT plant will produce whenever spot prices exceed its marginal running costs (~$130/MWh at gas prices of $12/GJ). And when spot prices exceed $300/MWh, the plant will face difference payments under a sold $300 Cap. Any *'under Cap revenues'* (i.e. net spot revenues below the $300 Cap strike price and above plant marginal running costs) will accrue to the plant owner. But with the typical peaking plant exhibiting ACFs of 2-8%, these will be minimal in aggregate[13].

Notice the storage assets in Fig.1 comprise stacked bars with two numeric results displayed. These reflect (i) total carrying cost, and (ii) a post-arbitrage carrying cost. Unlike a gas turbine, *'under Cap revenues'* for batteries and pumped hydro will be material because such plant is expected to operate daily. Consequently, we focus on the post-arbitrage carrying cost. The 4-hour battery has a total annualised carrying cost of $26.8 per MW per hr, whereas its post-arbitrage carrying cost is $17.5/MWh. It should be noted that a 4-hour battery is probably not capable of defending $300 Caps for its entire nameplate and in this sense, its carrying cost is *not* directly comparable to an OCGT. The

[11] Figures 1 and 2 assume BESS charging/dispatch costs of between ~$40-45/MWh and ~$98-111/MWh, and as with pumped hydro costs and prices have been derived from Gilmore (2024).
[12] By way of example, the annual carrying cost of a hypothetical 100MW OCGT plant equals $15.6 x 100MW x 8760 hours, or $13.7 million.
[13] In equivalent annualised terms this might average ~$1/MWh – meaning Caps could technically be sold at $14.6 rather than $15.6/MWh to break even.

6- or 8-hour batteries are a better comparison – and there is clearly a material gap in carrying costs. The gap is higher again for the on-balance sheet financed, 2000 MW // 48GWh, 24hr pumped hydro, at $40.6/MW/h (equivalent to the carrying cost of ~9¼ hour battery under existing conditions)[14]. Recall plant income is limited to:

1. The sale of $300 Caps, at $15.6/MW/h;

2. Spot market revenues from arbitrage, at ~17% ACF generation output, unit pumping costs of ~$30/MWh and generation dispatch of ~$90/MWh having been capped at $300 (due to 1. above);

3. FCAS revenues from frequency regulation and frequency contingency duties (see Table 1); and

- there is no market, or market price, for intermediate duration storage reserves.

The sum of merchant revenue sources is insufficient to provide a market-standard quantum of financial leverage (typically ~35%) for a 'BBB' rated entity. Recall that our model imposes gearing limitations via binding covenants, ultimately limiting gearing to ~16%. Equity returns are sub-optimal, the gravity of which is intensified by under-leverage. In short, this is consistent with the findings of Kear and Chapman (2013), Zafirakis et al., (2016), Newbery (2018b) and Delgado and Franco (2023) in other jurisdictions. As it stands, the NEM currently appears unable to support merchant, intermediate-duration storage reserves based on our model and input assumptions.

Recall from Section 1 that missing and incomplete markets provide the explanation for this outcome, with current conditions, and existing coal stockpiles, masking the storage task ahead. However to be clear, the optimal plant mix derived from modelling in Gilmore (2024), and the latest Integrated System Plan by the Australian Energy Market Operator, point towards 8+GW of new pumped hydro plant given our current understanding of technologies and technology costs.

