WACC Assumptions

AEMO Services Limited

13 November 2023

FINAL REPORT

Important notice

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EXECUTIVE SUMMARY

CEPA has been engaged by AEMO Services Limited (ASL) to provide advice on appropriate estimates of the weighted average cost of capital (WACC) for electricity generation and storage technologies. This report sets out our proposed estimates and the evidence we have relied on.

Context

ASL is an independent subsidiary of the Australian Energy Market Operator (AEMO), established to provide energy advisory and infrastructure planning advice to member governments and their partners who participate in the National Energy Market (NEM).

In November 2020, the New South Wales (NSW) Parliament passed the *Electricity Infrastructure Investment Act 2020* (EII Act), to enable the delivery of the NSW Government's Electricity Infrastructure Investment Roadmap. This legislation established the NSW Consumer Trustee, an independent statutory role with various planning, advisory and procurement functions that it must exercise in the long-term financial interests of NSW electricity consumers. To inform its planning functions as Consumer Trustee, ASL has asked CEPA to provide:

1. Separate WACC estimates for **different electricity generation, long-duration storage and firming technologies**, specifically: onshore wind; offshore wind; solar PV; short-duration batteries; long-duration batteries; pumped hydro; and open-cycle gas turbines (OCGT).[1] These estimates should reflect how the WACC would differ assuming:
    a. A 'typical' revenue model for that technology.
    b. A 'merchant' revenue model.
2. An estimate of how the WACC estimates for such assets would change if an asset is assumed to hold a **Long-Term Energy Services Agreement (LTESA)**, a policy mechanism implemented under the NSW Electricity Infrastructure Investment Roadmap.

The WACC estimates should be expressed in **pre-tax real terms**.

Approach

Estimating the WACC is a challenging task and necessarily involves judgement. The primary difficulty lies in there rarely being listed comparators that precisely match the risk characteristics of the assets being assessed. In practice, the cost of capital for any individual asset is also likely to reflect a range of specific features, such as the risk allocation embedded in its contracting arrangements. These features may differ across technologies, but there is also variation *within* the same technology type. Debt and equity providers may also hold differing views on the required return for a particular set of risks. Further, perceptions of risk are not fixed and may evolve over ASL's modelling horizon. Finally, the evidence available to inform judgements on WACC is limited, and sometimes contradictory.

The level of precision involved in this analysis is therefore low. In this context, we consider that that ASL's modelling results, informed by a range of assumptions on project costs and technical characteristics, should not be overly influenced by less well-evidenced assumptions on WACC differentials. Accordingly, the principles underpinning our analysis are to:

- Consider a wide range of evidence and explain how we have relied on it as transparently as possible.
- Acknowledge limitations and contradictions in the evidence by avoiding spurious levels of precision and reflecting only the most well-evidenced and material differences between technology / contract types.

[1] This report only considers WACCs for large-scale projects which are centrally dispatched (i.e., not behind-the-meter generation or storage units). Long-duration batteries have a duration of 8 hours or longer, whilst short-duration batteries have a duration of less than 8 hours.

- Account for differences in risks that may not persist over ASL's modelling horizon, noting that for practical reasons ASL needs to adopt a single WACC per technology.

Our approach involved three key steps:

- In **Step 1**, we developed a 'technology-neutral' WACC estimate for a generation or storage asset operating in the NEM. This is based on the central case methodology developed by Synergies for AEMO's Integrated System Plan (ISP). Although Synergies' methodology is not the approach that CEPA would necessarily adopt, for consistency it is important that the assumptions ASL use can be related back to the ISP. The technology-neutral WACC estimates are based on data up to 28 February 2023, reflecting interim reporting requirements for this engagement.
- In **Step 2**, we drew on multiple sources of evidence to assess whether a technology-specific increment or decrement should be applied to the technology-neutral WACC from Step 1.
- In **Step 3**, we explored how the WACC estimates might change if an asset holds an LTESA.

Our analysis in Steps 2 and 3 drew on several sources of evidence:

- A survey of debt and equity providers, conducted between July-August 2023.
- Qualitative risk analysis, informed by the findings of other studies and surveys of technology-specific WACC differences.
- Credit rating methodologies.
- Analysis of listed companies with investments in the technologies of interest.
- Analysis of independent expert valuation reports for Australian generation and storage assets.

Conclusions

Based on these sources of evidence, our proposed technology-specific estimates are presented in Table E.1 below. These estimates assume a 'typical' revenue model for each technology type, being a long-term power purchase agreement (PPA) for wind and solar PV assets, and more diverse and merchant-based revenue streams for the storage and firming technologies. In line with the principles stated above, these assumptions aim to reflect only the most well-evidenced differences that are likely to persist over time. The estimates are deliberately stylised, with a view to proposing assumptions that are 'roughly right' rather than 'precisely wrong'.

Table E.1: Pre-tax real WACC estimates by technology type ('typical' revenue model)

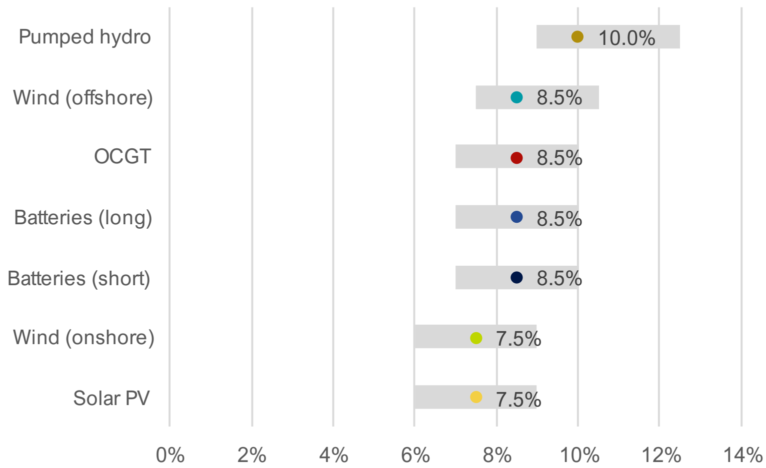
Technology	WACC assumption	Rationale
Solar PV, onshore wind	7.5%	We consider that our update of the ISP central case estimate is a reasonable anchor point for solar PV and onshore wind. This is evidenced by the results of the investor survey, review of other published surveys and studies, analysis of listed comparators, and qualitative assessment of relevant risks.
Batteries (short duration), batteries (long duration), OCGT	8.5%	We consider that a 1% uplift to the solar/onshore wind estimate is reasonable for these technologies. This reflects that these technology types are likely to face higher risk associated with their 'typical' revenue model, due to novelty, complexity, and policy-related risk. This is evidenced by our qualitative analysis, the investor survey, and the results of other published surveys and studies.
Offshore wind	8.5%	We consider that a 1% uplift to the solar/onshore wind estimate is reasonable for offshore wind. This reflects that offshore wind faces a higher level of construction risk relative to onshore wind / solar PV, due to this technology's relative

Technology	WACC assumption	Rationale
		immaturity in Australia (which may reduce over ASL's planning horizon). This is evidenced by our qualitative analysis, the investor survey, and the results of other published surveys and studies (including in jurisdictions where deployment of offshore wind is more advanced).
Pumped hydro	10.0%	We consider that a 2.5% uplift to the solar PV / onshore wind estimate is appropriate for pumped hydro. This reflects a 1% uplift related to revenue model risk (which we consider to be broadly similar to batteries and OCGT) and a further 1.5% uplift related to construction risk (which we have assumed is above that of offshore wind). The larger uplift for construction risk also reflects the investor survey responses, which although limited in number, place the WACC for pumped hydro above offshore wind.

Source: CEPA analysis

The investor survey and other evidence indicates that the WACC for a specific project could fall within a wide band above and below these point estimates. Recognising this, the figure below presents the point estimates in relation to our view of a reasonable range of possible WACC outcomes. These are largely informed by the survey results and reflect wider ranges for offshore wind and pumped hydro for which there is less evidence. While ASL could use these ranges to test the sensitivity of its modelling results, we would recommend placing less weight on the ranges than on the point estimates. This is consistent with our view that, for ASL's purposes, it is not appropriate to rely on strong assumptions of large WACC differences between technologies when the available evidence is so limited.

Figure E.1: Ranges for technology-specific WACC estimates (pre-tax real)



Source: CEPA analysis.

Table E.2 below presents our view on appropriate WACC assumptions for each technology, this time assuming that they are based on a purely *merchant* revenue model.

Table E.2: Pre-tax real WACC estimates by technology type (merchant revenue model)

Technology	WACC assumption	Rationale
Solar PV, onshore wind	9.0%	We consider that a 1.5% increment is a reasonable estimate of how the WACC may change when moving from an onshore wind / solar PV project with a 'typical' revenue model to a fully merchant model. This is based on the sources of evidence outlined in Section 4.2.1.
Batteries (short duration), batteries	9.0%	For these technologies, we propose a 0.5% increment compared to the 'typical project' assumption. This brings the assumed WACC in line with

Technology	WACC assumption	Rationale
(short duration), OCGT		solar PV and onshore wind, reflecting our assessment that the primary difference between these technologies relates to their revenue models.
Offshore wind	10.0%	We have proposed a 1.5% increment compared to the 'typical project' assumption. The reasons are as given for solar PV and onshore wind. The remaining 1% differential to solar PV and onshore wind reflects the allowance we have made for construction risk.
Pumped hydro	10.5%	We have proposed a 0.5% increment compared to the 'typical project' assumption. The reasons are as given for batteries and OCGT. The remaining 1.5% differential to solar PV and onshore wind reflects the allowance we have made for construction risk.

Source: CEPA analysis

In relation to LTESAs, we propose to apply, to the 'typical project' estimates in Table E.1:

- A 0.5% decrement to the pre-tax real WACC for onshore wind, solar PV, and offshore wind, within a range of 0.25-1.0%.
- For other technologies for whom the typical revenue model is assumed to be less contracted (batteries, pumped hydro, OCGT), a 1.5% decrement, within a range of 1.0-2.5%. Intuitively, this reflects a view that revenue model risk is the primary source of hurdle rate difference between these technologies and solar PV / wind – and that holding an LTESA largely eliminates this.

These estimates reflect our analysis, investor survey responses, and other evidence of investor views. However, the evidence is both limited and contradictory. Nonetheless, we consider that the estimates are consistent with the responses to the investor survey, which provides a recent 'market' view of LTESA options.

The resulting WACC estimates are presented in the table below. The remaining difference between offshore wind / pumped hydro and the other technologies reflects an allowance for construction risk, which LTESAs do not impact.

Table E.3: Pre-tax real WACC estimates by technology type (with LTESA)

Technology	WACC assumption
Solar PV, onshore wind	7.0%
Batteries (short duration), batteries (long duration), OCGT	7.0%
Offshore wind	8.0%
Pumped hydro	8.5%

CEPA economics matters

1. INTRODUCTION

CEPA has been engaged by AEMO Services Limited (ASL) to provide advice on appropriate estimates of the weighted average cost of capital (WACC) for electricity generation and storage technologies.

1.1. TERMS OF REFERENCE

ASL has asked CEPA to provide:

1. Separate WACC estimates for **different electricity generation, long-term storage and firming technologies**, specifically: onshore wind; offshore wind; solar PV; short-duration batteries; long-duration batteries; pumped hydro; and open-cycle gas turbines.[2] These estimates should reflect how the WACC would differ assuming:
    a. A 'typical' revenue model for that technology.
    b. A 'merchant' revenue model.
2. An estimate of how the WACC estimates for such assets would change if an asset is assumed to hold a **Long-Term Energy Services Agreement (LTESA)**, a policy mechanism implemented under the NSW Electricity Infrastructure Investment Roadmap.

The WACC estimates should be expressed in **pre-tax real terms**.

1.2. CONTEXT

ASL is an independent subsidiary of the Australian Energy Market Operator (AEMO), established to provide energy advisory and infrastructure planning advice to member governments and their partners who participate in the National Energy Market (NEM).

In November 2020, the NSW Parliament passed the *Electricity Infrastructure Investment Act 2020* (EII Act), to enable the delivery of the NSW Government's Electricity Infrastructure Investment Roadmap. This legislation established the NSW Consumer Trustee, an independent statutory role with various planning, advisory and procurement functions that it must exercise in the long-term financial interests of NSW electricity consumers.

In 2021, the NSW Government appointed ASL as the Consumer Trustee. In this role, ASL's functions include planning for the achievement of the infrastructure investment objectives established by the EII Act. These include:[3]

- minimum objectives for the construction of specified amounts of renewable generation infrastructure and long-duration storage infrastructure by the end of 2029, and
- overall objectives to construct additional infrastructure necessary to minimise costs to NSW electricity customers and meet the NSW energy security target and reliability standard.

To satisfy these requirements, at least every two years ASL must produce the **Infrastructure Investment Objectives Report (IIO Report)**.[4] This report which set outs a 20-year Development Pathway for the construction of electricity generation, long-duration storage and firming infrastructure in NSW to achieve the EII Act objectives. The Development Pathway aligns with the anticipated delivery of transmission network infrastructure for Renewable Energy Zones (REZs), as planned for by the Energy Corporation of NSW (EnergyCo) in its Network Infrastructure

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[2] This report only considers WACCs for large-scale projects which are centrally dispatched (i.e., not behind-the-meter generation or storage units). Long-duration batteries have a duration of 8 hours or longer, whilst short-duration batteries have a duration of less than 8 hours.

[3] ASL (2021), *2021 Infrastructure Investment Objectives Report*, December 2021, p. 3.

[4] The inaugural 2021 IIO Report was published in December 2021. An update was published in December 2022, in response to a direction from the NSW Minister for Energy under the EII Act to conduct a competitive tender for LTESAs for firming infrastructure.

Strategy.[5] The IIO Report also includes a 10-year plan for conducting competitive tenders for LTESAs, to give effect to the Development Pathway.

WACC estimates for electricity generation, long-term storage and firming technologies are an input to ASL's modelling framework that informs the IIO Report, REZ Authorisation and Network Option Advice. As described in Box 1 below, in relation to the IIO Report, the WACC estimates affect the choice of Development Path in two ways:

- Firstly, by changing the **relative cost** of each technology and the relative cost of assets located inside / outside of NSW. Relative costs determine which investments are included on the Development Pathway, subject to other modelling constraints.
- Secondly, by impacting **projected LTESA payments**, which in turn determine costs to NSW customers. Overall costs to NSW consumers are a factor in determining which of the Development Paths modelled by ASL is selected.

When setting the Development Path, relative differences in the assumed WACCs are more important than the absolute figures. This differs from other circumstances where WACCs are used, such as determining regulatory revenue allowances. However, absolute WACC values are important in other contexts where ASL may use these assumptions. For example, under its REZ Authorisation functions, ASL sets a maximum capital cost for the REZ development (i.e., the maximum capital amount that can be recovered from consumers in relation to the REZ).[6] This is based on an assessment of the benefits of the REZ network infrastructure to consumers, which is in part affected by the WACC assumptions for the generation, storage and firming projects that locate in a REZ.

Box 1. Impact of WACC estimates on the Development Pathway

Broadly, ASL follows a three-step process to determine the Development Pathway.

- **Step 1: System expansion.** ASL determines the annualised cost for each type of generation, long-duration storage and firming technology. The annualised cost reflects projected capital and operating costs (which evolve over time), and the WACC. Different WACCs apply for each technology type, and for assets located in and outside of NSW. New entrant assets located in NSW are assumed to have an LTESA, while assets located elsewhere in the NEM do not. ASL also determines the WACC, capital and operating costs for electricity transmission network assets. When ASL determines the Development Path, network investments are co-optimised with generation, storage and/or firming technologies. [7]

  ASL then determines what combination of electricity generation, long-duration storage, firming and transmission network investments meets the constraints set by the EII Act (for example, minimum construction quantities for renewable generation, the reliability standard, etc.), while minimising total system costs. Other factors held equal, a lower WACC equates to a lower annualised cost, which means that a particular investment is more likely to be included in the Development Pathway.
- **Step 2: Wholesale electricity market outcomes.** ASL conducts wholesale electricity market modelling, based on the Development Pathway from Step 1, to determine wholesale electricity market price outcomes. This is based on assumed variable costs, bidding behaviour, transmission constraints, and other assumptions. WACC estimates are not used in this step.
- **Step 3: NSW customer impacts.** Based on Step 2, ASL calculates projected wholesale market revenues for each generation, storage and firming investment included on the Development Pathway. This is combined with assumptions on other revenue sources[8] to determine whether each investment breaks even over its operating life (i.e., earns revenues that at least meet its capital costs, operating

[5] EnergyCo published a draft Network Infrastructure Strategy in September 2022.

[6] EnergyCo (2022), *Draft Network Authorisation Guidelines*, May 2022, pp. 26-27.

[7] The WACC for electricity transmission network assets is not within the scope of this report.

[8] For example, revenues from the provision frequency control ancillary services (FCAS) or network services.

costs and WACC). If there is a revenue gap, this is assumed to be met by payments under the investment's LTESA.[9]

In combination, Steps 1-3 allow ASL to determine the overall cost of a Development Pathway to NSW customers, which is comprised of network build costs, wholesale market costs and LTESA payments.[10] ASL may test multiple Development Pathways to determine which is consistent with the EII Act objectives, including minimising costs to NSW customers.

1.3. Our approach

Estimating the WACC is a challenging task and necessarily involves judgement. The primary difficulty lies in there rarely being listed comparators that precisely match the risk characteristics of the assets being assessed, which could otherwise be used to directly observe the cost of capital. Instead, estimates need to be derived from comparators that match some, but not all, of the risk characteristics of the assets in question.

In practice, the cost of capital for any individual asset is also likely to reflect a range of specific features, such as the risk allocation embedded in its contracting arrangements. These features may differ across technologies, but there is also variation *within* the same technology type. Debt and equity providers may also hold differing views on the required return for a particular set of risks. Further, perceptions of risk are not fixed and may evolve over ASL's modelling horizon. Finally, the evidence available to inform judgements on WACC is limited, and sometimes contradictory.

The level of precision involved in this analysis is therefore low. In this context, we consider that that ASL's modelling results, informed by a range of assumptions on project costs and technical characteristics, should not be overly influenced by less well-evidenced assumptions on WACC differentials. Accordingly, the principles underpinning our analysis are to:

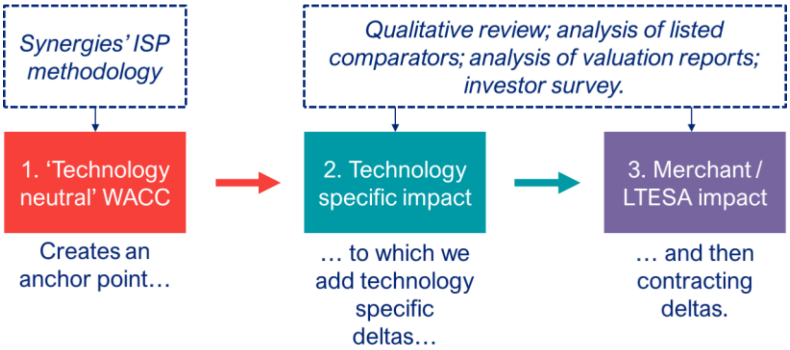
- Consider a wide range of evidence and explain how we have relied on it as transparently as possible.
- Acknowledge limitations and contradictions in the evidence by avoiding spurious levels of precision and reflecting only the most well-evidenced and material differences between technology / contract types.
- Account for differences in risks that may not persist over ASL's modelling horizon, noting that for practical reasons ASL needs to adopt a single WACC per technology.

Figure 1.1 describes our approach to addressing ASL's requirements, given these inherent limitations. Our methodology combines multiple sources of evidence to make the estimates as robust as possible.

[9] This is a modelling assumption that greatly simplifies how LTESAs will operate. A description of LTESAs is included in Section 5.1.

[10] The cost modelling focusses on incremental costs associated with a Development Pathway, and excludes other costs that make up consumer bills (for example, retailer operating costs, charges for existing transmission and distribution network infrastructure and environmental schemes).

Figure 1.1: Overview of our methodology



In **Step 1**, we developed a 'technology-neutral' WACC estimate for a generator or storage asset operating in the NEM. This is based on the central case methodology developed by Synergies for AEMO's Integrated System Plan (ISP). Although Synergies' methodology is not the approach that CEPA would necessarily adopt, for consistency it is important that the assumptions ASL use can be related back to the ISP. This step produced a 'technology-neutral' WACC estimate. Our conclusions are discussed in Section 2.

In **Step 2**, we drew on multiple sources of evidence to assess whether a technology-specific increment or decrement should be applied to the 'technology-neutral' WACC from Step 1. Section 4 sets our analysis for this step.

In **Step 3**, we explored how the WACC estimates might change if an asset holds an LTESA. Our conclusions are discussed in Section 5.

Our analysis in Steps 2 and 3 drew on several sources of evidence:

- A survey of debt and equity providers, reported in Section 3.
- Analysis of listed companies with investments in the technologies of interest.
- Independent expert valuation reports for Australian generation and storage assets.
- Credit rating methodologies for electricity assets.
- Qualitative risk analysis, informed by the findings of other studies and surveys of technology-specific WACC differences.

The appendices provide further detail on the sources of evidence that we have relied on.

1.4. Analytical framework

Investments in the NEM are financed with capital provided by both lenders (debt) and shareholders (equity). Debt and equity providers require a return that compensates them for the opportunity cost of committing funds to a particular investment over time: this is what the cost of debt and equity represent. The overall cost of capital for an investment is the weighted average its **cost of debt** and **cost of equity**. The weighting is determined by the level of **gearing**, being the proportion of debt and equity within the investment's overall capital structure.

Broadly, capital providers will require higher expected returns for riskier investments. Accordingly, differences in the risk profile of particular technologies can translate to differences in their required return on capital. However, different risks impact the cost of debt, cost of equity and level of gearing. The analytical framework that we have adopted for this engagement is detailed in Appendix A. We highlight the following key points in relation to the cost of equity, cost of debt, and gearing below.

The most widely applied method for estimating the cost of equity is the capital asset pricing model (CAPM). The CAPM assumes that only systematic risks which cannot be eliminated through diversification are relevant for determining required equity returns. In practice however, we acknowledge that some investors might account for such non-systematic risks by adjusting their hurdle rates (see Box 2). Some of the evidence we rely on to assess technology-specific risk (e.g., survey results) may therefore relate to non-systematic as well as systematic risk. Further, in the context of ASL's modelling framework, it may be more practical to reflect non-systematic risk as an adjustment to the assumed WACC, rather than through cashflows. For these reasons, when interpreting the evidence available to us, we have not sought to confirm that identified technology-specific risks (e.g., as reported by survey respondents) are purely related to systematic risk. This approach does not mean that we reject the CAPM framework's careful distinction between systematic and non-systematic risk. Rather, our approach for this report is rather a pragmatic decision that reflects the specific context in which these estimates will be used.

Box 2. WACC vs hurdle rate

An investment hurdle rate represents the minimum internal rate of return (IRR) required by investors over the life of the asset. If the projected future cashflows of an asset are discounted at the hurdle rate, the net present value (NPV) of those cash flows should be at least zero for the project to move ahead. When making investment decisions, WACCs can be applied as the discount rate to convert the projected future cash flows of an asset to NPV.

In practice, the actual discount rate that is applied in this context may not necessarily be the project's WACC.[11] For example, sometimes investors will choose to reflect certain non-systematic risks in the discount rate, rather than directly in the cash flows.[12] For the purpose of this report, we use the term 'hurdle rate' to reflect the minimum return that investors require to invest in an asset, noting that this may be different from an asset's WACC.

The prevailing theories of **cost of debt** centre on financial distress costs and by extension the probability of default. An entity's probability of default is often measured by its credit rating. A credit rating is a score assigned by a rating agency based on their assessment of the entity's financial strength against relevant risk factors. An entity's cost of debt can then be estimated using indices that track debt yields from issuers with a similar credit rating. Accordingly, we have drawn on credit rating agency methodologies to determine what they consider when assessing companies, and how these considerations will be impacted by different asset characteristics. For the purpose of this report, we have referred to the methodologies applied by Moody's to assess unregulated power companies, fully contracted power generation projects, and partially / non-contracted power generation projects.[13]

As discussed above, the WACC is the weighted average of the cost of debt and cost of equity, where the weighting is determined by **gearing** – being the proportion of debt and equity finance within the investment's overall capital structure. Higher gearing means a higher proportion of debt finance in the capital structure. The impact of differences in gearing on the asset's cost of capital is more complex than simply re-weighting the cost of debt and cost of equity components of the WACC, because the cost of debt and the cost of equity themselves are not independent of the capital structure. Given these considerations (detailed in Appendix A), we have opted to apply a single gearing assumption for all technology types and reflect differences in risk as a change to the cost of equity and/or cost of debt. In the simple framework, the relationship between cost of debt/equity and the WACC is very straightforward: if the cost of either debt or equity increases, leaving other things equal, the WACC increases, and vice versa. While gearing levels may be generally higher or lower for particular technology types, we consider that our approach provides a simple and transparent means of reflecting differences in risk. This avoids the complexity of attempting to determine appropriate technology-specific gearing benchmarks, noting that capital structures may vary materially across assets of the same technology (for example, because one type of financing approach has been more prevalent than another for certain asset types).

[11] For example, see Edwards, H. and Lane, K. (2021), *Why Are Investment Hurdle Rates So Sticky?*, RBA Bulletin – December 2021, 9 December 2021.

[12] For example, see Oxera (2011), *Discount rates for low-carbon and renewable generation technologies*, April 2011, p.7. We note that differences between WACCs and hurdle rates could arise for other reasons. However, these are less relevant for the purpose of this report.

[13] Moody's (2022), *Power Generation Projects Methodology*, January 12. Moody's (2017), *Unregulated Utilities and Unregulated Power Companies*, May 17.

1.5. OTHER ESTIMATION ISSUES

The context of ASL's analysis has several additional implications for estimating the WACC. While these issues involve some interesting theoretical questions, we have aimed to address them in a way that is proportionate to the likely impact on the outcomes of ASL's power system planning process.

A full discussion is provided in Appendix A. In summary, we highlight the following points:

- **Whole-of-life WACC.** ASL is using the WACC estimates to determine the relative cost of different technologies and contracting arrangements, over the life of each asset. Therefore, the WACC estimate should reflect the average return required **over the life of the project**. This differs from the return that may be required at a specific stage of project development. For example, the cost of equity in the construction period could be higher than in the operational period, and higher than the overall whole-of-life WACC. While we have attempted to account for this in interpreting the available evidence, it is not possible to entirely control for this factor.

- **Term of the cost of capital.** The term of the cost of capital refers to the time horizon over which returns are estimated. For example, the choice of term impacts the estimation of the risk-free rate through the chosen tenor of government bonds used as a proxy. For the purpose of this advice, we have opted to apply a 10-year term for estimating the WACC, across all technology types. This does not imply that all technology types have the same economic life. Rather, it reflects a view that a WACC based on a 10-year term can reasonably be assumed to apply over each asset's economic life. We consider that this is a reasonable simplification, considering evidence that investors commonly use a 10-year discount rate when making decisions on infrastructure investments with economic lives longer than 10 years.[14]

- **Timing of investments.** Given the nature of ASL's modelling, the WACC may be applied to future investments with a range of different construction dates. In principle, different construction dates could imply different pre-tax real WACCs. For example, because forward looking inflation expectations differ for an asset constructed in 2025 as compared to an asset constructed in 2035. Controlling for this would involve constructing a 'rolling' WACC estimate that would apply to each year of ASL's forecast period. We do not consider that this would be a proportionate approach. Accordingly, we have only established WACC estimates for a single point in time (as of 28 February 2023).

