Transmission access reform – Cost of capital impact

Energy Security Board

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FINAL REPORT

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GLOSSARY

For ease of reference, we list below the abbreviations and other symbols used in this report when analysing the cost of capital impact of the proposed transmission access reforms. This terminology and its meaning in the context of the analysis is detailed further in the body of the report.

A	The generator's level of access to RRP
CMM	Congestion Management Mechanism
CRM	Congestion Relief Market
CRMP	CRM Price
E	In the CMM, a generator's 'entitlement', i.e., the megawatt of its output that flow through a constraint
F	The price contractually agreed between a generator and its counterparty in a swap contract or PPA
G	A generator's physical dispatch quantity
k	The scaling factor applied in the calculation of congestion rebates in the CMM
MC	Marginal Cost
NEM	National Electricity Market
RRP	Regional Reference Price
RRP_{CRM}	The RRP determined in the CRM dispatch
RRP_{NEM}	The RRP determined in the NEM dispatch
S	The agreed quantity in a swap contract
α	The generator's participation factor in a constraint (i.e., the proportion of its output that flows through a constraint, also known as its constraint coefficient)

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EXECUTIVE SUMMARY

The Energy Security Board (ESB) has developed several options to change how electricity transmission network congestion is managed in the national electricity market (NEM). CEPA has been engaged to investigate how these potential reforms may impact the cost of capital required by investors in assets operating in the NEM. This report sets out our conclusions.

Context of the reforms

The current mechanics of NEM pricing place incentives on generators whose dispatch may be affected by constraints to bid at a price that is different from their marginal costs (this is known as "disorderly bidding"). The presence of disorderly bidding means that AEMO's dispatch based on the distorted bids is not the lowest cost. There are many undesirable additional consequences of this. Generators that have favourable costs can be displaced in dispatch by generators that are of higher cost. Further, generators are not incentivised to locate in places that deliver lowest overall system cost. The ESB reform proposals are intended to overcome the drawbacks of the system in both **operational** and **investment** timescales.

The ESB proposes two operational reforms, the **Congestion Relief Market (CRM)** and the **Congestion Management Mechanism (CMM)**. Both introduce a fundamental change to the NEM settlement arrangements that will in turn change which generators are dispatched when constraints bind. Under current arrangements, a generator's physical output is settled at the price determined at a reference node in their NEM region (the regional reference price, RRP). Under both the CRM and the CMM, settlement will have two components: a localised price for energy that generators will receive if they are physically dispatched, which reflects congestion at the generator's location; and the difference between the RRP and this localised price, which reflects the benefit of energy being transported from the generator's location to the regional reference node. 'Rights' to the latter component (which we have referred to in this report as 'access' to RRP) are allocated differently under the CRM and CMM.

Two proposals address investment incentives. The **congestion fee** model would require new generators to either pay for: the expected benefit they would receive for the cost of transporting energy to the regional reference node (currently received for free); the total cost of congestion they introduce in the system; or the cost of transmission investment associated with their connection. The **priority access** arrangement would give preferential allocation of the transportation benefits to incumbent generators and to new entrant generators in order of their connection.

While the reforms are likely to have a material impact on generator incentives, they have been designed to ensure that the overall level of revenues to generators as a group is not significantly affected, i.e., generator rights have been "grandfathered". However, the reforms do have a number of impacts on the risk faced by individual generators:

- In operational timeframes, as a result of the improvement in dispatch incentives, generators that have favourable costs would no longer be displaced in physical dispatch by generators with higher costs.
- In investment timeframes, the risk of cannibalisation by new entrants would be reduced, because generators would no longer have the current incentive to locate where they could cannibalise incumbents' returns, as they would either be allocated lower access priority than incumbents (under the priority access approach) or pay a congestion fee that internalises the costs associated with the congestion caused (under the congestion fee approach).

Implications for the cost of capital

We assessed the impact of the reforms on the weighted average cost of capital (WACC) by examining: the factors that affect the cost of debt, mainly considering default risk; the factors that affect the cost of equity, i.e., systematic risk in the framework of the capital asset pricing model (CAPM); and implications for the capital structure.

We conclude that each reform option has a different impact on the factors that affect the **cost of debt**. The **CRM alone** reduces downside risk and increases expected cash flows. Assuming that gearing is unchanged, the risk of default is therefore lower, pointing to a lower cost of debt on the margin.

- The **priority access model in combination with the CRM** provides additional protection against later cannibalisation by new entrants, further reducing downside risk and increasing expected cash flow. Assuming that gearing is unchanged, the risk of default is lower, again pointing to a lower cost of debt.
- The impact of **congestion fees in combination with the CRM** depends on how the fees are set. Congestion fees based on the connecting generator's forecast value of access to RRP would increase costs for new entrants, and this may or may not be offset by the benefits of the CRM. Therefore, the overall impact on the risk of default may be upwards or downwards, depending on the generator. Alternative options include calculating congestion fees based on the connecting generator's contribution to system-wide congestion or transmission investment costs. For generators siting in non-congested areas, these fees would be zero and the risk of cannibalisation would be reduced, pointing to a lower cost of debt for these generators.

Unlike the CRM, the CMM creates winners and losers relative to the status quo with respect to the generators' risk of losing access to RRP. Therefore:

- The **CMM alone** could lower the cost of debt for those generators that benefit from a reduction in downside risk and higher cash flow after the reform. However, other generators would experience greater downside risk and a reduction in cash flow, pointing to a higher cost of debt. This conclusion extends to the **CMM in combination with congestion fees**.
- However, if the **CMM was implemented in combination with priority access**, for generators siting in non-congested areas of the network the risk of cannibalisation would be unambiguously reduced, pointing to a lower cost of debt for these generators.

Under all the reform options, the materiality of cost of debt impacts will vary across generators, depending on their specific circumstances (e.g., how significant their risk of curtailment is expected to be under current arrangements).

We note that, instead of reducing the cost of debt, lower default risk may allow generators to be financed with a higher level of **gearing**. This would increase the optimal leverage for these generators, potentially allowing them to increase value from tax shields. The opposite applies to those generators for which the reform has an upwards impact on the cost of debt.

While there may be a theoretical argument that congestion risk is somewhat correlated with conditions in the wider economy, we consider that in practice this effect may not be material, or indeed not present at all. Therefore, we do not consider that the reforms are likely to have a material impact on systematic risk, and therefore on the **cost of equity** in either direction. This does not mean that non-systematic risk is irrelevant for investors. In practice, if the reforms remove non-systematic risk this may still impact investment decisions in the NEM.

In combination, these conclusions point to an **overall downwards impact on the risk factors that determine the cost of capital for the CRM and priority access reforms**. For the CMM, the impact on cost of capital is ambiguous and varies across generators. The impact of a congestion fee model depends on how the fees are set and the choice between the CRM and CMM.

Our assessment of the capital expenditure reforms focusses on generators planning to site in non-congested parts of the network. The capital expenditure reforms are likely to reduce the business case for locating in congested areas, because cannibalising existing generators' access is no longer profitable or possible. While this may affect the overall viability of projects planning to connect in a congested part of the NEM, this is the intended impact of the capital expenditure reforms: that generators bear the cost of increasing congestion, meaning that connecting in parts of the grid with limited spare access may no longer be viable.

The analysis of potential cost of capital impacts set out above does not necessarily mean that the reforms would in fact change the cost of capital. In practice, this will depend not only on the direction of the effects we have identified but also their magnitude. In particular, we would only expect the cost of debt to change materially if credit ratings change, and this would only happen if the change in expected future generator profits is sufficiently large.

1. INTRODUCTION

The Energy Security Board (ESB) has developed several options to change how electricity transmission network congestion is managed in the national electricity market (NEM). CEPA has been engaged to investigate how these potential reforms may impact the cost of capital required by investors in assets operating in the NEM.

This section sets the scene with a discussion of what factors matter when assessing the impact of the reform options on the cost of capital. Section 2 describes how we have analysed the congestion management reform options to identify their cost of capital impact. Section 3 presents our detailed analysis of each reform option. Our overall conclusions are summarised in section 4.

1.1. What is the cost of capital?

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 cost of debt and equity. The weighting is determined by the proportion of debt and equity within the investment's overall capital structure.

Broadly, capital providers will require higher expected returns for riskier investments. However, different risks matter for the cost of debt and cost of equity. These are outlined in the sections below.

1.2. What matters for assessing cost of equity impacts?

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 we need to distinguish 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.[1]

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

This intuition can be represented mathematically with reference to the parameter beta, which is used to calculate the cost of equity in the CAPM formulation. Beta depends on the covariance of returns for a given investment (Ri) with the returns of a diversified investment portfolio (Rm):

$$\beta = Covariance\ (R_i, R_m) \div Variance\ (R_m)$$

Covariance is a statistical measure of association between variables. In simple terms, if increasing (decreasing) Rm is associated with increasing (decreasing) Ri, their covariance is positive. If instead Ri tends to move in the opposite direction of Rm, their covariance is negative. If two variables are independent, i.e., the occurrence of one does not affect the occurrence of the other, their covariance is zero.

If we consider a case where the returns for a given investment include a component X of business-specific risk, which, by definition, is independent of market returns. That is, the returns of the investment can be expressed as Ri + X. In this case:

$$\beta = Covariance\ (R_i + X, R_m) \div Variance\ (R_m)$$

The covariance of a variable with a sum of variables is just the sum of the covariances with each of the variables, therefore:

$$Covariance\ (R_i + X, R_m) = \ Covariance\ (R_i, R_m) + Covariance\ (X, R_m)$$

Which, under the assumption that X and Rm are independent, equals:

$$Covariance\ (R_i, R_m)$$

The implication of the CAPM, as presented in this mathematical illustration, is that any risk to generator returns that is non-systematic does not affect beta.

This does not mean that non-systematic risk is necessarily irrelevant to investment decisions. When making investment decisions, investors will require that expected returns match the cost of equity. Even if it does not affect the cost of equity, business-specific risk might be reflected in the investors' decision-making as a change in the forecast cash flow and therefore in the expected returns of the project. Although we acknowledge that in practice some investors might deal with such risks by adjusting their hurdle rates, rather than expected cash flows, in a CAPM framework non-systematic risk does not affect the cost of equity.

Summary

Other factors held equal:

- If the reforms increase / decrease systematic risk, as represented by the covariance between expected NEM generator returns and expected stock market returns, beta may increase / decrease.
- In the CAPM framework, business-specific risk does not affect the cost of equity (although it may still be relevant for an investment decision).

1.3. What matters for assessing cost of debt impacts?

The prevailing theories of cost of debt centre on financial distress costs and by extension the **probability of default**. The probability of default of an entity is often mediated 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 the proposed reforms. 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.[2] 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. Only some of the risk factors are likely to be directly affected by reform options.

From our analysis of these methodologies, we can draw out some broad observations to understand how the proposed reforms might impact generator credit ratings 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. Therefore, a change in policy that increases the level of generator cash flows may have a positive impact on financial metrics and credit ratings.

- 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 a generator's ability to continue servicing debt under downside scenarios. Downside risk is a function of both the **magnitude** of the cash flow impact arising from an adverse event and its **probability**. Therefore, a change in policy that reduces the magnitude and/or probability of an adverse cash flow impact occurring may have a positive impact on credit ratings.

- Thirdly, in addition to projected cash flows and financial metrics, Moody's also considers a range of **qualitative factors**. In the methodologies we have reviewed for this analysis, the qualitative factors that might be impacted by the proposed reforms include pricing transparency, prospects for new generation, the length of time that the electricity market arrangements have been in place, the degree to which the market design has been tested, and expectations for material modifications. Therefore, a change in policy that has a material favourable impact on such factors may improve the credit rating.

- Finally, it is important to comment on **materiality**. We would only expect the cost of debt to change materially if credit ratings change. Ratings agencies will typically set thresholds for different risk factors, with a change in credit rating only occurring if a risk factor (or a combination of risk factors) moves beyond a given threshold. For example, a rating agency might specify that a given generator would receive a higher credit rating if its projected debt service coverage ratio[3] moved from a range of 1.4x-1.9x into a range of 1.9x-3.5x. Accordingly, to actually change the credit rating, the impact of the reform options on the debt service cover ratio would need to be material enough to move it into different range. Therefore, even if we are able to conclude on the *directional* impact of the reforms on generator cash flows, the *magnitude* of the impact affects the materiality of any change in the cost of debt.

Summary

Other factors held equal:

- If the reforms increase / decrease expected NEM generator cash flows, the cost of debt will decrease / increase.
- If the reforms increase / decrease the magnitude or probability of NEM generator downside risk, the cost of debt will increase / decrease.

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

[3] The ratio of cash flow available for debt service to interest and principal repayments

1.4. WACC IMPACT OF CHANGES IN 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 a change in gearing on the company'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 company. 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 proposition states that a company'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 company may find that a certain capital structure is preferable, in the sense that it maximises the value of the company. An important determinant of the optimal capital structure are tax considerations. In simple terms, increasing the proportion of debt finance can be advantageous because the company 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 company's creditworthiness is in doubt and, in the extreme, the costs associated with bankruptcy). In theory, a company will increase gearing only to the point where on the margin the benefit from the tax shield is equal to the cost of financial distress.

In this report, we describe the cost of capital impact of the reforms in terms of changes to the cost of debt and the cost of equity, assuming that gearing remains unchanged. In this 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. However, introducing dynamic considerations on gearing to this picture does not negate our conclusions on the directional impact of the reforms on cost of capital, and may even reinforce them.

For example, consider a generator whose downside risks decrease as a result of the reform. Other things equal, this increases expected free cash flow and reduces downside risk. This reduces the generator's cost of debt relative to the status quo. However, gearing may not be static. An alternative consequence of higher expected cashflows / lower downside risk is that rather than the cost of debt falling, the generator could instead maintain its credit rating at a higher level of gearing. 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. Accordingly, the generator can reduce its overall WACC by increasing the proportion of debt in its capital structure.

In other words, if a reform option results in 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 its credit rating. Similar considerations, in the opposite direction, would apply if the reform increased downside risk.

Summary

Other factors held equal, if the reforms increase / decrease the probability of financial distress (by either increasing expected cash flows or reducing downside risk), NEM generators may decrease / increase their level of gearing.

2. OUR APPROACH

This section describes our methodology for assessing the potential impact of the reforms on the cost of capital. In summary, we have:

- Examined the factors that are relevant for determining the cost of debt and equity finance for investments in the NEM. For the cost of debt, we have drawn on credit rating methodologies. For the cost of equity, we have focussed on the CAPM framework.
- Analysed the directional impact of the various reform options on these factors. This analysis is based on an assessment of how the reform options impact generator profits and risk. Different types of profit and risk impacts matter for the cost of debt and the cost of equity.