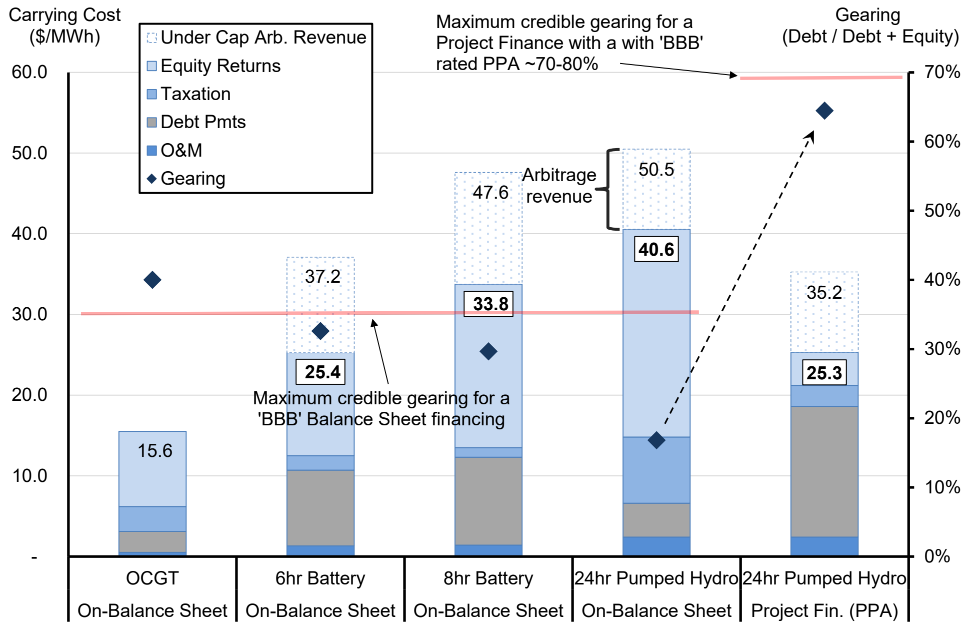
4.2 Project financing pumped hydro

Our merchant pumped hydro, financed on-balance sheet, presents as unviable in an energy-only market setting. Our next simulation analyses a switch to a 'project financing', facilitated by a Power Purchase Agreement (PPA). We assume the PPA, written by a 'BBB' rated counterparty, covers 100% of plant capacity. The PPA price is dynamically calculated as the minimum viable payment to ensure plant revenues equal plant carrying costs.

Comparative results are presented in Fig.2. All capex and operating costs have been held constant. Shifting to this industrial organisation and financing format reduces pumped hydro post-arbitrage carrying costs by 38%, from $40.6 to $25.3/MWh. Total *debt repayments* are significantly higher due to the change in capital structure – the present case achieves more optimal debt financing at c.64% (see Fig.2 dashed arrow). Additional debt has been facilitated by revenue security which accompanies the design and intent of PPA structures. The project benefits from an optimised capital structure, whereby lower cost debt is maximumly exploited to lower the project's overall Weighted Average Cost of Capital (WACC).

[14] While not presented above, for interest and avoidance of doubt, the carrying cost of a 24hr Li-ion battery at current capital cost estimates equates to ~$120/MWh, net of under cap arbitrage revenue.

Figure 2: Balance Sheet vs Project Finance



4.3 On-balance sheet financing in a semi-regulated storage market format

Section 4.2 illustrated the beneficial impact of 'revenue security' on the capital structure and WACC, and by extension, the carrying cost of capital-intensive pumped hydro plant. While an emerging trend in the NEM has been merchant and semi-merchant VRE plant (see Simshauser, 2020; Flottmann et al., 2022; Simshauser and Gilmore, 2022; Gohdes, 2023; Gohdes et al., 2023), in practice a majority of renewable plant capacity in Great Britain, Europe, the US and Australia has been underwritten by PPAs or CfDs (Newbery, 2017, 2018a, 2023; Grubb and Newbery, 2018). Fig.2 results confirm revenue security is vitally important for long-lived capital-intensive assets.

Yet a practical complexity of Section 4.2 results, and the PPA scenario in particular, is the sheer size of the contract. At 2000 MW, and $300 cap premiums at $25.3/MWh (i.e. well above OCGT costs) for a 15-year duration, few if any of Australia's merchant utilities are large enough to absorb the *operating leverage* implications of such a contract without adversely impacting their own credit metrics.[15] Furthermore, merchant utility trading books are constrained by retail contestability, imperfect retail tariff cap regulation along with missing and incomplete markets (Green, 2006; Anderson et al., 2007; Howell et al., 2010; Simshauser, 2019).

By our calculations, net cashflow requirements would be ~$440m per annum ($25.3 * 2000MW * 8760hrs), more than 60% of the Net Profits of either of Australia's largest vertically integrated merchant utilities.[16] Such firms may contract for smaller volumes, but this would fail to achieve NEM storage requirements.

Consequently, our modelling iterations must return to balance sheet financings and seek to capture revenue security benefits through an alternate policy pathway by examining missing and incomplete markets. Australia's energy-only gross pool is a merchant electricity market. There are no regulated revenue streams in the current design. But as Pollitt (2022, p.3) reminds us:

[15] Such an instrument, or a large component of it, is likely to be treated by ratings agencies as synthetic debt.
[16] The average Net Profit of Australia's largest (by market cap) vertically integrated utilities is ~$714million. Origin Energy Ltd reported an underlying profit of $747 million for FY23 while Australia's second largest, AGL Energy Ltd, recently reported FY24 guidance of $580-780m.