1.6. FUTURE UPDATES

ASL may wish to update these assumptions periodically to inform its modelling. We suggest that a practical approach is:

- To periodically update the assumptions, ASL could refresh the central technology-neutral estimate (as outlined in Section 2) and maintain the technology- and contract-specific WACC increments outlined in Sections 4 and 5. This ensures that the underlying WACC estimates continue to reflect up to date market evidence.

- The technology- and contract-specific WACC increments can then be reviewed less frequently, for example via a refresh of the investor survey. This means that the assumptions on technology-specific increments, which are inherently less robust than the underlying central case estimate, would only be updated where compelling evidence of a material change emerges.

[14] AER (2022), *Draft Rate of Return Instrument – Explanatory Statement*, June 2022, p.14. Energy Networks Australia (2021), *The term of the rate of return – Response to Draft AER Working Paper*, 2 July 2021, p.7 and p.9.

2. TECHNOLOGY-NEUTRAL WACC ESTIMATES

In this section, we set out an estimated WACC range for a generation or storage asset operating in the NEM. The estimates considered in this section are intended to be 'technology neutral', in the sense of reflecting an 'average' WACC across multiple renewable generation and storage technologies. Issues specific to a particular technology type are considered in Section 4.

The WACC estimates presented in this section also assume that the generation / storage asset does not hold an LTESA. The potential impact of LTESAs on WACC is discussed in Section 5.

These estimates are based on data up to 28 February 2023, reflecting interim reporting requirements for this engagement. The values of some parameters may have changed between then and the time of finalising this report.

2.1. Approach

To develop a technology-neutral WACC estimate, we have closely followed the central case WACC methodology developed by Synergies for AEMO's 2022 Integrated System Plan (ISP).[15] Since its original 2022 ISP report, Synergies has updated its estimates of the risk-free rate, market risk premium, debt risk premium and inflation. [16] However, their WACC methodology has remained the same.

This is not necessarily the methodology that CEPA would choose to adopt to estimate WACC. However, we think it is a logical anchor point for ASL's WACC assumptions, to provide comparability and alignment with the discount rate used in the ISP. Accordingly, to develop a technology-neutral WACC estimate as a starting point for our analysis, we have updated Synergies' central case estimate to February 2023.

2.2. Estimates

Overall, our February 2023 update produces a central pre-tax real WACC estimate of 7.54%. This compares to Synergies' June 2022 update of 7.14%, with a rounded figure of 7% adopted by AEMO.

Synergies advised that, to the extent that AEMO chooses to apply rounding to its discount rate estimates, it recommends rounding to the nearest half per cent.[17] Applying the same logic to our estimates would result in rounded estimates of 7.5%. We consider that rounding is appropriate, given the overall level of precision in the exercise, and have adopted 7.5% as the basis of our estimates.

Estimated values for each parameter are set out in the table below. More information on the estimates is provided in Appendix B.

[15] Synergies (2021), *Discount rates for use in cost benefit analysis of AEMO's 2022 Integrated System Plan: A report prepared for AEMO*. July 2021.

[16] Synergies (2022), *Updating the 2022 ISP Discount Rate: A report prepared for AEMO.* December 2022

[17] Synergies (2022), p.5.

Table 2.1: Summary of technology-neutral WACC parameter estimates as at 28th February 2023.

Parameter	Estimate
Risk-free rate	3.75%
MRP	6.80%
Asset Beta	0.50
Equity Beta	1.00
Tax rate	30%
Cost of Equity	**10.55%**
Debt risk premium	2.96%
Debt raising costs	0.10%
Cost of debt	**6.81%**
Gearing	50%
Expected Inflation	2.48%
Gamma	0.25
WACC – Post-tax nominal vanilla	**8.68%**
WACC Pre-tax real	**7.54%**

Source: CEPA analysis of Bloomberg data

3. INVESTOR SURVEY

ASL conducted a survey between 11 July and 11 August 2023 to understand investor views on how the cost of capital may differ by technology in practice. The survey was sent to members of the Clean Energy Council (CEC), Clean Energy Investors Group (CEIG) and over 100 other industry stakeholders that ASL engages with regularly. 24 unique responses were received from the survey participants, with responses aggregated in Appendix D.

The survey information set out in this report has been aggregated to protect confidential information provided by respondents. This means that some of the details we have relied on are not reported. For example, we have not separately reported quantitative responses related to OCGT, offshore wind and pumped hydro, due to the limited number of responses provided.

3.1.1. Survey results

Respondents were asked questions relating to the cost of debt, cost of equity and overall hurdle rate that applies for each technology, and the impact of an LTESA on each. Respondents were only asked to answer questions relating to technologies they were either actively involved in, or were actively considering, to limit unreliable answers. Respondents were also asked questions about the context of their responses to better understand any underlying assumptions, including:

- The type of organisation (project developer, bank, etc.).
- If they were typically involved in project finance or corporate finance arrangements (or both).
- What project phase they were considering (construction, operational, whole of life).
- The revenue model they considered typical for each technology (contracted, merchant, or a combination).
- Whether they could comment on the cost of capital, cost of debt, or both. Respondents who indicated an ability to comment on both the cost of debt and cost of equity were asked additional questions on the overall hurdle rate.

Respondents were provided with definitions of key terms and the assumptions they should apply when considering LTESA impacts. Even so, responses may be based on different assumptions and may not therefore be comparable. Similarly, there is a risk of bias to the extent that respondents may wish to influence the decision making of ASL or policy makers more broadly. Finally, it is important to recognise that the survey provides relatively few data points. Accordingly, it is important to interpret responses with caution, and consider these as only one source of evidence among others.

3.1.2. Analysis

Cost of debt

Responses provided a relative ranking of technologies with respect to their cost of debt and estimates of the cost of debt for each technology.

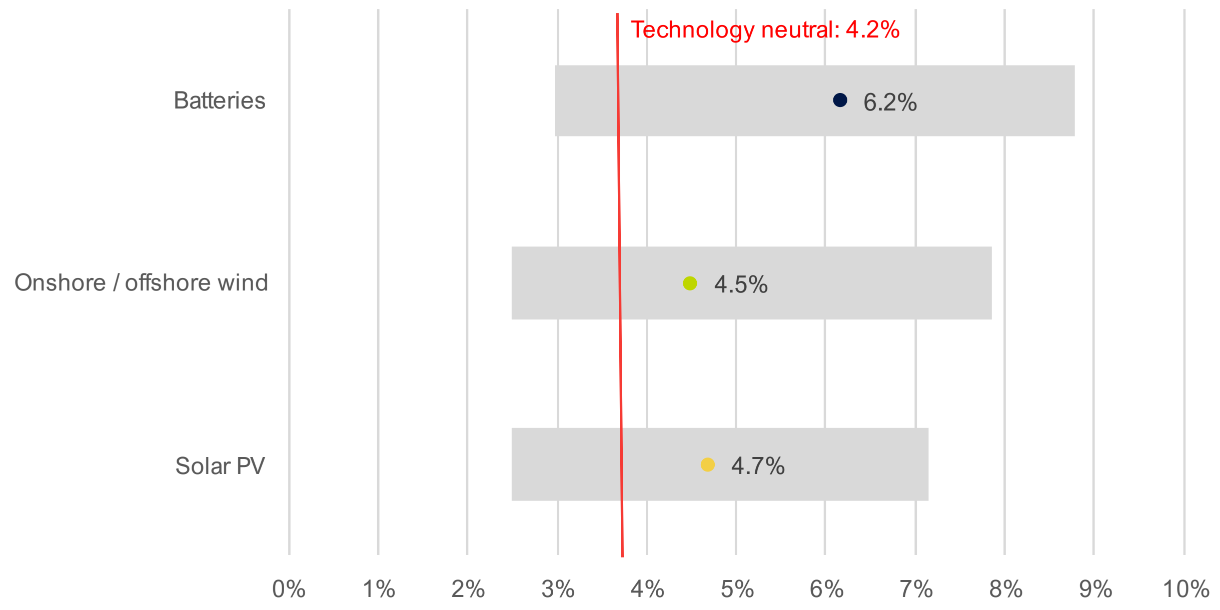
Qualitative rankings

Where respondents thought the cost of debt should vary across the technologies, solar PV and onshore wind primarily ranked below other technologies. Several respondents considered that the typical battery revenue model (involving a combination of merchant wholesale market revenues, arbitrage, and frequency control ancillary services) is perceived as riskier by lenders. Batteries of short and long duration were broadly considered to share similar risks, although it was noted that the debt tenor may differ for each category. Few responses commented on pumped hydro and OCGT. Those that did ranked the cost of debt for pumped hydro above that of batteries, and ranked the cost of debt for OCGT below that of pumped hydro.

Quantitative estimates

There was wide variation in the cost of debt estimates for solar PV, onshore wind and short-duration batteries (Figure 3.1). Offshore wind and long-duration batteries received just one response each, while no responses were provided for pumped hydro and OCGT. Responses fall both above and below the technology-neutral cost of debt estimate set out in Section 2. The average stated cost of debt for solar PV and onshore wind is relatively close to the technology neutral estimate.

Figure 3.1: Surveyed pre-tax real cost of debt (average of all responses and range)



Source: CEPA analysis of survey responses. To protect respondents' confidential information, results for short- / long-duration batteries and onshore / offshore wind have been aggregated.

Averaging the estimates provided for each technology may be misleading with respect to technology-specific differences. This is because estimates made by different respondents may reflect different underlying assumptions (e.g., the risk-free rate) that are not related to the technology type. This may be contributing to the average reported cost of debt for offshore wind, relative to onshore wind and solar PV.

A more informative view of perceived differences in the cost of debt across technologies can be derived by analysing those responses that commented on multiple technologies. The four responses that compared solar PV and onshore wind indicate no material difference between these technologies. Estimates for onshore wind were on average 0.2% higher, reflecting responses that considered the cost of debt for onshore wind to be either higher or the same as solar PV.

Table 3.1 shows the average reported difference between batteries and solar PV/onshore wind as the baseline. This reflects just one response for long duration batteries and three responses for short-duration batteries. Although there are few data points, the survey responses suggest that the cost of debt for batteries should potentially be higher than the technology neutral estimate set out in Section 2. Although we have not reported the offshore / onshore wind differential for confidentiality reasons, we note that it was not material.

Table 3.1: Surveyed difference in the pre-tax real cost of debt relative to solar PV/ onshore wind

	Batteries (short and long duration)	Pumped hydro	OCGT
Difference	+1.7%	n/a	n/a

Source: CEPA analysis of survey responses.

Cost of equity

Responses provided a relative ranking of technologies with respect to their cost of equity and estimates of the cost of equity for each technology.

Qualitative rankings

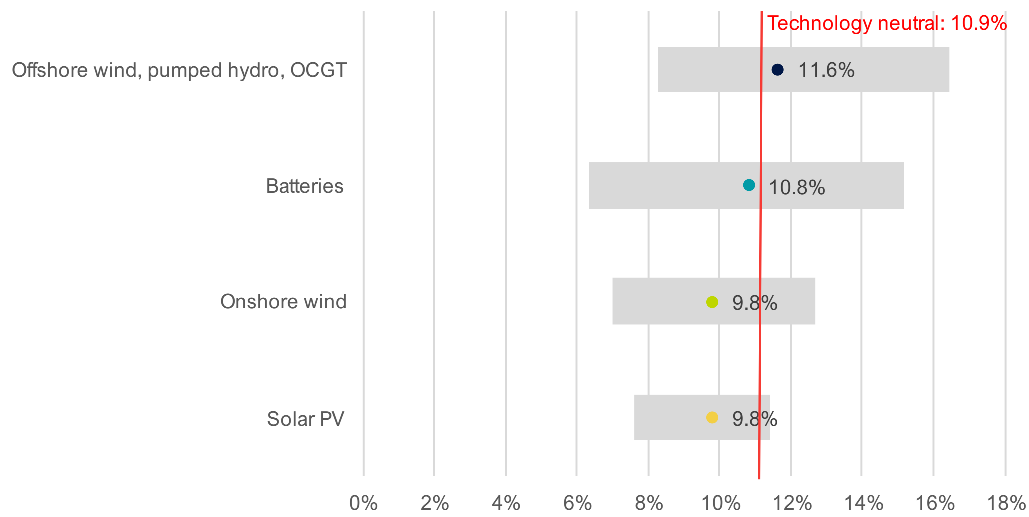
Where respondents thought the cost of equity should vary across the technologies, onshore wind was ranked the lowest most frequently. Solar PV was mostly ranked below batteries. When both long and short duration batteries were ranked by the same respondent, they were most frequently ranked the same. Offshore wind, pumped hydro and OCGT variously received some of the highest and lowest rankings across the technologies.[18]

One respondent considered that solar PV faced higher risk than onshore wind due to concentration risk and the increasing prevalence of rooftop solar systems creating competition during peak solar generation hours. Comparatively, onshore wind was considered to have less correlation with day-time generation and able to participate in peak demand periods. Construction and commissioning risk was highlighted in relation to offshore wind, particularly in Australia where offshore wind is currently more novel than in international markets. One respondent suggested that pumped hydro is more established than batteries, which may have operating risks that are yet to be fully understood. However, responses also noted that construction risks arising from geological complexities are a concern for pumped hydro. The only comment that mentioned OCGT noted that grid connection risk and high reliance on fuel costs could impact the hurdle rate.

Quantitative estimates

There was wide variation in the cost of equity estimates across technologies (Figure 3.2). Offshore wind and pumped hydro received only one response each. Responses fall above and below the technology-neutral cost of equity estimated set out in Section 2. Based on the average result for each technology, the technology neutral estimate exceeds the reported cost of equity for solar PV and onshore wind. The technology-neutral estimate is close to reports for batteries (long and short duration), although these fell within a wide range. The aggregated result for the other technologies sits above the technology neutral estimate, although again the range is wide. Despite the commentary received in relation to concentration risk, the average reported cost of equity for solar PV and onshore wind are similar.

Figure 3.2: Surveyed pre-tax real cost of equity (average of all responses and range)



Source: CEPA analysis of survey responses. To protect respondents' confidential information, results for short- / long-duration batteries and offshore wind / pumped hydro / OCGT have been aggregated.

[18] This was one of the more confusing survey results, and could indicate erroneous responses.

Averaging the estimates provided for each technology may be misleading with respect to technology-specific differences. This is because estimates made by different respondents may reflect different underlying assumptions (e.g., the risk-free rate or market risk premium) that are not related to the technology type.

A more informative view of perceived differences in the cost of equity across technologies can be derived by analysing those responses that commented on multiple technologies. The four responses that compared solar PV and onshore wind indicate no material difference between these technologies, with an estimated reported difference of nil on average. Responses reflected views that the cost of equity for solar PV could be variously higher, lower, or the same as for onshore wind.

Table 3.2 shows the average reported difference between the other technologies and solar PV/onshore wind as the baseline. This reflects just one response each for offshore wind and pumped hydro, two for OCGT and long duration batteries, and five for short duration batteries. This suggests broadly similar conclusions to Figure 3.2.

Table 3.2: Surveyed difference in the pre-tax real cost of equity relative to solar PV/ onshore wind

	Batteries (short and long duration)	Offshore wind, pumped hydro, OCGT
Difference	+1.7%	+2.3%

Source: CEPA analysis of survey responses. To protect respondents' confidential information, results for short- / long-duration batteries and offshore wind / pumped hydro / OCGT have been aggregated.

Overall hurdle rates

Responses provided a relative ranking of technologies with respect to their overall hurdle rate and estimates of the hurdle rate for each technology. These are stand-alone responses and are not calculated as a combination of the cost of debt and cost of equity responses above.

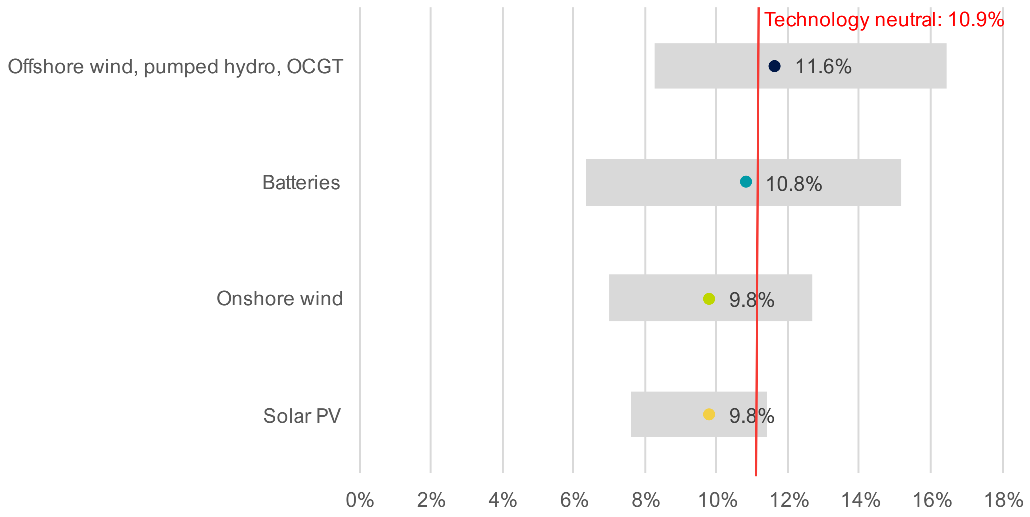
Qualitative rankings

Solar PV and onshore wind were consistently ranked the lowest or second lowest across responses. Pumped hydro was ranked as the highest where it was considered. With the exception of one response, batteries were ranked higher than solar and onshore wind. Of the three responses that ranked both kinds of batteries, two respondents ranked short-duration batteries below long-duration batteries and one ranked them the same. The two responses that considered OCGT assigned a similar ranking to batteries. Only one response ranked offshore wind, placing it second highest before pumped hydro.

Quantitative estimates

There was wide variation in the overall hurdle rate estimates across technologies (Figure 3.3). Offshore wind received only one response, while OCGT and pumped hydro each received two. The average reported hurdle rate for solar PV, onshore wind and batteries (short and long-duration) broadly aligns to the technology-neutral estimate set out in Section 2. Aggregated reported estimates for offshore wind, pumped hydro and OCGT fall above the technology-neutral estimate, although we note the limited number of responses provided and the wide range around the average.

Figure 3.3: Surveyed pre-tax real hurdle rate (average of all responses and range)



Source: CEPA analysis of survey responses. To protect respondents' confidential information, results for short- / long-duration batteries and offshore wind / pumped hydro / OCGT have been aggregated.

Averaging the estimates provided for each technology may be misleading with respect to technology-specific differences. This is because estimates made by different respondents may reflect different underlying assumptions (e.g., the risk-free rate or market risk premium) that are not related to the technology type.

A more informative view of perceived differences in hurdle rates across technologies can be derived by analysing those responses that commented on multiple technologies. The three responses that compared solar PV and onshore wind indicate no material difference between these technologies, providing estimates for onshore wind that were 0.2% higher than solar PV on average. Responses reflected views that hurdle rates for onshore wind could be variously higher, lower, or the same as for solar PV.

Table 3.3 shows the average reported difference between the other technologies and solar PV/onshore wind as the baseline. This reflects just one response each for long duration batteries and offshore wind, two for pumped hydro and OCGT, and three for short duration batteries. Compared to (Figure 3.3), this suggests a more pronounced difference between solar PV / onshore wind and offshore wind, batteries, and OCGT.

Table 3.3: Surveyed difference in the pre-tax real hurdle rate relative to solar PV/ onshore wind

	Batteries (short and long duration)	Offshore wind, pumped hydro, OCGT
Difference	+0.8%	+2.8%

Source: CEPA analysis of survey responses. To protect respondents' confidential information, results for short- / long-duration batteries and offshore wind / pumped hydro / OCGT have been aggregated.

3.1.3. Conclusions

Survey responses show there is wide variation in the assumed risk profiles and subsequent rate of return required across technologies. Across the survey, the following risks were raised in relation to certain technologies.

Table 3.4: Survey respondents' view of relevant risks by technology

	Solar PV	Wind (onshore)	Wind (offshore)	Batteries (short duration)	Batteries (long duration)	Pumped hydro	OCGT
Revenue volatility				X	X	X	X
Construction			X			X	
Concentration	X						
Novelty			X				

All else equal, the survey responses indicated that hurdle rates are perceived to be higher for batteries (short and long), pumped hydro and OCGT relative to wind (onshore/offshore) and solar PV. This is due to more complex, uncertain and novel revenue models for these peaking / firming technologies.

While responses noted that solar PV could face higher risk relative to onshore wind due to concentration risk, this was not reflected in the quantitative survey results.

All else equal, the survey responses indicated that hurdle rates may be higher for pumped hydro and offshore wind relative to other technologies, due to a higher risk of construction time and cost overruns. For offshore wind, construction risk is associated with the novelty of the technology in Australia, whereas for pumped hydro significant geological complexities and prolonged planning timeframes were considered to be key drivers.

4. TECHNOLOGY-SPECIFIC WACC ESTIMATES

In this section, we set out the sources of evidence that informed our judgement on whether the WACC for each generation, long-duration storage and firming technology of interest to ASL should differ from the 'technology neutral' estimates established in Section 2. We have considered five sources of evidence:

- The survey of investors, described in Section 3 and Appendix D.
- The findings of other studies into technology-specific WACC differences.
- Analysis of listed generation and storage companies (Appendix B.7).
- Independent expert valuation reports (Appendix C).
- Credit rating methodologies.

The analysis presented in this section assumes that the asset does not hold an LTESA. The impact of changing this assumption is considered in Section 5.

4.1. Identifying relevant risks

As a starting point, we have reviewed the sources described above to identify potential risk factors that could be relevant for the technologies of interest to ASL. As highlighted in Section 1.5, we have not sought to precisely assess whether these risks are systematic or non-systematic in nature.

The most relevant risks that our review identified are:

- Risks associated with the project's **revenue model**. That is, the extent to which project revenues are stable, predictable and well-understood.
- **Planning and construction** related risks. That is, the potential for unexpected delays in obtaining planning consents and completing construction, and associated impacts on development costs.
- Risks associated with the potential for **policy changes** to alter the expected future returns of certain technologies.
- Technology **maturity risk**, which arises from unforeseen underperformance or higher maintenance costs due to a technologies' novelty or unpredictability.
- **Concentration risk**, which relates to the correlated output of solar PV resulting in greater exposure to low or negative wholesale prices for this technology.
- **Curtailment risk**, which arises from the possibility of reduced revenue due to unexpected curtailment of output due to congestion on the transmission network.

In the following sections we discuss each risk in turn, concluding with a summary of technology-specific differences, based on this qualitative assessment.

4.2. Risk assessment

4.2.1. Risk 1: Revenue model

This risk relates to the exposure of an asset's revenue stream to unexpected fluctuations. This depends primarily on the extent to which future revenues are exposed to wholesale market prices, or secured through long-term contracts.

In the NEM, generation and storage assets may adopt a range of revenue models for the electricity that they produce. These include models that rely on long-term power purchase agreements (PPAs) – i.e., where the asset sells its output to an off-taker at a pre-determined price. At the other end of the spectrum are merchant models, where the asset is largely reliant on revenues generated through the wholesale electricity market at the prevailing market price. Combinations of these broad approaches are also possible; for example, an asset may contract for a substantial portion of its output while leaving a residual merchant exposure. Alternatively, vertically integrated companies with generation/storage and retail portfolios may back new investments with their retail customer base.

All else equal, contracts that provide long-term revenue certainty reduce risk for the asset, by lowering its exposure to uncertain future wholesale market prices.[19] This effect may be particularly significant for standalone variable renewable generators, who are unable to determine when they generate due to their reliance on wind and solar conditions. Unsurprisingly, this suggests that projects that can achieve greater revenue certainty through long-term contracts are more likely to have a lower cost of capital, all else equal. Supporting evidence for this claim is outlined in Table 4.1.[20]

Table 4.1: Evidence of the impact of revenue models on WACC

Source	Evidence
Gohdes and Simshauser (2022)	This recent study of the cost of capital for Australian renewable generation projects found that compared to a fully merchant project:[21] • For a project with a partial corporate or retail PPA, the required equity return is 2.5% lower, the required credit spread 60 basis points lower, and gearing 16% higher . • For a project with a full corporate or retail PPA, the required equity return is 4.25% lower, the required credit spread 80 basis points lower, and gearing 26.75% higher. Translating the differentials reported by Gohdes and Simshauser to pre-tax real terms implies an overall WACC uplift of 3.7% to 5.4% for a merchant project (relative to partial / full contracting).[22] In this paper, a partial PPA covered 50% of the asset's output, while a full PPA covered 100% of output. Our central case pre-tax real WACC estimate (7.5%) may reflect somewhere between a partly and fully contracted project. Accordingly, the upper end of the range is likely to overstate the difference between a typical project and a merchant project.
Moody's credit rating methodologies	The stability of cash flows is an important consideration in determining the credit rating (and therefore cost of debt) of a generation project (Appendix A.2). For example, Moody's rating methodology for power generation projects indicates that fully contracted cash flows that extend beyond the financing term are consistent with ratings of Baa and above (i.e., consistent with an S&P rating of between BBB- to BBB+).[23] This suggests that our central case cost of debt assumption (based on a BBB rating) is broadly consistent with a relatively contracted project. Accordingly, a cost of debt uplift may be appropriate for less contracted projects.

[19] Europe Economics (2018), *Cost of Capital Update for Electricity Generation, Storage and Demand Side Response Technologies*, November; NERA (2015), *Electricity Generation Costs and Hurdle Rates Lot 1: Hurdle Rates update for Generation Technologies*, July.

[20] In addition to these publicly available sources, we also considered the Aurora Energy Research 2023 March Market Consensus Survey. This provided survey evidence as of Q1 2023 on WACC differentials between a project with a 10-year corporate PPA and a fully merchant project. This is subscriber-only content that we cannot cite in this report. However, we consider that this evidence is broadly consistent with the assumptions we have adopted for the WACC difference between a typical solar PV / wind project and a merchant project.

[21] Gohdes and Simshauser (2022), *Renewable entry costs, project finance and the role of revenue quality in Australia's National Electricity Market*, Centre for Applied Energy Economics & Policy Research Working Paper Series, January 2022, p 8.

[22] We have assumed that the cost of equity impacts reported in Gohdes and Simshauser (2022) refer to a post-tax nominal cost of equity.

[23] Moody's (2022), *Rating Methodology – Power Generation Projects*, 12 January 2022, p.37. Stability of cash flow is just one of the factors contributing to the overall credit rating.

Source	Evidence
Investor survey results	As outlined in Appendix D, respondents to the survey commented that moving from a (partly) contracted revenue model to a merchant one would increase the cost of capital: • 1.0-2.0% uplift in the cost of equity (fully/partly contracted vs fully merchant). • 2.0-2.8% uplift in the cost of debt (fully/partly contracted vs. fully merchant). • 1.5-3.0% uplift in the overall pre-tax real hurdle rate (partly contracted vs. fully merchant). It is not always clear what baseline the survey responses were starting from (i.e., whether the point of comparison was a partly or fully contracted project, or precisely what respondents meant by 'partly contracted').
Oxford Economics (2023)	The cost of capital survey recently undertaken by Oxford Economics to inform the 2024 ISP reported a risk premium of c. 2.5% for merchant risk exposure. However, it is not clear what this estimate was relative to.
Grant Thornton (2019)	A 2018 survey conducted by Grant Thornton found that across solar, wind and hydro projects, 50% of respondents would apply less than a 2.0% adjustment for projects with 100% merchant exposure. Again, the reference point was not stated.[24]

There is evidence of differences in the revenue models currently adopted for particular technologies. For wind and solar PV projects, a PPA has been common for recent investments. For example, CEPA's analysis of new project-financed solar and wind developments reaching financial close between 2018-2022 indicates that a majority had a PPA in place, with a weighted average PPA duration of 10 years (including projects with and without PPAs).[25] The sole exception for wind, the Victorian Golden Plains wind farm, has received considerable attention as the first fully merchant Australian wind farm to be financed by commercial lenders (albeit facilitated by a commitment from the Clean Energy Finance Corporation), highlighting the relative novelty of this model for wind in the NEM generally.[26] Indeed, the Golden Plains project has since signed a PPA with Snowy Hydro for 40 per cent of its output and green certificates, with further contracts under negotiation.[27] This suggests that long-term PPAs are a relatively established business model for solar PV and onshore wind. This may also carry over to new offshore wind projects in Australia.