2.1. Overview of the reform options

The ESB is considering four core options to address both operational and capital expenditure inefficiencies that are associated with the current NEM design. The ESB intends to combine one of the operational reforms with one of the capital expenditure reforms. In addition, there is optionality around the precise design of each reform. We have assessed potential cost of capital impacts on the core reform options, and variants, listed in the table below.

A detailed description of the proposed reforms can be found in ESB (2023).[4]

Table 2-1: Congestion management reform options

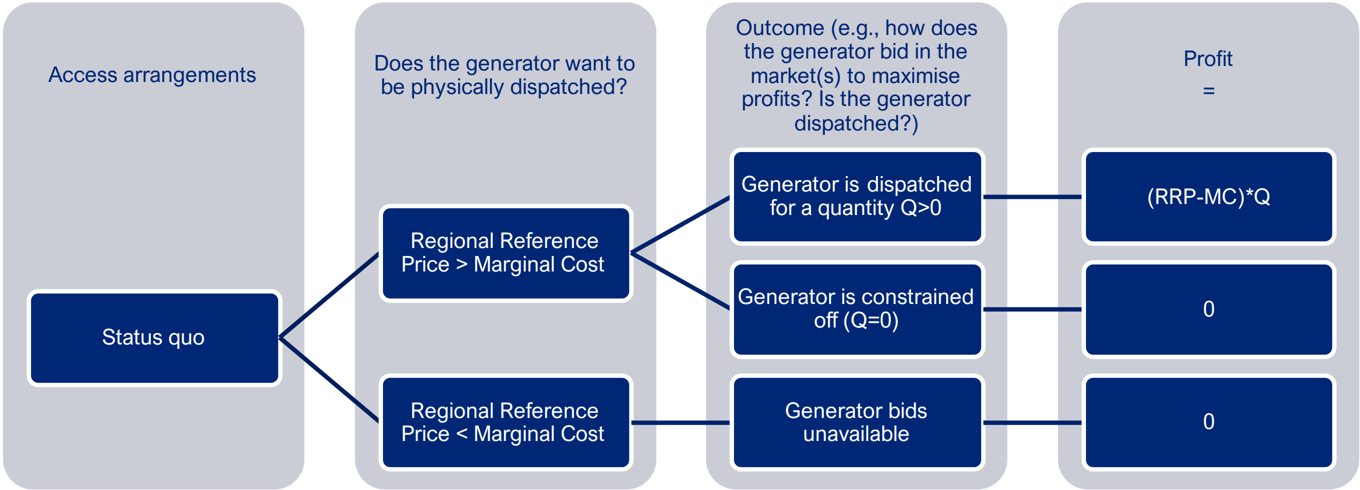
Operational reforms	Capital expenditure reforms
1. The congestion relief market (CRM) *NEM market participants may be settled at the regional reference price (RRP) determined in the NEM dispatch (RRP_{NEM}) or in the physical dispatch (RRP_{CRM}). We have considered both variants.* 2. The congestion management model (CMM). *The CMM introduces a mechanism of congestion charges and rebates that operates alongside the energy market. There are various ways to allocate charges and rebates. We have only considered the CMM (pro-rata entitlement) option.*	3. Congestion fees *Different approaches to calculating congestion fees are under consideration. The fees could reflect: (i) the expected future value of a connecting generator's access to RRP, (ii) the forecast total cost of congestion arising from the generator's connection, or (iii) the forecast cost of transmission investment required as a result of the generator's connection. We have considered all three variants.* 4. Priority access *We have considered the priority access model implemented with (i) unique queue positions and (ii) a smaller number of access tiers.*

2.2. Profit and risk analysis

The cost of capital reflects the risk that equity and debt holders face for a given investment (e.g., in a company that owns one or more generation assets). In the context of the access reforms, these risks may change if the reforms impact generators expected future profits. To analyse the impact of reform on profits, we use decision trees like the one shown in Figure 2.1.

[4] ESB (2023), Transmission Access Reform – Cost Benefit Analysis.

Figure 2.1: Decision tree example



The decision trees illustrate how a generator's expected future profits depend on:

- **The revenue streams that are available to a generator under each reform option.** For example, revenue streams include being remunerated for physical dispatch, or receiving access to RRP. These revenue streams are represented by the set of equations at the end of the 'branches' of each decision tree.
- **Which of the available revenue streams the generator earns in practice.** That is, on which branch of the decision tree the generator finds itself in any future dispatch interval. This depends on both physical dispatch and access to RRP across every dispatch interval for the life of the generator. A generator's willingness to be physically dispatched generally depends on the price for energy relative to their marginal cost (MC). A generator's ability to access RRP depends primarily on the risk of being displaced by other generators that participate in the same constraint.
- **The level of RRP (and the CRM price, after the reforms are introduced)**. The CRM price is defined in section 3.1 below.

2.3. Approach to assessing cost of capital impacts

As described in section 1, different types of impacts on expected future profits matter for the cost of debt and the cost of equity, reflecting the nature of the risk that lenders and investors are exposed to:

- The cost of debt is influenced by two factors, being whether the reforms impact (i) the **expected level of a generator's cash flows** and (ii) their **exposure to downside cash flow risk** (itself a function of the probability and magnitude of adverse cash flow events).
- The impact of the reforms on the cost of equity depends on whether they change the degree of **systematic risk** of the generator, i.e., the extent to which its returns vary in step with returns in the wider economy.

Having established the impact of the reform options on profits, we then consider how those impacts relate to the factors described above. We have analysed these impacts *directionally*. In practice, the magnitude of profit impacts matters for the size of any cost of capital effect, and indeed whether the cost of capital changes at all.

Unfortunately, there is limited information available to inform a judgement on the relative magnitude of the effects we have identified.[5] This places an important limitation on the conclusions we can draw in relation to the reforms.

[5] We note that the ESB has commissioned analysis by NERA Economic Consulting that involves modelling the operational impacts of the reform options. As the analysis has been conducted for two years, it does not provide information that would allow us to draw stronger conclusions on the cost of capital.

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3. ANALYSIS OF COST OF CAPITAL IMPACTS

3.1. TERMINOLOGY AND NOTATION

Throughout this section we use a consistent terminology and notation to describe profit and risk impacts of reforms.

- MC = Marginal cost
- G = Physical dispatch (MW):
  - Under current arrangements, G = G_{NEM}. I.e., physical output is the outcome of the NEM dispatch. This is settled at the price determined at a reference node in the generator's NEM region (the regional reference price, RRP).
  - The CRM gives generators an opportunity to increase/decrease their physical output G relative to G_{NEM} by trading congestion relief. Therefore, G = G_{NEM} + G_{adj} , where G_{NEM} is the outcome of the current NEM dispatch and G_{adj} is an adjustment to G_{NEM} that is determined through trades in the congestion relief market. G_{NEM} is settled at RRP. G_{Adj} is settled at a localised price for energy that reflects congestion at the generator's location (we refer to this as the 'CRM price', CRMP).[6]
  - With the CMM, G is the outcome of the current NEM dispatch and is settled at RRP. However, generation is also subject to a congestion charge that represents the difference between RRP and a localised price for energy that reflects congestion at the generator's location, meaning that the generator's output is effectively settled at this localised price. Given the analogy between the localised price of energy used for settlement in the CRM and in the CMM, and to facilitate comparisons between the two reform options, in this report we use the term CRMP to describe the localised congestion price in both the CRM and the CMM.
- A = Level of access to the RRP (MW):
  - Under current arrangements, A = G = G_{NEM} (all physical dispatch is remunerated at RRP).
  - With the CRM, A is the outcome of the current NEM dispatch (A = G_{NEM}).
  - With the CMM, A is allocated based on a formula. For example, under the pro-rata entitlement method, A is a function of generators' availability and participation in a constraint.

To facilitate comparisons, we discuss all the reform options in terms of physical dispatch (G) and access dispatch/allocation (A).

A design choice for the CRM is whether the NEM dispatch is settled at the RRP determined in the NEM dispatch (RRP_{NEM}) or the RRP determined in the congestion relief market (RRP_{CRM}). The two RRPs can differ, depending on time of the day and location on the network.[7] We distinguish between the two RRPs when this has implications for the assessment of cost of capital impacts.

[6] Some energy markets overseas have adopted pricing arrangements (sometimes referred to as "locational marginal pricing", LMP) whereby, similarly to the CRM, congestion is priced at localised points on the network. Given this shared characteristic, the ESB's Directions Paper used the term LMP to describe the local congestion relief prices within the CRM. In this report, we use the term "CRM price" rather than LMP, in line with the terminology adopted by the ESB in its subsequent documents to reflect the differences between the CRM design and the overseas markets where LMP is adopted.

[7] Potential reasons include changes in dispatch for constrained generators in looped flow networks, and changes in interconnector flows. ESB (2022), Transmission Access Reform - Directions Paper, p. 56.

3.2. Scope and assumptions

We have focused on the impact of reforms both on generators deriving their revenues from the NEM, without any form of hedging contract (we refer to these as “unhedged” generators), and on generators that have entered into contracts, such as swap contracts and power purchase agreements (PPAs), that provide a hedge against fluctuations in RRP (we refer to these as “hedged” generators).

The analysis assumes that participation factors are not rounded for the purposes of dispatch. The impact of rounding is considered separately in Section 3.7.

We have made other simplifying assumptions. For example, we assume that metered quantities are the same as dispatched quantities, that there are no transmission losses, and that generators do not receive large-scale generation certificates.

Finally, the analysis assumes that the CRM price is smaller than RRP used for settlement. This will generally be the case if a generator participates in a binding constraint, contributing to congestion. However, the CRM price may be greater than RRP in some cases – for example if the generator alleviates a constraint.

3.3. CRM

This section examines the impact of introducing the CRM alongside the current NEM dispatch. First, we consider a generator that has not entered into any forms of hedging contracts, and then one that has contracted part or all of its output through either a swap contract or a PPA.

The additional impact of combining the CRM with either capital expenditure reform (priority access and congestion fees) is discussed in Sections 3.5 and 3.6.

3.3.1. Unhedged generators

Summary cost of capital impact – CRM (unhedged generators)

- The CRM reduces generators downside risk and increases expected profits, leaving none worse off. This points towards a reduction in cost of debt overall.
- While there may be a theoretical argument that congestion risk is somewhat correlated with conditions in the wider economy, we consider that in practice this effect may not be material, or indeed not present at all. Therefore, we do not consider that the reform is likely to have a material impact on the cost of equity in either direction.
- We do not consider that the choice between RRP_{CRM} and RRP_{NEM} is likely to impact the cost of capital.

Profits under the reform relative to the status quo

To understand the impact of the CRM, we first analyse generator profits under current arrangements (i.e., the ‘status quo’). Under current arrangements, if more generation capacity is available in a location than can be accommodated by the transmission system, the NEM Dispatch Engine (NEMDE) will select the lowest cost combination of available generators taking into account the prices of their bids. The generators that are dispatched earn the RRP determined at the regional reference node in their region. Therefore, as long as the RRP is above its MC, a generator located behind a binding constraint will seek to maximise its chances of dispatch (e.g., by bidding at the floor price of -1,000 $/MWh) in order to earn RRP.

However, every other generator behind the same constraint has an incentive to behave in the same way, giving rise to what is known as ‘race to the floor’ or ‘disorderly’ bidding. When multiple bids are tied at the floor price, the NEMDE will prioritise those that minimise the cost of congestion – i.e., the bids of generators with lower participation factors. The participation factor (also known as constraint coefficient) of a generator in a constraint reflects the proportion of a generator’s output which flows through the transmission line to which the constraint relates. Typically, the further away a generator is located from a constrained line the less it uses of that line, and so a greater change in its output is required to achieve a one MW change in flow over the constrained line. This is reflected by a smaller coefficient.

This gives rise to "winner takes all" results, where a network constraint affects whether a generator is dispatched or not. Dispatch outcomes, i.e., which generators are dispatched, vary over time, as generators enter and exit the market, and their availability and demand patterns change. Consequently, generators are at risk of being constrained off in favour of other generators with lower participation factors bidding available in operational timeframes, or connecting over investment timeframes. If a generator is constrained off, it will not be able to earn RRP. This range of outcomes is represented in the decision tree at the top of Figure 3.1 overleaf. We use the letter 'Q' to denote the quantity dispatched. [8]

Under current arrangements, physical dispatch and access to RRP are closely interrelated. A generator receives RRP for its physical output. If it is constrained off, it loses access to RRP. One of the key changes under the proposed reforms is that the CRM (and the CMM) separate access to RRP from physical dispatch, which instead is settled at CRMP.

With the CRM, a generator obtains access A to the RRP in the NEM dispatch. In addition, through the CRM, it earns the CRMP for any unit of physical output beyond the NEM dispatch ($G_{adj} = G - G_{NEM} = G - A$). This can be written as:

$$Revenue = A \times RRP + (G - A) \times CRMP = CRMP \times G + (RRP - CRMP) \times A$$

Therefore,

$$Profit = (CRMP - MC) \times G + (RRP - CRMP) \times A$$

This shows that:

- As long as RRP>CRMP, the generator will profit from being awarded access in the NEM dispatch. As a result, the generator will have an incentive to bid in the NEM dispatch in a way that maximises A. This creates similar incentives for disorderly bidding as in the status quo.
- A generator's willingness to be physically dispatched depends on whether its CRMP is greater than MC. A generator's decision of whether and how to participate in the CRM depends on this and on the level of access secured in the NEM dispatch. The generator will seek to maximise its profits, as shown in the decision tree at the bottom of Figure 3.1.

[8] We assume for simplicity that the generator is either fully dispatched or completely constrained off. In practice, a generator may be only partly constrained off. If that is the case, its profits under current arrangements will be (RRP-MC)*Q', with Q>Q'>0. For this marginal generator, CRMP=MC. Therefore, after the reform its profits will remain equal to (RRP-MC)*Q'.