> *One key misunderstanding is there is no such thing as the 'free market' in the formal economy. Markets are highly regulated social institutions set up to deliver particular societal goals. So it is with the market for electricity. As such, in a modern democracy energy markets are our servants, not our masters. If the market is not delivering for society, we can change it...*

Newbery et al. (2019) observe industrial organisation within the electricity industry exhibits two business models, merchant (generation and retail) and regulated (networks). The latter facilitates 'secure revenues' and elevated gearing within the bounds of investment-grade credit metrics. We note there is currently no market for storage. But there is no reason preventing its establishment.

One plausible policy is to categorise intermediate duration storage reserves as a semi-regulated market, thus establishing a new asset class (i.e. semi-regulated assets).[17] The rationale for doing so is the central role that intermediate duration storage must play in a decarbonised power system, and the counterfactual in its absence, i.e. higher costs and prices for consumers (Gilmore, 2024), intractable gas market conditions (Simshauser and Gilmore, 2024) and deteriorating investment conditions for intermittent renewables in the presence of rising marginal curtailment rates (Simshauser and Newbery, 2024). In this sense, noting intermediate duration storage lowers renewable entry costs and reduces the intractability (shortage events) associated with the market for natural gas, pumped hydro presents more closely as a *'public good'*, and therefore may be better suited to a semi-regulated arrangement.

In simple terms, a semi-regulated approach for a pumped hydro would involve the plant arbitrage function remaining merchant, with operators continuing to sell $300 Caps and earn capped arbitrage revenues through the spot market. However, an additional regulated payment, designed to deal with the 'public good' element of intermediate duration storage, would be added, thus creating a semi-regulated asset. Adding a storage market to the NEM by way of a certificated scheme has previously been explored in Mountain et al., (2022) with their framework being analogous to Australia's Renewable Energy Target (i.e. administratively determined quantities, competitive market prices). Our concept is clearly *blunter* in application - storage would be banded (i.e. intermediate duration) with prices and quantities administratively determined - the design intent being to lower the cost of capital associated with capital-intensive, long-lived plant with indeterminant payback periods.

By obtaining an appropriate head of power, State Governments (or relevant authority) could determine the level of intermediate duration storage required for a NEM region. The regulated storage payment would then form part of the usual cost recovery process as with other regulated supply-chain assets – ideally as a non-bypass-able charge across all customer classes via monthly electricity bills (i.e. fixed charge).[18] The simplicity and transparency of generation plant means transaction costs associated with the (semi-) regulation of pumped hydro storage would be trivial compared to networks.

In our PF Model, we therefore introduce a third discrete revenue stream comprising a 'regulated' intermediate-duration reserve payment (which we reflect in both $/MWh carrying capacity and $/kWh/a storage duration) funded by the consumer rate base in a manner broadly consistent with Newbery et al. (2019). In this scenario, the pumped hydro plant reverts to an on-balance sheet financing, constrained by 'BBB' metrics, with a broader suite of revenues designed to minimise the carrying cost of capacity. Revenue streams for the 'semi-regulated' intermediate duration storage asset are therefore as follows:

- merchant spot market (arbitrage) revenues, net of $300 Cap payouts;

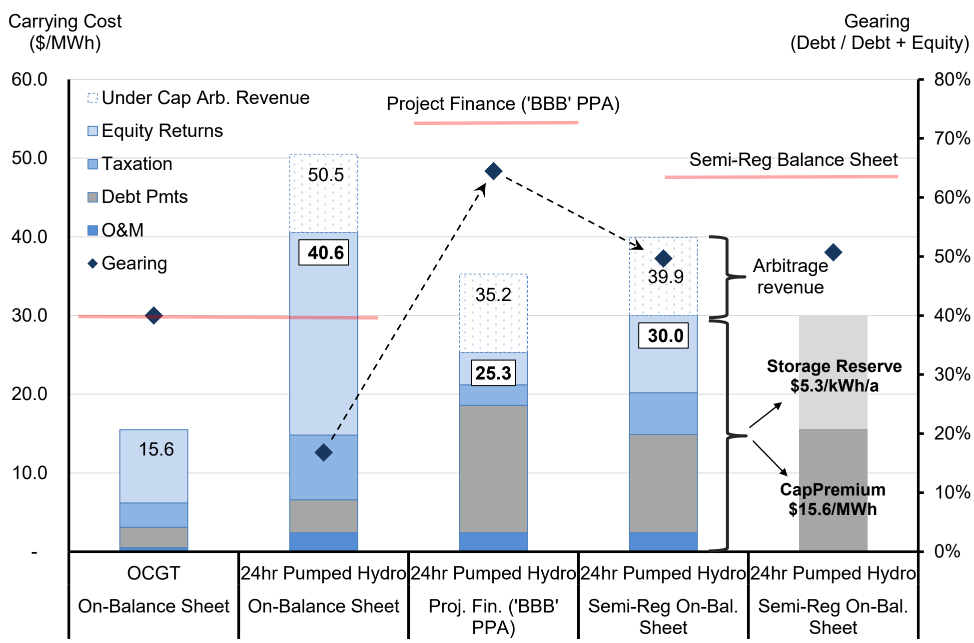
[17] See for example https://www.drax.com/press_release/drax-given-green-light-for-new-500-million-underground-pumped-storage-hydro-plant/
[18] One Reviewer also queried whether a charge might be levied on benefiting VRE generators.