However, this is less true of the other technologies of interest to ASL. Due to the types of services they provide, batteries (short and long-duration), pumped hydro and OCGT assets may have revenue models that are more complex and less tried-and-tested relative to solar PV and wind. In particular, these assets are more likely to have complex or bespoke revenue models that rely on multiple revenue streams, including (for example) short-term forward contracts, ancillary services, and contracts for network support services. As outlined for Risk 4 below, certain revenue models may also change operational risks.

The impact of novel revenue models on financing arrangements is illustrated by the Clean Energy Finance Corporation's (CEFC) role in financing grid-scale battery projects in Australia. For example, the CEFC has noted that *"similar to when the renewables sector was first getting established in Australia, the lending market has been somewhat hesitant to debt-fund standalone battery projects with merchant exposure. […] Large energy projects of this scale require substantial tailored investment solutions, reflecting their high start-up capital costs and emerging*

[24] Grant Thornton (2019), *Renewable energy discount rate survey results – 2018*, January 2019, p.7.

[25] CEPA reviewed the IJ Global transaction database to identify wind developments reaching financial close between 2018 and 2022, and then used a range of publicly available sources to identify contracting arrangements for these projects. Our results suggested that more than 60% of solar projects and 93% of wind projects had a PPA in place, or 73% of all projects. For projects with a PPA, the average duration was 13.5 years, or 13.25 years excluding government PPAs. Combining the average PPA duration with the proportion of projects with a PPA produces a weighted-average PPA duration of around 10 years.

[26] Clean Energy Finance Corporation (CEFC) (2022), *Media release – CEFC targets biggest emissions abatement in largest wind farm investment*, 30 November 2022.

[27] See https://www.snowyhydro.com.au/news/tagenergy-and-snowy-hydro-ink-momentous-renewable-power-purchase-agreement/, accessed 13 November 2023.

and untested revenue models."[28] The Capital Battery project – with an innovative revenue model combining a virtual offtake agreement, energy arbitrage and FCAS – represented the first time the CEFC introduced a co-lender to a battery project, having previously provided debt financing to battery projects on a sole basis.[29]

Our assessment of a material difference in the revenue models commonly adopted by different technologies is supported by evidence from investors surveys, as summarised in Table 4.2.

Table 4.2: Evidence of the 'typical' revenue model for different technologies

Source	Evidence
Investor survey	Survey responses (Appendix D) identified that contracted revenue models were most frequently considered common for solar PV and onshore wind. In comparison, the predominant response for batteries was a combination of contracted and merchant revenue models. Qualitative commentary received from survey participants also reflected technology-specific revenue model differences: • *"Banks take different views (and apply different risk margins) on battery's merchant risks which involve arbitrage trading activities."* • One respondent noted that their "[…] *perceived differences in debt cost reflected assumptions on the 'typical' contracting structure where wind and solar are heavily contracted and batteries are more merchant exposed."* • Another commented that "[v]*olatility in FCAS services affects the hurdle rate for BESS."*
Oxford Economics (2023)	Similar commentary was provided in the cost of capital survey recently undertaken by Oxford Economics to inform the 2024 ISP.[30] Their survey findings included that battery storage faces revenue uncertainty, owing to its status as a relatively nascent technology in Australia. In contrast, wind and solar PV were considered to be more mature technologies, whose revenue risk is partly mitigated through contracted off-take agreements, resulting in a relatively lower cost of capital.

Conclusion: In Australia, solar PV, onshore wind and offshore wind projects are more likely to have a revenue model that supports a lower cost of capital, relative to batteries (long and short duration), pumped hydro, and OCGT.

4.2.2. Risk 2: Construction risk

Construction risk arises from the possibility of delays in completing construction, in addition to the risk of unexpected escalation in construction costs.

For renewable generation and storage projects, a significant proportion of the overall project costs are up front, and uncertain or lengthy development durations can significantly impact their overall risk profile.[31] Construction risk is therefore impacted by the length and complexity of the pre-construction and construction period,[32] and the maturity of the underlying technology.

Assumptions around expected construction timeframes vary with the size of the project, and by technology:

[28] CEFC (2023), *ACT Gets a Capital Battery Financing – PFI Special Reports*, 17 January 2023, p.36.

[29] Ibid.

[30] Oxford Economics (2023), *Cost of Capital Survey 2023 – Report produced for the Australian Energy Market Operator*, 29 June 2023.

[31] Clapin, L. and Longden T. (2022), *Waiting to generate: an analysis of wind and solar project development lead-times in Australia's National Electricity Market*, ZeroCarbon Energy for the Asia-Pacific ZCEAP Working Paper ZCWP07-22, p.2.

[32] Feldman (2020).

- CSIRO notes construction times for pumped hydro of 3-7 years, while battery construction times varied from 0-5 years, with shorter duration batteries typically requiring shorter construction times.[33]
- The US Energy Information Administration (EIA) has ranked electricity generation technologies from shortest to longest lead times as follows: batteries (1 year), solar PV (2 years), onshore wind and gas turbines (3 years), and offshore wind (4 years).[34]

In relation to construction complexity:

- The investor survey (Appendix D) found that relative to onshore wind, offshore wind was considered likely to be more affected by resource, construction and commissioning risk given the nascent development of the technology in Australia. Respondents also commented that the cost of capital for pumped hydro was affected (increased) by construction risk associated with geological conditions and commissioning risk.
- Oxford Economics' 2023 survey for the ISP found that Australian industry stakeholders consider construction risk to be more prominent for pumped hydro, owing to geological concerns. This was considered to imply a higher cost of capital relative to other technologies.[35] Further, the presence of a greater number of commercial transactions provided better planning and construction benchmarks for certain technologies (onshore wind, solar PV) relative to others.[36]
- Another published study reported that the construction complexity of wind farms was slightly higher than for solar PV, and offshore windfarms were more complex than onshore windfarms.[37]
- Credit rating agency Moody's has commented (albeit in a US context) on the impact of construction and execution risk associated with offshore wind developments, noting more numerous permitting, financial and environmental risks relative to onshore assets.[38]

Construction risk is also related to the maturity of a technology, where construction delays or cost increases may be more likely for assets with limited prior local construction experience.[39] From this perspective, limited experience in the development of offshore wind projects in Australia may translate to a higher level of planning and construction risk for this technology type. Although experience with grid scale batteries and pumped hydro is growing, there are fewer local benchmarks for these projects relative to solar PV and onshore wind.

Differences in construction risk have contributed to reported differences in hurdle rates for offshore wind as compared to onshore wind and solar PV, summarised in Table 4.3.

Table 4.3: Findings of past studies in relation to hurdle rate differentials for onshore wind and offshore wind

Source	Evidence
NERA (2015)[40]	NERA reported pre-tax real hurdle rates of 8.2% for onshore wind and 10.4% for offshore wind (2.2% differential). Responses to the survey conducted by NERA reported that:[41]

[33] CSIRO (2023), *Renewable Energy Storage Roadmap*, March, pp.47 – 52.

[34] EIA (2022), *Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022*, March. Note the estimate for OCGT is a closed cycle gas turbine and estimate for pumped hydro is conventional hydropower.

[35] Oxford Economics (2023), p.6.

[36] Ibid., p. 17.

[37] Feldman (2020)

[38] Moody's (2019), *Research Announcement: Experienced ownership, contractual protections offset US offshore wind sector's risks*, 18 November 2019.

[39] Maturity may also impact risks in the operational period, which we consider separately under Risk 4 below.

[40] NERA (2015), *Electricity Generation Costs and Hurdle Rates*, July 2015, p.

[41] Ibid., p.34.

Source	Evidence
	• 40% of respondents considered construction risk to be relevant for onshore wind, compared to 100% for offshore wind. • 7% of respondents considered technology maturity risk to be relevant for onshore wind, compared to 61% for offshore wind. • Other risks may have contributed to the difference, including policy risk related to support mechanisms for offshore wind.
Europe Economics (2018)[42]	Europe Economics reported pre-tax real hurdle rates of 5.2% for onshore wind and 6.3% for offshore wind (1.1% differential). Their report noted that offshore wind was considered to be a less established technology, and to have more pronounced development and construction risks relative to onshore wind and solar PV.[43]
US National Renewable Energy Laboratory (2020)[44]	NERL report a +1% differential in the post-tax cost of equity for offshore wind relative to onshore wind (although the same cost of debt), for both the construction and operation period.[45] Applied to our central case pre-tax real estimate, this implies an increment of +0.6% to the overall hurdle rate. Their report cites inherently greater construction risk (which is also considered to apply to hydropower and geothermal technologies).
Grant Thornton (2019) [46]	Overall, Grant Thornton's survey found that: • Offshore wind was considered to be risker than solar PV across survey respondents. This trend was consistent internationally. • Survey respondents considered offshore wind projects to be riskier than onshore wind projects. This finding was consistent across every jurisdiction where onshore and offshore wind could be compared.
International Renewable Energy Agency (IRENA) (2023)[47]	IRENA report international WACC ranges for renewable energy technologies, primarily based on survey evidence. In jurisdictions where offshore wind has been more widely deployed than Australia, they report a relatively narrow difference between the average response for offshore and onshore wind (all post-tax nominal): • In China: solar PV 3.9%, onshore wind 3%, offshore wind 2.8%. • In other Asia-Pacific countries: solar PV 6.1%, onshore wind 7.2%, offshore wind 7.1%. • In Western Europe: solar PV 4%, onshore wind 3.3%, offshore wind 4.2%. • In North America: solar PV 5.4%, onshore wind 5.1%, offshore wind 5.2%.

It is important to note that:

- The effect of construction risk is time limited – once the project is operational, any construction-related risks have been realised. Nonetheless, this risk still contributes to the whole-life cost of capital for an asset.
- Where this risk is exacerbated by the relative immaturity of a given technology, it is reasonable to expect that this effect may diminish as local experience with cost estimation and project delivery increases.[48] Therefore, over time we might expect to see more muted hurdle rate differentials reported for offshore wind relative to onshore wind in Australia.

[42] Europe Economics (2018), *Cost of Capital Update for Electricity Generation, Storage and Demand Side Response Technologies*, November 2018.

[43] Ibid., p.34.

[44] NERL (2020), *Current and Future Costs of Renewable Energy Project Finance Across Technologies*, July 2020.

[45] Ibid., p. vii. We have assumed that their estimates are presented in nominal terms.

[46] Grant Thornton (2019).

[47] IRENA (2023), *The cost of financing for renewable power*, pp.10-11.

[48] For example, see IRENA (2023) p.15.

Based on the analysis set out above, we have developed a ranking from lowest (left) to highest (right) of how construction risk varies across technologies (noting that the magnitude of the difference is unknown).

Technology	Time to construct	Complexity to construct (1= low; 3 = high)	Recent local experience (1= high; 3 = low)	Overall construction risk
Solar PV	2 years ↓	1 – low ↓	1 – high ↓	↓ ↓ ↓ low
Onshore wind	3 years →	2 – medium →	1 – high ↓	→→ ↓ medium
Offshore wind	4 years ↑	3 – high ↑	3 – low ↑	↑ ↑ ↑ high
Batteries (short)	0 – X years ↓	1 – low ↓	2 – medium →	↓ ↓ →medium
Batteries (long)	X – 5 years ↑	2 – medium →	2 – medium →	↑ →→high
OCGT	3 years →	2 – medium →	2 – medium →	→→→medium
Pumped hydro	3 – 7 years ↑	3 – high ↑	3 – low ↑	↑ ↑ ↑ high

Conclusion: In Australia at the time of writing, construction risk is likely to be more pronounced for pumped hydro and offshore wind, relative to other technologies. Onshore wind, batteries, and OCGT may carry more construction risk relative to solar PV – although we expect this differential to be more muted, given that there is some local experience of developing all these technologies.

4.2.3. Risk 3: Policy risk

This risk relates to the potential for policy changes that alter future returns once resources have been committed to the project. We have identified two potential areas where policy risk may differ across technologies: for OCGT in relation to carbon emissions reduction policies; and for OCGT, pumped hydro and batteries in relation to future markets for electricity services.

Federal and state governments have signalled support for renewables and low-carbon firming assets as a mechanism to decarbonise Australia's energy sector and achieve net-zero targets. For more carbon intensive firming technologies, such as OCGT, there may be a higher risk that policy decisions to support emissions reduction restrict or erode their business model over time. Commentators have highlighted this issue in relation to recent electricity market design decisions.[49] Although this issue did not feature in responses to CEPA's survey, respondents to Oxford Economics' 2023 survey considered that fossil fuel investments have a higher risk premium, reflecting policy risk and a lower investment appetite generally.[50] As noted in Appendix A.2, exposure to environmental risk is considered a relevant factor in credit rating methodologies.

Several early studies (2015 and earlier) on technology-specific WACC differences have noted policy risk as a prominent factor influencing the cost of capital for renewable energy projects, primarily due to uncertainty in relation to government support schemes.[51] However, few later reports discussed this risk, or found that it was decreasing over time.[52] While this issue may no longer be substantial for variable renewable technologies such as wind and solar PV, it may remain relevant for storage and firming technologies. In particular, the revenue models for these technologies may be subject to ongoing policy uncertainty, given continued evolution in the NEM wholesale

[49] For example, the Australian Financial Review has reported comments by Dr Kerry Schott, former chair of the ESB, criticising the Victorian State Government's preference to exclude gas from the national capacity mechanism that was (at the time) being developed by the ESB. The ESB had previously recommended the inclusion of gas in the mechanism, to ensure sufficient firming capacity. Ludlow, M. (2023), *States hit for 'demonising' gas*, AFR, 28 February 2023.

[50] Oxford Economics (2023), p.7.

[51] Oxera (2011); NERA (2013); BMWI (2014); Zalewska (2015), *Comments of the NERA's Report "Electricity Generation Costs and Hurdle Rates"*.

[52] Egli (2020).

market design. For example, uncertainty remains around the future operation of the Capacity Investment Scheme[53] and the outcomes of ongoing AEMC reviews into markets for inertia[54] and other services that these flexible technologies could provide. However, this issue was not commented on in our investor survey, or the survey conducted by Oxford Economics.

Conclusion: Policy risk may be elevated for OGCT, batteries (long and short) and pumped hydro, given ongoing evolution of carbon emission reduction policies and future electricity market design. However, the evidence that this risk is material is less compelling than for Risks 1 and 2.

4.2.4. Risk 4: Technology maturity risk (operation period)

Technology maturity risk arises from unforeseen underperformance or higher maintenance costs due to a technologies' novelty or unpredictability. This risk was frequently referenced within the reports and studies that we reviewed.[55]

Broadly speaking, technologies that have more established local operating track records over multiple years, such as solar, onshore wind, and OCGT can be considered to have a higher level of maturity relative to offshore wind, batteries, and pumped hydro.

This risk did not particularly feature in the results of the investor survey conducted for this report, or the survey conducted by Oxford Economics. One respondent to CEPA's survey commented that pumped hydro assets have been deployed for decades and have longer lives relative to standard battery storage assets. They further noted that while batteries have been deployed recently in Australia, they may have certain operating risks depending on how they are utilised.

This reflects the commentary of some credit rating agencies in relation to how the operation of battery storage systems can affect their risk profile. For example, Fitch has commented that arbitrage revenue models may mean that batteries could face more rapid degradation and higher volatility in capital expenditure requirements, relative to renewable generators and thermal peaking plants.[56] Fitch suggested that battery systems that operate in this way may need to achieve stronger financial metrics to achieve a given credit rating, relative to other technologies (pointing to a potentially higher cost of debt, all else equal). Similarly, Moody's has commented on elevated cash flow risk for battery storage assets that combine contracted and merchant revenues, due to the risk of more rapid asset degradation.[57]

Conclusion: Technology maturity risk may be more pronounced for batteries (long and short), pumped hydro and offshore wind relative to other technologies. However, the evidence that this risk is material is less compelling than for Risks 1 and 2.

4.2.5. Risk 5: Fuel price risk

Fuel price risk reflects an asset's exposure to fuel input prices over the life of a project, such as the exposure of an OCGT asset to gas prices.[58] However, generators may enter into a combination of long-term and short-term

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[53] https://minister.dcceew.gov.au/bowen/media-releases/capacity-investment-scheme-power-australian-energy-market-transformation

[54] https://www.aemc.gov.au/rule-changes/efficient-provision-inertia

[55] Europe Economics (2018); Egli (2020), *Renewable energy investment risk: An investigation of changes over time and the underlying drivers,* Energy Policy, volume 140, p. 1111428; Fraunhofer ISP (2018), *Levelized cost of electricity renewable energy technologies*, March; Oxera (2011), *Discount rates for low-carbon and renewable generation technologies,* Prepared for the committee on climate change, April; BMWI & GIZ (2014), *Estimating energy system costs of sectoral RES and EE targets in the context of energy and climate targets for 2030*

[56] Fitch (2023), *Battery Storage Using Arbitrage May Face Rapid Asset Degradation*, 13 July 2023.

[57] Reported in Utility Dive (2018), *Project finance getting more viable for energy storage, Moody's says*, 21 March 2018.

[58] While OCGT in Australia relies on natural gas as the predominant fuel source, liquefied petroleum gas, refinery gas, gas oil, diesel, naphtha, and light crude can also be used.

contracts to source their fuel requirements and manage fuel price risk. Risk management may also be achieved through vertical integration (i.e., as both a gas producer and operator of gas-fired power stations). One report noted that the absence of fuel risk for renewable projects lends itself to having longer electricity contracts[59] which suggests that OCGT may have increased risk related to its revenue model as a result (consistent with our other findings in relation to Risk 1).

One respondent to CEPA's survey commented that OCGT has higher fuel costs relative to other technologies, which was a consideration for project hurdle rates.

Conclusion: OCGT assets may be subject to more fuel-price risk than renewable and storage technologies. However, the evidence that this risk is material is less compelling than for Risks 1 and 2.

4.2.6. Risk 6: Concentration and curtailment risk

Concentration risk relates to the inability of variable renewable generators to control their output in response to electricity prices. Without onsite storage, these generators can only produce electricity when the sun is shining or the wind is blowing, which may not perfectly correlate to hours of peak electricity demand. Respondents to both the CEPA and Oxford Economics surveys highlighted this risk in relation to solar PV:

- A respondent to CEPA's survey noted that solar PV was higher risk than onshore wind due to concentration risk and the increasing prevalence of rooftop solar systems creating competition during peak solar generation hours, resulting in more exposure to negative wholesale market pricing. Comparatively, onshore wind was considered to have less correlation with rooftop solar PV output and able to participate in peak demand periods.
- Oxford Economics noted that concentration of solar output and subsequent negative prices is emerging as a revenue risk for this technology.[60]

A related issue is the risk of curtailment. Curtailment occurs when system security or other operability constraints on the network restrict the usage of available generation output, or when there is surplus renewable energy available. AEMO's 2022 ISP suggests that curtailment related risk may primarily affect variable renewable generators: "[a]*ssuming there is sufficient transmission, most of the spill identified in the ISP modelling would be wind utility-scale wind and solar become direct competitors for dispatch* […] *At these times there is simply not enough operational demand to utilise all available renewable resources.* […] *Curtailment or spill of VRE generation is forecast to occur when there is higher solar generation: during daylight hours and during spring and summer."*[61]

In practice, concentration risk may be partly mitigated by contracts that fix the prices for solar PV output (although some merchant exposure may remain). Combining intermittent generators with on-site batteries may help to address both concentration and curtailment risk.

Conclusion: Solar PV may be more exposed to concentration and curtailment risk than other technologies. However, the evidence that this risk is material is less compelling than for Risks 1 and 2, given the availability of mitigants.

4.2.7. Risk 7: Congestion risk

Congestion risk relates to the unexpected curtailment of an asset's electricity output due to physical limits on the transmission network. CEPA's 2023 report for the Energy Security Board on the cost of capital impacts of

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[59] D. Feldman, M. Bolinger, and P. Schwabe (2020), *Current and Future Costs of Renewable Energy Project Finance Across Technologies*, National Renewable Energy Laboratory

[60] Oxford Economics (2023), p.7.

[61] AEMO (2022), Integrated system plan 2022, final report, p.46.

transmission access reform found that reduced exposure to future congestion may reduce downside risk and increase expected cash flows – pointing to a downwards impact on risk factors that affect the cost of debt.[62]

In the first instance, congestion risk is impacted primarily by location on the transmission network and the overall utilisation of available network capacity by other market participants. However, there may be a technology-specific dimension, in that standalone variable renewable generators may be less able to manage congestion risk by adjusting their operating strategy (as may be the case for dispatchable technologies).

The materiality of this effect may be impacted by future transmission network build (including the development of REZ) and policy reforms to better enable investors to manage the risks associated with congestion. This risk was not highlighted in our investor survey, or the survey conducted by Oxford Economics to inform the 2024 ISP.

Conclusion: Variable renewable generators may be more exposed to congestion risk. However, the evidence that this risk is material is less compelling than for Risks 1 and 2.

4.2.8. Summary

In summary, our conclusions from the risk assessment are that:

- Solar PV, onshore wind and offshore wind projects are more likely to have a revenue model that supports a lower cost of capital, relative to batteries (long and short duration), pumped hydro, and OCGT.
- Planning and construction risk is likely to be most elevated for pumped hydro and offshore wind, relative to other technologies. Onshore wind, batteries, and OCGT may carry more construction risk relative to solar PV – although we expect this differential to be more muted, given that there is local experience of developing all these technologies.
- Policy risk may be elevated for OGCT, batteries (long and short) and pumped hydro, given ongoing evolution of carbon emission reduction policies and future electricity market design. However, the evidence that this risk is material is less compelling than for Risks 1 and 2.
- OCGT assets may be subject to more fuel price risk than renewable and storage technologies. However, the evidence that this risk is material is less compelling than for Risks 1 and 2.
- Solar PV may be more exposed to concentration and curtailment risk than other technologies. However, the evidence that this risk is material is less compelling than for Risks 1 and 2.
- Variable renewable generators may be more exposed to congestion risk than dispatchable generation technologies. However, the evidence that this risk is material is less compelling than for Risks 1 and 2.

Table 4.4 summarises our qualitative risk analysis and the relative differences across technologies. Green indicates a relatively lower risk exposure, while red indicates a relatively higher risk exposure. Apart from revenue model risk and planning and construction risk (Risks 1 and 2), we consider that the evidence of other risks materially impacting the cost of capital is less compelling.

Table 4.4: Summary of qualitative risk assessment

Risk	Solar PV	Wind onshore	Wind offshore	Batteries short	Batteries long	Pumped hydro	OCGT
Revenue model	Green	Green	Green	Red	Red	Red	Red
Construction	Green	Green	Red	Green	Green	Red	Red
Policy	Green	Green	Green	Red	Red	Red	Red
Technology maturity	Green	Green	Red	Red	Red	Red	Green

[62] CEPA (2023), *Transmission access reform – Cost of capital impact*, 7 February 2023, pp.5-6.

Risk	Solar PV	Wind onshore	Wind offshore	Batteries short	Batteries long	Pumped hydro	OCGT
Fuel price							
Concentration and curtailment							
Congestion							

4.3. Conclusions

Drawing together the analysis in the preceding sections, below we present our proposed WACC estimates for each technology. We report on:

- **Technology specific point estimates** (Section 4.3.1), which we consider appropriate for use in ASL's modelling. Consistent with the principles set out in Section 1.3, the estimates aim to reflect only the most well-evidenced differences that are likely to persist over time. The estimates are deliberately stylised, with a view to proposing assumptions that are 'roughly right' rather than 'precisely wrong'.
- **Technology specific ranges (Section 4.3.2).** These ranges reflect larger differences between technologies compared to the point estimates, acknowledging that in practice WACCs may vary materially both across and within asset types. For modelling purposes, we suggest that ASL places less reliance on the ranges than on the point estimates. This reflects our view that it is not appropriate to apply strong assumptions on technology specific differences given the quality of the available evidence. For example, although the ranges show a wider range for pumped hydro and offshore wind assets, this is informed by only a handful of survey responses.
- **Merchant estimates (Section 4.3.3).** The estimates set out in Sections 4.3.1 and 4.3.2 reflect a view on the most common, or average, revenue model for the various technologies. We also provide estimates that assume a merchant revenue model. These estimates inform our analysis of LTESAs in Section 5.

4.3.1. Technology specific point estimates

The table below presents our proposed WACC estimates for each technology. These assumptions reflect a view on the most common, or average, revenue model for the various technologies.

Table 4.5: Pre-tax real WACC estimates by technology type ('typical' revenue model)

Technology	WACC assumption (pre-tax, real)	Rationale
Solar PV, onshore wind	7.5%	We consider that our update of the Synergies' central case estimate represents a reasonable anchor point for solar PV and onshore wind. This is evidenced by: • The results from our survey of investor views on WACC, which suggested an average pre-tax real WACC of 7.8% for onshore wind and 7.6% for solar PV. The cost of debt and equity reported in the survey were respectively consistent with, or lower than, the technology neutral estimate. • The results of Oxford Economics' survey, which suggest a median pre-tax real WACC of approximately 6% for solar PV and onshore wind. This suggests that the central case estimate is at least adequate for these technologies. • Our asset beta comparator sample, on which the central case is based, mainly reflects investments in these technologies (Appendix B.6). • Our qualitative assessment suggests that while onshore wind may face a higher level of construction related risk compared to solar PV, solar PV could experience higher levels of concentration and curtailment risk. On balance, we have not identified strong evidence of a material difference between these technologies. This includes our review of survey evidence, evidence from listed asset beta comparators (Appendix B.7) and independent expert reports (Appendix C).
Batteries (short duration), batteries (short duration), OCGT	8.5%	We consider that a 1% uplift to the solar/onshore wind estimate is reasonable for these technologies. This is evidenced by: • Our qualitative analysis, which suggests that these technology types are likely to face higher risk associated with their revenue model (due to novelty, complexity, and policy-related risk). • Our qualitative assessment suggests that OCGT may face additional risk related to carbon emission policy uncertainty and fuel price risk. However, batteries may face a higher level of risk associated with the relative immaturity of this technology (particularly when operated in line with a more complex revenue model). On balance, we do not consider that the evidence supports making a strong assumed distinction between these technology types. • The results from our investor survey. These support a view that there is a material difference in the risk of the typical revenue model for these technologies, relative to onshore wind and solar PV. In addition: ○ Respondents that commented on the difference in overall hurdle rates between solar/onshore wind and these technologies suggested increments of +0.6%.