Figure 3.1: Comparison between profits in the status quo and CRM – Unhedged generators

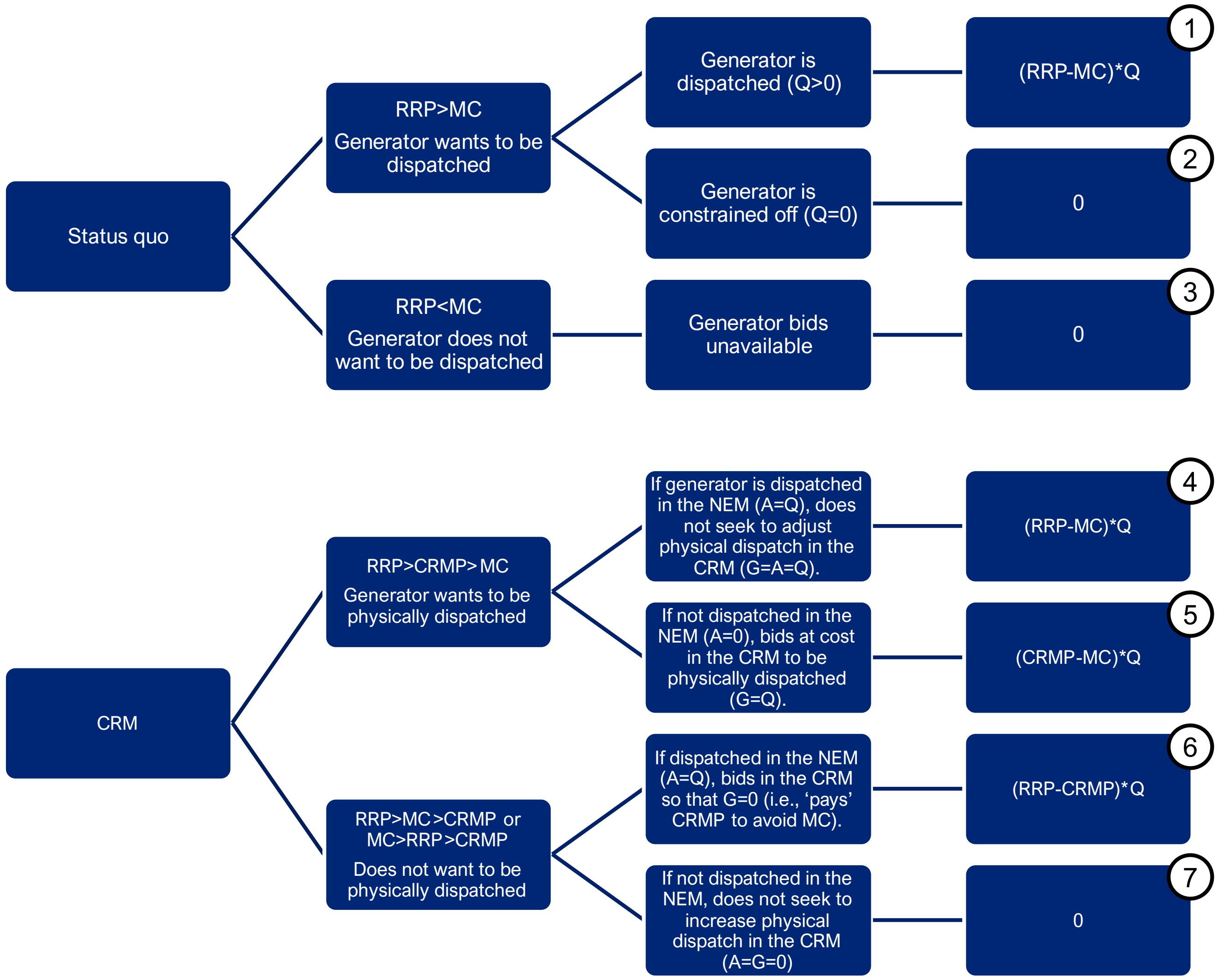


Figure 3.1 suggests that, under both the status quo and the reform, expected profits depend on the downside risk of being constrained off in the NEM dispatch (probability and magnitude) and the volatility of RRP. We analyse these factors below.

Impact of the CRM on the risk of being constrained off in the NEM dispatch

The **probability** of being constrained off in the NEM dispatch is similar under the CRM or status quo:[9]

- In operational timeframes, bidding incentives in the NEM are broadly the same, and similar dispatch outcomes may be expected.
- In investment timeframes, outcomes are also broadly similar. Currently, if a new entrant can achieve a better participation factor than existing generators that participate in the same binding constraints, the new entrant can displace the incumbents in the NEM dispatch – thus 'cannibalising' the incumbents' access to RRP. The CRM does not remove this feature of the current market arrangements and does not change the probability of being constrained off the NEM dispatch.[10]

[9] Assuming that the issue of out-of-merit-order (OOMO) generators discussed in Section 3.7 is addressed, or is not material.

[10] This also means that the impact on profits and risk of the CRM (without priority access and congestion fees) is the same for a new entrant as it is for an existing generator.

However, the **magnitude** of the impact of profit from being constrained off in the NEM dispatch is somewhat reduced with the CRM. This is because the generator can still earn profits as long as it remains cost-competitive enough to be physically dispatched (i.e., CRMP>MC), as can be seen by comparing cases 2 and 5 in Figure 3.1. If CRMP<MC, the generator is no worse off after the reform (compare cases 2 and 7). Therefore, the overall downside risk of losing access to RRP is reduced under the CRM.

Importantly, exposure to CRMP in the CRM gives generators an opportunity to increase profits relative to the status quo, not only when a generator is constrained off the NEM (as discussed above), but also when it is fully dispatched. In this case, if CRMP>MC, profits are the same as in the status quo (compare cases 1 and 4); if CRMP<MC, profits are higher than in the status quo (compare cases 1 and 6).

Because the CRM increases expected cash flows and reduces the downside risk of being constrained off in the NEM dispatch, it will tend to reduce cost of debt for all generators. The materiality of this impact will vary across generators, depending on their specific circumstances (e.g., how significant their risk of curtailment is expected to be under current arrangements). This observation is also applicable to other reform options and their impact on the cost of debt.

As discussed in section 2.3, access reforms can affect the cost of equity if they change the level of systematic risk in a generator returns, relative to the status quo. Our analysis of systematic risk is set out in Text Box 1. Overall, while there may be a theoretical argument that congestion risk is somewhat correlated with conditions in the wider economy, we consider that in practice this effect may not be material, or indeed not present at all. Therefore, we do not consider that the CRM, nor the other reform options, are likely to have a material impact on the cost of equity in either direction.

Text Box 1: Is congestion risk systematic?

Theoretically, it is possible that there is a degree of positive correlation between the incidence of congestion and stock market returns. This could be the case if higher stock market returns are associated with higher electricity demand (e.g., through population growth, or greater energy consumption with higher incomes),[11] higher levels of generation investment and more instances of binding constraints. This would translate to a degree of inverse correlation between generator returns and broader market returns.

If this relationship existed, reform options that reduce congestion risk for generators could increase covariance between their returns and stock market returns – pointing to a possible increase in beta.

However, this relies on the presumption that a positive correlation between congestion and stock market returns actually exists and is material. In practice, this may not be so. Firstly, and most importantly, new generation investment (and any resulting increase in congestion) may be more related to the energy transition than to broader economic conditions. Secondly, an increase in generation investment may prompt additional transmission network investment, limiting additional congestion. Thirdly, there may not be a consistent relationship between stock market returns and congestion in all parts of the grid: some locations may have ample spare capacity and would not be impacted.

Overall, while there may be a theoretical argument that congestion risk could be somewhat correlated with conditions in the wider economy, we consider that in practice this effect may not be material, or indeed not present at all. Therefore, we do not consider that the CRM, nor the other reform options, are likely to have a material impact on the cost of equity in either direction.

Impact of the CRM on RRP

A design choice for the CRM is whether the NEM dispatch is settled at the RRP determined in the NEM dispatch (RRP_{NEM}) or the RRP determined by physical dispatch (RRP_{CRM}). If the NEM dispatch continues to be settled at RRP_{NEM} after the introduction of the reform, the impact of changes in RRP should be limited, as RRP would be

[11] Another possible reason is that expectations of economic growth may increase returns available to prospective investors to invest in new generation, but this would only be relevant if generation investment was otherwise constrained by a lack of available capital.

determined in a market where bidding behaviour and investment incentives are broadly the same as under the status quo.

An important driver of the difference between RRP_{NEM} and RRP_{CRM} is race to the floor bidding in the NEM, which has the potential to create substantial counter-price flows between NEM regions – i.e., energy flowing from a higher RRP region to a lower RRP region. The result of counter-price flows is to further increase RRP in the high-price region and depress RRP in the low-RRP region. With RRP_{CRM}, which is based on cost-reflective bidding, counter-price flows may be reduced. As a result, RRP_{CRM} for a given generator could be either higher or lower than RRP_{NEM}, depending on the region of the NEM (and the time of the day), although in practice, clamping of counter-price flows by the market operator would reduce the divide between RRP_{NEM} and RRP_{CRM}.

However, predicting which RRP will be higher on average over time for a given generator, or across the entire system, is not straightforward, as counter-price flows are a complex function of generation capacity and network constraints, and these factors evolve over time. For example, at a given point in time, counter-price flows may run from larger regions (in terms of generation capacity) to smaller regions. In this case, the RRP increase affecting all the generators in the large region would dominate the RRP decrease affecting the generators in the smaller region and, on average across the system, RRP_{NEM} would be higher than RRP_{CRM}. If changes in network topography redirect counter-price flows from the smaller region to the larger region, on average across the NEM RRP_{NEM} would be lower than RRP_{CRM}. Therefore, adopting RRP_{CRM} in place of RRP_{NEM} for settling NEM dispatch does not have a clear-cut impact on expected profits.

In practice, RRP_{CRM} may be less volatile than RRP_{NEM}, as race to the floor bidding will contribute to more extreme values in the latter, if the regional reference nodes are on a loop where the springwasher effect applies to marginal -$1000/MWh bids. If RRP_{CRM} translated to less extreme variability around generator cash flows, this could reduce the magnitude of downside risk. However, it does not follow that this would necessarily occur. More extreme highs/lows in 5-minute prices do not necessarily mean that the average market price captured by the generator (e.g., over a year or its operating life) has a wider standard deviation. Further, generators that contract all or part of their capacity would in any case be protected against fluctuations in the RRP.

3.3.2. Hedged generators

Summary cost of capital impact – CRM (hedged generators)

- The CRM does not affect the generator's ability to hedge against fluctuations in RRP.
- The cost of debt impact is directionally the same as for the unhedged generator case above.
- We do not consider that the reform is likely to have a material impact on the cost of equity in either direction.

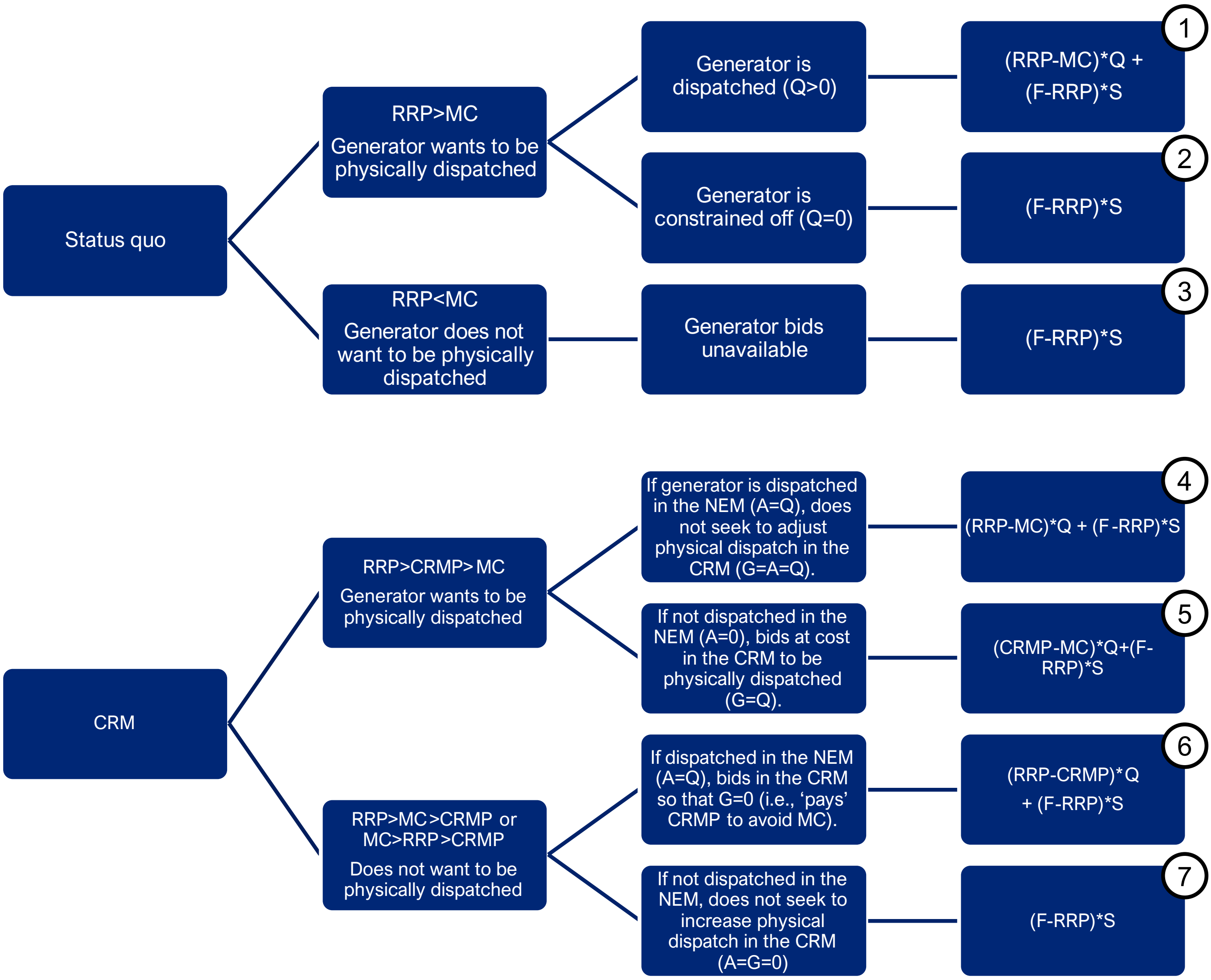
Swap contract

We consider a financial contract that pays the generator the difference between an agreed price F and RRP on a fixed quantity S. Profits can be expressed as the sum of market payoffs and contract payments:

- Under current market arrangements: (RRP-MC)*G + (F-RRP)*S.
- With the CRM: (CRMP-MC)*G + (RRP-CRMP)*A + (F-RRP)*S.

The contract provides a hedge against fluctuations in RRP, but otherwise bidding behaviour in both the NEM dispatch and the CRM is similar to that of unhedged generators, as shown in Figure 3.2.

Figure 3.2: Comparison between profits in the status quo and CRM – Swap contracts



Importantly, the introduction of the CRM does not reduce in any way the generator's chances of being dispatched in the NEM and accessing RRP. After the reform is introduced, the only situations where a generator is unable to access RRP are when it is constrained off the NEM (see cases 5 and 7). However, the counterfactual to these situations under the status quo (case 2) would also see the generator constrained off and unable to access RRP. In other words, the reform does not guarantee access to RRP only to the extent that the status quo does not either. Therefore, the CRM does not affect the generators' ability to enter into swap contracts.