- Forward sales of $300 Caps from the NEM's existing institutional design, and
- regulated 'intermediate-duration reserve' revenues, designed to cover *missing money* and defined by the difference between the post-arbitrage carrying cost of intermediate duration storage and $300 Caps in equilibrium.

Collectively, these measures simulate the economic impact of a *quasi-PPA* with security for ~30% of revenue, which enables higher gearing levels and a normal return to equity for the semi-regulated asset class. In exchange, plant operators would be bound by certain conventions.[19] Fig.3 illustrates the net effect of creating this semi-regulated asset class (see 4th and 5th stacked bars) and contrasts these with prior results. The 4th bar outlines the cost stack as measured by the carrying cost at $30.0/MWh and gearing ratio of ~50%. This result falls short of the project financing, albeit with lower operating leverage potentially making the investment thesis viable for private, ASX-listed or government-owned corporates.

The 5th bar in Fig.3 is the most crucial. It illustrates *how* the carrying cost can be split and recovered through merchant, and regulated, markets. The base amount of $15.6/MWh would be earned through merchant markets by way of forward $300 Cap sales. The missing money would be recovered by way of the regulated storage charge ($/kWh/a) and equates to the aggregate final carrying cost of plant (per annum) *less* that amount recovered through forward Cap sales in equilibrium (per annum). Given a 2000 MW pumped hydro plant with 48GWh of storage, this equates to $5.3/kWh/a. And for clarity, $5.3/kWh/a x 48GWh is the equivalent of the annual carrying cost ($30.0/MWh) *less* the equilibrium price of $300 Caps ($15.6/MWh), or $14.4/MWh.

Figure 3: Semi-regulated asset



4.4 Semi-regulated asset with a 3-Party Covenant Financing

The world of corporate finance places credit time horizons over assets. This creates frictions for plant entry with ultra-long asset lives. During the era of falling and low interest rates (in Australia, nominally 2012-2022) credit time horizons extended from ~15 to 25+ years but was always vulnerable to interest

[19] It is beyond the scope of this article to identify these in detail, but we would envisage some form of constraint over bids and offer prices in line with the long-term interests of consumers, transparency of any constraints, and requirements to maintain certain storage reserves as the power system approaches critical events in exchange for the regulated revenue stream.

rate increases (Offer, 2018). For very capital-intensive, 100-year duration assets, viability hinges critically on the level, rate and planned tenor of semi-permanent[20] debt facility structures.

Our final PF Model and industrial organisation iteration takes our semi-regulated pumped hydro asset one step further by applying the policy configuration outlined in Rosenberg et al. (2004) and Simshauser et al. (2016), viz. a 3-Party Covenant (3PC) financing. To summarise the changes, 3PC involves issuance of zero margin, 10-year Commonwealth Government bullet facilities[21] - that is, debt at the long-bond rate with a 'zero' credit spread, in turn secured by way of a *credit-wrap* by the electricity consumer rate base, the basis of which is through State-based legislation. To maximise the level of debt within the capital structure, the semi-regulated charge is extended from covering the missing money (i.e. intermediate storage reserve of $5.3/kWh/a in Fig.3) to the total carrying cost comprising both the $300 Cap ($15.6/MWh) and storage reserve ($5.3/kWh/a). This may appear a subtle change but creates a CfD over sold Caps and the missing money intermediate storage reserve component, expanding the secured revenue stream to the full post-arbitrage carrying cost.

Consequently, if the price of Caps fell below $15.6/MWh, regulated revenues would expand via the CfD to cover any gap. Conversely, if Cap prices rose above $15.6/MWh, regulated revenues would be returned to consumers – thus operating as a financial shock absorber. In practice this means 'secured revenues' rise from ~30% in Section 4.3, to 55% in the present scenario. It is this incremental step that makes a 3PC financing relevant.