Technology	WACC assumption (pre-tax, real)	Rationale
		o Respondents noted average cost of debt / equity increments of 1.7% and 1.4% for these technologies. In combination, these imply an overall pre-tax real WACC uplift of +1.7%. • Oxford Economics' investor survey, which suggested approximately a 1.5% difference between median results for onshore wind / solar PV and batteries/storage.[63] • This assumption is broadly consistent with the effect of adopting an asset beta taken from the 75th per centile of our sample distribution (0.6, compared to 0.5 in the central case – see Appendix B.7). This produces an 0.8% uplift in the overall pre-tax real WACC, which when combined with an increment to the cost of debt supports our proposed uplift.
Offshore wind	8.5%	We consider that a 1% uplift to the solar/onshore wind estimate is reasonable for offshore wind. This is evidenced by: • Our qualitative analysis, which suggests that offshore wind faces a higher level of planning and construction risk relative to onshore wind / solar PV. This reflects offshore wind's relative immaturity in Australia, which may reduce over ASL's planning horizon. • The results from the investor survey. We have not reported the offshore wind results separately due to the limited number of responses. When aggregated with pumped hydro and OCGT, the survey indicated a hurdle rate uplift of 2.3% compared to solar PV / onshore wind – however, this result reflects the combined impact of all three technologies. • The results of surveys undertaken in other jurisdictions, which suggested a +1% increment between onshore and offshore wind (related to construction risk) – see Section 4.2.2. This includes the 2023 estimates provided by IRENA, which report a less than 1% difference in some jurisdictions (e.g., North America). • As noted for batteries and OCGT, this assumption is broadly consistent with adopting an asset beta taken from the 75th per centile of our sample distribution, plus an increment to the cost of debt.
Pumped hydro	10.0%	We consider that a 2.5% uplift to the solar/onshore wind estimate is appropriate for pumped hydro. This reflects a 1% uplift related to revenue model risk (which we consider to be broadly similar to batteries and OCGT) and a further 1.5% uplift related to construction risk (which we have assumed is above that of offshore wind). The larger uplift for construction risk also reflects the investor survey responses, which although limited in number, place the WACC for pumped hydro above offshore wind. Other considerations include that:

[63] Oxford Economics (2023), p.6.

Technology	WACC assumption (pre-tax, real)	Rationale
		• Qualitatively, the investor survey results consistently ranked pumped hydro at the top end of the cost of debt and overall hurdle rate. • The 2.5% increment results in an overall WACC of 10.0%. This is close to the aggregate result for pumped hydro, offshore wind and OCGT – although we note that this reflects the combined impact of all three technologies. 10.0% is well below the top of the range (14.0%). Given the limited number of responses, we do not consider it is appropriate to place too much weight on the upper range of the responses.

4.3.2. Technology specific ranges

The table below provides WACC ranges by technology. These are drawn from the investor survey results presented in Section 3. The ranges are intended to acknowledge the possible breadth of WACCs that investors may apply in practice. However, as noted above we consider the ranges are less suitable for ASL's modelling than the point estimates in the preceding section.

Table 4.6: Technology specific ranges

Technology group	Base case	Low case	High case	Comment
Onshore wind / solar PV	7.5%	-1.5% (6.0%)	+1.5% (9.0%)	Range based on survey results (spread around mid-point).
Batteries (long / short duration) and OCGT	8.5%	-1.5% (7.0%)	+1.5% (10.0%)	The range maintains the relativity to onshore wind / solar.
Offshore wind	8.5%	-1.0% (7.5%)	+2.0% (10.5%)	The range increases the spread above onshore wind / solar in low and high cases – acknowledging the survey results.
Pumped hydro	10.0%	-1.0% (9.0%)	+2.5% (12.5%)	The range increases spread above onshore wind / solar in low and high cases – acknowledging the survey results.

4.3.3. Merchant estimates

The table below presents our view on appropriate WACC assumptions for each technology, this time assuming that they are based on a purely *merchant* revenue model.

Table 4.7: Pre-tax real WACC estimates by technology type (merchant revenue model)

Technology	WACC assumption (pre-tax, real)	Rationale
Solar PV, onshore wind	9.0%	We consider that a 1.5% increment is a reasonable estimate of how the WACC may change when moving from an onshore wind / solar PV project with a 'typical' revenue model to a fully merchant model. This is based on the sources of evidence outlined in Section 4.2.1. This reflects an assumption that the 'typical' model for onshore wind and solar PV is a relatively (but perhaps not fully) contracted project – for example, holding a PPA of 10-15 years, covering the majority of the projects' output.
Batteries (short duration), batteries (short duration), OCGT	9.0%	We have proposed a 0.5% increment compared to the 'typical project' assumption. This reflects: • The results of the investor survey, which suggested that these assets tend to have some degree of contracting (albeit less than solar PV and wind). • That the 1% differential assumed between these technologies and solar PV / onshore wind in the 'typical project' case (Table 4.5 above) primarily reflects differences in their revenue model. Accordingly, applying an 0.5% increment aligns the WACC estimate across these technologies. • This implies that other risk differences are less material – which is consistent with our qualitative conclusions in Section 4.2.8.
Offshore wind	10.0%	We have proposed a 1.5% increment compared to the 'typical project' assumption. The reasons are as given for solar PV and onshore wind, as we have assumed that the revenue models that are common for these technologies will tend to translate to offshore wind projects in future. The remaining 1% differential to solar PV and onshore wind reflects the allowance we have made for construction risk.
Pumped hydro	10.5%	We have proposed a 0.5% increment compared to the 'typical project' assumption. The reasons are as given for batteries and OCGT. The remaining 1.5% differential to solar PV and onshore wind reflects the allowance we have made for construction risk.

5. IMPACT OF LTESAS

In this section we assess the potential impact of LTESAs on the technology-specific WACC ranges set out in Section 3. We have considered two sources of evidence:

- Qualitative risk analysis.
- The survey of debt and equity providers.

5.1. WHAT ARE LTESAS?

The NSW Electricity Infrastructure Roadmap allows developers of eligible generation, long-duration storage (LDS) and firming projects to secure long term energy services agreements (respectively generation, LDS and firming LTESAs) that reduce exposure to low wholesale electricity market prices. The characteristics of generation and LDS LTESAs are outlined below. We have assumed that firming LTESAs are similar to LDS LTESAs, based on the firming tender guidelines published by ASL.

5.1.1. Generation LTESAs

An LTESA provides a series of long-term options to enter into swaps. If the option is exercised, the swap allows the holder of an LTESA to receive a fixed strike price ($/MWh) in exchange for the variable wholesale electricity market price. More specifically:

- The contract term will be up to 20 years, providing a series of options to enter into 2-year swaps.
- The swap is generation following (i.e., the volume matches the actual MWh output of the LTESA holder).
- The counterparty for the LTESA is the Scheme Financial Vehicle (SFV), rated Aa3 by Moody's.
- The strike price is a fixed nominal value (not escalating).

In periods where the LTESA holder has not exercised an option, it may be required to repay the SFV an amount up to the cumulative net swap payments it has received up to that point. The repayment mechanism applies if the project's dispatch-weighted average wholesale market price exceeds a specific repayment threshold price ($/MWh). Our understanding is that:

- The generation project will nominate the LTESA strike price and the repayment threshold price in its bid.
- Repayments will not lead to total net revenues per unit of output being less than the LTESA strike price.
- The repayment threshold price should provide the LTESA holder sufficient cash flow to meet its debt service and operating expense requirements in any period.
- Repayments are intended to be reduced if the LTESA holder has entered into a contract for its output (e.g., a PPA), such that the repayment mechanism does not interfere with the settlement of that contract. The drafting of the LTESA provided for Tender Round 3 (which ran in 2023) indicates that repayments will not be required in respect of electricity generation that is covered by an eligible commercial contract.[64]

5.1.2. LDS LTESAs

An LDS LTESA provides a series of long-term options to receive a minimum revenue amount for the services the LDS project provides. If the option is exercised for a given year, the LDS project would receive an annuity payment. The annuity payment will equal the lesser of (i) a maximum contracted annuity amount and (ii) net operational

[64] *LTESA Generation, July 2023, Clause 12.3 – Calculation of repayment amount.*

revenues from all revenue streams less a net revenue threshold. No annuity payment would be made if net operational revenues exceed the net revenue threshold. Other details include that:

- The maximum annuity payment and revenue threshold would be nominated by the LDS project in its bid, and escalated annually at the lesser of CPI or 3%.
- The annuity payment is subject to the LDS project achieving a nominated level of availability.
- The contract term will be up to 14 years for chemical batteries and 40 years for pumped hydro and other LDS technologies.
- The counterparty for the LTESA is the SFV, rated Aa3 by Moody's.

If the LDS LTESA holder's net operational revenues exceed the net revenue threshold in any year, revenues will be shared with the SFV. We understand that:

- The repayment amount will be calculated as the difference between (i) net operational revenues and (ii) the net revenue threshold, multiplied by a benefit-sharing percentage (50%). The SFV will not recover more than the historical cumulative net payments made to the LTESA holder.
- Repayments will not lead to total net revenues being less than the maximum annuity payment.
- The net revenue threshold should provide the LTESA holder sufficient cash flow to meet its debt service and operating expense requirements in any period.

5.2. Qualitative analysis

It is reasonable to expect that an LTESA (generation, LDS or firming) could potentially reduce the cost of debt and cost of equity. This is because LTESAs provide a 'backstop' level of contracted revenues that the asset can access by exercising the option, thus reducing downside risk and variation in future returns. LTESAs are intended to operate *alongside* commercial contracts, rather than as an alternative.[65] Accordingly, the impact of holding an LTESA should be assessed assuming it applies *in addition* to the assumed 'typical' revenue model for a given technology.

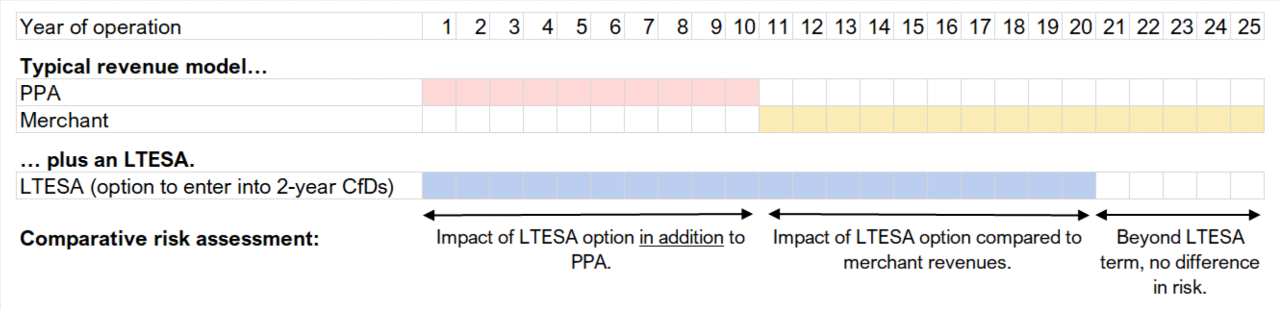
The typical revenue model may include both contracted and uncontracted revenue streams. This means that we need to make two comparisons when assessing the impact of LTESAs on hurdle rates:

- the difference between contracted revenues alone, and contracted revenues plus an LTESA; and
- the difference between uncontracted revenues alone, and uncontracted revenues plus an LTESA.

These periods are illustrated graphically in the figure below, for a scenario where the typical revenue model for an asset with a 25-year life is assumed to be a PPA for 10 years, followed by a further 15 years of merchant revenues. In this scenario, the LTESA term is 20 years.

[65] The LTESA consultation paper (p. viii) noted that these options are intended to encourage participation in the NEM and wholesale market contracts (such as for PPAs) and markets that emerge as a result of the ESB's post-2025 review process. Further, the design of the repayment obligation aims to incentivise participation in wholesale market contracts to support contract market liquidity (p.17). NSW Department of Planning, Industry and Environment (DPIE) (2021), *Long-Term Energy Services Agreement Design – Consultation Paper*, August 2021.

Figure 5.1: Illustration of LTESA and counterfactual



Source: CEPA analysis.

As illustrated in the figure, different considerations are likely to apply when assessing the impact of LTESAs in each period:

- In assumed contracted periods, the effect will depend on whether holding an LTESA provides any additional risk management benefit above and beyond the assumed existing contract terms. This may result from differences in counterparty credit quality – for example, with the LTESA providing a 'backstop' in the event that the original counterparty fails to honour its commitment.
- In assumed non-contracted periods during the LTESA term, the effect will depend on the risk differential between full merchant exposure and the option provided by an LTESA.
- Finally, the overall impact on the whole-of-life WACC for the asset will depend on the assumed proportion of contracted and uncontracted revenues over the asset's operating life, and the assumed term of the LTESA. This is likely to differ by technology.

We expand on these considerations below.

5.2.1. Impact in contracted periods

In periods where an existing contract is assumed to be present, holding an LTESA option does not affect the level or variability of revenues. However, there may be some risk reduction effect if LTESAs are viewed as providing a backstop if the counterparty to the existing contract fails to meet its obligations. The credit quality of the LTESA counterparty, the SFV, is likely to be stronger than a retailer or corporate counterparty.

We have reviewed two studies that provide estimates of how counterparty credit quality impacts the WACC:[66]

- Gohdes and Simshauser (2022) find that moving from a retailer to government offtaker may reduce the post-tax nominal cost of equity by 1.75-2.00%, reduce the pre-tax nominal cost of debt by 20-40 basis points, and allow gearing to be increased by 3.25-7.50%.[67] This translates to a 1.1-1.7% reduction in the pre-tax real WACC.[68]

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[66] In addition to these publicly available sources, we also considered the Aurora Energy Research 2023 March Market Consensus Survey. This provided survey evidence as of Q1 2023 on WACC differentials between a project with a 10-year corporate PPA and a 15-year government CfD. This is subscriber-only content that we cannot cite in this report. However, it has informed our judgement on the appropriate assumption for impact of counterparty credit quality on WACC.

[67] Gohdes and Simshauser (2022), p.8.

[68] Further details on Gohdes and Simshauser's results and the assumptions we have used to translate these to pre-tax real terms are outlined in Appendix E.

- The 2020 NAB report for the NSW Government found a more muted impact, suggesting that moving from an investment grade counterparty to a (near) sovereign counterparty could reduce the pre-tax real WACC by 0.2-0.7%.[69]

These estimates may overstate the additional impact of holding an LTESA alongside another contract:

- The study results are subject to uncertainty. For example, in Gohdes and Simshauser (2022), the larger cost of equity and gearing impacts associated with higher counterparty credit quality relate to a *partial* contract covering 50% of the asset's output. Counterintuitively, a smaller impact was reported for a contract covering 100% of output.
- LTESAs are options and therefore need to be exercised before they could mitigate the failure of an existing counterparty. For example, the generation LTESA contract for Tender Round 3 indicates that notice to exercise an option must be provided 6-12 months prior to the associated swap start date.[70] Accordingly, it is not the case that an LTESA would immediately 'fill the breach' in the event of counterparty failure.

5.2.2. Impact in uncontracted periods

In periods assumed to be uncontracted, the impact on WACC depends on how holding an LTESA option reduces risk relative to a merchant revenue stream alone. As discussed in Section 4.2.1, several studies have considered the WACC differential for a merchant asset and an asset with a contract covering all or part of its output. Drawing on this evidence, we have assumed (see Section 4.3.3):

- For wind and solar, a 1.5% pre-tax real WACC differential between a fully merchant asset and a typical asset (being partly merchant and partly contracted).
- For the other technologies, a 0.5% pre-tax real WACC differential between a fully merchant asset and a typical asset (being mostly merchant).

We can use these assumptions to decompose our assumptions for a 'typical' WACC into separate WACCs for (i) the portion of the asset's revenues that are assumed to be covered by a contract and (ii) the portion of the asset's revenues where merchant exposure is assumed.

This approach is illustrated below for scenarios that assume contracted revenues for 10 years for an onshore wind asset with a 25-year operating life. The calculations are anchored by our assumed WACC for a typical onshore wind project (7.5%) and a merchant onshore wind project (9.0%). We use these values to backsolve for a 'fully contracted' WACC.

Table 5.1: Illustrative impact of increasing contract duration

Period	Years	WACC
Contracted	10	5.25%
Uncontracted (merchant)	15	9.00%
Total years / average WACC	**25**	**7.50%**

Source: CEPA analysis

[69] NAB (2020), p.4. Further details on the NAB report and the translation to pre-tax real terms are outlined in Appendix E..

[70] Under clause 10.2(b) *"if LTES Operator wishes to exercise an Option to cause a Swap to become effective, it must notify SFV of its proposal to exercise the Option by delivering an Exercise Notice in respect of that Option and Swap to which that Option relates to SFV during the period commencing on the date that is 12 months prior to the Swap Start Date for the Swap to which the Option relates and ending on the last Business Day that is at least 6 months prior to the Swap Start Date."*

This stylised analysis indicates a WACC of 5.25% in contracted periods, 3.75% lower than our merchant assumption of 9.0%. This provides a rough guide to the potential WACC impact of holding an LTESA in uncontracted periods. However, this analysis is highly simplified and may be an overestimate:

- The assumption contract duration or operating life may not be consistent with the typical / merchant project assumptions. Increasing the assumed contracted period duration to 15 years would result in an indicative contracted period WACC of 6.5% (2.5% less than the merchant assumption).
- The assumed differential between a typical onshore wind project (7.50%) and merchant project (9.0%) is also uncertain. Although (see Section 4.3.3) we have adopted the lower end of the ranges suggested by the available evidence, this could be an over- or under-estimate. Changing this anchor point would alter the outcome of the analysis above.
- The evidence that informed the typical/merchant differential compared merchant revenues and PPAs that (typically) have a CfD structure. However, LTESAs and CfDs involve a different allocation of risk between a generator and its contracting counterparty (Box 3). Accordingly, replacing merchant revenues with an LTESA is likely to leave more risk (upside and downside) with the generator, and less with the counterparty, than would be the case for a PPA with a CfD structure.

Box 3: Risk allocation under alternative contractual forms

A variety of contract forms are used in the NEM. These include long-term PPAs with a CfD structure (with a counterparty that may be a corporate, retailer, or government) and LTESAs.

- Under a PPA with a CfD structure, a strike price (expressed in $/MWh) is agreed between the generator and the counterparty. When the spot price is below (above) the strike price, the counterparty pays (is paid) the difference to (by) the generator. If the CfD payments are calculated with reference to the generator's actual output and the difference between the spot price and the strike price in each trading interval, this contract structure completely removes the generator's exposure to spot price volatility.
- Under an LTESA, the generator holds a series of put options to enter into a CfD with a pre-determined fixed price – specifically, a sequence of 10 consecutive two-year CfDs. The generator must decide whether to exercise the options in advance, based on its expectation of spot prices over the following two years. If the generator exercises the option, the CfD operates as described above. Otherwise, it remains exposed to spot price volatility for the next two years. The generator would be expected to request the minimum fixed price that will make the project financially viable, taking into account expected future spot prices.

These arrangements result in different allocations of risk between the generator and the counterparty. Specifically, under the LTESA structure, the generator retains some exposure to uncertain future spot prices. This means less revenue certainty and greater risk (both upside and downside) to the generator, relative to the basic CfD structure described above, where the generator effectively has a fixed price guaranteed for the duration of the contract. This does not mean that *total* risk in the electricity market is affected by either contract structure – but simply that the *allocation* of risk between the parties to the contract is different.[71]

5.2.3. Proportion of contracted and uncontracted revenues

As illustrated in the preceding section, the assumed 'typical' contract duration is a material consideration when assessing how the WACC might be impacted by extending the contracted period.

We discussed in Section 4.2 that solar PV, onshore wind and offshore wind are likely to have a more highly contracted revenue model, compared to batteries (short and long duration), OCGT and pumped hydro. The impact

[71] Consistent with our terms of reference, this report does not express a view on the relative merits of LTESAs and CfDs as policy instruments to support the energy transition. The differing allocation of risk under these two contractual forms does not, in isolation of other relevant factors, determine which should be preferred.

of LTESAs is therefore likely to vary by technology and it seems reasonable to expect that any impact would be more modest for projects that are typically more highly contracted. However, there is uncertainty around the appropriate assumed level of contracting for either group of technologies.

For example, in relation to solar PV and wind:

- As noted in Section 4.2.1, there is evidence that long-term PPAs (10 years on average) are currently the dominant revenue model for Australian solar PV and onshore wind projects that have recently reached financial close. This may be a conservative estimate, as contracting reported at financial close may not represent the level of cover that applies over the asset's operating life. As noted above, the Golden Plains wind farm is the sole recent example of a merchant wind farm reaching financial close, but has since signed a PPA for 40% of its output and is negotiating further contracts. Commentary on corporate PPA trends suggests growth in these contracts for assets that have reached commercial operation.[72] This could point to assuming a contracted period of more than 10 years when assessing the impact of an LTESA.
- On the other hand, a sufficient volume of long-term commercial contracts may not be forthcoming to support the level of investment reflected in ASL's modelled Development Path. Indeed, we understand that this was one of the reasons why the NSW Government introduced LTESAs.[73] The survey conducted by Oxford Economics also reported a perception from some respondents that the availability of long-term commercial PPAs had declined over time.[74] This may mean that when assessing the impact of a LTESA on a wind or solar asset we should assume something less than a 10-year PPA.
- Finally, the definition of 'typical' for projects located outside NSW could be affected by the presence of government-issued contracts in other NEM regions.

5.2.4. Summary

Bringing the above analysis together, a *possible* estimate of the overall impact of an LTESA on an onshore wind project with an existing 10-year PPA (with CfD structure) could be constructed as follows:

- Extrapolating from the typical / merchant WACC assumptions (7.5% / 9.0% respectively), we derived an assumed WACC over contracted periods of 5.25%.
- Assuming a 0.25% reduction for the contracted period WACC as a result of holding an LTESA. This assumption reflects the lower end of the evidence on improved counterparty credit quality, for the reasons stated above.
- Assuming a 2.5% reduction for the uncontracted period WACC as a result of holding an LTESA. This assumption is below the indicative 3.75% estimated WACC difference between a fully merchant project and a project with a PPA (CfD structure), reflecting the difference between LTESAs and CfDs. Due to a lack of evidence, this indicative value reflects a judgement which may be incorrect.

Combining these parameters produces an overall WACC of 6.40% for a project with an LTESA, compared to 7.5% without – an overall reduction of around 1%.

[72] Business Renewable Centre Australia (2023), *Corporate Renewable Power Purchase Agreements in Australia – State of the Market 2022*, March 2023, p.12.

[73] NSW Department of Planning, Industry and Environment (DPIE) (2020), *NSW Electricity Infrastructure Roadmap – Detailed Report*, November 2020, Chapters 4 and 5.

[74] Oxford Economics (2023), p.9.

Table 5.2: Illustrative onshore wind scenario - Typical project vs. typical project + LTESA

Scenario	Assumptions	
	Years	WACC (LTESA impact)
Typical project without LTESA		
PPA (CfD structure) only	10	5.25%
Merchant only	15	9.00%
Total years / average WACC	**25**	**7.50%**
Typical project with LTESA		
PPA (CfD structure) + LTESA	10	5.00% (-0.25%)
Merchant + LTESA	10	6.50% (-2.5%)
Merchant only	5	9.00% (no change)
Total years / average WACC	**25**	**6.40% (-1.1%)**

As highlighted in the preceding discussion, there is considerable uncertainty around this estimate and it should be interpreted with caution. In the following sections, we discuss other evidence that we have also considered in forming our recommendation on the assumed impact of LTESAs for ASL's modelling.

5.3. Investor survey results

Survey respondents held mixed views on the impact of LTESAs on the cost of capital. Further, the results differed depending on what technology type (and associated revenue model) the response related to.

The table below summarises both qualitative and quantitative responses that related to wind and solar PV technologies. This indicates that respondents were divided as to whether holding an LTESA would, or would not, be likely to impact the overall hurdle rate for these technologies.

In contrast, responses that related to short- and long-duration batteries provided stronger evidence that holding an LTESA would reduce the cost of capital for these assets. Respondents provided estimates of a 1-2.5% reduction in the overall hurdle rate. The difference in responses for wind / solar PV and batteries appears primarily to reflect different assumptions around the typical revenue model for each group of technologies.

Table 5.3: Survey responses - LTESA impact - wind and solar PV

	Responses related to wind and solar PV	Responses related to batteries
Number of responses	7	8
Cost of debt	No change / unsure: 4 Increase: 1 Decrease: 1 No quantitative estimates	No change / unsure: 3 Increase: 0 Decrease: 4 Quantitative estimate: -1% to -1.5%
Cost of equity	No change / unsure: 3 Increase: 0 Decrease: 2 Quantitative estimate: -2%	No change / unsure: 3 Increase: 0 Decrease: 3 Quantitative estimates: -2% to -3%
Hurdle rate	No change / unsure: 3 Increase: 0 Decrease: 1 Quantitative estimate: -1%	No change / unsure: 3 Increase: 0 Decrease: 3 Quantitative estimates: -1% to -2.5%

Source: CEPA analysis of survey responses.

5.4. Other evidence

We have considered evidence on the potential impact of LTESAs from two other sources: NAB and Aurora Energy Research.

In its 2020 report for the NSW Government, NAB provided estimates of the impact of LTESAs on the WACC for onshore wind and solar assets. Overall, NAB estimated an impact of between -0.8% to +0.49% on the nominal vanilla WACC (-0.05% to +0.78% in pre-tax real terms).[75] NAB's assumptions reflected a comparison *between* an LTESA and a traditional PPA with a CfD structure, rather than an assumption that LTESAs would operate alongside, or as a backstop to, commercial contracts. The potential WACC increase (via lower gearing and a higher cost of equity) reflected NAB's view that the competitive tendering process for LTESAs could result in lower strike prices relative to a traditional PPA, reducing contracted cash flows. Although we consider that LTESAs should be assessed as a complement (rather than substitute) to commercial contracts, NAB's observations are consistent with our view that the level of the strike price could mute the impact of LTESAs on risks to equity providers.

We have also considered the Aurora Energy Research 2023 March Market Consensus Survey. This provided survey evidence as of Q1 2023 on WACC differentials between a project with a 10-year corporate PPA and a 20-year LTESA. The survey results are subscriber-only content, that we cannot cite here. However, we consider that this evidence is consistent with the assumptions we have adopted for the WACC difference between a typical solar PV / wind project and a project with an LTESA.

5.5. Conclusions

Reflecting the analysis above, to account for the impact of LTESAs we propose to apply:

- A 0.5% decrement to the pre-tax real WACC for onshore wind, solar PV, and offshore wind, within a range of 0.25-1.0%. The upper end of the range reflects the results of our stylised analysis set out in Section 5.2, while the lower end of the range recognises the ambiguous investor survey responses for these technologies. We consider that our recommended assumption is consistent with the evidence from the Aurora Energy Research 2023 March Market Consensus Survey.
- For technologies for whom the typical revenue model is considered to be less contracted (batteries, pumped hydro, OCGT) a 1.5% decrement, within a range of 1.0-2.5%. This reflects the range of survey responses provided (including those who considered LTESAs would have no impact on hurdle rates) and brings the assumed hurdle rate for these technologies in line with our assumptions for solar PV and wind.[76] Intuitively, this reflects a view that revenue model risk is the primary source of hurdle rate difference between these technologies and solar PV / wind – and that holding an LTESA largely eliminates this.
- We recognise that these estimates reflect limited evidence and depend materially on the assumptions applied for a typical project. Nonetheless, we consider that they are consistent with the responses to the investor survey, which provides the most recent 'market' view of LTESA options. To the extent that respondent views are forward looking, they will reflect the likely contracting opportunities for future projects. Reported views may also reflect the fact that LTESAs are a relatively new development, and views may evolve as familiarity with these products increases. However, it is difficult to control for this effect.

[75] Further details on NAB's results, including our translation of these to pre-tax real terms, can be found in Appendix E..

[76] After the -0.5% LTESA adjustment for these technologies.

APPENDIX A ANALYTICAL FRAMEWORK

Investments in the NEM are financed with capital provided by both lenders (debt) and shareholders (equity). Debt and equity providers require a return that compensates them for the opportunity cost of committing funds to a particular investment over time: this is what the cost of debt and equity represent. The overall cost of capital for an investment is the weighted average its **cost of debt** and **cost of equity**. The weighting is determined by the level of **gearing**, being the proportion of debt and equity within the investment's overall capital structure.

Broadly, capital providers will require higher expected returns for riskier investments. Accordingly, differences in the risk profile of particular technologies can translate to differences in their required return on capital. However, different risks impact the cost of debt, cost of equity and level of gearing. The risk analysis framework that we have adopted for this engagement is outlined in the sections below.