A similar argument applies to 'basis risk', i.e., the fact that, in some circumstances, a generator that is constrained off the NEM dispatch will be exposed to CRMP while its contracts reference RRP. Participation in the CRM is voluntary, and the generator can avoid exposure to CRMP and obtain the same profits as under the status quo (case 7=2). The generator will choose to participate in the CRM only when exposure to CRMP increases its profits (case 5>2), reducing the downside risk of being constrained off the NEM dispatch.

Since expected generator profits after the reform are greater than or equal to the status quo (4=1, 6>1; 5>2, 7=2) and downside risk is reduced, the CRM will tend to reduce cost of debt for hedged generators.

PPA

We consider a PPA where the generator sells its output to a counterparty, who pays the difference between an agreed price F and RRP.

To remove the incentive for contracted generators to be physically dispatched when their costs exceed the market price of energy, and to protect the counterparty from the risk buying at the agreed price F when RRP is materially below this level, PPAs often include a floor price – i.e., there is no trading under the PPA if RRP is below a certain level. Typically, the floor is set at a level below which the generator, in the absence of a PPA, would be unwilling to generate (e.g., 0 or minus the value of large-scale generation certificates (LGCs)).

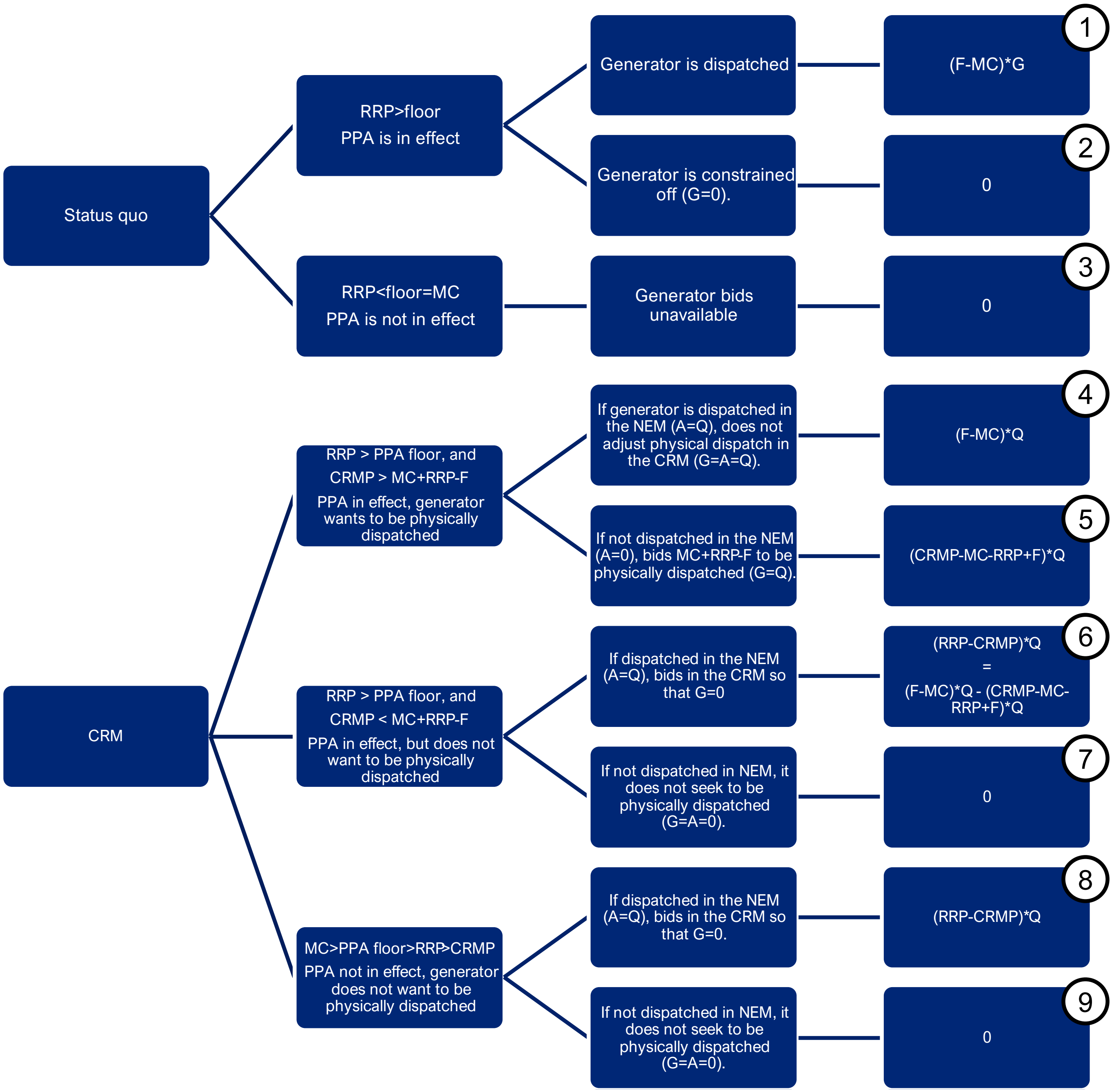
Here we assume that the floor is set below the generator's MC. Therefore, when RRP<PPA floor, the generator will bid unavailable under current arrangements. When RRP>PPA floor, the generator will seek to maximise NEM dispatch, and face the risk of being constrained off.

Profits can be expressed as the sum of market payoffs and contract payments:

- Under current arrangements: (RRP-MC)*G + (F-RRP)*G = (F-MC)*G
- With the CRM: (CRMP-MC)*G + (RRP-CRMP)*A + (F-RRP)*G

Profits after the reform can be rewritten as (F-MC)*A + (CRMP-MC-RRP+F)*(G-A), this suggests that the payoff for each MW of physical dispatch obtained in the CRM beyond the outcome of the NEM dispatch is CRMP-MC-RRP+F. Willingness to be physically dispatch depends on whether this payoff is greater than 0, as shown in Figure 3.3.

Figure 3.3: Comparison between profits in the status quo and CRM – PPAs



Similar observations apply as in the case of swap contracts:

- The CRM does not affect the generators' ability to enter into PPAs because the risk of being constrained off the NEM and losing access to RRP is the same before and after the introduction of the CRM.
- Since participation in the CRM is voluntary, a generator who is constrained off the NEM dispatch can avoid exposure to CRMP and obtain the same profits as under the status quo (case 7=2). A generator will choose to participate in the CRM only when exposure to CRMP increases its profits (case 5>2), reducing the downside risk of being constrained off the NEM dispatch.
- A generator who is not constrained off in the NEM dispatch is never worse off after the reform either. It can obtain the same profits as under the status quo (case 4=1) or greater if CRMP<MC+RRP-F (case 6>1).

Since expected generator profits after the reform are greater than or equal to the status quo and downside risk is reduced, the CRM will tend to reduce cost of debt for contracted generators.

3.4. CMM

The CMM introduces a mechanism of congestion charges and rebates that operates alongside the energy market. While physical dispatch G is the outcome of the current NEM dispatch and is settled at RRP, when a constraint binds generation is also subject to a congestion charge that represents the difference between RRP and a localised price for energy that reflects congestion at the generator's location (as discussed in Section 3.1, this localised price is analogous to CRMP). Congestion charges are then redistributed among generators as congestion rebates. The rebates can be expressed as a payment of RRP – CRMP on a quantity of 'access' A. Therefore, generator revenue under the CMM can be expressed as follows:

$$Revenue = G \times RRP - Congestion\ charge + Congestion\ rebate$$

$$= G \times RRP - G \times (RRP - CRMP) + A \times (RRP - CRMP)$$

$$= G \times CRMP + A \times (RRP - CRMP)$$

As shown in the last expression, revenue in the CMM can be written similarly as in the CRM, with the difference that access to RRP (A) is not determined as the outcome of market dispatch, but is allocated in the form of rebates, which could be calculated using various methods. Here we consider rebates based on the 'pro-rata entitlements' method, where access is calculated as:

$$A = E/\alpha = \min{(k, \alpha)} \times Q/\alpha$$

Where:

- Q is the maximum quantity that the generator bid into the dispatch (at any price) – i.e., the most it is available to generate for that dispatch interval.
- α is the generator's participation factor, i.e., the proportion of the generator's output that flows through the constraint.
- k is a scaling factor applied to all generators. It is set so that the sum of 'entitlements' E (i.e., the MW of generator output that flow through the constraint) across all generators is equal to the constraint limit. Note that k>0, or access would remain unallocated.

3.4.1. Unhedged generators

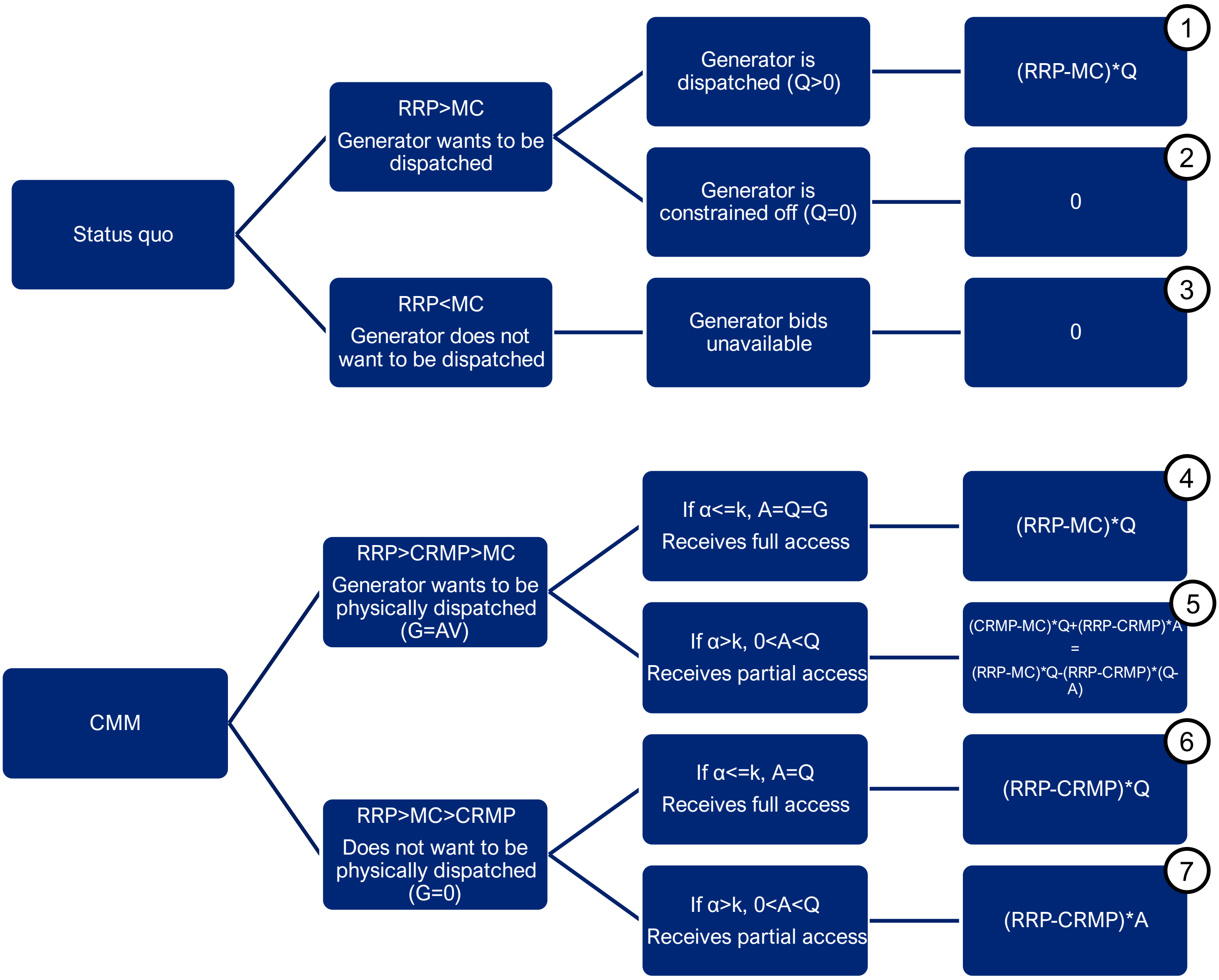
Summary cost of capital impact – CMM (unhedged generators)

- The impact of the CMM on the risk of being constrained off and expected profits depends on the generator's expected risk of being constrained off under the status quo. For a generator at low risk of being constrained off under current arrangements, the CMM may increase the cost of debt. For a generator at high risk of being constrained off, the CMM might lower the cost of debt. It is unclear which effect would dominate at the NEM-wide level.
- As per the arguments set out in Text Box 1, we do not consider that the reform is likely to have a material impact on the cost of equity in either direction.

Unhedged generator profits can be written as (CRMP-MC)*G + (RRP-CRMP)*A. Since the generator has a payoff of CRMP-MC on any unit of physical output, it is incentivised to bid at cost, seeking to be dispatched when CRMP>MC and not dispatched when CRMP<MC. The generator also has a profit of RRP-CRMP on any unit of access, so it will

seek to maximise access by maximising its availability (Q). For simplicity we assume that when the generator is dispatched, its output equals availability (G=Q). Figure 3.4 compares profits under the CMM and the status quo.

Figure 3.4: Comparison between profits in the status quo and CMM – Unhedged generators



Under both the status quo and the CMM, expected profits depend on the risk of losing access to RRP and the volatility of RRP. In addition, the CMM gives generators exposure to CRMP. We analyse these risk factors below.

Access to RRP

Under the status quo, access to the RRP is determined in the NEM dispatch. If generators behind a constraint bid the same price (e.g., the floor price), those with the lowest participation factors in the constraint are dispatched. A generator runs the risk of being constrained off only if enough competitors *with lower participation factors* are available over operational timeframes or enter the market over investment timeframes, cannibalising its access to RRP. A similar mechanism applies in the CRM.

