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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, with 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 – at least over the medium term – only serve to underscore this point. Wind and solar output need to be moved through space (networks) and time (storage). The storage asset class with by far the highest energy density, pumped hydro, appears to be facing structurally high capital costs with most recent estimates given via high profile projects under development (viz. Snowy 2.0, Borumba) being ~$5000-$6000/kW in real terms. Yet under-development of pumped hydro will result in sharply rising renewable curtailment rates and a greater reliance on gas turbines – with the latter likely to be intractable. In this article, we focus on material reductions in the carrying cost of capital-intensive, ultra-long-lived pumped hydro assets through a 3-Party Covenant (3PC) financing structure between governments, the consumer base and plant investors. Our modelling suggests this reduces the annual capital costs and imputed cost of storage during operations by more than 35%. Our 3PC model is orchestrated through a semi-regulated business model and issuance of 10-year Commonwealth Government Bonds with a zero 'credit spread' – all of which are critical to minimise costs to consumers.

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 generating plant. Over the period 2016-2024, more than 22GW of renewables across 160 projects reached financial close, representing $47 billion of investment. Over the same period, ~16GW of rooftop solar PV has also been 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 (Gilmore, 2024). This is more than a theoretical observation. From 2016-2024, more than 9GW of batteries, pumped hydros and gas turbines reached financial close across 35 separate projects, representing ~$34 billion of investment commitments (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 and intensity 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 renewable plant involves a complex balancing task. Given the intermittent nature of renewables, limits to its diurnal reliability, and the fact that many periods will see vast surpluses of wind and solar compared to aggregate final demand, the need for, and benefits of, storage capacity are axiomatic. Perhaps 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). And to generalise a vast literature, it is broadly accepted that no single generation technology can mitigate intermittency, maintain grid stability and ensure security of supply (Javed et al., 2020; Gilmore et al., 2023).

It is in this context that there has been a significant revival of interest in pumped hydro projects 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 dams constructed throughout Australia since 1888 found a systemic bias towards under-forecasting capital costs – the median cost blowout was 49% with an average of 120%. Australian results are globally consistent. Ansar et al. (2014) found worldwide median cost overruns of 27% with an average of 97% (see also (Callegari et al., 2018).[1] The 2000MW Snowy 2.0 project now has a $12 billion total budget, as does the 2000 MW / 48GWh Borumba project (in real terms).

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

[1] The exception to the rule was North America with a median capital cost overrun of 11%.

firming investment commitments. And thus far in Australia's NEM, they have[2]. While prima facie 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 investments in VRE, coal plant closures are 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 a further 4GW of projects are seeking financial close during 2024. The practical evidence is that battery investments are dominated by two-hour storage configurations due to energy market prices and plant costs. There is no question that two-hour (and in time, four-hour) storage assets help with power system resilience. But short duration storage provides limited support for inter-day intermittency.

3. The last line of defence with respect to 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 more than 40 days of structural gas supply shortfalls for the gas turbine fleet in New South Wales and Victoria if no additional intermediate-duration pumped storage is available following NEM coal plant closures – primarily due to gas infrastructure constraints.

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 tasks facing power system planners and operators 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 investment and 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, 2023). Deployment of energy-dense storage assets *at scale* will, all else equal, alleviate the most acute effects of curtailment for new VRE investment (Chyong and Newbery, 2022; Simshauser and Newbery, 2023). More importantly, storage at-scale ensures renewables deployment occurs at lowest levelized cost, by maintaining wind and solar Annual Capacity Factors at close to optimum levels.

By late-2023, the NEM had just over 800MW // 11.3GWh of pumped hydro in service, 2.4GW // 350GWh under construction, a further 2GW // 48GWh expected to reach financial close during 2024 and a plausible pipeline of 16.6GW // 250GWh in various stages of planning. The latest ISP presumes around 8GW to be optimal for the NEM, whereas Gilmore (2024) suggests 11GW // 485GWh is

[2] Gas turbines and associated PPAs are ideal for 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.

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).

However, there is a commercial complexity for pumped hydro plant in Australia's NEM. The NEM's organised spot electricity market coordinates plant scheduling and unit dispatch while the forward derivatives market is intended to tie the economics of the physical power system to Resource Adequacy and new capacity investment. 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), it does not have a market signal for 'intermediate duration storage' because it such duties are currently not 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'[3]. 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 is between 16 and 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 and 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 (i.e. 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 ~$11 billion. Our focus is on corporate financing with an objective of radically reducing the operating 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 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 appears uneconomic for intermediate duration storage given the 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 involving a (regulated) market for storage reserves. Our modelling culminates in a '3-Party Covenant' financing involving the credit-wrapped issuance of zero-margin 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.