A.1. WHAT MATTERS FOR ASSESSING DIFFERENCES IN THE COST OF EQUITY?

The most widely applied method for estimating the cost of equity is the capital asset pricing model (CAPM). The CAPM assumes that investors hold a diversified portfolio of investments. This means that only risks which cannot be eliminated through diversification are relevant for determining what return an equity investor would require. This means that the CAPM framework distinguishes between:

- **Business-specific risks**, which are unique to a particular investment. Equity investors can eliminate their exposure to such risks by holding a diversified portfolio. In a sufficiently diversified portfolio, on average, business-specific risks that cause lower returns for one investment will be offset by different business-specific risks that create higher returns for another investment.
- **Systematic risk**, which is the variability in returns that cannot be removed through diversification. Systematic risk is associated with factors that impact all investments in the portfolio. A diversified investor requires an overall return that is commensurate with the risk of its portfolio as a whole.

We can use an example of a gold prospecting company to demonstrate the difference between individual business risk and systematic risk. The likelihood of striking gold is low, but if gold is found returns are substantial. This means the variability of returns is very high and by extension business-specific risk is very high. However, whether a company strikes gold or not is unrelated to the performance of other investments within a diversified portfolio. To invest in the prospecting company, a diversified investor would therefore require a return that reflects the relationship between the company's returns and their portfolio's returns: that is, the element of variability in the company's returns that cannot be diversified away. The risk that the company will fail to strike gold may be material and potentially have a considerable impact on the company's cash flow. This risk is known to the diversified investor, however they do not require a higher return for this, because the risk is diversifiable.[77]

Although non-systematic risk does not affect the cost of equity in the CAPM framework, this does not mean that it is irrelevant to investment decisions. When considering a project, investors will require that expected returns are at least equal to the cost of equity. Even if it does not affect the cost of equity, a business-specific risk might be reflected in the investors' decision-making as a change in the forecast cash flows and therefore in the expected returns of the asset. However:

- We acknowledge that in practice some investors might deal with such non-systematic risks by adjusting their hurdle rates, rather than expected cash flows (see Box A.1 overleaf). Accordingly, some of the evidence we have collected on the risk profile of different technologies (e.g., survey results) may relate to non-systematic as well as systematic risk.

[77] Brealey, Myers, and Allen (2020), p. 170-174, and p. 224, provide an illustration of these concepts.

- In the context of ASL's modelling exercise, it is impractical to reflect non-systematic risk as an adjustment to cashflows. For example, we might identify that relative to other technologies OCGT faces a higher risk of future returns being constrained by emission reduction policies – most likely a non-systematic risk. Prospective investors could adjust projected future cashflows to account for this risk when deciding whether to invest. However, this would be challenging to implement in ASL's modelling. A change to the WACC assumption would be a more practical way for ASL to reflect any such technology-specific differences in non-systematic risk.

For these reasons, when interpreting the evidence available to us, we have not sought to confirm that identified technology-specific risks (e.g., as reported by survey respondents) are purely related to systematic risk. This approach does not mean that we reject the CAPM framework's careful distinction between systematic and non-systematic risk. This framework is universally adopted in Australian regulatory decisions and is entirely appropriate in the context of those decisions. It is also consistent with Synergies' methodology for the ISP.[78] Our approach for this report is rather a pragmatic decision that reflects the specific context in which these estimates will be used.

Box A.1. WACC vs hurdle rate

An investment hurdle rate represents the minimum internal rate of return (IRR) required by investors over the life of the asset. If the projected future cashflows of an asset are discounted at the hurdle rate, the net present value (NPV) of those cash flows should be at least zero for the project to move ahead. When making investment decisions, WACCs can be applied as the discount rate to convert the projected future cash flows of an asset to NPV.

In practice, the actual discount rate that is applied in this context may not necessarily be the project's WACC.[79] For example, sometimes investors will choose to reflect certain non-systematic risks in the discount rate, rather than directly in the cash flows.[80] For the purpose of this report, we use the term 'hurdle rate' to reflect the minimum return that investors require to invest in an asset, noting that this may be different from an asset's WACC.

A.2. What matters for assessing differences in the cost of debt?

The prevailing theories of cost of debt centre on financial distress costs and by extension the **probability of default**. An entity's probability of default is often measured by its credit rating. A credit rating is a score assigned by a rating agency based on their assessment of the entity's financial strength against relevant risk factors. An entity's cost of debt can then be estimated using indices that track debt yields from issuers with a similar credit rating.

Accordingly, we can draw on credit rating agency methodologies to determine what they consider when assessing companies, and how these considerations will be impacted by different asset characteristics. For the purpose of this report, we have referred to the methodologies applied by Moody's to assess unregulated power companies, fully contracted power generation projects, and partially / non-contracted power generation projects.[81] The methodologies are presented in a scorecard form, where the credit rating is a weighted average of ratings across different risk factors. Moody's undertakes a forward-looking assessment of the different factors, although this may be informed by both historical data and projections.

[78] Synergies (2021), *Discount rates for use in cost benefit analysis of AEMO's 2022 Integrated System Plan: A report prepared for AEMO*. July 2021.

[79] For example, see Edwards, H. and Lane, K. (2021), *Why Are Investment Hurdle Rates So Sticky?*, RBA Bulletin – December 2021, 9 December 2021.

[80] For example, see Oxera (2011), *Discount rates for low-carbon and renewable generation technologies*, April 2011, p.7. We note that differences between WACCs and hurdle rates could arise for other reasons. However, these are less relevant for the purpose of this report.

[81] Moody's (2022), *Power Generation Projects Methodology*, January 12. Moody's (2017), *Unregulated Utilities and Unregulated Power Companies*, May 17.

From our analysis of these methodologies, we can draw out some broad observations to understand how technology type and LTESAs might impact an asset's credit rating and by extension their cost of debt:

- Firstly, credit ratings are impacted by the **expected level of free cash flow** relative to the debt that must be serviced. This is reflected in financial metrics that inform the credit rating, which reflect the ratio of various cash flow measures to debt and interest. In broad terms, for a given level of debt that must be supported, stronger financial metrics are associated with a stronger credit rating.
- Secondly, rating agencies consider not only base case cash flow projections (which might reflect a view of most likely or expected cash flows), but also adverse scenarios. This reflects that debt providers are particularly concerned with **downside risk**, which increases the probability of default. Unlike equity investors, debt providers do not benefit from upside risk. When determining a credit rating, rating agencies will therefore consider an asset's ability to continue servicing debt under downside scenarios.
- Thirdly, in addition to projected cash flows and financial metrics, Moody's also considers a range of **qualitative factors**. The factors we consider most relevant for our analysis are outlined in the table below.

Table A.1: Summary of relevant qualitative factors considered in Moody's rating methodologies[82]

Unregulated power companies methodology	Power generation projects methodology
• **Cash flow predictability** – considering hedging or contractual arrangements to underpin revenues. • **Market framework and positioning** – considering how developed and settled the wholesale market framework is. The assessment includes the transparency of market arrangements, how long the framework has been in place, and expectations for material changes. • **Capital requirements and operating performance** – all else equal, projects of high technical complexity would tend to receive weaker credit scores.	• **Predictability and sufficiency of cash flows** – projects with contractual support will almost always receive a stronger score on this factor because cash flows are less volatile than for merchant projects. • **Regulatory support** – considerations exposure to environmental policies (e.g., emissions reduction) and whether the asset benefits from regulatory support (e.g., for renewable generation). • **Technology and operating performance** – simple, commercially-proven assets will generally receive a stronger score than those with high operating risks or more complex technology. • **Construction and ramp-up risk** – proven technologies that have been frequently deployed and benefit from an experienced supply chain are more likely to receive a stronger score relative to projects involving more complex technology or that is not commercially proven. Considerations include construction complexity and the possibility for cost overruns or delays. • **Off-taker risk** – the credit quality of the off-taker is important, considering it may be the sole or major source of revenue.

Source: CEPA analysis of Moody's rating methodologies.

Overall, if an asset's characteristics have a relatively favourable impact on the factors outlined above, this may result in a better credit rating compared to other asset types. However, even if we are able to conclude on the directional impact of particular asset characteristics, the magnitude of the impact is also important. Further, credit rating bands are broad and the cost of debt can vary for assets with the same credit rating.

[82] The power generation projects methodology applies to special purpose entities whose primary business purpose is the generation of electricity and whose assets are financed on a non-recourse, project finance basis. The unregulated power company methodology is applicable to companies whose principal business is the production and/or procurement and sale of electricity in unregulated markets.

A.3. What about capital structure?

As discussed above, the WACC is the weighted average of the cost of debt and cost of equity, where the weighting is determined by the proportion of debt and equity finance within the investment's overall capital structure. The proportion of debt and equity is often referred to as 'gearing' or 'leverage'. Higher gearing means a higher proportion of debt finance in the capital structure.

The impact of differences in gearing on the asset's cost of capital is more complex than simply re-weighting the cost of debt and cost of equity components of the WACC, because the cost of debt and the cost of equity themselves are not independent of the capital structure. As gearing increases, so too does the cost of debt and equity, reflecting the greater risk to investors in a more leveraged asset. The higher cost of debt and equity offsets the WACC impact of increasing the proportion of debt finance (which is generally lower cost than equity). The Modigliani and Miller theorem states that subject to certain conditions an asset's overall market value is independent of its capital structure – in other words, that the WACC is invariant to gearing.

In practice there are additional considerations that explain why a certain capital structure may be preferable for an asset, in the sense that it maximises its value. For example, increasing the proportion of debt finance can be advantageous because the asset benefits from the tax shield that applies to interest payments. However, this benefit does not continue indefinitely as gearing reaches higher levels, because of the costs of financial distress that arise when leverage is excessive (i.e., when the asset's creditworthiness is in doubt and, in the extreme, the costs associated with bankruptcy). In theory, gearing will increase only to the point where on the margin the benefit from the tax shield is equal to the cost of financial distress.

This means that if a particular asset characteristics points to relatively higher expected cashflows / reduced downside risk, and thus reduces the probability of financial distress, there are two mechanisms through which the overall cost of capital could fall (in addition to any impact on the cost of equity): either through a reduction in the cost of debt; or through being able to increase gearing (and benefit from the tax shield) without impacting the credit rating.[83] Similar considerations, in the opposite direction, would apply if the asset's characteristics increased downside risk. This is reflected in responses to the investor survey. For example, when considering whether there is a cost of debt differential between solar PV/onshore wind and batteries, one respondent commented that while the cost of debt was the same for all technologies, gearing levels would vary (leading to a differential in the overall hurdle rate). Other responses indicated technology-specific differences in the cost of debt.

Given these considerations, we have opted to apply a single gearing assumption for all technology types and reflect differences in risk as a change to the cost of equity and/or cost of debt. In the simple framework, the relationship between cost of debt/equity and the WACC is very straightforward: if the cost of either debt or equity increases, leaving other things equal, the WACC increases, and vice versa. While gearing levels may be generally higher or lower for particular technology types, we consider that our approach provides a simple and transparent means of reflecting differences in risk. This avoids the complexity of attempting to determine appropriate technology-specific gearing benchmarks, noting that capital structures may vary materially across assets of the same technology (for example, because one type of financing approach has been more prevalent than another for certain asset types).

A.4. Other estimation issues

The context of ASL's analysis has several additional implications for estimating the WACC, which we discuss below. While these issues involve some interesting theoretical questions, we have aimed to address them in a way that is proportionate to the likely impact on the outcomes of ASL's power system planning process.

[83] In other words, the level of gearing at which the benefit of the debt tax shield is offset by the cost of financial distress has shifted upwards.

A.4.1. Whole-life WACC estimate

ASL is using the WACC estimates to determine the relative cost of different technologies and contracting arrangements, over the life of each asset. In this context, it is appropriate that the WACC estimate reflects the average return required **over the life of the project**. This has two implications for our analysis.

Firstly, the context of this advice differs from a regulatory WACC, which is generally seeking to establish a reasonable return for each regulatory period (e.g., the next five years). While the WACC set for each regulatory period will *cumulatively* deliver the required WACC over an asset's life, in any given regulatory period the value may not be representative of the whole-of-life required return.

Secondly, the cost of capital may be different for a project while it is being constructed, compared to when it has commenced operation.[84] For example, the cost of equity in the construction period could be higher than in the operational period, if equity providers are exposed to the risk of development cost overruns which may be systematic to some extent. This risk would not be faced by an equity provider who invests in a project that has already been constructed. The cost of debt may also be affected by differences in risk exposure between the construction and operational phases.

To develop a whole-life average WACC, some care is required in interpreting the evidence we have drawn on. For example, the asset betas of the listed comparators that we have examined may be affected by their pipeline of development projects in addition to operating assets. However, limitations in the available evidence mean that it is not possible to entirely control for this factor.

A.4.2. Term of the cost of capital

The term of the cost of capital refers to the time horizon over which returns are estimated. For example, the choice of term impacts the estimation of the risk-free rate (i.e., through the chosen tenor of government bonds used as a proxy for the risk-free rate), the cost of debt (i.e., through the chosen tenor of corporate bonds used to determine the debt risk premium), and inflation (i.e., whether inflation expectations are estimated over a 5-year, 10-year or other horizon).

There are theoretical and practical arguments both for and against adopting different terms for different technologies. For example, one argument might be that the term should be aligned to the economic life of the asset, as the required return should be earned over this period. On the other hand, there are practical difficulties associated with estimating the risk free rate, cost of debt and inflation parameters based on terms of greater than ten years (e.g., availability of bond yield data to inform the cost of debt). Further, there is evidence that investors commonly use a 10-year discount rate when making decisions on infrastructure investments with economic lives longer than 10 years.[85]

For the purpose of this advice, we have opted to apply a 10-year term for estimating the WACC, across all technology types. Adopting a common WACC term does not imply an assumption that all technology types have the same economic life. Rather, it reflects a view that a WACC based on a 10-year term can reasonably be assumed to apply over each asset's economic life. Where relevant (for example, in Section 5 in relation to LTESAs), we have considered the implications of events that occur beyond the 10-year horizon for the whole-of-life WACC. We consider that this is a reasonable simplification, given the considerations outlined above.

A.4.3. Timing of investments

Given the nature of ASL's modelling, the WACC may be applied to future investments with a range of different construction dates. In principle, different construction dates could imply different pre-tax real WACCs. For example,

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[84] CEPA commented on this issue in a 2018 report for Ofgem, the energy sector regulator in Great Britain. CEPA (2018), *Review of cost of capital ranges for new assets for Ofgem's Networks Division*, 23 January 2018, p. 7.

[85] AER (2022), *Draft Rate of Return Instrument – Explanatory Statement*, June 2022, p.14. Energy Networks Australia (2021), *The term of the rate of return – Response to Draft AER Working Paper*, 2 July 2021, p.7 and p.9.

this may occur because forward looking inflation expectations over the life of an investment may be different for an asset constructed in 2025 as compared to an asset constructed in 2035.

Controlling for this would involve constructing a 'rolling' WACC estimate that would apply to each year of ASL's forecast period. We do not consider that this would be a proportionate approach. Accordingly, we have only established WACC estimates for a single point in time (as of 28 February 2023).

A.4.4. Future updates

ASL may wish to update these assumptions periodically to inform its modelling. We suggest that a practical approach is:

- To periodically update the assumptions, ASL could refresh the central technology-neutral estimate (as outlined in Section 2) and maintain the technology- and contract-specific WACC increments outlined in Sections 4 and 5. This ensures that the underlying WACC estimates continue to reflect up to date market evidence.
- The technology- and contract-specific WACC increments can then be reviewed less frequently, for example via a refresh of the investor survey. This means that the assumptions on technology-specific increments, which are inherently less robust than the underlying central case estimate, would only be updated where compelling evidence of a material change emerges.

APPENDIX B TECHNOLOGY-NEUTRAL ESTIMATES

This appendix sets out a detailed description of the approach to estimating the technology-neutral WACC set out in Section 2.

B.1. WACC FORMULATION

As noted above, ASL requires WACC estimates that are expressed in pre-tax real terms. This is because ASL models the annualised cost of each electricity generation and storage technology on a pre-tax, real basis.[86]

A pre-tax real WACC is a definition of the WACC that reflects inflation and tax considerations. The pre-tax real WACC is calculated using the following formula:

$$WACC = g \times R_d + (1 - g)R_e$$

Where:

- g is **gearing**, i.e., the proportion of the company's debt over the total of its debt and equity.
- Rd is the **pre-tax real cost of debt**, calculated as the sum of:
    - the **risk-free rate** (the rate of return on a risk-free asset, conventionally proxied by a long-term government security);
    - the **debt risk premium** (the additional return a lender requires as compensation for risk beyond the risk-free asset, which is a function of the company's credit rating); and
    - **debt raising costs** (the transaction costs involved in obtaining debt finance).
- Re is the **pre-tax real cost of equity**, i.e., the required return on an equity investment.

Under the Sharpe-Lintner Capital Asset Pricing Model (SL-CAPM), the post-tax cost of equity is calculated as:

$$R_e = Risk\ free\ rate + \beta_e \times MRP$$

Where:

- MRP is the **market risk premium**, i.e., the difference between the expected market return and the risk-free rate.
- β_e is the company's **equity beta**, i.e., a coefficient that measures the covariance between returns in the stock market as a whole and returns on the company's equity.

The equity beta term is intended to cover systematic or non-diversifiable risk; that is, risk that investors cannot mitigate through diversifying into a broader portfolio of companies. Data from equity markets is often used to estimate equity beta. When a regulated entity is not listed, an estimate of their beta must rely on data from listed companies which may be considered comparators; that is, they are considered by investors to be investment substitutes and have similar systematic risk exposure. Equity beta includes the effect of debt on returns, while an **asset beta** (or unlevered beta) has these effects removed, thus allowing risk to be compared for companies with different capital structures. In regulatory contexts, observed equity betas from comparators are converted to asset betas to derive an estimate of the asset beta of the regulated company. The asset beta is then 're-levered' using the regulator's gearing assumption to derive the equity beta to be used in the CAPM formula.

The post-tax cost of equity can be converted to pre-tax by applying a 'tax wedge' based on the company tax rate (*t*) to the cost of equity. Generally, the pre-tax cost of equity is calculated as:

$$R_e = R_e/(1 - t)$$

[86] ASL's capital and operating cost estimates for the 2023 IIO modelling are expressed in real 1 July 2022 terms.

However, in Australian the tax wedge is adjusted to account for the fact that Australia operates a tax imputation system, where investors receive credits for tax paid at the company level. This means they require a lower return than if the imputation system were not in place. The formula for the pre-tax cost of equity is adjusted as:

$$R_e = R_e/[1 - t(1 - \gamma)]$$

Where γ (gamma) is a parameter between 0 and 1 which measures the value that investors derive from imputation credits.

B.2. Methodology

To develop a technology-neutral WACC estimate, we have closely followed the central case WACC methodology developed by Synergies for AEMO's 2022 Integrated System Plan (ISP).[87] This is not necessarily the methodology that CEPA would choose to adopt to estimate WACC. However, we think it is a logical anchor point for ASL's WACC assumptions, to provide comparability and alignment with the discount rate used in the ISP. As outlined in the discussion below, we consider that in the context of this advice some minor departures from Synergies' ISP methodology are appropriate to set the asset beta.

Aside from these adjustments, for all other parameters we have applied Synergies' methodology as we understand it. In some instances, we were unable to fully determine from the Synergies report the exact methodology used to estimate parameters. In these instances, we adopted an approach that was aligned with Synergies' description of their methodology. We cross-checked our 2021 estimates to those of Synergies, as assurance that the underlying methodology we have applied is reasonably close to their approach. To develop a technology-neutral WACC estimate as a starting point for our analysis, we have updated Synergies' central case estimate to February 2023

Since its original 2022 ISP report, Synergies has updated its estimates of the risk-free rate, market risk premium, debt risk premium and inflation.[88] However, their WACC methodology has remained the same.

B.3. Market wide parameters

This section sets out our estimates for 'market-wide' parameters, which include the risk-free rate, market risk premium, gamma and expected inflation. These WACC parameters are the same for all firms operating in Australia. We would not expect these parameters to vary by technology type.

B.3.1. Risk-free rate

As outlined in the table below, we have adopted the same approach as Synergies to estimate the risk-free rate. Our February 2023 estimate is slightly lower than Synergies' estimate as of June 2022, reflecting movements in Commonwealth Government Security (CGS) yields.

[87] Synergies (2021), *Discount rates for use in cost benefit analysis of AEMO's 2022 Integrated System Plan: A report prepared for AEMO*. July 2021.

[88] Synergies (2022), *Updating the 2022 ISP Discount Rate: A report prepared for AEMO.* December 2022

Table B.1: Risk-free rate

	Methodology
Synergies methodology	20-day average of ten-year CGS yields.
CEPA methodology	Same as Synergies.
Synergies June 2022 estimate	3.82%
CEPA February 2023 estimate	3.75%[89]

B.3.2. Market risk premium

As outlined in the table below, we have adopted the same approach as Synergies to estimate the market risk premium (MRP).

Table B.2: Market risk premium

	Methodology
Synergies methodology	An average of the 'Ibbotson' and 'Wright' methods.
CEPA methodology	Same as Synergies.
Synergies June 2022 estimate	7.13%
CEPA February 2023 estimate	6.80%

The estimates reflect two different approaches: the 'Ibbotson' method and the 'Wright' method. The Ibbotson method takes the long-term average of excess returns, calculated as annual total equity market returns minus the annual risk-free rate. The Wright method estimates the MRP by subtracting the current risk-free rate from long-term average equity market returns.

Synergies' central estimates are based on a simple average of the Ibbotson and Wright approaches. Both methods rely on historical stock market data. For data pre-1958, we used the 'NERA'[90] dataset whilst for data from 1958 onwards we used data sourced from the AER's 2022 Rate of Return Instrument (RORI).[91] We have calculated the MRP using five alternative time horizons and adopt the median of these results. The resulting estimates are outlined in the table below, producing an MRP estimate of approximately 6.80%.

[89] Data sourced from Reserve Bank of Australia (RBA), F2 Capital Market Yields – Government Bonds series ID FCMYGBAG3D, 20 March 2023.

[90] Sourced from NERA (2015), *Historical Estimates of the Market Risk Premium,* February 2015.

[91] AER (2022), *AER – Historical Excess Returns,* December 2022.

Table B.3: Summary of historical MRP estimates (input to central and upper bound estimates)

From	To	Ibbotson	Nominal equity return	Wright
1883	2022	6.56%	11.45%	7.70%
1937	2022	5.87%	9.75%	6.01%
1958	2022	6.34%	10.13%	7.38%
1980	2022	6.19%	11.78%	8.03%
1988	2022	5.77%	11.03%	7.28%
Median		**6.19%**		**7.38%**

Source: CEPA analysis of NERA (2015) & AER (2022).

Note: Arithmetic average used. The estimates assume a risk-free rate of 3.75%, consistent with Section B.3.1. The estimates also assume a gamma of 0.25 (made up of a theta of 0.35 and a distribution rate of 0.70) – see Section B.3.3 and expected inflation of 2.48% - see Section B.3.4.

B.3.3. Gamma

As outlined in the table below, we have adopted Synergies' assumptions on gamma.

Table B.4: Gamma

	Methodology
Synergies methodology	Aligned with IPART's current estimate.
CEPA methodology	Same as Synergies.
Synergies June 2022 estimate	0.25
CEPA February 2023 estimate	0.25

Consistent with Synergies central case, we have used a gamma estimate of 0.25. This reflects a theta of 0.35 and a distribution rate of 0.70.

B.3.4. Expected inflation

Table B.5: Expected inflation

	Methodology
Synergies methodology	The 'break-even method'.
CEPA methodology	Same as Synergies.
Synergies June 2022 estimate	2.96%
CEPA February 2023 estimate	2.48%

The 'break-even method' estimates inflation as the difference between forward-looking yields on nominal long-term government bonds and yields on indexed bonds. The Reserve Bank of Australia (RBA) provides quarterly break-even inflation estimates based on 10-year bonds. As of February 2023 (when these estimates were developed), the RBA's most recent estimate for the December 2022 quarter was 2.45%.[92] Bloomberg also provides a 10-year breakeven estimate for Australia. Taking an average of Bloomberg's estimate over the 20 business days to 28 February 2023 (consistent with the averaging period for the risk-free rate and debt risk premium) provides an estimate of 2.48%. We have adopted 2.48% as the basis for our estimate.

[92] RBA, January 2023, *Average annual inflation rate implied by the difference between 10-year nominal bond yield and 10-year inflation indexed bond yield,* series ID GBONYLD,

We were unable to replicate Synergies' expected inflation estimate as of 30 June 2022 (using a range of methods in addition to the two described above). However, we consider that the approach outlined here is a reasonable reflection of their general approach – and can be readily replicated by ASL in future using published sources.

B.4. Sector-specific parameters

As discussed in Section 1.4, sector-specific parameters can vary across sectors and firms, depending on their specific risk characteristics. The sector-specific parameters are asset beta, gearing, and cost of debt (credit rating). Here, we consider estimates for these parameters for a generic generation/storage asset. Section 3 considers how these parameters might change for specific technologies.

B.4.1. Asset beta

Asset beta measures the systematic risk of an asset. That is, the degree to which the asset's returns are correlated with the those of the entire stock market. If an asset is not listed, the asset beta cannot be observed directly. Accordingly, it is standard practice to use a sample of listed comparators as proxies to estimate beta (and gearing). The comparator sample should include companies that an investor would consider to be investment substitutes and that have similar systematic risk exposure. Below we discuss our approach to determining the comparator sample and deriving beta estimates for the comparators, highlighting amendments that we have made to Synergies' methodology given the specific purpose of the WACC estimates we are developing.

Comparator selection

To identify our comparator sample, we started from listed companies that fall under two Global Industry Classification Standard (GICS) Utilities sector sub-industries: *Independent Power Producers & Energy Traders* and *Renewable Energy*. This differs from Synergies, which also considered comparators in the *Electric Utilities* sub-industry. We excluded this category, as it tended to capture comparators with electricity network assets – that are not relevant for the WACC estimates required by ASL. Although some companies with network assets also had investments in generation/storage technologies, we would expect the presence of network assets to (all else equal) result in an asset beta that is lower than appropriate for our purposes. Accordingly, we consider it is appropriate to exclude comparators with network assets from our sample.[93]

We then applied the following filters to remove companies from the sample:

- Removed firms from countries that did not have a FTSE Developed classification.[94]
- Removed firms whose operations were irrelevant to the technologies of interest to ASL. This was undertaken through a manual review of their Bloomberg descriptions and/or most recent annual reports. Our criteria for exclusion were slightly different from Synergies, given our focus on a specific set of technologies.
- Removed firms which did not have five years of data available (as of February 2023).
- Finally, we considered the impact of two different approaches to assessing the robustness of the beta estimates:
    - The first approach was aligned with Synergies' methodology. This involve excluding comparators that: had a market capitalisation of less than USD200m; had an equity beta estimate with a t-statistic less than 2; or had equity beta estimate with an R-squared value of less than 0.1.[95]

[93] We undertook a scan of the Electricity Utilities sub-industry to make sure that no highly relevant comparators were missed.

[94] FTSE Russell (2022), *FTSE Equity Country Classification September 2022 Annual Announcement.* 29 September 2022.

[95] In either their weekly beta estimates or monthly beta estimates.

- The second approach considered alternative filters that have been used in other contexts to estimate beta, which removed comparators: if their stock price data reflected an average bid-ask spread of less than 1%; or if the percentage of days that their shares were not traded exceeded 20%.

We tested the impact of the alternative filters to ensure that we did not miss information on comparators that were particularly relevant for ASL. While the second approach did identify some additional comparators, with investments in technologies of interest to ASL, we found that the application of the filters did not make a material difference to the asset beta estimate. Accordingly, for this report we have maintained the filters applied by Synergies.