Under the CMM with pro-rata entitlements, all generators are equally entitled (in proportion to their availability) to access congested lines, subject to the constraint limit. As generation capacity available behind the constraint increases, the scaling factor k diminishes to ensure that the sum of entitlements remains within the constraint limit. This means that, unlike the status quo and the CRM, the access of most existing generators diminishes every time competitors become available over operational timeframes, or enter the market over investment timeframes, *regardless of their participation factors*.[12]

In other words, all generators behind a constraint are likely to be required to share access with others, meaning that a generator in a congested area will mostly find itself in cases 5 and 7 of Figure 3.4, rather than 4 and 6. The impact of the CMM on profits and risk (relative to the status quo) depends largely on the generator's position in the energy system, creating 'losers' and 'winners': [13]

- Losers – A generator that, given its location in the energy system, under the status quo is not particularly at risk of being constrained off (i.e., one that under the status quo expects to find itself mostly in case 1) might expect lower profits under the CMM, where it will be sharing access with others. Profits in case 5 are lower than in case 1. Mathematically, it is possible that profits in case 7 are higher than in case 1, if CRMP is low enough below MC that it compensates for reduced access to RRP, but this becomes less likely over time as access to RRP under the CMM progressively reduces when new generators connect behind the constraint. For this generator, the introduction of the CMM can reduce expected profits and increase downside risk, which would increase the cost of debt.

- Winners – A generator that under the status quo has a high risk of being displaced by new entrants connecting nearby with more favourable participation factors (i.e., one that would expect to find itself more and more in case 2 rather than case 1) might expect higher profits under the CMM, where it shares the risk of being constrained off with all other generators behind the same constraint. Profits in both case 5 and 7 are higher than in case 2. Provided that this effect dominates any reduction in profits in those dispatch intervals where the generator would have been fully dispatched under the status quo, the CMM will increase expected profits. For this generator, the downside risk of being fully constrained off is reduced. This should decrease the cost of debt.

The magnitude of change in generators' expected profits and downside risk following the introduction of the CMM also depends on the expected level of congestion at the generators' location and in practice the redistribution of access operated by the CMM may be modest. In a very congested area, with the introduction of the CMM, some generators will go from being fully dispatched to sharing access equally with several competitors, others will go from being often fully constrained off to enjoying a more stable and substantial level of access. Conversely, in an area where available capacity barely exceeds constraint limits, generators stand to lose/win less, in terms of access to RRP, from the introduction of the CMM.

Exposure to CRMP

- For losers, this does not introduce further downside risk in addition to the reduction in access to RRP discussed above. Provided that CRMP is not more volatile than RRP,[14] the price risk that the generator faces under the CMM (case 5) is similar to price risk in the status quo (case 1).

- For winners, exposure to CRMP provides an opportunity to increase profits relative to the status quo (profits in case 5 and 7 are higher than in case 2).

Different considerations apply to hedged generators, as discussed in Section 3.4.2.

[12] There are some exceptions to this general rule. For example, a generator's level of access is not affected by new entrants as long as the generator's participation factor is lower than k. However, this becomes less likely as more capacity becomes available behind the constraint.

[13] Similar considerations apply when assessing the impact of the CMM from the perspective of a potential new entrant or of an existing generator.

[14] We note that, even if CRMP were more or less volatile than RRP across each five-minute dispatch interval, this would not necessarily mean that the average market price captured by the generator (e.g., over a year or its operating life) would have a wider or narrower standard deviation compared to the status quo.

Impact of the reform on RRP

Profits under the CMM, like in the CRM and the status quo, depend on the level and volatility of RRP. RRP in the CMM should be broadly similar to RRP_{CRM}, because the generator's output, after taking into account the congestion charge, is effectively priced at CRMP, which should promote cost-reflective bidding. As discussed in Section 3.3, adopting RRP_{CRM} in place of RRP_{NEM} for settling the market dispatch does not have a clear-cut impact on either the level or variability of expected profits.

3.4.2. Hedged generators

Summary cost of capital impact – CMM (hedged generators)

- The impact of the CMM on the risk of being constrained off and expected profits depends on the generator's expected risk of being constrained off under the status quo. For a generator at low risk of being constrained off under current arrangements, the CMM may increase the cost of debt. For a generator at high risk of being constrained off, the CMM might lower the cost of debt. It is unclear which effect would dominate at the NEM-wide level.
- For generators at low risk of being constrained off under current arrangements, the CMM may reduce the effectiveness of PPAs in providing a hedge against price risk. In principle, this could increase their cost of debt. However, the significance of this argument depends on the risk of congestion. The capital expenditure reforms that would be implemented alongside the CMM, either congestion fees or priority access, would reduce this risk going forward. Therefore, the impact of the CMM on generators' ability to enter into this type of contracts may be limited to parts of the network where congestion is already high.
- As per the arguments set out in Text Box 1, we do not consider that the reform is likely to have a material impact on the cost of equity in either direction.

The impact of introducing the CMM on contracted generators (who have entered either a swap contract or a PPA) is similar, in some respects, to the impact on unhedged generators. The impact on profits and risk (relative to the status quo) depends largely on the generator's position in the energy system:

- A generator that under the status quo is not particularly at risk of being constrained off can obtain lower expected profits and face a higher downside risk of seeing its access to RRP diminished under the CMM. This will tend to increase the cost of debt.
- A generator that under the status quo has a high risk of being displaced by new entrants can obtain higher expected profits and face a lower downside risk of seeing its access to RRP diminished under the CMM. This will tend to decrease the cost of debt.

In addition, the fact that the CMM (unlike the CRM) redistributes access to RRP among generators has some implications for the effectiveness of hedging contracts.

A generator that has entered a swap contract for a fixed quantity might find that the hedge becomes greater or smaller than originally intended – once the CMM enters into force and changes its level of access to RRP in the market. However, the contract will eventually expire, and the generator will be able to negotiate a new swap on a higher/lower quantity, reflecting access under the new regime. A generator under the CMM will not have perfect foresight of the level of access to RRP that it will enjoy in subsequent years, but similar uncertainty also exists under the status quo.

Under the CMM, a generator behind a binding constraint that is physically dispatched obtains a level of access to RRP that is lower than the physical output on which the PPA payments are calculated.[15] Potentially, this means that the CMM reduces the ability of generators to hedge against price risk using PPAs (relative to the status quo, where

[15] Conversely, a generator behind a binding constraint that chooses not to be physically dispatched will be exposed to RRP without receiving any hedge from the PPA. However, the generator will choose this option only if it increases its profits, given the level of RRP relative to its CRMP, MC, and PPA payments.

the PPA volume matches the generator's output). In principle, this might increase risk, leading to a higher cost of debt. However:

- The significance of this argument depends on the risk of congestion. In an area with little or no congestion, basis risk will be small or not present. Reforms that will be implemented alongside the CMM, either congestion fees or priority access, will reduce this risk going forward. Therefore, the impact of the CMM on generators' ability to enter into this type of contracts may be limited to parts of the network where congestion is already high.
- It is also worth noting that, while the CMM introduces some basis risk, it also reduces volume risk, at least for those generators who would have been constrained off under the status quo.

Detailed decision trees for hedged generators under the CMM are included in Appendix A.

3.5. Priority access

Summary cost of capital impact – Priority access

- Priority access with unique queue positions offers a generator complete protection from the risk that its level of access to RRP will be diminished in the future by subsequent new entrants. This removes a source of downside risk, pointing to a general downwards impact on the cost of debt, relative to both the status quo and the CRM/CMM alone for generators that site in non-congested areas.
- The cost of debt impact of a tiered approach to allocating priority access would be similar directionally to a unique queue position system, but is likely to be smaller in magnitude.
- Priority access may reduce the business case for locating in congested areas, because cannibalising existing generators' access is no longer possible.
- As per the arguments set out in Text Box 1, we do not consider that the reform is likely to have a material impact on the cost of equity in either direction.

Priority access would be implemented in addition to the CRM or the CMM to manage the allocation of access over investment timeframes. Under a priority access regime, access to RRP is allocated in order of the generators' position in a queue.

In the CRM, priority would apply only to the access dispatch and not physical dispatch. Bids tied at the floor price would be evaluated based on queue position. If they share the same queue position, access would then be based on constraint coefficients.

In the CMM, priority would apply to the allocation of access, to ensure that access is reserved to generators with the lowest queue position. Between incumbents sharing the same position, access would still be allocated on the basis of pro-rata entitlements.

We consider two alternative design options for priority access:

- a model with unique queue positions; and
- a tiered approach.

Unique queue positions

This system would have the following characteristics:

- Incumbents are tied at queue position zero (the front of the queue). Each new entrant has a unique queue position equal to the previous entrant's position plus one.
- Queue positions are permanent, and once a generator has joined the queue it cannot move to a higher position.

This model offers a generator complete protection from the risk that its level of access to RRP will be diminished in the future by subsequent new entrants siting behind the same constraint. This removes a source of downside risk, pointing to a general downwards impact on the cost of debt, relative to both the status quo and the CRM/CMM alone for generators that site in non-congested areas.

The significance of this impact depends on the extent to which, under the status quo, the generator would have been at the risk of cannibalisation by subsequent entrants. If this risk was low (for example because its position in the energy system made it unlikely that it would be displaced by competitors) the benefit from priority access would be relatively small. If this risk was high, the benefit would be larger.

It is relevant to note that priority access may reduce the business case for locating in congested areas, because cannibalising existing generators' access is no longer possible. For generators who were considering this strategy before priority access was introduced, expected free cash flow would naturally be lower with the reform than without. While this might increase the cost of debt (and/or reduce the overall viability) of a project planning to connect in a congested part of the NEM, this is the intended impact of the capital expenditure reforms: that generators bear the cost of increasing congestion, meaning that connecting in parts of the grid with limited spare access may no longer be viable. This argument applies not only to the unique queue position model, but also to the tiered approach, as well as congestion fees.

Tiered approach

This design option differs from the unique queue system described above in a number of respects. The table below sets out these differences and how they impact the cost of debt.

Table 3-1: Tiered priority access – Impact relative to status quo and unique queue positions

Difference with unique queue positions model	Impact relative to the status quo and the unique queue model
• Instead of unique queue positions, there is a limited number of access tiers (e.g., four tiers). • Each tier represents a certain amount of available access. Once access in a given tier is fully allocated, new entrants are placed into the subsequent tier. • When the system enters in force, incumbents are placed in the first tier. • Within the same tier there is no queue, and access is allocated based on either NEM dispatch (under the CRM) or congestion rebates (under the CMM).	Relative to the status quo (or the CRM/CMM implemented without priority access) the tiered system offers *partial* protection from the risk of being cannibalised by subsequent new entrants and reduces opportunities to cannibalise incumbents, because both risks and opportunities are limited to generators *within the same tier*. The impact of the tiered system varies depending on: • The level of congestion in the generator's location at the time of connection, to the extent that this determines whether the generator joins in a high priority or low priority tier. • To what extent, under the status quo, the generator would have able to cannibalise incumbents/ at risk of cannibalisation by later entrants. The directional impact on cost of debt relative to the status quo is similar to the outcomes shown in Figure 3.6, but likely to be smaller in magnitude relative to a unique queue position system, because opportunities/risks of cannibalisation remain, within the tiers.
Once a generator is in a given tier, they can move into a different tier in a number of ways: • A generator retires. This creates 'room' in the tier they were in. This would let other generators advance up the tiers, in the order of their connection date (e.g., the oldest	Although the ESB is still working through the details of the tiered model, we understand the general principle is that if generators are able to purchase access to a higher queue position, this would not erode the access of other existing generators (i.e., transmission capacity

generator in Tier 2 can move up to Tier 1, and so on).

- There is a generator funded transmission expansion. This creates room in a higher tier, which is taken by the generator(s) that funded the expansion. Everyone else stays in their original tier. The expansion would be large enough that the access of all existing generators is unchanged (i.e., not just their tier is the same, but the amount of MW access they actually receive is the same).
- There is a non-generator funded transmission expansion. This creates room in a higher tier, everyone in lower tiers moves up accordingly (without paying).
- As above, but generators have to pay to benefit from the new transmission expansion (i.e., via an auction to determine who moves into a higher tier).

would be expanded to leave the existing generators' position unchanged).

If the ESB is successful in developing a mechanism to implement this principle, the ability for generators to purchase a higher queue position should have no further cost of capital effect. However, if this cannot be implemented in practice, or if capital providers perceive it will not have the desired effect, this may create further uncertainty around the risk reduction benefit of introducing the priority access reform.

3.6. Congestion fees

Summary cost of capital impact – Congestion fees

- The cost of debt impact of a congestion fee model relative to the status quo depends on how the fees are set and the choice between the CRM and CMM.
- As per the arguments set out in Text Box 1, we do not consider that the reform is likely to have a material impact on the cost of equity in either direction.

Congestion fees are an alternative reform option that could be implemented instead of priority access, and in addition to the CRM or the CMM, to manage the allocation of access over investment timeframes and provide more efficient investment signals.

Different options are under consideration as to what the fee should represent, including:

- The forecast net present value (NPV) of the connecting generators' access to the RRP.
- The total cost of congestion caused by the connecting generator.
- The long run incremental cost (LRIC) of future transmission investment as a result of the generator connection.

We examine the impact of each of these options below.

Fees based on value of access to RRP

We assume that the NPV of future access to RRP can be calculated with perfect accuracy. The NPV of the sum of generator profits over all future dispatch intervals for the life of the project can be written as:

$$\sum Generator\ profits = \sum (CRMP - MC) \times G + \sum (RPP - CRMP) \times A - Congestion\ fee$$

$$= \sum (CRMP - MC) \times G + \sum (RPP - CRMP) \times A - \sum (RPP - CRMP) \times A = \sum (CRMP - MC) \times G$$

Relative to the CRM/CMM alone, the introduction of the congestion fee reduces expected profits, because the CRM/CMM alone provide generators an opportunity to access RRP (which may be more or less at risk of cannibalisation depending on the generator), which would be completely offset by the cost of the fee.

The fees may also reduce, although not eliminate completely, the likelihood that the generator's profits are cannibalised by subsequent entrants (because the fee makes cannibalisation less profitable), but in theory this benefit is perfectly offset by the fee itself: revenues earned through the NEM may be higher because loss of access to RRP that would otherwise have occurred does not materialise, but this is captured in a higher congestion fee.

These effects point to a higher cost of debt relative to the CRM/CMM alone. However, for incumbents, who do not pay a congestion fee and benefit from the reduced risk of cannibalisation, the reform would tend to decrease the cost of debt.

Relative to the status quo, this type of congestion fee (combined with one of the operational reforms) might increase or decrease cost of debt, depending on a generator's specific circumstances. If under current arrangements a generator is at high risk of being displaced by new entrants, the CRM/CMM reduce this downside risk by allowing the generator to earn CRMP on its physical output, and this risk reduction benefit may offset the cost of the fee. Conversely, a generator with a lower risk of being displaced under the status quo would be required to pay for the value of its access to RRP, without a significant risk reduction benefit.