[3] 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.

This article is structured as follows. Section 2 reviews relevant literature. Section 3 introduces our data and model. Section 4 explores results while policy implications and concluding remarks follow.

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[4] (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).[5]

But 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).

The sharply rising level of VRE capacity 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). Although short duration batteries are increasingly prominent, globally, electrical energy storage is dominated by pumped hydro (Rehman., 2015) for plant capacity of 1000+ MW and storage of 10-600 GWh (Guittet *et al.*, 2016).[6] There are currently over 400 pumped hydro plants worldwide totalling ~190GW including 105GW currently under construction (Nikolaos et al., 2023).

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[4] 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).

[5] 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.

[6] 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, the 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, 2023). 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', at scale 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 currently 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 currently dominate 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[7] 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 planned capex (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

[7] 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. (issue is lack of proximity)

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 horizons of project banks have 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 (see also 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.[8] 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 the financing of intermediate duration storage (nominally 15+ hours). The modelling sequence commences by accepting the NEM has incomplete and missing markets, which requires that we observe existing market conventions to begin with. We therefore commence 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 benchmark premium price paid for $300 Caps, in equilibrium, has historically been taken to be the annual 'carrying cost[9]' 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 a pumped hydro plant under various financing structures expressed as either a $300 Cap shortfall amount ($/MWh) or intermediate storage reserve ($/kWh/a).

[8] Most restructured electricity markets in the U.S. commenced with organised capacity markets.
[9] 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 is the *missing money* associated with 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 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 (i.e. 24hr storage) relevant to either the Queensland or New South Wales NEM 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	26
- Storage Capacity	(Hrs)	-	24	2
Overnight Capital Cost	($/kW)	1,588	2,626	547
- Storage	($/kWh)	-	83	450
- Contingency		-	20%	-
Plant Capital Cost	($ '000)	396,929	11,083,200	37,622
Operating Life	(Yrs)	35	100	20
Annual Capacity Factor	(%)	5.0	17.2-18.2**	16.7
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%	40.0%

* 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 $5500/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 entirely by regulated cashflows (regulated metrics), and one serviced entirely 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 results 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 exhibits 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 Merchant Price Capture

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)