Overall, this process yielded a comparator sample of 24 firms. This compares to Synergies' final comparator sample of 70 firms. Although our sample is smaller than that of Synergies (reflecting its narrower focus), we consider that it provides a reasonable number of comparators. A full list of the comparators included in our sample and their descriptions can be found in Section B.6.

Beta estimation

We made the following assumptions when estimating betas. Other than the cut-off date (28 February 2023), this is consistent with Synergies' approach.

- We adopted a 5-year estimation period ending on 28 February 2023.
- We estimated two different return specifications, a weekly return and a monthly return.[96]
- Equity betas were estimated relative to the returns on their local index.
- Equity betas were then de-levered using the Brealey-Myers approach.[97]

The resulting estimates are presented in the table below, compared to those used by Synergies to inform the 2022 ISP. Although there are differences, both sets of estimates place the asset beta in a range of 0.40 to 0.60.

[96] Weekly returns were estimated using the final day of the week. Monthly returns were estimated using the final day of each month.

[97] $Beta_{Equity} = Beta_{asset} * (1 + \frac{Debt}{Equity})$

Table B.6: Summary of asset beta results

	CEPA sample – February 2023		Synergies sample – July 2021[98]	
	Weekly	**Monthly**	**Weekly**	**Monthly**
Average	0.50	0.48	0.46	0.41
80th percentile	0.60	0.63	0.63	0.55
75th percentile	0.56	0.61	0.61	0.50
60th percentile	0.51	0.53	0.47	0.39
50th percentile (median)	0.49	0.47	0.38	0.32
40th percentile	0.45	0.37	0.36	0.28
25th percentile	0.39	0.33	0.33	0.25
20th percentile	0.38	0.28	0.27	0.23

Source: CEPA analysis of Bloomberg data.

Point estimate

Synergies selected its asset point estimates for the 2022 ISP as follows:

- For the central case, Synergies proposed relying on both the average and 60th percentile estimates, yielding a point estimate of 0.50.
- For the upper bound, Synergies proposed relying on the 75th percentile estimate, which it considered supported a point estimate of 0.60.
- For the lower bound, Synergies adopted an asset beta consistent with the AER's recent determinations for energy networks, with a point estimate of 0.24.

With reference to Synergies' central case approach, we propose a point estimate of 0.50, relying on both the average and 60th percentile estimates, to inform the technology-neutral WACC estimate presented in this section. In Section 4, we consider whether there is evidence to apply a different asset beta for particular technologies, based on the ranges shown above.

B.4.2. Credit rating and debt risk premium

As outlined in the table below, we have adopted the same approach as Synergies to estimate the debt risk premium, and the same assumptions in relation to the credit rating.

[98] Synergies' July 2021 beta estimates remained the basis for the June 2022 updated ISP WACC estimates.

Table B.7: Debt risk premium

	Methodology
Synergies methodology	20-day average of the difference between corporate BBB bonds and 10-year CGS yields. BBB yields drawn from RBA and Refinitiv.
CEPA methodology	Same as Synergies.
Synergies June 2022 estimate	2.58%
CEPA February 2023 estimate	2.96%

We have calculated the debt risk premium as the 20-day average of the difference between BBB-rated corporate bonds[99] and 10-year CGS.[100] This is consistent with Synergies' assessment for the ISP, which they based on observed credit ratings for listed Australian energy infrastructure providers.[101] Synergies also noted that adopting an investment grade credit rating (BBB- and above) is generally an uncontentious approach.

In Section 3, we consider whether there is evidence to apply a different credit rating / debt risk premium assumption for particular technologies.

For debt raising costs, Synergies apply an assumption of 0.10% across all scenarios. We adopt the same assumption and approach.

B.4.3. Gearing

As outlined in the table below, we have adopted the same assumption as Synergies on gearing.

Table B.8: Gearing

	Methodology
Synergies methodology	50%, based on the average and median value for the asset beta comparator sample.
CEPA methodology	Same as Synergies.

Gearing was estimated using the same comparator sample as for the asset betas, consistent with Synergies' approach. Gearing for each company was calculated daily using long-term debt and the market value of equity. These daily gearing estimates were then averaged over the five-year beta estimation period.

For our asset beta comparator sample (which differed from Synergies), average gearing is 41% and the median value is 45%. This suggests that it could be appropriate to adopt a lower gearing assumption than applied by Synergies for the ISP.

We note that in the pre-tax WACC formulation, changes in gearing have little effect on the overall WACC. For example, if we adopt a gearing value of 45% rather than 50%, our central case pre-tax real WACC estimate would be 7.28% rather than 7.37%. As the impact is not material, we have chosen to retain a gearing level of 50% that is consistent with the ISP analysis.

B.5. Overview

Overall, our February 2023 update produces a central pre-tax real WACC estimate of 7.54%. This compares to Synergies' June 2022 update of 7.14%, with a rounded figure of 7% adopted by AEMO.

[99] RBA and Refinitiv data.

[100] RBA data.

[101] More specifically: AGL Energy (Baa2, equivalent to BBB); Origin (Baa2, equivalent to BBB); Spark (A- for Victorian and South Australian network assets, Baa2 for NSW network assets); and Ibedrola (BBB+).

Synergies advised that, to the extent that AEMO chooses to apply rounding to its discount rate estimates, it recommends rounding to the nearest half per cent.[102] Applying the same logic to our estimates would result in rounded estimates of 7.5%.

Table B.9: Summary of technology-neutral WACC parameter estimates as at 28th February 2023.

Parameter	Central
Risk-free rate	3.75%
MRP	6.80%
Asset Beta	0.50
Equity Beta	1.00
Tax rate	30%
Cost of Equity	**10.55%**
Debt risk premium	2.96%
Debt raising costs	0.10%
Cost of debt	**6.81%**
Gearing	50%
Expected Inflation	2.48%
Gamma	0.25
WACC – Post-tax nominal vanilla	**8.68%**
WACC Pre-tax real	**7.54%**

Source: CEPA analysis of Bloomberg data

B.6. Comparator sample

In this section, we provide further information on the asset beta comparator sample. The table below provides a summary of the asset beta comparator sample we have applied, including information on their generation and storage assets, and contracting arrangements, where available.

[102] Synergies (2022), p.5.

Table B.10: Asset beta estimates for comparator sample

Company	Bloomberg description	Primary technology	Technology mix	Revenue contracting	Asset Beta - Weekly	Asset Beta - Monthly
7C Solarparken	7C Solarparken provides energy solutions. The company designs, develops, and operates photovoltaic energy systems. 7C Solarparken serves customers in Germany.	Solar	Mainly solar with some onshore wind generation.	25% of group assets are under contract to receive a fixed price.	0.17	0.24
ABO Wind	ABO Wind provides renewable energy services. The company designs and develops wind energy farms. ABO Wind offers services throughout Europe. ABO Wind offers investors solid investment opportunities in wind energy funds, wind farms, and bio energy projects.	Wind	Primarily wind.	N/A (develop and then sell assets).	0.45	0.61
AES Corporation	AES is an electric power distribution company. The company acquires, develops, owns, and operates renewable energy power plants. AES serves customers globally.	Solar / wind / gas	46% renewables (solar and wind), 32% gas (type unknown), 20% coal.	Primarily medium- (2-5 year) and long-term (5+ years) contract sales.	0.44	0.38
Brookfield Renewable Partners	Brookfield Renewable Partners operates as an investment company. The company focuses on investments in renewable power and transition sectors. Brookfield Renewable Partners serves clients worldwide.	Hydro / onshore wind / solar / storage	Capacity: hydro 32%, onshore wind 27%, solar 16%, storage 17%, other 8%.	Hydro, wind and solar under long-duration PPAs.	0.44	0.37
Capital Power Corporation	Capital Power Corporation operates a diversified portfolio of power generating facilities. The Company develops, acquiring and optimizing power generation from a diverse range of energy sources.	Gas / coal	19% wind / solar / other renewable, remainder gas / coal.	N/A	0.60	0.34
Clearway Energy	Clearway Energy owns, operates, and acquires renewable and conventional generation and thermal infrastructure projects. The company offers natural gas and dual fired, solar and wind generation and distribution services. Clearway	Solar / onshore wind	Capacity: solar 28%, onshore wind 44%, gas 28%.	Majority revenue derived from long-term contractual arrangements.	0.32	0.37

Company	Bloomberg description	Primary technology	Technology mix	Revenue contracting	Asset Beta - Weekly	Asset Beta - Monthly
	Energy serves commercial businesses, universities, hospitals, and government companies in the United States.					
Concord New Energy Group Limited	Concord New Energy Group Limited specializes in wind power electricity generation. The companies' principal businesses include wind farm investment and operations, and manufacturing of wind power equipment. Concord New Energy also provides wind power electricity generation services such as feasibility studies, technological consultation, power plant design, engineering,	Onshore wind	Capacity: 87% onshore wind, 13% solar.	40% of portfolio assets are under "subsidy pricing", which have stable cash flows.	0.15	0.17
EDP Renovaveis SA	EDP Renovaveis SA designs, develops, manages, and operates power plants. The company generates electricity using renewable energy sources through wind energy. EDP Renovaveis serves customers worldwide.	Onshore wind	Capacity: 86% onshore wind, 14% mix of solar and offshore wind.	The majority of electricity is sold through PPAs or regulated tariffs.	0.72	0.51
Electric Power Development Co	Electric Power Development Co generates, transmits, distributes, and sells electric power using hydroelectric, wind-power, nuclear, coal-fired and other thermal power stations throughout Japan.	Coal / hydro	2% wind, 35% hydro, 36% coal.	PPA / guaranteed tariffs.	0.16	0.14
Encavis	Encavis provides electricity generation from power plants. The company produces power from renewable energy sources which includes solar energy plants and wind farms, as well as specialises in the technical operation of solar parks, routine maintenance, monitoring, incident management, and performance analysis. Encavis serves renewable energy sector in Europe.	Solar / onshore wind	N/A	Guaranteed tariffs and long-term PPAs.	0.38	0.27
Energix-Renewable Energies	Energix is an alternative energy company that invests in wind energy projects.	Solar / onshore wind	Capacity: 70% solar, 30% onshore wind.	Output in US is sold through long-term contracts.	0.74	0.71

CEPA economics matters

Company	Bloomberg description	Primary technology	Technology mix	Revenue contracting	Asset Beta - Weekly	Asset Beta - Monthly
				Assets in Israel and Poland have guaranteed CPI-linked tariffs.		
Enlight Renewable Energy	Enlight Renewable Energy is a renewable energy company. The company specializes in the initiation, development, financing, construction, management, and operation of wind and solar energy projects. Enlight Renewable Energy serves customers worldwide.	Solar / onshore wind	N/A	77% of capacity is under long-term PPAs. 23% under merchant sales.	0.59	0.56
ERG S.p.A.	ERG is a producer of energy from renewable sources (wind, solar, hydroelectric and thermoelectric) in Europe, with presence mainly in Italy, France and Germany. The company via a subsidiary carries out centralized Energy Management activities for all the generation technologies, and the Operations and Maintenance activities for most of its wind farms.	Onshore wind / hydro	EBITDA: 60% onshore wind,11% solar, 4% combined cycle gas (and electricity purchased), 25% hydro.	Renewable sales benefit from various guaranteed tariffs and other incentives. 37% of revenue was from guaranteed tariffs.	0.36	0.28
Kenon Holdings Limited	Kenon operates various businesses worldwide. The company's businesses engage in the development and operation of power generation facilities in Latin America, the Caribbean, and Israel. Kenon also owns businesses in the automotive, foundry manufacturing, international shipping, and solar technology industries.	CCGT	Wind, CCGT, OCGT and cogen.	Mixture of long-term PPAs and merchant exposure.	0.51	0.89
Meridian Energy Ltd.	Meridian Energy operates as a state-owned electricity generator. The company produces hydro-electric power and supplies electricity to residential, business, and rural customers. Meridian Energy provides services throughout New Zealand.	Hydro	91% hydro, 9% wind.	50/50 contracted sales and spot revenue.	1.13	1.13

Company	Bloomberg description	Primary technology	Technology mix	Revenue contracting	Asset Beta - Weekly	Asset Beta - Monthly
NextEra Energy Partners LP	NextEra Energy Partners owns, operates and acquires contracted clean energy projects including wind and solar.	Onshore wind	80% wind, 17% solar, remainder storage.	Long-term contracts.	0.47	0.46
Northland Power Inc.	Northland Power owns or has an economic interest in power generation facilities in Canada, the United States and Germany. The company's facilities produce electricity from clean natural gas and renewable energy sources, such as solar, wind and biomass. Northland Power maintains an active development and construction program for additional new power generation opportunities.	Offshore wind / onshore wind	EBITDA: 56% offshore wind, 25% onshore wind, 12% gas, 7% 'utilities'.	N/A	0.40	0.19
OPC Energy Ltd	OPC Energy provides energy solutions. The company focuses on the field of power generation and supply, including development, construction, and operation of power plants, as well as power generation and supply to private customers and to Israel electricity corporation. OPC Energy serves customers in Israel.	Thermal	Constructing OCGT, wind, solar.	N/A	0.55	0.35
RWE AG	RWE is a globally active energy company. The company generates and trades electricity. RWE has a capacity of about 10 gigawatts based on renewable sources, as well as gas fleet and an internationally active energy trading business. RWE serves clients in Europe, Asia-Pacific, and the United States.	Offshore wind	30% offshore wind, 7% onshore wind/solar, remainder coal/nuclear/hydro/gas/trading.	N/A	0.55	0.56
Scatec ASA	Scatec operates as an energy company. The Company installs, operates, and maintains solar, hydro, and wind power plants. Scatec serves customers worldwide.	Solar / hydro	EBITDA: 50% solar, 48% hydro, 2% onshore wind.	All generation assets across their portfolio are sold under 20-25 year PPA agreements, with some	0.49	0.62

Company	Bloomberg description	Primary technology	Technology mix	Revenue contracting	Asset Beta - Weekly	Asset Beta - Monthly
				guaranteed by the government.		
TransAlta Corporation	TransAlta Corporation is a non-regulated electric generation and marketing company with its growth focused in developing coal and gas-fired generation. The company is currently focused on Australia, Canada, the United States, and Mexico.	Hydro / gas	EBITDA: 30% hydro, 18% wind/solar, 36% gas, 16% 'other'.	N/A	0.54	0.54
TransAlta Renewables Inc.	TransAlta Renewables owns renewable power generation facilities. The company invests in contracted, renewable power generation assets including wind and hydroelectric plants.	Solar / onshore wind	EBITDA: 37% Canadian onshore wind, 19% USA onshore wind and solar, 3% hydro, 41% gas.	Essentially all generation is contracted, weighted average of life remaining of PPAs is approximately 12 years.	0.85	0.64
Uniper SE	Uniper operates as an international energy company. The company owns and manages a portfolio of power plants located across Europe and Russia, as well as focuses on commodity trading business, such as power, emission certificates, natural gas, liquefied natural gas, coal, and freight. Uniper also operates power and gas storage facilities.	Hydro / gas / coal / nuclear	37% flexible gas.	N/A	0.50	0.66
Vistra Corp	Vistra Corp provides utility services. The company generates energy. Vistra Corp serves customers worldwide.	Non-renewable	6% renewable (operating + development).	N/A	0.50	0.48

Source: CEPA analysis of Bloomberg data.

B.7. Evidence of technology-specific differences

In this section, we consider whether evidence from listed comparators supports a technology-specific WACC estimate. To explore potential differences in risk between companies with varying technologies and contracting arrangements, we collected publicly available information on these characteristics of the asset beta comparator sample. To provide an initial view, we sourced the relevant data from the most recent annual report (as at March 2023) and investor presentations.

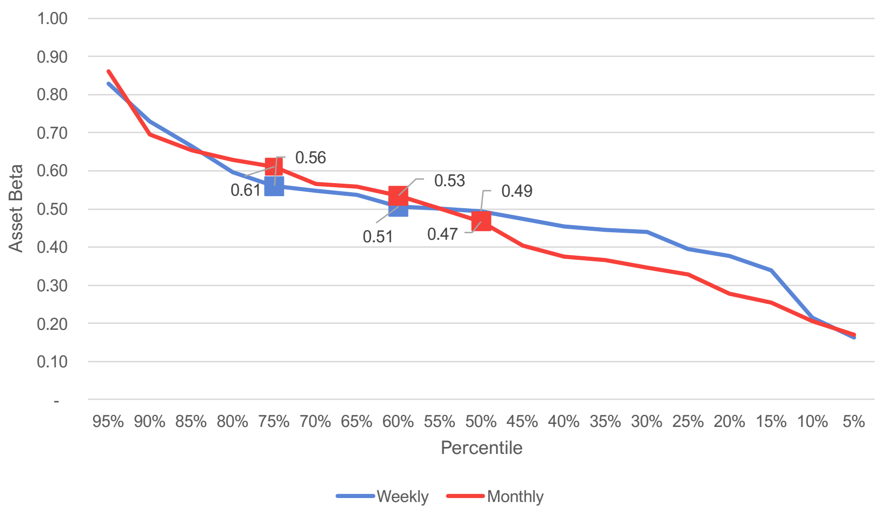
There are several limitations to the data we have been able to obtain:

- Firstly, there is no consistent measure available of the split in technologies across all the comparators. In theory, EBITDA as a measure of profit would be the most informative in determining the generation split for each company: this is because beta reflects the covariance between the company's returns (i.e., profits) and the returns on the broader market. As this is not available for every company, for some we instead collected reported installed capacity (MW) and/or revenues. Capacity can be less informative of the relative contribution of each technology type to the company's returns, as costs and revenues can differ significantly between different generation types. For example, material differences might be expected between renewable (low marginal cost) generators and OCGT which requires the purchase of gas.
- Secondly, the data represents a snapshot of the most recent financial results. For some of the companies, this is the 2021 financial year. Our beta estimation is over a five-year period from 2018-2023. Therefore, this snapshot might not fully represent the technology split over our estimation period. More fundamentally, beta relates primarily to the relationship between future *expected* returns of the company and broader market. A snapshot of historical data may fail to capture changes in expected future returns – for example, related to a company's development pipeline.

With these caveats in mind, the table in Section B.6 above indicates that the average of the weekly / monthly estimates for predominantly (80-100%) onshore wind comparators is 0.41, compared to the overall sample average of 0.49. However, this is based on just three comparators (Concord, EDP Renovaveis and NextEra). Further, the three predominantly wind comparators have asset betas in a range of 0.15 to 0.72 – suggesting the influence of factors other than the technology type. In light of this, and the limitations noted above, our overall judgement is that this limited evidence does not point to a technology-specific difference in asset beta.

However, the average asset beta estimate for the entire comparator sample falls within a range. The figure below presents the distribution of these results. We have considered this distribution when reflecting our qualitative assessment of technology-specific risks into a quantitative WACC estimate (Section 4.3).

Figure A.1: Distribution of comparator asset beta estimates



Source: CEPA analysis of Bloomberg data

APPENDIX C REVIEW OF INDEPENDENT EXPERT REPORTS

C.1. Overview

Independent expert reports (IERs) are prepared to provide advice to shareholders on the fairness and reasonableness of a proposed transaction. In some circumstances, the Corporations Act and ASX listing rules require an entity to commission a report to ensure shareholders receive adequate information. A key element of an IER is establishing the fair valuation of the company in question. IERs that use a discounted cashflow methodology will include an assumed WACC as the discount rate. Therefore, IERs that value companies with energy generation, storage or firming assets, using a discounted cash flow methodology, are relevant sources of evidence for this advice.

In practice, we have found this to be a relatively sparse source of information, either because there have been limited acquisitions of ASX-listed companies with investments in relevant technologies, or the IERs are not always publicly available. Where IERs are available, a discounted cash-flow methodology may not always be used to value the relevant assets, particularly when these assets are part of a development pipeline and not yet operational. In other cases, the relevant generation and storage assets are a small component of the overall assets being valued, and the discount rate applied in the valuation may not be reflective of the inherent risks of the technologies we are interested in.

Using the IJGlobal database, CEPA collated information on relevant Australian company transactions over the last 10 years.[103] Out of the 82 transactions we identified, 10 IERs were found. Seven of these independent reports included calculations of discount rates that were relevant to the technologies of interest. Across available sources, limited information was found on offshore wind, batteries, pumped hydro and open cycle gas turbines. No information was found on battery technologies in Australia.

Table C.1: Number of sources found across IERs and supplementary sources, by technology type

Target Technology	Australia	Other Countries
Solar PV	3	1
Wind (onshore)	4	4
Wind (offshore)	-	-
Short duration batteries	-	-
Long duration batteries	-	1
Pumped hydro	1	-
Open cycle gas turbines	1	-

The reports primarily provide evidence on asset beta and the overall discount rate, with limited useful information provided on the debt risk premium, credit ratings or gearing. Accordingly, the analysis below focusses on differences in the asset beta and the overall WACC applied by the valuer.

C.2. Evidence on asset beta

The table below presents asset beta assumptions taken from the independent expert reports that we reviewed. This indicates an asset beta range of:

- 0.6 – 0.7 for solar PV assets.

[103] Search parameters used were Transaction Type: Company Acquisitions, Primary Sector: Power and Renewables, Regions: Australia, Dates: 01/01/2013 – 07/03/2023. This resulted in 82 transactions.

- 0.4 – 0.6 for onshore wind, placing limited weight on the DUET (EDL Australia) valuation given that the discount rate was primarily applied to non-wind assets.
- 0.6 – 0.7 for hydro, although hydro assets do not appear to include pumped hydro and represent a small fraction of the overall assets being valued.
- 0.69 – 0.75 for OCGT, with the lower bound reflecting a 10-year offtake agreement and the upper bound reflecting a merchant project.
- While some of the Australian valuation reports included battery assets, these were not valued using a discounted cash flow methodology, and hence no WACC estimate was made. A valuation related to a battery located in the Philippines applied an asset beta assumption of 0.48.

We note that only in one case (ACEN) was the same valuer establishing a discount rate for multiple technology types. For Australian assets, onshore wind (0.57) was slightly lower risk than solar (0.63). The ranking was reversed for assets located in the Philippines (solar ranked lowest risk, behind the battery and then onshore wind). The technology specific-differences, and the different technology ranking for Australia and the Philippines, reflected the valuer's decision to adopt a different comparator sample for each technology type and country. No commentary or qualitative reasoning was provided to support the different comparator samples, or the result they produced.

Taken together, the other IERs point in a similar direction as the ACEN Australian valuation, with onshore wind having a materially lower range than solar. Further, it is interesting to note that the asset beta assumptions applied for the solar asset valuations are all materially higher than suggested by the listed comparator sample described in section above (i.e., a range of 0.6-0.7 compared to our point estimate of 0.5). The other IERs also set the asset beta assumption with reference to a comparator sample. In practice the comparator samples reflected a mix of technologies, in addition to those of the same type as the assets being valued. Again, the precise reasons for the sample selection are not stated. As these IERs were valuing a single technology, it is difficult to judge whether the valuer would in practice have used a different assumption for wind and solar assets.

Table C.2: IER commentary on asset beta

Company	Year	Assets valued	Solar PV	Wind (onshore)	Pumped hydro	Battery	OCGT
Australia							
Spark Infrastructure	2021	Bomen Solar Farm. Approximately 95% output contracted under commercial PPAs for 5 years, 82% for 10 years.	0.6 – 0.7				
Zenith Energy	2020	Owns, operates or maintains 400MW of gas, diesel, solar, wind and geothermal, serving the mining sector in remote areas of Australia. Solar accounts for 3%, the majority is gas and diesel. Energy is sold under PPAs.	0.60 - 0.66*				
ACEN	2021	Wind and solar, including New England Solar (NSW) expected to commence operation in January 2023.	0.63	0.57			
Tilt Renewables	2021	9 wind farms generating in Australia and NZ. Approximately 80% Australian assets under commercial PPAs.		0.5 – 0.6			
WindLab	2020	Ownership and commercial interest in operating wind farms. In addition, a risk premium differential of 0.3% was applied between projects with 20-year government PPAs compared to a project with a 5-year PPA.		0.4 – 0.5			
DUET (EDL Australia)		EDL owns, operates and maintains remote and clean energy operations (Waste Coal Mine Gas, landfill gas, wind). Wind 4% Australian generation.		0.7 – 0.75			
Pacific Energy	2019	Specialise in supplying generation to remote sites in Australia and Africa. Own 2 grid-connected hydro power stations in Victoria (6MW, 1% total generation) under recurring 5-year commercial PPAs.			0.6 – 0.7		
ERM Power	2019	Operates 2 peaking OCGTs in Western Australia and Queensland, the former with a 10-year offtake agreement.					0.69 with off-take, 0.75 without
Other							

Company	Year	Assets valued	Solar PV	Wind (onshore)	Pumped hydro	Battery	OCGT
Tilt Renewables (NZ)	2021	See above.		0.5 – 0.6			
ACEN (Philippines)	2021	Alaminos battery, expected to provide ancillary services under 10-15 year contract.	0.40	0.57		0.48	

*Asset beta not directly stated, estimate based on reported equity beta and leverage.

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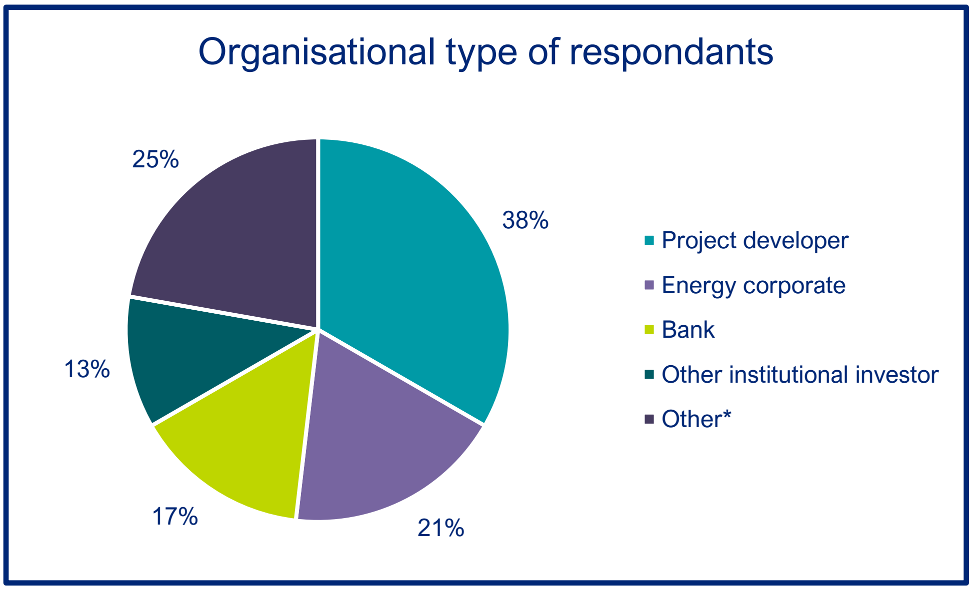
APPENDIX D SURVEY RESPONSE SUMMARY

The following information has been drawn from a survey of debt and equity investors conducted between 11 July and 11 August 2023. The survey was sent to members of the Clean Energy Council (CEC), Clean Energy Investors Group (CEIG) and over 100 other industry stakeholders that ASL engages with regularly. Where required, survey responses have been aggregated to protect the anonymity of respondents.