3PC financings are first and foremost a 'credit wrap'. The credit wrap is designed to reduce credit spreads and amplify gearing ratios. Credit wrapped financings have long existed in various formats across a variety of infrastructure assets (see Smith and Warner, 1979; Kahan and Tuckman, 1993; Diggle et al., 2004; Rosenberg et al., 2004; Simshauser et al., 2016). Diggle et al. (2004) observe issuing costs are absorbed by issuers, but liquidity costs are borne by investors with consumers bearing the cost of credit spreads.

Recall our context starts with intermediate duration storage being a public good – lowering VRE entry costs through reduced marginal curtailment (Simshauser and Newbery, 2024), shifting otherwise *spilled energy* through time, and minimising intractable gas market outcomes and unserved load events (Simshauser and Gilmore, 2024). Recall further that the intermediate storage problem is unlikely to be revealed anytime soon in organised forward markets because the storage task is currently being *masked* by coal stockpiles. Moreover, timing of coal plant exit is inherently uncertain. Risks of public goods being undersupplied is a well understood problem in economics. Specifically, public goods compounded by planning complexities of this nature are unlikely to be solved by organised merchant markets when the optimal solution is capital intensive, involving ultra-long asset lives with indeterminant payback periods spanning beyond the credit time horizon of capital markets.

If a pumped hydro is credit wrapped by the consumer rate base and backed by State-based legislation in the relevant jurisdiction, then Commonwealth Government Securities (i.e. 10-Year Bonds) are capable of being originated without impacting the Commonwealth or State Government sovereign credit ratings. 3PC can add liquidity to aggregate debt issuance, enhance the credit quality of intermediate duration storage assets, lower the 'public good cost' of requisite intermediate duration storage, and create a policy mechanism to resolve storage in a timely manner.

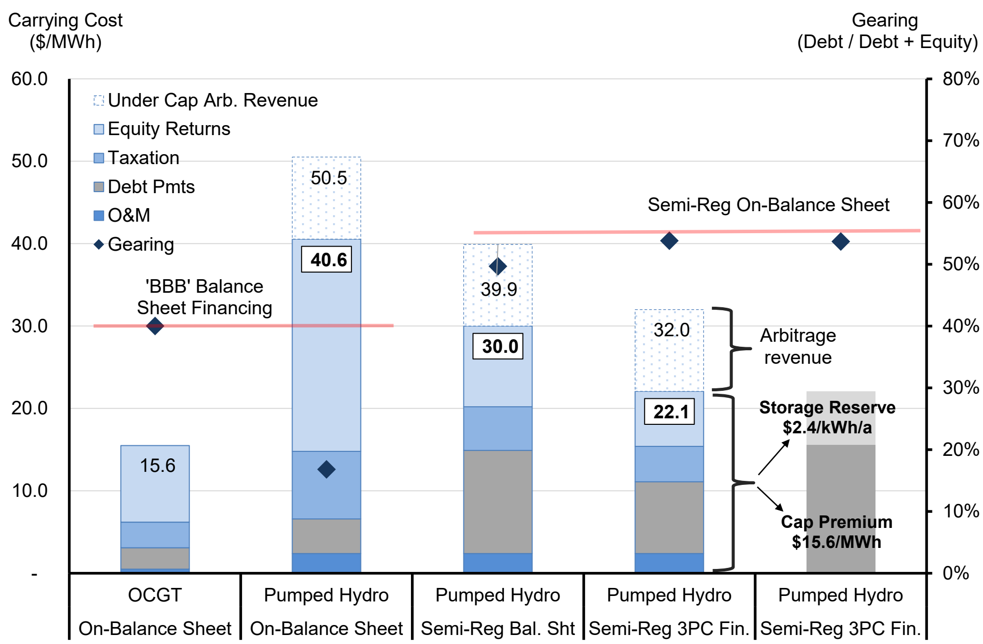
As an aside, 3PC Financing originally envisaged a power project arrangement between the US Federal Government, a State Public Utility Commission and a power project proponent with an aim of dramatically reducing the weighted average cost of capital for low emissions power projects (see

[20] A semi-permanent debt facility is one in which the principal is not fully repaid at the end of the loan tenor. This means principal repayments are lower for equity investors but introduces a non-trivial refinancing risk for debt investors.
[21] In simple terms, a bullet facility is interest only with a single point refinancing.