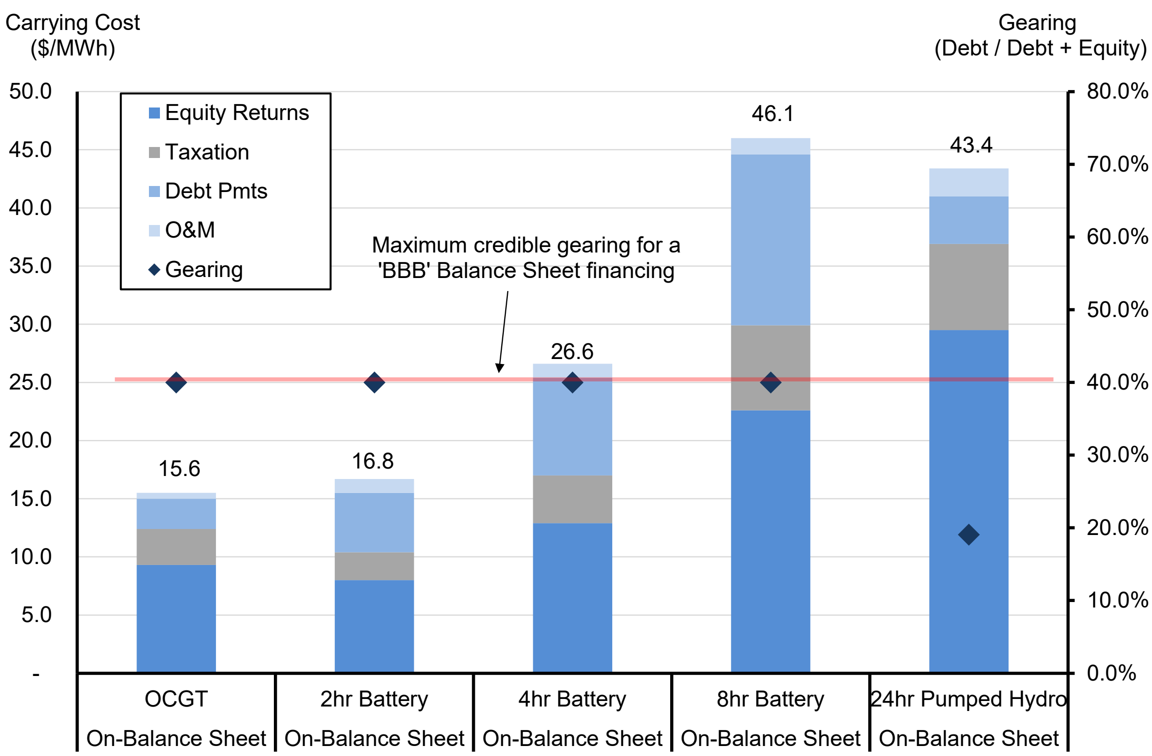
4. PF Model Results

Model results commence with base case 'on-balance sheet financings' for various flexible firming assets including batteries, pumped hydro and gas turbines while strictly observing existing market conventions. Each asset presumes 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, along with 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, 2hr, 4hr and 8hr Lith-Ion battery and 24hr pumped hydro. The carrying cost of each technology is presented as 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 Caps, given by OCGT entry costs, at $15.6/MWh.[10] The carrying cost comprises the annual fixed and sunk costs per MW per hour, including a 'normal' equity return[11].

The 2hr battery, which represents >90% of the NEM's batteries in service, has a carrying cost of $16.8/MW/h before accounting for arbitrage revenues. To be clear, a 200MW/400MWh battery could not realistically support 200MW of sold $300 Caps due to inadequate storage/runtime – and is thus not a like-for-like comparison. Conversely, the ability of batteries to perform Frequency Control Ancillary Services (FCAS) is unparalleled in response times and may earn as much as 60% of revenues from such markets. The 4hr battery, somewhat closer to a suitable proxy for $300 Caps,

[10] In practice, the OGCT plant produce whenever spot prices exceed marginal running costs (of ~$100/MWh at gas prices of $9/GJ). Under Cap revenues (i.e. net revenues between the Cap price and marginal running costs) therefore arise and in equivalent terms typically average ~$1/MWh – meaning Caps could be sold at $14.6 rather than $15.6/MWh.

[11] 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.

exhibits a sizable cost step up to $26.6/MWh pre arbitrage FCAS activities, while the 8hr battery equates to $46.1/MWh on the same basis.

The carrying cost of the on-balance sheet financed, 2000 MW // 48GWh, 24hr pumped hydro is $43.4/MWh nett of arbitrage revenues. Pumped hydro gearing in this scenario is only ~20%. This is not a 'commercial level' of debt within the capital structure. The ideal gearing result would be closer to ~35% but our model limits the amount of debt due to binding covenants, which in turn reflect sub-optimal plant earnings in the presence of incomplete and missing markets. 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, especially 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 in 1 and 2 above is insufficient to provide a market-standard quantum of financial leverage for a 'BBB' rated entity. 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.