D.1. Respondent Information

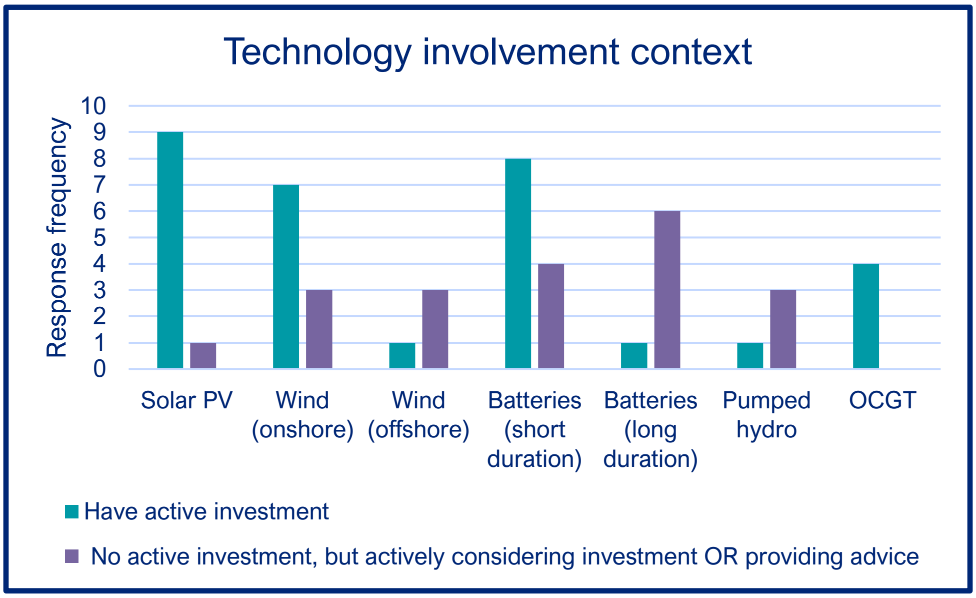
This section relates to the following survey questions:

1. Which description best matches your organisation?
2. Please indicate which technologies your organisation is actively involved in.
3. Please indicate in what context your organisation typically invests in / advises on each technology.
4. Please indicate which phase of the project lifecycle your responses will relate to.
5. Please indicate what revenue model you consider to be most common for each technology. Please assume this revenue model applies when responding to other questions in this survey, unless indicated otherwise.
6. Please indicate whether you are able to comment on the cost of debt, cost of equity, or both.

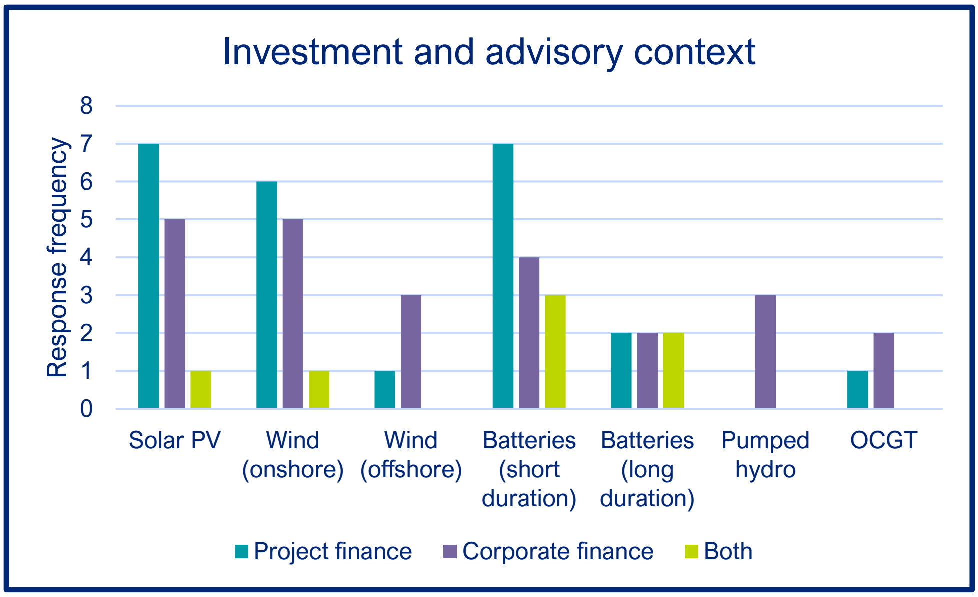


The survey received 24 individual responses across a range of organisations.

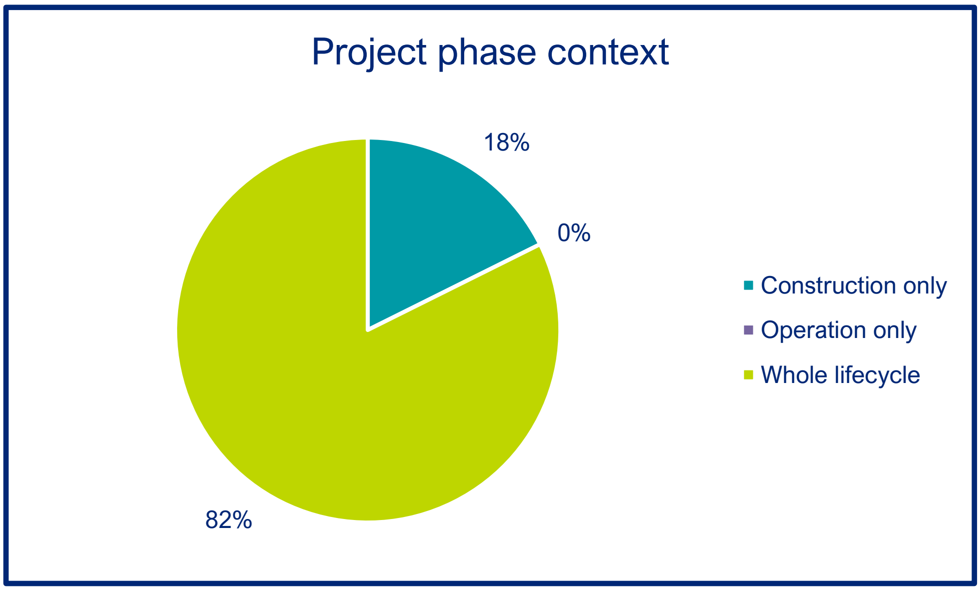
*Other includes all other categories with less than 3 responses (superannuation funds, private investors, investment advisors, non-financial corporates and contractors).



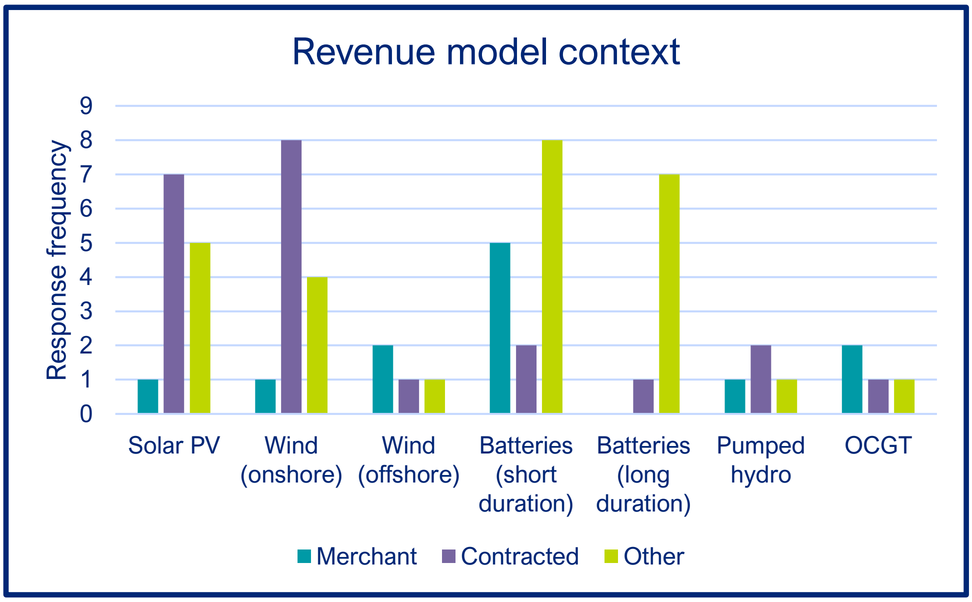
Many survey respondents either had active investments or were considering investments or providing advice across the technologies of interest. Respondents were most familiar with solar PV, onshore wind and short-duration batteries.



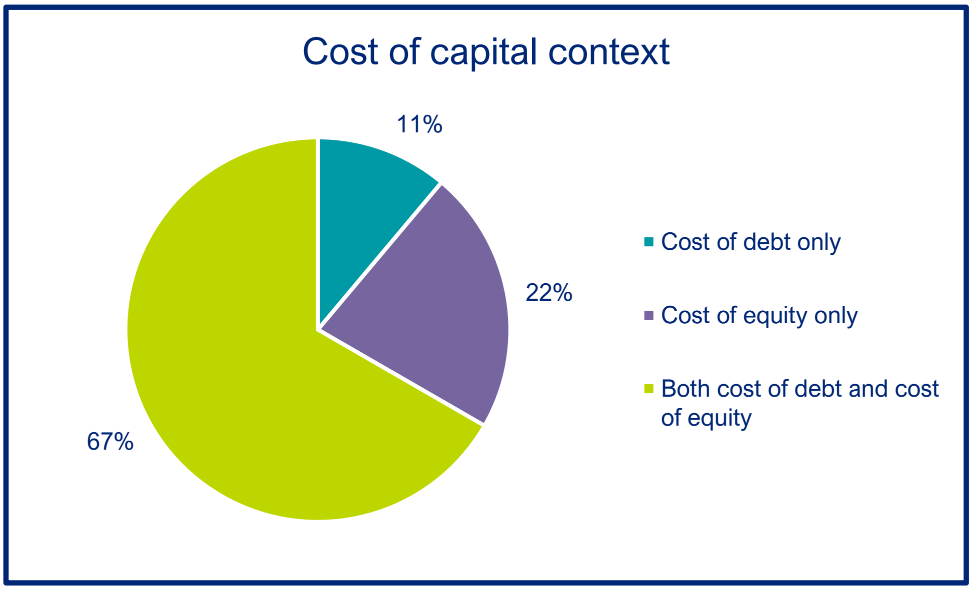
Except for pumped hydro which was purely corporate finance, respondents approached the survey from a mix of project finance and corporate finance investment and advisory perspectives.



Most respondents considered projects from a whole lifecycle (both construction and operational phases) perspective with a small number involved only in construction or pre-construction phases.



Respondents thought that contracted revenue models were most common for solar PV and onshore wind projects. 'Other' was the predominant response for batteries (long and short duration). All respondents who selected 'other' noted that projects typically had a combination of merchant and contracted revenue.



Most respondents commented on the cost of capital from both cost of debt and cost of equity perspectives. These respondents were also asked additional questions relating to overall hurdle rates later in the survey.

D.2. Cost of debt

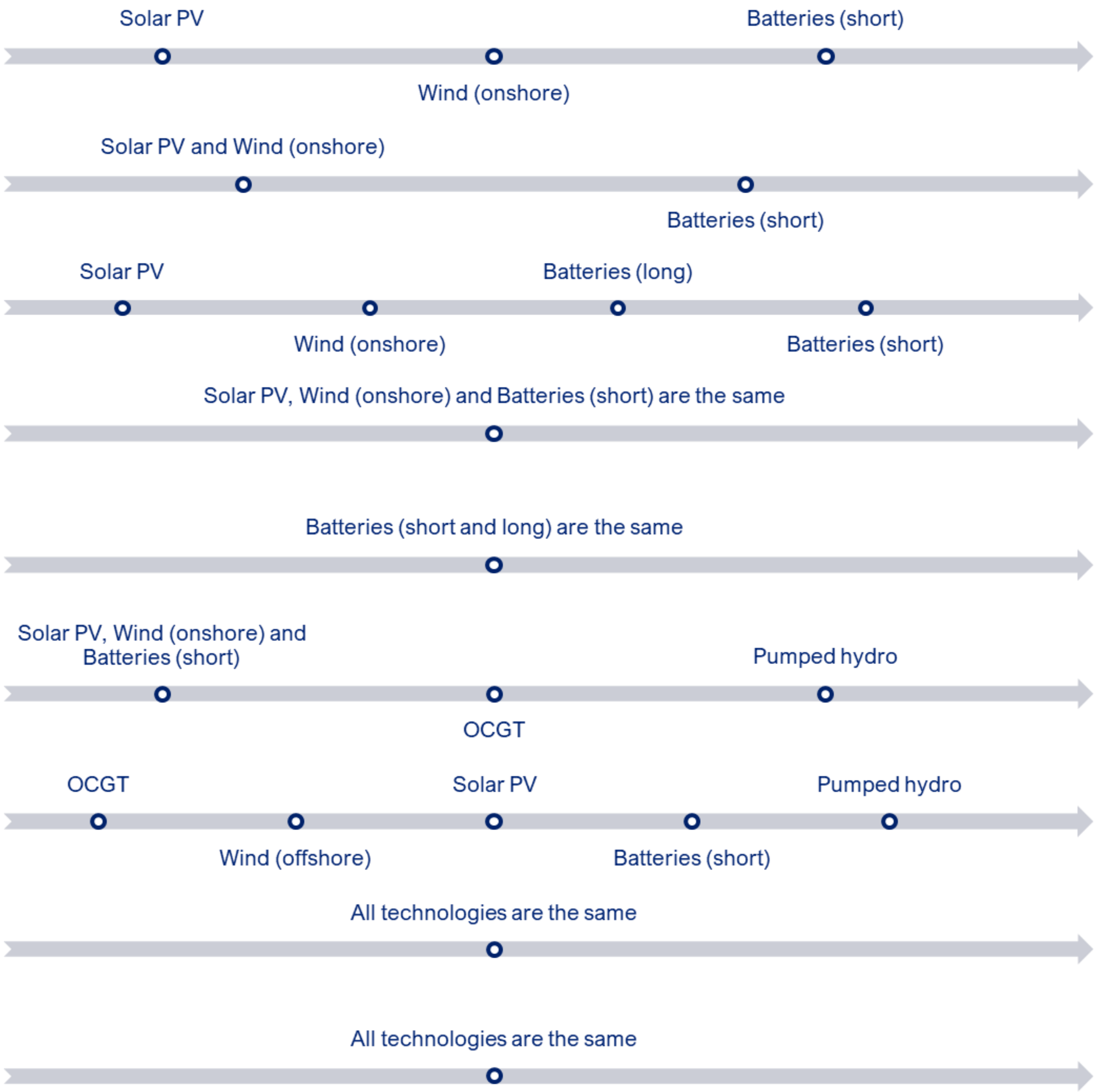
This section relates to the following survey questions:

7. Please rank each technology from lowest to highest cost of debt.
8. Please indicate the cost of debt (%) you consider appropriate for each technology.
9. Please indicate if your responses are stated as pre-tax or post-tax and in real or nominal terms. What inflation assumptions, if any, are used?

Cost of debt: Relative rankings

Nine respondents participated in ranking the various technologies from lowest (left) to highest (right) cost of debt. Responses are summarised in the figure below:

Figure D.1: Cost of debt, ranked by technology type (left low, right high)



- Where respondents thought the cost of debt should vary across the technologies, solar PV and onshore wind primarily ranked below other technologies.
- Four respondents thought onshore wind and solar PV should have the same cost of debt. Two respondents thought onshore wind should have a higher cost of debt than solar PV, and the one respondent who ranked offshore wind thought it had a lower cost of debt than solar PV. Reasons for the various rankings of onshore wind and solar PV were not provided.
- Three respondents thought the cost of debt for short and long duration batteries was the same, while one respondent thought the cost of debt should be higher for short duration batteries. Respondents also commented that the typical battery revenue model (involving a combination of merchant wholesale market revenues, arbitrage, and frequency control ancillary services) was considered riskier by lenders. Respondents also noted that short and long duration batteries shared similar risks, although one respondent noted there could be a slight difference due to the tenor of debt between the two (i.e., long-duration batteries were considered likely to have a longer tenor).
- Two responses thought pumped hydro had a higher cost of debt than short duration batteries and one respondent thought OCGT should have a lower cost of debt than pumped hydro.

Cost of debt: Estimates

Four respondents provided estimates for the cost of debt across solar PV, wind and battery technologies. For comparison, these have been converted to pre-tax real estimates[104]. Only one response was collected for long-duration batteries and offshore wind respectively. The respondent who provided an estimate for offshore wind also provided the same estimate for onshore wind and solar.

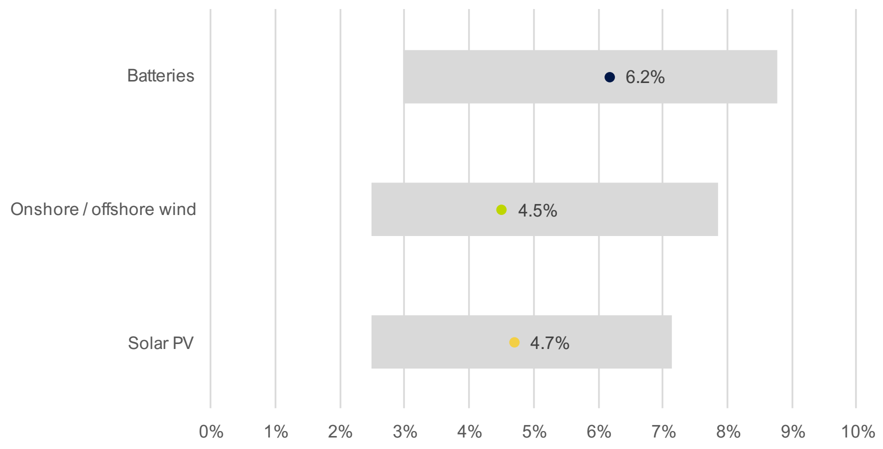
Table D.1: Pre-tax real cost of debt estimates

	Solar PV	Wind (onshore and offshore)	Batteries (short and long duration)	Pumped hydro	OCGT
Average	4.7%	4.5%	6.2%	n/a	n/a
Min	2.5%	2.5%	3.0%	n/a	n/a
Max	7.1%	7.9%	8.8%	n/a	n/a

There was a wide degree of variation in the cost of debt estimates for solar PV, onshore wind and short-duration batteries (Figure D.2). Offshore wind and long-duration batteries received only one response each.

[104] We assume 2.5% inflation, a corporate tax rate of 30%, 25% gamma and a BBSW of 3.6% (as of end of February 2023 for 3-month BBSW).

Figure D.2: Pre-tax real cost of debt (range and average)



Where respondents provided estimates for multiple technologies, the average magnitude of the difference (delta) between the compared technologies has been recorded in the table below, using onshore wind and solar PV as the baseline. Only one comparison was made for offshore wind and long duration batteries.

Table D.2: Average delta to the pre-tax cost of debt estimates of different technologies compared to onshore wind and solar PV

	Batteries (short and long duration)	Pumped hydro	OCGT
Difference	+1.7%	n/a	n/a

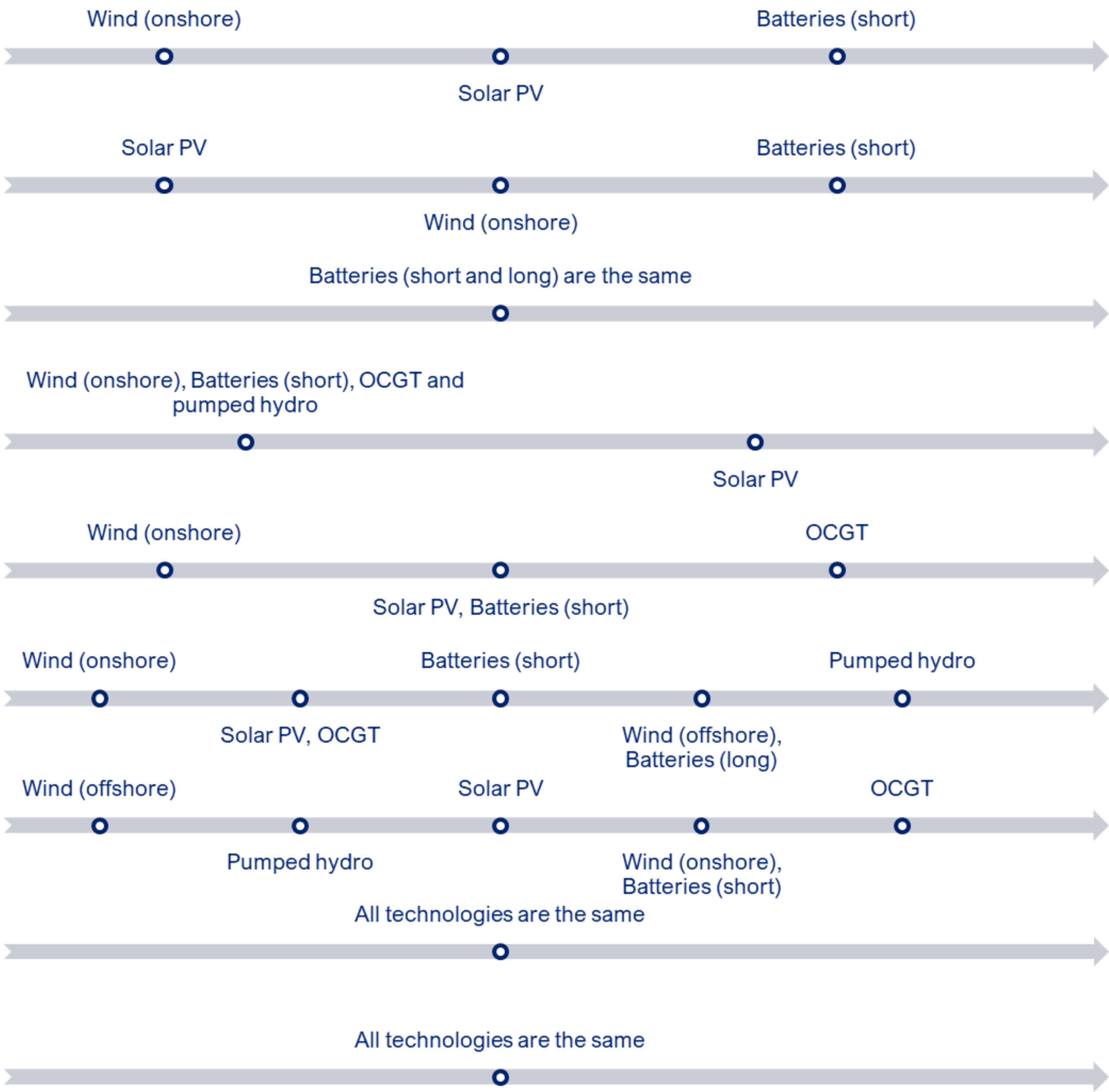
D.3. Cost of equity

> This section relates to the following survey questions:
>
> 10. Please rank each technology from lowest to highest cost of equity.
> 11. What risk-free rate would you currently use to determine the cost of equity?
> 12. What market risk premium would you currently use when determining the cost of equity?
> 13. Please indicate the cost of equity (%) you consider appropriate for each technology.
> 14. Please indicate if your responses are stated as pre-tax or post-tax and in real or nominal terms. What inflation assumptions, if any, are used?

Cost of equity: Relative rankings

Nine respondents participated in ranking the various technologies from lowest (left) to highest (right) cost of equity:

Figure D.3: Cost of equity, ranked by technology type (left low, right high)



Across the rankings, there was wide variation.

- Onshore wind was ranked the lowest most frequently (4 responses).
- Solar PV was mostly lower than batteries (4 responses) with one response saying solar PV was higher than short-duration batteries and another response saying solar PV and short-duration batteries are the same.
- Short and long-duration batteries were ranked together, they were mostly ranked the same with one response ranking short-duration batteries lower than long-duration batteries.
- OCGT and pumped hydro were ranked some of the highest and lowest across the technologies.

Through the comments section, a respondent noted solar PV was of higher risk than onshore wind due to concentration risk and the increasing prevalence of rooftop solar systems creating competition during peak solar generation hours and more exposure to negative pricing as a result. Comparatively, onshore wind has less correlation with day time generation and can participate in peak demand periods. Construction and commissioning risk was noted in relation to offshore wind, particularly in Australia where offshore wind is a novelty. Pumped hydro was thought to be more established than batteries, which may have operating risks that are yet to be fully understood. However, it was also noted that geological complexities (resulting in construction risk) was a concern for pumped hydro. Long and short-duration batteries were noted again to be comparable, but affected by FCAS volatility. The only comment that mentioned OCGT noted connection risk and high reliance on fuel costs could impact the hurdle rate.

Cost of equity: Risk-free rate and Market Risk Premium Assumptions

A wide range of responses were received when respondents were asked what risk-free rate (RFR) and market risk premium (MRP) they use to calculate the cost of equity. One respondent used the prevailing BBSY (bank bill swap rate) as the risk-free rate, but did not provide a current estimate.[105] Six of the seven respondents who provided their underlying assumptions for the risk-free rate referenced 10-year government bonds, which is the same reference point as the technology neutral estimate. Although some participants that they may use different averaging periods, in most cases responses are broadly comparable to the technology neutral estimate of 3.75%. No additional commentary was provided regarding respondent’s underlying methodology for determining the MRP.

The assumptions column states responses to an overarching question on what basis respondents had answered *all* questions on the cost of equity. Based on the responses, it is not clear that this accurately captures the basis of the RFR and MRP assumptions.

Table D.3: Respondents’ RFR and MRP assumptions

	RFR	MRP	Stated assumptions
	4.0%	6.0%	Post-tax, nominal
	6.3%		Pre-tax, real
	4.1%	5.0-8.0%	Pre-tax, nominal
	4.0%	7.0%	Pre-tax, nominal
	4.0%	4.5%	Pre-tax, real
	3.3-3.5%	6.0%	Post-tax, nominal
	BBSY	4.6%	Not stated
Average	**4.3%**	**5.7%**	
Min	**3.3%**	**4.5%**	

[105] For reference, as at the end of February 2023, the 3-month BBSY was approximately 3.6%.

	RFR	MRP	Stated assumptions
Max	**6.3%**	**8.0%**	

Cost of equity: Estimates

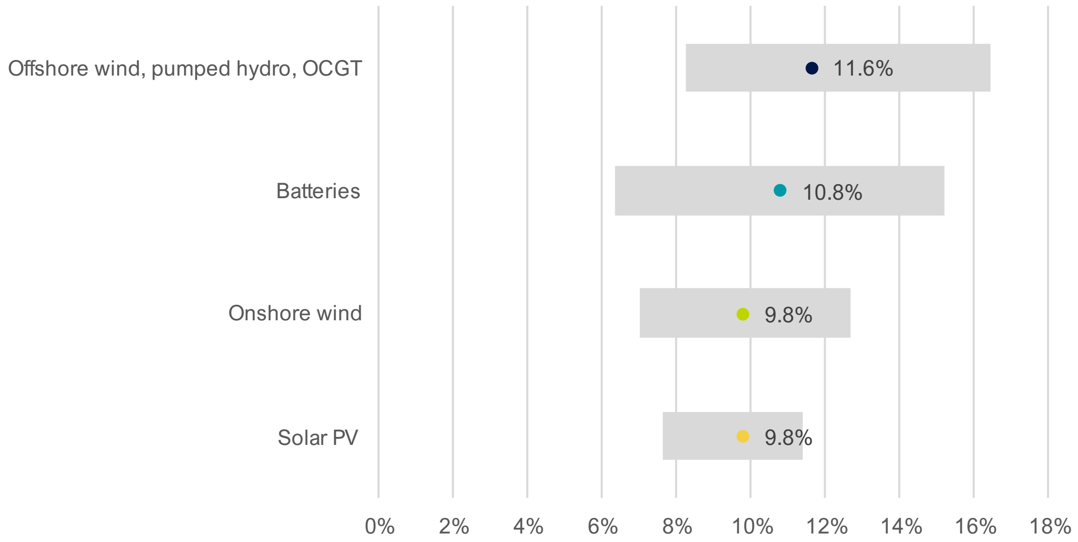
Six respondents provided estimates for the cost of equity across technologies. For comparison, these have been converted to pre-tax real estimates[106]. Only one response was collected for offshore wind and pumped hydro respectively, while OCGT had two responses. The one respondent that provided a cost of equity estimate for offshore wind did so for all technologies and placed offshore wind second highest, below pumped hydro.