As with the priority access model, the introduction of congestion fees affects the investment decisions of prospective new generators. Projects that would have been profitable under the status quo may no longer be after congestion fees are introduced (e.g., if their business case relied heavily on the cannibalisation of access to the RRP), whereas other projects that would not have been viable under the status quo due to a high risk of cannibalisation would become investable under the CRM/CMM, despite the introduction of congestion fees (for example, if their marginal cost is below CRMP). As noted above, this also means that the congestion fees do not remove the risk of cannibalisation entirely, because some potential new entrants may find that investment profitable despite the fee.

Finally, we note that the analysis above assumes that the NPV of access to RRP over the life of an investment can be calculated with perfect accuracy. In practice, the calculation will be complex and it may be challenging to achieve a very high degree of accuracy. However, as long as congestion fees do not systematically under or overestimate the true value of access, this should not affect expected future profits. From a cost of capital perspective, since the fee would be known upfront, before the investment decision is finalised, inaccuracy in the fee would not in itself increase uncertainty around returns.

Fees based on the total cost of congestion caused by the connecting generator

Under this approach, the fee is calculated as the increase in the total cost of congestion that is forecast to occur following the generator's connection, relative to the total cost of congestion forecast in the ISP optimal development path – where the total cost of congestion is defined as the NPV of future system-wide dispatch costs including constraints minus future system-wide dispatch costs assuming no constraints.

This means that if the generator's connection was deemed consistent with the ISP, the fee would be zero. For this generator:

- *Relative to the CRM/CMM alone*, the reform reduces the downside risk of losing access to RRP (because the fees should disincentivise new generation connecting above the level envisaged in the ISP) and increases expected cash flows, pointing to a lower cost of debt.
- *Relative to the status quo*, the impact depends on which operational reform is introduced alongside the fees.
  - The CRM plus the fee reduces the downside risk of losing access to RRP for all generators, pointing to a lower cost of debt.
  - The CMM plus the fee provides better protection from congestion relative to the CMM alone, but to the extent that the fees do not completely eliminate the risk of cannibalisation, there will still be winners and losers relative to the status quo. In other words, the impact on cost of debt may vary across generators.

If the new generator was larger, different technology or delivered at a different time than forecast in the ISP for that location, the fee would reflect the full impact that the generator's location decision has on system-wide congestion – including the increase in the congestion costs of all other generators resulting from its connection.[16] Therefore, for a generator who chose to connect in excess of the ISP forecast level of generation at that location, this approach is likely to result in higher fees than based on the generator's future value of access to RRP, which only captures the cost of congestion *to the extent that the connecting generator gains access to RRP*.

Fees based on the LRIC of future transmission investment

Under this approach, the fee is calculated as the NPV of the increase in network expenditure required to provide a defined level of generator access with the new generator connected to the system. A method would be required to calculate LRIC. An option for this would be that AEMO or another body (e.g., the TNSP) run an ISP-style calculation under two scenarios, with and without the new generator, and calculate the change to the NPV of the recommended transmission expenditure due to the generation investment. [17]

If a new connection is consistent with the ISP's optimal development path, the two scenarios would be identical and the congestion fee would be zero. Therefore, in this case, the direction of impacts on the cost of debt is similar to the case of connection fees based on the total cost of congestion.

However, it is unclear whether the fee for a generator who chose to connect in excess of the ISP forecast level of generation at that location would be higher or lower with the LRIC method relative to the total cost of congestion. Therefore, it is uncertain whether the LRIC method will provide a smaller or even greater reduction of downside risk than the total cost of congestion method.

3.7. Other design choices

Incentives of OOMO generators

Both the CRM and the CMM give generators the opportunity to earn RRP without being without being physically dispatched. This is a profitable strategy, as long as RRP>CRMP and MC>CRMP.

However, this also gives OOMO generators (i.e., generators with MC>RRP, who would bid unavailable under the status quo) an opportunity to earn profits by cannibalising other generators' access to RRP. This can increase the risk of other generators being constrained off after the reform relative to the status quo, because:

- In operational timeframes, existing high-cost generators, who are currently only profitably dispatched at peak periods of high RRP, will have an incentive to always bid available regardless of their willingness to generate.
- In investment timeframes, prospective new entrants who would have been too costly to operate profitably in the status quo may have a more attractive business case under the reforms.

The ESB is considering some design choices that could reduce these arbitrage opportunities for OOMO generators. These options include:

- modifying the bidding guidelines and giving the AER a monitoring role to prevent OOMO arbitrage, for example if it identified anomalies in bidding behaviour relative to a generator's inferred costs; and/or
- excluding OOMO generators from dispatch based on their bids relative to RRP.

[16] ESB (2022), Transmission access reform – Directions paper, p. 80.

[17] Ibid., p. 81.

Both options present advantages and challenges.[18] If the risk of OOMO arbitrage is not material or is addressed appropriately, it will not affect the conclusions of our analysis. Instead, if the risk is material and not addressed, it could lower the expected profits of 'in merit order' generators to the point of offsetting any gains from the reform in terms of cost of debt reductions and efficient investment signals (noting that other benefits from the reform are not affected, for example efficiency of physical dispatch in operational timeframes).

Rounding participation factors

The participation factor (also known as constraint coefficient) of a generator in a given constraint reflects the proportion of a generator's output which flows through the transmission line to which the constraint relates. If more generation capacity is available than can be accommodated by the transmission system, NEMDE will choose the lowest cost combination of available generators taking into account the prices offered and their coefficients. When competing generators all offer the same price (e.g., because generators have bid the market floor price), coefficients become determinative: NEMDE minimises the cost of congestion by dispatching generators with the lowest coefficients first.

This gives rise to "winner takes all" results when a network constraint is affecting the dispatch of generators. Dispatch outcomes, i.e., which generators are dispatched, vary over time, as generators enter and exit the market, and their availability and demand patterns change.[19]

Coefficients are highly granular, reflecting the physics of the way electricity flows across a meshed network. It is normal for each generator in a constraint to have a unique coefficient, potentially less than 0.1 or 0.01 higher or lower than another generator. However, under current arrangements, "winner takes it all" outcomes can occur even in the presence of very small differences in coefficients.

To socialise congestion risk and reduce volatility in dispatch outcomes, the ESB is considering rounding coefficients to one or two decimal places for the purposes of dispatch in the NEM. Generators that, after rounding, have the same coefficient will share any available dispatch quantity equally (in proportion to the quantity of their relevant bids). Rounding would not apply in the CRM dispatch, to preserve efficient physical dispatch outcomes.

In terms of expected profits and downside risk, the introduction of rounding in addition to the CRM would leave some generators better off and other worse off relative to the CRM without rounding, depending on whether their coefficient after rounding is lower or higher than before. Consider for example rounding to one decimal place. A generator with a coefficient of 0.749 and one with a coefficient of 0.651 would share a coefficient of 0.7 after rounding. For the former, the downside risk of being constrained off is reduced, and expected profits increase, pointing to a lower cost of debt. The opposite is true for the latter, pointing to a higher cost of debt. Like with any reforms that create 'winners and losers', the impact of rounding on the volatility of generator profits depends on whether a given generator is more or less at risk of being constrained off after rounding.

It is worth noting that the redistribution of congestion risk achieved with rounding is less extensive than the one that would occur under the CMM. In the CMM, a generator shares access virtually with everyone else behind the same constraint. With rounding, sharing is limited to generators with similar coefficients. In the extreme, a generator may not be affected by rounding at all (for example, if despite rounding its coefficient remains below/above that of the marginal generator who is the first to be constrained off).

[18] ESB (2022), Transmission access reform - Directions paper, p. 49-50.

[19] Ibid., p. 20.

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4. CONCLUSIONS

This section summarises our overall conclusions in relation to the cost of debt, cost of equity and capital structure.

Impact on the cost of debt

We find that the cost of debt is influenced by two factors, being whether the reforms impact:

- The **expected value of a generator's future cash flows.** Higher expected future cash flows reduce a generator's operational leverage and therefore default risk, assuming no change in capital structure.
- The generator's **exposure to downside cash flow risk**, itself a function of the probability of adverse events (primarily the risk of losing access to RRP as a result of congestion) and the magnitude of their impact on cash flows.

The table below summarises how the different reform options might affect these factors.

Table 4-1: Directional impact of reform options on cost of debt factors

Reform option	Directional impact on cost of debt factors
CRM (RRP_{NEM} or RRP_{CRM})	⇩ *Compared to status quo:* Expected free cash flow is higher due to the opportunity of trading in the CRM. The probability of being constrained off is the same, but the adverse impact on profit is smaller, pointing to a reduction in downside risk. Choosing RRP_{NEM} or RRP_{CRM} does not have a material impact.
CMM (pro-rata entitlement)	⇩ ⇧ *Compared to status quo:* The CMM requires all generators behind a constraint to share access to RRP with others. For a generator that is at high risk of losing access to RRP under current arrangements, this increases expected free cash flow and decreases downside risk. Conversely, for a generator that is at low risk of losing access to RRP under current arrangements, the CMM decreases expected free cash flow and increases downside risk.
Congestion fee	**Fee based on the value of access to RRP** ⇧ *Fee + CRM/CMM, compared to CRM/CMM alone:* Expected free cash flow is lower for new entrants than in the CMM/CRM alone, as a result of the fee. The fee also means that any reductions in the likelihood of cannibalisation from the reform do not translate to a positive cash flow impact. ⇩ ⇧ *Fee + CRM/CMM, compared to status quo:* For a given generator, the impact relative to the status quo depends on whether the ability to earn CRMP under the reform (as opposed to being constrained off under current arrangements) provides greater benefits than the cost of the fee.
	Fee based on the total cost of congestion or the cost of transmission investment ⇩ *Fee + CRM/CMM, compared to CRM/CMM alone:* For new entrants whose connection is deemed to be compatible with the ISP optimal development path, the fee is zero and the risk of cannibalisation is reduced. Therefore, free cash flow is higher and downside risk lower. ⇩ *Fee + CRM, compared to status quo:* For new entrants whose connection is in line with the ISP, the fee is zero and the risk of cannibalisation is reduced. ⇩ ⇧ *Fee + CMM, compared to status quo:* For new entrants whose connection is in line with the ISP, the fee is zero and the expected level of access to RRP will be improved relatively to the CMM alone. However, to the extent that the risk of congestion is not completely eliminated, there will still be winners and losers relative to the status quo.
Priority access	⇩ *Priority access + CRM/CMM, compared to status quo or CRM/CMM alone:* For new entrants siting in a non-congested area, the risk of being displaced by subsequent new entrants is reduced – entirely in the case of a queue with unique positions for each generation, partly for a tiered priority access model. This points to higher expected free cash flow and a reduction in downside risk.

We find that the **CRM** may have a downwards impact on the cost of debt. If this reform is implemented, the probability of a generator being constrained off in the NEM dispatch is similar to today: bidding incentives are broadly unchanged, as is the risk of being displaced by other generators connecting at a later date. However, the impact of being constrained off in the NEM dispatch is reduced. If the generator is cost competitive, it can trade in the CRM and be physically dispatched to earn its CRMP: this compares to earning no revenue at all under the status quo. Accordingly, the magnitude of downside risk is reduced and expected free cash flow will be higher relative to the status quo. To the extent that a generator is not constrained off in the NEM dispatch, the reform gives them an opportunity to increase profits by trading in the CRM (when CRMP is below marginal cost), again increasing expected free cash flow relative to the status quo. The magnitude of these benefits will vary across generators and may or may not be material.

The CRM design involves a choice between RRP_{NEM} or RRP_{CRM}. It is possible that – looking across prices in each 5-minute dispatch interval – RRP_{CRM} is less volatile than RRP_{NEM}. This is because the impact of disorderly bidding may sometimes contribute to more extreme RRP_{NEM} values (for example, if the regional reference nodes are on a loop). If RRP_{CRM} translated to less extreme variability around generator cash flows, this could reduce the magnitude of downside risk. However, it does not follow that this would necessarily occur. More extreme highs/lows in 5-minute prices do not necessarily mean that the average market price captured by the generator (e.g., over a year or its operating life) has a wider standard deviation. Further, generators that contract all or part of their capacity would in any case be protected against fluctuations in the RRP.

The impact of the **CMM** on the cost of debt is different to the CRM. This is because the CMM effectively requires all generators behind a constraint to share access to RRP with others. While this might be perceived as a fairer outcome than the status quo, it creates winners and losers. Winners would see a reduction in the magnitude of the downside risk of losing access to RRP and an increase in free cash flow – which is consistent with a lower cost of debt. However, the reverse outcome applies for losers under the CMM – pointing to a potentially higher cost of debt for these generators. From a NEM-wide perspective, it is not clear which effect would dominate. This depends on the relative magnitude of the change for winners and losers. For example, if losses from the CMM are spread over many generators, their small individual loss may not be material enough to actually change their credit rating. Conversely, a small number of winners with a material gain from the CMM might see an improvement in their credit rating.

As noted above, the ESB intends to combine the CRM or CMM with one of the capital expenditure reforms. Under the **congestion fee** model, new connecting generators would be required to pay a charge. Three different approaches to calculating the charge are under consideration:

- Congestion fee based on the forecast NPV of the connecting generator's access to the RRP:
    - *Relative to the CRM/CMM alone*, this reduces free cash flow for all new entrants, as the congestion fee means they have to pay for the value of their access to RRP. The fees also reduce the likelihood that the generator's profits are cannibalised by subsequent entrants (because the fee makes cannibalisation less profitable), but in theory this benefit is perfectly offset by the fee itself: revenues earned through the NEM may be higher because loss of access to RRP that would otherwise have occurred does not materialise, but this is captured in a higher congestion fee. These effects point to a higher cost of debt relative to the CRM/CMM alone. However, for incumbents, who do not pay a congestion fee and benefit from the reduced risk of cannibalisation, the reform would tend to decrease the cost of debt.
    - *Relative to the status quo,* this type of congestion fee (combined with one of the operational reforms) might increase or decrease cost of debt, depending on a generator's specific circumstances. If under current arrangements a generator is at high risk of being displaced by new entrants, the CRM/CMM reduce this downside risk by allowing the generator to earn CRMP on its physical output, and this risk reduction benefit may offset the cost of the fee. Conversely, a generator with a lower risk of being displaced under the status quo would be required to pay for the value of its access to RRP, without a significant risk reduction benefit.