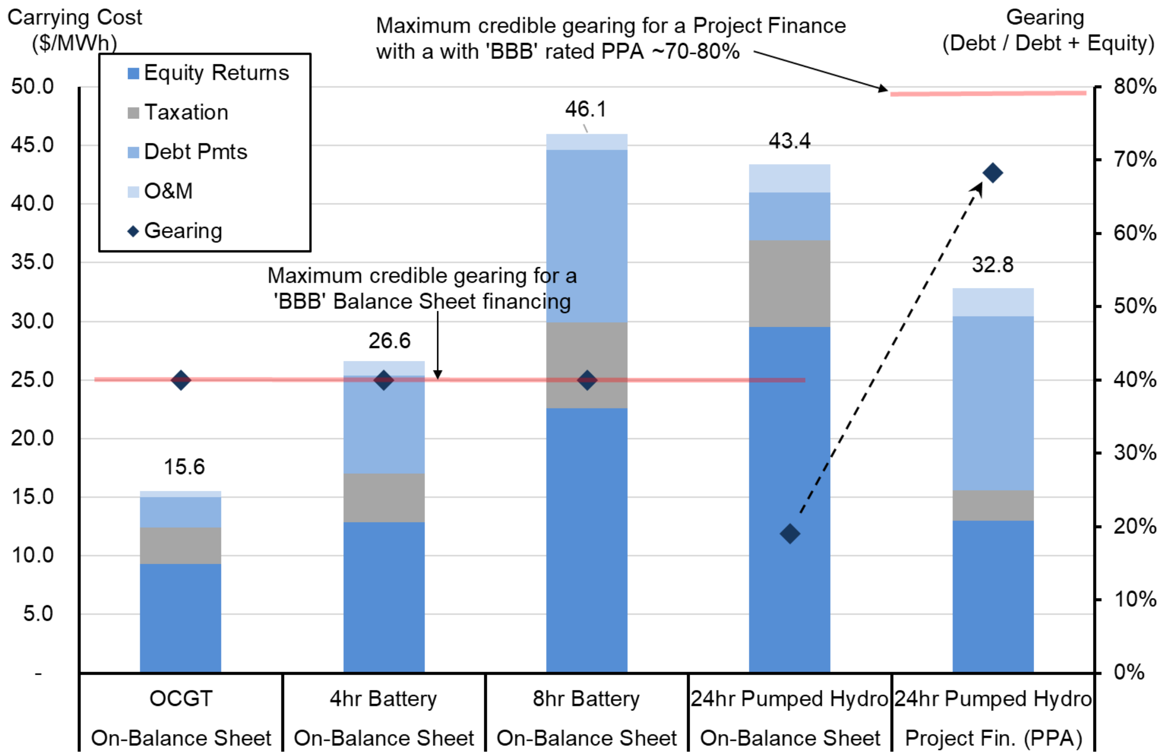
While not presented above, for interest and avoidance of doubt, the carrying cost of a 24hr Li-ion battery at current capital cost estimates equates to ~$125/MWh. We note other storage technologies are emerging but observed data is unavailable.

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 financed' plant, 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 the plant carrying cost.

Results are presented in Figure 2. All capex and operating costs have been held constant. Shifting to this industrial organisation and financing format reduces the pumped hydro's carrying cost by 24%, from $43.4 to $32.8/MWh. Total *debt repayments* are significantly higher due to the change in capital structure – the present case achieves more optimal debt financing at c.68% (see Figure 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).

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, falling as it did to $32.8/MWh.

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). Figure 2 results suggest revenue security is vitally important for long-lived pumped hydro assets.

Yet a practical complexity of the Section 4.2 results, and the PPA scenario in particular, is the sheer size of the contract. At 2000 MW, and at a strike price of $32.8/MWh (ex carbon prices, well above OCGT entry 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.[12] 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 approximately $575m per annum ($32.8 * 2000MW * 8760hrs), more than 80% of the Net Profits of either of Australia's largest two vertically

[12] Such an instrument, or a large component of it, is likely to be treated by ratings agencies as synthetic debt.

integrated merchant utilities.[13] 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 purely merchant electricity market. There are no regulated revenue streams in the current design. But as Pollitt (2022, p.3) reminds us:

> *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 (electricity networks). The latter facilitates 'secure revenues' and elevated gearing within the bounds of investment-grade credit metrics. Furthermore, we note there is currently no market for storage, but there is no reason preventing its establishment.

One plausible policy pathway is to categorise intermediate duration storage reserves as a semi-regulated market, thus establishing a new asset class (i.e semi-regulated assets).[14] 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, 2023). In this sense, noting that intermediate duration storage lowers the entry cost of renewables, and reduces the intractability (and 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 with competitively determined market prices). Our concept clearly *blunter* in application; storage would be banded (i.e. intermediate duration) and with prices and quantities administratively determined, the design intent being to lower the cost of capital associated with very capital-intensive, long-lived plant with *otherwise* 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).[15] The simplicity and transparency of generation plant means transaction costs associated

[13] 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.
[14] See for example https://www.drax.com/press_release/drax-given-green-light-for-new-500-million-underground-pumped-storage-hydro-plant/
[15] One Reviewer also queried whether a charge might be levied on benefiting VRE generators.

with the (semi) regulation of pumped hydro storage would be trivial in comparison to the complexity of regulating electricity 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 specifically designed to minimise the carrying cost of capacity. Revenue streams for the 'semi-regulated' intermediate duration storage asset are therefore as follows:

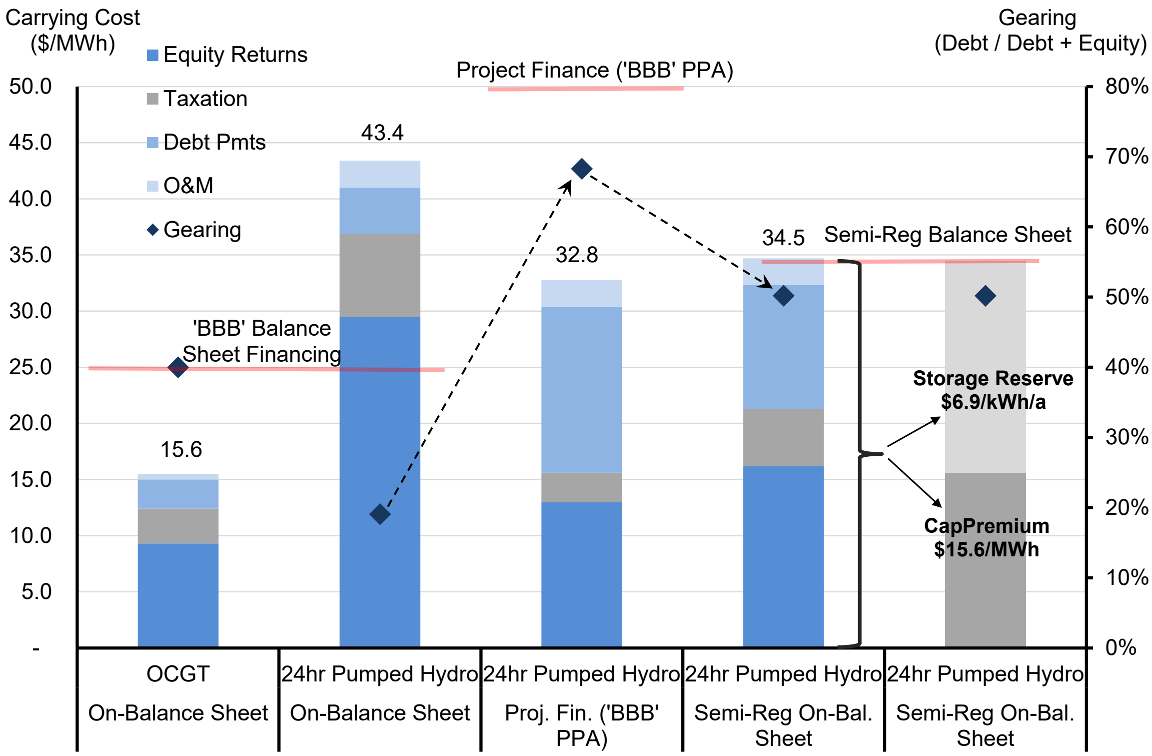
- merchant spot market (arbitrage) revenues, net of $300 Cap payouts;
- Forward sales of $300 Caps from the NEM's existing institutional design, and
- regulated 'intermediate-duration reserve' revenues, which cover the missing money defined by the difference between the net carrying cost of intermediate duration storage and the equilibrium price of $300 Caps.

Collectively, these measures simulate the economic impact of a *quasi-PPA* with security for ~35% of revenue, which enables higher gearing levels and a normal equity return for the semi-regulated asset class. In exchange plant operators would be bound by certain conventions.[16] Figure 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 stack bar outlines the cost stack as measured by the carrying cost at $34.5/MW/h and gearing ratio of ~50%. This result compares favourably (albeit +$1.7/MWh higher) to the project financing but with lower operating leverage – making the investment thesis viable for private, ASX-listed or government-owned corporates.

The 5th bar in Figure 3 is the most crucial. It illustrates *how* the carrying cost is recovered through merchant and regulated markets. The base amount of $15.6/MWh is earned through merchant markets by way of forward Cap sales. The missing money is recovered by way of the regulated storage charge ($/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 $6.90/kWh/a. And for clarity, $6.90/kWh/a x 48GWh is the equivalent of the annual carrying cost ($34.5/MWh) *less* the equilibrium price of $300 Caps ($15.9/MWh), or $18.9/MWh.

[16] 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.