Rosenberg et al., 2004). The policy architecture involves financially engineering the cost and level of debt raised through reorganising the allocation of power project financial risk. The concept is analogous to Monoline Insurers[22] wrapping the bond issues of Australian regulated utilities during the 2000s – the result being lenders had additional recourse to credit wrappers (i.e. the Monolines) while issuers (i.e. Australian regulated utilities) achieved materially lower costs of debt finance (see Chava and Roberts, 2008).

In our scenario, 3PC Financing involves the Commonwealth Government issuing zero margin 10-year bonds, set within a long-dated semi-permanent structure, the State Government passing legislation to institute the regulated intermediate duration reserve charge thus providing the credit wrap, and the pumped hydro project proponent to deliver the project. As Fig.4 notes, the carrying cost of plant is reduced very significantly by comparison to our starting point of $40.6/MWh, falling by ~50% to $22.1/MWh (equivalent to the carrying cost of ~5-hour battery under existing conditions). Gearing rises from 16% to ~54% which lies at the upper end of our semi-regulated utilities benchmark (~55%) and well above merchant utilities (~35%). Furthermore, the regulated intermediate storage reserve is reduced from $5.3/kWh/a (Fig.3) to $2.4/kWh/a.

Figure 4: Semi-regulated with a 3-Party Covenant Financing



Tab.4 compares the storage assets we have modelled, with Column 2 setting out the initial capital cost of storage ($/kWh), Column 3 reveals the annual cost of storage, the 4th column highlights the value earned through the sale of $300 Caps given existing markets in equilibrium, while the final column identifies the missing money arising from missing and incomplete markets. If our missing market (i.e. intermediate duration storage reserve) and financing policy (i.e. 3PC) were formalised as energy policy mechanisms, then the cost of intermediate duration storage can be reduced very substantially ($9.1/kWh.a to $2.4) as Tab.4 illustrates.

[22] Monolines were 'AAA' rated insurance companies which provided credit wraps to bond issues of regulated utilities (BBB rated). More than $6 billion of debt issued by Australian electricity and gas utilities (e.g. United Energy, Powercor, Citipower, ETSA Utilities, Basslink, ElectraNet, Envestra) were wrapped by the monolines (e.g. Ambac, FSA, XLCA, MBIA), reducing spreads from 100+bps to ~40bps over swap rates.

Table 4: Storage costs incl. 3PC ($/kWh/a)

	Capital Cost of Storage	Annual Storage Cost	Cap Premium Equivalent*	Net Storage Cost
Column	2	3	4	5 = (3 - 4)
	($/kWh)	($/kWh/a)	($/kWh/a)	($/kWh.a)
4 Hr Battery	723.5	38.2	3.8	34.5
6 Hr Battery	586.8	37.0	5.7	31.3
8 Hr Battery	518.4	37.0	5.7	31.3
24 Hr Pumped Hydro	216.5	14.8	5.7	9.1
Semi Reg Pumped Hydro	216.5	11.0	5.7	5.3
3PC Pumped Hydro	216.5	8.1	5.7	2.4

* Adjusted for minimum 6 hours run time, at $15.6/MWh.