Table D.4: Pre-tax real cost of equity estimates

	Solar PV	Wind (onshore)	Batteries (short and long duration	Offshore wind, pumped hydro, OCGT
Average	9.8%	9.8%	10.8%	11.6%
Min	7.6%	7.0%	6.3%	8.3%
Max	11.4%	12.7%	15.2%	16.4%

There was a wide degree of variation in the cost of equity estimates across technologies (Figure D.4). Offshore wind and pumped hydro received only one response each.

Figure D.4: Pre-tax real cost of equity (range and average)



Where respondents provided estimates for multiple technologies, the magnitude of difference between the compared technologies has been recorded as an average delta (change), using onshore wind and solar PV as the baseline.

[106] See footnote 111.

Table D.5: Average delta to the pre-tax cost of equity estimates of different technologies compared to onshore wind and solar PV

	Batteries (short and long duration)	Offshore wind, pumped hydro, OCGT
Difference	+1.7%	+2.3%

D.4. Hurdle rates

> This section relates to the following survey questions:
>
> 15. Please rank each technology from lowest to highest overall hurdle rate.
> 16. Please indicate the overall hurdle rate (%) you consider appropriate for each technology.
> 17. Please indicate if your responses are stated as pre-tax or post-tax and in real or nominal terms. What inflation assumptions, if any, are used?

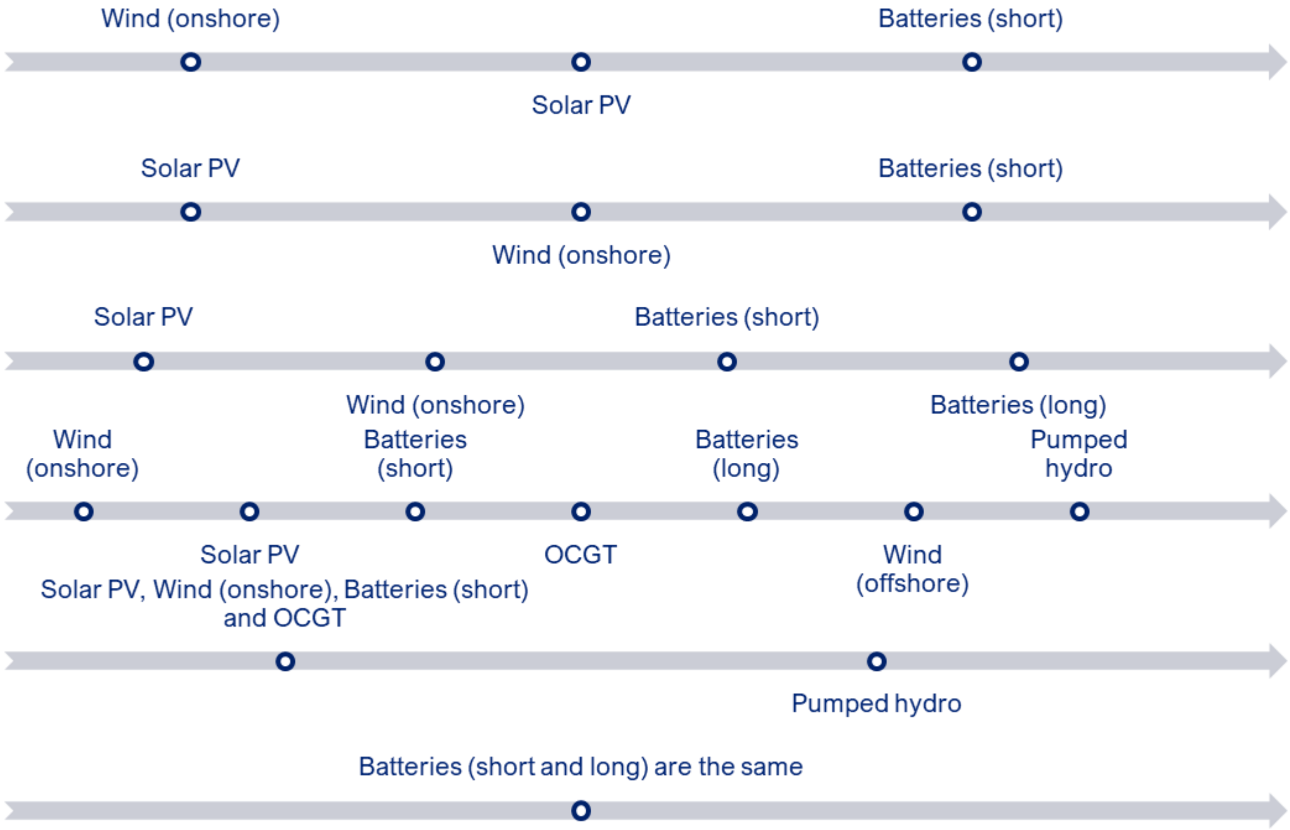
This section was only asked to respondents who said they could comment from both cost of debt and cost of equity perspectives. The hurdle rate provided are stand-alone responses and are not calculated as a combination of any cost of debt and cost of equity responses.

Hurdle rates: Relative rankings

Five respondents ranked the various technologies from lowest (left) to highest (right) overall hurdle rate across technologies.

- Solar PV and onshore wind were consistently ranked the lowest or second lowest across responses.
- Pumped hydro was ranked the highest in the two responses it was mentioned.
- With the exception of one response, batteries were ranked higher than solar and onshore wind. Of the three responses that ranked both kinds of batteries, two respondents ranked short-duration batteries below long-duration batteries and one ranked them the same.
- The two responses that considered OCGT ranked the hurdle rate similar to batteries.
- Only one response ranked offshore wind, and it was ranked second highest before pumped hydro.

Figure D.5: Hurdle rate, ranked by technology type (left low, right high)



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Hurdle rates: Estimates

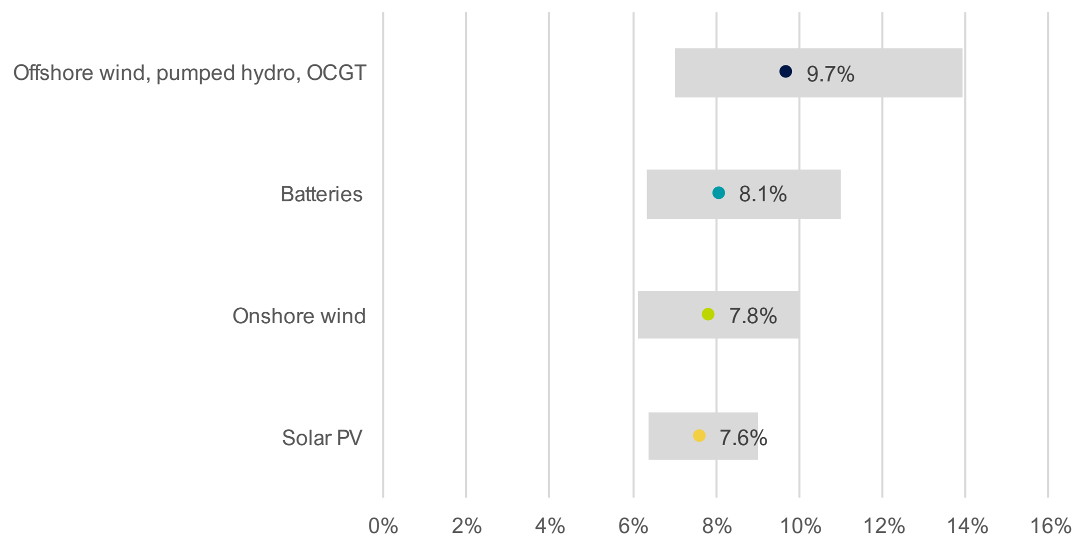
Four respondents provided estimates for the overall hurdle rate across technologies. For comparison, these have been converted to pre-tax real estimates[107]. Only one response was collected for offshore wind while pumped hydro and OCGT had two responses.

Table D.6: Pre-tax real hurdle rate estimates

	Solar PV	Wind (onshore)	Batteries (short and long duration	Offshore wind, pumped hydro, OCGT
Average	7.6%	7.8%	8.1%	9.7%
Min	6.4%	6.1%	6.3%	7.0%
Max	9.0%	10.0%	11.0%	13.9%

There was a wide degree of variation in the overall hurdle rate estimates across technologies (Figure D.6). Offshore wind received only one response, while OCGT and pumped hydro each received two.

Figure D.6: Pre-tax real hurdle rate (range and average)



Where respondents provided estimates for multiple technologies, the magnitude of difference between the compared technologies has been recorded as an average delta (change), using onshore wind and solar PV as the baseline.

Table D.7: Average delta to the pre-tax hurdle rate estimates of different technologies compared to onshore wind and solar PV

	Batteries (short and long duration)	Offshore wind, pumped hydro, OCGT
Difference	+0.8%	+2.8%

[107] See footnote 111.

D.5. REVENUE MODEL ASSUMPTIONS

This section depends on the respondent's answer to question 5 and relates to the following survey questions:

18. For any technologies where you indicated a merchant revenue model is not common, how would the cost of debt change if the project was merchant?
19. For any technologies where you indicated a merchant revenue model is not common, how would the cost of equity change if the project was merchant?
20. For any technologies where you indicated a merchant revenue model is not common, how would the hurdle rate change if the project was merchant?

Survey respondents were in broad agreement that merchant revenue models would increase the cost of debt, cost of equity, and overall hurdle rates across technologies. In summary, responses estimated:

- A 200-280bps increase in the cost of debt (related to solar PV / wind only
- A 100-200bps increase in the cost of equity (related to solar PV / wind only).
- A 150-350bps in the overall hurdle rate (related to batteries only).

Qualitative commentary is summarised below.

Cost of debt impact

In the context of **long and short duration batteries**, one respondent did not consider a fully merchant project would be able to attract debt financing due to the higher risk and would need to be fully funded by equity. They assume batteries are partially contracted with significant merchant exposure.

Another respondent noted the same for **solar PV** and would not consider financing a fully merchant solar PV project. They also noted that a fully merchant **short-duration battery** project would only be considered under exceptional circumstances. For **onshore wind**, an increased debt margin was considered likely as the project becomes more merchant. They assume contracted revenue arrangements for solar and wind.

Cost of equity impact

In the context of **solar PV** and **onshore wind**, one respondent considered a higher return would be required for a purely merchant project. They assume contracted revenue arrangements for solar and wind.

Hurdle rate impact

In the context of **long and short duration batteries**, one respondent considered a higher return would be required for a fully merchant project. They assumed up to 70% of the project's revenues are contracted under a 'typical' revenue model.

Another respondent considered that a higher discount rate would be required for **solar PV, onshore wind** and **short-duration batteries** if under a fully merchant revenue model, due to price fluctuations. They assume that the 'typical' project would have both contracted and merchant exposure.

Another respondent noted that under a merchant revenue model, **solar PV** would be subject to high concentration risk from competing with other large scale solar and residential solar, and investing in a merchant solar PV project in isolation would be unlikely. For **onshore and offshore wind**, they considered the hurdle rate would increase due to lower gearing and a higher cost of equity due to increased price exposure risk. For **batteries, pumped hydro** and **OCGT**, they considered that much lower gearing would increase hurdle rates. They assume a combination of contracted and merchant exposure under the typical revenue model.

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D.6. LTESA Impact

> This section relates to the following survey questions:
>
> 21. Please indicate the directional impact that holding an LTESA would have on the cost of debt.
> 22. Please indicate the absolute impact (-/+%) that holding an LTESA would have on the cost of debt.
> 23. Please indicate the directional impact that holding an LTESA would have on the cost of equity.
> 24. Please indicate the absolute impact (-/+%) that holding an LTESA would have on the cost of equity.
> 25. Please indicate the directional impact that holding an LTESA would have on the overall hurdle rate.
> 26. Please indicate the absolute impact (-/+%) that holding an LTESA would have on the cost of debt, cost of equity, and overall hurdle rate.

Respondents were asked to consider the following assumptions when responding to questions on generation LTESAs:

> The NSW Electricity Infrastructure Roadmap allows developers of eligible generation projects to secure long term energy services agreements (generation LTESAs) that reduce exposure to low wholesale electricity market prices.
>
> Assume the project holds a generation LTESA. The LTESA provides an option to enter into a 20-year swap, that would protect 100% of the project's output from merchant price risk. The counterparty to the swap is Aa3 rated by Moody's. The option can be used alongside any commercial PPAs or other contracts that the project has entered into (i.e., can be used cover uncontracted output). The LTESA will not interfere with the settlement of any commercial PPAs/contracts.
>
> Please assume that the project is not located in a REZ.

Similarly, respondents were asked to consider the following assumptions when responding to questions on long-duration storage LTESAs:

> The NSW Electricity Infrastructure Roadmap allows developers of long-duration storage (LDS) and firming projects to secure long term energy services agreements (LDS / Firming LTESAs) that reduce revenue risk.
>
> Assume the project holds an LDS / Firming LTESA. The LTESA provides an option to receive a top-up payment to a pre-defined minimum revenue amount, for a term of 10 years. The minimum revenue amount would have been specified by the project in its bid for the LTESA.
>
> The counterparty is Aa3 rated by Moody's. The option can be used alongside any commercial PPAs or other contracts that the project has entered into (i.e., to bridge a shortfall in contracted revenues). The LTESA will not interfere with the settlement of any commercial PPAs/contracts.
>
> Please assume that the project is not located in a REZ.

LTESA: impacts

Survey respondents held mixed views on the impact of LTESAs on the cost of capital. Further, the results differed depending on what technology type (and associated revenue model) the response related to.

The table below summarises both qualitative and quantitative responses that related to wind and solar PV technologies. This indicates that respondents were divided as to whether holding an LTESA would, or would not, be likely to impact the overall hurdle rate for these technologies.

In contrast, responses that related to short- and long-duration batteries provided stronger evidence that holding an LTESA would reduce the cost of capital for these assets. Respondents provided estimates of a 1-2.5% reduction in the overall hurdle rate. The difference in responses for wind / solar PV and batteries appears primarily to reflect different assumptions around the typical revenue model for each group of technologies.

Table D.8: Survey responses - LTESA impact - wind and solar PV

	Responses related to wind and solar PV	Responses related to batteries
Number of responses	7	8
Cost of debt	No change / unsure: 4 Increase: 1 Decrease: 1 No quantitative estimates	No change / unsure: 3 Increase: 0 Decrease: 4 Quantitative estimate: -1% to -1.5%
Cost of equity	No change / unsure: 3 Increase: 0 Decrease: 2 Quantitative estimate: -2%	No change / unsure: 3 Increase: 0 Decrease: 3 Quantitative estimates: -2% to -3%
Hurdle rate	No change / unsure: 3 Increase: 0 Decrease: 1 Quantitative estimate: -1%	No change / unsure: 3 Increase: 0 Decrease: 3 Quantitative estimates: -1% to -2.5%

Source: CEPA analysis of survey responses.

APPENDIX E EVIDENCE FROM OTHER STUDIES

E.1. GOHDES AND SIMSHAUSER (2022)[108]

Gohdes and Simshauser (2022) present survey results that describe the impact of various contracting and counterparty arrangements on the cost of equity, cost of debt and gearing for a variable renewable generator. The survey results reflect the views of 14 respondents that were either the principal investor or project financier of the asset, as of 2021. The mean value of the survey results in presented in the table below. A 'partial' PPA represents 50% of run-of-plant, while a 'full' PPA covers 100% of output.[109] A merchant asset has no contract in place. It is not clear whether the assumed PPA duration is the life of the asset, or a shorter period.

Table E.1 Gohdes and Simshauser (2022) survey results (mean results)

Counterparty and contract	Equity return (%)	Credit spread (bp)	Gearing ratio (%)
Merchant	12.25%	2.60%	40.75%
Partial Corporate PPA	9.75%	2.00%	56.75%
Full Corporate PPA	8.00%	1.80%	69.25%
Partial Retail PPA	9.75%	2.00%	57.50%
Full Retail PPA	8.00%	1.80%	67.50%
Partial Government CfD	7.75%	1.80%	64.25%
Full Government CfD	6.25%	1.40%	72.50%

Source: Gohdes and Simshauser (2022), p.8.

We understand that the results above represent a post-tax nominal cost of equity and a pre-tax nominal cost of debt. Accordingly, adjustments are required to translate these observations to pre-tax real terms to inform our analysis. The table below sets out CEPA's derivation of pre-tax real values for the reported cost of equity and cost of debt impacts, and the overall effect on the pre-tax real WACC. Our assumptions are described in the notes to the table. These results indicate:

- Moving from a retailer or corporate PPA to a government CfD reduces the pre-tax real WACC by 1.7% in the case of a partial contract (50% of output covered) and 1.1% in the case of a full contract (100% output covered). It is not clear why the reported impact is lower for a full contract than a partial contract.
- Moving from a merchant revenue model to a retailer / corporate PPA reduces the pre-tax real WACC by approximately 3.7% for a partial PPA and 5.4% for a full PPA.
- Moving from a merchant revenue model to a government CfD reduces the pre-tax real WACC by approximately 5.3% for a partial CfD and 6.6% for a full CfD.
- Moving from a partial contract (50%) to a full contract (100%) reduces the pre-tax real WACC by 1.3% (government CfD), 1.7% (retailer PPA) and 1.9% (corporate PPA).

[108] Gohdes, N. and Simshauser, P., *Renewable entry costs, project finance and the role of revenue quality in Australia's National Electricity Market*, Cambridge Working Papers in Economics 2206, 24 January 2022.

[109] Gohdes and Simshauser (2022), p.12.

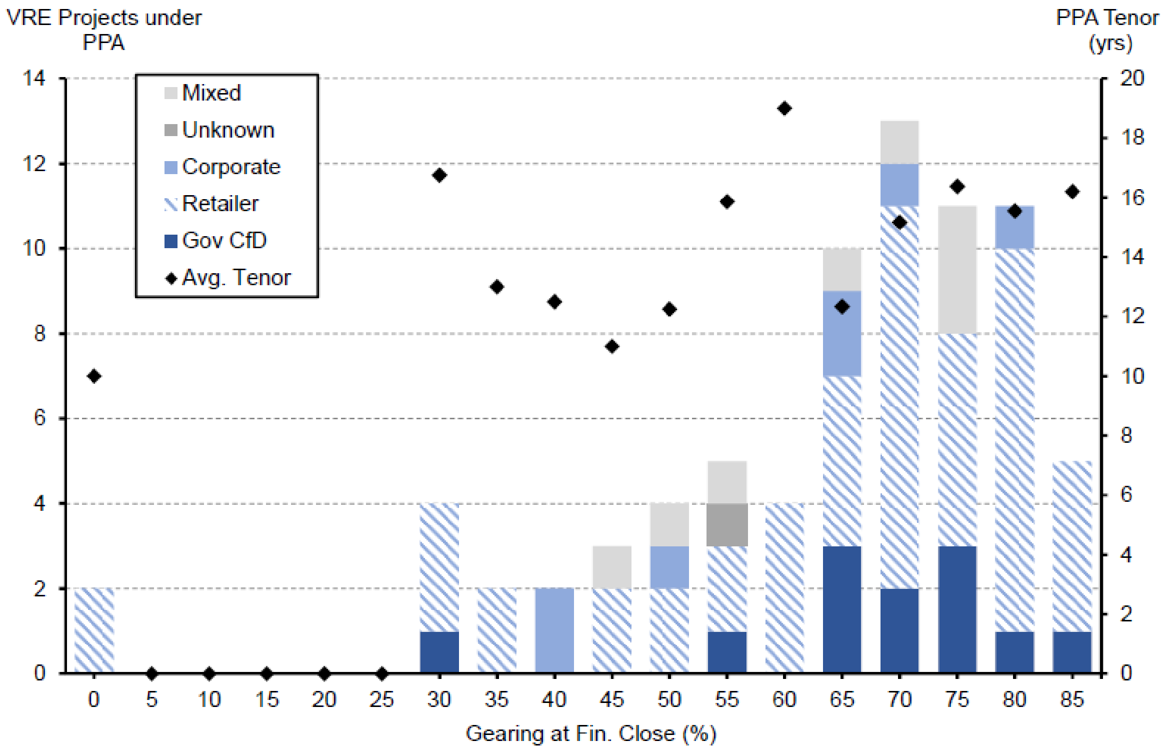
Table E.2: Translation of Gohdes and Simshauser (2022) results to pre-tax real terms

Counterparty and contract	Pre-tax real cost of equity (%)	Pre-tax real cost of debt (%)	Gearing (%)	Pre-tax real WACC (%)
Merchant	15.20%	4.26%	40.75%	10.74%
Partial Corporate PPA	11.69%	3.68%	56.75%	7.14%
Full Corporate PPA	9.24%	3.48%	69.25%	5.25%
Partial Retail PPA	11.69%	3.68%	57.50%	7.08%
Full Retail PPA	9.24%	3.48%	67.50%	5.35%
Partial Government CfD	8.89%	3.48%	64.25%	5.42%
Full Government CfD	6.79%	3.09%	72.50%	4.11%

Source: CEPA analysis of Gohdes and Simshauser (2022). Notes: (1) Pre-tax nominal cost of debt is Gohdes and Simshauser (2022) reported credit spread applied on top of a 3.75% risk-free rate, consistent with CEPA's technology neutral WACC estimate. (2) Pre-tax real calculation assumes a tax rate of 30%, inflation of 2%, and gamma of 0. The tax rate and inflation assumptions are consistent with those reported in Gohdes and Simshauser (2022), p.7. The paper does not report a gamma assumption, which is why we have assumed it is zero. Assuming a gamma value consistent with the technology neutral WACC estimate materially reduces the results reported above, although the impact is smaller for differences between contract / counterparty types.

Gohdes and Simshauser's paper also presents contemporaneous information on the PPA tenor, counterparty and gearing level of variable renewable energy projects, reproduced in the figure below. This puts the average PPA tenor at between 10 and 19 years, for the projects captured in the dataset.

Figure E.1: Gohdes and Simshauser (2022) – project characteristics



Source: Gohdes and Simshauser (2022), p.9.

E.2. NAB (2020)[110]

NAB was engaged by the NSW Government to provide advice on the potential impact of the EII Act on the WACC for generation and storage technologies. NAB presented evidence from a survey of equity investors, alongside its own internal references cases and market observations.

NAB provided estimates of the impact of counterparty credit quality impact on WACC, described in the table below. The investor survey results reflect an assumption of at least 75% PPA coverage over the life of the asset.

Table E.3: NAB (2020) – cost of debt and counterparty credit quality (median results)

Technology / counterparty	Cost of debt (pre-tax nominal)	Cost of equity (post-tax nominal)	Gearing
Historical NAB reference case			
Onshore wind (investment grade retailer)	2.90%	9-10%	62.50%
Onshore wind (sovereign or near sovereign)	2.91%	8.25%-9.25%	61.07%
Solar PV (investment grade retailer)	2.80%	8.75%-9.75%	68.65%
Solar PV (sovereign or near sovereign)	2.66%	8.25%-9.25%	72.41%
Contemporary NAB view			
Onshore wind (investment grade retailer)	3.00%	9-10%	67.50%
Onshore wind (sovereign or near sovereign)	2.95%	8.25%-9.25%	67.50%
Solar PV (investment grade retailer)	3.00%	8.75%-9.75%	67.50%
Solar PV (sovereign or near sovereign)	2.95%	8.25%-9.25%	67.50%
Investor survey			
Onshore wind (investment grade retailer)	3.03%	9.20%	65.00%
Onshore wind (sovereign or near sovereign)	2.76%	8.50%	65.00%
Solar PV (investment grade retailer)	2.86%	8.96%	65.00%
Solar PV (sovereign or near sovereign)	2.71%	8.61%	67.50%

Source: NAB (2020), p.8.

We have translated these estimates to pre-tax real terms. The results are shown in the table below, with the assumptions included in the notes. The results indicate that, compared to an investment grade retailer, a (near) sovereign counterparty reduces the pre-tax real WACC by between 0.2% to 0.7% (or 0.4% on average across all results).

[110] NAB, *NSW Electricity Infrastructure Roadmap – Weighted Average Cost of Capital Report*, November 2020.

Table E.4: Translation of NAB (2020) results to pre-tax real terms

Technology / counterparty	Cost of debt	Cost of equity	Gearing	WACC
Historical NAB reference case				
Onshore wind (investment grade retailer)	1.0%	10.8-12.2%	62.5%	4.6-5.2%
Onshore wind (sovereign or near sovereign)	1.0%	9.7-11.1%	61.1%	4.4-4.9%
Solar PV (investment grade retailer)	0.9%	10.4-11.8%	68.7%	3.9-4.3%
Solar PV (sovereign or near sovereign)	0.7%	9.7-11.1%	72.4%	3.2-3.6%
Contemporary NAB view				
Onshore wind (investment grade retailer)	1.1%	10.8-12.2%	67.5%	4.2-4.7%
Onshore wind (sovereign or near sovereign)	1.0%	9.7-11.1%	67.5%	3.8-4.3%
Solar PV (investment grade retailer)	1.1%	10.4-11.8%	67.5%	4.1-4.6%
Solar PV (sovereign or near sovereign)	1.0%	9.7-11.1%	67.5%	3.8-4.3%
Investor survey				
Onshore wind (investment grade retailer)	1.1%	11.03%	65.0%	4.6%
Onshore wind (sovereign or near sovereign)	0.8%	10.05%	65.0%	4.1%
Solar PV (investment grade retailer)	0.9%	10.70%	65.0%	4.4%
Solar PV (sovereign or near sovereign)	0.8%	10.21%	67.5%	3.9%

Source: CEPA analysis of NAB (2020). Notes: (1) Consistent with NAB (2020) p.6 and p.11, we have assumed inflation of 1.9%, a tax rate of 30% and gamma of 0.

NAB (2020) also provided estimates of the impact of LTESAs on the nominal vanilla WACC. These are shown in the table below, along with CEPA's translation to pre-tax real terms (using the same assumptions as stated above). NAB's assumptions reflect a comparison *between* and LTESA and traditional PPA with a CfD structure (rather than an assumption that LTESAs would operate alongside, or as a backstop to, commercial contracts). The impact on gearing and the cost of equity reflects NAB's view that the competitive tendering process for LTESAs could result in lower strike prices (relative to a traditional CfD), reducing contracted cash flows.

Table E.5: NAB (2020) – impact of LTESA on WACC parameters

NAB assumptions	Pre-tax nominal cost of debt	Post-tax nominal cost of equity	Gearing	Nominal vanilla WACC
%	nil to -0.25%	+0.25 to +0.50%	nil to -5%	-0.08 to + 0.49%
CEPA translation to pre-tax real	**Pre-tax real cost of debt**	**Pre-tax real cost of equity**	**Gearing**	**Pre-tax real WACC**
%	nil to -0.25%	+0.35 to +0.70%	nil to -5%	-0.05 to + 0.78%

Source: CEPA analysis of NAB (2020), p.13. Notes: (1) Consistent with NAB (2020) p.6 and p.11, we have assumed inflation of 1.9%, a tax rate of 30% and gamma of 0.

NAB (2020) also provided indicative WACC assumptions for battery energy storage systems (BESS), pumped hydro and new build gas peakers. The assumptions did not vary materially across technologies, as shown in the table below. The values reflected NAB's internal view at the time, which acknowledged that there were a limited number of precedents.

Table E.6: NAB (2020) assumptions by technology type

	Onshore wind	Solar PV	BESS	Pumped hydro	Gas peaker
Real vanilla WACC	2.88%	2.88%	2.66%	2.81%	3.00%

Source: NAB (2020), pp.18-19. Notes: (1) All estimates assume a (near) sovereign counterparty, for comparability across technologies.

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