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, thereby creating 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 this was always vulnerable to interest 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[17] 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 a zero margin, 10-year bullet facility[18] issued by the Commonwealth Government 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. the intermediate storage reserve of $6.9/kWh/a, or in carrying cost equivalent terms, $34.5/MWh - $15.6/MWh = $18.9/MWh per Figure 3) to the total carrying cost comprising both the $300 Cap ($15.6/MWh) and storage reserve (in Fig.3, $6.9/kWh/a). This may appear a subtle change but effectively creates a CfD over sold Caps and the missing money intermediate storage reserve component. This has the effect of expanding the secured revenue stream to the full 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

[17] 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.
[18] In simple terms, a bullet facility is interest only with a single point refinancing.

'secured revenues' rise from ~35% in Section 4.3, to 69% 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 (or eliminate) 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, Brooks and Stewart, 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 that our context starts with intermediate duration storage being a public good – lowering the entry costs of renewables through reduced marginal curtailment (Simshauser and Newbery, 2023), shifting otherwise *spilled energy* through time, and minimising intractable gas market outcomes and unserved load events (Simshauser and Gilmore, 2024). Moreover, 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. Furthermore, the 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 very capital intensive, involving ultra-long asset lives and indeterminant payback periods which span well beyond the credit time horizon of banks and 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 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[19] 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 Commonwealth Government Securities 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 Figure 4 notes, the carrying cost of plant is reduced very significantly by comparison to our starting point of \$43.4/MWh, falling by more than 35% down to \$27.5/MWh. Gearing rises from 20% to ~55% which lies at the upper-end of the range between regulated utilities (~66%) and merchant utilities (~33%) (Simshauser & Akimov, 2019). Furthermore, the regulated intermediate storage reserve is reduced from \$6.9/kWh/a (Fig.3) to \$4.3/kWh/a.

[19] 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.

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

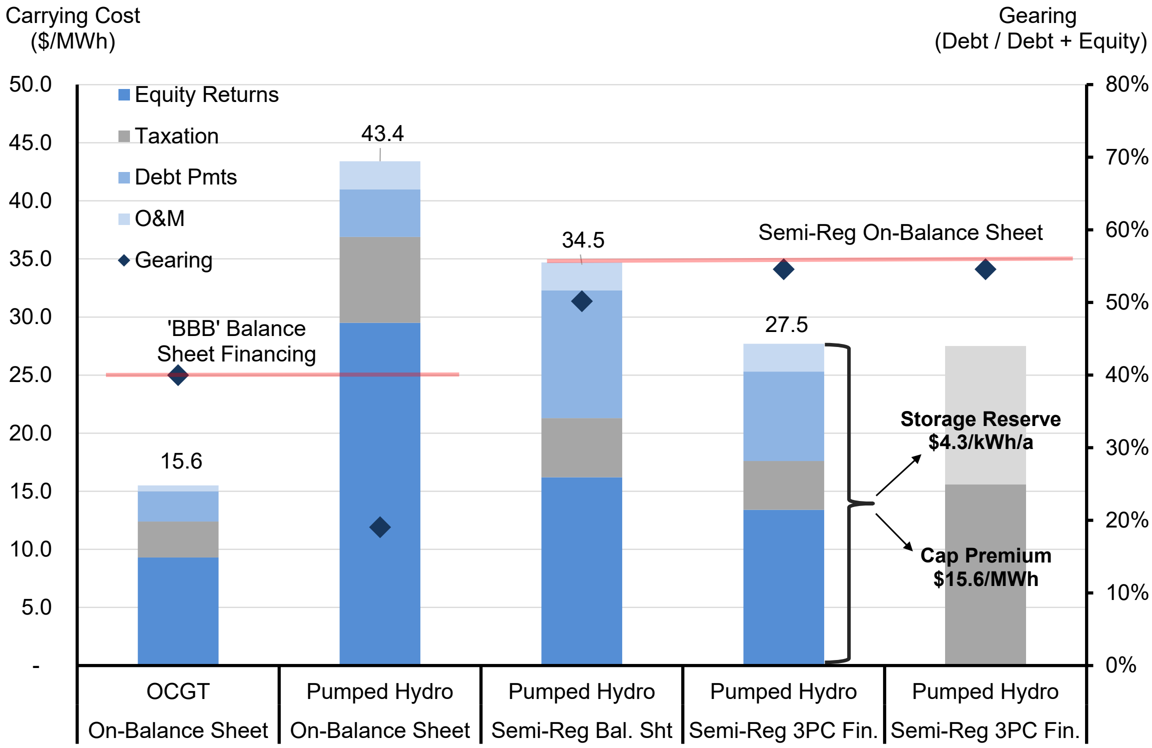


Table 4 sets out a comparison of the storage assets we have modelled, with Column 2 setting out the initial capital cost of storage per kWh, Column 3 reveals the annual cost of storage, the 4th column highlights the value earned through the sale of $300 Caps given existing markets in equilibrium, while 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) can be formalised as energy policy mechanisms, then the cost of intermediate duration storage can be reduced by 57% compared to a counterfactual, from $10.1 to $4.3/kWh/a as outlined in Table 4.