- Congestion fee based on the total cost of congestion arising from the generator's connection. The increase in the cost of congestion that is forecast to occur following the generator's connection would be assessed relative to the cost of congestion in the ISP optimal development path. Therefore, as long as a generator's connection was deemed consistent with the ISP, the fee would be zero. For these generators:
  - *Relative to the CRM/CMM alone*, the reform reduces the downside risk of losing access to RRP (because the fees should disincentivise new generation connecting above the level envisaged in the ISP) and increases expected cash flows, pointing to a lower cost of debt. Similar conclusions apply to incumbents, who would also benefit from the same reduction in downside risk.
  - *Relative to the status quo,* the impact depends on which operational reform is introduced alongside the fees. The CRM plus the fee reduces the downside risk of losing access to RRP for all generators, pointing to a lower cost of debt. The CMM plus the fee provides better protection from congestion relative to the CMM alone, but to the extent that the fees do not completely eliminate the risk of cannibalisation, there will still be winners and losers relative to the status quo.
- Congestion fee based on the cost of future transmission investment. It has been suggested that the increase in the cost of transmission that is forecast to occur following the generator's connection would be assessed relative to the cost of transmission in the ISP optimal development path. Therefore, as long as a generator's connection was deemed consistent with the ISP, the fee would be zero and the cost of debt impact under this approach would be directionally similar to the 'total cost of congestion' approach (although the risk reduction impact of the two approaches may differ, depending on which one results in the highest fees for generators choosing to connect in excess of the ISP forecast levels).

The effect of the **priority access** model is different. Under this reform, a generator's access to the RRP is allocated in order of their unique position in a queue (or according to their access tier – as discussed below). This offers generators complete protection from the risk of being displaced by a subsequent new entrant, pointing to higher expected cash flow and less downside risk, which may have a corresponding downwards impact on the cost of debt. In principle, this effect is greater than under the congestion fee model, where some risk of access being eroded by a new entrant still remains (the extent of this risk depending on how large congestion fees are under each alternative fee calculation approach) and the generator has no defined access right.

In addition to priority access based on unique queue positions, the ESB is also considering a model in which generators are assigned to access 'tiers'. Within a tier there is no queue – all generators receive access based on the CRM or CMM logic. While a tiered approach provides some protection from access cannibalisation, it is less than under the 'pure' priority access model. This is because (depending on how the tiers are managed) a generator could still be displaced by a new entrant with a better participation factor that is assigned to the same tier. It is not clear whether this would result in the priority access model being equivalent to the congestion fee model from a cost of debt perspective. It may be that a tiered priority access model still has a greater risk reduction impact, because each generator still has priority over those in other tiers, whereas under the congestion fee model, the risk reduction benefit depends on the relative economics for a new generator of locating in a given location.

It is relevant to note that congestion fees and priority access (either model) may reduce the business case for locating in congested areas, because cannibalising existing generators' access is no longer profitable or possible. For generators who were considering this strategy before either reform is introduced, expected free cash flow would naturally be lower with the reform than without. While this might increase the cost of debt (and/or overall viability) of a project planning to connect in a congested part of the NEM, this is the intended impact of the capital expenditure reforms: that generators bear the cost of increasing congestion, meaning that connecting in parts of the grid with limited spare access may no longer be viable.

Impact on the cost of equity

We find that the impact of the reforms on the cost of equity depends on whether they affect the generators' systematic risk, i.e., the extent to which changes in the generators' expected returns are associated with changes in returns in the wider economy. This is a key insight of the CAPM framework and is linked to the assumption that investors hold a well-diversified portfolio of investments. The benefit of diversification is that, on average, business-specific risks that cause lower returns for one company will be offset by different business-specific risks that create higher returns for another company. This reduces the volatility of the returns of the overall portfolio, i.e., the risk of the portfolio, to systematic risk.

In this framework, business-specific risks unique to a particular investment are not relevant to determine the investor's required return, because they do not contribute to the risk of the diversified portfolio. Instead, a company's contribution to the risk of the portfolio is limited to its systematic risk. For example, the risk that a gold prospecting company will fail to strike gold may be material and potentially have a considerable impact on the company's cash flow, but it is not systematic. This risk is known to the diversified investor, however they do not require a higher return for it, because the risk is diversifiable.[20]

This intuition can be represented mathematically with reference to the parameter beta, which is used to calculate the cost of equity in the CAPM formulation. As shown is Section 1.2, beta is not affected by elements of risk that are independent of market returns. The implication is that any risk to generator returns that is non-systematic does not affect beta. Therefore, if the downside risk of congestion were non-systematic, removing this risk (as a result of the reforms) would not have an impact on the cost of equity.

While there may be a theoretical argument that congestion risk is somewhat correlated with conditions in the wider economy, we consider that in practice this effect may not be material, or indeed not present at all. Therefore, we do not consider that the reforms are likely to have a material impact on the cost of equity in either direction.

This does not necessarily imply that non-systematic risk is irrelevant to investment decisions. When making investment decisions, investors will require that expected returns match the cost of equity. Even if it does not affect the cost of equity, business-specific risk might be reflected in the investors' decision-making as a change in the forecast cash flow and therefore in the expected returns of the project. Although we acknowledge that in practice some investors might deal with such risks by adjusting their hurdle rates, rather than expected cash flows, in a CAPM framework non-systematic risk does not affect the cost of equity.

Overall impact on the cost of capital

We conclude that each reform option has a different impact on the factors that affect the **cost of debt**. The **CRM alone** reduces downside risk and increases expected cash flows, pointing to a reduction in the cost of debt. In combination with the capital expenditure reforms:

- The **priority access model in combination with the CRM** provides additional protection against later cannibalisation by new entrants, further reducing downside risk and increasing expected cash flow, again pointing to a reduction in the cost of debt.
- The impact of **congestion fees in combination with the CRM** depends on how the fees are set. Congestion fees based on the connecting generator's forecast value of access to RRP would increase costs for new entrants, and this may or may not be offset by the benefits of the CRM. Therefore, the overall impact on the cost of debt may be upwards or downwards, depending on the generator. Alternative options include calculating congestion fees based on the connecting generator's contribution to system-wide congestion or transmission investment costs. For generators siting in non-congested areas, these fees would be zero and the risk of cannibalisation would be reduced, pointing to a lower cost of debt for these generators.

Unlike the CRM, the CMM creates winners and losers relative to the status quo. Therefore:

- The **CMM alone** could lower the cost of debt for those generators that benefit from a reduction in downside risk and higher cash flow after the reform. However, other generators would experience greater downside

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

risk and a reduction in cash flow, pointing to a higher cost of debt. This conclusion extends to the **CMM in combination with congestion fees**.

- However, if the **CMM was implemented in combination with priority access**, for generators siting in non-congested areas of the network the risk of cannibalisation would be unambiguously reduced, pointing to a lower cost of debt for these generators.

Under all the reform options, the magnitude of cost of debt impacts will vary across generators, depending on how significant their risk of curtailment is expected to be under current arrangements.

We note that, instead of reducing the cost of debt, reforms that lower generator default risk may allow generators to be financed with a higher level of **gearing**. This would increase the optimal leverage for these generators, potentially allowing them to increase value from tax shields.

We do not consider that the reforms are likely to have a material impact on the **cost of equity** in either direction.

In combination, these conclusions point to an **overall downwards impact on the risk factors that determine the cost of capital for the CRM and priority access reforms**. For the CMM, the impact on cost of capital is ambiguous and varies across generators. The impact of a congestion fee model depends on how the fees are set and the choice between the CRM and CMM.

Our assessment of capital expenditure reforms is mostly focused on generators planning to site in non-congested parts of the network. The capital expenditure reforms are likely to reduce the business case for locating in congested areas, because cannibalising existing generators' access is no longer profitable or possible. While this may affect the overall viability of projects planning to connect in a congested part of the NEM, this is the intended impact of the capital expenditure reforms: that generators bear the cost of increasing congestion, meaning that connecting in parts of the grid with limited spare access may no longer be viable.

Finally, the analysis of potential cost of capital impacts set out above does not necessarily mean that the reforms would in fact change the cost of capital. In practice, this will depend not only on the direction of the effects we have identified but also their magnitude. In particular, we would only expect the cost of debt to change materially if credit ratings change, and this would only happen if the change in expected future generator profits is sufficiently large.

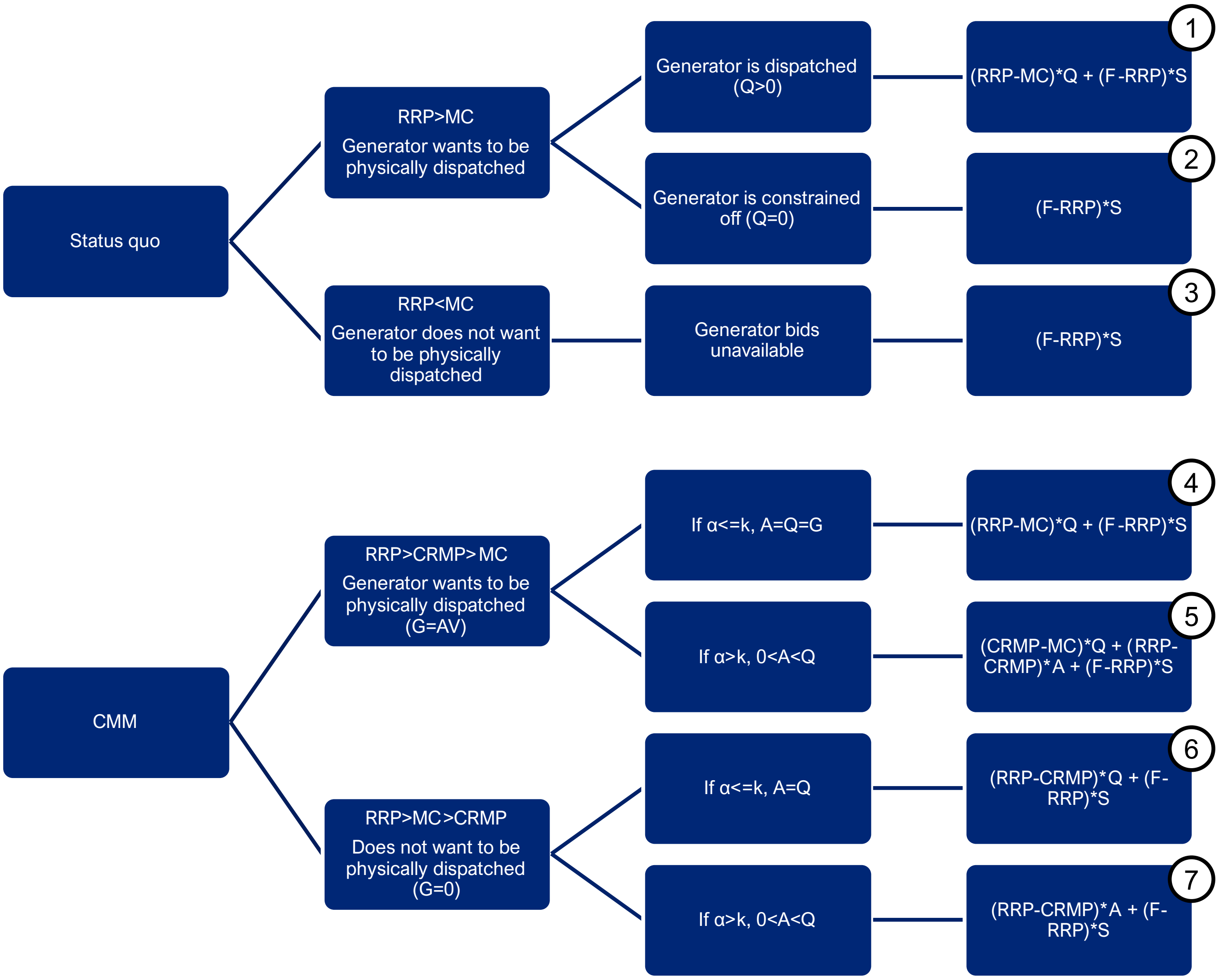
Appendix A PROFIT ANALYSIS OF HEDGED GENERATORS UNDER THE CMM

Swap contracts

We consider a financial contract that pays the generator the difference between an agreed price F and RRP on a fixed quantity S.

Profits in the CMM can be written as (CRMP-MC)*G + (RRP-CRMP)*A + (F-RRP)*S. This provides the same bidding incentives as those of unhedged generators, because the additional term (F-RRP)*S introduced by the contract is independent of the dispatch outcome.

Figure A 1: Comparison between profits in the status quo and CMM – Swap contracts

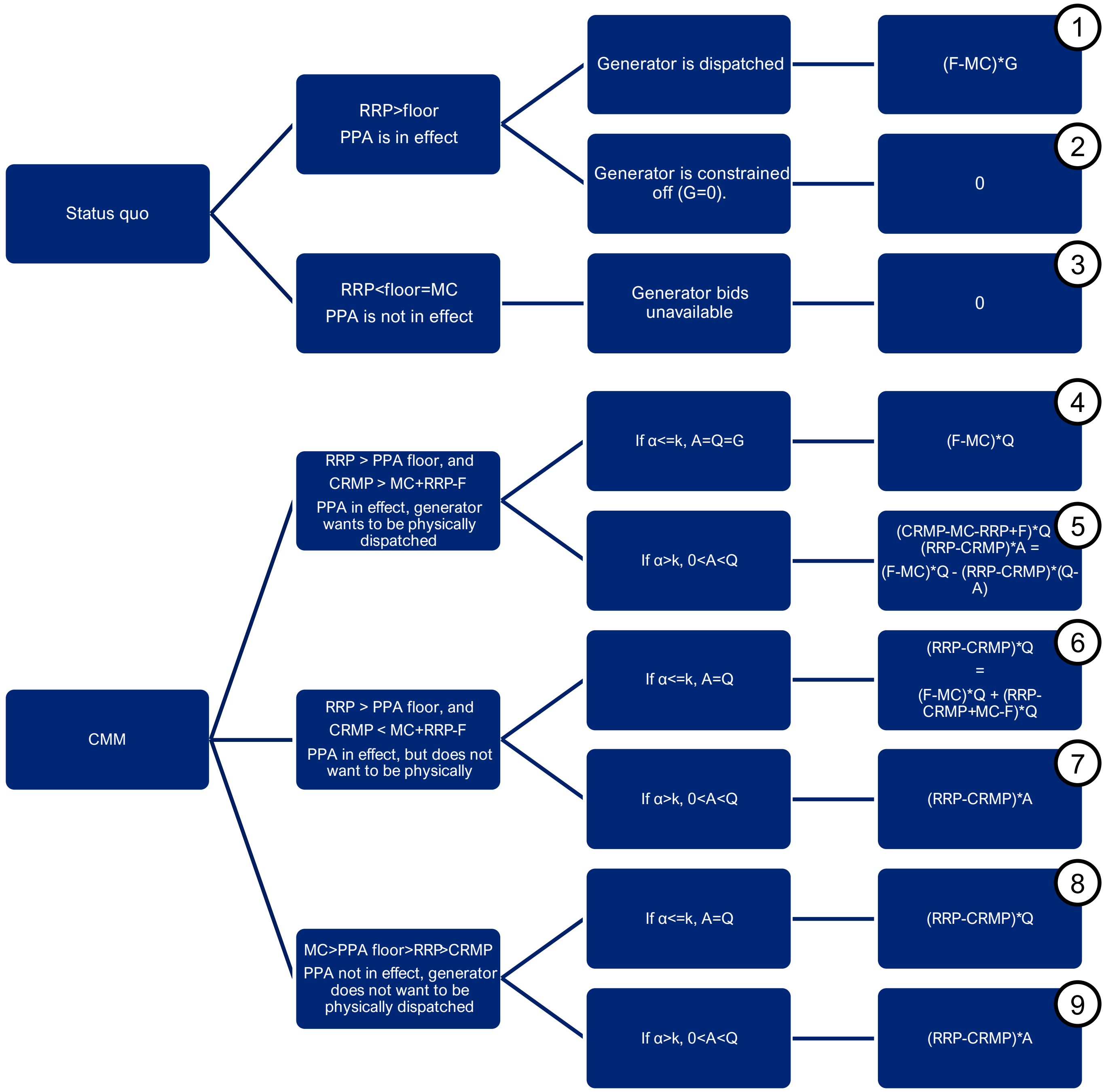


PPAs

We consider a PPA where the generator sells its output to a counterparty, who pays the difference between an agreed price F and RRP. The PPA floor price is below the generator's MC. Therefore, when RRP<PPA floor, under current arrangements the generator will bid unavailable, and under the CMM it will seek to maximise its congestion rebate without being physically dispatched.