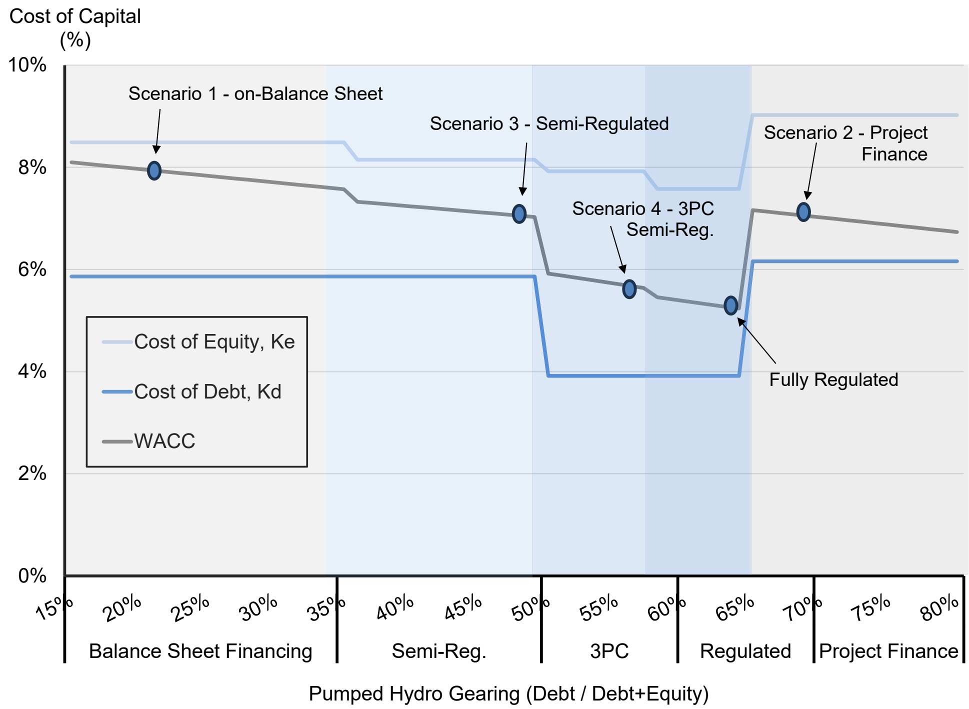
5. Policy Implications

Our quantitative results and the progressively lower 'carrying cost' of intermediate duration storage ($22.1/MWh, Fig.4) and associated storage reserve ($2.4/kWh/a, Tab.4) are the product of financial engineering and correcting for missing markets, made possible by two distinct policy instruments, viz. an intermediate duration storage market comprising regulated revenues, and 3PC financing. Collectively, the headline carrying cost of intermediate duration storage seems capable of being reduced by almost 50%, from $40.6/MWh as an unviable merchant plant, to $22.1/MWh under our preferred model – the 'semi-regulated 3PC' plant. And within this carrying cost, the annualised cost of storage reduces from $9.1 to $2.4/kWh.a net of arbitrage revenues.

One further proposition might be a CfD for 100% of plant capacity and output. While not illustrated in Section 5, we modelled a fully regulated asset which further reduced the carrying cost, to $17.8/MWh. However, a 100% CfD also extracts the plant from forward markets. Our preferred option, the 'semi-regulated 3PC plant', would remain as an *active market participant* and critically, repackage intermittent VRE output into useable forward products for customers.

Noting the underlying construction and operational cost of plant was held constant in all scenarios, how reductions in the carrying cost were achieved is set out conceptually in Fig.5. The x-axis in Fig.5 plots gearing levels and the y-axis measures the cost of capital. Revenue quality matters and ultimately drives the quantity, and price, of debt (gearing) in the pursuit of the optimal capital structure and overall weighted average cost of capital.

Figure 5: Stylised Weighted Average Cost of Capital



6. Concluding remarks

Energy markets were designed in the 1980-1990s with an objective of maximising productive, allocative and dynamic efficiency in power systems typically characterised by over-capacity and prices above efficient levels. To generalise, the initial task of the 1990s market design was *not* to deliver additional capital-intensive capacity – although any requirement would in theory be adequately signalled by forward markets. The primary task was to ration existing plant, and through innovation, augment the incumbent plant stock with less capital-intensive generating assets (i.e. which were readily available via OCGT and CCGT). Provided market price caps were set at efficient levels and political interference minimised, such assets were viable with manageable payback periods. In Australia's NEM, almost 10GW of gas turbines worth $13.2 billion were deployed.

Short duration storage assets have relatively quick paybacks and sit well within the *credit time horizon* of banks and capital markets. In Australia's NEM, more than 3GW ($3.8 billion) has been committed over the past 4 years, with a further 3GW expected to reach construction during 2024 alone.

However, with few exceptions (e.g. 840MW Millmerran coal plant in Queensland), our 1990s-designed market has not delivered capital-intensive merchant assets with longer payback periods. This includes intermediate duration storage. Given missing and incomplete markets, the payback for an intermediate duration pumped hydro plant is indeterminate and sits beyond the credit time horizon. Uncertainty over future prices, future energy policy, future storage technologies and future political changes are simply too great.

Some minimum level of certainty is required by project banks and capital markets. But this same level of certainty is *not required* by central planners and policymakers (Offer, 2018). A primary task of power system planners and policymakers is to manage the complexity and uncertainty of spot and forward commodity (electricity) markets that are unable to be managed by debt and equity capital markets.

That some risks are too difficult for the capital markets to navigate is not an indictment of our energy markets during an episode of power system transformation. Energy markets and agents that operate within them can be expected to achieve efficient outcomes under conditions of relative stability and within the credit time horizon applied by banks, bond investors and the institutional equity capital markets. Beyond this boundary, some form of policy intervention is required such as public ownership, retention of private sector involvement through subsidies, regulatory charges or awarding monopoly franchises (Offer, 2018; Newbery et al., 2019).