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)
2 Hr Battery	723.5	73.6	1.9	71.7
4 Hr Battery	586.8	58.3	3.8	54.5
8 Hr Battery	518.4	50.5	5.7	44.8
24 Hr Pumped Hydro	216.5	15.8	5.7	10.1
Semi Reg Pumped Hydro	216.5	12.6	5.7	6.9
3PC Pumped Hydro	216.5	10.0	5.7	4.3

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

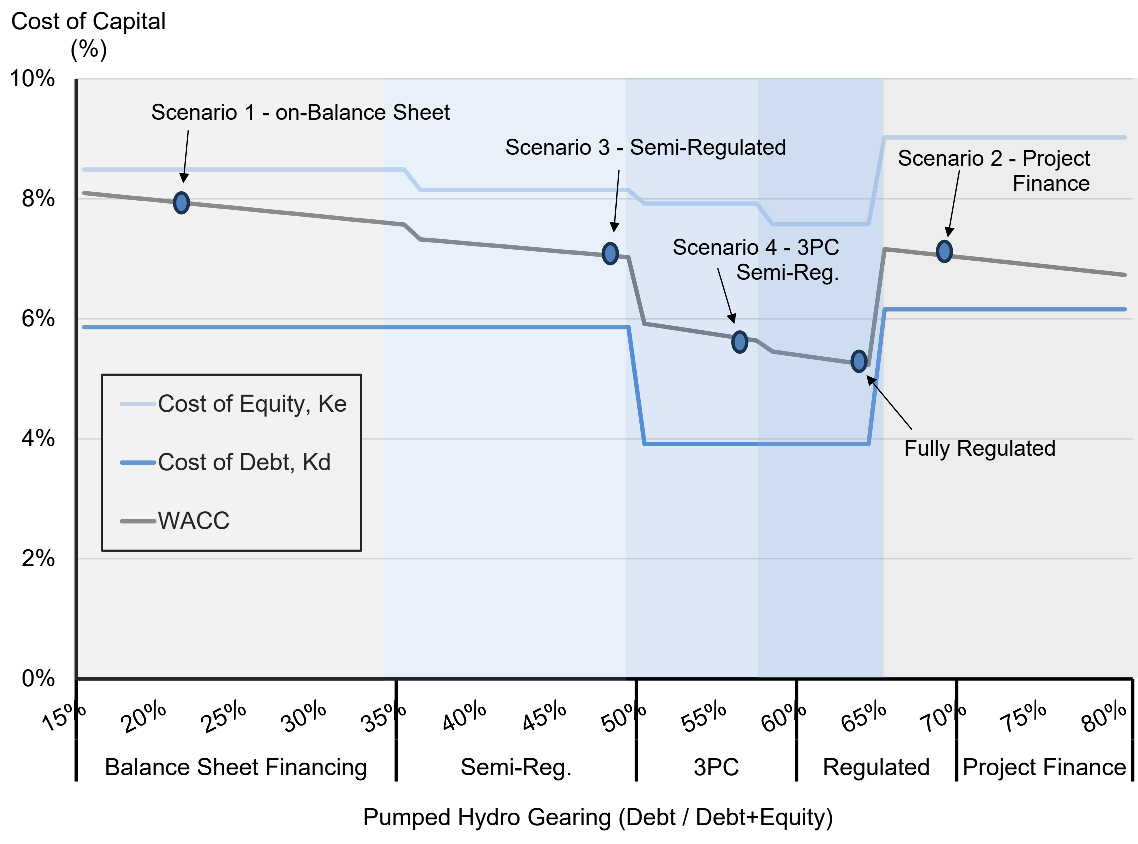
5. Policy Implications

Our quantitative results and the progressively lower 'carrying cost' of intermediate duration storage ($27.5/MWh, Fig.4) and associated storage reserve ($4.3/kWh/a, Table 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 37%, from $43.4/MWh as an unviable merchant plant, to $27.5/MWh under our preferred model – the 'semi-regulated 3PC' plant. And the annualised cost of storage reduces by 57%, from $10.1 to $4.3/kWh, net of $300 Caps and arbitrage revenues.