Profits under the CMM can be expressed as the sum of market payoffs and contract payments: (CRMP-MC)*G + (RRP-CRMP)*A + (F-RRP)*G. This can be rewritten as (F-MC)*A + (CRMP-MC-RRP+F)*(G-A), suggesting that the payoff for each MW of physical dispatch obtained in the CRM beyond the outcome of the NEM dispatch is CRMP-MC-RRP+F. Willingness to be physically dispatch depends on whether this payoff is greater than 0.

Figure A 2: Comparison between profits in the status quo and CMM – PPAs



Appendix B STAKEHOLDER SUBMISSIONS

The ESB received a number of stakeholder submissions to its Directions Paper for Transmission Access Reform. Some of these submissions include comments on the cost of capital. In this appendix, the comments are summarised, organised by topic, and considered in the light of the findings included in this report.

B.1. Exposure to CRMP in the CRM and CMM

Stakeholder submissions

Some stakeholders have expressed concerns that CRMP would increase risk and deter investment:

- Iberdrola considers that exposure to CRMP is likely to expose investors to large swings in price compared to the current framework where congestion is a small change in volume, increasing investment risk and hurdle rates. Tilt Renewables and the Smart Energy Council note that CRMP would cause significant disruption and uncertainty in the market, deterring or at least deferring new investment in generation and storage.
- Shell comments on the design of the CRM, arguing that generators should be able to access RRP where there is no congestion or if they do not wish to access CRMP, or there would be a risk that generators will be unable to make the same level of financial market contracts available. According to Shell, the CRM opt-out provision is central to this.
- Energy Consumers Australia (ECA) offers a different perspective, citing international evidence showing that markets with locational pricing are better placed to attract investment with low costs of capital than Australia.

Some stakeholders expressed concerns that the reform could disrupt contract markets. For example, Snowy Hydro considers that the CRM and CMM can reduce the quantity of contracts made available in each region. The Australian Financial Markets Association (AFMA) argues that, by introducing basis risk between RRP and CRMP, the CMM would reduce the effectiveness of the RRP as a pricing signal and participants' ability to manage their risk. The Smart Energy Council considers that negotiating new offtake agreements will be more complex as neither party will be able to manage the risk that CRMP raises. Flow Power considers that CMM rebates would be determined as an approximate hedge against basis risk and this would complicate contracting.

Response

The cost of capital impact of exposure to CRMP depends on how this exposure affects the expected level and volatility of generator profits, as discussed in section 1, relative to the status quo. The analysis of generator profits and risk set out in this report does not support a view that the opportunity to earn CRMP, in and of itself, increases uncertainty, investment risk, and the cost of capital for generators.

Firstly, we are not aware of any evidence demonstrating that CRMP is significantly more volatile than RRP – noting that even if CRMP were more or less volatile than RRP across each five-minute dispatch interval, this would not necessarily mean that the average market price captured by the generator (e.g., over a year or its operating life) would have a wider or narrower standard deviation compared to the status quo.

Secondly, we note that the CRM and CMM expose generators to CRMP only to the extent that they are unable to access RRP as a result of congestion. Where there is little congestion, exposure to CRMP will be limited (and CRMP will tend to be closer to RRP), and vice versa. As shown in this report, on average across the NEM, the CRM and CMM do not increase the risk of congestion relative to current arrangements (although the CMM with pro-rata entitlements redistributes this risk among generators), and the introduction of either priority access or congestion fees would in fact reduce this risk, potentially significantly.

Thirdly, and most importantly from a cost of capital perspective, *if a generator's ability to access to RRP is reduced as a result of congestion* (which, on average across the NEM, is in fact less likely to occur once the CRM/CMM +

either priority access or congestion fees are implemented), then the ability to earn CRMP through the CRM/CMM gives generators an opportunity to earn higher profits than would have otherwise been the case. In other words, once the congestion risk that exists both under current arrangements and after the reforms is taken into account, exposure to CRMP does not represent a downside risk.

This last point is related to Shell's argument around opt-out provisions. Participation in the CRM is not mandatory – a generator can choose to trade in the CRM only when this increases their profits relative to outcome of the NEM dispatch.

B.2. CRM AND CMM IMPACT ON CONTRACT MARKETS

Stakeholder submissions

Some stakeholders expressed concerns that the reform could disrupt contract markets:

- Shell argues that without guaranteed access to the RRP there is a risk that generators will be unable to make the same level of financial market contracts available. The Smart Energy Council considers that negotiating new offtake agreements will be more complex as neither party will be able to manage the risk that CRMP raises.
- Snowy Hydro considers that the CRM and CMM can reduce the quantity of contracts made available in each region.
- The Australian Financial Markets Association (AFMA) argues that, by introducing basis risk between RRP and CRMP, the CMM would reduce the effectiveness of the RRP as a pricing signal and participants' ability to manage their risk. Flow Power considers that CMM rebates would be determined as an approximate hedge against basis risk and this would complicate contracting.
- CS Energy expressed concerns over contract liquidity and hedging costs.

Response

The argument that without guaranteed access to RRP generators might have difficulties entering into contracts must be examined with reference to the impact of the reforms in terms of the risk to generators of not being able to access RRP, *relative to the status quo.*

As discussed in Section 3.3.2, the CRM, in and of itself, does not affect this risk. Therefore, it does not reduce the generators' ability to enter into contracts that reference the RRP. In addition, a generator has *an option to* earn CRMP whilst its contracts reference the RRP, but it will only do so if this increases its profits relative to the status quo (i.e., it can choose to take on this basis risk only when it is an upside risk). In other words, the CRM will not leave any generator worse off, including when the generator is a party to swap or PPA-type contracts.

As discussed in Section 3.4.2, the CMM can potentially reduce the effectiveness of certain types of contracts as a hedge against price risk. We have considered the example of a PPA, where the contract volume is aligned with the generator's physical output. To the extent that the CMM rebates provide the generator with a level of access to RRP that is lower than the volume of physical output on which contract payments are calculated, this creates basis risk. However:

- The significance of this argument depends on the risk of congestion. In an area with little or no congestion, basis risk will be small or not present. Reforms that will be implemented alongside the CMM, either congestion fees or priority access, will reduce this risk going forward. Therefore, the impact of the CMM on generators' ability to enter into this type of contracts may be limited to parts of the network where congestion is already high.
- It is also worth noting that, while the CMM introduces some basis risk, it also reduces volume risk, at least for those generators who would have been constrained off under the status quo.

B.3. CMM REBATES

Stakeholder submissions

Some stakeholders raised concerns with the difficulty of forecasting congestion rebates under the CMM:

- The Clean Energy Investors Group (CEIG) argues that, as a result of this difficulty, financiers will be hesitant to finance new developments, which could result in either unavailable or very expensive debt.
- CEIG adds that the CMM does not protect a project from a second generator connecting nearby causing more severe congestion and resulting in negative impacts on the level of rebates received. Flow Power considers that it would be time consuming and costly to anticipate all the potential outcomes of a CMM reform and then allocate those risks amongst the parties.
- According to the Clean Energy Council (CEC), the CMM is effectively a 'tax and rebate' model dependent on the dictates of a central regulatory body, and as such cannot be meaningfully forecast and therefore cannot underpin investment decisions.

Response

The difficulty of forecasting future expected profits under the CMM depends largely on the difficulty of forecasting the future level of access to RRP that a generator will obtain under the rebates system. This level of access will depend on the availability of current and potential future competitors connected behind the same constraint. In addition, profits under the CMM depend on CRMP.

Accurately forecasting profits under the CMM may be complex, but calculating expected profits of a generator under current arrangements with the same degree of accuracy is not without challenges either, as that too requires assumptions on the future level of availability current and potential future competitors. While the CMM might require a forecast of CRMP, an additional complexity under current arrangements relative to the CMM is that the risk of being constrained off is more dependent on the generator's participation factor in a constraint relative to that of potential new entrants. On balance, the level of complexity may be comparable across the two regimes.

As discussed in this report, the impact of the CMM on risk to cash flows depends on the likelihood that a generator would be cannibalised under the status quo. Indeed, for some generators, outcomes under the CMM may be more favourable and predictable than under current arrangements.

If rebates under the CMM are based on a formula, as in the pro-rata entitlement method, the outcomes of the reform will be determined in the market and as a result of changes in the generation mix, rather than being centrally planned.

B.4. CONGESTION FEES

Stakeholder submissions

- ACCIONA and CEC note that congestion fees do not remove congestion risk for incumbents, as generators may still choose to pay fees and connect in a congested area.
- CEIG and Hydro Tasmania have raised concerns that paying a fee does not protect a new entrant from the risk that subsequent new entrants will connect nearby and displace them.
- CEC argues that fees are hard to determine and then readjust as more information / changed network conditions come to light. This will result in unpredictability of fees, increasing investor risk. Hydro Tasmania too expressed concerns around the workability of congestion fees.

Response

We agree with ACCIONA and CEC that congestion fees do not eliminate the risk that an incumbent's access to RRP is eroded by new entrants who, if sufficiently cost-competitive, may find that investment remains profitable despite having to pay the fee. However, the congestion fee would represent an improvement relative to current arrangements with respect to the risks faced by incumbents, because it would remove the risk of being displaced by new entrants whose business model relies primarily on the cannibalisation of incumbents' profits (as the fee would offset the gains from cannibalisation).

In relation to CEIG and Hydro Tasmania's concern that paying a fee does not protect a new entrant from the risk of cannibalisation, we note that this concern could potentially be addressed by factoring the risk of future cannibalisation into the calculation of the fee, so that a generator does not pay for access that it does not end up benefiting from. Alternatively, priority access could be introduced alongside a congestion fee.

We acknowledge that in practice calculating congestion fees with a high degree of accuracy will be challenging. However, as long as the fee does not systematically under or overestimate the value of future access, this will not affect a generator's expected future profits. From a cost of capital perspective, since the fee would be known upfront, before the investment decision is finalised, inaccuracy in the fee would not in itself increase uncertainty around returns.

B.5. Priority access

Stakeholder submissions

ACCIONA raised a number of concerns on priority access:

- Incumbents' sunk investment needs to be respected and this could be achieved by allocating a position of "0" to incumbents. However, this approach would reduce the access of new entrants. This would appear to work against the objective of facilitating further new investment to support the energy supply transition.
- The queue proposal seeks to address uncertainty, but in doing so it introduces further uncertainty and complexity. In particular it has the potential to exacerbate the existing risk and delays in the connection process. It is unlikely that this proposal would translate to a level of improved certainty on congestion.
- Priority access artificially introduces a new inefficiency into the energy market dispatch, and while dispatch in the CRM could trade away this inefficiency, the deliberate introduction of this inefficiency does not seem warranted by the objective of the proposal and the extent of the problem. In fact, ACCIONA does not agree that congestion risk is materially impacting the cost of capital faced by project developers and therefore that reforms to firm up transmission access are required.

Hydro Tasmania submitted that the priority access model enables investors to determine the level of access for new assets based on conditions at the time of making their investment, and should result in a much lower cost of capital than under congestion fees or the status quo.

Response

Priority access reduces the access of new entrants only to the extent that they are seeking to connect in an area of the network that is already congested. Otherwise, priority access would reduce the new entrants' risk of being cannibalised by other generators connecting after them, reducing their cost of capital and improving their investment case. While this might increase the cost of debt (and/or overall viability) of a project planning to connect in a congested part of the NEM, this is the intended impact of the capital expenditure reforms: that generators bear the cost of increasing congestion, meaning that connecting in parts of the grid with limited spare access may no longer be viable.

Our analysis suggests that a priority access regime that allocates access to RRP on the basis of unique queue positions or priority tiers would reduce the risk of cannibalisation and therefore the uncertainty around the risk of future congestion.

The interactions between a priority access regime and the existing connection process were discussed in the Transmission Access Reform directions paper.[21] In particular, the paper considered the uncertainty for prospective new entrants that would arise if other projects that are speculative or at risk of not proceeding sought to be assigned a queue position as early as possible to secure higher priority access. The paper discusses potential solutions to this issue, including introducing qualifying criteria and 'use it or lose it' provisions to provide greater certainty that projects that receive a queue position are indeed highly likely to proceed and be committed in reasonably short timeframes. The paper also suggested that connection applicants could receive an indicative queue position in response to their connection application, which would then be finalised upon completion of the connection agreement. These provisions could help reduce uncertainty during the connection process.

As ACCIONA points out, the implementation of the CRM or CMM alongside either priority access or congestion fees would promote efficient dispatch outcomes. ACCIONA questions the current cost of capital impact of congestion risk and the need for reforms that firm up priority access. We note that:

- Even if the current impact of congestion on cost of capital were small (which would have to be demonstrated), congestion risk may become more significant in the future.
- The rationale for the reforms is not limited to cost of capital considerations. The reforms are intended to promote more efficient dispatch outcomes and investment decisions.

Hydro Tasmania's comments are in line with our conclusions regarding the directional impact of priority access relative to congestion fees.

[21] ESB (2022), Transmission Access Reform – directions paper, p. 85-89.

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