Energy traders and portfolio managers within merchant vertically integrated utilities pursue an optimal allocation of derivatives and physical generation assets for a given (contestable) retail load, observed policy settings and market relativities within medium-term timeframes. Rival merchant utilities do not look to manage matters of security of supply at the power system level – they look to do so at their own portfolio level. System planners on the other hand are forced to look beyond rival portfolios and near-term profit results – and must focus on the entirety of the power system, and as it would seem, the adjacent market for natural gas (Simshauser and Gilmore, 2024). It is in this context that missing and incomplete markets are frequently identified.

Just because intermediate duration storage has indeterminate payback periods given existing energy market designs (with their present, but fading, baseload plant stock) does not mean such assets are not economic. But long lead times for development and construction means commitment decisions are awkward and struggle commercially. The difference between economic and commercial is sometimes identified by the 'public good' of an asset class.

The intermittency of VRE and the limits of the NEM's adjacent market for natural gas means intermediate duration storage is necessary. And until markets are able to accurately price such services, a large component of these assets may best be considered a public good, requiring policy guidance. And as is the case with other public goods such as national defence, the role of government is to determine the quantity needed to manage the stated risk, to nominate an authority to provide the good, and then spread costs as far and wide as possible across the tax base – or in this instance, the electricity rate base, to minimise cost impacts. Meanwhile, assets that sit within the credit time horizon of banks (i.e. solar, wind, OCGTs and short duration storage) can, and should, continue to be successfully undertaken by the private sector.

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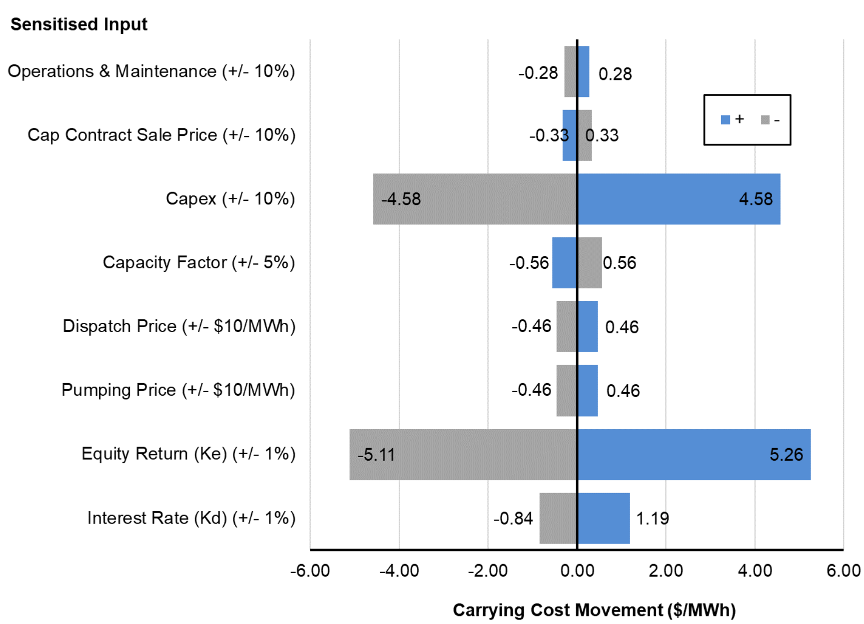
8. Appendix A

To ensure robustness of results, a series of input variable sensitives were run for each of the four pumped hydro scenarios. Outputs from the two most critical scenarios, viz. Fully Merchant and 3-Party Credit Wrap scenarios, are depicted in Figures A1 and A2 respectively. The impact on the overall plant carrying cost is reflected on the x axis in $/MWh.

Figure A1: Fully Merchant Sensitivities



For the fully merchant plant, capex costs and equity return hurdles emerge as the most sensitive input variables. Movements in interest rates (Kd) are notably less impactful due to the low levels of debt supported within the capital structure. Recall equity comprises >80% of the capital structure under this scenario, explaining the sensitivity to capex overruns and elevated equity return requirements.

Notably, the impact of capital cost overruns and equity returns are less material for the 3-Party Credit Wrap scenario due to the lower overall cost of capital and a decreased reliance on equity funding. The impact of varying the cost of equity and cost of debt is skewed to the upside under this scenario (i.e. plant economics benefit more from a -1% decrease in Ke/Kd than they are harmed by an equivalent increase). This is primarily due to the 'shock absorbing' nature of the 3PC consumer-wrapped revenue stream. Regulated revenues rise in line with the higher capital cost, which in turn facilitates increased bankability and allows for a greater quantum of debt financing to offset some portion of prima-facie cost increase.

Figure A2: Semi-regulated 3-Party Credit Wrap Sensitives