One further proposition might be a CfD for 100% of plant capacity and output. While not illustrated in Section 5, we have modelled this as a fully regulated asset and further reduces the carrying cost to $23.7/MWh. However, a 100% CfD –while seemingly even lower cost – also extracts the plant from the market. 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 Figure 5. The x-axis plots gearing levels and the y-axis measures the cost of capital. Revenue quality matters and ultimately drives the quantity, and the 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 with prices above efficient levels. To generalise, the initial task of the 1990s energy 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 at the time was to ration existing plant, and through innovation, augment the incumbent plant stock with less capital-intensive generating assets which were readily available (i.e. OCGTs, CCGTs). 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. More than 3GW or $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 typically 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 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 development and construction times means commitment decisions are awkward, and they 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 market for natural gas (Simshauser and Gilmore, 2024) 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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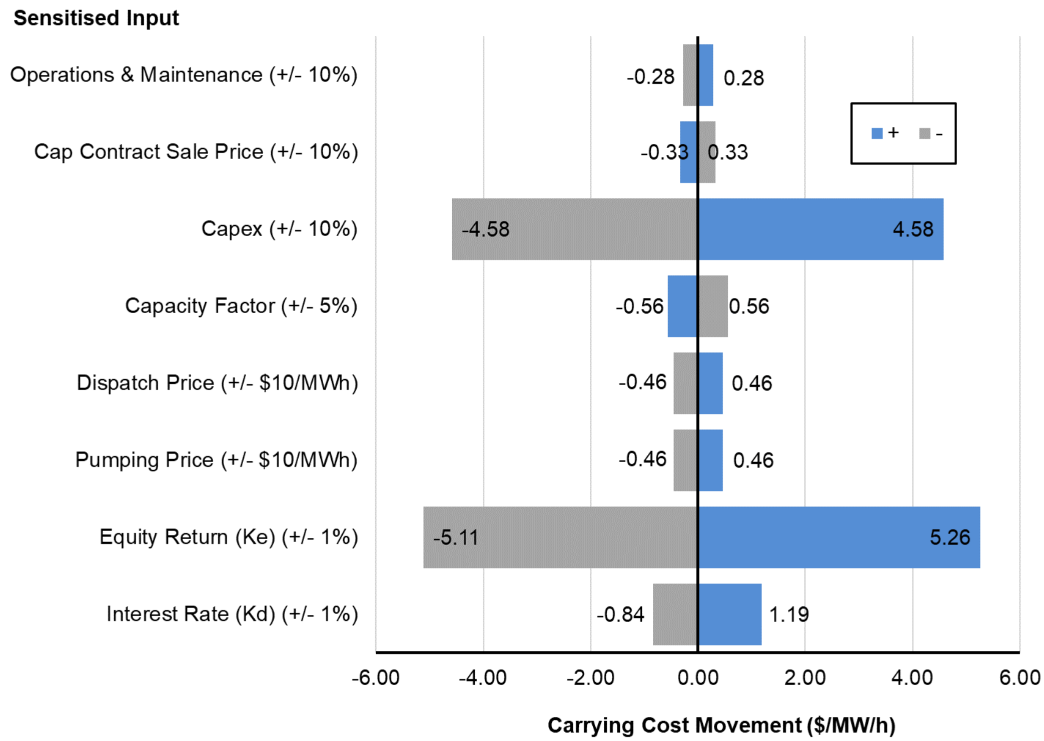
8. Appendix A

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 – the 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 $/MW/h.

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 (ie. 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, which explains the plant's 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 project's cost of equity and cost of debt is skewed to the upside for this scenario (i.e. the pumped hydro benefits more from a -1% decrease in Ke/Kd than it is harmed by an equivalent increase). This is primarily due to the 'shock absorbing' nature of the 3PC consumer-wrapped revenue stream. Here, revenues rise in line with the higher capital cost, which in turn facilitates increased bankability and allows for greater quantums of debt financing to offset some portion of prima-facie cost increase. Whether this is how the policy works is of course a matter for policymakers.

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